BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of the Application of Pacific Gas and Electric Company for Approval of its 2018-2020 Electric Program Investment Charge Investment Plan. (U39E).	Application 17-04-028
And Related Matters.	Application 17-05-003 Application 17-05-005 Application 17-05-009

COMPLIANCE FILING OF SAN DIEGO GAS & ELECTRIC COMPANY'S (U 902 E) 2017 ELECTRIC PROGRAM INVESTMENT CHARGE ANNUAL REPORT

Emma D. Salustro
Kirstie C. Raagas
8330 Century Park Court, CP32D
San Diego, CA 92123
Telephone: (858) 654-1861 (Salustro)
Telephone: (619) 699-5003 (Raagas)
Facsimile: (619) 699-5027
E-mail: ESalustro@semprautilities.com
E-mail: KRaagas@semprautilities.com

Attorneys for:
SAN DIEGO GAS & ELECTRIC COMPANY

February 28, 2018

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of the Application of Pacific Gas and Electric Company for Approval of its 2018-2020 Electric Program Investment Charge Investment Plan. (U39E).	Application 17-04-028
And Related Matters.	Application 17-05-003 Application 17-05-005 Application 17-05-009

COMPLIANCE FILING OF SAN DIEGO GAS & ELECTRIC COMPANY'S (U 902 E)
2017 ELECTRIC PROGRAM INVESTMENT CHARGE ANNUAL REPORT

Pursuant to Ordering Paragraph 16 of Decision (D.) 12-05-037 and in accordance with the Annual Report Outline provided in Attachment 5 of D.13-11-025, San Diego Gas & Electric Company (SDG&E) hereby submits its 2017 Annual Report for its Electric Program Investment Charge (EPIC) Program (Report), provided as Attachment A hereto. In addition, SDG&E provides the excel file titled "SDG&E 2017 EPIC Project Status Report" in accordance with D.13-11-025 as Attachment B,[1] and its EPIC Final Reports as Attachment C.[2] Together, these documents provide an overview of SDG&E's EPIC activities and program financial information during the 2017 calendar year.

[1] SDG&E, the California Energy Commission (CEC), Pacific Gas and Electric Company (PG&E), and Southern California Edison Company (SCE) (together, the EPIC Administrators) are required to provide with the annual report "electronically in spreadsheet format the information identified in Attachment 6 to report on projects described in Section 4.b of the EPIC annual report outline adopted by this decision." D.13-11-025 at 63. *Id*. at Attachment 5 and Attachment 6.

[2] The EPIC Administrators "must include with their [EPIC] annual report a final report on every project completed during the previous year." D.13-11-025 at 136, Ordering Paragraph 14. Due to size, Attachment C is being made available to all parties via Notice of Availability.

SDG&E and its fellow EPIC Administrators are required to each submit an annual report "detailing program activities."[3] The annual reports are designed "to facilitate consistent reporting by the [EPIC] Administrators on their investment plans and project results."[4] In accordance with D.12-05-037, SDG&E serves this Report on "all parties in the most recent EPIC proceeding, and all parties to the most recent general rate cases for [SDG&E, PG&E, and SCE], and each successful and unsuccessful applicant for an EPIC funding award" through December 31, 2017.[5]

Respectfully submitted,

/s/ Kirstie C. Raagas

Kirstie C. Raagas
Attorney for:
SAN DIEGO GAS & ELECTRIC COMPANY
8330 Century Park Court, CP32D
San Diego, CA 92123
Telephone: (619) 699-5003
Facsimile: (619) 699-5027
E-mail: kraagas@semprautilities.com

February 28, 2018

[3] D.12-05-037 at 8.
[4] D.13-11-025 at 4-5, 62.
[5] *Id*. at Ordering Paragraph 16.

ATTACHMENT A

SDG&E 2017 EPIC ANNUAL REPORT

San Diego Gas & Electric Company

2017 EPIC Annual Report

February 28, 2018



Table of Contents

I. EXECUTIVE SUMMARY 1

A. Overview of Programs/Plan Highlights 1

B. Status of EPIC-1 and EPIC-2 Projects 2

1. EPIC-1 Projects 4

2. EPIC-2 Projects 5

II. INTRODUCTION AND OVERVIEW 7

A. Background on the EPIC Program 7

B. EPIC Program Components 7

C. EPIC Program Regulatory Process 7

D. Coordination among EPIC Administrators 8

E. Transparent and Public Process 8

III. SDG&E'S EPIC BUDGET AND RELATED COSTS 9

A. SDG&E Authorized Budget and Incurred Costs for EPIC-1 (2012 – 2014) and EPIC-2 (2015 -2017) 9

B. Commitments/Encumbrances for TD&D Projects 10

C. Commitments/Encumbrances for Program Administration 11

D. Fund Shifting Above 5% between Program Areas 11

E. Uncommitted/Unencumbered Program Funds 11

IV. SDG&E EPIC-1 PROJECTS 11

Project 1: Smart Grid Architecture Demonstrations 11

Project 2: Visualization and Situational Awareness Demonstrations 14

Project 3: Distributed Control for Smart Grids 16

Project 4: Demonstration of Grid Support Functions of Distributed Energy Resources 19

Project 5: Smart Distribution Circuit Demonstrations 22

V. SDG&E EPIC-2 PROJECTS 25

Project 1: Modernization of Distribution System and Integration of Distributed Generation and Storage 25

Project 2: Data Analytics in Support of Advanced Planning and System Operations 27
Project 3: Monitoring, Communication, and Control Infrastructure for Power System Modernization 30
Project 4: System Operations Development and Advancement 33
Project 5: Integration of Customer Systems into Electric Utility Infrastructure 35
Project 6: Collaborative Programs in RD&D Consortia 38
VI. CONCLUSION 42
A. Key Results for 2017 for SDG&E EPIC Projects 42
B. Next Steps for SDG&E's EPIC Program 43

APPENDICES

Appendix 1 EPIC-1, Project 1: Smart Grid Architecture Demonstrations Program
Appendix 2 EPIC-1, Project 2: Visualization and Situational Awareness Demonstration
Appendix 3 EPIC-1, Project 3: Distributed Control for Smart Grids
Appendix 4 EPIC-1, Project 4, Module 1: Demonstration of Grid Support Functions of Distributed Energy Resources – Pre-Commercial Demonstration and Value Assessment
Appendix 5 EPIC-1, Project 4, Module 2: Demonstration of Grid Support Functions of Distributed Energy Resources – Pre-Commercial Demonstration of Communications Standards for DER
Appendix 6 EPIC-1, Project 4, Module 3: Demonstration of Grid Support Functions of Distributed Energy Resources – Pre-Commercial Demonstration of the EPRI DRIVE Tool
Appendix 7 EPIC-1, Project 5, Module 1: Smart Distribution Circuit Demonstrations – Demonstrations of Advanced Circuit Concepts and Devices
Appendix 8 EPIC-1, Project 5, Module 2: Smart Distribution Circuit Demonstrations – Pre-Commercial Demonstration of Methodologies and Tools for Energy Storage Integration into Smart Distribution Circuits
Appendix 9 EPIC-2, Project 1: Modernization of Distribution System and Integration of Distributed Generation and Storage
Appendix 10 EPIC-2, Project 2: Data Analytics in Support of Advanced Planning and System Operations
Appendix 11 EPIC-2, Project 3: Monitoring, Communication and Control Infrastructure for Power System Modernization
Appendix 12 EPIC-2, Project 4: System Operations Development and Advancement
Appendix 13 EPIC-2, Project 5: Integration of Customer Systems into Electric Utility Infrastructure

Appendix 14 EPIC-2, Project 6: Collaborative Programs in RD&D Consortia – Demonstration of Methodology and Tools for Estimating Propensity for Customer Adoption of Photovoltaics

Appendix 15 EPIC-2, Project 6, Module 2: Collaborative Programs in RD&D Consortia – Unmanned Aerial Systems Data Lifecycle Management and Deep Learning Demonstration

I. EXECUTIVE SUMMARY

Pursuant to Ordering Paragraph 16 of Decision (D.) 12-05-037 and in accordance with the Annual Report outline provided in Attachment 5 of D.13-11-025, San Diego Gas & Electric Company (SDG&E) hereby submits its 2017 EPIC Annual Report (Report). This Report provides an overview of SDG&E's EPIC activities during the 2017 calendar year. As required by D.13-11-025, SDG&E is providing additional information about SDG&E's EPIC activities in an excel file titled, "SDG&E 2017 EPIC Project Status Report" as Attachment B, and its EPIC Final Reports as Attachment C.[1]

SDG&E proposed and received approval for five projects that demonstrate smart grid system integration solutions in its first triennial application for years 2012-2014 (EPIC-1).[2] In addition, SDG&E proposed and received approval for six projects that demonstrate grid modernization and technology integration solutions in its second triennial application for years 2015-2017 (EPIC-2).[3] This Report summarizes SDG&E's progress and status for projects approved for both EPIC-1 and EPIC-2.

A. Overview of Programs/Plan Highlights

In A.12-11-002, SDG&E requested Commission approval of five programs that demonstrate smart grid system integration solutions. In November 2013, SDG&E's Application and First Triennial EPIC Plan was approved in full, with minor modifications, by the Commission in D.13-11-025. The total SDG&E budget for the first triennial cycle is $8,600k. Ten percent of this amount ($860k) is allotted to program administration. The remainder ($7,740k) is allotted to technical work in the Technology Demonstration and Deployment (TD&D) programs, which are limited to pre-commercial demonstrations.

In A.14-05-004, SDG&E requested Commission approval of its Second Triennial EPIC Plan which included five programs that have the potential to help modernize the electric grid to improve customer benefits, as well as a sixth project through which SDG&E will participate in industry RD&D consortia. In April 2015, SDG&E's Application and Second Triennial EPIC

[1] D.13-11-025 at 63 and 136.
[2] Application (A.) 12-11-002, which was approved by the California Public Utilities Commission (Commission) in D.13-11-025. SDG&E's Application (A.17-05-009) for its third triennial application for years 2018-2020 (EPIC-3) is still pending at the time of this filing.
[3] A.14-05-004, which was approved by D.15-04-020.

Plan was approved in full, with minor modifications, by the Commission in D.15-04-020. The total committed SDG&E budget for the second triennial cycle is $8,679k. Ten percent of the total authorized budget of $8,792 ($879k) is allotted to program administration. The remainder of the committed budget ($7,800) is allotted to technical work in TD&D programs, which are limited to pre-commercial demonstrations.

B. Status of EPIC-1 and EPIC-2 Projects

As discussed in further detail below, throughout 2017, SDG&E completed four of the five EPIC-1 projects. The final reports for the four completed projects are provided with this annual report (*see* Appendices 1 to 8). The unfinished project (EPIC-1, Project 2) was partially completed, and a final report for the completed part is delivered with this annual report (provided as Appendix 2). The remainder of this project will be performed in 2018, and a final report for that portion of the project will be provided upon completion.

In 2017, SDG&E continued the work on the six EPIC-2 projects and completed all six projects. The final reports for the six EPIC-2 projects are provided with this annual report (*see* Appendices 9 to 15).

SDG&E's updated portfolio for both EPIC-1 and EPIC-2 is provided in Table 1 below.

Table 1. SDG&E's EPIC-1 and EPIC-2 Portfolio as of December 31, 2017

EPIC-1 Projects (2012 – 2014)				
EPIC Project	**Incurred[4] Costs ($ thousands)**	**Encumbered[5] Costs ($ thousands)**	**Commitments[6] ($ thousands)**	**Project Status**
1. Smart Grid Architecture Demonstrations	1,402	1,406	1,406	Complete
2. Visualization and Situational Awareness Demonstrations	1,061	2,075	2,301	In Progress
3. Distributed Control for Smart Grids	1,386	1,392	1,392	Complete
4. Demonstration of Grid Support Functions of Distributed Energy Resources	1,095	1,200	1,200	Complete
5. Smart Distribution Circuits Demonstrations	1,433	1,441	1,441	Complete
6. SDG&E Program Administration	582	746	860	In Progress
Total	**$6,959**	**$8,260**	**$8,600**	

EPIC-2 Projects (2015 – 2017)				
EPIC Project	**Incurred Costs ($ thousands)**	**Encumbered Costs ($ thousands)**	**Commitments ($ thousands)**	**Project Status**
1. Modernization of Distribution System & Integration of Distributed Generation and Storage	1,971	2,009	2,009	Complete
2. Data Analytics in Support of Advanced Planning and System Operations	957	1,111	1,111	Complete
3. Monitoring, Communications, and Control Infrastructure for Power System Modernization	1,288	1,305	1,305	Complete
4. System Operations Development and Advancement	1,064	1,088	1,088	Complete
5. Integration of Customer Systems into Electric Utility Infrastructure	978	985	985	Complete
6. Collaborative Programs in RD&D Consortia	830	1,561	1,561	Complete
7. SDG&E Program Administration	372	510	620	In Progress
Total	**$7,460**	**$8,569**	**$8,679**	

[4] As used in this Report, incurred costs means actual booked expenditures.
[5] As used in this Report, encumbered costs are funds that are specified for contracts (D.13-11-025 at 101; Ordering Paragraph 45) or for in-house work necessary in collaboration with a contractor (D.13-11-025 at 53). They differ from commitments in that commitments are the identification of blocks of funds to be assigned to projects, whereas encumbrances specify how the commitments will be used in the projects.
[6] As used in this Report, commitment means assigned for anticipated work on a project, including anticipated contractual commitments, equipment purchases, software licenses, associated technical work by the SDG&E project team, and other expenses directly associated with the project work.

1. EPIC-1 Projects

Project 1: Smart Grid Architecture Demonstrations

All project activities were completed in 2017. IEC 61850 was identified as a principal component of the new architecture. A representative test system was constructed, and a total of eleven use cases were defined to demonstrate the use of IEC 61850 standards. The recommendation is that SDG&E plan for long-term migration to an architecture that incorporates IEC 61850 standards

Project 2: Visualization and Situational Awareness Demonstrations

In 2017, the project final report was completed. Funds were encumbered to continue work in 2018 on selected use cases, to gain additional value. With the solutions demonstrated in the project, the SDG&E project team has made significant improvements over the state-of-the-art approaches at SDG&E in each of the areas addressed by the eight use cases this project presented.

The project was presented at the following events: EPIC Symposium on February 2017 in Sacramento, Data Analytics Conference on September 2017 in San Diego, OSIsoft T&D User Group Meeting on September 2017 in New Orleans, and EPIC Fall Symposium in October 2017 in San Diego.

Project 3: Distributed Control for Smart Grids

In 2017, the project final report was completed. The project concluded with the final task, which involved conducting extensive tests on the system, beginning with factory acceptance testing and culminating with system acceptance testing, and a final pre-commercial demonstration of the operation and performance of the system at SDG&E's Integrated Test Facility (ITF). The results of those tests and the comparison between the different approaches were documented and used to formulate findings and conclusions.

The project was presented at the EPIC Symposium on February 2017 in Sacramento, and at the EPIC Fall Symposium in October 2017 in San Diego.

Project 4: Demonstration of Grid Support Functions of Distributed Energy Resources

This project's primary focus was on pre-commercial demonstrations to assess the value of distributed energy resources (DER) grid support functions in various alternative application situations. This project consists of three modules: value assessment of grid support functions of DER, communication standards for grid support functions of DER, and demonstration and comparison of the EPRI and SDG&E DER hosting capacity analysis tools. All three modules were completed in 2017 and comprehensive final reports (with project approach, results, findings, recommendations, metrics, and value proposition sections) were prepared for each of the modules individually. For Module 1 (which was a substantial part of this project), a prime contractor was selected by competitive procurement. Three bidders responded to the solicitation.

All bids passed the initial screening criterion of being responsive to the request for proposal, and they were all evaluated and scored in accordance with the evaluation criteria. Schweitzer Engineering Laboratories (SEL) was selected for the contract award. SEL was the highest scoring bidder. Modules 2 and 3 were smaller efforts for which the contractors were selected by sole source.

Project 5: Smart Distribution Circuit Demonstrations

The project concluded in 2017. The project was divided into 2 modules:

- Module 1: Demonstration of Advanced Circuit Concepts – SDG&E selected Schweitzer Engineering Laboratory (SEL) as the prime contractor for this module. The focus was to perform pilot demonstrations of smart distribution circuit features in a laboratory for a set of selected test circuits. Using simulations and hardware-in-the-loop (HIL) testing, the desired features and upgrades were tested in the selected circuits to assess their suitability for widespread adoption.
- Module 2: Pre-Commercial Demonstration of Methodologies and Tools for Energy Storage Integration into Smart Distribution Circuits – All project activities were completed in the year 2017. The test included identification, evaluation, selection, and demonstration of methodologies and tools for prospective use in planning future energy storage projects. Test results from the test system were documented and evaluated. Chosen tools, software programs and methodologies were recommended to stakeholders.

2. EPIC-2 Projects

Project 1: Modernization of Distribution System and Integration of Distributed Generation and Storage

The project focused on a pre-commercial demonstration of a substation communication network based on the IEC 61850 communication standards. Members of SDG&E's substations and protection sections were engaged in the project planning in both project team and project stakeholder (prospective user) roles. Intelligence was gathered on the status of the IEC standards and the vendor equipment options for the demonstration. A prime contractor was added to the project team. A test system was developed, and a pre-commercial demonstration performed for selected use cases. The demonstration showed clear advantages of IEC 61850 over legacy communication standards.

Project 2: Data Analytics in Support of Advanced Planning and System Operations
All project activities were completed in 2017. The pre-commercial demonstration included ingestion of several data sources into a data lake, test build of preliminary predictive models for major electric distribution asset management use cases, and visualization development using business intelligence tools to provide insight into the health of various assets on the utility distribution system. Based on the project findings, it is recommended that SDG&E and other utility stakeholders commercially adopt and implement advanced data analytics techniques for effective asset management.

Project 3: Monitoring, Communication, and Control Infrastructure for Power System Modernization

All project activities were completed in 2017. The project focus was on pre-commercial demonstration of an Open Field Messaging Bus (Open FMB) for interoperability, peer-to-peer communication, and multiple protocol conversion. A representative test system was constructed, and a total of thirteen use cases were defined to demonstrate the use of OpenFMB for monitoring and control. As a result of this demonstration, it is recommended that work be continued to further define the OpenFMB standard so that it can be successfully utilized in future utility distribution system projects and deployments.

Project 4: System Operations Development and Advancement

All project activities were completed in the year 2017. A PHIL (Power Hardware In the Loop) test system was developed to examine improvements of the distribution system containing modern system component by optimization, using the RAMCO (Regional Aggregation Monitoring and Circuit Optimizers) and LRAM (Local Resource Aggregation and Monitoring). Results from the test system were evaluated and concluded that, the system operated as intended and optimized the distribution system. The recommendation is that stakeholders pursue this system further and commercialize it.

Project 5: Integration of Customer Systems into Electric Utility Infrastructure

The primary objective of this project was to investigate and address the evolving gateway between customers and utilities to facilitate increase in reliable deployment of clean energy technologies to support distribution systems. All project activities were completed in 2017. The project focus was on performing pre-commercial demonstration of advanced monitoring schemes, root-cause analysis tools, and assessment methodologies for safe and reliable integration and interoperability of customer systems with the distribution system and thereby increasing ratepayer satisfaction and benefits.

Project 6: Collaborative Programs in RD&D Consortia

Project development on demonstrations through collaborative R&D consortia focused on two modules. All project activities were completed in 2017.

For the project module on forecasting customer adoption of photovoltaic (PV), the project team used machine learning to identify several important attributes driving adoption for disadvantaged communities (DAC) and other locations (non-DAC) at the zip code level. Owner occupancy emerged as a key attribute explaining the difference in PV market share. The percentage of owner occupied homes is 50% for DAC zip codes compared to 63% for non-DAC zip codes. It is recommended that SDG&E not commercially adopt these methods and tools at this juncture, without more foundational work being done first.

For the module on unmanned aerial systems (UAS) data lifecycle management and deep learning demonstration, the project demonstrated integration with existing and future SDG&E

infrastructure, software applications and legacy data sets with the ability to ingest, store, analyze and report on SDG&E assets derived from Geographic Information System (GIS), Power Line Systems – Computer Aided Draft and Design (PLS-CADD), unmanned aircraft system (UAS) collected data and other various sources. Three test cases were demonstrated including equipment identification, vegetation encroachment identification, and cataloging and remote asset management. It is recommended that SDG&E pursue additional evaluation of UAS technology for stakeholder groups within the company that will benefit from the aggregation of various sources of data into a data management platform that also provides advanced analytical capabilities.

II. INTRODUCTION AND OVERVIEW

A. Background on the EPIC Program

The EPIC program was established by the Commission in D.11-12-035 to provide public interest investments in applied research and development, technology demonstration and deployment, market support, and market facilitation of clean energy technologies and approaches for the benefit of ratepayers of California investor-owned utilities (IOUs). D.12-05-037 established the purposes and governance structure for the EPIC program and D.13-11-025 clarified many of the program's regulatory requirements.

The EPIC program is designed to provide funding for electric utility research, development, and demonstration (RD&D). Specific funding allotments are made to four EPIC program administrators, including SDG&E.[7] The EPIC program is intended to run until 2020 and is comprised of three triennial program cycles (*i.e.*, EPIC-1, EPIC-2, EPIC-3).

B. EPIC Program Components

The IOUs, including SDG&E, may only administer EPIC projects in the area of pre-commercial technology demonstration and deployment (TD&D). Post-commercial demonstrations and deployments are not allowed. Utility participation in the early stages of the research and development process, *i.e.*, basic research and applied research for new utility-related technology, is also not allowed.

C. EPIC Program Regulatory Process

Pursuant to D.12-05-037, SDG&E was required to submit an application seeking Commission approval of an EPIC plan every three years. SDG&E submitted its First Triennial

[7] The EPIC administrators are the California Energy Commission (CEC), SDG&E, Southern California Edison Company (SCE) and Pacific Gas and Electric Company (PG&E).

EPIC Plan for years 2012-2014 (A.12-11-002) on November 1, 2012 (EPIC-1) and received full Commission approval of its EPIC-1 Plan in D.13-11-025. No hearings were held. SDG&E submitted its Second Triennial EPIC Plan for years 2015-2017 (A.14-05-004) on May 1, 2014 (EPIC-2) and received Commission approval of its EPIC-2 Plan in D.15-04-020. No hearings were held. SDG&E submitted its Third Triennial EPIC Plan for years 2018-2020 (A.17-05-009) on May 1, 2017 (EPIC-3). As of the date of this Report, SDG&E is awaiting a decision from the Commission on its EPIC-3 Application.

In accordance with Ordering Paragraph 16 of D.12-05-037 and consistent with the Annual Report outline provided in Attachment 5 of D.13-11-025, SDG&E and the other EPIC Administrators are required to submit an annual report annually on February 28, 2013 through February 28, 2020. This is the sixth annual report submitted by SDG&E for its EPIC program.

D. Coordination among EPIC Administrators

The four EPIC Administrators have regular teleconferences and face-to-face meetings as needed to coordinate EPIC activities.

E. Transparent and Public Process

SDG&E is committed to conducting competitive procurements for those parts of the project work that require contracted services or major purchases of equipment or software. Development and issuance of request for proposals (RFPs) for two EPIC-1 projects were initiated in late 2014 and for a third EPIC-1 project in 2015. Competitive procurements for four additional EPIC projects were initiated in 2016 (including one for an EPIC-1 project and three for EPIC-2 projects). One informal competitive procurement was performed for an EPIC-2 project in 2017.

SDG&E and the other EPIC Administrators are required to host at least two stakeholder meetings annually to discuss their EPIC programs, proposals, and progress.[8] On January 30, 2017, SDG&E hosted a one-day workshop with EPRI and the other EPIC Administrators, the purpose of which was to conduct a gaps analysis on the proposed content of the Administrators' EPIC plans to assure the projects were filing key gaps in RD&D in a global context. In addition, SDG&E, together with the IOU Administrators, hosted two EPIC public stakeholder workshops

[8] D.12-05-037 at 74.

(March 9, 2017 and March 24, 2017), where the planning and coordination process was summarized, and the IOU Administrators presented examples of projects under consideration for their respective EPIC-3 Applications. SDG&E also participated in the EPIC Fall Symposium (October 18, 2017).

SDG&E established and maintains an EPIC website accessible to the public: https://www.sdge.com/epic. This website provides EPIC program information and updates, as well as SDG&E's EPIC annual reports and EPIC projects' final reports.

III. SDG&E'S EPIC BUDGET AND RELATED COSTS

A. SDG&E Authorized Budget and Incurred Costs for EPIC-1 (2012 – 2014) and EPIC-2 (2015 -2017)

Table 2 below, sets forth SDG&E's Commission-authorized EPIC budget incurred costs for EPIC-1 and EPIC-2 as of December 31, 2017.

Table 2. SDG&E Budget and Incurred Costs for EPIC-1 and EPIC-2 as of December 31, 2017 (in $ thousands)

	EPIC Triennial 1 (2012 – 2014)		EPIC Triennial 2 (2015 – 2017)	
	Technology Demonstration & Deployment	**Program Administrative**	**Technology Demonstration & Deployment**	**Program Administrative**
SDG&E Commission-Authorized Budget[9]	7,740	860	7,800	879
SDG&E Incurred Costs[10] as of December 31, 2017	6,376	582	7,088	372

Table 3 below, sets forth SDG&E's disbursements to the CEC and Commission for EPIC-1 and EPIC-2 as of December 31, 2017.

[9] D.13-11-025 for EPIC-1 and D.15-04-020 for EPIC-2.
[10] Incurred costs mean actual booked expenditures.

Table 3. SDG&E's Disbursements to the CEC and Commission for EPIC-1 and EPIC-2 as of December 31, 2017 (in $ thousands)

	EPIC Triennial 1 (2012 – 2014)		EPIC Triennial 2 (2015 – 2017)	
	Technology Demonstration & Deployment	**Program Administrative**	**Technology Demonstration & Deployment**	**Program Administrative**
SDG&E Disbursements to CEC	16,127	3,024	30,674	2,991
SDG&E Disbursements to Commission for Regulatory Oversight	N/A	273	N/A	224

B. Commitments/Encumbrances[11,12] for TD&D Projects

SDG&E has committed $7,740k of its TD&D budget for the EPIC-1 cycle to the five projects in its approved First Triennial Plan. As of December 31, 2017, SDG&E has encumbered $7,514k of EPIC-1 funds for contracted activities and in-house work in collaboration with a contractor. As of December 31, 2017, SDG&E has expended $5,698k on contracted work. SDG&E has spent $678k on internal project work. The total expenditures through December 31, 2017 on EPIC-1 TD&D project work is therefore $6,377k. Further detail is provided in Attachment B.

SDG&E has committed $8,059k of its EPIC-2 TD&D budget to the six projects in its approved EPIC-2 plan. This constitutes full commitment of the ***approved*** EPIC-2 TD&D funds. As of December 31, 2017, SDG&E has encumbered $8,059k of EPIC-2 funds for contracted

[11] Commitment means assigned for anticipated work on a project, including anticipated contractual commitments, equipment purchases, software licenses, associated technical work by the SDG&E project team, and other expenses directly associated with the project work.

[12] Encumbrances are funds that are specified for contracts (D.13-11-025 at 101; Ordering Paragraph 45) or for in-house work necessary in collaboration with a contractor (D.13-11-025 at 53). They differ from commitments in that commitments are the identification of blocks of funds to be assigned to projects, whereas encumbrances specify how the commitments will be used in the projects.

activities and in-house work in collaboration with a contractor. As of December 31, 2017, SDG&E has expended $6,649k on contracted work. SDG&E has spent $438k on internal project work. The total expenditures through December 31, 2017 on EPIC-2 TD&D project work is therefore $7,088k. Further detail is provided in Appendix A.

C. Commitments/Encumbrances for Program Administration

As of December 31, 2017, SDG&E has made the following commitments for its program administration budgets: $860k for EPIC-1 and $620k for EPIC-2. SDG&E has spent a cumulative $954k for overall program administration expenses through 2017, which includes both EPIC-1 and EPIC-2 costs. Of this amount, $582k is attributed to EPIC-1 and $372k is attributed to EPIC-2.

D. Fund Shifting Above 5% between Program Areas

SDG&E has done no fund shifting to date.

E. Uncommitted/Unencumbered Program Funds

SDG&E does not have any ***approved*** program TD&D funds that are uncommitted as of December 31, 2017. However, there is a small difference ($68.6k) between the $7,868.6k that was authorized for EPIC-2 and the $7,800k that is committed for TD&D. The difference exists because SDG&E did not propose to invest this amount in SDG&E's Application for EPIC-2. Therefore, SDG&E's approved budget in D.15-04-020 reflects the amount proposed in its EPIC-2 Application. Should SDG&E decide to commit the $68.6k (which is currently uncommitted/unencumbered), the Commission in D.15-04-020 advised SDG&E that they may submit a subsequent regulatory filing seeking approval to invest these funds.[13]

IV. SDG&E EPIC-1 PROJECTS

The following is a high-level summary and status report of EPIC-1 projects.

Project 1: Smart Grid Architecture Demonstrations

i. Investment Plan Period
2012-2014 (EPIC-1)

[13] D.15-04-020 at 34-35.

ii. Assignment to Value Chain
Distribution

iii. Objective
The specific objectives of the project were to: perform pilot demonstration of key candidate prototype building blocks of the SDG&E smart grid architecture to determine their suitability for adoption in the architecture; document the results and make recommendations of whether specific building blocks should be adopted; and, provide demonstration results to the SDG&E interdepartmental smart grid architecture team to support the implementation phase for any building blocks adopted.

iv. Scope
The distribution system architecture building blocks were created after reviewing the existing architecture, identifying next generation architecture principles, and evaluating standards and protocols for the various architectural constructs. IEC 61850 was identified as the priority building block for demonstration. A test plan was written, and testing undertaken at SDG&E's ITF. The pre-commercial demonstration for IEC 61850 included modeling and simulation of a distribution substation and two feeders that included multiple Intelligent Electronic Devices (IED) and distributed energy resources (DERs) on the circuits. Additional demonstrations also included the comparison using IEC 61850 as a communication path and Open Field Message Bus (OpenFMB) as an alternative communication path to communicate between a simulated control center and devices in the modeled substation and distribution feeders. An analysis was performed, and recommendations were made relative to adoption of IEC 61850.

v. Deliverables
A comprehensive final report was developed describing the work and results of the project.

vi. Metrics
The following metrics were identified for this project and evaluated during the pre-commercial demonstration. These metrics are not exhaustive given the pre-commercial demonstration approach for this project.

- Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy
    - Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (P.U. Code § 8360) – Use of configuration inheritance and descriptive data point naming supported by IEC 61850 makes the task of configuring devices in substation and feeders considerably easier when contrasted to the conventional approach. Digitization of devices using IEC 61850 can potentially lower the barriers of adoption of newer technologies within the electric infrastructure.

    - Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (P.U. Code § 8360) – The industry has many standards that exist among several standards development organizations that may be applicable to multiple layers of the power systems architecture. A key standard is the IEC 61850 protocol suite. The extent of harmonization efforts that have included IEC 61850 show that the suite has the potential of becoming a key building block in the future smart grid architecture that enable effective communication and interoperability of equipment connected to the electric grid.
- Safety, Power Quality, and Reliability (Equipment, Electricity System) – The use of IEC 61850 in the field could enable interoperability, improve protection coordination and provide effective information sharing between field devices and backend systems. The following sub-factors could be enhanced with the use of IEC 61850:
    - Increase in the number if nodes in the power system at monitoring points
    - Reduction in outage numbers, frequency, and duration.
    - Reduction in system harmonics

vii. Schedule
February 10, 2016 to December 31, 2017

viii. EPIC Funds Encumbered as of December 31, 2017
$1,406k

ix. EPIC Funds Spent as of December 31, 2017
$1,402k

x. Partners (if applicable)
n/a

xi. Match Funding (if applicable)
n/a

xii. Match Funding Split (if applicable)
n/a

xiii. Funding Mechanism (if applicable)
A combination of in-house work and pay-for-performance contracts was used. A Request for Proposal (RFP) was released in third quarter of 2016, with contractor selection completed in 2017.

xiv. Treatment of Intellectual Property (if applicable)
No IP developed.

xv. Status Update

Project activities completed in 2017.

- The project was implemented in four phases:
  - Phase 1 – SDG&E Internal Project Work Prior to contractor procurement
  - Phase 2 – Architecture Baseline and Development
  - Phase 3 – Pre-Commercial Demonstration of IEC 61850
  - Phase 4 – SDG&E Internal Project Work prior to project conclusion
- As part of architecture development in Phase 2, Smart Grid Architecture Model (SGAM) framework was identified as best suited to document the current and proposed architecture necessary to adapt to the changing demands on the system. IEC 61850 is a principal component of the platform that warranted further investigation in the third phase of the project.
- In the third phase, a representative test system was constructed, and a total of eleven use cases were defined to demonstrate the use of IEC 61850 standards. The uses cases included tests of the ability of IEC 61850 to integrate substation and feeder devices and perform some of the advanced communications and automation necessary to optimize the use of DER and other IEDs. Other tests were defined to examine the process and organizational impact of utilizing IEC 61850, while others were used to compare IEC 61850 with other protocols, such as DNP 3.0 and OpenFMB. The demonstration showed that IEC 61850 has some unique abilities that offered tangible benefits over current approaches.
- The various use cases documented in the final report (in Phase 4) comprehensively demonstrate that IEC 61850 is a robust standards platform that offers numerous advantages over conventional approaches. The recommendation is that SDG&E plan for long-term migration to an architecture that incorporates IEC 61850 standards.

Project 2: Visualization and Situational Awareness Demonstrations

i. Investment Plan Period

2012-2014 (EPIC-1)

ii. Assignment to Value Chain

Distribution

iii. Objective

The objective of this demonstration project is to explore how data collected from sensors and devices can be processed, combined, and presented to system operators in a way that enhances grid monitoring and situational awareness. This project will look at how data currently unexploited and separately processed can be integrated and visually presented for strategic use by system operators. When transformed and presented in a visually integrated manner, this data can be invaluable for utilities to optimize grid operations as well as provide insights in the performance of the overall utility system. This visual framework also provides

insights into customers' energy consumption behavior to serve them more effectively, foster energy conservation, and reduce peak demand. The demonstration of specific visualization and situational awareness concepts will be used to help SDG&E make choices on which options should be adopted into a future visualization and situational awareness system.

iv. Scope

The work will include requirements definition for the visualization and situational awareness based on where data could yield significant value, prototyping the data integration schemes, displays and algorithms, and implementing a testing plan. A roadmap will be developed for integrating project results deemed suitable for commercial adoption into SDG&E's power system.

The following eight use cases, addressing a wide range of SDG&E business needs within the smart grid visualization area, were selected for the project: (1) Transmission Fault Location Visualization, (2) Load Curtailment Visualization, (3) Automation of Quarterly Electric Utility Reports, (4) Visualization of Outage History Playback, (5) AMI for Operations Visualization, (6) Customer-owned DER Visualization, (7) Imagery Management, and (8) GIS Visualization infrastructure modernization.

v. Deliverables

A comprehensive final project report describing the work and results of the project.

vi. Metrics

The project tracking metrics will be the milestones in the project plan. Technical project metrics will include the completion of the initial specification for a visualization and situational awareness system, the demonstration of a system display mock-up, and the specifications and recommendations regarding adoption by SDG&E.

Also, major project results will be submitted in technical papers and presentations for consideration by major technical conferences and publications.

The following metrics were identified for this project and further explained in the final report:

- Safety, Power Quality, and Reliability (Equipment, Electricity System).
- Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy.
- Adoption of EPIC technology, strategy, and research data/results by others.

vii. Schedule

February 10, 2016 to August 31, 2018

viii. EPIC Funds Encumbered as of December 31, 2017
$2,075k

ix. EPIC Funds Spent as of December 31, 2017
$1,061k

x. Partners (if applicable)
n/a

xi. Match Funding (if applicable)
n/a

xii. Match Funding Split (if applicable)
n/a

xiii. Funding Mechanism (if applicable)
SDG&E EPIC funding used for work performed by the internal SDG&E project team.

xiv. Treatment of Intellectual Property (if applicable)
No IP developed.

xv. Status Update
Major project activities completed in 2017. Based on the feedback from early users of the project results – which has been uniformly positive – this project has successfully achieved all its key objectives. Through the performed work, SDG&E has demonstrated novel solutions to the selected use cases, and, in the process, has also gained reusable software artifacts and substantial experience in integrating GIS, historical, asset management, and other major SDG&E computer systems. Both aspects will provide usability well beyond the direct utility of the software components produced by the project.

The project committed additional funds by the end of 2017 to perform additional work on selected use cases to give them greater value and further development.

Project 3: Distributed Control for Smart Grids

i. Investment Plan Period
2012-2014 (EPIC-1)

ii. Assignment to Value Chain
Distribution

iii. Objective
The objective of this project was to test alternatives for communication and control across distribution system resources to ensure that devices operate in a complementary manner and ensure optimum distribution system performance,

reliability, and stability. The project tested distributed control methods and approaches to control distribution circuit resources and integrate them as part of a unified control scheme with other higher-level control systems, such as the distribution management system (DMS). The project assessed the scalability and performance of alternative control schemes.

iv. Scope

Phase 1 – Design and Development of Technical Solution: This phase will include requirements definition for the distributed control concepts to be demonstrated. The requirements definition will consider the functions, specifications, control interface, control algorithms, data models, data exchange, and security requirements for using distributed (less centralized) control in future electric utility power distribution systems. It will build on existing infrastructure in the SDG&E system.

Phase 2 – System Installation and laboratory testing at SDG&E's Integrated Test Facility (ITF): This phase will involve the installation of the test system, modeling and verification of RTDS circuit models, integration of hardware, development of control and operational schemes, development of the test plan for evaluation of the proposed distributed control concepts, and the execution of the test plan.

Phase 3 – Data Collection and Analysis for the Pre-Commercial Demonstration: This phase will include detailed analysis of the data collected, including functions of the proposed system, control methodologies of the system (including updates to existing strategies), results of testing and effect on the existing SDG&E control system, benefits, costs, challenges, and impact on the overall SDG&E distribution system and equipment, particularly with respect to operational situations.

v. Deliverables

A comprehensive final project report was developed describing the work and results of the project.

vi. Metrics

The project tracking metrics will be the milestones in the project plan. Technical metrics for this project will be based on comparing the performance of distribution system operations when various new control schemes are in place with the performance of the same operations when the control schemes are not in place. These performance metrics will include measures of power quality, electrical loss reductions, asset health maintenance, and adaptability to new device types in the distribution system.

Also, major project results will be submitted as technical papers and presentations for consideration by major technical conferences and publications.

The following metrics were identified for this project and further explained in the final report:

- Economic Benefits.
- Safety, Power Quality, and Reliability (Equipment, Electricity System).
- Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy.
- Effectiveness of information dissemination.
- Adoption of EPIC technology, strategy, and research data/results by others.

vii. Schedule
January 12, 2015 to December 31, 2017

viii. EPIC Funds Encumbered as of December 31, 2017
$1,392k

ix. EPIC Funds Spent as of December 31, 2017
$1,386k

x. Partners (if applicable)
n/a

xi. Match Funding (if applicable)
n/a

xii. Match Funding Split (if applicable)
n/a

xiii. Funding Mechanism (if applicable)
SDG&E EPIC funds were applied to a combination of in-house work and a pay-for-performance contract. A prime contractor was selected by competitive procurement in the second quarter of 2016. Five bidders responded to the solicitation. All bids passed the initial screening criterion of being responsive the request for proposal, and they were all evaluated and scored in accordance with the evaluation criteria. Quanta Technology, LLC was selected for the contract award. Quanta was the highest scoring bidder.

xiv. Treatment of Intellectual Property (if applicable)
No IP developed.

xv. Status Update

2017 saw the completion of the project. The results provided quantifiable evidence that the distributed control of system resources could achieve benefits when compared to a conventional approach. Major benefits identified included:

- Increase the utilization and contribution of DERs

- Reduce and even prevent unintentional reverse power flow
- Produce a flatter voltage profile over the length of a circuit
- Bring voltage profiles back inside the permissible range after a system event
- Reduce system electrical losses
- Improve the power factor of a circuit
- Reduce the number of operations of controllable assets like capacitor banks, voltage regulators and load tap changers
- Dynamically adjust protection settings to increase system reliability

The tests demonstrated that the greatest benefits were obtained when the control system was able to coordinate the control of two adjacent substations and when the regionally-based master controller was controlling the system, because it provided more possibilities for system optimization.

Additional tests demonstrated that a purely substation-based control scheme was still able to provide benefit, although not to the same extent as when the master controller was present, due to the inability to coordinate and therefore optimize between the two substations.

The demonstrated benefits of the distributed control approach in the areas of DER integration, improved grid stability, reliability and power quality and better utilization of controllable assets certainly warrants additional research, as well as inclusion into the technology roadmap of any utility facing an expansion in DER and IED devices on the distribution system.

Project 4: Demonstration of Grid Support Functions of Distributed Energy Resources

i. Investment Plan Period
2012-2014 (EPIC-1)

ii. Assignment to Value Chain
Distribution

iii. Objective
The objective of EPIC-1, Project 4, Demonstration of Grid Support Functions of Distributed Energy Resources (DER) was to demonstrate grid support functions of DER, which can improve distribution system operations. In other words, the objective was to assess the viability of using DER to provide non-traditional functions, such as volt/VAr optimization, fast-response peaking or emergency power, peak shaving, and distribution system status information. The chosen sub-projects and modules quantified the value of specific grid support functions in specific application situations and provided a basis for SDG&E to determine which functions it wants to pursue commercially in the development of its smart grid. This project consisted of three modules: value assessment of grid support functions of DER, communication standards for grid support functions of DER, and

demonstration and comparison of the EPRI and SDG&E DER hosting capacity analysis tools.

iv. Scope

As previously mentioned, this project was broken into three modules: value assessment of grid support functions of DER, communication standards for grid support functions of DER, and demonstration and comparison of the EPRI and SDG&E DER hosting capacity analysis tools. The scope of each module is described individually below:

Module 1: This module addresses value assessment of grid support functions of DER, to demonstrate and determine the viability of specific DER functions and to identify which, if any, grid support functions of DER and application situations (use cases) should be pursued in advanced distribution system automation.

Module 2: This module addresses pre-commercial demonstration of communication standards for grid support functions of DER. Furthermore, it investigates how the choice of communication standards may affect functionality of DER in the distribution systems.

Module 3: This module addresses pre-commercial demonstration of EPRI's Distribution Resource Integration and Value Estimation (DRIVE) tool. Moreover, it compares SDG&E's Iterative Integration Capacity Analysis (ICA) tool with DRIVE tool and defines the pros and cons of each method. A set of recommendations was made for enhancement of hosting capacity estimation techniques at SDG&E.

v. Deliverables

The key deliverable for each module of this project was a comprehensive final report on the procedure, findings, and results. A section on conclusions and recommendations, and a separate section on metrics and value proposition completed each report. Collectively, these module final reports provide:

- Descriptions of DER functions demonstrated, application situations, testing performed, and test and analysis results.
- Recommendations regarding DER functions (or communication standard or hosting capacity tool) which should be pursued commercially and adopted by SDG&E.
- Recommendations for technology transfer of knowledge gained (on function viability and interoperability system requirements to support functions) into commercial practice and/or to standards working groups, as may be appropriate.
- Recommendations for integration systems to encourage "plug and play" capabilities in the inverters (power conditioning systems) and other integration components.
- Analysis of the metrics and value proposition.

vi. Metrics
Technical metrics for the pre-commercial demonstration were determined during the demonstration planning phase.

One measure of success for Module 1 of this project was whether it provided a basis for deciding which DER functions warrant commercial pursuit in future distribution system development. Metrics for this module also included the identification of suitable interoperability requirements, interconnection systems, and communication protocols that support the functions.

In Module 2, the metrics included a determination of which communication standards are preferred to support the adoption of viable grid support functions.

In Module 3 of this project, the metrics addressed the pros and cons of the SDG&E hosting capacity tool in comparison with the EPRI DRIVE DER hosting capacity tool.

vii. Schedule
April 1, 2014 to December 31, 2017

viii. EPIC Funds Encumbered as of December 31, 2017
$1,200K

ix. EPIC Funds Spent as of December 31, 2017
$1,095K

x. Partners (if applicable)
n/a

xi. Match Funding (if applicable)
n/a

xii. Match Funding Split (if applicable)
n/a

xiii. Funding Mechanism (if applicable)
EPIC funding of an internal SDG&E project team working with a pay-for-performance prime contractor. For Module 1 (which was a substantial part of this project), a prime contractor was selected by competitive procurement. Three bidders responded to the solicitation. All bids passed the initial screening criterion of being responsive to the request for proposal, and they were all evaluated and scored in accordance with the evaluation criteria. Schweitzer Engineering Laboratories (SEL) was selected for the contract award. SEL was the highest scoring bidder. Modules 2 and 3 were smaller efforts for which the contractors were selected by sole source.

xiv. Treatment of Intellectual Property (if applicable)
No IP developed.

xv. Status Update
The three modules of this project were successfully accomplished with collaboration of the SDG&E internal team and the contractors' team. Final reports were completed individually for each module. They were carefully reviewed by the internal stakeholders, the SDG&E internal team, and the contractors' team.

Project 5: Smart Distribution Circuit Demonstrations

i. Investment Plan Period
2012-2014 (EPIC-1)

ii. Assignment to Value Chain
Distribution

iii. Objective
The objective of this project was to perform pilot demonstrations of smart distribution circuit features and associated simulation work to identify best practices for integrating new and existing distribution equipment in these circuits. Simulations took advantage of hardware-in-loop testing with a real-time digital simulator currently available at SDG&E. Using simulations to optimize one particular circuit, desired features were tested in that circuit to assess their suitability for widespread commercial adoption.

iv. Scope
The project included laboratory testing of alternative distribution circuit components and designs, and it included detailed examination of evaluation tools for integration of energy storage. Tests were staged, and data was taken. Data analysis was performed, and recommendations were made on best practices for robust distribution circuit practices in the future.

The project was broken into two modules:

- Module 1: Demonstration of Advanced Circuit Concepts: The focus of this module was to perform pilot demonstrations of smart distribution circuit features in a laboratory for a set of selected test circuits. Using simulations and hardware-in-the-loop (HIL) testing, the desired features and upgrades were tested in the selected circuits to assess their suitability for widespread adoption.
- Module 2: Pre-Commercial Demonstration of Methodologies and Tools for Energy Storage Integration into Smart Distribution Circuit: The chosen focus of this specific project module was on pre-commercial demonstration of methodologies and tools for energy storage integration into smart distribution circuits. The work included identification, evaluation, selection and

demonstration of methodologies and tools for prospective use in planning future energy storage projects.

v. Deliverables

Comprehensive final project reports were developed for both modules describing the work and results.

vi. Metrics

The project tracking metrics included the milestones in the project plan. Technical metrics were developed to guide the actual demonstration work. In general, the ultimate measure of success was having a benchmark future distribution circuit design concept that helps advance future distribution system development. The circuit design can assimilate a wide variety of existing and emerging device types and has a protection system that allows this assimilation to be done without compromising reliability or safety.

The following metrics were identified for Module 1 and further explained in the final report:

- Economic Benefits.
- Safety, Power Quality, and Reliability (Equipment, Electricity System).
- Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy.
- Effectiveness of information dissemination.
- Adoption of EPIC technology, strategy, and research data/results by others.

The following metrics were identified for Module 2 and further explained in the final report.

- **Potential energy and cost savings**
  - Avoided procurement and generation costs
  - Nameplate capacity (MW) of grid-connected energy storage – use methodology and tools to target ESS size for each application
- **Economic benefits**
  - Maintain/reduce capital costs (by proper sizing and increase in utilization factor)
  - Non-energy economic benefits
- **Safety, Power Quality, and Reliability (Equipment, Electricity System)**
  - Outage number, frequency and duration reductions
  - Electric system power flow congestion reduction
  - Forecast accuracy improvement
  - Public safety improvement and hazard exposure reduction
  - Reduced flicker and other power quality differences

- **Effectiveness of information dissemination**
  - A technology transfer plan was presented in the final report.

vii. Schedule
July 7, 2014 to December 31, 2017

viii. EPIC Funds Encumbered as of December 31, 2017
$1,441k

ix. EPIC Funds Spent as of December 31, 2017
$1,433k

x. Partners (if applicable)
n/a

xi. Match Funding (if applicable)
n/a

xii. Match Funding Split (if applicable)
n/a

xiii. Funding Mechanism (if applicable)
For both Module 1 and Module 2, SDG&E EPIC funds were applied to support a team of internal technical staff and pay-for-performance contractors. The contractors were selected as per SDG&E procurement policy.

xiv. Treatment of Intellectual Property (if applicable)
No IP developed.

xv. Status Update
The project was concluded in 2017. As previously mentioned, the project was broken into two modules:

- Module 1: Demonstration of Advanced Circuit Concepts: Developed with the assistance of Schweitzer Engineering Laboratories, Inc. This module was developed in 3 phases:
  - Phase 1 of the project covered the evaluation and documentation of products and technologies currently available for improved distribution circuit design, system operation, and protection.
  - Phase 2 of the project included selection and modeling of three diverse SDG&E distribution circuits viz., coastal-residential, urban, and desert-rural in a modeled environment for demonstration of advanced circuit concepts. The observations and results captured were analyzed and the findings from stand-alone device testing provided inputs on how to modify the existing circuits for improved reliability and performance.

- Phase 3 of the project included findings and recommendations from the demonstration in Phase 2. The recommended system architecture for commercial implementation of voltage support coordination scheme is provided.

- Module 2: Pre-Commercial Demonstration of Methodologies and Tools for Energy Storage Integration into Smart Distribution Circuits: All project activities were completed in the year 2017. The project team held working sessions to define the use cases and technical details. Simulation systems, different tools and methodologies were selected to be evaluated based on input from project stakeholders. The pre-commercial demonstration was carried out at SDG&E's ITF and/or at the contractor's site. A comprehensive final report was developed, including the pre-commercial demonstration approach, test result analysis, findings, recommendations, metrics, value proposition and conclusions.

V. SDG&E EPIC-2 PROJECTS

The following is a high-level summary and status report of EPIC-2 projects.

Project 1: Modernization of Distribution System and Integration of Distributed Generation and Storage

i. Investment Plan Period
2015-2017 (EPIC-2)

ii. Assignment to Value Chain
Distribution

iii. Objective
The objective of this project was to demonstrate distribution system infrastructure modernization solutions, including advances in distribution system design to enable use of new technologies, such as power electronic components, new protection systems, distributed generation and alternative storage technologies. The work built on the current state of the art for these devices and any track record that was available from the industry.

iv. Scope
This project has been focused on the pre-commercial demonstration of the international standard, IEC 61850, in a substation network. Investigating the application and usefulness of IEC 61850 will help SDG&E to assess the benefits and challenges of implementing this standard in substations. This pre-commercial demonstration will also investigate the interoperability of multiple vendor products.

This project will create knowledge to help SDG&E assess whether IEC 61850 should be adopted commercially and what the adoption requirements and processes would be. The knowledge may help other utilities with similar decision processes.

v. Deliverables
A comprehensive final report on the work and results of the project.

vi. Metrics
The following metrics were identified for this project. Given the proof of concept nature of this EPIC project, these metrics are forward looking to prospective adoption of IEC 61850 standards.

The main protection concerns that were identified in this project were speed and reliability. The following metrics address these concerns.

- Potential energy and cost savings:
  Due to reduced engineering efforts in the design process using IEC 61850 equipment, cost savings flow through to ratepayers. The integrated engineering tools make it easier to design the substation and test the equipment before deployment, which is hard to achieve now and is more time consuming with current legacy systems.

- Economic benefits:
  - Maintain/reduce operation and maintenance costs:
    - IEC 61850 digital equipment allows easier maintenance and debugging of the equipment using advanced embedded software tools.
    - The labor costs associated with the process bus implementation are reduced significantly. This is primarily due to the reduction in wiring.
  - Improvements in system operation efficiency and adding automation features:
    - Operation efficiency can be improved using IEC 61850 equipment especially with the new peer-to-peer communication feature, which allows major improvements of operations. More equipment can be monitored and operated to reduce the causes of outages and improve the reliability. Peer-to-peer communication also allows increased functional capabilities in the protection scheme.

vii. Schedule
January 4, 2016 to December 31, 2017

viii. EPIC Funds Encumbered as of December 31, 2017
$2,009k

ix. EPIC Funds Spent as of December 31, 2017
$1,971k

x. Partners (if applicable)
n/a

xi. Match Funding (if applicable)
n/a

xii. Match Funding Split (if applicable)
n/a

xiii. Funding Mechanism (if applicable)
A combination of in-house work and a pay-per-performance contract were used.

xiv. Treatment of Intellectual Property (if applicable)
No IP developed.

xv. Status Update
The project was completed in 2017. Stakeholders from SDG&E's substations and protection sections worked with the internal project team and contractor to plan and review the task work in this project. Options for performing the demonstration were explored, including at an actual substation or in a laboratory. Due to cost and risk considerations, it was decided to perform the demonstration in a laboratory using a substation mock-up. Intelligence was gathered on the status of the IEC standards and the vendor equipment options for the demonstration.

The project team finished a successful laboratory demonstration for several substation-protection use cases. A key recommendation coming from the project was for SDG&E to further explore commercial adoption of IEC 61850. Internal stakeholders are doing so.

Other technology transfer activities have included presentations at various conferences. Included were a presentation at the IEC 61850 Europe 2017 Conference in September 2017 and acceptance for presentation at DistribuTECH 2018 (presented in January 2018). The project was also presented at EPIC Symposiums on December 1, 2016 in Sacramento and on October 18, 2017 in San Diego.

Project 2: Data Analytics in Support of Advanced Planning and System Operations

i. Investment Plan Period
2015-2017 (EPIC-2)

ii. Assignment to Value Chain
Distribution

iii. Objective

This project was designed to address the anticipated "data tsunami" associated with more widespread system monitoring and more widespread use of controllable devices in the power system. It helped to create better data management. It also demonstrated solutions for the data management issues and challenges expected to accompany the extensive amount of real-time and stored data being archived from field devices and identify the data mining procedures and the data-archiving methods, utilizing this data to improve power system operations. Solutions that are deemed to be best practices were documented for use in improving the data management systems that support power system operations. The project results are expected to benefit SDG&E and other utilities.

iv. Scope

This demonstration project determined the quantity and location of data-generating devices in the power system, the generation capabilities of these devices, and how the resulting data was being stored and archived. The project determined how the use of vast amounts of data to support the power system operations, such as pot event analysis, predictive maintenance, and asset management. The project identified and performed advanced analytics for various types of distribution system asset failures. The project demonstrated integration of multiple data sources into a data lake, creation of test models to perform predictive, and created visualizations for business user engagement. The pre-commercial demonstration system was used to demonstrate specific use cases from the roster of use cases developed by SDG&E's Electric Distribution Engineering (EDE) team.

v. Deliverables

A comprehensive final report was developed describing the work and results of the project.

vi. Metrics

The following metrics were identified for this project and evaluated during the course of the pre-commercial demonstration. These metrics are not exhaustive given the pre-commercial demonstration approach for this project.

- Safety, Power Quality, and Reliability (Equipment, Electricity System) – The use of machine learning and advanced data analytics can help stakeholders predict the failure of equipment based on current and historical operational data and other data. The following sub-factors could be analyzed with advanced data analytics:
    - Number of outages, frequency and duration reductions
    - Forecast accuracy improvement
    - Public safety improvement
    - Utility worker safety improvement
- Economic Benefits – Advanced data analytics can provide significant economic benefits by helping the identification of failing or aging equipment, before they fail, thereby reducing operational expenditures

and planning capital expenditures effectively. The following sub-factors could be affected with advanced data analytics:
    - Maintain/reduce operations and maintenance costs
    - Maintain/reduce capital costs
    - Improvement in system operation efficiencies

vii. Schedule
October 16, 2015 to December 31, 2017

viii. EPIC Funds Encumbered as of December 31, 2017
$1,111k

ix. EPIC Funds Spent as of December 31, 2017
$957k

x. Partners (if applicable)
n/a

xi. Match Funding (if applicable)
n/a

xii. Match Funding Split (if applicable)
n/a

xiii. Funding Mechanism (if applicable)
Combination of in-house work and pay-for-performance contracts. A Request for Proposal (RFP) was released in third quarter of 2016, with contractor selection completed in 2017.

xiv. Treatment of Intellectual Property (if applicable)
No IP developed.

xv. Status Update
Project activities completed in 2017:
- The project was implemented in three phases:
    - Phase 1 – SDG&E Internal Project Work Prior to contractor procurement
    - Phase 2 – Project Development Activities
    - Phase 3 – SDG&E Internal Project Work prior to project conclusion
- Phase 2 included the significant technical demonstration of the project:
    - Ingestion of several data sources into the data lake
    - Test build of preliminary predictive models for major electric distribution asset management use cases, and
    - Visualization development using business intelligence tools to provide insight into the health of various assets on the grid

- Four use cases successfully demonstrated the ability to predict equipment failure using machine learning techniques on vast amount of data for:
    - Underground electric distribution cable,
    - 600-amp tee Connectors,
    - Padmount service transformers, and
    - Overhead distribution wire failures (i.e. wire down)
- It is recommended that SDG&E and other utility stakeholders commercially adopt and implement advanced data analytics techniques for effective asset management.

Project 3: Monitoring, Communication, and Control Infrastructure for Power System Modernization

i. Investment Plan Period
2015-2017 (EPIC-2)

ii. Assignment to Value Chain
Distribution

iii. Objective
The objective of this project was to demonstrate advanced monitoring, communication and control infrastructure needed to operate an increasingly complex power system infrastructure. In other words, to test system controls to "sort" data and use what is helpful and useful.

iv. Scope
To achieve this objective, the project undertook a demonstration to evaluate an Open Field Message Bus (OpenFMB) with respect to SDG&E's existing architecture and vision for the future. The project demonstrated interoperability through secure, peer-to-peer control and communication between multiple distribution system equipment types based on existing standards. The approach included development of a test system for use in a pre-commercial demonstration to evaluate and demonstrate OpenFMB in a controlled environment within SDG&E's laboratory. The test system consisted of several controllable utility distribution system devices networked to mimic two feeders on SDG&E's distribution network. These devices were networked using differing network technologies designed to reproduce field conditions. The project also demonstrated communications interoperability among different vendor products through the use of adapters which converted those products' legacy communications technologies to OpenFMB. The OpenFMB network used multiple communications protocols, including MQTT, DDS, and R-GOOSE, to accomplish 13 use cases developed for this project. The pre-commercial demonstration system was subjected to a number of test cases to verify its correct operation and validate the use cases.

v. Deliverables

A comprehensive final report was developed describing the work and results of the project.

vi. Metrics

The following metrics were identified for this project and evaluated during the course of the pre-commercial demonstration. These metrics are not exhaustive given the pre-commercial demonstration approach for this project.

- Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy
  - Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (P.U. Code § 8360) – The EPIC project demonstrated the potential value of OpenFMB in addressing interoperability issues that exist in the electric system today, with multiple vendor technologies/systems unable to interface or interact with each other in a seamless manner. OpenFMB could provide a framework that enables the coexistence of traditional IEDs or devices that operate in a centralized manner with new IEDs or devices (especially DERs) that have the capability to operate in a decentralized manner.
  - Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (P.U. Code § 8360) – This EPIC project established a potential OpenFMB framework that could be implemented in the secondary layer that sits between the enterprise layer in a utility control center, and the primary layer that sits on multiple devices or equipment in the field. Next generation of IEDs or DERs may provide the necessary communication technology and application framework that enable peer to peer communication between devices and routes the information through the OpenFMB framework to disparate systems in the backend.
- Safety, Power Quality, and Reliability (Equipment, Electricity System) The use of OpenFMB framework to deploy decentralized applications could enable interoperability and improve information sharing between field devices and backend systems. The following sub-factors could be enhanced with the use of OpenFMB:
  - Reduction in outage numbers, frequency, and duration.
  - Reduction in system harmonics
  - Increase in the number if nodes in the power system at monitoring points
  - Public safety improvement and hazard exposure reduction

vii. Schedule

November 1, 2015 to December 31, 2017

viii. EPIC Funds Encumbered as of December 31, 2017
$1,305k

ix. EPIC Funds Spent as of December 31, 2017
$1,288k

x. Partners (if applicable)
n/a

xi. Match Funding (if applicable)
n/a

xii. Match Funding Split (if applicable)
n/a

xiii. Funding Mechanism (if applicable)
SDG&E EPIC funds applied to a combination of in-house work and a pay-for-performance contract. An RFP was released in third quarter of 2016, with contractor selection completed in 2017.

xiv. Treatment of Intellectual Property (if applicable)
No IP developed.

xv. Status Update
Project activities completed in 2017

- The project was implemented in three phases:
  - Phase 1 – SDG&E Internal Project Work Prior to contractor procurement
  - Phase 2 – Project Development Activities
  - Phase 3 – SDG&E Internal Project Work prior to project conclusion
- In the second phase, a representative test system was constructed, and a total of thirteen use cases were defined to demonstrate the use of OpenFMB for monitoring and control.
- The primary objectives for evaluation of OpenFMB was to demonstrate its use for:
  - Interoperability
  - Peer-to-peer communication, and
  - Multiple protocol conversion
- Use cases that were demonstrated address the following applications:
  - Volt/VAr control
  - Autonomous DER control
  - Enhanced feeder redeployment
  - Dynamic subscription
  - Provisioning and administration

- As a result of this demonstration, it was found that OpenFMB is not yet a standard for peer-to-peer interoperability. Gaps and options in OpenFMB's definitions are hindrances to achieving interoperability.
- It is recommended that work be continued to further define the OpenFMB standard so that it can be successfully utilized in future utility distribution system projects and deployments.

Project 4: System Operations Development and Advancement

i. Investment Plan Period
2015-2017 (EPIC-2)

ii. Assignment to Value Chain
Distribution

iii. Objective
The objective of this project was to support continued modernization of SDG&E's power system via demonstrations of improved capabilities in system operations. The project demonstrated a systematic process for the realignment of operating practices with advances in technology, software and standards used in the power system. The realignment is broad and addresses system integration issues and technology transfer.

iv. Scope
This project was focused on a distributed, autonomous, and scalable architecture, which included robust communication architecture and a hardware and software platform for aggregating and dispatching coordinated net-load resources (the difference between the load and power from Distributed Energy Resources (DER) in localized regions of the distribution system). The architecture included a concept of Localized Residential Aggregation and Monitoring (LRAMs) and Regional Aggregation, Monitoring & Circuit Optimizer (RAMCOs) for control and aggregation of customer-owned distributed generation and controllable loads on distribution systems. The project work was performed by a team comprised of SDG&E technical staff and the contractor.

v. Deliverables
A comprehensive final report on the project.

vi. Metrics
The following metrics were used to evaluate the project from different perspectives including Project Success Factors, Project Implementation Milestones, and Technical Achievements.

- **Potential energy and cost savings**
  - Number and total nameplate capacity of distributed generation facilities – 15 sites were included in the demonstration.

- Peak load reduction (MW) from summer and winter programs-- One of the implemented use cases was focused on circuit level load management and emergency dispatch. Based on aggregated resources, up to 20% load reduction was achieved.

- **Economic benefits**
  - Reduction in electrical losses in the transmission and distribution system – The demonstrated method incorporated Volt/VAr management at the primary and secondary levels, to reduce kVA and losses (up to 3% in the tested case).
  - Number of operations of various existing equipment types (such as voltage regulators) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear – The propose method utilized fast action of DERs and secondary resources to reduce voltage and load fluctuations and enhance life cycle. Unnecessary tap operations were eliminated. Capacitor switching was prevented.
- **Safety, Power Quality, and Reliability (Equipment, Electricity System**
  - Electric system power flow congestion reduction – In the emergency mode of the control platform, the circuit level power flow and demand were managed through control of aggregated resources to prevent congestion.
  - Increase in the number of nodes in the power system with monitoring capability – Real time monitoring and 5-minute or 10-minute system prediction were included as an integral part of the platform design. A phasor measurement unit system also provided high-resolution data for enhanced visualization.
- **Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy**
  - Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (P.U. Code § 8360) – Integration between SCADA/DMS and the DER aggregation platform was identified as a cost-effective solution to ensure integrity of the system.
- **Effectiveness of information dissemination**
  - Stakeholder participation in workshops – Project stakeholders within SDG&E were selected and invited to workshops.
  - Technology transfer – A plan was made for knowledge transfer through journals and conferences. A panel presentation was accepted for DistribuTECH 2018, in San Antonio (presented in January 2018).

vii. Schedule
November 11, 2015 to December 31, 2017

viii. EPIC Funds Encumbered as of December 31, 2017
$1,088k

ix. EPIC Funds Spent as of December 31, 2017
$1,064k

x. Partners (if applicable)
n/a

xi. Match Funding (if applicable)
n/a

xii. Match Funding Split (if applicable)
n/a

xiii. Funding Mechanism (if applicable)
A combination of in-house work and a pay-for-performance contract was used.

xiv. Treatment of Intellectual Property (if applicable)
No IP developed.

xv. Status Update
All project activities were completed in the year 2017. The project team held working sessions to define the baseline evaluation, concept of operations, use cases, other technical details, project schedule and resource management. Based on use cases, engineering and design, the test plan and test system were developed. The pre-commercial demonstration was carried out at the ITF, after successful factory acceptance and site acceptance tests. A comprehensive final report was developed, including the pre-commercial demonstration description, test result analysis, findings, recommendations, metrics, value proposition and conclusions.

Project 5: Integration of Customer Systems into Electric Utility Infrastructure

i. Investment Plan Period
2015-2017 (EPIC-2)

ii. Assignment to Value Chain
Distribution

iii. Objective
The project addressed the evolving gateway between customers and utilities. Specifically, it demonstrated the safe and reliable interoperability of customer systems with the distribution and transmission system and California Independent System Operator (CAISO) operations to improve grid operations and thereby increase ratepayer satisfaction and benefits.

iv. Scope
Alternative solutions for successful customer interoperability with utility systems were identified. Requirements for integration of these solutions with utility

systems were specified. Promising interoperability systems were demonstrated to create a knowledge base to support decisions on prospective commercial deployment of the systems. The work was performed by a team comprised of SDG&E technical staff and a contractor.

v. Deliverables

A comprehensive final report on the work and the results of the project were delivered after project completion.

vi. Metrics

Project tracking metrics included whether the SDG&E/contactor project team met milestones in the project plan. Technical metrics for the demonstration work were identified during performance of the demonstration. Metrics for this project are based on comparing the performance of power system operations when various interoperability solutions are in place with the performance of operations when they are not in place. The commercial adoption of this project will be impacted by the following metrics:

- Potential energy and cost savings
  - The project demonstrated new technologies and analysis methods for monitoring, visualization, and root-cause analysis of distribution systems by using various measurement techniques and data sources and integrating them in one platform to provide a unique monitoring and visualization user experience. This will create significant cost savings through reducing the required nameplate capacity of energy storage and distribution generation facilities due to the enhancement of the operations by providing additional means of awareness about the system behavior.
  - Avoided procurement and generation costs – Accurate monitoring enables utilities to predict generation costs especially through predicting dynamic events caused by varying characteristics of DER energy productions, loading effect of electric vehicle charging stations, and power electronic apparatus.

- Economic Benefits
  - Operation costs of the system can be significantly reduced by increased awareness and monitoring capability of the system.
- Safety, Power Quality, and Reliability
  - Electric system power flow congestion reduction – Any possible congestion might be diminished due to the improved monitoring, and visibility of the system. Any probable failure, or transient behavior can be properly predicted to avoid possible damage to the personnel, or equipment.
  - Forecast accuracy improvement – With improved visibility of the system, better forecasting capability is provided for the system, and any undesired behavior can be avoided by properly designing protection systems.

- Utility worker safety improvement and hazard exposure reduction– Utility workers safety can be considerably improved by enhanced awareness of distribution assets in the real-time mode. Other obtained safety related improvements include facilitated root cause analysis, operator and engineers training, and assessment of operation and design procedures for new technologies and approaches.
- Increase in the number of nodes in the power system with monitoring capability–This project provided more visibility, and situational awareness through increasing number of devices which monitor the system performance.

o Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy

This project was successful in completing demonstrations of candidate interoperability solutions to create knowledge that will support SDG&E decisions regarding commercial adoption.

In addition, key results are presented in the final report are being submitted for consideration for publication or presentation in relevant technical journals and conferences.

vii. Schedule
October 16, 2015 to December 31, 2017

viii. EPIC Funds Encumbered as of December 31, 2017
$985k

ix. EPIC Funds Spent as of December 31, 2017
$978k

x. Partners (if applicable)
n/a

xi. Match Funding (if applicable)
n/a

xii. Match Funding Split (if applicable)
n/a

xiii. Funding Mechanism (if applicable)
SDG&E EPIC funding applied to internal project team work and a pay-for-performance contract.

xiv. Treatment of Intellectual Property (if applicable)
No IP developed.

xv. Status Update

All project activities were completed in 2017. The key system capabilities that were successfully demonstrated and validated were:

- Monitoring distribution assets in the field (outside of substations) in real-time, based on measurements received from monitoring devices.
- Tapping into historical data collected to playback and investigate events over extended periods as selected and required by an operator or an engineer. This approach resolved major issues in previous systems due to lack of proper time synchronization and difficulty of alignment of the data points from various devices.
- Providing a set of tools for pre/post event analysis based on various data types and sources; this feature was shown to be very effective for root cause analysis, training of operators and engineers, and assessment of operation and design procedures for new technologies and approaches.

Project 6: Collaborative Programs in RD&D Consortia

i. Investment Plan Period

2015-2017 (EPIC-2)

ii. Assignment to Value Chain

Distribution

iii. Objective

The objective of this project was to accomplish highly leveraged demonstration work through collaborative projects in industry R&D consortia. This included information and intelligence leveraging by better informing the project content in EPIC activities with the knowledge of relevant activities occurring in a worldwide sense.

iv. Scope

The project team worked with R&D consortia to organize pre-commercial demonstration projects that focused on two modules:

- Demonstration of methodology and tools for estimating propensity for customer adoption of photovoltaics – The focus of this project module was to identify methodologies and tools for determining the primary drivers for residential photovoltaic (PV) adoption, predict residential PV adoption over time, and to demonstrate selected methods on a use case (*e.g.*, propensity to adopt PV on the zip code level). The effort also developed recommendations about whether to adopt all or some of the methods and tools on a commercial basis. The project team focused specifically on residential sector PV market adoption. Additionally, the project team conducted machine learning (ML) analytics on disadvantaged communities (DAC) zip codes and evaluated the difference in propensity to adopt solar PV between DAC and other zip codes.

- Unmanned aerial systems data lifecycle management and deep learning demonstration – The focus of this project module was to demonstrate tools that ingested and analyzed data collected by means of unmanned aircraft systems (UAS), existing red, green & blue (RGB) imagery, geographic information systems (GIS), power line systems – computer aided design and drafting (PLS-CADD) and other various inspection data types. The project module demonstrated the tools' ability to automatically identify and tag assets shown in RGB imagery, specifically avian covers, in real-world locations through machine learning. Additional identification of vegetation modeled using light imaging detection and ranging (LiDAR) data that encroached into pre-determined zone(s) around electrical wires provided a road map for future proactive vegetation maintenance efforts.

v. Deliverables

Two comprehensive final reports for the two project modules were developed describing the work and results of the project modules.

vi. Metrics

The commercial adoption methodologies and tools for estimating propensity for customer adoption of photovoltaics will be impacted by the following metrics.

- Potential energy and cost savings
  - Avoided customer energy use (kWh saved) – The use of tools to estimate customer adoption of PV would lead to understanding the contribution of electric load from PV systems, which in turn will provide the customers with reduced energy usage and economic savings.
  - Avoided procurement and generation costs – Accurate estimation of customer PV adoption rates would enable utilities to estimate the avoided cost to procure energy from sources that might be inefficient or contribute to environmental pollution.

- Environmental benefits
  - Greenhouse Gas (GHG) emissions reductions – Adoption of PV would lead to reduced emissions from fossil fuel-based sources which would have to be used in absence of renewable resources like PV.

The project metrics used to evaluate and test UAS technology and machine learning tools include:

- Habitat area disturbance reductions – UAS technologies allow for a remotely operate vehicle to access sensitive habits without impacting the land through vehicular are personnel incursions. The use cases demonstrated a process to capture and analyze electrical facilities, surrounding vegetation and terrain features from an aerial drone. The UAS

technology can reduce habitat area disturbance by replacing some required physical inspections with UAS derived inspections.

- Wildlife fatality reductions (electrocutions, collisions) – This project module studied the feasibility of combining UAS derived imagery with deep learning analytics to determine the location and condition of avian covers on electrical facilities. The avian covers provide a level of protection against electrocution for birds with large wing spans resting on electrical distribution and transmission poles. Currently the avian covers are assessed by physical inspection taken from ground observation on scheduled maintenance intervals. UAS data capture and associated deep learning analytics could provide increase inspections, improved evaluation of the presence and condition of avian covers resulting in reducing the risk to wildlife.
- Utility work safety improvement and hazardous exposure reduction – This project module studied several uses case for utilizing UAS technology and machine learning analytics to remotely observe, measure and catalog electrical facilities and surrounding terrain. The technology and process remove utility workers from making physical inspection where in many cases required access through hazardous terrain and complete inspections in close proximity to energized facilities and equipment.

vii. Schedule
March 1, 2016 to December 31, 2017

viii. EPIC Funds Encumbered as of December 31, 2017
$1,561k

ix. EPIC Funds Spent as of December 31, 2017
$830k

x. Partners (if applicable)
n/a

xi. Match Funding (if applicable)
n/a

xii. Match Funding Split (if applicable)
n/a

xiii. Funding Mechanism (if applicable)
SDG&E EPIC funds applied to an internal team and collaborative consortium to define, set up, and execute two collaborative pre-commercial demonstration project modules.

xiv. Treatment of Intellectual Property (if applicable)
No IP developed.

xv. Status Update

The two project module activities were completed in 2017

- Module on demonstration of methodology and tools for estimating propensity for customer adoption of photovoltaics
    - The project to demonstrated methodologies and tools for forecasting the propensity for residential customer solar PV adoption in California and SDG&E zip codes included the following major tasks:
        - Literature Review and Methodology Justification
        - Methodology Framework Development
        - Demonstration Plan
        - Disadvantaged Communities Analysis
    - Using machine learning, the project identified the several important attributes driving adoption at the non-DAC and DAC zip code level. Comparing adoption in DAC and non-DAC zip codes, owner occupancy emerged as a key attribute explaining the difference in PV market share. The percentage of owner occupied homes is 63% for non-DAC zip codes, compared to 50% for DAC zip codes.
    - The strength of aggregate and zip code-level back-casts suggest that causal models can be used to forecast residential rooftop PV adoption moving forward with a reasonable degree of accuracy, even when the analysis is spatially disaggregated. Such methods could support integrated resource planning and a better understanding of likely solar PV installation location.
    - The project recommends that SDG&E not commercially adopt these methods and tools at this juncture, without more foundational work being done first.
    - Based on the pre-commercial demonstration results and findings of this project, the following actions by SDG&E or other stakeholders are recommended as steps toward prospective commercial adoption of the demonstrated methods and tools:
        - Improve SDG&E's existing zip-code-based bass diffusion technique with refinements for the long-run market share parameters based on significant customer attributes.
        - Improve certain model input parameters (*e.g.*, historical PPA prices, kilowatt-hour production, technical suitability due to shading and orientation, price sensitivity, and correlation between homeownership and credit scores.
        - Leverage the same or equivalent methodology to evaluate solar PV adoption for other specific segments of interest and potentially individual customer analysis, including but not limited to: commercial and industrial customers, low-income customers, and customers on distribution feeders that are capacity constrained or at risk for reverse power flow.
        - Adapt the methodology for use in forecasting adoption of other DER types.

        - Consider utilizing a customer discrete choice survey approach to facilitate independent estimation of both the long-run market share parameters and the Bass diffusion coefficients
- Module on unmanned aerial systems data lifecycle management and deep learning demonstration
    - Unmanned Aerial Systems (UAS) have provided a unique opportunity for SDG&E and other utilities to obtain, disseminate and use aerial sensor data that provides benefits such as cost savings to its ratepayers and lower physical risks to SDG&E personnel while increasing public safety.
    - The project module was able to demonstrate integration with existing and future SDG&E infrastructure, software applications and legacy data sets with the ability to ingest, store, analyze and report on SDG&E assets derived from GIS, PLS-CADD, UAS collected data and other various sources.
    - The three test cases identified for the project included:
        - Avian Cover Identification – Test case to evaluate the identification of assets (avian cover) through advanced analytics on RGB images and demonstrate value for continual maintenance and visual inspection.
        - Vegetation Encroachment Identification – Test case to evaluate identification of vegetation encroachment within a buffer zone around power lines, thereby assisting in identification of trees for maintenance and trimming.
        - Cataloging and Remote Asset Management – Test case to demonstrate ingestion of data from various data sources and cataloging metadata information of existing assets that enables remote visualization and management of assets.
    - It is recommended that SDG&E pursue additional evaluation of UAS technology for stakeholder groups within the company that will benefit from the aggregation of various sources of data into a data management platform that also provides advanced analytical capabilities. The evaluation should also focus on developing requirements for integration of this data management platform into the SDG&E information technology environment.

VI. CONCLUSION

A. Key Results for 2017 for SDG&E EPIC Projects

As of December 31, 2017, SDG&E committed all EPIC-1 and EPIC-2 funds for its 11 Commission-approved EPIC-1 and EPIC-2 projects. SDG&E performed work on all 11 of these projects and completed 10 of them in 2017. The remaining project is in progress and scheduled to be completed in 2018.

Attached to this Report as Appendices 1 to 15, are 15 final reports for the EPIC projects that have been completed to date. Two of the projects were split into multiple work modules, and a final report was prepared for each module. There is a total of 15 module final reports for the 11 projects. These EPIC final reports are also available on the SDG&E EPIC website at www.SDGE.com/EPIC.

B. Next Steps for SDG&E's EPIC Program

For the partially completed project, work will continue in 2018 on completion of the project plan and on performance of tasks in the plan.

Specifically, for the unfinished project, the following are the next steps:

- EPIC-1, Project 2: Devise and demonstrate additional use cases relative to visualization and situational awareness capabilities in system operations. Prepare a final report on the added use cases.

For the EPIC-1 and EPIC-2 projects, $14,457k was awarded to contractors through December 31, 2017.

Work will commence on SDG&E's proposed EPIC-3 projects once a Commission decision is issued approving SDG&E's EPIC-3 Application.

ATTACHMENT B

SDG&E 2017 EPIC PROJECT STATUS (EXCEL FILE)

Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project (objective; scope; deliverables; schedule)	Date of the Award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($000)	Committed Funding Amount ($000)	Funds Expended to date: Contract/Grant Amount ($000)	Funds Expended to date: In house expenditures ($000)	Funds Expended to date: Total Spent to date ($000)	Administrative and overhead costs to be incurred for each project	Leveraged Funds	Partners	Match Funding	Match Funding Split	Funding Mechanism	Intellectual Property	Identification of the method used to grant awards	If competitively selected, provide the number of bidders passing the initial pass/fail screening for project	If competitively selected, provide the name of selected bidder.	If competitively selected, provide the rank of the selected bidder in the selection process.	If competitively selected, explain why the bidder was not the highest scoring bidder, explain why a lower scoring bidder was selected.	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization. (This column is applicable to the CEC only.)	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals (This column is applicable to the CEC only.)	Applicable metrics	Update
1st triennial (2012-2014)	SDG&E	Smart Grid Architecture Demonstrations	Pre-commercial Demonstration	The specific objectives of the project were to: perform pilot demonstration of key candidate prototype building blocks of the SDG&E smart grid architecture to determine their suitability for adoption in the architecture; document the results and make recommendations of whether specific building blocks should be adopted; and, provide demonstration results to support the implementation phase for any building blocks adopted.	03/15/2017	Yes	Distribution	1,406	1,406	1,344	57	1,402	N/A	0	None	0	N/A	A combination of in-house work and pay-for-performance contracts was used. A Request for Proposal (RFP) was released in third quarter of 2016, with contractor selection completed in 2017.	None to date	RFP	2	Quanta Technology, LLC	1st	N/A	N/A	Yes - (Team member AVECS)	N/A	The following metrics were identified for this project and evaluated during the course of the pre-commercial demonstration. These metrics are not exhaustive given the pre-commercial demonstration approach for this project. • Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy o Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) - Use of configuration inheritance and descriptive data point naming supported by IEC 61850 makes the task of configuring devices in substation and feeders considerably easier when contrasted to the conventional approach. Digitization of devices using IEC 61850 can potentially lower the barriers of adoption of newer technologies within the electric infrastructure. o Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) - The industry has many standards that exist among several standards development organizations that may be applicable to multiple layers of the power systems architecture. A key standard is the IEC 61850 protocol suite. The extent of harmonization efforts that have included IEC 61850 show that the suite has the potential of becoming a key building block in the future smart grid architecture that enable effective communication and interoperability of equipment connected to the electric grid. • Safety, Power Quality, and Reliability (Equipment, Electricity System) - The use of IEC 61850 in the field could enable interoperability, improve protection coordination and provide effective information sharing between field devices and backend systems. The following sub-factors could be enhanced with the use of IEC 61850: o Increase in the number if nodes in the power system at monitoring points o Reduction in outage numbers, frequency, and duration. o Reduction in system harmonics	All project activities were completed in 2017. IEC 61850 was identified as a principal component of the new architecture. A representative test system was constructed, and a total of eleven use cases were defined to demonstrate the use of IEC 61850 standards. The recommendation is that SDG&E plan for long-term migration to an architecture that incorporates IEC 61850 standards.
1st triennial (2012-2014)	SDG&E	Visualization and Situational Awareness Demonstrations	Pre-commercial Demonstration	The objective of this demonstration project was to explore how data collected from sensors and devices can be processed, combined, and presented to system operators in a way that enhances grid monitoring and situational awareness. This project looked at how data currently unexploited and separately processed can be integrated and visually presented for strategic use by system operators. When transformed and presented in a visually integrated manner, this data can be invaluable for utilities to optimize grid operations as well as provide insights in the performance of the overall utility system. The demonstration of specific visualization and situational awareness concepts will be used to help SDG&E make choices on which options should be adopted into a future visualization and situational awareness system.	In-house only	No	Distribution	2,075	2,301	653	408	1,061	N/A	0	None	0	N/A	SDG&E EPIC funding used for work performed by the internal SDG&E project team.	None to date	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	The project tracking metrics will be the milestones in the project plan. Technical project metrics will include the completion of the initial specification for a visualization and situational awareness system, the demonstration of a system display mock-up, and the specifications and recommendations regarding adoption by SDG&E. Also, major project results will be submitted in technical papers and presentations for consideration by major technical conferences and publications. The following metrics were identified for this project and further explained in the final report: • Safety, Power Quality, and Reliability (Equipment, Electricity System). • Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy. • Adoption of EPIC technology, strategy, and research data/results by others.	Major project activities completed in 2017. Based on the feedback from early users of the project results - which has been uniformly positive - this project has successfully achieved all its key objectives. Through the performed work, SDG&E has demonstrated novel solutions to the selected use cases, and, in the process, has also gained reusable software artifacts and substantial experience in integrating GIS, historical, asset management, and other major SDG&E computer systems. Both aspects will provide usability well beyond the direct utility of the software components produced by the project. The project committed additional funds by the end of 2017 to perform additional work on selected use cases to give them greater value and further development.
1st triennial (2012-2014)	SDG&E	Distributed Control for Smart Grids	Pre-commercial Demonstration	The objective of this project was to test alternatives for communication and control across distribution system resources to ensure that devices operate in a complementary manner and ensure optimum distribution system performance, reliability, and stability. The project tested distributed control methods and approaches to control distribution circuit resources and integrate them as part of a unified control scheme with other higher-level control systems, such as the distribution management system (DMS). The project assessed the scalability and performance of alternative control schemes.	06/01/2016	No	Distribution	1,392	1,392	1,333	53	1,386	N/A	0	None	0	N/A	SDG&E EPIC funds were applied to a combination of in-house work and a pay-for-performance contract. A prime contractor was selected by competitive procurement in the second quarter of 2016.	None to date	RFP for prime contractor and sole source for consultant to help prepare the RFP.	5	Quanta Technology, LLC	1st	N/A	N/A	No	N/A	The project tracking metrics will be the milestones in the project plan. Technical metrics for this project will be based on comparing the performance of distribution system operations when various new control schemes are in place with the performance of the same operations when the control schemes are not in place. These performance metrics will include measures of power quality, electrical loss reductions, asset health maintenance, and adaptability to new device types in the distribution system. Also, major project results will be submitted as technical papers and presentations for consideration by major technical conferences and publications. The following metrics were identified for this project and further explained in the final report: • Economic Benefits. • Safety, Power Quality, and Reliability (Equipment, Electricity System). • Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy. • Effectiveness of information dissemination. • Adoption of EPIC technology, strategy, and research data/results by others.	2017 saw the completion of the project. The results provided quantifiable evidence that the distributed control of system resources could achieve benefits when compared to a conventional approach. Major benefits identified included: • Increase the utilization and contribution of DERs • Reduce and even prevent unintentional reverse power flow • Produce a flatter voltage profile over the length of a circuit • Bring voltage profiles back inside the permissible range after a system event • Reduce system electrical losses • Improve the power factor of a circuit • Reduce the number of operations of controllable assets like capacitor banks, voltage regulators and load tap changers • Dynamically adjust protection settings to increase system reliability The tests demonstrated that the greatest benefits were obtained when the control system was able to coordinate the control of two adjacent substations and when the regionally-based master controller was controlling the system, because it provided more possibilities for system optimization.
1st triennial (2012-2014)	SDG&E	Demonstration of Grid Support Functions of Distributed Energy Resources	Pre-commercial Demonstration	The objective of EPIC-1, Project 4, Demonstration of Grid Support Functions of Distributed Energy Resources (DER) was to demonstrate grid support functions of DER, which can improve distribution system operations. In other words, the objective was to assess the viability of using DER to provide non-traditional functions, such as volt/VAr optimization, fast-response peaking or emergency power, peak shaving, and distribution system status information. This project consisted of three modules: value assessment of grid support functions of DER, communication standards for grid support functions of DER, and demonstration and comparison of the EPRI and SDG&E DER hosting capacity analysis tools.	Calendar Year 2015 and Calendar Year 2017	No for first contract and Yes for second and third contracts	Distribution	1,200	1,200	1,012	83	1,095	N/A	0	None	0	N/A	EPIC funding of an internal SDG&E project team working with a pay-for-performance prime contractor. For Module 1 (which was a substantial part of this project), a prime contractor was selected by competitive procurement. Modules 2 and 3 were smaller efforts for which the contractors were selected by sole source.	None to date	RFP for prime contractor for first project module. Sole source for prime contractors for second and third modules.	3	Schweitzer Engineering Laboratories for first module. Klu and EPRI for second and third modules respectively.	1st	N/A	N/A	No	N/A	Technical metrics for the pre-commercial demonstration were determined during the demonstration planning phase. One measure of success for Module 1 of this project was whether it provided a basis for deciding which DER functions warrant commercial pursuit in future distribution system development. Metrics for this module also included the identification of suitable interoperability requirements, interconnection systems, and communication protocols that support the functions. In Module 2, the metrics included a determination of which communication standards are preferred to support the adoption of viable grid support functions. In Module 3 of this project, the metrics addressed the pros and cons of the SDG&E hosting capacity tool in comparison with the EPRI CRIVE DER hosting capacity tool.	The three modules of this project were successfully accomplished with collaboration of the SDG&E internal team and the contractors' team. Final reports were completed individually for each module. They were carefully reviewed by the internal stakeholders, the SDG&E internal team, and the contractors' team and then revised into final form for public release.
1st triennial (2012-2014)	SDG&E	Smart Distribution Circuit Demonstrations	Pre-commercial Demonstration	The objective of this project was to perform pilot demonstrations of smart distribution circuit features and associated simulation work to identify best practices for integrating new and existing distribution equipment in these circuits. Simulations took advantage of hardware-in-loop testing with a real-time digital simulator currently available at SDG&E. Using simulations to optimize one particular circuit, desired features were tested in that circuit to assess their suitability for widespread commercial adoption.	12/04/2015	No for first contract and Yes for second contract	Distribution	1,441	1,441	1,356	77	1,433	N/A	0	None	0	N/A	For both Module 1 and Module 2, SDG&E EPIC funds were applied to support a team of internal technical staff and pay-for-performance contractors. The contractors were selected as per SDG&E procurement policy.	None to date	RFP for prime contractor and sole source for consultant to help prepare the RFP.	4	Schweitzer Engineering Laboratories for first module. Quanta Technology, LLC for second module.	1st for Schweitzer Engineering Laboratories for first module.	N/A	N/A	No	N/A	The project tracking metrics included the milestones in the project plan. Technical metrics were developed to guide the actual demonstration work. In general, the ultimate measure of success was having a benchmark future distribution circuit design concept that helps advance future distribution system development. The circuit design can assimilate a wide variety of existing and emerging device types and has a protection system that allows this assimilation to be done without compromising reliability or safety. The following metrics were identified for Module 1 and further explained in the final report: • Economic Benefits. • Safety, Power Quality, and Reliability (Equipment, Electricity System). • Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy. • Effectiveness of information dissemination. • Adoption of EPIC technology, strategy, and research data/results by others. The following metrics were identified for Module 2 and further explained in the final report. • Potential energy and cost savings • Economic benefits • Safety, Power Quality, and Reliability (Equipment, Electricity System) • Effectiveness of information dissemination	The project was concluded in 2017. As mentioned, the project was broken into two modules: Module 1: Demonstration of Advanced Circuit Concepts: Developed with the assistance of Schweitzer Engineering Laboratories, Inc. This module was developed in 3 phases: o Phase 1 of the project covered the evaluation and documentation of products and technologies currently available for improved distribution circuit design, system operation, and protection. o Phase 2 of the project included selection and modeling of three diverse SDG&E distribution circuits viz., coastal-residential, urban, and desert-rural in a modeled environment for demonstration of advanced circuit concepts. The observations and results captured were analyzed and the findings from stand-alone device testing provided inputs on how to modify the existing circuits for improved reliability and performance. o Phase 3 of the project included findings and recommendations from the demonstration in Phase 2. The recommended system architecture for commercial implementation of voltage support coordination scheme is provided. Module 2: Pre-Commercial Demonstration of Methodologies and Tools for Energy Storage Integration into Smart Distribution Circuits – All project activities were completed in the year 2017. The test included identification, evaluation, selection and demonstration of methodologies and tools for prospective use in planning future energy storage projects. Test result from the test system were documented and evaluated. Chosen tools, software programs and methodologies were recommended to stakeholders.
								7,514	7,740	5,698	678	6,377																	

Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project (objective; scope; deliverables; schedule)	Date of the Award	Was this project awarded in the immediately prior calendar year?	Assignment to Value Chain	Encumbered Funding Amount ($000)	Committed Funding Amount ($000)	Funds Expended to date: Contract/Grant Amount ($000)	Funds Expended to date: In house expenditures ($000)	Funds Expended to date: Total Spent to date ($000)	Administrative and overhead costs to be incurred for each project	Leveraged Funds	Partners	Match Funding	Match Funding Split	Funding Mechanism	Intellectual Property	Identification of the method used to grant awards	If competitively selected, provide the number of bidders passing the initial pass/fail screening for project	If competitively selected, provide the name of selected bidder.	If competitively selected, provide the rank of the selected bidder in the selection process.	If competitively selected, explain why the bidder was not the highest scoring bidder, or explain why a lower scoring bidder was selected.	If interagency or sole source agreement, specify date of notification to the Joint Legislative Budget Committee (JLBC) was notified and date of JLBC authorization. (This column is applicable to the CEC only.)	Does the recipient for this award identify as a California-based entity, small business, or businesses owned by women, minorities, or disabled veterans?	How the project leads to technological advancement or breakthroughs to overcome barriers to achieving the state's statutory energy goals (This column is applicable to the CEC only.)	Applicable metrics	Update
2nd triennial (2015 - 2017)	SDG&E	Modernization of Distribution System & Integration of Distributed Generation and Storage	Pre-commercial Demonstration	The objective of this project was to demonstrate distribution system infrastructure modernization solutions, including advances in distribution system design to enable use of new technologies, such as power electronic components, new protection systems, distributed generation and alternative storage technologies. The work was focused on pre-commercial demonstration of emerging substation communication standards.	Calendar Year 2017	Yes	Distribution	2,009	2,009	1,927	44	1,971	N/A	0	None	0	N/A	A combination of in-house work and pay-per-performance were used.	None to date	Sole Source for prime contractor and competitive bid for equipment vendors.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	The following metrics were identified for this project. Given the proof of concept nature of this EPIC project, these metrics are forward looking to prospective adoption of IEC 61850 standards. The main protection concerns that were identified in this project were speed and reliability. The following metrics address these concerns. i. Potential energy and cost savings: Due to reduced engineering efforts in the design process using IEC 61850 equipment, cost savings flow through to ratepayers. The integrated engineering tools make it easier to design the substation and test the equipment before deployment, which is hard to achieve now and is more time consuming with current legacy systems.	The project was completed in 2017. Stakeholders from SDG&E's substations and protection sections worked with the internal project team and contractor to plan and review the task work in this project. Options for performing the demonstration were explored, including at an actual substation or in a laboratory. Due to cost and risk considerations, it was decided to perform the demonstration in a laboratory using a substation mock-up. Intelligence was gathered on the status of the IEC standards and the vendor equipment options for the demonstration. The project team finished a successful laboratory demonstration for several substation-protection use cases. A key recommendation coming from the project was for SDG&E to further explore commercial adoption of IEC 61850. Internal stakeholders are doing so. Other technology transfer activities have included presentations at various conferences. Included were a presentation at the IEC 61850 Europe 2017 Conference in September 2017 and acceptance for presentation at DistribuTECH 2018 (presented in January 2018). The project was also presented at EPIC Symposiums on December 1, 2016 in Sacramento and on October 18, 2017 in San Diego.
2nd triennial (2015 - 2017)	SDG&E	Data Analytics in Support of Advanced Planning and System Operations	Pre-commercial Demonstration	This project was designed to address the anticipated "data tsunami" associated with more widespread system monitoring and more widespread use of controllable devices in the power system. It helped to create better data management. It also demonstrated solutions for the data management issues and challenges expected to accompany the extensive amount of real-time and stored data being archived from field devices and identify the data mining procedures and the data-archiving methods, utilizing this data to improve power system operations. Solutions that are deemed to be best practices were documented for use in improving the data management systems that support power system operations.	02/07/2017	Yes	Distribution	1,111	1,111	753	203	957	N/A	0	None	0	N/A	Combination of in-house work and pay for-performance contracts. A RFP was released in third quarter of 2016, with contractor selection completed in 2017.	None to date	RFP	2	Sparta Consulting, dba KPIT	1st	N/A	N/A	No	N/A	The following metrics were identified for this project and evaluated during the course of the pre-commercial demonstration. These metrics are not exhaustive given the pre-commercial demonstration approach for this project. • Safety, Power Quality, and Reliability (Equipment, Electricity System) – The use of machine learning and advanced data analytics can help stakeholders predict the failure of equipment based on current and historical operational data and other data. The following sub-factors could be analyzed with advanced data analytics: o Number of outages, frequency and duration reductions o Forecast accuracy improvement o Public safety improvement o Utility worker safety improvement • Economic Benefits – Advanced data analytics can provide significant economic benefits by helping the identification of failing or aging equipment, before they fail, thereby reducing operational expenditures and planning capital expenditures effectively. The following sub-factors could be affected with advanced data analytics: o Maintain/reduce operations and maintenance costs o Maintain/reduce capital costs o Improvement in system operation efficiencies	All project activities were completed in 2017. The pre-commercial demonstration included ingestion of several data sources into a data lake, test build of preliminary predictive models for major electric distribution asset management use cases, and visualization development using business intelligence tools to provide insight into the health of various assets on the utility distribution system. Based on the project findings, it is recommended that SDG&E and other utility stakeholders commercially adopt and implement advanced data analytics techniques for effective asset management.
2nd triennial (2015 - 2017)	SDG&E	Monitoring, Communications, and Control Infrastructure for Power System Modernization	Pre-commercial Demonstration	The objective of this project was to demonstrate advanced monitoring, communication and control infrastructure needed to operate an increasingly complex power system infrastructure. In other words, to test system controls to "sort" data and use what is helpful and useful.	01/24/2017	Yes	Distribution	1,305	1,305	1,266	22	1,288	N/A	0	None	0	N/A	Combination of in-house work and pay for-performance contracts. A RFP was released in third quarter of 2016, with contractor selection completed in 2017.	None to date	RFP	3	GE Grid Solutions	1st	N/A	N/A	No	N/A	The following metrics were identified for this project and evaluated during the course of the pre-commercial demonstration. These metrics are not exhaustive given the pre-commercial demonstration approach for this project. • Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy o Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360) -The EPIC project demonstrated the potential value of OpenFMB in addressing interoperability issues that exist in the electric system today, with multiple vendor technologies/systems unable to interface or interact with each other in a seamless manner. OpenFMB could provide a framework that enables the coexistence of traditional IEDs or devices that operate in a centralized manner with new IEDs or devices (especially DERs) that have the capability to operate in a decentralized manner. o Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) - This EPIC project established a potential OpenFMB framework that could be implemented in the secondary layer that sits between the enterprise layer in a utility control center, and the primary layer that sits on multiple devices or equipment in the field. Next generation of IEDs or DERs may provide the necessary communication technology and application framework that enable peer to peer communication between devices and routes the information through the OpenFMB framework to disparate systems in the backend. • Safety, Power Quality, and Reliability (Equipment, Electricity System) - The use of OpenFMB framework to deploy decentralized applications could enable interoperability and improve information sharing between field devices and backend systems. The following sub-factors could be enhanced with the use of OpenFMB: o Reduction in outage numbers, frequency, and duration. o Reduction in system harmonics o Increase in the number if nodes in the power system at monitoring points o Public safety improvement and hazard exposure reduction	All project activities were completed in 2017. The project focus was on pre-commercial demonstration of an Open Field Messaging Bus (Open FMB) for interoperability, peer-to-peer communication, and multiple protocol conversion. A representative test system was constructed, and a total of thirteen use cases were defined to demonstrate the use of OpenFMB for monitoring and control. As a result of this demonstration, it is recommended that work be continued to further define the OpenFMB standard so that it can be successfully utilized in future utility distribution system projects and deployments
2nd triennial (2015 - 2017)	SDG&E	System Operations Development and Advancement	Pre-commercial Demonstration	The objective of this project was to support continued modernization of SDG&E's power system via demonstrations of improved capabilities in system operations. The project demonstrated a systematic process for the realignment of operating practices with advances in technology, software and standards used in the power system. The realignment is broad and addresses system integration issues and technology transfer.	02/15/2017	Yes	Distribution	1,088	1,088	1,033	31	1,064	N/A	0	None	0	N/A	A combination of in-house work and pay-for-performance contracts was used. A RFP was released in third quarter of 2016, with contractor selection completed in 2017.	None to date	RFP	3	Quanta Technology, LLC	1st	N/A	N/A	No	N/A	The following metrics were used to evaluate the project from different perspectives including Project Success Factors, Project Implementation Milestones, and Technical Achievements. • Potential energy and cost savings • Economic benefits • Safety, Power Quality, and Reliability (Equipment, Electricity System • Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy • Effectiveness of information dissemination	All project activities were completed in the year 2017. A PHIL (Power Hardware In the Loop) test system was developed to examine improvements of the distribution system containing modern system component by optimization, using the RAMCO (Regional Aggregation Monitoring and Circuit Optimizers) and LRAM (Local Resource Aggregation and Monitoring). Results from the test system were evaluated and concluded that, the system operated as intended and optimized the distribution system. The recommendation is that stakeholders pursue this system further and commercialize it.
2nd triennial (2015 - 2017)	SDG&E	Integration of Customer Systems into Electric Utility Infrastructure	Pre-commercial Demonstration	The project addressed the evolving gateway between customers and utilities. Specifically, it demonstrated the safe and reliable interoperability of customer systems with the distribution and transmission system and California Independent System Operator (CAISO) operations to improve grid operations and thereby increase ratepayer satisfaction and benefits.	Calendar Year 2017	Yes	Distribution	985	985	915	63	978	N/A	0	None	0	N/A	SDG&E EPIC funding applied to the internal project team work and a pay-for-performance contract.	None to date	Sole Source	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Project tracking metrics included whether the SDG&E/contactor project team met milestones in the project plan. Technical metrics for the demonstration work were identified during performance of the demonstration. Metrics for this project are based on comparing the performance of power system operations when various interoperability solutions are in place with the performance of operations when they are not in place. The commercial adoption of this project will be impacted by the following metrics: o Potential energy and cost savings ß The project demonstrated new technologies and analysis methods for monitoring, visualization, and root-cause analysis of distribution systems by using various measurement techniques and data sources and integrating them in one platform to provide a unique monitoring and visualization user experience. This will create significant cost savings through reducing the required nameplate capacity of energy storage and distribution generation facilities due to the enhancement of the operations by providing additional means of awareness about the system behavior. ß Avoided procurement and generation costs – Accurate monitoring enables utilities to predict generation costs especially through predicting dynamic events caused by varying characteristics of DER energy productions, loading effect of electric vehicle charging stations, and power electronic apparatus. o Economic Benefits ß Operation costs of the system can be significantly reduced by increased awareness and monitoring capability of the system. o Safety, Power Quality, and Reliability • Electric system power flow congestion reduction – Any possible congestion might be diminished due to the improved monitoring, and visibility of the system. Any probable failure, or transient behavior can be properly predicted to avoid possible damage to the personnel, or equipment. • Forecast accuracy improvement – With improved visibility of the system, better forecasting capability is provided for the system, and any undesired behavior can be avoided by properly designing protection systems. • Utility worker safety improvement and hazard exposure reduction – Utility workers safety can be considerably improved by enhanced awareness of distribution assets in the real-time mode. Other obtained safety related improvements include facilitated root cause analysis, operator and engineers training, and assessment of operation and design procedures for new technologies and approaches. • Increase in the number of nodes in the power system with monitoring capability – This project provided more visibility, and situational awareness through increasing number of devices which monitor the system performance. o Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy	All project activities were completed in 2017. The key system capabilities that were successfully demonstrated and validated were: • Monitoring distribution assets in the field (outside of substations) in real-time, based on measurements received from monitoring devices. • Tapping into historical data collected to playback and investigate events over extended periods as selected and required by an operator or an engineer. This approach resolved major issues in previous systems due to lack of proper time synchronization and difficulty of alignment of the data points from various devices. • Providing a set of tools for pre/post event analysis based on various data types and sources; this feature was shown to be very effective for root cause analysis, training of operators and engineers, and assessment of operation and design procedures for new technologies and approaches.
2nd triennial (2015 - 2017)	SDG&E	Collaborative Programs in RD&D Consortia	Pre-commercial Demonstration	The objective of this project was to accomplish highly leveraged demonstration work through collaborative projects in industry R&D consortia. This included information and intelligence leveraging by better informing the project content in EPIC activities with the knowledge of relevant activities occurring in a worldwide sense.	For first module: GIS Surveyors, Inc (08/03/2017, GE Grid Solutions (09/01/2017), Harris Corporation (10/6/2017), Network Mapping (10/12/2017), Price Waterhouse Coopers (09/01/2017) For second module: Navigant Consulting (09/11/2017)	Yes	Distribution	1,561	1,561	755	75	830	N/A	0	None	0	N/A	SDG&E EPIC funds applied to an internal team and collaborative consortium to define, set up, and execute 2 collaborative pre-commercial demonstration project modules.	None to date	Competitive procurement	6 for module on UAS and 3 for module on customer propensity	For first module: GIS Surveyors, Inc, GE Grid Solutions, Harris Corporation, Network Mapping, Price Waterhouse Coopers For second module: Navigant Consulting	For first module: Top 3 bidders were all selected For second module: Rank 1 was selected	N/A	N/A	Yes (GIS Surveyors, Inc.)	N/A	• The commercial adoption methodologies and tools for estimating propensity for customer adoption of photovoltaics will be impacted by the following metrics. o Potential energy and cost savings · Avoided customer energy use (kWh saved) – The use of tools to estimate customer adoption of PV would lead to understanding the contribution of electric load from PV systems, which in turn will provide the customers with reduced energy usage and economic savings. · Avoided procurement and generation costs – Accurate estimation of customer PV adoption rates would enable utilities to estimate the avoided cost to procure energy from sources that might be inefficient or contribute to environmental pollution. o Environmental benefits ·Greenhouse Gas (GHG) emissions reductions – Adoption of PV would lead to reduced emissions from fossil fuel based sources which would have to be used in absence of renewable resources like PV. • The project metrics used to evaluate and test UAS technology and machine learning tools include: o Habitat area disturbance reductions - UAS technologies allow for a remotely operate vehicle to access sensitive habits without impacting the land through vehicular are personnel incursions. The use cases demonstrated a process to capture and analyze electrical facilities, surrounding vegetation and terrain features from an aerial drone. The UAS technology can reduce habitat area disturbance by replacing some required physical inspections with UAS derived inspections. o Wildlife fatality reductions (electrocutions, collisions) - This project module studied the feasibility of combining UAS derived imagery with deep learning analytics to determine the location and condition of avian covers on electrical facilities. The avian covers provide a level of protection against electrocution for birds with large wing spans resting on electrical distribution and transmission poles. Currently the avian covers are assessed by physical inspection taken from ground observation on scheduled maintenance intervals. UAS data capture and associated deep learning analytics could provide increase inspections, improved evaluation of the presence and condition of avian covers resulting in reducing the risk to wildlife. o Utility work safety improvement and hazardous exposure reduction - This project module studied several uses case for utilizing UAS technology and machine learning analytics to remotely observe, measure and catalog electrical facilities and surrounding terrain. The technology and process remove utility workers from making physical inspection where in many cases required access through hazardous terrain and complete inspections in close proximity to energized facilities and equipment.	Project development on demonstrations through collaborative R&D consortia focused on two modules. All project activities were completed in 2017. For the project module on forecasting customer adoption of photovoltaic (PV), the project team used machine learning to identify several important attributes driving adoption for disadvantaged communities (DAC) and other locations (non DAC) at the zip code level. Owner occupancy emerged as a key attribute explaining the difference in PV market share. The percentage of owner occupied homes is 50% for DAC zip codes compared to 63% for non-DAC zip codes. It is recommended that SDG&E not commercially adopt these methods and tools at this juncture, without more foundational work being done first. For the module on unmanned aerial systems (UAS) data lifecycle management and deep learning demonstration, the project demonstrated integration with existing and future SDG&E infrastructure, software applications and legacy data sets with the ability to ingest, store, analyze and report on SDG&E assets derived from Geographic Information System (GIS), Power Line Systems – Computer Aided Draft and Design (PLS-CADD), unmanned aircraft system (UAS) collected data and other various sources. Three test cases were demonstrated including equipment identification, vegetation encroachment identification, and cataloging and remote asset management. It is recommended that SDG&E pursue additional evaluation of UAS technology for stakeholder groups within the company that will benefit from the aggregation of various sources of data into a data management platform that also provides advanced analytical capabilities.
								8,059	8,059	6,649	438	7,088																	

ATTACHMENT C

SDG&E EPIC FINAL REPORTS
APPENDICES 1 through 15

Appendix 1
EPIC-1, Project 1: Smart Grid Architecture Demonstrations Program

EPIC Final Report

Program	**Electric Program Investment Charge (EPIC)**
Administrator	**San Diego Gas & Electric Company**
Project Number	**EPIC-1, Project 1**
Project Name	**Smart Grid Architecture Demonstrations Program**
Date	**December 31, 2017**

Attribution

This comprehensive final report documents the work done in this EPIC project. The project team for this work included the following individuals, listed alphabetically by last name.

SDG&E

Atef, Kahveh
Espinoza, Mike
Giourdjian, Arthur
Goodman, Frank
Katmale, Hilal
Kayali, Molham
Orozco, Alfonso
Salmani, Amin
Smith, Greg
Thant, Aung

Quanta Technology, LLC

Bidram, Ali
Boroughs, David
Holbach, Juergen
Katiraei, Farid
Koosha, Bahman
Mohammadi, Davood
Momeni, Ahmad
Proudfoot, Douglas
Soltani, Bahar
Udren, Eric
Ward, Solveig
Yazdanian
Yousefpoor, Nima
Zamani, Amin

ABB

Beltram, Fabricio
Morbin, Samuel
Pelikan, John
Rietmann, Peter

SGS

Abbey, Chad
Breaden, Craig
Mangeney, Estelle
Smith, David

EXECUTIVE SUMMARY

The objective of EPIC-1, Project 1 (Smart Grid Architecture Demonstrations) was to conduct pilot demonstrations of key candidate prototype components of the SDG&E smart grid architecture to determine their suitability for adoption in the architecture. The demonstration results are intended to be used by SDG&E and other users to aid in selection of architecture components for adoption and to support the implementation phase for adopted components.

This project was one of three SDG&E EPIC projects on pre-commercial demonstration of communications standards for power system operations. The three projects were:

- Smart Grid Architecture Demonstrations
  - Focus: Communications standards for integration of feeder equipment and DER into networked automation
- Monitoring, Communication, and Control Infrastructure for Power System Modernization
  - Focus: Open Field Message Bus
- Modernization of Distribution System and Integration of Distributed Generation and Storage
  - Focus: IEC 61850 in substation network

The principal standard of interest in these three demonstrations was IEC 61850, which is an open standard developed by industry stakeholders and promulgated through the International Electrotechnical Commission. The intent of these EPIC demonstrations is to increase the body of knowledge available to aid users in making decisions regarding their future power system communications architecture. The final reports for all three of these projects are posted on the SDG&E EPIC website at www.sdge.com/epic

Electric utility power systems are becoming increasingly complex. Recent years have seen a rapid and sustained increase in the deployment of intelligent electronic devices (IEDs), with increasing processing capabilities and communication requirements. These trends make it necessary to reevaluate the traditional utility communication models and data architectures. The focus of this project was to examine the options, assess their suitability to address specific needs, and perform pre-commercial demonstrations of promising architecture components.

The project provided an assessment of the current SDG&E distribution operations architecture, with a focus on identifying gaps in existing processes and applications. A number of industry reference architectures were reviewed. The CEN-CENELEC-ETSI[1] Smart Grid Coordination Group's Smart Grids Architecture Model (SGAM) framework was identified as best suited to document the current and proposed architecture necessary to adapt to the changing demands on the system. In addition to looking at reference architectures, the project also examined the status, content, and trends of major utility communications standards and ongoing work by several standard development organizations. The International Electrotechnical Commission (IEC) TC-57 family of communication standards was identified as an open (non-proprietary) platform with existing broad acceptance for substation applications and possible usage in distribution circuits. IEC 61850 is a principal component of the platform that warranted further investigation in the second (demonstration) phase of the project. The

[1] In Europe the standards for safety and quality for product and service are developed and agreed by the three officially recognized European Standardization Organizations: the European Committee for Standardization (CEN), the European Committee for Electrotechnical Standardization (CENELEC) and the European Telecommunications Standards Institute (ETSI).

project furthermore provided a ten-year implementation roadmap on how the proposed changes to the SDG&E architecture could be accomplished.

A test system was constructed, and a total of eleven use cases were defined to demonstrate the use of IEC 61850 standards. The uses cases included tests of the ability of IEC 61850 to integrate substation and feeder devices and perform some of the advanced communications and automation necessary to optimize the use of DER and other IEDs. Other tests were defined to examine the process and organizational impact of utilizing IEC 61850, while others were used to compare IEC 61850 with other protocols, such as DNP 3.0 and OpenFMB[2]. The demonstration showed that IEC 61850 has some unique abilities that offered tangible benefits over current approaches. These include:

- Improved protection systems.
- Enhanced distribution system operations.
- Improved distribution system stability.
- Improved system performance under emergency conditions.

Other use cases demonstrated that correct selection of tools and vendor products can minimize the level of effort and issues encountered, as there are still issues around IEC 61850 interoperability that complicate system integration issues. Improving interoperability and simplifying system configuration are two focus areas for the user community working on enhancements to the standard so continued improvement is expected. The performance of DNP 3.0 and IEC 61850 were found to be comparable when used between substation and simulated utility control center. However, there was a large difference in the performance of IEC 61850 and OpenFMB when used for the same application, with IEC 61850 substantially outperforming OpenFMB because none of the devices tested provided native support for OpenFMB, necessitating the use of protocol converters.

The project demonstrated that IEC 61850 provides real, tangible benefits. It also underscored that the plug-and-play concept envisaged by the creators of the standard remains a work in progress and that constructing an IEC 61850-based system can be challenging, especially when different vendor products are integrated together. However, the benefits far outweigh the challenges, and the adoption of the IEC 61850 protocol should be one of the cornerstones of the new SDG&E architectural construct.

The recommendation is therefore that SDG&E should pursue the operational deployment of IEC 61850 via a pilot project that aside from exploring the operational adoption of the standards, should also be tasked with quantifying costs and benefits to form the basis for developing a cost-benefit analysis for wide-scale deployment, examining the changes to standard operating procedures necessary to fully leverage the benefit of a digital substation, and acting as a training platform for engineering, testing and commissioning personnel.

[2] Distributed Network Protocol, and Open Field Message Bus.

TABLE OF CONTENTS

EXECUTIVE SUMMARY ..... **III**

LIST OF ACRONYMS AND ABBREVIATIONS ..... **XIV**

1 INTRODUCTION **1**

1.1 Objective 1
1.2 Issue/problem being addressed 1
1.3 Project description, tasks, and deliverables produced 2
1.4 How to read this report 4

2 PROJECT APPROACH **6**

2.1 Phase 1 – SDG&E Internal Project Work Prior to Contractor Procurement 6
2.2 Phase 2 – Task 1: Baseline 9
2.2.1 Introduction to SGAM 9
2.2.2 RACI analysis 11
2.2.3 Business layer 12
2.2.4 Functional layer 13
2.2.5 Information layer 14
2.2.6 Communications layer 16
2.2.7 Component layer 19
2.2.8 Security architecture 19
2.2.9 Conclusions regarding SDG&E's current situation 20
2.3 Phase 2 – Task 2: Evaluate reference architectures 23
2.3.1 Smart Grids Architecture Model (SGAM) 23
2.3.2 IEC TC-57 reference architecture 23
2.3.3 Gridwise framework 24
2.3.4 EPRI Intelligrid 26
2.3.5 Others 26
2.3.6 Recommended architecture framework for SDG&E 27
2.4 Phase 2 – Task 3: Evaluate standards and protocols 29
2.4.1 Standards included in NIST Smart Grid Roadmap 29
2.4.2 Other relevant standards that could impact distribution operations 41
2.4.3 Harmonization efforts among standards 47
2.4.4 Summary and conclusions regarding standards and protocols 49
2.5 Phase 2 – Task 4: Define architecture for SDG&E 50
2.5.1 Architecture governance 50
2.5.2 Business layer 52
2.5.3 Functional layer 52
2.5.4 Information layer 52
2.5.5 Communications layer 56
2.5.6 Component layer 58
2.5.7 Representative security architecture model 58

2.5.8 Issues or problems addressed by the proposed architecture 60
2.5.9 Summary and roadmap for proposed architecture implementation 63
2.5.10 Implementation planning 64
2.6 Phase 3 – Task 5: Design test system 67
2.6.1 System components 70
2.6.2 Use cases 71
2.6.3 Data collection 76
2.7 Phase 3 – Task 6: Build the test system 77
2.7.1 Test plans 77
2.7.2 System setup 77
2.8 Phase 3 – Task 7: Perform the demonstration 80
2.8.1 System Tests 80
2.8.2 Use Case 1: Lifecycle asset provisioning and integration with IEC 61850 85
2.8.3 Use Case 2: Maintenance testing of IEDs 92
2.8.4 Use Case 3: Breaker failure scheme 99
2.8.5 Use Case 4: Automatic transfer scheme 103
2.8.6 Use Case 5: Improved protection coordination 108
2.8.7 Use Case 6: DER control mode change 114
2.8.8 Use Case 7: Grid support using DERs 122
2.8.9 Use Case 8: Emergency load management tests 131
2.8.10 Use Case 9: Dynamic emergency load control and management with DERs using OpenFMB 139
2.8.11 Use Case 10: Dynamic circuit load management 145
2.8.12 Use Case 11: Volt-var control via OpenFMB 154
2.9 Phase 4 – SDG&E Internal Project Work Prior to Project Conclusion 160
3 FINDINGS 161
3.1 Challenges observed in SDG&E's current architecture 161
3.2 Most appropriate architectural model for SDG&E's future use 161
3.3 Trends in communications standards development 162
3.4 Roadmap for proposed architecture implementation 162
3.5 Engineering an IEC 61850 system 163
3.6 IEC 61850 Interoperability 164
3.7 Testing an IEC 61850 system 165
3.8 Implementing a breaker failure scheme using IEC 61850 166
3.9 Implementing an automatic transfer scheme using IEC 61850 166
3.10 Improving protection coordination using IEC 61850 166
3.11 Integrating DER devices into an IEC 61850 scheme 166
3.12 Using DER devices for grid support in an IEC 61850 scheme 167
3.13 Emergency load management in an IEC 61850 scheme 167
3.14 OpenFMB versus IEC 61850 for integrating DER 167
3.15 Using IEC 61850 between substation and simulated control center 168
3.16 Cost comparison – IEC 61850 vs a conventional design 168

4 RECOMMENDATIONS AND NEXT STEPS 170
4.1 Recommendations regarding commercial adoption of the demonstrated architecture 170
4.2 Recommendations for tech transfer of results from this EPIC project 171
5 METRICS AND VALUE PROPOSITION 172
5.1 Metrics 172
5.2 Value Proposition 172
6 REFERENCES 174
A. APPENDIX A – IEC 61850 TOOLS AND UCA 2017 INTEROPERABILITY TEST 175
A.1 Introduction 175
A.2 Test program 176
A.3 Engineering tools 176
A.4 Summary 176
B. APPENDIX B – THE IEC 61850 SYSTEM CONFIGURATION PROCESS 179
B.1 Classical P&C engineering process 179
B.2 IEC 61850 P&C engineering process 182
C. APPENDIX C – OPENFMB PRIMER 189
C.1 Introduction to OpenFMB 189
C.2 Advantages 191
C.3 Implementation and adoption challenges 192
D. APPENDIX D – ADDITIONAL USE CASE RESULTS 193
D.1 Use Case 1: Lifecycle asset provision and integration 193
D.2 Use Case 2: Maintenance testing of IEDs 206
D.3 Use Case 4: Automatic transfer scheme 219
D.4 Use Case 5: Improved protection coordination 225
D.5 Use Case 6: DER control test results 230
D.6 Use Case 7: Grid support using DERs 233
D.7 Use Case 8: Test Records for Emergency load management tests 271

Figure Index

Figure 1-1. Phase 2 tasks. 3
Figure 1-2. Phase 3 tasks. 4
Figure 2-1. Business Units that participate in Distribution Operations functions 12
Figure 2-2. Distribution Operations major functional groups 14
Figure 2-3. SDG&E as-is information layer 15
Figure 2-4. SDG&E as-is communications application layer 17
Figure 2-5. SDG&E as-is communications transport layer 18
Figure 2-6. SGIP's Smart Grid catalog of standards (as of 3/13/2017). 30
Figure 2-7. Business function categories and functions, augmented with target functions 54
Figure 2-8. Proposed information layer architecture 55
Figure 2-9. Proposed communications applications layer 57
Figure 2-10. Proposed communications transport layer 59
Figure 2-11. Single Line Diagram of the test system showing key elements. 68
Figure 2-12. System configuration of actual IEDs showing interconnections. 69
Figure 2-13. Substation racks. 78
Figure 2-14. Feeder rack. 79
Figure 2-15. Snapshot of the MicroSCADA HMI for a particular system operating condition 82
Figure 2-16. A binary GOOSE message sent by RER620 to trip CCR2-32R for a downstream feeder fault 84
Figure 2-17. Analog GOOSE message sent by REC670 to RTAC to be used in GS-DER use case 84
Figure 2-18. Main steps to integrate a new IED for an IEC 61850 based system 87
Figure 2-19. Main steps to integrate a new IED for a system with DNP3.0 and hardwired interconnections 87
Figure 2-20. IEC 61850 engineering tools and data flow 88
Figure 2-21. Main steps to remove an existing IED from an IEC 61850 based system 89
Figure 2-22. Main steps to remove an existing IED from a traditional system 89
Figure 2-23. Test set-up for maintenance testing of IEDs 93
Figure 2-24. Behavior of different test modes used for IED maintenance testing use case 95
Figure 2-25. Behavior of different simulation modes used for IED maintenance testing use case 96
Figure 2-26. Isolated testing using IEC 61850 test mode 97
Figure 2-27. Breaker failure logic 101
Figure 2-28. Automatic transfer scheme logic 105
Figure 2-29. Fault currents and relay settings on feeder 109
Figure 2-30. Blocking logic and trip logic of feeder relay at Substation C 111
Figure 2-31. Logic diagram of the DER-CMC use case 115
Figure 2-32. Test system SLD highlighting DER locations and circuit and bus identifiers 117
Figure 2-33. Response of the Battery to a sequence of control commands 118
Figure 2-34. Response of PV1 to a sequence of control commands (Control Mode 1) 119
Figure 2-35. Response of PV1 to a sequence of control commands (Control Mode 2) 119
Figure 2-36. PV output power when its control mode changes to droop 120
Figure 2-37. PV terminal voltage (average value) when the PV control mode changes to V-Q droop 121
Figure 2-38. Logic diagram of the GS-DER use case 124
Figure 2-39. BESS voltage prior and during a fault at Bus 305. 125
Figure 2-40. Trip signals for an SLG fault downstream of the CCR2-32R (Case 7.5) 127
Figure 2-41. Fault voltages and current prior, during, and subsequent to an SLG fault on Bus 305. 128
Figure 2-42. Reactive power contribution of DERs during the test (Case 7.11) 129
Figure 2-43. Real and reactive power flowing through the feeder breaker (CCR1) (Case 7.11) 129

Figure 2-44. Real and reactive power flowing through the feeder breaker (CCR2) (Case 7.11) 129
Figure 2-45. Circuit power factors during the test (Case 7.11) 130
Figure 2-46. Voltage of Bus 305 during the test (adjusted by reactive power contribution of BESS 2) ... 130
Figure 2-47. Logic diagram of the ELM use case 133
Figure 2-48. Power of the transformer banks during the test (Case 8.1) 135
Figure 2-49. Power of the DER units during the test (Case 8.1) 135
Figure 2-50. Power of the DER units during the test (Case 8.9) 136
Figure 2-51. Power of the transformer banks during the test (Case 8.9) 136
Figure 2-52. Power of the DER units during the test (Case 8.10) 137
Figure 2-53. Power of the transformer banks during the test (Case 8.10) 137
Figure 2-54. Power of the DER units during the test (Case 8.11) 138
Figure 2-55. Power of the transformer banks during the test (Case 8.11) 138
Figure 2-56. Load shedding performed by the use case logic to address the load shedding request (Case 8.11) 138
Figure 2-57. A high-level system diagram and data flow for the DELCAM use case 141
Figure 2-58. Real power flow through feeder CB without BESS contribution (Case 9.3) 143
Figure 2-59. Real power flow through feeder CB with BESS contribution through OpenFMB platform (Case 9.3) 143
Figure 2-60. Reactive power flow through feeder CB with and without BESS contribution (Case 9.2) ... 144
Figure 2-61. A high-level system diagram and data flow for DCLM use case 147
Figure 2-62. Real power flow through feeder CB with and without BESS contribution (Case 10.2) 149
Figure 2-63. Reactive power flow through feeder CB with and without BESS contribution (Case 10.2) . 149
Figure 2-64. Overall system setup for comparing MMS and DNP3 communication protocols 151
Figure 2-65. Test condition for comparison between MMS and DNP3 protocols 152
Figure 2-66. A high-level system diagram and data flow for VVM use case 156
Figure 2-67. Reactive power flow through feeder CB with and without BESS contribution (Case 11.3) . 158
Figure 2-68. Voltage reference for GridCo device (Case 11.3) 159
Figure A-1. IOP testing in ballroom of Marriott Convention Center, New Orleans 175
Figure A-2. Continuing testing and reviewing of progress 175
Figure B-1. Classical P&C engineering process and documentation 180
Figure B-2. IEC 61850 top-down engineering process 182
Figure B-3. IEC 61850 Engineering Documentation 184
Figure B-4. IEC 61850 configuration process 185
Figure C-1. Evolution from present data communication with field devices towards OpenFMB [12] 190
Figure C-2. Graphical representation of the OpenFMB framework 190
Figure C-3. Unified Modeling Language (UML) representation of OpenFMB data model for BESS 191
Figure D-1. Step 1: Configure new IED, functions and settings 194
Figure D-2. Step 2: Export and Import ICD/CID file of the new IED device 195
Figure D-3. Example XML format of a CID file 196
Figure D-4. Step 3: Engineer data flow 197
Figure D-5. Step 4: Import SCD and connect input section 198
Figure D-6. Step 5: Upload SCD/CID to new IED and GOOSE subscribers 199
Figure D-7. Using IEC 61850 tool to check basic communication and data model consistency 200
Figure D-8. Detected revision mismatch in a report control block between SCD and real IED 200
Figure D-9. GOOSE matrix in system engineering tool 201
Figure D-10. IEC 61850 testing tool showing data flow view and simulated faulty IED 202
Figure D-11. GOOSE input section for a single device in Vendor 1 IED tool 202
Figure D-12. Deleting and IED in Vendor 2's configuration tool 203

Figure D-13. Tekron Time Server Configuration 204
Figure D-14. Open configuration file before downloading to new time master device 205
Figure D-15. Setting mode in Vendor 2's configuration tool for REC670 208
Figure D-16. Online status of received GOOSE (q=good) in REC670 (mode=on) 209
Figure D-17. Captured GOOSE (q=good) message sent by REF615 209
Figure D-18. Setting mode in Vendor 2's configuration tool for REF615 210
Figure D-19. Online status of received GOOSE (q=test) in REC670 (mode=on) 211
Figure D-20. Captured GOOSE (q=test) message sent by REF615 211
Figure D-21. Setting mode to "test" in Vendor 2's configuration tool for REC670 212
Figure D-22. Online status of received GOOSE (q=test) in REC670 (mode=test) 213
Figure D-23. Captured GOOSE (q=good) message sent by REC670 213
Figure D-24. Setting mode to "test/blocked" in Vendor 2's configuration tool for REC670 214
Figure D-25. Captured GOOSE messages with test and test/blocked modes 215
Figure D-26. Captured events from REC670 and REF615 216
Figure D-27. Captured GOOSE messages with test and test modes 216
Figure D-28. Setting Simulation Flag in Omicron Tool 217
Figure D-29. Omicron Tool: Simulated SV streams 218
Figure D-30. Reponses of the SMA inverter in Control Mode 1 230
Figure D-31. Reponses of the SMA inverter in Control Mode 2 230
Figure D-32. Response of BESS 2 in Control Mode 1 231
Figure D-33. Response of BESS 2 in Control Mode 2 231
Figure D-34. Response of BESS 2 in Control Mode 3 (output power) 232
Figure D-35. Response of BESS 2 in Control Mode 1 (terminal voltage) 232
Figure D-36. DER reactive power measurements (Mvar) 233
Figure D-37. CCR1 power flow measurement (MW & Mvar) 233
Figure D-38. CCR2 power flow measurement (MW & Mvar) 234
Figure D-39. CCR1 & CCR2 power factor measurement (pu) 234
Figure D-40. DER reactive power measurements (Mvar) 235
Figure D-41. CCR1 power flow measurement (MW & Mvar) 235
Figure D-42. CCR2 power flow measurement (MW & Mvar) 236
Figure D-43. CCR1 & CCR2 power factor measurement (pu) 236
Figure D-44. RMS voltage at bus #305 (pu) 237
Figure D-45. DER reactive power measurements (Mvar) 238
Figure D-46. CCR1 power flow measurement (MW & Mvar) 238
Figure D-47. CCR2 power flow measurement (MW & Mvar) 239
Figure D-48. CCR1 & CCR2 power factor measurement (pu) 239
Figure D-49. DER reactive power measurements (Mvar) 240
Figure D-50. CCR1 power flow measurement (MW & Mvar) 240
Figure D-51. CCR2 power flow measurement (MW & Mvar) 241
Figure D-52. CCR1 & CCR2 power factor measurement (pu) 241
Figure D-53. Battery instantaneous voltage (kV) - High voltage side 242
Figure D-54. Battery rms voltage (pu) - High voltage side 242
Figure D-55. Fault current at Bus #305 (kA) 243
Figure D-56. Battery initial trip signal 243
Figure D-57. Battery local trip signal 244
Figure D-58. Battery final trip signal 244
Figure D-59. 751 relay trip signal 245
Figure D-60. 751 relay pickup signal 245

Figure D-61. Battery instantaneous voltage (kV) - High voltage side 246
Figure D-62 Battery rms voltage (pu) - High voltage side 246
Figure D-63. Fault current at Bus #305 (kA) 247
Figure D-64. Battery initial trip signal 247
Figure D-65. Battery local trip signal 248
Figure D-66. Battery final trip signal 248
Figure D-67. 751 relay trip signal 249
Figure D-68. 751 relay pickup signal 249
Figure D-69. Battery instantaneous voltage (kV) - High voltage side 250
Figure D-70. Battery rms voltage (pu) - High voltage side 250
Figure D-71. Battery initial trip signal 251
Figure D-72. Battery local trip signal 251
Figure D-73. Battery final trip signal 252
Figure D-74. 751 relay trip signal 252
Figure D-75. 751 relay pickup signal 253
Figure D-76. CBCCR2 status signal 253
Figure D-77. Battery instantaneous voltage (kV) - High voltage side 254
Figure D-78. Battery rms voltage (pu) - High voltage side 254
Figure D-79. Fault current at Bus #305 (kA) 255
Figure D-80. Battery initial trip signal 255
Figure D-81. Battery local trip signal 256
Figure D-82. Battery final trip signal 256
Figure D-83. 751 relay trip signal 257
Figure D-84. 751 relay pickup signal 257
Figure D-85. CBCCR2 status signal 258
Figure D-86. Battery instantaneous voltage (kV) - High voltage side 259
Figure D-87. Battery rms voltage (pu) - High voltage side 259
Figure D-88. Fault current at Bus #305 (kA) 260
Figure D-89. Battery initial trip signal 260
Figure D-90. Battery local trip signal 261
Figure D-91. Battery final trip signal 261
Figure D-92. 751 relay trip signal 262
Figure D-93. 751 relay pickup signal 262
Figure D-94. Battery instantaneous voltage (kV) - High voltage side 263
Figure D-95. Battery rms voltage (pu) - High voltage side 263
Figure D-96. Fault current at Bus #305 (kA) 264
Figure D-97. Battery initial trip signal 264
Figure D-98. Battery local trip signal 265
Figure D-99. Battery final trip signal 265
Figure D-100. 751 relay trip signal 266
Figure D-101. 751 relay pickup signal 266
Figure D-102. DER reactive power measurements (Mvar) 267
Figure D-103. CCR1 power flow measurement (MW & Mvar) 267
Figure D-104. CCR2 power flow measurement (MW & Mvar) 268
Figure D-105. CCR1 & CCR2 power factor measurement (pu) 268
Figure D-106. DER reactive power measurements (Mvar) 269
Figure D-107. CCR1 power flow measurement (MW & Mvar) 269
Figure D-108. CCR2 power flow measurement (MW & Mvar) 270

Figure D-109. CCR1 & CCR2 power factor measurement (pu) 270
Figure D-110. DER active power flow measurements (MW) 271
Figure D-111. LTC active power flow measurements (MW) 271
Figure D-112. CCR2_30R and CCR1_306R active power flow measurements (MW) 272
Figure D-113. DER active power flow measurements (MW) 273
Figure D-114. LTC active power flow measurements (MW) 273
Figure D-115. CCR2_30R and CCR1_306R active power flow measurements (MW) 274
Figure D-116. DER active power flow measurements (MW) 275
Figure D-117. LTC active power flow measurements (MW) 275
Figure D-118. CCR2_30R and CCR1_306R active power flow measurements (MW) 276
Figure D-119. DER active power flow measurements (MW) 277
Figure D-120. LTC active power flow measurements (MW) 277
Figure D-121. CCR2_30R and CCR1_306R active power flow measurements (MW) 278
Figure D-122. DER active power flow measurements (MW) 279
Figure D-123. LTC active power flow measurements (MW) 279
Figure D-124. CCR2_30R and CCR1_306R active power flow measurements (MW) 280
Figure D-125. DER active power flow measurements (MW) 281
Figure D-126. LTC active power flow measurements (MW) 281
Figure D-127. CCR2_30R and CCR1_306R active power flow measurements (MW) 282
Figure D-128. DER active power flow measurements (MW) 283
Figure D-129. LTC active power flow measurements (MW) 283
Figure D-130. CCR2_30R and CCR1_306R active power flow measurements (MW) 284
Figure D-131. DER active power flow measurements (MW) 285
Figure D-132. LTC active power flow measurements (MW) 285
Figure D-133. CCR2_30R and CCR1_306R active power flow measurements (MW) 286
Figure D-134. DER active power flow measurements (MW) 287
Figure D-135. LTC active power flow measurements (MW) 287
Figure D-136. CCR2_30R and CCR1_306R active power flow measurements (MW) 288
Figure D-137. DER active power flow measurements (MW) 289
Figure D-138. LTC active power flow measurements (MW) 289
Figure D-139. CCR2_30R and CCR1_306R active power flow measurements (MW) 290
Figure D-140. DER active power flow measurements (MW) 291
Figure D-141. LTC active power flow measurements (MW) 291
Figure D-142. CCR2_30R and CCR1_306R active power flow measurements (MW) 292

Table Index

Table 1-1. Navigating the document 4
Table 2-1. SGAM Zones 10
Table 2-2. As-is state of the SDG&E business layer 12
Table 2-3. As-is state of the SDG&E functional layer 14
Table 2-4. Summary of key gaps in the context of SGAM architecture 21
Table 2-5. IEC 60870 standards 31
Table 2-6. IEC 61850 family of standards 32
Table 2-7. IEC 62351 family of cyber security standards 38
Table 2-8. Other standards in NIST CoS that could impact Distribution Operations 39
Table 2-9. IEEE C37.118 standard 43
Table 2-10. Cyber security standards not in SGIP COS 44
Table 2-11. Summary of key gaps between baseline and proposed architectures 60
Table 2-12. System components and their role. 70
Table 2-13. Use cases developed for Phase 3 testing 72
Table 2-14. IEC 61850-specific use case description 72
Table 2-15. Interface-1 communication test cases (DNP3) 80
Table 2-16. Interface-2 communication test cases (MMS) 81
Table 2-17. Interface 3 communication test cases (GOOSE and SV) 83
Table 2-18. Lifecycle asset provisioning test cases and results 90
Table 2-19. Maintenance testing of IEDs test cases and results 97
Table 2-20. Breaker failure scheme test cases and results 102
Table 2-21. Automatic transfer scheme test cases and results 106
Table 2-22. Selected settings for the overcurrent relays 112
Table 2-23. Use cases developed for Phase 3 testing 112
Table 2-24. DER-CMC test cases 116
Table 2-25. GS-DER test cases 123
Table 2-26. ELM test cases 134
Table 2-27. DELCAM test cases 142
Table 2-28. Anti-islanding test cases with OpenFMB 144
Table 2-29. DCLM test cases 148
Table 2-30. Anti-islanding test cases with IEC 61850 150
Table 2-31. Test results round trip time of MMS and DNP3 153
Table 2-32. VVM test cases 157
Table B-1. Classical P&C engineering documentation 181
Table B-2. Overview of IEC 61850 engineering tools 182
Table B-3. Overview of IEC 61850 engineering workflow 186
Table B-4. IEC 61850-6 SCL File Types 188
Table D-1. Values of mode and behavior according to IEC 61850-7-4 Edition 2 206
Table D-2 Tissue values of mode and behavior for blocked 206
Table D-3. Quality bit definition table according IEC 61850-7-3 Edition 2 207

LIST OF ACRONYMS AND ABBREVIATIONS

BESS	Battery Energy Storage System
CB	Circuit Breaker
CEN	Comité Européen de Normalisation European Committee for Standardization
CENELEC	Comité Européen de Normalisation Electrotechnique European Committee for Electrotechnical Standardization
CIM	Common Information Model
COS	Catalog of Standards
CT	Current Transformer
DCLM	Dynamic Circuit Load Management
DELCAM	Dynamic Emergency Load Control and Management
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DSO	Distribution System Operator
D-SCADA	Distribution SCADA
EPIC	Electric Program Investment Charge
ETSI	European Telecommunications Standards Institute
FAT	Factory Acceptance Test
GID	Generic Interface Description
GOOSE	Generic Object-Oriented Substation Event
GWAC	GridWise Architecture Council
IEC	International Electrotechnical Corporation
IED	Intelligent Electronic Device
IOP	Interoperability Test
ITF	Integrated Test Facility
kW	Kilowatt
LTC	Load Tap Changer
MMS	Manufacturing Messaging Standard
MQTT	Message Queueing Telemetry Transport
OpenFMB	Open Field Message Bus
PHIL	Power Hardware in the Loop
PT	Potential Transformer (aka Voltage Transformer)
RACI	Responsible, Accountable, Consulted and Informed
RAMCO	Regional Aggregator, Monitor, and Circuit Optimizer
RFP	Request for Proposal
RTDS	Real Time Digital Simulator
RTU	Remote Terminal Unit
SAT	Site Acceptance Test

SCADA	Supervisory Control and Data Acquisition
SDG&E	San Diego Gas and Electric
SDO	Standards Developing Organization
SGAM	Smart Grids Architecture Model
SGIP	Smart Grid Interoperability Panel
TE	Transactive Energy
TOGAF	The Open Group Architecture Framework
UCA IUG	Utility Communication Architecture International Users Group
VR	Voltage Regulator

1 INTRODUCTION

1.1 Objective

This project was one of three SDG&E Electric Program Investment Charge (EPIC) projects on pre-commercial demonstration of communications architecture for power system operations. The three projects were:

- Smart Grid Architecture Demonstrations (EPIC-1, Project 1)
    - Focus: Communications standards for integration of feeder equipment and DER into networked automation
- Monitoring, Communication, and Control Infrastructure for Power System Modernization (EPIC-2, Project 3)
    - Focus: Open Field Message Bus
- Modernization of Distribution System and Integration of Distributed Generation and Storage (EPIC-2, Project 1)
    - Focus: IEC 61850 in Substation Network

The principal standard of interest in these three demonstrations was International Electrotechnical Commission (IEC) 61850, which is an open (non-proprietary) standard developed by industry stakeholders and promulgated through the IEC. IEC 61850 is part of the IEC TC-57 family of open communications standards for power systems. The intent of these EPIC demonstrations was to increase the body of knowledge available to aid users in making decisions regarding their future power system communications architecture. The final reports for all three of these projects are posted on the San Diego Gas & Electric (SDG&E) EPIC website at www.sdge.com/epic. This body of work was limited in scope by funding availability in the SDG&E EPIC program, and it is acknowledged that a much larger body of work in this area is needed.

This report is the comprehensive final report for the first project listed above. This project was chartered to perform a pre-commercial demonstration of smart grid architecture components to serve as a blueprint for future distribution system development. "Smart grid" is a vague term that means many different things to different individuals, and its popularity is therefore waning due to the confusion it causes. For purposes of this report, when it is necessary to use the term, it is intended to mean advanced distribution system automation.

The specific objectives of this program were to:

- Perform pilot demonstrations of key candidate prototype building blocks of the SDG&E smart grid architecture to determine their suitability for adoption in the architecture;
- Document the results and make recommendations on whether specific building blocks should be adopted; and
- Provide demonstration results to the SDG&E interdepartmental smart grid architecture team to support the implementation phase for any building blocks adopted.

1.2 Issue/problem being addressed

Electric utility power distribution systems are becoming increasingly complex with the integration of intelligent electronic devices (IEDs). As a result, a more advanced system architecture is needed that

can be easily assimilate the new IEDs, have low latency, and be standardized among vendors. The communication architecture including protocols, object models and related standards should be compatible with the electrical system configuration. With new IEDs being introduced in the electrical system, the communication standards for device information models and protocols must ensure necessary information transfers are done to properly operate the more complex system. The new smart grid architecture must address the information exchange requirements for both actual operations of the physical smart grid and for the business transactions associated with those operations.

One type of IED that is seeing very rapid growth on utility systems is distributed energy resources (DER). The increased DER penetration creates unique challenges, such as two-way power flow, changes in system protection practices, and voltage regulation considerations. There is an industry need for demonstrations of advanced communications architecture that would enable the information exchange among the growing number of devices in increasingly complex utility systems.

1.3 Project description, tasks, and deliverables produced

To enable the development of new smart grid architecture, this project focused on investigating and demonstrating architectural constructs to aid SDG&E and the industry in decisions regarding long-term advancements in communication architecture and standards.

Additionally, the project investigated the benefits of one specific protocol, IEC 61850, to determine the feasibility and requirements for application in substations and feeders (including DERs). North American electric utilities are beginning to transition to using IEC 61850 within their substations. Widespread adoption of IEC 61850 has already occurred in some parts of the world. IEC 61850 is based on modern information technology concepts which can be used to structure data, standardize device models, increase peer-to-peer communication and reduce unnecessary wiring. A real-time model of a typical distribution substation with multiple feeders equipped with both conventional distribution system assets and DER was constructed using power hardware in the loop (PHIL)[3] to demonstrate specific uses cases in a controlled environment.

The project was implemented in two phases:

- Phase 1 - SDG&E Internal Project Work Prior to contractor procurement that includes
- Phase 2 – Architecture Baseline and Development
- Phase 3 – Pre-Commercial Demonstration of IEC 61850
- Phase 4 - SDG&E Internal Project Work prior to project conclusion

The Phase 1 activities included the following tasks:

- Task #1 - Development of Project Plan
- Task #2 - RFP Development
- Task #3 - RFP Release, Proposal Evaluation, and Vendor Selection
- Task #4 - Contracting, Procurement, Resourcing, and Kick-Off

The Phase 2 activities included the following tasks:

[3] Using a Real Time Digital Simulator (RTDS)

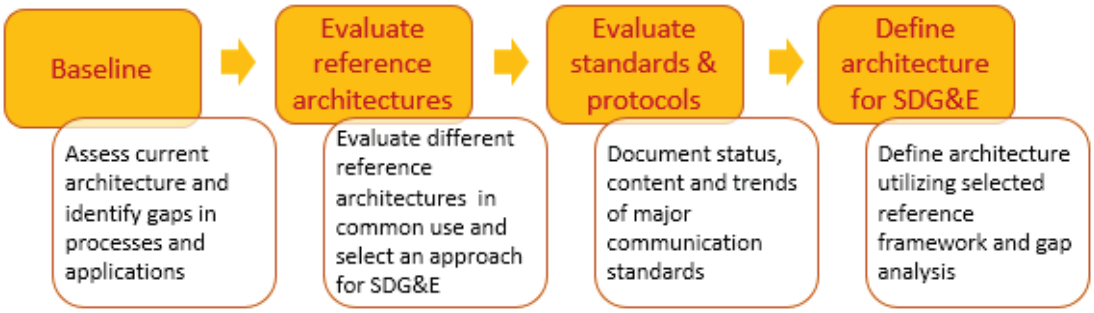


Figure 1-1. Phase 2 tasks.

Phase 2 – Task 1: Baseline

The goal of this task is to establish the as-is condition of the SDG&E system architecture. It assesses the building blocks of the current Distribution Operations architecture. The assessment also focus on identifying gaps in existing processes and applications.

Phase 2 – Task 2: Evaluate reference architectures

The focus of this task is to evaluate the different reference architectures in common-use in the industry and select the one most suitable for SDG&E to document the desired future state.

Phase 2 – Task 3: Evaluate standards and protocols

The goal of this task is to review the status, content, and trends of major utility communications standards (information models, protocols, and relevant cyber security standards), including ongoing relevant work at Standard Development Organizations (SDOs)

Phase 2 – Task 4: Define architecture for SDG&E

This task uses the results from the preceding tasks to define an architecture that utilizes the selected framework and findings from the standard and protocol research, to address the previously identified gaps in the as-is SDG&E architecture.

The purpose of Phase 3 of the project was to demonstrate real-world applications of the standards identified in Phase 2 and show how these can be used in the distribution system to addresses the information exchange needs between major system elements, especially with the increasing penetration of Distributed Energy Resources (DER).

The Phase 3 activities were divided into the following tasks:

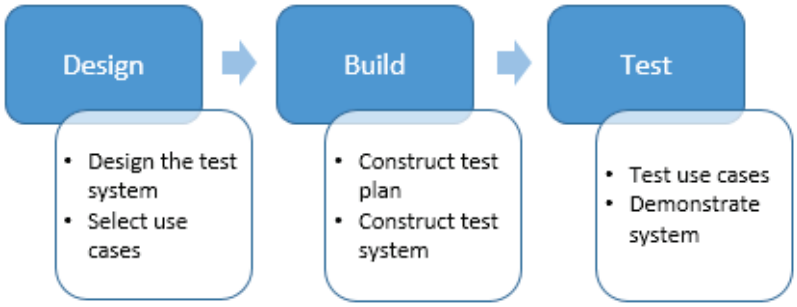


Figure 1-2. Phase 3 tasks.

Phase 3 – Task 5: Design

This task involved the design of a test system and selection of use cases capable of demonstrating the application of the standards identified in Phase 2 in as realistic a fashion as possible and to provide a platform to contrast the performance of the conventional approach to system control with that of an IEC 61850-based approach.

Phase 3 – Task 6: Build

This task involved the creation of a series of factory and site acceptance test procedures intended to test the execution of the use cases on the test platform, as well as the construction of the test system per the design generated in task 5.

Phase 3 – Task 7: Test

This task involved the execution of the use cases on the test system, and the capture of the results, that formed the basis for the findings, recommendations and next steps.

The Phase 4 activities included the following tasks:

- Task #1 – Comprehensive Final Report
- Task #2 – Technology Transfer

1.4 How to read this report

The table below provides a quick reference guide on the primary content areas of the report and the page number where each starts.

Table 1-1. Navigating the document

Item	Description	Starts on page
Baseline	**Phase 2 – Task 1: Baseline** Analyzes the SDG&E as-is condition by assessing the building blocks of the current Distribution Operations architecture and focuses on identifying gaps in existing processes and applications.	9

Item	Description	Starts on page
Evaluate reference architectures	**Phase 2 – Task 2: Evaluate reference architectures** Evaluates the different reference architectures in common-use in the industry and selects the one most suitable for SDG&E to document the desired future state	23
Evaluate standards & protocols	**Phase 2 – Task 3: Evaluate standards and protocols** Reviews the status, content, and trends of major utility communications standards	29
Define architecture for SDG&E	**Phase 2 – Task 4: Define architecture for SDG&E** Defines an architecture that utilizes the selected framework and findings from the standard and protocol research to address the previously identified gaps in the as-is SDG&E architecture.	50
Design	**Phase 3 – Task 5: Design** Designs a test system and selects use cases capable of contrasting the performance of the conventional approach to system control with that of an IEC 61850-based approach.	67
Build	**Phase 3 – Task 6: Build** Creates factory and site acceptance test procedures and constructs a test system.	77
Test	**Phase 3 – Task 7: Test** Details the problem statement, objective(s), test case(s) and results for each of the eleven use cases	80
	Findings Summarizes the results	161
	Recommendations and next steps Where to from here	170
	Appendix A - UCA 2017 interoperability test Describes the activities at the UCA 2017 interoperability test	173
	Appendix B - Simplifying the IEC 61850 system configuration process Addresses some of the current challenges and contrasts the capabilities of several tools	177
	Appendix C – OpenFMB Primer Provides some background information on the OpenFMB protocol suite which is evaluated in several use cases	187
	Appendix D – Additional use case results Provides the results for any test cases that were not described in the use	191

2 PROJECT APPROACH

2.1 Phase 1 – SDG&E Internal Project Work Prior to Contractor Procurement

Task 1 – Project Plan Development

Objective – Develop detailed work plan for the project.

Approach – The project team met with internal stakeholders to conduct a review of existing architecture and future plans to migrate to a more modern standards and protocols. Following activities were reviewed with the stakeholders:

- OpEx2020 vision and Vision 2030
- Relevant projects completed under GRC 2012
- Projects ongoing under EPIC-1 and EPIC-2
- Advanced Distribution Management System (Phase 2)
- Distributed Energy Resource Management System (DERMS) (relevant to the project area)
- Demand Response Management System (DRMS) (relevant to the project area)
- SCADA system
- Existing SDG&E architecture for electrical and communications infrastructure
- 61850 Substation Pilot
- Other relevant material, including but not limited to the IEC TC-57 architecture

The project team identified conceptual, functional and system requirements for the pre-commercial demonstration project. These requirements were identified by reviewing SDG&E's existing plans and high-level use cases to identify key systems and their interactions for key modes of operation. The project plan identified staffing requirements for the project, both internal and contracted, with definition of needed skills. Required equipment and other resources were also identified.

Output – Project work plan including technical scope definition, schedule, budget, and staffing requirements was developed.

Task 2 – RFP Development

Objective - Develop RFP for competitive procurement of contractor services for the requisite phases of the technical scope.

Approach – An RFP was developed for the contracted portion of the work, the contained the following sections:

- Brief Project Background
- Statement of Project Objective
- Scope of Work
- Approach
- List of Deliverables
- Expectations for Tech Transfer Plan
- Project Schedule
- Selection Criteria

- Solicitation Schedule
- Encouragement for Bids with DBE Participation

The RFP was sent to multiple recipients. The proposals expected from the respondents included (at a minimum):

- Meeting the requirements of the RFP (being responsive)
- Proposed technical approach for performing the work
- Concept of operations and system architecture
- System infrastructure specifications
- Test plan for testing at SDG&E facilities
- Measurement, verification and analysis of data
- Findings and recommendations, based on the results
- Tech transfer plan for use of project results
- Reporting to SDG&E
- Conformance with CPUC EPIC Decision 12-05-037 and other relevant EPIC decisions

The selection criteria (at a minimum) addressed the responsiveness of the bidder to the RFP requirements, elaboration on technical approach, cost, bidder experience and company qualifications, DBE participation, team structure, management plan, qualifications of individual team members, proposed schedule, cost, and acceptance of SDG&E Terms and Conditions. Bidders were encouraged to include DBE companies in their project team.

Output – RFP document was developed for release to recipients.

Task 3 – RFP Release, Proposal Evaluation, and Vendor Selection

Objective - Release RFP to external recipients, evaluate proposals received and shortlist prime contractor.

Approach – The project team worked with SDG&E supply management to release the RFP and manage the contractor selection. Obtained bidder responses from supply management and organized for stakeholders review during the evaluation process. Received proposal submittals were be validated, a proposal review team was established and a proposal review schedule was developed. Developed detailed evaluation criteria that evaluated the technical and financial response from the bidders. Scoring criteria incorporated an individual scoring sheet and a consolidated scoring workbook will be developed. Formed an internal proposal and project review panel of SDG&E subject matter experts from stakeholder groups to use the project results. Subsequent to developing the evaluation criteria, responses were sent to the review panel for review and scoring. Two review panel meetings were conducted to review the scores and discuss the proposals. During the evaluation process the scoring matrix was populated to get a clear picture of strength of the bidders' proposals. Proposals were reviewed along with the scoring approaches and scoring criteria. Follow up technical questions were developed for clarification from bidders. The proposals were evaluated to assess proposer's assumptions on SDG&E team activities and identify project risks. Evaluation workshops were conducted for bidders who meet the criteria to be vetted further, and necessary discussions on the technical aspects of the SOW and other terms and conditions were conducted that culminated in the selection of a vendor.

Output – Vendor selection including proposal evaluation matrix, scoring matrix and identification of the selected vendor.

Task 4 – Contracting and Procurement

Objective – Procurement of selected contractor services under contract with Supply Management.

Approach - Engaged with the selected contractor in contract discussions to finalize the scope of work, schedule and budget for the project deliverables. The following documents were developed and finalized as part of the contracts package:

- Detailed scope of work
- Detailed project schedule
- Detailed Project Budget
- Professional services agreement

Output – Prime contractor agreement was finalized with SDG&E supply management and the contractor.

2.2 Phase 2 – Task 1: Baseline

This task involved the analysis of the current SDG&E architecture. A methodology to document the findings was required and the CEN-CENELEC-ETSI[4] Smart Grid Coordination Group's Smart Grids Architecture Model (SGAM) framework was selected for this purpose. As will be described in greater detail in Task 2, SGAM was just one of several reference architectures evaluated for selection to document the desired end-state addressed in Task 4. SGAM was selected because there was an existing body of work available on the current SDG&E architecture that aligned with the SGAM approach. It did not however, preclude the possibility of the final architecture being defined in something other than SGAM.

2.2.1 Introduction to SGAM

A few words are required on the SGAM framework to contextualize the as-is architecture evaluation described in the rest of this section. The SGAM framework is a three dimensional model – two of which describe the so-called Smart Grid Plane.

The two dimensions of the Smart Grid Plane are Domains (covering the complete electrical energy conversion chain: Bulk Generation, Transmission, Distribution, DER and Customers Premises) and Zones (representing the hierarchical levels of power system management: Process, Field, Station, Operation, Enterprise and Market).

The various domain and zone elements are defined in the table that follow:

[4] In Europe the standards for safety and quality for product and service are developed and agreed by the three officially recognized European Standardization Organizations: the European Committee for Standardization (CEN), the European Committee for Electrotechnical Standardization (CENELEC) and the European Telecommunications Standards Institute (ETSI).

Table 2-1. SGAM Zones

Domain	Description
Bulk Generation	Representing generation of electrical energy in bulk quantities, such as by fossil, nuclear and hydro power plants, off-shore wind farms, large scale solar power plant (i.e., PV, CSP) – typically connected to the transmission system
Transmission	Representing the infrastructure and organization which transports electricity over long distances
Distribution	Representing the infrastructure and organization which distributes electricity to customers
DER	Representing distributed electrical resources directly connected to the public distribution grid, applying small-scale power generation technologies (typically in the range of 3 kW to 10,000 kW). These distributed electrical resources may be directly controlled by DSO
Customer Premises	Hosting both – end users of electricity, also producers of electricity. The premises include industrial, commercial and home facilities (e.g., chemical plants, airports, harbors, shopping centers, homes). Also generation in form of e.g., photovoltaic generation, electric vehicles storage, batteries, micro turbines… are hosted

Zone	Description
Process	Including the physical, chemical or spatial transformations of energy (electricity, solar, heat, water, wind …) and the physical equipment directly involved. (e.g., generators, transformers, circuit breakers, overhead lines, cables, electrical loads any kind of sensors and actuators which are part or directly connected to the process…).
Field	Including equipment to protect, control and monitor the process of the power system e.g., protection relays, bay controller, any kind of intelligent electronic devices which acquire and use process data from the power system.
Station	Representing the areal aggregation level for field level, e.g., for data concentration, functional aggregation, substation automation, local SCADA systems, plant supervision…
Operation	Hosting power system control operation in the respective domain, e.g., distribution management systems (DMS), energy management systems (EMS) in generation and transmission systems, microgrid management systems, virtual power plant management systems (aggregating several DER), electric vehicle (EV) fleet charging management systems.
Enterprise	Includes commercial and organizational processes, services and infrastructures for enterprises (utilities, service providers, energy traders…). e.g., asset management, logistics, work force management, staff training, customer relation management, billing and procurement…
Market	Reflecting the market operations possible along the energy conversion chain, e.g., energy trading, mass market, retail market.

The third dimension consist of five interoperability layers (Business, Function, Information, Communications and Component) that are overlaid on the Smart Grid plane following the same Domains and Zones.

The SGAM framework is established by merging the concept of the interoperability layers and smart grid plane. This merge results in the model which spans three dimensions:

- Interoperability (Layers)
- Domains
- Zones

The sub-sections that follow describe the SDG&E as-is state according to this model.

2.2.2 RACI analysis

The Business and Functional layers were developed by first identifying the key Distribution Operations functions, and the business units that have involvement in the functions, assessed through a RACI analysis (responsible, accountable, consulted and informed). The RACI view demonstrates the accountability and responsibility of physical business components, containing business services by business areas or other external organizational units.

- Responsible (R) stakeholders are those that undertake the exercise/action; i.e., do the work.
- Accountable (A) stakeholders are those that own the exercise/deliverable. Only one stakeholder should be accountable for an exercise/deliverable. They may own the budget (i.e., purse strings) and/or have overall management responsibility for the exercise/deliverable.
- Consulted (C) stakeholders are those from whom input is gathered in order to produce the deliverable. They tend to be subject matter experts in specific business areas or technologies.
- Informed (I) stakeholders are those to whom the deliverable is distributed as they tend to have a dependency on its content.

As expected most of the accountability/responsibility falls within the electric operations business area, more specifically Electric Distribution Operations control.

The RACI matrix also showed two areas of concern of stakeholders with regards to the business architecture:

1. Functions where responsibility may fall in multiple business units (siloed operations), and
2. Functions that may need to be further defined to support future operations, mainly market services.

There are several business functions that have multiple business units either responsible, accountable, or both. This is subject to further review to determine if a proper segregation of duties exist for those business functions. Specific observations made include:

- Multiple A, R, or A/R assignments made for a function but appears to be justified based on apparent division of duties depending on circumstances
- More than 1 to 2 A, R, or A/R assignments that may warrant further investigation of flow of responsibility/accountability
- Multiple organizations are A, R, or A/R and perform the same functions—Possible siloed operations that might be made more efficient through standardized or common platforms

2.2.3 Business layer

The SDG&E business layer has been defined in terms of business units and their interdependencies to support the core distribution operation functions. These functions in turn support SDG&E core mission business objectives of providing safe, reliable electric service to customers. The SGAM business layer was constructed, identifying which domain and zone each business unit appears to influence, based on the accountability (A) or responsibility (R) assignment made in the RACI matrix.

Figure 2-1 summarizes the major Business Units that are identified based on SDG&E organization to be involved in supporting the SGAM functional layer.

The main business areas are:

- Planning and policy (asset management)
- Electric operation, that by itself has two sub areas of engineering and operation. Operation also splits between grid operation (transmission grid - EGO) and distribution operation (EDO).
- Information technology and operation technology, and
- Customer services.

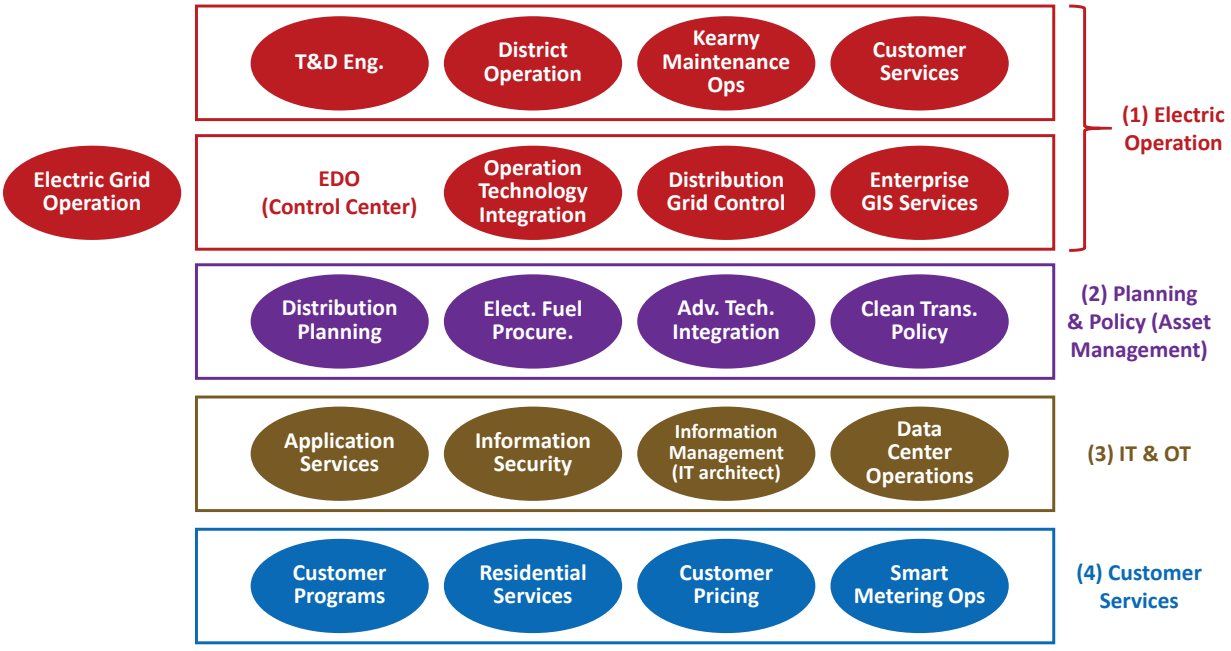


Figure 2-1. Business Units that participate in Distribution Operations functions

As identified in the SGAM analysis, different functional groups were identified in different zones that appear to be common across the domains of interest for Distribution Operations.

Table 2-2. As-is state of the SDG&E business layer

Zones	As-is state
Enterprise	**SDG&E Weather**: Weather and solar potential forecasts are generated daily and distributed across multiple organizations.

Zones	As-is state
	IT&OT: Information and Operation Technology supports all operational units through the establishment and maintenance of common infrastructures, communications networks, applications, data centers, and databases. Data management, archiving and retrieval is necessary across a common function to gather and process data from all domains and zones in order to provide the total picture of system status. As shown at the Functional layer, independent organizations also provide some level of data management, archiving, retrieval, and disposal for their own purposes.
Operation	**DER**: DER monitoring & control functions are shared among the DER group in Electric Operations organization, and the Electric and Fuel procurement group in the Asset Management organization. The SCADA group also gets involved with DER management since any DER control must first be coordinated and approved with SCADA operations. Thus several business units may become involved in a DER operation. The DER group in Electric Operations also becomes involved in microgrid islanding operations as well. **Emergency Operations (management)**: This group provides information on storm crew and fire operations, to support of Electric Systems operations. Thus the group serves cross-cutting functions across all the domains in Electric Operations. This group has full responsibility for these functions, and informs any group who needs to be aware of that information, depending on the circumstances.
Domains	**As-is state**
Transmission	The transmission domain is included in the architecture since it is part of Electric Operations business unit, which encompasses both the EDO and Electric Grid Operations (EGO). EGO works with EDO to coordinate load management and share other information that may affect overall system reliability. EDO works to coordinate management of large scale storage as it related to Grid Operations.
Distribution	EDO in the Electric operations business unit has multiple responsibilities and accountabilities in both Domains as described earlier. However, EDO and DER groups are separate entities, connected only at the top Electric Operation level.
DER	
Customer	Similar to the component, communications, information, and functional layers, the Customer business layer is “self-contained” in the customer business domain, with accountability extending into the Enterprise layer. The CSF and Smart meter operations group of Customer services is accountable for the Customer (end user) monitoring, but the Customer engagement group within the IT&OT Business Unit also shares responsibility for monitoring, and engaging DRMS.

2.2.4 Functional layer

Figure 2-2 summarizes the major functional groups in which the majority of the Distribution Operations functions in the RACI analysis can be categorized.

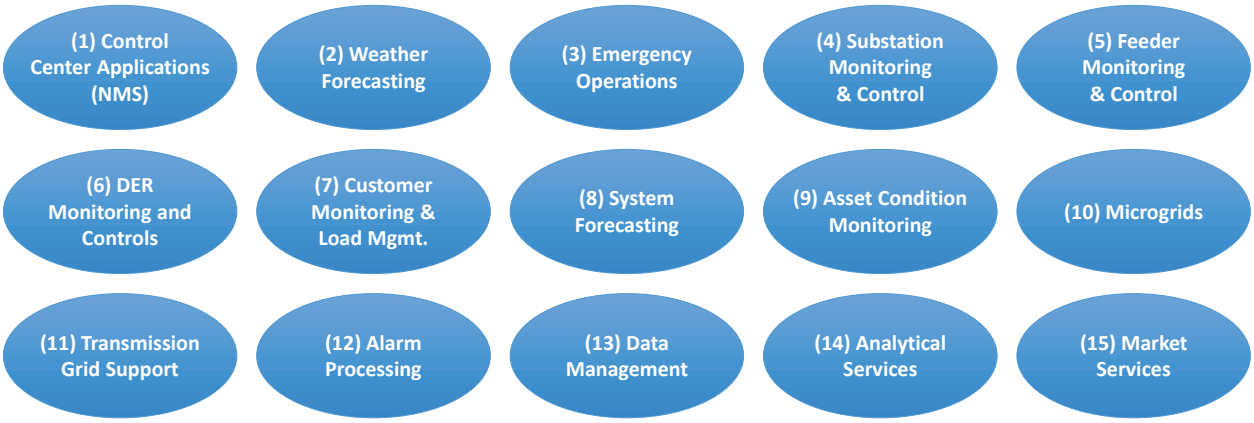


Figure 2-2. Distribution Operations major functional groups

Table 2-3. As-is state of the SDG&E functional layer

Domains	As-is state
Distribution	Most of the functions noted in the RACI analysis fall in the distribution domain, since these functions are the primary responsibility of the EDO. Operation of these distribution functions are interdependent with the DER and Customer functions, since overall system operation and function is affected by the operation of each of these individual domains.
DER	DER functions include the requirements to support distributed generation and storage functions, as described in the component layer. Responsibility for the individual functions lies across several business units as depicted in the RACI analysis.
Customer	Direct customer-facing functions are self-contained within the Customer Services business unit. The Meter Data Management (MDM) and Load Management functions provides data that can be shared and utilized across the other domains.

2.2.5 Information layer

For Enterprise, Data clients/interface points are via an Enterprise Service Bus (ESB). MultiSpeak also exists at the Enterprise layer for communications between the Network Management System (NMS) and the operations zones, and with field DER devices.

Below the Enterprise level, there appears to be an absence of a well-defined information layer. The purpose of an information layer is to describe the information that is being used and exchanged between functions, services, and components. It contains information objects and the underlying canonical data models. These information objects and canonical data models represent the common semantics for functions and services in order to allow an interoperable information exchange via the communications layer.

Within SDG&E there appears to be a variety of means for information exchange via vendor proprietary protocols, specific to a given application or use case, resulting in systems and applications being operated separately. The as-is situation is summarized in Figure 2-3. (NOTE: “Proprietary” in Figure 2-3 refers to “vendor proprietary protocols”.)

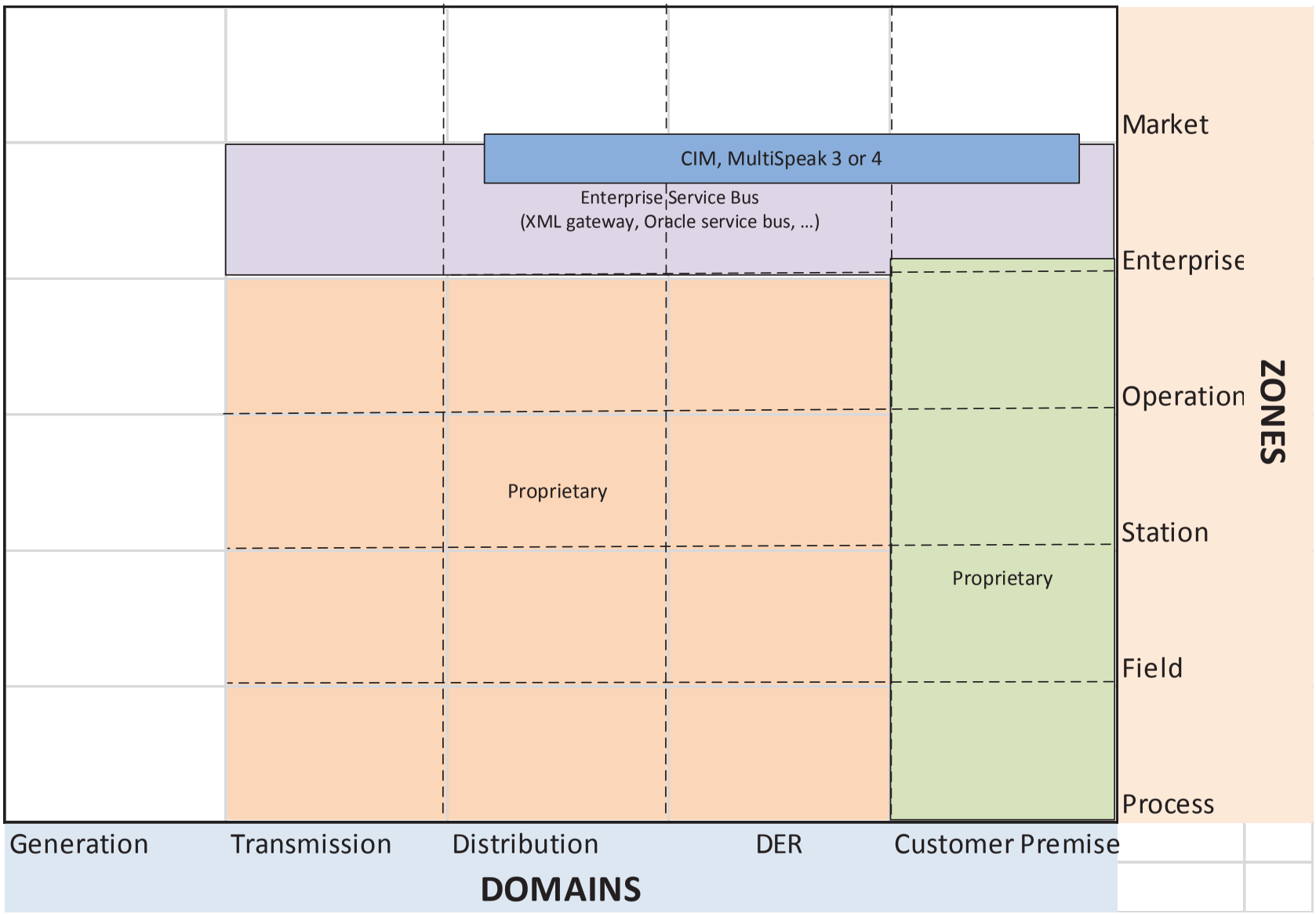


Figure 2-3. SDG&E as-is information layer

2.2.6 Communications layer

The communications layer can be defined as having two parts:

1. The communications applications protocol layer: Communications protocols related to applications such as DNP3, MODBUS, ICCP, etc. that define not only how the protocols interface with the transport protocol layers, but also describe data formats, objects, logical connectivity, etc. that support the given application.
2. The communications transport protocol layer: OSI layer 4 and below, which comprises the transport (layer 4), network (layer 3), data link (layer 2), and physical (layer 1).

2.2.6.1 Communications applications protocol layer

For Enterprise, Data clients/interface points are via an Enterprise Service Bus (ESB). MultiSpeak also exists at the Enterprise layer for direct communications with field DER devices; it is transparent to the zones in between.

At the market layer, a specific protocol is absent to support distribution operations. ICCP exists in the transmission domain, which has become the standard in the transmission domain to support communications between control centers of external entities and SDG&E, including CAISO.

In the Station and Field zones across the distribution and DER domains there exists a variety of communications applications protocols including DNP3, C37.118, IEC 61850, as well as legacy protocols SCOM, and MODBUS. The customer premise domain from process to Enterprise is connected via a specific vendor field area network platform. This is summarized in Figure 2-4 below.

2.2.6.2 Communications transport layer

In the Operation and Enterprise zones, TCP/IP is the prevalent communications wide area networks between sites, and Ethernet based local area networks within a site. IP version 4 is in operation. SDG&E Plans to migrate to IP version 6 is unknown at this time. For the market zones, the use of serial communications appears to be prevalent.

For distribution and DER at the station, field, and process zones, legacy serial connections exist, as well as some IP based communications. Point-to-point radios such as low capacity microwave radio, or point-to-multipoint low speed MAS radios also exist at these levels, primarily not for direct customer interfaces. The RF mesh network associated with the vendor-specific field area network has been established to connectivity with customer applications.

An array of communication media are used to connect the SCADA server to the various devices; microwave, fiber, leased lines, cellular lines (Verizon) and radios (4F and Tropos), among others. Only a fraction of the links are capable of high-speed communication – typically those to the newer generation SI/SA equipped substations – which allows the use of DNP over TCP. DNP serial and SCOM, a legacy serial protocol, are in use to the balance of the SCADA devices. Some substations are equipped with condition based monitoring equipment, and a separate communication path, normally utilizing Modbus, is used to interface with these devices.

Figure 2-5 below maps the current status of the SDG&E communications transport layer to the SGAM Smart Grid plane.

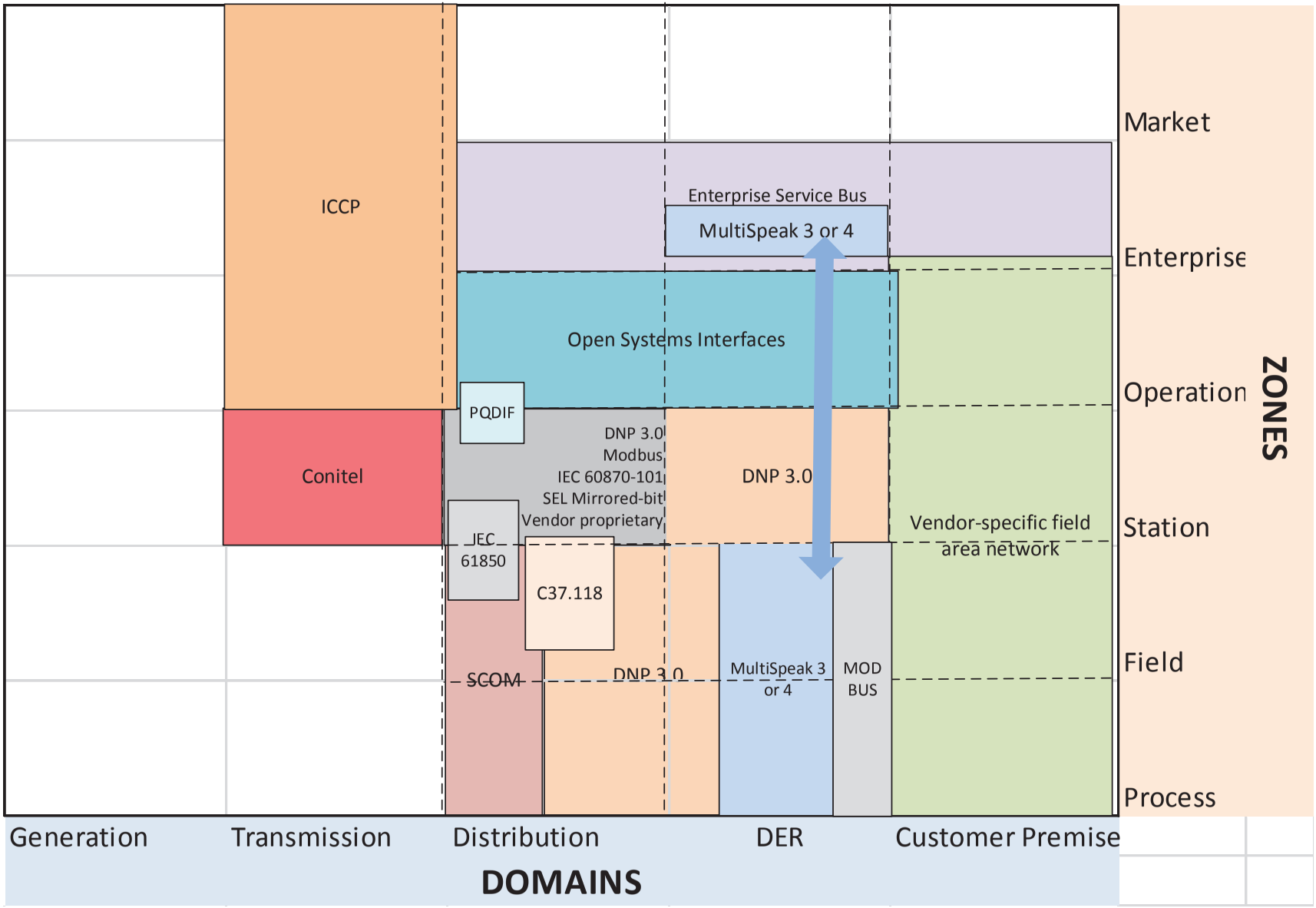


Figure 2-4. SDG&E as-is communications application layer

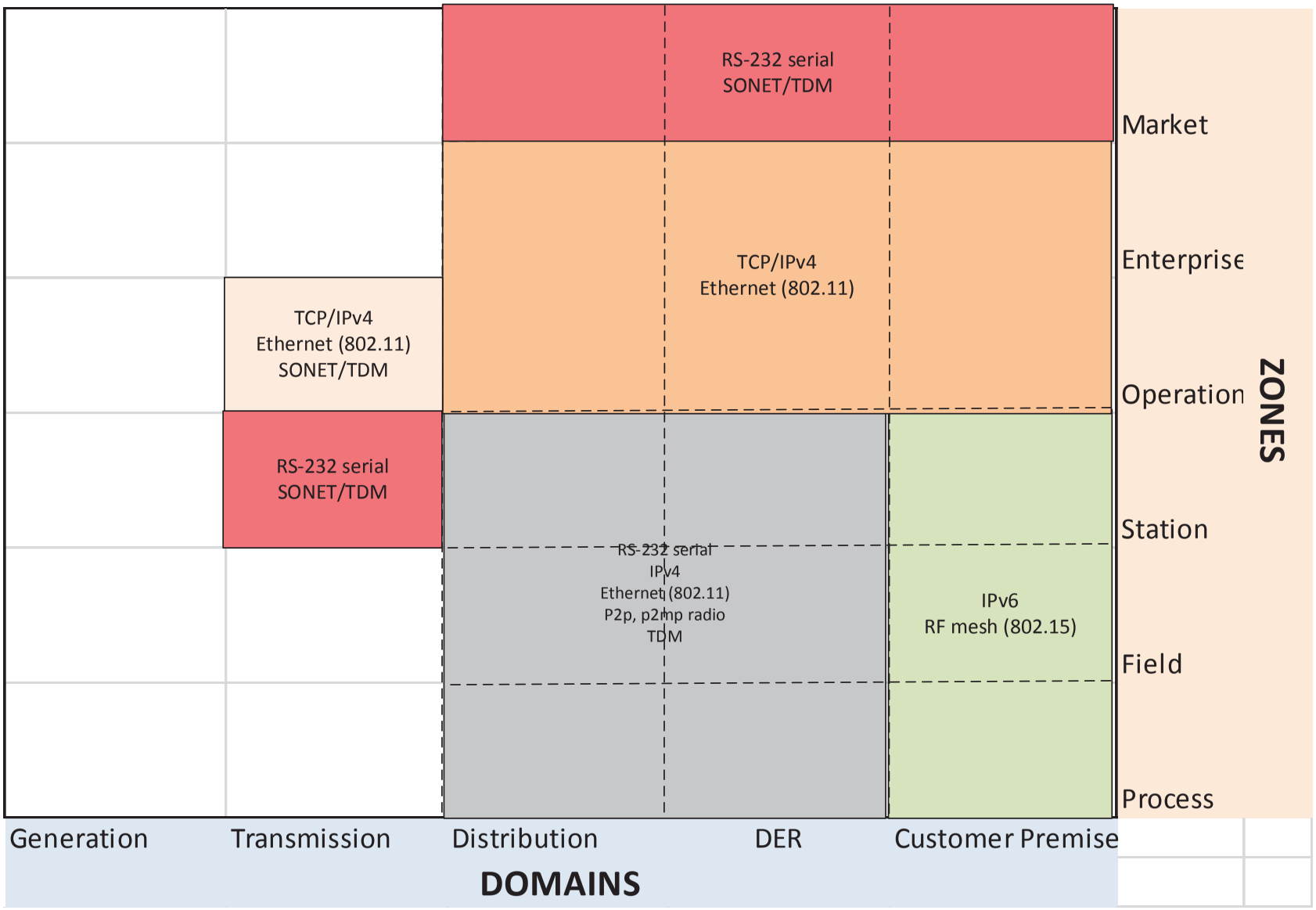


Figure 2-5. SDG&E as-is communications transport layer

2.2.7 Component layer

Electric Distribution Operations (EDO) maintains the current distribution SCADA system and Network Management System (NMS). The primary elements of the system are in the Distribution domain that includes a centralized SCADA server at the operations level that communicates downstream with substation and field devices, and upstream with the NMS, the PI data repository and other clients.

The SCADA server is currently communicating with three different categories of devices:

- *Substation Level*: Legacy SCADA Remote Terminal Unit (RTU) based systems
- *Substation Level*: Substation integration/automation (SI/SA) based systems that utilize data concentrator/substation controller devices (Real-Time Automation Controllers, or RTACs) to integrate data from various microprocessor based Intelligent Electronic Devices (IEDs). Most of these IEDs are inside the substation but there are a few pilot projects in progress where downstream feeder IEDs are integrated back into the substation via a separate RTAC and communications network. Both the feeder and substation RTACs share a secure gateway to the SCADA server.
- *Field level*: There is a subset of feeder devices that are SCADA enabled and under SCADA control, such as SCADA switches, SCADA capacitors, SCADA reclosers, etc. Some circuits also include sensors for faulted circuit indication (FCI) that are communicating through SCADA.

A DER Management System (DERMS) is currently located in the station level and is communicating with a Control Area Manager (CAM). This is a vendor-specific control platform that performs data aggregation and control of groups of assets.[5] The CAM would normally communicate directly with the DER assets but to ensure coordination with, and adherence to, standard operating procedures for the protection and control of distribution assets, all controls are channeled via a Substation Modernization Platform (SMP)[6] gateway device that provides a SCADA-controlled permissive to allow, or block, DERMS controls. A DERMS client is also located at the Enterprise level for monitoring.

Metering data is extracted from meters via a Meter Data Management System (MDMS) and usage data is fed into data warehouse. There is a separate Demand Response Management System (DRMS) that utilizes the vendor specific field area network communication platform. The MDMS and DRMS currently have no touchpoints to SCADA, at any of the levels, and are utilizing a completely separate infrastructure.

2.2.8 Security architecture

Security services support cross domain foundational services, and is discussed in this baseline review at a high-level. The SDG&E security architecture is subject to review of details of what is deemed as confidential and can be disclosed. Key characteristics of the SDG&E security architecture include:

- Data Acquisition Security: SCOM protocol has no security features. DNP3 serial/IP features used
- Security network architecture: shared with Enterprise Information Security
- SCADA Access Security:

[5] A detailed description of the platform and its architecture are considered outside the charter of this document.

[6] Product name for a substation hardened, data concentrator manufactured by Cooper

- User login: Requires separate log-ons by system. Two factor authentication not available (i.e., No smart cards, tokens, dongles or biometric systems in use).
- Remote Operating Access: via VPN and IT security infrastructure but with limited functionality and profile diversity.
- Access Security management: Using simple user account management

The Distribution Operations security architecture is compliant with SDG&E security policies. SDG&E security policies take into account applicable NERC CIP requirements, as well as NISTIR 7628 guidelines.

2.2.9 Conclusions regarding SDG&E's current situation

After meeting with a comprehensive list of internal stakeholders representing Reliability, DER, ADMS, Distribution Planning, EDO, IT, SPACE and Customer Generation, a composite picture of the current and planned control architecture was created. Some of the architectural challenges observed are summarized below:

- **Parallel communication paths**. In some instances there are multiple communication paths from control center entities to the same physical location stemming from restrictions of the existing communication infrastructure, and desire to separate daily operations from experimental and pilot technologies.
- **Time domain separation**. There are functions that require a certain speed of response that are being performed at locations in the architecture that make it challenging to obtain deterministic levels of performance.
- **Centralized decision making**. The architecture is highly centralized, which places restrictions on the speed of response and limits the ability to perform distributed autonomous actions.
- **Communications infrastructure**. The absence of a high speed communication backbone to substation and field devices places restrictions on the type of devices and data that can be integrated into the system.
- **Duplication of functions**. The planned architecture contains some duplication of functions, like Volt/var control for example, with multiple entities identified as being responsible for this application. This may be just a matter of finalizing the correct "owner" for the application, but having the same or similar application in multiple locations is problematic.
- **Roles and responsibilities**. The current architectural depiction developed in the Distributed Control center project did not previously map functions to stakeholders and responsible parties. The RACI analysis for this Smart Grid Architecture Demonstration Project has now established a map of existing roles and responsibilities.
- **DER integration**. DER devices are integrated into the architecture but more as one-offs or pilots than a large scale deployment.
- **Scalability**. There is a concern whether the architecture as currently envisaged can scale adequately, both in terms of increased DER penetration as well as the ability to manage more autonomous functions given the highly centralized nature of the design.

Potential gaps or issues in relation to the SGAM architecture is summarized in Table 2-4.

Table 2-4. Summary of key gaps in the context of SGAM architecture

Ref ID.	Baseline Architecture Issue	Impact
SGAM Component Layer		
C1	SCADA controls are centralized at the control center: As the capabilities of the communications infrastructure advances, additional intelligence will need to be deployed closer to the customer premise, allowing pro-active decisions to be made locally to avoid or minimize outages, while informing the utility systems and operators of the local actions taken. Migration to this architecture will impact all SGAM layers, including present business processes Control of DER assets is not coordinated via SCADA. Direct control is accomplished via vendor proprietary dedicated links. However, the DER asset owners must coordinate with Distribution Operations SCADA prior to implementing any controls	High
C2	The Customer domain appears to be independently operated with no interoperability with other domains. Any data exchange occurs at the Enterprise level, when may impede the implementation of timely actions to improve service.	Med
SGAM Communications Transport Layer		
CT1	Only a fraction of links are capable of high-speed communications (typically those to the newer generation SA/SA equipped substations	Med
SGAM Communications Applications Layer		
CA1	Specific protocol to support distribution operations at market level is absent. Not currently a widely utilized application. However, as utilities migrate to a distribution systems operator (DSO) role, communications among market entities (third party service providers, DER aggregators, CAISO, other utilities) will be important.	Med
CA2	Some legacy protocols still in use such as SCOM, MODBUS; there is a variety of legacy protocols from the process to the Operations levels across all domains. Each protocol requires a certain amount of maintenance and upkeep. There is no clear path of interoperability between the protocols, without having to go to the Enterprise zone to allow a common interface between systems. The component layer confirms that there are no direct connections from the Customer domain to allow interoperable processes to occur	Med
SGAM Information Layer		
I1	In the SGAM context, this layer is virtually non-existent in the SDG&E environment, from the operations layer to the process layer, across all domains. Proprietary methods of defining data information requirements exist with “siloed” applications, and no set of standards. Most of the information formats are defaulted to the communications applications protocols. This is a key gap; to support the multiple proprietary methods results in an increased cost of operations.	High

Ref ID.	Baseline Architecture Issue	Impact
SGAM Functional/Business Layers		
F1	There are independent functions at the market level, for specific needs in Customer programs and Electric & Fuel procurement. There appears to be gaps in this area to support future Distribution operations requirements	Med
F2	Certain functions appear to have multiple business units who are assigned responsibility or accountability, such as: • Storm and fire operations • Feeder Control • Asset condition based monitoring • Load management (emergency) • Substation monitoring, control Some of these multiple assignments can be attributed to the varying requirements of the functions: based on certain operating conditions: at times a certain group may be responsible for the function until a normal operational state is returned; under other conditions, another group may have the responsibility.	Low
F3	Functions of alarm processing, data management, and analytical services appear to be performed independently by the groups in relation to the alarms, data, and analytics for which the group has responsibility or most interest in. Thus these functions may be replicated across several organizations.	High
F4	Reconciliation of proposed use cases with functional and business processes. For Phase 3 testing, a certain number of use cases are identified for testing at the ITF. These use cases should also be reviewed to determine their impact on existing functions, groups, and RACI assignments for Distribution Operations, to identify any changes that may be required from existing processes	High
SGAM Business Layer		
B1	The Distribution, DER, and Customer domains appear to be independently managed with few cross-domain services. This may impede efficiency of operations	Med

2.3 Phase 2 – Task 2: Evaluate reference architectures

This Task provides a summary review of reference architectures including:

- SGAM architecture
- IEC TC-57 reference architecture
- Gridwise Architecture
- EPRI Intelligrid architecture
- Others, including DOE Grid architecture initiative

The objective is to propose a comprehensive architectural framework that would help SDG&E properly capture various aspects of the grid modernization. The key considerations in the selection of the reference architecture are [5]:

- Grid architecture is not just an electric circuit; it is a network of structures that are coupled together within certain constraints. Changes to the grid impact all the set of structures, not just siloed domains.
- Grid architecture is evolving, and needs to accommodate existing legacy systems while drawing plans for future architecture versions.
- Grid architecture involves multiple tiers, and are more that enterprise wide IT systems. Various structures are involved in control, communications, measurement and sensing, data management, and computational capabilities within utility system elements, and non-utility system elements.
- Grid control and coordination may include local optimization and system wide coordination.

The following items can be considered as the motivations for the development and utilization of a reference architecture:

- To obtain a comprehensive plan for the development of future system and components;
- To provide the possibility of identifying the gaps in the “as-is” system
- To provide a proper methodology for addressing standardization gaps
- To identify the required harmonization between standards and suggest possible approaches for this purpose.

2.3.1 Smart Grids Architecture Model (SGAM)

The CEN-CENELEC-ETSI Smart Grid Coordination Group’s Smart Grids Architecture Model (SGAM) Framework [1] aims at offering a support for the design of smart grids use cases with an architectural approach allowing for a representation of interoperability viewpoints in a technology neutral manner, both for current implementation of the electrical grid and future implementations of the smart grid.

Since the model was discussed in some depth in the preceding section, it will not be re-examined again.

2.3.2 IEC TC-57 reference architecture

The TC57 reference architecture, developed through the IEC efforts, helps visualize the existing object models, services, and protocols that are applied in the management of power system and how they relate to each other, and can provide a guide to SDG&E in the formulation of a target reference architecture. The TC57 reference architecture incorporates the key standards that are also included in

the NIST reference [2], although not all the TC57 standards are currently in the NIST Catalog of Standards.

The TC57 reference architecture also provides a “layered” approach starting with a top layer concerned with integration of systems/applications via inter-application messaging as provided via commercial off-the-shelf middleware. Below the top layer are the next two layers considered for data representation (as specified in the Common Information Model (CIM) and Generic Interface Description (GID) interfaces, respectively), as specified in the interface standards of 61970 and 61968. Below these layers represents the various transmission and distribution computer systems/applications for which integration standards are being developed in TC57. The protocols and standards included in the TC57 reference architecture can be harmonized with several layers in the SGAM architecture, especially at the Information and Communications layers.

2.3.2.1 TC57 future trends

Based on the existing TC57 reference architecture, several future trends are identified and discussed in TC57 reference architecture document [3]:

1. Develop a strategy to combine and harmonize the work of these various activities to help facilitate a single, comprehensive plan for deployment of these standards in product development and system implementations. The following are suggested as starting points:
   - Use of Common Object Modeling Language and Rules
   - Harmonization at Model Boundaries
   - Resolution of Model Differences
   - Basis of a Future Vision for TC57
   - Process of Starting New Work in TC57
2. Now that the TC57 standards, such as the 61968/61970 CIM and 61850 standards, have been recognized as pillars for realization of the Smart Grid objectives of interoperability and device management, it is imperative that a correct understanding of these standards and their application be made available to the key stakeholders and all other interested parties involved in implementing the Smart Grid.
3. The future reference architecture for power system information exchange is intended to provide a roadmap for future work in standards development within TC57 that takes into consideration new utility industry needs, directions in new available technology to address these needs, and other relevant activities of a broader nature. It also seeks to establish a strategy for addressing these needs, such as IntelliGrid, the GridWise Architecture Council, etc.

2.3.3 Gridwise framework

The GridWise Architecture Council (GWAC) [4] has turned to the question of how to take advantage of the increased availability of two-way communications and intelligent, communicating devices and sensors within the electric power infrastructure and end-use sites of electric power. The topic of transactive energy (TE) as a means to effectively manage and control an increasingly complex electric power infrastructure has emerged as a focal topic in GWAC’s work to build on previous interoperability work.

The GWAC defines transactive energy as follows:

The term "transactive energy" is used here to refer to techniques for managing the generation, consumption or flow of electric power within an electric power system through the use of economic or market-based constructs while considering grid reliability constraints. The term "transactive" comes from considering that decisions are made based on a value. These decisions may be analogous to or literally economic transactions.

The elements of TE are the components of a transactive architecture that need to be addressed in the design of a system. They provide a starting point for discussion by presenting the basic structure for an approach to transactive architecture design.

GWAC provides some guidance on the creation of a conceptual architecture for transactive energy. Please note that GWAC does not provide such an architecture; that is, the work to be done by a core team of experienced system architects that and would represent the design of a specific example of a TE system. Rather, GWAC suggests key elements and principles to be considered in the development of the Transactive Energy Conceptual Architecture. To that end, the following principles are listed as starting points for the architectural foundation:

1. Strong consideration should be given to the inherent structure of the energy systems under consideration; the hierarchical structure of large-scale power delivery systems from the Balancing Authority to distribution grid endpoint on one hand, and the smaller scale less hierarchical structure of micro-grids on the other. Likewise, the existing control structure for involved energy systems should be considered when developing the structure of the TE architecture.
2. Self-similarity or an approximation may be evident in the relevant structures and should be considered as a means of obtaining scalability and organizational regularity (as a means of dealing with complexity), but recognize that differing goals may apply at different levels in the recursion.
3. Layering for optimization decomposition may be considered as a mathematical foundation for structure of the control and coordination portions of the architecture.
4. The architecture should be agnostic to the general physical layer (refer to the Control Abstraction Model): specific sensors and controls, energy types, etc., should not be specified nor eliminated by the architecture.
5. The ability of the TE system to operate should not be limited to any specific type of communications network or specific technology; e.g., it must not be limited to broadband Internet communications only.
6. The architecture should accommodate open international standards, and must not restrict implementations to proprietary interfaces, algorithms, communication protocols, or application message formats.
7. To the extent possible, the architecture should be adaptable to changes in underlying energy systems, in terms of structure, capabilities, business models, and innovation in value creation and realization.
8. The architecture should include plans for convergence of network types over time: physical networks (energy system infrastructures), information and communication networks, financial networks, and social networks.

As mentioned in this section, GWAC does not provide a reference architecture. Therefore, it is not possible to present a use case for GWAC.

2.3.4 EPRI Intelligrid

The Integrated Energy and Communications Systems Architecture (IECSA or IntelliGrid architecture [5]) project initiated by EPRI represents the initial steps on a journey toward a more capable, secure, and manageable energy provisioning and delivery system. The IntelliGrid architecture project envisions a variety of plausible futures for electric and energy service operations ranging from advanced automation to dynamic consumer response. The project results propose the next steps in the process of bringing this vision to fruition. These steps include using more rigorous systems engineering practices, application of IntelliGrid architecture principles, and implementing the project recommendations.

The IntelliGrid Reference Architecture is based on an Architecture Framework bounded by the information infrastructure requirements of the power system industry. The framework includes the business needs of the power system industry, the strategic vision based on high level concepts of distributed information, the tactical approaches based on technology independent techniques, the standards, technologies, and best practices that could be used in the power industry, and a methodology for project engineers to use to create a coherent system out of the individual pieces. The reference architecture is based on an Architecture Framework bounded by the information infrastructure requirements of the power system industry. The framework includes:

- **Business Needs** of the power system industry, as captured in the power system operations functions, and categorized into the **IECSA Environments**
- **Strategic Vision** based on **High Level Concepts** of distributed information
- **Tactical Approach** based on **Technology Independent Techniques** of common services, information models, and interfaces.
- **Standard Technologies** and **Best Practices** that could be used in the power industry
- **Methodology** for automation architects, power system planners, project engineers, information specialists, and other IntelliGrid users to zone in on the exact parts of the IntelliGrid Architecture that is directly relevant to them, and to quickly access the IntelliGrid recommendations.

The IntelliGrid Reference Architecture framework generalizes and extracts the architecturally significant requirements by cross-cutting energy industry requirements involving distributed information, and provides a technology-independent architecture for project engineers to use as they determine solutions for specific implementations.

2.3.5 Others

In the previous sections, the most widely accepted reference architectures are discussed. However, there are many other reference architectures that are not discussed in detail in this report; they are variations from the widely accepted reference architectures. This section briefly introduces these reference architectures:

2.3.5.1 PNNL Grid Architecture/DOE Grid Architecture Initiative

This reference architecture is prepared for the US Department of Energy (DOE) by Pacific Northwest National Laboratory (PNNL) [6]. It provides selected views into a possible future where the utility power system(especially at the distribution level) becomes a platform for energy innovation, with coordination (not centralized command and control) of many types of resources, allowing multiple control and market mechanisms and approaches to coexist on and connect to the utility power system simultaneously without compromising electric reliability.

2.3.5.2 Smart Grid Reference Architecture

Smart Grid Reference Architecture (SGRA) [7] is collaboratively developed by SCE, IBM, and Cisco. This reference architecture is designed to address the challenges, concerns and questions facing smart grid architects implementing smart grid solutions for their utility. As with any reference architecture, it aims to provide a foundation for utilities in the development of their smart grid architectures and to serve as a guide for implementing specific new features.

2.3.5.3 P2030

This is a standard prepared by IEEE [8]. It provides guidelines in understanding and defining smart grid interoperability of the electric power system with end-use applications and loads. Integration of energy technology and information and communications technology is necessary to achieve seamless operation for electric generation, delivery, and end-use benefits to permit two-way power flow with communication and control. Interconnection and intra-facing frameworks and strategies with design definitions are addressed in this standard, providing guidance in expanding the current knowledge base. This expanded knowledge base is needed as a key element in grid architectural designs and operation to promote a more reliable and flexible electric power system.

2.3.5.4 Smart Grid Conceptual Model

Smart Grid Conceptual Model [9] is a document prepared by NIST/SGIP which provides a tool for discussing the structure and operation of the power system. It defines a set of domains, actors, applications, associations and interfaces that can be used in the process of defining smart grid information architectures. It includes diagrams that can be used for visualizing the use cases and components of the smart grid and its implementation.

2.3.5.5 Smart Energy Reference Architecture

Microsoft has developed a reference architecture based on familiar, cost-effective Microsoft platforms that can serve as the basis for development of the "integrated utility of the future." The Microsoft Smart Energy Reference Architecture (SERA) is Microsoft's first comprehensive reference architecture that addresses technology integration throughout the full scope of the smart energy ecosystem. SERA has been endorsed by a number of global solutions providers whose energy industry solutions span the entire energy ecosystem — from the power grid to the home. SERA helps utilities by providing a method of testing the alignment of information technology with their business processes to create an integrated utility.

2.3.6 Recommended architecture framework for SDG&E

Taking into account each architecture attributes to meet intended purposes, one architecture, SGAM, has been developed relatively recently (2012), building on existing architectures such as the NIST Conceptual Model (NIST 2009), the GridWise Architecture Framework (GWAC 2008), as well as architecture standards like The Open Group Architecture Framework (TOGAF).[7] The SGAM model can describe an architecture through interoperability layers that relate potential use cases and functions and their effect on business requirements and processes. The SGAM model attributes can relate to the elements presented in the discussion above.

[7] TOGAF was developed by The Open Group starting 1995, with several revisions since then

The relatively recent NIST Special Publication 1108r3 (September 2014), advocates the SGAM reference architecture as "a template for architects to follow while building aspects of a smart grid architecture, regardless of an architect's specialty (such as areas of transmission, distribution, IT, back office, communications, asset management, and grid planning." The SGAM utilizes an enterprise-wide, service-oriented approach to describe a smart grid architecture. The architectural framework provided by SGAM can be used as a guide to connect business objective and processes to the functional and system requirements needed to support the business objectives:

- To provide stakeholders a common understanding of the elements that make up the smart grid and their relationships
- To provide key stakeholder communities traceability between the functions and the goals of the smart grid
- To provide a series of high-level and strategic views of the envisioned business and technical services, supporting systems, and procedures
- To provide a technical pathway to the integration of systems across domains, companies, and businesses
- To guide the various implementation architectures, systems, organizational structures and supporting standards that make up the smart grid

The SGAM is an evolving framework, and NIST is working through the SGIP's Smart Grid Architecture Committee (SGAC) to align this effort with the European Union Smart Grid- Coordination Group (SG-CG), the International Electrotechnical Commission (IEC) TC57 WG19 (IEC 62357), and IEC TC8 WG5 and 6 (Use cases).

2.3.6.1 SGAM architecture framework for SDG&E

The SGAM model is the best fit for SDG&E because of its capability to relate the technical layers with business goals, as well as define use cases in relation to their impact on all key layers.

To confirm selection of the recommended reference architecture for SDG&E, meetings and discussions were held with the representatives of SDG&E. Based on these discussions, SGAM was selected for the representation of the SDG&E reference architecture. The main reasons for choosing SGAM were as follows:

- SGAM reuses the existing models (e.g., NIST) and architectural frameworks (GWAC)
- Coherence of SGAM with respect to the overall smart grid standardization process from Smart Grid Coordination group (SGCG)
- SGAM is the most comprehensive reference architecture for use case development because of incorporating business, function, information, communication, and component layers.
- It is possible to map the TC57 in the communication and information layers of SGAM.

2.4 Phase 2 – Task 3: Evaluate standards and protocols

The goal of this task was to review the status, content, and trends of major utility communications standards (information models, protocols, and relevant cyber security standards), including, but not limited to IEC 61850 (for substation, feeder and DER), IEC 61968/61970 CIM, IEEE 1815 (DNP3), and ongoing relevant work at Standard Development Organizations (SDOs).

Two sources of standards development were reviewed:

1. A list of standards that have been deemed relevant by NIST for smart grid implementation were identified. This list provides a starting point and reference source for all standards that have been considered in smart grid implementation. Then the extent of acceptance of the standards were evaluated, through industry experience in industry conferences, sharing of lessons learned, etc. to develop a profile of the most prevalent standards that have actually been included in reference architectures around the industry.
2. Standardization activities within IEC Technical Committee 57 (TC57) and associated working groups (WG): IEC TC57 is chartered with developing standards for electric power system management and associated information exchange in the areas of generation, transmission and distribution real-time operations and planning, as well as information exchange to support wholesale energy market operations. The object models, services, and protocols within TC57 are described as to how they relate to each other through a reference architecture for power system information exchange. Several standards developed through TC57 are included in the NIST list of standards.

From the review, a "qualified" list of standards and protocols are identified that represent industry practices, that are used to benchmark with SDG&E practices currently in place with its "as-is" architecture. The difference between the two represent the gaps that exist in the SDG&E architecture to support the needed protocols and standards.

2.4.1 Standards included in NIST Smart Grid Roadmap

The NIST list of standards now identifies 81 smart grid-listed standards, shown in Figure 2-6. Many other standards are undergoing development and require modifications, some of which are being addressed through the Smart Grid Interoperability Panel Priority Action Plans (SGIP PAPs). They may not be included in the NIST Catalog of Standards (CoS) at this time, but have been listed in Reference [2] as a relevant standard. The SGIP SGAC and SGCC, are also addressing some of these needed modifications. Experience gained with devices designed to meet the requirements of the standards from interoperability testing and certification activities managed by Interoperability Testing and Certification Authorities (ITCAs) will also influence the changes to these standards.

SGIP's Smart Grid Catalog of Standards

Full List of Standards by Entry Number

	SGIP Catalog of Standards	Date
1.	ANSI C12.1-2008 listed Sept 5 2012	10/15/2014
2.	ANSI C12.18-2006 listed Sept 5 2012	10/15/2014
3.	ANSI C12.19-2008 listed Sept 5 2012	10/15/2014
4.	ANSI C12.19-2012-dated 2014-10-07	08/17/2015
5.	ANSI C12.20-2010 listed Sept 5 2012	10/15/2014
6.	ANSI C12.21-2006 listed Sept 5 2012	10/15/2014
7.	ANSI C12.22-2008 listed Sept 5 2012	10/15/2014
8.	ASHRAE 135-2010 BACnet listed Nov 21 2011	10/15/2014
9.	CEA-709.1-C-2014-02-14rev1	10/15/2014
10.	CEA-709.2-A-2014-02-14rev1	10/15/2014
11.	CEA-709.3-2014-02-14rev1	10/15/2014
12.	CEA-709.4-2014-02-14rev1	10/15/2014
13.	CEA-852.1-2014-02-14rev1	10/15/2014
14.	CEA-852-B-2014-02-14rev1	10/15/2014
15.	CEA-CEDIA-CEB29- dated 2012-03-01v1	10/15/2014
16.	IEC 15067.3-dated 2012-11-05	08/17/2015
17.	IEC_60870-6-503 listed Sept 5 2012	10/15/2014
18.	IEC 60870-6-702-1998 listed Sept 5 2012	10/15/2014
19.	IEC 60870-6-802	10/15/2014
20.	IEC_61850-1	10/15/2014
21.	IEC 61850-10	10/15/2014
22.	IEC 61850-2	10/15/2014
23.	IEC 61850-3	10/15/2014
24.	IEC 61850-4	10/15/2014
25.	IEC 61850-5	10/15/2014
26.	IEC 61850-6	10/15/2014
27.	IEC 61850-7-1	10/15/2014
28.	IEC 61850-7-2	10/15/2014
29.	IEC 61850-7-3	10/15/2014
30.	IEC 61850-7-4	10/15/2014
31.	IEC 61850-7-410	10/15/2014
32.	IEC 61850-7-420	10/15/2014
33.	IEC 61850-8-1	10/15/2014
34.	IEC 61850-90-5	10/15/2014
35.	IEC 61850-9-2	10/15/2014
36.	IEC 62351-1	10/15/2014
37.	IEC 62351-2	10/15/2014
38.	IEC 62351-3	10/15/2014
39.	IEC 62351-4	10/15/2014
40.	IEC 62351-5	10/15/2014
41.	IEC 62351-6	10/15/2014
42.	IEC 62351-7	10/15/2014

	SGIP Catalog of Standards	Date
43.	IEC 62351-8-dated 2014-03-21	08/17/2015
44.	IEC-62541 Parts 1-7 listed Nov 2013	10/15/2014
45.	IEEE 1377-dated 2011-02-02	08/17/2015
46.	IEEE 1701	10/15/2014
47.	IEEE 1815-2010 listed Dec 31 2011	10/16/2014
48.	IEEE 1901-2010 listed Jan 31 2013	10/16/2014
49.	IEEE C37.238	10/16/2014
50.	IEEE C37.239-2010 listed May 4 2012	10/16/2014
51.	IEEE1901.2-dated 2011-09-02L	08/17/2015
52.	IETF RFC 6272 listed July 7 2011	10/16/2014
53.	ITU-T G.9960	10/16/2014
54.	ITU-T G.9972	10/16/2014
55.	MultiSpeak® Security V1.0-dated 2013-12-05	10/16/2014
56.	MultiSpeak® V3.0-dated 2013-12-05v1	10/16/2014
57.	NAESB REQ 19	10/16/2014
58.	NAESB REQ 21	10/16/2014
59.	NAESB REQ 22	10/16/2014
60.	NEMA SG-AMI 1	10/16/2014
61.	NISTIR 7628 listed Sept 5 2012	10/16/2014
62.	NISTIR 7761 listed July 7 2011	10/16/2014
63.	NISTIR 7761-dated 20130920R1	10/16/2014
64.	NISTIR 7862	10/16/2014
65.	NISTIR 7943-dated 20140615	8/17/2015
66.	OASIS EMIX listed Dec 31 2011	10/16/2014
67.	OASIS WS	10/16/2014
68.	OASIS-Energy Interop	10/16/2014
69.	OpenADR-2 0a-dated 2012-08-17-sh	10/16/2014
70.	OpenADR-2 0b-dated 2012-08-17rev2	10/16/2014
71.	SAE J1772-2010 listed July 7 2011	10/16/2014
72.	SAE J2836 Use Cases (1-3) listed July 7 2011	10/16/2014
73.	SAE J2847-1 listed Oct 14 2011	10/16/2014
74.	SEP2 0-dated 2013-12-02 update	10/16/2014
75.	SG AMI-1	10/16/2014
76.	SGIP 2011-0008-1	10/16/2014
77.	ANSI/ASHRAE/NEMA Standard # 201p (FSGIM)	03/01/2017
78.	ANSI/CTA-2045	03/01/2017
79.	ITU-T G.9903	03/01/2017
80.	NAESB RMQ.26	03/01/2017
81.	NEMA Standards Publication SG-IPRM 1-2016	03/01/2017

Figure 2-6. SGIP's Smart Grid catalog of standards (as of 3/13/2017).[8]

Of the 81 NIST Smart Grid listed standards, the Quanta team has identified approximately 40 of those listed standards, and at least 10 more relevant standards (not listed in the CoS at this time) that would be more closely related to reference architecture requirements for SDG&E Distribution Operations. The following sections summarize the standards that are listed in the NIST catalog of Standards that may be relevant to SDG&E Distribution Operations.

2.4.1.1 IEC-60870-6

IEC published standard is referred to as TASE.2, comprising 60870-6-503, -505, -702, and -802. The major objectives of TASE.2 are to provide (1) increased functionality and to (2) maximize the use of

[8] List downloaded (3/13/2017) from http://www.sgip.org/wp-content/uploads/SGIPs-Catalog-of-Standards-Complete-List-of-Entries_2017.pdf

existing OSI-compatible protocols, specifically the Manufacturing Messaging Standard (MMS) protocol stack. TASE.2 provides a utility-specific layer over MMS. In addition to SCADA data and device control functionality, the TASE.2 standards also provide for exchange of information messages (i.e., unstructured ASCII text or short binary files) and structured data objects, such as transmission schedules, transfer accounts, and periodic generation reports. This standard is also known as the Inter-control center protocol (ICCP), from the name given by the EPRI project that sponsored the development of the draft specifications for this standard. Its use is prevalent in communications between external control centers. Table 2-5 summarizes the IEC 60870-6 standards.

Table 2-5. IEC 60870 standards

Standard	Application	Comments
IEC 60870-6 -503 Telecontrol Application Service Element 2 (TASE.2)	Defines the messages sent between control centers of different utilities. (T,D)	Open, mature standard developed and maintained by an SDO. It is widely implemented with compliance testing. This is part of the IEC 60870 Suite of standards. It is used in almost every utility for inter-control center communications between SCADA and/or Energy Management System (EMS) systems. It is supported by most vendors of SCADA and EMS systems
IEC 60870-6-702 Telecontrol Equipment and Systems - Part 6: Telecontrol protocols compatible with ISO standards and ITU-T recommendations - Section 702: Functional profile for providing the TASE.2 application service in end systems	Defines a standard profile, or set of options for implementing the application, presentation, and session layers. (T)	This is known as an A-profile. For a complete protocol implementation of TASE.2, this A-profile must interface to a connection-oriented transport profile, or T-profile that specifies the transport, network and possibly data link layers. A T-profile that is commonly used with this standard includes RFC1006, TCP, IP, and Ethernet. This section of the standard defines the Protocol Implementation Conformance Statements (PICS) for TASE.2, including tables specifying which services and objects are mandatory and optional for compliance with the standard.
IEC 60870-6-802 Telecontrol Equipment and Systms - Part 6: Telecontrol protocols compatible with ISO standards and ITU-T recommendations - Section 802: TASE.2 Object Models	Standard for Communications between electric power control centers. Formerly known as Inter control center Protocol (ICCP), the standard is used for communication of electric power system status and control messages between power control centers. (T)	This part of the standard defines the object models used at the application layer of the protocol. It includes data objects for basic Supervisory Control and Data Acquisition (SCADA) as well as specific objects for control center concepts such as Transfer Accounts, Device Outages, and Power Plants.

2.4.1.2 IEC 61850

The IEC 61850 standard is a suite of protocols that address communications networks and systems in substations. This standard defines communications within transmission and distribution substations for

automation and protection. It is being extended to cover communications beyond the substation to integration of distributed resources and between substations.

IEC 61850 is an open standard with conformance testing that is developed and maintained by an SDO. It has been widely adopted world-wide and is starting to be adopted in North America. Developed initially for field device communications within substations, this set of standards is now being extended to communications between substations, between substations and control centers, and including hydroelectric plants, DER, and synchrophasors. It is also adapted for use in wind turbines (IEC 61400-25) and switchgears (IEC 62271-3).

Descriptions of the individual parts of the IEC 61850 specification are shown in Table 2-6 below.

Table 2-6. IEC 61850 family of standards

Standard	Comments
IEC 61850-1 and -2	Part 1 of the standard, provides an overview of the other parts of the standard and an introduction to key concepts used in the rest of the standard, such as logical nodes. Part 2 of the standard is the glossary.
IEC 61850-3	Part 3 of IEC 61850 applies to substation automation systems (SAS). It describes the communication between intelligent electronic devices (IEDs) in the substation and the related system requirements. The specifications of this part pertain to the general requirements of the communication network, with emphasis on the quality requirements. It also deals with guidelines for environmental conditions and auxiliary services, with recommendations on the relevance of specific requirements from other standards and specifications.
IEC 61850-4	The specifications of this part pertain to the system and project management with respect to the following: • Engineering process and its supporting tools • Life cycle of the overall system and its IEDs • Quality assurance beginning with the development stage and ending with discontinuation and decommissioning of the SAS and its IEDs. The requirements of the system and project management process and of special supporting tools for engineering and testing are described. The IEC 61850-4 covers system and project management requirements for Utility Automation Systems, which implies a broader scope than the substation automation communication equipment only. However, the language in the document is heavily based on Substation Automation.
IEC 61850-5	This part of IEC 61850 applies to Substation Automation Systems (SAS). It standardizes the communication between intelligent electronic devices (IEDs) and the related system requirements. The specifications of this part refer to the communication requirements of the functions being performed in the substation automation system and to device models. All known functions and their communication requirements are identified.
IEC 61850-6	Specifies a file format for describing communication-related IED (Intelligent Electronic Device) configurations and IED parameters, communication system configurations, switch yard (function) structures, and the relations between them. The main purpose of this format is to exchange IED capability descriptions, and SA system descriptions between IED engineering tools and the system engineering tool(s) of different manufacturers in a compatible way. The defined language is called System Configuration description Language (SCL). The IED and communication system model in SCL is according to IEC 61850-5 and IEC

Standard	Comments
	1850-7-x. SCSM specific extensions or usage rules may be required in the appropriate parts. The configuration language is based on the Extensible Markup Language (XML) version 1.0 (see XML references in Clause 2). This standard does not specify individual implementations or products using the language, nor does it constrain the implementation of entities and interfaces within a computer system. This part of the standard does not specify the download format of configuration data to an IED, although it could be used for part of the configuration data.
IEC 61850-7-1	The purpose of this part of the IEC 61850 series is to provide – from a conceptual point of view – assistance to understand the basic modeling concepts and description methods for: • Substation-specific information models for power utility automation systems, • Device functions used for power utility automation purposes, and • Communication systems to provide interoperability within power utility facilities Furthermore, this part of the IEC 61850 series provides explanations and provides detailed requirements relating to the relation between IEC 61850-7-4, IEC 61850-7-3, IEC 61850-7-2 and IEC 61850-5. This part explains how the abstract services and models of the IEC 61850-7-x series are mapped to concrete communication protocols as defined in IEC 61850-8-1.
IEC 61850-7-2	This part of IEC 61850 applies to the ACSI communication for utility automation. The ACSI provides the following abstract communication service interfaces: a. Abstract interface describing communications between a client and a remote server for the following: ▪ Real-time data access and retrieval ▪ Device control ▪ Event reporting and logging ▪ Setting group control ▪ Self-description of devices (device data dictionary) ▪ Data typing and discovery of data types ▪ File transfer b. Abstract interface for fast and reliable system-wide event distribution between an application in one device and many remote applications in different devices (publisher/subscriber) and for transmission of sampled measured values (publisher/subscriber).
IEC 61850-7-3	This part of IEC 61850 specifies constructed attribute classes and common data classes related to substation applications. In particular, it specifies the following: • Common data classes for status information • Common data classes for measured information • Common data classes for control • Common data classes for status settings • Common data classes for analogue settings • Attribute types used in these common data classes This International Standard is applicable to the description of device models and functions of substations and feeder equipment.
IEC 61850-7-4	This part specifies the abstract information model of devices and functions, consisting of data objects contained in Logical Nodes (LNs). This part was initially just for substation automation, but has been expanded to include the common Logical Nodes used in many different domains, including:

Standard	Comments
	• Intra-substation information exchanges • Substation-to-substation information exchanges • Substation-to-control center information exchanges • Power plant-to-control center information exchanges • Information exchange for distributed generations • Information exchange for distributed automations • Information exchange for metering This part also specifies normative naming rules for multiple instances and private, compatible extensions of logical node (LN) classes and data object (DO) names.
IEC 61850-7-410	This part of IEC 61850 specifies the additional common data classes, logical nodes and data objects required for the use of IEC 61850 in a hydropower plant. The Logical Nodes and Data Objects defined in this part of IEC 61850 belong to the following fields of use: • Electrical functions. This group includes LN and DO used for various control functions, essentially related to the excitation of the generator. New LN and DO defined within this group are not specific to hydropower plants; they are more or less general for all types of larger power plants. • Mechanical functions. This group includes functions related to the turbine and associated equipment. The specifications of this document are intended for hydropower plants, modifications might be required for application to other types of generating plants. Some more generic functions are defined under Logical Node group K. • Hydrological functions. This group of functions includes objects related to water flow, control and management of reservoirs and dams. Although specific for hydropower plants, the LN and DO defined here can also be used for other types of utility water management systems. • Sensors. A power plant will need sensors providing measurements of other than electrical data. With a few exceptions, such sensors are of general nature and not specific for hydropower plants.
IEC 61850-7-420	This International Standard defines the IEC 61850 information models to be used in the exchange of information with distributed energy resources (DER), which comprise dispersed generation devices and dispersed storage devices, including reciprocating engines, fuel cells, microturbines, photovoltaics, combined heat and power, and energy storage. The IEC 61850 DER information model standard utilizes existing IEC 61850-7-4 logical nodes where possible, but also defines DER-specific logical nodes where needed.
IEC 61850-8-1	IEC 61850-8-1 maps the: • Abstract service models defined in IEC 61850-7-2 as “Abstract Communication Services Interface (ACSI)”, including the Generic Object-Oriented Substation Event (GOOSE) and Sampled Values (SV) messages • Common data classes (CDCs) defined in IEC 61850-7-3 • Data objects in Logical Nodes (LNs) defined in the IEC 61850-7-4, 7-410, and 7-420 to the “bits and bytes” protocols of the Manufacturing Message Specification (MMS) at the ISO/OSI Application Layer, that runs over IEC 8802-3 (commonly referred to as Ethernet) at the ISO/OSI Data Link Layer • Time synchronization uses the Simple Network Time Protocols (SNTP) protocol • Different profiles are established for different types of messages, ranging from the very fast GOOSE event messages and rapid continuous sampled values messages running directly over Ethernet, to special time synchronization interactions over UDP, to the

Standard	Comments
	normal information exchange messages running over TCP/IP The standard also addresses additional mapping issues, including file transfers, the system configuration language, conformance, multicast, and timing issues.
IEC 61850-9-2	IEC 61850 supports "sampled values" which are continuously streaming raw measurements from sensors, e.g., voltage measurements from Potential Transformers (PTs) or water flow measurements in hydro plants. This standard maps the abstract services defined in IEC 61850-7-2 for retrieving these sampled values to the (A-Profile) Manufacturing Message Specification (MMS) as standardized in IEC 61850-8-1 and to (T-Profile) TCP/IP over (essentially) Ethernet over fiber optic media. Other media may also be used, but are not specified in this document.
IEC 61850-10	IEC 61850 was originally focused on substation automation. This part defines the conformance testing requirements and measurement techniques for ensuring optimal performance for implementations of substation automation using IEC 61850. The testing covers the following: • General testing plan and procedure requirements • Quality assurance requirements • Use of SCL files • Documentation and test reports • Positive and negative test cases for the services defined in IEC 61850-7-2 • Accuracy of time synchronization • Performance tests
IEC 61850-90-5	This technical report is a part of the IEC 61850 series of standards that adds a method for exchanging synchrophasor data between PMUs, PDCs, WAMPAC (Wide Area Monitoring, Protection, and Control) systems, and between control center applications. The data, to the extent covered in IEEE C37.118.2 - 2011, is transported in a way that is compliant to the concepts of IEC 61850. This document also provides routable profiles for IEC 61850-8-1 GOOSE and IEC 61850-9-2 SV packets. These routable packets can be utilized to transport general IEC 61850 data as well as synchrophasor data.

2.4.1.3 IEEE 1815 (DNP3)

This standard is used for substation and feeder device automation, as well as for communications between control centers and substations. IEEE 1815 is an open, mature, widely implemented specification initially developed and supported by a group of vendors, utilities, and other users, and now maintained by an SDO.

IEEE has adopted as an IEEE standard, IEEE Std 1815-2010, excluding the cybersecurity part which is being updated by IEEE Substation Committee Working Group (WG) C12.

2.4.1.4 IEEE C37.238-2011

This standard is IEEE Standard Profile for Use of IEEE 1588 Precision Time Protocol in Power System Applications, for Ethernet communications for power systems.

This standard specifies a common profile for use of IEEE 1588-2008 Precision Time Protocol (PTP) in power system protection, control, automation and data communication applications utilizing an Ethernet communications architecture.

The profile specifies a well-defined subset of IEEE 1588-2008 mechanisms and settings aimed at enabling device interoperability, robust response to network failures, and deterministic control of delivered time quality. It specifies the preferred physical layer (Ethernet), higher level protocol used for PTP message exchange and the PTP protocol configuration parameters. Special attention is given to ensuring consistent and reliable time distribution within substations, between substations, and across wide geographic areas. (Source: IEEE PC37.238 D4.0 – Scope Statement).

IEEE PSRC Subcommittee Working Group H7 has been developing the standard. C37.238, which will incorporate IEEE 1588, the Standard for time management and clock synchronization across the Smart Grid for equipment needing consistent time management, as required for profiles for electric power systems.

2.4.1.5 IEEE C37.239-2010

This Standard defines the Common Format for Event Data Exchange (COMFEDE) for Power Systems, for the interchange of power system event data.

A common format for data files used for the interchange of various types of event data collected from electrical power systems or power system models is defined. Extensibility, extension mechanisms, and compatibility of future versions of the format are discussed. An XML schema is defined. A sample file is given. It doesn't define what is transferred via communications. It is only a file format for offline analysis and data exchange.

2.4.1.6 MultiSpeak V3.0

The MultiSpeak initiative is a collaborative effort between the National Rural Electric Cooperative Association (NRECA) and software vendors serving the electric utility industry [10]. MultiSpeak is currently in use in the daily operations of more than 800 electric cooperatives, investor-owned utilities, municipals, and public power districts in at least 21 different countries. However, with the incorporation of web services and especially the addition of the service bus architecture, the capabilities of MultiSpeak are scalable and the uses are not limited to smaller utilities. This recognition has led to a growing interest in the power of MultiSpeak among municipal and investor-owned utilities.

The Initiative has developed a specification package that defines standard data interfaces between software applications commonly used by small electric utilities. MultiSpeak defines software interfaces, data objects and message structures. These interface, data, and message definitions permit vendors to write a common interface that facilitates communication with other types of software.

MultiSpeak 3.0 supports the following back-office software applications:

- Customer Information Systems (CIS)
- Geographic information systems (GIS)
- Engineering analysis (EA)
- Interactive voice response systems (IVR)
- Automated staking

- Supervisory control and data acquisition (SCADA)
- Automated meter reading (AMR)
- Outage management (OM)
- Load management (LM)
- Customer relationship management (CRM)

Version 3 includes support for real-time integration using web services.

Security can be implemented over a MultiSpeak interface with MultiSpeak security V1.0, also included in the SGIP CoS.

2.4.1.7 Cyber Security: NISTR 7628

NISTR 7628 is a guideline first published by NIST in 2010. It was developed through a participatory public process that, starting in March 2009, included several workshops as well as weekly teleconferences, all of which were open to all interested parties. NISTR 7628, Revision 1 was released in September 2014 and includes updates to the document for such areas as security architecture and privacy.

The guidelines are not prescriptive, nor mandatory. Rather they are advisory, intended to facilitate each organization's efforts to develop a cybersecurity strategy effectively focused on prevention, detection, response, and recovery. The guideline includes the following:

- An overview of the cybersecurity strategy used by the Cyber Security Working Group (CSWG) to develop the high-level cybersecurity smart grid requirements;
- A tool for organizations that are researching, designing, developing, implementing, and integrating smart grid technologies—established and emerging;
- An evaluative framework for assessing risks to smart grid components and systems during design, implementation, operation, and maintenance; and
- A guide to assist organizations as they craft a smart grid cybersecurity strategy that includes requirements to mitigate risks and privacy issues pertaining to smart grid customers and uses of their data.

NISTIR 7628 Guidelines for Smart Grid Cybersecurity, consists of 3 volumes:

- Vol 1: *Smart Grid Cybersecurity Strategy, Architecture, and High-Level Requirements* (http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol1.pdf)
- Vol 2: *Privacy and the Smart Grid* (http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol2.pdf)
- Vol 3: *Supportive Analyses and References* (http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol3.pdf)

2.4.1.8 Cyber Security: IEC 62351 family of standards

The IEC 62351 Family of standards: Power systems management and associated information exchange - Data and communications security (shown in Table 2-7) is an open standard, developed and maintained by an SDO. Defines security requirements for power system management and information exchange, including communications network and system security issues, Transmission Control Protocol (TCP) and Manufacturing Messaging Specification (MMS) profiles, and security for Inter-control center Protocol

(ICCP) and substation automation and protection. It is for use in conjunction with related IEC standards, but has not been widely adopted yet.

Table 2-7. IEC 62351 family of cyber security standards

Standard	Description
IEC 62351-1	Provides an introduction to the remaining parts of the IEC 62351 series, primarily to introduce the reader to various aspects of information security as applied to power system operations. The scope of the IEC 62351 series is information security for power
IEC 62351-2	Part 2 of the IEC 62351 series covers the key terms used in the series, including references to original definitions of cyber security terms and communications terms.
IEC 62351-3	Part 3 of the IEC 62351 series provides technical specifications on ensuring the confidentiality, tamper detection, and message level authentication for SCADA and other telecontrol protocols which use TCP/IP as a message transport layer between communicating entities. TCP/IP-based protocols are secured through specification of the messages, procedures, and algorithms of Transport Layer Security (TLS).
IEC 62351-4	Part 4 of the IEC 62351 series provides specifications to secure information transferred when using ISO 9506, Manufacturing Message Specification (MMS)-based applications; specifying which procedures, protocol extensions, and algorithms to use in MMS to provide security.
IEC 62351-5	Part 5 of the IEC 62351 series specifies messages, procedures, and algorithms that apply to the operation of all protocols based on/derived from IEC 60870-5, Telecontrol equipment and systems-Part 5: Transmission protocols. The focus of this 62351-5 is on the application layer authentication and security-issues that are a result of application layer authentication. While authentication of sources and receivers is considered the most important requirement and confidentiality is not considered important, encryption can be included by combining this standard with other security standards, such as IEC 62351-3, TLS.
IEC 62351-6	Part 6 of the IEC 62351 series addresses security for IEC 61850 profiles through specification of messages, procedures, and algorithms. IEC 61850 specifies a number of different profiles which have different constraints, performance requirements, and security needs, but the primary requirement is for authentication of sources of data, receivers of data, and data integrity. Therefore, different security options are specified.
IEC 62351-7	Part 7 of the IEC 62351 series provides an abstract model of network and system data elements that should be monitored and controlled. Its focus is network and system management, one area among many possible areas of end-to-end information security. The primary focus is the enhancement of overall management of the communications networks supporting power system operations, by specifying monitoring and control of communication networks and systems. Intrusion detection and intrusion prevention are addressed.
IEC 62351-8	Part 8 of the IEC 62351 series specifies role-based access control (RBAC) requirements. RBAC is an alternative to the all-or-nothing super-user model. RBAC is in keeping with the security principle of least privilege, which states that no subject should be given more rights than necessary for performing that subject's job. RBAC enables an organization to separate super-user capabilities and package them into special user accounts termed roles for assignment to specific individuals according to their job needs.

2.4.1.9 Organization for the Advancement of Structured Information Standard (OASIS)

2.4.1.9.1 Energy Interoperation (EI)

Energy interoperation describes an information model and a communication model to enable demand response and energy transactions. XML vocabularies provide for the interoperable and standard exchange of: DR and price signals, bids, transactions and options, and customer feedback on load predictability and generation information.

This standard uses the EMIX information model for price and product as payload information. The DR specification is built on a unified model of retail (OpenADR) and wholesale (input from the ISO/RTO Council) DR. OpenADR 2.0 is a profile on EI.

2.4.1.9.2 EMIX (Energy Market Information eXchange)

EMIX provides an information model to enable the exchange of energy price, characteristics, time, and related information for wholesale energy markets, including market makers, market participants, quote streams, premises automation, and devices.

2.4.1.9.3 WS-Calendar

This is an application for XML serialization of IETF iCalendar for use in calendars, buildings, pricing, markets, and other environments. A communication specification used to specify schedule and interval between domains.

WS-Calendar describes a limited set of message components and interactions providing a common basis for specifying schedules and intervals to coordinate activities between services. The specification includes service definitions consistent with the OASIS SOA Reference Model and XML vocabularies for the interoperable and standard exchange of:

- Schedules, including sequences of schedules
- Intervals, including sequences of intervals

2.4.1.10 Other NIST cataloged standards that could impact distribution operations

Within the NIST/SGIP smart grid catalog of standards there are other standards that may indirectly impact SDG&E Distribution Operations. These standards define the interoperability requirements between customers, service providers, or other cross cutting technologies such as communications transport. Information models in the customer and service provider domains may ultimately provide input to Distribution operations to make more informed decisions on management of the network. Table 2-8 provides a list of other NIST standards that could impact SDG&E distribution operations.

Table 2-8. Other standards in NIST CoS that could impact Distribution Operations

Standard	Application	Smart Grid Conceptual Architecture Domains
ANSI C12 Suite	Standards for electricity metering. There are many sections to the ANSI C12 standard, each covering specific aspects of metering.	Customer, Service provider

Standard	Application	Smart Grid Conceptual Architecture Domains
IEEE 1901-2010 (ISP) and International Telecommunications Union Telecommunication Standardization Sector (ITU-T) G.9CCR2 (06/2010)	Coexistence mechanism for wireline home networking transceivers," specify Inter-System Protocol (ISP) based Broadband (> 1.8 MHz) PLC (BB-PLC) coexistence mechanisms to enable the coexistence of different BB-PLC protocols for home networking.	Customer
NAESB REQ18, WEQ19 Energy Usage Information	The standards specify two-way flows of energy usage information based on a standardized information model.	Customer, Service provider
NAESB REQ-21 Energy Services Provider Interface (ESPI)	ESPI builds on the NAESB Energy Usage Information (EUI) Model and, subject to the governing documents and any requirements of the applicable regulatory authority, will help enable retail customers to share energy usage information with third parties who have acquired the right to act in this role.	Customer, Service provider
NAESB REQ-22 Third Party Access to Smart Meter-based Information Business Model Practices	Establishes voluntary Model Business Practices for Third Party access to Smart Meter-based information." These business practices are intended only to serve as flexible guidelines rather than requirements, with the onus on regulatory authorities or similar bodies to establish the actual requirements. They are also not intended for any billing or collection activities.	Customer, Service provider
NAESB RMQ.26 Open Field Message Bus (Open FMB)	The OpenFMB™ framework provides a specification for power systems field devices to leverage a non-proprietary and standards-based reference architecture, which consists of internet protocol (IP) networking and Internet of Things (IoT) messaging protocols. The framework supports Distributed Energy Resources that communicate based on a common schematic definition and then can process the data locally for action (control, reporting). OpenFMB™ supports field-based applications that enable: • Scalable peer-to-peer publish/subscribe architecture • Data-centric, rather than device-centric, communication including support for harmonized system and device data • Distributed operations augmenting centralized control	Distribution, Operations
Open Automated Demand 2.0 Response (OpenADR)	The specification defines messages exchanged between the Demand Response (DR) Service Providers (e.g., utilities, independent system operators (ISOs) and customers for price-responsive and reliability-based DR.	Operations, service providers
Smart Energy Profile 2.0-2013	Home Area Network (HAN) Device Communications and Information Model.	Customer

Standard	Application	Smart Grid Conceptual Architecture Domains
Internet Protocol Suite, Request for Comments (RFC) 6272, Internet Protocols for the Smart Grid.	Internet Protocols for IP-based Smart Grid Networks IPv4/IPv6 are the foundation protocol for delivery of packets in the Internet network. Internet Protocol version 6 (IPv6) is a new version of the Internet Protocol that provides enhancements to Internet Protocol version 4 (IPv4) and allows a larger address space.	Cross-cutting communications transport layer that supports smart grid applications
SAE J2836/1: Use Cases for Communication Between Plug-in Vehicles and the Utility Grid	This document establishes use cases for communication between plug-in electric vehicles and the electric power grid, for energy transfer and other applications.	Requirements

2.4.2 Other relevant standards that could impact distribution operations

There are several standards not currently in the NIST catalog of Standards, but have been recognized through other Smart Grid Standards organizations, or identified by NIST as relevant to the Smart Grid roadmap, but may be undergoing development or modifications. Experience gained with devices designed to meet the requirements of the standards from interoperability testing and certification activities managed by Interoperability Testing and Certification Authorities (ITCAs) will also influence the changes to these standards. The following sections summarize those standards.

2.4.2.1 IEC 60870-5

Not included in the NIST Catalog of Standards is IEC 60870 part 5, known as Transmission protocols. While these protocols may be transparent to SDG&E Distribution Operations, they are listed here for reference. The IEC TC 57 WG3 have developed a protocol standard for telecontrol, teleprotection, and associated telecommunications for electric power systems. The result of this work is IEC 60870-5. Seven documents specify the base IEC 60870-5:

- IEC 60870-5-1 Transmission Frame Formats
- IEC 60870-5-2 Data Link Transmission Services
- IEC 60870-5-3 General Structure of Application Data
- IEC 60870-5-4 Definition and Coding of Information Elements
- IEC 60870-5-5 Basic Application Functions
- IEC 60870-5-6 Guidelines for conformance testing for the IEC 60870-5 companion standards
- IEC TS 60870-5-7 Security extensions to IEC 60870-5-101 and IEC 60870-5-104 protocols (applying IEC 62351)

The IEC TC 57 has also generated companion standards:

- IEC 60870-5-101 Transmission Protocols - companion standards especially for basic telecontrol tasks
- IEC 60870-5-102 Transmission Protocols - Companion standard for the transmission of integrated totals in electric power systems (this standard is not widely used)

- IEC 60870-5-103 Transmission Protocols - Companion standard for the informative interface of protection equipment
- IEC 60870-5-104 Transmission Protocols - Network access for IEC 60870-5-101 using standard transport profiles
- IEC TS 60870-5-601 Transmission protocols - Conformance test cases for the IEC 60870-5-101 companion standard
- IEC TS 60870-5-604 Conformance test cases for the IEC 60870-5-104 companion standard

IEC 60870-5-101/102/103/104 are companion standards generated for basic telecontrol tasks, transmission of integrated totals, data exchange from protection equipment & network access of IEC-101 respectively. IEC-101 is similar to the basic serial communications protocol, while IEC-104 utilizes network protocols such as TCP/IP.

2.4.2.2 IEC 61968 application integration at electric utilities

The IEC 61968/61970 families of standards define information exchanged among control center systems using common information models [3] [11]. They define application-level energy management system interfaces and messaging for distribution grid management in the utility space.

IEC WG 14 was formed to address the need for standards for System Interfaces for Distribution Management Systems (SIDMS). The IEC 61968 series is intended to facilitate inter-application integration of the various distributed software application systems supporting the management of utility electrical distribution networks. These standards define requirements, integration architecture, and interfaces for the major elements of a utility's Distribution Management System (DMS) and other associated external IT systems. Examples of DMS include Asset Management Systems, Work Order Management Systems, Geographic Information Systems, Customer Information Systems, while Customer Resource Management is an example of an external IT system interface. The message-based technology used to mesh these applications together into one consistent framework is referred to as Enterprise Application Integration (EAI); IEC 61968 guides the utility's use of EAI.

Specific Parts of the IEC 61968 Specification include:

- IEC 61968-1 – Interface architecture and general requirements [Published]
- IEC 61968-2 – Glossary [Published]
- IEC 61968-3 – Interface for Network Operations [NO] [Published]
- IEC 61968-4 – Interfaces for Records and Asset management [AM] [Published]
- IEC 61968-5 – Interfaces for Operational planning & optimization [OP] [Under Development]
- IEC 61968-6 – Interfaces for Maintenance & Construction [MC] [Published]
- IEC 61968-7 – Interfaces for Network Extension Planning [NE] [Under Development]
- IEC 61968-8 – Interfaces for Customer Support [CS] [Published]
- IEC 61968-9 – Interface Standard for Meter Reading & Control [MR] [Published]
- IEC 61968-10 – Interfaces for Business functions external to distribution management [Retired]. This includes Energy management & trading [EMS], Retail [RET], Supply Chain & Logistics [SC], Customer Account Management [ACT], Financial [FIN], Premises [PRM] & Human Resources [HR]
- IEC 61968-11 – Common Information Model (CIM) Extensions for Distribution [Published]
- IEC 61968-12 – Common Information Model (CIM) Use Cases for 61968 [Retired]

- IEC 61968-13 – Common Information Model (CIM) RDF Model exchange format for distribution [Published]
- IEC 61968-14-1-3 to 14-1-10 [2] – Proposed IEC Standards to Map IEC61968 and MultiSpeak Standards [Under Development]
- IEC 61968-14-2-3 to 14-2-10 – Proposed IEC Standards to Create a CIM Profile to Implement MultiSpeak Functionality [Under Development]

2.4.2.2.1 Cyber security requirements

The standard focuses on the development of abstract information models, does not include any protocols, and assumes that any mapping of the abstract models to actual protocols or application components will utilize appropriate security. Methods and technologies used to implement functionality conforming to this CIM standard, including security, are considered outside of the scope of this standard; only the abstract models are specified in the IEC 61968 series.

2.4.2.3 IEEE C37.118

These set of standards defines phasor measurement units (PMUs) performance specifications and well as data transfer formats. The specification is targeted for the transmission and distribution Smart Grid conceptual architecture domains, but is not included in the SGIP catalog of standards. Table 2-9 below summarizes the components of the IEEE C37.118 Standard.

PMUs have widely been utilized in the transmission domain, but are now also finding application in distribution operations to monitor feeder and substation status. SDG&E is already utilizing PMUs on certain distribution applications.

Table 2-9. IEEE C37.118 standard

Standard	Application	Comments
IEEE C37.118.1-2011 IEEE Standard for Synchrophasor Measurements for Power Systems	Defines phasor measurement unit (PMU) performance specifications	Open standard, widely implemented, developed and maintained by an SDO. Standard is overseen by the IEEE Power System Relaying Committee (PSRC) Relaying Communications Subcommittee Working Groups H11 and H19. This standard is intended to become an IEEE/IEC dual-logo standard.
IEEE C37.118.2 Standard for synchrophasor data transfer for power systems	Defines communications for phasor measurement units (PMUs).	Some items not covered in C37.118-2005 include communication service modes, remote device configuration, dynamic measurement performance, and security IEEE PSRC WG C5 has developed a “Guide for Synchronization, Calibration, Testing, and Installation of Phasor Measurement Units (PMU) applied in Power System Protection and Control” based on the C37.118 standards and previous publications by North American Synchro-Phasor Initiative (NASPI) in these areas. They are part of PAP13 relating to harmonization of IEC 61850 and IEEE C37.118 standards (PAP13: Harmonization of IEEE C37.118 with IEC 61850 and Precision Time Synchronization -

2.4.2.4 IEEE 1547 Suite

This family of standards defines physical and electrical interconnections between the grid and distributed generation (DG) and storage. It is not included in the SGIP Catalog of Standards.

IEEE 1547 family of standards are open standards developed and maintained by an SDO with significant implementation for the parts covering physical/electrical connections. The parts of this suite of standards that describe messages are not as widely deployed as the parts that specify the physical interconnections. Many utilities and regulators require their use in systems. Revising and extending the IEEE 1547 family is a focus of PAP07, covering energy storage interconnections (PAP07: Energy Storage Interconnection Guidelines - http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PAP07Storag).

When applied to utility-interactive equipment, Underwriters Laboratories (UL) 1741, "Standard for Safety Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources," should be used in conjunction with 1547 and 1547.1 standards which supplement them. The products covered by these requirements are intended to be installed in accordance with the National Electrical Code, National Fire Protection Association (NFPA) 70.

2.4.2.5 Various cyber security standards

A set of Cyber security standards are identified in NIST SP 1108 document are shown and described in Table 2-10 below.

The most notable standard is the NERC Critical Infrastructure Protection (CIP) 002-009, that applies to the bulk electric system, but is also used as prudent practices is other sectors.

Table 2-10. Cyber security standards not in SGIP COS

Standard	Comments
Security Profile for Advanced Metering Infrastructure, v 1.0, Advanced Security Acceleration Project – Smart Grid, December 10, 2009 http://osgug.ucaiug.org/utilisec/amisec/Shared%20Documents/AMI%20Security%20Profile%20(ASAP-SG)/AMI%20Security%20Profile%20-%20v1_0.pdf	This document provides guidance and security controls to organizations developing or implementing AMI solutions. This includes the meter data management system (MDMS) up to and including the HAN interface of the smart meter. The Advanced Metering Infrastructure Security (AMI-SEC) Task Force was established under the Utility Communications Architecture International Users Group (UCAIug) to develop consistent security guidelines for AMI. This is not included in SGIP Catalog of Standards.
Department of Homeland Security (DHS), National Cyber Security Division. 2009, September. Catalog of Control Systems Security: Recommendations for Standards Developers. https://www.smartgrid.gov/document/dhs_national_cyber_security_division_catalog_control_systems_security_recommendations_stand	The catalog presents a compilation of practices that various industry bodies have recommended to increase the security of control systems from both physical and cyber attacks. This is a source document for the NIST Interagency Report NISTIR 7628, *Guidelines for Smart Grid Cyber Security* http://csrc.nist.gov/publications/nistir/ir7628/introduction-to-nistir-7628.pdf http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol1.pdf http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol2.pdf http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol3.pdf

Standard	Comments
	This is not included in SGIP Catalog of Standards.
DHS Cyber Security Procurement Language for Control Systems	The National Cyber Security Division of the Department of Homeland Security (DHS) developed this document to provide guidance to procuring cybersecurity technologies for control systems products and services. It is not intended as policy or standard. Because it speaks to control systems, its methodology can be used with those aspects of Smart Grid systems. This is a source document for the NIST Interagency Report NISTIR 7628, *Guidelines for Smart Grid Cyber Security* http://csrc.nist.gov/publications/nistir/ir7628/introduction-to-nistir-7628.pdf http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol1.pdf http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol2.pdf http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol3.pdf This is not included in SGIP Catalog of Standards.
IEC 61851: Electric vehicle conductive charging system - Part 1: General requirements http://webstore.iec.ch/webstore/webstore.nsf/Artnum_PK/44636	Applies to equipment for charging electric road vehicles at standard alternating current (ac) supply voltages (as per IEC 60038) up to 690 V and at direct current (dc) voltages up to 1 000 V, and for providing electrical power for any additional services on the vehicle if required when connected to the supply network. This is not included in SGIP Catalog of Standards.
IEEE 1686-2007 http://standards.ieee.org/findstds/standard/1686-2007.html	The IEEE 1686-2007 is a standard that defines functions and features to be provided in substation intelligent electronic devices (IEDs) for critical infrastructure protection programs. The standard covers IED security capabilities including the access, operation, configuration, firmware revision, and data retrieval. Open standard, developed and maintained by an SDO. Not widely implemented yet. This is not included in SGIP Catalog of Standards.
NERC Critical Infrastructure Protection (CIP) 002-011, and CIP-014	These standards cover organizational, processes, physical, and cybersecurity standards for the bulk power system. Mandatory standards for the bulk electric system. Currently being revised by the North American Electric Reliability Corporation (NERC). This is not included in SGIP Catalog of Standards.
NIST Special Publication (SP) 800-53 http://dx.doi.org/10.6028/NIST.SP.800-53r4 http://dx.doi.org/10.6028/NIST.SP.800-82	These standards cover cybersecurity standards and guidelines for federal information systems, including those for the bulk power system. Open standards developed by NIST. SP 800-53 defines security measures required for all U.S. government computers. SP800-82 defines security specifically for industrial control systems, including the power grid. This is not included in SGIP Catalog of Standards

2.4.2.6 IEC 62325: Common Information Model for energy market communications

IEC Working Group 16 is charged with developing a framework for deregulated energy market communications with a focus on the interface between utilities and the energy market. With the

transition of monopoly energy supply structures to deregulated energy markets the function of the markets depends heavily on seamless e-business communication between market participants. Today EDIFACT or X12 messages, or propriety HyperText Markup Language (HTML) and XML solutions based on Internet technologies are being used. With the advent of new e-business technologies such as ebXML by UN/CEFACT (United Nations / Centre for Trade and Electronic Business) together with OASIS (Organization for the Advancement of Structured Information Standards), and Web Services by W3C, an energy market specific profile of these standards can be used for regional energy markets. This profile allows the re-use of proven core components and communication platforms across markets, thus saving cost and implementation time. Because some of these technologies are still developing, other technologies or converged technologies are not excluded for the future.

Besides general requirements and guidelines, this framework includes the business operational view and profiles of technical e-business communication architectures together with migration scenarios. It supports the communication aspects of all e-business applications in deregulated energy markets with emphasis on system operators. The business operational view includes the market communication aspects of system operator applications with interfaces to other market participants from trading over-supply to balancing planned generation and consumption, change of supplier, market services and billing.

- IEC 62325 consists of the following parts, detailed in separate IEC 62325 standard documents:
- IEC 62325-101: General guidelines
- IEC 62325-102: Energy market model example
- IEC 62325-301: Common information model (CIM) extensions for markets
- IEC 62325-351: CIM European market model exchange profile
- IEC 62325-450: Profile and context modeling rules
- IEC 62325-451-1: Acknowledgement business process and contextual model for CIM European market
- IEC 62325-451-2: Scheduling business process and contextual model for CIM European market
- IEC 62325-451-3: Transmission capacity allocation business process and contextual models for European market
- IEC 62325-451-4: Settlement and reconciliation business process, contextual and assembly models for European market
- IEC 62325-451-5: Problem statement and status request business processes, contextual and assembly models for European market
- IEC 62325-451-6: Publication of information on market, contextual and assembly models for European style market
- IEC 62325-452: North American style market profiles
- IEC 62325-501: General guidelines for use of ebXML
- IEC 62325-502: Profile of ebXML
- IEC 62325-503: Market data exchanges guidelines for the IEC 62325-351 profile
- IEC 62325-504: Utilization of web services for electronic data interchanges on the European energy market for electricity
- IEC 62325-550-2: Common dynamic data structures for North American style markets
- IEC 62325-552-1: Dynamic data structures for day ahead markets (DAM)

Whereas the parts of the current framework edition are restricted to the use of the ebXML technology, the planned parts are intended to convert the framework into a more open framework also taking into account other e-business technologies besides ebXML, such as Web Services. This will also include an abstraction service model with mapping to the various e-business technologies to hide the e-business technology actually used from the application. Further the standardization of basic business content including a market information model is planned, which could be the extension of the CIM model used in control centers.

IEC 62325-301:2014 specifies the common information model for energy market communications. The common information model (CIM) is an abstract model that represents all the major objects in an electric utility enterprise typically involved in utility operations and electricity market management. By providing a standard way of representing power system resources as object classes and attributes; along with their relationships; the CIM facilitates the integration of market management system (MMS) applications developed independently by different vendors; between entire MMS systems developed independently; or between an MMS system and other systems concerned with different aspects of market management; such as capacity allocation; day-ahead management; balancing; settlement; etc.

The IEC 62325 standards are part of a series of standards. IEC 61970 standards define the EMS application programming interfaces and the IEC 61968 standards define System interfaces for distribution management. IEC 62325-301 corresponds to the IEC 61970-301 and the IEC 61968-11 standards that describe parts of the common information model relevant to modeling interfaces for EMS, DMS and MMS systems. While there are multiple IEC standards dealing with different parts of the CIM, there is a single, unified information model comprising the CIM behind all these individual standards documents.

2.4.3 Harmonization efforts among standards

2.4.3.1 Harmonization activities related to IEC 61850

Several NIST PAPs (PAP07, PAP08, PAP12, and PAP13) are dedicated to further development work in various areas.

PAP07 has developed requirements to update IEC 61850-7-420 Distributed Energy Resource (DER) Information Models to include storage devices and Smart Grid functionality necessary to support high penetration of DER. PAP07 is also mapping the information models to application protocols including Smart Energy Profile (SEP2) and DNP3. The new information models requirements are included in the IEC Technical Report, IEC 61850-90-7 published in February 2013 and is also included in the modified normative standard that will follow.

Click on the referenced links for more information regarding harmonization efforts being addressed:

- PAP07: Energy Storage Interconnection Guidelines - http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PAP07Storage
- NIST PAP12 has been working on the mapping of IEEE 1815 (DNP3) to IEC 61850 objects, and it has resulted in a draft IEEE standard P1815.1 being completed in early 2011 for adoption by IEEE around mid-2011. (PAP12: Mapping IEEE 1815 (DNP3) to IEC 61850 Objects - http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PAP12DNP361850)
- NIST PAP13 was established to assist and accelerate the integration of standards (IEEE C37.118 and IEC 61850) that impact phasor measurement systems and applications that use

synchrophasor data, as well as implementation profiles for IEEE Std 1588 for precision time synchronization. (PAP13: Harmonization of IEEE C37.118 with IEC 61850 and Precision Time Synchronization - http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PAP1361850C27118HarmSynch)

- PAP8 is working on harmonizing this family of standards, the IEC 61970 family of standards (Common Information Model or CIM), and MultiSpeak for distribution grid management (PAP08: CIM/61850 for Distribution Grid Management - http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PAP08DistrObjMultispeak**).**

IEEE will split current IEEE C37.118-2005 into two parts in its new revision to facilitate the harmonization with IEC standards: C37.118.1 Standard for synchrophasor measurements for power systems aimed to become an IEEE/IEC dual-logo standard, and C37.118.2, Standard for synchrophasor data transfer for power systems to be harmonized with / transitioned to IEC 61850-90-5, which was published in May 2012.

2.4.3.2 Harmonization efforts with IEC 61968

PAP08, CIM for Distribution Grid Management,[9] focuses on the development of new Unified Modeling Language (UML) models for real-time and planning control center application information exchanges covering distribution functions Energy Management Systems (EMSs) and Distribution Management Systems (DMSs) such as:

- Fault Location, Isolation, and Service Restoration (FLISR), Volt/var/Watt Optimization (VVWO), Distribution Operation Model and Analysis (DOMA), Distribution Energy Resources (DER) management system, Load Management System (LMS), Planned Outage Management, Feeder Reconfiguration, etc, that are covered in IEC 61968 Parts 3, 5, 7, and the new DER Part (with no number assigned yet).
- Back office and asset management applications, such as covered in IEC 61968 Parts 4, 6, 8 & 9, including asset management (Part 4), maintenance & construction (Part 6), customer interactions (Part 8), and meter reading and control interactions (Part 9)
- Utility interactions with manually operated equipment (e.g., switching orders for field crews).

Since PAP08 also covers IEC 61850 for substation automation, there is close coordination of models under development for both standards to ensure that they are harmonized.

PAP14, Transmission and Distribution Power System Model Mapping,[10] is coordinating development of extensions of IEC 61968-11 models based on Smart Grid requirements. The tasks of PAP14 include: developing strategies to expand and integrate MultiSpeak, IEC 61850, IEC 61968, IEC 61970, IEEE PC37.237 (Time Tagging Standard), IEEE PC37.239 (Common Format for Event Data Exchange - COMFEDE) and the future IEEE Common Settings file format for Smart Grid Applications; developing a summary of information required from the power system for various Smart Grid applications; and mapping that information with the already defined models from MultiSpeak, IEC 61970, IEC 61968-11, and IEC 61850.

[9] PAP8 CIM for Distribution Grid Management – for more information see http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PAP08DistrObjMultispeak .

[10] PAP14 Transmission and Distribution Power System Model Mapping – for more information see http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PAP14TDModels .

2.4.4 Summary and conclusions regarding standards and protocols

The industry has many standards that exist among several standards development organizations (SDO's) that may be applicable to multiple layers of the power systems architecture. The key goal is to identify the standards that can be tailored to support SDG&E's specific requirements and use cases. The NIST/SGIP activities maintaining the Catalog of Standards (CoS), as well as IEC TC57 work provides a well-tested source of standards for consideration in SDG&E's distribution operations architecture.

A key standard is the IEC 61850 protocol suite. It has been recognized at the substation and interoperable field connectivity. The IEC 61850 standard is also gaining industry acceptance for future architectures including DER integration. The extent of harmonization efforts that have included IEC 61850 show that the protocol suite is becoming a key building block in the future smart grid architecture.

IEC protocol standards also have an accompanying cyber security set of standards (IEC 62351) that can be used to provide optimal protection of assets through the implementation of harmonized cyber security practices, further protecting the overall reference architecture

2.5 Phase 2 – Task 4: Define architecture for SDG&E

The comprehensive, end-to-end, detail architecture needs to support the utility business domains and common enabling services, as well as utilizing data models and functional elements that assume a service-oriented process.

The primary business focus is Distribution Operations, and all business units that support this process. From the business perspective, a comprehensive architecture definition that will incorporate all layers of business domains with appropriate logical groupings of business capabilities providing related business functions while requiring similar skills and expertise is developed.

From the functional view, application services structural models are provided to help the engineers and system architects identify how to best deploy the various application services in SDG&E utility network infrastructure. A vertical architecture model representation is suggested. At the top of the model are elements needed to support external agencies (regulators, interchange and balancing authorities, etc.). At the bottom are the application services needed by end-user and behind the meter devices (smart appliances, PEV chargers, building energy managers, etc.). In between are several layers where application services may be located to support utility assets and distribution operation functionalities.

In addition, analytical analysis structure models, communication and data exchange platforms are incorporated in the reference architecture definition. These are important aspects of the architecture describing how applications, services and functionalities can be distributed across the whole distribution system. The distributed architecture has to also address issues of latency, scalability, interoperability and robustness.

2.5.1 Architecture governance

The current distribution operations system architecture is in a state of flux as mechanisms are being developed to integrate new devices and technologies into the system – among these DER devices and the accompanying management system. There are limitations with the current and planned architecture that present challenges to deploying more distribution automation applications and supporting large scale deployment of DER devices. Distributed control architecture will be investigating control architectures, concepts and methodologies that will broadly be applicable to all aspects of the advanced distribution automation to achieve further alignment and enhancement toward the performance metrics of the system.

To achieve the above objectives, the proposed target architecture will be developed based on three principles:

1. Component layer architecture based on a more distributed control
2. Use cases chosen for Phase 3 testing that are representative of the additional or new functions that may be required of the SDG&E organization to implement, operate, and maintain, and
3. Changes or Modifications to SDG&E business processes or functions to accommodate future requirements based on new services or changes at the information, communications, and component layers driven by implementation of standards or other architecture changes.

2.5.1.1 Distributed control architecture

The master architecture proposed introduces a fully hierarchical, yet distributed control approach. In this architecture, all field related control commands and data exchanges with substation or field control devices are guided through SCADA communications. This approach also recognizes the fact that peer-to-peer communications among field devices can be implemented through field area networks, using OpenFMB or any other standardized open communication schemes.

Complex applications have different control requirements and may need to utilize higher speed of communications and more granular measurements (larger bandwidth) in order to react to fast dynamic events and to apply corrective measures. Such controls may need to be implemented in the field closer to the end devices rather than at a centralized control center for superior performance. However, the command of actions should be supervised by a higher level controller with overriding capability. The main reason for incorporating this approach is the fact that localized controllers may not utilize system wide information to evaluate impact of their local actions on the rest of the system. The supervisory controller can determine any corrective and coordinating response to maintain the service quality in all areas.

Some exceptions in the aforementioned approach is handling of the AMI data and revenue meters at customer sites. Because of the level of investment in AMI, the existence and utilization of a parallel communication path is considered acceptable, with the condition that ultimately AMI data is populated in the PI Historian as the centralized database for all platforms. In addition, some investment is required to enhance the frequency and amount of data collection from the AMI system in support of load estimation algorithm as part of SCADA system and other applications.

The activities associated with market participation of certain DERs and dispatch of those resources (DSO and Aggregators) that are directly under the agreement with CAISO are implemented through a different communication platform. The communication system and data exchange associated with these resources need to meet certain technical requirements and the security compliance, subject to the approval of CAISO and regulatory agencies (NERC and FERC) that can become completely outside of the scope of distribution systems.

New requirements at the component layer will also roll up through the SGAM business, functional, information, and communications layers.

2.5.1.2 Future use cases

The new architecture for SDGE is driven by future use cases associated with DER integration into distribution operations, and how the use cases will be accommodated at the business, functional, information, communications, and component layers. The new architecture should also address gaps that have been identified, to improve overall business processes and functions.

2.5.1.3 Changes to SDG&E business processes or functions

With the proliferation of DER devices in the Distribution domain, the requirement for a Distribution System Operator (DSO) will emerge. DSO will function primarily in the Market zone, with interfaces at the business layer. While the need for DSO services at SDG&E may be undefined at this point, it may need to be accounted in the target reference architecture.

In addition functional responsibilities may need to be realigned among business units in some cases to fill gaps identified in the baseline architecture analysis, as well as accommodate new functions driven by the identified use cases.

For the most part, the SDG&E baseline architecture is reusable, but with some modifications described in the following sections.

2.5.2 Business layer

The present baseline business architecture and relevant organizations appear to be adequate for the target architecture. Thus the SGAM business layer is unchanged and is not shown again. Within the SDG&E organization, business units exist that already become involved in DER control, and market services. It may be a matter of redefining job responsibilities to cover new functions regarding DER at the feeder level, DSO services for DER as the need develops, and streamlining multiple accountability/responsibility assignments as previously discussed.

2.5.3 Functional layer

Figure 2-7 provides a view of the baseline business function categories and business functions, with notations where expansion or modifications of functions may be performed.

Data analytics and data management may be combined into common platforms to serve multiple business units to gain a better economy of scale. Business Unit to oversee each platform is subject to further review.

Alarm processing functions may not be easily consolidated. Each business unit has responsibility for reacting to their own set of alarms, and have specialized resources to address issues. However a common operations center could also have some economies. The feasibility of consolidating alarm processes would be subject to further review.

2.5.4 Information layer

Use of standards at the information layer will facilitate interoperability among different vendor choices and systems, helping to lower SDG&E operating costs by not having special interfaces to support proprietary or redundant systems.

For Enterprise, Data clients/interface points: SDG&E currently uses an Enterprise Service Bus, and MultiSpeak. At the Enterprise/Systems zone, IEC 61968 can be implemented to support the CIM model. Part 1 of IEC 61968 is the first in a series that, taken as a whole, defines interfaces to support the inter-application integration of utility enterprise systems including metering, distribution and related functions. IEC 61968 also has provisions to create a CIM profile to implement MultiSpeak functionality. IEC 61968 also reaches into the Operations zone, with harmonization efforts with CIM/61850 for distribution grid management.

At the market zone, standards include OASIS, and IEC 62325. The actual choice of SDG&E for implementation may be influenced by SDG&E's direction and position on how to implement market services for transmission as well as distribution in the future. OASIS is included in SGIP's catalog of standards, IEC 62325 is not.

Below the Enterprise zone, and in the Distribution and DER domains, the IEC 61850 suite of standards provides some definitions for object models that could be used to define information exchanges. In the customer premise domain there are several meter related standards included in the SGIP catalog of standards that help define information to be exchanged between the utility, customer, and third party provider. The proposed architecture is summarized in Figure 2-8 below.

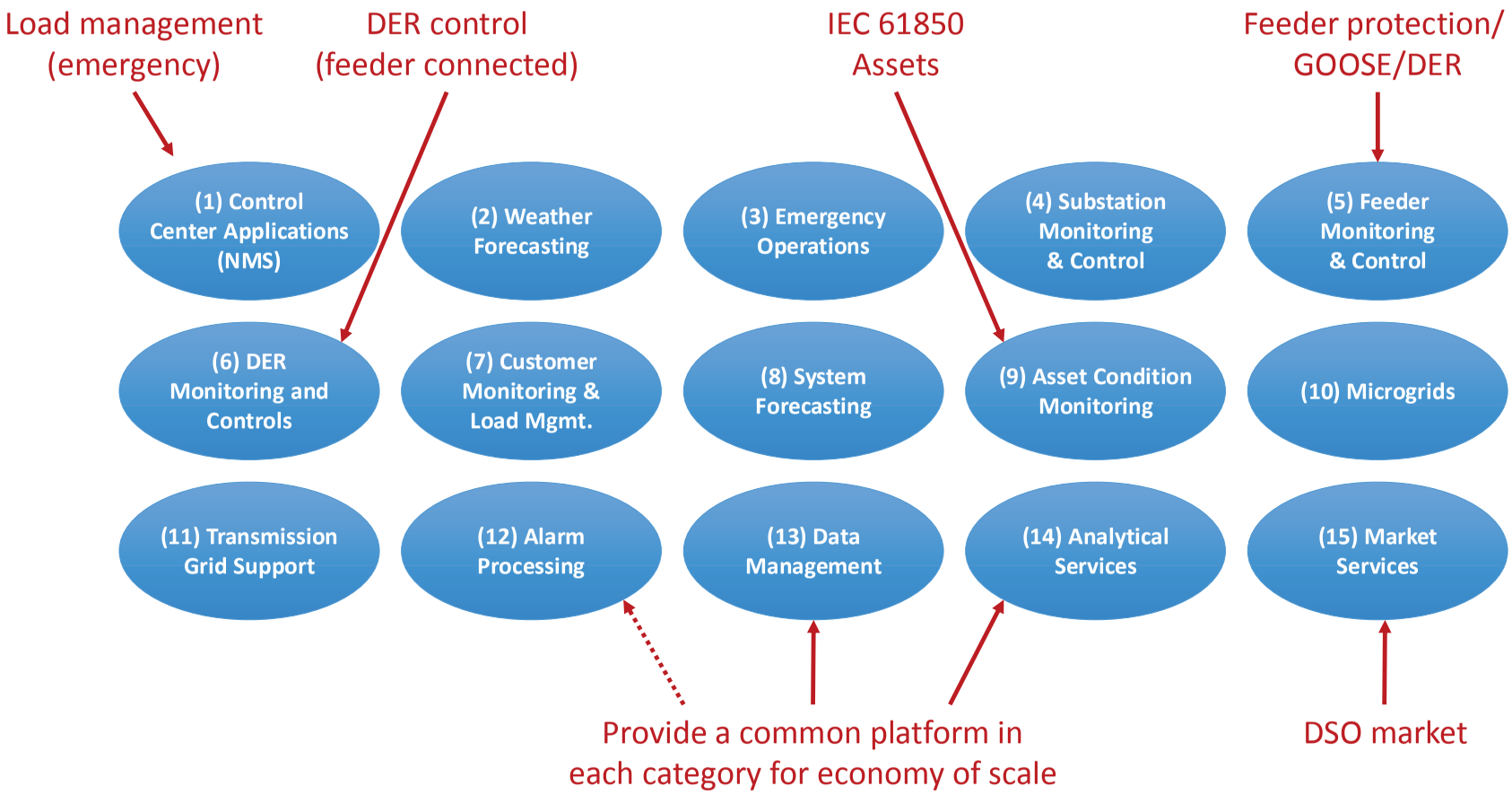


Figure 2-7. Business function categories and functions, augmented with target functions

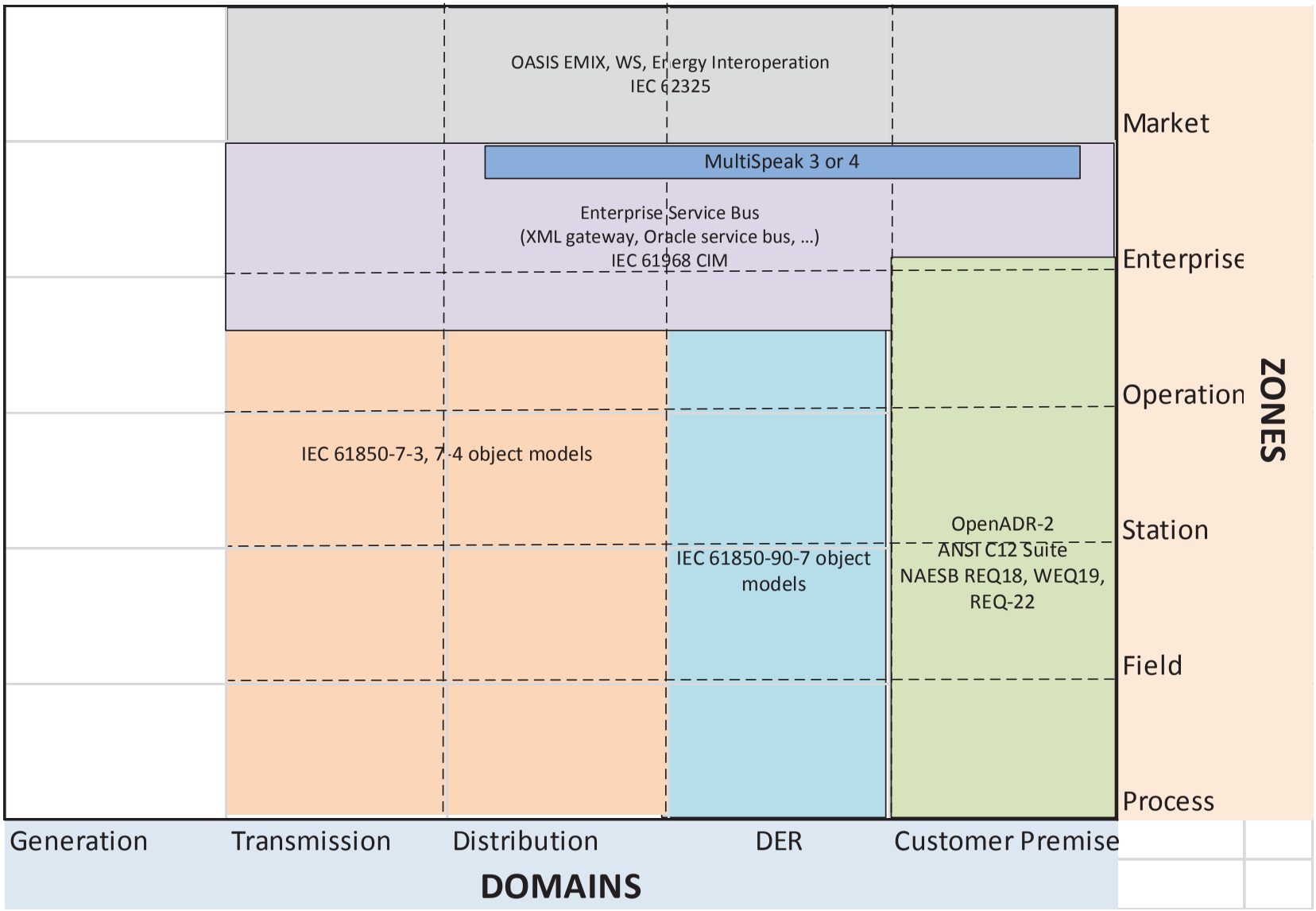


Figure 2-8. Proposed information layer architecture

2.5.5 Communications layer

As noted earlier, the communications layer can be defined as having two parts:

1. The communications applications layer
2. The communications transport layer

2.5.5.1 Communications applications architecture

The key platforms of IEC 61850 and NAESB RMQ.26 are overlaid on the previous baseline communications applications layer to show their integration with and inter-operability to the various SDG&E interfaces. This is depicted Figure 2-9.

For Enterprise, Data clients/interface points: The reference architecture for the information layer, overlaps somewhat with the communications applications layer, in that with the reference standards, functions are provided to support both layers, which will ride over the communications transport layer. At the Enterprise/Systems zone, IEC 61968 can be implemented to support the CIM model. Part 1 of IEC 61968 is the first in a series that, taken as a whole, defines interfaces to support the inter-application integration of utility enterprise systems including metering, distribution and related functions. IEC 91698 also has provisions to create a CIM profile to implement MultiSpeak functionality. IEC 91698 also reaches into the Operations zone, with harmonization efforts with CIM/61850 for distribution grid management.

At the market zone, standards include OASIS, and IEC 62325. The actual choice of SDG&E for implementation may be influenced by SDG&E's direction and position on how to implement market services for transmission as well as distribution in the future. OASIS is included in SGIP's catalog of standards, IEC 62325 is not.

At the operations layer and below, IEC 61850 provides a ubiquitous platform to provide interoperable communications among components in the various zones, with mapping to most of the SDG&E communications applications protocols already in service including: DNP3, C37.118, MultiSpeak 3, IEC 60870-101.

However, certain communications application protocols is use by SDG&E are legacy, and interfaces to a standardized IEC-61850 may require further migration considerations:

- MODBUS (field zone)
- SCOM (field zone)
- SEL Mirrored bit (substation zone)
- Other vendor proprietary (substation zone)
- PQDIF (substation zone)
- Open Systems Interfaces (Operations zone)

- In the customer premise domain, the field area network is a vendor-specific product that is based on open standards, but may also require special interface considerations in a standardized reference architecture.

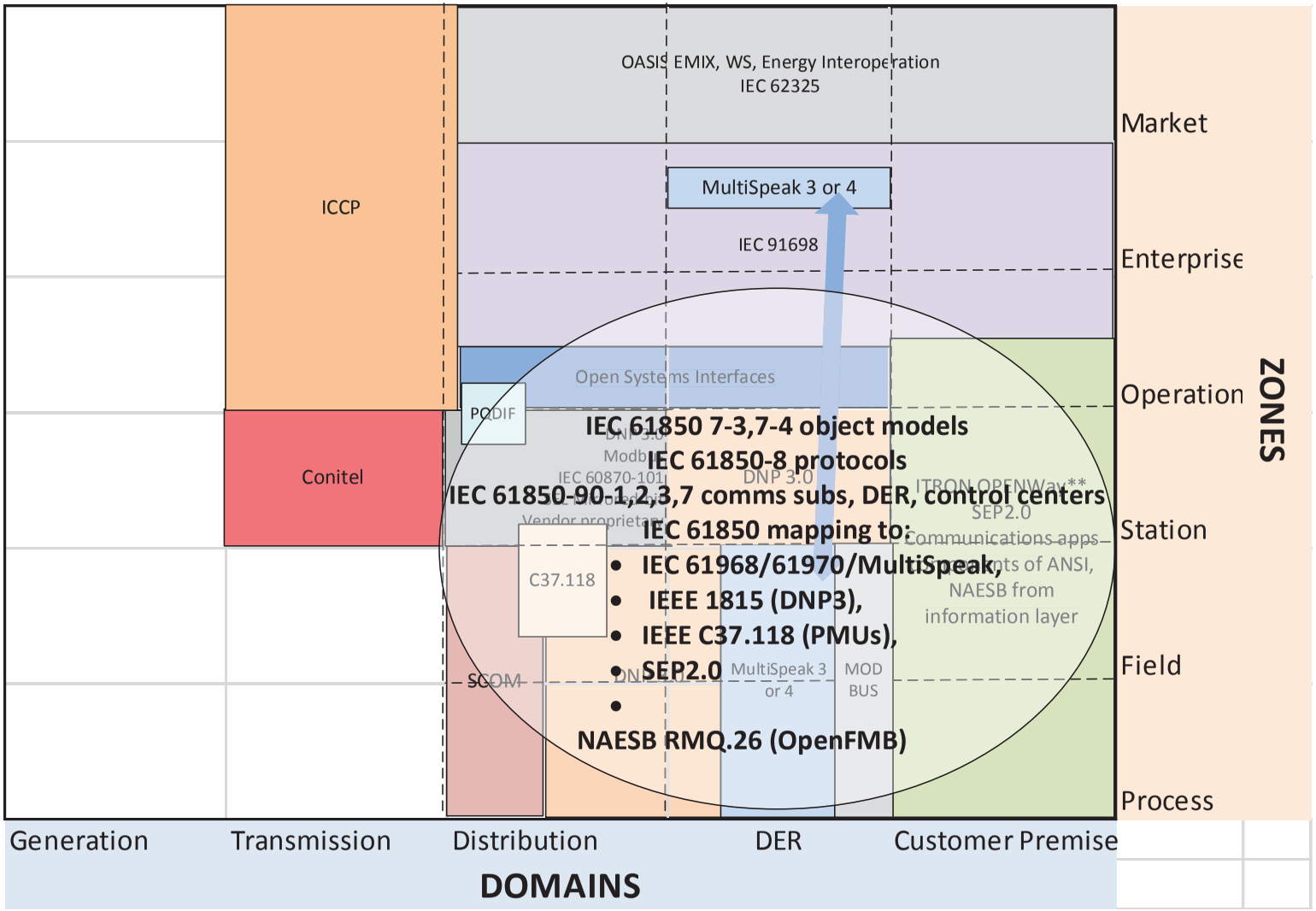


Figure 2-9. Proposed communications applications layer

- The implementation of NAESB RMQ 26 (OpenFMB) is also included in the reference communications applications architecture. The OpenFMB will interface with various power system components that communicate using various protocols such as DNP3.0, Modbus, IEC 61860, SEP 2.0, XMPP, CoAP and others. Open FMB aims to replace multiple proprietary systems with an Open system based on the Internet protocol, and may well be a complement to IEC 61850 field implementations.

2.5.5.2 Communications transport architecture

Figure 2-10 shows the target communications transport architecture.

For the target communications transport layer, the goal is to migrate from legacy time-division-multiplexed (TDM) based technologies such as SONET or T1, to TCP/IP based transport that utilize link layer technologies such as Ethernet or MPLS.

In the Operation and Enterprise zones, TCP/IP is already the prevalent communications wide area networks between sites, and Ethernet based local area networks within a site. IP version 4 is in operation. SDG&E Plans to migrate to IP version 6 is unknown at this time, but IPv4 is expected to be prevalent in the industry for many more years. In the market zone, migration from legacy TDM to TCP/IP should occur.

For distribution and DER at the station, field, and process zones, legacy serial connections exist, as well as some IP based communications. Point-to-point radios such as low capacity microwave radio, or point-to-multipoint low speed MAS radios also exist at these levels, primarily not for direct customer interfaces. The RF mesh network associated with vendor-specific field area network has been established to connectivity with customer applications. Legacy serial connections should eventually migrate to Ethernet/IP based communications transport.

2.5.6 Component layer

To achieve the objectives of eliminating areas of parallel control, allowing a more distributed control architecture, and avoiding proprietary communications protocols, the proposed component architecture introduces a fully hierarchical, yet distributed control approach. In this architecture, all field related control commands and data exchanges with substation or field control devices are guided through SCADA communications. This approach also recognizes the fact that peer-to-peer communications among field devices can be implemented through field area networks, using OpenFMB or any other standardized open communication schemes.

The activities associated with market participation of certain DERs and dispatch of those resources (DSO and Aggregators) that are directly under the agreement with CAISO are implemented through a different communication platform. The communication system and data exchange associated with these resources need to meet certain technical requirements and the security compliance, subject to the approval of CAISO and regulatory agencies (NERC and FERC) that can become completely outside of the scope of distribution systems.

2.5.7 Representative security architecture model

The *Smart Grid Reference Architecture* document shows the Security Logical Model. For further discussion on the model, please refer to the referenced document.

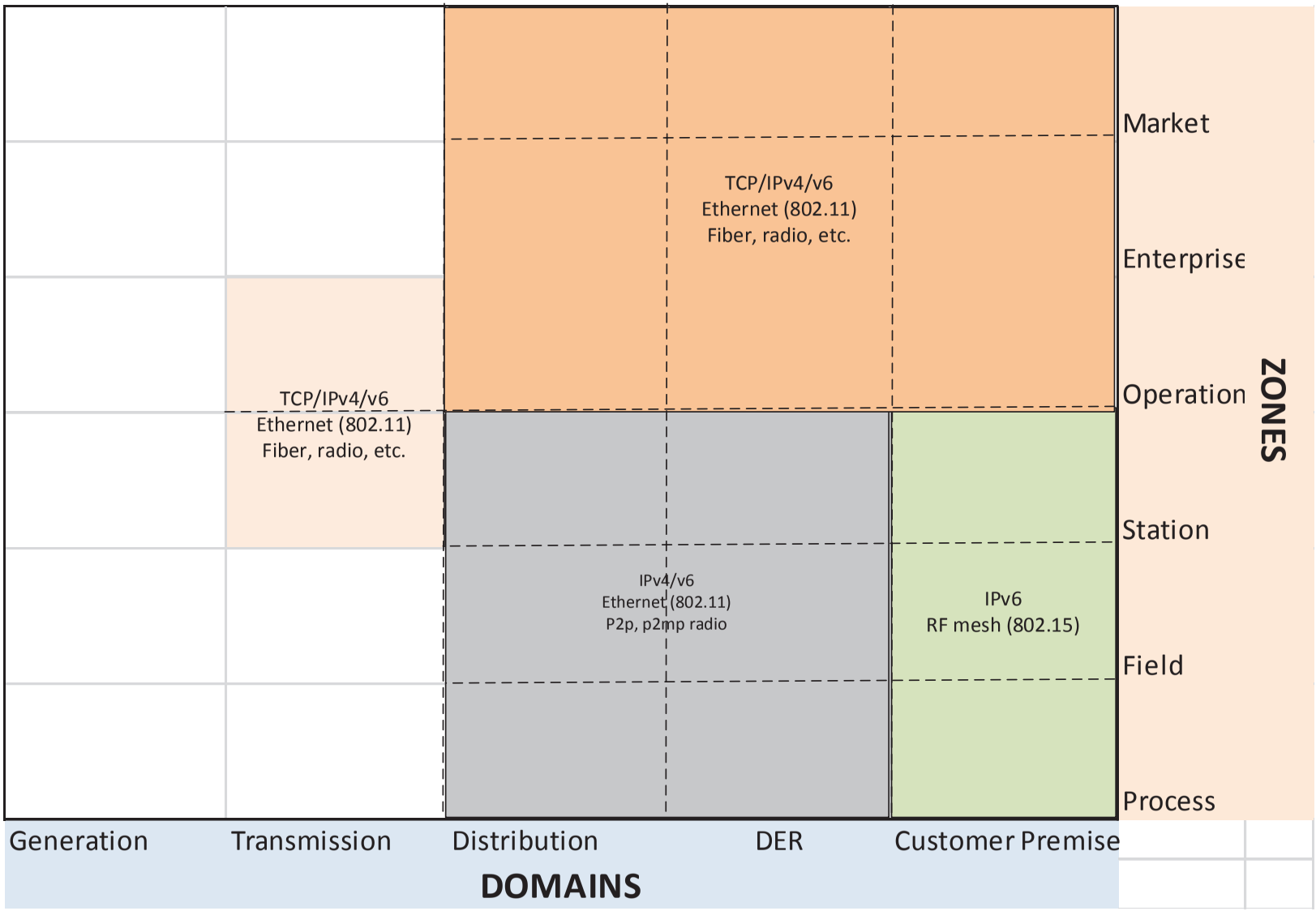


Figure 2-10. Proposed communications transport layer

The Security Services Stack Model has several parts:

- Support services – services that may come from another portion or tier of the architecture but are necessary to support the services in the tier being described
- Foundation services – key security services, generally needed throughout the architecture which other services depend or expand upon
- Core services – the primary security architecture service stack
- Integration services – services specifically providing integration between security and other architectural tiers or business systems

The Security Synergy Model illustrates how security services can be shared to meet various Smart Grid security requirements.

SDG&E cyber security policies may be reviewed to determine how the recommended target architecture will affect baseline security policies.

2.5.8 Issues or problems addressed by the proposed architecture

This section describes the key gaps between the current (as-is) and proposed (to-be) reference architectures. This difference, or delta, defines the scope of work that needs to be undertaken in order to transition from the current to the proposed architecture. This scope is thus the scope of the program(s) or project(s) that need to be completed in order to reach the proposed business architecture. Table 2-11 presents a summary of key gaps between baseline and proposed architectures.

Table 2-11. Summary of key gaps between baseline and proposed architectures

Ref ID.	Baseline Architecture Issue	Impact	How addressed by proposed architecture
SGAM Component Layer			
C1	SCADA controls are centralized at the control center: As the capabilities of the communications infrastructure advances, additional intelligence will need to be deployed closer to the customer premise, allowing proactive decisions to be made locally to avoid or minimize outages, while informing the utility systems and operators of the local actions taken. Migration to this architecture will impact all SGAM layers, including present business processes Control of DER assets is not coordinated via SCADA. Direct control is accomplished via vendor proprietary dedicated links. However, the DER asset owners must coordinate with Distribution Operations SCADA prior to implementing any controls	High	Architecture changes to eliminate SCADA areas of parallel control as described in target component architecture, and allow for a more distributed component architecture. Fundamentally, all controller should utilize the same source of operational data and should have access to the same system models The concept of unifying data sharing and information accessibility across all control platforms also requires standardization of the data exchange mechanism and, more specifically, avoiding proprietary communication protocols.
C2	The Customer domain appears to be independently operated with no interoperability with other domains. Any data	Med	Because of the level of investment in AMI, the existence and utilization of a parallel communication path is considered

Ref ID.	Baseline Architecture Issue	Impact	How addressed by proposed architecture
	exchange occurs at the Enterprise level, when may impede the implementation of timely actions to improve service.		acceptable, with the condition that ultimately AMI data is populated in the PI Historian as the centralized database for all platforms. In addition, some investment is required to enhance the frequency and amount of data collection from the AMI system in support of load estimation algorithm as part of SCADA system and other applications. Standardization at the Enterprise zone through the use of CIM, MultiSpeak, and other standards will facilitate the data exchange with other layers and zones.
SGAM Communications Transport Layer			
CT1	Only a fraction of links are capable of high-speed communications (typically those to the newer generation SA/SA equipped substations	Med	This issue will only be solved over time, as future architectures are deployed based on their cost/benefit to the SDG&E business process. However the target architecture does position future implementation to be consistent with interoperable standards, using state-of-the art technology.
SGAM Communications Applications Layer			
CA1	Specific protocol to support distribution operations at market level is absent. Not currently a widely utilized application. However, as utilities migrate to a distribution systems operator (DSO) role, communications among market entities (third party service providers, DER aggregators, CAISO, other utilities) will be important.	Med	Standards have been identified to support market operations that cover both the information and communications applications layers. Development and implementation of these standards will depend on the role of SDG&E in future distribution market services.
CA2	Some legacy protocols still in use such as SCOM, MODBUS; there is a variety of legacy protocols from the process to the Operations levels across all domains. Each protocol requires a certain amount of maintenance and upkeep. There is no clear path of interoperability between the protocols, without having to go to the Enterprise zone to allow a common interface between systems. The component layer confirms that there are no direct connections from the Customer domain to allow interoperable processes to occur	Med	The legacy protocols in use at the substation and field levels will not be replaced overnight. However the new reference architecture provides a path for interoperable protocols and “adapters” (i.e., through OpenFMB, IEC 61850) to possibly accommodate the legacy protocols, or continue supporting interfaces at the Enterprise zone through more efficient standardized processes.
SGAM Information Layer			
I1	In the SGAM context, this layer is virtually	High	The reference architecture defines

Ref ID.	Baseline Architecture Issue	Impact	How addressed by proposed architecture
	non-existent in the SDG&E environment, from the operations layer to the process layer, across all domains. Proprietary methods of defining data information requirements exist with "siloed" applications, and no set of standards. Most of the information formats are defaulted to the communications applications protocols. This is a key gap; to support the multiple proprietary methods results in an increased cost of operations.		standards for the information layer that adapt to both the information and communications applications layers. With the standardized approach, the siloed data applications can be harmonized for greater use and distribution across the SDG&E organization.
SGAM Functional/Business Layers			
F1	There are independent functions at the market level, for specific needs in Customer programs and Electric & Fuel procurement. There appears to be gaps in this area to support future Distribution operations requirements	Med	The market services gap is addressed in CA1 above, pertaining to industry standards to facilitate the process. A RACI analysis is required to identify SDG&E organizational units that would be anticipated to participate in distribution market requirements.
F2	Certain functions appear to have multiple business units who are assigned responsibility or accountability, such as: Storm and fire operations Feeder Control Asset condition based monitoring Load management (emergency) Substation monitoring, control Some of these multiple assignments can be attributed to the varying requirements of the functions: based on certain operating conditions: at times a certain group may be responsible for the function until a normal operational state is returned; under other conditions, another group may have the responsibility.	Low	This is more of an organizational characteristic than an issue. Responsibilities and accountabilities have been documented in a RACI analysis, and included as part of the SGAM business and functional layers.
F3	Functions of alarm processing, data management, and analytical services appear to be performed independently by the groups in relation to the alarms, data, and analytics for which the group has responsibility for, or most interest in. Thus these functions may be replicated across several organizations.	High	Standardization through a reference architecture facilitates the use of common platforms across multiple business units. Data management and analytical services may benefit from the common platform approach to serve multiple organizations, from a cost and efficiency standpoint. Alarm processing may also benefit through a common network management platform, however several organizations have their own set of alarms for which they are responsible, that may not have commonality with other groups (i.e., security alarms, vs.

Ref ID.	Baseline Architecture Issue	Impact	How addressed by proposed architecture
			equipment malfunction alarms). A common organization or business process to service all the alarms would be subject to further review.
F4	Reconciliation of proposed use cases with functional and business processes. For phase 3 testing, a certain number of use cases are identified for testing at the ITF. These use cases should also be reviewed to determine their impact on existing functions, groups, and RACI assignments for Distribution Operations, to identify any changes that may be required from existing processes	High	Target Business and Functional layers have identified the new requirements associated with the future DER integration requirements that the use cases represent, and sorted out roles and responsibilities for the functions through a RACI analysis. Existing SDG&E organizational structure appears adequate to accommodate new roles, it is just a matter of redefining responsibilities to align with Target component layer, and reduced parallel operation of components.
SGAM Business Layer			
B1	The Distribution, DER, and Customer domains appear to be independently managed with few cross-domain services. This may impede efficiency of operations	Med	As a result of the Target architectures developed and standardized at the other layers as described above, this gap is inherently incorporated and addressed.

2.5.9 Summary and roadmap for proposed architecture implementation

Implementation of the target architecture should be performed as the opportunity arises from DER growth, market development, and general legacy component replacements. A 10-year implementation time frame is expected for near full deployment. The considerations that would be necessary to work toward the eventual migration to the target architecture is described in the previous sections. The general activities that would be required are summarized below in the context of SGAM layers:

- **Component layer***:* take into account distributed control recommendations, primarily more pro-active direct SCADA control incorporating DERMS, field devices, to mitigate parallel operations. DSO server to negotiate DER integration and control.
- **Communications applications layer**: more use of IEC 61850 for transport and applications interfaces; utilize adapters to interface with other standards protocols such as DNP3, MultiSpeak, C37.118, etc. Interfaces to legacy protocols such as SCOM are to be determined. To support use cases, IEC 61850-8-1 (GOOSE), IEC 61850-7-2, to be implemented
- **Information layer**: Implement standardized approach to information exchange utilizing IEC 61850, IEC 61968/61970, etc. This would include document/drawing files, XML files, IEC 61850-7-3, 7-4 Object Models, IEC 61850-6 Engineering, especially to support use cases.
- **Functional layer**: Changes driven by more direct SCADA control, new functions from DER related use cases: Modification of certain existing Distribution Operations functions (from baseline functional layer) taking into account more prevalent use of DER integration at the feeder level:
  - Asset Condition-based Monitoring

        - Designing, Engineering, building, commissioning, and maintaining IEC 61850 compliant protection and automation systems
        - Maintenance testing of IEC 61850 compliant relay/IED
    - Feeder Protection
        - Breaker failure scheme with GOOSE messaging
        - Automatic Transfer scheme using GOOSE messages
        - Protection Coordination with IEC 61850 (including anti-islanding protection of DERs, reclosing/relaying operation, enhanced operation of feeder protection
    - DER Control (Feeder connected)[NOTE: this is in addition to existing Distribution Operations function of DER control(generation/storage)
        - Remotely change control mode of DER (IEC 61850)
        - Using multiple large scale DERs, correct feeder power factor/improve feeder voltage; coordinated use of ride-through capabilities to enhance system performance under network faults and/or transient disturbances
    - Load management (emergency)
        - Effective utilization of DER contributions to offset customer loads

- **Business layer:** defined roles and responsibilities relating to new functions from DER use cases, potential other modifications based on gaps discovered during baseline RACI analysis:
    - Definition of market services including DSO responsibilities
    - Siloed operations in alarm processing, data management, data analytics
    - For a single function, assignments of accountability or responsibility to multiple entities

The present baseline business architecture and relevant organizations appear to be adequate for the target architecture. Within the SDG&E organization, business units that already exist become involved in DER control, and market services. It may be a matter of redefining job responsibilities to cover new functions at the feeder level, DSO services for DER as the need developed, and streamlining multiple accountability/responsibility assignments as previously discussed.

Any legacy or proprietary protocols or information models may need to be transitioned to a more standards based approach over time to realize the full economies and advantages of a standardized reference architecture.

2.5.10 Implementation planning

Generally, in utilities, a change of technology, architecture, or processes is a multi-year process, being driven by cost/benefit feasibility, as well as regulatory constraints. Many types of utility assets (i.e., substations, field devices, etc.) are designed to last 20-30, or even 40 years or more, and thus waiting to make an end of asset life replacement can be a challenge.

Key drivers for change may include: level of DER penetration and growth, where an asset stands in its life cycle, or benefit/costs analysis to evaluate if there are other more cost-effective ways to support the present mode of operation of the business of energy delivery.

Potential architecture changes are related to the expected increase of DER integration and its impact on Distribution Operations, functionally and organizationally. Adoption of industry standards may also impact the organization through the requirement for additional tools, software, or systems. Some

general milestones are listed below to provide a high-level roadmap for the architecture migration. These are notional time frames, subject to refining based on SDG&E infrastructure requirements and capabilities.

2.5.10.1 Phase 2 planning: First three years

1. *Review Business Processes and Functions as defined by the baseline RACI analysis*

   Review the gaps identified in the baseline RACI matrix to determine if it is feasible to improve processes: Redundant processes identified such as data analytics, data management, and alarm processing to determine if common platforms for each function may be feasible. This could possibly be used as a "springboard" for standards implementation.

   Review and assess the multiple "A" or "R" assignments to confirm their validity, or identify reasons for the multiple assignments. (Some can be attributed to the varying requirements of the functions based on certain operating conditions).

2. *Perform DER integration forecast:* The speed of DER integration into the SDG&E system will be a pacing factor for what needs to be done, and how fast it should be done. Thus DER Integration could be a catalyst in the target architecture implementation.
3. *Asset age inventory:* review relevant distribution assets to determine if there are any prime candidates due for replacement that can be used as a catalyst for architecture upgrade
4. *Review and develop plan for SGAM component layer changes to meet target:* develop a plan for implementing changes at the component layer to eliminate areas of parallel control, establish a more distributed operations as described in the target architecture.
   a. Based on component changes, develop plan for related requirements at the communications, information, functional, and business process layers
5. *Perform a communications review* to determine the feasibility of implementing more high-speed networks

2.5.10.2 Phase 3 implementation: years 4 through 10

1. Based on DER integration forecast develop action plan to support it:
   a. Identify and develop a plan for SDG&E's role in distribution market operations. In conjunction with this, identify relevant market standards and protocols that would support the market operations
   b. Start with "low hanging fruit": Identify areas of higher growth, and the adequacy of the current infrastructure to support it, and how IEC 61850 may be implemented to meet requirements.
2. Review requirements and implement changes to support IEC 61850 implementation, including:
   a. Organizationally to support use cases: groups responsibilities, skills required
   b. requirement for additional tools, software, or systems
3. Review feasibility to support Enterprise standards implementation including IEC 61968, MultiSpeak, etc., including:
   a. Organizationally to support use cases: groups responsibilities, skills required
   b. requirement for additional tools, software, or systems
4. Based on planned implementations, develop and implement a cyber security plan for a standardized approach to support the target architecture.

2.5.10.3 Legacy devices

Within the present SDG&E architecture, there are legacy devices that utilize legacy communications protocols and networks that may need to be supported until such time it becomes cost-effective to replace them. However, there are dual platform devices offered by some vendors that could support both the legacy and latest standards, utilizing adapters or other interface schemes, that could facilitate the migration and reduce the risk of the stand-alone legacy devices.

Implementation of new architecture may be impeded if new and legacy technologies cannot co-exist.

2.6 Phase 3 – Task 5: Design test system

While the primary focus of the project was on distribution automation (DA) and DER integration, two other areas were included; distribution substation automation and non-functional activities. The complex interaction between the protection and control elements in the substation and along the feeder made it important to include substation equipment in the use cases and testing[11]. Non-functional activities involve those associated with the deployment and maintenance of IEDs, regardless of location, and because IEC 61850 results in some specific challenges, this was identified as a third focus area of testing.

A single line diagram of the test system is illustrated in Figure 2-11 below. The test system was selected in a way that all the aforementioned three areas could be tested. An actual substation was selected as the basis for the model and additional substation and feeder-based DER devices were added, and/or sizes increased to exacerbate certain use case conditions to better illustrate the problems and efficacy of the solutions.

While much of the system was modelled in the Real Time Digital Simulator (RTDS), extensive use was made of actual hardware devices – both IEDs and DER. These are indicated in yellow in the diagram above. IEDs included protective relays, Remote Terminal Units (RTU), Load Tap Changer (LTC), meters and Voltage Regulators (VR). DER included a Battery Energy Storage System (BESS) and a Smart Inverter/Photovoltaic array.

Figure 2-12 below shows the system configuration and how the various physical devices were interconnected. One of the purported benefits of the IEC 61850 standard is interoperability between the products of different vendors, and the test system was constructed using equipment from multiple vendors to test this premise. Accordingly, IEC 61850 equipment from three different vendors were procured to fulfill various protection and control functions.

[11] It is worthwhile noting that a separate EPIC project was specifically tasked with examining the deployment of IEC 61850 in a substation. Care was taken not to duplicate any of the work performed under the auspices of that project.

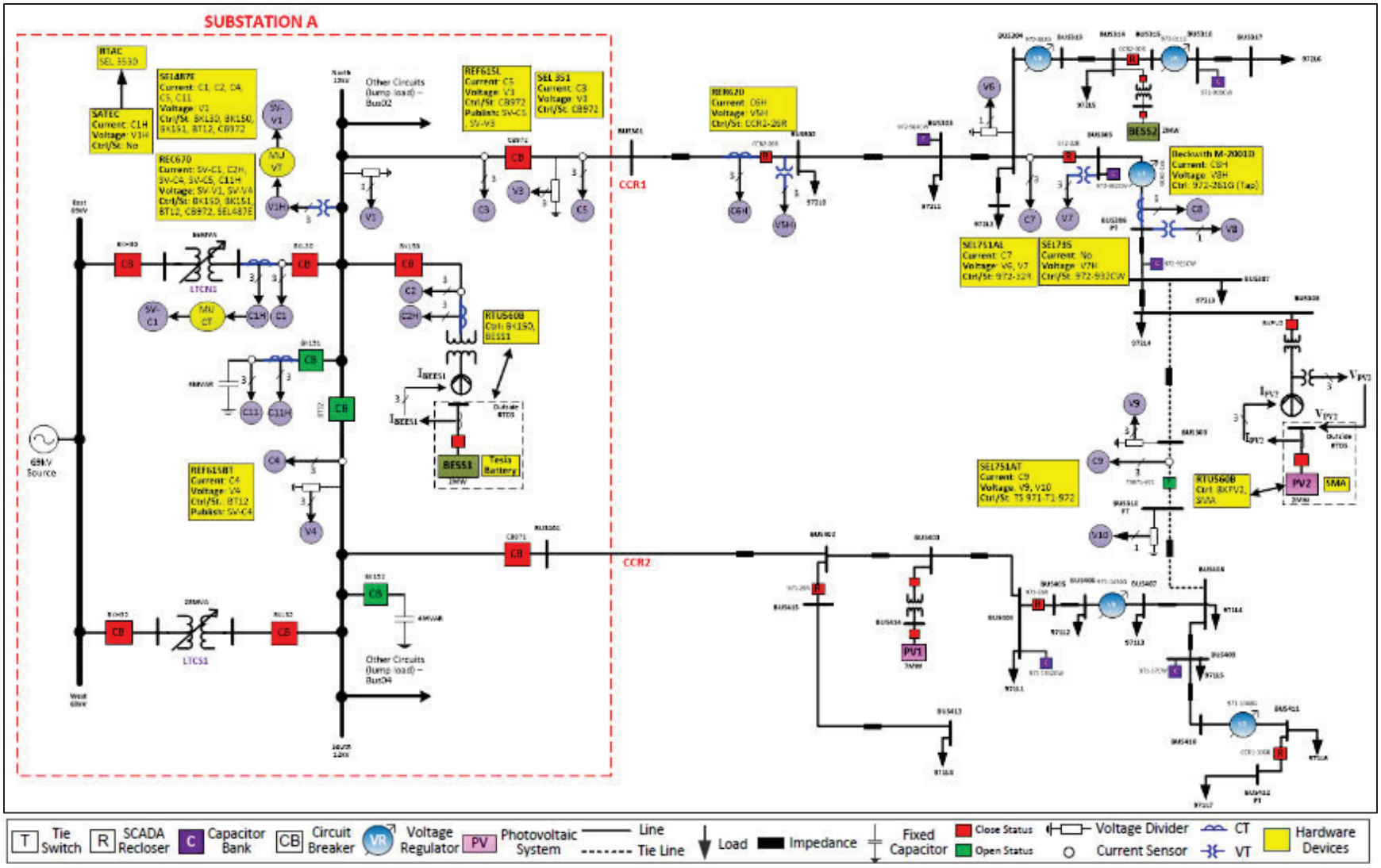


Figure 2-11. Single Line Diagram of the test system showing key elements.

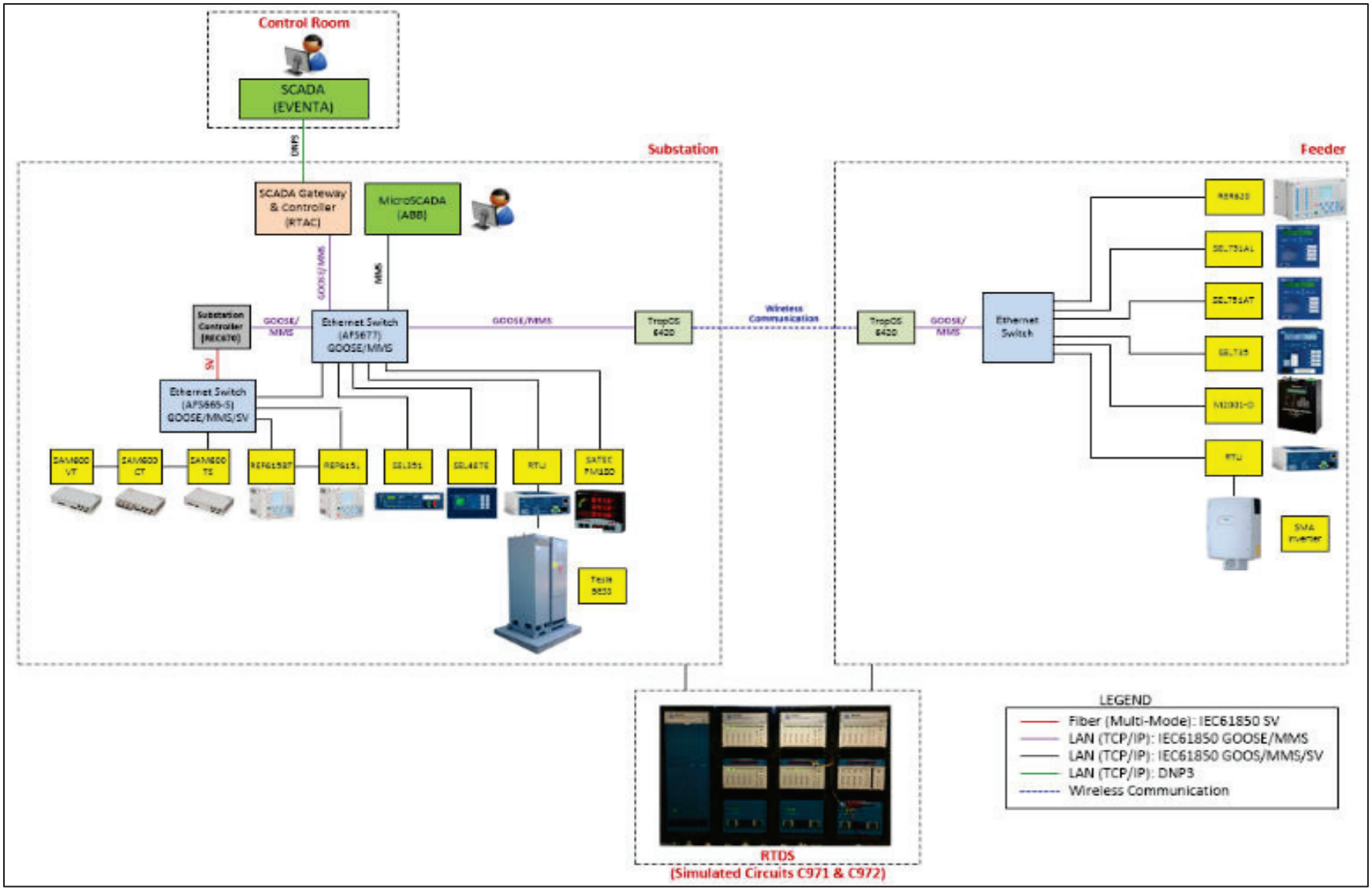


Figure 2-12. System configuration of actual IEDs showing interconnections.

To fully exercise the capabilities of the IEC 61850 communications, the substation communication topology employed both a Station Bus and a Process Bus.

- The IEC 61850-8-1 Station Bus was used by the various IEDs to exchange data among themselves using the peer-to-peer capabilities of IEC 61850, as well as for control commands from the different devices in the architecture capable of issuing these.
- The IEC 61850-9-2 Process Bus was used to interconnect merging units with protection and control IEDs and provide sample values from RTDS-simulated Current Transformers (CT) and Potential Transformers (PT).

The downstream feeder-based IEDs were connected wirelessly to the substation equipment via an extension of the Station Bus using a high-speed wireless network.

2.6.1 System components

Table 2-12 that follows lists the primary system components, the products selected and the role of each element. Note that the selection of equipment does not imply a specific preference for that vendor or that product, nor does it confer any endorsement for their use.

Table 2-12. System components and their role.

Device	Role
Simulated SCADA control center	This device provided a platform from where the control and monitoring of substation and feeder assets could be performed. The Simulated control center interfaced with the Substation Data Concentrator via the DNP 3.0 protocol.
Substation Gateway	This device acted as a conduit between the SCADA control center and the rest of the equipment in the configuration. It communicated upstream to the SCADA control center via DNP 3.0 and downstream to other system components via the IEC 61850 Station Bus. The original intent was to use both MMS and GOOSE communication services, but the final configuration only employed GOOSE for reasons to be discussed in more detail in the Recommendations section.
Substation HMI	In addition to providing local control and monitoring functionality during system testing, the Substation HMI provided event recording and alarming. It also hosted the IED configuration software used to build and maintain the system setup and several engineering and diagnostic tools used to facilitate testing and troubleshooting. It communicated to both substation and feeder devices via the MMS communication service.
Network firewall	This device was intended to provide a secure access point for remote maintenance activities such as retrieving monitoring data or to perform remote diagnostics. The functionality to be tested in the use cases that were eventually selected did not require the use of the firewall and it was not deployed in the final system.
Time Server	This device was a dedicated time server providing high accuracy time synchronization of

Device	Role
	the entire digital substation automation system. It used a combination of services to time synchronization the various system components, including: • IEEE1588 time sync protocol • SNTP • IRIG-B
IEC 61850 Station bus / Ethernet Switch	This device provided the Station bus that the Substation Gateway, Substation HMI, Time Server, and most of the substation and feeder IEDs connected to.
Wireless gateway and router	Communications between the substation and feeder equipment was accomplished wirelessly using a high-speed meshed wireless network.
IEC 61850 Gateway for legacy device integration	As will be discussed in a section that follows, the project was unable to source any DER controllers with native support for IEC 61850. It was therefore necessary to integrate these legacy devices into the IEC 61850 network using a protocol converter capable of communicating to the DER controllers via the supported protocol – which happened to be Modbus in both cases.
Protection and control devices	To test interoperability, different IED types from a variety of vendors were used. The IED types included protective relays, voltage regulators, meters, remote terminal units, and cap bank controllers. • Substation P&C devices: Merging units, bus tie protection, feeder protection, power quality meter, and substation controller • Feeder P&C devices: Recloser (CCR2-26R and CCR2-32R), voltage regulator (CCR2-261G), cap bank controller (CCR2-932CW), and feeder tie controller (TSCCR1-CCR2) Both MMS and GOOSE communication services were used to integrate these into the system and in data exchange between the devices.
Stand-alone merging units	Utilizing modular stand-alone merging units and the IEC 61850 Process bus, conventional CTs and PTs were integrated into the configuration for use by the Protection and Control Devices.
RTDS	A real-time digital simulator (RTDS) was used to represent the 12kV distribution study system with all major protection and control (P&C) assets modeled.
DER Devices	Selected power devices: two inverters were used for the power hardware-in-the-loop (PHIL) testing in this project. These inverters were interfaced with the power system (RTDS) through a Remote Terminal Unit unit, which converted IEC 61850 GOOSE (Generic Object-Oriented Substation Event) messages to the protocol supported by the inverter (Modbus).

2.6.2 Use cases

Use cases were developed to test the application of the IEC 61850 standard in the three separate areas defined earlier, i.e., distribution automation (DA) and DER integration, substation automation and non-functional activities. An additional three use cases were defined to compare the performance of IEC 61850 against existing and emerging protocol standard (DNP 3.0 and OpenFMB). Table 2-13 below lists the uses cases and identifies which area each addresses.

Table 2-13. Use cases developed for Phase 3 testing

Use Case	Name	Protocol	Non Functional	Substation Automation	DA and DER Integration
1	Full Lifecycle Asset Provisioning	IEC 61850	☑		
2	Maintenance Testing		☑		
3	Breaker Failure Scheme			☑	
4	Automatic Transfer			☑	
5	Improved Protection Coordination			☑	
6	DER Control Mode Change				☑
7	Grid Support using DERs				☑
8	Emergency Load Management				☑
9	Dynamic Emergency Load Control and Management	IEC 61850 OpenFMB		☑	☑
10	Dynamic Circuit Load Management	IEC 61850 DNP 3.0		☑	☑
11	Volt-var control	OpenFMB		☑	☑

Table 2-14 that follows provides additional details on each of the IEC 61850-specific use cases.

Table 2-14. IEC 61850-specific use case description

Use Case	Title	Description

1	Lifecycle Asset Provisioning	The utilization of the IEC 61850 standard in protection and automation systems requires changes to the design, engineering, building, commissioning and maintenance procedures used today.
		The IEC 61850 engineering process is based on the use and exchange of XML-based description of system components, system configurations and capabilities. During the lifecycle of an automation and protection system, changes, replacements, extensions and reductions of the system are typical scenarios that require special consideration.
		The objective of this use case was to demonstrate the engineering process to:
		• Create IEC 61850 system configuration files including:
		  ▪ MMS mapping and HMI integration
		  ▪ Peer to peer (GOOSE) communication between IEDs
		  ▪ Sample values assignments (process bus)
		• Facilitate documentation of the system design and implementation,
		• Simplify the process of updating and reconfiguring an existing system,
		• Adding, removing, or replacing single components (IED and/or DER) in the existing system

2	Maintenance test	For maintenance purposes, regular time-based or condition-based testing is performed on IEDs to confirm their proper operation. To do this, the test

Use Case	Title	Description
		engineer must isolate the IED under test from the system to avoid any undesired breaker operations during the maintenance testing process. In the case of conventional, non-IEC 61850, wire-connected systems, the test engineer opens test switches to perform maintenance tests. However, the situation is much different in the IEC 61850 environment, where the isolation of the relay/IED can be done through communications. The latest IEC 61850 standard defines a test mode and simulation features specifically to address this. This use case applied and verified the use of the test mode and simulation features to facilitate maintenance testing of relays/IEDs, as compared to a traditional wire-connected system. The objective of the use case was to investigate, test, and document the isolation and re-routing mechanism for GOOSE and process bus links. The main questions to be addressed included: • How can the IED read process bus data provided by a test set versus the actual merging unit information during the maintenance test? • How can a GOOSE link to any other device (for example breaker failure start) be interrupted during the maintenance test?
3	GOOSE Performance/Breaker Failure	With the use of IEC 61850 communications, copper wire interconnection between IEDs can be replaced by GOOSE message exchange to perform certain actions. An example is breaker failure signals. When a feeder circuit breaker fails to operate and isolate a fault, the feeder relay needs to send a breaker failure trip to the bus protection relay in order to isolate the bus from the faulty section. While the industry has extensive experience with the performance of this feature using a hard-wired scheme, the use of GOOSE messages to accomplish this function has not been widely reported upon. The objective of this use case was to contrast the performance of a GOOSE-message based breaker failure scheme with that of the conventional approach.
4	Automatic Load Switch	Automatic transfer schemes are used to maintain continuity of supply during the transfer of a bus from one power source to an alternate power source. A proper transfer system must be designed in such a way that it i) operates quickly and ii) prevents damages to loads connected to the transferred bus. In the events of losing one of the main in-feeds, e.g., due to an accidental breaker operation at the 69kV voltage level or a transformer fault, the dead bus can be energized and fed via the bus tie. Ideally, the outage of one of the main supply transformers can trigger a load transfer to the other in-feed. However, before the bus tie can be closed to complete the transfer, certain criteria must be checked to ensure safe and reliable load transfer. The criteria become more important in the presence of DERs in distribution circuits. The objective of this use case is to implement an automatic transfer scheme Using IEC 61850 GOOSE messages based on SDG&E practice and requirements. Circuit breaker positions, voltage phasor measurements, fault indications and synchronizing condition information are transmitted via IEC 61850 communication protocol and processed by the substation computer or a dedicated automation controller. Hot switch over (closed transition) and cold switch over (open transition) scenarios should be included in the design. Therefore, the main objective of the use case is a fast and reliable power

Use Case	Title	Description
		source transfer with the use of IEC 61850 GOOSE messaging system.
5	Enhanced Protection coordination for subs	Short-circuit faults on distribution circuits are typically detected and isolated by inverse-time overcurrent protective devices. The coordination between different over current elements installed along the distribution feeder and those located on the substation is achieved via time coordination with acceptable margins. However, this traditional approach may result in long operating times of feeder relays when the fault occurs in a location close to the substation. On the other hand, with the growing amount of distributed energy resources (DERs), bi-directional protection elements may have to be utilized for selective fault clearance. The anti-islanding protection of DERs shall also ensure that automatic reclosing will not fail and no unintentional island will be form as a result of fault isolation. This use case focus on the application of IEC 61850 communication system in order to enhance the protection coordination in distribution systems embedding DERs. The main objective of this use case is to enhance overcurrent protection coordination among conventional protective devices, particularly when the penetration of DERs is significant. More specifically, this use case will focus on three protection challenges and will demonstrate how IEC 61850-based communications among protection devices and DERs can address these issues. The issues are as follows: • Improved anti-islanding protection of DERs • Improved reclosing/relaying operation • Enhanced operation of feeder protection
6	DER Control Mode Modification	Large-scale integration of distributed energy resources (DERs), particularly high penetration of variable energy resources (VERs) such as PV systems, is causing adverse impacts on the power flow and quality of distribution circuits. In many cases, it is needed to control active and reactive power contribution of large DERs actively and frequently in order to manage voltage level across the circuit or to control large amount of re-verse power flow when the circuit is in light-load conditions. In some cases, the control modes of DERs should change to an active scheme such as voltage/frequency droop control to enable direct interaction with the grid. Control mode change (CMC) in DERs can improve system performance in a distribution grid dominated by DERs. The main objectives of this use case is to remotely change the control mode of a DER for the enhanced operation of the distribution system. More importantly, this will be done through IEC-61850 communication protocol to further facilitate DER integration into electric grid. Although large-scale DERs may directly be connected to distribution substation, the focus of this use case would be feeder-connected DERs.
7	Grid Support using DER	One of the key utility benefits claimed for the deployment of large-scale DERs is the grid supporting capabilities of these DERs. Examples of these capabilities include controlled reactive power contribution, active power adjustment, ride-through functionalities, and voltage control modes. While some control aspects of DERs are autonomous, i.e., they will happen automatically (and locally) in response to changes in the DER terminal

Use Case	Title	Description
		voltages and grid frequency, the DER control parameters can be modified remotely if the DER has proper communication features. However, adjustment of DER control mode/parameters would require co-ordination among multiple DER units, which can provide the service. This is to prevent any conflict among the control operations of various DERs. In addition, it is essential to coordinate the intelligent electronic devices (IEDs) located within the same vicinity with DERs to enhance. The main objective of this use case is to evaluate smart inverter functionalities of DERs that are recently introduced in order to facilitate grid integration and high penetration. The use case aims to effectively utilize DER control features in order to provide support to the distribution grid under various abnormal conditions. In particular, this use case will focus on the following two grid-supporting aspects: • Utilizing DERs to correct feeder power factor and/or to improve feeder voltage through management of the reactive power flow within the distribution feeder. • Coordinated use of DER ride-through capabilities to enhance system performance under network faults and/or transient disturbances.
8	Emergency Load Management	Currently, SDG&E performs surgical load shedding based on pre-determined look-up tables with rotational schedules for the distribution circuits that can be placed in outage in order. When an emergency load shed-ding request is made by California independent system operator (CAISO), the pre-scheduled look-up table will define which circuits shall be shed. The schedule incorporates information on type of customers connected to the circuits and excludes outage on circuits that serve critical facilities such as hospitals, elderly residential housing, fire stations, etc. However, since the current practice works based on the circuit interruption, there is a possibility that more loads than required amount are de-energized in response to a load-shedding request. With the increasing integration of distributed energy resources (DER), there will be opportunities to minimize customer interruption during emergency conditions. This can be done through effective utilization of DER contributions to offset customer loads. In other words, proper dispatch of DERs can potentially help with efficient load management in distribution circuits. If there are cases where loads must be disconnected, it can be determined based on real-time measurements and controls such that the smallest possible amount of load is de-energized to achieve the defined load-management target. Further, an improved rotational scheme can be employed to improve the load shedding strategy. The main objectives of this use case is to monitor field data and properly utilize DERs in order to: • Reduce the needs for disconnecting large amount of customers, based on the generation contribution from DERs, and • Use the real-time information from field assets to perform partial load shedding, to restore some loads through alternative power sources, if possible, and to rotate the scheduled outages more frequently as the need for load reduction changes.

Use Case	Title	Description
9	Dynamic Emergency Load Control and Management with DERs	This use case incorporates development of an OpenFMB communication platform for monitoring and control of DERs and field devices on distribution circuits. The objective is to investigate capabilities of OpenFMB framework for managing the communications among various field devices (primarily, DERs and feeder breaker).
10	Dynamic Circuit Load Management with DERs	This use case focuses primarily on the development of an IEC 61850/MMS communication platform between SCADA and substation gateway/controller for monitoring and control of DERs and field devices on distribution circuits. The communications with field assets, including DERs is done via IEC 61850/GOOSE protocol, but the DNP 3.0 communications between the SCADA and substation was replaced with MMS to conduct a comparative analysis.
11	Volt-var control via OpenFMB	The objective of this use case is to demonstrate how the OpenFMB communications platform can be utilized with a variety of DER devices equipped with legacy protocol interfaces to enable DER to DER communications and implement a Volt-var scheme utilizing DER assets.

2.6.3 Data collection

In order to analyze the performance of the system it was essential to collect measurements, statuses, setpoints, and commands during each test. Three approaches were simultaneously used for data collection during the testing:

- The SCADA (EVENTA) was continuously recording all the analog and binary values reported from the system (RTDS). This data was recorded for the purpose of performance evaluation. The time resolution for archiving the data was adjustable in SCADA, and the project selected an appropriate time resolution required for post-mortem data analysis depending on the use case.
- The Substation HMI (MicroSCADA) was also recording a list of desired parameters during each test; including desired breaker powers, switch statuses, DER outpour powers, trip and pickup signals, cap bank statuses, etc.
- A list of important signal (binary and analogues) were saved in the RTDS in the COMTRADE format. These results were used for comparison against the baseline system without IEC 61850 communication.

2.7 Phase 3 – Task 6: Build the test system

2.7.1 Test plans

Test plans were created for both Factory and Site Acceptance Testing. The test plans incorporated a comprehensive set of tests to evaluate both basic device interconnectivity, as well as those specifically created to test the various use cases for the different configurations.

A number of performance criteria has also been identified and analyzed to evaluate the level of efficiency. Some of the main performance criteria considered for this study include (but not limited to):

- DER integration using ICE 61850 communication
- DER involvement/contribution
- Improved fail-safe scheme
- Coordination between protection system and Low-Voltage Ride-Through (LVRT) capability of DERs
- Improved protection coordination between substation and feeder devices
- Improved customer reliability
- Reverse power flow management in the presence of intermittent DERs

The comparisons are made against a baseline system in which conventional communication schemes are utilized (no IEC 61850 communication in place).

2.7.2 System setup

The hardware components identified in the previous section were procured and installed in three 19" racks.

- Two racks were used to house all the protection, automation and control equipment used inside the substation.
- One rack housed all protection and control equipment used outside the substation, i.e., along the feeder or in the field (feeder automation devices).

Figure 2-13 and Figure 2-14 below show the three sets of racks containing the various substation and feeder equipment described in the previous task.

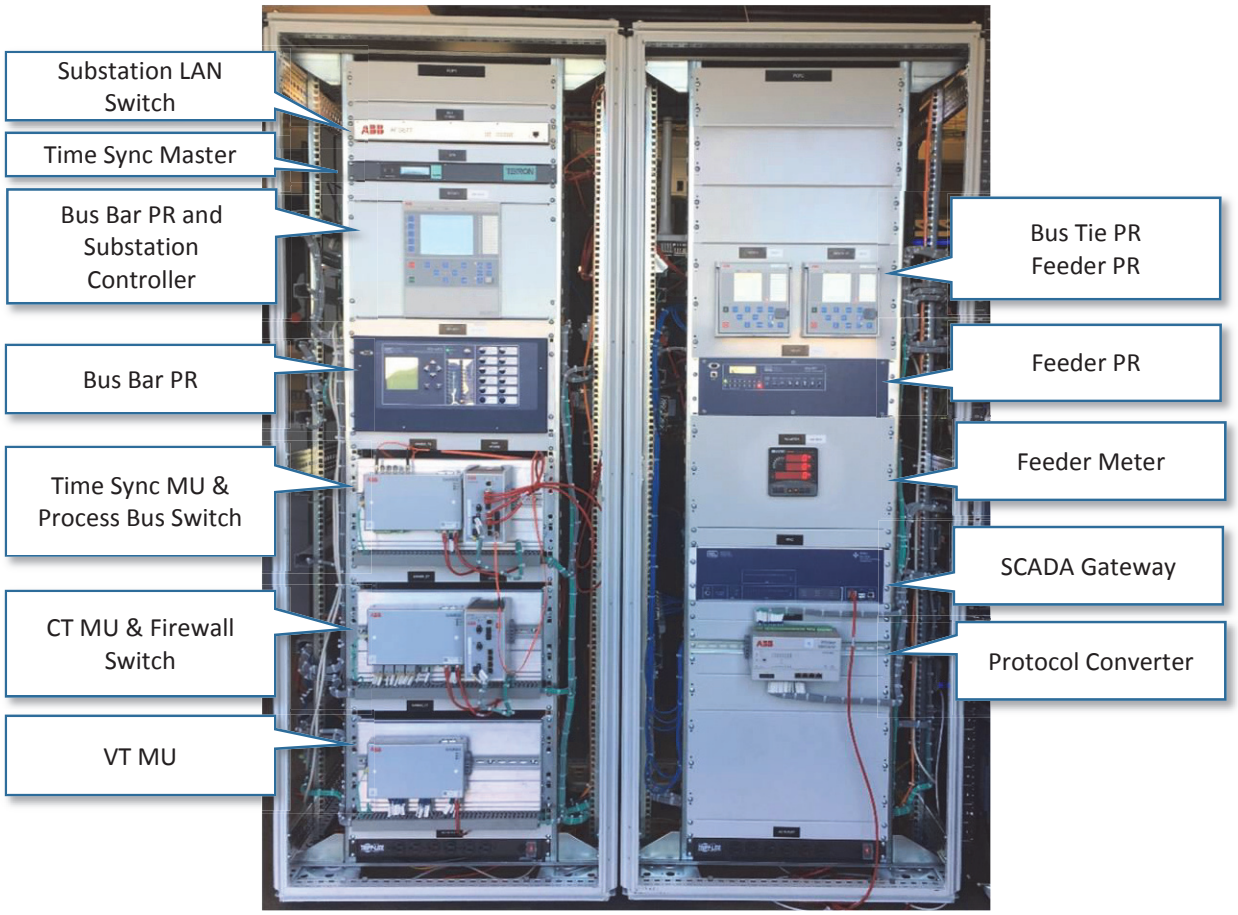


Figure 2-13. Substation racks.

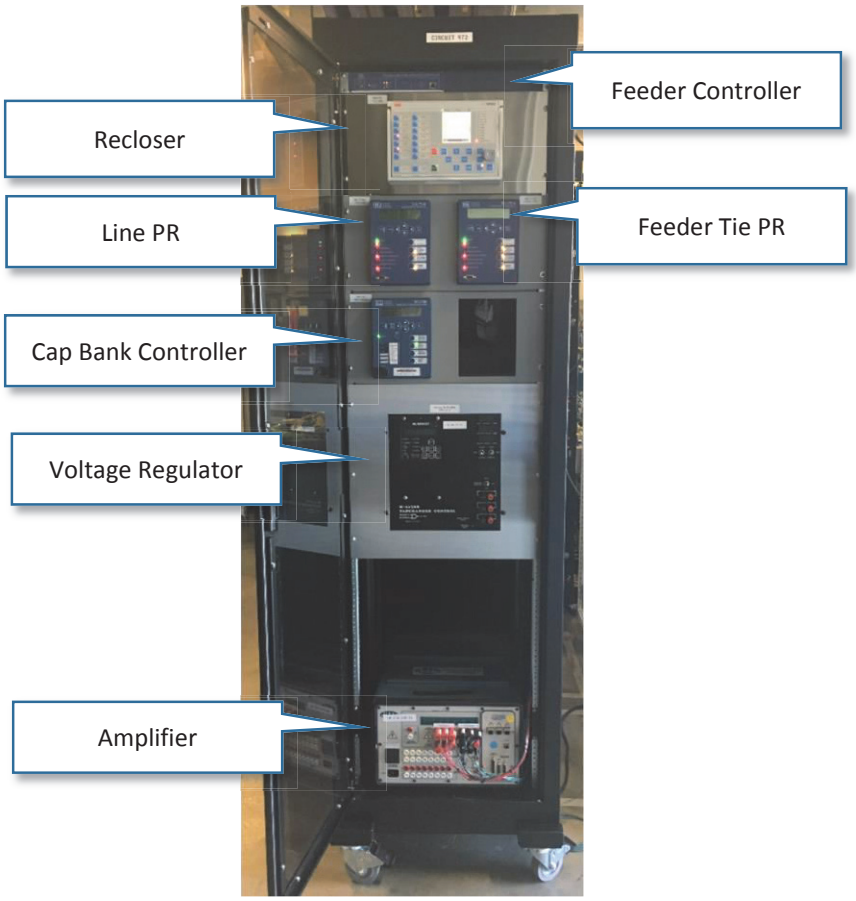


Figure 2-14. Feeder rack.

2.8 Phase 3 – Task 7: Perform the demonstration

Testing of the system was implemented in three separate phases:

- Separate Factory Acceptance Testing of the substation and feeder racks with limited hardware-in-the-loop[12]
- Factory acceptance testing of the integrated system with additional hardware-in-the-loop
- Site acceptance testing of the complete model with extensive hardware-in-the-loop, including an actual Battery Energy Storage System and smart PV inverter.

2.8.1 System Tests

The two Factory Acceptance Tests and the Site Acceptance Test were conducted over a staggered period with a total duration of approximately 4 weeks. Each of the sessions built on the experience gained during the subsequent test cycle and, as progressively more equipment was integrated into the system, the tests became more complete, more complex, and more representative of the real-world system the project aimed to simulate and test.

In addition to the testing of the application-specific use cases (defined in more detail in the sub sections that follow), several use case independent tests were performed to verify the interconnection of system components via the three primary protocols in use:

1. Interface 1: SCADA communications between the control center and the Substation via DNP 3.0
2. Interface 2: SCADA communications between Substation and Feeder equipment using the MMS communication service
3. Interface 3: Peer-to-peer communications among substation and field devices using the GOOSE communications service

2.8.1.1 Interface 1: Communications between control center and Substation SCADA Gateway

Several tests were executed to verify communications between the SCADA gateway and the control center as enumerated in Table 2-15.

Table 2-15. Interface-1 communication test cases (DNP3)

Case#	Test Case	Description
0.6	IP/Port number verification	Ensure that RTAC and SCADA server can ping each other
0.7	Analogue input (measurements) reading by SCADA	Change the power flow of the circuit and verify that the changes are reflected in the SCADA HMI
0.8	Analogue output (setpoints) writing by SCADA	Issue setpoints and/or curtailment signals to the substation BESS and/or PV systems and verify that they are applied correctly
0.9	Binary input (status) reading by SCADA	Change the status of switching devices and verify that the

[12] Necessitated by the two sets of racks being constructed in two different locations: the two substation racks in Raleigh, North Carolina, at ABB's Smart Grid laboratory, and the Feeder rack in Toronto, Ontario, at Quanta Technology's Sustainable Technology Integration Laboratory (QT-STIL).

Case#	Test Case	Description
		changes are reflected in the SCADA HMI
0.10	Binary output (commands) writing by SCADA	Send open/close command to switching devices (or tap up/down a VR) and verify that it is applied properly

2.8.1.2 Interface 2: Communications between Field/Substation and Substation Controller

The tests of this section are aimed to verify MMS communication between the substation MicroSCADA (SYS600) and substation/field devices. Table 2-16 lists major Group-2 test cases.

Table 2-16. Interface-2 communication test cases (MMS)

Case#	Test Case	Description
0.11	IP/Port number verification	Ensure that all relevant devices can reach to each other.
0.12	Analogue input (measurements) reading by MicroSCADA	Change the power flow of the circuit and verify that the changes are reflected in the MicroSCADA HMI
0.13	Analogue output (setpoints) writing by MicroSCADA	Issue setpoints and/or curtailment signals to the substation BESS and/or PV systems and verify that they are applied correctly
0.14	Binary input (status) reading by MicroSCADA	Change the status of switching devices and verify that the changes are reflected in the MicroSCADA HMI
0.15	Binary output (commands) writing by MicroSCADA	Send open/close command to switching devices (or tap up/down a VR) and verify that it is applied properly

Several tests were executed to verify the MMS communications between the MicroSCADA and field/substation devices. Figure 2-15 shows a snapshot of the MicroSCADA HMI for a particular system operating condition. The comparison between values shown on the HMI and the actual values in RTDS (or seen by the actual device) indicate proper communications between the MicroSCADA and field/substation devices. The operator can also send command to devices through the MicroSCADA HMI, which was confirmed in this testing. For the sake of brevity, the results of all tests will not be presented in this report.

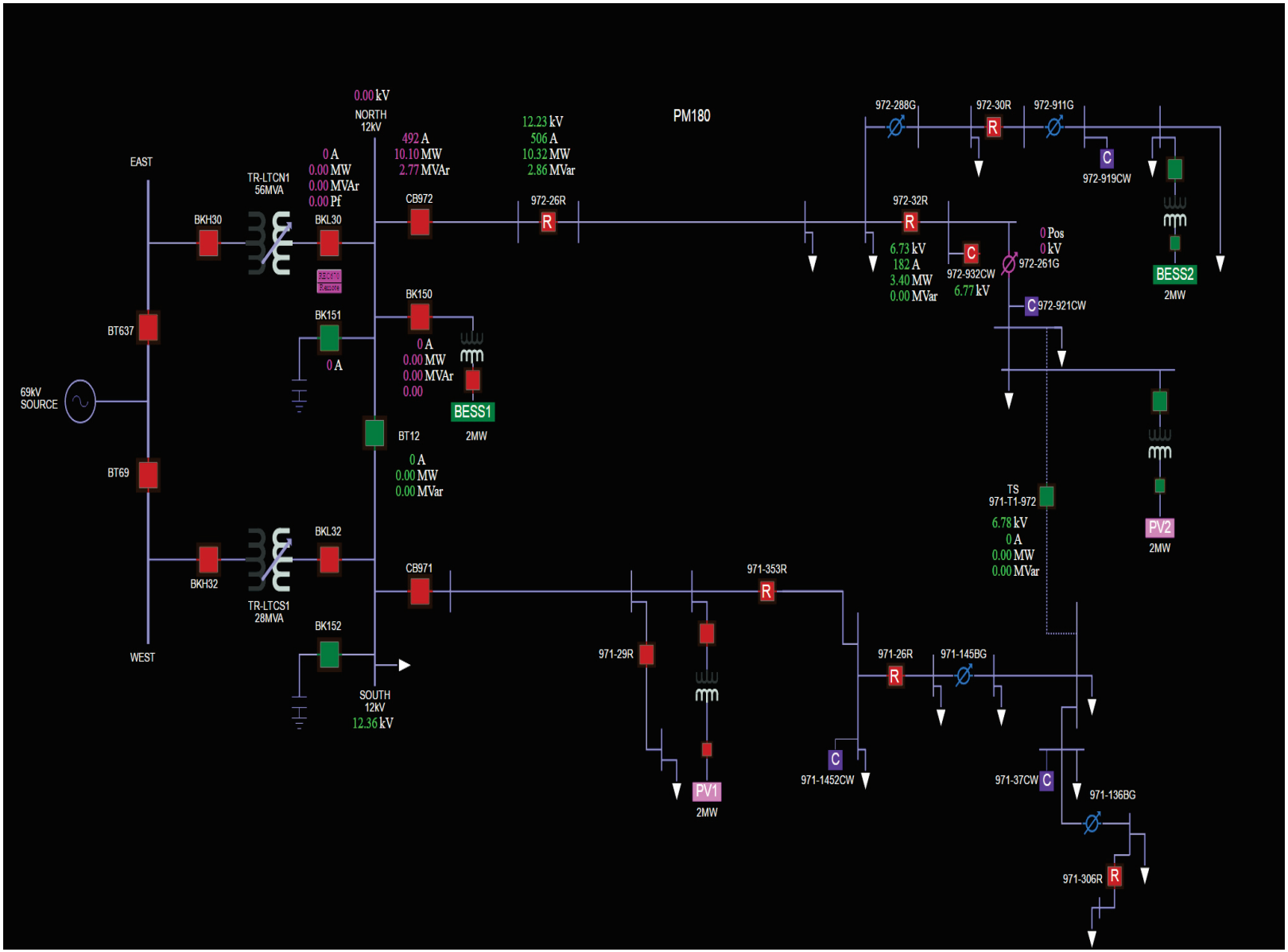


Figure 2-15. Snapshot of the MicroSCADA HMI for a particular system operating condition

2.8.1.3 Interface 3: Peer-to-Peer and analogue sampled values communications

The most important (and challenging) part of this test category is to verify the multi-cast GOOSE communication between various IEDs in the system (peer-to-peer communication) and the sampled analogue values published by the merging units. To facilitate this part of the testing, an integrated testing tool from vendor 2 will be used. The tool is a substation automation tool that enables easy diagnosis and troubleshooting of IEC 61850 configuration in P&C IEDs, the visualization of GOOSE messages and sampled values streams, and the communication simulation of an IED. With the use of this tool, the communication verification for an IEC 61850 compliant automation system and/or application can be done effectively, such that the root cause of the communication issue can be identified.

Table 2-17 provides a list of major tests that have been conducted to verify GOOSE and Sample Value (SV) communications among various IEDs. A comprehensive set of tests was conducted to ensure the desired devices can communicate in a peer-to-peer (P2P) manner. Due to the space limitations, however, the results of only a limited number of tests are presented and briefly discussed in this section. It is worth noting the majority of use-case studies in this project require devices to have direct (P2P) communications.

Table 2-17. Interface 3 communication test cases (GOOSE and SV)

Case#	Test Case	Description
0.16	IP/Port number verification	Ensure that all relevant devices can reach to each other.
0.17	Analogue GOOSE (measurements)	Change the power flow of the circuit and verify that the changes are reflected in the subscribing IED
0.18	Binary GOOSE (e.g., trip)	Issue trip signals to a feeder IED and verify it is received correctly
0.19	Double Point GOOSE (e.g., Circuit Breaker Position)	Change the status of switching devices and verify that the changes are reflected in the subscribed IED
0.20	Sampled Value stream published by a merging unit and subscribed by an IED	Inject analog value to merging unit and verify value is correct at subscribing IED

Figure 2-16 and Figure 2-17 show binary and an analog GOOSE messages sent by two different IEDs to provide various functionalities. The binary GOOSE message shown in Figure 2-16 is a trip signal sent by RER620 recloser relay to trip breaker CCR2-32R for a downstream fault on bus 305. The breaker is subscribing to this message, and as soon as the trip message is issued, the breaker will open.

The analog GOOSE message shown in Figure 2-17 is the real power flowing through the substation transformer (LTCN1 in Figure 2-11). These power values are calculated and published by REC670 relay. The feeder controller (substation RTAC in Figure 2-11) subscribes to these values to calculate and control system power factors on a real-time basis.

After completion of the system tests and verification that all interfaces were operational, the use cases were tested. The sections that follow describe each of the use cases in detail.



Figure 2-16. A binary GOOSE message sent by RER620 to trip CCR2-32R for a downstream feeder fault

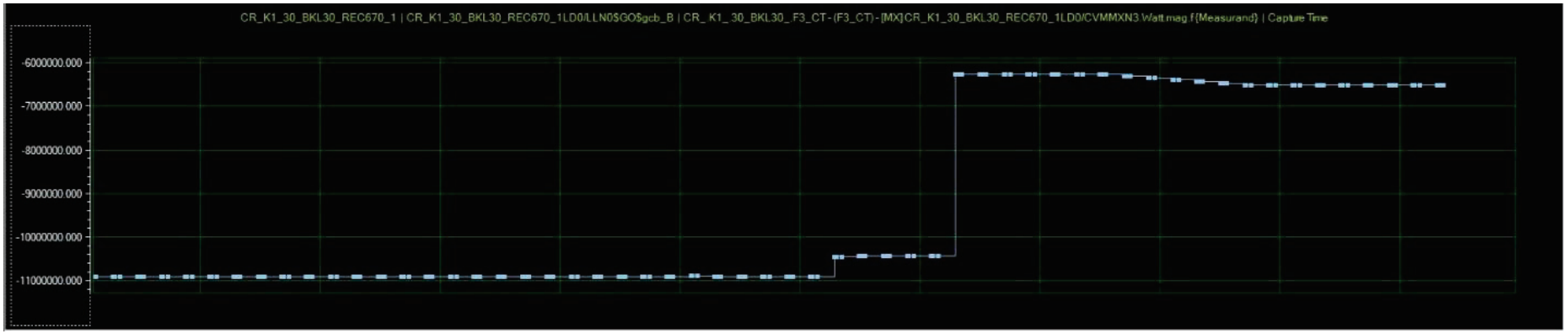


Figure 2-17. Analog GOOSE message sent by REC670 to RTAC to be used in GS-DER use case

2.8.2 Use Case 1: Lifecycle asset provisioning and integration with IEC 61850

2.8.2.1 Problem statement

The utilization of the IEC 61850 standard in protection and automation systems will require a change of design, engineering, building, commissioning, and maintenance procedures used today. Many of the previous tasks are replaced by software configuration and programming with new standard software tools. The engineering process is based on the use and exchange of XML-based description of IED and system configurations and capabilities. During the lifecycle of an automation and protection system, changes, replacements, extensions, and reductions of the system are typical scenarios that need special consideration.

2.8.2.2 Objective

The objective of this use case is the demonstration of the engineering process to:

- Create IEC 61850 system configuration files including
    - MMS mapping and HMI integration
    - Peer-to-peer (GOOSE) communication between IEDs
    - Sample values assignments (process bus)
- Facilitate documentation method of a system design and implementation
- Update and reconfigure an existing system easily
- Add, remove, or replace single components (IEDs) in the existing system

The term IED (intelligent electronic device) is, in the following, used for any intelligent protection and control devices and includes advanced DER controllers, protection relays, DFRs, tap changers, voltage controllers, reclosers, etc.

2.8.2.3 Description

The use case tests start with an existing system configuration description file (SCD) that has integrated all substation components as specified in the test setup. The objective of these test cases is to investigate how IEC 61850 can facilitate life-cycle provision and integration of the new/replaced IEDs. The following are the most common scenarios utilities will be confronted with in terms adapting an existing engineered system in service.

2.8.2.3.1 Integration of a new IED

The standard allows for different sequences to add a new device to an existing system The two most common are either “top-down”, where the engineering starts at the system configuration tool, or “bottom-up”, where the configuration starts with the IED tool. Today, the most common method is bottom-up, as it is the scenario supported by most vendors. Therefore, the use case is also focusing on the bottom-up approach. The process and the engineering tools involved to engineer the IEC 61850-based solutions are illustrated in the upper part of Figure 2-18. It starts with the configuration of the IEDs using the corresponding IED configuration tool. Data modeling and communication information is then exported according IEC 61850 as CID file. The CID file of the new device is imported to the system engineering tool in order to complete the data flow engineering for the newly added device. Part of the data flow engineering is to connect the data from the newly-added device with any potential subscriber (for GOOSE) or client (for MMS). The result of the data flow engineering is documented as a machine-

readable SCD file. Any device that requires data from the new device will need to be updated based on the new version of the SCD file. The SCD file is also used to ensure consistent documentation of the IEC 61850 data model and the system communication of the completely engineered system. Subsequent changes are always updated in the latest system configuration data file (SCD). In practice, the SCD import by the IED tool may not always be supported and thus a subset (e.g., a CID file instead) may be used as explained later.

The steps required to add a new IED for a traditional solution based on DNP3.0 and hardwired interconnection is outlined in Figure 2-19 for comparison. Even though the approach and process to engineer a classic protection and automation solution based on hardwired interconnections and DNP3.0 communication are not analogous to an IEC 61850 solution, a similar structure has been applied for the sake of comparison in order to highlight the benefits and drawbacks of an IEC 61850-based solution.

IEC 61850 engineering tools and data flow used for use-case testing is illustrated in Figure 2-20. Essentially, two different tools had been used to add the new IED. An SEL-351 was chosen as the new IED, and the Vendor 1's configuration tool was used as the IED configuration tool. On the system side, the IEC 61850 engineering functionality inside Vendor 2's configuration tool was used for the data flow engineering and creation of the SCD file.

2.8.2.3.2 Removing an existing IED

Removing an existing IED from the system may be required in cases of de-commissioning certain feeders, but removal may also apply in cases of an existing IED becoming obsolete and being replaced with a new device from a different manufacturer. In this case, the existing IED needs to be removed before adding the new IED. The steps required to remove an existing IED from the system is illustrated in Figure 2-21. Basically, within three steps, an IED can be removed from an IEC 61850 based system. All activities can be done centrally (e.g., from the systems engineering computer with access to all IEDs). In the case of a traditional hardwired solution, not all activities can be handled from a central engineering workstation. There is a fair amount of hands-on work involved to remove the physical interconnection cables. Figure 2-22 presents the main steps to remove an existing IED from a traditional system.

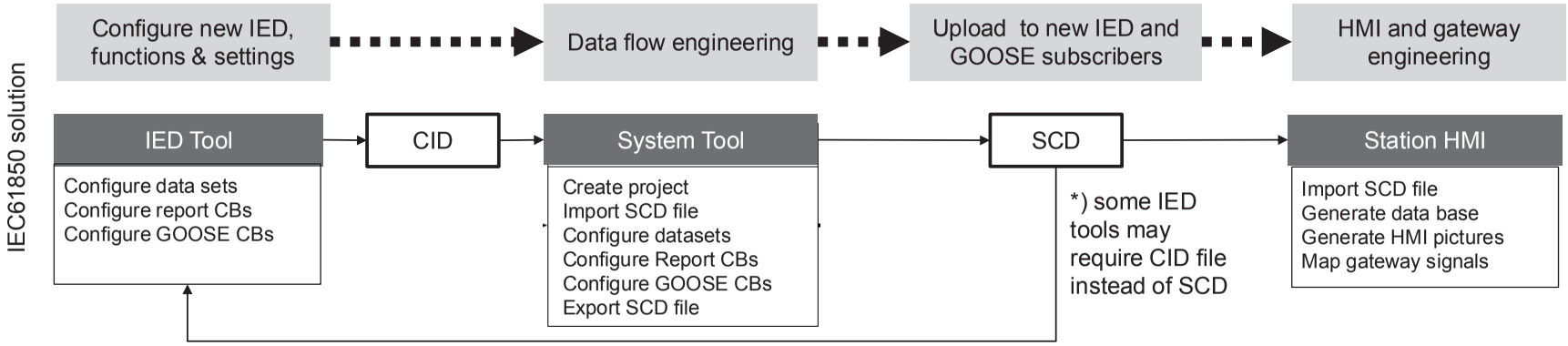


Figure 2-18. Main steps to integrate a new IED for an IEC 61850 based system

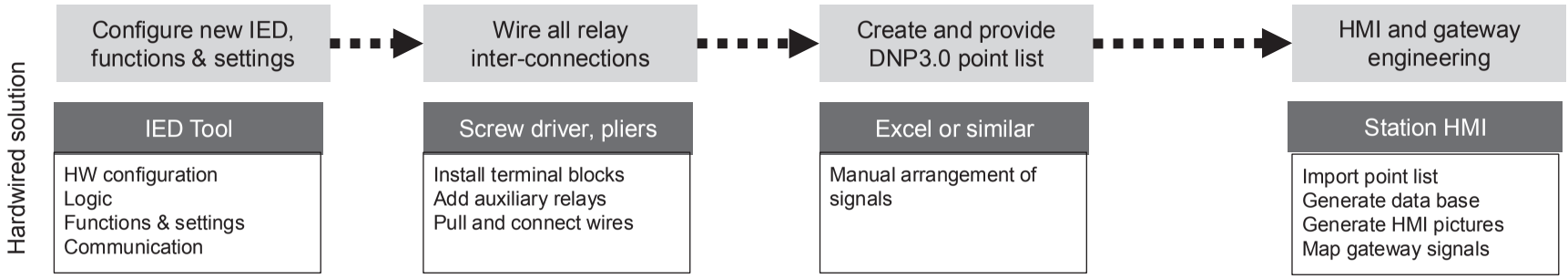


Figure 2-19. Main steps to integrate a new IED for a system with DNP3.0 and hardwired interconnections

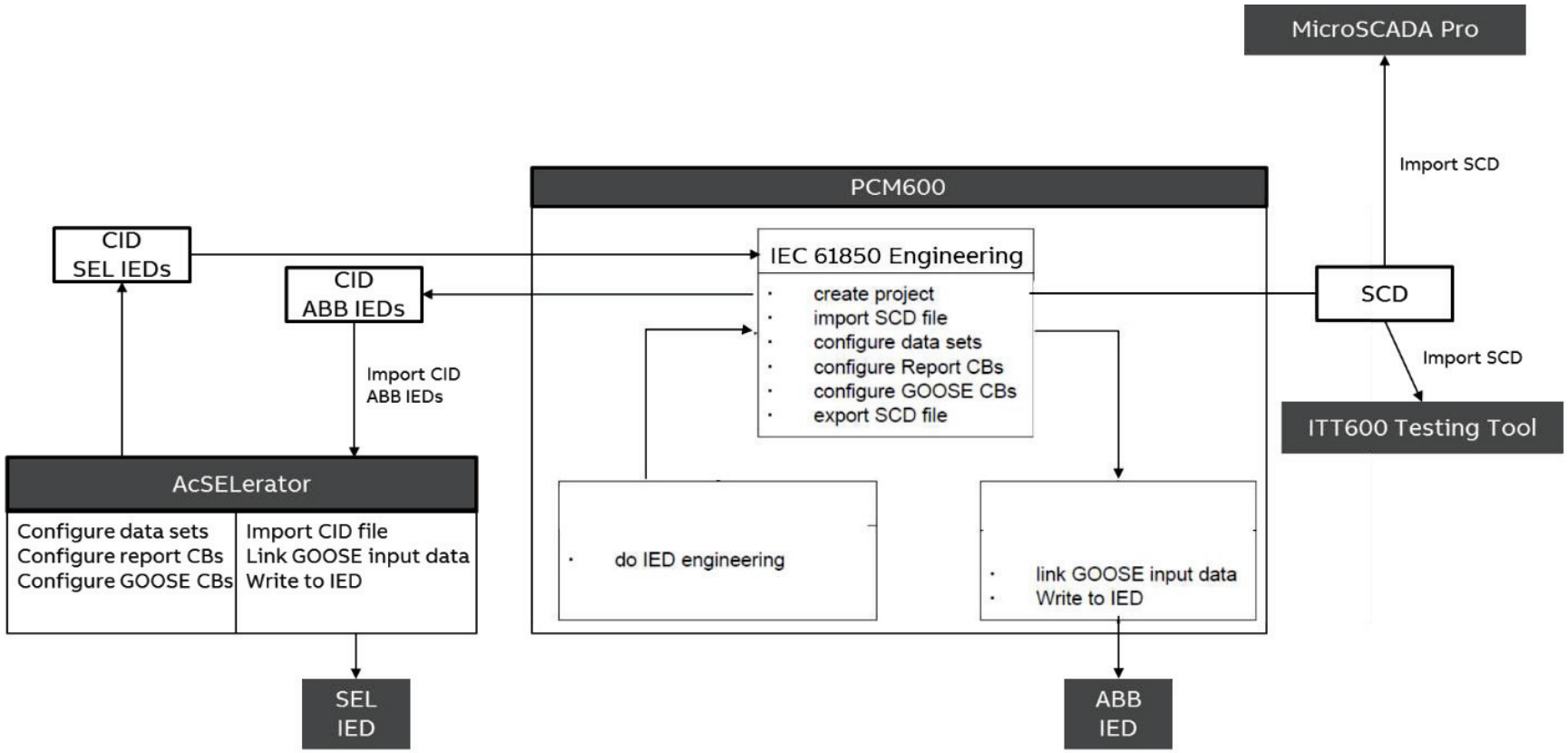


Figure 2-20. IEC 61850 engineering tools and data flow

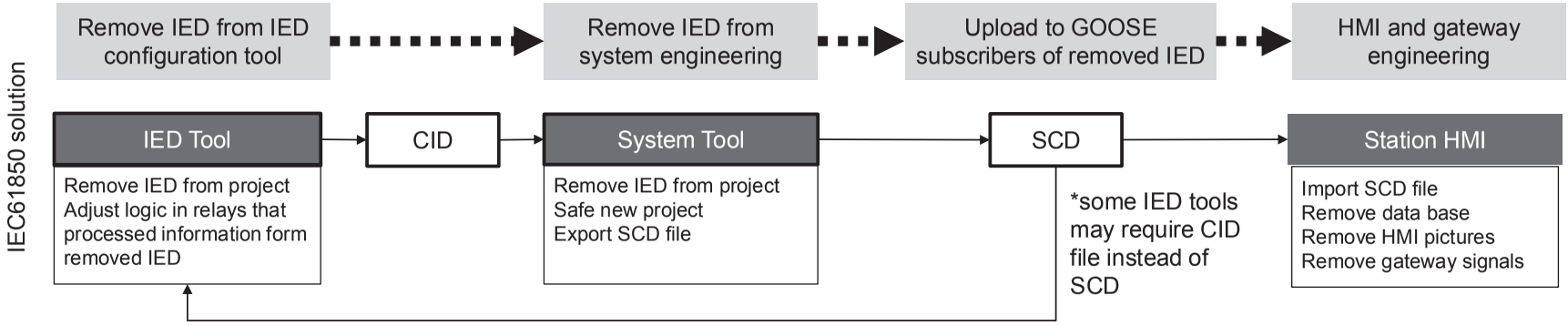


Figure 2-21. Main steps to remove an existing IED from an IEC 61850 based system

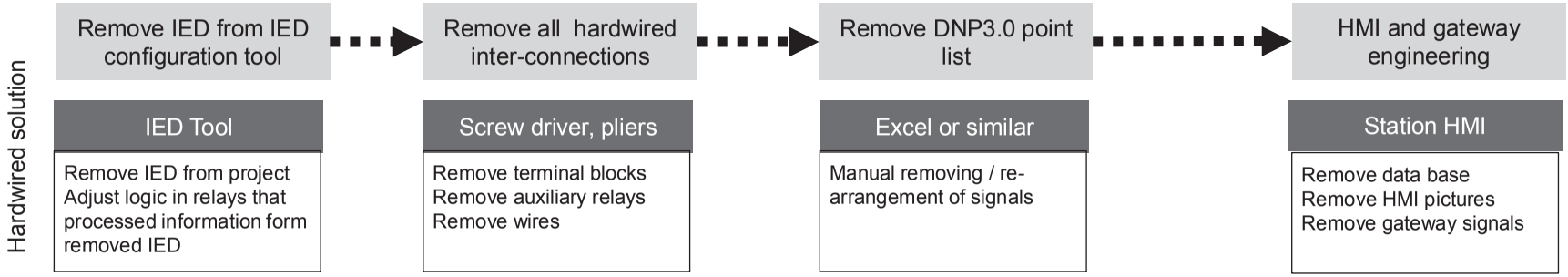


Figure 2-22. Main steps to remove an existing IED from a traditional system

2.8.2.3.3 Replacing a failed IED in an existing system

A very common scenario is the need to replace a faulty device in an existing system. Ideally, the new IED that replaces the faulty IED is an identical device, meaning same manufacturer, model, and version. In such a case, minimal effort is required to replace the faulty device. Basically, the backup configuration needs to be loaded to the new installed device. In cases where the new device differs from the failed device, the two scenarios explained earlier apply ("Removing an existing IED" and "Integrating a new IED"). By combining these two steps, one can reduce the number of configurations downloaded to the relevant IEDs to only one cycle.

2.8.2.3.4 Replacing a failed time source in an existing system

The time sync source is a special case. Although part of the IEC 61850 based system, it does not provide IEC 61850 data models and/or communication services and its sole function is to synchronize all of the different devices within the IEC 61850 system. In addition to the SNTP and IEEE1588 PTP recommended by the standard, IRIG-B and PPS were also implemented in the test system because some of the IEDs did not support SNTP. The replacement of a failed time server device does not impact the IEC 61850 engineering files (e.g., the SCD file). It is sufficient to keep a backup of the configuration and load it back into the new time server device in case of replacement. If a faulty time server is replaced with a different brand and model, the configuration needs to be re-created using the relevant parameters of the failed unit, including Ethernet port addressing and parameters for SNTP and PTP.

2.8.2.4 Test cases and results

Table 2-18 presents the lifecycle asset provisioning test cases and results.

Table 2-18. Lifecycle asset provisioning test cases and results

Test #	Test case	Description (IEC 61850 design)	Results Conventional Design	Results IEC 61850 Design
1	Integrate new IED into existing system	- Configure new IED, functions and settings - Provide ICD/CID file of the new IED device - Import ICD/CID file to system engineering tool - Engineer data flow - Upload SCD/CID to new IED and GOOSE subscribers - Add new signals and pictures to HMI and gateway - Basic test of communication (Ping, MMS, GOOSE)	- There is no standard process defined. - No formal definition on how to document engineered solution - Hardware required to establish interconnection between IEDs	**- Clear workflow according IEC 61850, button up method verified successfully.** **- Consistent SCD file for complete system documentation of IEC 61850 portion created.** **- Some efficiency challenges observed with certain products.**

Test #	Test case	Description (IEC 61850 design)	Results Conventional Design	Results IEC 61850 Design
2	Remove existing IED from existing system	- Update system engineering by removing IED device - Upload SCD/CID file to devices subscribing to GOOSE of removed IED - Remove signals and pictures related to removed IED at the HMI and Gateway	- Configuration as well as mechanical work is required. - Simulation is not possible.	**- All activities can be done from a central engineering workstation. A safe and efficient approach. The impact of a removed IED can be simulated before it is removed.**
3	Replace failed time source device into existing system	- Upload existing configuration file to new time master device - Check correct synchronization of connected devices	- Replacing the hardware and loading new configuration is straight forward. - Supervision is more limited especially if IRIG-B method is used.	**- Replacing the hardware and loading new configuration is straight forward.** **- The verification of correct time sync is automatically done as it is part of the quality information in the messages and time server can be accurately supervised**

Problem
Improved Result

2.8.2.5 Findings

Comparing the tasks required for an IEC 61850-based solution versus a traditional solution using DNP3.0 for the communication to an RTU and using hardwired interconnections between IEDs for the given scenarios show that, overall, the steps are similar; however, the biggest difference is when communication is applied to replace hardwired interconnections. With IEC 61850, all interconnections are engineered virtually by applying GOOSE and sampled-value real-time communication services. The greatest benefit is that the complete engineering can be handled within the IED and system tools (and testing is possible immediately after the engineering is complete using the IEC 61850 testing tools), making the process of engineering and testing extremely efficient. With a traditional solution, additional tools and hardware are required, and testing takes more time as relevant infrastructure needs to be made available.

The demonstration of the different scenarios and related use cases proved that the engineering process as defined in the IEC 61850 reference model worked. However, depending on the capability of the specific IED tool, some deviations may need to be addressed. For example, not all IED tools support the import of the SCD file. This could discourage engineers from creating an SCD file as the benefit is not immediately visible when looking only at the engineering process. It is still highly recommended to create an SCD for each system to ensure consistent documentation of the IEC 61850 portion. In addition to simplifying the process of configuring the interfaces to, and the databases of, Station HMIs and gateways, the process of engineering and troubleshooting is also much easier.

Having the IEC 61850 system engineering capability built-in to the IED configuration tool is an advantage, as no extra steps are required to import / export the IEC 61850 configuration as SCD files.

Using the IEC 61850 standard for documentation (SCD file) is a good way to document all IEC 61850 relevant information, including data modeling, substation communication services, and network structure. What is missing is the documentation of the link between the IEC 61850 signal and the IED internal variables or logic. This was resolved in this project by creating a GOOSE table that documented these internal connections.

Basic communication and data model verification can be automated using an IEC 61850 testing tool. Beyond the basic communication test, it also provides verification of software and configuration revisions, including SCL consistency checks, by automatically scanning the network for any connected IEC 61850 device and comparing the scanned information with the original SCD file.

2.8.3 Use Case 2: Maintenance testing of IEDs

2.8.3.1 Problem statement

For maintenance purposes – replacing existing/failed IEDs, logic change/upgrade, or adding new IEDs to the system – a condition-based testing is performed on IEDs to confirm their proper operation. To do this, the test engineer must isolate the IED under test from the system to avoid any undesired breaker operations during the testing process. In the case of wired-connected systems, the test engineer should open test switches to perform maintenance tests. However, the situation is much different in an IEC 61850 environment, where the isolation of the relay/IED can be done through communications. This use case demonstrates how IEC 61850 communications can facilitate field-testing of IEDs, as compared to the traditional wire-connected systems.

2.8.3.2 Objective

The objective of this use case is to demonstrate the isolation, testing, and simulation mechanism for GOOSE and process bus links provided by IEC 61850 Edition 2. To verify the capability and advantages of these features, the test cases are subdivided in two main topics:

1. Functionality of the modes and behavior – On, On-blocked, test, test-blocked
2. The sampled value data received through an external device using the simulated flag

2.8.3.3 Description

The IEC 61850 standard provides a mechanism that allows for the isolation of an IED for field testing purposes. In Edition 1, the interpretation of the mode and behavior of this feature was not described, and the implementation of this mechanism was only possible by configuring specific logic in the IEDs. Edition 2 of the standard addressed these short comings and clarified these “gray areas” by providing specific rules regarding the behavior of the different modes. To enable interoperable testing and isolation out of the box, without application-specific programming, the modes selection and quality information according IEC 61850 Edition 2 is applied.

In the project system setup, the SEL relays used were only supporting IEC 61850 Edition1. Therefore, the entire system was set up as an IEC 61850 Edition 1 system. In order to execute the test cases for this use case, two Vendor 2 IEDs were selected out of the complete system setup. They were re-configured as

IEC 61850 Edition 2 devices for these particular tests. Figure 2-23 illustrates the setup used to perform the tests related to this use case.

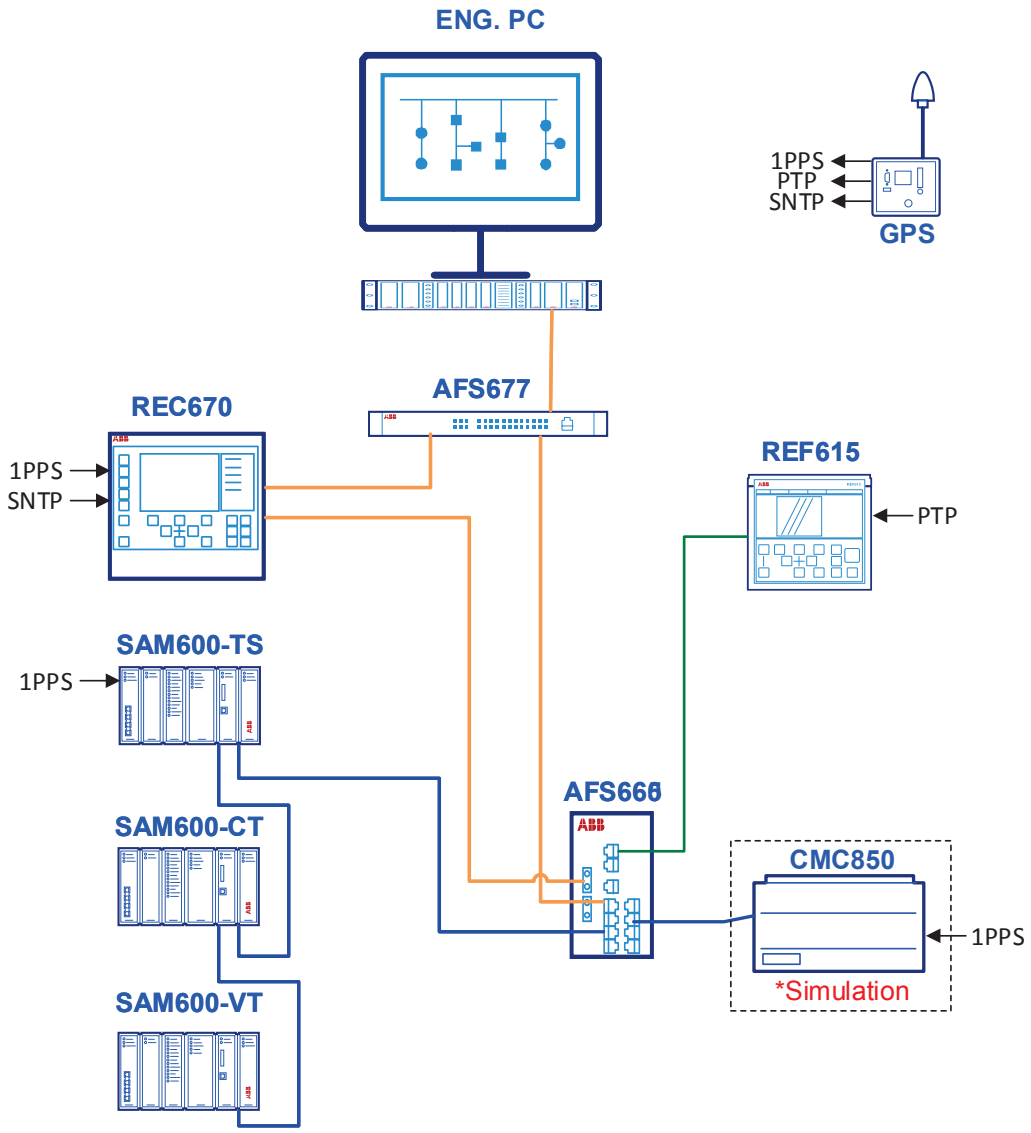


Figure 2-23. Test set-up for maintenance testing of IEDs

2.8.3.4 Isolation of an IED using mode/behavior

In traditional solutions, where hardwired interconnections between IEDs are used for bay to bay information exchange but also where hardwired connection between bay level and process level is used, isolation of equipment under testing is done using test switches. The test switch installed between the IED and the process allows for the disconnection of individual connection in order to test (i.e., protection functions without tripping the breaker).

With IEC 61850, the hardware connections between relays, and between relay and process, become virtual by using real-time communication to exchange data between the different functions allocated at

the station and process level. In order to isolate devices in these modern systems, other means are required. That is where the standard definitions for mode and behavior come into play.

In this use case, the proper behavior of an IED for the different mode of operation has been tested. The main focus was to verify and confirm the treatment of the GOOSE and SV message under different mode operation. The different modes and their behavior are illustrated in Figure 2-24.

2.8.3.4.1 Simulation of data and measurements

Setting the simulation to TRUE allows the IED under test to subscribe to GOOSE or SV streams from a simulated device or a test set. The simulation flag in the GOOSE or SV message indicates whether the signal is original or simulated. A data object in the logical node LPHD defines whether an IED will receive the original or the simulated message. If the data object Sim is set to TRUE, then the IED will receive all GOOSE and SV messages with a simulation flag set to TRUE. If, for a specific GOOSE or SV message, no simulated message exists, the IED will continue to receive the original message. The two behaviors with Sim=FALSE and Sim=TRUE are illustrated in Figure 2-25.

2.8.3.4.2 Testing protection using isolation and simulation

A complete test scenario addressing bus zone protection is demonstrated in this section.

The IEC 61850 Edition 2 mode and simulation features allows for virtual isolation of the bus zone protection IED for testing purposes. The steps required to isolate the different devices involved in the testing, and how to run the protection test using a test set sending simulated sampled value messages, is illustrated in Figure 2-26. The sequence of actions is as follows:

1) Set the mode of the REL615 protection IED to “Test”
2) Set the mode of the REC670 unit to “Test/Blocked”, so that it will accept GOOSE communication from protection IED under test but not trip the real breaker
3) Inject a fault current/voltage to the REF615 using the RTDS
4) The protection function of the REF615 trips and sends a GOOSE to trip the breaker connected to REC670
5) The REC670 confirms the correct tripping of the breaker by sending position operation OK, which is capture by Vendor 2’s configuration tool acting as an MMS client; the REC670 will not operate the tripping contact as the device is in test/blocking mode

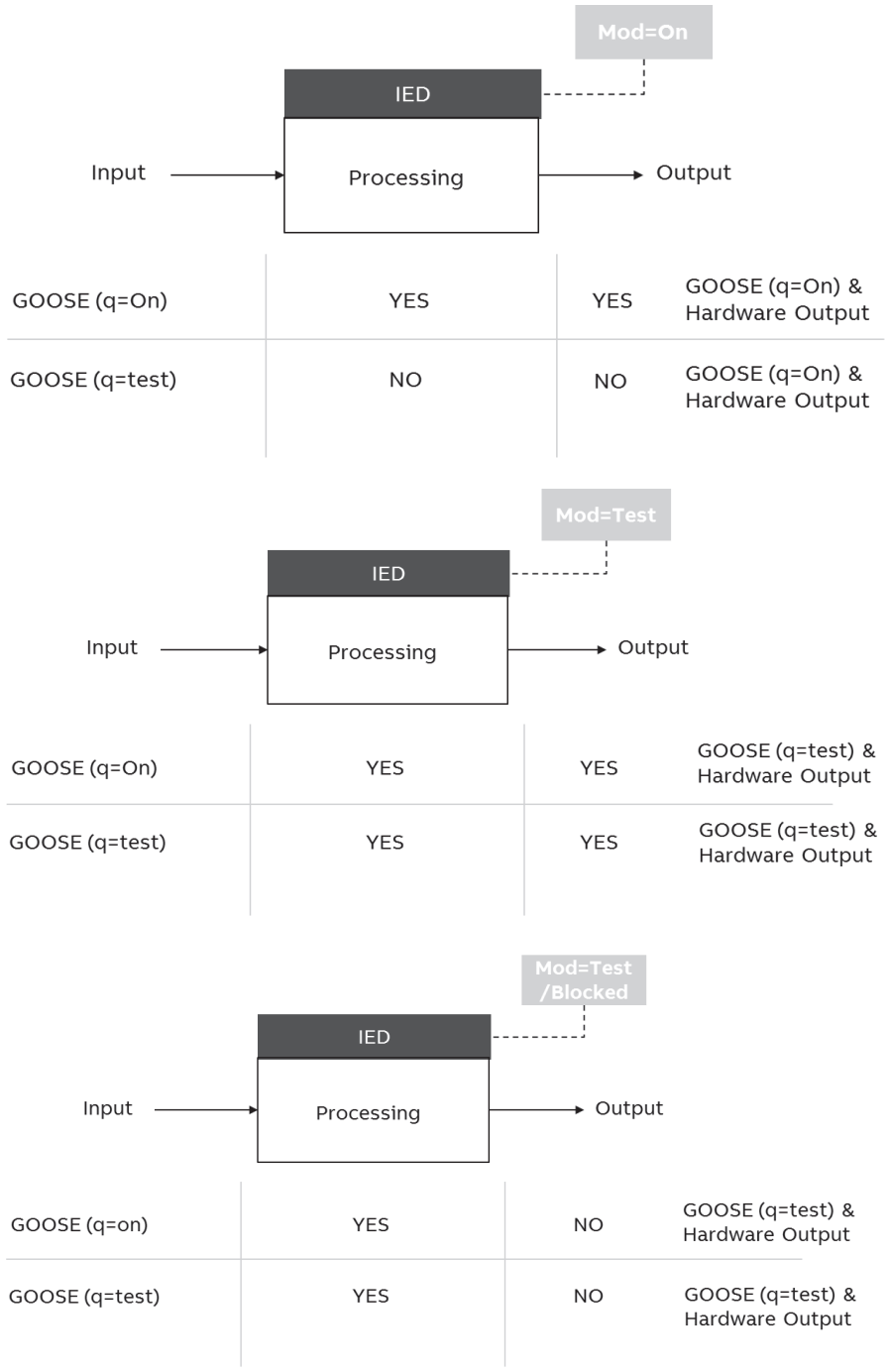


Figure 2-24. Behavior of different test modes used for IED maintenance testing use case

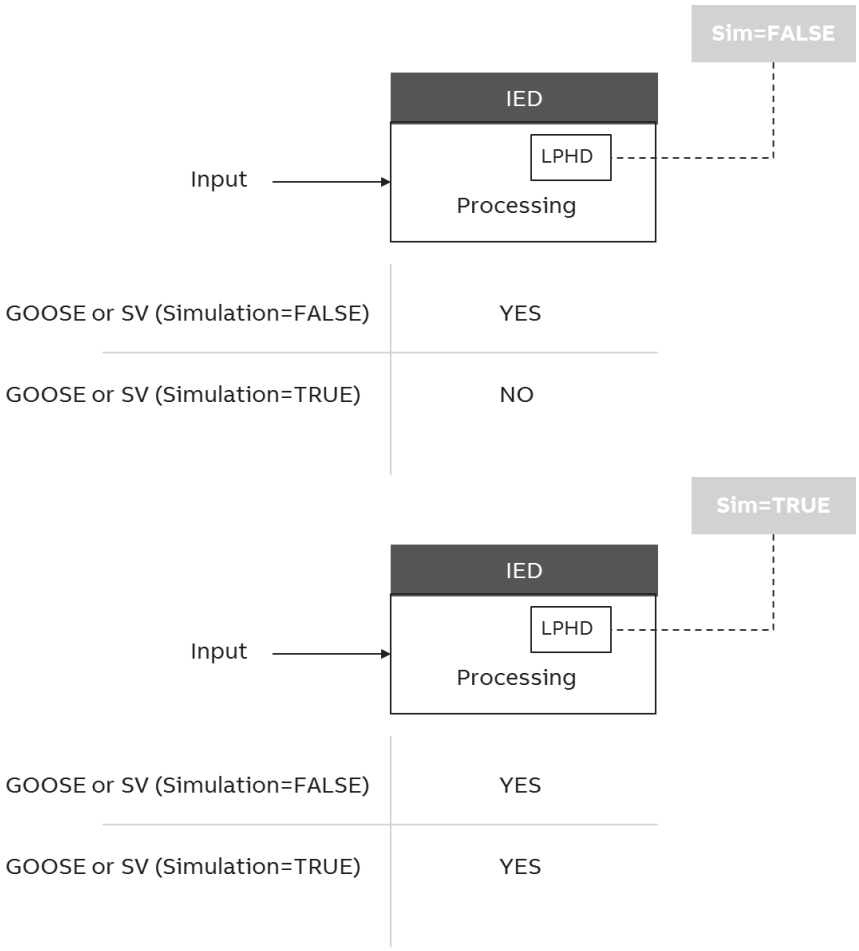


Figure 2-25. Behavior of different simulation modes used for IED maintenance testing use case

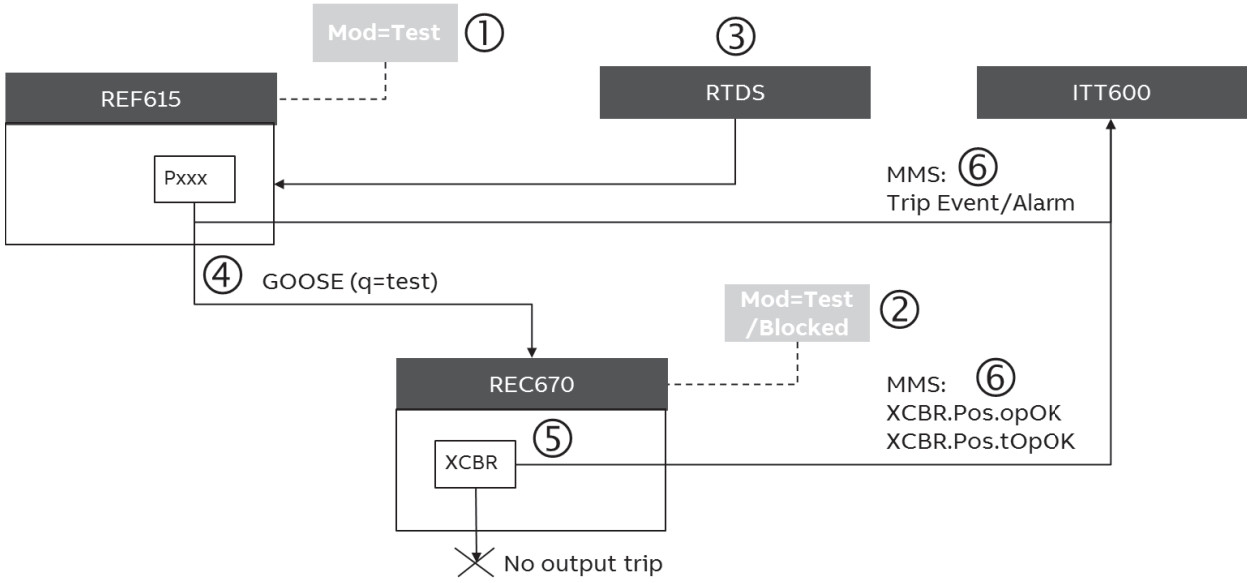


Figure 2-26. Isolated testing using IEC 61850 test mode

2.8.3.5 Test cases and results

Table 2-19 presents the maintenance testing of IEDs test cases and results.

Table 2-19. Maintenance testing of IEDs test cases and results

Test #	Test case	Description (IEC 61850 Design)	Results Conventional Design	Results IEC 61850 Design
1	Normal operation IEC 61850 Edition 2 Mode: On	- Set both IEDs to mode=on - Publish a GOOSE message from REF615 to REC670 - Confirm REC670 is receiving the GOOSE message correctly	Normal operation	Normal operation
2	Isolation of an IED IEC 61850 Edition 2 Mode: Test	- Set REF615 to mode=test - Publish a GOOSE message from REF615 to REC670 - Confirm that REC670 is not accepting the GOOSE message with q=test	Local, physical disconnection of interconnection wires	IED can be set to test mode, one command isolates all signals, control via contact, IED HMI or from remote, protected by role based access control
3	Isolation of multiple IEDs IEC 61850 Edition 2 2 IEDs Mode: Test	- Set REC670 & REF615 to mode=test - Publish a GOOSE message from REF615 to REC670 - Confirm that REC670 is accepting the GOOSE message with q=test	Local, physical disconnection of interconnection wires at multiple locations	Send a test mode command to each IED that needs to be isolated
4	Blocking outputs	- Set REC670 to mode=test/blocked - Publish a GOOSE message from	Local, physical disconnection of	IED can be set to test mode, one command

Test #	Test case	Description (IEC 61850 Design)	Results Conventional Design	Results IEC 61850 Design
	IEC 61850 Edition 2 Mode: Test/Blocked	REF615 to REC670 - Confirm that REC670 is accepting the GOOSE message with q=test - Confirm IED under test does not trip the breaker	process connecting wires	blocks all output contacts, control via contact, IED HMI or from remote, protected by role based access control
5	Connecting test-set IEC 61850 Edition 2, Simulation=Off	- Set REC670 to simulation=off - Publish a simulated sampled value stream where REC670 is a subscriber using the Omicron Test set - Confirm REC670 is ignoring the simulated sampled values	Wire multiple copper cables from test set to test switch contacts, attention required in order to not have open CT circuits	Connect test set to process bus access point (1 Ethernet cable), no risk of open CT circuits
5	Testing with injection IEC 61850 Edition 2, Simulation=On	- Set REC670 to simulation=On - Publish a simulated sampled value stream where REC670 is a subscriber using the Omicron Test set - Confirm REC670 is processing the sampled value from the test set	IED performs function based on injected values	IED performs function based on injected values. SV can be monitored and captured with IEC 61850 testing tool for documentation

Problem
Improved Result

2.8.3.6 Findings

IEC 61850 Edition 1 did not completely address all requirements needed for interoperable testing (e.g., the ability to isolate and inject simulated test messages). In order to enable such functions with an Edition 1 system, custom application programming is required in the IEDs. Edition 2 has been extended to support a “Simulation” Mode. In Simulation mode, the receiving relay accepts a GOOSE message that is flagged with the simulation bit=true instead of receiving an actual GOOSE message.

The demonstration has proven that using the IEC 61850 Edition 2 test mode and simulation feature easily allows for the isolation of the equipment under test to be performed from the central engineering computer. An available access point at the process bus Ethernet switch allows easy access to connect the test equipment. Injection of simulated sampled values using the test set triggered the protection function as expected. All related events, alarms, and measurements were automatically collected, which allowed for efficient documentation and conclusion of the test.

Compared to the traditional isolation and testing using test switches and hardwired test set, the solution based on IEC 61850 allowed for more efficient testing, plus quality documentation without any extra effort. It also is a very safe solution compared to the traditional approach, as the testing engineers do not have to deal with current circuits and hardwired connections. The solutions based on IEC 61850 have even further potential application: technically, it would be possible to conduct all of these tests from a remote location, fully exploring the benefits of process bus and IEC 61850 Edition 2 testing and simulation features.

Some care needs to be taken for the block mode. Initially, there was some confusion concerning the behavior when an IED is in block mode. Further investigation clarified the issue. As IEC 61850 Edition 2 was not clear, a tissue[13] has been approved clarifying the behavior to eliminate misinterpretation. So, it is important to ensure that IEDs not only adhere to IEC 61850 Edition 2 but that they also address the latest tissue concerning blocking. During such a solution, engineering care has to be taken to ensure proper implementation of the block bit inside the IEDs application. Different vendors and products will have slightly different approached on how this information is connected to the desired logical nodes. In the case of the tested Vendor 2 670 series product, any output linked to primary equipment-related Logical Nodes such as XCBR was, per default, linked to the blocking information. Whereas, the blocking of other outputs would require a connection of the blocking signal of the relevant LN in the design stage.

The "successful operation" feedback using the OR functional constraint OpRcvd and OpOk, which allows closed loop feedback of an isolated test scenario without controlling an output signal, may not be supported by every IEC 61850 Edition 2 compliant device, as it is an optional feature. In this project test setup, it was only possible with the REC670.

2.8.4 Use Case 3: Breaker failure scheme

2.8.4.1 Problem statement

With the use of IEC 61850 communications, traditional copper wiring can be replaced by GOOSE message exchange between different IEDs to perform certain actions. One example is in the use of breaker failure signals to the neighboring circuit breaker IED via GOOSE messaging. When a circuit breaker fails to operate and isolate a fault within the feeder, the feeder relay needs to send a breaker failure initiate signal to the bus protection relay in order to isolate the bus from the faulty section. While the industry has extensive experience with the performance of this feature using the hardwiring of IEDs, the use of GOOSE messaging has not been widely exercised. Despite the advantages, using GOOSE messaging for this purpose is relatively new, and the performance restrictions are not well documented. Therefore, it is imperative to investigate the performance of a GOOSE-message-based breaker failure scheme before wide deployment.

2.8.4.2 Objective

The objective of Use Case 3 was the performance evaluation of a GOOSE-message-based breaker failure scheme. The primary evaluation criteria were speed and reliability. The demonstration for Use Case 3 exhibited the effectiveness of GOOSE-messaging for breaker failure implementation.

2.8.4.3 Description

In Use Case 3, various tests were used to evaluate the performance of a GOOSE-message-based breaker-failure scheme. The scheme used bus protection relays REC670 and SEL487 to perform tripping of all bus breakers (if a breaker failure of one of the feeder breakers is detected). In such an instance, all feeder relays, including the tie protection relay, will send a signal via IEC 61850 GOOSE message that a trip command was issued to the breaker.

The logic starts the breaker failure timer upon the reception of this signal (if the current through the breaker is above a certain level). The breaker failure timer is set with a 150-ms time delay. This confirms

[13] Tissue is a Technical Issue – nomenclature used in the IEC 61850 standards community

that the breaker has actually failed and has not opened as required. The 150-ms time delay takes the following delays into consideration – measured from the moment of detection of the fault by the relay:

- 1-cycle trip-propagation time
- 3-cycle breaker-opening time
- 3 cycle relay-reset time
- 2-cycle safety margin

The current detectors are non-directional, overcurrent elements that monitor phase and ground (or residual) current. It is good practice to set the phase fault detector element above 120 percent of maximum load, where possible. If the phase current detector cannot be set above load, a negative sequence element may be used in addition. This will prevent misoperations due to incorrect breaker-failure initiations during commissioning or maintenance testing. Figure 2-27 illustrates the breaker failure logic.

Some applications have low fault currents that are difficult to reliably detect using the current detectors. Typical examples of these situations are:

- Transformer faults
- Weak or zero in-feed trips
- Overvoltage trips
- Circuit breaker restrike

In these applications, the breaker failure scheme can be modified to use a breaker “52a” contact in parallel with the current detector. With this change, both the dropout of the current detector and the opening of the 52a contact indicate an open breaker, and so are used for supervision.

The 52a breaker contact was not used for this demonstration, as it was assumed that the fault current is always higher than 120% of load current. It should be noted that extending the beaker failure scheme would not require any additional wiring and could be performed by reconfiguring the existing IEDs and enhancing the logic.

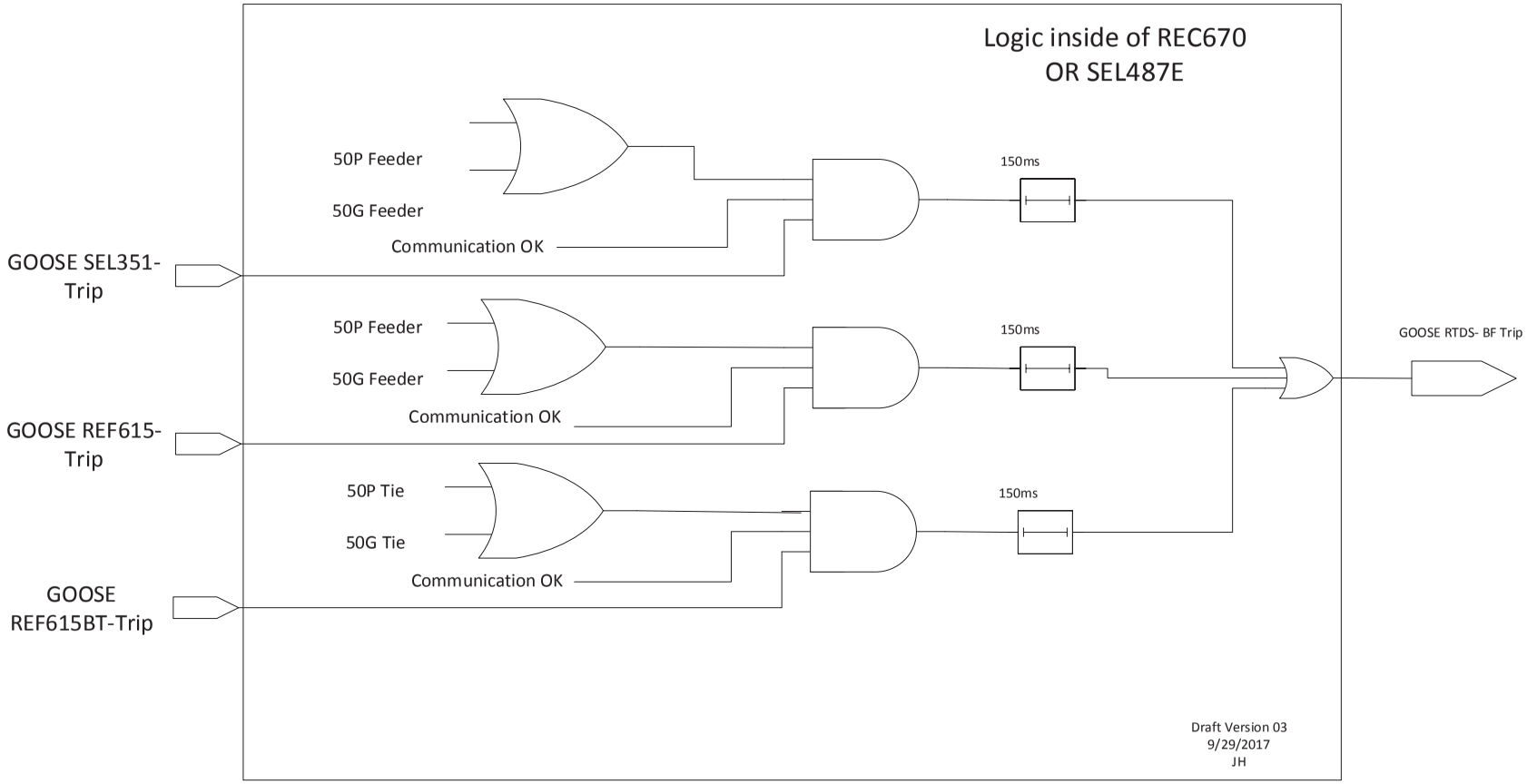


Figure 2-27. Breaker failure logic

2.8.4.4 Test cases and results

The selected test cases demonstrated the correct breaker failure functionality, including under extreme conditions (Table 2-20).

Table 2-20. Breaker failure scheme test cases and results

Case	Test Case	Description	Result of Wired Design	Result of IEC 61850 Design
1	Feeder relay issues correct operation and breaker opens	• Close target circuit breaker • Inject overcurrent into target IED by A-G Fault on Bus 301 • Instant Trip CCR2 CB2 by SEL351 & REF615 in substation • Check correct operation • Capture measurements and events using DFR	No Breaker Failure operation was issued as expected.	No Breaker Failure operation was issued as expected.
2	Feeder relay issues correct operation and breaker fails (GOOSE)	• Close all breakers • Isolate breaker trip command of target breaker/IED • Inject overcurrent into target IED by A-G Fault on Bus 301 • Breaker failure GOOSE message is sent to bus IED • All surrounding breakers are tripped. Instant Trip by SEL351 & REF615 in substation but breaker CCR2 CB2 fails. BF trip by REF670 and SEL487E after 150 ms • Check correct operation • Capture measurements and events using DFR	Correct Breaker Failure operation after 210 ms	Correct Breaker Failure operation after 210 ms
3	Feeder relay issues correct operation and breaker fails but no BF on temporary fault	• Close all breakers • Isolate breaker trip command of target breaker/IED • Inject overcurrent into target IED by A-G Fault on Bus 301 for 100 ms • Instant Trip by SEL351 & REF615 in substation but breaker CCR2 CB2 fails. No BF trip. • Check correct operation • Capture measurements and events using DFR	No Breaker Failure operation was issued as expected.	No Breaker Failure operation was issued as expected.

Case	Test Case	Description	Result of Wired Design	Result of IEC 61850 Design
4	Feeder relay issues correct operation and breaker fails but no breaker failure initiate is send due to interrupted communication	• Close all breakers • Isolate breaker trip command of target breaker/IED • Inject overcurrent into target IED by A-G Fault on Bus 301 • Breaker failure GOOSE message is not sent to bus IED due to interrupted communication • Alarm of failed communication is issued • Check correct operation • Capture measurements and events using DFR	A failed wire connection used for breaker failure initiate can cause major outage if not detected before needed	Alarm of failed communication link allows for repair of connection before it is needed.

Problem
Improved result

2.8.4.5 Findings

The demonstration showed that a breaker-failure scheme can easily be implemented with the information available in the IEC 61850 system without the need of wiring.

In addition, Use Case 3 demonstrated that the breaker-failure scheme based on IEC 61850 GOOSE communication is more reliable than a wired implementation, as all communication links are continuously monitored. Any communication interruption will be alarmed and can be used to locate and resolve the problem. Wired breaker-failure implementation occasionally failed due to connection problems that were not detected before the signal was needed.

2.8.5 Use Case 4: Automatic transfer scheme

2.8.5.1 Problem statement

Automatic transfer schemes are used to maintain continuity of supply during the transfer of a bus from one power source to an alternate power source. A proper transfer system must be designed in such a way that it operates quickly and prevents damage to loads connected to the transferred bus. In cases of losing one of the main in-feeds (e.g., due to an accidental breaker operation at the 69-kV level or a transformer fault), the dead bus can be energized and fed via the bus tie. Ideally, the outage of one of the main supply transformers can trigger a load transfer to the other in-feed. However, before the bus tie can be closed to complete the transfer, certain criteria must be checked to ensure safe and reliable load transfer. The criteria become more important in the presence of DER in distribution circuits.

2.8.5.2 Objective

During the project, the implementation of an automatic transfer scheme using IEC 61850 GOOSE messages was demonstrated. Circuit breaker positions, voltage measurements, fault indications, and so

on, were transmitted via IEC 61850 communication protocol and processed by a control logic that was implemented in one of the substation IEDs (Vendor 2 REC670). In a traditional power-source transfer scheme, the aforementioned information is normally exchanged via a hardwired connection between the different components. In Use Case 4, however, it was demonstrated how GOOSE messages can be used for this purpose.

The main objective of Use Case 4 was to demonstrate the benefits of using IEC 61850 GOOSE messages for the implementation of a fast and reliable power-source transfer scheme. These benefits include the following:

- The scheme can be easily changed and extended. All necessary information required by the scheme logic is available in an IEC 61850-based substation, and this information can be accessed without the need for additional wiring. Any command or action can be sent to any IED connected to the IEC 61850 system (including the IED located on the feeder, as in this demonstration).

- All communication links are continuously monitored. This improves the reliability of the transfer scheme implementation. Any communication interruption will be alarmed, and this alarm can be used to activate predefined actions in the logic to prevent undesired behavior of the transfer scheme.

2.8.5.3 Description

SDG&E uses the Main-Tie-Main bus configuration in order to have redundant sources available for feeder loads. Under normal conditions, the load is distributed in approximately equal amounts between the two alternative sources. During a planned or unplanned outage of one of the sources, the load is automatically transferred to the remaining source if certain conditions are fulfilled.

Before an automatic transfer sequence is performed, the control logic of the automatic transfer scheme typically processes the following information:

- Breaker status
- Protection equipment operations and status
- Voltage levels
- Control Switch inputs

For the demonstration of Use Case 4, a slow transfer scheme with residual voltage monitoring (as shown in Figure 2-28) was selected.

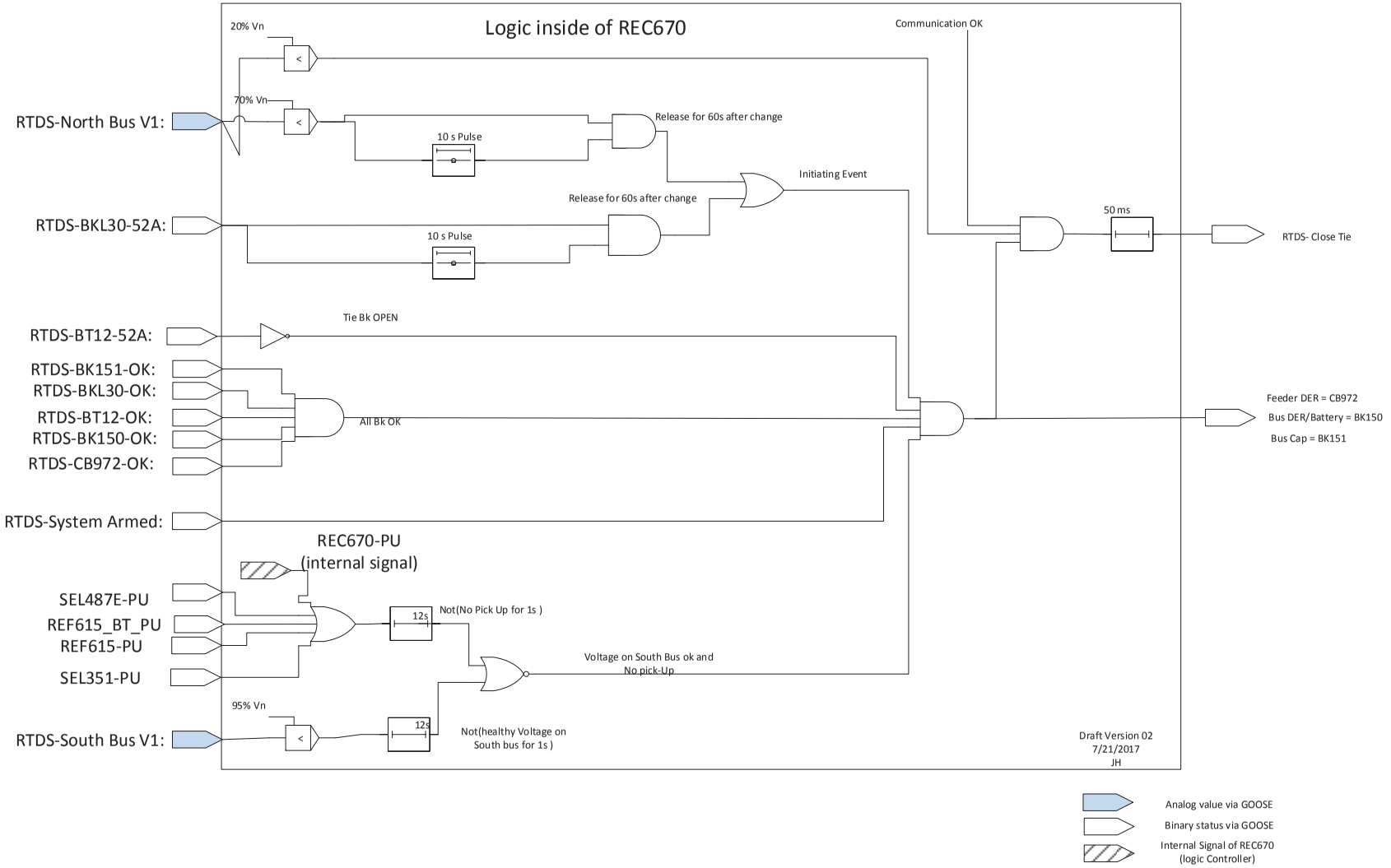


Figure 2-28. Automatic transfer scheme logic

The automatic transfer scheme is triggered by either the disappearance of the measured north-bus voltage (<70% $V_{Nominal}$) or by the opening of the low-side transformer breaker (BKL30). Before the tie breaker is closed, the following conditions must be fulfilled within a time window of 10 s:

- The North Bus residual voltage generated by the inductive load declines to below 20%
- All breakers are operational
- Tie breaker is open
- The scheme is armed
- There was no protection pickup for the last 12 s
- The south bus voltage is healthy (>95% VNominal)

After all conditions are met, a transfer will be initiated. Before the tie breaker can close, the following occurs:

- A transfer trip is sent to the DER connected on the feeder
- The North Bus cap bank is disconnected
- The battery connected to the North Bus is disconnected

It should be noted that the focus of Use Case 4 was not so much on the actual auto transfer scheme logic, but rather on the implementation of the transfer using GOOSE messaging instead of wired connections.

2.8.5.4 Test cases and results

The selected test cases should demonstrate that the automatic transfer scheme performs correctly for all situations, so that:

- For all source interruptions, a correct (fast and reliable) load transfer is expected
- For all bus and feeder faults that result in a bus operation, no load transfer is expected

Table 2-21. Automatic transfer scheme test cases and results

Case	Test Case	Description	Results IEC 61850 Design
1	HV side North Bus transformer breaker BKH30 opens	- All transformer breakers (BKH30, BKL30, BKH32, BKL32) as closed and North Bus and South Bus are energized - Disconnect source by opening HV breaker of North Bus transformer T2 (BKH30) - Automatic transfer scheme is started - Check correct operation - Capture measurements and events using DFR	Scheme transferred correct after 130 ms
2	MV side North Bus transformer breaker BKL30 opens	- All transformer breakers (BKH30, BKL30, BKH32, BKL32) as closed and North Bus and South Bus are energized - Disconnect source by opening MV breaker of North Bus transformer T2 (BKL30) - Automatic transfer scheme is started - Check correct operation - Capture measurements and events using DFR	Scheme transferred correct after 144 ms

Case	Test Case	Description	Results IEC 61850 Design
3	South Bus is de-energized when North Bus Transformer Breaker opens	- South Bus High Side breaker BKH32 is open, all other transformer breakers (BKH30, BKL30BKL32) as closed and only North Bus is energized - Disconnect source by opening MV breaker of North Bus transformer T2 (BKL30) - Automatic transfer scheme is not started - Check correct operation	Scheme did not initiate a load transfer (correct operation)
4	Tie breaker is already closed when HV North Bus breaker opens	- All transformer breakers (BKH30, BKL30, BKH32, BKL32) closed and North Bus and South Bus energized - Tie breaker (BT12) is closed -Disconnect source by opening HV breaker of North Bus transformer T2 (BKH30) -Automatic transfer scheme is started -Check correct operation	Scheme did not initiate a load transfer (correct operation)
5	Close-In feeder fault	-All transformer breakers (BKH30, BKL30, BKH32, BKL32) closed and North Bus and South Bus energized -Apply close-in feeder fault (on Bus 301) -Automatic transfer scheme is not started -Check correct operation	Scheme did not initiate a load transfer (correct operation)
6	North Bus de-energization after Bus Fault	-All transformer breakers (BKH30, BKL30, BKH32, BKL32) closed and North Bus and South Bus energized -Apply 3-phase fault on North Bus -Automatic transfer scheme is not started -Check correct operation	Scheme did not initiate a load transfer (correct operation)
7	Breaker BKH30 opens and communication from tie relay is interrupted, everything else is normal	-All transformer breakers (BKH30, BKL30, BKH32, BKL32) closed and North Bus and South Bus energized - Tie breaker (BT12) is closed -Interrupt Communication and open BKH30 - Check correct operation	Scheme did not initiate a load transfer (correct operation) Improvement of reliability as GOOSE message is monitored

Improved result

2.8.5.5 Findings

The demonstration showed that an automatic transfer scheme can easily be implemented with the information available in the IEC 61850 system without additional wiring. The system has access to all data provided by the IEDs integrated in the IEC 61850 system. In this demonstration, IED's located on the feeder were also integrated, and therefore, transfer trip commands to the DER located on the feeder had been realized. Any scheme change or extension can be performed by editing only the scheme logic and configuration of IEDs. No new wiring is required. Additionally, Use Case 4 demonstrated that an automatic transfer scheme based on IEC 61850 GOOSE communication is more

reliable than a wired implementation, as all communication links are continuously monitored. Any communication interruption is alarmed and can be used to activate predefined actions in the logic to prevent undesired behavior of the transfer scheme.

2.8.6 Use Case 5: Improved protection coordination

2.8.6.1 Problem statement

Short-circuit faults on distribution circuits are typically detected and isolated by inverse-time overcurrent protective devices. The coordination between overcurrent elements installed along the distribution feeder and those located on the substation is achieved via time coordination (following minimum recommended margins). However, this traditional approach may result in long feeder-relay operating times if the fault occurs near the substation. This is particularly problematic for faults near the substation with high fault currents as they can be dangerous and cause major damage if not cleared quickly. To mitigate this problem, it is common practice to use instantaneous overcurrent elements in addition to the traditional approach. Coordination with instantaneous overcurrent elements on the feeder can be very challenging and cannot always be guaranteed.

For example, on circuit CCR2 of the Creelman substation, the instantaneous element of the feeder protection was set to 7600 A for the phase element and 3360 A for the ground element. This leads to an uncoordinated, fast fault clearing for fault currents of 9600 A directly beyond the recloser 26R relay. At present, SDG&E must accept the uncoordinated operation in order to limit the fault current energy (I^2t).

2.8.6.2 Objective

During the project, it was demonstrated how protection coordination can be improved when an IEC 61850-based communication system is utilized. For example, to determine a faulty section and clear the fault in a faster, coordinated way, the protection pickup signal can be communicated between relays via IEC 61850 GOOSE messaging. Additionally, for high resistive faults, the sensitivity of the protection scheme can be increased to result in faster operation.

With the increase of DER, bi-directional protection elements may need to be utilized for selective fault clearance. Figure 2-29 presents the fault currents and relay settings on feeder.

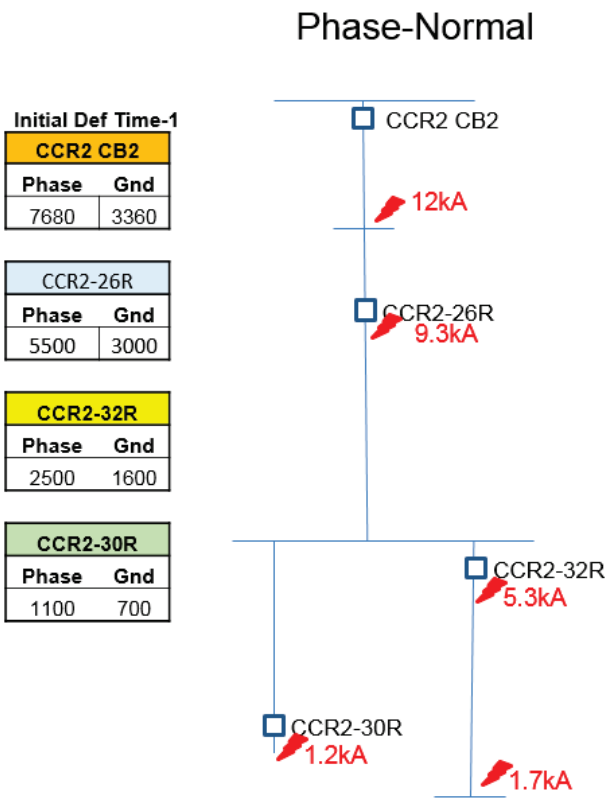


Figure 2-29. Fault currents and relay settings on feeder

Other applications for the utilization of IEC 61850 GOOSE message exchange between feeder and substation relays are as follows:

- In the presence of large-scale DER on the distribution circuit, the status of a feeder circuit breaker (CB) can be used to send a direct transfer trip (DTT) signal to the DER and disconnect it upon CB opening. This can improve both the security and dependability of the anti-islanding protection. The IEC 61850 can help expedite the process of DER disconnection by sending a high-speed DTT signal and by confirming that the DER has ceased energization.
- During the hazard season and/or circuit reconfiguration, the electric distribution operation (EDO) group can send remote signals to disable auto-reclosing mechanisms and/or to change the protection settings group in a protective device(s).

2.8.6.3 Description

Use Case 5 demonstrated the protection advantages of using GOOSE messaging to exchange information between the feeder and the substation relays. A GOOSE message that signals the pickup for a fault was sent from feeder recloser 26R to block the substation feeder relay from fast operations. The feeder relay in the Creelman substation had an additional sensitive instantaneous ground and phase element activated that would be blocked via a GOOSE message from the downstream recloser 26R whenever the recloser picked up with a ground or phase element.

The logic used inside the substation feeder relay (as shown in Figure 2-30) required recloser relay 26R to send each signal as active-low and active-high simultaneously. Only if the receiving relay received a signal as active-low and active-high, would it process and block or unblock the sensitive instantaneous elements. This was done for security reasons so as not to rely on a single signal for this critical protection action.

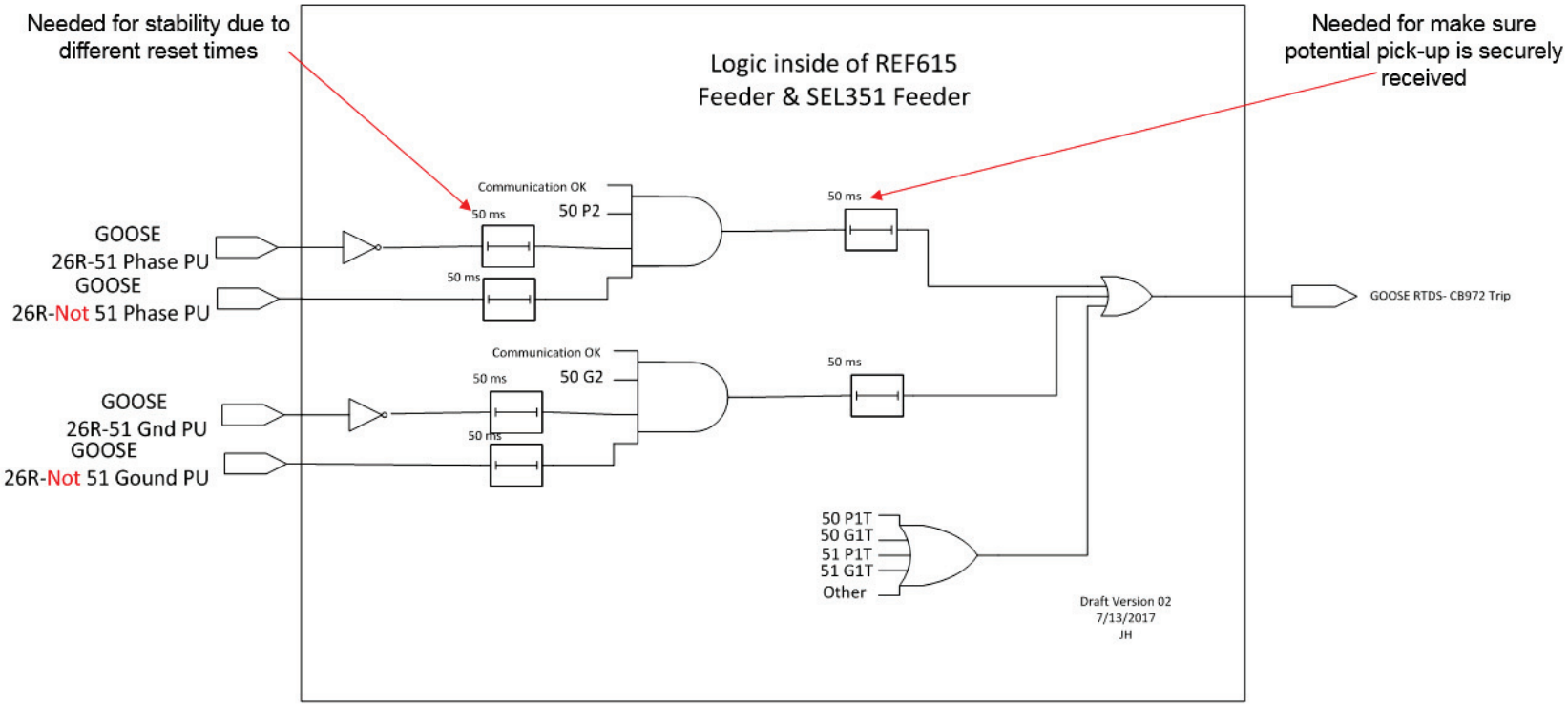


Figure 2-30. Blocking logic and trip logic of feeder relay at Substation C

The delay timer in the logic are needed to assure correct operation when both relays have different pickup operation speeds, and also to accommodate the signal propagation time.

The pickup settings for the new, additional, GOOSE-signal-controlled instantaneous elements of the substation feeder relay were 1500 A for the phase element and 500 A for the ground element. The pickup settings must be coordinated with the settings of the downstream recloser relay, so that the recloser relay will always pick up for the downstream fault whenever the sensitive element of the substation relay picks up. The 51 elements of the recloser relay were set to 800 A for the phase element and 400 A for the ground element. Any load connected between the recloser and the substation relays must be considered for the phase-element setting.

Table 2-22. Selected settings for the overcurrent relays

Sub IR	CCR2		CCR2-26R					
			PROFILE 1			PROFILE 3		
	NORMAL		NORMAL			FAST/SENSITIZED		
	Phase	Gnd	2	Phase	Gnd		Phase	Gnd
Initial Trip Settings								
Min Trip Pick Up Amps	800	500	Enabled	800	400	Enabled	705	35
TCC for Initial, Test, & Closing Profiles	CO-8	CO-8		SEL U2	SEL U3		SEL U2	SEL U3
Time Mult (Time Dial)	2.5	6.5		1.40	6.20		1.40	6.20
Min TCC Response Time (sec)				0.05	0.05		0.05	0.05
Time Adder				0	0		0	0
Disc Reset Type (EM or DT)			E/M	calc	calc	E/M	calc	calc
Low Cut-off (Amps)				N/A	N/A		N/A	N/A
Initial Def Time-1	11160	7800		6360	3000		705	35
Initial Def Time-2 (with GOOSE Application)	1500	500		NA	NA		5500	3000

2.8.6.4 Test cases and results

For the demonstration, faults were applied on different locations along the feeder, and the protection response was observed. The close-in faults were all simulated with a 5 ohm resistor to limit the fault currents to a level that could be injected into the relays with the available current amplifiers.

Table 2-23. Use cases developed for Phase 3 testing

Test #	Test case	Description	Results Conventional Design	Results IEC 61850 Design
1	Substation bus fault	• South Bus and North Bus are energized, and all feeder breakers are closed • Inject A-G Fault on North Bus • Busbar protection trips all bus breakers	Instantaneous bus fault clearing by bus differential relay	Instantaneous bus fault clearing by bus differential relay
2	Feeder close-in fault	• North Bus is energized, and target feeder is connected • Inject A-G Fault (with 5 Ohm) on Bus 301 • Feeder relay issues a trip instantaneously as it will not receive blocking signal from remote relay	Element 51 in the feeder relay cleared the fault after 1.5 s due to 1.6 kA fault current	Fast fault clearing after 60 ms by advanced protection scheme

Test #	Test case	Description	Results Conventional Design	Results IEC 61850 Design
3	Feeder end-of-line fault	• North Bus is energized, and target feeder is connected • Inject a B-G Fault on Bus 302 • Downstream IED trips and does not send unblock GOOSE message to feeder relay	Element 51 in the 26R recloser cleared fault after 1.2 s due to 1.6 kA fault current	Element 51 in the 26R recloser cleared fault after 1.2 s due to 1.6 kA fault current
3a	Feeder end-of-line fault	• North Bus is energized, and target feeder is connected • Inject a 3-pole Fault on Bus 302 • Downstream IED trips and does not send unblock GOOSE message to feeder relay	Element 51 in the 26R recloser cleared fault after 2.5 s due to 1.8 kA fault current	Element 51 in the 26R recloser cleared fault after 2.5 s due to 1.8 kA fault current
3b*	Feeder end-of-line fault	• North Bus is energized, and target feeder is connected • Inject a 3-pole Fault on Bus 302 (without additional resistor) • Downstream IED trips and does not send unblock GOOSE message to feeder relay	Instantaneous fault clearing by 26R recloser and CCR2 relay due to 9.3 kA fault current (coordination problem)	Instantaneous fault clearing of 26R relay due to 9.3 kA fault current. Sensitive element of CCR2 relay was blocked, and instantaneous element was well coordinated
4	Resistive Feeder close-in fault	• North Bus is energized, and target feeder is connected • Inject A-G resistive (20 Ohm) Fault on Bus 301 • Feeder relay issues a trip instantaneously as it will not receive blocking signal from remote relay	Element 51 in the feeder relay cleared the fault after 3.5s due to 830 A fault current	Fast fault clearing after 80 ms by advanced protection scheme
5	Feeder end-of-line fault	• North Bus is energized, and target feeder is connected • Inject B-G Fault on Bus 305 • Downstream IED trips and does not send unblock GOOSE message to feeder relay	Fault cleared by 32R recloser	Fault cleared by 32R recloser

Problem
Improved result

* Test Case 3b has only been theoretically evaluated. The available amplifier did not allow the replay of a 9.6-kA fault current (60 A secondary).

2.8.6.5 Findings

Use Case 5 demonstrated that IEC 61850 communication provided the following benefits:

- Enhanced operation of feeder protection: If a fault takes place between the feeder breaker and the downstream protective device, the fault can be quickly located through communication between the feeder relay and the downstream IED such that the operation of the feeder relay will be expedited for high resistive faults and close-in faults that can potentially damage the power equipment.
- Improved anti-islanding protection of DER: During a fault on the distribution substation, all the feeder breakers will open to isolate the fault. This will cause distribution feeders with DER to form a potential island. In such situations, direct transfer trips (DTTs) will be sent to all DER within the islanded feeder to ensure anti-islanding protection for all substation faults.
- Improved reclosing/relaying operation: If the circuit topology is changed, or during fire hazard season, the EDO department can block the reclosing mechanism on some IEDs and/or change the protection settings group of some protection IEDs. With appropriate control logic implemented in the substation controller, IEC 61850 communication can be used to perform these tasks more effectively.

2.8.7 Use Case 6: DER control mode change

2.8.7.1 Problem statement

Large-scale integration of DERs and high penetration of variable generation units such as PV systems cause adverse impact on the power quality and circuit voltages. In many cases, it is required to control active and reactive power of large DER output actively and frequently to manage voltage levels across the circuit or to control large amounts of reverse power flow when the circuit is under light-load conditions. In these cases, the control modes of the DERs may need to be changed and this use case demonstrates how IEC 61850 can be used to implement DER Control Mode Change (DER-CMC).

2.8.7.2 Description and objectives

This use case incorporates communications to DERs on distribution systems as part of the substation automation schemes (substation based controls) or through SCADA/DMS control signals that are sent through substation automation. The control modes considered in this study include:

- Remote active power curtailment/settlement and reactive power adjustment (1)
- Remote power factor (pf) control methods of inverters (2)
- Droop control modes that adjust reactive power setpoint based on a linear droop curve that determines the reactive power setpoint (3)
- DER idle mode, where DER is connected to the system, but has no interaction or power exchange with the grid (4)

In this use case, the IEC 61850 GOOSE messaging will be used mainly for communications to DER units that support this protocol. If the DER does not support the IEC 61850 protocol, a gateway is used as the protocol converter to enable communication with the DER supporting conventional communications.

Mode change or setting change and exchange of information on measurements and/or status from the DER location and operation will be transferred to the DER through GOOSE messages.

As part of this use case, communication with the battery at the ITF parking lot was examined using an additional cell modem and gateway installed at the site and accessed from ITF. The gateway device supports protocol conversion at the site. The logic diagram of this use case is shown in Figure 2-31. Logic diagram of the DER-CMC use case.

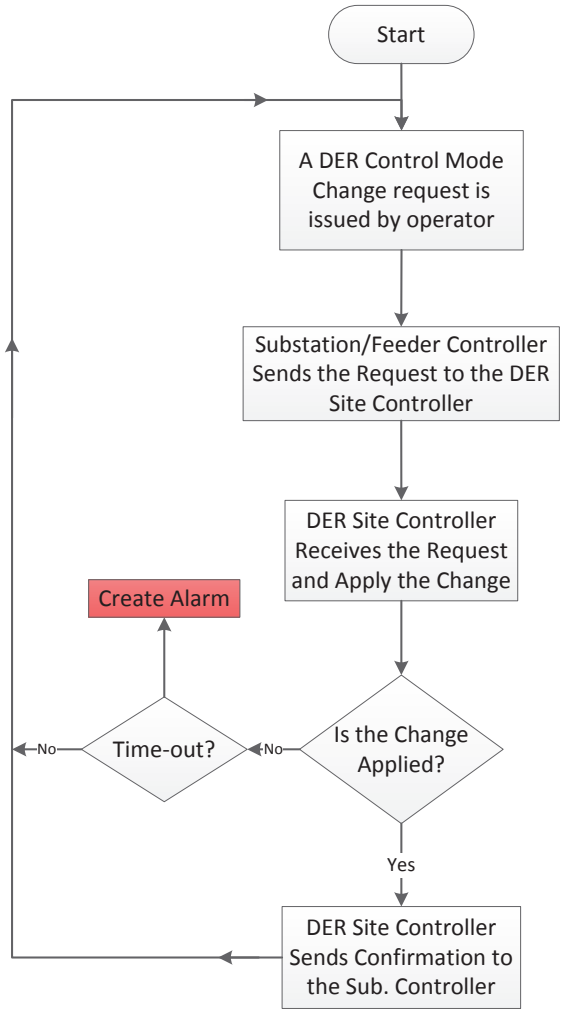


Figure 2-31. Logic diagram of the DER-CMC use case

2.8.7.3 Test cases and results

As discussed in previous sections, the purpose of this use case is to verify that the DER control mode and parameters can be modified/changed remotely through IEC 61850 communications with the DERs. For this purpose, the operator will change the DER control mode and/or parameters through GOOSE/MMS commands/setpoints. The commands/setpoints are issued from the HMI to the DER, and the results (DER responses) are collected.

lists major test cases for this use. Although all tests have been conducted, only the results of a selected number of cases will be presented and briefly discussed in this section due to space limitations. . The results of additional tests cases are provided in Appendix D. Figure 2-32 identifies the locations of the DER devices that are referenced in the test cases.

Table 2-24. DER-CMC test cases

Case	Test Conditions	Description	Remark
1.1	Substation controller requests a control mode change from Local/Droop to remote P-Q adjustment mode (3-->1)	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.2	Issue P/curtailment command to the DER and check if the DER is following	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.3	Issue Q command to the DER and check if the DER is following	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.4	Issue pf command to the DER and check if the DER is following	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.5	Substation controller requests a control mode change from remote P-Q mode to remote P-pf adjustment mode (1→2)	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.6	Issue P/curtailment command to the DER and check if the DER is following	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.7	Issue Q command to the DER and check if the DER is following	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.8	Issue pf command to the DER and check if the DER is following	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.9	Substation controller requests a control mode change from remote P-pf mode to Local/Droop mode (2-->3)	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.10	Issue VQdroop (droop coefficient) command to the DER and check if the DER is following	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.11	Issue VLband (low setpoint of the voltage band) command to the DER and check if the DER is following	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.12	Issue VHband (high setpoint of the voltage band) command to the DER and check if the DER is following	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
1.13	Substation controller requests a control mode change from Local/Droop mode to Idle mode (3-->4)	test for all DERs (PV1, PV2, BESS1, and BESS2)	4 cases
DER Control Modes: (1) Remote P/Q Adjustment (2) Remote P/pf Adjustment (3) Local (V-Q Droop) (4) Idle			

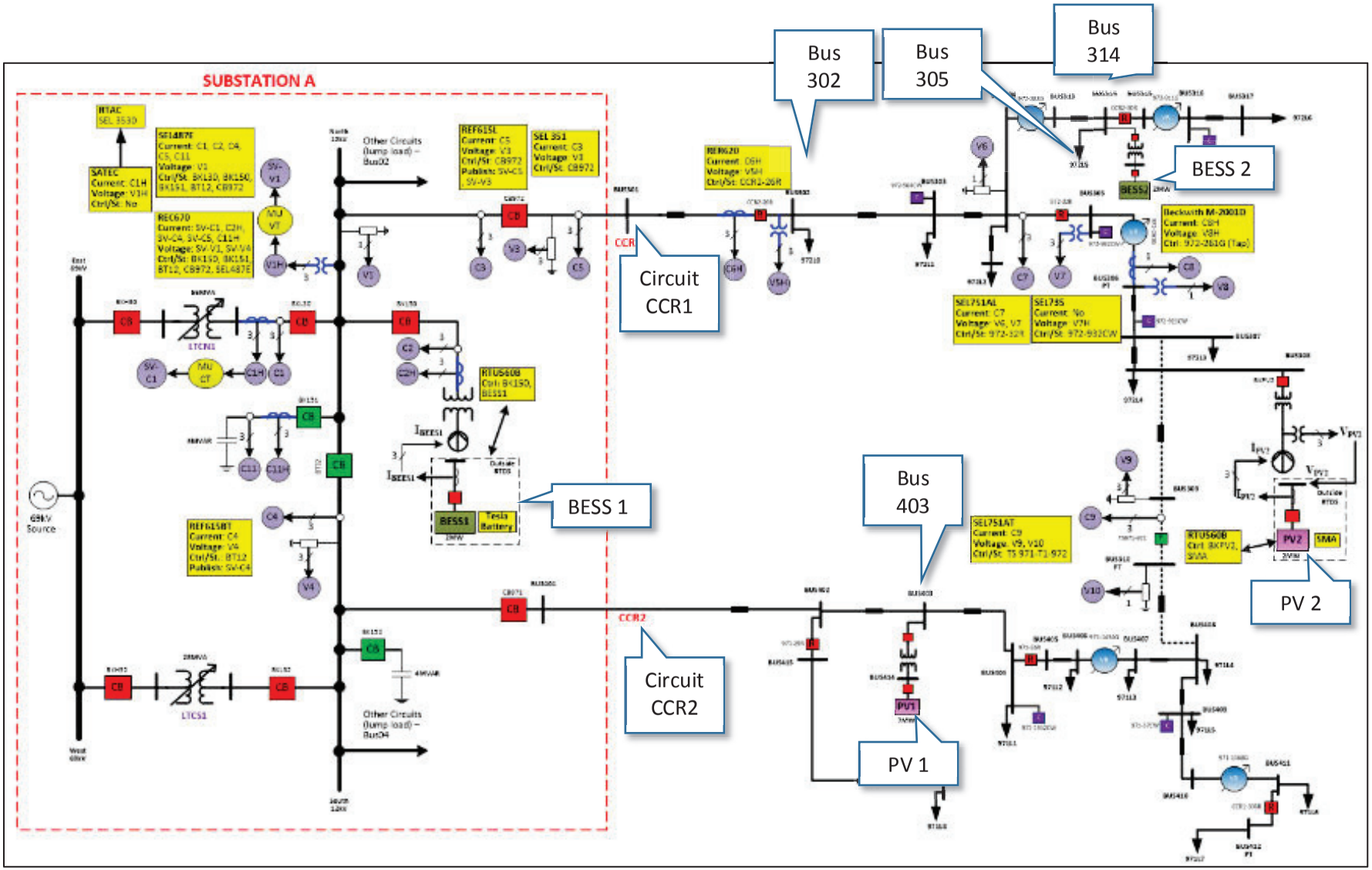


Figure 2-32. Test system SLD highlighting DER locations and circuit and bus identifiers

2.8.7.3.1 BESS 1

As discussed earlier, an RTU is used as a gateway between BESS 1 and substation gateway to operate as a protocol converter. This is mainly due to the fact that the existing DERs available in the market do not support IEC 61850 communication. For example, the BESS used in this project was supporting Modbus for the communication. Further, the battery has limited capability in supporting all control modes defined previously in Table 2-24. BESS2 is only supporting control mode 1 (Remote P and Q adjustment) and control mode 4 (idle).

Figure 2-33 shows the response of BESS 1 to the following sequence of control commands:

(0). The battery control mode is changed from 4 to 1
(1). The battery active power is changed from zero to 1 MW
(2). The battery reactive power is changed from zero to 0.5 Mvar (while P_{SP}=1 MW)
(3). The battery active power is changed from 1 MW to –0.7 MW
(4). The battery reactive power is changed from 0.5 Mvar to –0.5 MW
(5). The battery control mode is changed from 1 to 4

All control commands (mode and parameter change) are transferred to the Battery gateway (RTU) through IEC 61850 (GOOSE) communication. More specifically, a GOOSE message is issued from the substation gateway to the battery RTU located at the battery site. The RTU then converts the command from GOOSE to the protocol supported by the battery (in this case Modbus).

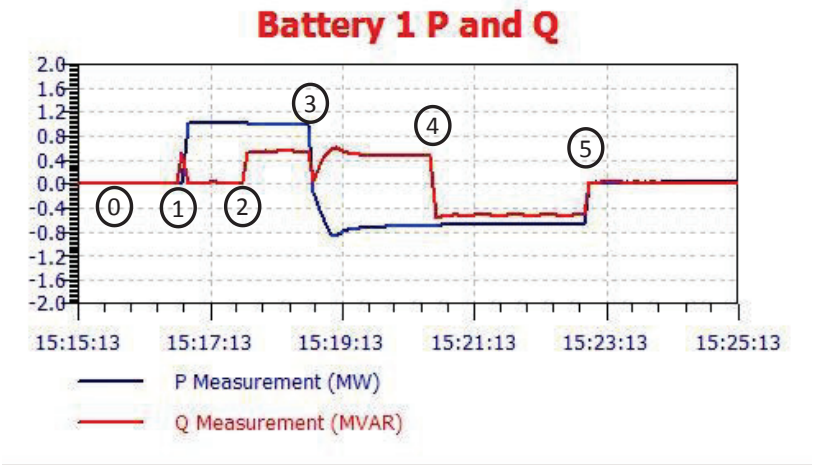


Figure 2-33. Response of the Battery to a sequence of control commands

2.8.7.3.2 PV 1

This case investigates changing control mode and parameters of PV 1 simulated in the RTDS. Therefore, all of the GOOSE commands are sent from the RTAC to the RTDS. Figure 2-34 shows the response of PV 1 to a sequence of control commands as follows:

(0). The PV control mode is changed to 1
(1). The PV active power is curtailed to 2 MW (from 3.5 MW)

(2). The PV reactive power is changed from zero to 1 Mvar (while P=2 MW)
(3). The PV reactive power is changed from 1 Mvar to –1 MW
(4). The PV control mode is changed from 1 to 4

To evaluate the performance of the PV under other control modes, particularly Control Mods 2 (remote active power and power factor adjustment) and Control Mode 3 (V-Q Droop), further tests were executed. Figure 2-35 shows the response of PV1 to the second series of control commands as follows:

(0). The PV control mode is changed to 2 (P=3.5 MW)
(1). The PV power factor setpoint is changed from unity to 0.9
(2). The PV power factor setpoint is changed from 0.9 to 0.8
(3). The PV power factor setpoint is changed from 0.8 to –0.9
(4). The PV active power is curtailed to 2 MW
(5). The PV power factor setpoint is changed from –0.9 to –0.8

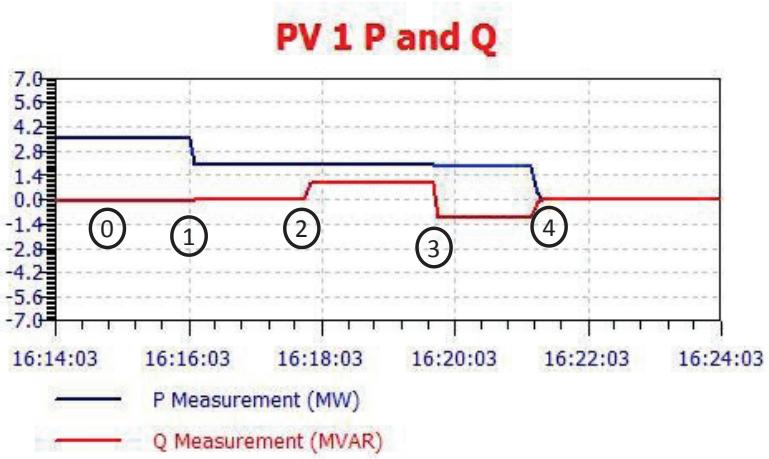


Figure 2-34. Response of PV1 to a sequence of control commands (Control Mode 1)

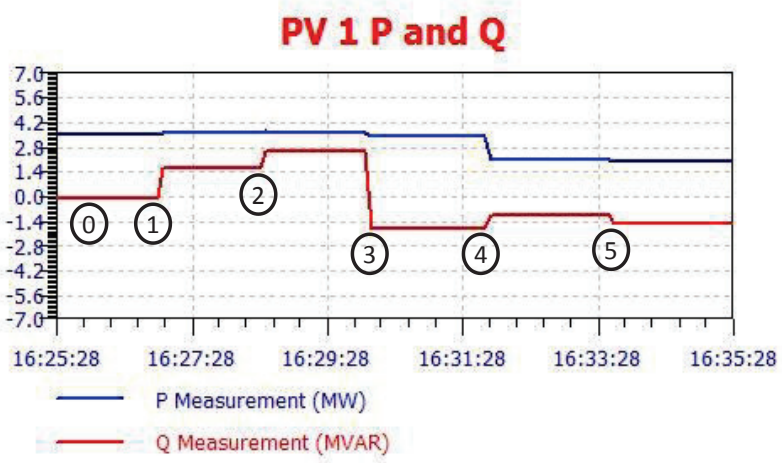


Figure 2-35. Response of PV1 to a sequence of control commands (Control Mode 2)

Finally, the following two figures present the performance of the PV inverter when it is switched to the V-Q droop control mode (Control Mode 3). Figure 2-36 and Figure 2-37, respectively, show the output power and terminal voltage of the PV, when the PV control mode is changed to V-Q droop. As indicated in Figure 2-36, the PV terminal voltage is higher than the droop high voltage threshold (V_{Hband}) prior to control mode change. Therefore, as soon as the control mode is changed to the V-Q droop, the PV reduces its output reactive power (see Figure 2-36) such that the voltage comes back to the permissible range[14] as highlighted in Figure 2-37.

The same sets of tests have been executed for all DERs under study (PV 1, PV 2, BESS 1, and BESS 2) to ensure their control modes and/or parameters can be adjusted through GOOSE messages from the substation RTAC. The result of those tests are provided in Appendix D – Additional Use Case results.

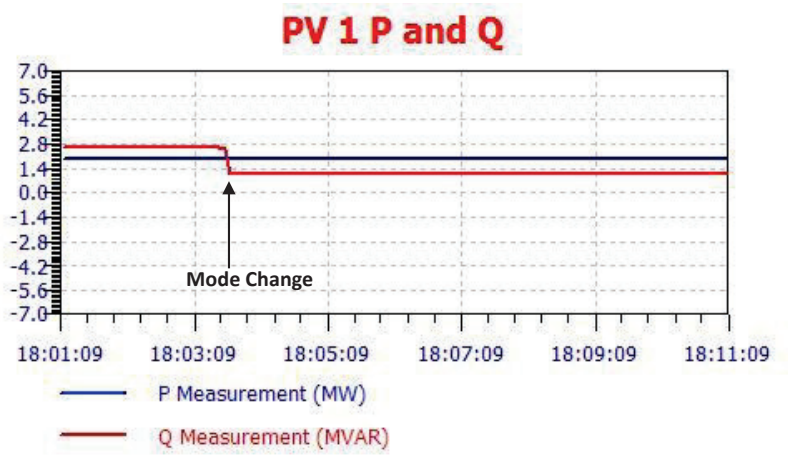


Figure 2-36. PV output power when its control mode changes to droop

[14] The permissible voltage range for each inverter can be remotely adjusted. For PV 1, this range is defined as (0.95pu, 1.05pu).

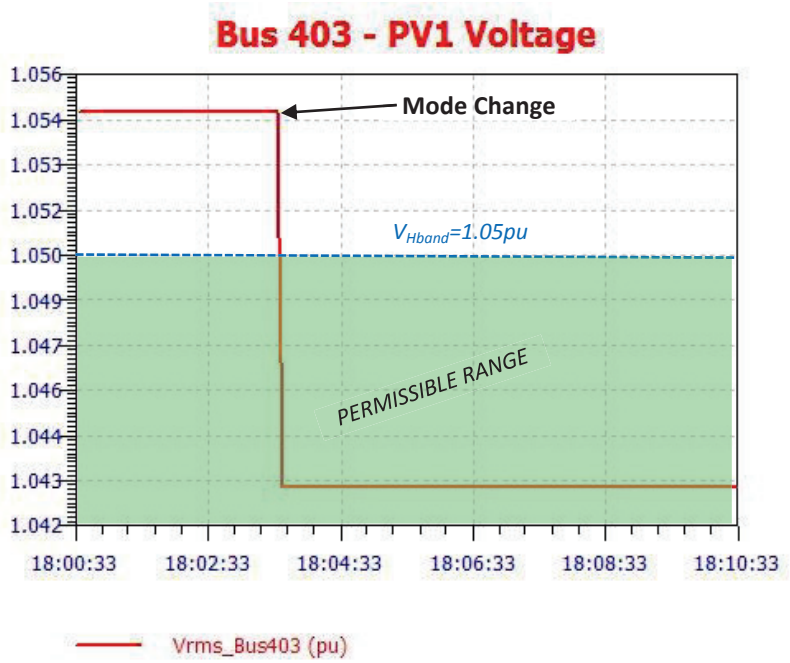


Figure 2-37. PV terminal voltage (average value) when the PV control mode changes to V-Q droop

2.8.7.4 Findings

The following is a list of findings for the DER-CMC use case:

- At the time the tests were conducted there were no commercially available DERs that provided native support for the IEC 61850 communication protocol. Although IEC 61850-7-420 intends to standardize the communications between DERs and other equipment, it is has still not been fully accepted by DER vendors.
- Since DER object models have not been fully developed/adopted, it is necessary to use a gateway between the DER and other equipment to enable peer-to-peer IEC 61850-based communication. The gateway should be capable of subscribing to both analog and digital values.
- In a peer-to-peer approach for DER-CMC, it is important to note which device is in charge of controlling the DER at each moment.
- The specific application and required speed of response will dictate which of the two IEC 61850 messages services, GOOSE or MMS, should be used for integrating DERs into the distribution circuit. For highly time critical application the peer-to-peer communications supported by GOOSE is the appropriate response. For less time critical applications either GOOSE or MMS are feasible options.
- The capabilities of DER devices differ and this impacts the feasibility of some applications. For example, the battery used in this study did not support V-Q droop mode, while the inverter did not support modifying the upper and lower voltage thresholds in the VQ-droop mode – both of which limited the functionality that could be implemented.

2.8.8 Use Case 7: Grid support using DERs

2.8.8.1 Problem statement

One of the key utility benefits claimed for large-scale deployment of DERs is that DERs provide grid-supporting capability such as reactive power management and voltage controls. Some control aspects of DERs are autonomous, meaning that it will happen automatically and locally in response to changes in the voltages and frequency of the grid. However, there are other grid-supporting features that would require coordination among multiple DER units within the same vicinity or in a coordinated fashion among all DERs that can provide the service. DERs will also need to be coordinated with the protection system to support the distribution grid effectively.

2.8.8.2 Description and objectives

The main objective of this use case is to evaluate inverter functionalities of DERs that are introduced to facilitate grid integration and high penetration levels. In this use case, communications through IEC 61850 will be used to control DERs or apply new setpoints for voltage and reactive power out of DERs. The control of reactive power and bus voltages is done centrally through the feeder controller. In particular, the feeder controller monitors the reactive power flow through the substation transformer and adjusts the reactive power setpoints of all DERs in order to meet the power factor target at the substation level.

The use case will also investigate IEEE 1547/Rule 21 functionalities of the inverter as it relates to grid support. In other words, it is investigated how the peer-to-peer communications among DERs and various protection equipment can enhance system performance under transient incident and grid fault.

2.8.8.3 Test cases and results

As described in Section 2.8.8.2, the goal of this use case is to effectively control DERs for supporting the distribution network under various operating conditions. In particular, voltage and/or reactive power support is of interest in this use case. It was studied how a distributed control using peer-to-peer communication among IEDs can help with effective utilization of DERs for the distribution grid support. Furthermore, the coordination between the system protection and low-voltage ride-through (LVR) capability of DERs is improved using the GOOSE messages between the protection relays and DER site controller. Several test cases were considered to evaluate the performance of this use case and to ensure enhanced operation of the system. Table 2-25 that follows lists major test cases considered for the GS-DER use case. Figure 2-38 presents a logic diagram of the GS-DER use case … Due to space limitations, only the results of a selected number of cases will be presented and briefly discussed in the following subsections. The results of all cases are provided in Appendix D – Additional Use Case results.

Table 2-25. GS-DER test cases

Case#	Test Conditions	Description	Remark
7.1	CCR1: Pload=1.0pu, PPV1=0.1pu CCR2: Pload=1.0pu, PPV2=0.1pu, PBESS1=0, PBESS2=0	High load profile (fix), low PV (fix)	Adjust Pf_target and evaluate the performance
7.2	CCR1: Pload=1.0pu, PPV1=0.2pu CCR2: Pload=1.0pu, PPV2=0.2pu, PBESS1=0 MW, PBESS2=-1 MW	High load profile (fix), low PV (fix)	Adjust voltage with DER and evaluate the performance
7.3	CCR1: Pload=1.0pu, PPV1=0.5pu CCR2: Pload=1.0pu, PPV2=0.7pu, PBESS1=0, PBESS2=0, QBESS2=–0 .5 MW	High load profile (fix), high PV (fix)	Adjust Pf_target and evaluate the performance
7.4	Repeat Case 7.1 and trip CCR2-932CW	High load profile (fix), low PV (fix)	Adjust Pf_target and evaluate the performance
7.5	Permanent SLG fault at Bus 305		BESS2 to provide LVRT, as appropriate
7.6	Permanent LLLG fault at Bus 305		BESS2 to provide LVRT, as appropriate
7.7	Permanent SLG fault at Bus 302		BESS2 to provide LVRT, as appropriate
7.8	Repeat Case 7.5, with CCR2-32R failing to operated properly		BESS2 to provide LVRT, as appropriate
7.9	Temporary SLG fault at Bus 305 (t=5cycles)		BESS2 to provide LVRT, as appropriate
7.10	Temporary LLLG fault at Bus 305 (t=3cycles)		BESS2 to provide LVRT, as appropriate
7.11	CCR1: Pload= 1pu, PPV1=0.2pu CCR2: Pload=1pu, PPV2=0.2pu, PBESS1=0 MW, PBESS2=–1 MW	High load profile (fix), high PV (fix)	Adjust Pf_target and evaluate the performance
7.12	Repeat Case 7.3 and trip Battery 1	High load profile (fix), high PV (fix)	Adjust Pf_target and evaluate the performance
NOTES: Light-Load Steady-State (LLSS) condition: No DER, Pload_CCR1=0.4pu, Pload_CCR2=0.4pu High-Load Steady-State (HLSS) condition: No DER, Pload_CCR1=0.95pu, Pload_CCR2=0.95pu			

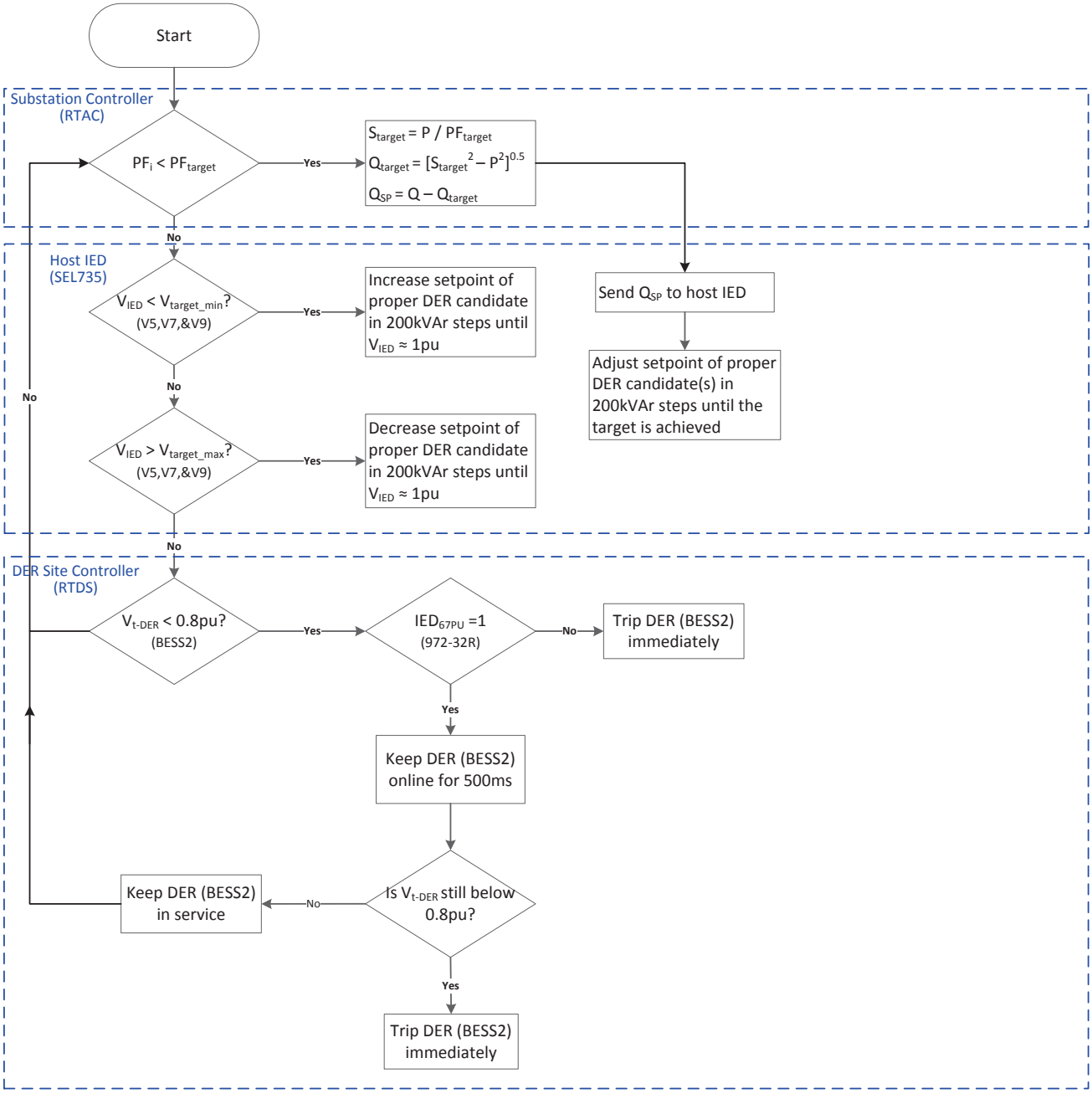


Figure 2-38. Logic diagram of the GS-DER use case

2.8.8.3.1 Case 7.4: Coordination between DER's LVRT and System Protection

This test focuses on the coordination between Recloser CCR2-32R and the feeder battery energy storage system (BESS 2). The location of these two devices were indicated previously in Figure 2-11. For a fault downstream of the recloser (e.g., Fault at Bus 305 in Figure 2-11), it is likely that the anti-islanding protection of BESS 2 operates in a non-coordinated manner with respect to the recloser. The unnecessary operation of the BESS 2 anti-islanding protection may even exacerbate the situation since DERs are supposed to provide LVRT support. Thus, it is desired that the recloser operates first for such fault cases to clear the fault. If the recloser fails to operate, then the BESS anti-islanding protection should immediately disconnect the unit.

Assuming that a solid single-phase-to-ground (SLG) fault takes place at Bus 305 (see Figure 2-11), Figure 2-39 shows the three-phase instantaneous voltage of the BESS bus (i.e., Bus 314) prior to and during the fault. It can be seen that the voltage of the faulty phase (Phase A) is significantly affected due to the fault, which will cause the anti-islanding protection of BESS 2 to very quickly initiate a trip.[15] However, since CCR2-32R will detect a forward (downstream) fault, it will block operation of the BESS 2 anti-islanding protection for a pre-defined time period (500 ms in this project). In other words, the pickup signal of Recloser CCR2-32R is communicated to BESS 2 through GOOSE messaging to work as a blocking signal for downstream faults.

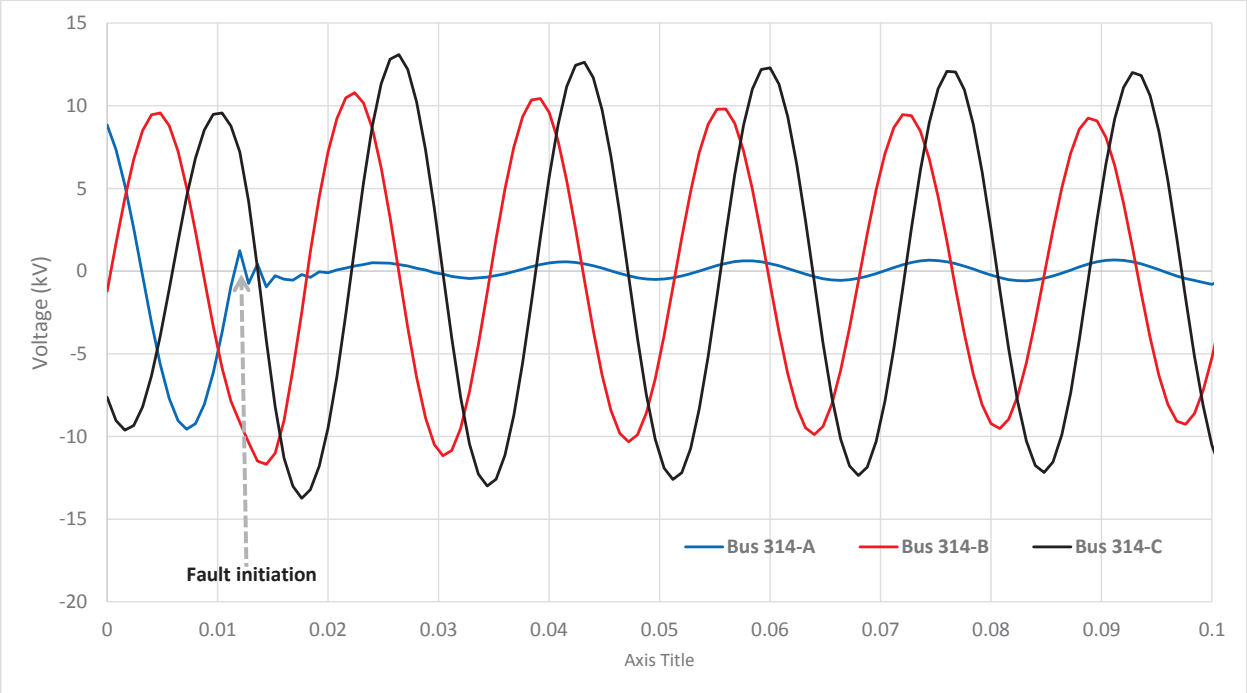


Figure 2-39. BESS voltage prior and during a fault at Bus 305.

[15] IEEE 1547 Standard has been used in this project for the design of the DER anti-islanding protection.

Figure 2-40 illustrates trip and blocking signals generated during the SLG fault on Bus 305. Figure 2-40 (a) shows that the local anti-islanding trip signal of BESS 2 (BESS trip initiation signal) has picked up in about 297 ms after the fault initiation. However, since CCR2-32R has already detected the forward fault and issued the pickup signal (see Figure 2-40 (b)), the BESS local trip is blocked. This is shown in Figure 2-40 (d) where the final BESS 2 trip signal has not picked up. Meanwhile (while the BESS 2 trip is blocked for 500ms), Recloser CCR2-32R has isolated the fault by tripping its corresponding breaker (see Figure 2-40 (c)).

Figure 2-41 shows the fault voltages and current prior to, during, and subsequent to the fault scenario described earlier. Figure 2-41 (a) and Figure 2-41 (b) indicate that, subsequent to the fault, the BESS voltage is retrieved, confirming proper operation of the anti-islanding scheme augmented with the blocking signal. The results of remaining test cases are provided in Appendix D – Additional Use Case results.

2.8.8.3.2 Case 7.11: Grid support through power factor and voltage control

For Case 7.11, illustrated previously in Table 2-25, the system is highly-loaded while the PV generation is relatively low. Further, one of the batteries (BESS 2) is in charge mode. Initially, the power factor target of this circuit is set at 0.9, which is lower than the prevailing power factors of the circuits (i.e., 0.94 for CCR1 and 0.965 for CCR2). Therefore, the implemented logic at the RTAC does not take any action. Then, the following targets are selected for the power factor at the substation level:

(1). $PF_{target1}$=0.95
(2). $PF_{target2}$=0.98

Figure 2-42 through Figure 2-45 indicate the system response to the aforementioned sequence of targets defined for the power factor (orange circles show the time at which a new power factor target is defined). As can be observed in these figures, the controller has utilized DERs to achieve the power factor target. This is shown in Figure 2-42, where the controller has modified the DER reactive power setpoints for improving circuit power factor. Figure 2-43 and Figure 2-44 show the real and reactive power of Circuit 1 (CCR 1) and Circuit 2 (CCR 2), respectively.

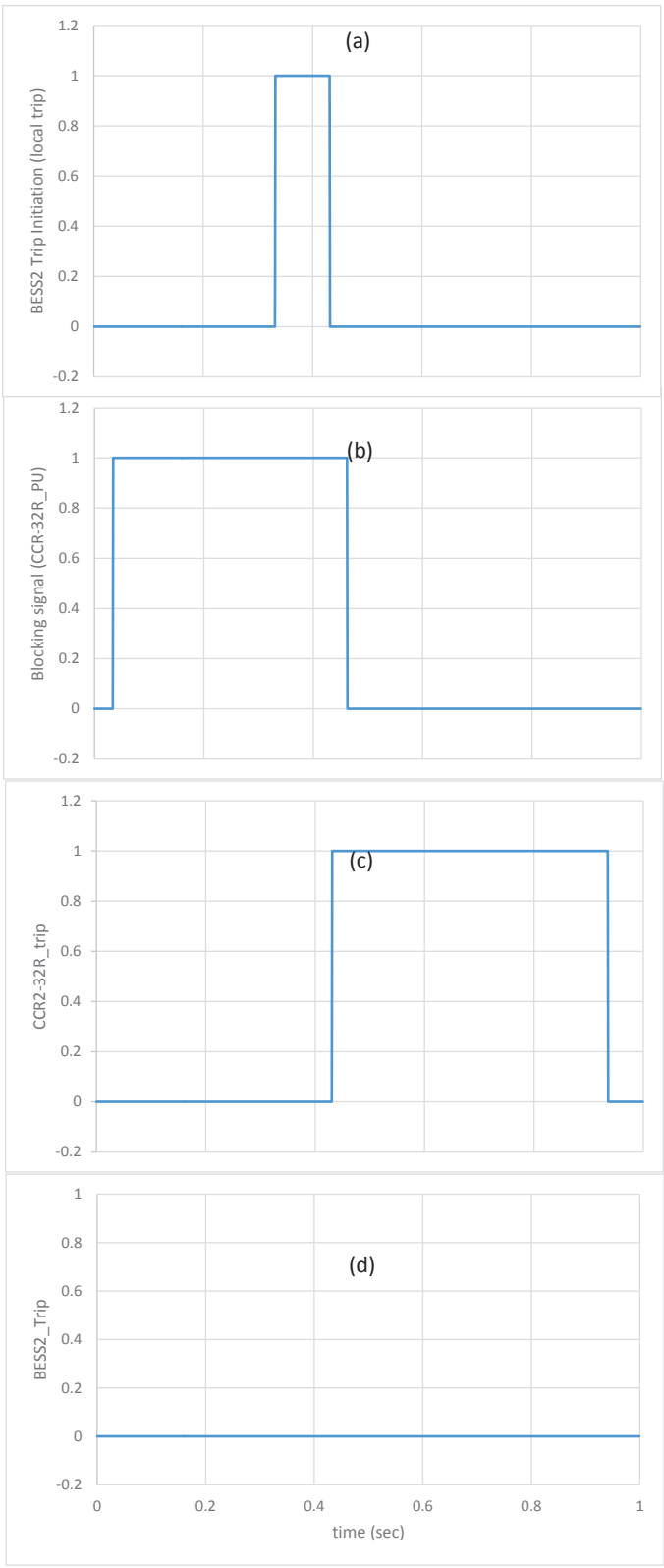


Figure 2-40. Trip signals for an SLG fault downstream of the CCR2-32R (Case 7.5)

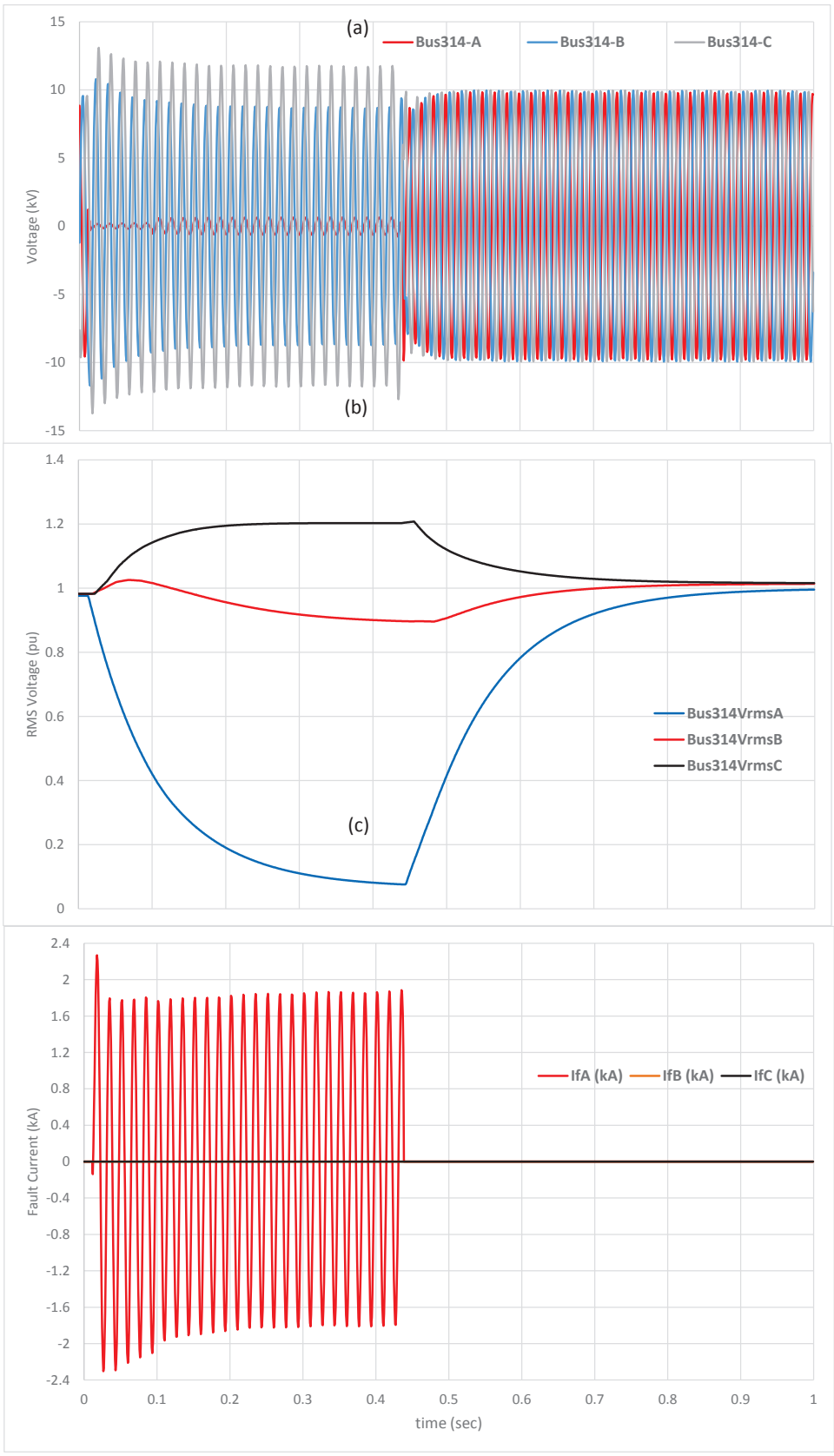


Figure 2-41. Fault voltages and current prior, during, and subsequent to an SLG fault on Bus 305.

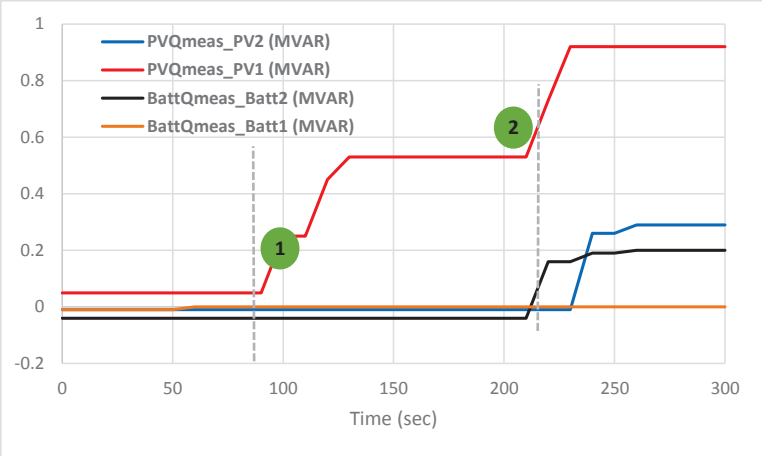


Figure 2-42. Reactive power contribution of DERs during the test (Case 7.11)

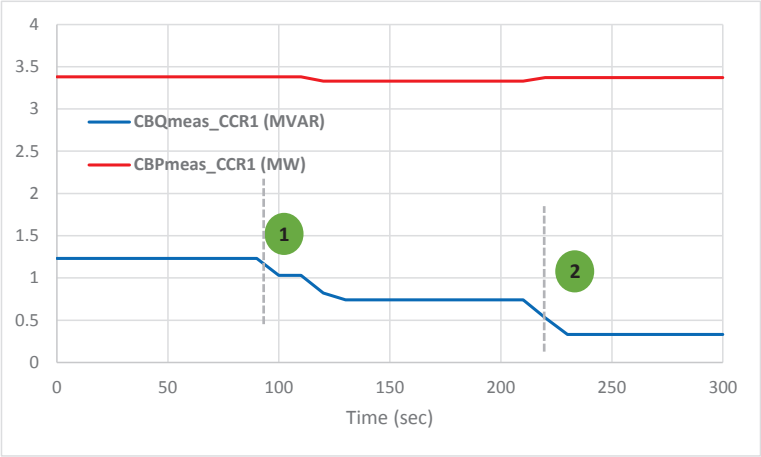


Figure 2-43. Real and reactive power flowing through the feeder breaker (CCR1) (Case 7.11)

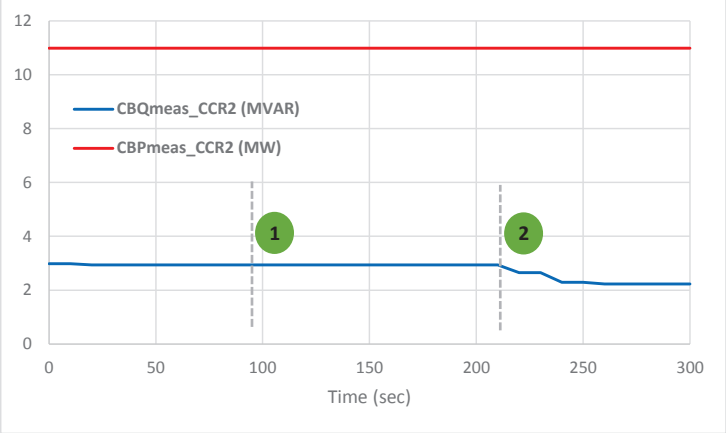


Figure 2-44. Real and reactive power flowing through the feeder breaker (CCR2) (Case 7.11)

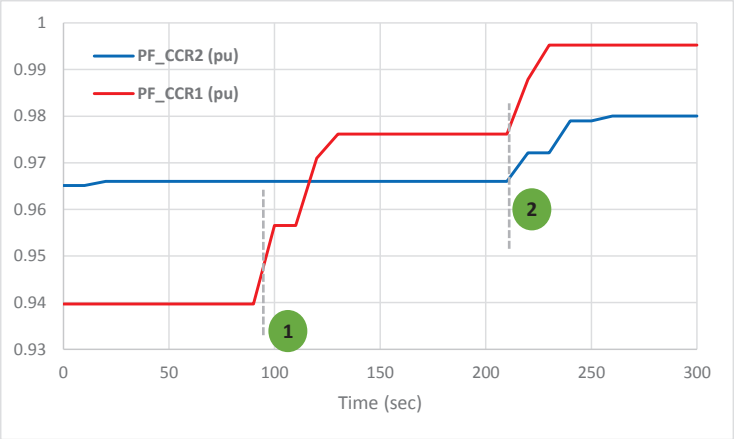


Figure 2-45. Circuit power factors during the test (Case 7.11)

As shown in Figure 2-40 and Figure 2-44, with increased reactive power contribution of DERs, the total reactive power drawn from the grid decreases. This, in turn, results in the improved power factor at both circuit and substation levels. Figure 2-45 shows the calculated power factor for both CCR 1 and CCR 2. It is evident from the figure that, with the DER contributions, both power factor targets (0.95 and 0.98) are achieved.

It should also be noted that, in this use case, the voltage of major points are continuously reported to the feeder controller through GOOSE messages. The controller will try to adjust the voltage through utilization of the most appropriate DER (for example, the closest DER to the monitored point). This use case attempts to keep the voltage of various points in the circuit within a range that is adjustable by the operator. In this test case, this range has been defined to be between 0.98 pu and 1.02 pu. Figure 2-46 shows the voltage of a monitored bus (Bus 305) during the test. It can be observed that the voltage has been regulated and brought to the target range.

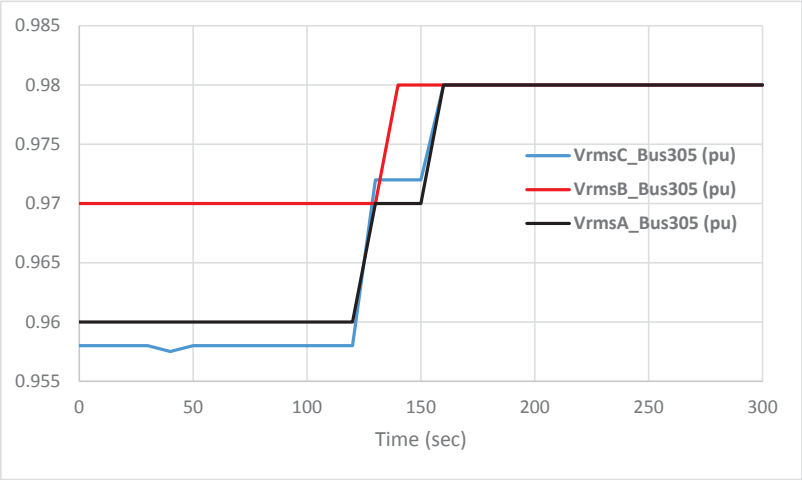


Figure 2-46. Voltage of Bus 305 during the test (adjusted by reactive power contribution of BESS 2)

2.8.8.4 Findings

The following is a list of findings for this use case:

- This use case shows how peer-to-peer communications among DERs and other protection and control equipment can enhance distribution system operation through
    - Improved power factor at the substation level obtained by increased involvement of DERs
    - Enhanced voltage profile through proper DER reactive power contribution
- The direct communication between DERs and the downstream protective device(s) can provide coordination between system protection and low-voltage ride-through (LVRT) capability of DERs. In particular, the following observations were made through the course of test execution:
    - For a downstream fault, the downstream protective device will block the operation of the anti-islanding protection of DERs for a specified period of time, which is not longer than the utility/standard requirement. This will afford time to the protective device to clear the fault and prevent unnecessary operation of the DER. This is important, as the trip of the DER for such a fault case can aggravate the situation.
    - For an upstream fault, direct transfer trips (DTT) will be sent to the DER within the islanded feeder to ensure anti-islanding protection.
- The peer-to-peer communication between DER and other protective equipment can improve both security and dependability of DER anti-islanding protection.

2.8.9 Use Case 8: Emergency load management tests

2.8.9.1 Problem statement

Currently, SDG&E performs surgical load shedding based on pre-determined look-up tables with rotational schedules for the distribution circuits that can be placed in outage order. When an emergency load shedding request is made by the California Independent System Operator (CAISO), the pre-scheduled look-up table will define which circuits shall be shed. The schedule incorporates information on type of customers connected to the circuits and excludes outage on circuits that serve critical facilities such as hospitals, elderly residential housing, fire stations, etc. However, since the current practice works based on the circuit interruption, there is a possibility that more loads than required are de-energized in response to a load-shedding request.

With the increasing integration of DER, there will be opportunities to minimize customer interruption during emergency conditions. This can be done through effective utilization of DER contributions to offset customer loads. In other words, proper dispatch of DERs can potentially help with efficient load management in distribution circuits. If there are cases where loads must be disconnected, it can be determined based on real-time measurements and controls such that the smallest possible amount of load is de-energized to achieve the defined load-management target. Further, an improved rotational scheme can be employed to improve the load shedding strategy.

2.8.9.2 Description and objectives

The main objectives of this use case is to monitor field data and properly utilize DERs in order to:

- Reduce the need for disconnecting large numbers of customers, based on the generation contribution from DERs, and
- Use the real-time information from field assets to perform partial load shedding, to restore some loads through alternative power sources if possible, and to rotate the scheduled outages more frequently as the need for load reduction changes.

Field monitoring and fast control will help to reduce the amount of reserve load reduction (margin for load fluctuation sensitivity), since a fast partial load shedding scheme can be implemented through IEC 61850 GOOSE and active communication of DER and load fluctuations. GOOSE messaging was used for controls in this use case. Figure 2-47 presents the logic diagram of the emergency load management (ELM) use case.

2.8.9.3 Test cases and results

This use case aims at utilizing DERs for emergency load management in distribution networks. The goal of the use case is to improve system reliability and economics by reducing load interruption during emergency situations. In other words, the emergency load shedding request by an ISO can be addressed with no load interruption or partial load shedding if DERs can be involved (properly dispatched) during the process. The logic diagram of this use case is provided in Figure 2-47.

The performance of the ELM function is evaluated through a full set of tests as described in Table 2-26. Similar to previous use cases, only the results of a selected number of cases is presented and briefly discussed in the following subsections, due to space limitations. Results of other cases are provided in Appendix D – Additional Use Case results.

2.8.9.3.1 Case 8.1: Real-time power flow control of substation banks

In this use case, it was demonstrated how the active power flow through substation transformer banks can be controlled by effective utilization of DERs. The RTAC at the substation continuously monitors the real power flow through the transformer banks. If this power exceeds a threshold defined by the operator, the additional required power is calculated. The RTAC will then communicate the calculated power target of each control zone to the corresponding controller of the zone. Subsequently, the control zone host/engine will determine the DER power setpoints to achieve the target. If the target is achieved by only dispatching DERs, a “successful” alarm is issued to the SCADA; otherwise, the operator will receive a “fail” alarm.

In Case 8.1, the power target of the transformer bank is set at P_{maxH}=8 MW.[16] The power flowing through both substation transformer banks are shown in Figure 2-48. As can be seen in this figure, the power of the North transformer bank is higher than the threshold (8 MW) prior to the activation of the use case

[16] It is acknowledged that this is a very low threshold, but it is selected for the evaluation of the use case.

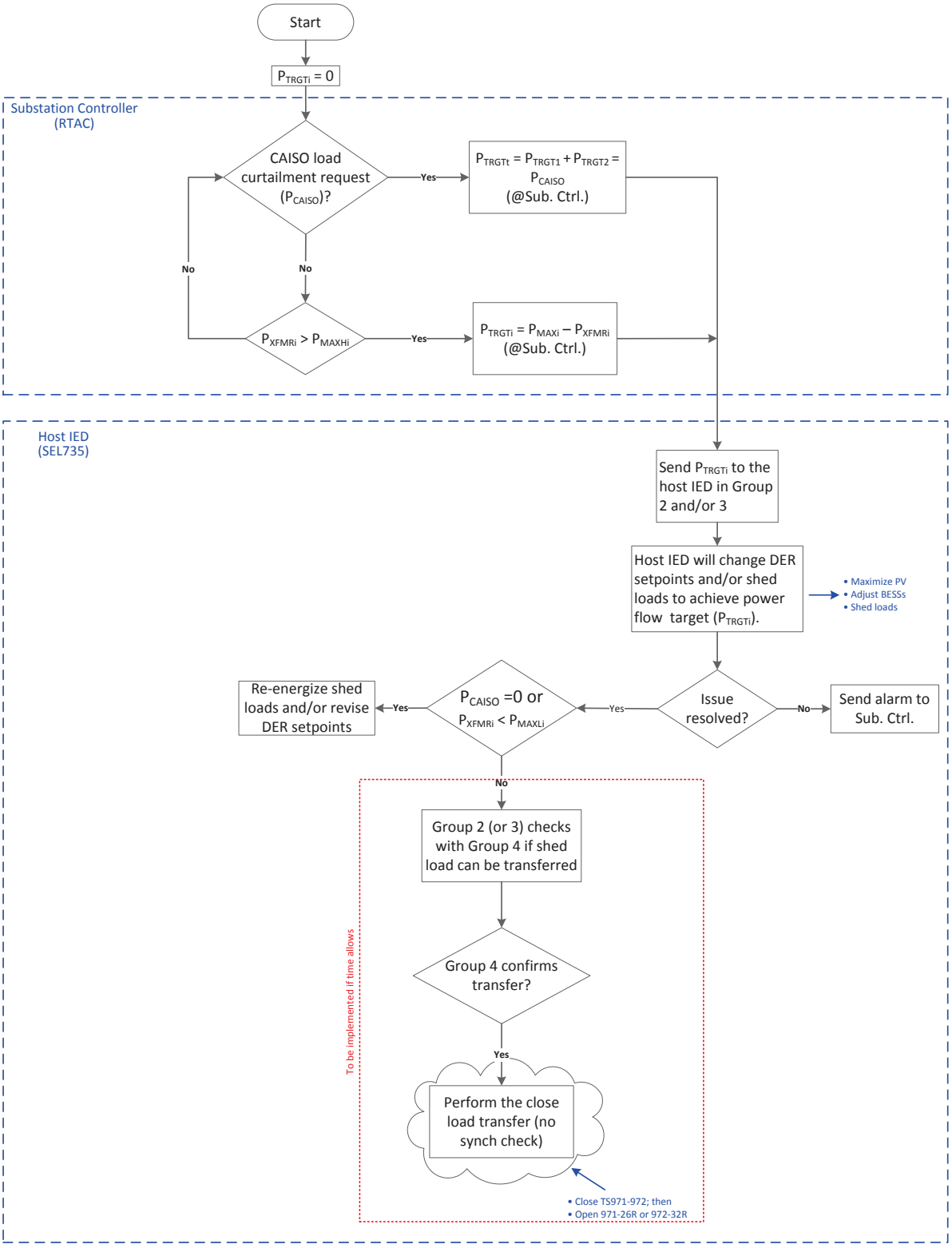


Figure 2-47. Logic diagram of the ELM use case

Table 2-26. ELM test cases

Case#	Test Conditions	Description	Remark
8.1	CCR1: Pload= 1pu, PPV1=0.7 MW (SR=0.2pu) CCR2: Pload=1pu, PPV2=0.5 MW (SR=1pu), PBESS1=0, PBESS2=0 PCAISO=0 MW	High load profile (fix), low PV (fix)	Pxfmr to be adjusted by the control scheme
8.2	CCR1: Pload= 1pu, PPV1=0.7 MW (SR=0.2pu) CCR2: Pload=1pu, PPV2=0.5 MW (SR=0.5pu), PBESS1=0, PBESS2=0 PCAISO=3 MW	High load profile (fix), low PV (fix)	Achieve power target, as applicable
8.3	Continue Case 8.2 with PCAISO=1.5 MW	High load profile (fix), low PV (fix)	Achieve power target, as applicable
8.4	Continue Case 8.3 with PCAISO=2 MW	High load profile (fix), low PV (fix)	Achieve power target, as applicable
8.5	CCR1: Pload= 1pu, PPV1=1 MW (SR=0.4pu) CCR2: Pload=1pu, PPV2=0.7 MW (SR=0.5pu), PBESS1=0.5, PBESS2=1, PCAISO=0 MW	High load profile (fix), medium PV (fix)	Pxfmr to be adjusted by the control scheme
8.6	Repeat Case 1.3 with PV2 out of service		
8.7	CCR1: Pload= 1pu, PPV1=0.7 MW (SR=0.2pu) CCR2: Pload=1pu, PPV2=0.5 MW (SR=0.5pu), PBESS1=0, PBESS2=0 PCAISO=3 MW (BESS2_SOC<20%)		
8.8	Continue Case 8.4 with PCAISO=0 MW	High load profile (fix), low PV (fix)	Achieve power target, as applicable
8.9	Continue 8.5 with PCAISO=2 MW		
8.10	Continue 8.9 with PCAISO=1 MW		
8.11	Continue 8.10 with PCAISO=1 MW		

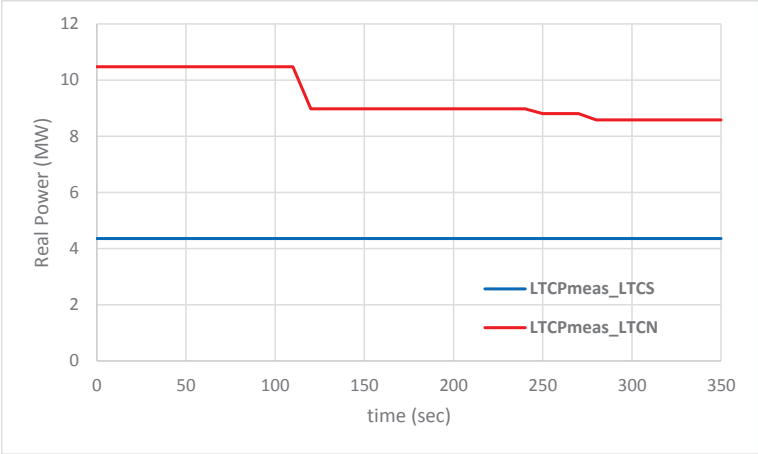


Figure 2-48. Power of the transformer banks during the test (Case 8.1)

logic at about t=100s (red line). Once the logic is enabled, the power targets are calculated for each control zone. The controller of each zone will then dispatch DERs to limit the power of the transformer banks.

Figure 2-49 presents the output power of the DERs during the aforementioned tests. The figure shows that the algorithm first uses all of the PV 2 capacity (by releasing the curtailed power) and then calculates the BESS setpoints for achieving the target. It is also important to note that since the power of the South transformer bank is below the threshold (P_{maxH}>4.3 MW), no adjustment has been done on DERs connected to Circuit CCR1 (see Orange line in Figure 2-49). Finally, it can be seen that the power of the North transformer bank becomes less than the threshold subsequent to the successful completion of the test (see red line in Figure 2-48).

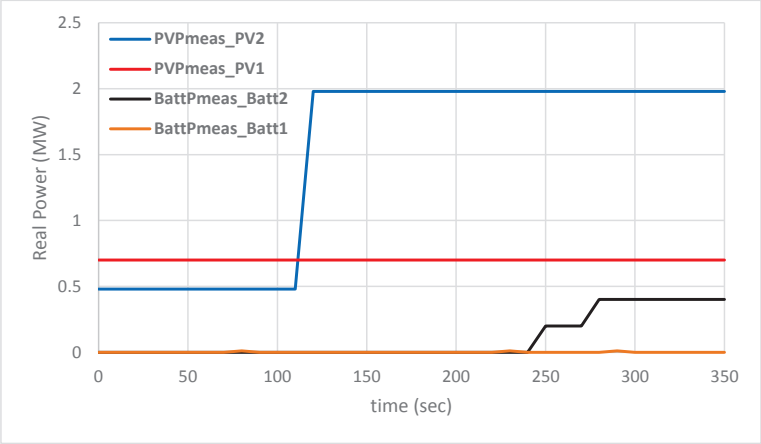


Figure 2-49. Power of the DER units during the test (Case 8.1)

2.8.9.3.2 Case 8.9: California ISO load shedding request.

In previous test cases, there was no load-shedding request from CAISO (P_{CAISO}=0 MW). Once CAISO makes a request, it will be addressed with a higher priority. Assuming a case where PV2 is out of service (e.g., due to a fault), and CAISO sends a 2- MW request (other DERs have some initial power values), the

request is received by the substation RTAC, and it will determine the power target of each control zone based on the reserve capacity calculation.

The control zone engine will first maximize the power drawn from the renewable resources (e.g., PVs) and then defines BESS setpoints. As shown in Figure 2-50, the majority of the power comes from the curtailed section of PV 1, and the rest is supplied by both BESSs. As a result, the total amount of 2 MW is achieved through the contribution of DERs. This is shown on Figure 2-51, where the total amount of decrease in transformer bank powers is about 2 MW.

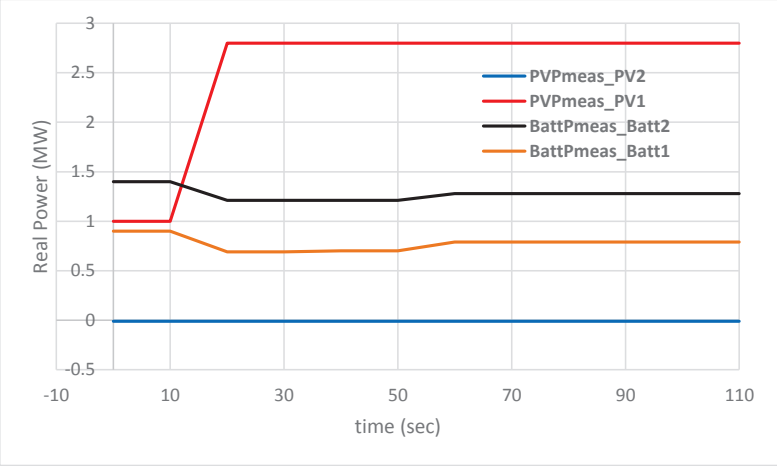


Figure 2-50. Power of the DER units during the test (Case 8.9)

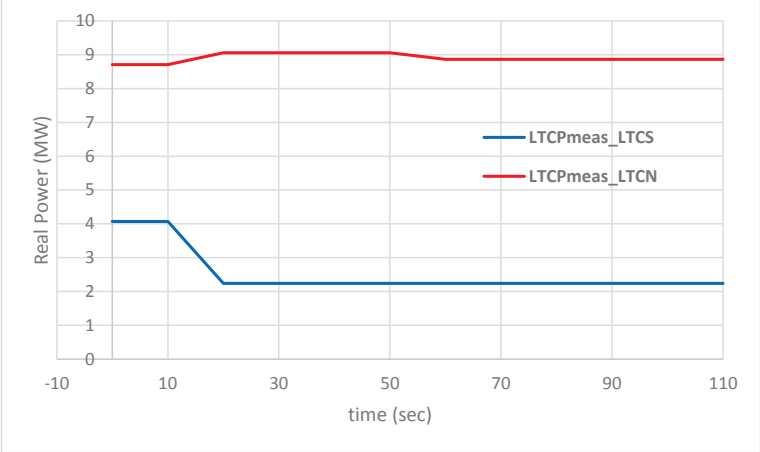


Figure 2-51. Power of the transformer banks during the test (Case 8.9)

2.8.9.3.3 Case 8.10: California ISO load shedding request.

Assuming that another 1- MW power request is made by the CAISO (continuation of Case 8.9), and considering that the maximum power is already drawn from the PV system (PV 1) based on the prevailing solar radiation, the only resources left to supply the remaining powers are BESS 1 and BESS 2 (note that PV 2 is out of service). Figure 2-52 and Figure 2-53 show the DER output power and the transformer bank power during this test. These figures indicate that the 1- MW request is addressed by the dispatch of BESSs (note the change in the power of North transformer bank in Figure 2-53).

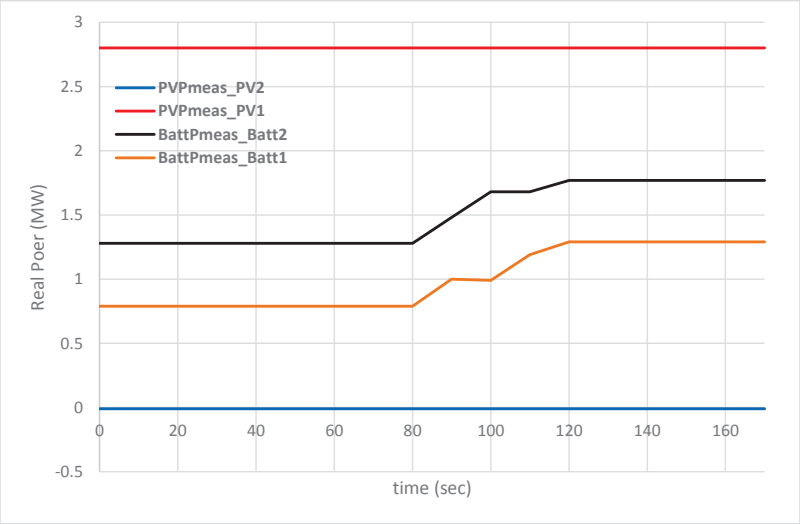


Figure 2-52. Power of the DER units during the test (Case 8.10)

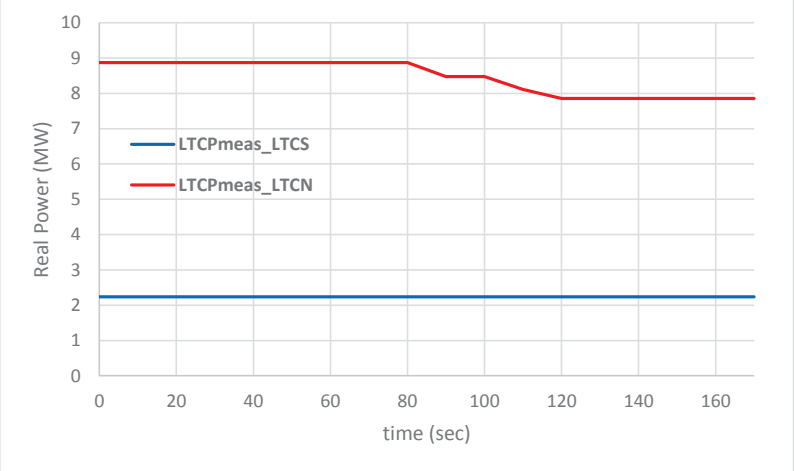


Figure 2-53. Power of the transformer banks during the test (Case 8.10)

2.8.9.3.4 Case 8.11: California ISO load shedding request.

Assuming that another 1- MW request is made by the CAISO for a third time (continuation of Case 8.10), Figure 2-54 and Figure 2-55 show the DER output power and the transformer bank power during this test. It can be observed that the output power of BESS 2 has not changed during the test, although it still has some capacity left. This is because the State of Charge (SOC) of this battery is critical (less than 20%) and, thus, the control zone host does not load the battery further. However, since the request cannot be fully addressed by BESS 1 (even at full capacity), the algorithm shed the sheddable load (CCR2-30R) as shown in Figure 2-56.

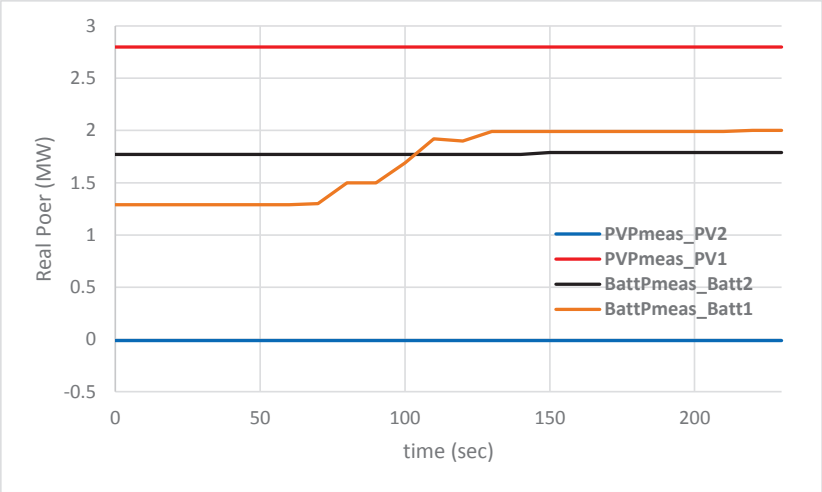


Figure 2-54. Power of the DER units during the test (Case 8.11)

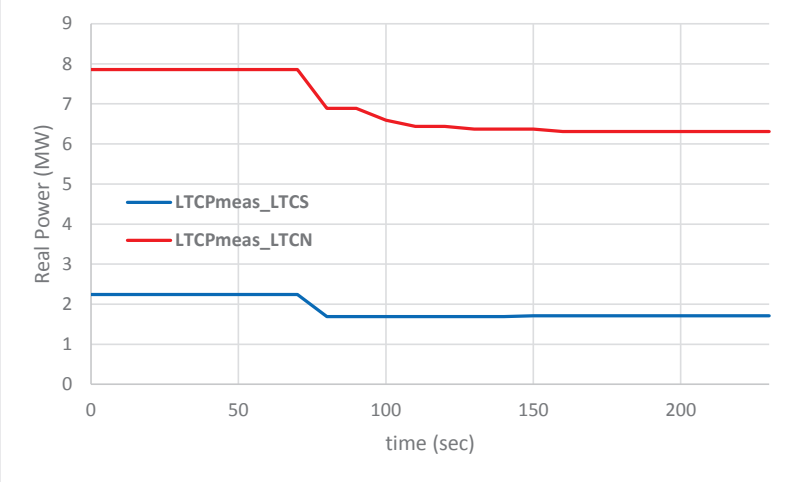


Figure 2-55. Power of the transformer banks during the test (Case 8.11)

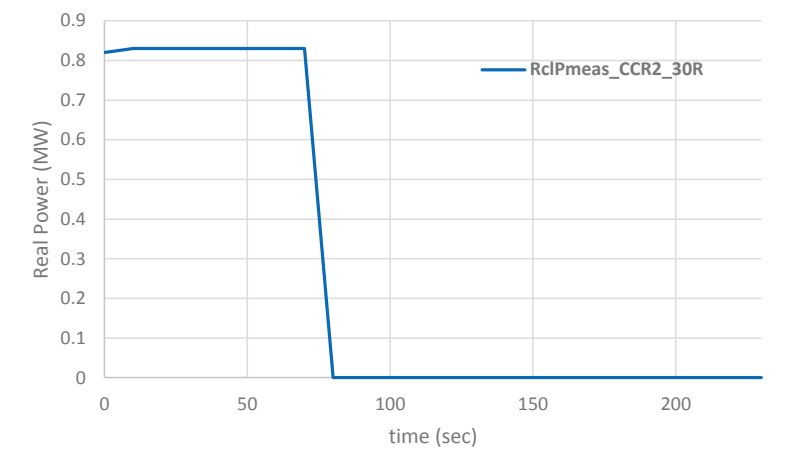


Figure 2-56. Load shedding performed by the use case logic to address the load shedding request (Case 8.11)

The results of the remaining test cases are provided in Appendix D – Additional Use Case results.

2.8.9.4 Findings

The following is a list of findings for the ELM use case:

- Integrating DERs into the distribution system control can improve performance of the system under emergency condition. This use case shows how DERs can be effectively employed to:
    - Address ISO load shedding requests with minimum interruption (or in some cases, no interruption) to customers. This will enhance reliability parameters normally used in system reliability analysis.
    - Control the power flow through the transformer banks at the substation on a real-time basis.
    - To manage reverse power flow through effective use of BESS while maximum energy is obtained from renewable resources.
- The peer-to-peer communications with DERs enables implementing a distributed control for distribution systems. Such an approach can enhance the reliability of the control system (advanced fail-safe).
- Since this use case utilizes a distributed control approach in which some control decisions are made within distributed control zones, it is very important that the control zone hosts at least one IED with a certain amount of control logic capability. It was found that most of the typical equipment used for feeder protection do not have enough control logic capability to enable a distributed control approach.
- During the course of the pre-commercial demonstration phase, it was discovered that some of the feeder IEDs did not have the capability to subscribe to analog GOOSE messages. This ability is a pre-requisite for functioning as a control zone engine – so this needs to be taken into account when selecting IEDs for this role.

2.8.10 Use Case 9: Dynamic emergency load control and management with DERs using OpenFMB

2.8.10.1 Problem statement

While high penetration of DERs, particularly variable energy resources (VERs) such as PV systems, are changing the shape of the distribution systems, they offer solutions for local load management of distribution circuits. In many cases, with the control of active and reactive power contribution of large DERs, the power flow limits of feeders (forward or reverse direction) can be controlled, under high- or light-load conditions. It is noted that DERs on circuits need to be closely controlled to enable direct interaction with the grid operator.

Dynamic Emergency Load Control and Management (DELCAM) can improve system performance in a distribution grid dominated by DERs. Two major challenges to achieve this objective are: 1) control and operation of large number of DERs that are distributed along the circuits, and 2) remote communications with DERs in the field environment. For the purpose of this use case, the communication is established in the Open Field Message Bus (OpenFMB) framework.

2.8.10.2 Description and objectives

This use case incorporates development of an OpenFMB communication platform for monitoring and control of DERs and field devices on distribution circuits. The objective is to investigate capabilities of OpenFMB framework for managing the communications among various field devices (primarily, DERs and feeder breaker). The new architecture should be able to enable peer-to-peer communications in a coordinated and standard fashion. Field devices with various communication protocols are included in the use case to demonstrate functionalities of OpenFMB in data exchange and traffic control.

OpenFMB will be an extension of substation communication bus to directly interact with field devices. The communication capabilities of a DER are used in this case to change the DER setpoints in order to maintain a loading level (power flow level condition) for the circuit specified by the system operator. The proposed test setup for this use case incorporates OpenFMB based field monitoring, communications, and data management with multiple devices, including:

- Interface to Distribution System Operator (DSO) though a RAMCO[17] device;
- Peer-to-peer communications and monitoring of circuit loading through a CB relay;
- Peer-to-peer communications, monitoring, and control of a utility-scale energy storage system, installed on the circuit under investigation, downstream of the CB;

In addition, the use case incorporates the grid interconnection aspect of the battery energy storage system (BESS) during unintentional islanding. By monitoring the CB status, a direct transfer trip signal is sent to the BESS to cease energization of the circuit. As a feedback signal, the open status of the BESS breaker (or control mode change) will be communicated to the CB relay to enable reclosing as required.

A high-level system diagram including main components involved in this use case is illustrated in Figure 2-57. The dashed lines shows other communication paths that exist, but are not studied in this use case.

[17] Regional Aggregator, Monitor, and Circuit Optimizer.

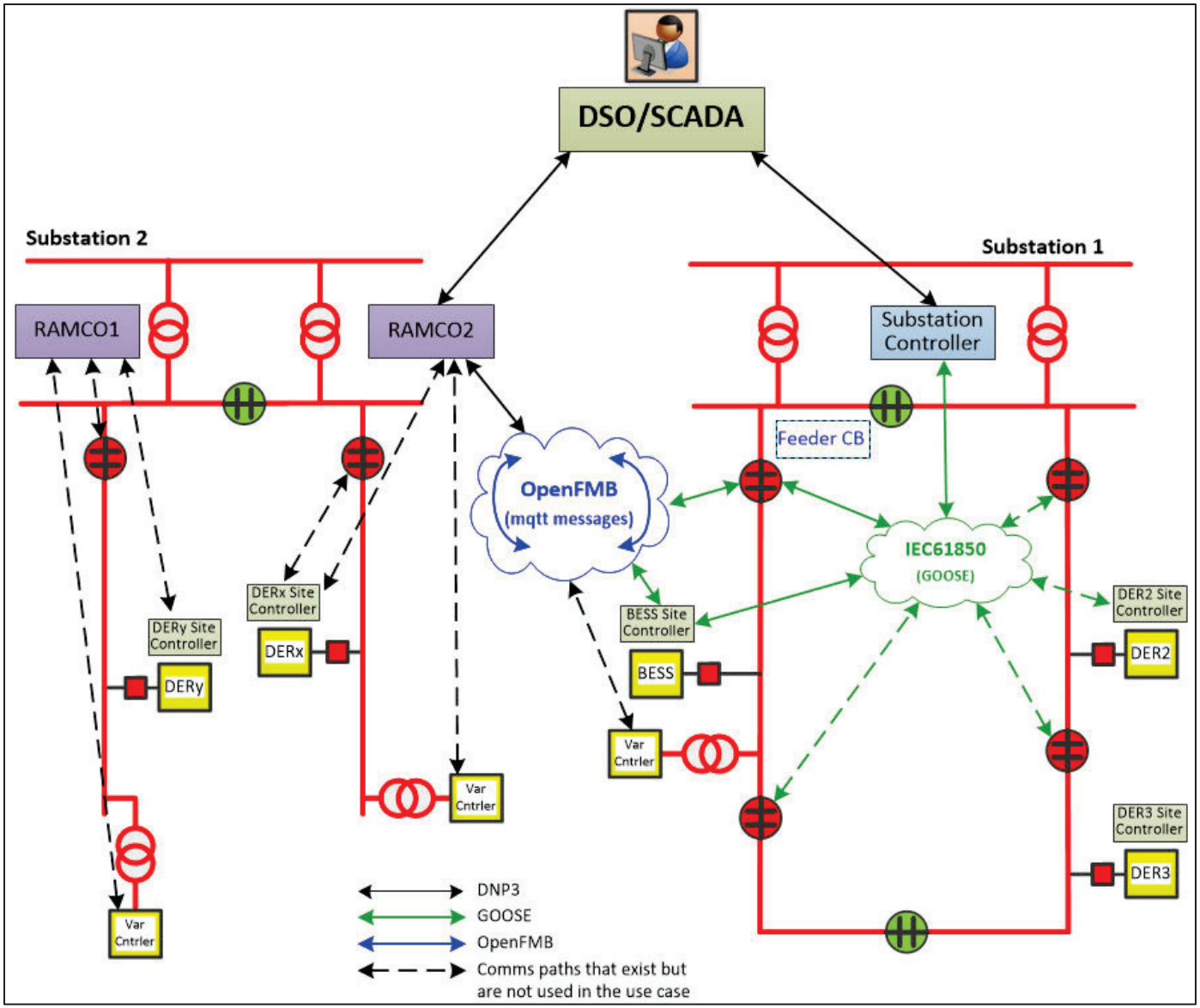


Figure 2-57. A high-level system diagram and data flow for the DELCAM use case

2.8.10.3 Test cases and results

Several test cases were considered to evaluate the performance of this use case and to ensure enhanced operation of the system using OpenFMB communication platform. Table 2-27 lists the tests executed for the evaluation of the DELCAM use case. Due to space limitations, only the results of two test cases will be presented and briefly discussed in the following subsections. The results of additional tests cases are provided in Appendix D.

Table 2-27. DELCAM test cases

Case #	Description	Remark
9.1	DSO/SCADA setpoints are zero, and no power adjustment is requested; Load variations and PV variations are applied; CB power flow follows the changes in the load and PV	Executed for Case 9.2, 9.3, and 9.5/9.6 (3 cases total)
9.2	DSO/SCADA sends initialization, along with setpoints for Interval 1 Interval 1 (early morning): load is the range of 4 to 6 MW and PV production forecast is in the range of 1 to 2 MW CB Setpoint 1: P < 4 MW and Q < 1 Mvar (BESS SOC > 50%)	Low PV profile (1-2 MW) and High Load profile (4-6 MW); trip CCR2-932CW.
9.3	DSO/SCADA sends initialization, along with setpoints for Interval 1 Interval 2 (noon time frame): load is the range of 2 to 3 MW and PV production is strong and expected in the range of 4 to 6 MW CB setpoint 2: P > -1.5 MW and pf is close to 1 (as much as possible)	High PV profile (4-6 MW) and Low Load profile (2-3 MW)
9.4	Due to a fault, CB is tripped; BESS needs to get also disconnected. (evaluate total response time, from CB open to BESS disconnect / change of mode)	Test was repeated five/5 times
9.5	DSO/SCADA sends initialization, along with setpoints for Interval 3 Interval 3 (evening time frame): load is the range of 4 to 6 MW and PV production forecast is low CB Setpoint 3: P < 5 MW and Q < 1 Mvar	No PV profile and High Load profile; P_setpoint is changed to 3 MW; then, Q_setpoint is changed to -2 MW;
9.6	DSO/SCADA sends initialization, along with setpoints for Interval 2 Interval 2 (noon time frame): load is the range of 2 to 3 MW and PV production is strong and expected in the range of 4 to 6 MW CB setpoint 2: P > -2 MW, and -1 MW < Q < 1 MW	High PV profile and Low Load profile; changed Q_setpoint to -2 MW;

In Case 9.3, a high PV profile and a low load profile have been used for the test (noon time frame). In addition, the real/active power setpoint defined by the DSO operator is set at P_{DSO} = –1.5 MW; this means that the RAMCO logic should keep the real power flow of the feeder greater than –1.5 MW. Figure 2-58 shows the real power flow through feeder CB when the BESS is not utilized (RAMCO logic is not activated). This figure indicates that, due to the high PV generation, a significant reverse power flows through this CB (note blue line in Figure 2-58). The goal of this test is to limit the reverse power flow through feeder CB to about –1.5 MW.

Figure 2-59 shows the real power flow of the CB when the RAMCO logic is enabled to adjust the BESS setpoints through OpenFMB platform. The figure also illustrates the plot of the BESS output power during the test. As can be observed in Figure 2-59, the real power of the CB has been regulated to meet the target defined by the DSO operator, i.e., –1.5 MW (note green line in Figure 2-59). This is done through the controlled charging of the BESS located downstream on the CB (see gray line in Figure 2-59).

It is also worth mentioning that, due to the RAMCO processing and calculation time, the target is normally met with a certain delay.

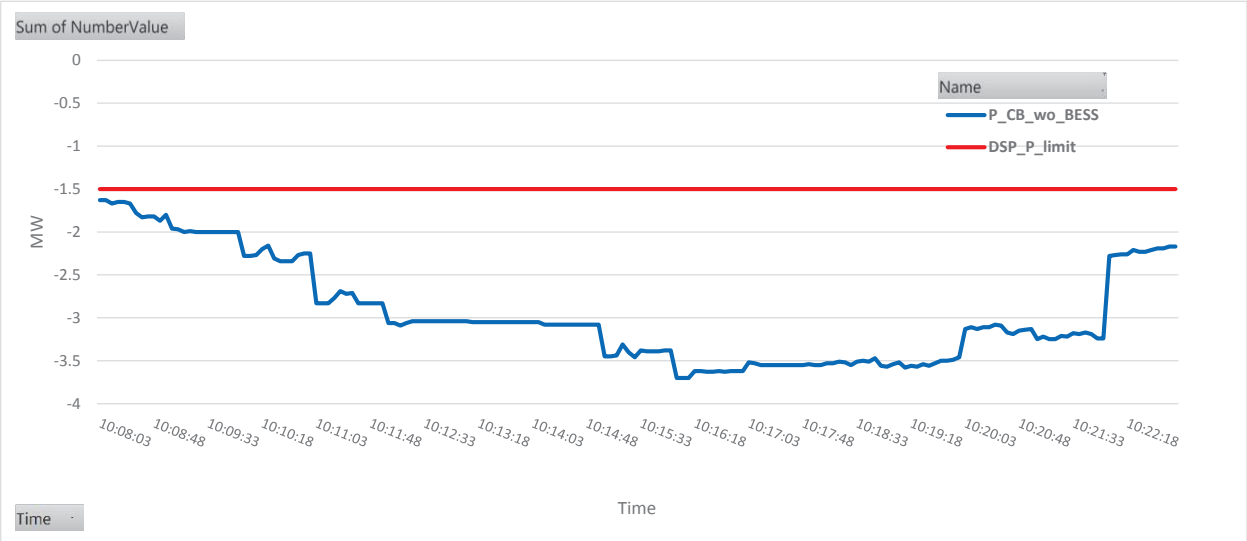


Figure 2-58. Real power flow through feeder CB without BESS contribution (Case 9.3)

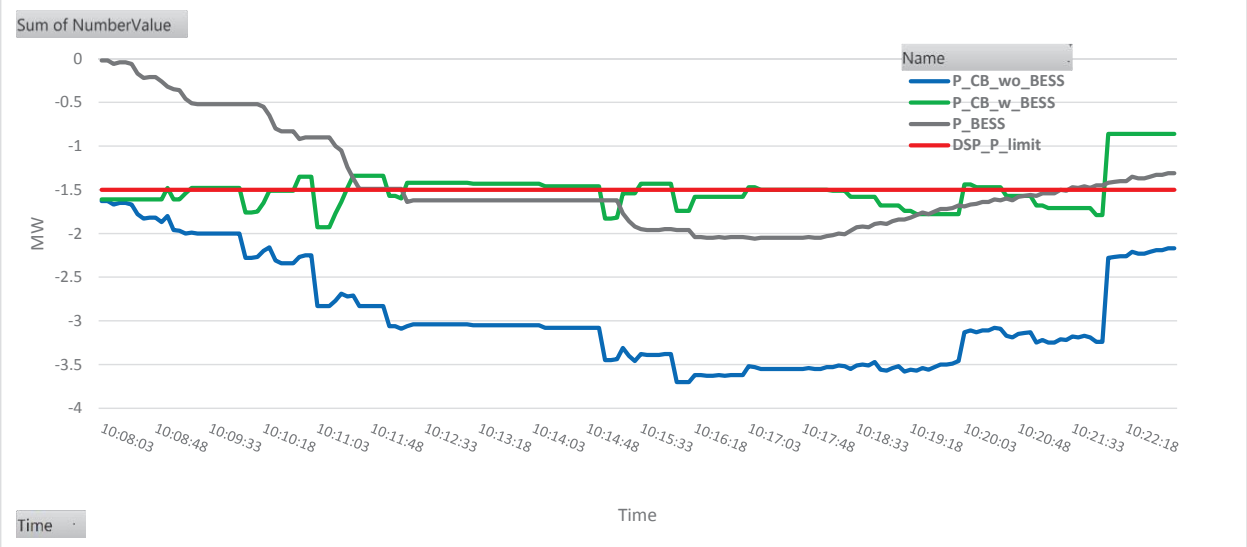


Figure 2-59. Real power flow through feeder CB with BESS contribution through OpenFMB platform (Case 9.3)

In Case 9.2 the situation is low PV profile and high load profile (early morning time frame). In this case, the reactive power target of the DSO (Q_{DSO}) is 1 Mvar , that is, the RAMCO should maintain the reactive power of the circuit below 1 Mvar . Figure 2-60 shows the reactive power flow of the CB when the RAMCO logic is enabled and adjusts the BESS contribution through OpenFMB platform. As can be observed in this figure, the reactive power of the CB is always below the target (1 Mvar), through the

BESS support located downstream on the CB. It should be noted that a Cap Bank is tripped at 10:52 to examine the system performance under transient situations.

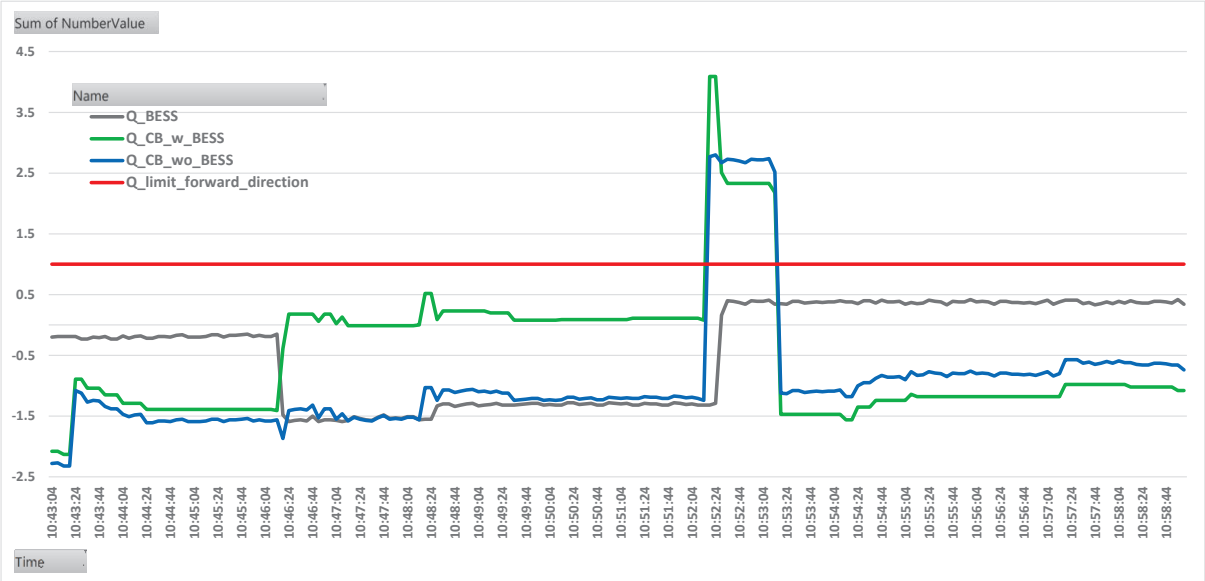


Figure 2-60. Reactive power flow through feeder CB with and without BESS contribution (Case 9.2)

The second category of tests considered in this use case are related to the communication-assisted anti-islanding protection of DERs. The purpose of this category of tests is to determine how long it will take to disconnect a DER from the circuit subsequent to an islanding situation, using OpenFMB communication platform. To that end, the time between the instant that the CB opens until de-energization of the BESS is calculated for several test scenarios. These results are tabulated in the following table for 5 tests:

Table 2-28. Anti-islanding test cases with OpenFMB

Run	Time	Event	Round Trip (s)
1	00:36:24.995 00:36:22.545 00:36:22.545	BESS confirmation received BESS command sent CB Opens	2.45
2	00:44:03.895 00:44:01.846 00:44:01.846	BESS confirmation received BESS command sent CB Opens	2.049
3	00:49:07.546 00:49:05.846 00:49:05.846	BESS confirmation received BESS command sent CB Opens	1.7
4	00:52:19.995 00:52:18.845 00:52:18.845	BESS confirmation received BESS command sent CB Opens	1.15
5	00:54:27.995 00:54:26.545 00:54:26.545	BESS confirmation received BESS command sent CB Opens	1.45
Mean			**1.76**

Table 2-28 shows that the overall time for the anti-islanding protection of DERs are relatively large. In some cases, the time is even more that IEEE standard requirements[18]. This is mainly due to multiple (bi-directions) communication adaptors[19] being employed in the OpenFMB platform. One potential solution is to reduce pooling periods of the adapters (increase pooling frequency); however, the challenge for a large-scale implementation of the platform should be investigated. As will be discussed in next section (Section 2.8.11.3), similar tests will result in quite faster action when IEC 61850/GOOSE is being used for the communication between the CB relay and DER site controller.

2.8.10.4 Findings

The following is a list of findings for the DELCAM use case:

- OpenFMB framework can enable effective utilization of DERs to control the power flow through the feeder breaker on a real-time basis, considering load and (renewable) generation variations.
- The use of OpenFMB framework enables an integrated control system where field and substation devices with various communication protocols can be included in the control scheme (leading to a more optimized control).
- Open FMB enables interoperability with field devices and systems operating in the grid. The framework is compatible with multiple data models, communication protocols, and technologies. However, it should be noted that these are the application requirements that determine the success parameters and also limit the scope in an OpenFMB platform.
- Based on the results of anti-islanding tests, it can be cautiously concluded that OpenFMB communication platform is not suitable for very time-critical applications (such as system protection). This is mainly due to multiple (bi-directions) communication adaptors[20] being employed in the OpenFMB platform. Although the timing can be improved through the use of fast adapters, the challenge for a large-scale implementation of the platform is still valid and should be looked into.

2.8.11 Use Case 10: Dynamic circuit load management

2.8.11.1 Problem statement

As discussed earlier, DERs on circuits can be closely controlled to regulate loading level (power flow level condition) for the circuit specified by the system operator. Dynamic Circuit Load Management (DCLM) use case aims to achieve the same objective as Use Case 9 (see Section 2.8.10), except with the use of IEC 61850 communication protocol. Further, this use case investigates the advantages and disadvantages of using MMS (manufacturing message specification) for communications between the substation gateway and SCADA, as compared to DNP3 (distributed network protocol).

[18] The excising IEEE 1547 standard requires a maximum of 2second operation for DER anti-islanding protection.

[19] In this study, DNP3 has been used as the bridging protocol to main devices utilized in the use case.

2.8.11.2 Description and objectives

This use case mainly focuses on development of an IEC 61850/MMS communication platform between SCADA and substation gateway/controller for monitoring and control of DERs and field devices on distribution circuits. In particular, the communications with field assets including DERs is done through IEC 61850/GOOSE protocol, but the DNP3 communication between the SCADA and substation was replaced with MMS to conduct a comparative analysis.

The proposed test setup for this use case incorporates IEC 61850-based field monitoring, communications, and data management with multiple devices in the test system (see Section 2.8.10.2). The use case also addresses the grid interconnection aspect of the BESS during unintentional islanding. By monitoring the CB status, a signal has to be sent to the BESS to cease energization to the grid when the CB opens. As a feedback signal, open status of the BESS breaker (or control mode change) should be communicated back to the CB relay to enable reclosing as required.

A high-level system diagram including main components involved in the OpenFMB DELCAM use case is illustrated in Figure 2-61. The dashed lines shows other communication paths that exist, but are not studied in this use case.

2.8.11.3 Test cases and results

Several test cases were considered to evaluate the performance of DCLM use case and to ensure enhanced operation of the system using IEC 61850 communication platform.

Table 2-29 lists the tests executed for the evaluation of the DCLM use case.

As shown in last row of Table 2-29, a number of tests were also executed to compare the response time of the MMS communication protocol with the conventional DNP3 protocol (utilized between substation gateway and SCADA center). Similarly, for the sake of brevity, only the results of limited number of cases are presented and discussed in this report. The results of additional tests cases are provided in Appendix D.

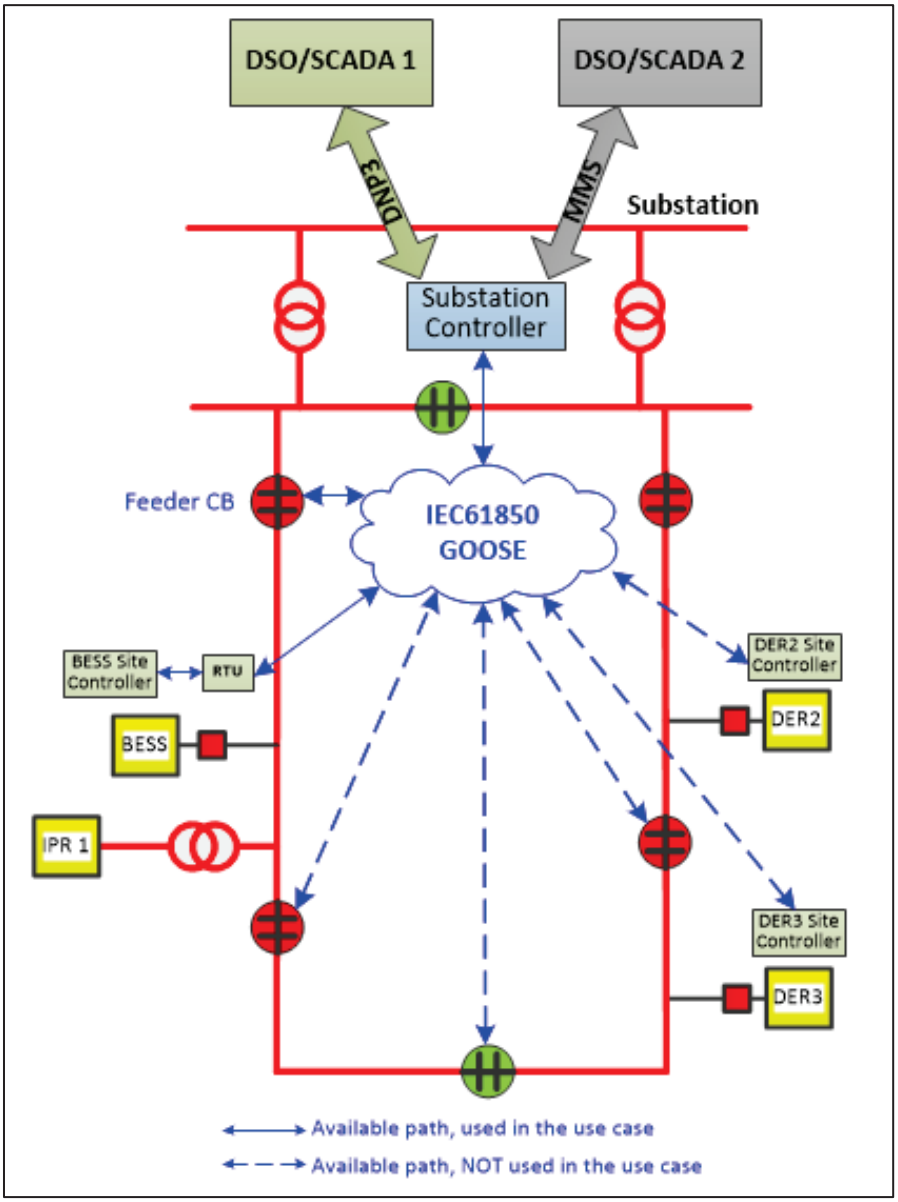


Figure 2-61. A high-level system diagram and data flow for DCLM use case

Table 2-29. DCLM test cases

Case #	Description	Remark
10.1	DSO/SCADA setpoints are zero, and no power adjustment is requested; Load variations and PV variations are applied; CB power flow follows the changes in the load and PV.	
10.2	DSO sends initialization, along with setpoints for Interval 1; Interval 1 (early morning): load is the range of 4 to 6 MW, and PV production forecast is the range of 1 to 2 MW; CB Setpoint 1: P < 4 MW, and 0 < Q < 1 Mvar BESS SOC > 50% (BESS size is 2 MW)	Low PV profile (1-2 MW) and High Load profile (4-6 MW)
10.3	Interval 2 (noon time frame): load is the range of 2 to 3 MW, and PV production is strong and expected in the range of 4 to 6 MW CB setpoint 2: P > -1.5 MW, and pf close to 1 (as much as possible)	High PV profile (4-6 MW) and Low Load profile (2-3 MW)
10.4	Due to a fault, CB is tripped; BESS needs to be also disconnected. (evaluate total response time, from CB open to BESS disconnect or change of mode)	Test was repeated five/5 times
10.5	CB is reclosed (circuit is restored) DSO sends initialization, and performs control based on the prevailing system conditions (upon the control mode change to DCLM)	
10.6	Interval 3 (evening time frame): load is the range of 4 to 6 MW, and PV production forecast is very low CB Setpoint 3: P < 5 MW, Q < 1 Mvar	No PV profile and High Load profile.
10.7	Comparison of response times of MMS and DNP3 communication protocols for monitoring and control through SCADA	Several tests

Case 10.2 presents the case of a low PV profile and a high load profile (morning time frame). The real and reactive power setpoints, which are defined by the DSO operator, are set at P_{DSO} = 4 MW and 0 Mvar < Q_{DSO} <1 Mvar , respectively. Thus, the RAMCO logic aims at keeping the real power flow of the feeder smaller than 4 MW while maintaining the reactive power close to zero.

Figure 2-62 shows the real power flow through feeder CB with and without the BESS contribution (with and without RAMCO logic enabled). The BESS contribution (P) as well as the real power limit (P_Upper_Limit) are also shown in this figure. As can be clearly seen in Figure 2-62, the BESS contribution has always made the feeder real power to be smaller than 4 MW, which is the DSO target.

Figure 2-63 shows the reactive power flow through feeder CB with and without the BESS contribution (with and without RAMCO logic enabled). The BESS contribution (Q) as well as the reactive power limit (Q_Upper_Limit) are also shown in this figure. It is evident from Figure 2-63 that the BESS has absorbed reactive power (at its maximum capacity) to bring the feeder reactive power within the limit defined by the DSO operator. In time frames when the RAMCO cannot meet the target, it will send the additional required power (Delta_Q) to the DSO.

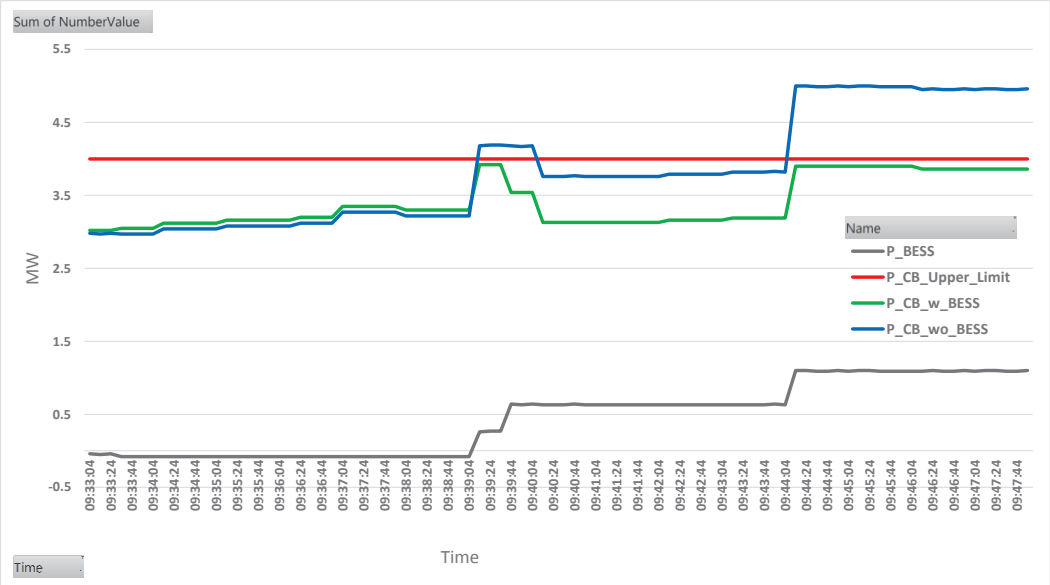


Figure 2-62. Real power flow through feeder CB with and without BESS contribution (Case 10.2)

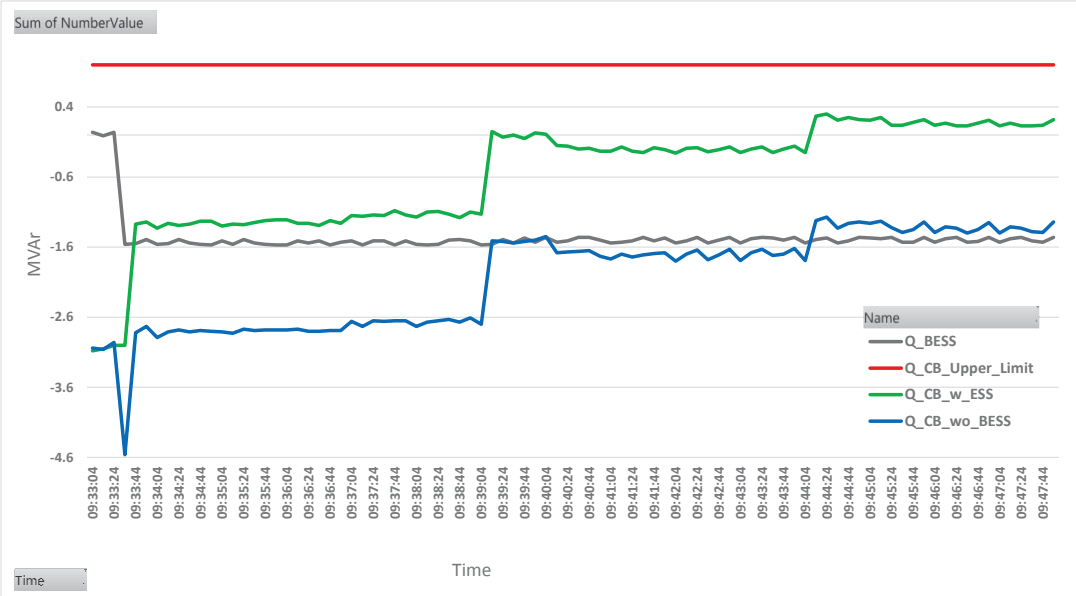


Figure 2-63. Reactive power flow through feeder CB with and without BESS contribution (Case 10.2)

Anti-islanding protection tests were conducted to determine how long it will take to disconnect a DER from the circuit subsequent to an islanding situation, using IEC 61850 communication platform (GOOSE). Thus, the time between the instant the CB opens until de-energization of the BESS is calculated for several test scenarios. These results are tabulated in the following table for five tests:

Table 2-30. Anti-islanding test cases with IEC 61850

Run	Round trip time (ms)	Remark
1	392.1	BESS discharging, and RTAC is in the loop
2	392.3	BESS discharging, and RTAC is in the loop
3	491.4	BESS discharging, and RTAC is in the loop
4	372.8	BESS charging, and RTAC is in the loop
5	412.1	BESS charging, and RTAC is in the loop
Mean	**412.2 (ms)**	

Table 2-30 shows promising results for an IEC 61850-based anti-islanding protection scheme. This is worth noting that the results of Table 2-30 are for the case where substation controller (RTAC) is in the loop (to change the control mode[21]) and, thus, it is not a fully peer-to-peer communication. It is expected that a peer-to-peer communication can further decrease the operating time (approximately to half). However, even with the existing setup, an IEC 61850-based scheme is about 4 to 5 times faster than an OpenFMB-based one.

As mentioned earlier, a set of tests were also conducted to compare the round trip time of the MMS communications with DNP3 communications, when utilized between the substation gateway and SCADA. Figure 2-64 shows the overall system setup for comparing these two communication protocols (between SCADA system and substation controller). As shown in this figure, a software interface or a middleware (Triangle software) has been employed between the substation gateways and SCADA as a converter for traditional SCADA system. The middleware is used for both test scenarios (MMS and DNP3) to make the test conditions as similar as possible.

To remove the variable impact of the latency associated with communications downstream of the Substation Controller, the downstream devices were bypassed as shown in Figure 2-65 below. Both DNP 3.0 and MMS messages were internally looped in the substation controller. The round trip times for both setpoints and commands were measured with MMS and DNP3 communications in place, separately.

Table 2-31 reports a summary of results for several test cases executed to calculate the round trip times of DNP3 and MMS communications. It is evident from the results that the difference between the response times are negligible (2.463 ms for DNP3 vs 2.503 ms for MMS). It should, however, be acknowledged that the engineering process for MMS communication protocol is simpler that that with DNP3 communication protocol (assuming a system with native support for IEC 61850 is available).

[21] Since there was no access to the CB of the BESS, control mode change has been selected as an alternative option. However, authors acknowledge that this may slightly affect the final results.

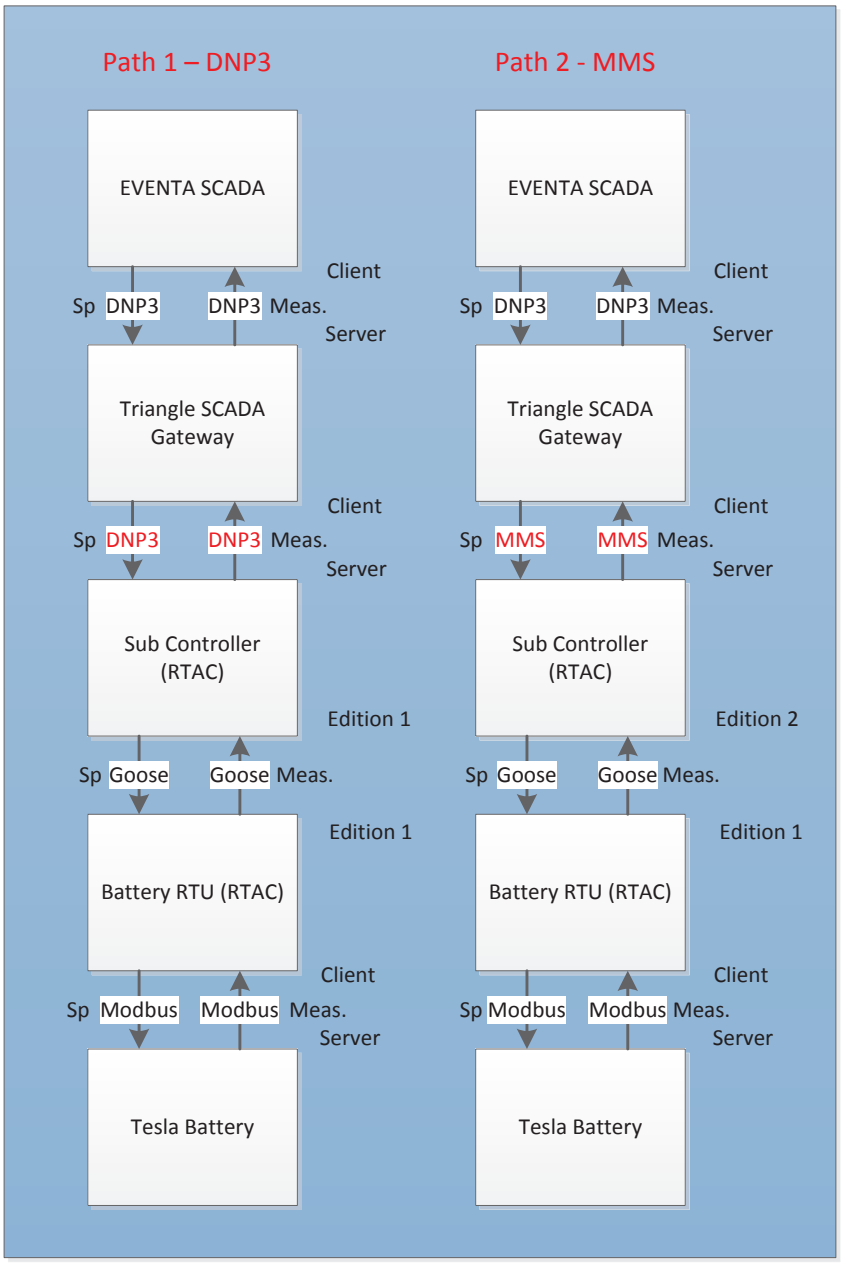


Figure 2-64. Overall system setup for comparing MMS and DNP3 communication protocols

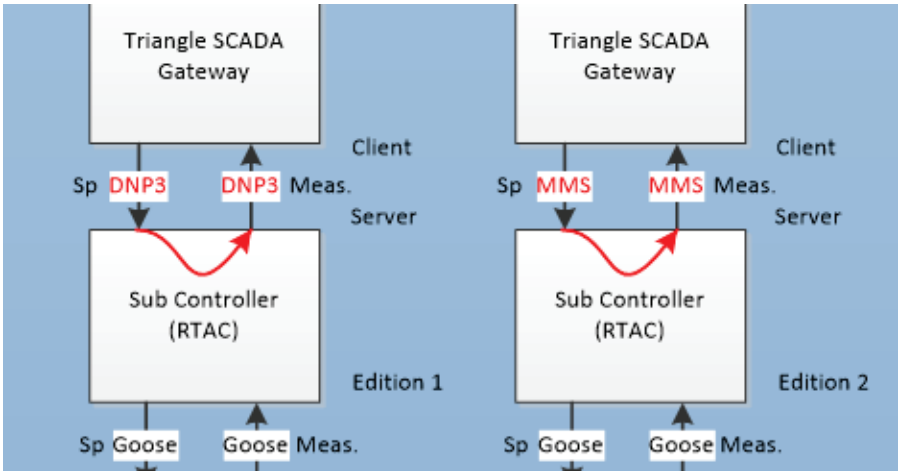


Figure 2-65. Test condition for comparison between MMS and DNP3 protocols

Table 2-31. Test results round trip time of MMS and DNP3

Data Point Name	Event Time Stamp	Time (ms)	Loop Time (ms)	Event Time Stamp	Time (ms)	Loop Time (ms)
	DNP3			MMS		
RTAC.BattPSp_Batt1	Nov 02 2017 17:41:50.568	63710.568	2.787	Nov 02 2017 13:14:35.977	47675.977	2.884
RTAC.BattPmeas_Batt1	Nov 02 2017 17:41:53.355	63713.355		Nov 02 2017 13:14:33.093	47673.093	
RTAC.BattPSp_Batt1	Nov 02 2017 17:41:38.713	63698.713	2.641	Nov 02 2017 13:14:24.990	47664.99	2.584
RTAC.BattPmeas_Batt1	Nov 02 2017 17:41:41.354	63701.354		Nov 02 2017 13:14:22.406	47662.406	
RTAC.BattPSp_Batt1	Nov 02 2017 17:41:28.472	63688.472	2.865	Nov 02 2017 13:14:12.994	47652.994	2.581
RTAC.BattPmeas_Batt1	Nov 02 2017 17:41:31.337	63691.337		Nov 02 2017 13:14:10.413	47650.413	
RTAC.BattPSp_Batt1	Nov 02 2017 17:41:13.291	63673.291	2.086	Nov 02 2017 13:14:02.012	47642.012	2.423
RTAC.BattPmeas_Batt1	Nov 02 2017 17:41:15.377	63675.377		Nov 02 2017 13:13:59.589	47639.589	
RTAC.BattPSp_Batt1	Nov 02 2017 17:41:01.673	63661.673	1.664	Nov 02 2017 13:13:29.976	47609.976	2.435
RTAC.BattPmeas_Batt1	Nov 02 2017 17:41:03.337	63663.337		Nov 02 2017 13:13:27.541	47607.541	
RTAC.BattPSp_Batt1	Nov 02 2017 17:40:49.625	63649.625	1.72	Nov 02 2017 13:13:18.990	47598.99	2.776
RTAC.BattPmeas_Batt1	Nov 02 2017 17:40:51.345	63651.345		Nov 02 2017 13:13:16.214	47596.214	
RTAC.BattPSp_Batt1	Nov 02 2017 17:40:33.369	63633.369	1.988	Nov 02 2017 13:13:04.975	47584.975	2.425
RTAC.BattPmeas_Batt1	Nov 02 2017 17:40:35.357	63635.357		Nov 02 2017 13:13:02.550	47582.55	
RTAC.BattPSp_Batt1	Nov 02 2017 17:39:14.849	63554.849	2.486	Nov 02 2017 13:12:54.991	47574.991	2.897
RTAC.BattPmeas_Batt1	Nov 02 2017 17:39:17.335	63557.335		Nov 02 2017 13:12:52.094	47572.094	
RTAC.BattPSp_Batt1	Nov 02 2017 17:38:44.145	63524.145	3.193	Nov 02 2017 13:12:42.005	47562.005	2.271
RTAC.BattPmeas_Batt1	Nov 02 2017 17:38:47.338	63527.338		Nov 02 2017 13:12:39.734	47559.734	
RTAC.BattPSp_Batt1	Nov 02 2017 17:38:23.393	63503.393	1.902	Nov 02 2017 13:12:32.128	47552.128	2.988
RTAC.BattPmeas_Batt1	Nov 02 2017 17:38:25.295	63505.295		Nov 02 2017 13:12:29.140	47549.14	
RTAC.BattPSp_Batt1	Nov 02 2017 17:38:00.559	63480.559	2.752	Nov 02 2017 13:12:22.098	47542.098	2.307
RTAC.BattPmeas_Batt1	Nov 02 2017 17:38:03.311	63483.311		Nov 02 2017 13:12:19.791	47539.791	
RTAC.BattPSp_Batt1	Nov 02 2017 17:37:39.080	63459.08	2.206	Nov 02 2017 13:12:10.085	47530.085	1.953
RTAC.BattPmeas_Batt1	Nov 02 2017 17:37:41.286	63461.286		Nov 02 2017 13:12:08.132	47528.132	
RTAC.BattPSp_Batt1	Nov 02 2017 17:37:24.785	63444.785	1.512	Nov 02 2017 13:11:58.060	47518.06	2.022
RTAC.BattPmeas_Batt1	Nov 02 2017 17:37:26.297	63446.297		Nov 02 2017 13:11:56.038	47516.038	
RTAC.BattPSp_Batt1	Nov 02 2017 17:37:13.465	63433.465	3.853	Nov 02 2017 13:11:46.061	47506.061	2.776
RTAC.BattPmeas_Batt1	Nov 02 2017 17:37:17.318	63437.318		Nov 02 2017 13:11:43.285	47503.285	
RTAC.BattPSp_Batt1	Nov 02 2017 17:37:05.986	63425.986	1.311	Nov 02 2017 13:11:32.081	47492.081	2.363
RTAC.BattPmeas_Batt1	Nov 02 2017 17:37:07.297	63427.297		Nov 02 2017 13:11:29.718	47489.718	
RTAC.BattPSp_Batt1	Nov 02 2017 17:36:54.343	63414.343	2.952	Nov 02 2017 13:11:18.103	47478.103	3.032
RTAC.BattPmeas_Batt1	Nov 02 2017 17:36:57.295	63417.295		Nov 02 2017 13:11:15.071	47475.071	
RTAC.BattPSp_Batt1	Nov 02 2017 17:36:44.487	63404.487	2.813	Nov 02 2017 13:11:06.094	47466.094	3.107
RTAC.BattPmeas_Batt1	Nov 02 2017 17:36:47.300	63407.3		Nov 02 2017 13:11:02.987	47462.987	
RTAC.BattPSp_Batt1	Nov 02 2017 17:36:33.689	63393.689	3.596	Nov 02 2017 13:10:52.099	47452.099	2.557
RTAC.BattPmeas_Batt1	Nov 02 2017 17:36:37.285	63397.285		Nov 02 2017 13:10:49.542	47449.542	
Average Time (ms)	2.463			2.503		

2.8.11.4 Findings

The following is a list of findings for the DCLM use case:

- IEC 61850 communication protocol can enable effective utilization of DERs to control the power flow through the feeder breaker on a real-time basis, considering load and (renewable) generation variations. Also, the results of several tests showed that, for supervisory control actions when time responses are not very critical, both OpenFMB and IEC 61850 can provide a communication platform to achieve satisfactory performances.
- Based on the results of anti-islanding tests, it can be concluded that IEC 61850 communication platform enables very fast actions to time-critical applications (such as system protection).
- Comparing the MMS and DNP3 communication for data monitoring and supervisory actions shows that
    - The response times of these two communication protocols are comparable (no significant difference was observed).

- Since the data point are available in an IEC 61850-base system, the mapping between the substation gateway and SCADA is relatively simple with MMS (as compared to DNP3). However, any change in the number of data point should be done through the substation configuration tool (SCT).

2.8.12 Use Case 11: Volt-var control via OpenFMB

2.8.12.1 Problem statement

Granular reactive power management through DERs as well as localized secondary voltage control with static voltage regulators, such as GridCo devices, can provide potential solutions to voltage fluctuations in distribution circuits dominated by DERs. The secondary voltage control devices are deployed at any location that (i) there is a need for voltage quality enhancement and/or (ii) there are residential and/or small commercial PVs and BESSs connected to a service transformer. However, the setting of these devices should be defined centrally to ensure optimum system performance.

Two major challenges to achieve this objective in DER-dominated circuits are:

(1). Control and operation of large number of DERs that are distributed along the circuits, and
(2). Remote communications with field DERs and secondary static voltage regulators.

2.8.12.2 Description and objectives

The main objective of this use case is to investigate capabilities of OpenFMB communication platform for managing the communications among various field devices (primarily, DERs and secondary GridCo units). The new architecture should be able to enable peer-to-peer communications in a coordinated and standard fashion. Field devices with various communication protocols are included in the use case to evaluate and demonstrate functionalities of OpenFMB in data exchange and traffic (data flow) control.

This use case incorporates development of an OpenFMB communication platform for monitoring and control of DERs and secondary devices on distribution circuits. The communication capabilities of the DER are also used to change their reactive power (Q) setpoints in coordination with load variations and changes in circuit conditions. The voltage and reactive power setpoints for secondary circuits are provided through control center operator.

The proposed test setup for this use case includes OpenFMB based field monitoring, communications, and data management with multiple devices, including:

- Interface to DSO though a RAMCO device,
- Peer-to-peer communications and monitoring of circuit loading through a CB relay,
- Peer–to-peer communications, monitoring and control of a utility-scale energy storage system, installed on the circuit under investigation downstream of the CB,
- Communications and control command exchange with a GridCo device dedicated to manage voltage, reactive power, and DERs on a secondary system that has multiple DERs[22].

[22] GridCo interface is done through a Localized Residential Aggregator and Monitor (LRAM) at service transformer.

This use case deals with reactive power management of one BESS unit, and voltage/reactive power control of one set of secondary systems. The Gridco device manages voltage and reactive power of secondary system, through a localized residential aggregator and monitor (LRAM) controller.

A high-level system diagram including main components involved in the OpenFMB DELCAM use case is illustrated in Figure 2-66. The dashed lines shows other communication paths that exist, but are not studied in this use case. It is noted that, as opposed to Use Case 9 (Figure 2-57), communication with one of the GridCo devices is essential in this use case.

2.8.12.3 Test cases and results

The goal of this use case is to effectively control DERs and secondary static voltage regulators for improved voltage profile within distribution circuits. In particular, the reactive power setpoint of the BESS as well as voltage reference setpoint of the GridCo device are controlled in order to regulate feeder voltage at both primary and secondary levels, respectively.

The test cases listed in Table 2-32 were conducted to evaluate the performance of this use case and to ensure enhanced operation of the system using OpenFMB communication platform. In addition to load and (renewable) generation variations, the test cases consider transient events such capacitor bank tripping to thoroughly examine the use case. While the results of a selected number of cases are presented and briefly discussed in this section, the results of additional tests cases are provided in Appendix D.

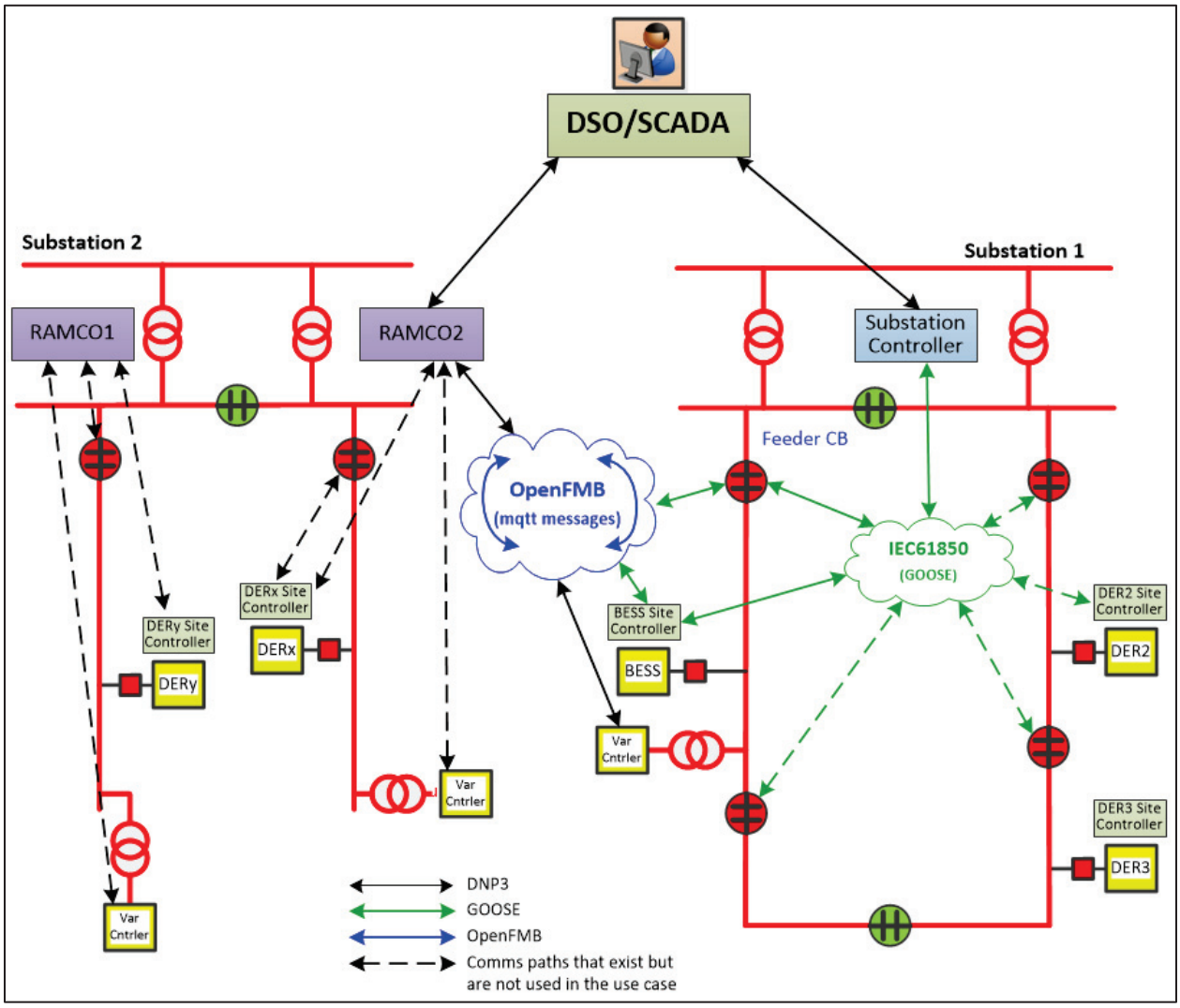


Figure 2-66. A high-level system diagram and data flow for VVM use case

Table 2-32. VVM test cases

Case #	Description	Remark
11.1	DSO setpoints are zero, and no power adjustment is requested; Load variations and PV variations are applied; Voltage are at normal range (120V for GridCo). GridCo has pf =1, Voltage and Q control mode CB power flow follows the changes in the load and PV	
11.2	DSO sends initialization for new mode, and setpoints for Interval 1 Interval 1 (early morning): load is the range of 4 to 6 MW PV production forecast is around 1 to 2 MW Voltage reduction by 2%	Low PV profile (1-2 MW) and High Load profile (4-6 MW); voltage reduction command (2%) was sent 4 minutes after; CCR2-932CW was then tripped;
11.3	Interval 2 (noon time frame): Load is the range of 2 to 3 MW, and PV production is strong and expected in the range of 4 to 6 MW Start with voltage reduction by 4% (to avoid overvoltage)	High PV profile (4-6 MW) and Low Load profile (2-3 MW); voltage reduction (4%) was issued 3 minutes after; CCR2-932CW was turned on later; then, CCR2-932CW and CCR2-921CW were tripped; voltage increase (2%) was sent 13 minutes after;
11.4	Interval 3 (evening time frame): load is the range of 4 to 6 MW, and PV production forecast is low Voltage increase by 2%	No PV profile and High Load profile (4-6 MW); voltage increase (2%) was sent 5 minutes after; CCR2-919CW was tripped later.

The following set of transient incidents were also applied to the system in this case to further evaluate the response of the control system:

- Voltage reduction command (4%) at 16:50
- Connect CCR2-932CW Cap Bank at 16:53
- Trip CCR2-932CW and CCR2-921CW Cap Banks at 16:55
- Voltage increase command (2%) at 16:59

For some of the scenarios described above (e.g., Points 1 and 2), the BESS has reached its maximum reactive power capacity (–1.6 Mvar) and, thus, it cannot contribute further. However, when required, the RAMCO logic calculate the additional reactive power required (Delta_Q) and send it back to the DSO (note gray line in Figure 2-67). It is also observed that when the voltage increase command is sent to the RAMCO (from DSO), the RAMCO has adjusted BESS setpoint to make a leading power factor at the feeder level (see red line around 16:59, Figure 2-67).

Figure 2-68 shows the reference and measured voltage of the secondary voltage regulator (GridCo device) for Case 11.3. The figure indicates that the static voltage regulator has successfully regulate the voltage of the secondary side of the service transformer.

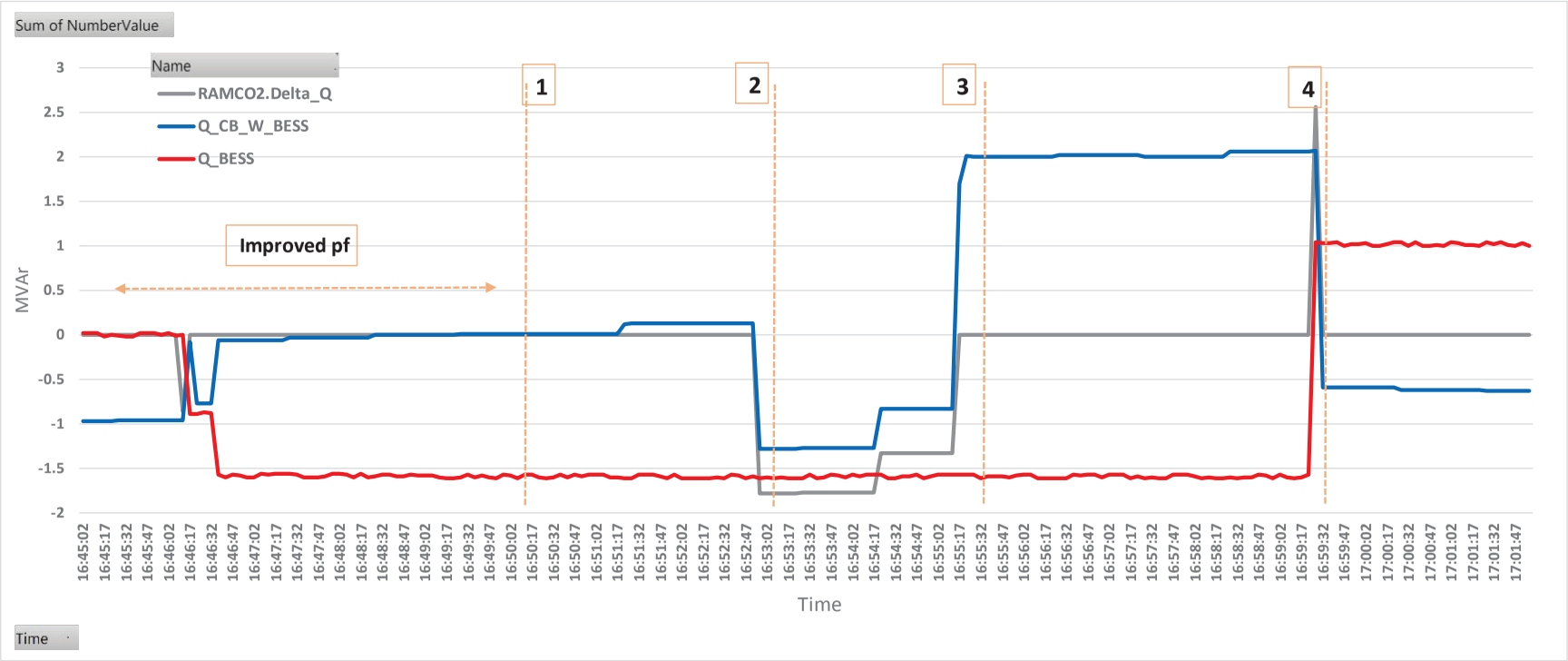


Figure 2-67. Reactive power flow through feeder CB with and without BESS contribution (Case 11.3)

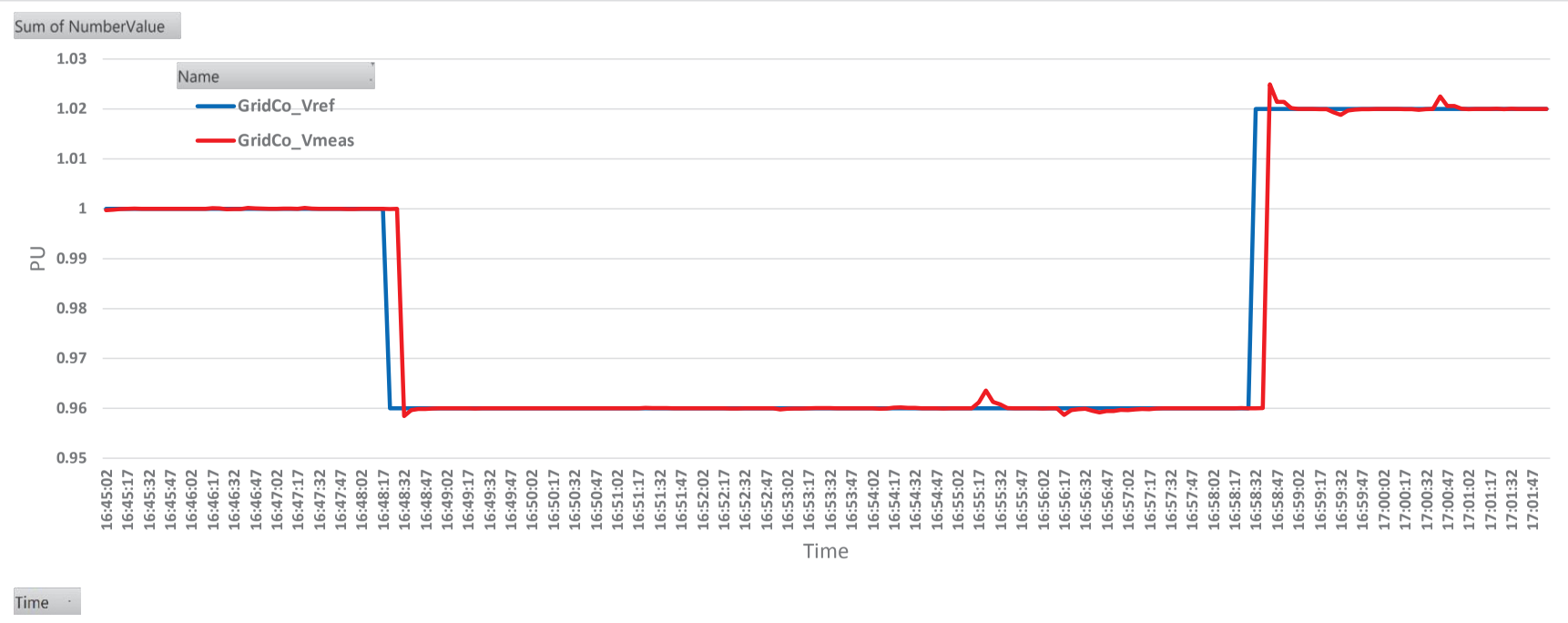


Figure 2-68. Voltage reference for GridCo device (Case 11.3)

2.8.12.4 Findings

The following is a list of findings for the DCLM use case:

- OpenFMB framework can enable effective utilization of DERs and secondary static voltage regulators to control the voltage of distribution feeders on a real-time basis, considering load and (renewable) generation variations.
- The use of OpenFMB framework enables an integrated control system where field and substation devices with various communication protocols can be included in the control scheme (resulting in a more optimized control).
- Open FMB enables interoperability with field devices and systems operating in the grid. The framework is compatible with multiple data models, communication protocols, and technologies. Further, the requirements of this application (use case) can be met using OpenFMB as the communication platform.

2.9 Phase 4 – SDG&E Internal Project Work Prior to Project Conclusion

Task 1 – Comprehensive Final Report

Objective – Develop comprehensive final report

Approach - Develop a comprehensive final report based on the CPUC EPIC Final Report guideline developed by the three IOUs. The report presented in this document follows the outline developed by the IOUs to share the results of the project undertaken.

Output – Comprehensive final report as presented in this document.

Task 2 – Technology Transfer

Objective – Develop technology transfer plan to share results with all stakeholders.

Approach – A technology transfer plan was developed to share the results with SDG&E stakeholders and with other stakeholders in the industry that would benefit from this pre-commercial demonstration

Output – Technology transfer plan as documented in Section 4.2 of this report.

3 FINDINGS

The subsections that follow summarize the primary findings from both phases of the project.

3.1 Challenges observed in SDG&E's current architecture

The primary architectural challenges observed were:

- **Parallel communication paths**. In some instances there are multiple communication paths from control center entities to the same physical location stemming from restrictions of the existing communication infrastructure, and desire to separate daily operations from experimental and pilot technologies.
- **Time domain separation**. There are functions that require a certain speed of response that are being performed at locations in the architecture that make it challenging to obtain deterministic levels of performance.
- **Centralized decision making**. The architecture is highly centralized, which places restrictions on the speed of response and limits the ability to perform distributed autonomous actions.
- **Communications infrastructure**. The absence of a high speed communication backbone to substation and field devices places restrictions on the type of devices and data that can be integrated into the system.
- **Duplication of functions**. The planned architecture contains some duplication of functions, like Volt/var control for example, with multiple entities identified as being responsible for this application. This may be just a matter of finalizing the correct "owner" for the application, but having the same or similar application in multiple locations is problematic.
- **Roles and responsibilities**. The existing architectural documentation did not map functions to stakeholders and responsible parties. The RACI analysis for this Smart Grid Architecture Demonstration Project has now established a map of existing roles and responsibilities.
- **DER integration**. DER devices are integrated into the architecture but more as one-offs or pilots than a large scale deployment.
- **Scalability**. There is a concern whether the architecture as currently envisaged can scale adequately, both in terms of increased DER penetration as well as the ability to manage more autonomous functions given the highly centralized nature of the design.

3.2 Most appropriate architectural model for SDG&E's future use

The following architectural models were examined:

- CEN-CENELEC-ETSI Smart Grid Coordination Group's SGAM architecture
- IEC's TC-57 reference architecture
- GridWise Architecture Council's Gridwise Architecture
- EPRI's Integrated Energy and Communications Systems Architecture (Intelligrid) architecture
- PNNL/DOE's Grid Architecture Initiative
- SCE, IBM, and Cisco's Smart Grid Reference Architecture
- IEEE's P2030
- NIST/SGIP's Smart Grid Conceptual Model
- Microsoft's Smart Energy Reference Architecture

The SGAM model was selected as the best fit for SDG&E because of its capability to relate the technical layers with business goals, as well as define use cases in relation to their impact on all key layers. The main reasons for choosing SGAM were as follows:

- SGAM was evaluated as the most comprehensive reference architecture for use case development because it incorporates business, function, information, communication, and component layers.
- SGAM builds on existing architectures such as the NIST Conceptual Model (NIST 2009), the GridWise Architecture Framework (GWAC 2008), as well as architecture standards like TOGAF and Archimate, which allows reuse of existing models
- It is possible to map the TC57 in the communication and information layers of SGAM.
- The relatively recent NIST Special Publication 1108r3 (September 2014), advocates the SGAM reference architecture as "a template for architects to follow while building aspects of a smart grid architecture, regardless of an architect's specialty (such as areas of transmission, distribution, IT, back office, communications, asset management, and grid planning." So that endorsement lent additional credibility to the selection.

3.3 Trends in communications standards development

The industry has many standards that exist among several standards development organizations that may be applicable to multiple layers of the power systems architecture. The key goal is to identify the standards that can be tailored to support SDG&E's specific requirements and use cases. The NIST/SGIP activities maintaining the Catalog of Standards, as well as IEC TC57 work provides a well-tested source of standards for consideration in SDG&E's distribution system architecture.

A key standard is the IEC 61850 protocol suite. The extent of harmonization efforts that have included IEC 61850 show that the suite is becoming a key building block in the future smart grid architecture.

3.4 Roadmap for proposed architecture implementation

A 10-year implementation time frame is expected for near full deployment. The general activities required to migrate to the proposed architecture in the context of the SGAM layers include:

- **Component layer***:* Mitigate parallel operations and facilitate more distributed control through implementation of pro-active direct SCADA control incorporating DERMS and peer-to-peer field device communication. A DSO server may be added to negotiate DER integration and control.
- **Communications applications layer**: Implement the IEC 61850 standard for transport and applications interfaces to support use cases (including IEC 61850-8-1 (GOOSE), IEC 61850-7-2). IEC 61850 also utilizes adapters capable of interfacing other standard protocols such as DNP3, MultiSpeak, C37.118, etc. Interfaces to legacy protocols such as SCOM are to be determined.
- **Information layer**: Implement standardized approach to information exchange utilizing IEC 61850, IEC 61968/61970, etc. This would include document/drawing files, XML files, IEC 61850-7-3, 7-4 Object Models, IEC 61850-6 Engineering, especially to support use cases.
- **Functional layer**: Modify existing baseline Distribution Operations functions to account for changes driven by more direct SCADA control and more prevalent use of DER integration at the feeder level:
  - Asset Condition-based Monitoring

        - Designing, Engineering, building, commissioning, and maintaining IEC 61850 compliant protection and automation systems
        - Maintenance testing of IEC 61850 compliant relay/IED
    - Feeder Protection
        - Breaker failure scheme with GOOSE messaging
        - Automatic Transfer scheme using GOOSE messages
        - Protection Coordination with IEC 61850 (including anti-islanding protection of DERs, reclosing/relaying operation, enhanced operation of feeder protection
    - DER Control (Feeder connected)[NOTE: this is in addition to existing Distribution Operations function of DER control(generation/storage)
        - Remotely change control mode of DER (IEC 61850)
        - Using multiple large scale DERs, correct feeder power factor/improve feeder voltage; coordinated use of ride-through capabilities to enhance system performance under network faults and/or transient disturbances
    - Load management (emergency)
        - Effective utilization of DER contributions to offset customer loads
    - System Load Forecasting (high level)
        - Incorporate DER resources into day-ahead and short-term forecasts
- **Business layer:** Review baseline roles and responsibilities and consider business area realignments relating to new functions from DER use cases, and potential other modifications based on gaps discovered during baseline RACI analysis:
    - Definition of market services including DSO responsibilities
    - Siloed operations in alarm processing, data management, data analytics
    - For a single function, assignments of accountability or responsibility to multiple entities

Any legacy or proprietary protocols or information models should be transitioned to a more standards based approach over time to realize the full economies and advantages of a standardized reference architecture.

3.5 Engineering an IEC 61850 system

The test cases performed in use case 1 comparing the tasks required to construct an IEC 61850-based solution versus a traditional solution using DNP 3.0 with hardwired interconnections between IEDs show that, overall, the steps are similar. However, there is a significant difference in the effort to engineer and test the two systems. The IEC 61850 approach relies on virtual interconnections and offers the ability to test the logic and automation as they are being engineered and parametrized, as opposed to waiting for physical switchgear to be assembled and tested. This “real-time” testing during the engineering process reduces the time required for factory and site testing, as well as that for equipment start-up and commissioning.

The configuration inheritance and use of descriptive data point naming supported by IEC 61850 (as opposed to the much more limited and opaque digital, analog and control input/output numbering supported by conventional protocols) also makes the tasks of configuring gateways and substation Human Machine Interfaces (HMIs) considerably easier when contrasted to the conventional approach.

However, use case 1, and the overall process of configuring the system for the configuration employed on this project with IEDs from multiple different vendors, was still not a simple task. There were several issues related to interoperability between the devices that needed to be solved that added to the engineering effort that would not have been required on a simpler, conventional system. The added features provided by IEC 61850, specifically those related to the peer-to-peer GOOSE message exchange, come at the cost of added configuration complexity. The issues encountered included the following:

- The configuration tools provided by the vendors of the various IEDs had widely different levels of capabilities in terms of being able to integrate data from other vendor's products. This led to a separate analysis on engineering tools that is presented in Appendix B.
- It was necessary to find a mechanism to document which IEDs were publishing which data via GOOSE, and which IEDs were subscribing for, and using, these data. In the absence of a tool that did this, the team created an Excel spreadsheet to document this matrix, but it was a non-ideal solution and more work is required in this area by the vendors. This is also addressed in Appendix B.
- Different vendors used different names to refer to the same data point. There are some areas where the standard is open to interpretation and implementations differ from one vendor to the next. There was even one instance of two IEDs from the same vendor having different names for the same data type.
- Initially, the project goal was to set up a fully functional IEC 61850 Edition 2 system following the latest implementation of the standard. Unfortunately, this proved impossible because some of the selected devices only supported Edition 1. In theory, Edition 2 devices will interface with Edition 1 devices (although the reverse is not true). Unfortunately, reality and theory proved to be two different things and numerous problems were experienced, especially in the area of GOOSE messaging and set-up. As a result, the project was forced to "downgrade" some devices to Edition 1 to ensure interoperability.
- One of the vendors had an issue that any changes to the publisher/subscriber setup required the setup to be cleared and re-imported, but this would also erase some of the communication parameters, necessitating re-entry.
- Some IEDs were incapable of subscribing to analogue points, making it impossible to use them in applications where the IED had to be able to monitor analogue values to make decisions and take actions.
- One of the vendor's configuration tool created a configuration output file (the CID file) that contained not only selected data set to be published, but all available data. Several other bugs were detected and communicated to the vendor, leading to the conclusion that the vendor had not deployed many (any?) IEC 61850 IEDs to date.

As described above, the project team experienced several challenges related to inter-vendor interoperability. The team also observed limitations in some of the vendor configuration tools that made the engineering process more challenging than it needed to be. This triggered further analysis into the state of the industry on IEC 61850 interoperability – the results of which are provided in Appendix B and summarized in the section that follows.

3.6 IEC 61850 Interoperability

The 2017 UCA Interoperability (IOP) test session took place at the Marriott Hotel at the Convention Center in New Orleans, LA, October 14-19, 2017. It was the third of a series of biannual IOP sessions. There were over 200 attendees – vendors, utilities, laboratories, and institutions as test participants or

witnesses. The sponsor of IOP events is the UCA International Users Group (UCA IUG), a mutual-help consortium of IEC 61850 users, product vendors, and standard developers. A description of the proceedings is provided in Appendix A, and summarized below:

- The 2017 interoperability test demonstrated a broad offering of IEC 61850 products and engineering tools which were successfully integrated into typical system applications.
- Integration required moderate levels of engineering effort, creating the appearance of advanced and maturing product development, but with some products in beta state.
- Ethernet network configuration problems were the most challenging detractor from interoperability test progress. This demonstrates a focus topic for utility users of IEC 61850. Notably, it appears that pre-test network engineering project management faltered before this IOP, with infrastructure problems delaying progress in IEC 61850 application integration. This comprises a major lesson for utility users of IEC 61850.
- IOP included testing for other services and capabilities which generally worked well:
    - Merging units and sampled value (SV) communications per 61850-9-2 and UCA 9-2 LE, with a serious remaining ambiguity about sample timing synchronization to be resolved.
    - IEC TR 61850-90-5 WAN-routable GOOSE and SV (R-GOOSE and R-SV). Both are used for wide-area synchrophasor transport as well as GOOSE for control. Authentication feature not tested.
    - Time synchronization via IEEE 1588 PTP and PPS in addition to IRIG-B.
    - Network security policy implementations.
- Product vendors and third-party tool developers demonstrated a variety of tools which showed an advanced stage of development, apparently close to or at commercial product refinement.
- Tools offered a variety of functions including IEC 61850 system configuration (GOOSE and MMS client-server association), network traffic monitoring and testing, product configuration and configuration-file format conversion, SCL file analysis or validation, and product communications simulation (multiple devices simulated within one tool).
- IOP discussions highlighted tools for and means of viewing and documenting GOOSE connections which are convenient, and not based on hand-built Excel spreadsheets. These deserve trials in practical projects.

The interoperability tests showed that large and complex systems utilizing multiple vendor's products and tools can be engineered and made operational, but require expert knowledge. There were several configuration tools on display that showed good progress on solving some of the engineering challenges experienced by the project team in building the test system. Some of these tools are discussed further in Appendix B.

3.7 Testing an IEC 61850 system

For maintenance purposes – replacing existing/failed IEDs, logic change/upgrade, or adding new IEDs to the system – condition-based testing is performed on IEDs to confirm their proper operation. To do this, the test engineer must isolate the IED under test from the system to avoid any undesired breaker operations during the testing process. In the case of wired-connected systems, the test engineer opens test switches to perform maintenance tests. However, the situation is much different in an IEC 61850 environment, where the isolation of the relay/IED can be done through communications.

The IEC 61850 standard provides a mechanism that allows for the isolation of an IED for field testing purposes. In Edition 1, the interpretation of the mode and behavior of this feature was not described,

and the implementation of this mechanism was only possible by configuring specific logic in the IEDs. Edition 2 of the standard addressed these short comings and clarified these “gray areas” by providing specific rules regarding the behavior of the different modes.

The test cases described in Use Case 2: Maintenance testing of IEDs, demonstrated how the use of the simulation, test and block modes of operation simplify the testing process. These modes enable the verification of application logic and correct operation of devices without impacting the rest of the system. The tests showed how the concept of “virtual test switches” provides an easy and quick way to isolate a device under test and thoroughly test it, all without the presence of any physical test switches.

3.8 Implementing a breaker failure scheme using IEC 61850

Use Case 3: Breaker failure scheme, demonstrated that a breaker-failure scheme could be easily implemented in an IEC 61850 system without the need for physical wiring. It furthermore showed that a breaker-failure scheme based on IEC 61850 GOOSE communication was more reliable than a wired implementation because “hidden problems”, like bad connections, are detected and alarmed in real-time – as opposed to being discovered after the fact when the breaker fails to operate.

3.9 Implementing an automatic transfer scheme using IEC 61850

Use Case 4: Automatic transfer scheme, demonstrated that an automatic transfer scheme could be implemented in an IEC 61850 system without the need to add any additional wiring. Over and above the conventional substation-based transfer scheme, the tests demonstrated how IEDs located on the feeder were also integrated into the transfer scheme and how transfer trip commands could be sent to the DER located on the feeder. As with the breaker failure scheme, the ability of the IEC 61850 based system to alarm on communication loss to participating devices, demonstrated how the system was able to detect and alarm on failures that would be hidden in the conventional approach.

3.10 Improving protection coordination using IEC 61850

Use Case 5: Improved protection coordination, provided several uses cases that demonstrated a protection scheme that used IEC 61850 to integrate data from substation and feeder protective relays was able to perform at least as well, and in some cases considerably better than the existing, conventional scheme. This included cases where the existing design took 1.5 seconds to clear a feeder close-in fault, while the improved awareness provided by the IEC 61850 design allowed the same fault clearing to be done in 60ms. A resistive close-in fault that took 3.5 seconds to clear in the current scheme, was shown to clear in 80 ms using IEC 61850. Moreover, the use case detected a coordination problem with the existing scheme for an end-of-line fault which the IEC 61850 design was able to correct.

3.11 Integrating DER devices into an IEC 61850 scheme

Use Case 6: DER control mode change, demonstrated how the control modes of DER devices can be controlled when they are integrated into an EIC 61850 system. At the time the tests were conducted there were no commercially available DERs that provided native support for the IEC 61850 communication protocol. It was therefore necessary to use a gateway between the DER and other equipment to integrate them into the IEC 61850 system. When selecting a gateway is it imperative that

the device be able to subscribe to both analog and digital values which, as was discovered on this project, is not always the case.

The specific application and required speed of response will dictate which of the two IEC 61850 messages services, GOOSE or MMS, should be used for integrating DERs into the distribution circuit. For highly time critical application the peer-to-peer communications supported by GOOSE is the appropriate response. For less time critical applications either GOOSE or MMS are feasible options.

The capabilities of DER devices differ and this impacts the feasibility of some applications. For example, the battery used in this study did not support V-Q droop mode, while the SMA inverter did not support modifying the upper and lower voltage thresholds in the VQ-droop mode – both of which limited the functionality that could be implemented.

3.12 Using DER devices for grid support in an IEC 61850 scheme

Use Case 7: Grid support using DERs, demonstrated that peer-to-peer communications among DERs and other protection and control equipment was able to enhance distribution system operation through improved power factor at the substation level, obtained by increased involvement of DERs, and enhanced voltage profile, through proper DER reactive power contribution.

The direct communication between DERs and the downstream protective device(s) enabled coordination between system protection and the low-voltage ride-through (LVRT) capability of the DERs. This prevented unnecessary operation of the DER and was able to improve both the security and dependability of DER anti-islanding protection.

3.13 Emergency load management in an IEC 61850 scheme

Use Case 8: Emergency load management tests, demonstrated that using IEC 61850, DERs could be effectively employed to address load shedding requests with minimum interruption to customers, that power flow through the transformer banks at the substation could be controlled on a real-time basis, and finally, reverse power flow could be managed through effective use of BESS while energy obtained from renewable resources was optimized.

3.14 OpenFMB versus IEC 61850 for integrating DER

Use Case 9: Dynamic emergency load control and management with DERs using OpenFMB and Use Case 11: Volt-var control via OpenFMB, explored the use of OpenFMB for several test cases. The testing demonstrated that the OpenFMB framework could be used to integrate DERs and control the voltage of distribution feeders on a real-time basis, considering load and (renewable) generation variations, but with several caveats:

OpenFMB is even more of a nascent technology than IEC 61850. At the time of testing there were no DER devices with native support for OpenFMB and as a consequence, protocol conversion was necessary. This involved using gateway devices to convert between Modbus, DNP3.0, IEC 61850 and OpenFMB's MQTT[23]. A side-by-side comparison of OpenFMB versus IEC 61850 was performed for one

[23] MQTT is a lightweight messaging protocol for small sensors and mobile devices, optimized for high-latency or unreliable networks.

specific application, and as would be expected, the IEC 61850 outperformed the OpenFMB by an order of magnitude because of the delays introduced by the protocol conversion in the OpenFMB set-up. Until native support is available, OpenFMB is not viable for any application requiring high-speed, protection-level response. In addition, the use of gateways obviates the purported simplicity of data exchange and configurability, so these benefits weren't observable in the test system.

Another finding related to the maturity of the available open-source firmware/software. The implementation of the publically available OpenFMB MQTT drivers was not an easy task and required significant development to get the system operational. The protocol has promise to assist in the integration of grid-edge devices, but lack of product availability made it clear that OpenFMB still has a way to go before being ready for operational deployment.

3.15 Using IEC 61850 between substation and simulated control center

Use Case 10: Dynamic circuit load management, included a test that contrasted the performance of DNP 3.0 and IEC 61850 for communications between a substation and a simulated control center. A direct comparison was difficult because the simulated control center did not offer native support for IEC 61850 and it was necessary to use a software gateway to convert from DNP 3.0 to IEC 61850. To make the comparison as equivalent as possible, a similar software gateway was used to convert DNP 3.0 back to DNP 3.0, thereby introducing the same order of intermediate delays. The tests showed little difference between the performance of the two systems. In this case, the MMS message service was used, which more closely aligns with the DNP 3.0, master/slave model (than would GOOSE), because MMS will be the IEC 61850 message service used between control center and substation when/if this becomes common practice. Given relatively comparable performance, one of the key differentiators between the two approaches will be the ease of configuration changes and the elimination of the complicated, time-consuming and error prone, point mapping required with the conventional SCADA protocol approach.

3.16 Cost comparison – IEC 61850 vs a conventional design

When doing a cost comparison of IEC 61850 versus a conventional approach, there are normally three different categories of costs and benefits that need to be examined:

- Those that impact the purchase price of the equipment and are directly related to IEC 61850
- Those that impact the purchase price of the equipment and involved design changes that are enabled by IEC 61850
- Those that result from reduction in utility labor in engineering, commissioning and the on-going operations and maintenance of the system enabled by the networked/connected features of the IEC 61850 system

In general terms, the business case for an IEC 61850 system, especially one that involves a process bus, is stronger for larger and more complex substation designs. This makes it simpler to make a business case for IEC 61850 in transmission system applications as opposed to distribution system applications. However, that certainly does not preclude the possibility of a positive business case for IEC 61850 in distribution applications.

In one study performed for a North American utility in the east, moving away from their traditional distribution substation design that specified large numbers of test switches, pilot lights, annunciators,

meters, separate relay functions per IED, etc. to an “all-digital” IEC 61850-based design held the potential to deliver CAPEX savings of over 30%.

Other studies suggest a more modest CAPEX savings of between 10% and 20% are possible when reductions in the time required for engineering, testing, start-up, etc. are factored in. However, it is also true that the first few installations of an IEC 61850-based design will be considerably more expensive because of the learning curve and costs.

In many cases, the largest potential for savings came from implementing design changes that are not directly related to IEC 61850, but which are enabled by it.

There are savings to be gained in utility labor in the design, engineering, start-up, commissioning and ongoing maintenance phases. Some of the savings are relatively easily quantified while others are more speculative and are based on what-if scenarios like extent of changes during the pre-in-service date, and the number of substation events that occur post-in-service. Regardless, the data suggested that the added equipment costs of the IEC 61850 Substation Bus system are more than offset by the savings from reduction in utility labor.

Some of the design modifications represent a change in philosophy and utility practices. A phased commercial adoption process, including laboratory and test-site simulations and formal personnel training programs, is recommended to ensure acceptance of the changes by utility personnel and to optimally manage the process.

4 RECOMMENDATIONS AND NEXT STEPS

4.1 Recommendations regarding commercial adoption of the demonstrated architecture

The various use cases documented in this report comprehensively demonstrate that IEC 61850 is a robust standards platform that offers numerous advantages over conventional approaches. As such the recommendation is that SDG&E plan for deployment of the technology. However, the project also identified several interoperability challenges when integrating devices from different vendors, and the process of engineering and configuring the system was more complex that desired. It is therefore recommended that SDG&E implement a pilot project using IEC 61850 before considering any large scale deployment. The pilot project should be planned such that sufficient time exists to work through any interoperability issues. Aside from exploring the operational adoption of the standards, the pilot project should have several other objectives:

- Quantify costs and benefits, and then develop a cost-benefit analysis for wide-scale deployment
- Examine what changes to standard operating procedures are necessary to fully leverage the benefit of a digital substation.
- Use the pilot project as a training platform for engineering, testing and commissioning personnel.

Deploying IEC 61850 for applications involving feeder equipment and non-substation based DERs is more complex than those inside the substation boundary, and high-speed and reliable communications are a prerequisite. It is recommended that a pilot project that explorers the non-substation applications of IEC 61850 and allows for real-world testing also be undertaken. This EPIC project used a high speed wireless system that performed well in the lab environment, but it is recommended that additional testing be performed on a carefully selected substation and feeder combination and the performance evaluated over an extended period of time to ensure the maturity of the standards is such that system performance is consistent and reliable.

As noted, there are currently no DER devices that offer native support for IEC 61850, and any DER devices currently require gateways to integrate into an IEC 61850 system. As DER devices are released that fully support IEC 61850, it is recommended that these be lab tested on a test bed before deployment in the field. This test bed should be constructed to represent a typical substation/feeder configuration with the aim of performing interoperability testing as new devices are released. Once the devices prove capable of operating in the IEC 61850 system and supporting the required applications, they can be moved out of the lab and into a substation/feeder pilot.

Experiences on the project suggest that more investigation into the operational readiness of OpenFMB is required. The same testbed proposed for testing new IEC 61850-enabled DER could be used to perform proof-of-concept testing on OpenFMB devices as they become commercially available and fully evaluate the feasibility and benefits of wide-scale deployment.

As the natural next step, it is recommended to prepare a comprehensive business case for deployment of IEC 61850 in distribution substations and circuits for both protection and automation purposes. The use cases introduced and demonstrated in this project provide quantified basis to prepare a breakdown of all cost categories. In addition, the project has categorized the cost saving areas. Additional SDG&E

stakeholder participation will be needed to assign appropriate dollar values on the benefit categories and assess the benefits.

4.2 Recommendations for tech transfer of results from this EPIC project

The results of the project should be communicated to the industry at large. After posting this final report on the SDG&E public EPIC web site, its availability on the website should be widely announced. It is also recommended that technical papers be written that summarize the work and key findings. These papers should be submitted to appropriate industry conferences and technical journals to ensure the experience gained is shared with additional stakeholders. A comprehensive slide file should be used to present the project findings internally to SDG&E stakeholders and at appropriate external events.

5 METRICS AND VALUE PROPOSITION

5.1 Metrics

The following metrics were identified for this project and evaluated during the course of the pre-commercial demonstration. These metrics are not exhaustive given the pre-commercial demonstration approach for this project.

Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy

- Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)
    - Use of configuration inheritance and descriptive data point naming supported by IEC 61850 makes the task of configuring devices in substation and feeders considerably easier when contrasted to the conventional approach. Digitization of devices using IEC 61850 can potentially lower the barriers of adoption of newer technologies within the electric infrastructure.
- Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360)
    - The industry has many standards that exist among several standards development organizations that may be applicable to multiple layers of the power systems architecture. A key standard is the IEC 61850 protocol suite. The extent of harmonization efforts that have included IEC 61850 show that the suite has the potential of becoming a key building block in the future smart grid architecture that enable effective communication and interoperability of equipment connected to the electric grid.

Safety, Power Quality, and Reliability (Equipment, Electricity System)

The use of IEC 61850 in field could enable interoperability, improve protection coordination and provide effective information sharing between field devices and backend systems. The following sub-factors could be enhanced with the use of IEC 61850:

- Increase in the number if nodes in the power system at monitoring points
- Reduction in outage numbers, frequency, and duration.
- Reduction in system harmonics

5.2 Value Proposition

The purpose of EPIC funding is to support investments in R&D projects that benefit the electricity customers of SDG&E, PG&E, and SCE. The primary principles of EPIC are to invest in technologies and approaches that provide benefits to electric ratepayers by promoting greater reliability, lower costs, and increased safety. This EPIC project contributes to these primary and secondary principles in the following ways:

- Reliability – This project demonstrated the potential of improving reliability through implementing breaker failure, automatic transfer, protection coordination, and DER integration using IEC 61850. The use of digital signals over analog signals through the use of IEC 61850 has the potential to help improve reliability by providing relevant data for effective electric system operations.
- Lower Costs – The IEC 61850 approach relies on virtual interconnections and offers the ability to test the logic and automation as they are being engineered and parametrized, as opposed to waiting for physical switchgear to be assembled and tested. Utilizing IEC 61850 as the communication standard and engineering devices based on IEC 61850 digital models has the potential to lower costs for integration of devices and applications that can help utilities operate their electric infrastructure efficiently and in a cost effective manner.

6 REFERENCES

[1] C.-C.-E. S. G. C. Group, "Smart Grid Reference Architecture," Nov. 2012.

[2] N. S. P. 1108r3, "NIST Framework and Roadmap for Smart Grid Interoperability Standards," 2014.

[3] I.-6. n. 10-6-2010, "www.iec.ch/," [Online].

[4] T. G. A. Council, "GridWise Transactive Energy," Jan. 2015.

[5] J. Hughes, "The Integrated Energy and Communication Systems Architecture-Volume I: User Guidelines and Recommendations".

[6] PNNL, "Reference Architecture".

[7] IBM/SCE/CISCO, "Smart Grid Reference Architecture," 2011.

[8] "Guide for Smart Grid Interoperability of Energy Technology and Information Technology Operation with the Electric Power System (EPS), and End-Use Applications and Loads".

[9] NIST/SGIP, "Smart Grid Conceptual Model".

[10] "www.multispeak.org," [Online].

[11] I. 6. T. Architecture, "Part 1: Reference Architecture for Power System Information Exchange," Second Edition Draft, October 1, 2011.

[12] OpenFMB website: https://openfmb.github.io/#overview.

[13] P. d. M. L. Kristoff, "21st Century Electric Distribution System Operations," http://resnick.caltech.edu/docs/21st.pdf.

[14] S.-C.-I. S. team, " Smart Grid Reference Architecture," Volume 1, July 14, 2011.

A. APPENDIX A – IEC 61850 TOOLS AND UCA 2017 INTEROPERABILITY TEST

A.1 Introduction

The 2017 UCA Interoperability (IOP) test session took place at the Marriott Hotel at the Convention Center in New Orleans, LA, October 14-19, 2017. It was the third of a series of biannual IOP sessions. There were over 200 attendees – vendors, utilities, laboratories, and institutions as test participants or witnesses.

The sponsor of IOP events is the UCA International Users Group (UCA IUG), a mutual-help consortium of IEC 61850 users, product vendors, and standard developers. The UCA name has its origin in the 1990s development of the EPRI Utility Communications Architecture, whose components were absorbed into IEC 61850 in 2000; the user group also migrated its focus to IEC 61850, and a few other IEC utility communications and integration standards. See more information at http://www.ucaiug.org/ .



Figure A-1. IOP testing in ballroom of Marriott Convention Center, New Orleans



Figure A-2. Continuing testing and reviewing of progress

A.2 Test program

The services to be tested at IOP included:

1. Substation project integration trial with tools.
2. Substation Configuration Language (SCL) tool operation.
3. Precision Time Protocol (PTP) per IEEE 1588, with profiles IEC 61850-9-3 and IEEE C37.238.
4. IEC TR 61850-90-5 UDP/IP Routable GOOSE (R-GOOSE) operation.
5. Cybersecurity strategies.

A warehouse full of test information and documents is available at http://IEC 61850.ucaiug.org/2017IOP-NOrleans/IOP%20Documents/Forms/AllItems.aspx .

The tests exposed long lists of detail issues documented and available online at the test website http://IEC 61850.ucaiug.org/2017IOP-NOrleans/IOP%20Documents/Forms/AllItems.aspx. While progress was uneven or chaotic at times, the participants all made massive progress in assembling an interoperable substation application from diverse tools and equipment in a few days.

We note that the integration team comprised the world's leading experts in IEC 61850 design concepts and product development, with a limited number of utility engineers witnessing the proceedings. In the writer's opinion, massive and complex IEC 61850 standards and product development requires a persistent or continuous process like this to find and fix interoperability problems before users struggle with them.

A.3 Engineering tools

The SCL and integration test tracks merged as two engineering tool suppliers split the substation project described below, and interacted with all the vendor and product specific tools and file formats to generate a functioning application. The workflow did not have the smooth operation of a well-developed process yet, yet there are massive details that are correctly handled by the tools in their current state.

The author was focused on the operation of tools, with a special eye on GOOSE integration and documentation. The system tools have means of engineering and documenting GOOSE and MMS client-server connections. We have only begun assessment of how these documentation capabilities could serve practical projects or lifecycle maintenance in a utility environment, but seeing live what information is provided gives us a basis for further questioning and process development.

A simple freeware tool *SCLViewer* found on the UCA website (not the IOP website) by the writer during these tests helps with easy parsing of configuration data provided as .xml SCL files, which are not easily read by human interpreters. This tool is accessible only to UCA members on the website; other readers can contact the author for files and instructions.

A.4 Summary

The 2017 interoperability test demonstrated a broad offering of IEC 61850 products and engineering tools which were successfully integrated into typical system applications.

Integration required moderate levels of engineering effort, creating the appearance of advanced and maturing product development, but with some products in beta state.

Ethernet network configuration problems were the most challenging detractor from interoperability test progress. This demonstrates a focus topic for utility users of IEC 61850. Notably, it appears that pre-test network engineering project management faltered before this IOP, with infrastructure problems delaying progress in IEC 61850 application integration. This comprises a major lesson for utility users of IEC 61850.

IOP included testing for other services and capabilities which generally worked well:

- Merging units and sampled value (SV) communications per 61850-9-2 and UCA 9-2 LE, with a serious remaining ambiguity about sample timing synchronization to be resolved.
- IEC TR 61850-90-5 WAN-routable GOOSE and SV (R-GOOSE and R-SV). Both are used for wide-area synchrophasor transport as well as GOOSE for control. Authentication feature not tested.
- Time synchronization via IEEE 1588 PTP and PPS in addition to IRIG-B.
- Network security policy implementations.

Product vendors and third-party tool developers demonstrated a variety of tools which showed an advanced stage of development, apparently close to or at commercial product refinement.

Tools offered a variety of functions including IEC 61850 system configuration (GOOSE and MMS client-server association), network traffic monitoring and testing, product configuration and configuration-file format conversion, SCL file analysis or validation, and product communications simulation (multiple devices simulated within one tool).

OPAL-RT real-time power system simulator offers IEC 61850 SV and GOOSE interfaces, which have already been available from RTDS.

System configuration engineering tools (SCTs) include capabilities for:

- Building applications based on Standard-defined logical nodes (LNs) and data objects (DOs), plus user-defined logical nodes of types GGIO and GAPC.
- Building applications as a one-line diagram with primary power apparatus and instrument transformers; and creating substation configuration SSD SCL file.
- Engineering 61850 networked applications based on P&C functions and substation configuration, without P&C devices specified (top-down).
- Attaching and integrating P&C devices to an already-engineered substation application.
- Building substation applications based on pre-selected IEDs (bottom-up).
- Generating configured IED files (CID and IID) for processing by vendor tools, or direct loading into selected products with direct import capability.
- Producing various formats of project documentation, which are topics for further evaluation.

SCTs still lack:

- Multi-project managed system engineering interface (SED) file handling capabilities.
- Other project segmentation features as clear menu choices. The investigators hypothesize work-arounds.
- User logic presentation – the Standard still lacks Part 90-11 that is supposed to define how to do this. But blind generic nodes GGIO and GAPC are available for embedding user-defined logic functions.

The project investigators are focused on project engineering which includes:

- Automated IECX 61850 Part 6 compliant project engineering that includes defined LNs mixed with practical user-defined logic blocks - as contrasted with hand-mapping and documentation of GOOSE or MMS DOs. The IOP yielded strong evidence that this can be done and documented with newly-demonstrated tools.
- Means by which protection zones or project segments are safely isolated for maintenance configuration. The IOP did not produce a clear approach, and the investigation continues. SED-file project segmentation and management is not yet implemented in any tool.

IOP discussions highlighted tools for and means of viewing and documenting GOOSE connections which are convenient, and not based on hand-built Excel spreadsheets. These deserve trials in practical projects.

B. APPENDIX B – THE IEC 61850 SYSTEM CONFIGURATION PROCESS

This appendix contrasts the conventional process to configure a protection and control (P&C) system with that utilizing the methodology envisaged by the IEC 61850 standard.

B.1 Classical P&C engineering process

In order to define an IEC 61850 engineering process, the steps involved in classical P&C engineering are defined. These same steps need to be included in IEC 61850 engineering but the specifics of the process are different.

Classical P&C engineering is typically a top-down process, starting with a station layout, with details for each level specified throughout the engineering process. Documentation is mainly drawing-based. The typical conventional P&C engineering process and document types are shown in Figure B-1, while documentation specifics are given in Table B-1.

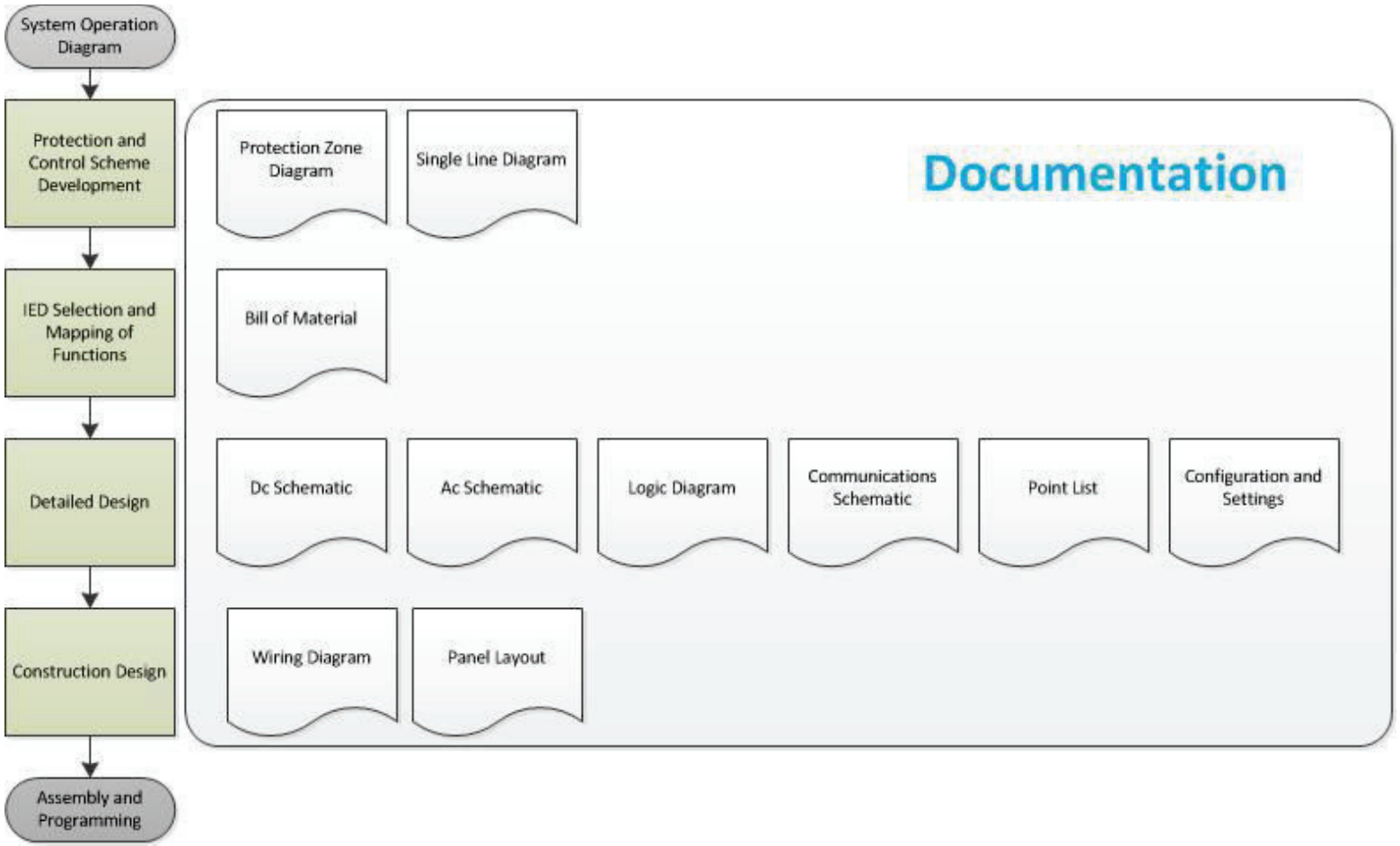


Figure B-1. Classical P&C engineering process and documentation

Table B-1. Classical P&C engineering documentation

Document	Description
System Operation Diagram	The system operation diagram is prepared by the planning group as input to P&C engineering. The System Operation Diagram typically shows: • Power system components • Voltage level • Circuit breakers, switches • CT location, CT polarity, PT locations There is no industry standard on what needs to be shown in System Operation Diagram and information will vary from utility to utility.
Single Line Diagram	The single line diagram provides the schematic design of protection and control, based on the input from the System Operation Diagram. Many utilities document the protection and control scheme in the single line diagram with scheme logic. Other utilities document scheme logic separately as part of the P&C documentation package.
Ac Schematic	The ac schematic shows the system with all three phases (Three-Line Diagram) and provides the detailed connection paths of the IED ac measuring circuits including: • Terminal numbers • Test switches • CT and PT ratios • CT polarity/star point location • CT taps
Dc Schematic	Traditionally, the dc schematic showed the complete protection and control scheme, including logic. This changed with the use of numerical relays where the available inputs and outputs (I/O) are shown as graphics and/or in a table.
Logic Diagram	Logic diagrams describe customized logic and scheme logic configured in numerical relays and IEDs. The logic diagrams may also include portions of the manufacturer's fixed logic, for better understanding of the scheme in testing. The logic diagram typically shows all input information, relay and scheme logic, and outputs.
Communications Schematic	The communications schematic shows: • Physical network and device diagram (routers, switches, network connections, gateways, and other networking components) • Functional data flows • Protocols (DNP3, IEC 61850, etc.) • Time synchronization equipment and protocol. • Cybersecurity design with physical and electronic security perimeters, firewalls, gateways, and isolation zones or DMZs. • Communications media (copper, fiber, microwave, etc.). • Communications circuit identification by type.
Miscellaneous P&C documentation	Configuration of numerical relays typically also includes assignments of labels, LEDs, targets and other customized HMI elements. Additionally, SCADA point lists and communications settings may need to be entered in the relays. Generally, these are based on standard templates, with application-specific customization for each zone or IED.

B.2 IEC 61850 P&C engineering process

The IEC 61850 engineering process envisions and supports a top-down engineering process as illustrated in Figure B-2. However, most utilities are still using a bottom-up engineering approach for the IEC 61850 configuration with the system specification and engineering done in the traditional way, since many implementations use conventional wired solution in parallel to IEC 61850 services.

There is a substantial effort involved in IEC 61850 project engineering when starting from scratch without a standard design, as is generally the case for a trial or pilot project. However, it should be recognized that today's P&C engineering is largely based on templates and protection scheme standards. IEC 61850 projects will also benefit from standard designs and templates when they have been established.

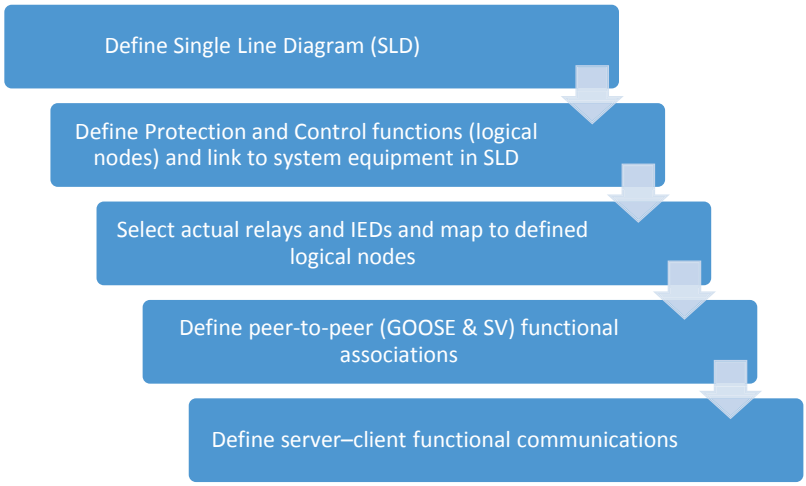


Figure B-2. IEC 61850 top-down engineering process

The user should be able to employ in sequence the system specification tool, the system configuration tool, and the IED configuration tool to design and engineer an IEC 61850 based protection and control system. Each of the different tools is used in a different phase of the project and is used for a specific design and engineering step. Table B-2 describes the different tasks performed by the different tools.

Table B-2. Overview of IEC 61850 engineering tools

Tool Domain	Functionality
System Specification Tool	In the project requirement phase, a System Specification Tool allows user to describe elements of the application as a single-line diagram, with application names and the required functions to be performed. This formal description can be used for evaluation of capabilities of alternative products, as well as serving as an input to a system configuration tool in the system design phase. The tool output specification includes standardized IEC 61850 functions (logical nodes or LNs) and their defined I/O signals (data objects), as well as user-defined LNs.

Tool Domain	Functionality
System Configuration Tool	The System Configuration Tool assigns the above-configured protection and control functions to actual IEDs. The input comprises the required functions and associated data flows defined during the system specification phase above. In this second step the communication connections between the IEDs are configured by the system configuration tool, so that the intended system functionality is implemented.
IED Configuration Tool	The IED Configuration Tool uses the output of the system configuration tool to create actual IED parameters and settings for each specific selected IED. This tool or toolset is usually manufacturer-specific, or even specific to an IED type.

Most IEC 61850 systems today are engineered using the bottom-up approach. This is based on familiarity, along with the fact that reliable manufacturer-independent system specification tools were not available in the past. Utilities must understand and slowly adjust to the new top-down engineering approach, which dramatically changes long-standing practices. Therefore the system specification is still generally performed in the traditional way and documented in drawings and legacy file types.

IEC 61850 P&C Engineering Documentation

The documents produced in the IEC 61850 P&C engineering process are similar to those for classic P&C engineering, as illustrated in Figure B-3. The abbreviations SSD and SCD refer to specific IEC 61850 System Configuration Language (SCL) XML file types explained below.

IEC 61850 Engineering Tools and Workflow

Figure B-4 shows the workflow for IEC 61850 configuration, which involves five distinct steps (Table B-3).

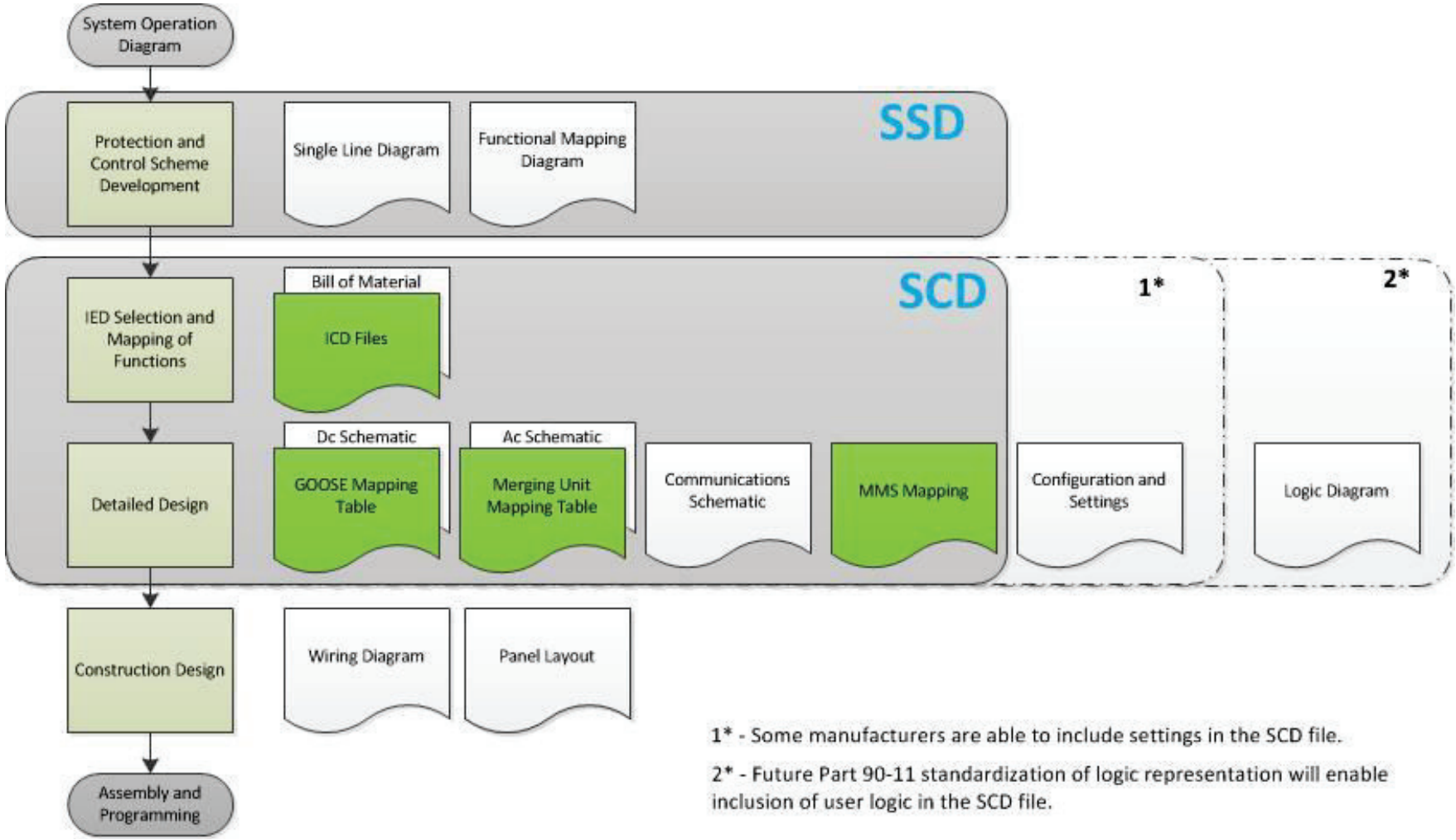


Figure B-3. IEC 61850 Engineering Documentation

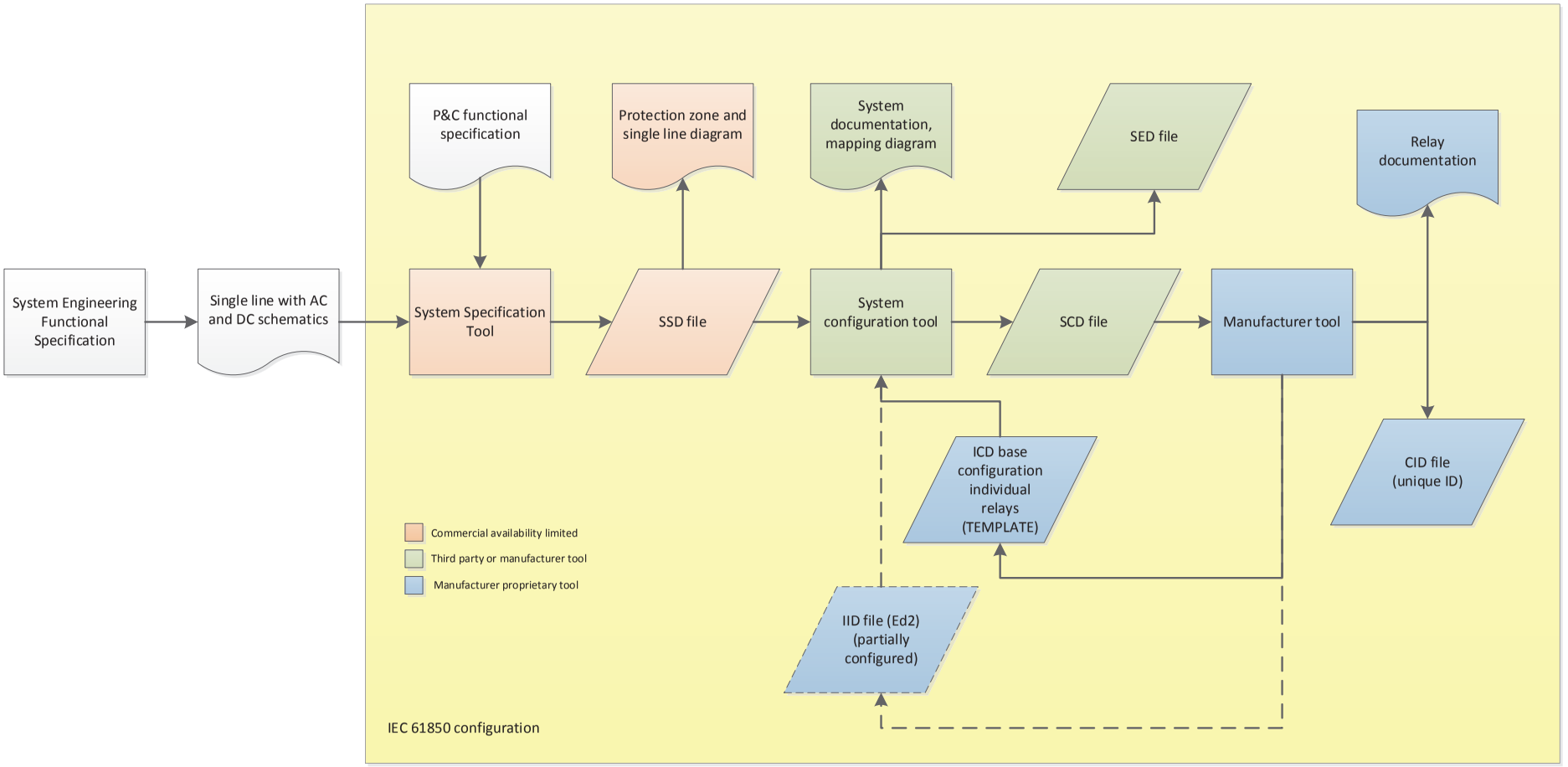


Figure B-4. IEC 61850 configuration process

Table B-3. Overview of IEC 61850 engineering workflow

Step	Description
0	The starting input for the IEC 61850 engineering process is the system engineering functional specification. In Figure B-4, a third-party system specification tool capability described in Part 6 takes user input of the single-line diagram and the functions to be applied in the substation to create a System Specification Description (SSD) file in XML format. Since tools with this one-line/function entry capability are just emerging, users have been entering manual configuration information directly into the system configuration tool along with product vendor-provided ICD information described next.
1	A set of manufacturer-specific tools include for each IED an IED Capability Description (ICD) file in XML format, with semantics and syntax as defined by IEC 61850 Part 6. Each ICD file describes the total communications and application model support capabilities of the IED, which the engineering process will configure for the IED's specific role. The system configuration tool requires an ICD file for each IED to be used in the IEC 61850-based communications system.
2	A third-party system configuration tool imports ICD files for all IEDs that are involved in the substation protection and control system communications. The IEDs can be senders (servers), receivers (clients), publishers, subscribers, or all of these. The tasks of the system configuration tool include: • Assigning addresses for all IEDs • Programming the dataflow directly among IEDs (GOOSE connections) • Programming dataflow between IEDs and primary equipment (process bus connections) • Creating lists of data objects for client systems (such as HMI and SCADA concentrator) The system configuration tool uses the SSD file, or direct input of the user's application intentions, to develop these configurations. The resulting system configuration with communications data connections is compiled in a Substation Configuration Description (SCD) file in XML format as defined in IEC 61850-6.
3	The SCD-defined data connections need to be applied as updated configurations of the individual IEDs. The manufacturers' proprietary tools read the SCD files and extract relevant information to configure each IED. The output from each manufacturer's tool is one or multiple Configured IED Description (CID) files - XML files produced for each IED separately. Each manufacturer's tool also must convert the contents of each CID file to a setting file in the product vendor's proprietary format, since there are only a few IEDs on the market that can accept CID files directly as setting files. The SCD file is also the input for the configuration tools of client systems (HMI, SCADA/enterprise servers, historian), listing all logical functions and data objects available by network communications.
4	Documentation of system configuration is to be produced by the system configuration tool. Separately, vendor tools document the IED configuration.

B.2.1 Summary of IEC 61850 Part 4 and Part 6

IEC 61850-4 covers system and project management. IEC 61850-6 covers configuration description language (SCL) for communication in electrical substations related to IEDs. This section provides a high level summary of these standards with regard to how they are related to the system configuration process.

IEC 61850-4: System and project management

For purpose of this document, the engineering process described in Part 4 is of interest.

Part 6 defines actor roles in the engineering process as follows (numerals are text quoted from the standard; italicized sub-items are authors' comments):

5. The project requirement engineer sets up the scope of the project, its boundaries, interfaces, functions and special requirements ranging from needed environmental conditions, reliability and availability requirements up to process related naming and eventual specific address range restrictions or product usage. They define what they want to have application wise and how they wants to operate the system (project requirement specification). They finally accept the delivered system.

   This role would correspond to the System Engineering Functional Specification in Step 0 in the preceding section.
6. The project design engineer defines, based on the requirements specification, how the system shall look like; its architecture, requirements on the products needed to fulfil the required functions, how the products should work together. They thus define the system design specification.

   This role would correspond to Step 1, where the P&C design engineer uses a System Specification Tool to create an SSD (System Specification Description) file.
7. The manufacturer supplies the products from which the system is built. If necessary, they supply a project specific IED configuration.

   This role would correspond to the supply of ICD (IED Capability Description) files (or IID files – Instantiated IED Description) in Step 1.
8. The system integrator builds the system, engineers the interoperation between its components based on the system design specification and the concretely available products from the manufacturers, and integrates the products into a running system. This results in a system configuration description.

   This role corresponds to using the System Configuration Tool to create an SCD (System Configuration Description) file in Step 2.
9. The IED parameterizing engineer uses the set-up possibilities of the system and device configuration to adjust the process, functional and system parameters of an IED to the project-specific characteristics.

   This role corresponds to importing the SCD file in the manufacturer IED configuration tool in Step 3.
10. The testing and commissioning engineer tests the system on the basis of the system configuration description, system design and requirements specification and additional documentation, and puts the system into operation.

    This role would correspond to creating system configuration documentation and IED documentation in Step 4.

IEC 61850-6: Configuration description language for communication in electrical substations related to IEDs

This part of the standard specifies a description language for the configuration of electrical substation IEDs; Substation Configuration description Language (SCL).

The standard first provides an overview of the different file types used in the engineering of an IEC 61850 substation automation system, and then gives a detailed specification of the datasets and naming conventions for these files. It would be expected that the system configuration tool creates the required

files and that a user will only work on a higher level, defining the LNs, communications, and the physical devices in the system.

Table B-4 gives an overview of the tools that create the various files and the dataflow between the tools. Part 6 describes these in detail. The files are tabulated below:

Table B-4. IEC 61850-6 SCL File Types

File	Description
IED Capability Description (ICD) file	It defines complete capability of an IED. This file needs to be supplied by each manufacturer to make the complete system configuration. The file contains a single IED section, an optional communication section and an optional substation part which denotes the physical entities corresponding to the IED.
System Specification Description (SSD) file	This file contains complete specification of a substation automation system including single line diagram for the substation and its functionalities (logical nodes). This will have Substation part, Data type templates and logical node type definitions but need not have IED section. IEC 61850-6 provides a formal means to define the single line diagram with customer's functional names and the intended automation system functionality at the primary equipment identified in the single line description (SSD, system specification description). Commercial products for creating SSD files are presently limited. The system configuration tools typically include defining a single line diagram and theoretically could create an SSD file as an output, but this functionality is not provided. Many of them have the ability to import SSD files so it would be beneficial to have this functionality in the future so that SSD files could be exchanged between different system configuration tools.
Substation Configuration Description (SCD) file	This is the file describing complete substation detail. It contains substation, communication, IED and Data type template sections. An .SSD file and different .ICD files contribute in making an SCD file.
Configured IED Description (CID) file:	It is a file used to have communication between an IED configuration tool to an IED. It can be considered as an SCD file stripped down to what the concerned IED need to know and contains a mandatory communication section of the addressed IED.
Instantiated IED Description (IID) file:	It defines the configuration of one IED for a project and is used as data exchange format from the IED configurator to the system configurator. This file contains only the data for the IED being configured: one IED section, the communication section with the IED's communication parameters, the IED's data type templates, and, optionally, a substation section with the binding of functions (LNodes) to the single line diagram.
System Exchange Description (SED) file	This file is to be exchanged between system configurators of different projects. It describes the interfaces of one project to be used by another project, and at re-import the additionally engineered interface connections between the projects. It is a subset of an SCD file with additional engineering rights for each IED as well as the ownership (project) of SCL data.

The last two file types (IID and SED) were introduced with Edition 2. While the tools are expected to handle the creation of these files, the user still needs to have substantial knowledge of the IEC 61850 standard. In order to define the required functionality, the user needs to be familiar with Logical Node names, and names for parameters and values to be communicated via GOOSE and MMS from these Logical Nodes. Logical Nodes are defined in IEC 61850-7-4.

C. APPENDIX C – OPENFMB PRIMER

OpenFMB differs from legacy protocols such as DNP3, MODBUS, and even IEC 61850 in a number of ways and represents a novel way of enabling interoperability of field devices. By means of introduction, this section provides background on the framework and then explains considerations going forward.

C.1 Introduction to OpenFMB

Open Field Message Bus (OpenFMB) represents one of the Smart Grid Interoperability Panel's (SGIP) EnergyIoT initiatives that attempts to bring Internet of Things (IoT) and interoperability to the power systems. It was specifically intended for application to field devices and field level computing (sometimes referred to as *fog computing* as the corollary to cloud computing). The stakeholder group describe OpenFMB as:

> *Open Field Message Bus (OpenFMB) is a framework and reference architecture comprised of existing standards that enables grid edge interoperability and distributed intelligence, augments operational systems, and enhances integration with field devices.*

The frameworks subscribe to a number of guiding principles, which include:

- Based on operational and functional requirements
- Flexible architecture
- No reinventing the wheel
- Focus on business value and objectives
- Collaborate with standards bodies
- No stranded resources
- Security built-in from the beginning

Figure C-1 presents the vision for the evolution of grid communication, essentially precipitated by the accelerated integration of grid-edge devices, most notably distributed energy resources (DER). As shown, legacy hub-and-spoke architectures require that all data flows must pass by way of the back office servers, ultimately leading to data congestion, and unnecessary configuration of multiple links. By enabling peer-to-peer communication in the field, traffic can be customized to the needs of the use case, only implicating the actors and data points minimally required to deliver the functionality.

Figure C-2 provides an illustration of the various layers of OpenFMB that make this possible. Peer-to-peer middleware forms the transport layer, which is compatible with multiple physical media (WiFi, cellular, BPL, Fiberoptics). The OpenFMB data model underpins the interface layer and interacts with the transport layer and higher level functions. Finally, the management services layer provides higher level functions that support monitoring of a given application and its evolution over time.

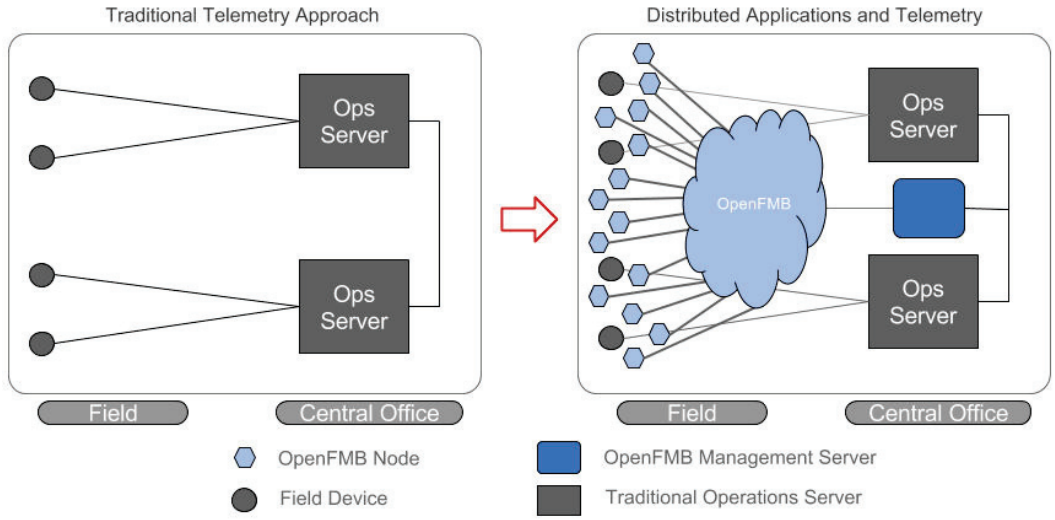


Figure C-1. Evolution from present data communication with field devices towards OpenFMB [12]

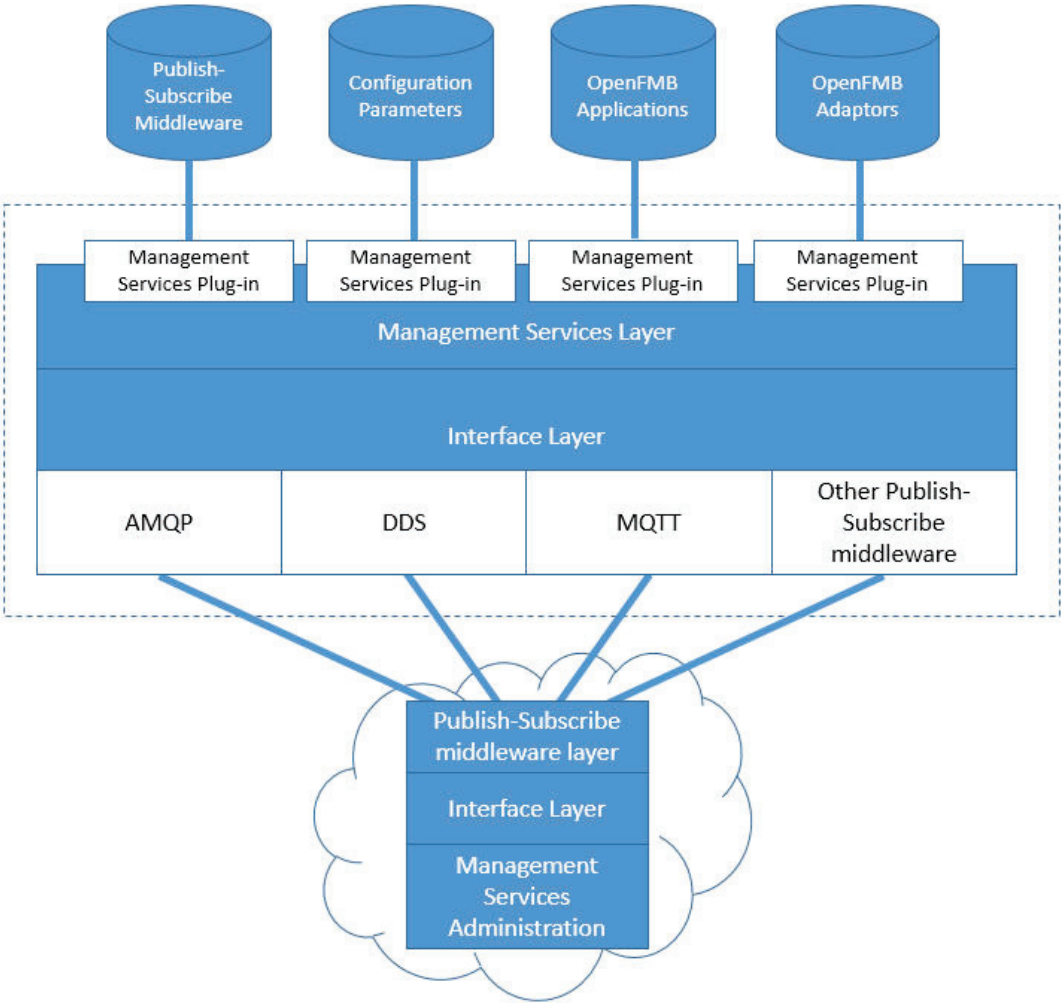


Figure C-2. Graphical representation of the OpenFMB framework

Similarly to IEC 61850, the underlying data model is one of the key features that supports interoperability and scalability. A common representation of typical devices and applications ensures that disparate manufacturers conform to agreed-upon semantics, greatly reducing the time to configure and test a given interface. In addition to other packet information related to the publish-subscribe process, these data models are passed as XML payloads over the middleware. This standard, hierarchical structure greatly reduces the time for configuration of systems and development of new applications.

Figure C-3 presents a unified modeling language (UML) representation of the data model for a battery energy storage system (BESS). This includes multiple attributes that describe the system characteristics, time stamp information for the payload, and variables related to its operation.

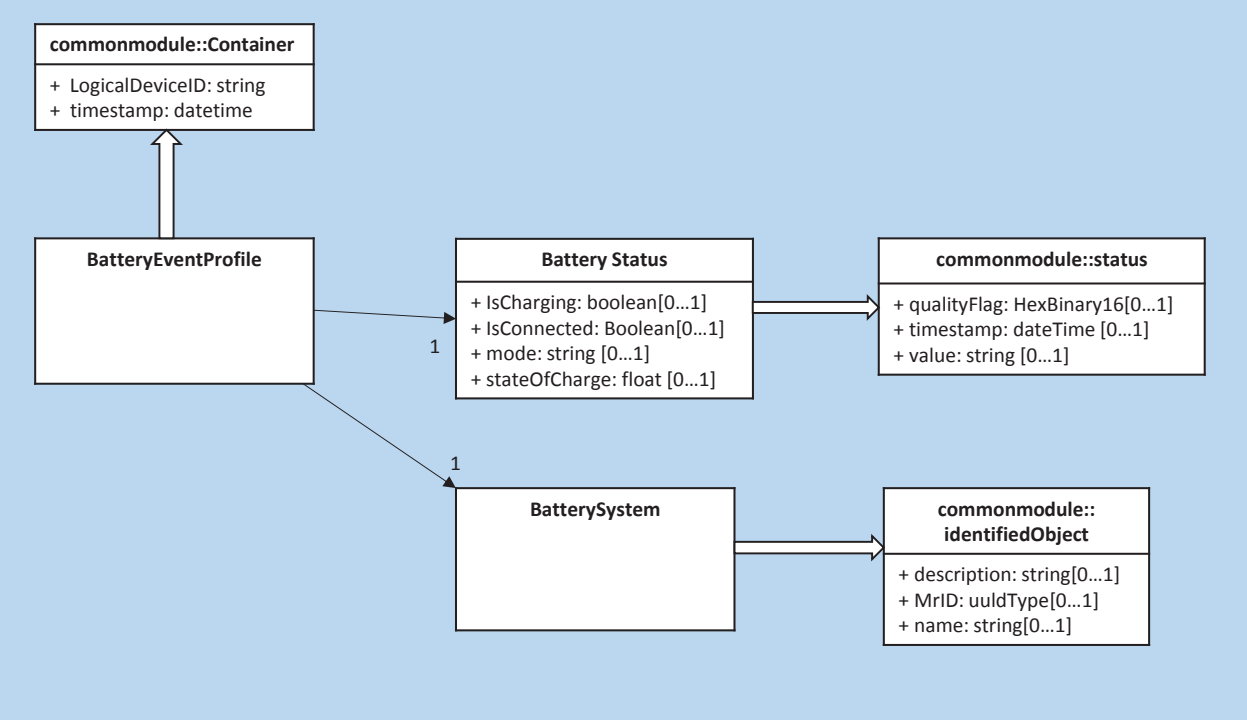


Figure C-3. Unified Modeling Language (UML) representation of OpenFMB data model for BESS

C.2 Advantages

The OpenFMB framework presents a number of advantages to the industry, particular in light of the development of IoT applications in the power sector and in related fields. As it utilizes internet protocol (IP) based technologies, it enables higher-level functions not possible in legacy protocols, and the fact that it is based on an open-standards approach, the risk of vendor lock-in is greatly reduced, as specific implementation must be vetted by the wider community, avoiding proprietary interpretations.

Specifically, the key advantages are summarized as follows:

- Ratified (NAESB) standard providing a common semantic language for field device integration.
- Highly scalable compared to legacy protocols due to pub-sub nature of bus architecture, common transport layer and unified information model.

- Enables peer-to-peer integration using IoT technology, breaking out from traditional hub-and-spoke architectures. This makes the framework highly amenable to the architectures studied in the SODA project and distributed of various levels of aggregation out to the substation and the field.
- No implicit binding to underlying transport layer, allowing appropriate technologies to be used for specific use cases.
- Information model based on best-of-breed harmonization of CIM and 61850. The information model will continue to evolve as these two groups address the gap in the information model and as new applications are developed.
- Common information models are easily extendable to add extra data, while maintaining backwards compatibility with nodes that don't know about the additional data. E.g., If wind speed information is added to generator measurement data, nodes that don't know about wind speed can still understand the real power measurement.

C.3 Implementation and adoption challenges

While OpenFMB possesses many promising attributes, challenges persist, in part due to the significant change that it represents to distribution operations and communication. The framework has been pushed by a few of the larger progressive utilities, led primarily by Duke Energy and the *Coalition of Willing*, a group of vendors committed to piloting these technologies. However, until greater traction can be achieved—which will likely involve a combination of market push and continued proliferation of grid-edge assets—challenges for widespread implementation will likely continue.

The most common challenges are the following:

- Limited uptake by the industry at this stage. This is probably the greatest stumbling block and in a conservative industry, these things generally take time and require vetting and experimentation through such mechanisms as EPIC or other state and federal level funding. This is countered somewhat by a relatively strong community and support through the SGIP.
- Current information model has limited device support. While many of the grid-edge assets are covered, novel devices such as the RAMCO and the Grid Co device needed to be forced into similar type data models. This should improve through greater adoption and pilots but remains a challenge for the short-term.
- Most field devices do not yet explicitly support OpenFMB out-of-the-box. This fact results directly from adoption and mirrors the support of IEC 61850 in the early days of its implementation.
- Protocol translation to legacy protocols still required at the edge. Following on from the previous point, the only way to enable an OpenFMB node from a non-compliant device is through installation of an additional translator at the remote terminal unit (RTU).
- Some publish-subscribe protocols require a broker, meaning they're not truly peer to peer (e.g., MQTT). Middleware based around DDS avoid the use of a broker and hence avoid single points of failure and reduce latency.
- Migration from legacy architectures will likely have some challenges. As with the integration of DER and the struggles associated with the paradigm shift to distributed production of energy, the shift towards distributed control architecture will be met with similar technology and organizational issues. The best approach revolves around establishing a roadmap with input from relevant stakeholders, well defined use cases, considering possible future use cases, and how implementation of OpenFMB can drive value for the utility and other organizations.

D. APPENDIX D – ADDITIONAL USE CASE RESULTS

Use cases 1, 2, 4, 5, 6, 7, 8 and 9 consisted of multiple test cases. The earlier use case sections only detailed a representative sub-section of these test cases for the sake of brevity. The sections that follow document the results of those test cases that were omitted from the earlier sections.

D.1 Use Case 1: Lifecycle asset provision and integration

D.1.1 Test Case 1: Integrate new IED into existing system

In this section, the detailed steps required to properly add a new IED (from two different vendors) to an existing IED from the system are documented using a short description and the related screen shots for evidence.

Step 1: Configure new IED, functions and settings

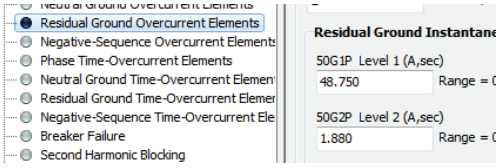
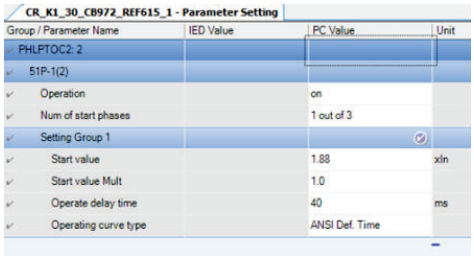
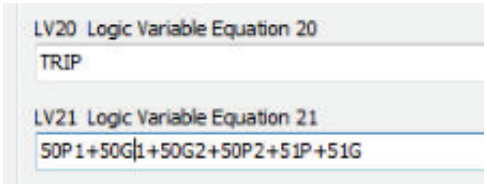
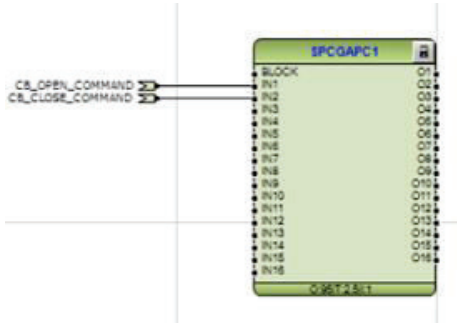
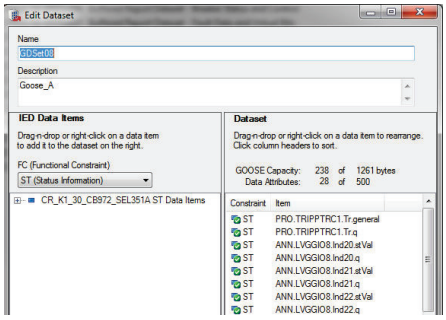
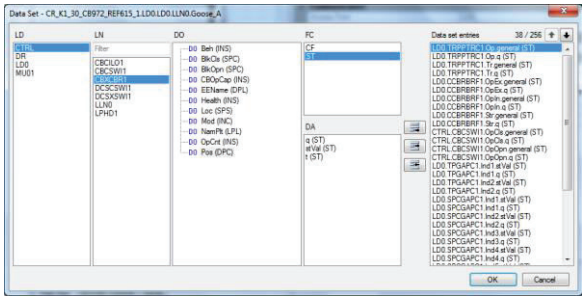
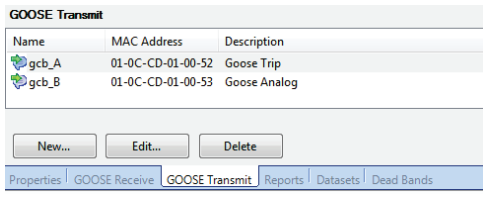
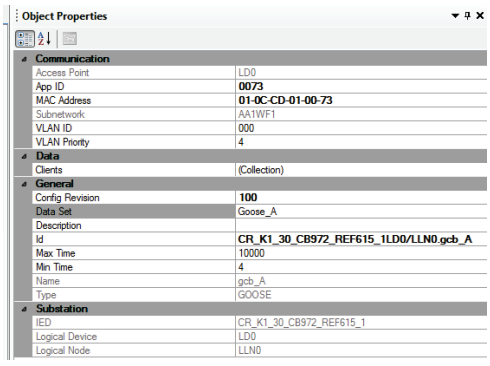
Description	Vendor 1	Vendor 2
Configure protection settings		
Connect variables with functions	 Note: Variables are used as interface to a function. Later the variables are connected with the relevant GOOSE message	
Configure data sets		
Configure GOOSE control blocks		

Figure D-1. Step 1: Configure new IED, functions and settings

Step 2: Export and Import ICD/CID file of the new IED device

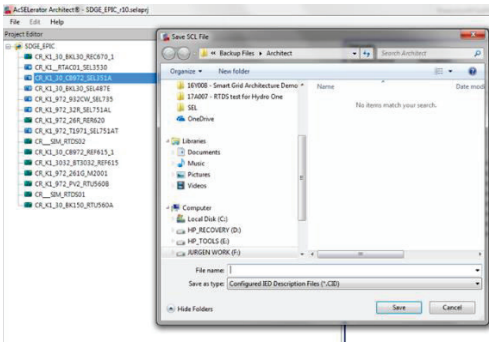
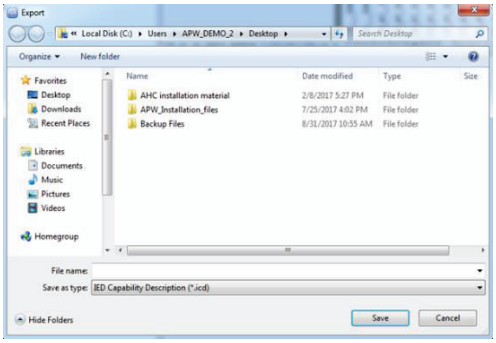
Description	Vendor 1	Vendor 2
Export: The IEC 61850 configuration, including GOOSE message assignments are store and distributed in form of CID or IED files	 In case of Vendor 1 devices a CID file is created as input for the system engineering task.	 In case of the Vendor 2 devices an ICD or SCD file is created as input for the system engineering task. In the given set-up there was no need to export the ICD/SCD file as the IEC 61850 system engineering function inside the Vendor 2's configuration tool was used.

Figure D-2. Step 2: Export and Import ICD/CID file of the new IED device

The users do not have to deal with the XML format of the different SCL files such as the mentioned ICD or CID File. Rather the IED and system engineering tools handle the details and provide the engineers a user friendly interface for the different engineering and configuration activities. Nevertheless if one needs to look at an SCL file any browser can be used to look up the details. An example of the XML format is shown in Figure D-3.

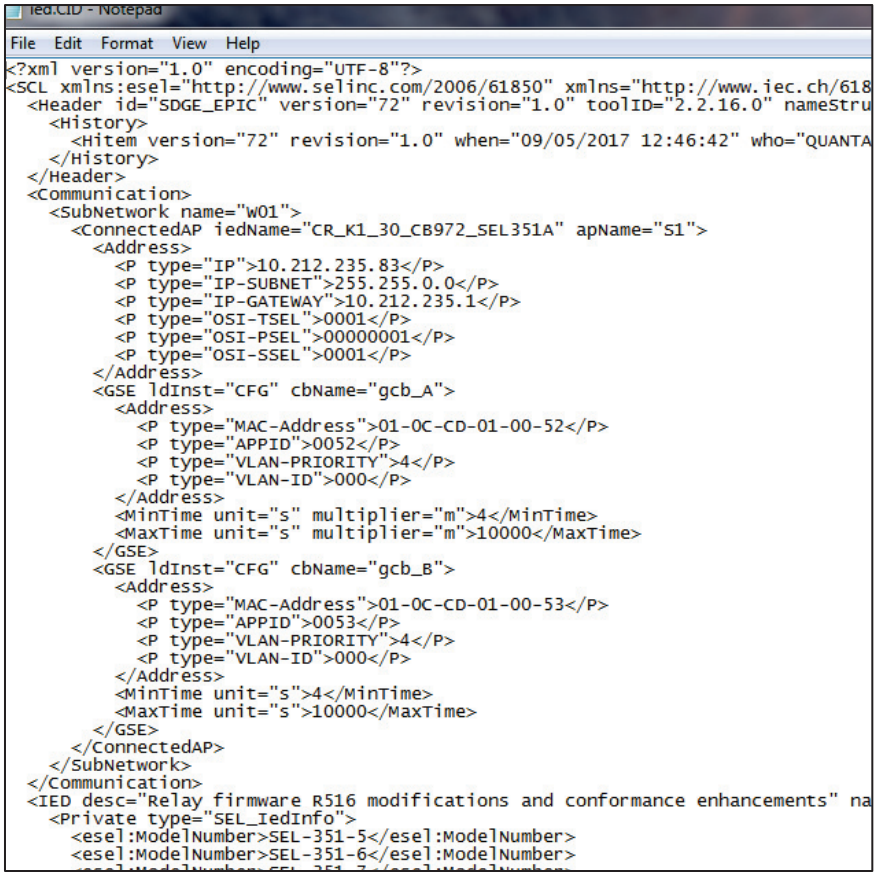


Figure D-3. Example XML format of a CID file

Step 3: Engineer data flow

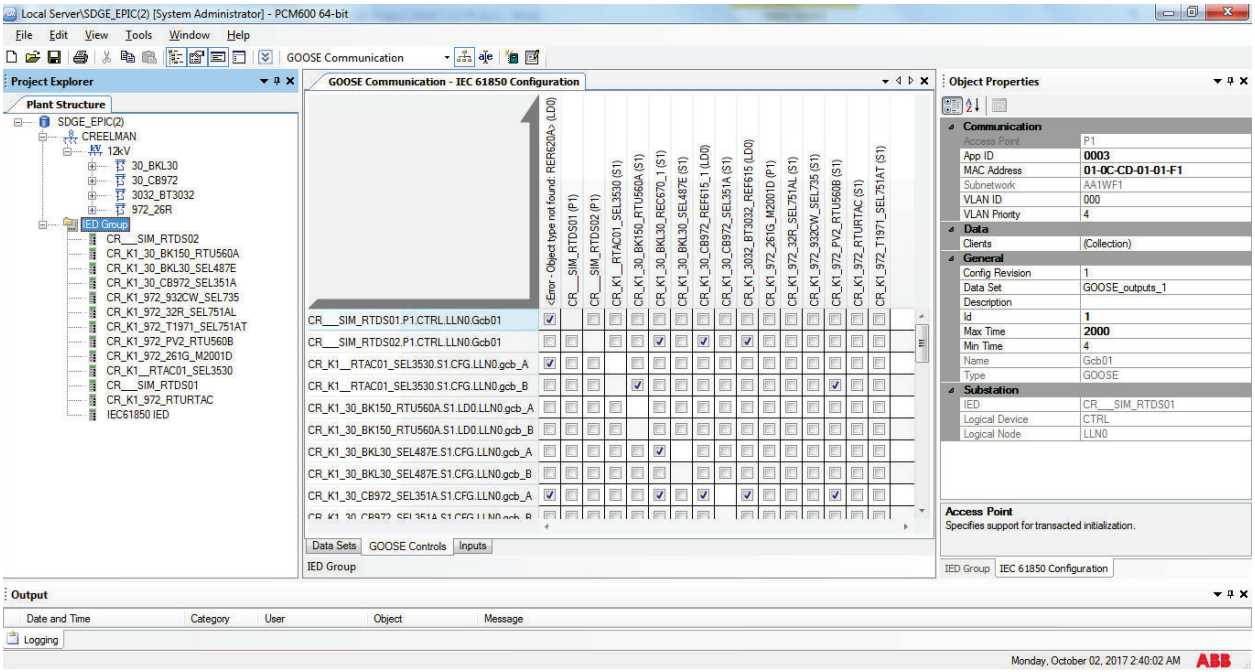


Figure D-4. Step 3: Engineer data flow

Step 4: Import SCD and connect input section

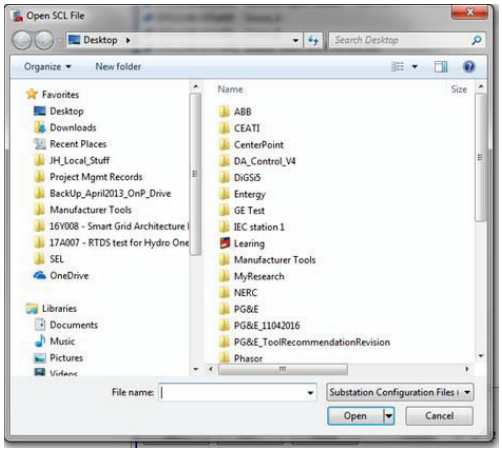
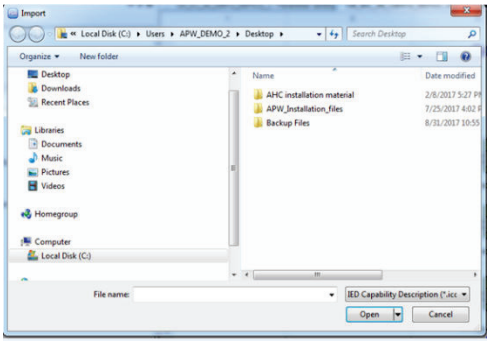
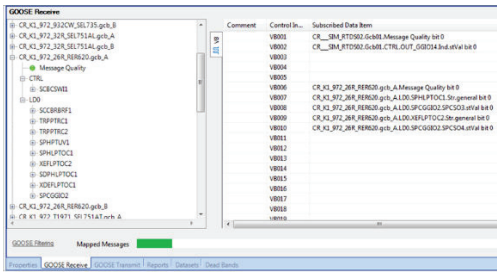
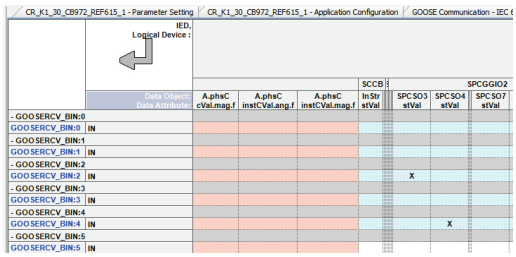
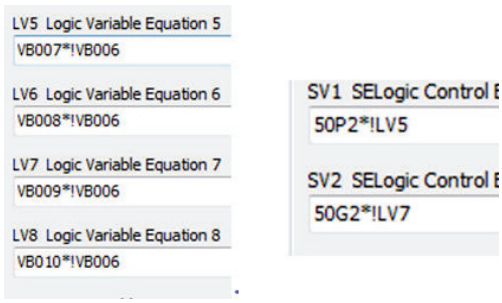
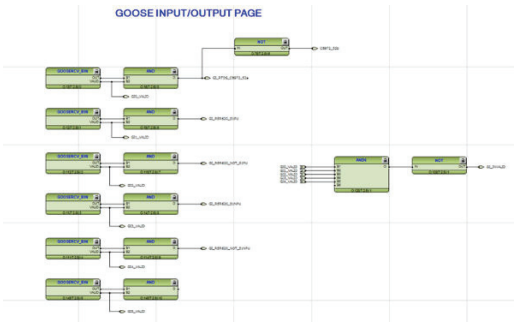
Description	Vendor 1	Vendor 2
Import: Importing the ICD, CID file makes it possible for any manufacturer to understand the IED capabilities		
and configure the signals to internal connection points	 Vendor 1 uses VBxxx for binary input signals	
Connect to internal logic	 VBxxx are connected to internal logic	

Figure D-5. Step 4: Import SCD and connect input section

Step 5: Upload SCD/CID to new IED and GOOSE subscribers

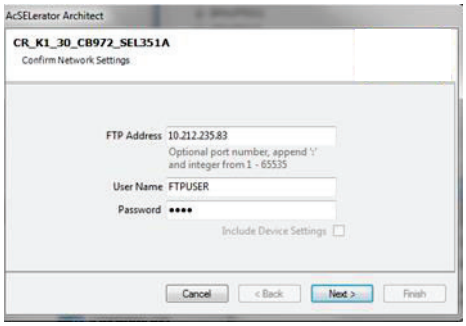
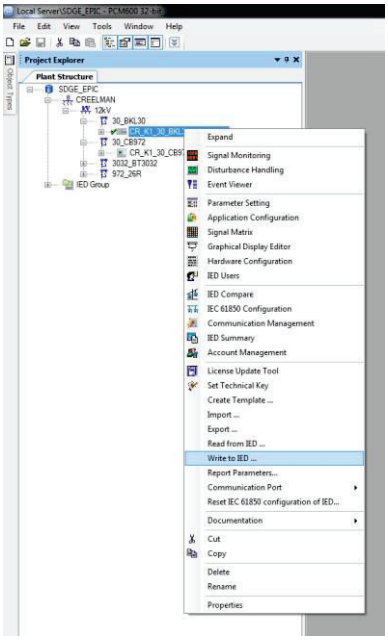
Description	Vendor 1	Vendor 2
Upload new configuration file (including communication section) to IED	 Vendor 1 uses two different tools to manage settings (QuickSet) and Communication configuration (Architecture)	 Settings and Communication configuration is managed in one tool (Vendor 2's configuration tool) and transmitted to the relay together

Figure D-6. Step 5: Upload SCD/CID to new IED and GOOSE subscribers

Step 6: Basic test of communication

Taking the full advantage of IEC 61850 data modeling and documenting the communication related information (communication section) as part of the SCD file is a pre-condition to enable the automatic check functionality using an IEC 61850 testing tool. After downloading the new configuration to the IEDs scan and comparison with the original SCD files provides a fast and reliable way to confirm correct configuration.

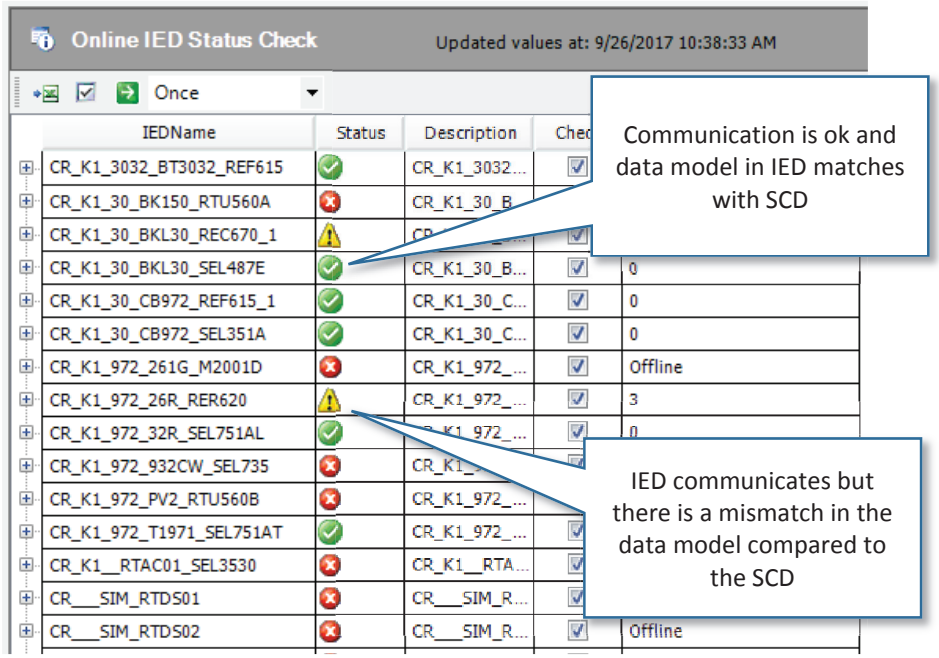


Figure D-7. Using IEC 61850 tool to check basic communication and data model consistency

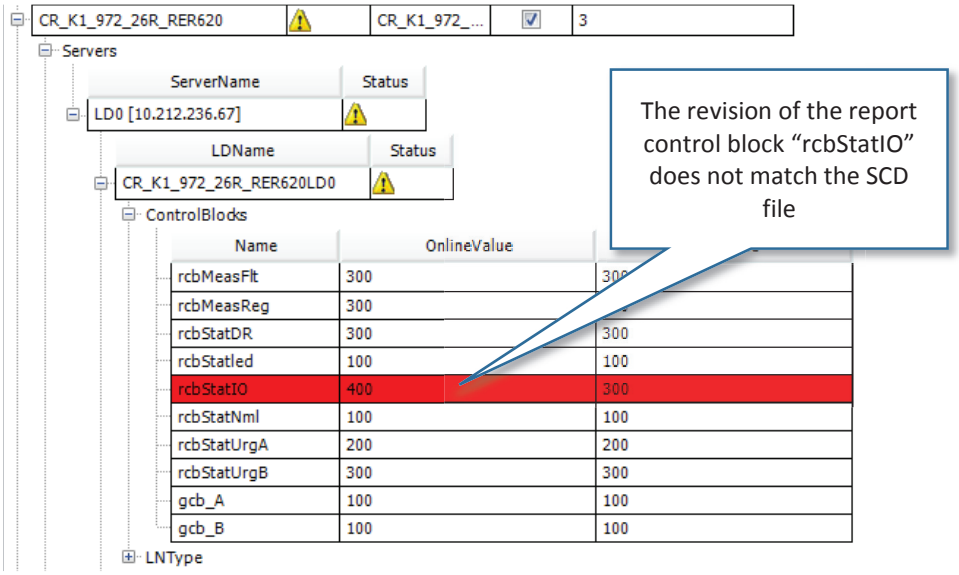


Figure D-8. Detected revision mismatch in a report control block between SCD and real IED

D.1.2 Test Case 2: Remove existing IED from system

In this section the detailed steps required to properly remove an existing IED from the system are documented using a short description and the related screen shots for evidence. The SEL-351 IED had been chosen as target IED for removal.

Step 1: Check impact of the target IED to related devices

In order to confirm the impact of related IEDs and functions before removing an existing IED following checks can be done to identify the IEDs requiring an update after removing a defined IED.

A) Check the GOOSE table document: As part of the system documentation a comprehensive table with all devices and GOOSE messages has been developed showing not only the GOOSE communication between the different devices but also the link of the GOOSE message to the internal logic of variable inside the IED.

B) Check the GOOSE matrix in IEC 61850 system engineering tool: The has also been used as system engineering tool for the IEC 61850 portion. A GOOSE matrix provides an overview on all engineered GOOSE communications across the project and allows to quickly identify IED dependencies. Figure D-9 shows a section of the GOOSE matrix of the project. Each cross in the table means there is a connection between the GOOSE control block listed on vertical line and the device shown on the horizontal line.

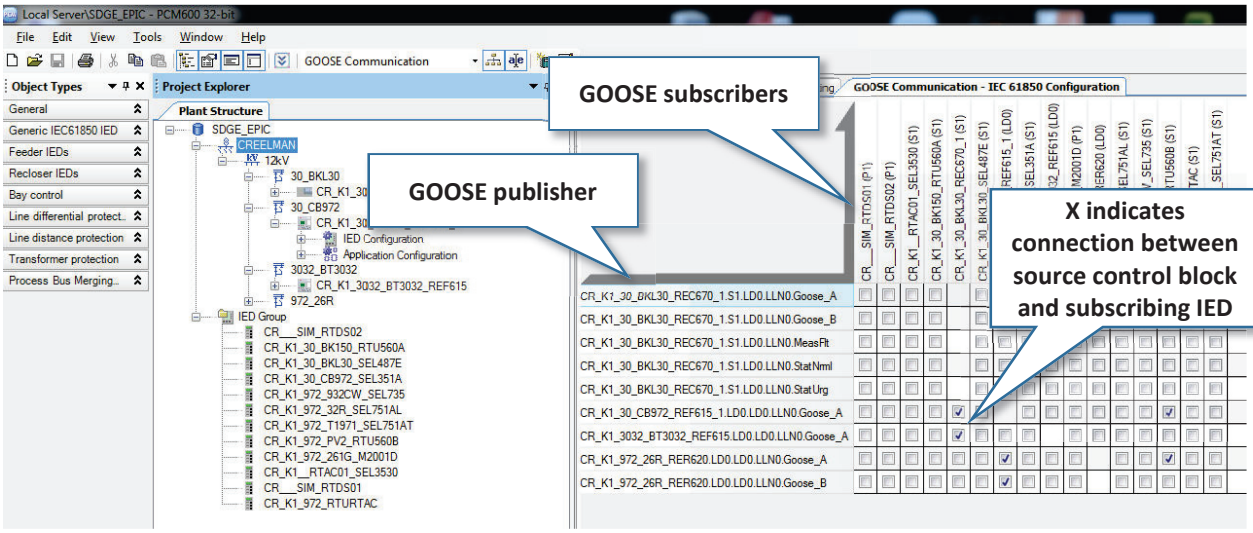


Figure D-9. GOOSE matrix in system engineering tool

C) Use the Vendor 2's configuration tool testing tool to highlight impact of removed IED using data flow view tab: By loading the up-do-date SCD file into the IEC 61850 testing tool Vendor 2's configuration tool and opening the data flow view tab all devices and communication links are graphically shown. Selecting the IEDs targeted for removal to fault simulation (IED will turn into red color) automatically colors communication depending IEDs into orange color. It provides an easy and quick way to identify the IEDs subscribing to the IED that shall be removed.

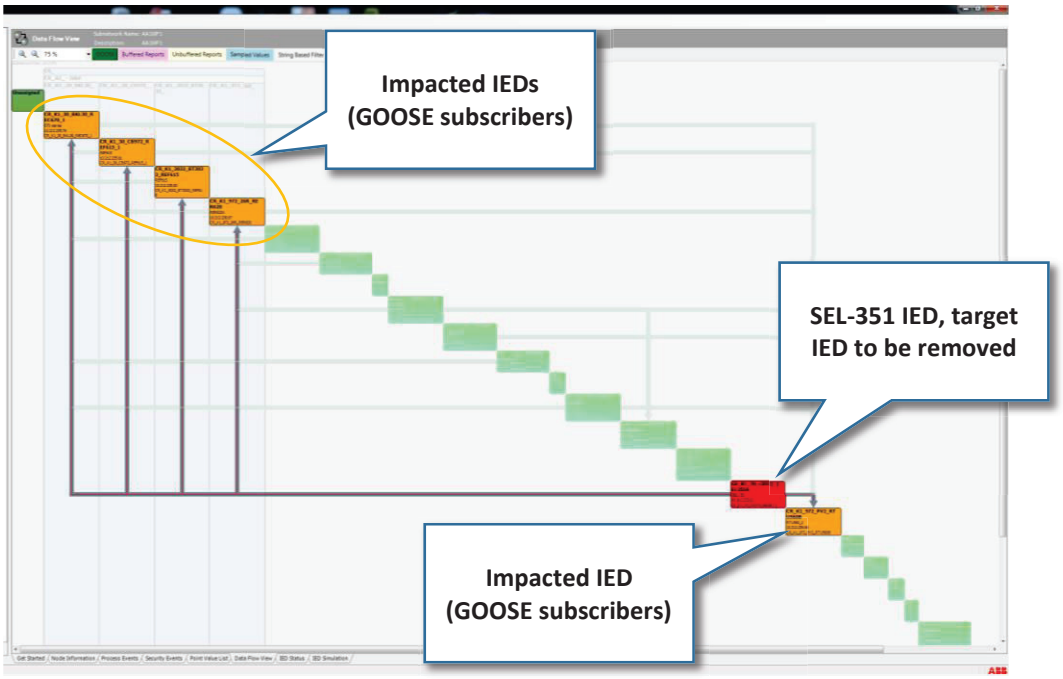


Figure D-10. IEC 61850 testing tool showing data flow view and simulated faulty IED

D) Manual check in IED configuration tools: Manual verification of dependent IEDs is also possible looking at each individual IED and its GOOSE input sections. It is a rather slow process as it required manually opening of each IED and checking the relations.

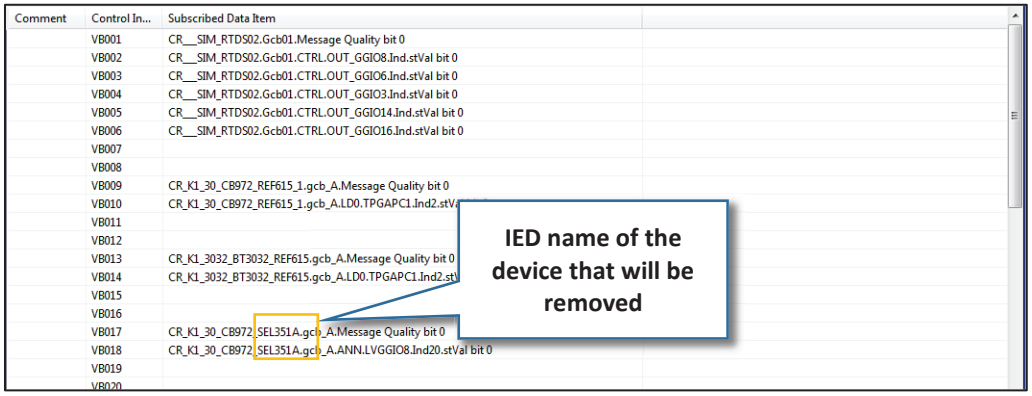


Figure D-11. GOOSE input section for a single device in Vendor 1 IED tool

Step 2: Remove IED in system and IED tools

There are only a few steps required to remove an active device from an engineering project. First step is to remove it from the IEC 61850 system engineering tool and consequently from the IED configuration tool in case the IED configuration tool holds one project for multiple IEDs. In this project the SEL-351 had to be removed at two locations: In Vendor 2's configuration tool (in this content used as system

engineering tool) and in the SEL Architect (IED configuration tool). If an IED would be chosen for removal it would only be required to be deleted once in the Vendor 2's configuration tool as the IED and the IEC 61850 system engineering is handled inside the same tool.

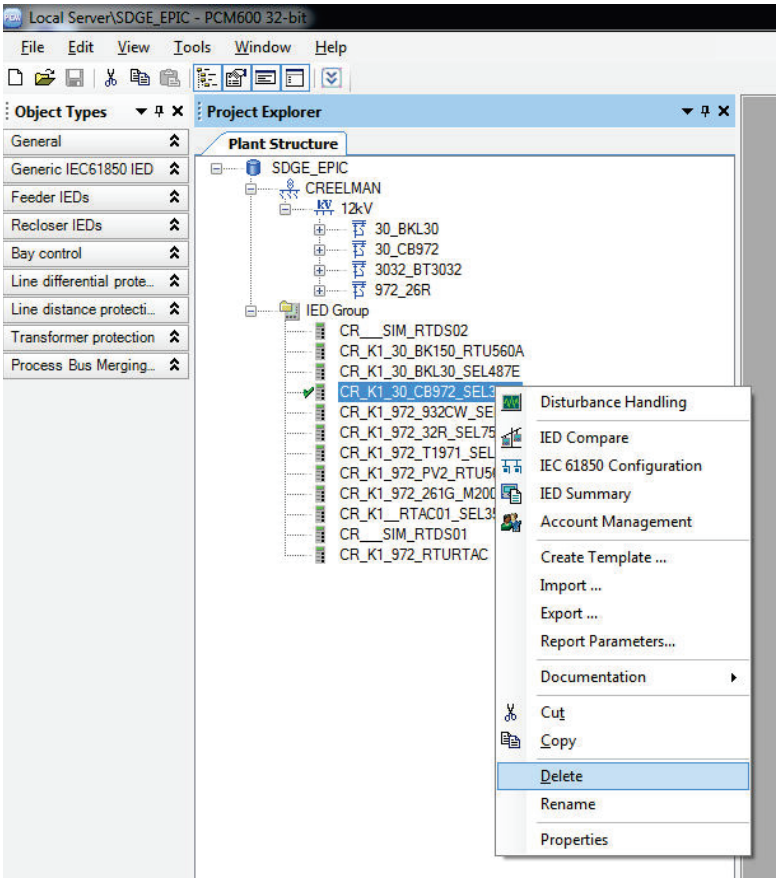


Figure D-12. Deleting and IED in Vendor 2's configuration tool

Step 3: Load all impacted IEDs with new configuration

Finally all impacted IEDs (GOOSE subscribers of the removed IED) need to be loaded with the updated configuration file to make sure they do not subscribe to the GOOSE messages of the removed device anymore.

Beside the IEDs also the MMS client devices such as the station HMI in our set-up need to be loaded with the updated SCD file and related internal data point and graphical elements are removed by manual engineering.

Step 4: Confirm correct configuration and function

The breaker failure function was selected to verify the proper removal of the SEL-351 feeder relay. The SEL-351 is kept in the system and publishes the MMS and GOOSE messages. After removal all data receiver such as GOOSE subscribers will not read the information from the network event thought the message is still there. To prove that a manual trigger in the SEL-351 was used to force the breaker failure

GOOSE message. REC670 the BF GOOSE receiver this not process the information as it was removed as part of the removal engineering process. So correct behavior was proven.

D.1.3 Test Case 3: Replace failed time source device into existing system

The time server is used to synchronize all equipment as part of the system. Four different time sync methods are applied: SNTP, PPS, PTP and IRIG-B. The time master itself does not have an IEC 61850 data model and supervision is in this project kept very simple as it was not a focused area of this project. So it means the reach of the time servers IP address is the main criteria for supervision.

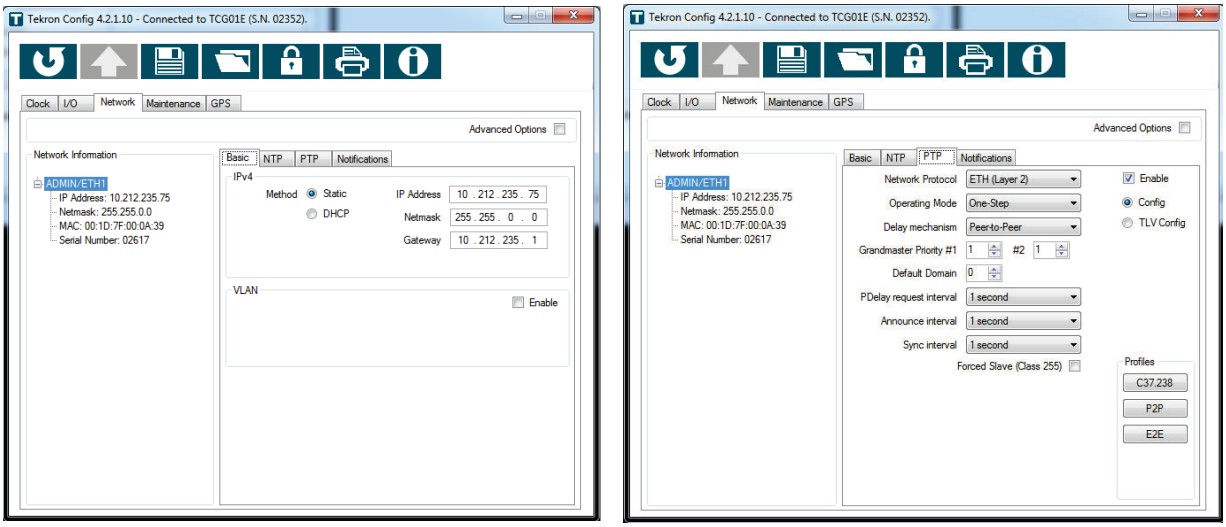


Figure D-13. Tekron Time Server Configuration

In case of a time server failure the operator will be informed about the failure at different levels:

1. System overview picture: An alarm on the time server symbol indicates the failure
2. Alarm list: An active alarm will be shown in the arlarm list
3. Event list: There is also shown an event about the time server failure, and consequently following time tagged events from any IED will be received with a quality flag time faulty that will be shown in the event list with a “T” entry at the beginning of each indivdual event list entry

In practices the faulty time server would be replaced by an equivalent device and the configuration backup is restored to the new time server hardware. There was no need to change any setting for any other device in the system to get time synchronization working again.

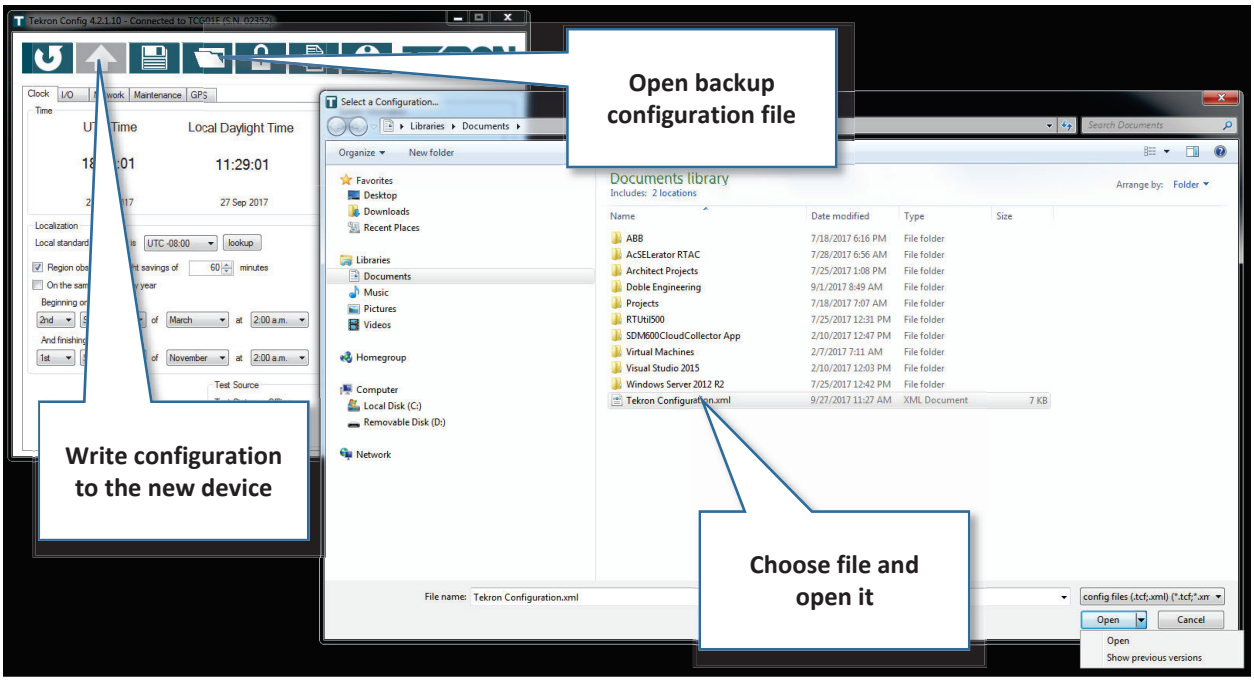


Figure D-14. Open configuration file before downloading to new time master device

Correct working of time synchronization was confirmed by checking the status of the earlier listed three levels of alarm indication.

D.2 Use Case 2: Maintenance testing of IEDs

For this use case the configuration for REC670 and REF615 is changed from IEC 61850 Edition 1 to Edition 2. Table D-1 and Table D-2 provide an overview about the different modes and the behavior according to IEC 61850 Edition 2. Note that blocked mode and behavior had been clarified with a tissue that supersedes the relevant IEC 61850 Edition 2 standard.

Table D-1. Values of mode and behavior according to IEC 61850-7-4 Edition 2

Value	Mode	
1	on	The application represented by the LN works. All communication services work and get updated values
2	on-blocked	The application represented by the LN works. No output data (digital by relays or analogue setting) will be issued to the process. All communication services work and get updated values. Data objects will be transmitted with quality "operatorBlocked". Control commands will be rejected. See note below Table A.1.
3	test	The application represented by the LN works. All communication services work and get updated values. Data objects will be transmitted with quality "test". Control commands with quality test will be accepted only by LNs in "test" or "test-blocked" mode. "Processed as valid" means that the application should react in the manner what is foreseen for "test".
4	test/blocked	The application represented by the LN works. No output data (digital by relays or analogue setting) will be issued to the process. All communication services work and get updated values. Data objects will be transmitted with quality "test". Control commands with quality test will be accepted only by LNs in TEST or TEST-Blocked mode.
5	off	The application represented by the LN doesn't work. No process output is possible. No control command should be acknowledged (negative response). Only the data object Mod and Beh should be accessible by the services.
NOTE	The Mod ="blocked" from edition 1 is changed in edition 2 to "on-blocked".	

Table D-2 Tissue values of mode and behavior for blocked

2	blocked	The application represented by the LN works. No (wired) output data (digital by relays or analogue setpoints) will be issued to the process. All communication services work and get updated values. Data objects will be transmitted with a relevant quality. Control commands with Test=false will be accepted. Control commands with Test=true will be rejected (negative acknowledgment with AddCause=Blocked-by-Mode).

Table D-3. Quality bit definition table according IEC 61850-7-3 Edition 2

Quality type definition			
Attribute name	**Attribute type**	**Value/Value range**	**M/O/C**
	PACKED LIST		
validity	CODED ENUM	good | invalid | reserved | questionable	M
detailQual	PACKED LIST		M
overflow	BOOLEAN	DEFAULT FALSE	M
outOfRange	BOOLEAN	DEFAULT FALSE	M
badReference	BOOLEAN	DEFAULT FALSE	M
oscillatory	BOOLEAN	DEFAULT FALSE	M
failure	BOOLEAN	DEFAULT FALSE	M
oldData	BOOLEAN	DEFAULT FALSE	M
inconsistent	BOOLEAN	DEFAULT FALSE	M
inaccurate	BOOLEAN	DEFAULT FALSE	M
source	CODED ENUM	process | substituted DEFAULT process	M
test	BOOLEAN	DEFAULT FALSE	M
operatorBlocked	BOOLEAN	DEFAULT FALSE	M

D.2.1 Test Case 1: IEC 61850 Edition2, Mode: On

This is the normal operation mode for IEDs. The status of the publisher and subscriber is as followed:

Publisher: REF615, Mod/Beh = ON, q = good
Subscriber: REC670, Mod/Beh = ON, q = good

To verify the correct behavior the breaker position of the REF615 is published as GOOSE message. The REC670 subscribes to that GOOSE message.

Step 1: Change mode of the IED

The mode of the IED is changed using Vendor 2's configuration tool of from the IEDs HMI.

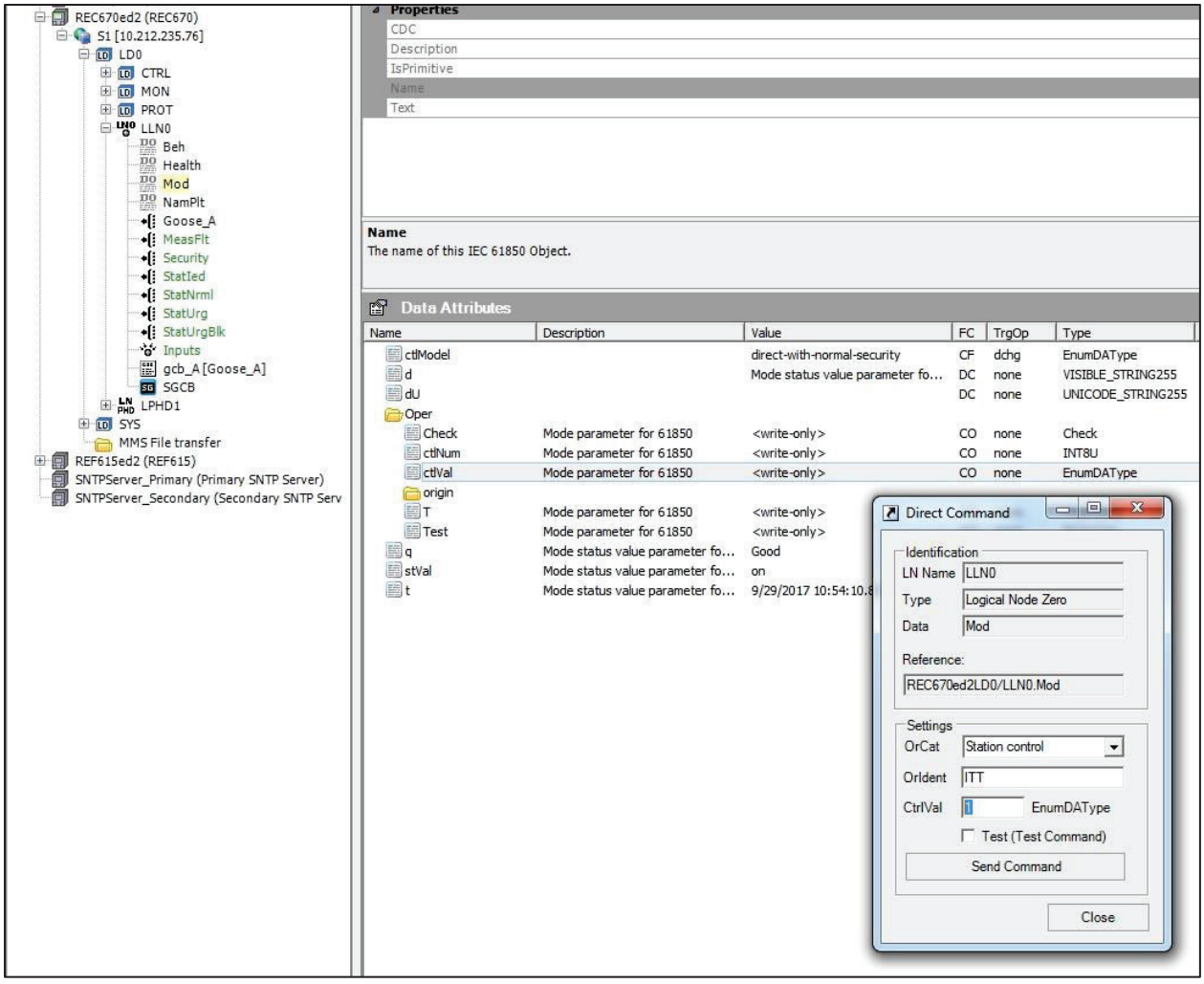


Figure D-15. Setting mode in Vendor 2's configuration tool for REC670

Step 2: Check correct circuit breaker status in subscriber IED

The circuit breaker status at the REF615 was closed. To verify the correctly received value at the REC670 the online status monitoring of the logic residing inside the REC670 is used:

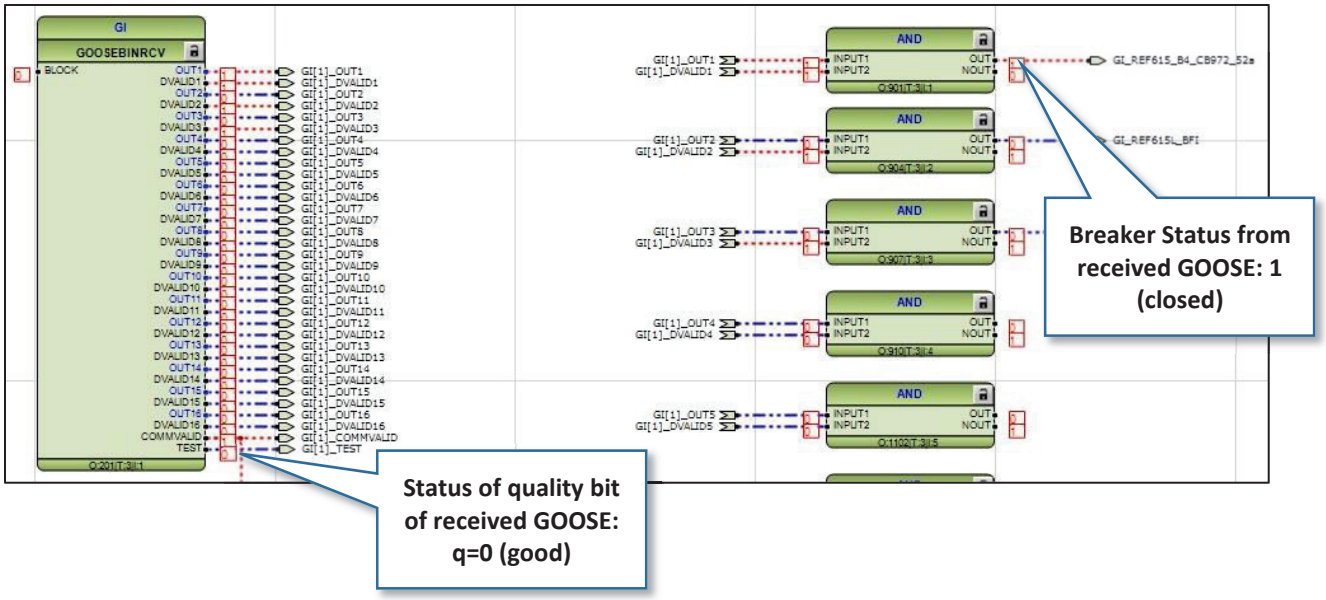


Figure D-16. Online status of received GOOSE (q=good) in REC670 (mode=on)

Step 3: Check captured message on the station bus

The capture of the GOOSE message demonstrates the status change and the quality bit information:

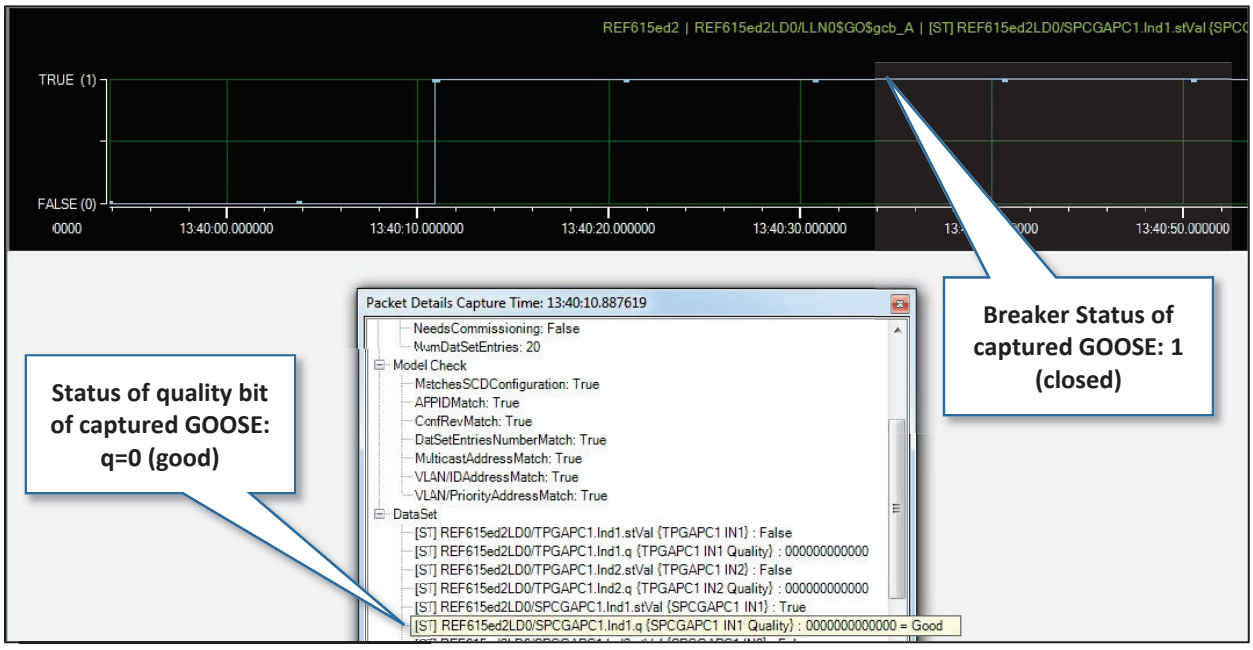


Figure D-17. Captured GOOSE (q=good) message sent by REF615

D.2.2 Test Case 2: IEC 61850 Edition2, Mode: Test

In this situation the IED in mode=test is isolated from IEDs in normal operation. Meaning the IEDs under normal operation will ignore the GOOSE message from the IED in test mode.

Publisher: REF615, Mod/Beh = Test, q=test
Subscriber: REC670, Mod/Beh = ON, q= good

To verify the correct behavior the breaker position of the REF615 is published as GOOSE message. The REC670 subscribes to that GOOSE message. The subscriber should receive the test GOOSE message but not process the status value.

Step 1: Change mode of the IED

The mode of the REF615 is changed using Vendor 2's configuration tool to "test".

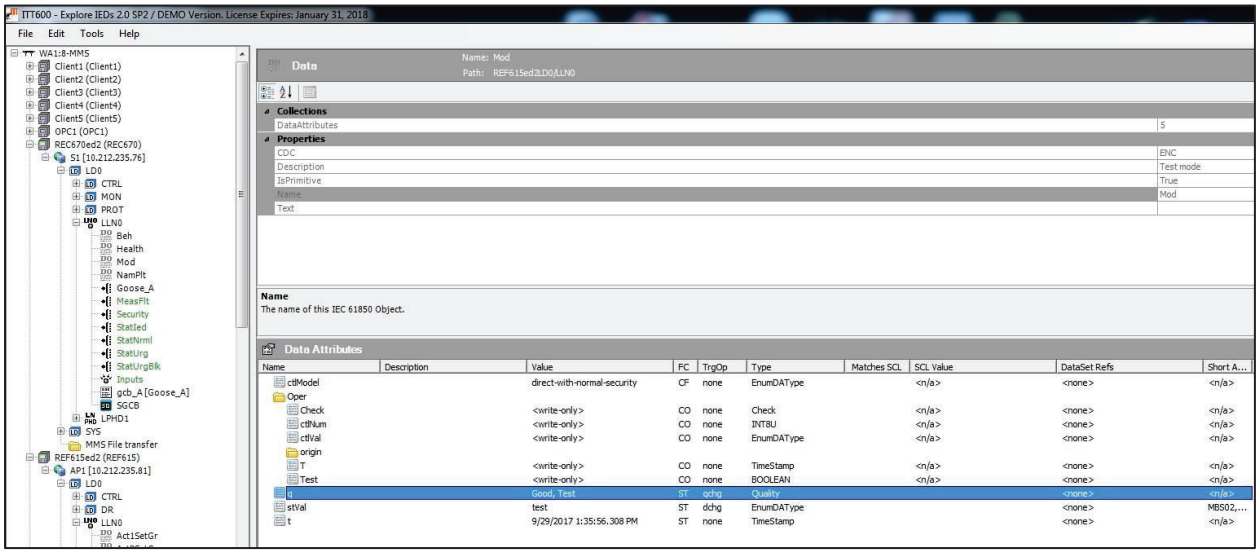


Figure D-18. Setting mode in Vendor 2's configuration tool for REF615

Step 2: Check correct circuit breaker status in the subscriber IED

The circuit breaker status at the REF615 was closed. To verify the correctly received value at the REC670 the online status monitoring of the logic residing inside the REC670 is used:

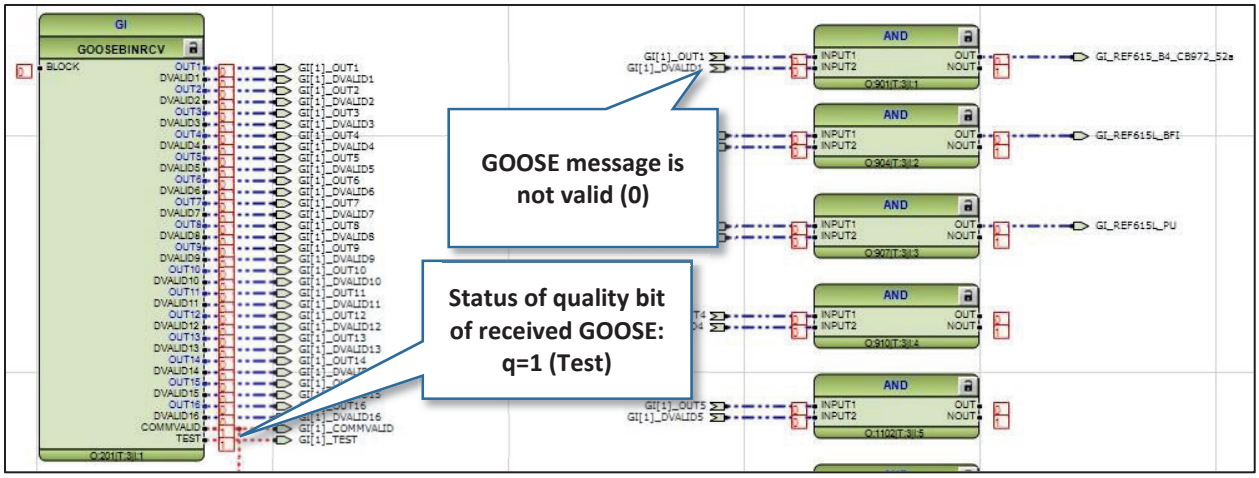


Figure D-19. Online status of received GOOSE (q=test) in REC670 (mode=on)

Step 3: Check captured message on the station bus

The capture of the GOOSE message demonstrates the status change and the quality bit information:

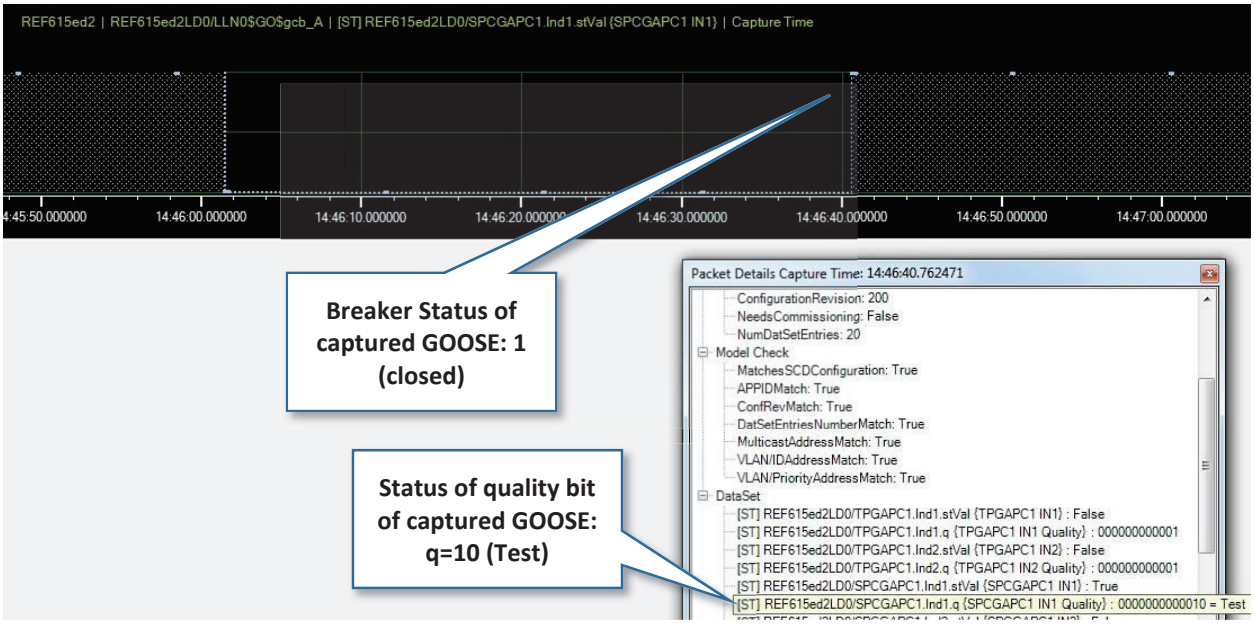


Figure D-20. Captured GOOSE (q=test) message sent by REF615

D.2.3 Test Case 3: IEC 61850 Edition2, Both IEDs Mode: Test

In this situation both IEDs are isolated from the rest of the system as both are set into mode=test. Meaning the both IEDs under test will now accept the GOOSE message from each other.

Publisher: REF615, Mod/Beh = Test, q=test
Subscriber: REC670, Mod/Beh = Test, q= test

To verify the correct behavior the breaker position of the REF615 is published as GOOSE message. The REC670 subscribes to that GOOSE message. The subscriber should receive the test GOOSE message and process it.

Step 1: Change mode of the IED

The mode of the REC670 is changed using Vendor 2's configuration tool to "test". Note the REF615 is already in test mode from the previous test case.

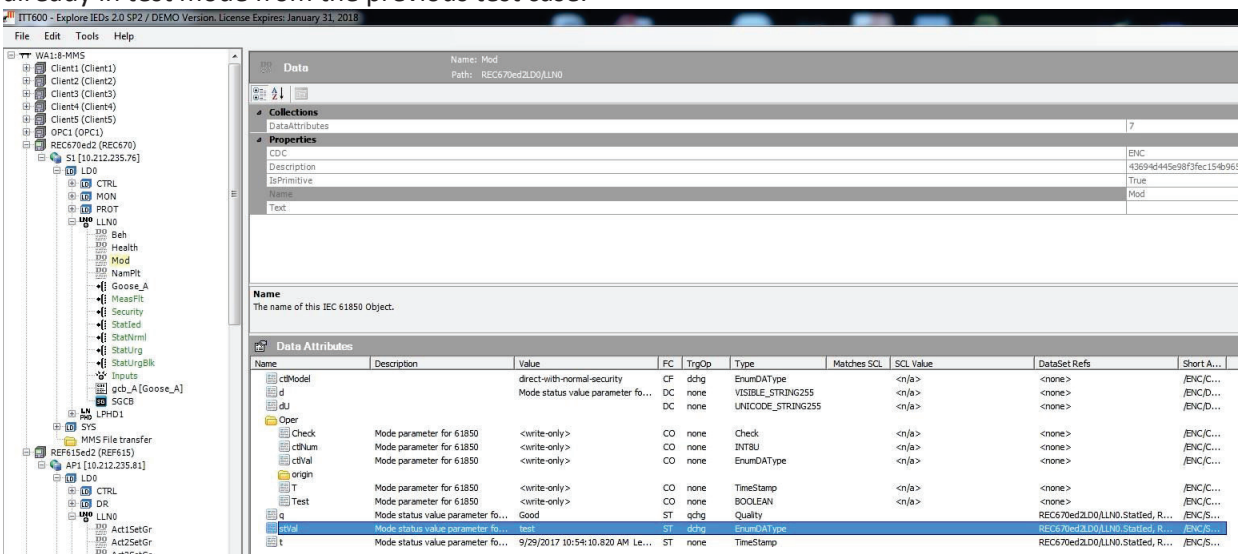


Figure D-21. Setting mode to "test" in Vendor 2's configuration tool for REC670

Step 2: Check correct circuit breaker status in the subscriber IED

The circuit breaker status at the REF615 was opened. To verify the correctly received value at the REC670 the online status monitoring of the logic residing inside the REC670 is used:

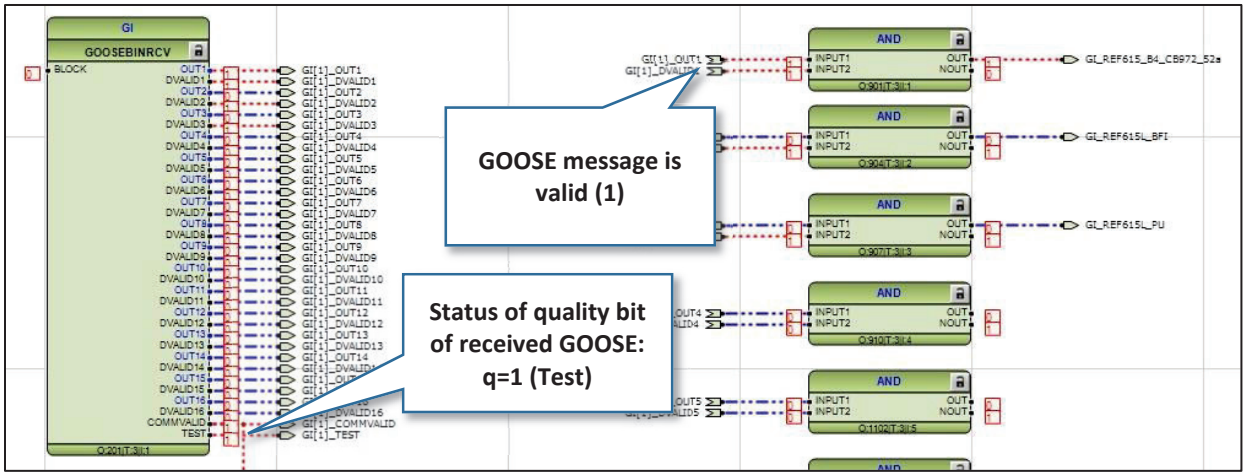


Figure D-22. Online status of received GOOSE (q=test) in REC670 (mode=test)

Step 3: Check captured message on the station bus

The capture of a general trip GOOSE message from REC670 triggered by received SV with q=test from the REF615 demonstrates that both IEDs behave correctly.



Figure D-23. Captured GOOSE (q=good) message sent by REC670

D.2.4 Test Case 4: IEC 61850 Edition2, Mode: Test/Blocked

In this situation as both IEDs are in test mode they are isolated from IEDs in normal operation. Meaning the IEDs under normal operation will ignore the GOOSE messages from the IEDs in test mode. The subscriber is additionally blocked and shall not control outputs.

Publisher: REF615, Mod/Beh = Test, q=test
Subscriber: REC670, Mod/Beh = Test/Blocked, q= good

Note: In order to not trip the output contact, either the signal needs to be connected to a LN related to a primary equipment such as XCBR or the LN needs to be linked to the block signal.

Step 1: Set REC670 to Test/Block mode, REF615 is already in Test mode from previous test case

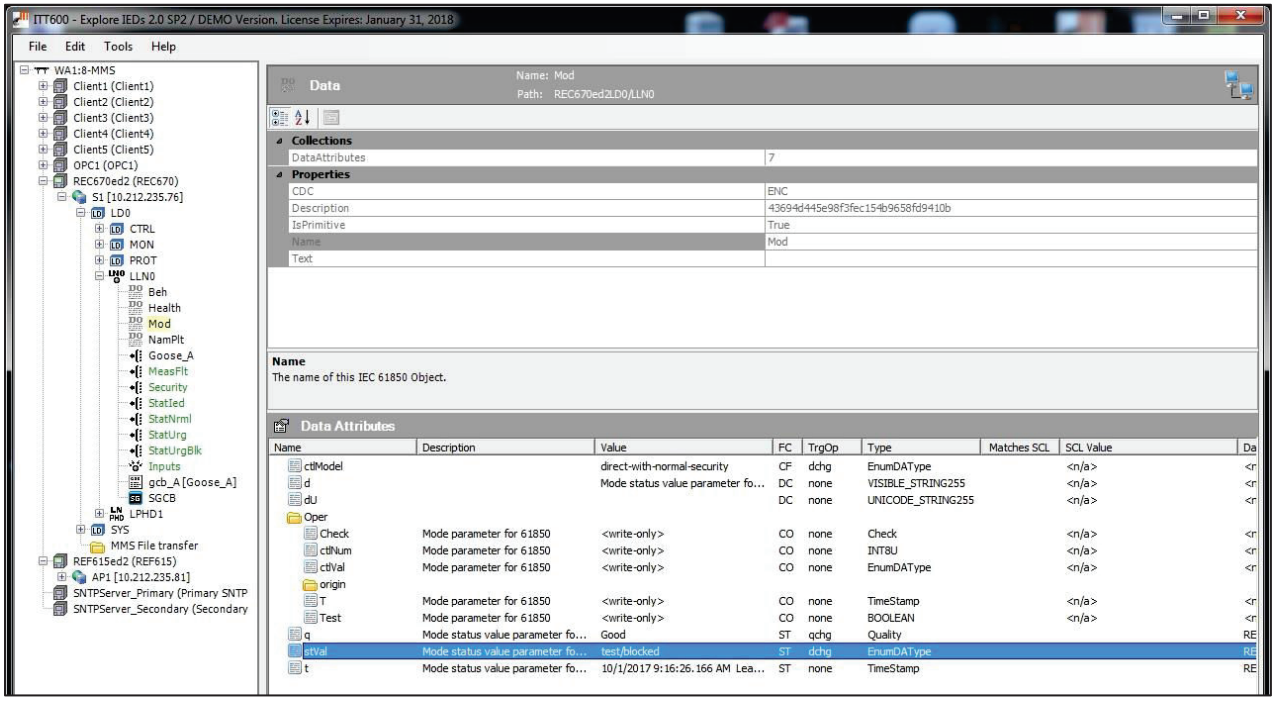


Figure D-24. Setting mode to "test/blocked" in Vendor 2's configuration tool for REC670

Step 2: Simulate overcurrent situation using RTDS injecting to REF615 and observe correct GOOSE trip message in Vendor 2's configuration tool

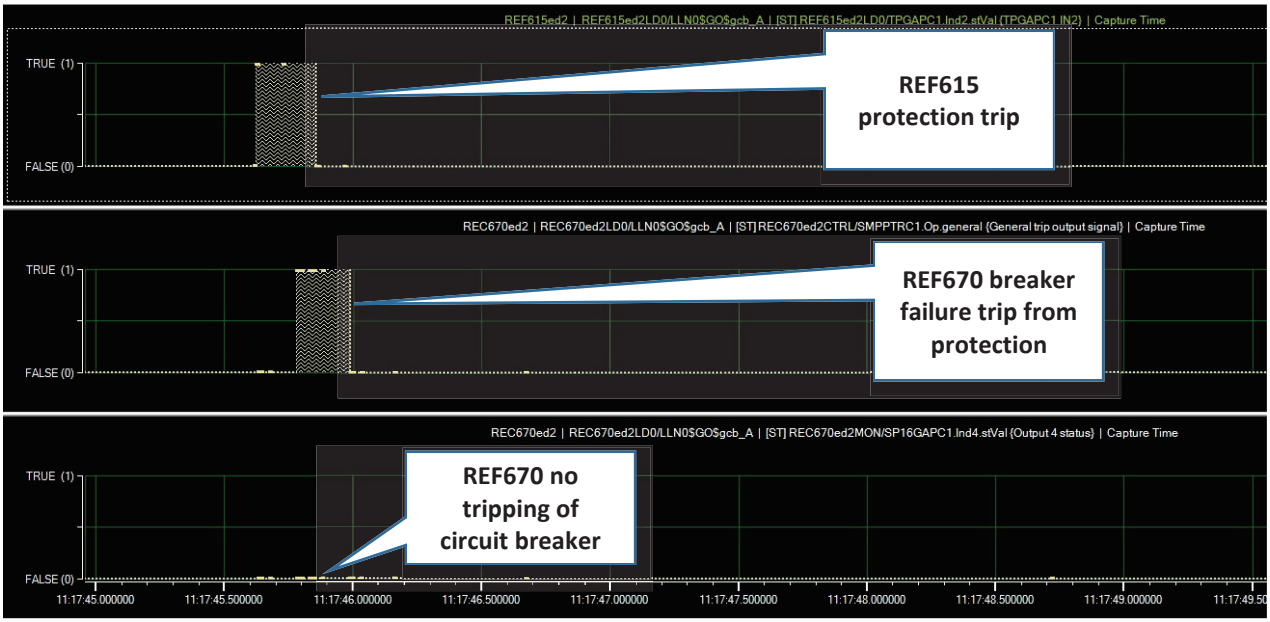


Figure D-25. Captured GOOSE messages with test and test/blocked modes

Step 3: Confirm correct behavior checking relevant events received by Vendor 2's configuration tool as an MMS client to REF615 and REC670.

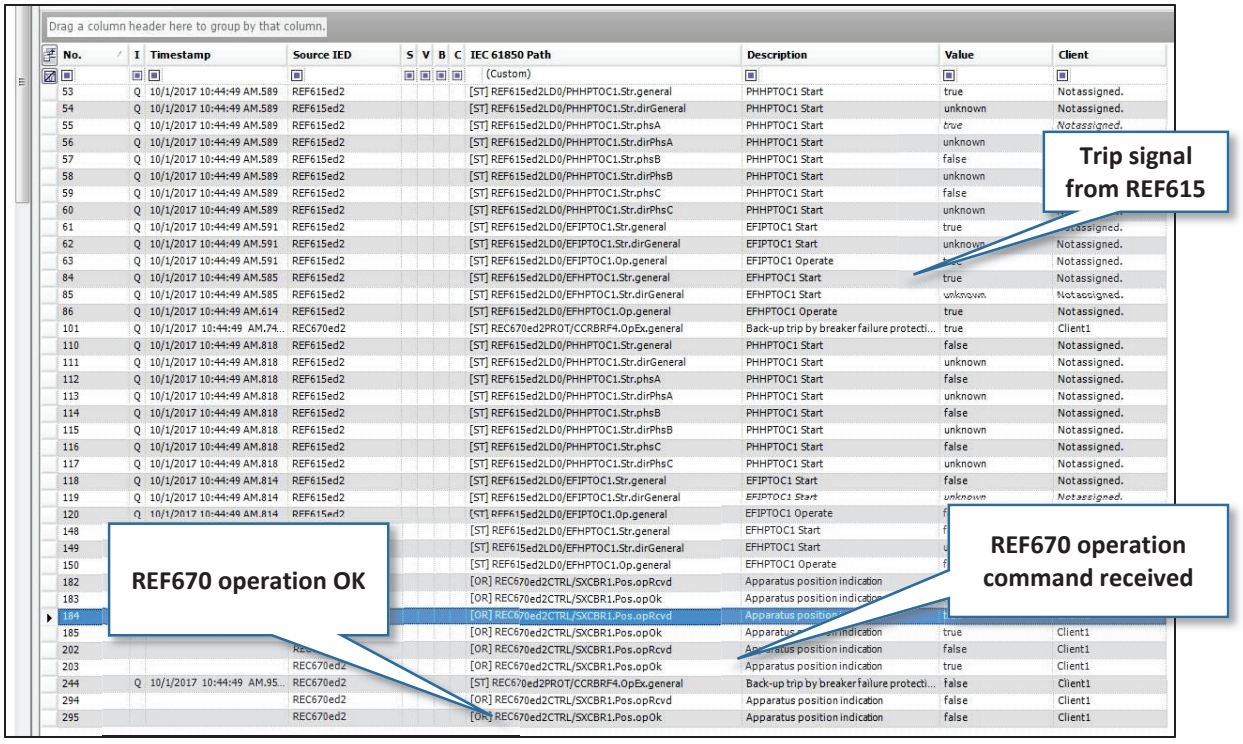


Figure D-26. Captured events from REC670 and REF615

Step 4: Confirm the correct operation in case both REC670 and REF615 are in test mode

In this scenario the GOOSE message connected to the REC670 XCBR position should be published with q=test compared to the situation in step 2 where it is not published because REC670 was in test/blocked mode.

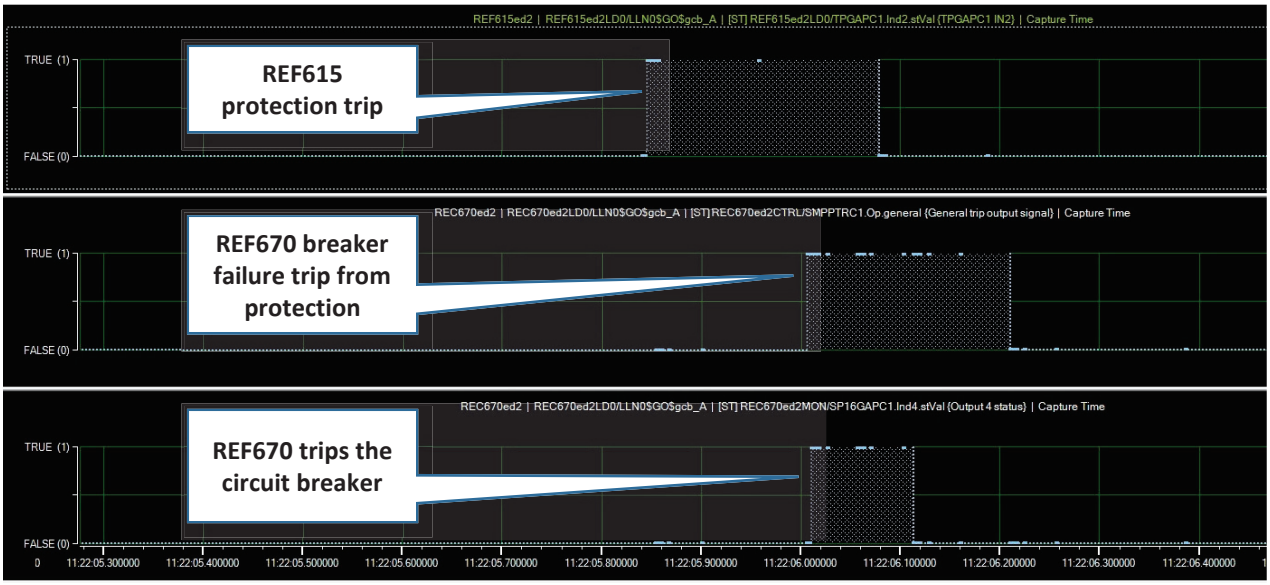


Figure D-27. Captured GOOSE messages with test and test modes

D.2.5 Test Case 5: IEC 61850 Edition2, Simulation: Off

This is the normal operation mode for IEDs. The status of the publisher and subscriber is as followed:

Publisher: Omicron CMC850, Simulation = OFF
Subscriber: REC670 - BKL30, LPHD.Sim = off

To verify the correct behavior the measurement on the REC670 HMI is compared to the value submitted by SAM600 and injected by RTDS.

D.2.6 Test Case 6: IEC 61850 Edition2, Simulation: On

This is the situation where test-set is connected and the IED subscribes to the measurements from the test-set.

Publisher: Omicron CMC850, Simulation = On
Subscriber: REC670 - BKL30, LPHD.Sim = On

To verify the correct behavior the measurement on the REC670 HMI is compared to the value injected by the test-set.

Step 1: Connect test-set and inject simulated sampled values

Before starting simulation in the omicron test-set, the simulation flag is set to simulated.

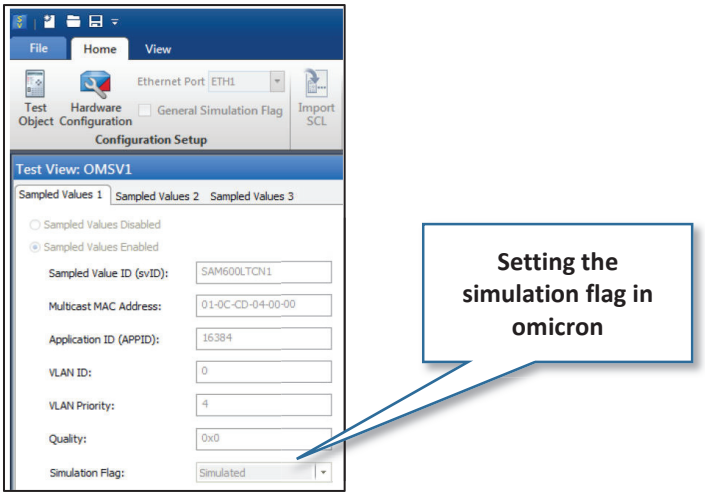


Figure D-28. Setting Simulation Flag in Omicron Tool

Step 2: The following values are injected to the process bus:

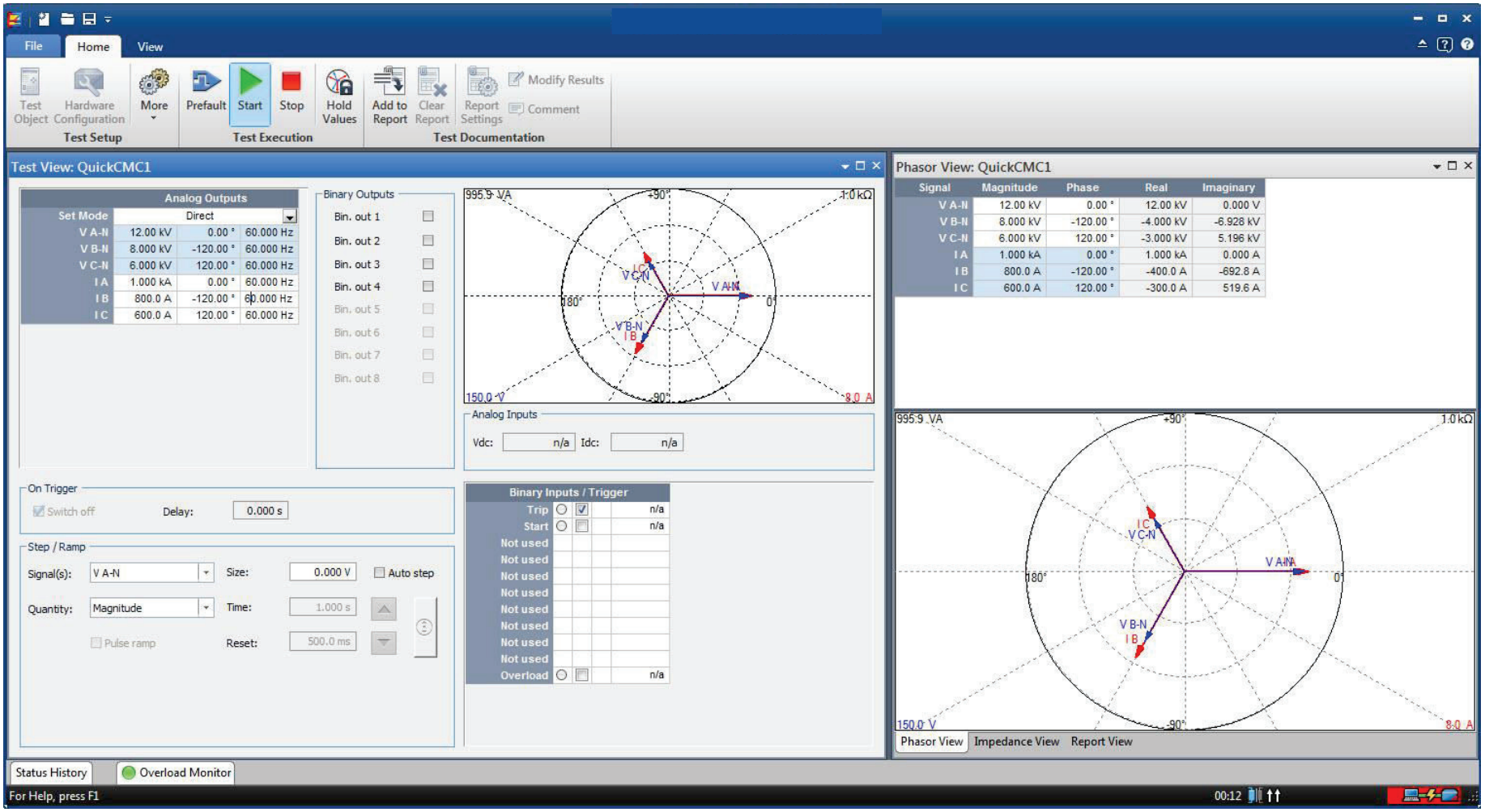
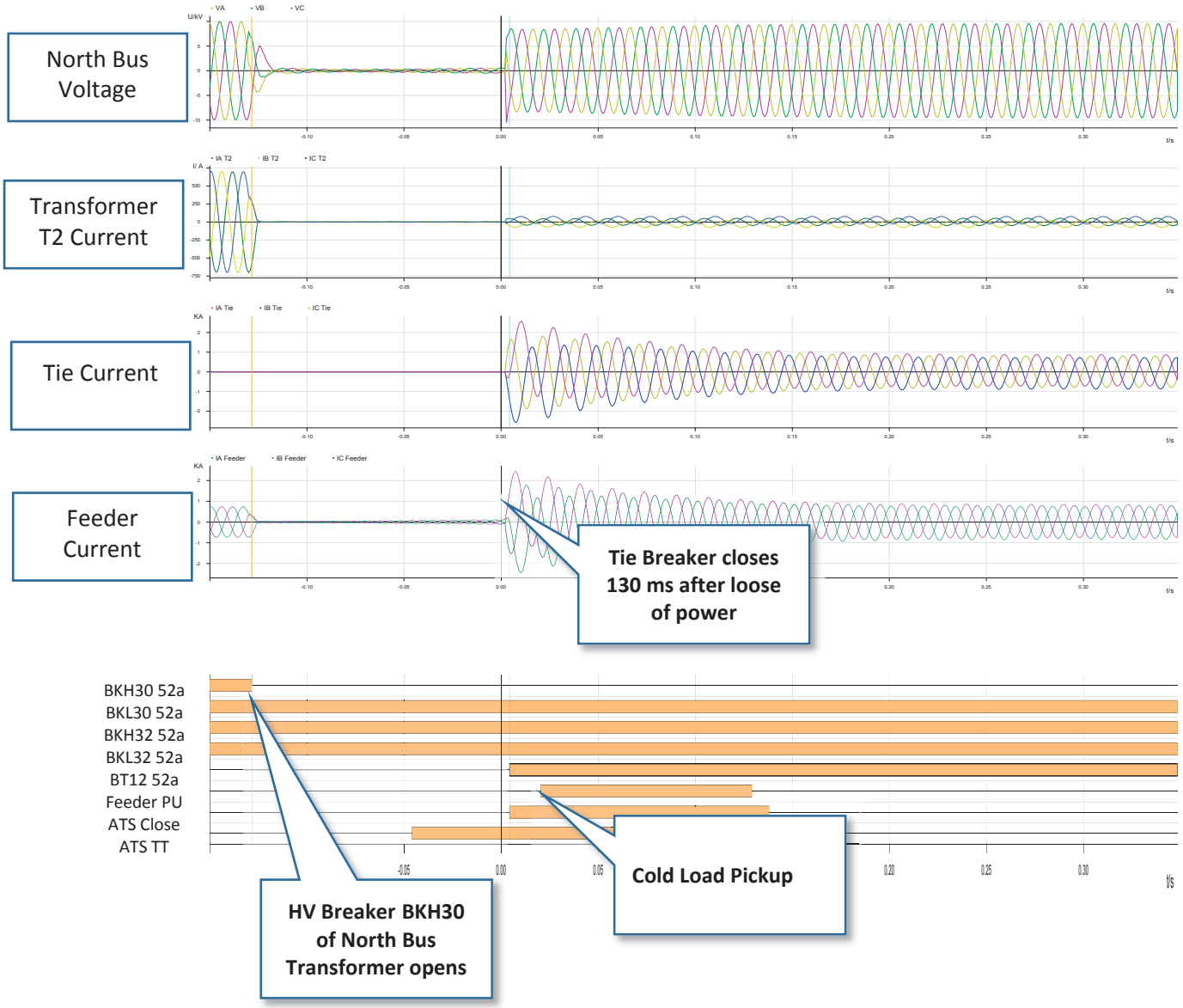


Figure D-29. Omicron Tool: Simulated SV streams

D.3 Use Case 4: Automatic transfer scheme

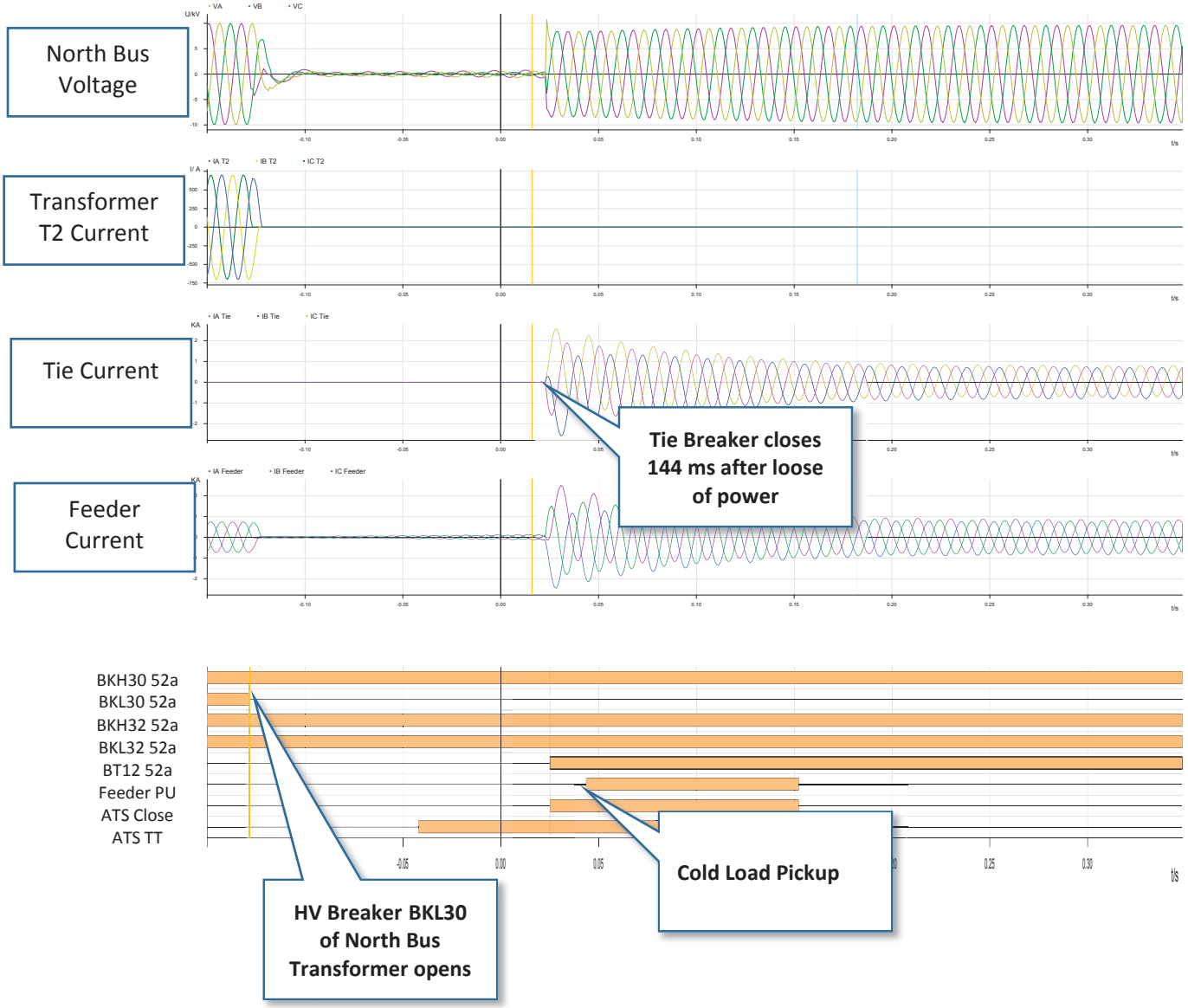
D.3.1 Test Case 1: HV-Side north bus transformer breaker opens

Case	Test Case	Description	Results IEC 61850 Design
1	HV-side North Bus transformer breaker BKH30 opens	• All transformer breakers (BKH30, BKL30, BKH32, BKL32) closed and North Bus and South Bus energized • Disconnect source by opening HV breaker of North Bus transformer T2 (BKH30) • Automatic transfer scheme is started • Check correct operation • Capture measurements and events using DFR	Scheme transferred correctly after 130 ms



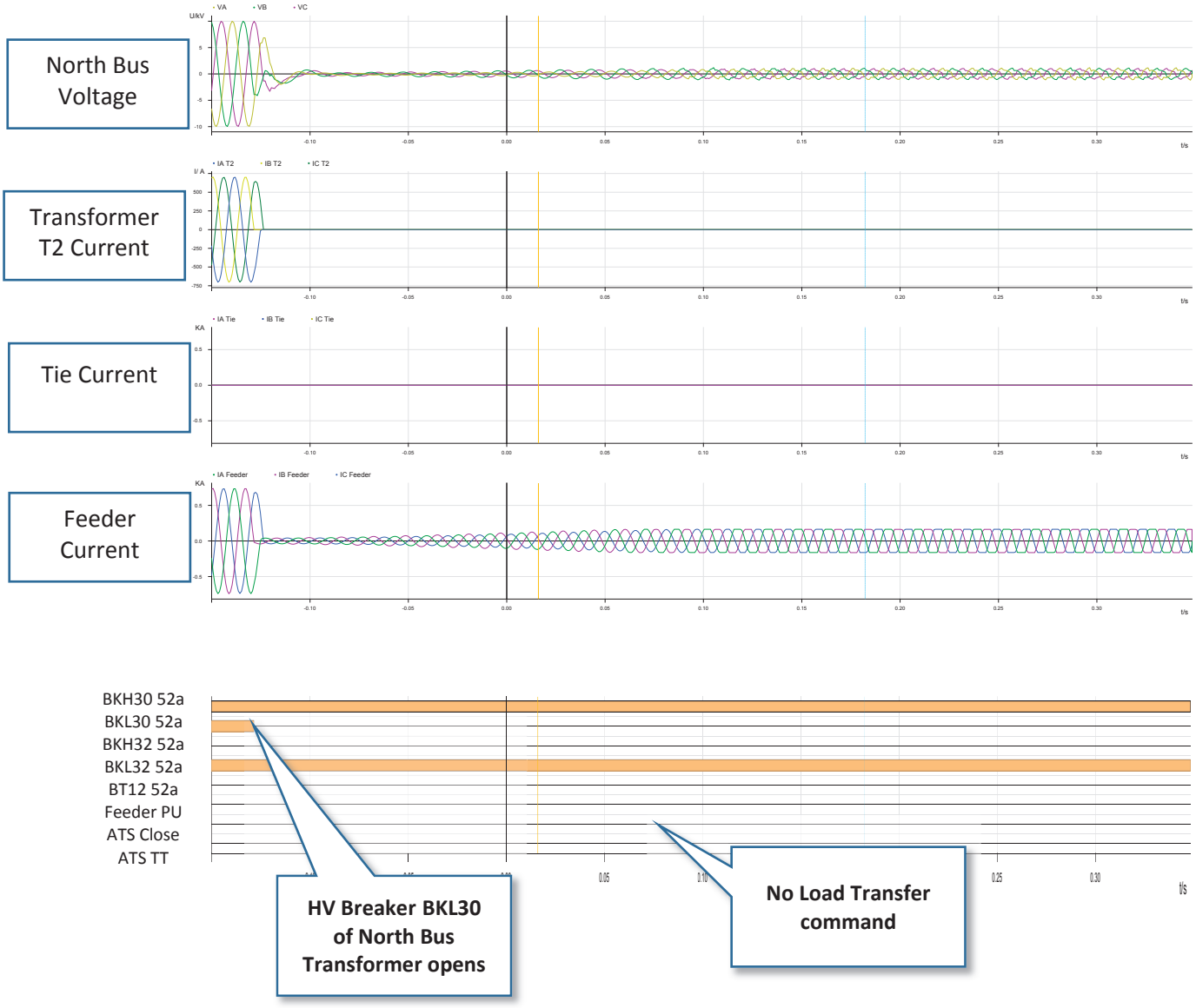
D.3.2 Test Case 2: MV side north bus transformer breaker opens

Case	Test Case	Description	Results IEC 61850 Design
2	MV-side North Bus transformer breaker BKL30 opens	• All transformer breakers (BKH30, BKL30, BKH32, BKL32) closed and North Bus and South Bus energized • Disconnect source by opening MV breaker of North Bus transformer T2 (BKL30) • Automatic transfer scheme is started • Check correct operation • Capture measurements and events using DFR	Scheme transferred correctly after 144 ms



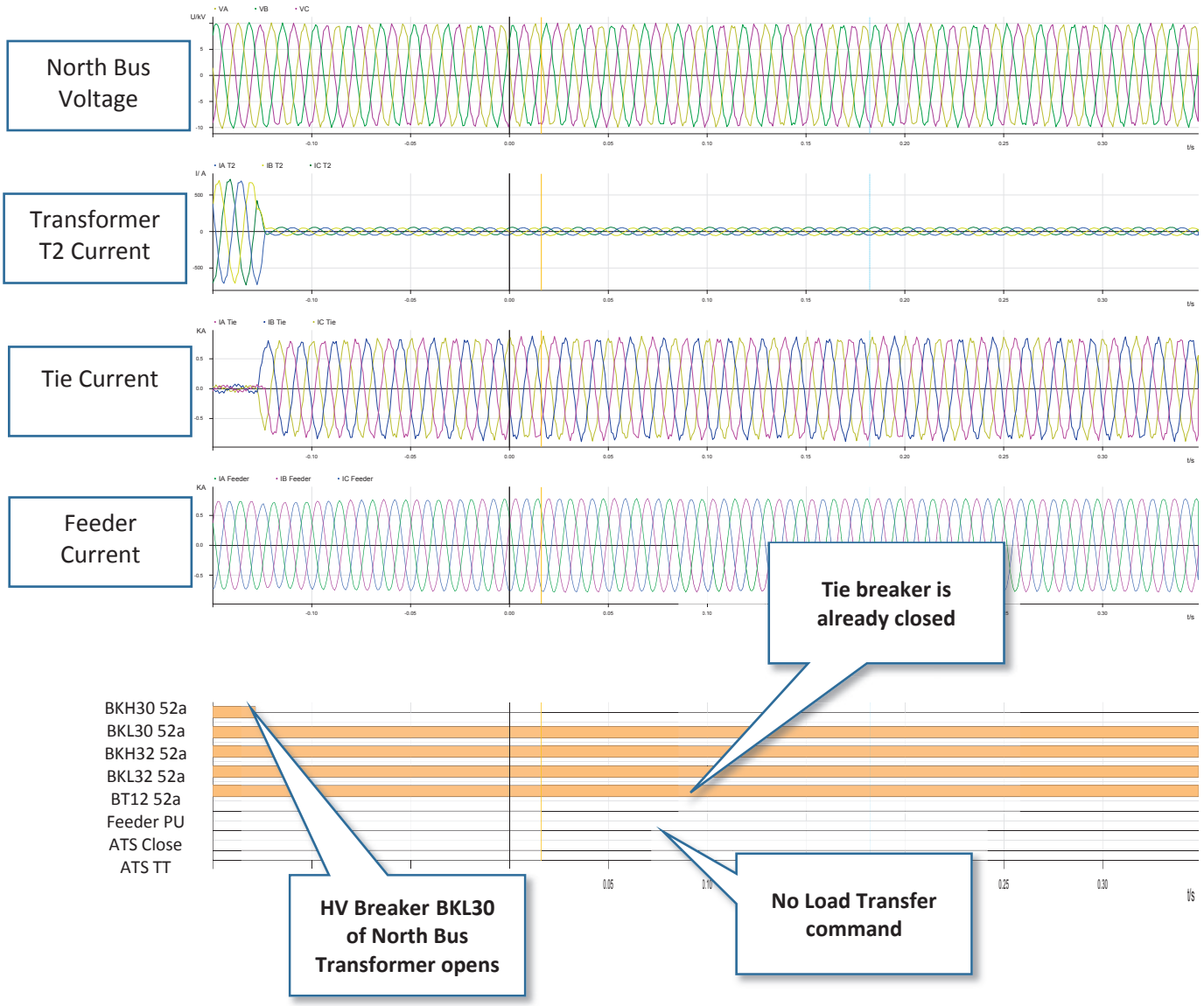
D.3.3 Test Case 3: South bus is de-energized when north bus transformer breaker opens

Case	Test Case	Description	Results IEC 61850 Design
3	South Bus is de-energized when North Bus transformer breaker opens	• South Bus High Side breaker BKH32 is open, all other transformer breakers (BKH30, BKL30BKL32) closed, and only North Bus is energized • Disconnect source by opening MV breaker of North Bus transformer T2 (BKL30) • Automatic transfer scheme is not started • Check correct operation	Scheme did not initiate a load transfer (correct operation)



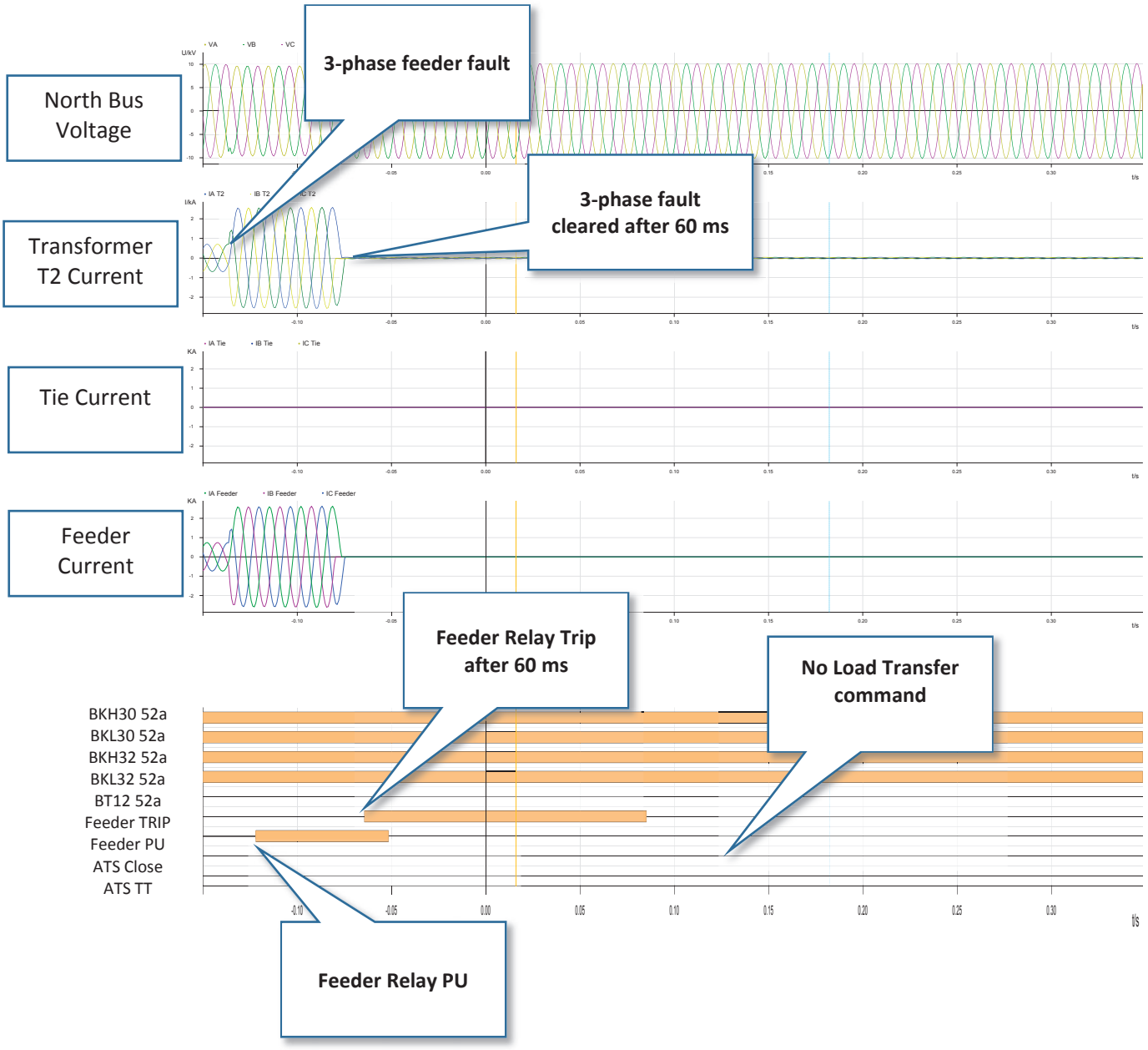
D.3.4 Test Case 4: Tie breaker is already closed when north bus transformer breaker opens

Case	Test Case	Description	Results IEC 61850 Design
4	Tie breaker is already closed when HV North Bus breaker opens	• All transformer breakers (BKH30, BKL30, BKH32, BKL32) closed and North Bus and South Bus energized • Tie breaker (BT12) is closed • Disconnect source by opening HV breaker of North Bus transformer T2 (BKH30) • Automatic transfer scheme is started • Check correct operation	Scheme did not initiate a load transfer (correct operation)



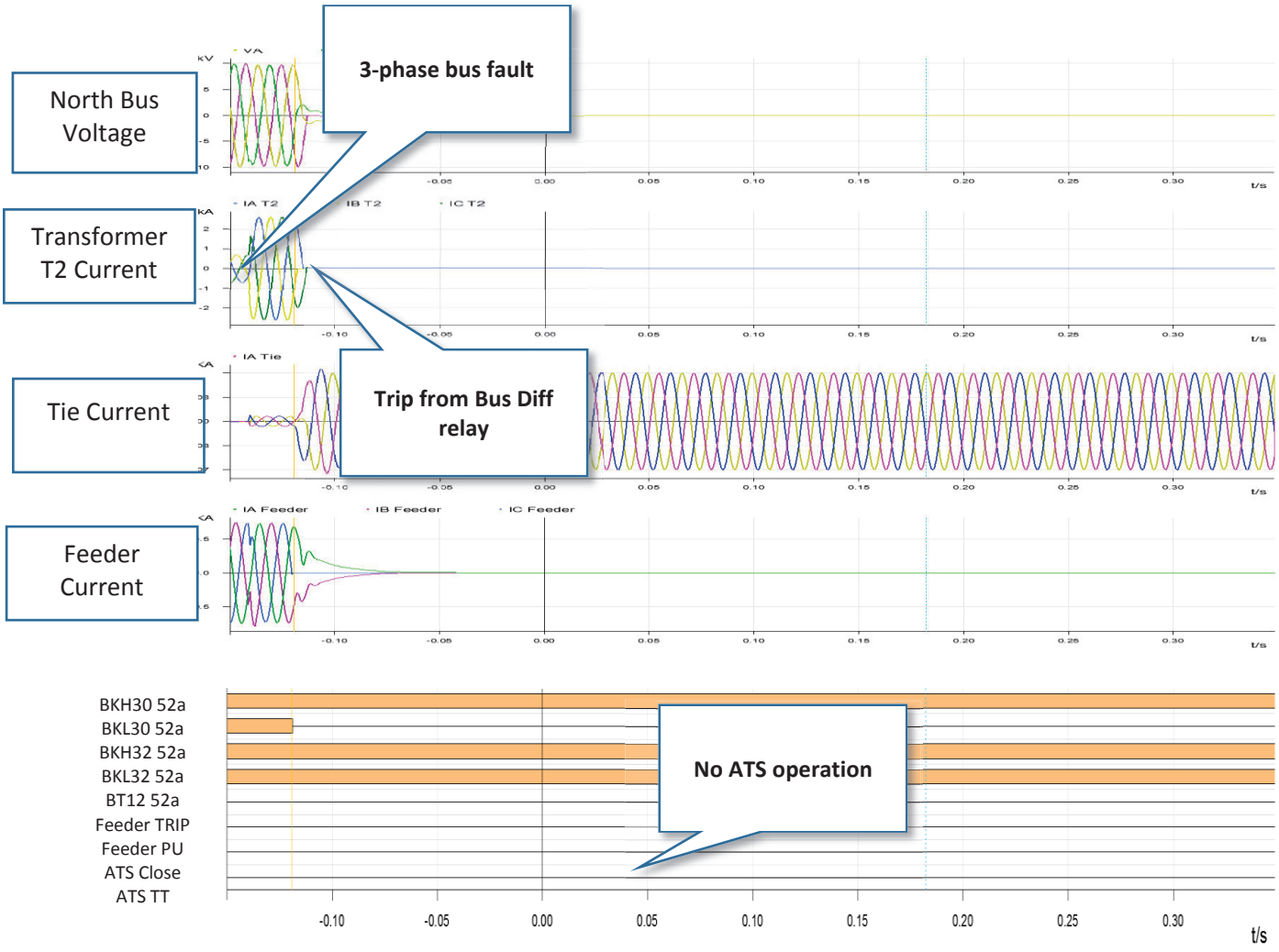
D.3.5 Test Case 5: Close-in feeder fault

Case	Test Case	Description	Results IEC 61850 Design
5	Close-In feeder fault	• All transformer breakers (BKH30, BKL30, BKH32, BKL32) closed and North Bus and South Bus energized • Apply close-in feeder fault (on Bus 301) • Automatic transfer scheme is not started • Check correct operation	Scheme did not initiate a load transfer (correct operation)



D.3.6 Test Case 6: North bus de-energization after bus fault

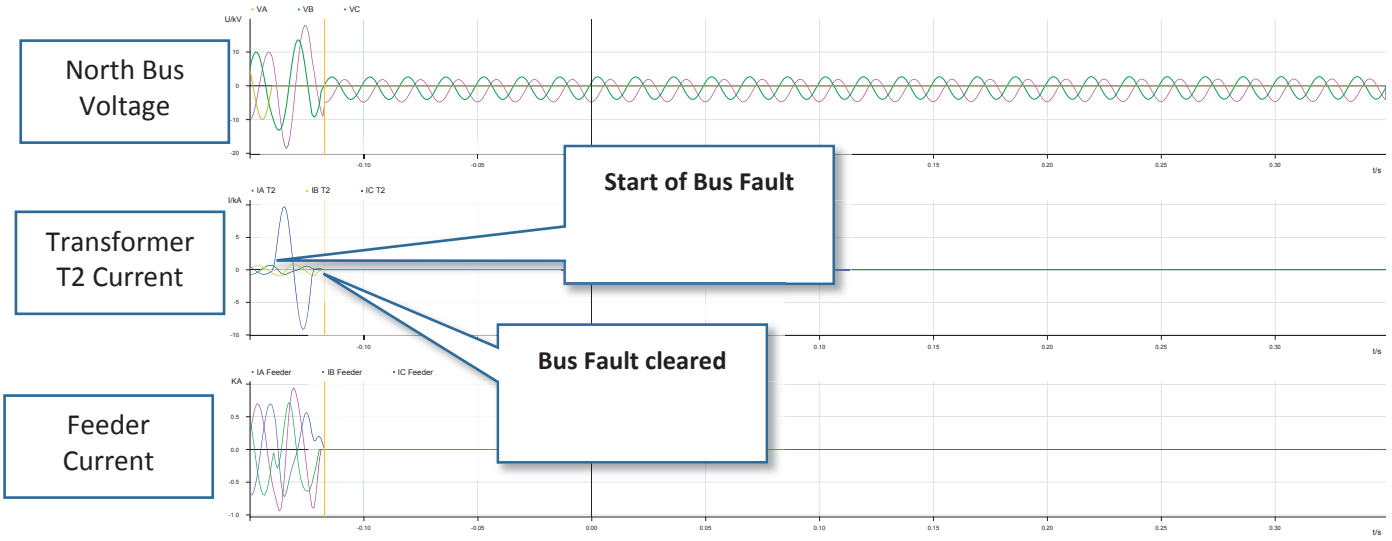
Case	Test Case	Description	Results IEC 61850 Design
6	North Bus de-energization after Bus Fault	• All transformer breakers (BKH30, BKL30, BKH32, BKL32) closed and North Bus and South Bus energized • Apply 3-phase fault on North Bus • Automatic transfer scheme is not started • Check correct operation	Scheme did not initiate a load transfer (correct operation)

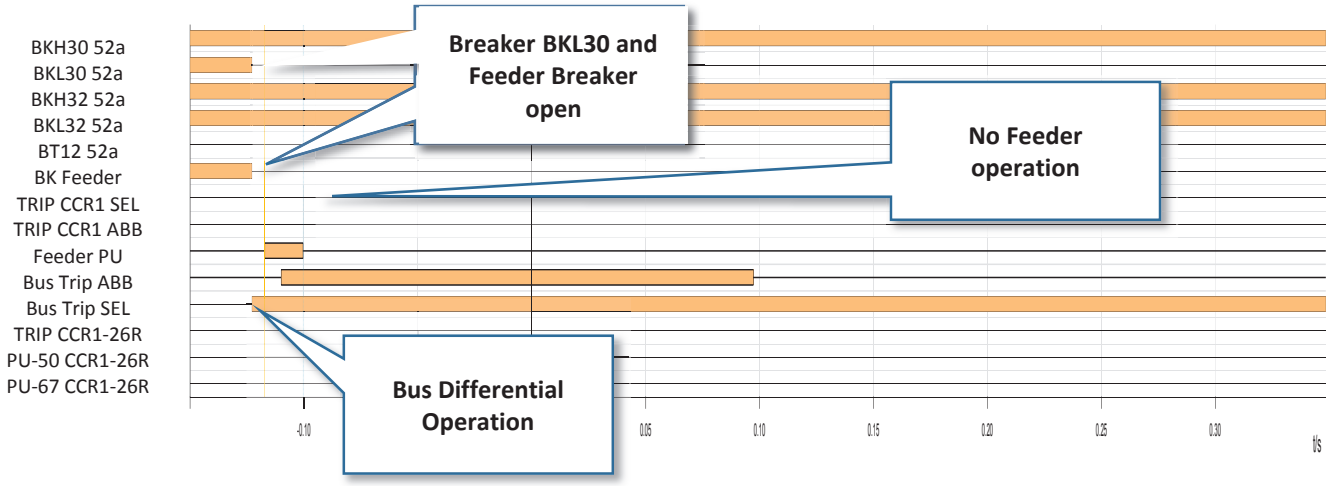


D.4 Use Case 5: Improved protection coordination

D.4.1 Test Case 1: Scheme response for bus fault

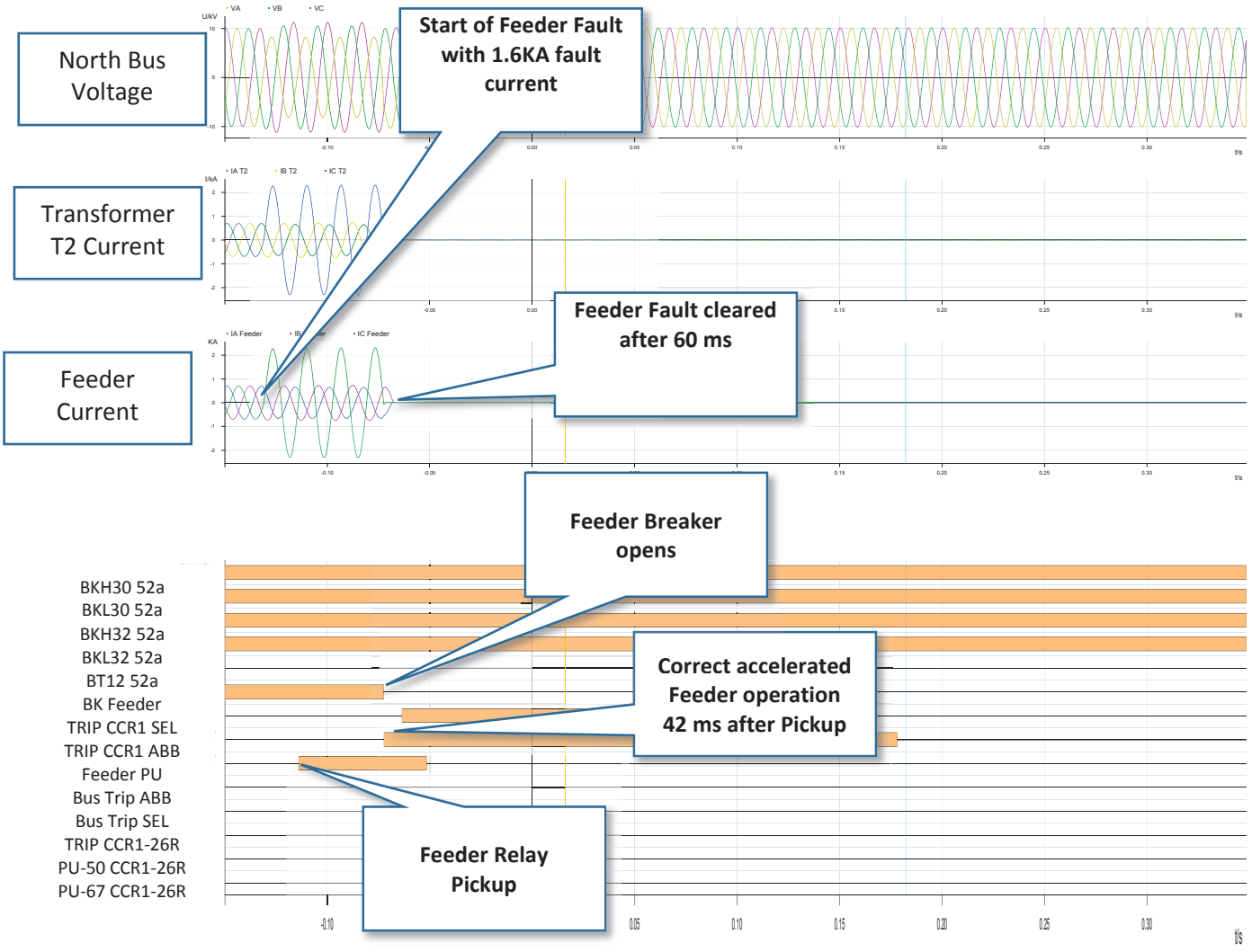
Test #	Test case	Description	Results Conventional Design	Results IEC 61850 Design
1	Substation bus fault	• South Bus and North Bus energized and all feeder breakers closed • Inject A-G Fault on North Bus • Bus protection trips all bus breakers	Instantaneous bus fault clearing by bus differential relay	Instantaneous bus fault clearing by bus differential relay





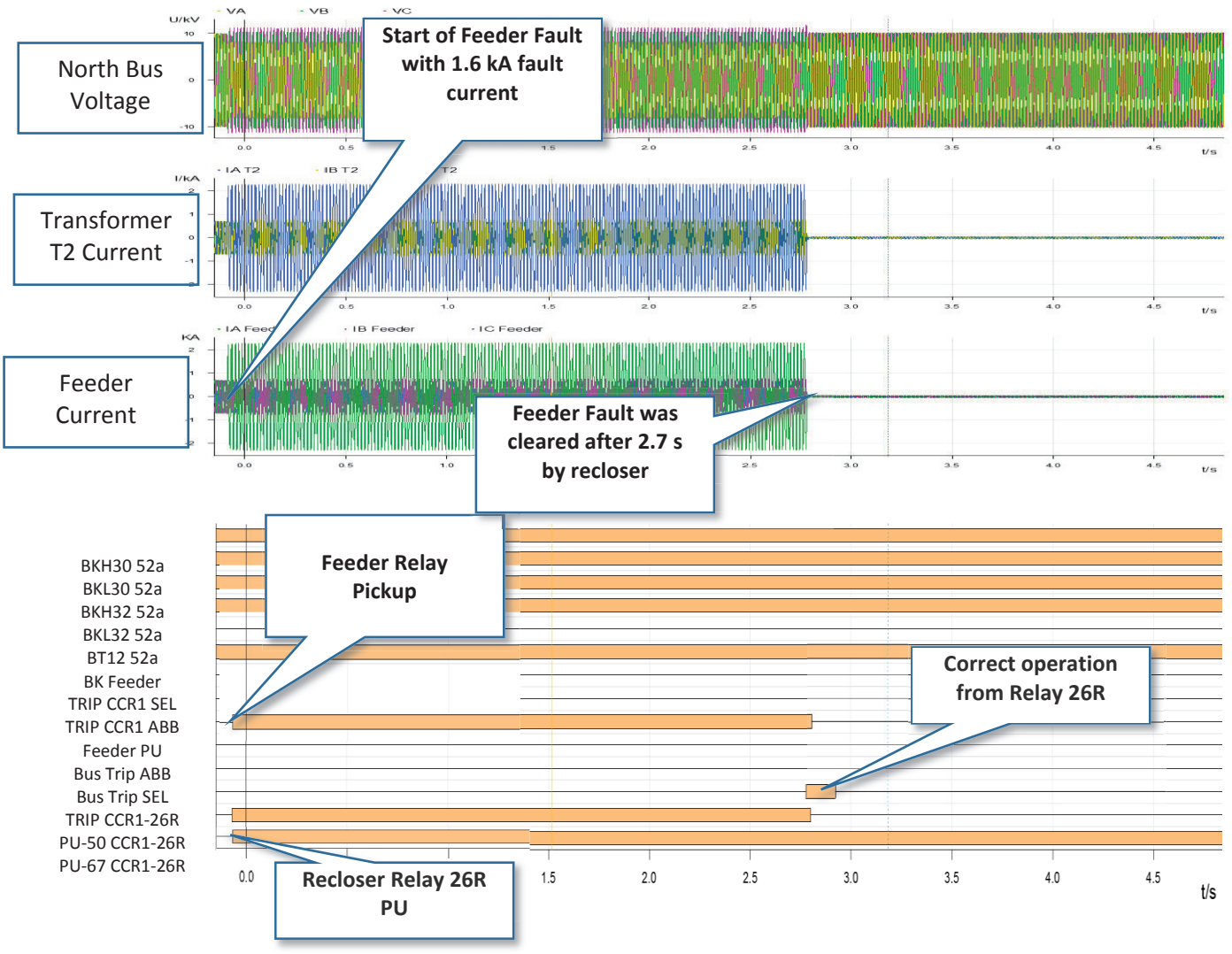
D.4.2 Test Case 2: Scheme response for close-in feeder fault

Test #	Test case	Description	Results Conventional Design	Results IEC 61850 Design
2	Close-In Feeder Fault	• North Bus is energized and target feeder is connected • Inject a A-G Close-In Feeder Fault (on Bus 301) with 5 Ohm • Feeder relay issues an instantaneous trip as it will not receive blocking signal from remote recloser	Element 51 in the feeder relay cleared the fault after 1.5 s due to 1.6 kA fault current	Fast fault clearing after 60 ms by advanced protection scheme



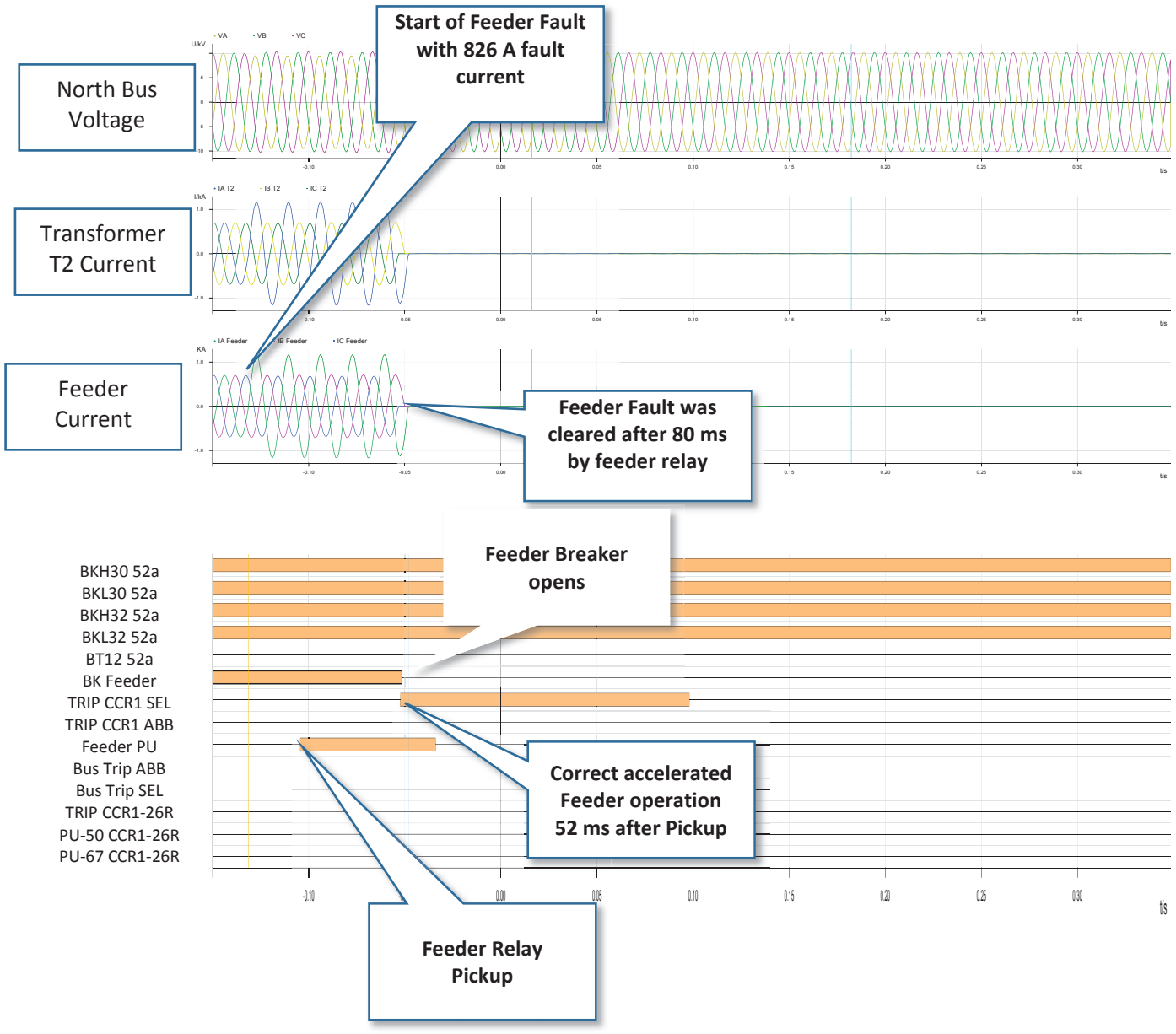
D.4.3 Test Case 3: Scheme response for feeder fault behind next recloser

Test #	Test case	Description	Results Conventional Design	Results IEC 61850 Design
3	Feeder Fault behind next Recloser	• North Bus is energized and target feeder is connected • Inject a A-G Feeder Fault (on Bus 302) with 5 Ohm • Recloser will trip fault and block CCR2 relay in Substation	Element 51 in the 26R recloser cleared fault after 1.2s due to 1.6 kA fault current	Element 51 in the 26R recloser cleared fault after 1.2 s due to 1.6 kA fault current



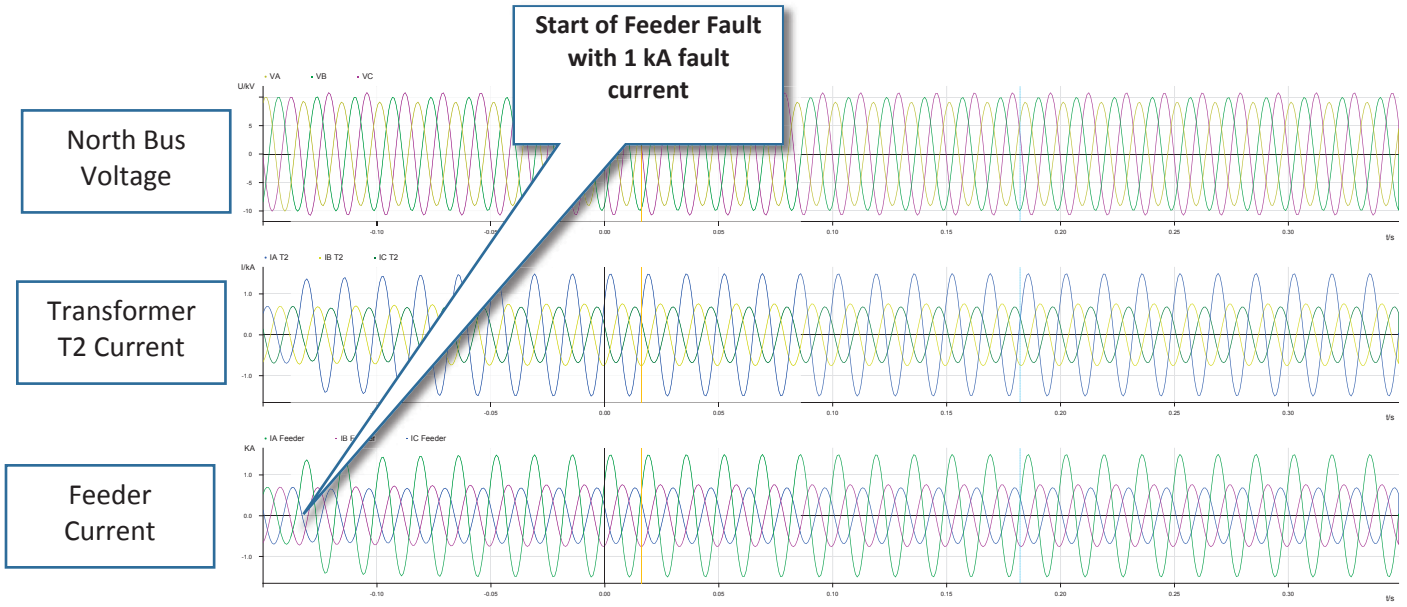
D.4.4 Test Case 4: High resistive close-in feeder fault

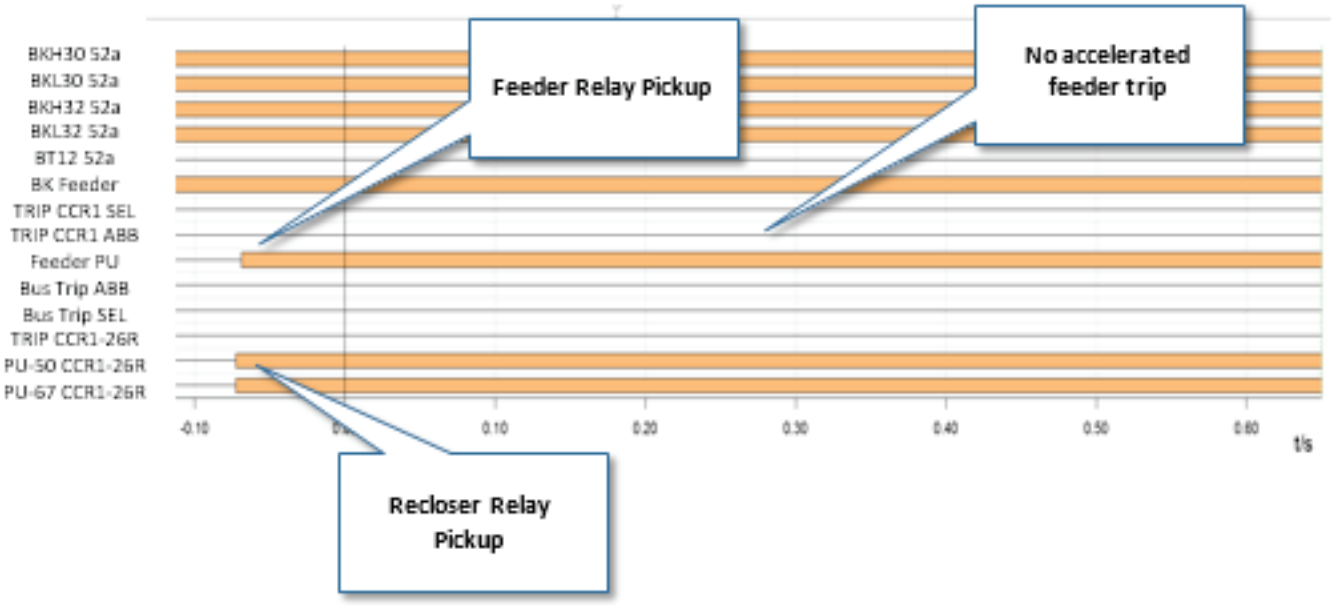
Test #	Test case	Description	Results Conventional Design	Results IEC 61850 Design
4	High Resistive Close-In Feeder Fault	• North Bus is energized and target feeder is connected • Inject a A-G Close-In Feeder Fault (on Bus 301) with 20 Ohm • Feeder relay issues an instantaneously trip as it will not receive blocking signal from remote recloser	Element 51 in the feeder relay cleared the fault after 3.5s due to 830 A fault current	Fast fault clearing after 80 ms by advanced protection scheme



D.4.5 Test Case 5: Feeder end-of-line fault

Test #	Test case	Description	Results Conventional Design	Results IEC 61850 Design
5	Feeder End-of-Line Fault	• North Bus is energized and target feeder is connected • Inject a A-G Feeder End-of-Line Fault (on Bus 305) • Recloser 32R will trip fault	Fault cleared by 32R recloser after 1.2 s based on fault current	Fault cleared by 32R recloser after 1.2 s based on fault current





D.5 Use Case 6: DER control test results

D.5.1 PV 2 Results (SMA Inverter)

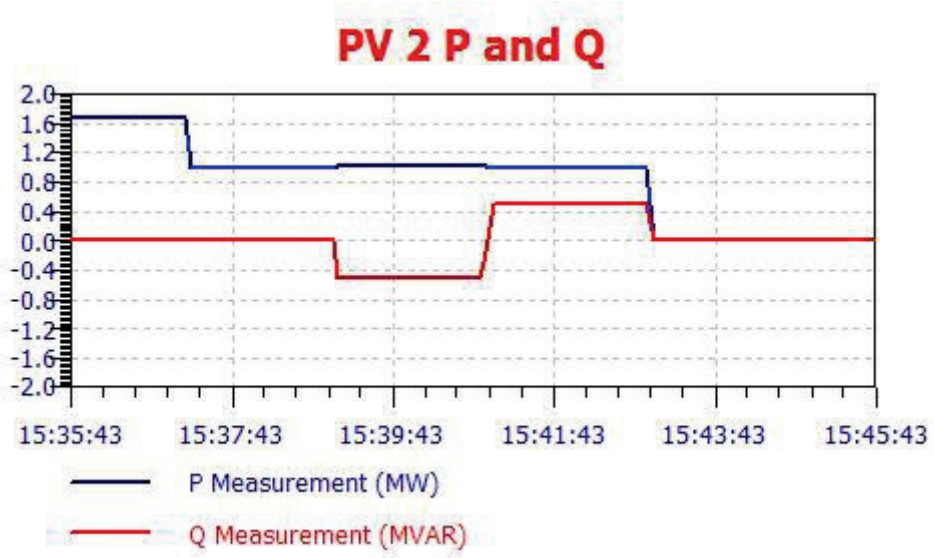


Figure D-30. Reponses of the SMA inverter in Control Mode 1

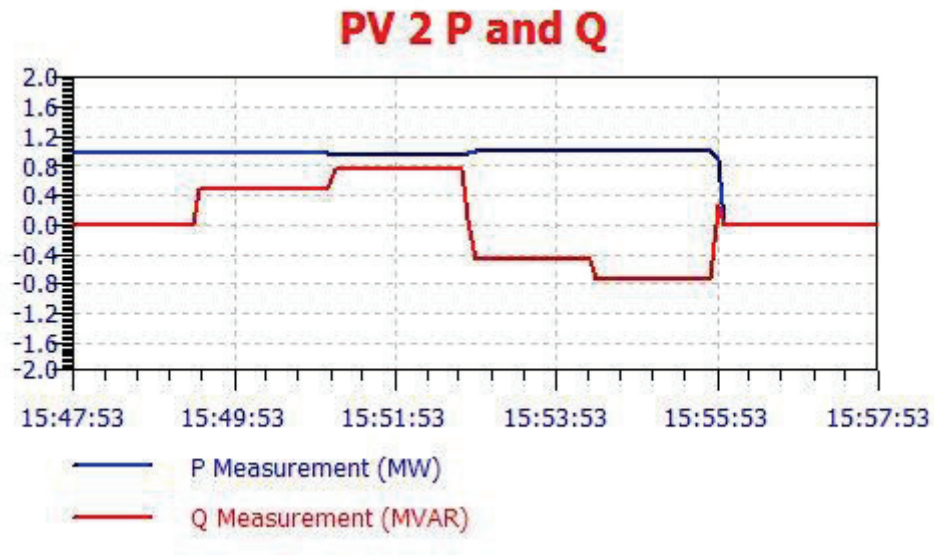


Figure D-31. Reponses of the SMA inverter in Control Mode 2

D.5.2 BESS 2 Results (Simulated)

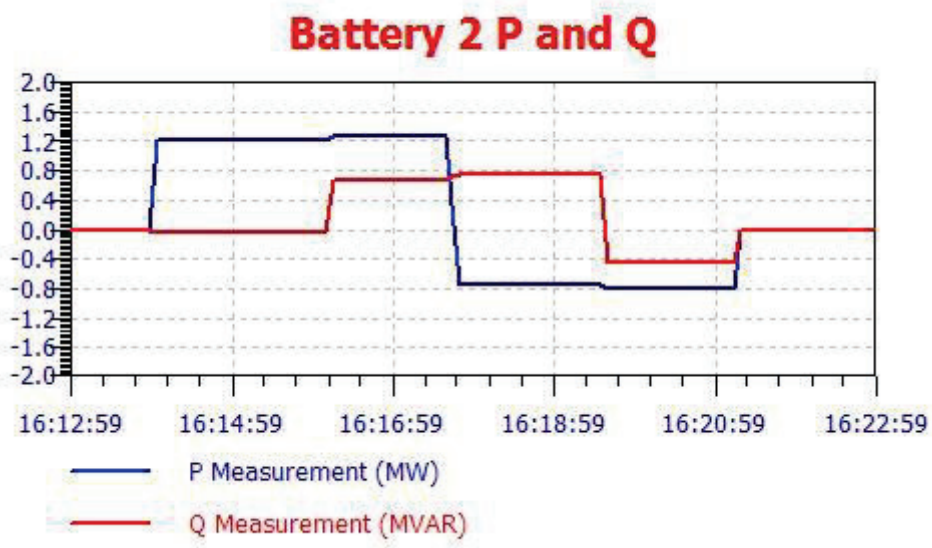


Figure D-32. Response of BESS 2 in Control Mode 1

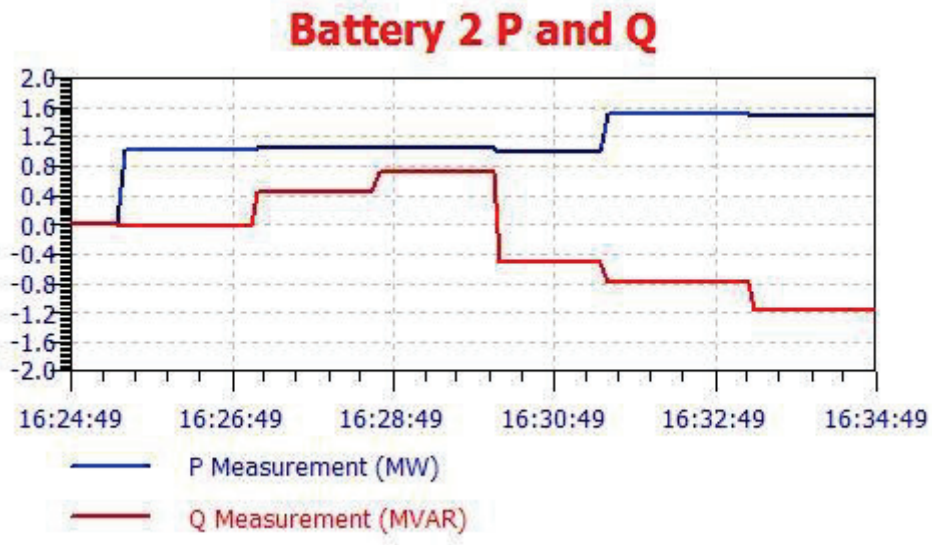


Figure D-33. Response of BESS 2 in Control Mode 2

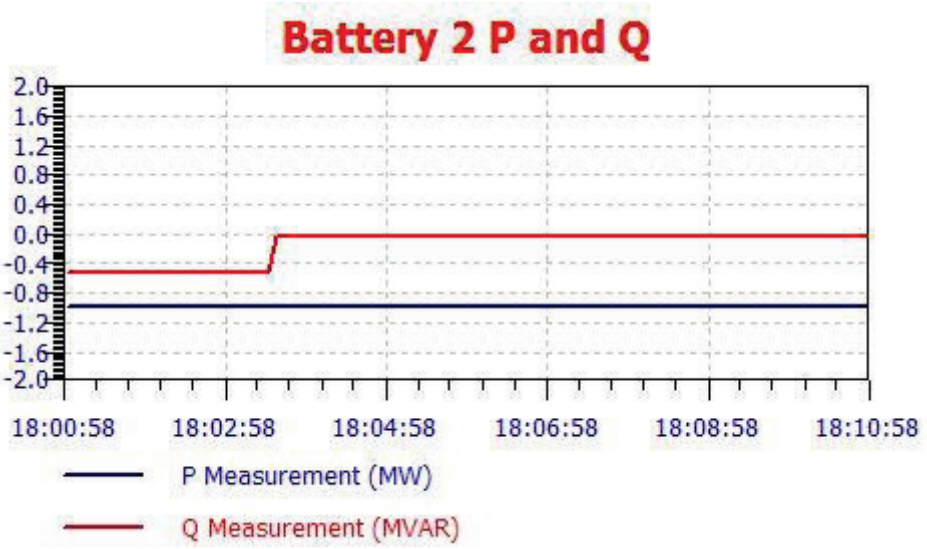


Figure D-34. Response of BESS 2 in Control Mode 3 (output power)

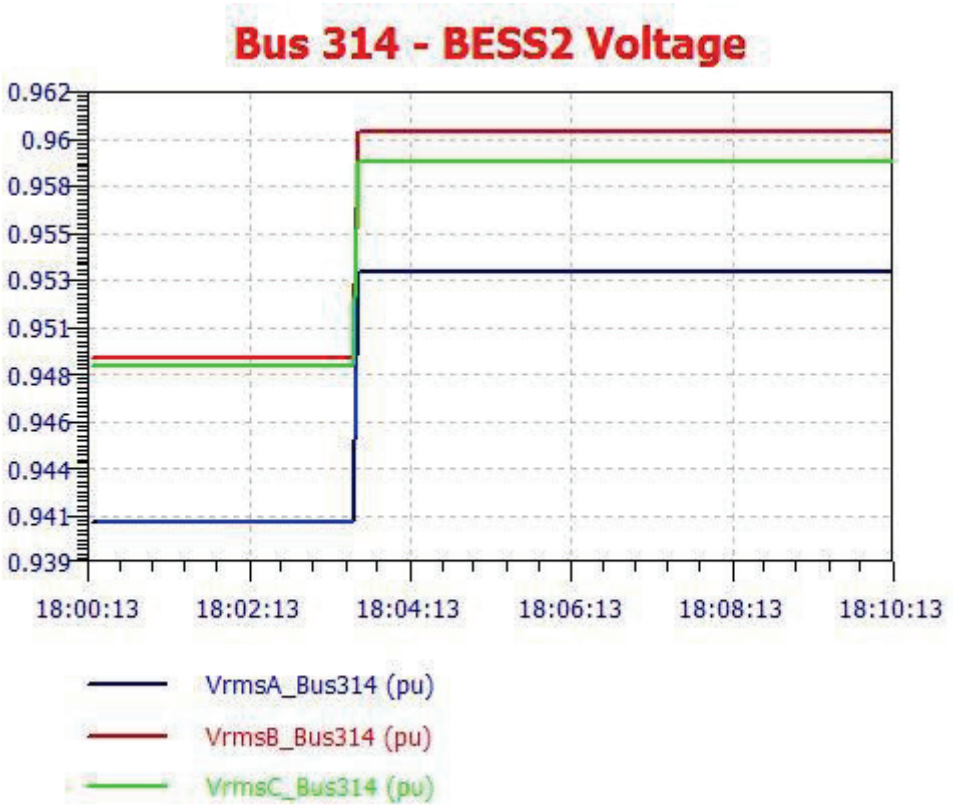


Figure D-35. Response of BESS 2 in Control Mode 1 (terminal voltage)

D.6 Use Case 7: Grid support using DERs

D.6.1 Test Case 7.1 Results

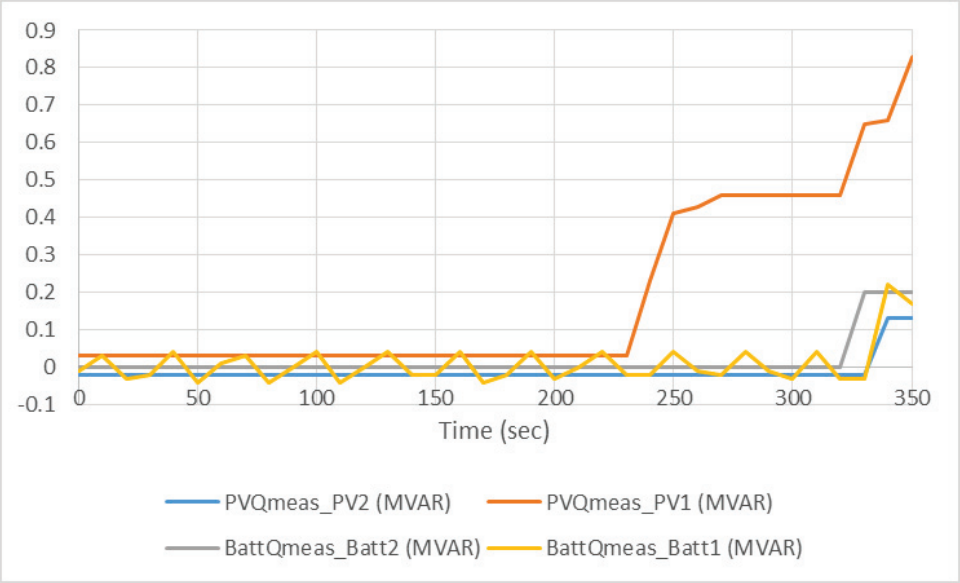


Figure D-36. DER reactive power measurements (Mvar)

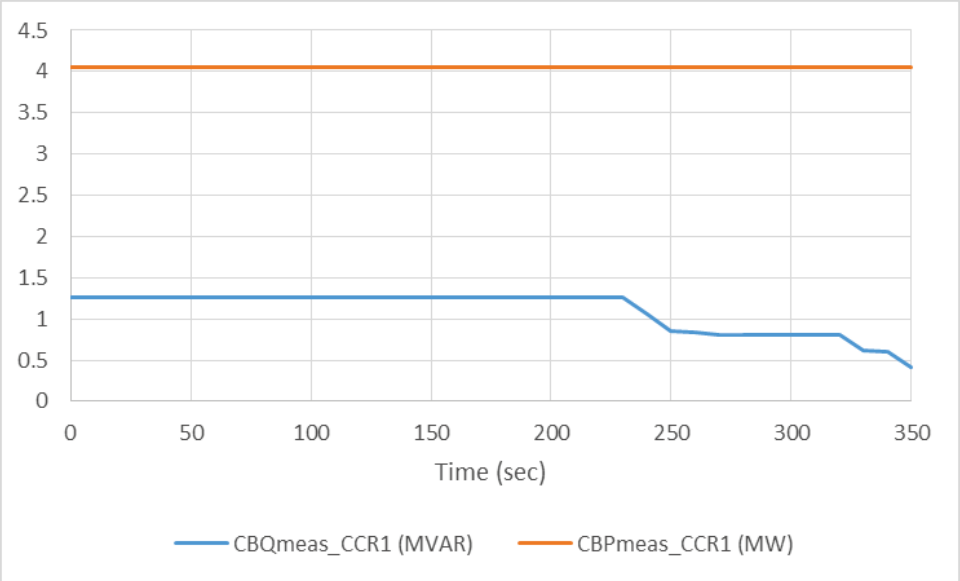


Figure D-37. CCR1 power flow measurement (MW & Mvar)

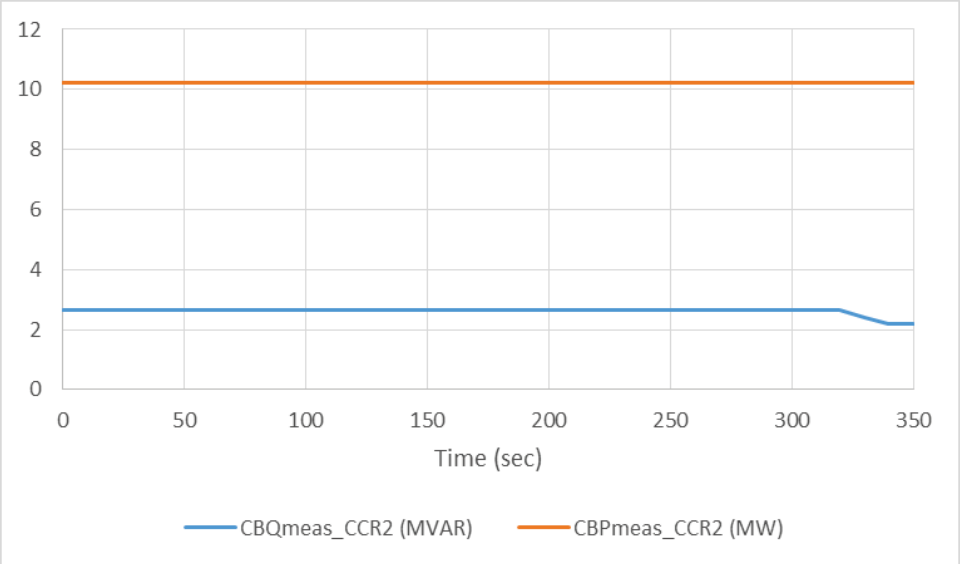


Figure D-38. CCR2 power flow measurement (MW & Mvar)

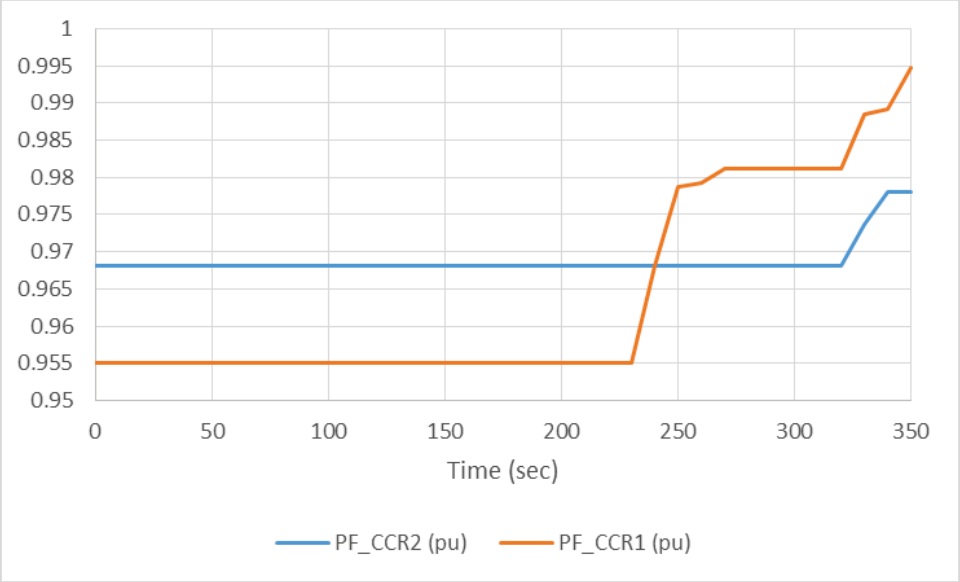


Figure D-39. CCR1 & CCR2 power factor measurement (pu)

D.6.2 Test Case 7.2 Results

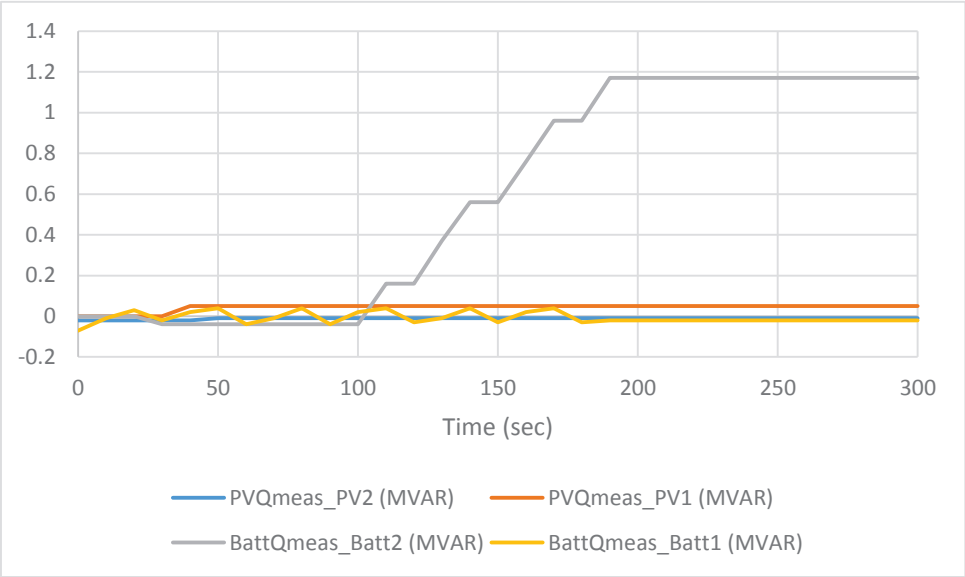


Figure D-40. DER reactive power measurements (Mvar)

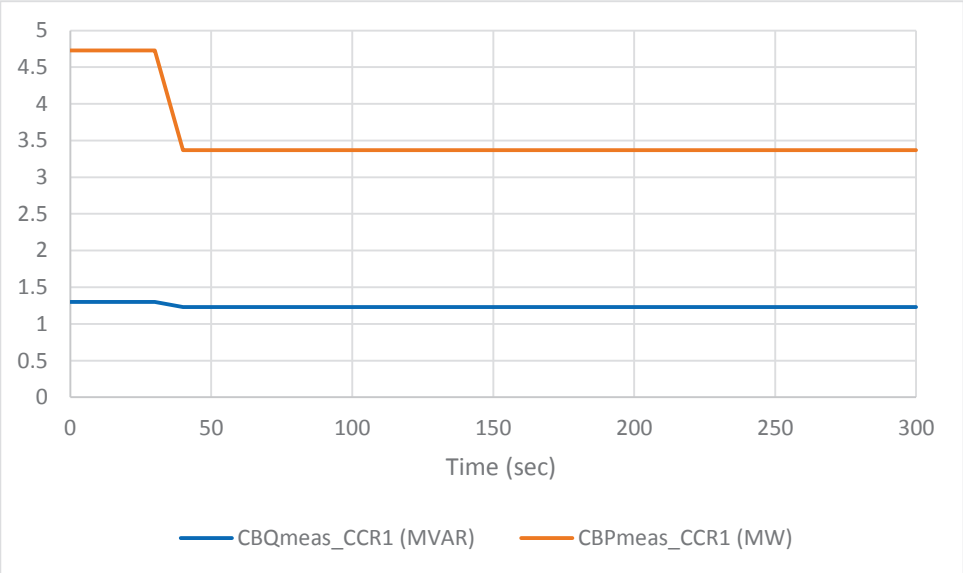


Figure D-41. CCR1 power flow measurement (MW & Mvar)

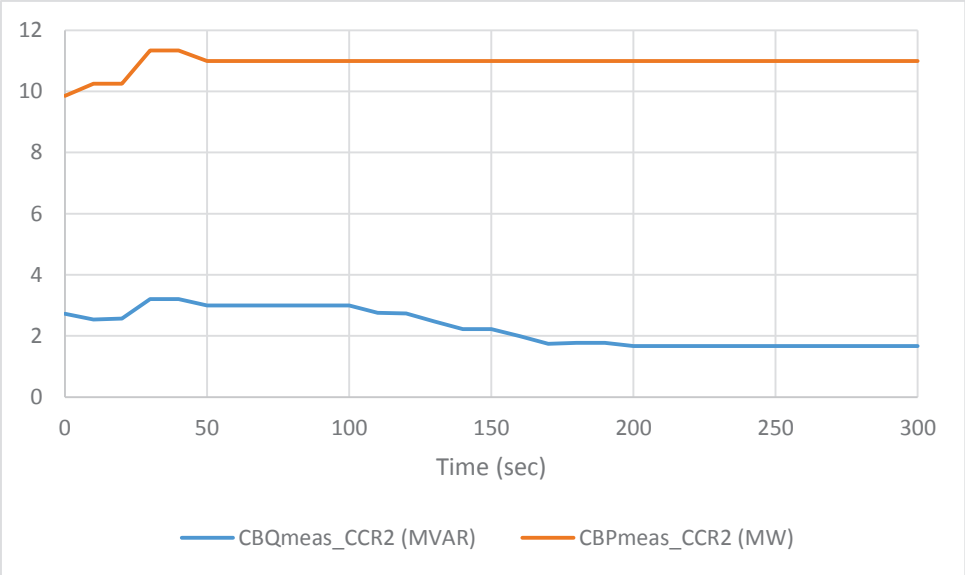


Figure D-42. CCR2 power flow measurement (MW & Mvar)

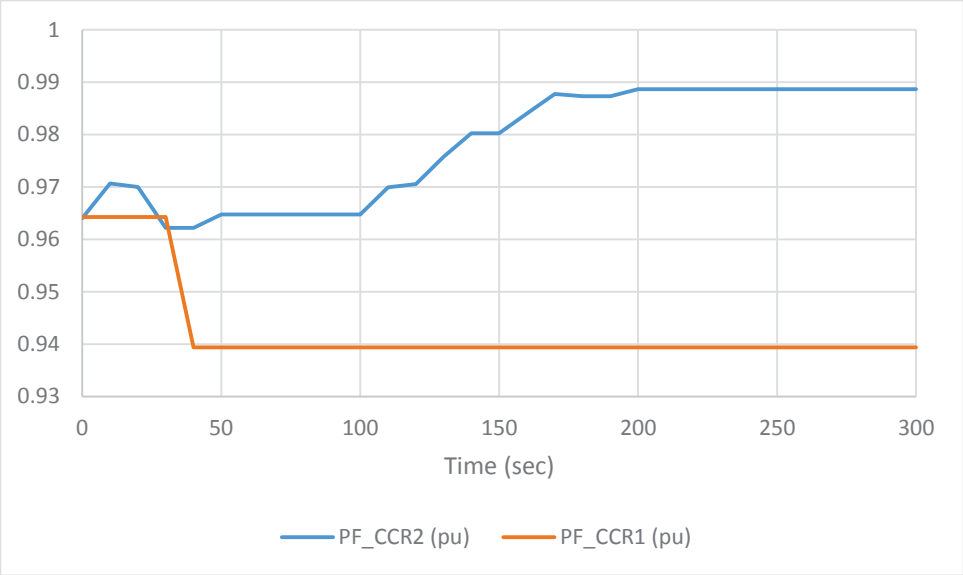


Figure D-43. CCR1 & CCR2 power factor measurement (pu)

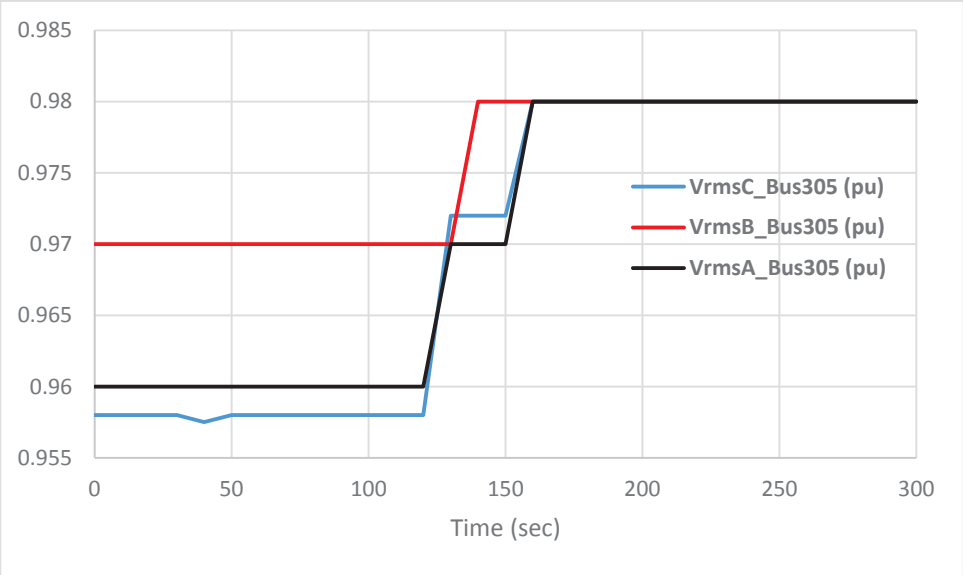


Figure D-44. RMS voltage at bus #305 (pu)

D.6.3 Test Case 7.3 Results

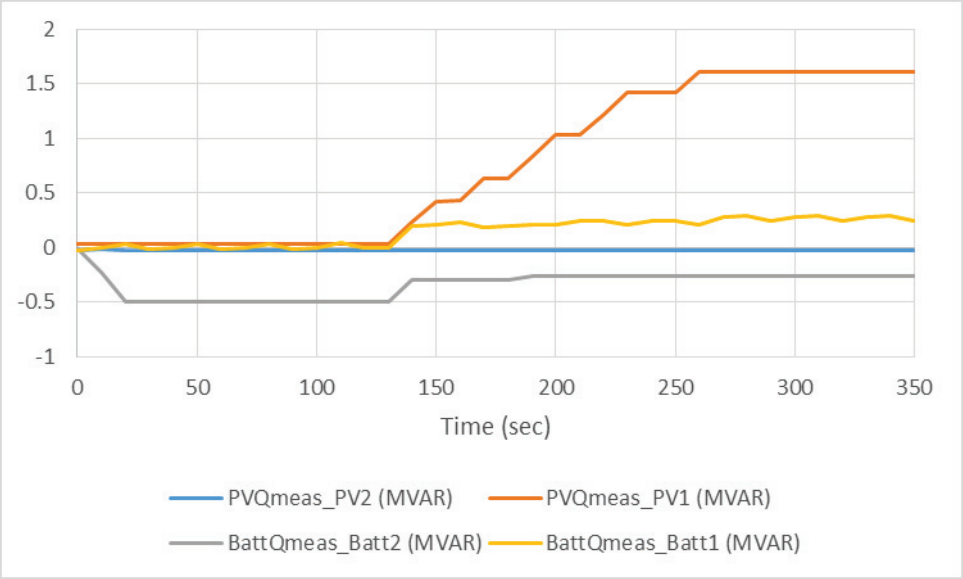


Figure D-45. DER reactive power measurements (Mvar)

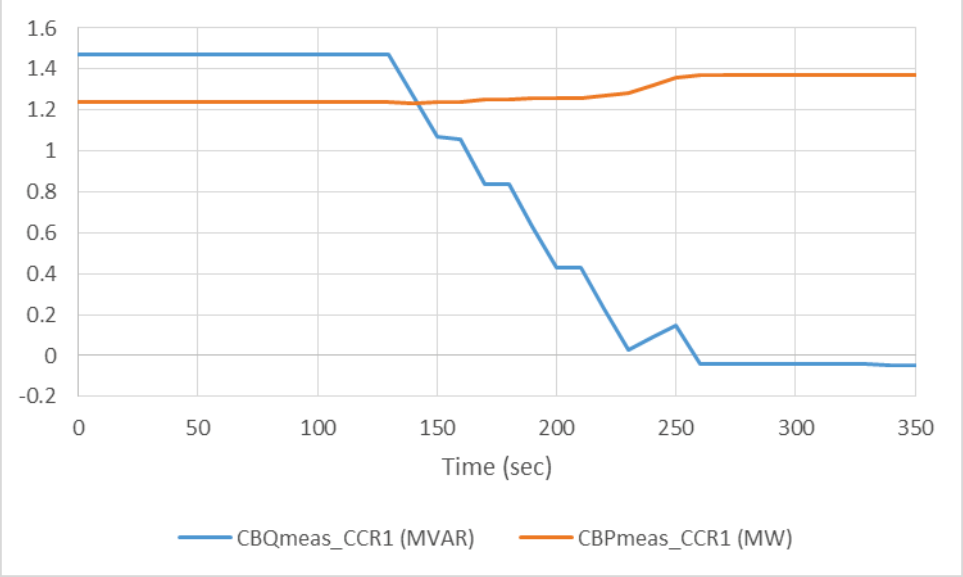


Figure D-46. CCR1 power flow measurement (MW & Mvar)

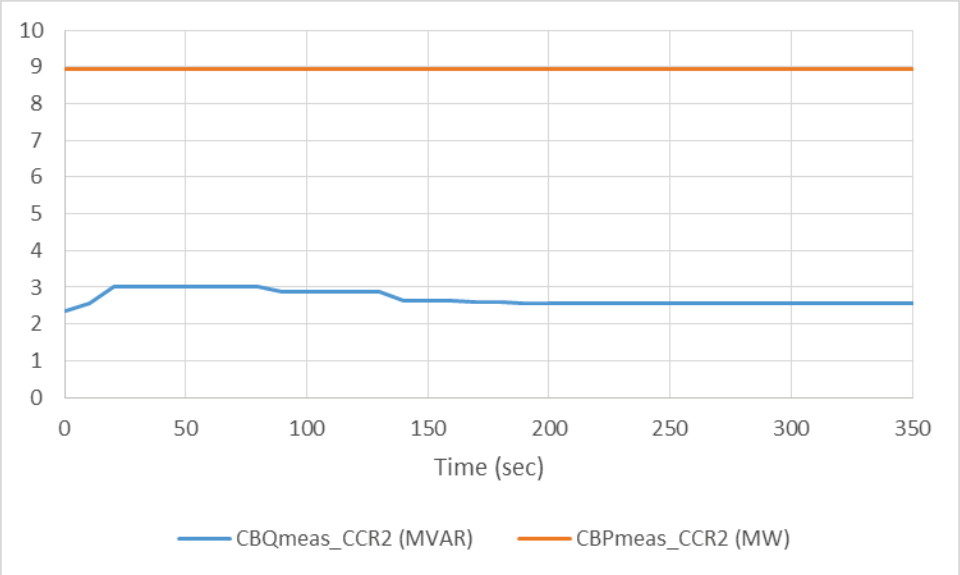


Figure D-47. CCR2 power flow measurement (MW & Mvar)

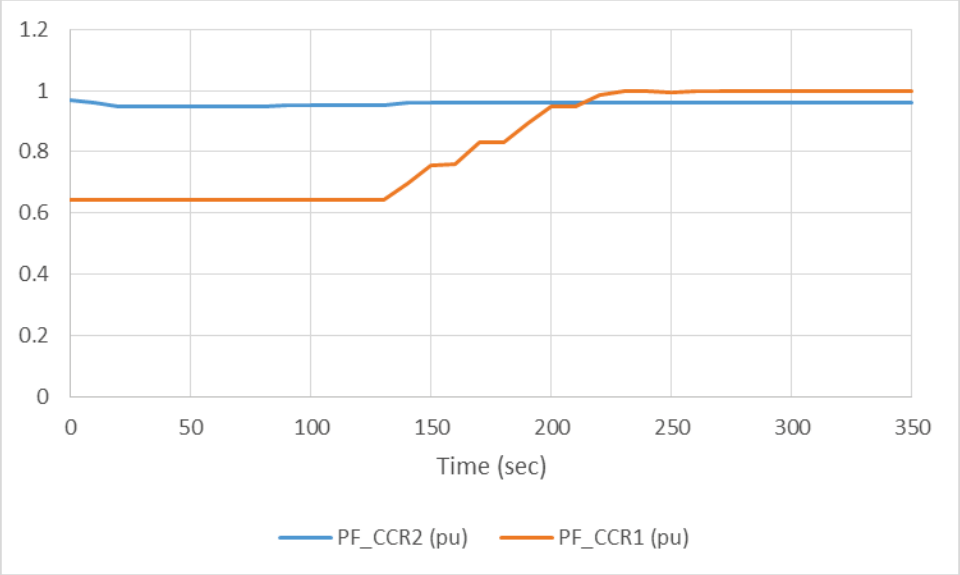


Figure D-48. CCR1 & CCR2 power factor measurement (pu)

D.6.4 Test Case 7.4 Results

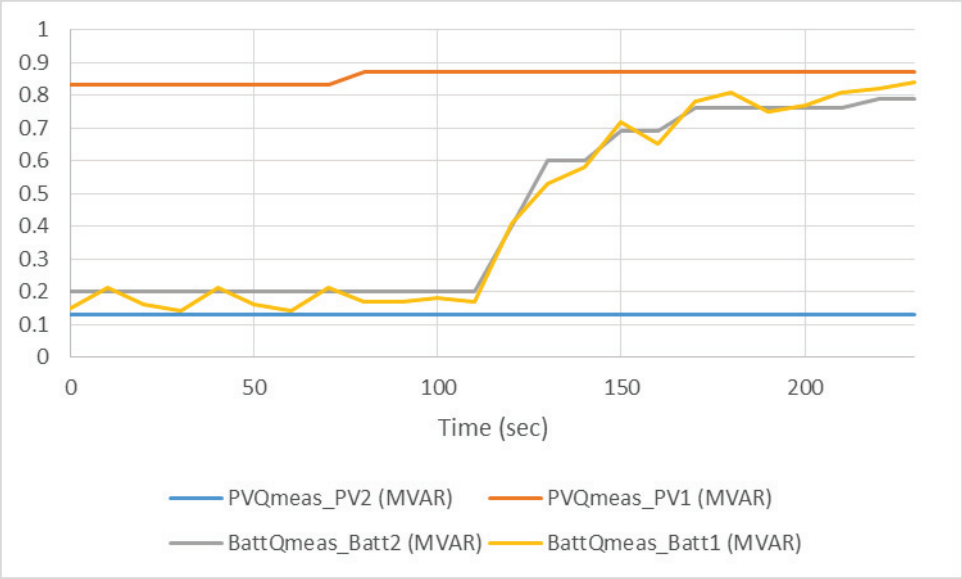


Figure D-49. DER reactive power measurements (Mvar)

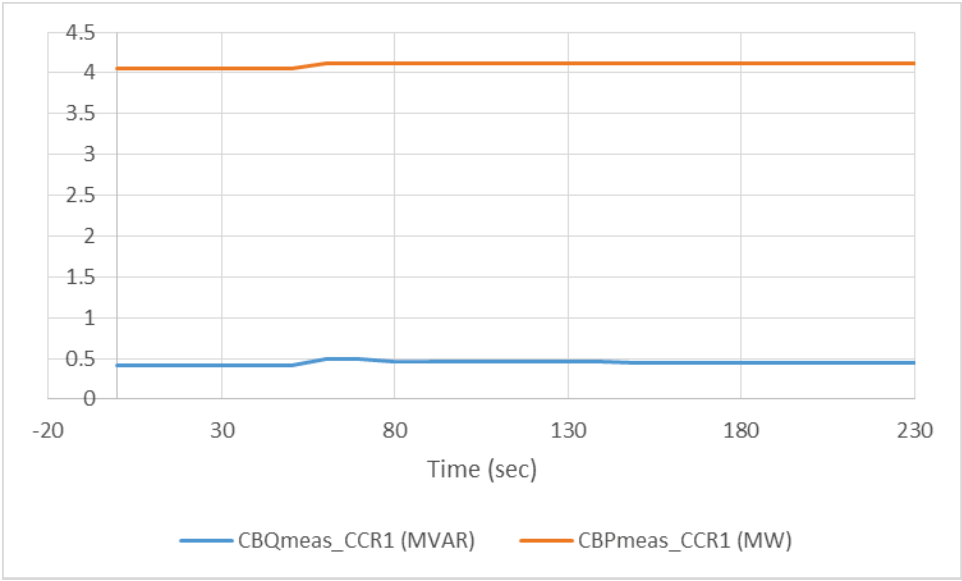


Figure D-50. CCR1 power flow measurement (MW & Mvar)

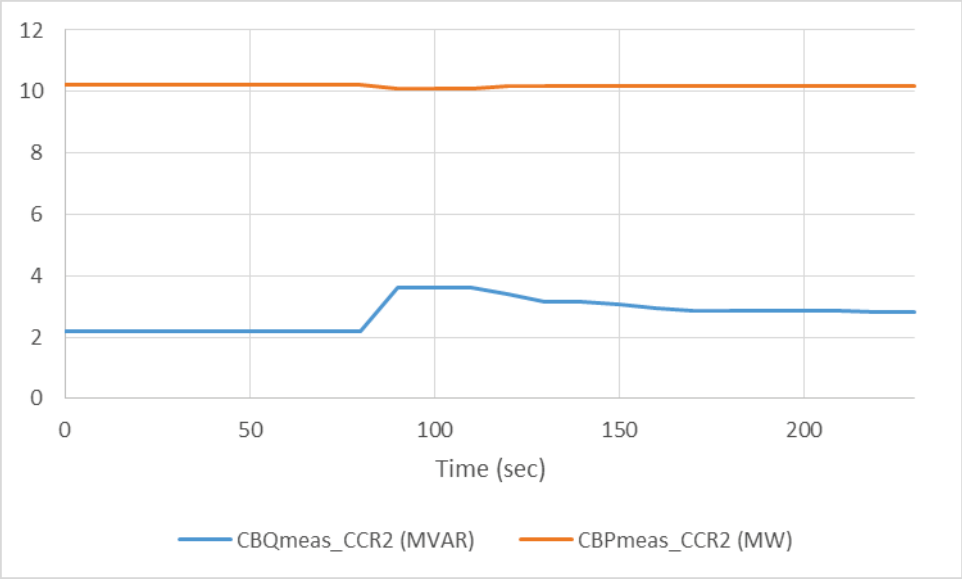


Figure D-51. CCR2 power flow measurement (MW & Mvar)

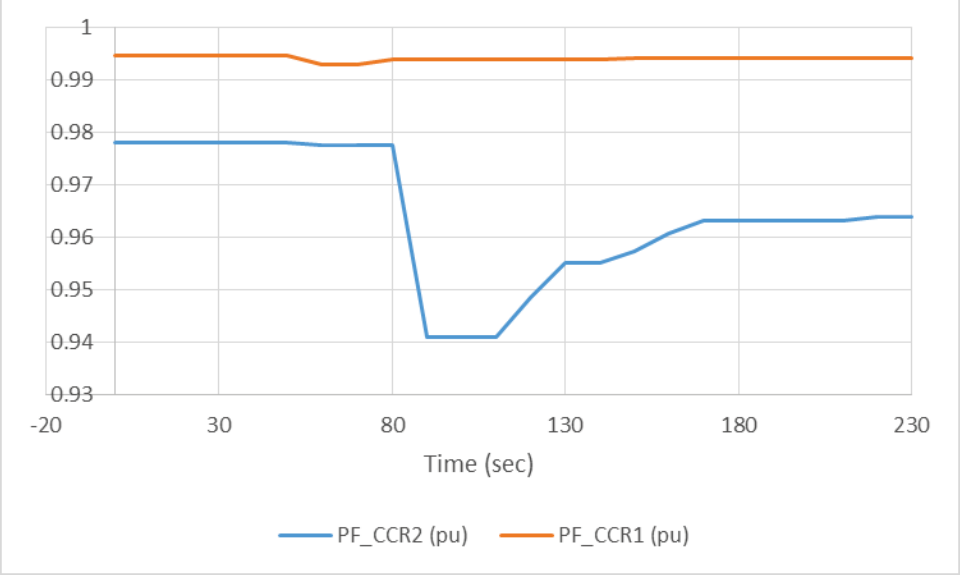


Figure D-52. CCR1 & CCR2 power factor measurement (pu)

D.6.5 Test Case 7.5 Results

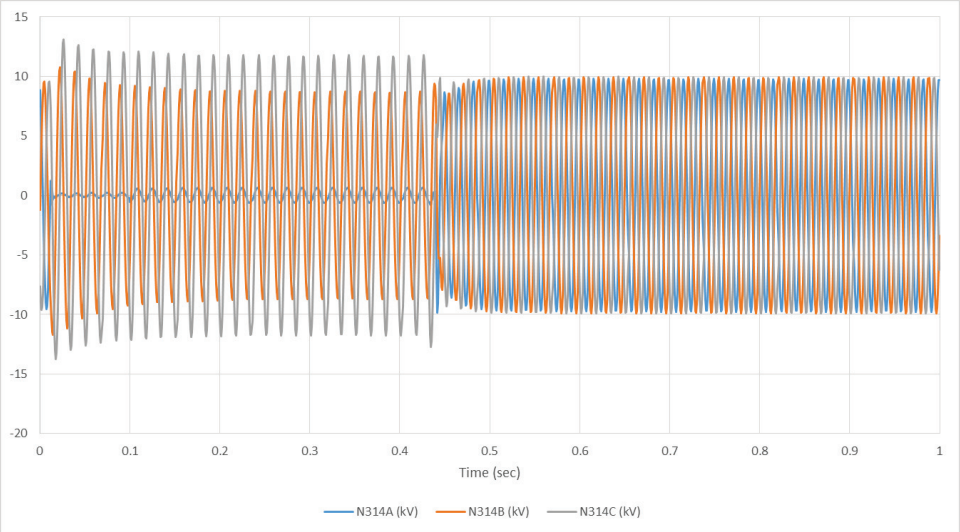


Figure D-53. Battery instantaneous voltage (kV) - High voltage side

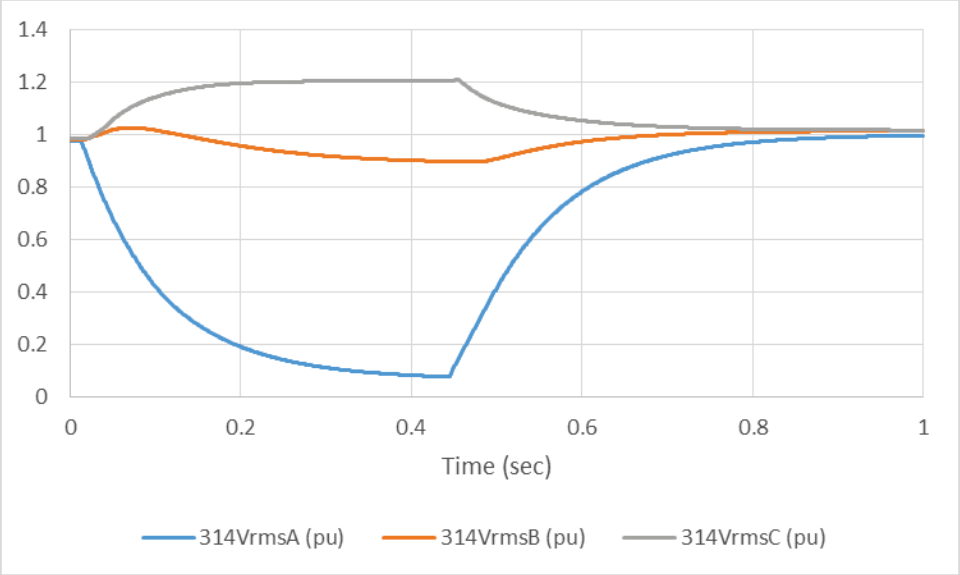


Figure D-54. Battery rms voltage (pu) - High voltage side

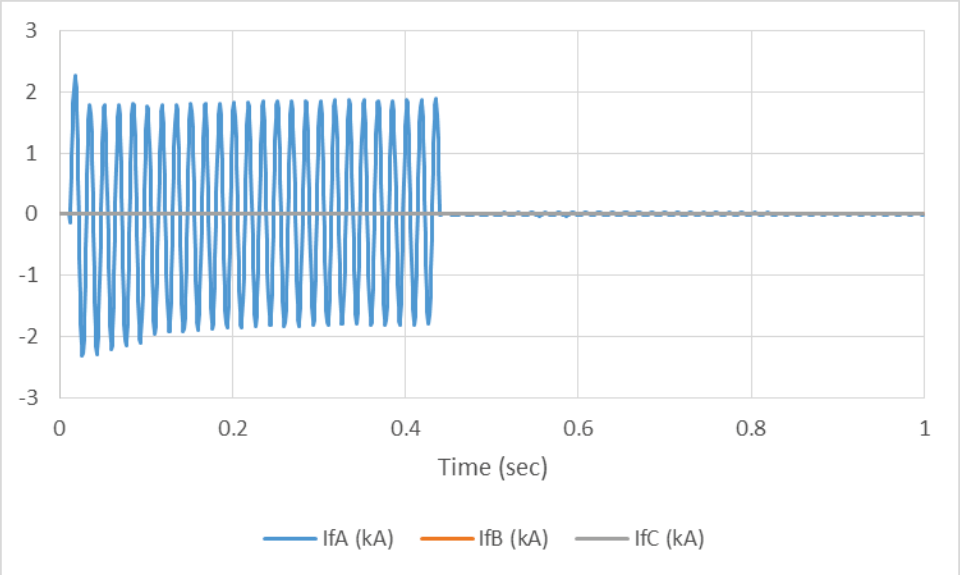


Figure D-55. Fault current at Bus #305 (kA)

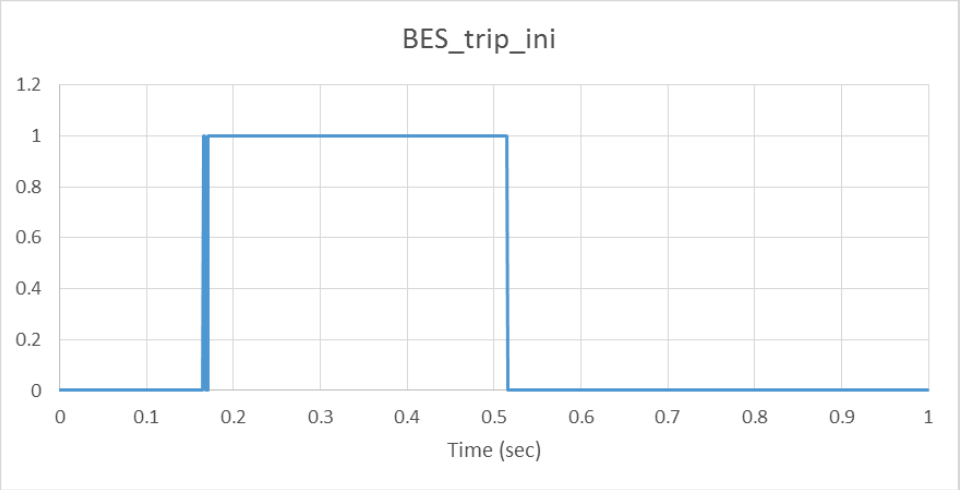


Figure D-56. Battery initial trip signal

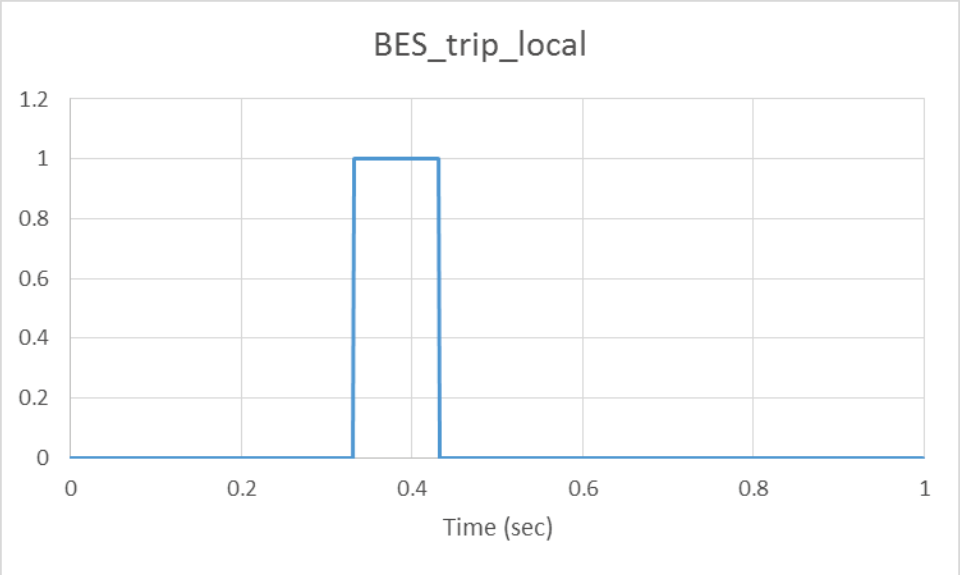


Figure D-57. Battery local trip signal

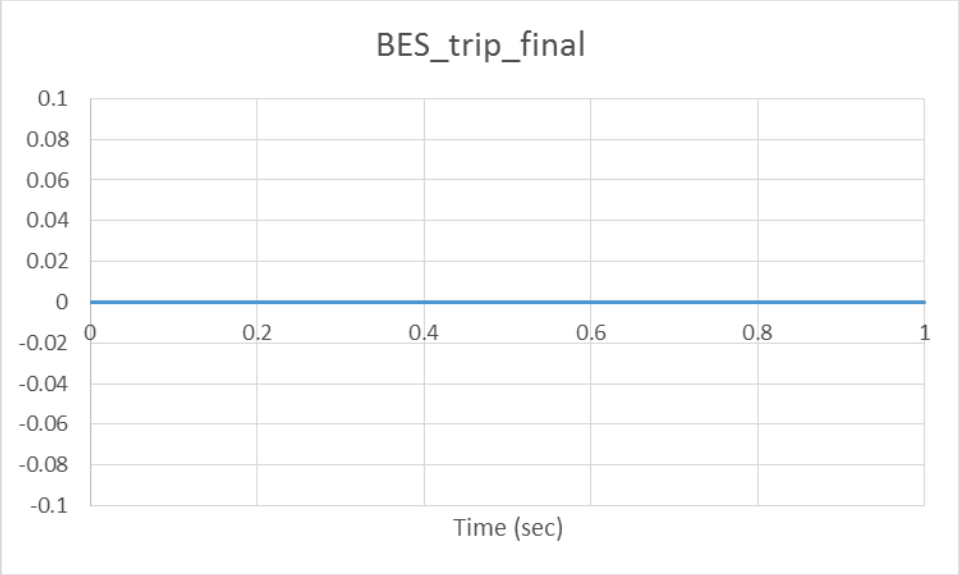


Figure D-58. Battery final trip signal

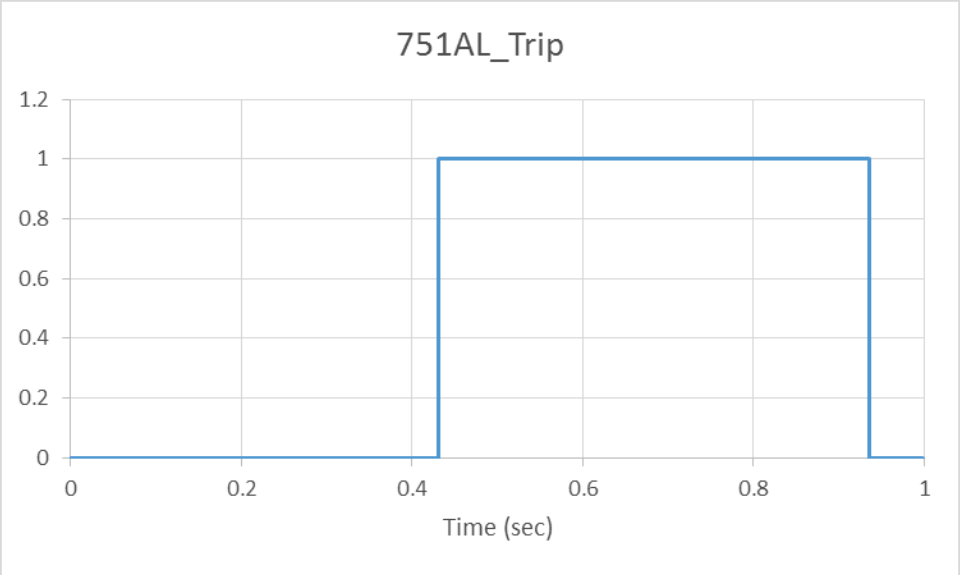


Figure D-59. 751 relay trip signal

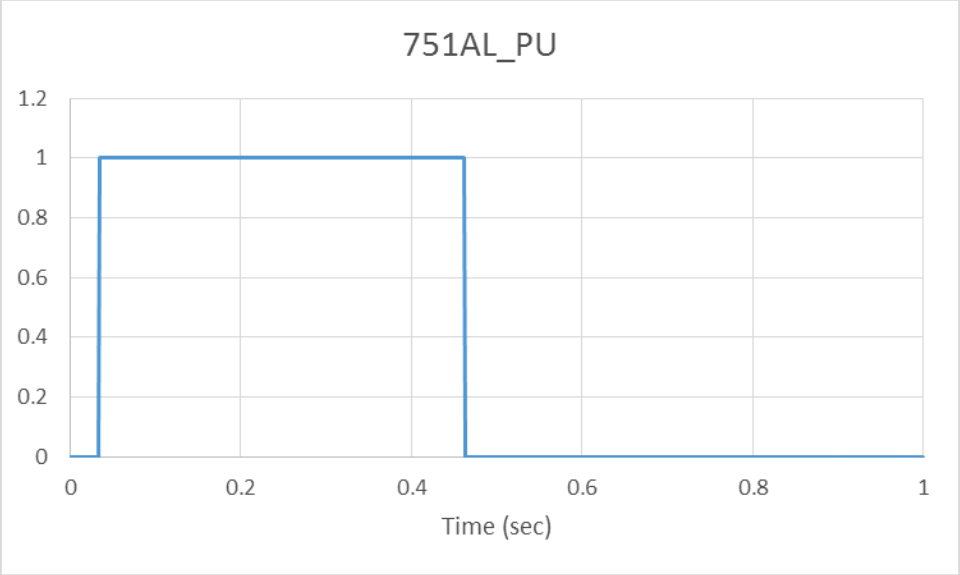


Figure D-60. 751 relay pickup signal

D.6.6 Test Case 7.6 Results

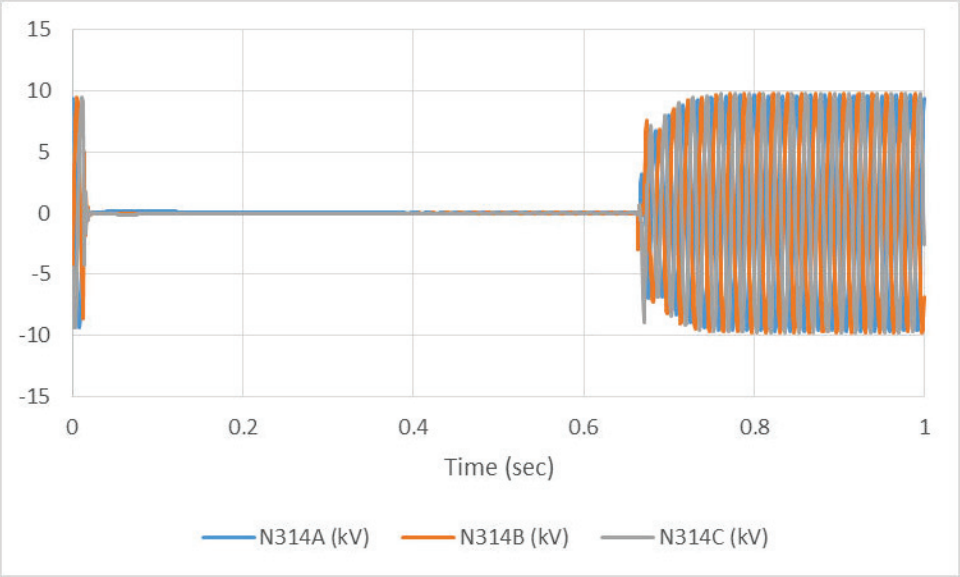


Figure D-61. Battery instantaneous voltage (kV) - High voltage side

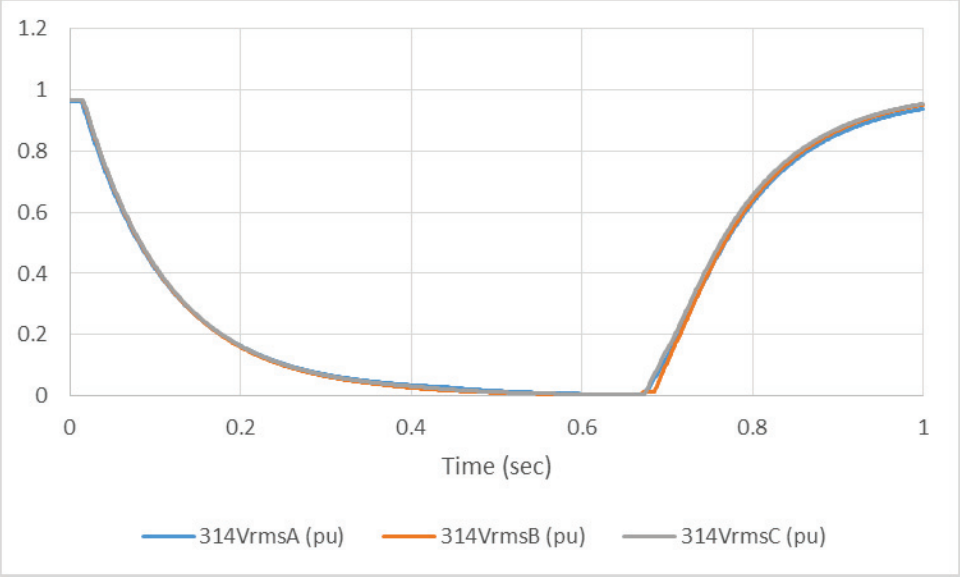


Figure D-62 Battery rms voltage (pu) - High voltage side

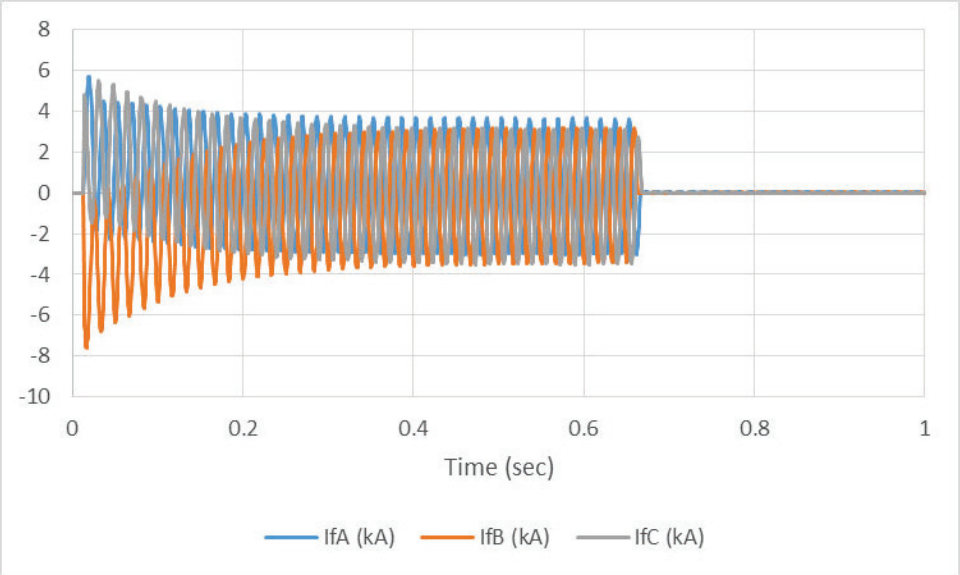


Figure D-63. Fault current at Bus #305 (kA)

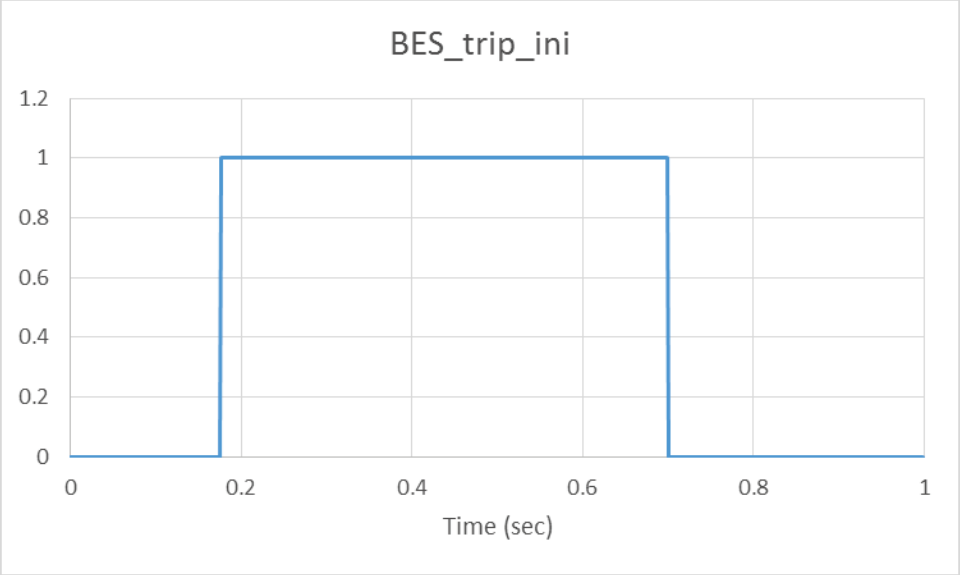


Figure D-64. Battery initial trip signal

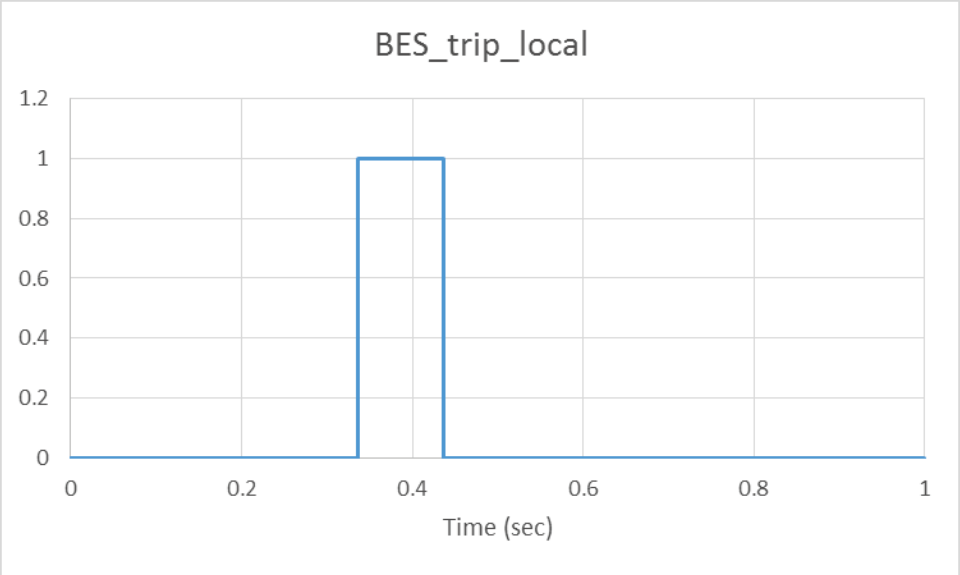


Figure D-65. Battery local trip signal

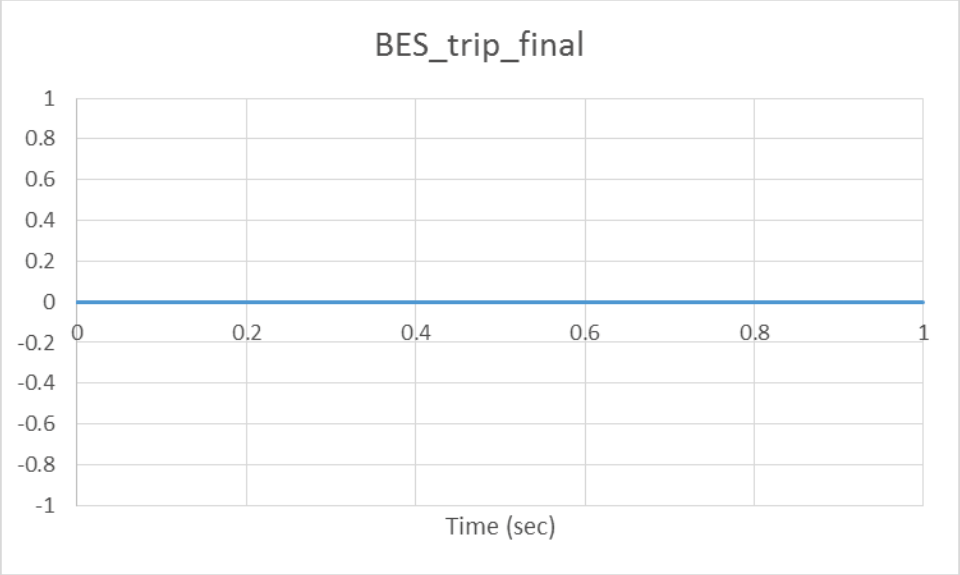


Figure D-66. Battery final trip signal

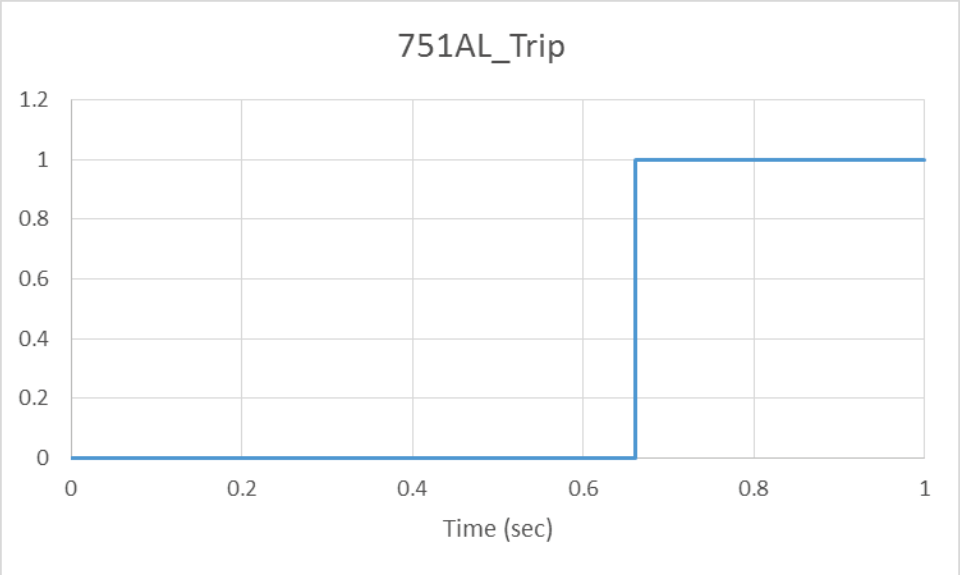


Figure D-67. 751 relay trip signal

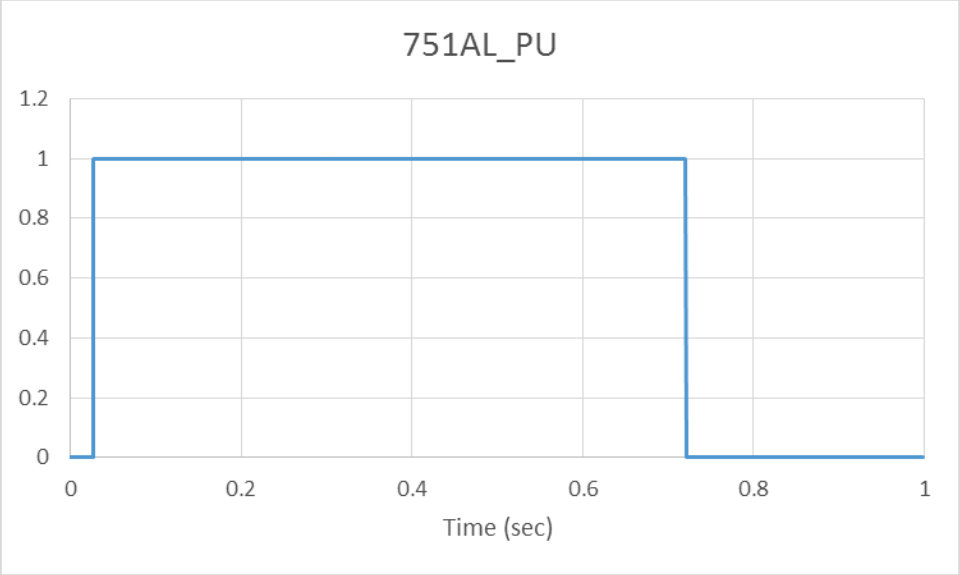


Figure D-68. 751 relay pickup signal

D.6.7 Test Case 7.7 Results

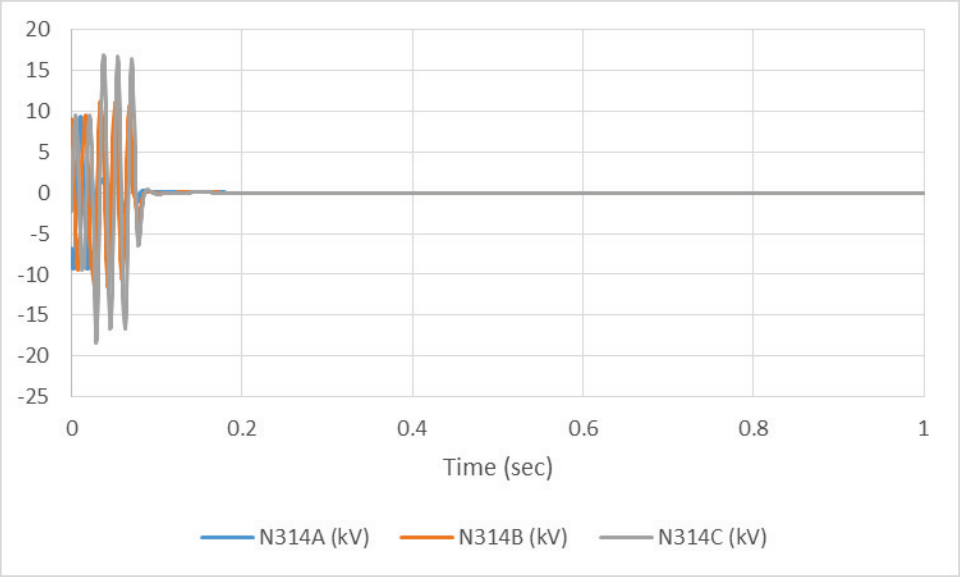


Figure D-69. Battery instantaneous voltage (kV) - High voltage side

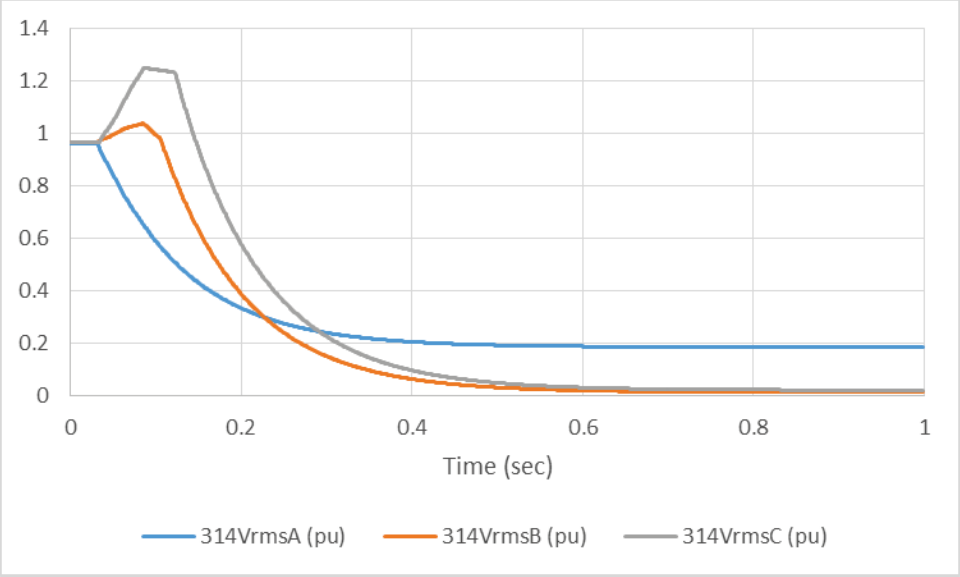


Figure D-70. Battery rms voltage (pu) - High voltage side

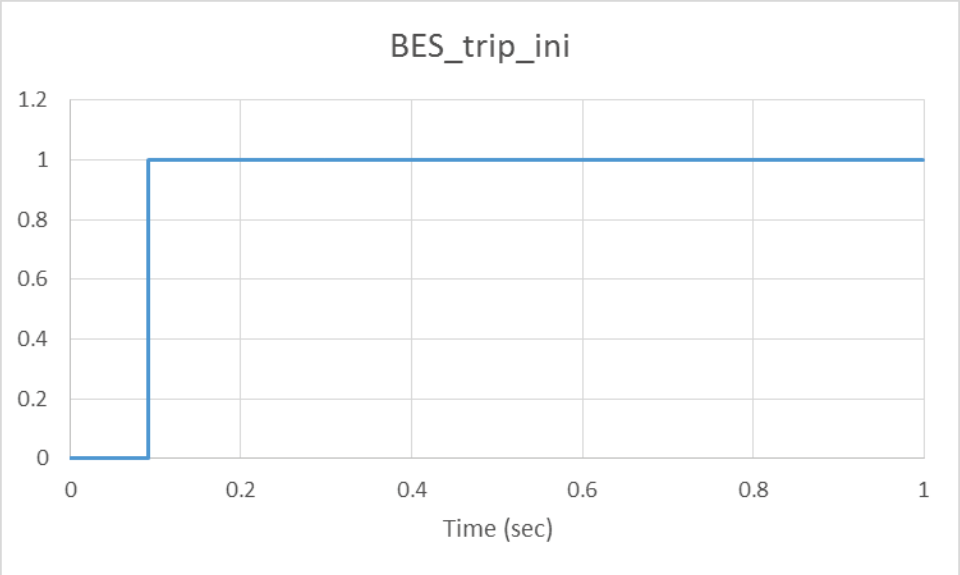


Figure D-71. Battery initial trip signal

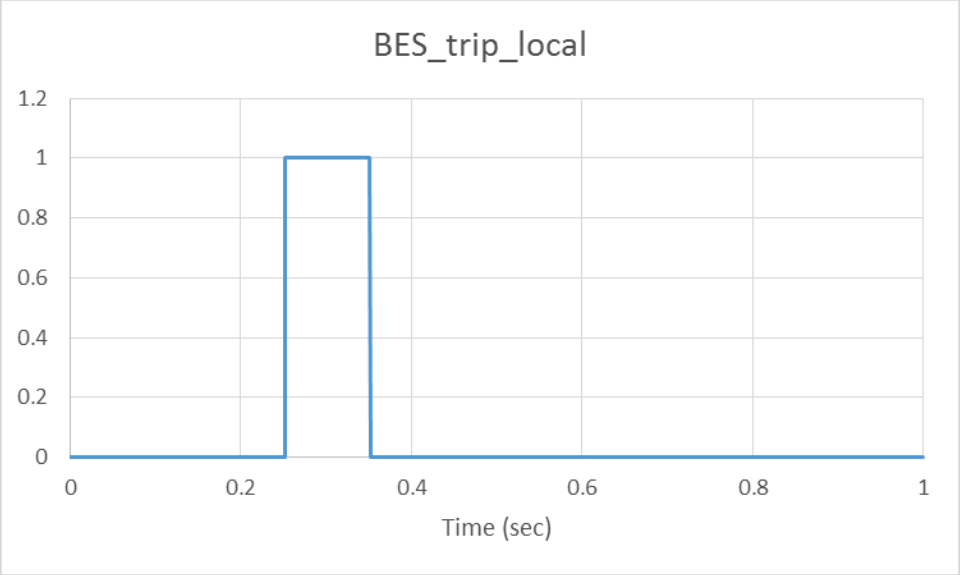


Figure D-72. Battery local trip signal

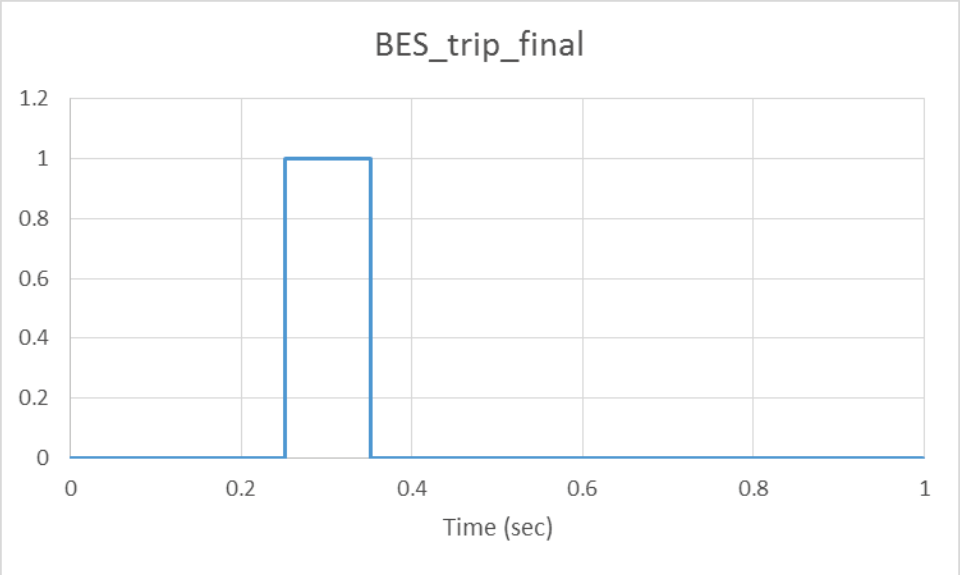


Figure D-73. Battery final trip signal

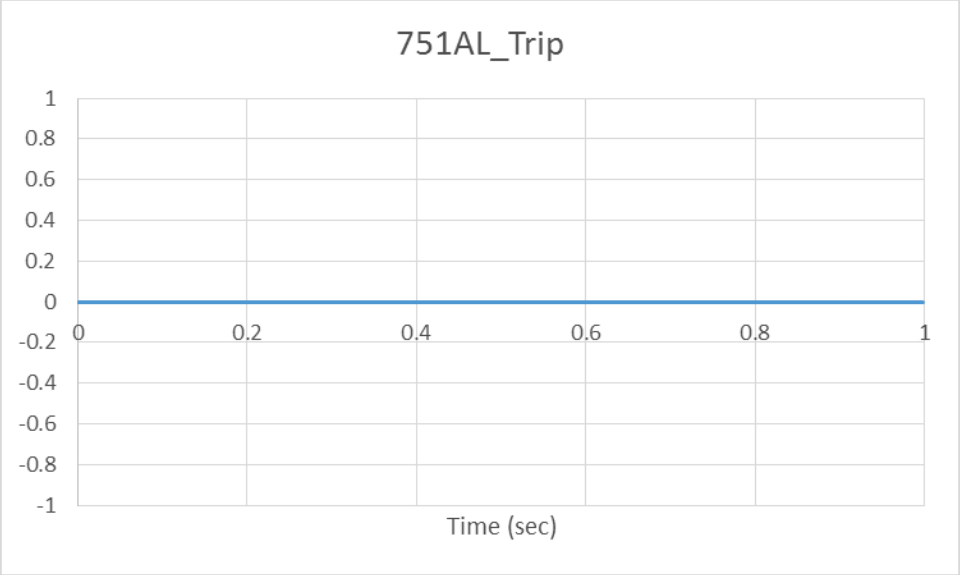


Figure D-74. 751 relay trip signal

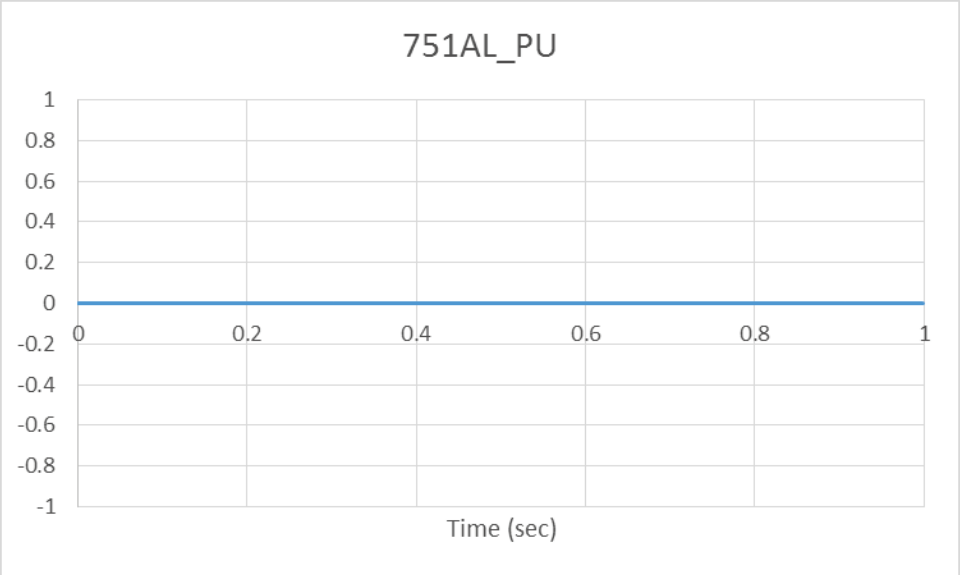


Figure D-75. 751 relay pickup signal

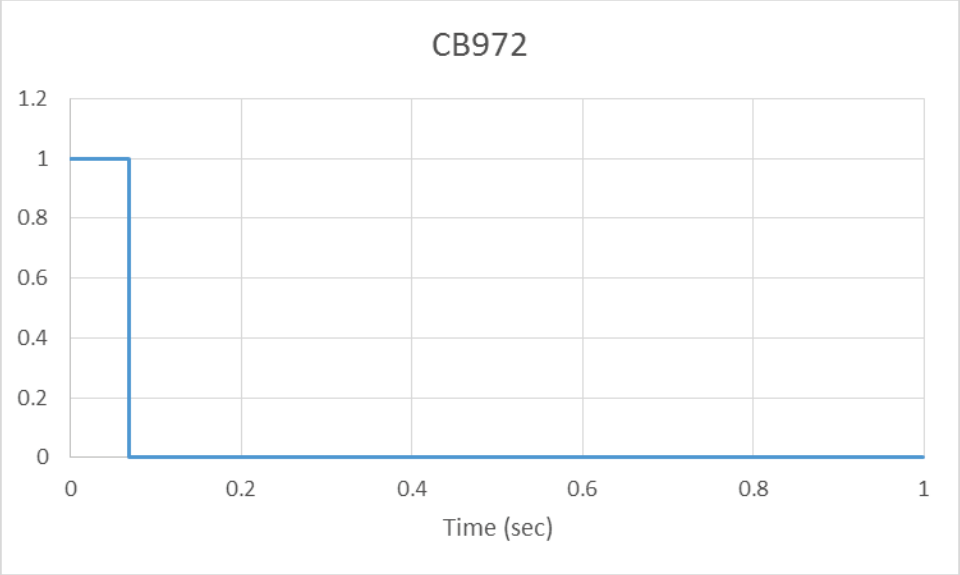


Figure D-76. CBCCR2 status signal

D.6.8 Test Case 7.8 Results

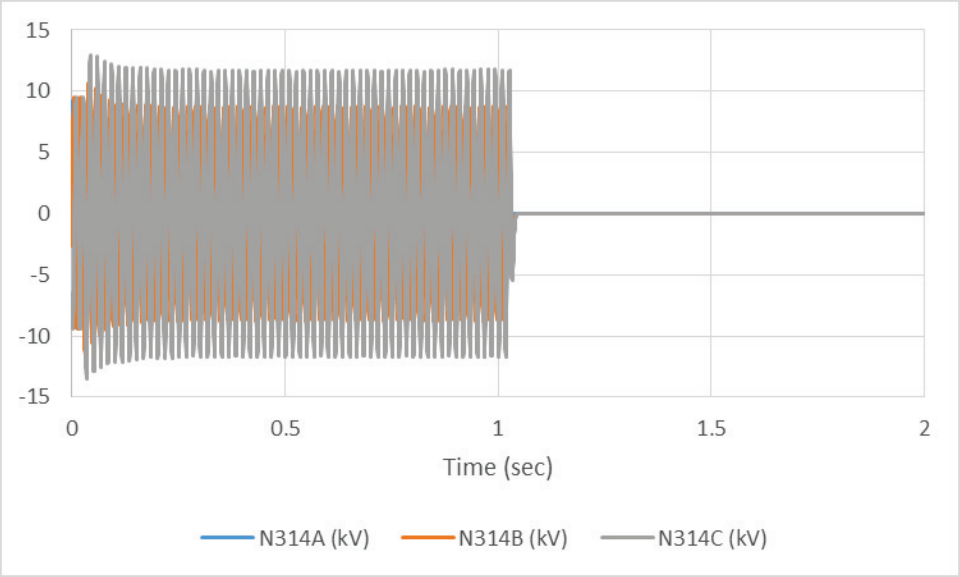


Figure D-77. Battery instantaneous voltage (kV) - High voltage side

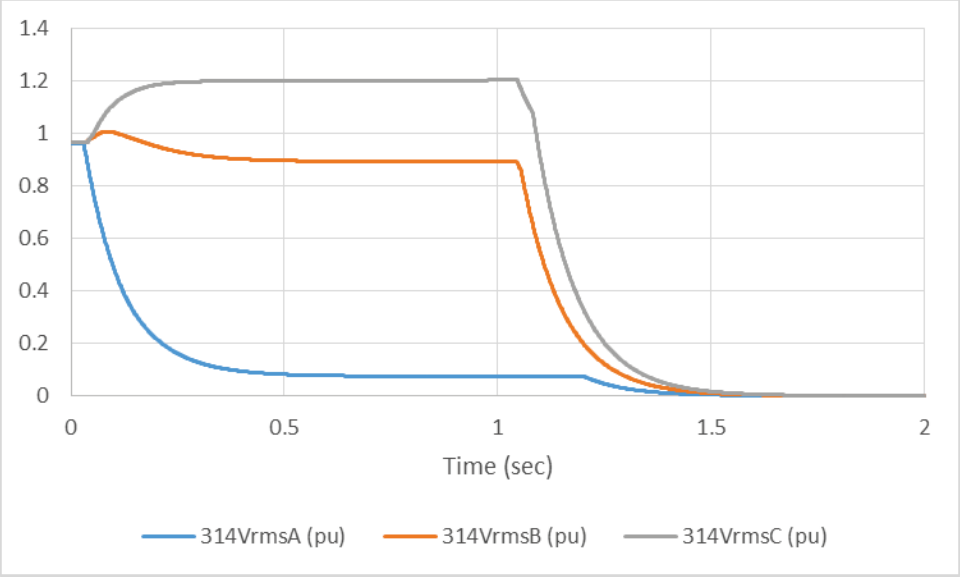


Figure D-78. Battery rms voltage (pu) - High voltage side

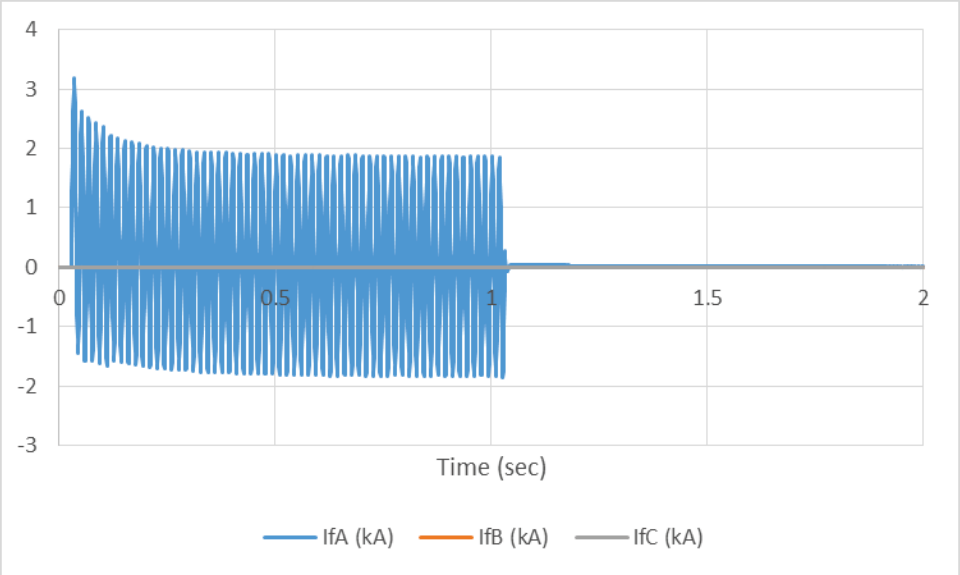


Figure D-79. Fault current at Bus #305 (kA)

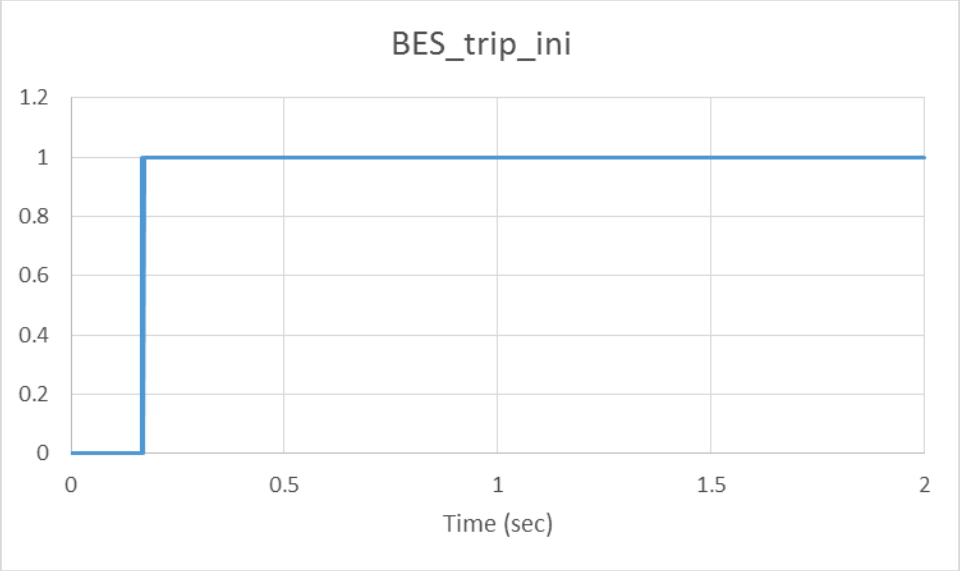


Figure D-80. Battery initial trip signal

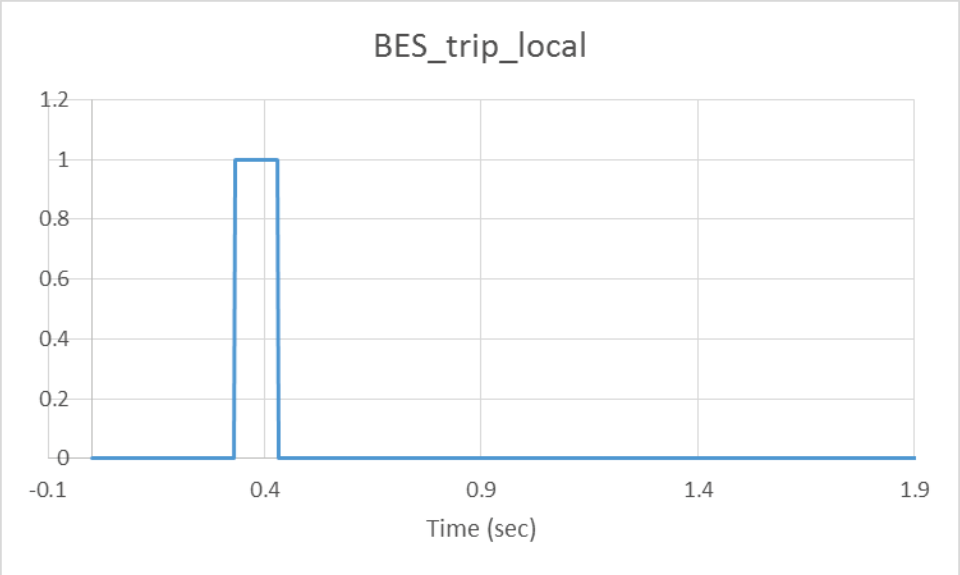


Figure D-81. Battery local trip signal

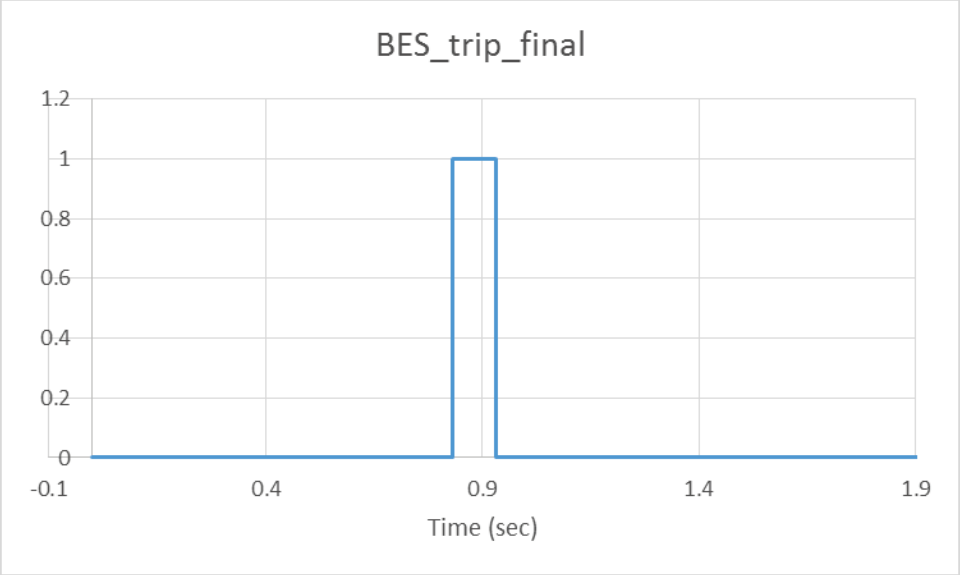


Figure D-82. Battery final trip signal

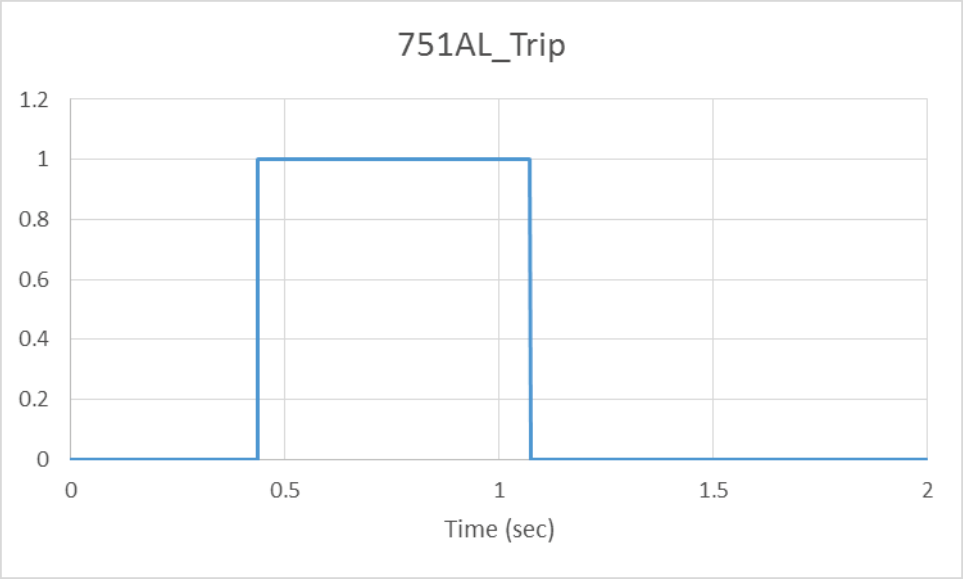


Figure D-83. 751 relay trip signal

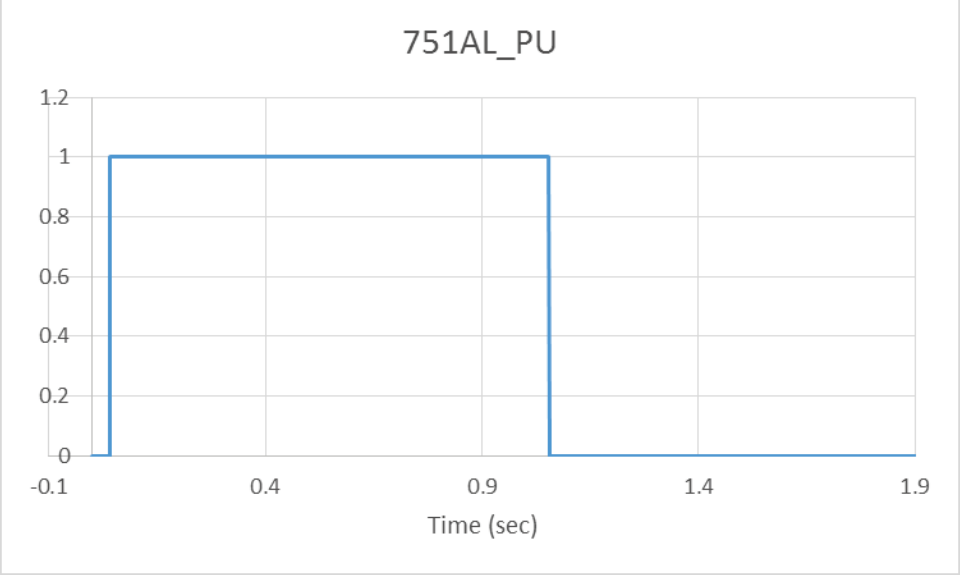


Figure D-84. 751 relay pickup signal

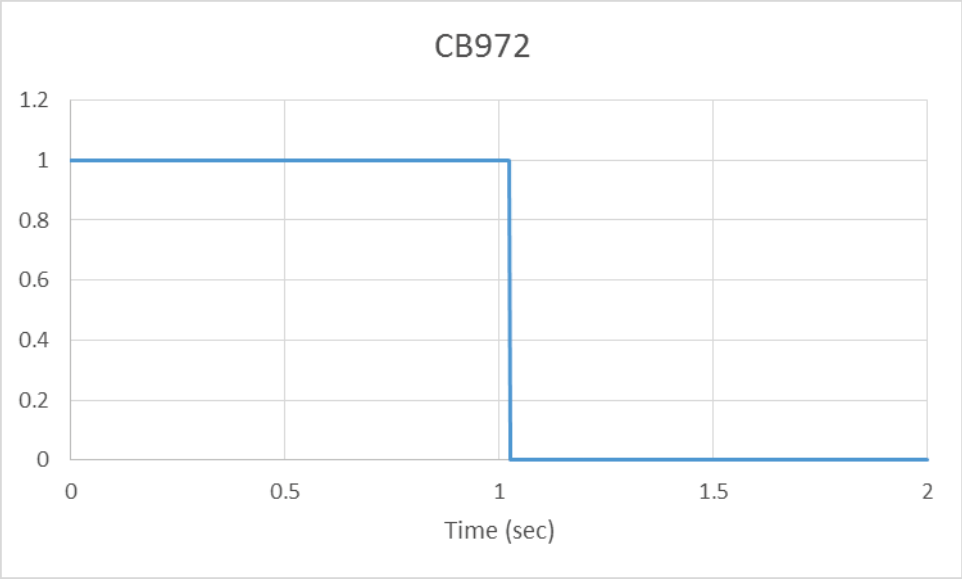


Figure D-85. CBCCR2 status signal

D.6.9 Test Case 7.9 Results

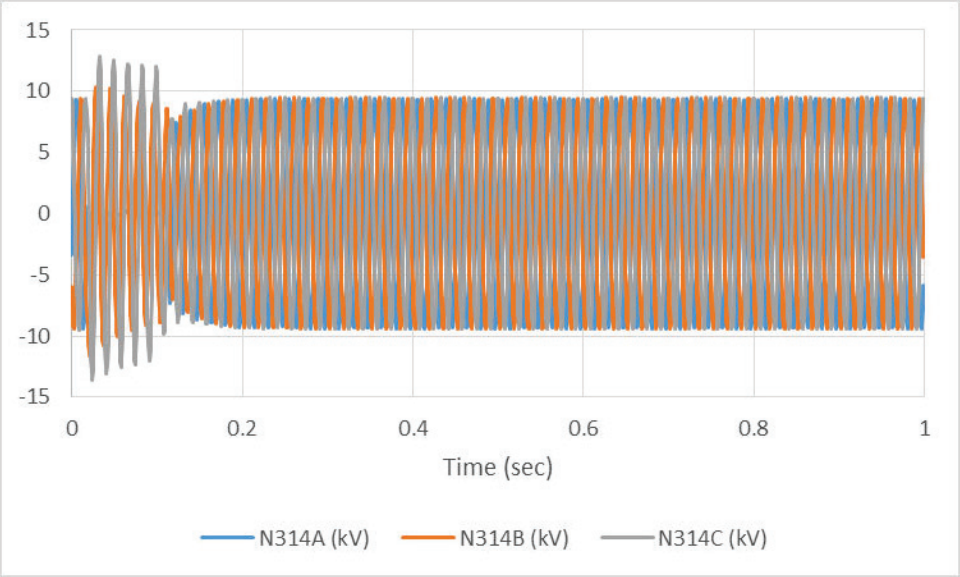


Figure D-86. Battery instantaneous voltage (kV) - High voltage side

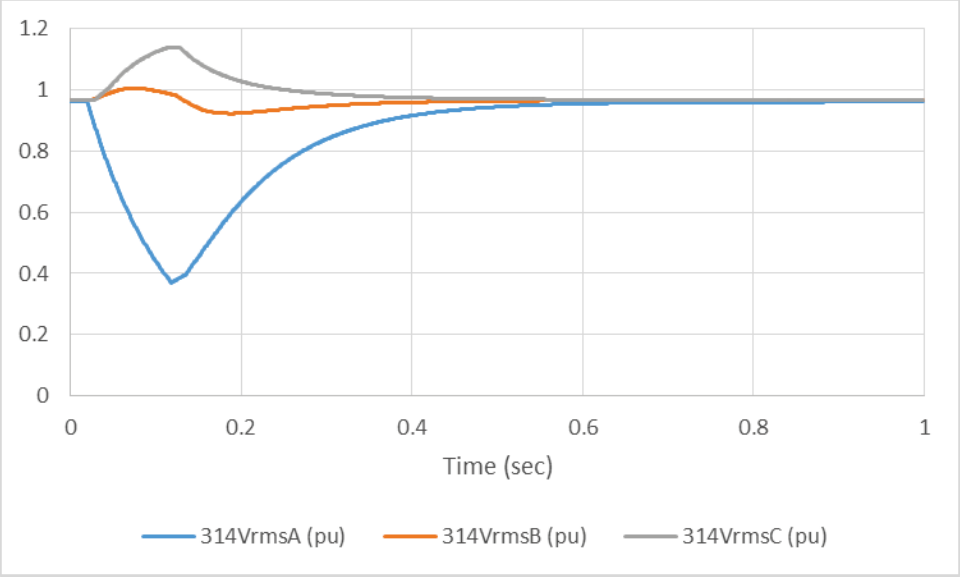


Figure D-87. Battery rms voltage (pu) - High voltage side

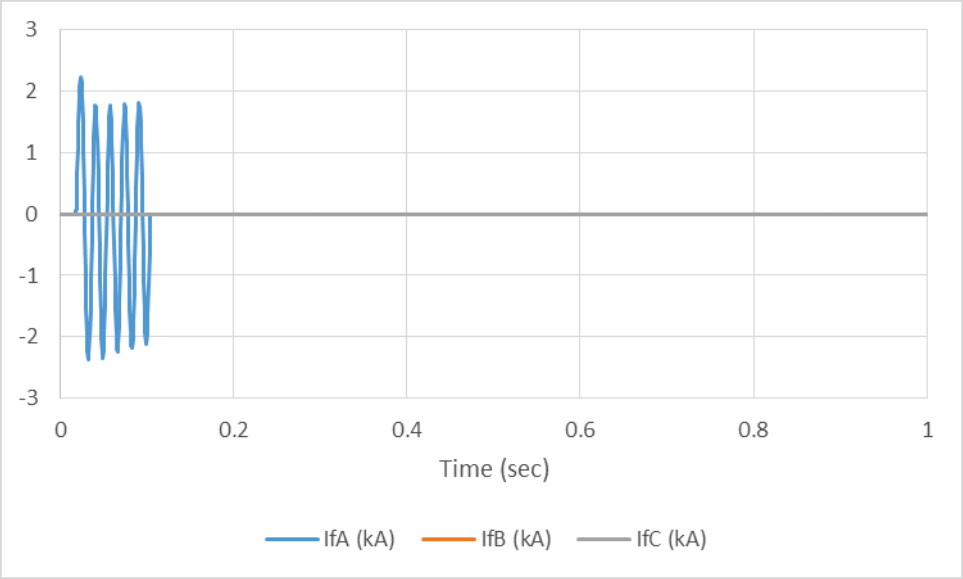


Figure D-88. Fault current at Bus #305 (kA)

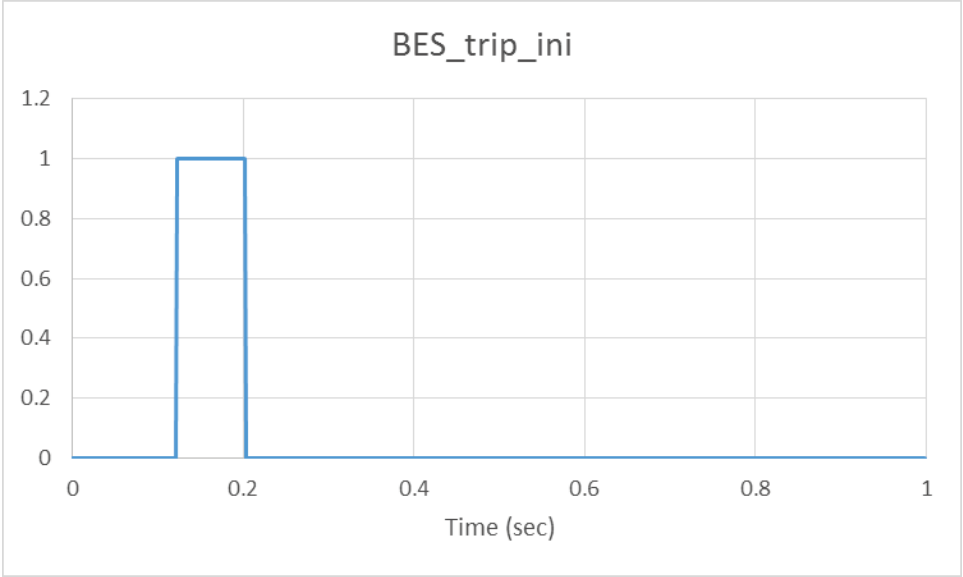


Figure D-89. Battery initial trip signal

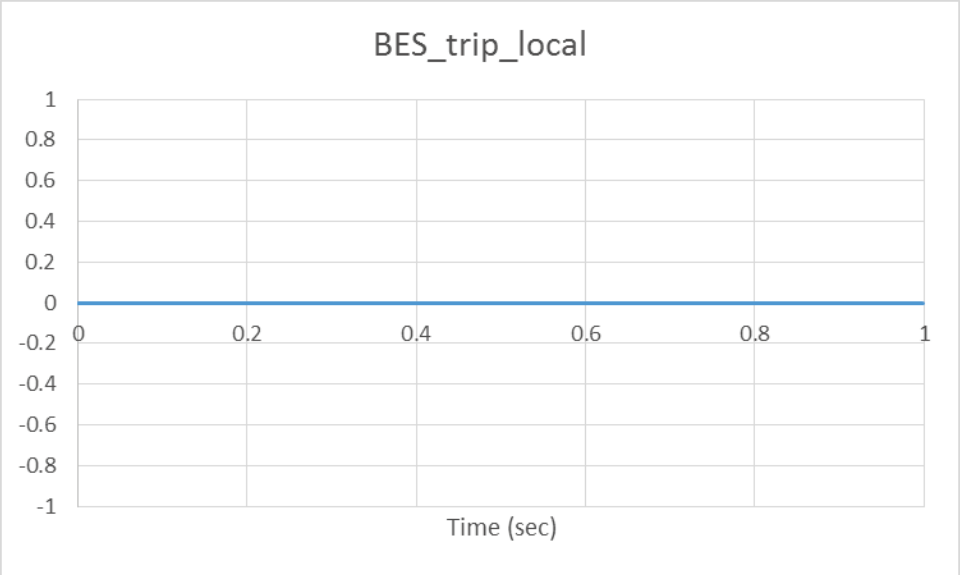


Figure D-90. Battery local trip signal

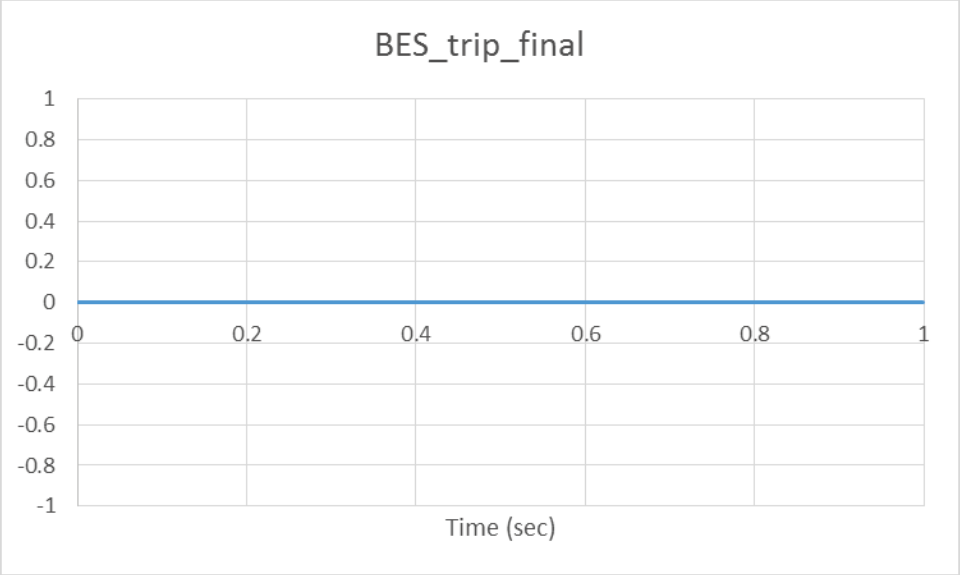


Figure D-91. Battery final trip signal

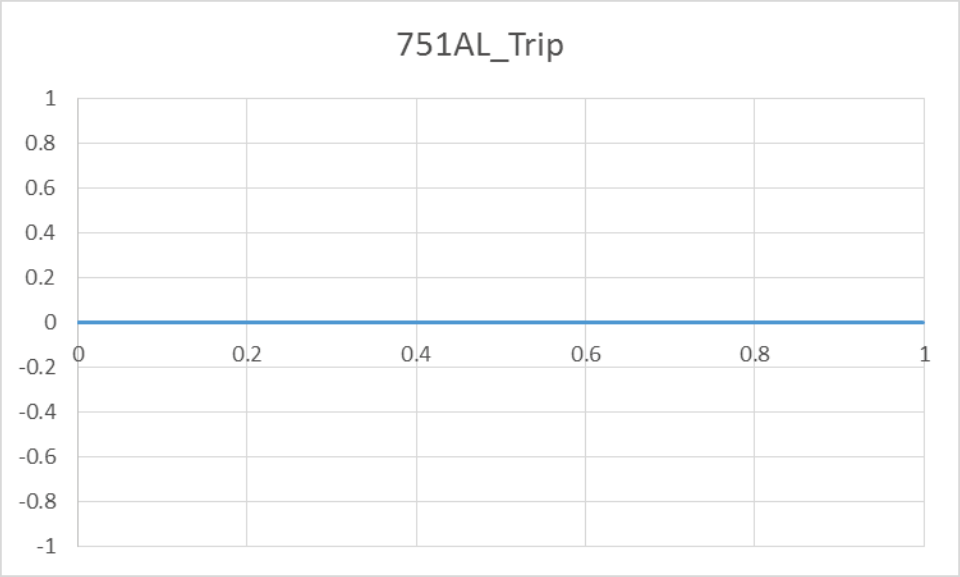


Figure D-92. 751 relay trip signal

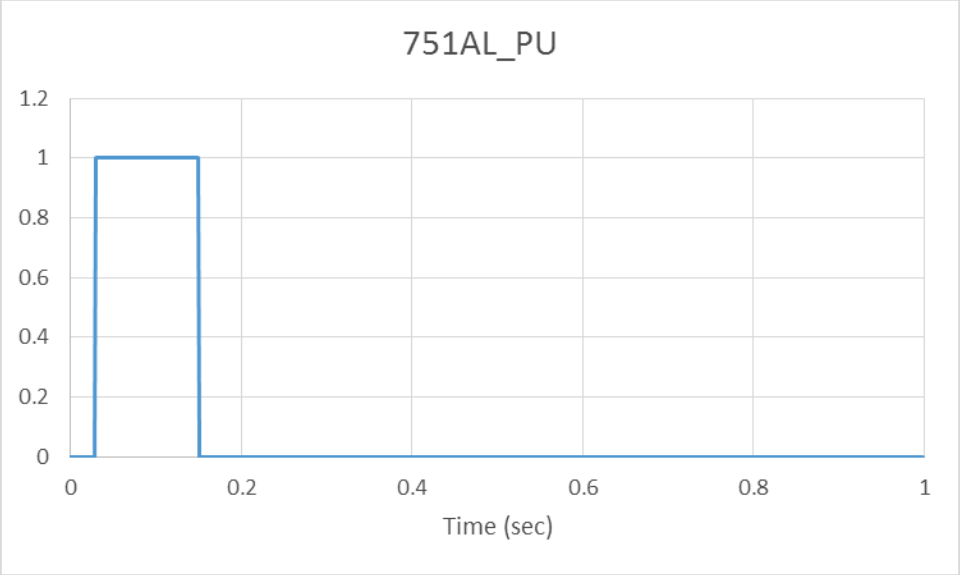


Figure D-93. 751 relay pickup signal

D.6.10 Test Case 7.10 Results

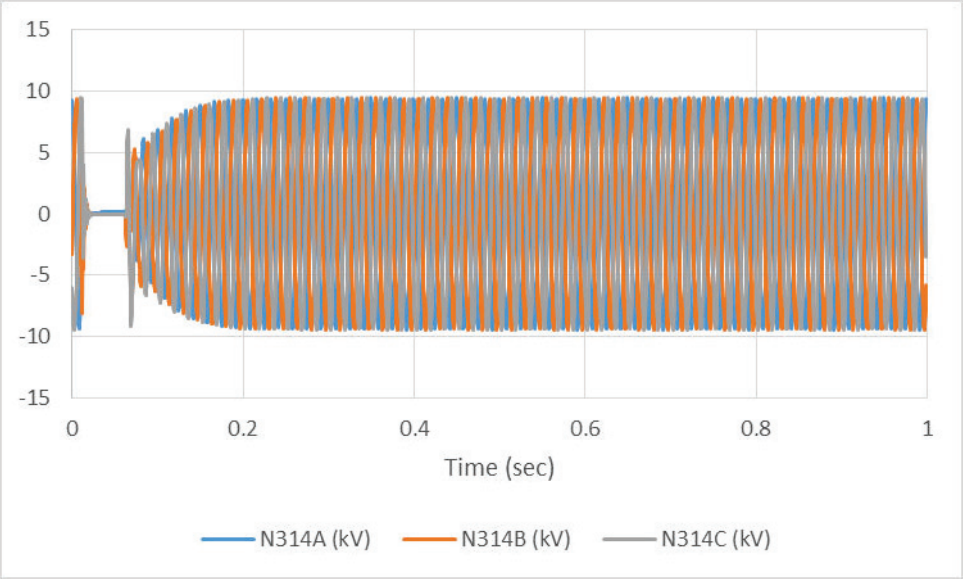


Figure D-94. Battery instantaneous voltage (kV) - High voltage side

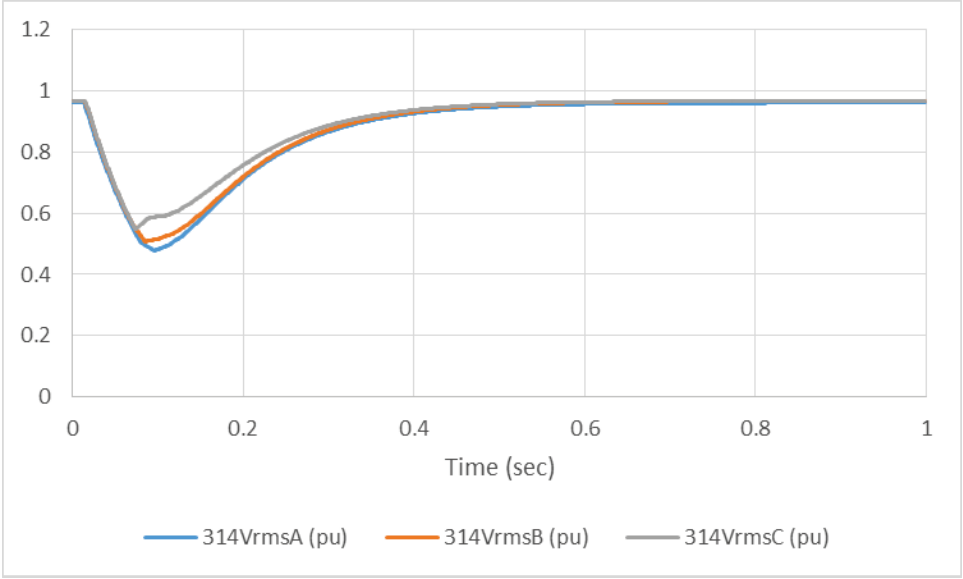


Figure D-95. Battery rms voltage (pu) - High voltage side

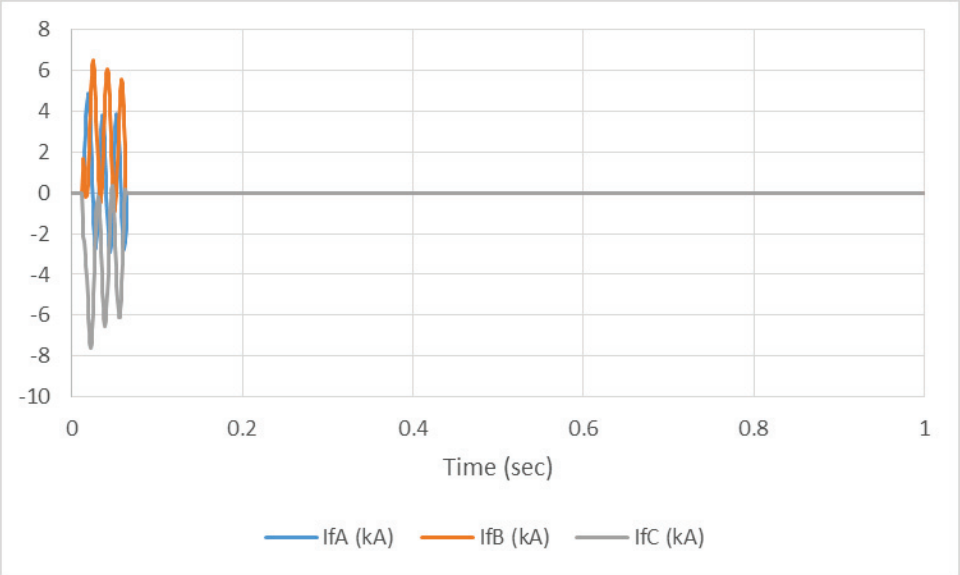


Figure D-96. Fault current at Bus #305 (kA)

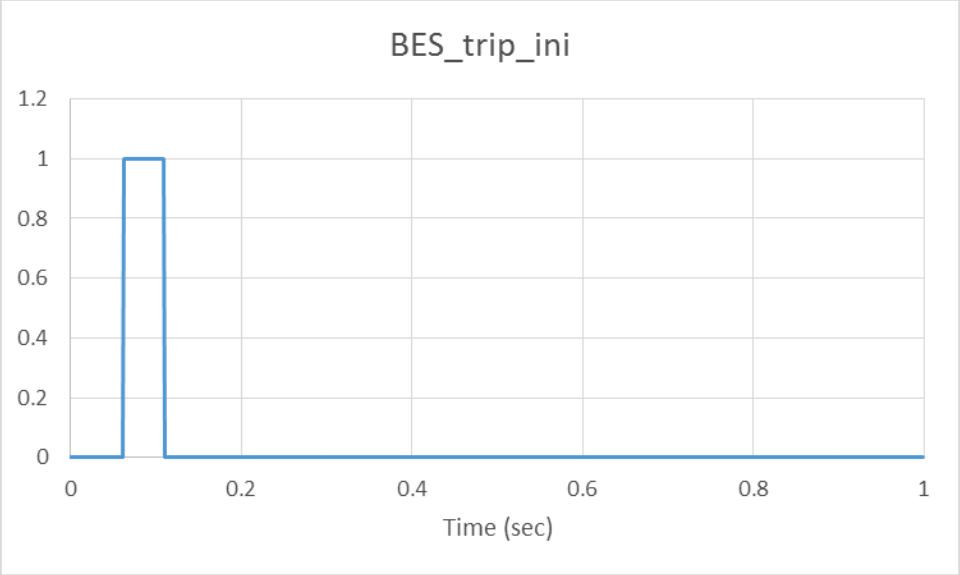


Figure D-97. Battery initial trip signal

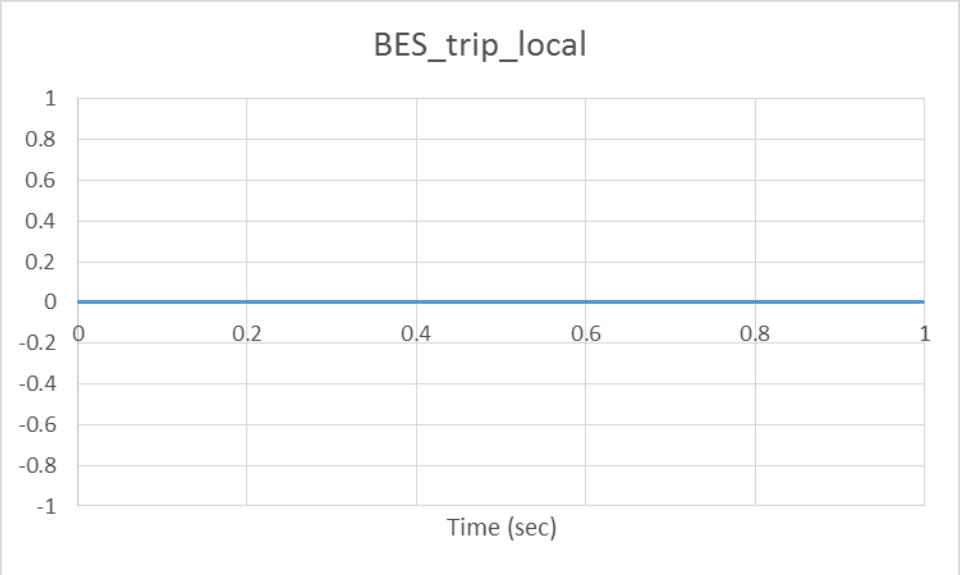


Figure D-98. Battery local trip signal

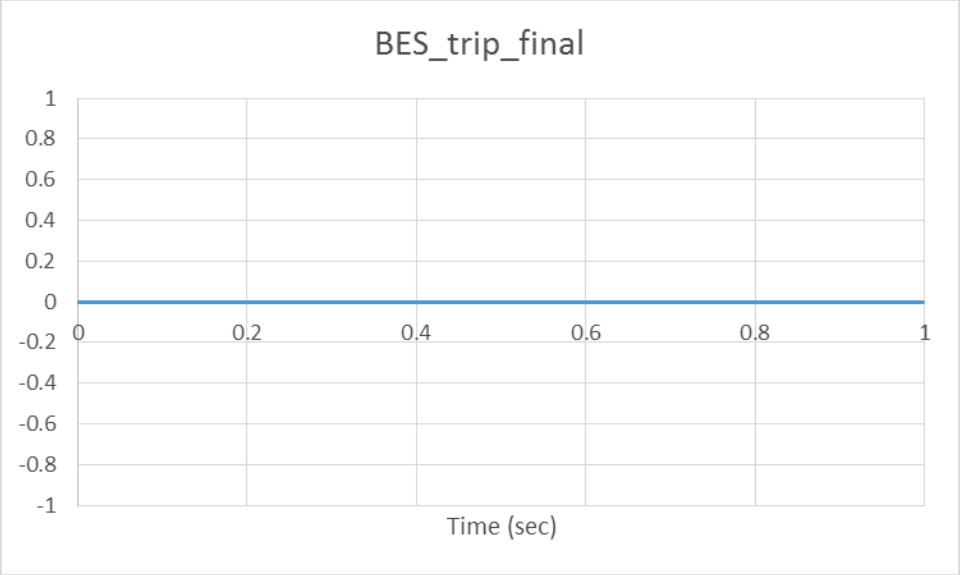


Figure D-99. Battery final trip signal

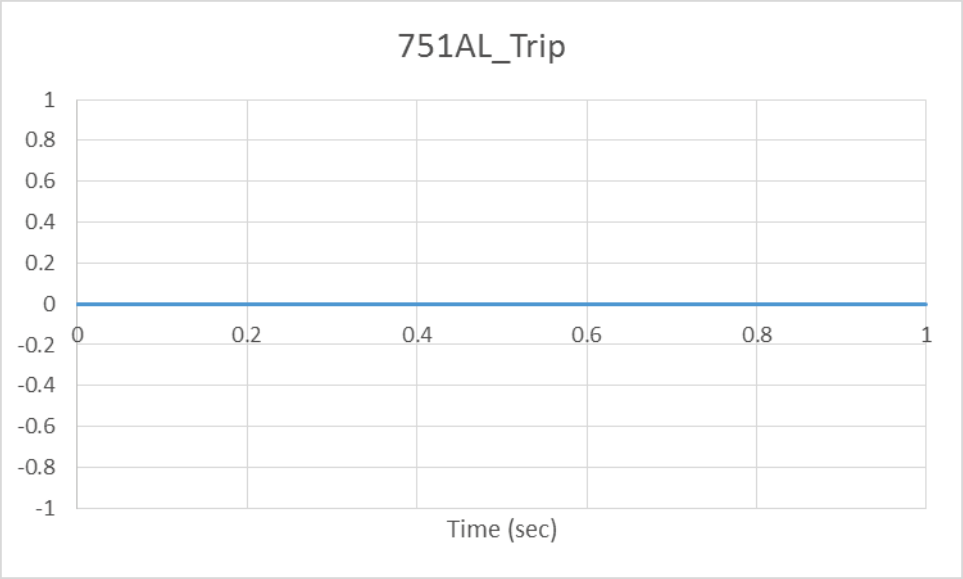


Figure D-100. 751 relay trip signal

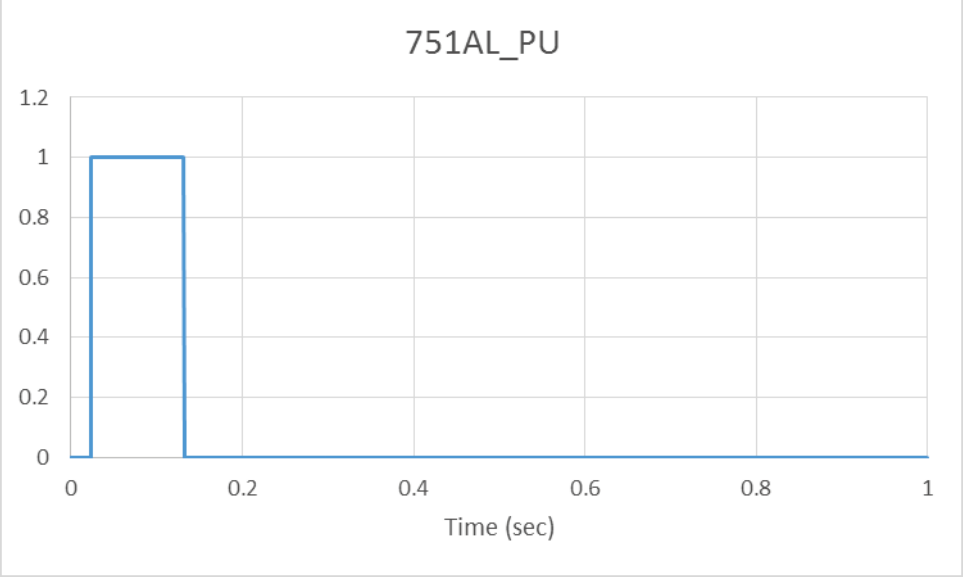


Figure D-101. 751 relay pickup signal

D.6.11 Test Case 7.11 Results

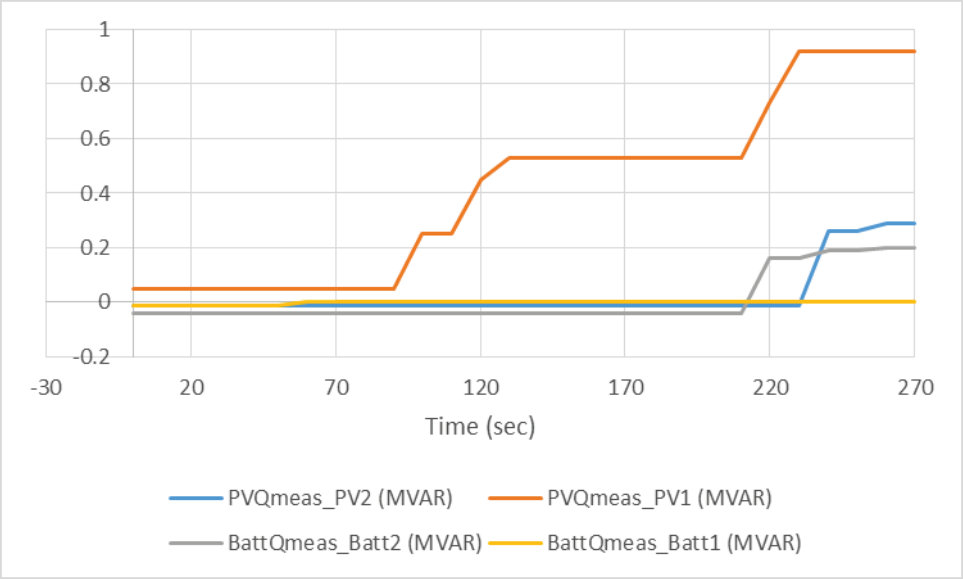


Figure D-102. DER reactive power measurements (Mvar)

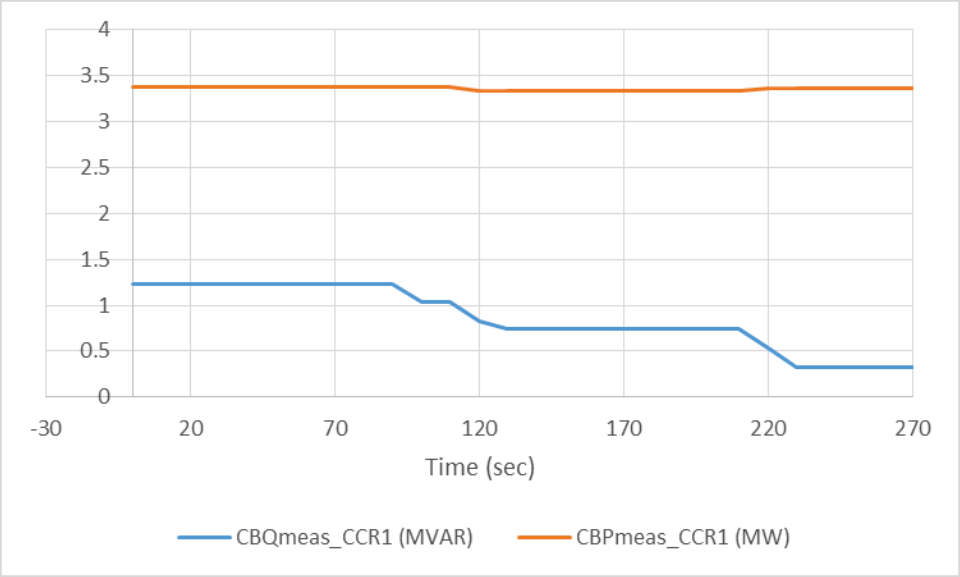


Figure D-103. CCR1 power flow measurement (MW & Mvar)

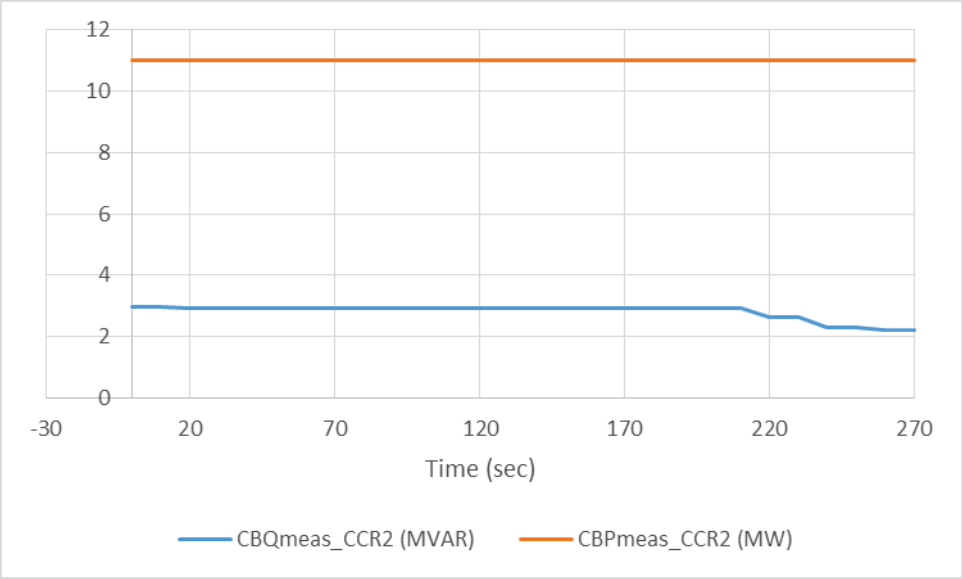


Figure D-104. CCR2 power flow measurement (MW & Mvar)

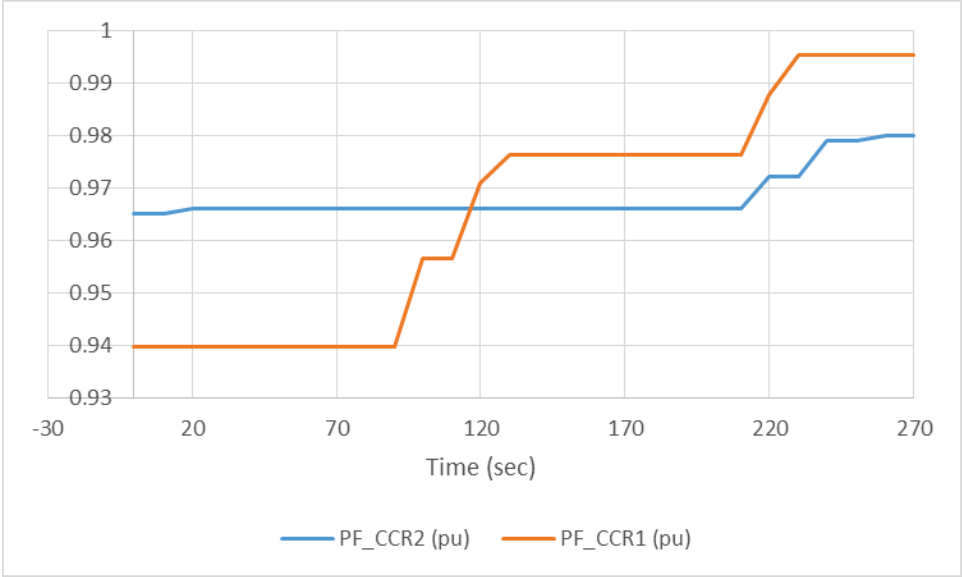


Figure D-105. CCR1 & CCR2 power factor measurement (pu)

D.6.12 Test Case 7.12 Results

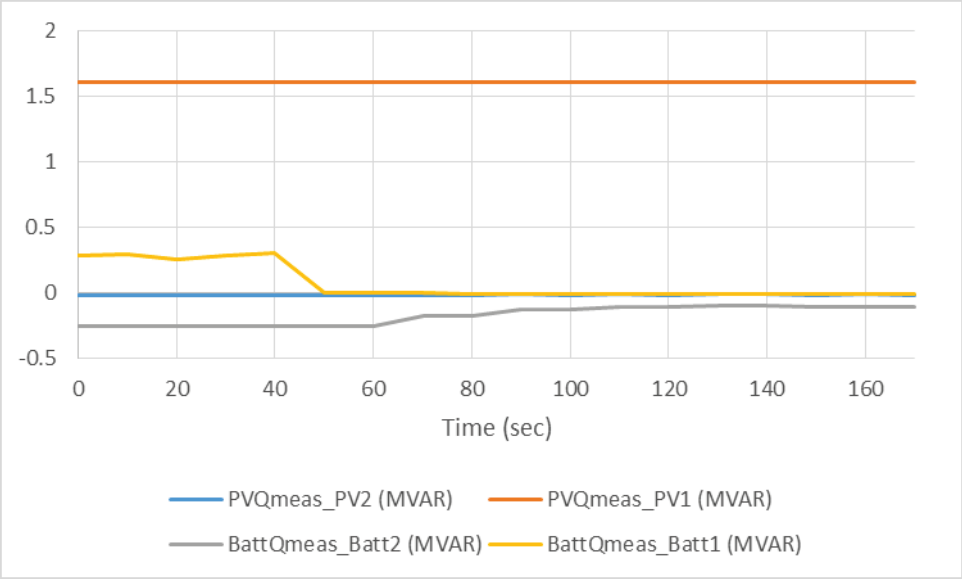


Figure D-106. DER reactive power measurements (Mvar)

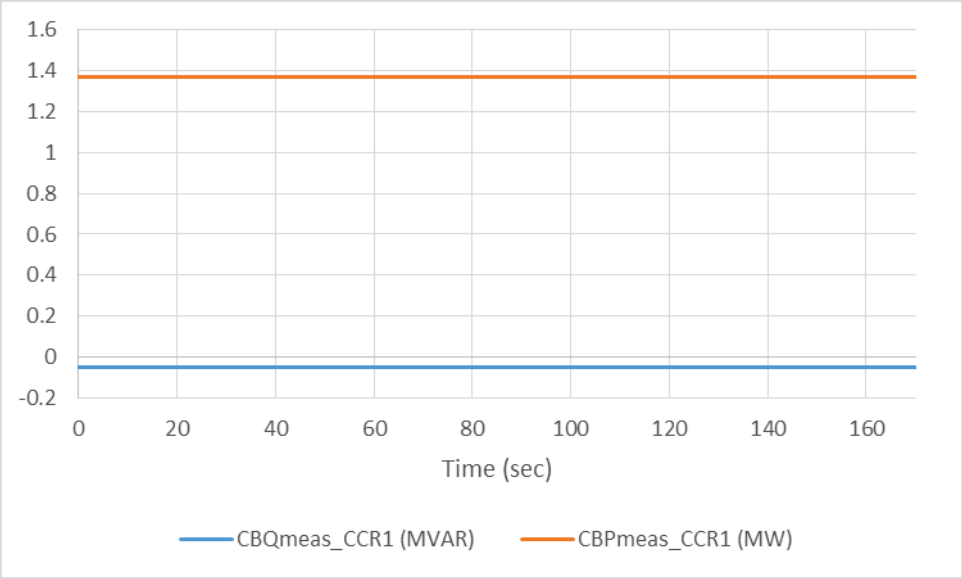


Figure D-107. CCR1 power flow measurement (MW & Mvar)

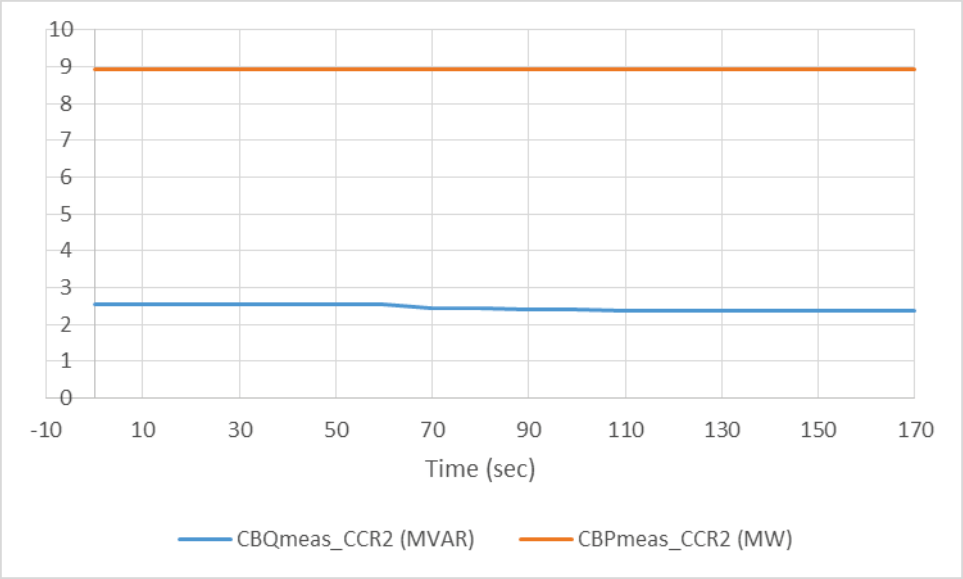


Figure D-108. CCR2 power flow measurement (MW & Mvar)

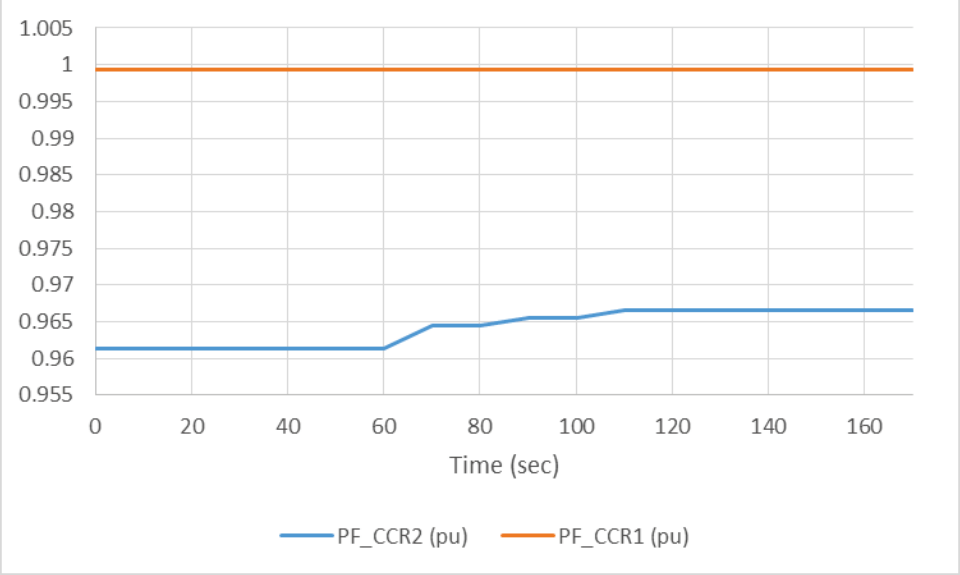


Figure D-109. CCR1 & CCR2 power factor measurement (pu)

D.7 Use Case 8: Test Records for Emergency load management tests

D.7.1 Test Case 8.1 Results

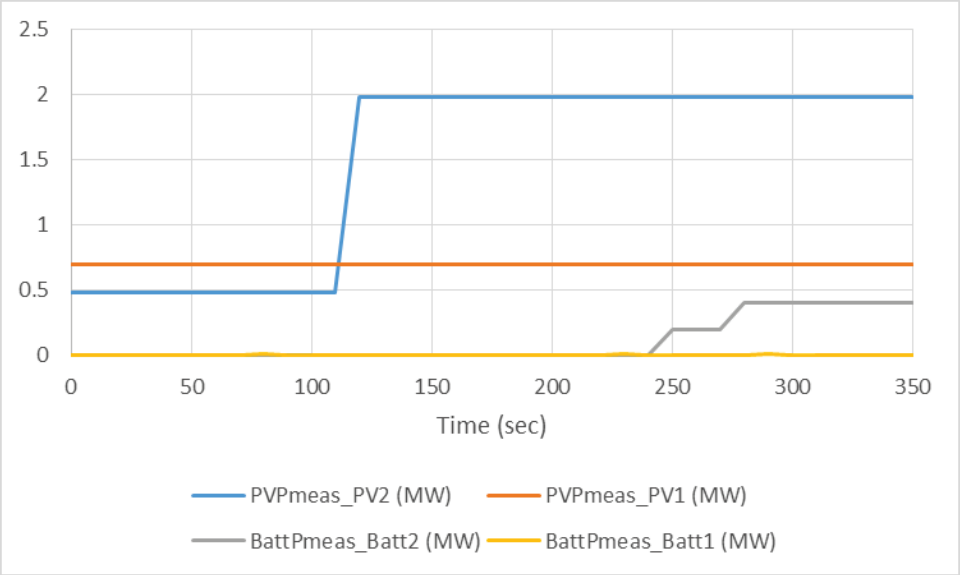


Figure D-110. DER active power flow measurements (MW)

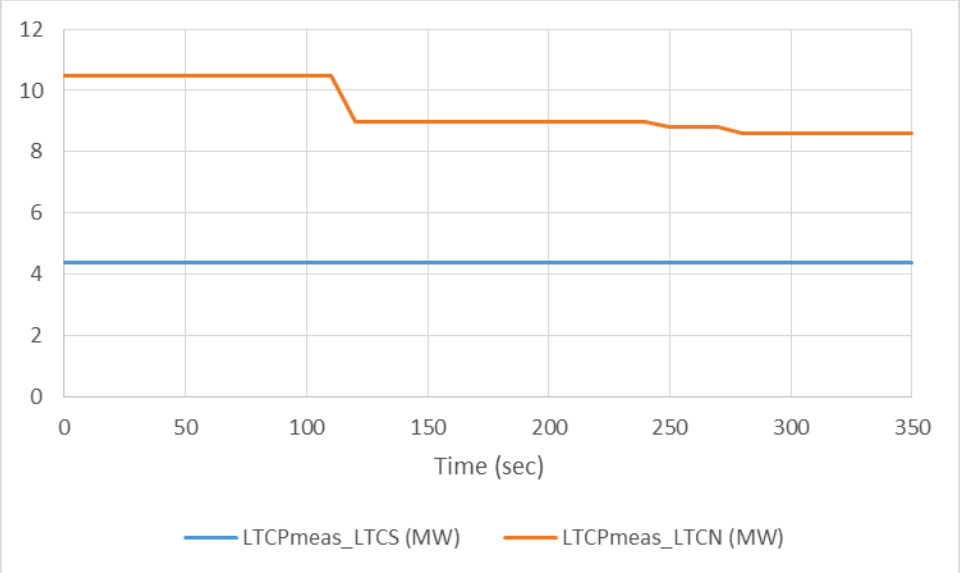


Figure D-111. LTC active power flow measurements (MW)

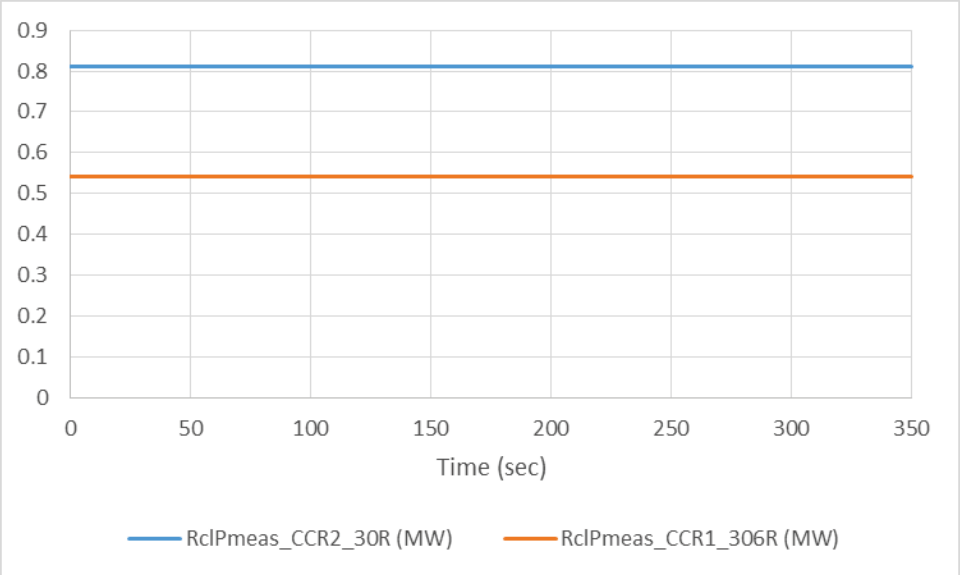


Figure D-112. CCR2_30R and CCR1_306R active power flow measurements (MW)

D.7.2 Test Case 8.2 Results

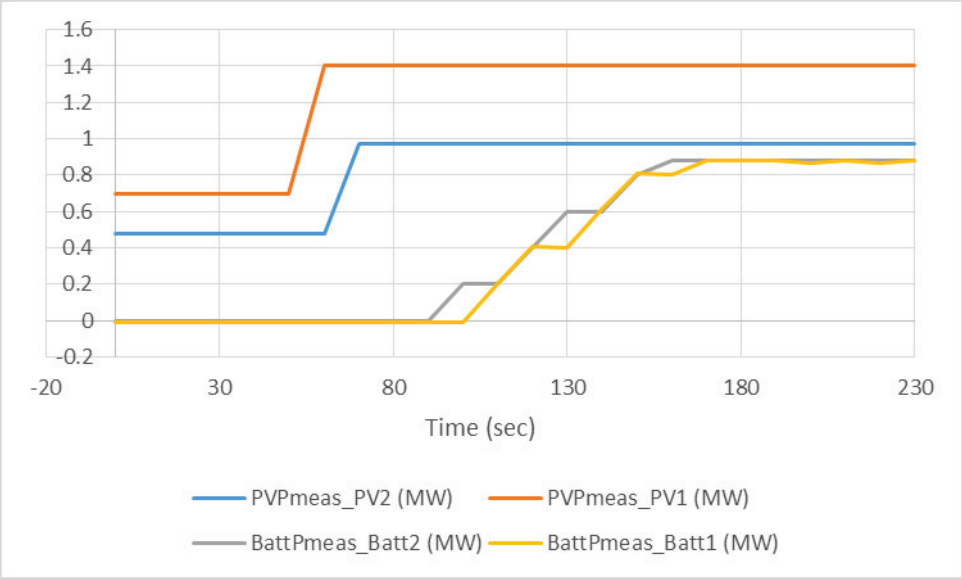


Figure D-113. DER active power flow measurements (MW)

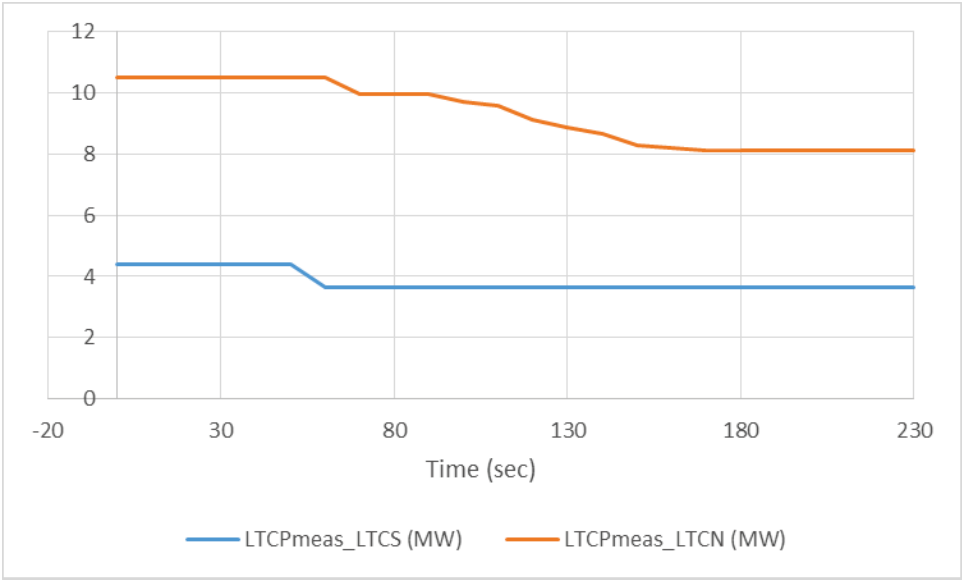


Figure D-114. LTC active power flow measurements (MW)

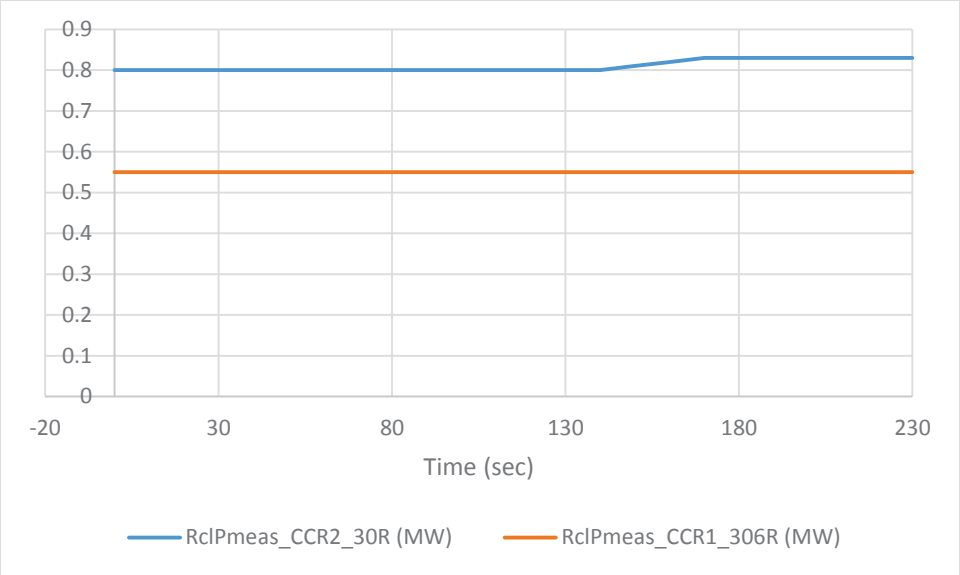


Figure D-115. CCR2_30R and CCR1_306R active power flow measurements (MW)

D.7.3 Test Case 8.3 Results

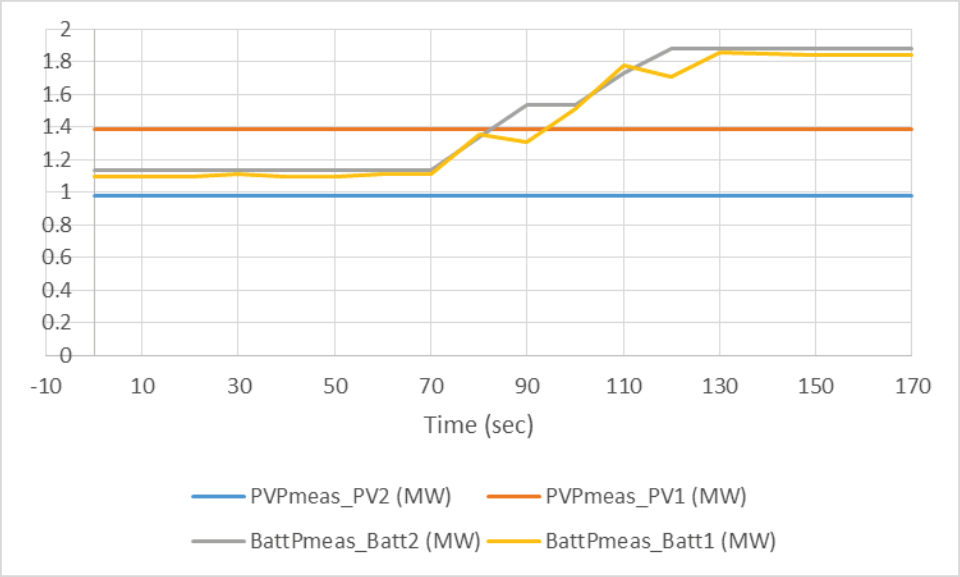


Figure D-116. DER active power flow measurements (MW)

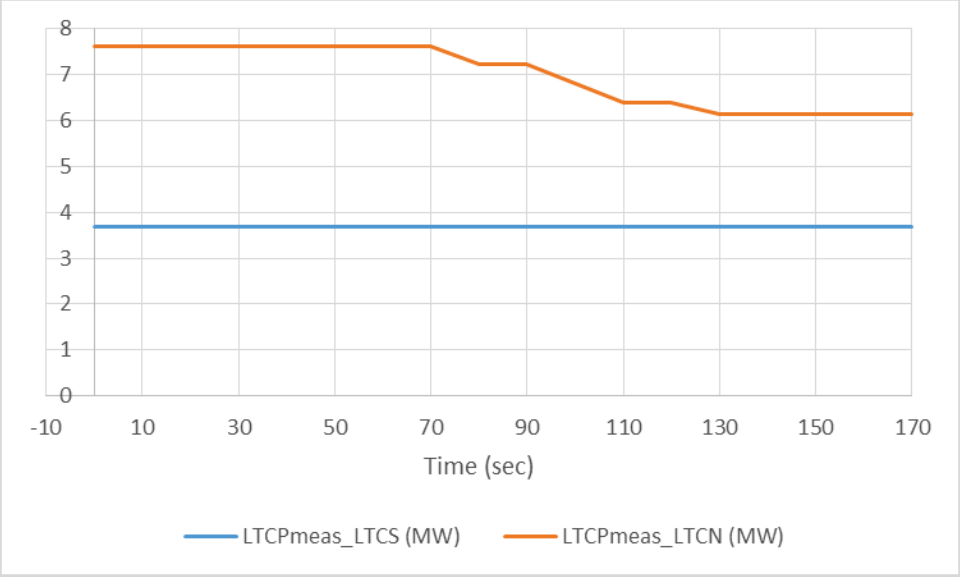


Figure D-117. LTC active power flow measurements (MW)

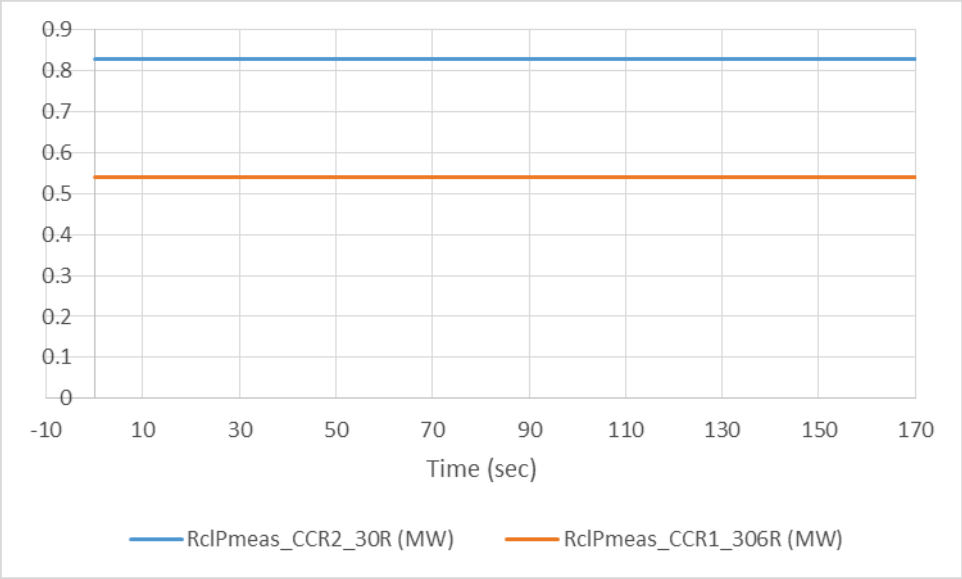


Figure D-118. CCR2_30R and CCR1_306R active power flow measurements (MW)

D.7.4 Test Case 8.4 Results

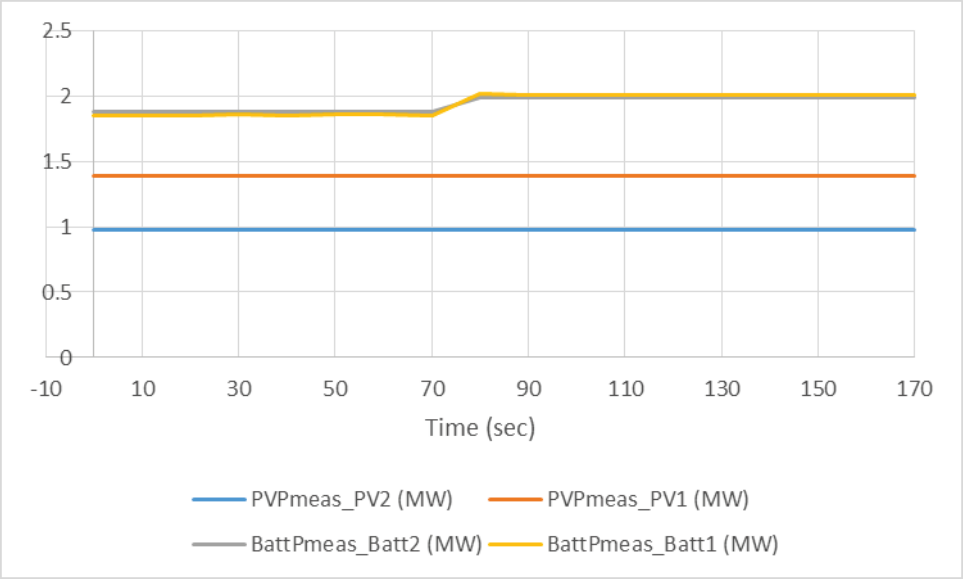


Figure D-119. DER active power flow measurements (MW)

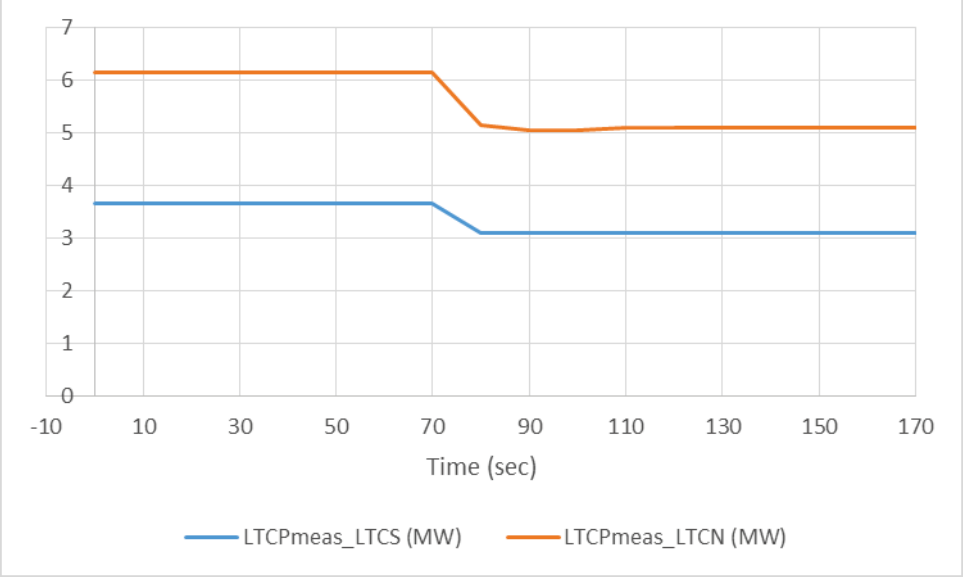


Figure D-120. LTC active power flow measurements (MW)

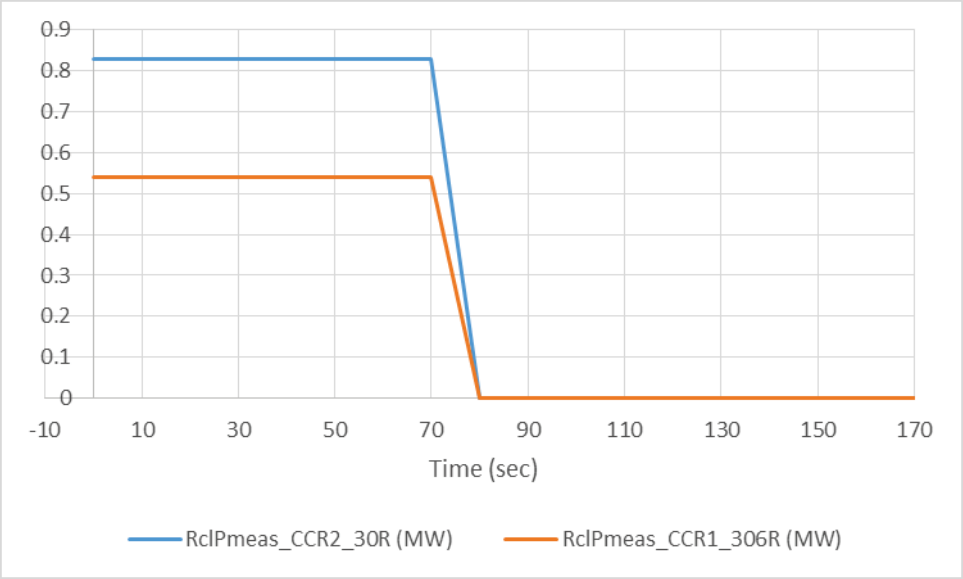


Figure D-121. CCR2_30R and CCR1_306R active power flow measurements (MW)

D.7.5 Test Case 8.5 Results

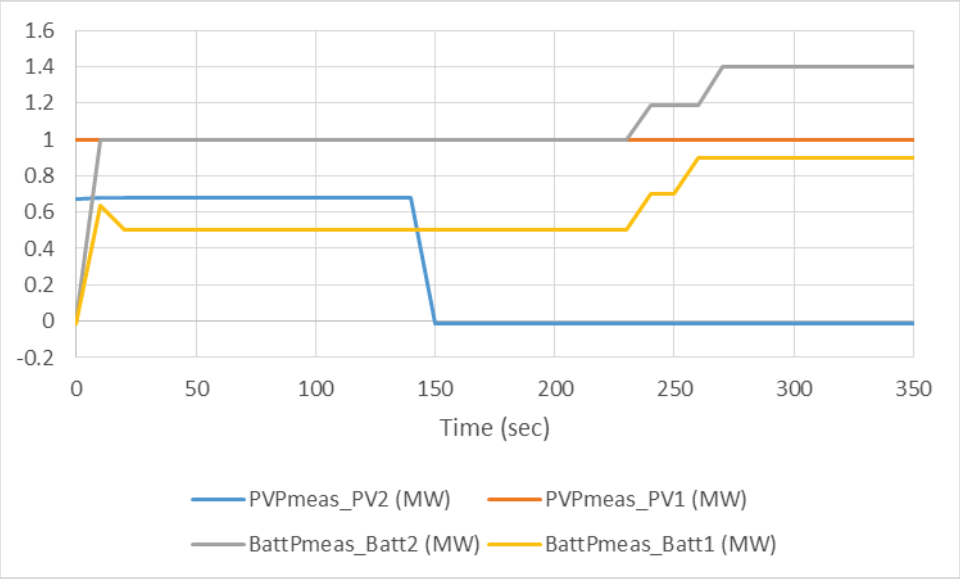


Figure D-122. DER active power flow measurements (MW)

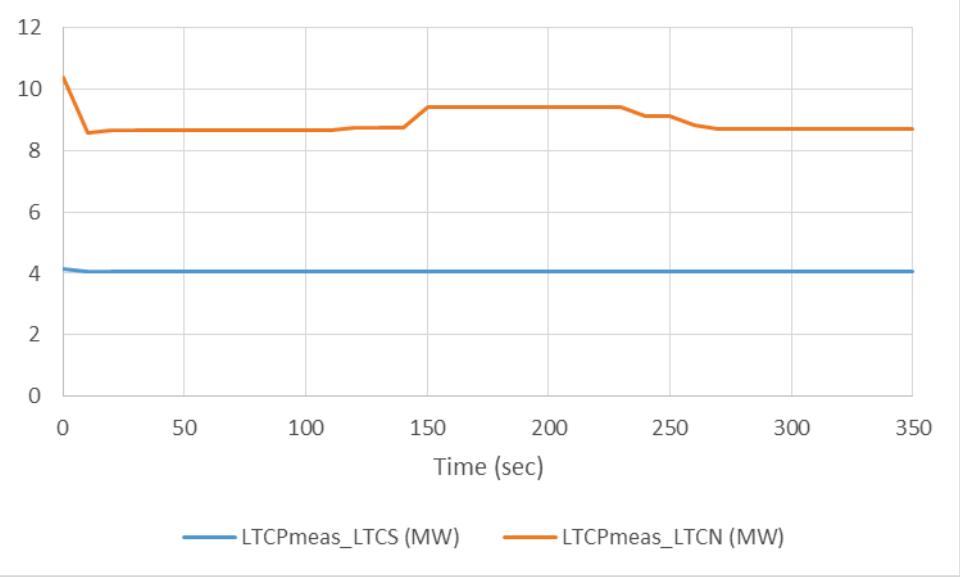


Figure D-123. LTC active power flow measurements (MW)

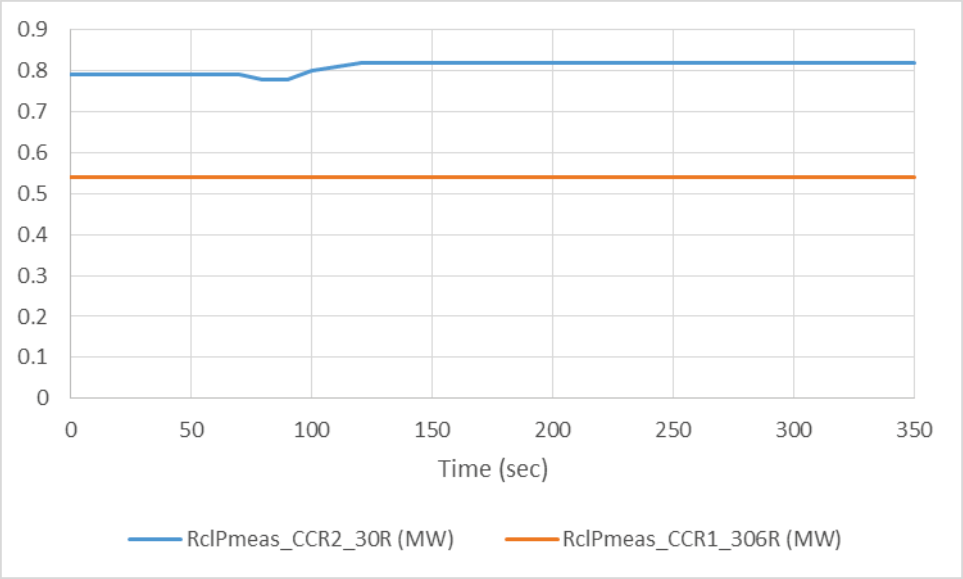


Figure D-124. CCR2_30R and CCR1_306R active power flow measurements (MW)

D.7.6 Test Case 8.6 Results

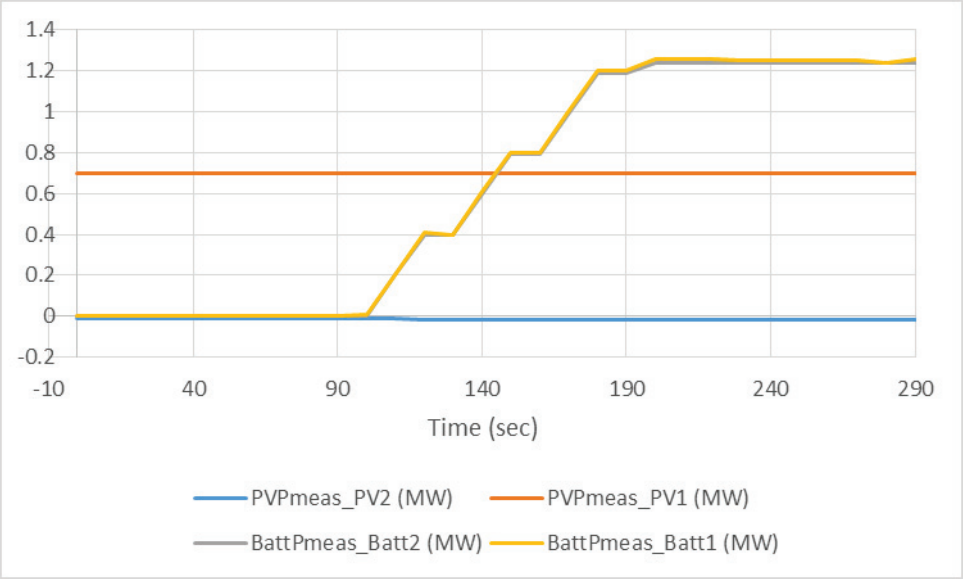


Figure D-125. DER active power flow measurements (MW)

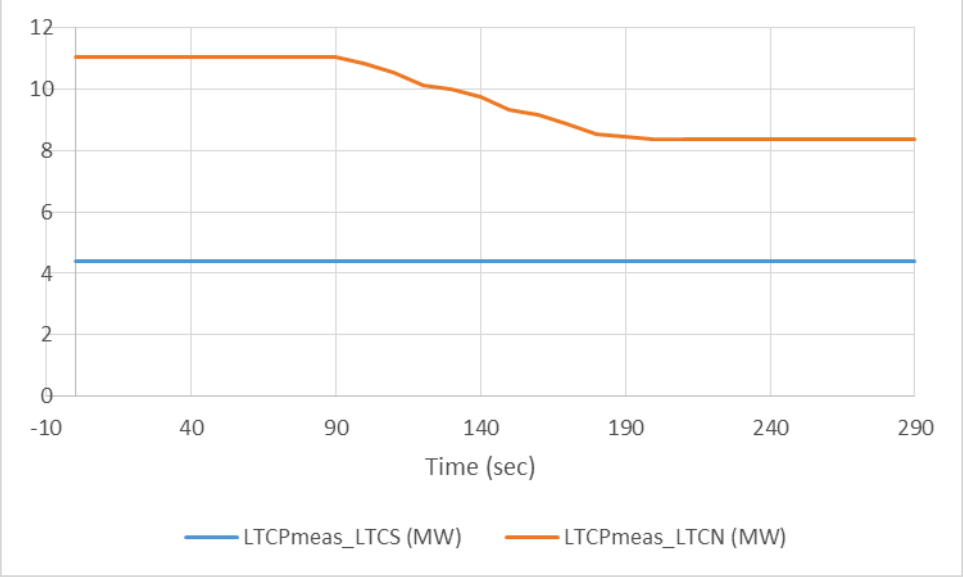


Figure D-126. LTC active power flow measurements (MW)

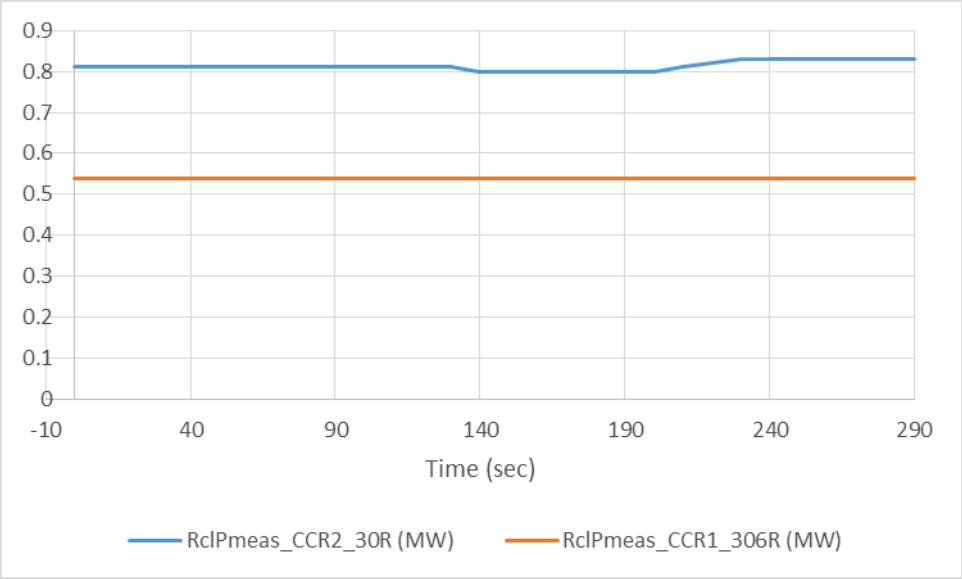


Figure D-127. CCR2_30R and CCR1_306R active power flow measurements (MW)

D.7.7 Test Case 8.7 Results

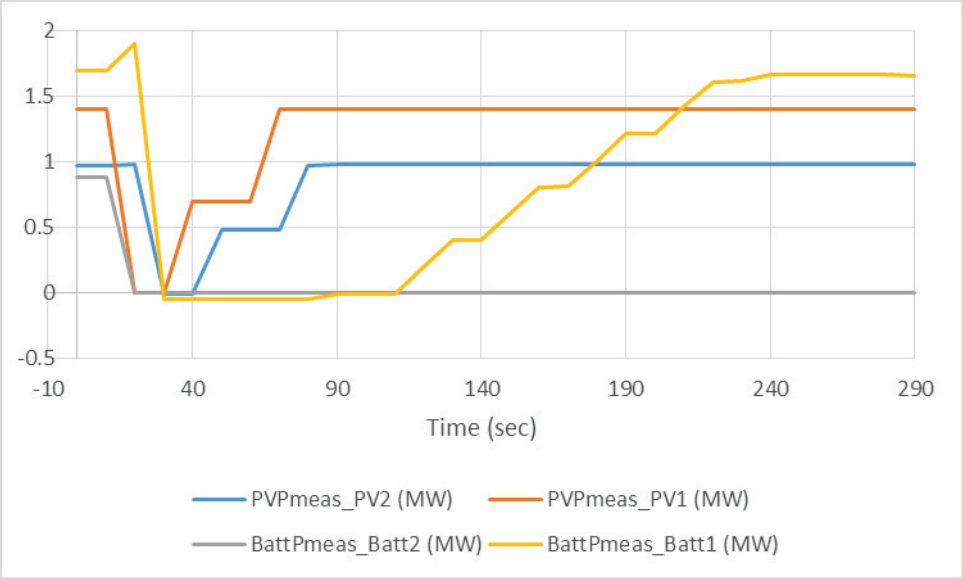


Figure D-128. DER active power flow measurements (MW)

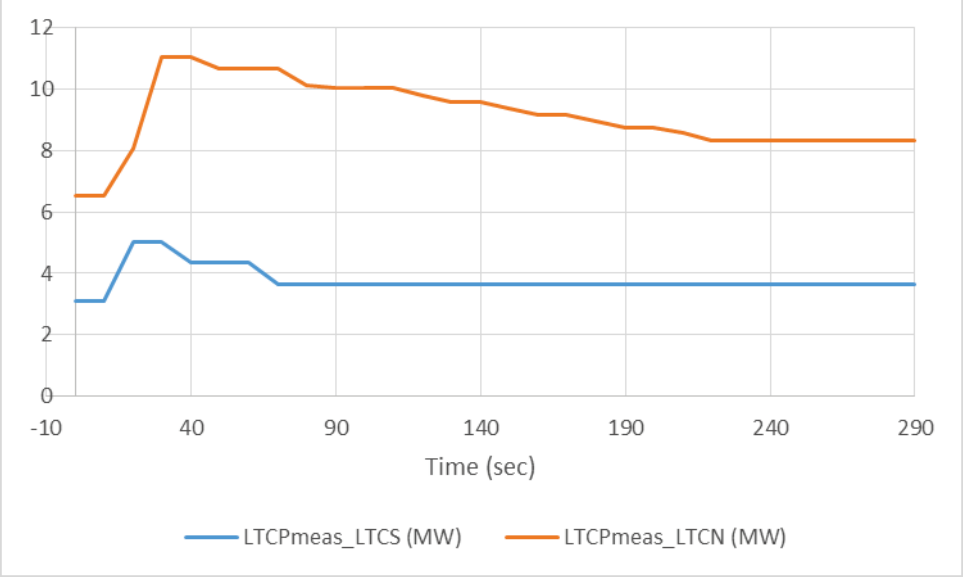


Figure D-129. LTC active power flow measurements (MW)

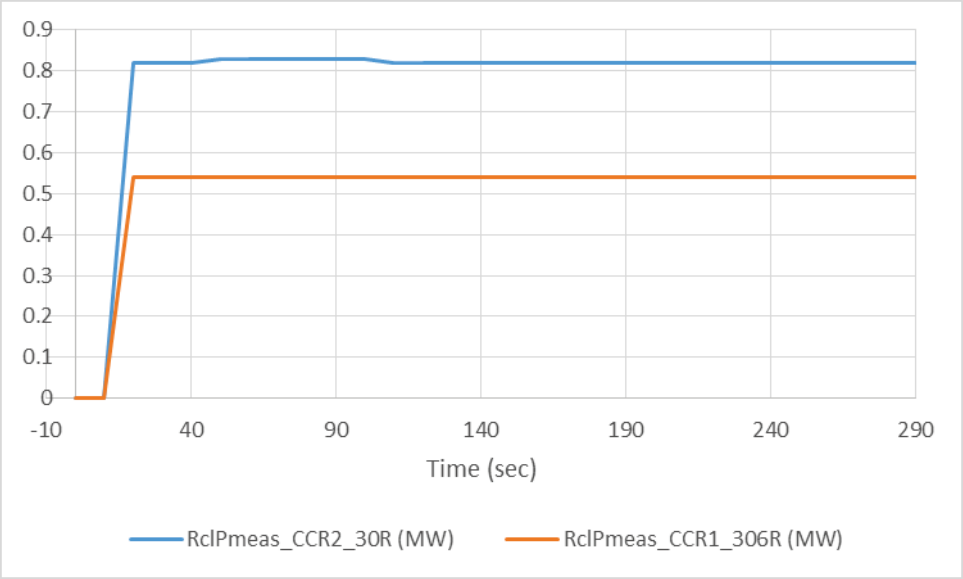


Figure D-130. CCR2_30R and CCR1_306R active power flow measurements (MW)

D.7.8 Test Case 8.8 Results

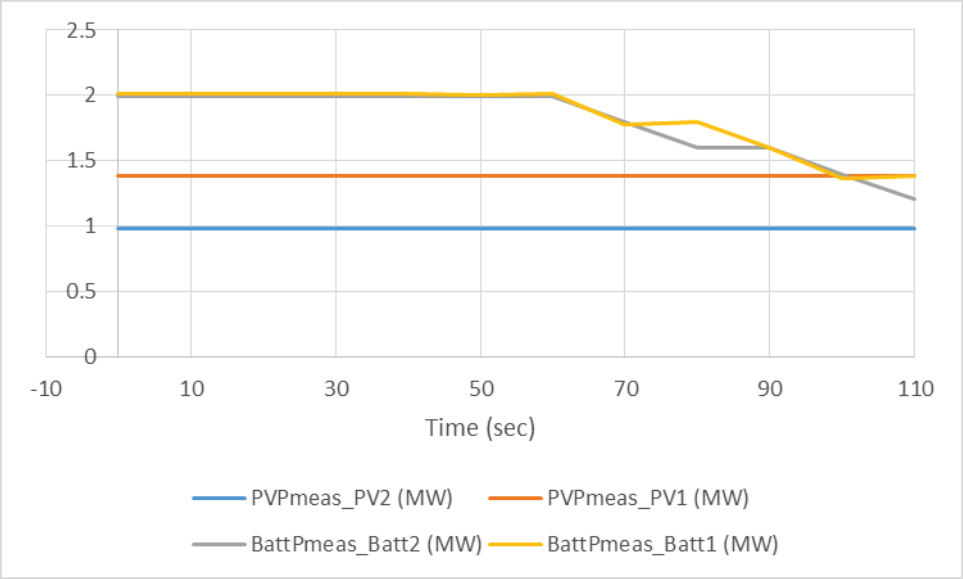


Figure D-131. DER active power flow measurements (MW)

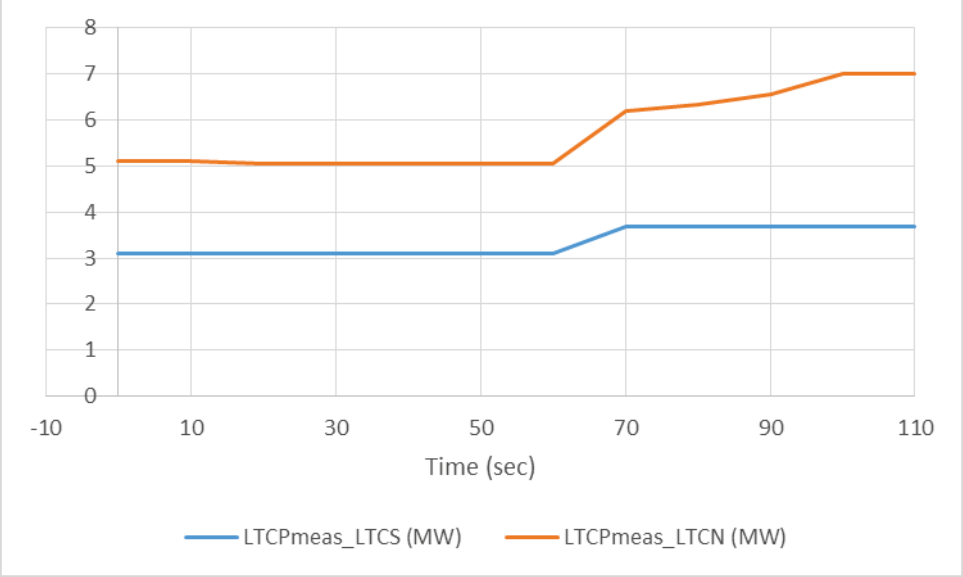


Figure D-132. LTC active power flow measurements (MW)

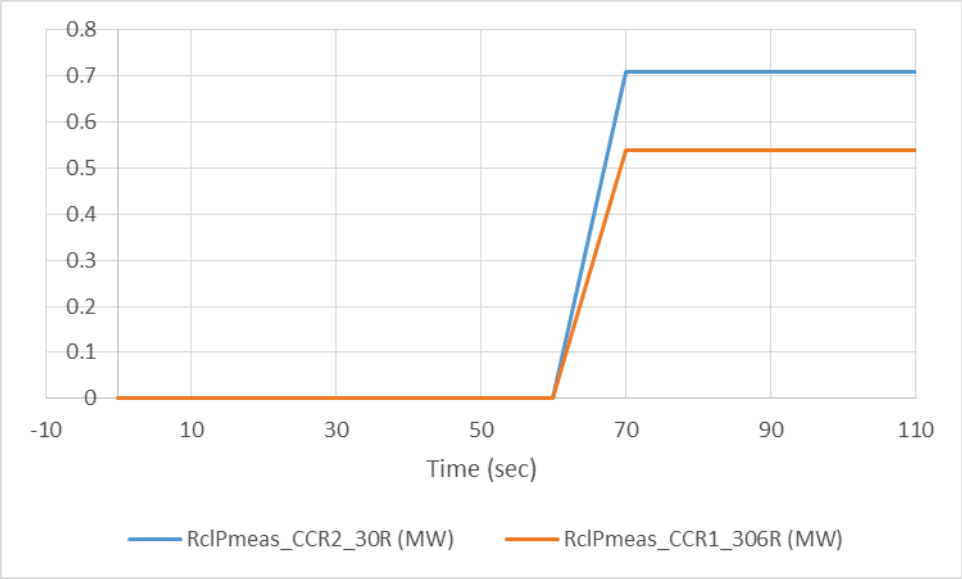


Figure D-133. CCR2_30R and CCR1_306R active power flow measurements (MW)

D.7.9 Test Case 8.9 Results

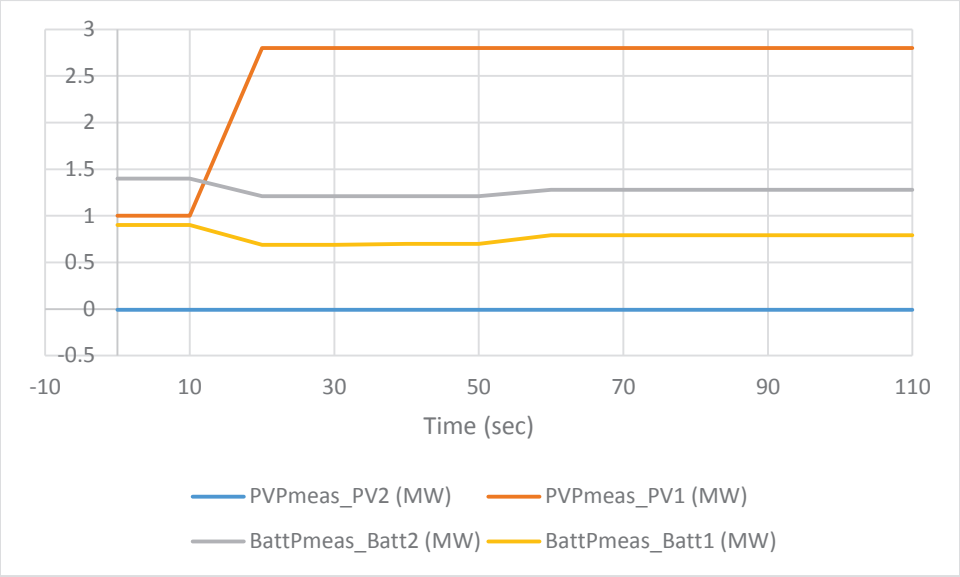


Figure D-134. DER active power flow measurements (MW)

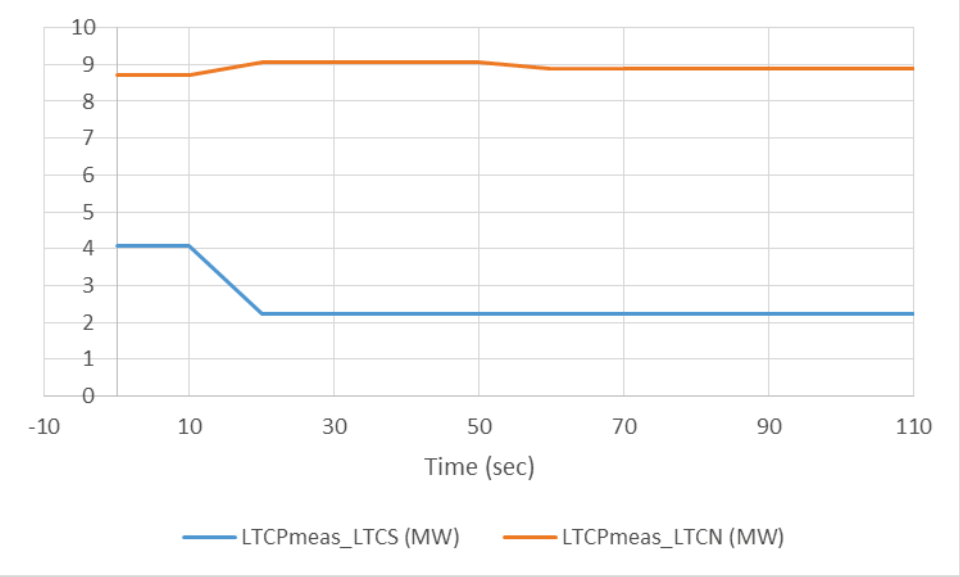


Figure D-135. LTC active power flow measurements (MW)

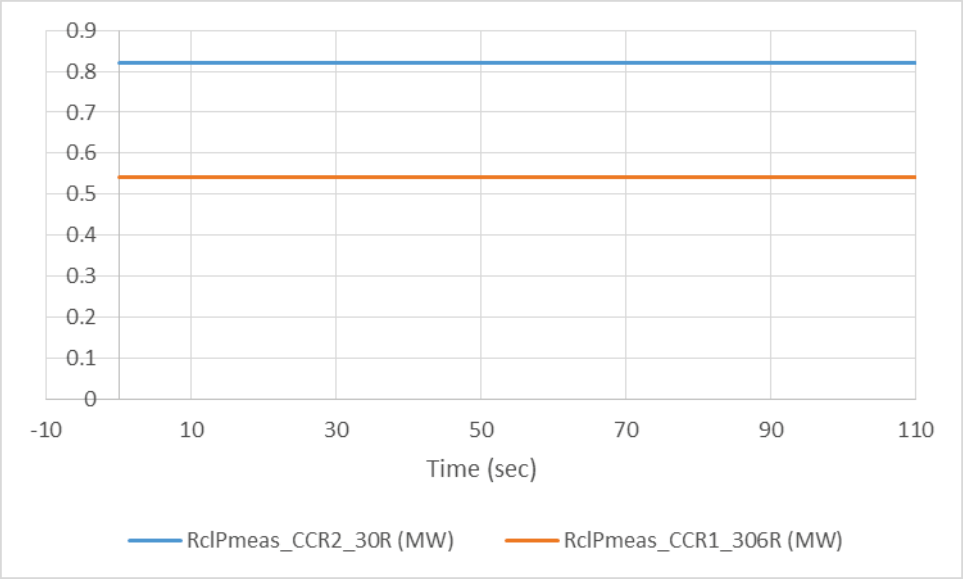


Figure D-136. CCR2_30R and CCR1_306R active power flow measurements (MW)

D.7.10 Test Case 8.10 Results

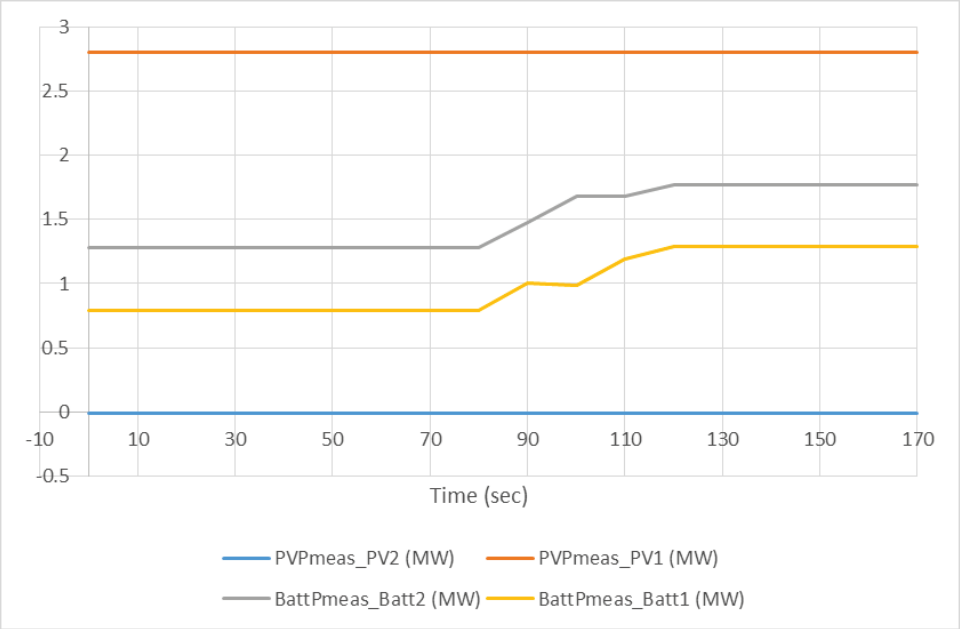


Figure D-137. DER active power flow measurements (MW)

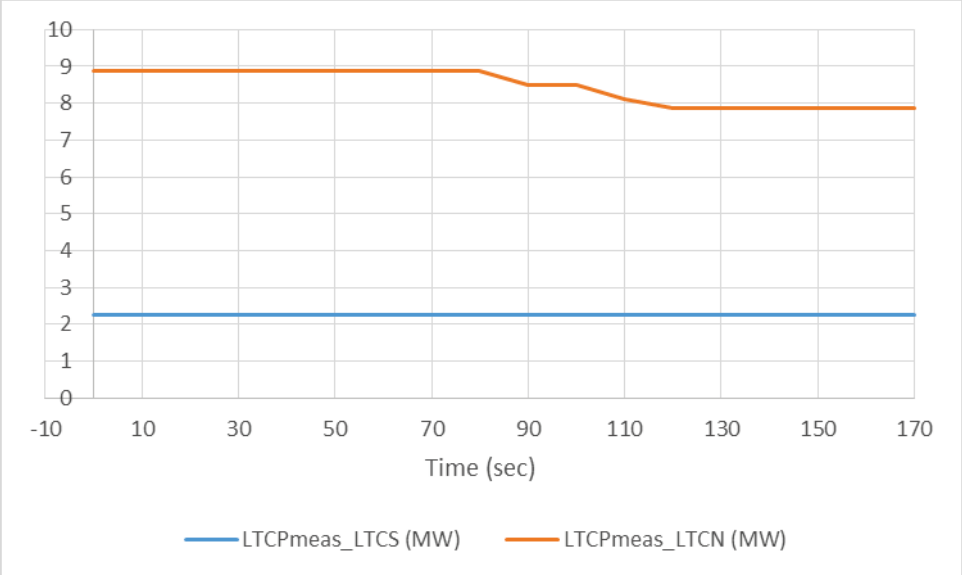


Figure D-138. LTC active power flow measurements (MW)

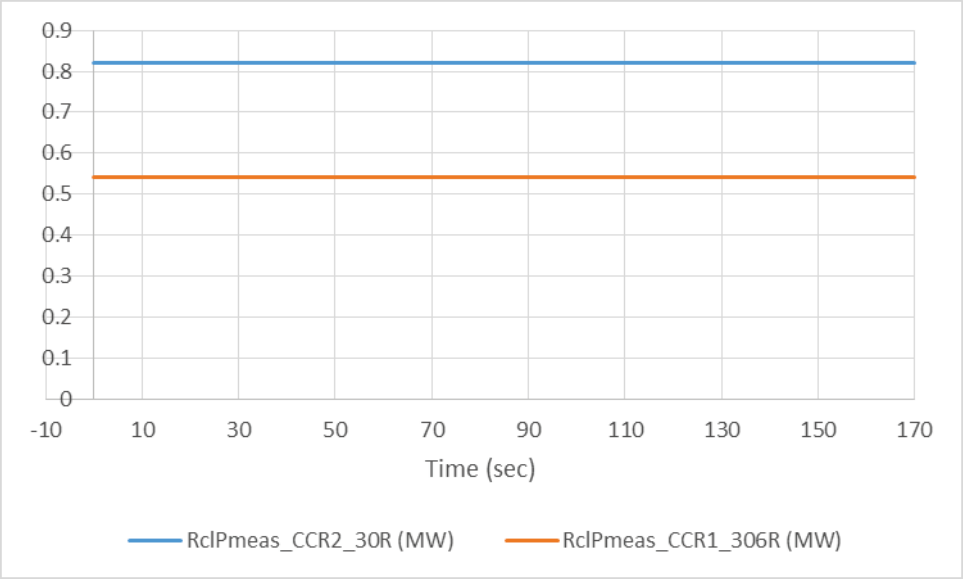


Figure D-139. CCR2_30R and CCR1_306R active power flow measurements (MW)

D.7.11 Test Case 8.11 Results

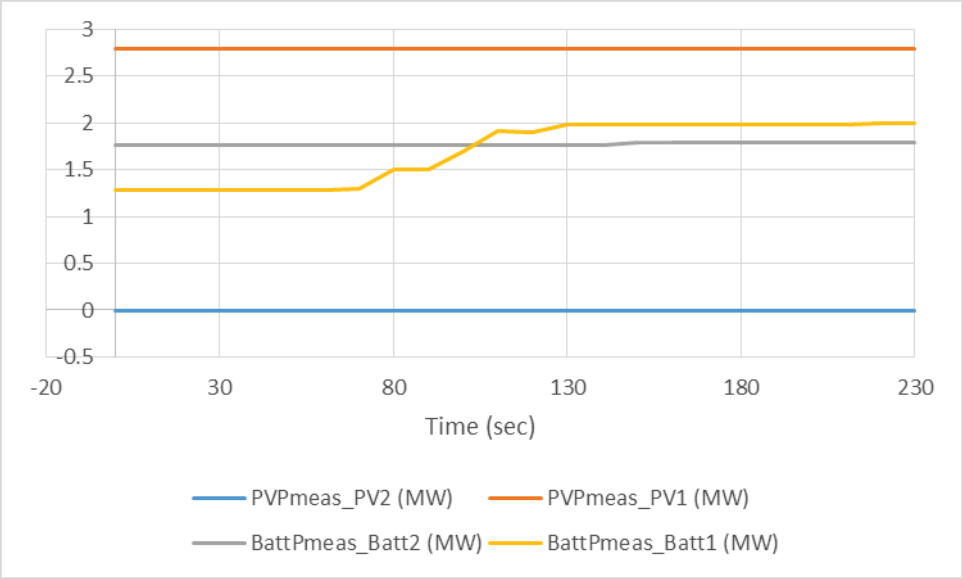


Figure D-140. DER active power flow measurements (MW)

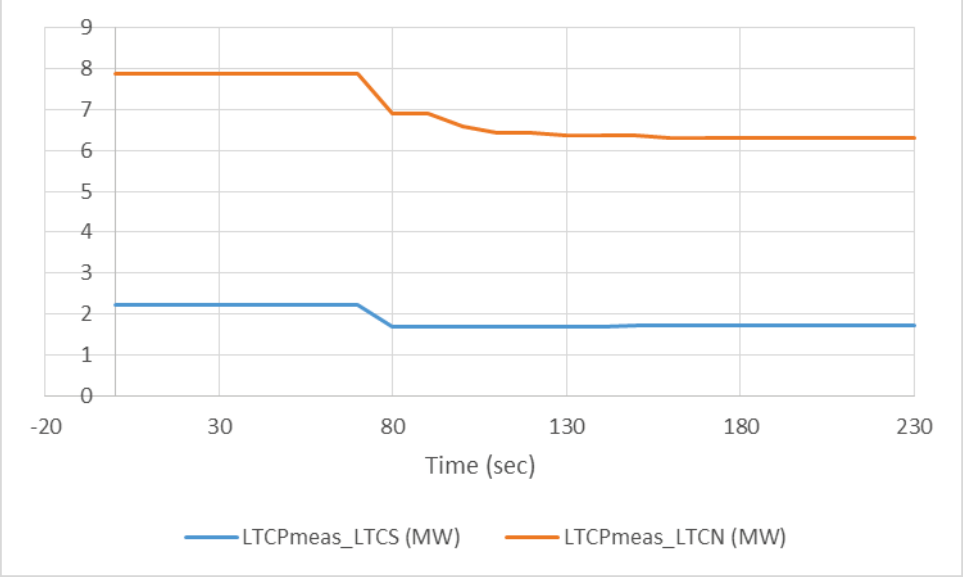


Figure D-141. LTC active power flow measurements (MW)

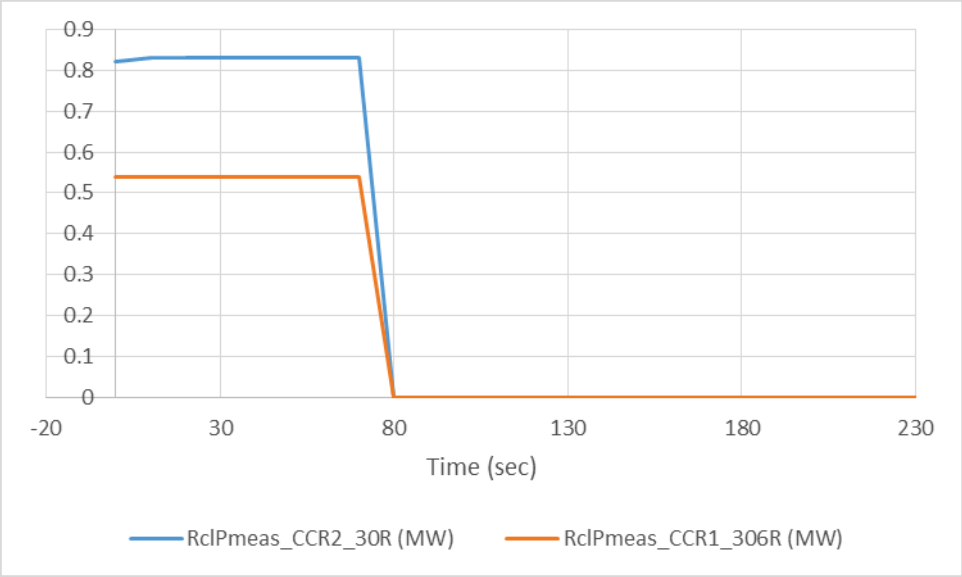


Figure D-142. CCR2_30R and CCR1_306R active power flow measurements (MW)

Appendix 2

EPIC-1, Project 2: Visualization and Situational Awareness Demonstration

San Diego Gas & Electric Company

EPIC Final Report

Program	**Electric Program Investment Charge (EPIC)**
Administrator	**San Diego Gas & Electric Company**
Project Number	**EPIC-1, Project 2**
Project Name	**Visualization and Situational Awareness Demonstration**
Date	**December 31, 2017**

Attribution

This comprehensive final report documents work done in this EPIC activity.

The project team for this work included the following individuals, listed alphabetically by last name.

SDG&E Staff

Gayatri Alapati
Cullan Bittner
Brian Braidic
Casey Cook
Srihari Darapaneni
Susmita Duncan
Aksel Encinas
Frank Goodman
Zlatina Gounev
David Hawkins
Molham Kayali
Kyle Kewley
Mark Liwanag
Iman Mazhari
Timothy McDermott
Bao Nguyen
Subburaman Sankaran
Mark Stiefel
Sowajanya Sunkara
Chris Surbey

Quanta Technology, LLC

Boza Avramovic
Dino Lelic

EXECUTIVE SUMMARY

This report summarizes project objectives, technical approach, results, and lessons learned for the EPIC-1 Project #2, Visualization and Situational Awareness Demonstration. Work on this project started with planning tasks in 2016, with most of the implementation work performed in 2017.

The role of the system operator is changing. Where distribution operators of earlier times used to deal mainly with limited information from low-bandwidth supervisory control and data acquisition (SCADA) systems and switching decisions, smart grid operations now must consider new classes of data from numerous devices. The deployment of these numerous sensors, intelligent devices, meters, and other communication nodes within the SDG&E power distribution system generates a massive amount of highly granular data, sometimes referred to as a "data tsunami". By merely extending the existing ways of fragmented presentation of information, the data tsunami may overwhelm system operators and diminish the value of the data. However, *if presented appropriately by filtering, combining related data from different sources in line with cognitive capabilities and task related needs of users, and by adding geospatial dimension to operational, historical, and other types of data, information derived from this massive amount of data will increase the operators' ability to process and better react to relevant information, resulting in improved grid operations and reliability*. The objectives of this project were aligned with the second approach.

Objectives (EPIC-1, Project 2)

The objective of this demonstration project was to explore how data collected from sensors and devices can be processed, combined, and presented to system operators in a way that enhances grid monitoring and situational awareness. In particular, this project has looked at how data currently unexploited and separately processed can be integrated and visually presented for strategic use by system operators.

When transformed and presented in a visually integrated manner, this data can be invaluable for utilities to optimize grid operations as well as provide insights into the performance of the overall utility system. This visual framework also provides insights into customers' energy consumption behavior to serve them more effectively, foster energy conservation, and reduce peak demand. The demonstrated specific visualization and situational awareness concepts will be used in the future to help SDG&E make better choices on which options should be adopted for a future visualization and situational awareness system.

Scope

The following eight use cases, addressing a wide range of SDG&E business needs within the smart grid visualization area, were selected for the project: (1) Transmission Fault Location Visualization, (2) Load Curtailment Visualization, (3) Automation of Quarterly Electric Utility Reports, (4) Visualization of Outage History Playback, (5) AMI for Operations Visualization, (6) Customer-owned DER Visualization, (7) Imagery Management, and (8) GIS Visualization infrastructure modernization.

Approach

The work on implementing each of the use cases included 1) requirements definition for the visualization and situational awareness to be provided by the use case, 2) prototyping the data integration schemes, displays, and algorithms, and 3) implementation of a testing plan.

Results

The key element of the solutions for all use cases is the use of GIS data and GIS visualization capabilities to visually and functionally integrate other types of data relevant for a use case, which, in the past, has usually been handled separately. An emphasis throughout the project was on developing solutions that are sufficiently responsive, flexible, configurable, and reusable. Therefore, a successful demonstration of these novel solutions not only addressed the current business needs of the eight use cases, but also provided a knowledge base and software artifacts that will help SDG&E find better solutions for its future visualization and situational awareness needs.

The developed solutions collectively cover a truly wide spectrum of SDG&E business areas, users, business applications, and technology topics that had to be addressed:

- ***Business Areas***: Transmission Operations, Distribution Operations, Emergency Operations Center (EOC), Transmission and Distribution Engineering, Distribution Planning, Maintenance and Construction Services, Emergency Management and Aviation Services, Regulatory Compliance, Finance, and Vegetation Management
- ***Business Functions***: Accurate geographic location of transmission faults, Geospatial Data Visualization for Situational Awareness, Load Curtailment Dashboard for EOC use, and Improvements in Asset Management, Operations, and GIS Maintenance afforded by new Network Model, Process improvements via automation and geospatial awareness in combination with Business Intelligence, Empowering end users via enhanced mobility and configurability to match their business needs

Recommendations

Based on the outcomes of pre-production demonstrations, the results for use cases 1 through 6 are recommended for production implementation. Results of use cases 7 and 8 (Imagery Management and GIS Visualization Infrastructure Modernization) have met the narrow objectives set for each of those use cases; however, in both instances, the efforts are just an initial step toward what is required to be a more extensive development and investigation, before the cumulative results are ready for production. For all of the other cases, the effort to transition to production is minimal – measured in fractions of FTE – and generally consists of moving the artifacts from the test to QA environments, engineering review, and customer acceptance. In one case (Visualization of Customer-owned DER), no additional work is required beyond what was necessary for the pre-production demonstration.

Conclusions

Based on the feedback from early users of the project results - which has been uniformly positive - this project has successfully achieved all of its key objectives. Through the performed work, SDG&E has demonstrated novel solutions to the selected use cases, and, in the process, has also gained reusable software artifacts and substantial experience in integrating GIS, historical, asset management, and other major SDG&E computer systems. Both aspects will provide usability well beyond the direct utility of the software components produced by the project.

TABLE OF CONTENTS

Attribution i

EXECUTIVE SUMMARY ii

List of Figures vii

Acronyms and Definitions ix

1 INTRODUCTION 1

1.1 Project Objectives 2

1.2 Scope of Work – Use Cases 2

1.3 Main Visualization Components 2

2 USE CASES FOR DEMONSTRATION 4

2.1 Transmission Fault Location Visualization (UC #1) 4

2.1.1 Background 4

2.1.2 Objective 4

2.1.3 Users 4

2.1.4 Solution Approach, Solution Components, and Work Flow 5

2.1.5 Results 8

2.1.6 Observations, Challenges, and Lessons Learned 11

2.2 Load Curtailment Visualization (UC #2) 11

2.2.1 Background 11

2.2.2 Objective 12

2.2.3 Users 12

2.2.4 Solution Approach, Solution Components, and Work Flow 12

2.2.5 Results 17

2.2.6 Observations, Challenges, and Lessons Learned 17

2.3 Automation of Quarterly Electric Utility Reports (UC #3) 18

2.3.1 Background 18

2.3.2 Objective 19

2.3.3 Users 19

2.3.4 Solution Components and Work Flow 19

2.3.5 Results 26

2.3.6 Observations, Challenges, and Lessons Learned 34

2.4 Historical Outages Playback (UC #4) 34

2.4.1 Background 34

2.4.2 Objective 34

2.4.3 Users 35

2.4.4 Solution Approach, Solution Components, and Work Flow 35
2.4.5 Results 42
2.4.6 Observations, Challenges and Lessons Learned 53
2.5 AMI for Operations (UC #5) 53
2.5.1 Background 53
2.5.2 Objective 53
2.5.3 Users 53
2.5.4 Solution Approach, Solution Components, and Work Flow 54
2.5.5 Results 54
2.5.6 Observations, Challenges and Lessons Learned 61
2.6 Customer-Owned DER Visualization (UC #6) 62
2.6.1 Background 62
2.6.2 Objective 62
2.6.3 Users 62
2.6.4 Solution Approach, Solution Components, and Work Flow 62
2.6.5 Results 67
2.6.6 Observations, Challenges, and Lessons Learned 67
2.7 Imagery Management (UC #7) 68
2.7.1 Background 68
2.7.2 Objective 68
2.7.3 Users 68
2.7.4 Solution Approach, Solution Components, and Work Flow 68
2.7.5 Results 69
2.7.6 Observations, Challenges, and Lessons Learned 74
2.8 GIS Visualization Infrastructure Modernization (UC #8) 75
2.8.1 Background 75
2.8.2 Objective 76
2.8.3 Users 76
2.8.4 Solution Components, and Approach 76
2.8.5 Observations, Challenges, and Lessons Learned 100
3 KEY ACCOMPLISHMENTS AND RECOMMENDATIONS 101
3.1 Key Accomplishments 101
3.2 Recommendations and Insights 101
3.3 Technology Transfer Plan for Applying Results into Practice 103
4 CONCLUSIONS 104

5 METRICS AND VALUE PROPOSITION 105
5.1 Project Metrics 105
5.2 Value Proposition: Primary and Secondary Guiding Principles 106
6 APPENDIX: FOUNDATIONAL COMPONENTS 107
6.1 Esri GIS Components 107
6.1.1 ArcGIS Servers 107
6.1.2 Portal for ArcGIS 110
6.1.3 ArcGIS Web Adapter 110
6.1.4 ArcGIS Desktop and Server 111
6.1.5 ArcGIS Data Store 111
6.2 OSIsoft PI 112
6.2.1 PI Integrator for Esri® ArcGIS® Overview 115
6.3 Power BI 116

List of Figures

Figure 1-1. Main Components of Visualization and Situational Awareness Demonstration 3
Figure 2-1. Transmission Fault Location Data Flow Diagram 5
Figure 2-2. Request ArcGIS Geoprocessing Service Code Fragment 7
Figure 2-3. PI Fault Location Template – Highlighted Item Updated by Custom C# 8
Figure 2-4. Map with Fault Location 9
Figure 2-5. Map Detail with Fault Location (indicated by a pin) 10
Figure 2-6. Load Curtailment Data Flow Diagram 13
Figure 2-7. Example EDO HTML Load Curtailment Page 14
Figure 2-8. Example Load Curtailment Map 15
Figure 2-9. Load Curtailment Dashboard 16
Figure 2-10. "As-Is" Report Creation Process 18
Figure 2-11. Example Legacy Script Used for Generating Reports 18
Figure 2-12. Options to Support Reports Creation 20
Figure 2-13. Selected Architecture for Reports Generation 21
Figure 2-14. Metrics Extension and ArcGIS Insights-Based Process 22
Figure 2-15. Schematic of the Report Generation Process Using Insights and Sample Results 23
Figure 2-16. Spatial-Eye-Based Work Flow 24
Figure 2-17. Spatial-Eye-Based and ArcGIS-Insights-Based Process and Sample Result 25
Figure 2-18. New, Largely-Automated Process 26
Figure 2-19. Report Options Using Insights 27
Figure 2-20. Distribution System Facts Report 28
Figure 2-21. Distribution Substation Report 29
Figure 2-22. Distribution and Transmission Pole Count by District 30
Figure 2-23. Tabular Report of SDG&E Distribution System Facts 31
Figure 2-24. Tabular Report of Substructures 31
Figure 2-25. Primary Distribution System Facts 32
Figure 2-26. Overhead Structure Count by District 33
Figure 2-27. Work Flow for Generating Outage Features 36
Figure 2-28. Transformation of GIS Features into FME Feature Store Native Format 37
Figure 2-29. Matching of Outage Data with NMS Data 38
Figure 2-30. Matching of EROD Data and GIS Data 38
Figure 2-31. Matching Process Main Output 39
Figure 2-32. Matching Process: Additional Output Table 39
Figure 2-33. Matching Outage Data with NMS Data 40
Figure 2-34. Output of Second Step Matching 40
Figure 2-35. Second Step Matching Log 41
Figure 2-36. Matching Process Log 41
Figure 2-37. Setup for History Playback 42
Figure 2-38. Configuration of Outages to Display 43
Figure 2-39. Outages for a Selected Feeder and Date Range 44
Figure 2-40. Selection of History Interval 45
Figure 2-41. Specifying Date Range 46
Figure 2-42. Additional Outage Criteria 47
Figure 2-43. Crew Error-Caused Outages (within Crew Contact category) 49
Figure 2-44. All Weather-Related Outages 50
Figure 2-45. Outages Due to Two Cause Types 51

Figure 2-46. Map with Temperature and Circuit Loading Features 52
Figure 2-47. AMI for Operations Data Flow Diagram 54
Figure 2-48. Custom Widget: Customizable Heat Map Colors 55
Figure 2-49. Custom Widget: Customizable Symbols 56
Figure 2-50. Custom Widget: Selecting Facilities of Interest 56
Figure 2-51.Power BI Display of Voltage Exceedance Events (tile size proportional to # of events) 57
Figure 2-52. Breaker CIR_1030 Events 58
Figure 2-53. Custom Widget: Dynamic Heat Map of Voltage Exceedances over a Specified Time Interval 59
Figure 2-54. Event Detail: Voltage Chart 60
Figure 2-55. Custom Widget: Power BI Showing Voltage Exceedance 61
Figure 2-56. Customer Generation Location and Size 64
Figure 2-57. Battery Charge and Discharge Charts 65
Figure 2-58. CAISO LMP, Battery Revenue and Cost 66
Figure 2-59. UC 6 Data Flow Diagram 67
Figure 2-60. LiDAR Data Extent (red lines are boundaries of LiDAR extent) 70
Figure 2-61. LiDAR Data in 3D in ArcPro 71
Figure 2-62. Search Tool with Search by Area Extent Circled 72
Figure 2-63. Selection of Image Files Based on Area of Interest 73
Figure 2-64. Virtualization of GPUs 78
Figure 2-65. Custom Widget: Display Manager, Selection by Parameter 80
Figure 2-66: Custom Widget: Display Manager, Selection by Owner (SDG&E) 81
Figure 2-67: Features Available when Owner Selected 82
Figure 2-68. UI for URL Formation 84
Figure 2-69. Select Desired Features to Display via URL 85
Figure 2-70. Example of Created URLs 86
Figure 2-71. Example URL to LiveStreet 87
Figure 2-72. Example URL to Google Maps 88
Figure 2-73. NetExplorer Trace Configuration Display 90
Figure 2-74. A NetExplorer Trace Output 91
Figure 2-75. Details of the Trace (on Details tab) 92
Figure 2-76. Display Related Records by Features 93
Figure 2-77. Display with Excluded Features 94
Figure 2-78. Same Display with Included Features (no exclusions) 95
Figure 2-79. Basic Mode Trace Input Options 97
Figure 2-80. Basic Mode Trace Output Options 98
Figure 2-81. Basic Mode Trace Details Options 99
Figure 6-1. Esri ArcGIS Enterprise Components 106
Figure 6-2. Esri Image Server 107
Figure 6-3. Esri GeoEvent Server 108
Figure 6-4. Esri GeoAnalytics Server 108
Figure 6-5. Esri Insights 109
Figure 6-6. OSISoft PI System Components 112
Figure 6-7. OSISoft Standard PI Architecture 113
Figure 6-8. OSISoft Generic On-Premises Architecture 114

Acronyms and Definitions

AF (PI AF)	PI Asset Framework (PI AF) is a single repository for asset-centric models, hierarchies, objects, and equipment (hereafter referred to as elements)[1].
AMI	Advanced Metering Infrastructure
API	Application Program Interface
Basemap	Basemap contains reference geospatial information based on what the cartographer is trying to communicate. Information is added to a basemap by overlaying other information on top of basemap to create a final map.
DER	Distributed Energy Resource
EDO	Electric Distribution Operations
eGIS	Enterprise GIS
EMS	Energy Management System
EROD	Electric Reliability Operations Department (SDG&E)
ETL	A database usage process to Extract, Transform, and Load information. Typically associated with Data Warehouse activities.
Feature (on a map)	Individual item on a map
Feature layer	A feature layer is a grouping of similar geographic features (e.g., electric circuits, poles, buildings, parcels, cities, roads, and earthquake epicenters). Features can be points, lines, or polygons (areas). Feature layers are used for visualizing data on top of basemaps. In the context of integration with PI, feature layer is a collection of AF elements based on the same AF template.
Feature service	A collection of related feature layers. Feature services are managed by Esri ArcGIS. Real time updates of feature services are done via Esri ArcGIS GeoEvent Processor (new name: ArcGIS GeoEvent Extension for Server)
FME	Feature Manipulation Engine, a Safe Software's ETL application
FFS	FME Feature Store, the FME native data format
GIS	Geographic Information System
GPU	Graphics Processing Unit
HTTP; HTTPS	Hyper Text Transfer Protocol. HTTPS is over Secure Sockets Layer (SSL) to ensure secure data transfer in transit.
ID	Identifier

[1] PI AF - Overview - OSIsoft Tech Support, https://techsupport.osisoft.com/Products/PI-Server/PI-AF/Overview/

IIS	Internet Information Services (formerly Server), an extensible web server created by Microsoft
IoT	Internet of Things
JSON	JavaScript Object Notation
Lat/Lon	Latitude/Longitude of a geographical point
LiDAR	Lidar (also called LIDAR, LiDAR, and LADAR) is a surveying method that measures distance to a target by illuminating that target with a pulsed laser light, and measuring the reflected pulses with a sensor. Differences in laser return times and wavelengths can then be used to make digital 3D-representations of the target [source: Wikipedia]
LMP	Locational Marginal Price
NMS	Network Management System (SDG&E)
PNode (pnode)	CAISO pricing node, the location in the network at which LMPs are provided
PV	Photovoltaic (solar) cells for producing electricity from Sun energy
RT	Real Time
SSL	Secure Sockets Layer (SSL): uses encryption for data in transit
Widget[2]	An element of a graphical user interface (GUI) that displays information or provides a specific way for a user to interact with the operating system or an application

[2] http://whatis.techtarget.com/definition/widget

1 INTRODUCTION

This report documents the demonstration work and results for EPIC-2, Project 2, Visualization and Situational Awareness Demonstration, describes key lessons learned, and identifies opportunities to provide additional value to SDG&E in the future by leveraging the insights and the specific solution patterns of this project.

Decades ago, *situation awareness* (SA) was formally defined by Endsley[3] in terms of three concepts - perception, comprehension, and projection: "SA is...the perception of the elements in the environment **within a volume of time and space**, the comprehension of their meaning, and the projection of their status in the near future". While tweaks to this definition have been suggested since, the essential elements still remain, which is that, for situational awareness, one needs to consider perceptions within the contexts of both time and space. To do this, one has to be able to readily understand the information contained in the observations, and from these two and other domain knowledge, project the status in the near future.

In the power system industry, the systems that manage and present geo-spatial and other kinds of slowly changing data (e.g., spatial data) have existed largely in separate silos from the systems that deal with operational, time-varying data. Yet, both kinds of data are essential for comprehension of the true state of the system at a point in time, especially during emergencies, and for assessing a progression of that state into the near future.

In the case of SDG&E, geo-spatial data is handled by Esri ArcGIS, and operational data eventually flows into OSISoft PI Data Historians. Each of the systems is very powerful in its own domain, and is constantly being updated and extended with new features for analysis and presentation of results. The combination of the capabilities of the two brings the situational awareness contributions that neither of the two systems can achieve alone. For this reason, several of the activities in this task are centered on the technologies used to merge the information of the two aforementioned (and other) systems (i.e., geospatial and time series data), as necessary to fulfill specific SDG&E business needs.

The third major component used in this project is Power BI from Microsoft. Out of the box, this tool brings Excel-like capabilities for end users to programmatically, or through a GUI, configure the data sources to use, perform data analytics on the collected data, and select desired built-in or newly developed visualization widgets for display. During this project, SDG&E has developed a Java-based functionality to incorporate Power BI widgets within Esri geospatial features, so the users can see and interact with the map or Power BI widgets in a coordinated fashion. For example, a selection of an element in a Power BI table highlights the corresponding element on a geospatial map, and vice versa.

A brief overview of each of these commercial building blocks is presented in the appendix.

[3] Mica R. Endsley, "Toward a theory of situation awareness in dynamic systems," Human Factors, 1995, Vol 37, pp. 32-64

1.1 Project Objectives

The objectives of the Visualization and Situational Awareness Demonstration project were to:

- Examine how data currently unexploited and separately processed can be integrated and visually presented for strategic use by system operators
- Demonstrate how data collected from sensors and devices can be processed, combined, and presented to system operators in a way that enhances utility system monitoring and situational awareness

1.2 Scope of Work – Use Cases

The stated objectives of the project were realized through implementation of the following eight use cases:

1. Transmission Fault Location Visualization
2. Load Curtailment Visualization
3. Automation of Quarterly Electric Utility Reports
4. Historical Outages Playback
5. AMI for Operation Visualization
6. Customer-Owned DER Visualization
7. Imagery Management
8. GIS Visualization Infrastructure Modernization.

1.3 Main Visualization Components

Use cases were implemented by combining functionality of core components from Esri, OSISoft, and Microsoft with third party applications and custom applications developed by the SDG&E team. An overview of the SDG&E components that comprise the demonstration system, plus other interacting systems and components is shown in Figure 1-1. The GIS components are on the left side of the figure; OSISoft PI components are on the right side; Power BI is in the cloud in the middle of the figure; and Smart Grid components, T&D Operations, and AMI components complement the picture. The main end-user interactions are through the web portal (in the middle of the figure), while the developers have local access at various points throughout the system.

A brief overview of functionality of the core commercial components is provided in the appendix; the custom code developed by SDG&E is discussed in the context of specific solutions for the various use cases.

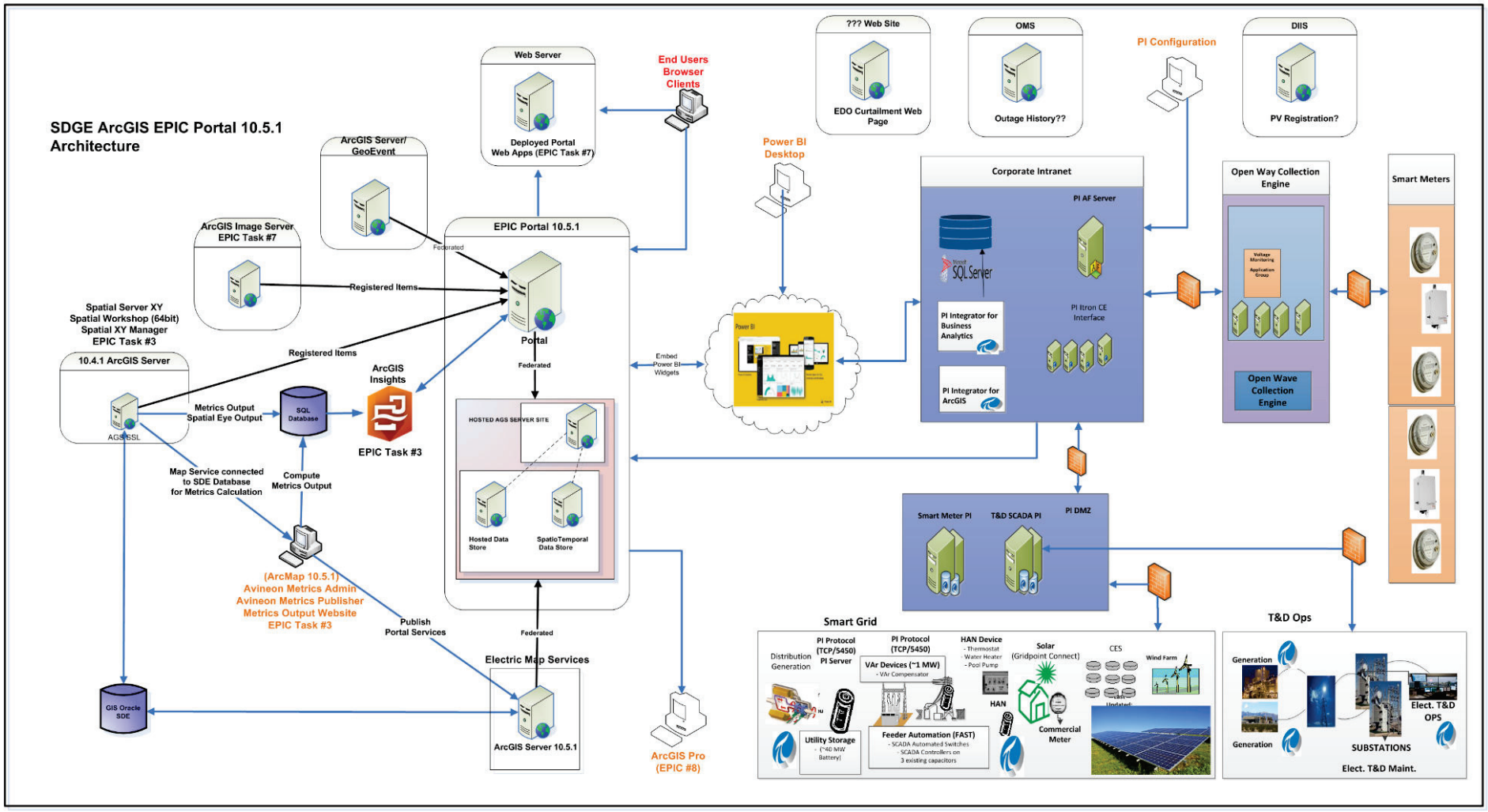


Figure 1-1. Main Components of Visualization and Situational Awareness Demonstration

2 USE CASES FOR DEMONSTRATION

This project is comprised of eight use cases covering a broad range of SDG&E smart grid business needs. The description of use cases in this section consists of the following:

- Background
- Objectives
- Users
- Solution Approach, Solution Components, and Work Flow
- Results
- Observations, Challenges, and Lessons Learned

Use-case results are demonstrated to internal SDG&E users, from among those listed for each use case.

2.1 Transmission Fault Location Visualization (UC #1)

2.1.1 Background

At SDG&E, substation relays are equipped with a function to compute a linear distance (i.e., a distance from the substation housing the relay along the line) to the line fault. When a fault occurs, relays detect it and compute the linear distance. This information eventually flows into the PI archiving system, from which an existing program called *PI Notification* sends text e-mails to relevant users with information about the fault.

The intent of Use Case #1 was to develop the Transmission Fault Location application that will enhance situational awareness about the fault by: (1) extending the e-mail message with a link to a specific web page on the ArcGIS Portal; (2) developing the functionality to generate the target web page and show a geospatial map on the page with the electric circuits and fault indicators at the exact location of the fault; and (3) showing any other geospatial layers, such as weather, fire, earthquake, etc., that may be available in the GIS system.

2.1.2 Objective

The objective of this use case was to provide the ability for end users to see fault locations and associated data on a geographical map within ArcGIS Portal.

2.1.3 Users

- Transmission operation group (Grid Operations)
- Maintenance crew - Kearny Maintenance and Ops
- System protection - System Protection and Control Engineering (SPACE)

2.1.4 Solution Approach, Solution Components, and Work Flow

Components involved in the solution:

- PI Notification: sends e-mails to users
- PI Integrator: pushes dynamic data updates to update maps
- ArcGIS Geo Processing: a service to convert linear distance to a fault obtained from PI to the latitude and longitude (Lat/Lon) of the fault by using the geometry of the asset in the geospatial database
- GeoPortal: displays geospatial maps with electric circuits overlays, along with fault indicator(s) on the affected electric circuits, and any other layers, such as weather, fire, lightning strikes, etc.

The technical solution uses two cooperating processes. The first is supported by an SDG&E custom program and by components from both the PI system and Esri GIS system. This is an event-driven process, with the event being an arrival of new fault data to PI Data Historian. When this event triggers, the custom program retrieves the description of the fault from PI Data Historian (tieline, substation, and the linear distance from the substation along the tieline) and invokes an ArcGIS Geo Processing service called ArcGIS Linear Referencing Geoprocessing service to compute the Lat/Lon of the faulted location. After receiving the results, the custom program updates PI Data Historian with this Lat/Lon data. The second process is based on leveraging the "out of the box" functionality of PI Integrator for Esri ArcGIS and is shown in a simplified form in Figure 2-1.

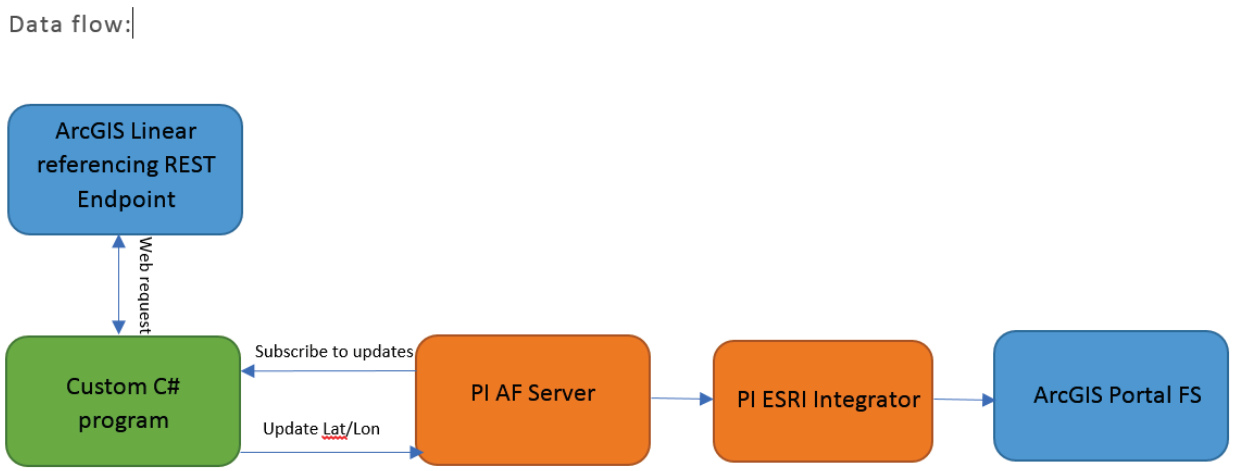


Figure 2-1. Transmission Fault Location Data Flow Diagram

The process consists of the following steps:

1. The PI Integrator for Esri ArcGIS publishes the PI Fault Distance template to ArcGIS Portal, where it gets registered as a feature service, with its own URL
2. When the feature layer is added to a map, the ArcGIS client makes a periodic request (at pre-configured intervals, e.g., every 2 seconds) to the registered PI Esri integrator URL for the Fault Distance layer data
3. The PI Integrator for Esri ArcGIS then requests the data from the PI system, specifically from the Asset Framework (AF) Server (if it is not cached) and returns the data to the client

4. The requested features are drawn on the map according to the retrieved data, including redrawing of the fault locations based on the latest retrieved Lat/Lon data

Please note that the mechanism for dynamic map feature updates described above is the same for any use case that uses PI Integrator for Esri ArcGIS. The only differences are which of the PI data templates (such as the fault Lat/Lon in this use case) drive the display.

A JavaScript Object Notation (JSON) code snippet illustrating a request from the ArcGIS of a Linear Referencing endpoint is shown in Figure 2-2.

The custom C# program automatically updates the computed Lat/Lon result in PI (Figure 2-3).

GET https://apwgisppit006.corp.se.sempra.com/arcgis/rest/service

Body Cookies (2) Headers (11) Tests

Pretty Raw Preview JSON


```
        {
            "paramName": "OutageOutput",
            "dataType": "GPFeatureRecordSetLayer",
            "value": {
                "displayFieldName": "",
                "geometryType": "esriGeometryPoint",
                "spatialReference": {
                    "wkid": 4326,
                    "latestWkid": 4326
                },
                "fields": [
                    {
                        "name": "OBJECTID",
                        "type": "esriFieldTypeOID",
                        "alias": "OBJECTID"
                    },
                    {
                        "name": "Tieline",
                        "type": "esriFieldTypeString",
                        "alias": "Tieline",
                        "length": 15
                    },
                    {
                        "name": "Distance",
                        "type": "esriFieldTypeDouble",
                        "alias": "Distance"
                    },
                    {
                        "name": "LOC_ERROR",
                        "type": "esriFieldTypeString",
                        "alias": "LOC_ERROR",
                        "length": 50
                    }
                ],
                "features": [
                    {
                        "attributes": {
                            "OBJECTID": 1,
                            "Tieline": "TL 619",
                            "Distance": 38,
                            "LOC_ERROR": "NO ERROR"
                        },
                        "geometry": {
                            "x": -117.13729651999995,
                            "y": 32.784049035000066
                        }
                    }
                ],
                "exceededTransferLimit": false
            }
        }
    ],
    "messages": []
}
```


Figure 2-2. Request ArcGIS Geoprocessing Service Code Fragment

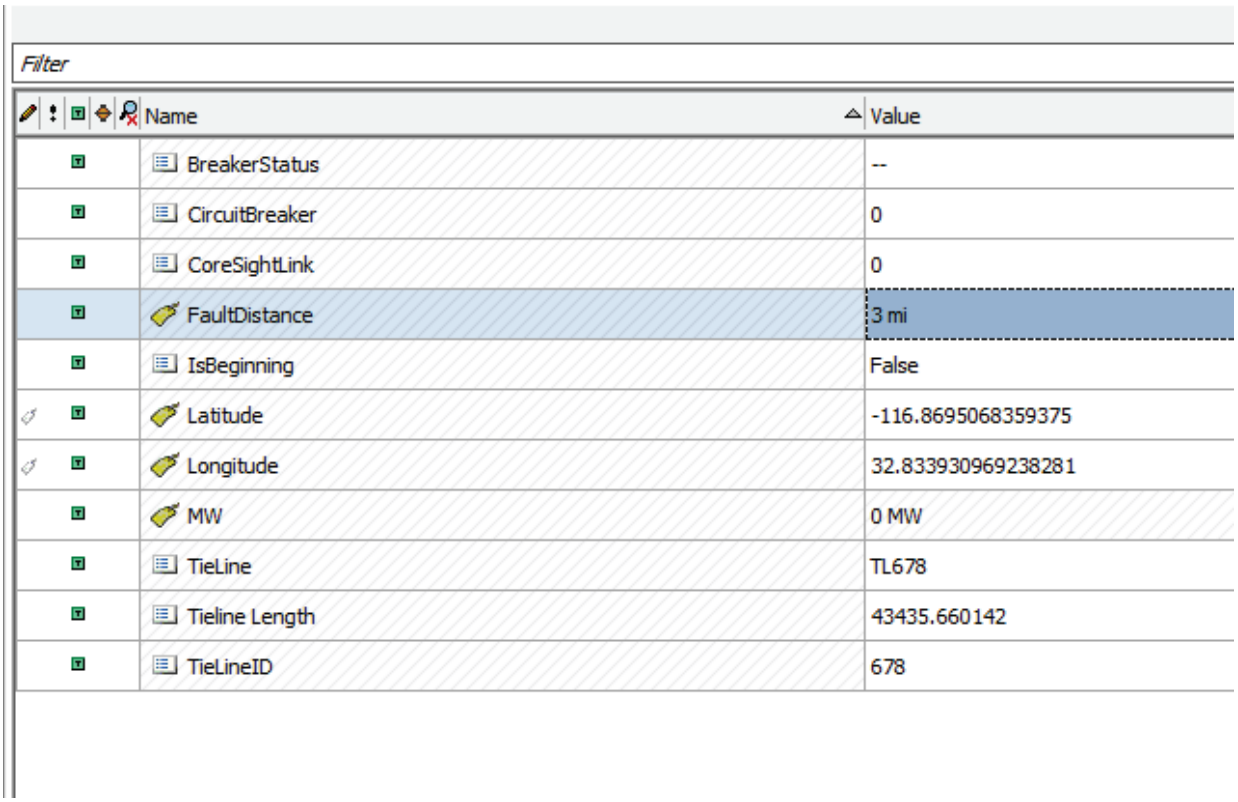


Figure 2-3. PI Fault Location Template – Highlighted Item Updated by Custom C#

2.1.5 Results

2.1.5.1 Representative Results

Figure 2-4 shows two fault locations: one labeled BB23042 (near San Diego), and the other labeled AL678. In this example, the user has clicked the pin for the latter fault, and a popup display provides more details, including name (which is the name of a relay in PI comprised of a tieline ID, e.g. 678, and a substation ID, e.g., AL), circuit name, fault distance, and the exact coordinates of the fault.

However, at this level of detail, it is not possible to say if there are multiple circuits in the affected area. By zooming in (Figure 2-5), it can be seen that there are actually several circuits (at different voltage levels), and the Fault Pin pinpoints exactly the affected circuit (matching the description in the popup table of the previous figure).

Incidentally, these two figures also illustrate the useful automatic decluttering capability of the GIS software.

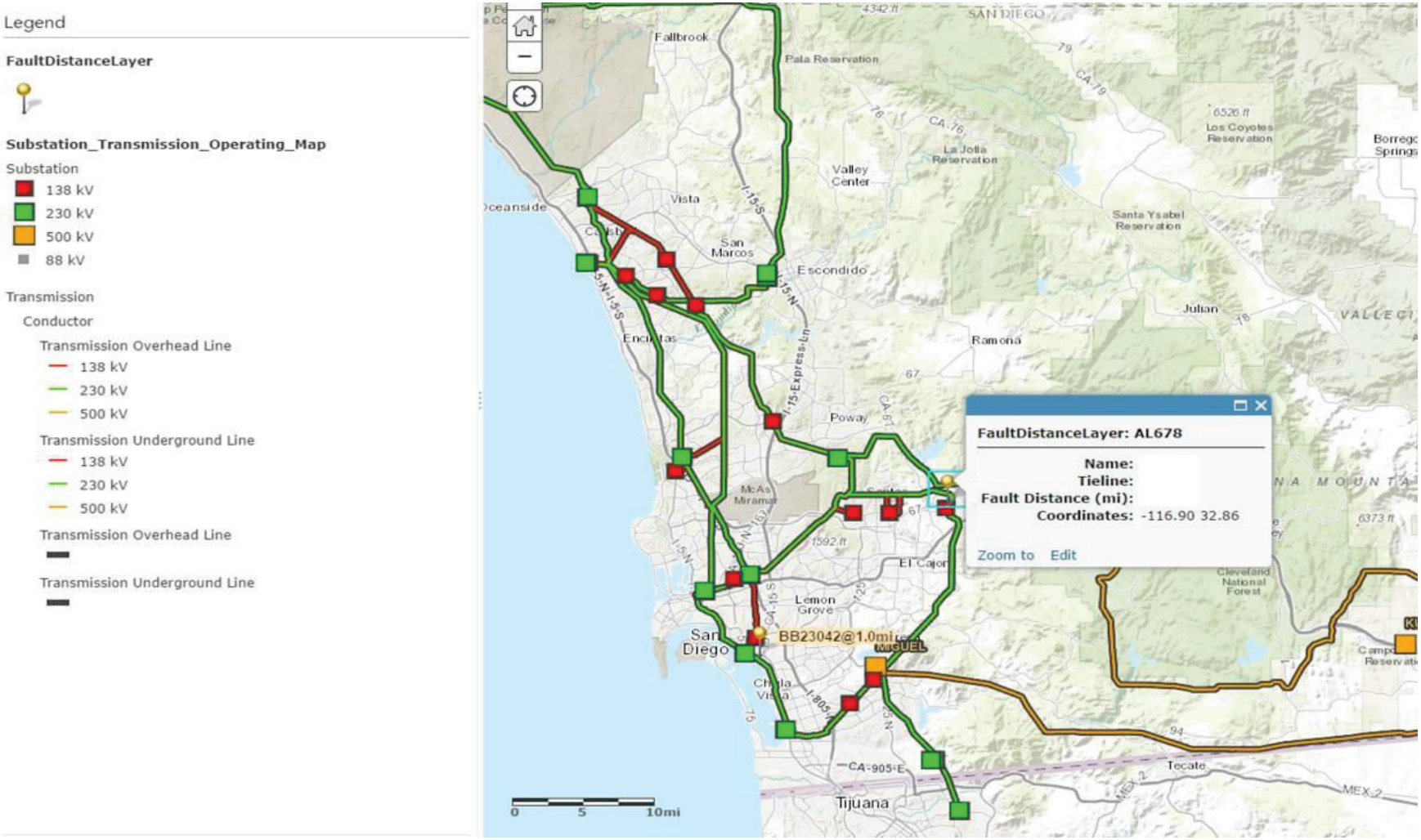


Figure 2-4. Map with Fault Location

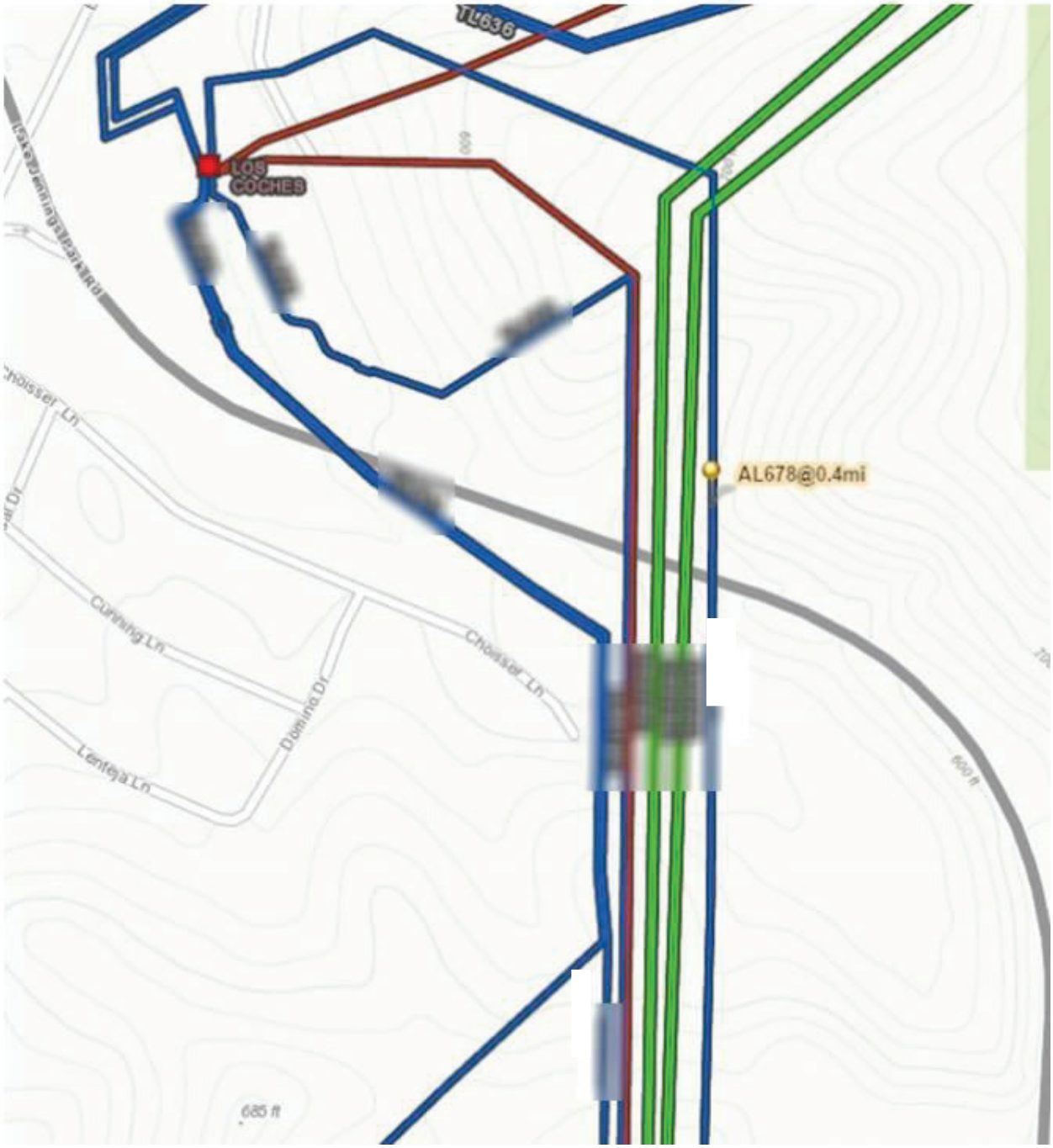


Figure 2-5. Map Detail with Fault Location (indicated by a pin)

2.1.6 Observations, Challenges, and Lessons Learned

Challenges and Resolutions

- SDG&E may eventually want to use a double-ended fault algorithm to provide even more accuracy
- Handling of faults on tapped lines is a challenge, especially when the single ended fault location algorithm is used – as for some fault locations, it is ambiguous if the fault has occurred on the main trunk or a tapped line. The work on overcoming this challenge is still in progress, with an expectation that the use of a double-ended fault algorithm will help in the resolution. Nevertheless, in the vast majority of fault location cases, the existing solution is fully functional.
- Creation of the reference layer of electrical circuits (from which the fault x-y coordinates and the x-y coordinates of the circuits themselves are derived): the GIS database may have a line asset represented as multiple line segments, each with a "from" and a "to" side and with a significant number of other attributes. ArcGIS has a service called ArcGIS Geoprocessing Service to convert a linear distance (along an asset) to the x-y coordinates of the point at the end of the linear distance. However, this service is time consuming when there are a lot of segments to peruse. To increase the ArcGIS Geoprocessing Service performance, it was necessary to perform an upfront work to appropriately concatenate line segments and create a new, simplified, composite line that always spans two substations. The line ID of this composite line needs to be provided to PI, where it serves as a key for linking the x-y information of the fault computed by ArcGIS Geoprocessing Service with operational data from PI. Any time there is a reconfiguration of a physical line, this process of so-called "digitizing" (i.e., updating of the composite line) needs to be repeated (only the very first time and after a reconfiguration). The initial effort to "digitize" all the lines, given that all 69-kV and higher voltage lines are included, was substantial. Once initially completed, an incremental effort to update after a reconfiguration is much less intensive, as such events are relatively infrequent, and the scope is much smaller (as it involves only the reconfigured lines).

Recommendations

- The labor to create the initial reference layers of electric circuits is significant and should be planned for in advance
- A process is needed to "re-digitize" lines any time there is a reconfiguration, or to digitize new lines, with an associated process to reflect the changes, if any, of the line ID in PI.

2.2 Load Curtailment Visualization (UC #2)

2.2.1 Background

Currently, SDG&E EDO updates load curtailment plans via a spreadsheet (shown later in Figure 2-7). The spreadsheet is posted on the EDO Website.

The spreadsheet shows the current total MW request for load shedding from CAISO, the amount of load already shed, as well as a list of circuits in groups according to the order in which they need to be opened to affect the load shedding. The groups are labeled Run 1, Run 2, and so on, and are arranged so that the circuits in Run 1 are opened first. Then, if there is need for more load shedding, the circuits of Run 2 are opened, and so forth. The coloring of circuits is chosen to reflect the likelihood of load shedding, with red designating the first group of circuits to open.

The information in the spreadsheet is a combination of asset names and real time load data. The intent of this use case is to display the same tabular (i.e., the spreadsheet) information but through a geospatial map, with visual cues identifying the order in which the circuits are to be opened. Examples in the results section illustrate additional options and benefits provided by the geospatial displays that in total should provide a better visual sense of when and where the load is being shed. This aspect of being able to quickly grasp the extent and location of load shedding may be very important, taking into account that load shedding is seldom required, but when it is, it is usually associated with emergency situations during which effective situation assessment is paramount.

2.2.2 Objective

The objective of Use Case #2 was to develop an ArcGIS Portal map to visualize the current SDG&E load curtailment plan.

2.2.3 Users

- Emergency Operations Center (EOC) personnel, during emergencies
- Distribution Operations

2.2.4 Solution Approach, Solution Components, and Work Flow

Components:

- Internal SDG&E Web site: the current load curtailment plan published to the site (existing functionality)
- Custom Python program periodically “scrapes” EDO Curtailment Webpage and writes the parsed curtailment results to PI
- PI Integrator for Esri ArcGIS publishes Curtailment Template to GIS Portal
- Current values of the map’s dynamic widgets (e.g., current total loads on each of the circuits marked for curtailment are updated through periodic queries from Esri portal client via PI Esri Integrator to the PI Data Historian); this can be seen later in Figure 2-7
- Esri Operations Dashboard for ArcGIS: a dashboard with the Load Curtailment map as one of its elements (example shown later in Figure 2-9)

A simplified diagram of the major data flows is shown in Figure 2-6.

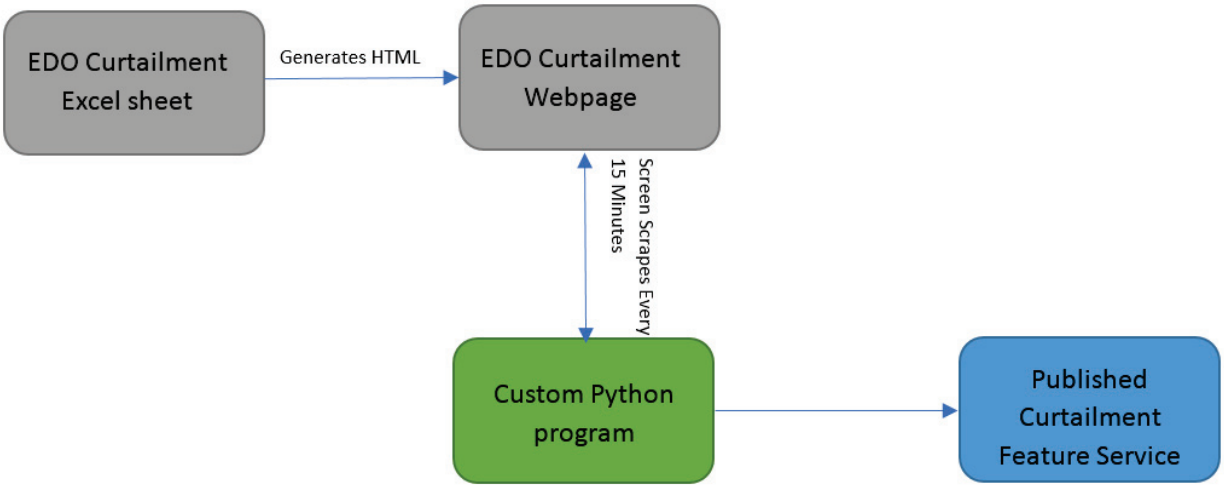


Figure 2-6. Load Curtailment Data Flow Diagram

An example of an EDO HTML Load Curtailment Page (the source of data for this use case) is shown in Figure 2-7.

An ArcGIS Portal map of load curtailment is shown in Figure 2-8. The legend on the left shows use of color to convey the status of circuits with respect to load shedding (e.g., previously or currently curtailed, early restored, or one of the exempt circuits); or it is a circuit in the first group to be curtailed (red), or in one of the later rounds (orange, light orange, yellow, etc.).

The Curtailment layer has every circuit, and each circuit has an associated Status field. When Status field is blank, the corresponding circuit is filtered out from the display.

The map is made into a dashboard using the program Esri Operations Dashboard (Figure 2-9). Multiple circuits can be selected by interactively encircling a region of interest. The widget on the lower right will then summarize the total MW dropped from the selected circuits. The list on the left side contains only the circuits that are due for curtailment.

SDGE
A Sempra Energy utility

30 Set Refresh Rate Legend Manual Subs

Electric Distribution Operations

Last Update: 6/1/2016 3:25:05 PM

Daily Totals **

ISO Requested MW:	0.00
SDG&E MW Total:	0.00
PGP MW Total:	0.00
MW Dropped:	0.00
Cust Affected:	000

Current Run: NONE

	Run #1	Run #2	Run #3	Run #4	Run #5	Run #6	Run #7	Run #8	Run #9	Run #10
ISO Requested MW:	25.00	25.00	25.00	25.00	25.00					
SDG&E Contribution:	27.51	27.88	27.03	25.71	26.32					
PGP:	0	0	0	0	0					
Run Start Time:	0									
Run End Time:	0									
Total MW Dropped:	27.51	27.88	27.03	25.71	26.32					
Customers Affected:	21,465	20,893	12,629	23,549	31,641					

Index	Block	Circuit	Total Customers	Community Area	Breaker Status	MW Dropped	MW Dropped	MW Dropped	MW Dropped	MW Dropped	MW Dropped	MW Dropped	MW Dropped	MW Dropped	MW Dropped
1	1A	434	2,172	MIRA MESA	CLOSE	2.98									
2	1A	229	1,820	MIRA MESA	CLOSE	2.18									
3	1A	524	1,838	BARRETT LAKE, CASA DE ORO, DEHESA, JAMUL	CLOSE	1.46									
4	2A	463	1,993	CHULA VISTA S, OTAY MESA, SAN YSIDRO	CLOSE	4.87									
5	2A	456	2,313	ESCONDIDO E, ESCONDIDO NE	CLOSE	2.88									
6	2A	715	1,639	MISSION VLY, NAS-MIRAMAR	CLOSE	3.92									
7	3A	831	4,510	MIRA MESA, NORTHCITY WEST	CLOSE	4.78									
8	3A	244	2,648	BLOSSOM VALLEY, LAKESIDE, LAKESIDE E, SAN VICENTE	CLOSE	2.34									
9	3A	63	2,532	NORTHCITY WEST, RHO SANTA FE S, SOLANA BEACH	CLOSE	2.09									
10	4A	83	2,365	LA MESA N, MISSION GORGE	CLOSE		0.90								
11	4A	72	2,655	ELCAJON W	CLOSE		2.08								
12	4A	382	970	MISSION VLY	CLOSE		3.74								
13	5A	988	1,267	ORTEGA	CLOSE		1.25								
14	5A	944	1,724	RHO DEL REY	CLOSE		0.74								
15	5B	177	1,440	POWAY N, POWAY S	CLOSE		0								
16	6A	500	2,835	LAKE HODGES S, RHO BERNARDO	CLOSE		1.46								
17	6A	740	2,438	PT LOMA N	CLOSE		4.40								
18	6B	258	2	CHULA VISTA W	CLOSE		0								
19	7A	850	445	VISTA S	CLOSE		5.80								
20	7A	1153	0	MIRA MESA	CLOSE		0								
21	7A	1166	321	ALPINE W, BARRETT LAKE, DEHESA, JAMUL WEST	CLOSE		0.02								
22	8A	358	1,120	ALPINE W, DEHESA, VIEJAS	CLOSE		4.37								
23	8A	291	3,140	LAKE HODGES S, RHO BERNARDO	CLOSE		2.80								
24	8A	210-172R	171	WARNER SPRINGS	CLOSE		0.31								
25	9A	443	3	SAN YSIDRO	CLOSE			2.65							
26	9A	103	1,833	BAY PARK, MISSION BAY	CLOSE			2.65							
27	9A	512	2,596	DEL MAR, NORTHCITY WEST, SOLANA BEACH	CLOSE			2.82							
28	10A	290	3,119	RHO BERNARDO	CLOSE			1.67							
29	10A	768	1,528	LAGUNA HILLS, LAGUNA NIGUEL, MISSION VIEJO	CLOSE			1.77							
30	10A	775	506	CLAIREMONT	CLOSE			3.70							
31	11A	797	2,447	LAGUNA NIGUEL	CLOSE			0.44							
32	11A	588	109	CARLSBAD	CLOSE			7.15							
33	11A	774	488	CLAIREMONT, NAS-MIRAMAR	CLOSE			4.19							
34	12A	452	3,804	ESCONDIDO E, ESCONDIDO NE, LAKE WOHLFORD	CLOSE				1.32						
35	12A	517	453	ESCONDIDO S, ESCONDIDO W	CLOSE				2.32						
36	12B	487	0	OCEANSIDE	CLOSE				0						
37	13A	745	20	TORREY PINES	CLOSE				3.65						
38	13A	986	2,526	MISSION VIEJO, ORTEGA	CLOSE				1.82						
39	13A	975	1,339	RAMONA E, SDCOUNTRY ESTATES	CLOSE				0.37						
40	14A	590	2,663	BONITA, OTAY MESA, RHO DEL REY	CLOSE				1.09						
41	14A	468	126	CENTER CITY	CLOSE				2.19						
42	14A	1117	2,866	CARLSBAD, ENCINITAS S	CLOSE				2.26						
43	15A	296	1,309	SAN MARCOS W	CLOSE				2.46						
44	15A	438	4,485	MIRA MESA	CLOSE				3.17						
45	15A	68	1,494	FAIRBANKS RCH S, NORTHCITY WEST, RHO BERNARDO	CLOSE				2.75						
46	16A	112	2	CENTER CITY	CLOSE				0.88						
47	16A	947	654	FLETCHER HILLS	CLOSE				0.19						
48	16A	510	1,808	DEL MAR, NORTHCITY WEST	CLOSE				1.25						
49	17A	951	390	MIRA MESA	CLOSE					3.90					
50	17A	502	4,427	LAKE HODGES S, RHO BERNARDO	CLOSE					2.71					
51	17A	73-14R	728	DEHESA, DESCANSO, JAPATUL, VIEJAS	CLOSE					0.49					
52	18A	410	2,148	ELCAJON W, GRANITE HILLS, SINGING HILLS	CLOSE					0.60					
53	18A	561	2,570	LAGUNA HILLS, LAGUNA NIGUEL	CLOSE					1.76					
54	18A	65	3,131	LA JOLLA N, TORREY PINES	CLOSE					2.17					
55	19A	188	1,819	ESCONDIDO NW, ESCONDIDO W, SAN MARCOS E	CLOSE					1.85					

Figure 2-7. Example EDO HTML Load Curtailment Page

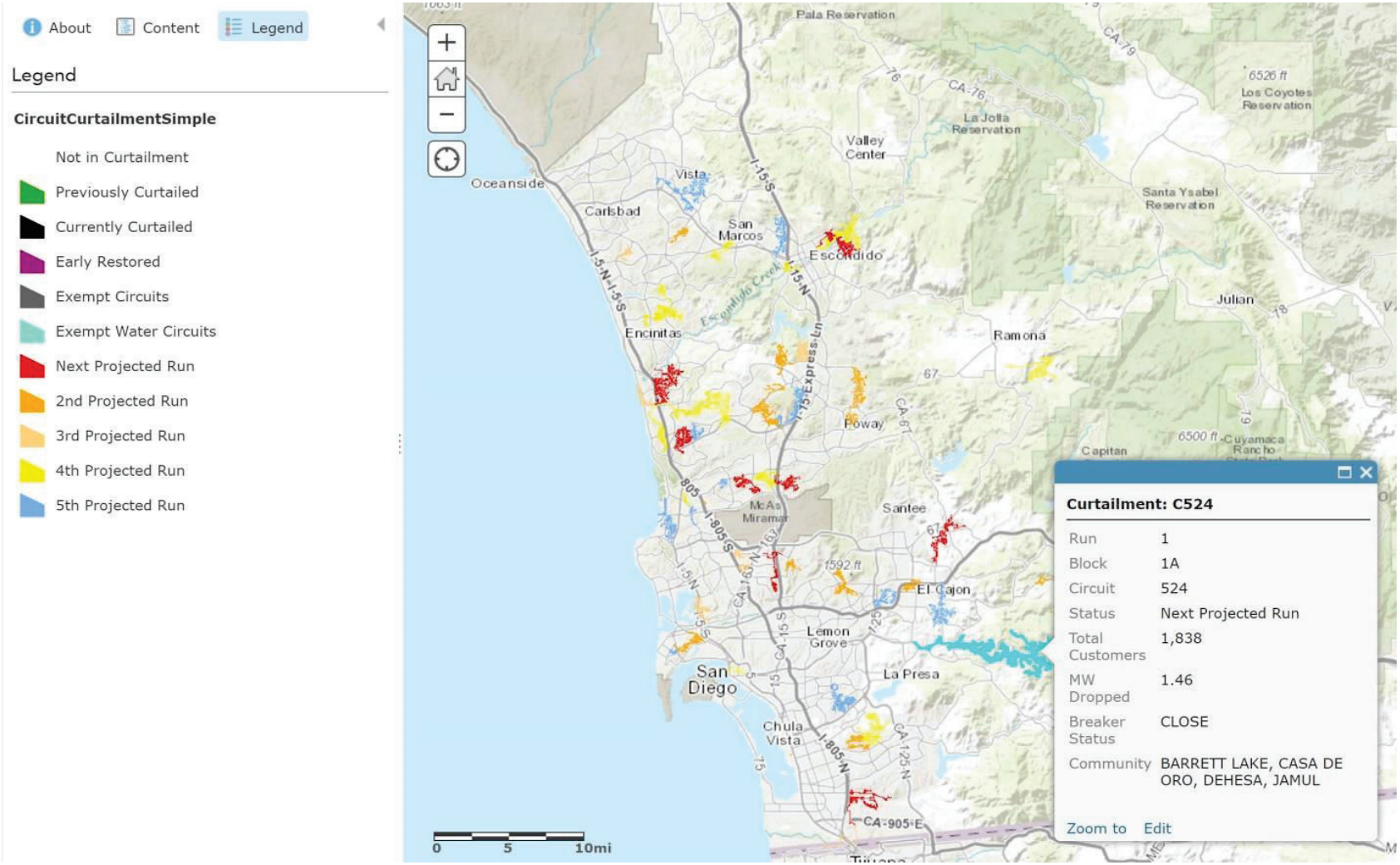


Figure 2-8. Example Load Curtailment Map

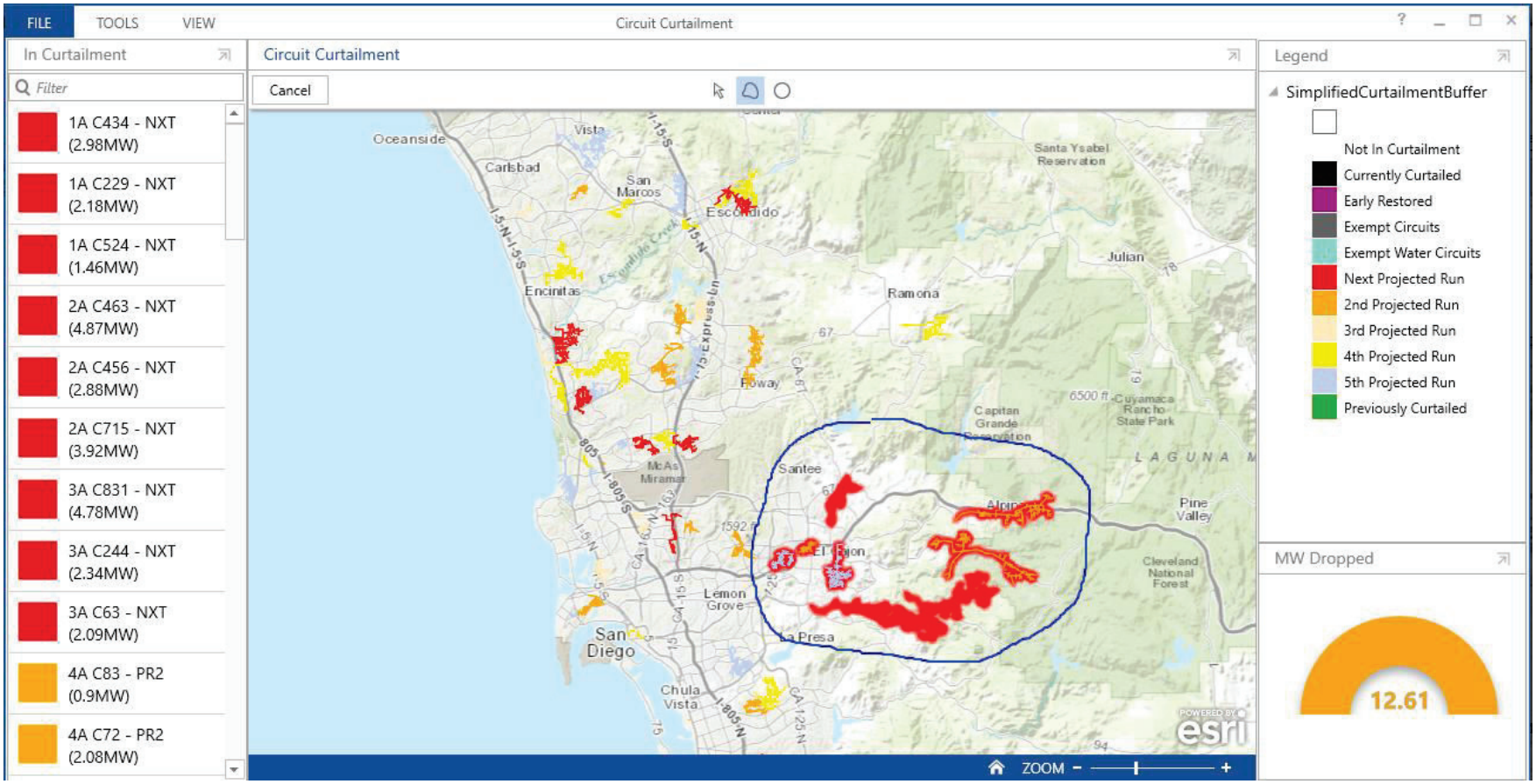


Figure 2-9. Load Curtailment Dashboard

This dashboard example illustrates how the end users are empowered by this solution – they can merely draw a boundary around a region of interest, and the display will automatically update with the total MW to be dropped within the region based on the actual load at the time of inquiry. Note that the legend adapts to the selected region of interest. This example also illustrates how the solution enables a user to get information of interest very quickly and in an intuitive way.

2.2.5 Results

2.2.5.1 Features

- Geospatial maps show the circuits for load shedding (either just finished, in progress, or planned)
- Color coding used to indicate both the (near) real time and the planned load shedding status
- Automatic decluttering of circuits that are not involved in load shedding
- Built in capabilities of GIS system can be leveraged to quickly create load shedding dashboard, which further extend usability of the displays by empowering users to make ad-hoc inquiries about load shedding amounts in any region of interest

2.2.5.2 Representative Results

The figures shown above illustrate the basic functionality and features of the load shedding use case.

2.2.6 Observations, Challenges, and Lessons Learned

Challenges and Resolutions

- In the absence of available APIs to interface with the SDG&E Web legacy system where the load curtailment schedules are posted, an interface to this system was implemented by scraping the site's web pages. Such technology is inferior to an interface based on a dedicated API.
- The electrical line circuits' information used for GIS visualization is rebuilt nightly to ensure the circuits' layer is a good reference for all the uses in need of this information. A coordination with PI data (at the level of line ID updates where new lines are created, or existing lines are retired) is also required any time the electrical circuit layout and connectivity change.
- Initially, the circuit layer visualization on the map was very slow. Significant improvements were made by using the Esri "generalization" tool to remove extreme details such as a lot of vertices. The result is circuit representation without a visually perceptible loss of information, yet enabling a substantial speedup of rendering. For example, it originally took upward of 20 seconds to render the electric circuit layers; it now takes a fraction of a second. When zooming in, the circuit layout is still sufficiently accurate.

Recommendations

- From a development perspective, it is recommended to replace scraping of web pages with an interface via a dedicated API
- From a usage standpoint, the development team will seek further feedback from the managers of EOC after a planned demonstration of the function is presented to them in the near future

2.3 Automation of Quarterly Electric Utility Reports (UC #3)

2.3.1 Background

SDG&E regularly has to prepare various reports (typically quarterly) about its assets in 1) Full Distribution, 2) Primary Equipment, 3) Substations, and 4) Transmission, based on a combination of GIS criteria such as:

- Features (e.g., wood poles)
- Attributes (e.g., characteristics like length of poles)
- Polygons (e.g., high risk fire area)
- Networks (e.g., by circuit)

The process to prepare the reports is quite laborious and lengthy (several weeks) and involves the analysis and computation of around 1500 analytics.[4] It involves a GIS/Business Analyst to perform data reconciliation of active circuits, manual editing and execution of many scripts/queries, and manual entry of each individual result into Microsoft Excel reporting templates. Figure 2-10 illustrates the steps involved, and Figure 2-11 provides a sample of one of many scripts used in the process.

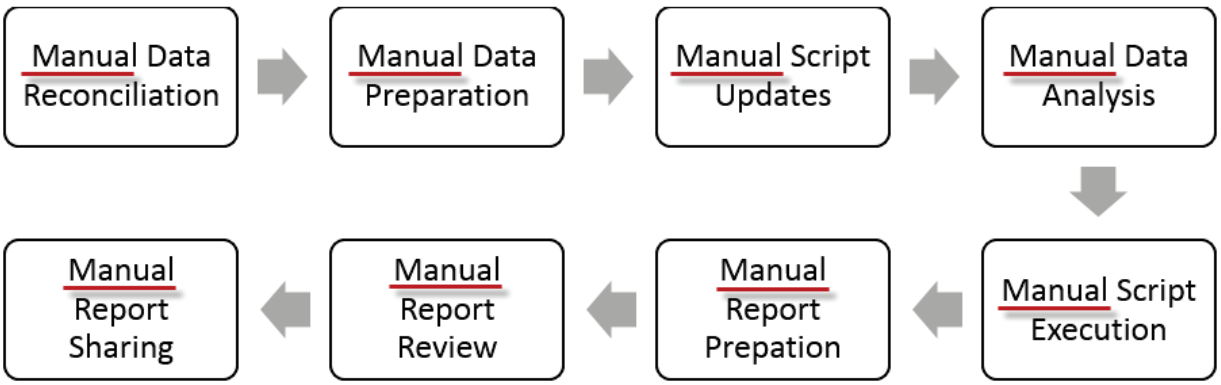


Figure 2-10. "As-Is" Report Creation Process

```
CONSTRUCTIONSTATUS IN ('A','R') AND (SUBTYPECD IN (1,2) OR (SUBTYPECD IN (4,5) AND
DISTRIBUTIONIDC = 'Y' AND TRANSLIFECYCLECD IN (2,3,4))) AND MATERIAL = 'WOOD' AND (GlobalID IN
(SELECT StructureGUID FROM SEU_GIS_ELEC.OHStruct_PriOH WHERE PriOHGUID IN (SELECT GlobalID
FROM SEU_GIS_ELEC.PriOHConductor WHERE NOMINALVOLTAGE = 12 AND FeederID NOT IN
('11','218','484','1246','MC1','NC1','SCE','DEAD','NEUT'))) OR (GlobalID IN (SELECT StructureGUID FROM
SEU_GIS_ELEC.OHStruct_PriUG WHERE PriUGGUID IN (SELECT GlobalID FROM
SEU_GIS_ELEC.PriUGConductor WHERE NOMINALVOLTAGE = 12 AND FeederID NOT IN
('11','218','484','1246','MC1','NC1','SCE','DEAD','NEUT')))))
```

Figure 2-11. Example Legacy Script Used for Generating Reports

[4] **Analytics** [Wikipedia] is the discovery, interpretation, and communication of meaningful patterns in data. In the context of this use case, analytics is any data transformation from the source data into a reportable item (a cell) in any of the reports, or an intermediate result from which the reportable items are composed.

The aim of Use Case #3 is to utilize advanced GIS technologies (spatial analytics) to substantially automate the process, and, at the same time, to provide flexibility to end users to configure the reports' content to their specific needs. The specific objectives for the use case are presented in the next section.

2.3.2 Objective

The objectives of Use Case #3 were:

- To evaluate an option for a self-service Electric eGIS reporting tool and demonstrate a chosen method to provide a flexible, intuitive self-service reporting application using the eGIS and/or other databases. The focus was on providing functionality to explore the data, ease of use, and achievement of high performance.
- In selecting the solution, to address reporting performance and consider the use of third-party software options (e.g., Spatial Eye, Metrics Extension to ArcGIS) as well as integration of the existing Esri GIS Portal technology, while also leveraging the SDG&E existing product licensing.
- In developing the solution, identify a methodology that is repeatable for other types of spatial reports from GIS. The methodology should be resilient to changes and cost effective in addressing changes with data model, analysis functions, and business rules.

2.3.3 Users

Electric eGIS users

- T&D engineering group
- Asset management group
- Land management
- Regulatory and compliance group
- Tax group

2.3.4 Solution Components and Work Flow

2.3.4.1 Solution Components

- **Metrics Extension**: An extension to ArcGIS for Server from Avineon is used to define, compute, and store asset statistics and trends from GIS databases.
- **Spatial Eye Workshop**: Advanced software tool from Spatial Eye is used for designing spatial analytics from data in complex data models. It is used to integrate data easily and to modernize manual scripts, analysis, and processes into spatial analytics models.
- **Spatial Eye XY Server**: Server software from Spatial Eye to schedule the execution of spatial analytics models and store the results in spatial data warehouse, data marts, and export to Microsoft Spreadsheets.
- **ArcGIS Insights**: Web application from Esri to visualize and analyze raw data in GIS or results precomputed by server tools such as Spatial Eye XY Server, or ArcGIS GeoAnalytics, or ArcGIS GeoEvents server.

- **ArcGIS Portal**: Web foundation from Esri to implement role-based access to GIS content for self-service reports.

2.3.4.2 Solution Approach and Work Flow

The use case core reporting requirements are based on the current GIS report requirements. This includes the ability to create reports via a user input, such as lists of all wood poles over 60 feet in length within a High Risk Fire Area. The execution of such requests would typically consist of selecting features, attributes, polygons, and electric networks (circuits) from valid domains.

The technologies illustrated in Figure 2-12 were reviewed as potential solution candidates for this use case. A closer review of the workflow and the GIS data model illustrated the need to choose a spatial analytics tool that can simplify the data joining, analysis, and aggregation of spatial and non-spatial data sets for a Business Analyst.

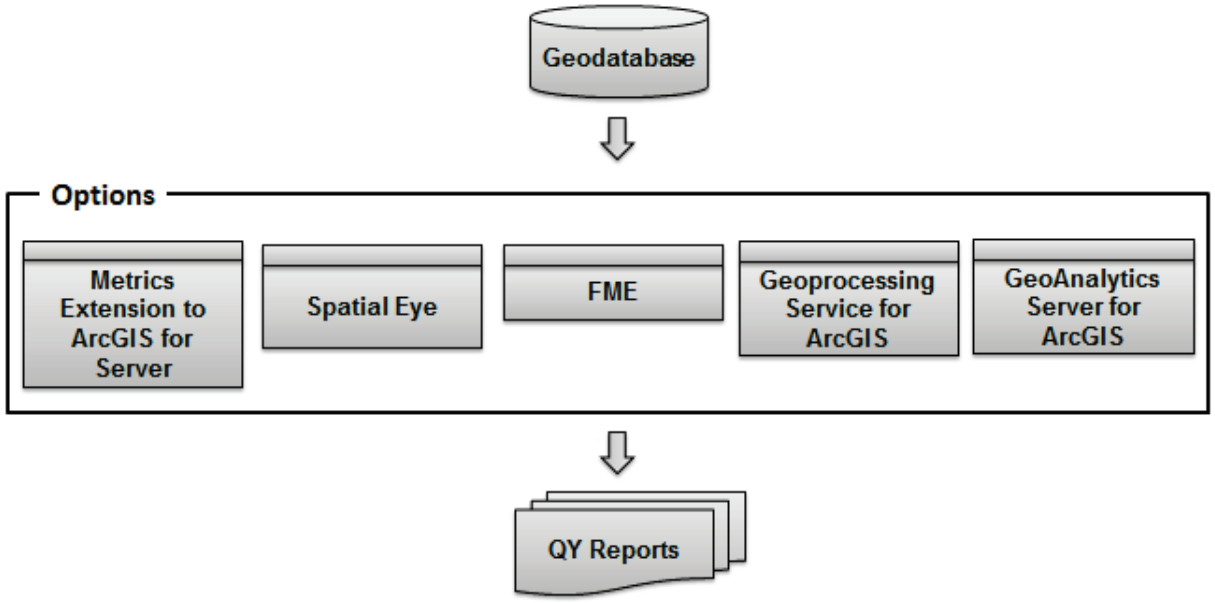


Figure 2-12. Options to Support Reports Creation

Figure 2-13 illustrates a solution architecture selected for in-depth research and feasibility analysis within this use case.

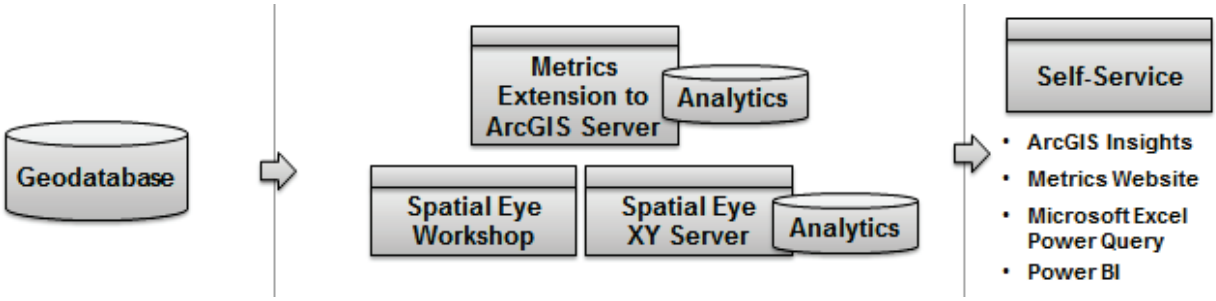


Figure 2-13. Selected Architecture for Reports Generation

The solution component (Metric Extension) was installed on an SDG&E server and configured to generate reporting data for visualization using ArcGIS Insights (Figure 2-14). Metrics Extension was tested for its ability to define, compute, and schedule metrics for this purpose. The results were visualized using ArcGIS Insights (see Figure 2-15 for an example of the output and the user selection choices).

The Spatial Eye Workshop and Spatial Eye XY server software components were installed and configured on the SDG&E Server (see Figure 2-16 and Figure 2-17). The queries, business rules, and manual analytics steps currently used for QY reporting were carefully analyzed and translated as business collections in a spatial analytics model. This analytics model was executed using the XY server and the results that were written to a) Spatial Eye Analytics data and b) Microsoft Excel files. These were visualized using Workbooks and Cards within ArcGIS Insights, as well as a Microsoft Excel reporting template currently used by Business Analysts.

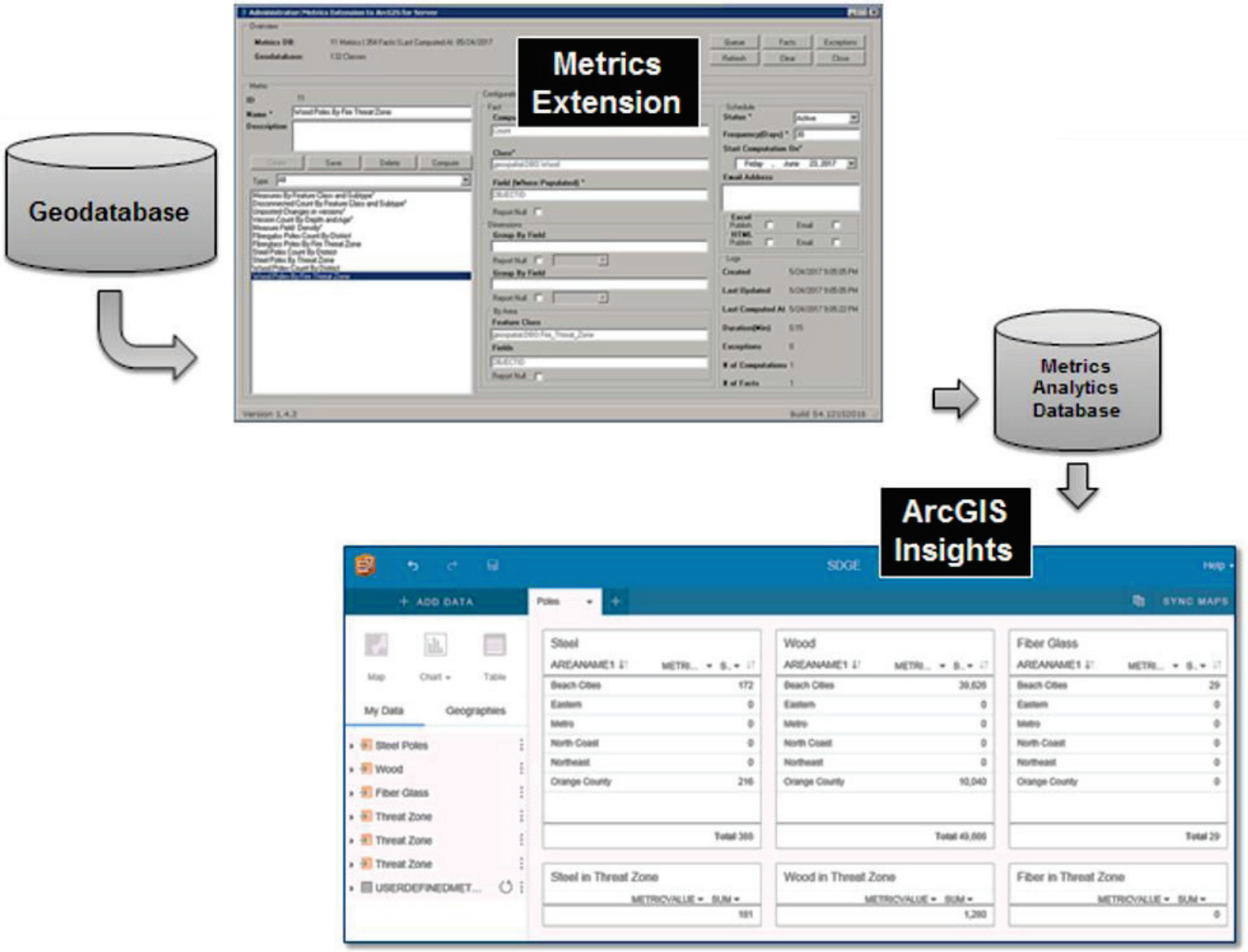


Figure 2-14. Metrics Extension and ArcGIS Insights-Based Process

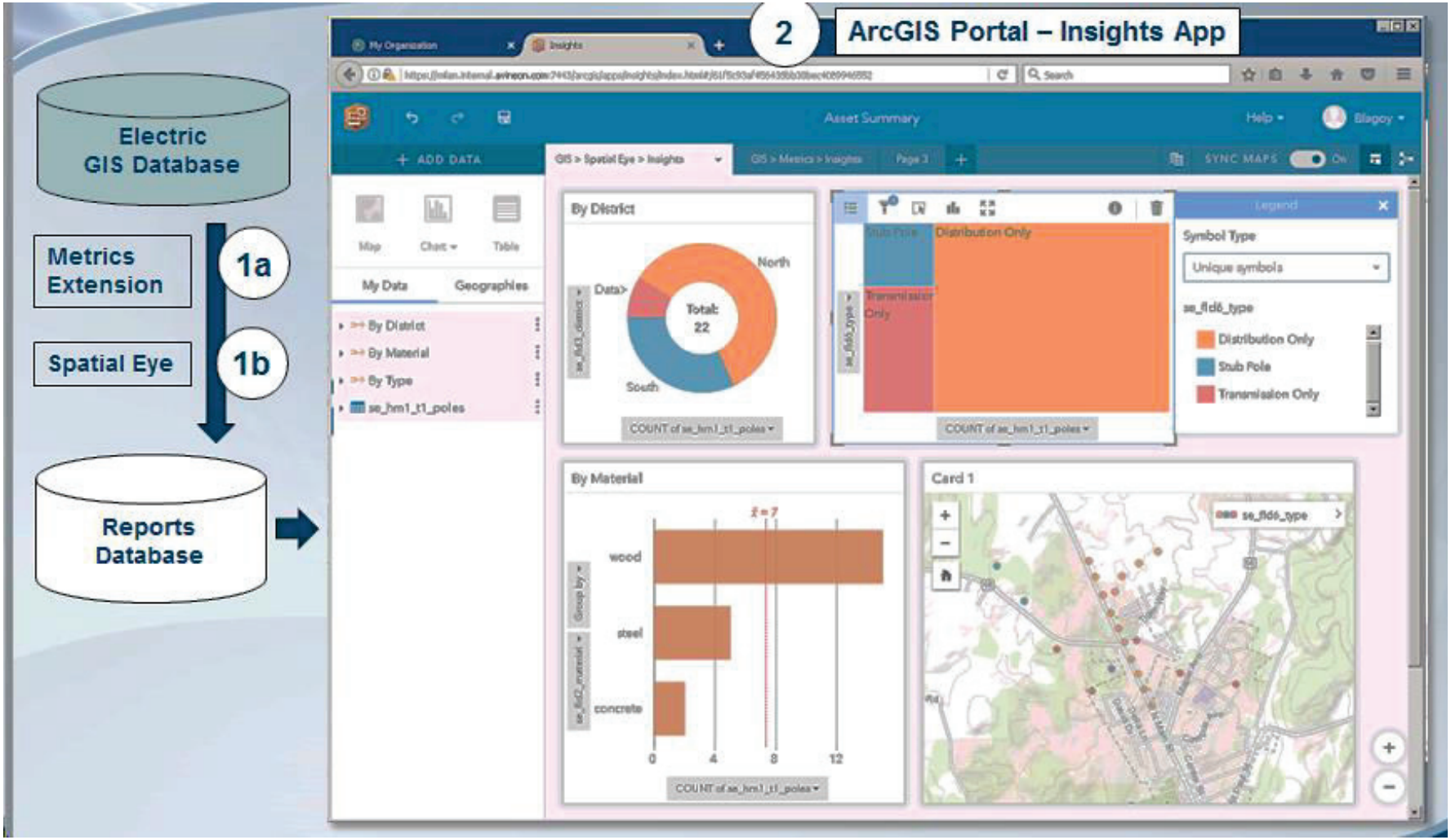


Figure 2-15. Schematic of the Report Generation Process Using Insights and Sample Results

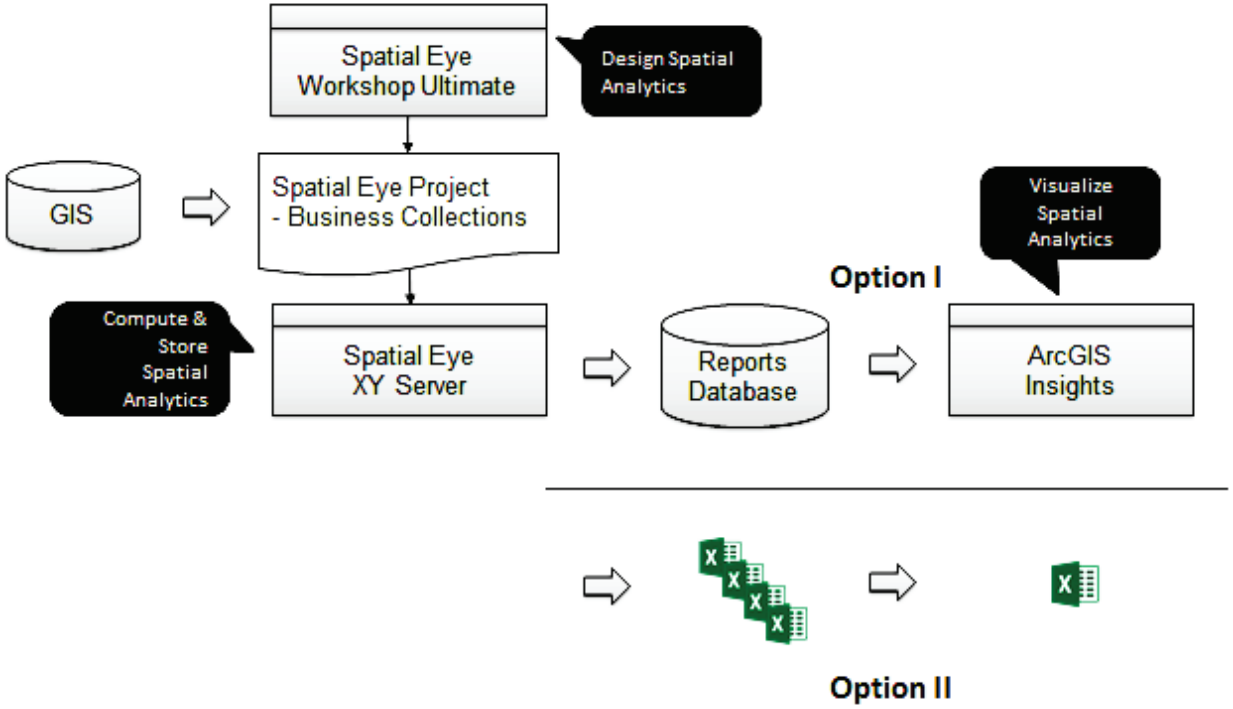


Figure 2-16. Spatial-Eye-Based Work Flow

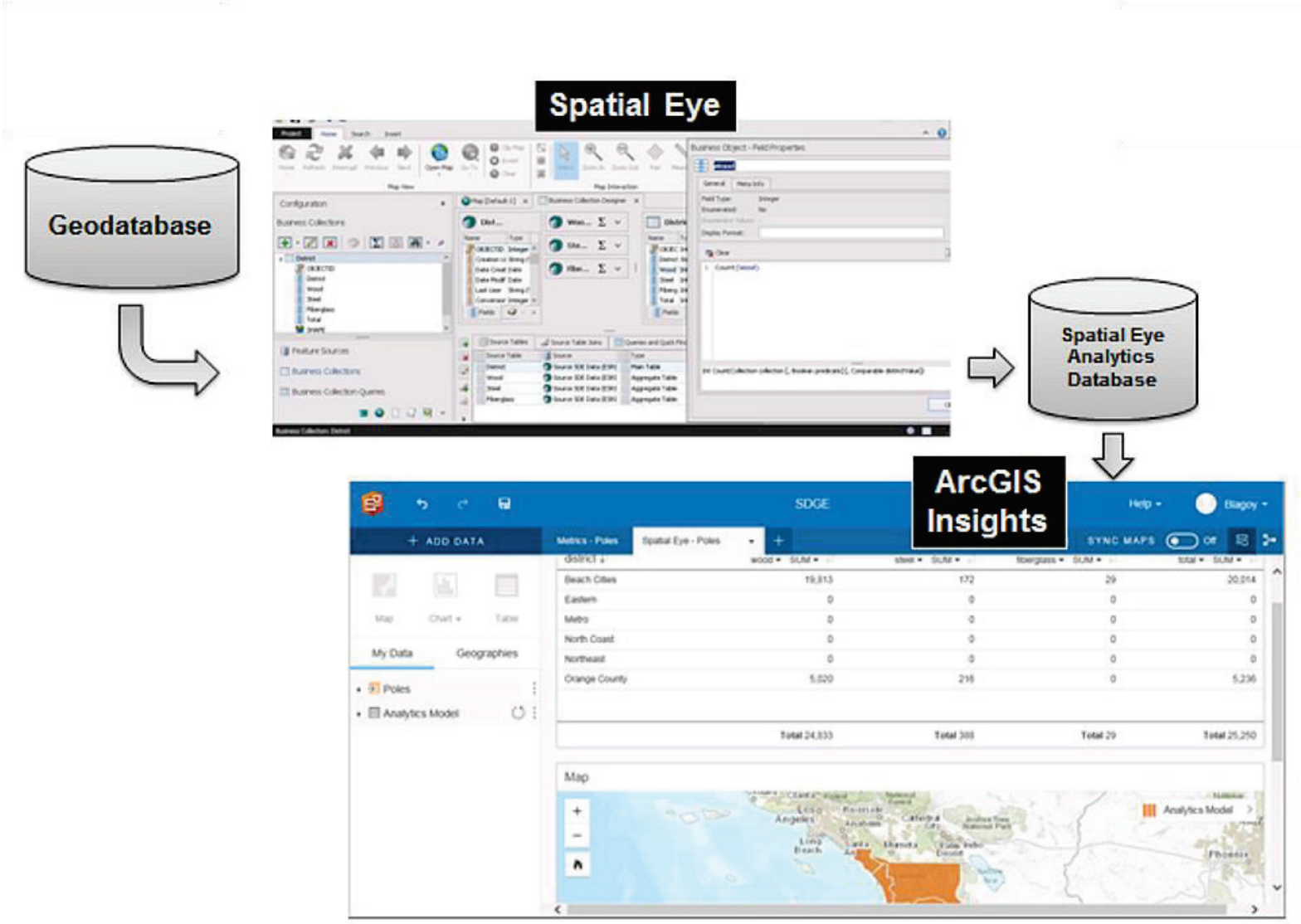


Figure 2-17. Spatial-Eye-Based and ArcGIS-Insights-Based Process and Sample Result

2.3.5 Results

2.3.5.1 Features

The research resulted in the identification of a repeatable and scalable methodology for spatial analysis and self-service reporting. The methodology was successfully verified to automate the computation of spatial analytics, and the results were compared with manual computation methods for Q2 2017 reporting period. This was done for 1) Full Distribution; 2) Primary and Equipment, and 3) Substations. The methodology for transmission reporting, however, was not included for in-depth analysis due to budget and timeline constraints.

The application of the solution components to this use case has demonstrated between 80% to 100% automation within various tasks of the reporting process, as illustrated in Figure 2-18 (the "blue" processes are ~80% automated, and the "green" processes – which used to be manual – were fully automated. The only remaining manual sub-process is "Report Review", which was, indeed, intended to stay that way.

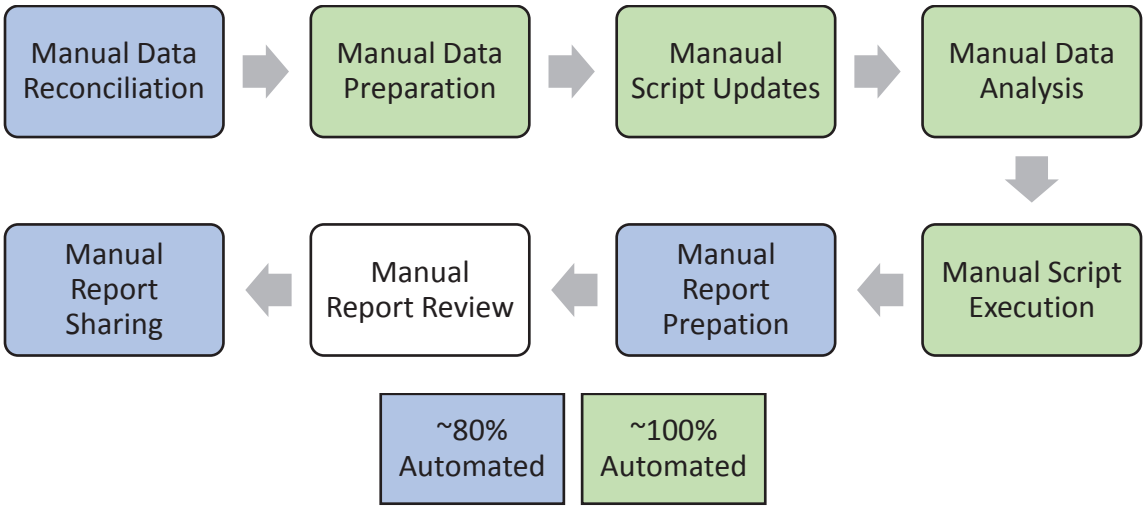


Figure 2-18. New, Largely-Automated Process

Thanks to this automation, the resulting work flow greatly simplifies the original multi-week process to a multi-day process comprised of the following steps:

1. Copy active circuits spreadsheet into designated folder
2. Verify and update business collections in Spatial Eye Workshop to verify the join-with-active-circuits spreadsheet
3. Click Run button in XY Server to compute analytics and write them to a) database and b) spreadsheets
4. Verify cards in ArcGIS Insights and formulas in the reporting template spreadsheet

2.3.5.2 Representative Results

Sample screenshots of the options available to end users are presented in Figure 2-19 through Figure 2-26.

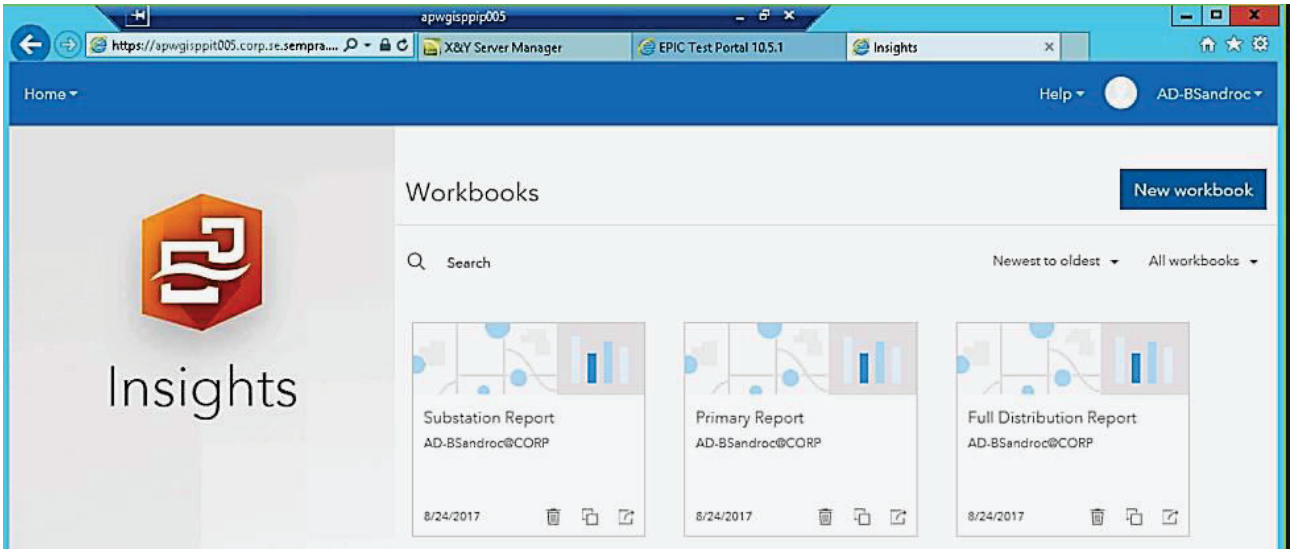


Figure 2-19. Report Options Using Insights

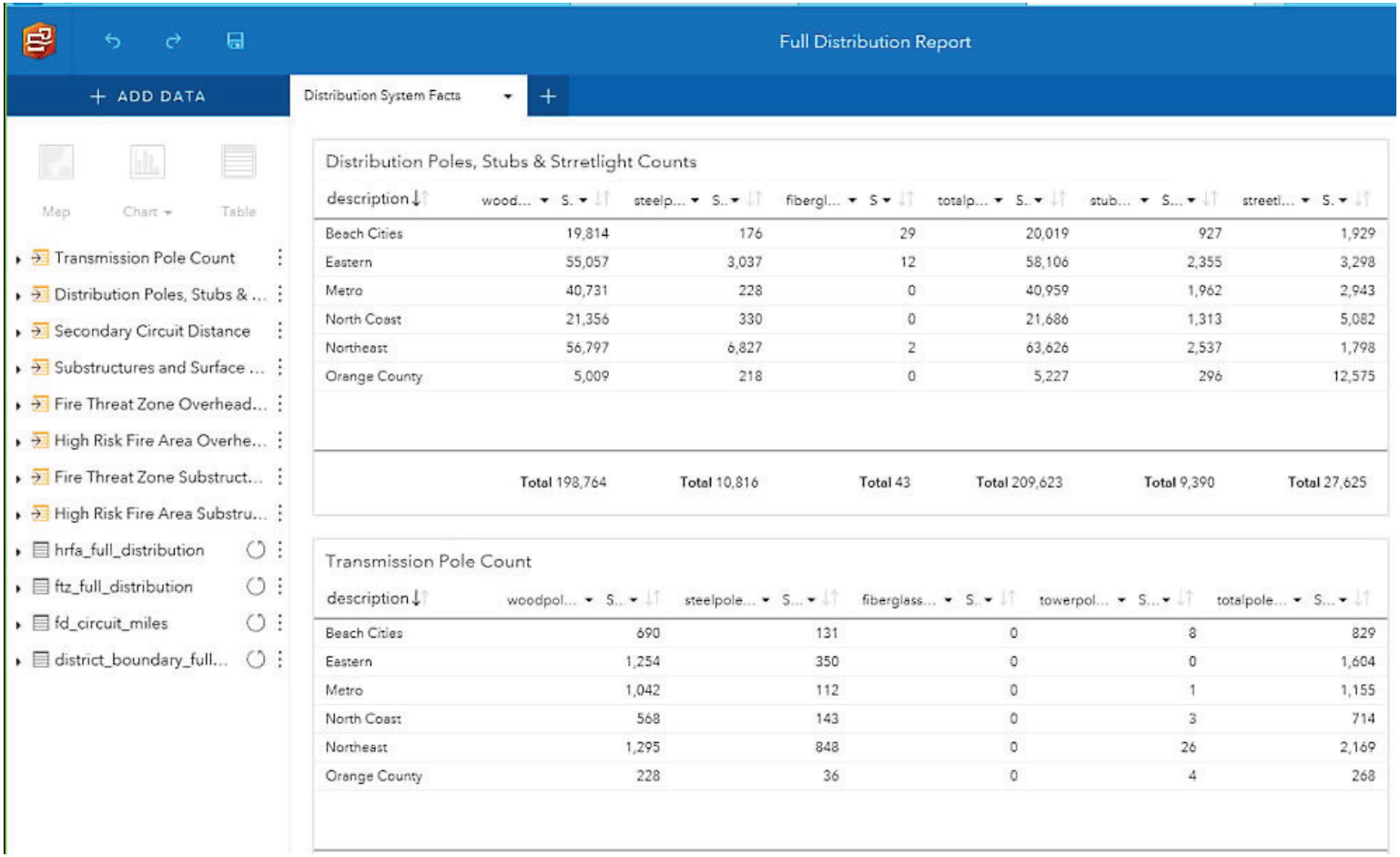


Figure 2-20. Distribution System Facts Report

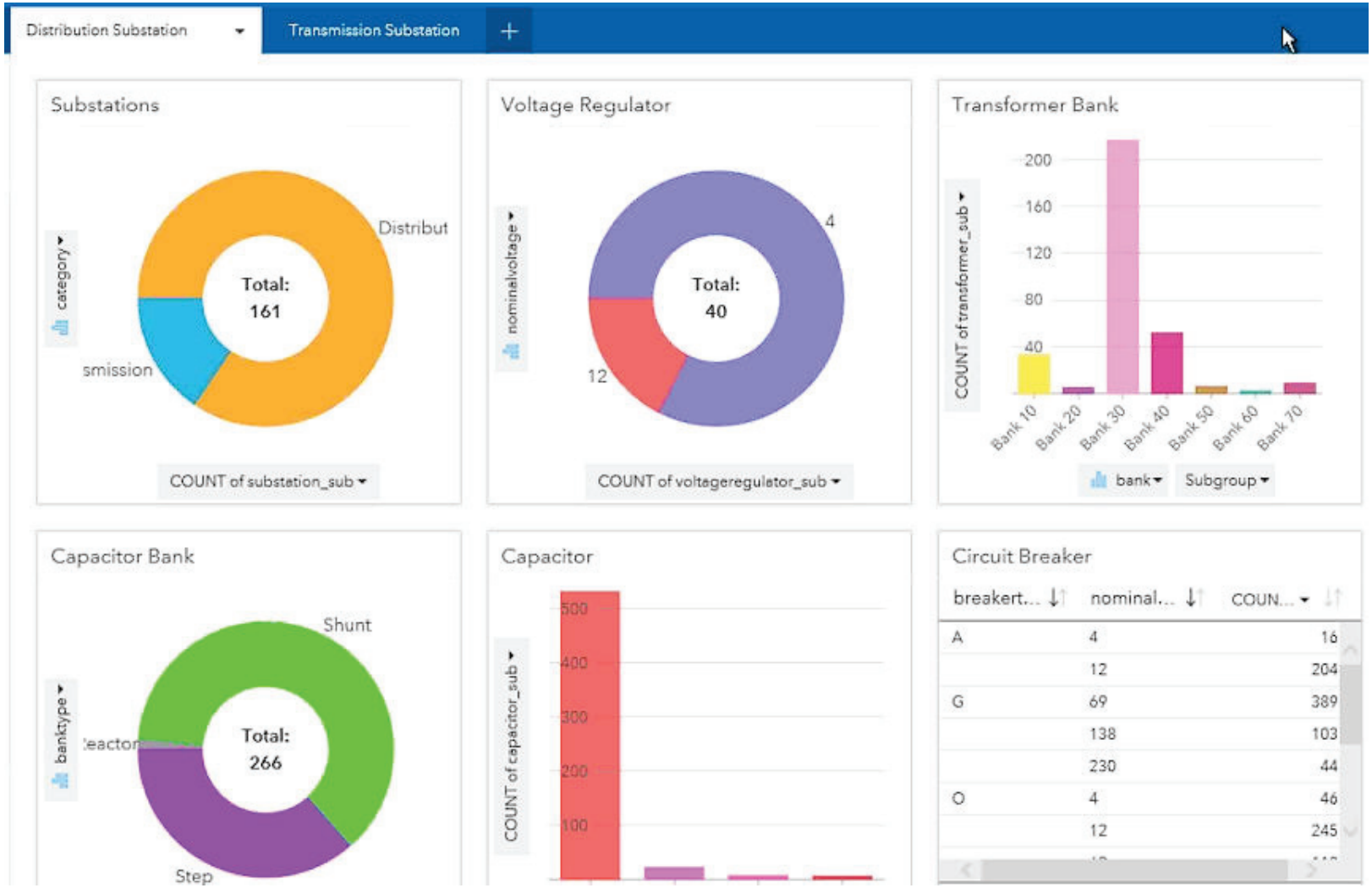


Figure 2-21. Distribution Substation Report

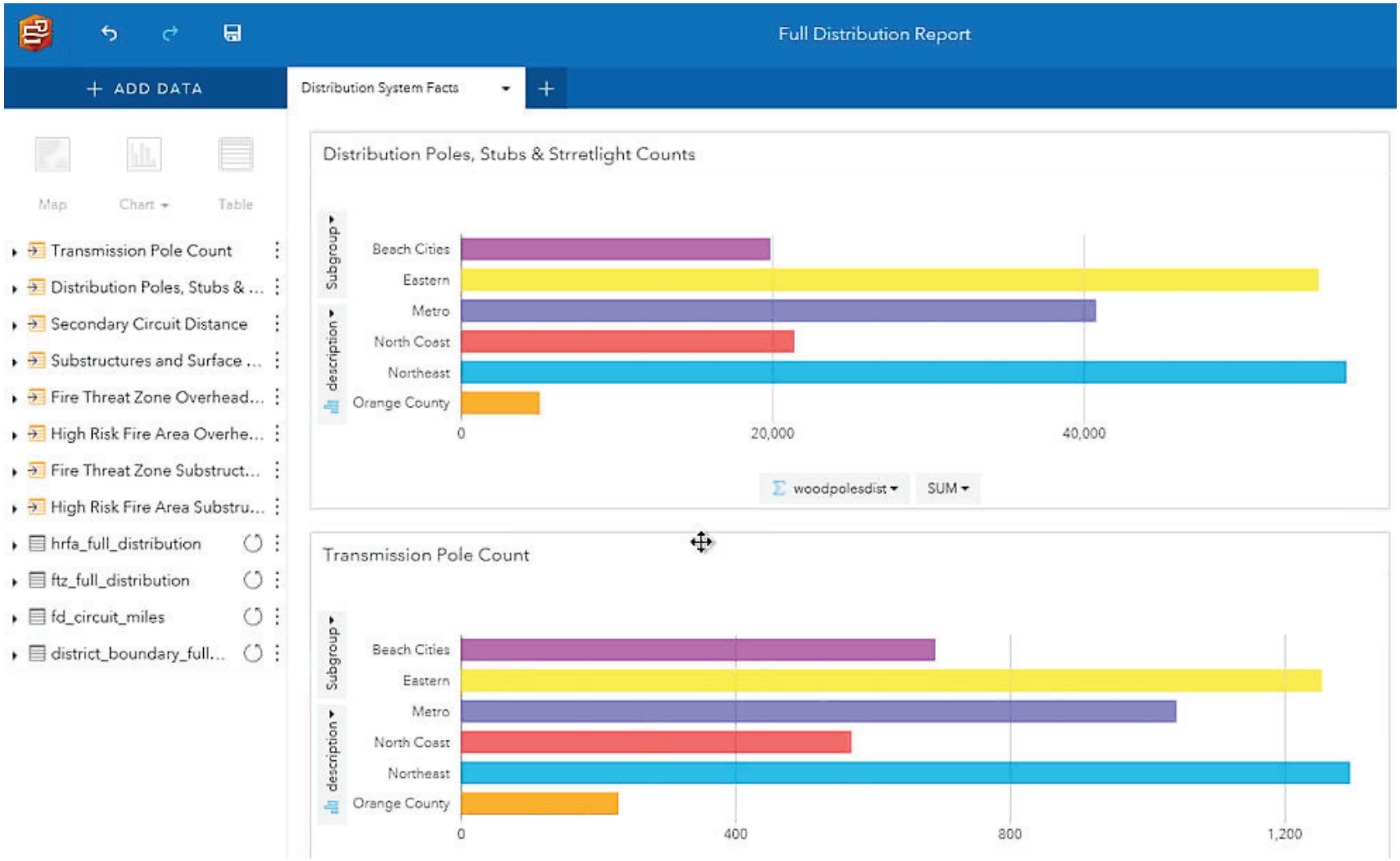


Figure 2-22. Distribution and Transmission Pole Count by District

Overhead	Distribution only				Transmission Underbuild				Stub Pole	UG Streetlight
	Wood	Steel	Fiberglass	*Total*	Wood	Steel	Fiberglass	*Total*		
BC	20,154	149	2	*20,305*	713	112	0	*825*	1,144	1,999
CM	41,547	184	0	*41,731*	1,073	83	0	*1,156*	2,892	3,130
EA	56,308	2,016	8	*58,332*	1,303	305	0	*1,608*	2,805	3,300
NC	21,569	298	0	*21,867*	572	141	0	*713*	1,588	5,445
NE	60,027	3,693	2	*63,722*	1,329	813	0	*2,142*	3,002	2,594
OC	5,193	130	0	*5,323*	231	31	0	*262*	365	12,641
Total	204,798	6,470	12	*211,280*	5,221	1,485	0	*6,706*	11,796	29,109
FTZ	73,004	5,490	9	*78,503*	1,654	981	0	*2,635*	3,222	3,924
HRFA	34,187	3,276	2	*37,465*	819	299	0	*1,118*	1,298	179

Figure 2-23. Tabular Report of SDG&E Distribution System Facts

Surface/Underground	Substructures						Surface	
	Manhole	Subsurf. Enclosure	Vault	Primary Handhole	Secondary Handhole	*Handhole Total*	Pad	Enclosure
BC	1,493	5	166	6,153	19,576	*25,729*	17,924	14
CM	1,245	1	548	6,270	25,108	*31,378*	18,010	7
EA	305	31	110	4,669	19,697	*24,366*	14,993	8
NC	568	24	46	8,289	30,521	*38,810*	24,680	6
NE	447	10	37	9,862	33,672	*43,534*	29,018	4
OC	417	191	32	5,017	24,876	*29,893*	13,325	1
Total	4,475	262	939	40,260	153,450	*193,710*	117,950	40
FTZ	150	9	100	5,817	20,302	*26,119*	19,968	6
HRFA	30	8	50	900	3,053	*3,953*	3,599	1

Figure 2-24. Tabular Report of Substructures

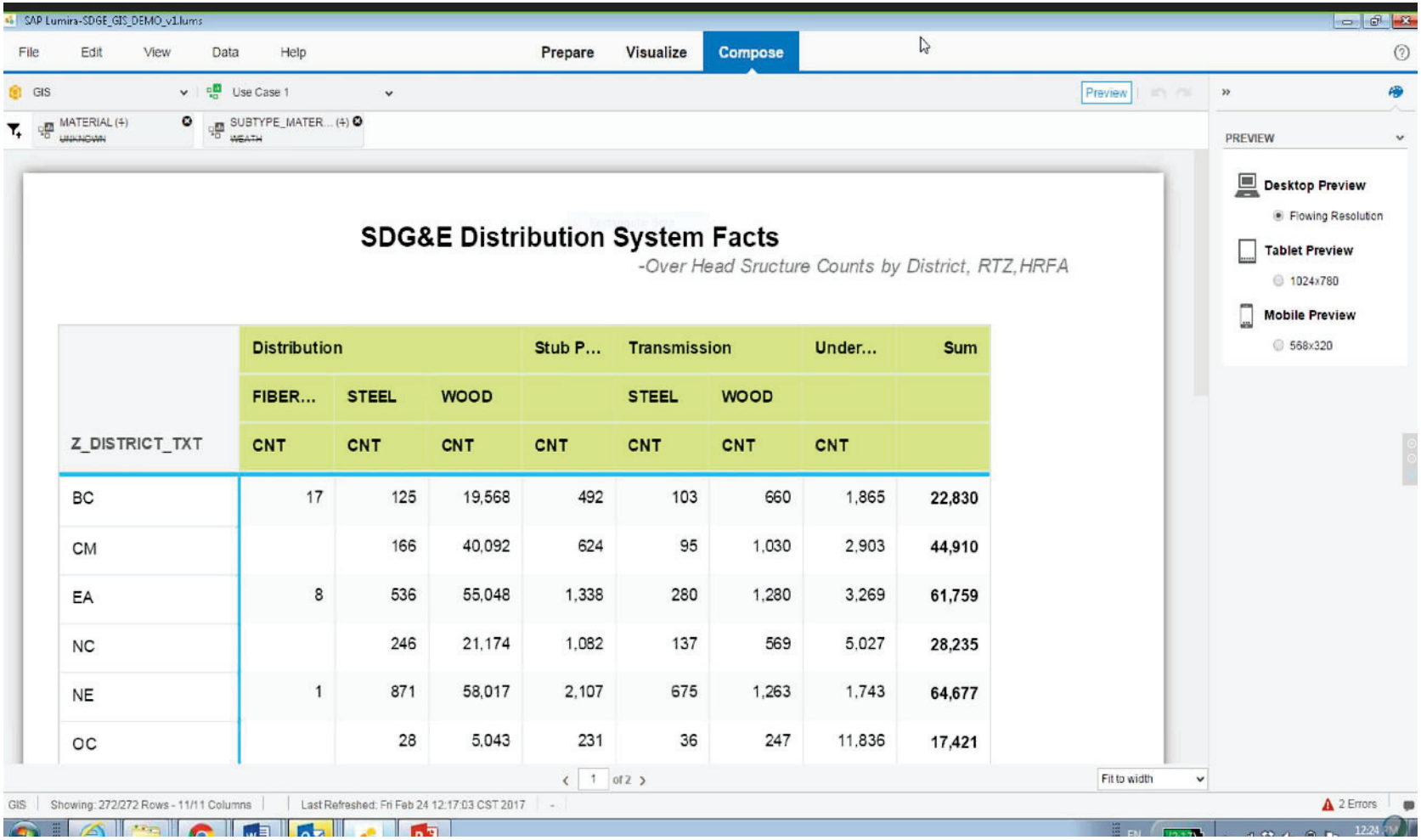
SDG&E PRIMARY DISTRIBUTION SYSTEM FACTS

Quantity of Distribution Circuits	Total/KV
12kV	804
4kV	224
Total Quantity:	1,028

Primary Distribution Infrastructure		Miles			Poles*				Substructures*			Surface*	
		OH Conductor	UG Cable	*Total*	Wood	Steel	Fiberglass	*Total*	Handholes	Manholes	Vaults	Pads	Enclosures
BC	12kV	459	1,579	*2,038*	15,304	243	1	*15,548*	5,909	1,439	67	17,699	13
	4kV	95	58	*153*	2,368	15	1	*2,384*	103	223	5	338	2
CM	12kV	576	1,540	*2,116*	28,335	230	0	*28,565*	6,029	1,136	429	17,817	0
	4kV	195	73	*268*	7,657	62	0	*7,719*	133	112	57	382	0
EA	12kV	1,715	1,102	*2,817*	44,535	2,133	8	*46,676*	4,599	295	16	14,909	6
	4kV	97	17	*114*	3,339	9	1	*3,349*	47	14	0	194	1
NC	12kV	517	2,160	*2,677*	16,746	416	0	*17,162*	8,101	550	5	24,549	5
	4kV	105	58	*163*	3,179	45	0	*3,224*	171	74	1	679	2
NE	12kV	2,516	2,466	*4,982*	51,877	4,302	2	*56,181*	9,696	431	1	28,885	4
	4kV	89	15	*104*	2,142	177	0	*2,319*	45	4	0	206	2
OC	12kV	188	1,278	*1,466*	4,426	157	0	*4,583*	5,060	410	5	13,264	1
	4kV	11	15	*26*	391	1	0	*392*	77	58	1	102	0
Total	12kV	5,971	10,125	*16,096*	161,223	7,481	11	*168,715*	39,394	4,261	523	117,123	29
	4kV	592	236	*828*	19,076	309	2	*19,387*	576	485	64	1,901	7
FTZ	12kV	3,287	1,718	*5,005*	64,240	6,125	9	*70,374*	5,705	140	0	19,857	5
	4kV	85	17	*102*	1,952	172	0	*2,124*	54	4	0	220	2
HRFA	12kV	1,629	299	*1,928*	30,496	3,403	2	*33,901*	895	29	0	3,576	1
	4kV	43	5	*48*	958	130	0	*1,088*	11	0	0	72	0

*Structures that have both 12kV and 4kV are counted as 12kV

Figure 2-25. Primary Distribution System Facts



Z_DISTRICT_TXT	Distribution			Stub P...	Transmission		Under...	Sum
	FIBER...	STEEL	WOOD		STEEL	WOOD		
	CNT	CNT	CNT	CNT	CNT	CNT	CNT	
BC	17	125	19,568	492	103	660	1,865	**22,830**
CM		166	40,092	624	95	1,030	2,903	**44,910**
EA	8	536	55,048	1,338	280	1,280	3,269	**61,759**
NC		246	21,174	1,082	137	569	5,027	**28,235**
NE	1	871	58,017	2,107	675	1,263	1,743	**64,677**
OC		28	5,043	231	36	247	11,836	**17,421**

Figure 2-26. Overhead Structure Count by District

2.3.6 Observations, Challenges, and Lessons Learned

Metrics, with its zero-programming ease-of-use approach, was able to generate ~25% of the analytics within SDG&E QY report. Spatial Eye was more complex to use, but it was able to generate 100% of the analytics within SDG&E QY report.

While ArcGIS Insights provided better visuals (charts, maps, etc.) with interactive experience, the views did not match exactly the Excel reporting template currently used by SDG&E. The alternative is to export this analytics as Excel spreadsheets and reference them within the SDG&E's Microsoft Excel reporting template. This provides a viable path with minimal changes to the end users of the report.

Challenges and Resolutions

- Biggest hurdle was translating the needed SQL queries to the Spatial Eye language (once queries are translated, they can be reused without needing to manually translate them for each use).
- There is a significant learning curve to master Spatial Eye queries and to setup Spatial Eye projects.
- Automating the process is the key to process speed improvement (many steps could be done overnight); once the circuit/subs list is up to date, the users can run queries at any time.

Recommendations

- An investment in terms of time, effort, and training is needed to master Spatial Eye queries and the setup of Spatial Eye projects.

2.4 Historical Outages Playback (UC #4)

2.4.1 Background

The goal of this task was to provide an ability to visually represent historical electrical outages up to 5 years in the past as points on a geographical map, with a user being able to interactively specify the history duration and to select additional geospatial layers to display. The core information needed to accomplish this goal are the Lat/Lon of each outage of interest. However, such information is not readily available in one place. For example, the database of assets contains exact geographical locations of all facilities and equipment, but does not have information about outages. Likewise, a database of outages does not have the Lat/Lon of the outaged facilities.

An ability to look at historical outage data in the context of the exact geographical location and other data that might have had some impact on the outages is of great value to both Operations and T&D Engineering. Prior to this effort, various pieces of the overall outage picture were scattered among different SDG&E systems. The aim of Use Case #4 was to develop a GIS-based application for replaying outages along with other kinds of related data in order to get a better grasp of the potential causes and of the outage restoration performance. It is hoped that the insights from these replays might help improve outage restoration performance in the future.

2.4.2 Objective

In technical terms, the goal of this task was to integrate information from the systems of record for the outage data, build appropriate applications for associating outages with the Lat/Lon, and to provide

needed support to end users to enable them to interactively peruse outage information on a geographical map.

2.4.3 Users

- T&D Engineering
- Distribution Operation

2.4.4 Solution Approach, Solution Components, and Work Flow

2.4.4.1 Solution Components

- Outage Management System: source of outage data
- Postgres DB: the store for the extracted outage data
- Esri Web AppBuilder: a development tool for creating custom widgets for ArcGIS
- GIS Portal

2.4.4.2 Work Flow

Prior to this use case, SDG&E did not have all the needed information required to draw an outage location on a geographical map within one data source. Relevant data is spread across three main data sources, as follows:

- **FP_PROD** – Oracle database instance which receives outages from Network Management System (NMS) in a near real-time. This source does not contain the Lat/Lon of the outage facilities and equipment.
- **PRO_VAQ_ELEC** – Oracle instance storing electric GIS assets (structures, devices) in an Esri ArcSDE geodatabase. This is the source of Lat/Lon data, but this source does not have outage data.
- **EROD.xlsx** – Excel spreadsheet supplied by the Electric Reliability Group with 5 years' worth of scrubbed (validated and accepted) outage data. This source is supplied on a monthly basis and refreshed in the Electric Reliability web application by the FME process depicted in the workflow diagrams that follow. This source does not contain the outage Lat/Lon data.

In the diagrams that follow, the source data stores are shown as yellow shapes. The data sources are utilized within a multi-step process to produce an outage point feature that can be represented geospatially on a map. To accomplish this, the source EROD data needs to be matched to another source that can provide these coordinates for the outage through a two-step approach: in the first step, an attempt is made to match the existing GIS features (structures, devices) stored in PRO_VAQ_ELEC to the EROD records (the historical outage data). When a match cannot be found, then, in the second step, an attempt is made to match the EROD records to NMS data via an Oracle database view to EROD records. If neither of these sources can provide a location, an error is raised requiring manual intervention to establish a location.

An overview of the overall workflow is shown in Figure 2-27, followed by a more detailed description of its sub-processes.

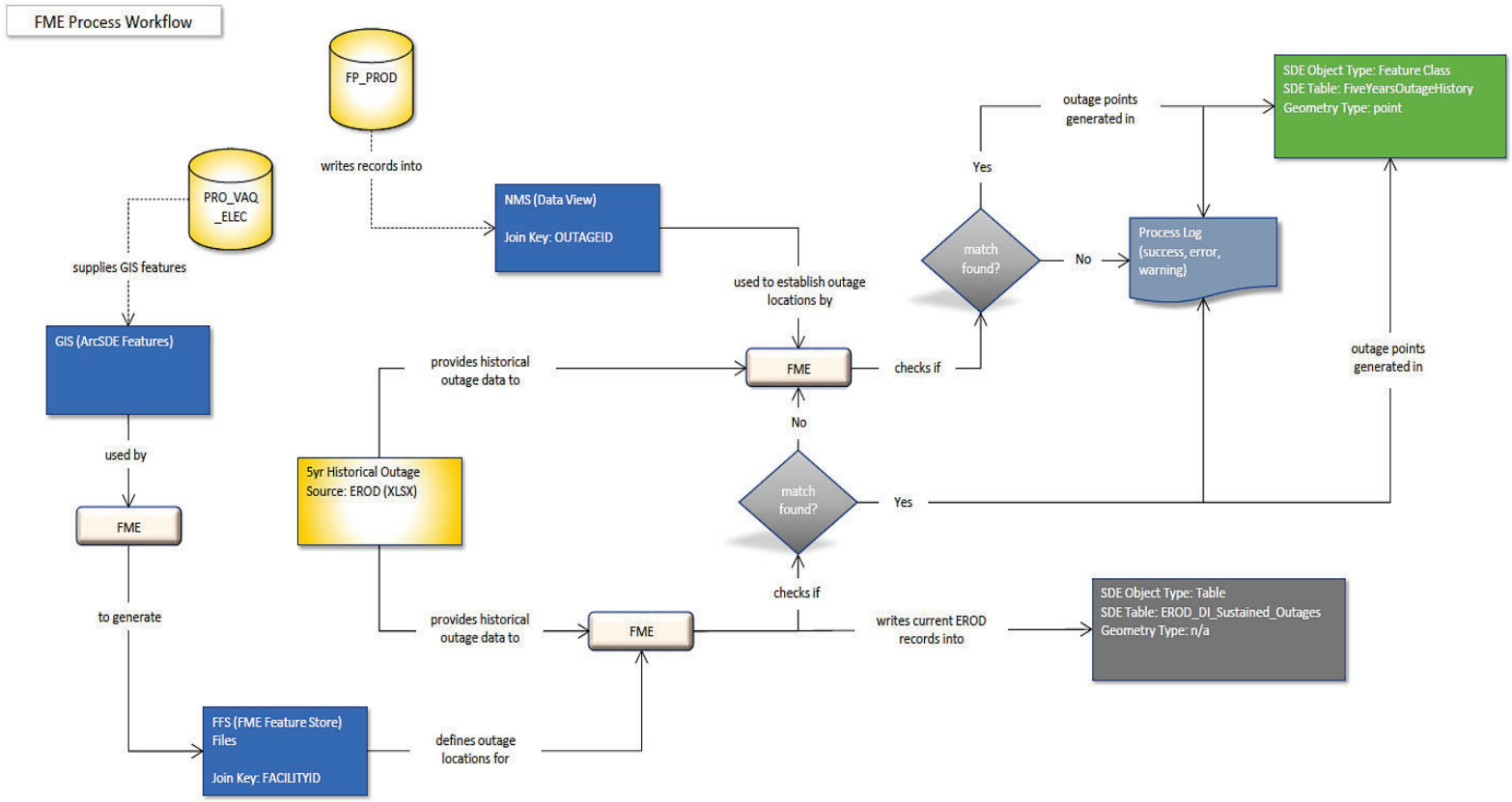


Figure 2-27. Work Flow for Generating Outage Features

The following workflow describes in more detail how the process illustrated in Figure 2-27 is carried out.

1. To prepare for matching EROD records to the asset location data stores, there is a preliminary step to read 1.3 million features found in 10 different feature classes, and transform this information using the Safe Software's ETL application FME (Feature Manipulation Engine) into a format that greatly improves the performance of the matching process. The results are stored in a single file in FME's native format FFS (FME Feature Store), as shown in Figure 2-28.

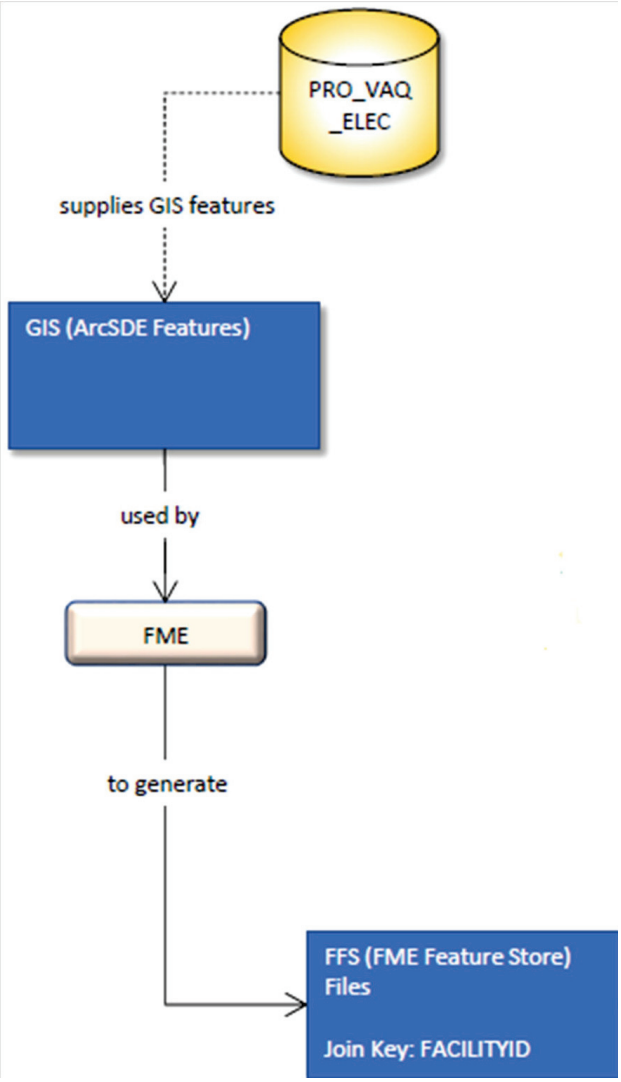


Figure 2-28. Transformation of GIS Features into FME Feature Store Native Format

2. The secondary source for a given outage location consists of records read from NMS. A database view is created from FP_PROD and is made available to FME if required (see Figure 2-29).

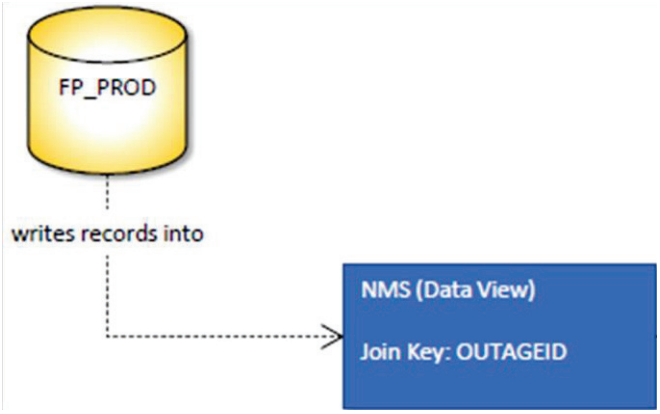


Figure 2-29. Matching of Outage Data with NMS Data

3. With these two data sources available, an FME process is then used to attempt the 2-step matching process. First match is attempted between the source EROD data and the GIS data (see Figure 2-30).

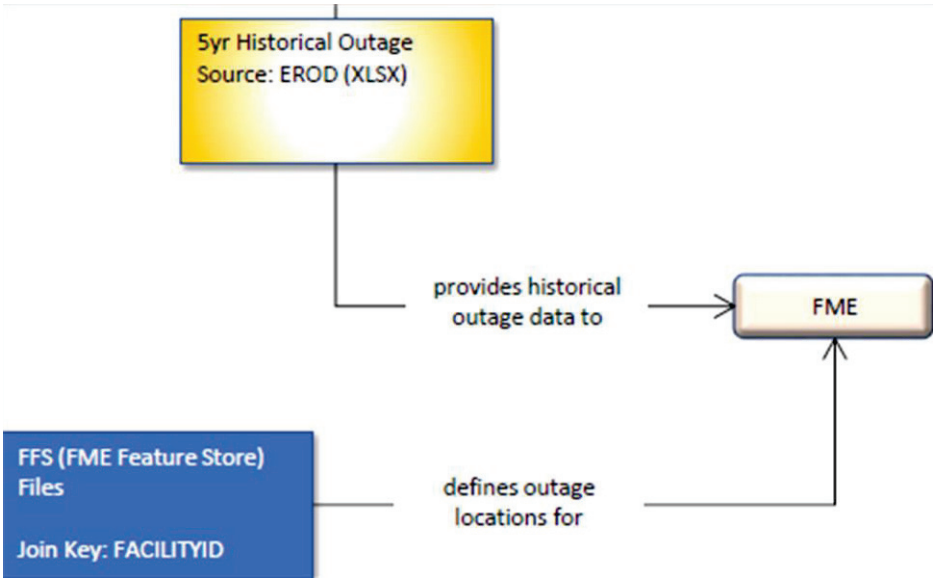


Figure 2-30. Matching of EROD Data and GIS Data

4. If a match is found, then a point feature is generated in a geodatabase. A record is also written into a process log for reference (see Figure 2-31).

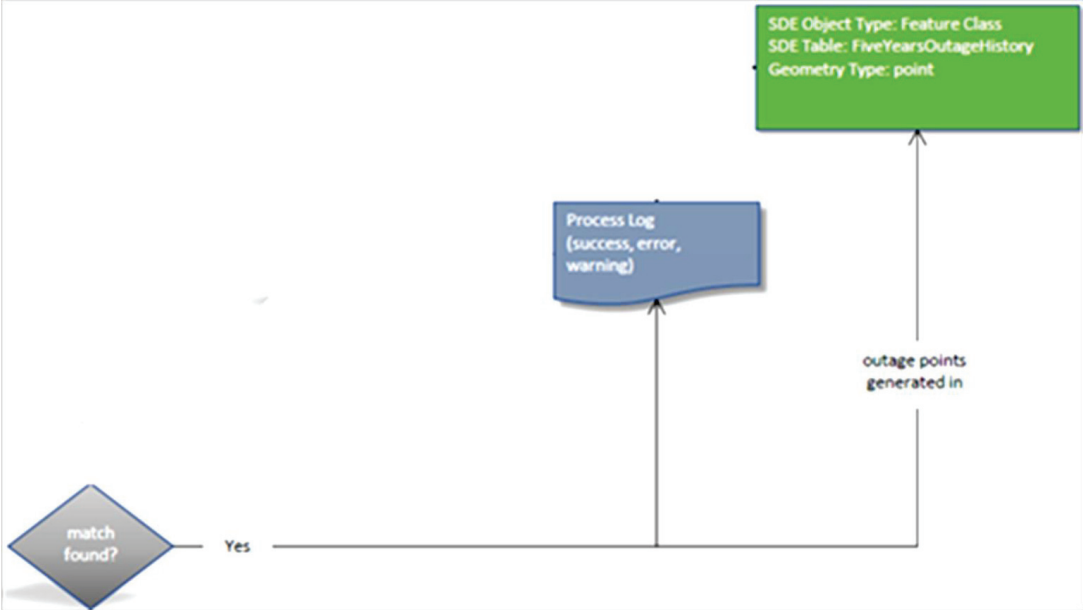


Figure 2-31. Matching Process Main Output

5. At the same time, a table is populated with the source EROD data for possible future reference (see Figure 2-32).

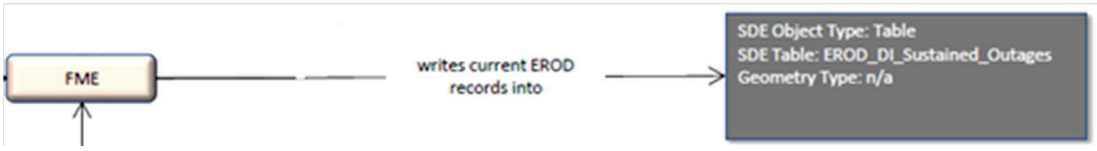


Figure 2-32. Matching Process: Additional Output Table

6. If a match to the GIS could not be found, the second step is to match EROD data to NMS records (see Figure 2-33).

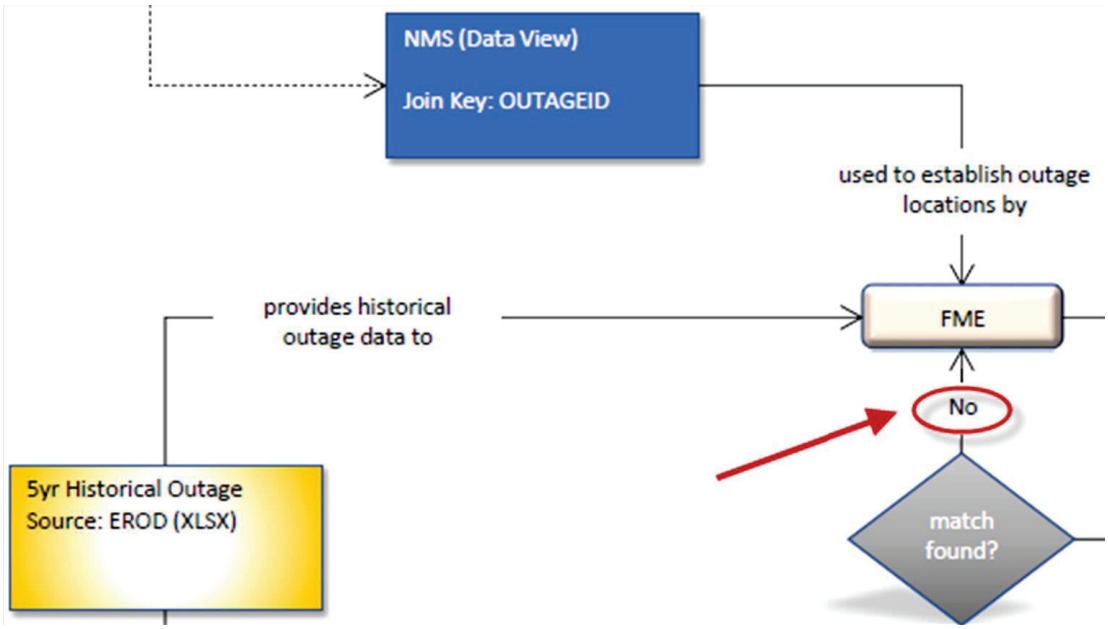


Figure 2-33. Matching Outage Data with NMS Data

7. If a match is found, a point feature is generated in the output feature class that will be presented within the Electric Reliability web application (see Figure 2-34).

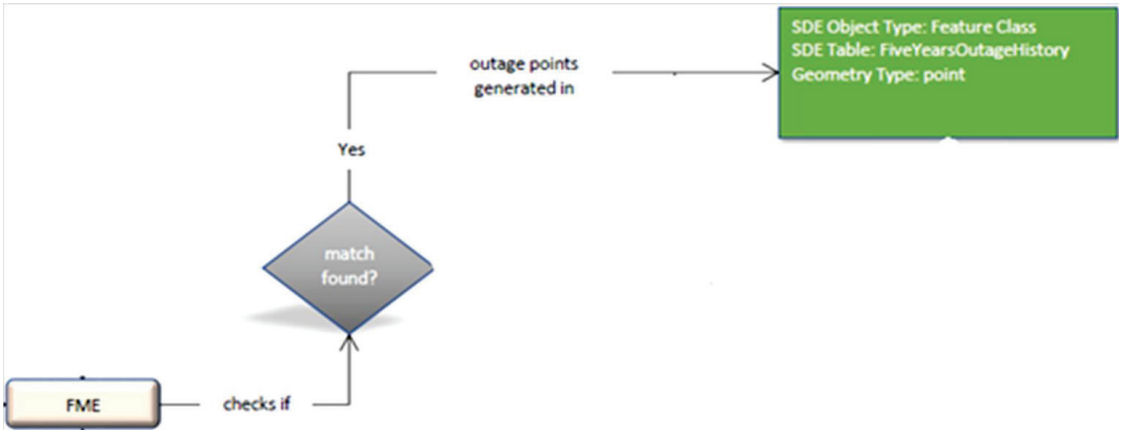


Figure 2-34. Output of Second Step Matching

8. If a match cannot be established from NMS, an error is produced in the output processing log file (see Figure 2-35). These EROD records need to be manually researched to establish an actual geographic location.

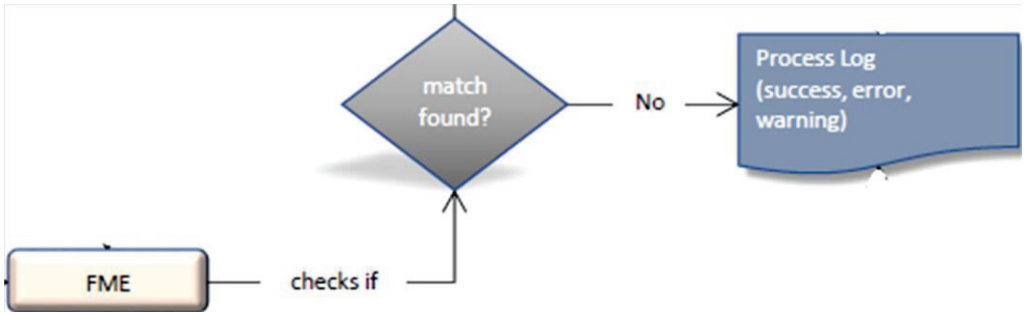


Figure 2-35. Second Step Matching Log

9. As noted previously, both match processes write out success or failure into a process log (see Figure 2-36).

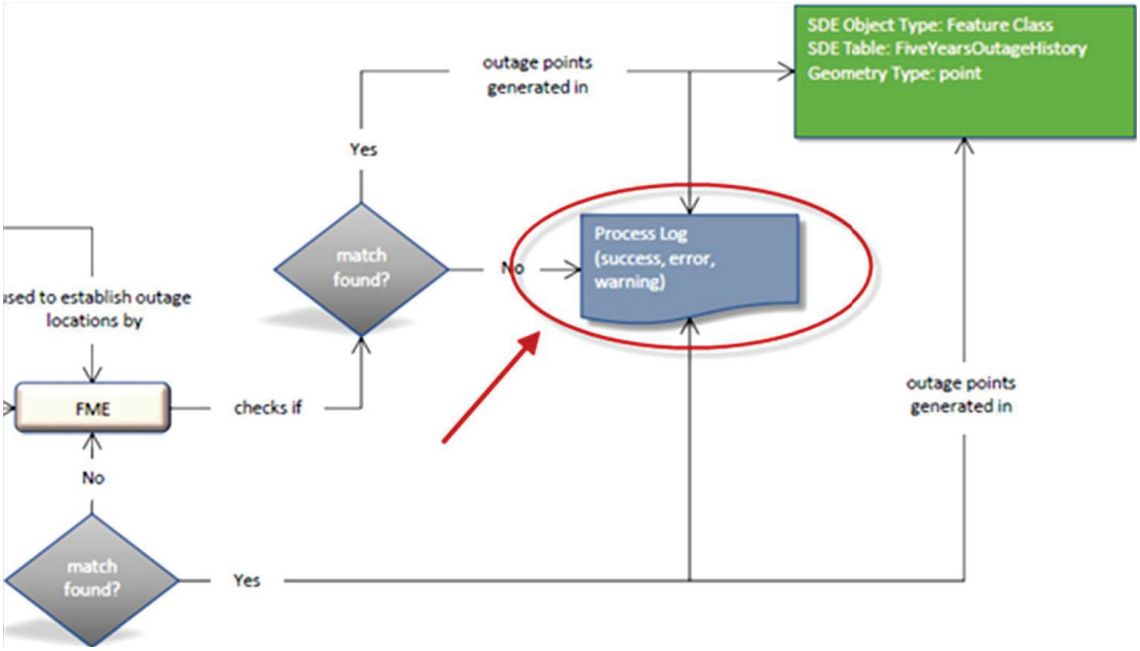


Figure 2-36. Matching Process Log

With the outage data assigned to the geographical location through the above processes, the resulting features could be presented alone or in combination with other geo-enables features like SCADA data and weather at the time of the outage. Updates to the SCADA data on maps are accomplished with the help of PI Integrator for Esri ArcGIS, through a mechanism explained in more detail within the Use Case #1 description.

Figure 2-37 provides an example of how to configure an outage playback on a map and what options are available for displaying additional, complementary data. More details and examples of the application capability for replaying outages is also available in the Results section.

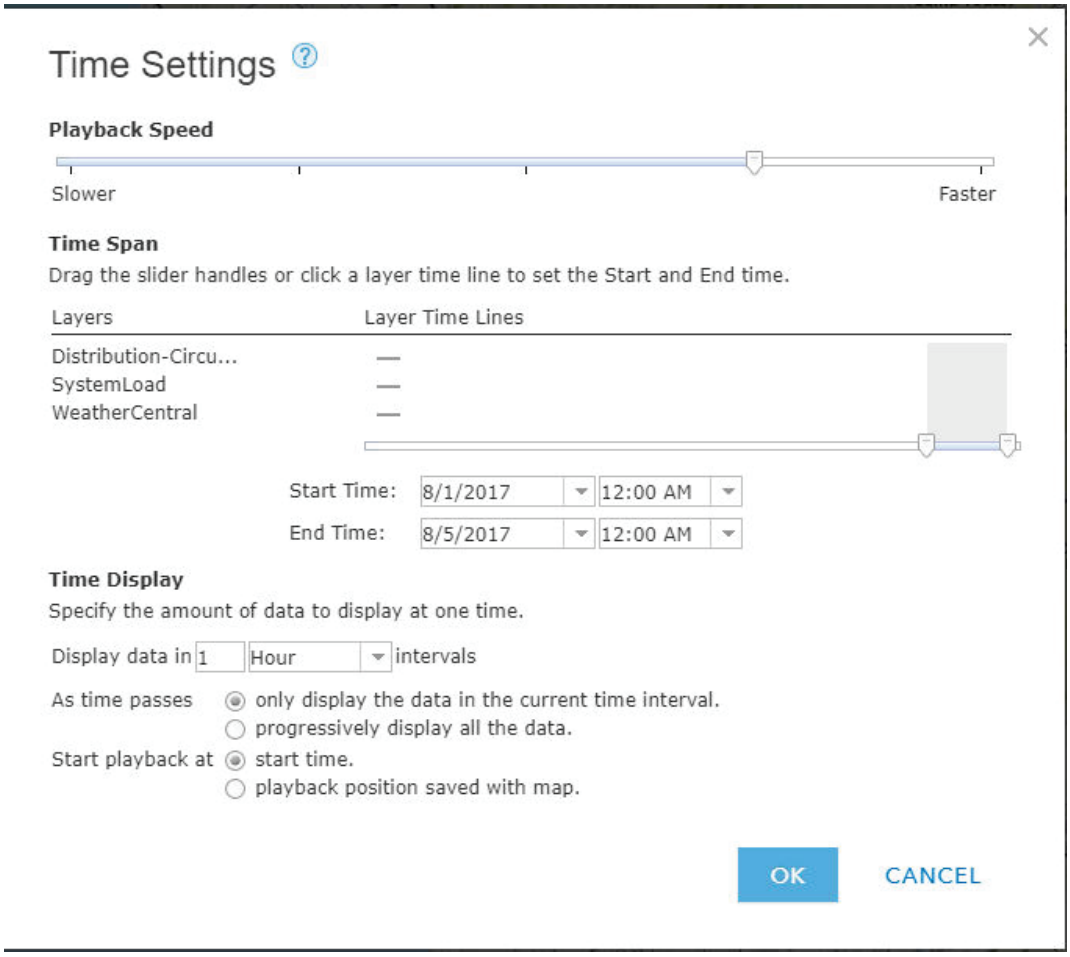


Figure 2-37. Setup for History Playback

2.4.5 Results

An ArcGIS Web app builder widget, called Outage Filter, has been created to enable a user to select and display Electric Reliability Outages based on the criteria in the following groups (see Figure 2-38):

1. Feeder or District ID
2. Time Interval
3. Additional Outage Parameters

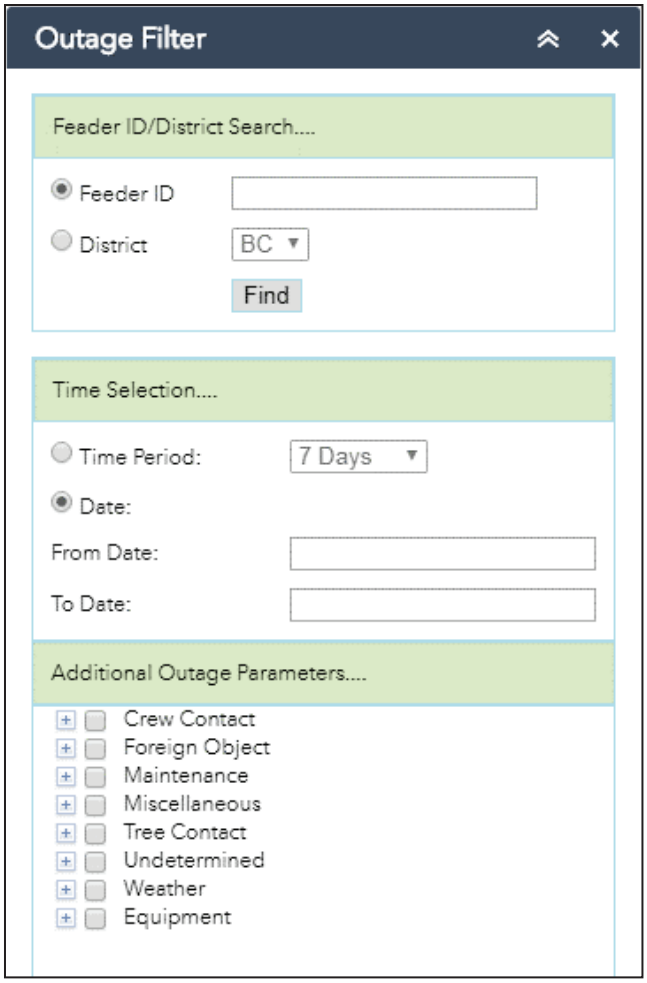


Figure 2-38. Configuration of Outages to Display

1. Feeder ID or District

   In this category, the user can choose either a Feeder ID or a District. For example, Figure 2-39 shows outages for a feeder ID 214.

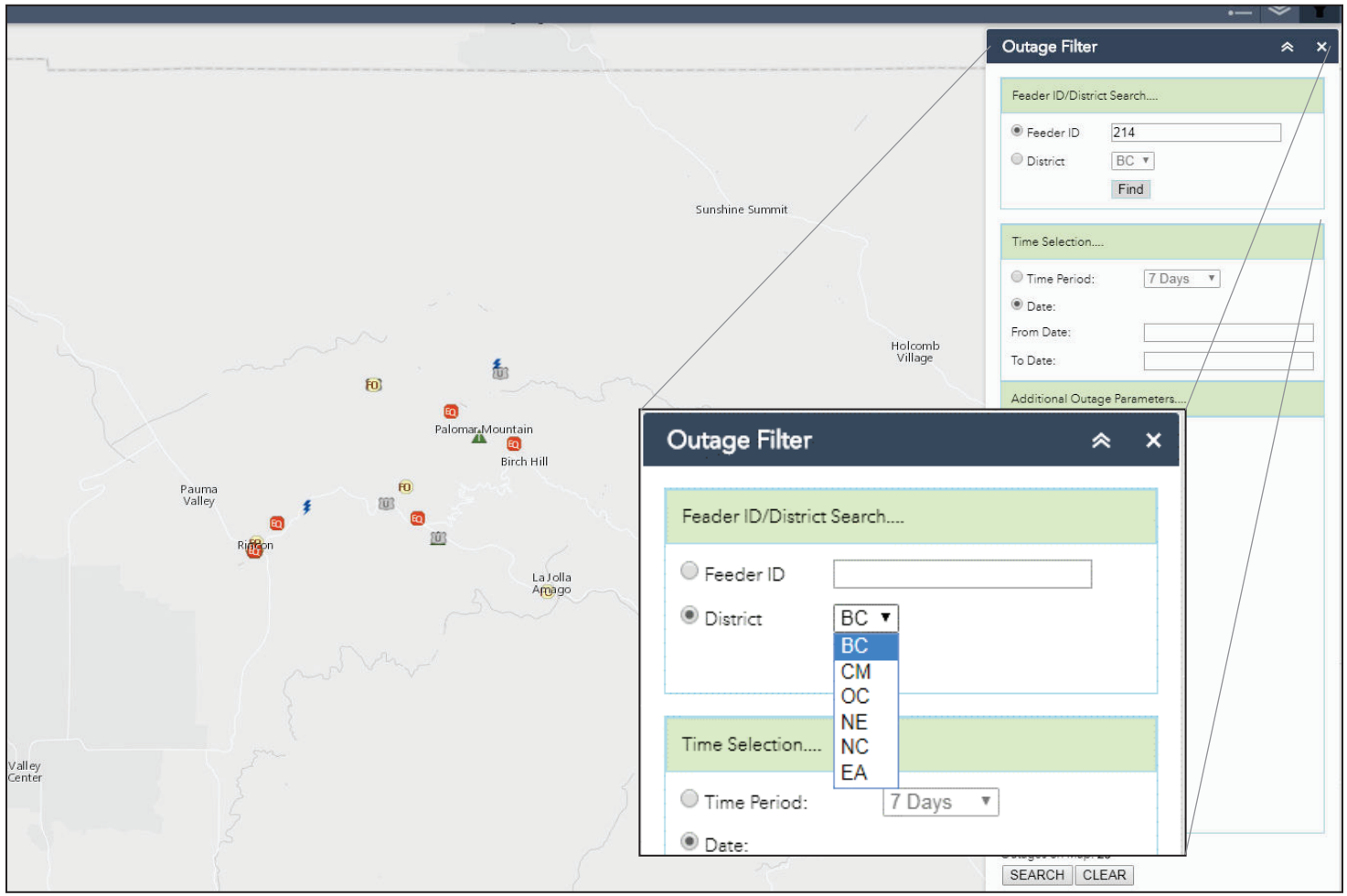


Figure 2-39. Outages for a Selected Feeder and Date Range

Similarly, when a user selects a district code (inset in Figure 2-39 above), the resulting map shows the outages in that district, including that district's boundary.

2. Time Selection:

   Users can specify the time interval of interest in one of two ways, relative and absolute. In the relative method, invoked by selecting the "Time Period" radio button, the choices are the number of days prior to today (e.g., All Days, 5 Days, etc., as seen in Figure 2-40).

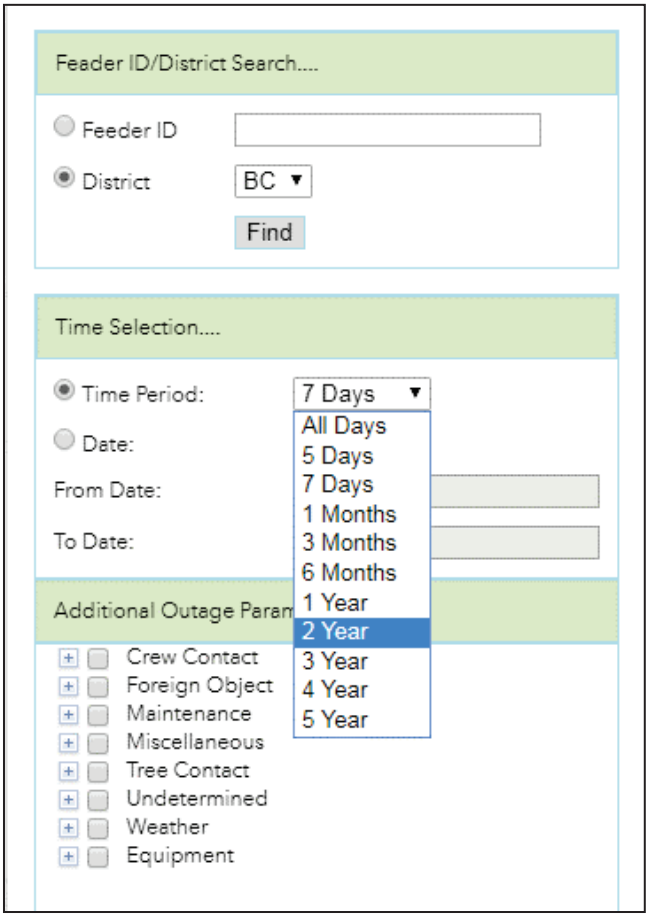


Figure 2-40. Selection of History Interval

In the absolute method, the user choses “Date” radio button and is given an option to enter “From Date” and “To Date”, as shown in Figure 2-41 below. The dates can be entered by typing in the date fields or by using the calendar widget.

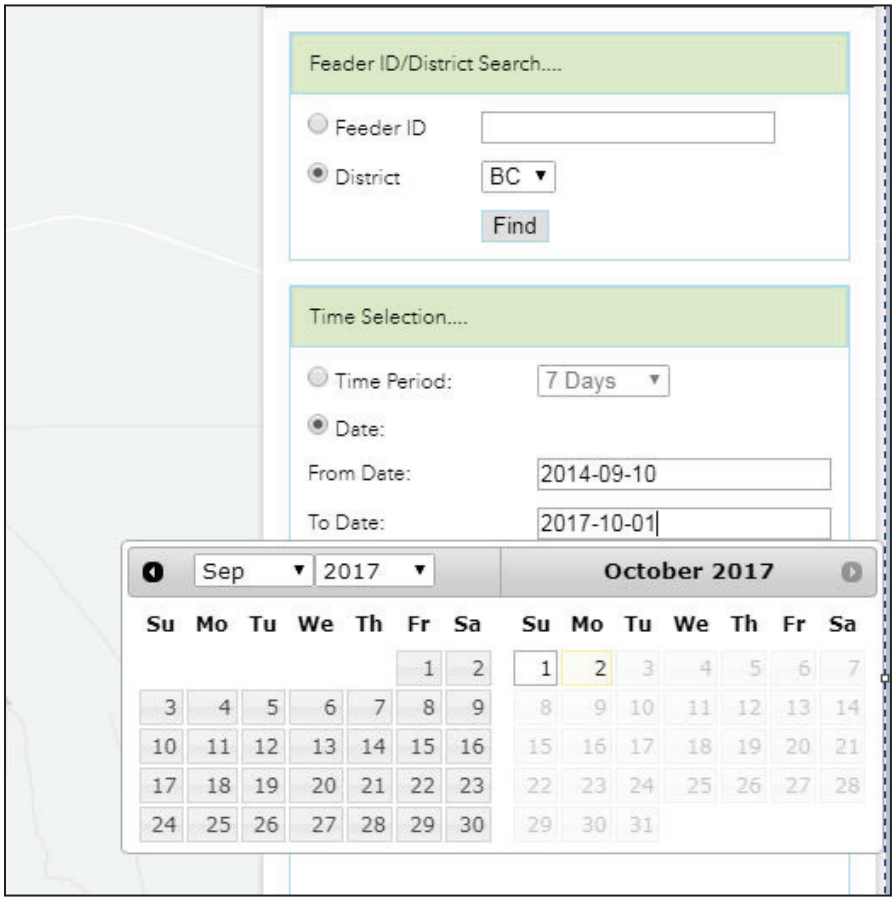


Figure 2-41. Specifying Date Range

3. Additional Outage Parameters

   In the Filter widget, Outage Parameters are selected from groups of related outage-cause categories. The current list of outage-cause categories contains the following:

   - Crew Contact
   - Foreign Object
   - Maintenance
   - Miscellaneous
   - Tree Contact
   - Undetermined
   - Weather
   - Equipment

Each of the categories may contain additional subcategory items that the user can reveal and choose from. For example, Figure 2-42 shows Crew Contact and Foreign Object categories revealed.

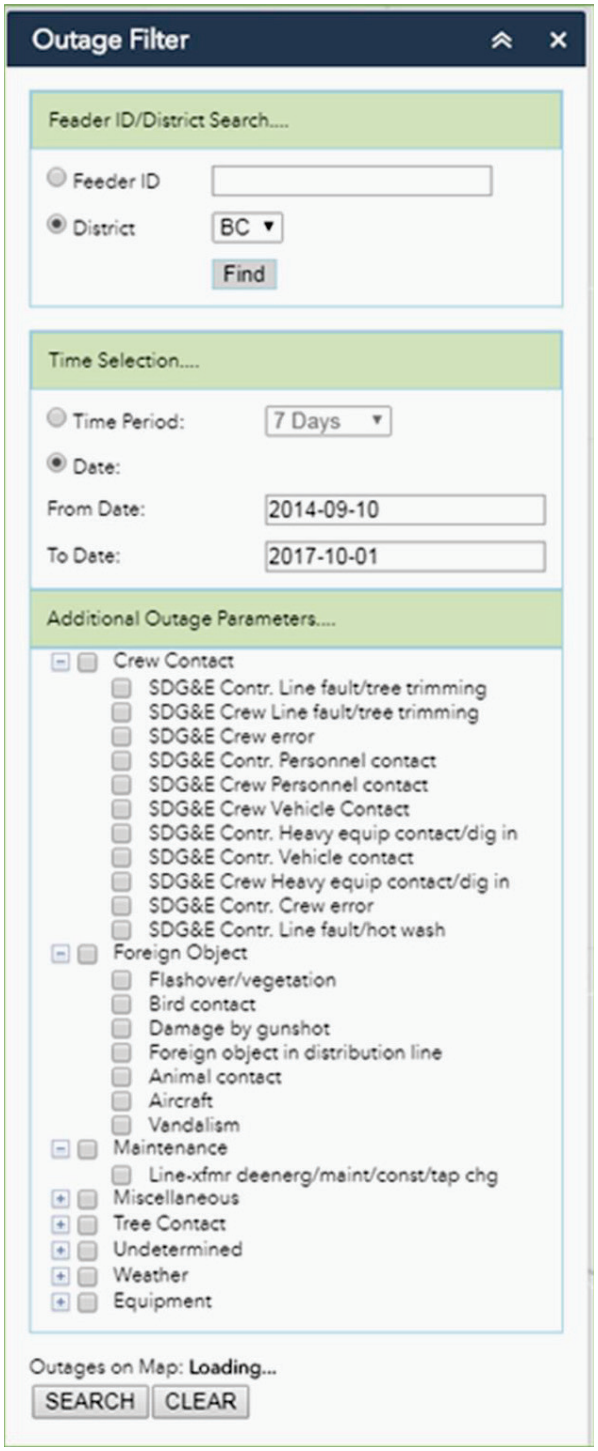


Figure 2-42. Additional Outage Criteria

The following series of figures illustrates what the user sees by selecting different outage categories: Figure 2-43 shows Crew Error-caused outages (within Crew Contact category); Figure 2-44 shows all weather-related outages (including all sub-cause categories); and Figure 2-45 shows outages due to two cause types – specifically, Cable Fault (from Equipment category) and Line Fault/Hot Wash (from Tree Contact category).

As indicated earlier, the user can select to display any combination of outage data, circuit loading, and weather data. For example, Figure 2-46 presents the weather and circuit loading information at a particular point in time, in this case at 3 PM on August 1, 2017. Weather station colors on the map are light orange/gray. According to the legend on the left side of the screen snapshot, the temperatures are in the upper 80s. Also, according to the legend for percent of rating, the orange system load symbols (the squares) indicate loading >50% of their rating.

By adding loading and weather condition data, the user can draw useful conclusions about the possible cause of the outage and the progress of restoration, which, lacking this capability, would be much harder to accomplish.

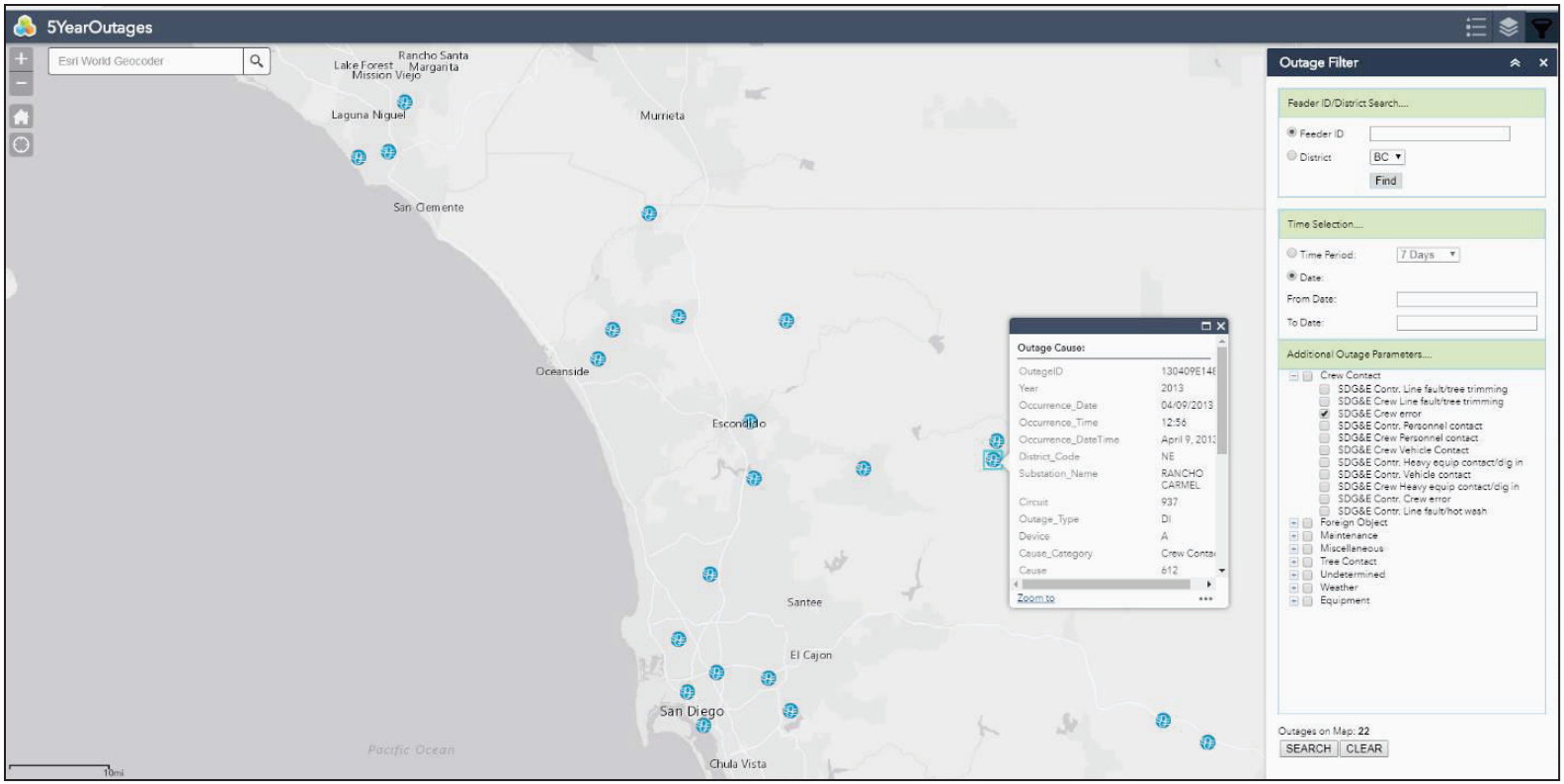


Figure 2-43. Crew Error-Caused Outages (within Crew Contact category)



Figure 2-44. All Weather-Related Outages

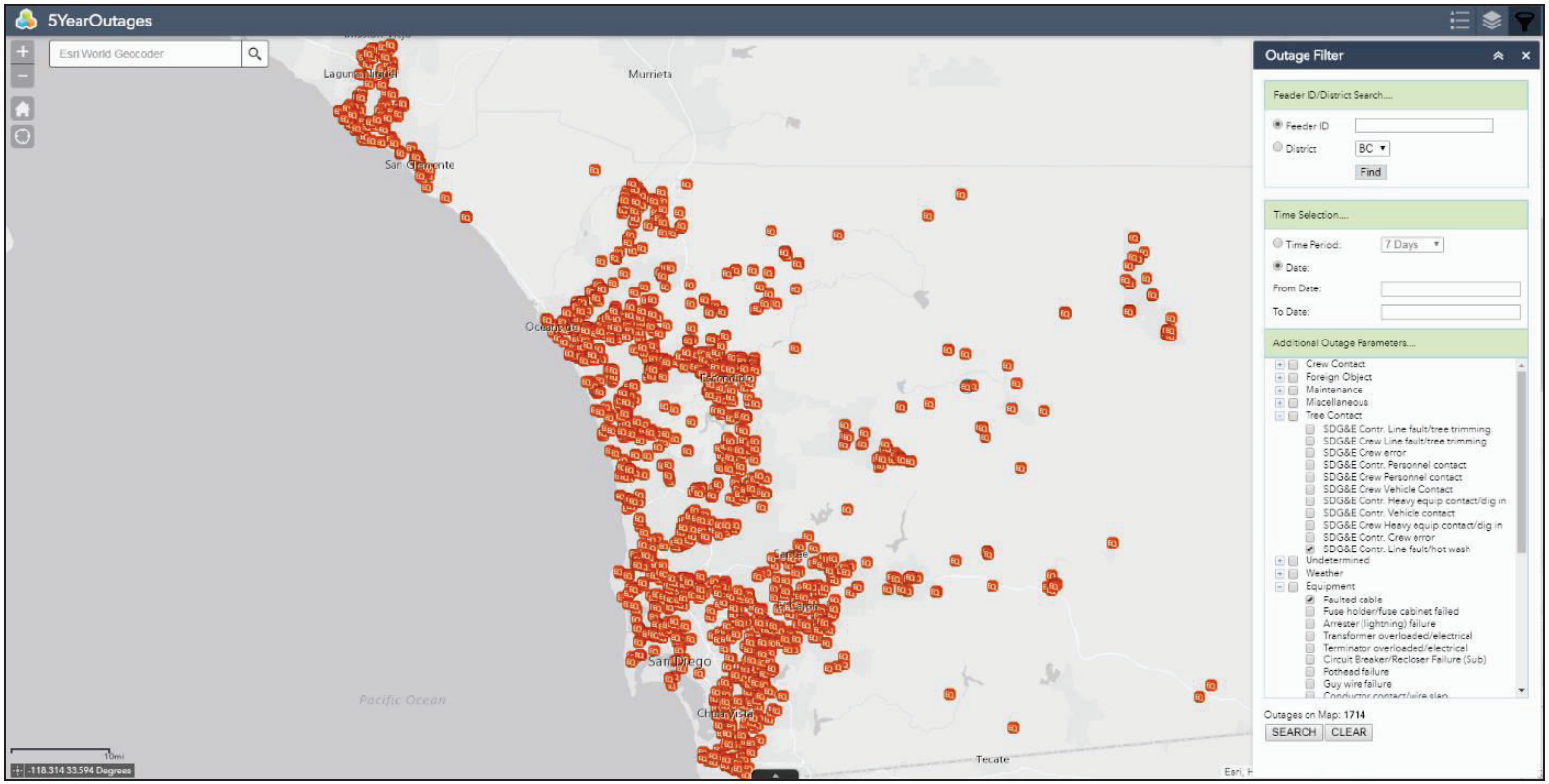


Figure 2-45. Outages Due to Two Cause Types

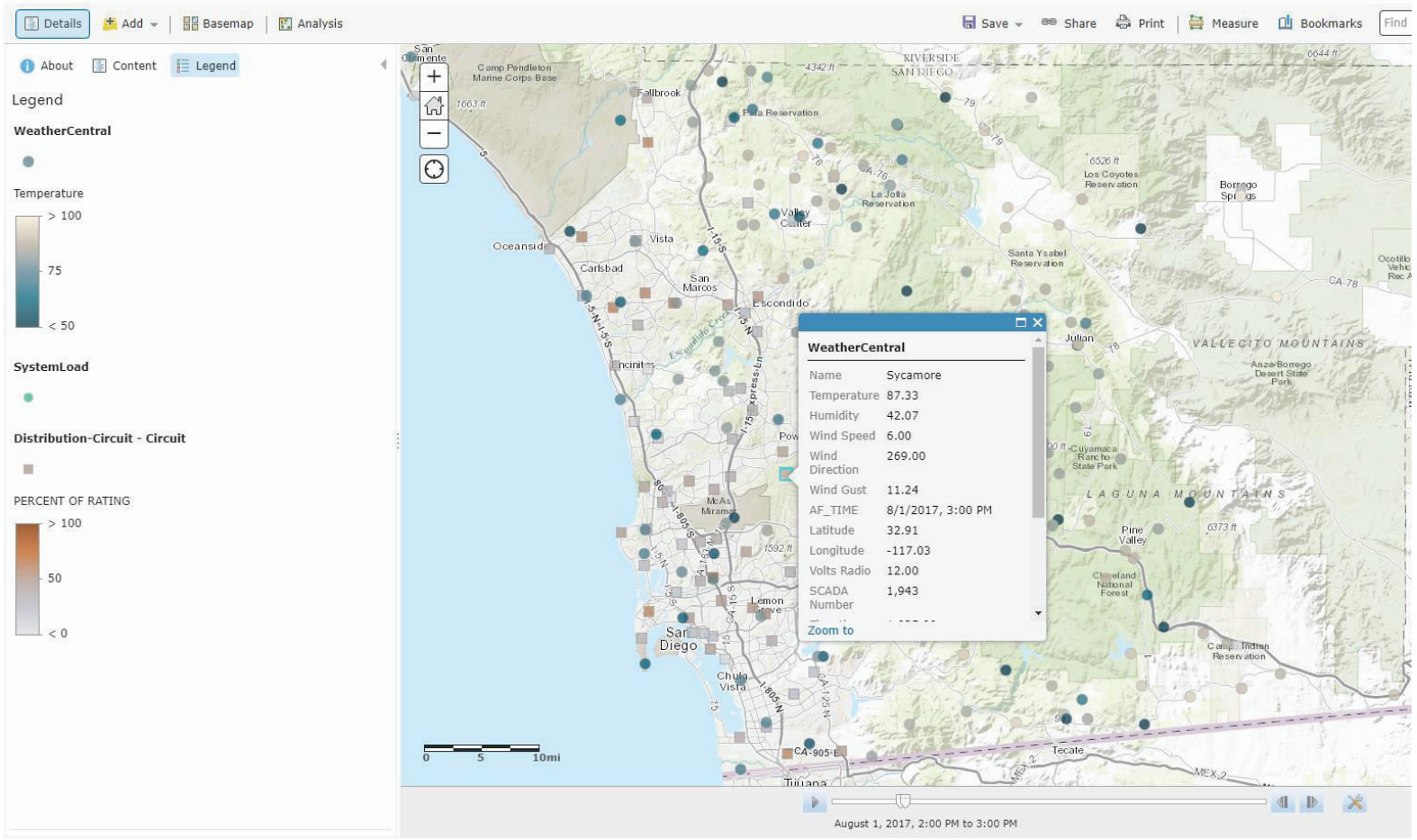


Figure 2-46. Map with Temperature and Circuit Loading Features

2.4.6 Observations, Challenges and Lessons Learned

Challenges and Resolutions

- Sources of outage data were in different systems of record (for example, the current outage management system does not yet have the full 5 years of history). As a result, the collection, transformation, and validation of the transformed outage data required significant effort on the part of SDG&E staff. Also, before this project, outage data was not geographically enabled. As part of this use case process, all relevant outage data for the rolling 5-year history is brought into one place, is geo enabled, and is made current on a daily basis.
- One of the challenges was identifying the appropriate data owners.
- The design of custom widgets required careful analysis and development, as the goal was to make general components that can be reused; the need for generality added to the challenge.

Recommendations

- The most important starting point is to collect and formulate solid user requirements
- There is a need to continuously communicate with various stakeholders and data owners, to affirm requirements and share results
- Continue developing widgets to serve the evolving needs of end customers.

2.5 AMI for Operations (UC #5)

2.5.1 Background

A widespread availability of AMI data provides an opportunity to get a clearer real-time picture of the voltage situation across the SDG&E network. The purpose of Use Case #5 is to overlay the AMI and SCADA voltage data onto a GIS map containing the electrical circuit topology and to create a heat map that shows the voltage swell and swag data. This visualization capability is expected to assist during emergency operations under various scenarios, such as the following:

- Storm
- Red Flags (e.g., Wind – Santa Ana)
- Earthquake
- Wildfire

After the fact, the historical playback capability should allow analysis of voltage behavior during different situations and, thus, provide a valuable insight about the need for system upgrades.

2.5.2 Objective

The objective of this task was to overlay the AMI and SCADA voltage data onto a GIS map with circuit topology and create a heat map that shows the voltage swell and swag data on the GIS map.

2.5.3 Users

- Electric T&D Engineering

- Electric Distribution Planning
- Electric Distribution Operation

2.5.4 Solution Approach, Solution Components, and Work Flow

Solution components:

- Smart Meter PI
- DMZ PI
- Power BI
- PI Event Frame: detect voltage changes that constitute an event (e.g., voltage above 1.05%)
- ArcGIS picks up 10 years' worth of the events captured by PI Event frame
- Esri Webapp application builder to integrate Power BI widgets and other customizations for GIS Portal
- GIS Portal

An ability to show the substation SCADA data and the field devices' power quality data as map layers is created by the PI Integrator for Esri ArcGIS, and custom components indicated in green in Figure 2-47.

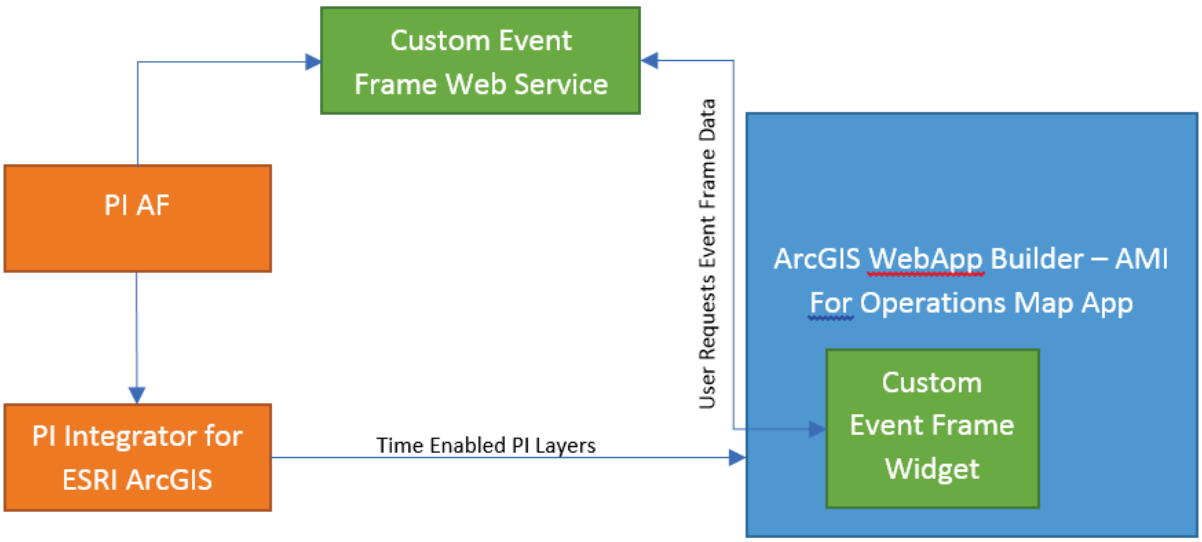


Figure 2-47. AMI for Operations Data Flow Diagram

2.5.5 Results

2.5.5.1 Features

- Voltage for primary distribution circuits with visual indicator % of nominal voltage and Visualization display for additional parameters available in Historian (PF, THD, voltage & load unbalance, etc.).

- Trending granular distribution circuit voltage analysis based on AMI data with the intent to identify possible future problem areas.
- Visualizations for other Intelligent Electronic Device (IED) data beyond typical SCADA such as microprocessor controlled circuit breakers, relays, transformers, regulators, and capacitors. The System Protection and Control group can provide detail.
- Visualizations for emergency operations various scenarios:
- Storm, Red Flag (Wind – Santa Ana), Earthquake, Wildfire

2.5.5.2 Representative Results

Figure 2-48 through Figure 2-51 illustrate (self-explanatory) custom widgets for configuring various display attributes for this use case.

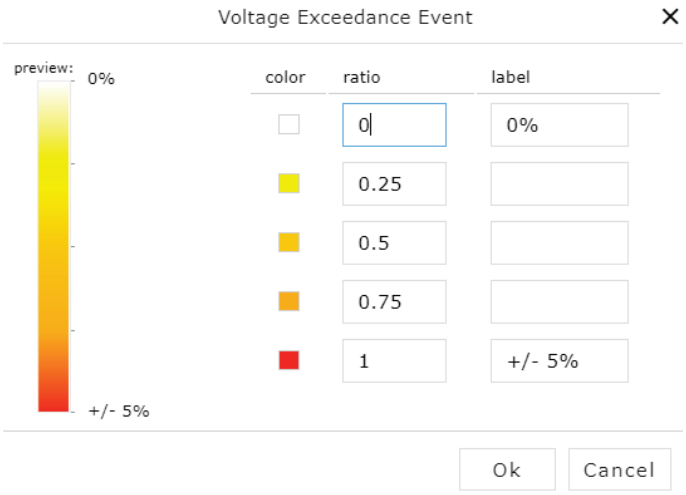


Figure 2-48. Custom Widget: Customizable Heat Map Colors

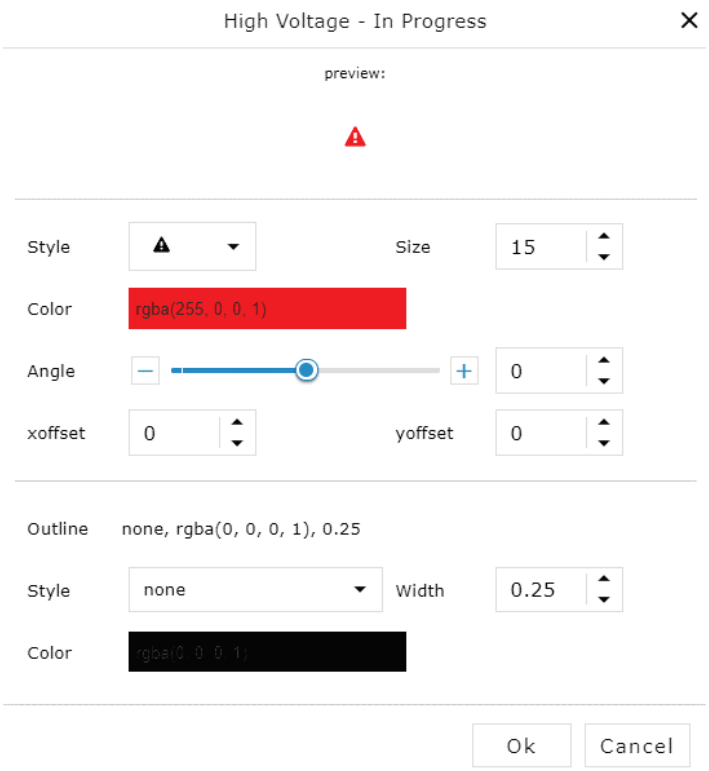


Figure 2-49. Custom Widget: Customizable Symbols

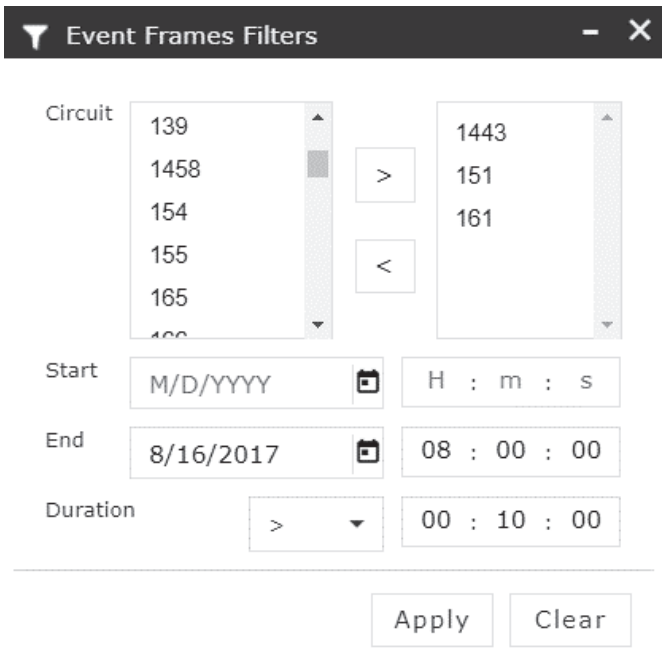


Figure 2-50. Custom Widget: Selecting Facilities of Interest

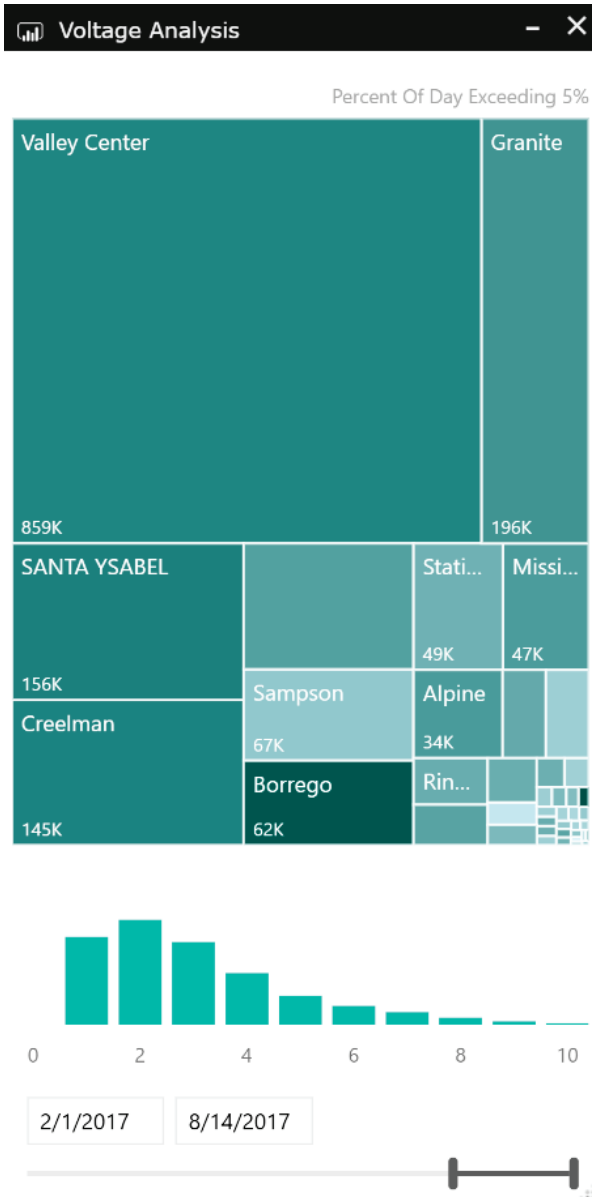


Figure 2-51.Power BI Display of Voltage Exceedance Events (tile size proportional to # of events)

The histogram at the bottom is the distribution of metering errors over the time horizon indicated in the timeline at the bottom of figure (from 2/1/2017 to 8/14/2017).

Selecting any of the boxes is akin to zooming in. For example, by “clicking” on Valley Center, the display will update to show the counts on meters within that station only, and the histogram will also update to show exceedance by all meters in the Valley Center substation.

By a further zoom-in action, one can get to a breaker of interest shown in the left-hand side of Figure 2-52; details on the number of exceedances as shown by tile size on the right; the histogram of metered deviations below the tiles; and the timeline bar at the very bottom.

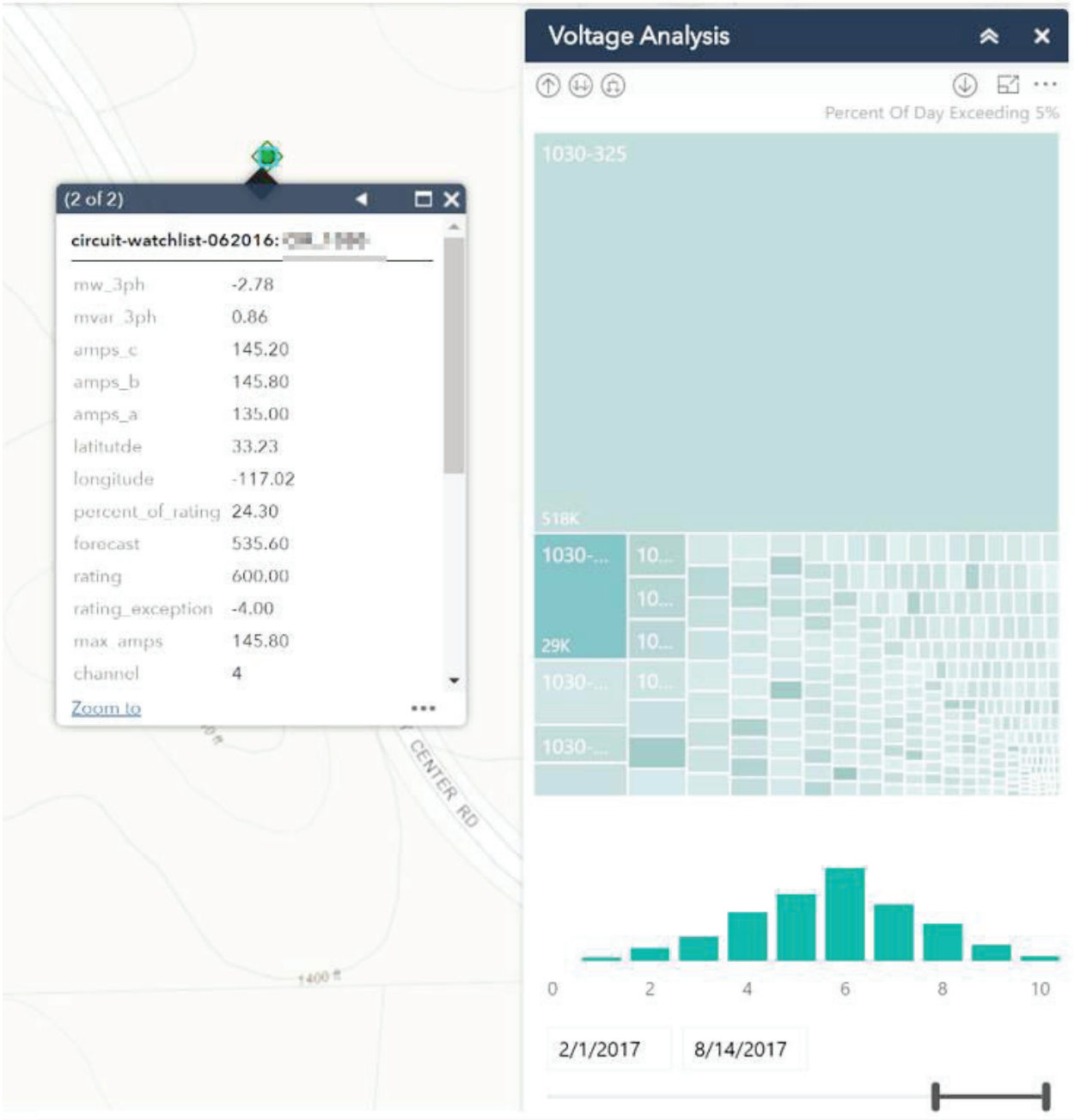


Figure 2-52. Breaker CIR_1030 Events

Figure 2-53 shows an event loader configured to retrieve and display events for a given date, and an interval relative to that date specified by the values in the “From” and “To” fields. The asterisk (*) in the date field means current time; solid icon colors mean the event is still in effect at the end of the selected interval; hollow icons mean the event occurred and completed prior to the end of the specified interval.

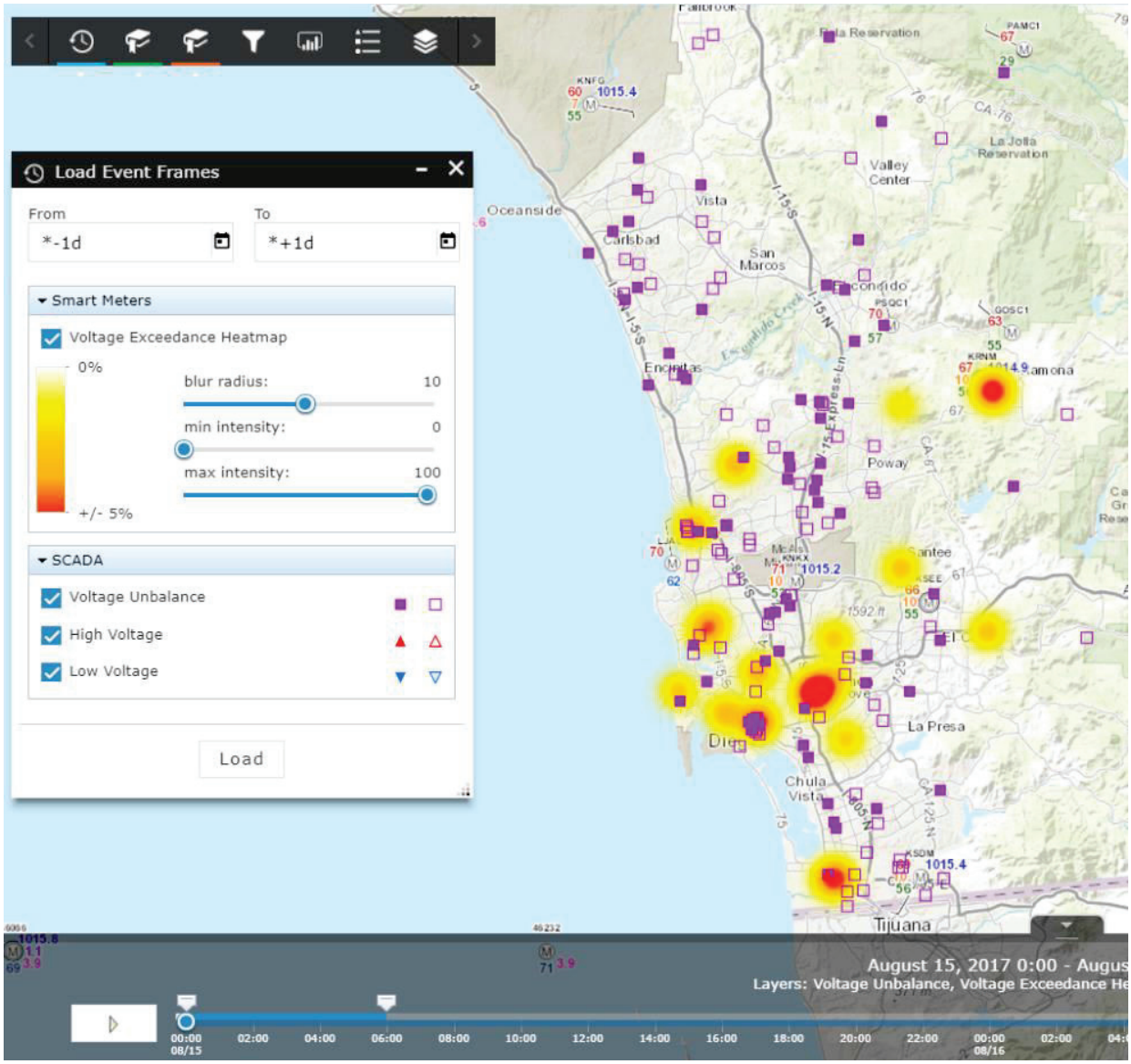


Figure 2-53. Custom Widget: Dynamic Heat Map of Voltage Exceedances over a Specified Time Interval

By “clicking” on an event, one gets additional details. For example, Figure 2-54 shows a, b, and c phase currents from SCADA at the event time. This illustrates a still ongoing event; hence, the square is filled with color, and End date/time is not filled in.

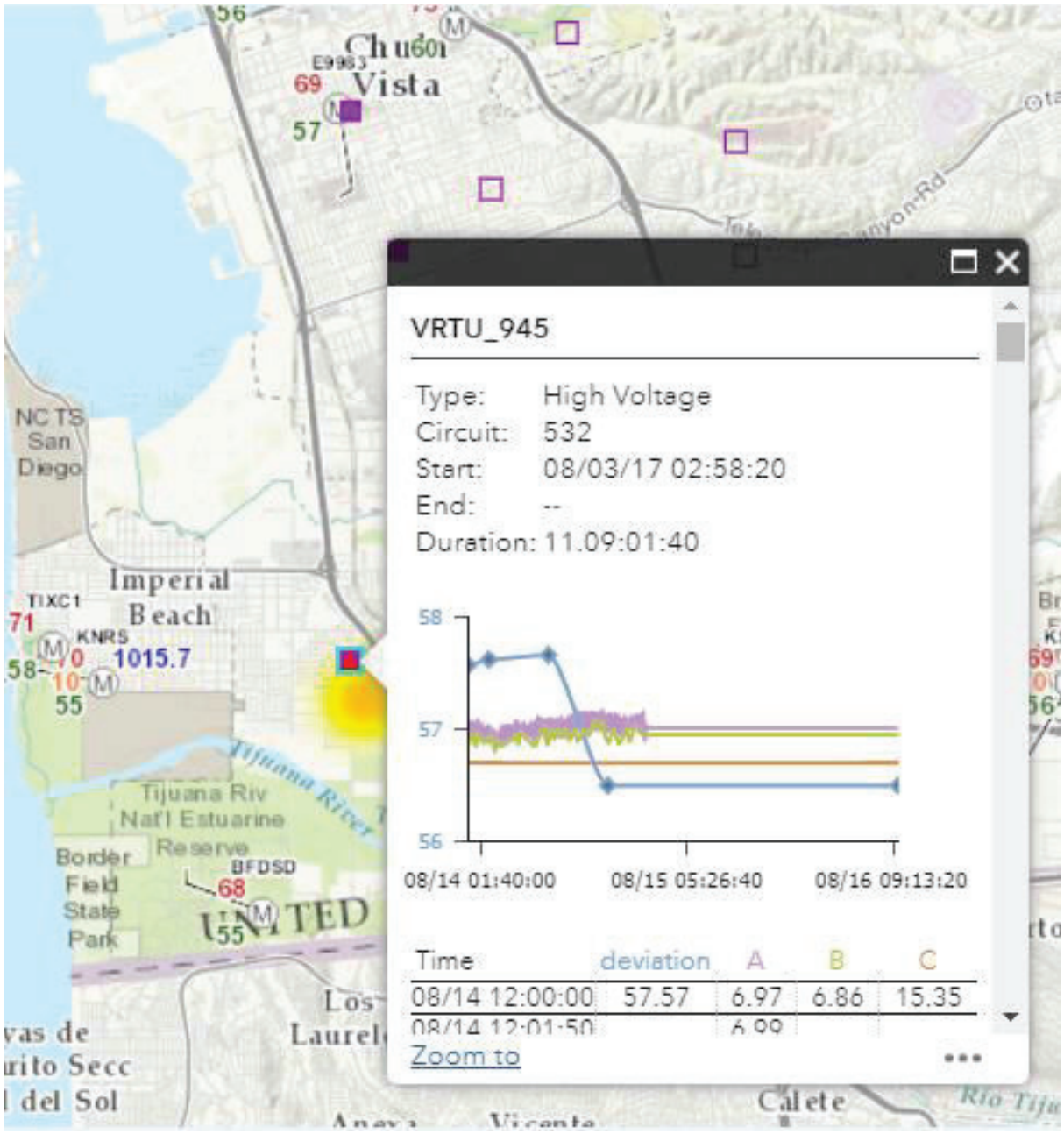


Figure 2-54. Event Detail: Voltage Chart

Figure 2-55 is a Power BI custom widget in conjunction with a geospatial display, showing tabular details of the events configured according to Figure 2-53. Due to the integration of Power BI with geospatial visualization, by selecting any element in the table, the corresponding element on the map is identified.

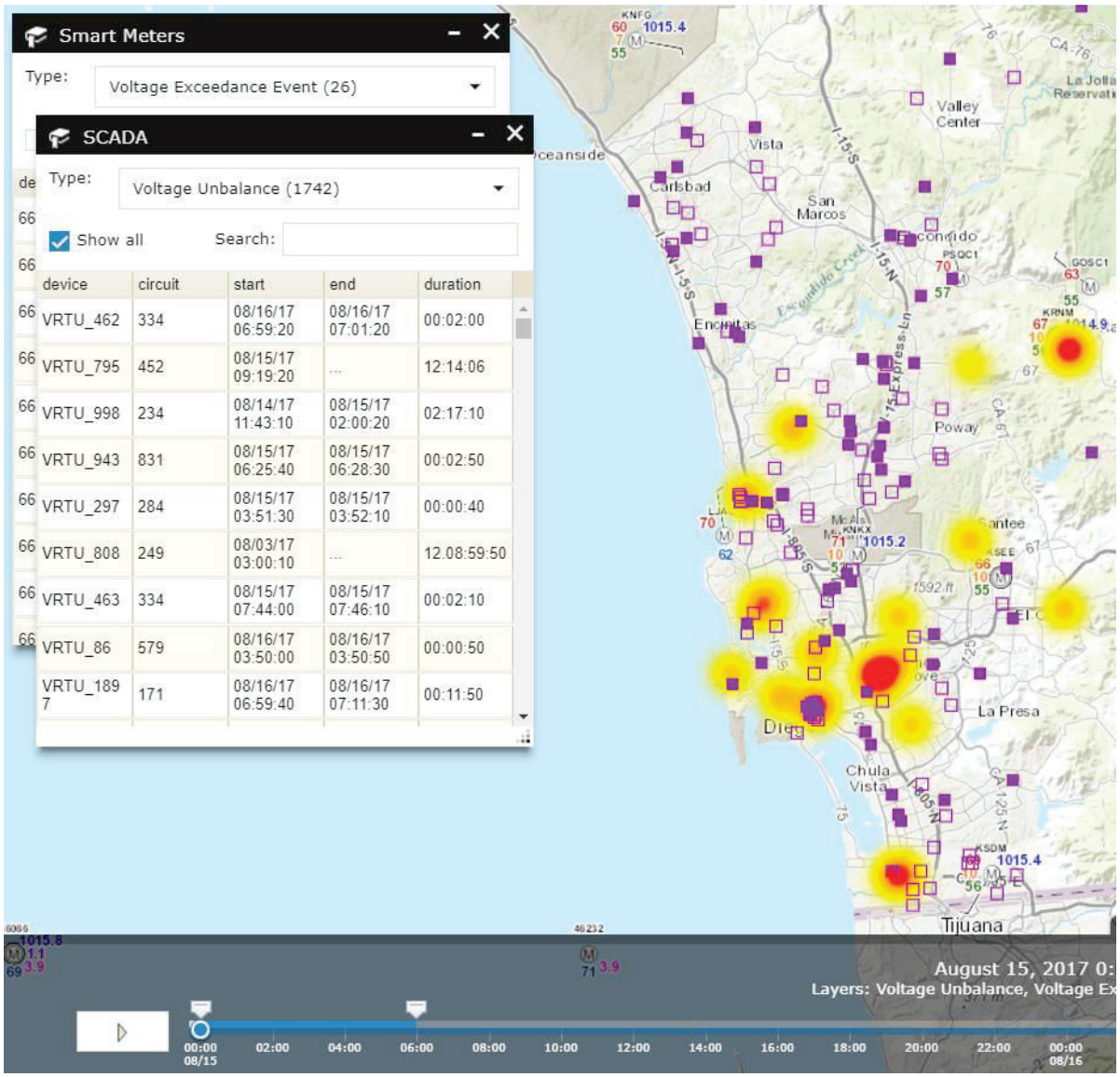


Figure 2-55. Custom Widget: Power BI Showing Voltage Exceedance

2.5.6 Observations, Challenges and Lessons Learned

Challenges and Resolutions

- Coming up with a solution to integrate Power BI and ArcGIS, with the solution that is configurable so it can be reused. The task has been successfully solved with a custom program.
- Customizing Power BI widgets.
- Esri has a component for integrating Power BI with Esri maps, but that solution requires Power BI to also be on premises. In this case, Power BI was a cloud based solution, and hence, SDG&E needed to develop an alternative solution for integrating Power BI widgets within Esri maps.

- An early user's feedback indicated a need for customizable widgets, such as different symbols for the items that can be displayed on maps. As a result, the team developed a customizable widget for configuring symbols by the end user.
- Authenticating users with MS OAUTH (used by Power BI users) was a challenge: Power BI is a cloud-based application, the rest of the needed applications are on premises. The challenge was to implement a single sign-on in this hybrid environment due to a lack of templates (for accomplishing this task) and due to terse documentation. After a good deal of trial and error, the hurdle was overcome.

Recommendations

- It is suggested to design custom widgets to be as generic as possible. In this project, that approach has proven to be very helpful, and it is expected that it will continue to be helpful in future projects.
- Applications should be designed to be customizable by end-users, which helps with usability, and ultimately, with adoption of the function.

2.6 Customer-Owned DER Visualization (UC #6)

2.6.1 Background

Given the significant installed capacity of DERs, it is becoming important to be able to incorporate into GIS maps a representation of customer-owned energy resources' name-plate data, with an ability to group by transformer, circuit, and substation. Specifically, the desired features are:

- Visualizing customer-generated load via the transformers to the circuits in ArcGIS portal.
- Real time visualization of DER (generators and storage) data for dispatch (30 kW or more).

2.6.2 Objective

The objectives of Use Case #6 were to incorporate a representation of customer-owned Energy Resources' nameplate data by transformer, circuit, and substation data presentments.

2.6.3 Users

- T&D Engineering
- Electric System Planning and Grid Modernization
- Electric Distribution Operation
- DER (part of Growth and Technology Integration)

2.6.4 Solution Approach, Solution Components, and Work Flow

Solution components:

- DIIS: system of record for registration data of DER devices
- Esri Web AppBuilder: Esri custom application to retrieve data from DIIS and develop custom geo-features
- GIS Portal

For this use case, a layer displaying all customer generation systems was created with many attributes, including nameplate rating. The layer is symbolized with circles, with their size representing nameplate ratings (see Figure 2-56).

Also, an advanced energy storage dashboard is created as part of this use case (Figure 2-57). This dashboard contains pricing data for different large battery storage systems along with relevant CAISO locational marginal pricing data.

The top half of the dashboard shows the two battery systems EC and ES that can be selected to view individually. It shows instantanious MW data, along with a Discharge + Charge trend. The discharge and charge trend begin at zero for the start of the time period selected and increase from there. That way, one can easilly see total charge and discharge values for any point in the selected time range without doing any additional calculations.

The lower half of the dashboard contains pricing data. CAISO_LMP shows the current price per MWh in the real-time market. Revenue shows revenue from the batteries discharging based on CAISO_LMP, and Cost shows cost from the batteries charging based on LMP. Calculations are done per battery system based on their respective CAISO PNode pricing data. The Net trend shows net for the period (Revenue minus Cost). The very bottom of the display has the time range selector to adjust the period the dashboard is displaying.

There is also an Advanced Energy Storage dashboard created for this use case (see Figure 2-58). This Power BI dashboard contains pricing data for different large battery storage systems along with relevant CAISO pricing data. The architecture for the display is shown in Figure 2-59.

The top half of the dashboard shows the two battery systems EC and ES that can be selected to view individually. It shows instantanious MW data, along with a Discharge + Charge trend. The discharge and charge trend begin at zero for the start of the time period selected and increase from there. That way, one can easilly see total charge and discharge values for any point in the selected time range without doing any additional calculations.

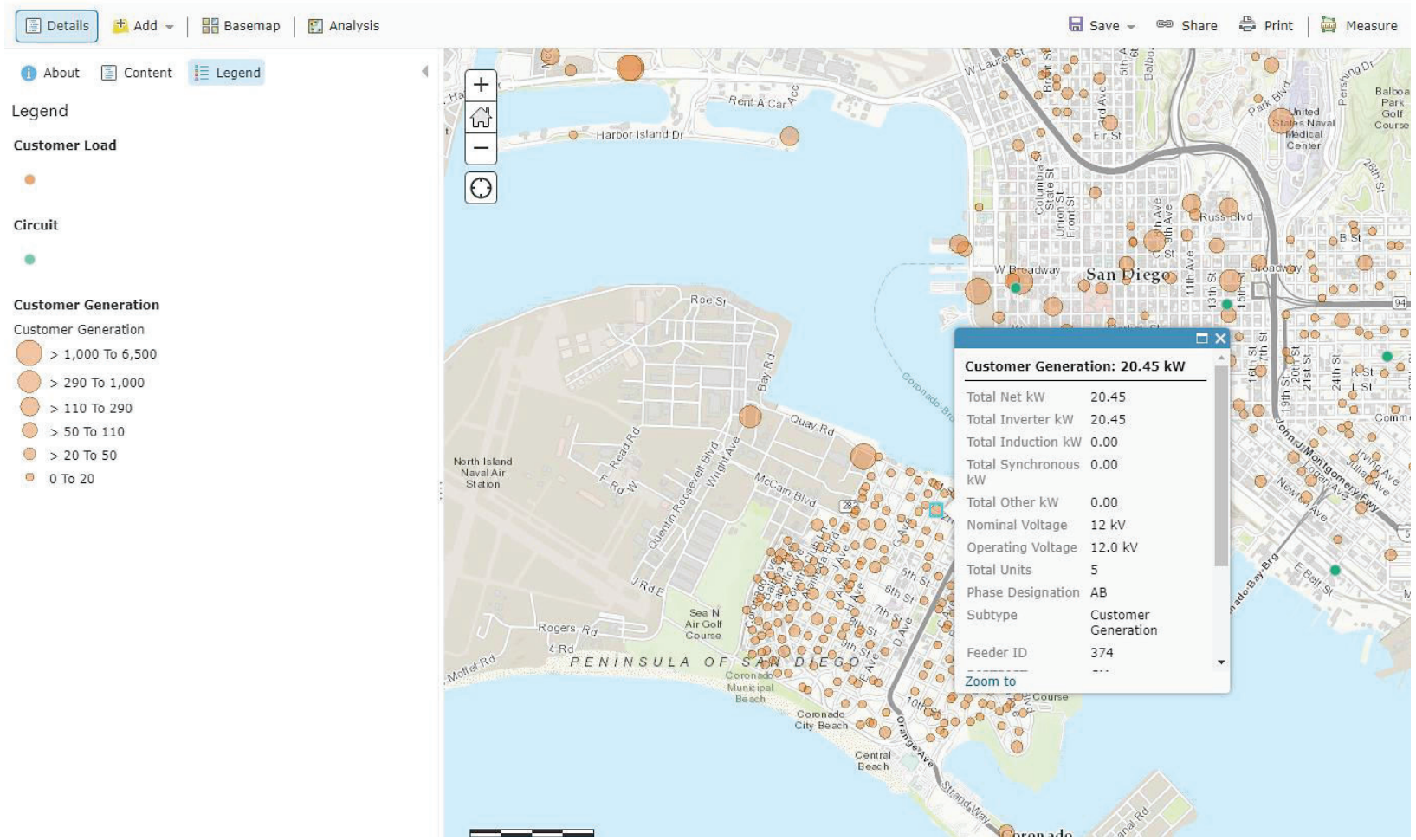


Figure 2-56. Customer Generation Location and Size

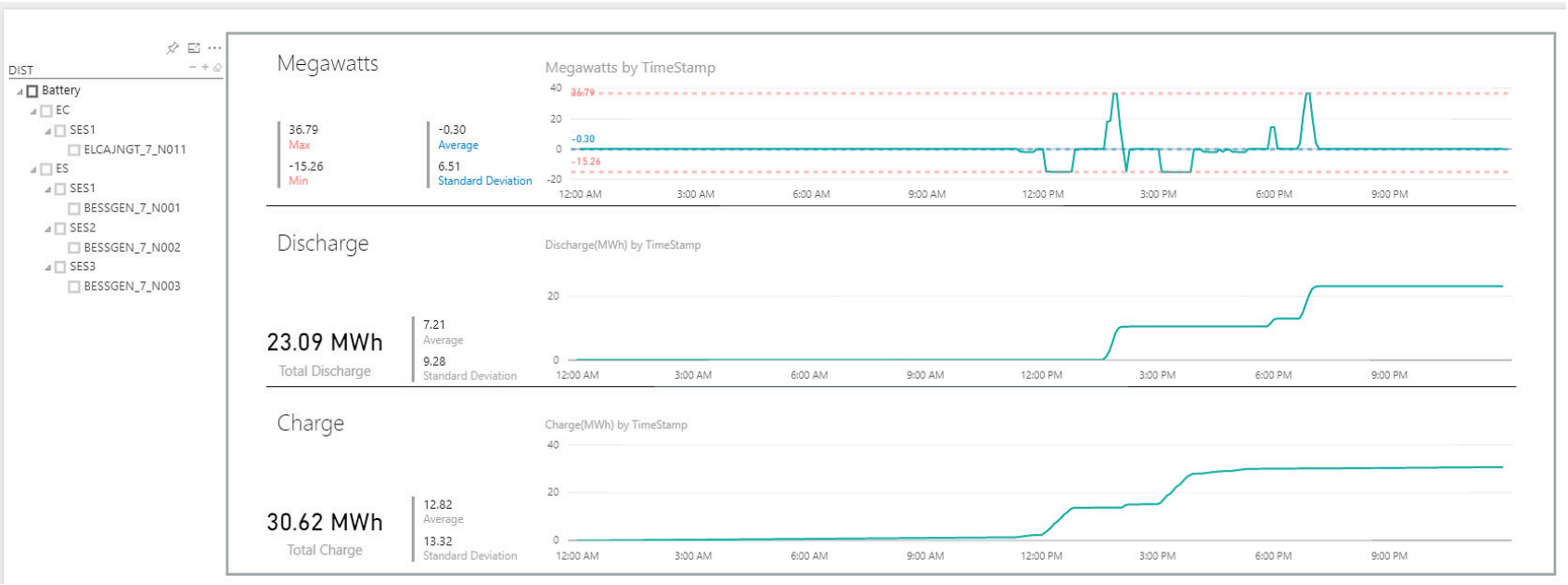


Figure 2-57. Battery Charge and Discharge Charts

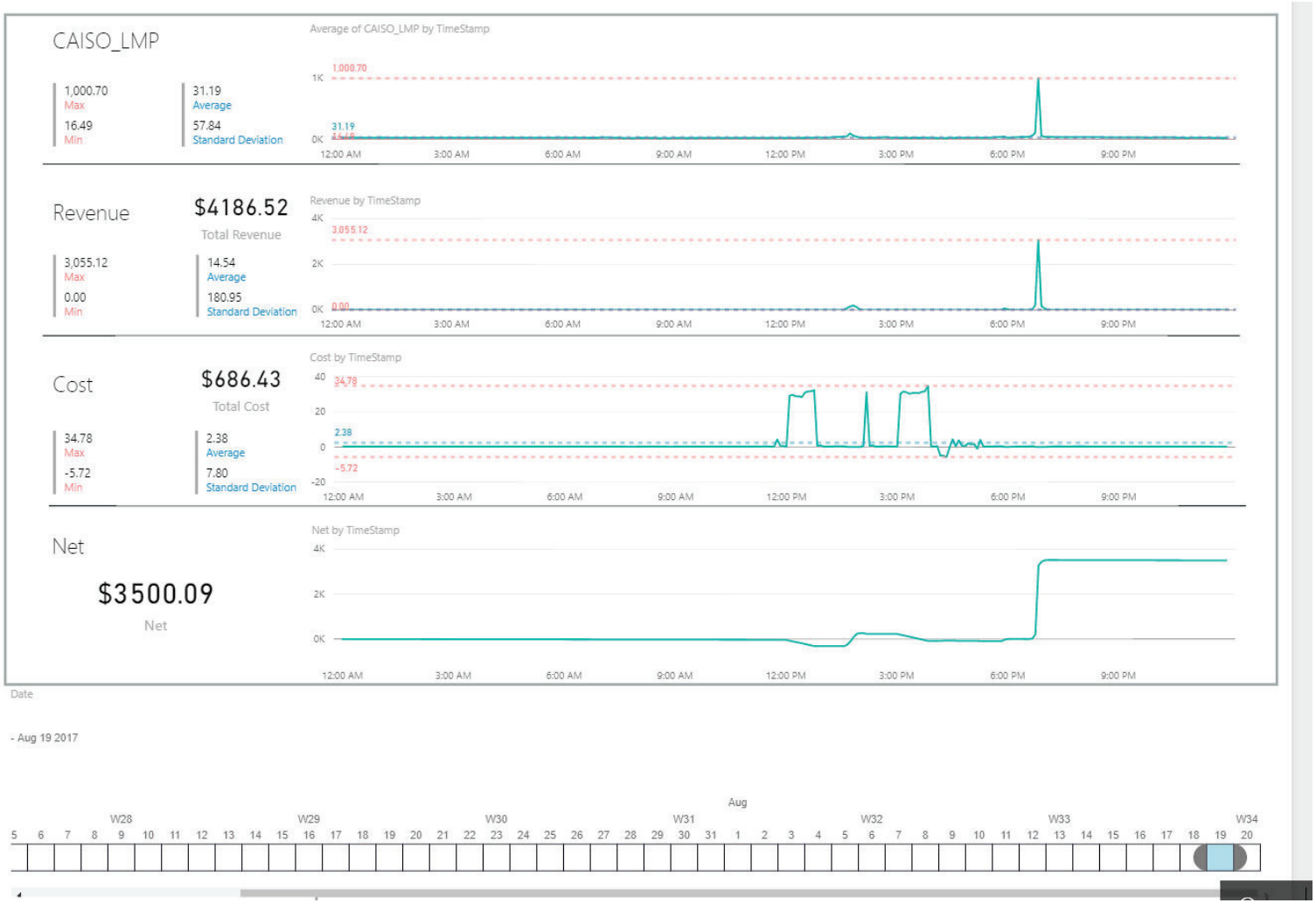


Figure 2-58. CAISO LMP, Battery Revenue and Cost

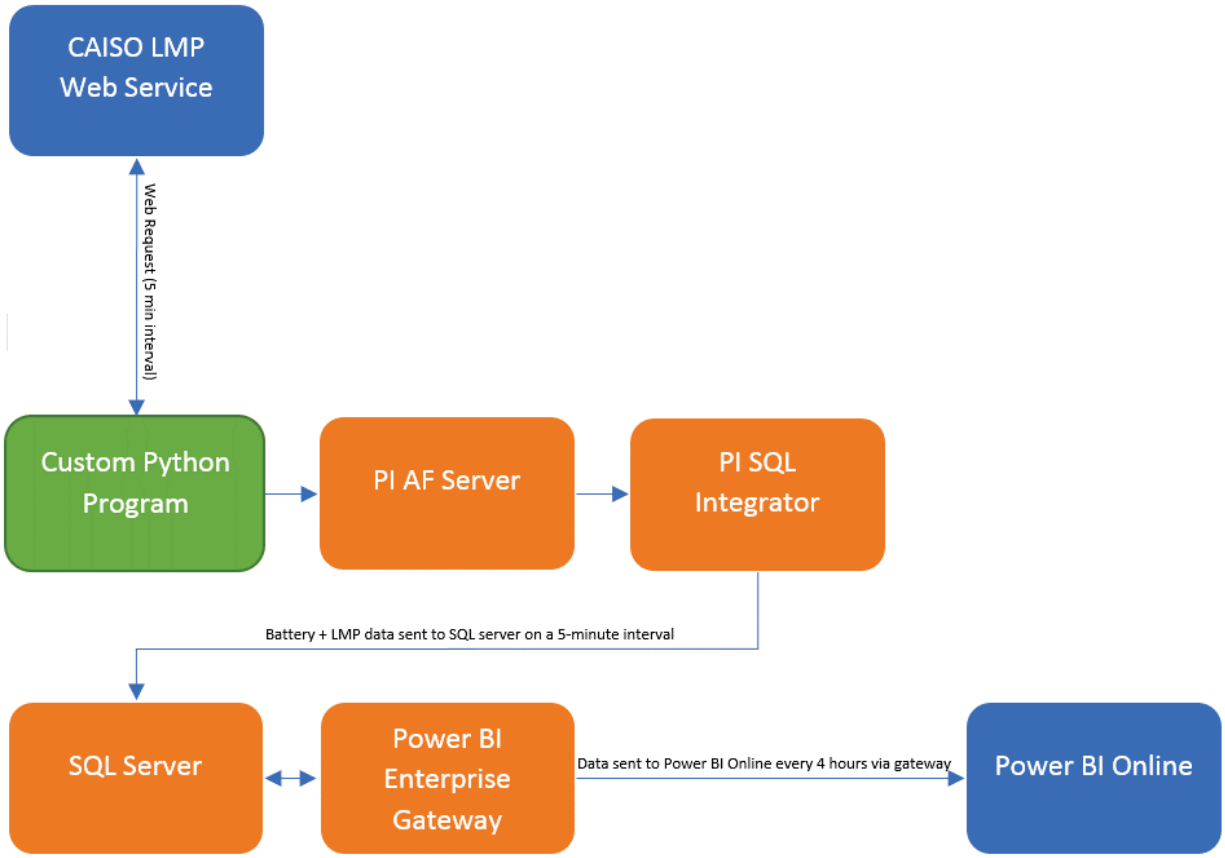


Figure 2-59. UC 6 Data Flow Diagram

2.6.5 Results

Major results of this use case are standardization of battery models in PI, real time visualizatin of DER (geenerators and storage) data for dispatch (30 MW or more), and geospatial presentation of customer generation based on the nameplate data (e.g., household or industrial PVs).

2.6.6 Observations, Challenges, and Lessons Learned

Challenges and Resolutions

- For operations, actual PV output is important, whereas the registration system used as the source of the production data for DER visualization records only nameplate data. SDG&E is still evaluating options for converting nameplate data to operational data. Some of those thoughts are listed in the Recommendation section.
- For batteries, a challenge was combining within SDG&E the PI battery model and operational data with CAISO pricing data. This required the development of an interface to retrieve the CAISO data and an application to store this data within PI (see Figure 2-59).

- Battery systems are from different vendors with different data models and different naming conventions (i.e., there are no standards for modeling batteries). This resulted in the SDG&E team having to spend quite a bit of time to analyze and develop an SDG&E standard model for representing batteries in order to accommodate all the different battery manufacturers.
- Design and development of the battery dashboard (selection of items to display).

Recommendations

- Ideas for converting PV nameplate data to actual real time output: use an existing, nearby solar plant for which there is real time data, and apply the same scaling factor between the nameplate capacity and the actual output to rooftop PV outputs in the vicinity of the PV plant. Also, consider use of models that produce kW output for given solar conditions.
- For batteries, it would be ideal to have a dashboard similar to the one currently used with real time prices to display Day-ahead market prices

2.7 Imagery Management (UC #7)

2.7.1 Background

An anticipated increase in the amount and variety of data from drones, imagery, video, and 3D sources necessitates a comprehensive image data management strategy. This use case aims to explore and demonstrate technologies for integration and management of LiDAR, imagery, and 3D data, with the goal to learn how to manage multidimensional data information efficiently, and how to use previously collected drone data with existing GIS data to improve data quality.

More specifically, the aim is to be able to see the data sources visually, in a geographic context, as opposed to searching for the data via file and folder names. This should save time and effort in organizing huge amounts of data. Additionally, the aim is to provide historic references for source data to help understand the data acquisition patterns. The specific objectives to support these aims are presented in the next section.

2.7.2 Objective

The objective of Use Case #7 was to prepare an image catalog to search and find data through a user-provided area extent on a geographical map. A custom search should also be supported to allow for a search through the data catalog using date/time, pole, tieline, circuit, or facility ID.

2.7.3 Users

- Construction Services
- Electric Transmission and Distribution Engineering
- Substation and Corporate Security

2.7.4 Solution Approach, Solution Components, and Work Flow

2.7.4.1 Solution Components

The following components were used to implement the use case:

- Esri Web AppBuilder 2.5: the application builder is used to deploy the 'Image Discovery' widget[5]
- ArcPro and ArcGIS
- Esri ArcGIS portal 10.5.1

2.7.4.2 Data Formats Used for this Project

- LiDAR
- Oblique imagery (JPEG, GeoTIFF, ECW, JP2)
- Video files from UAV

2.7.4.3 Work Flow

1. Data is organized on a NAS folder.
   a. Collected from different departments, through FTP site or folders on a server.
   b. The data is cleaned to reflect only imagery formats and associated metadata (e.g., PDF files with accuracy report, weather data excel files, circuit diagrams, or any QA/QA reports for the data).
   c. The data is organized by circuits, tielines, type of data, and year obtained.
2. Each type of data is ingested into ArcGIS or ArcPro in different workflows.
3. Publish datasets to portal as mosaic dataset to accommodate the search.
4. Application is created using the Web AppBuilder 2.5 and the Image Discovery widget to find the data in an area extent or an area specified. The Image Discovery widget with the area extent selection icon circled can be seen later in Figure 2-62.

A similar tool called GOSI was developed at PG&E. GOSI uses PG&E Operational Mesoscale Modeling System, or POMMS, which has similar aims, but goes deeper than the scope of this project could accommodate. Furthermore, SDG&E leveraged the available Esri products, which were covered by the existing SDG&E licenses.

2.7.5 Results

Examples of different representations of datasets are shown in Figure 2-60 (data by LiDAR extent) and Figure 2-61 (LiDAR data in 3D). The user starts image discovery by selecting an area of interest. In Figure 2-62, the circled icon designates the user is choosing an area extent method, after which the user can place on a map a rectangle of a desired size at a desired location.

When a user specifies an area of interest (via a rectangle in this example), the image data files available for the selected area are listed on the right-side pane of Figure 2-63.

[5] Esri custom widget, developed through an open source process, and copyrighted to Esri.

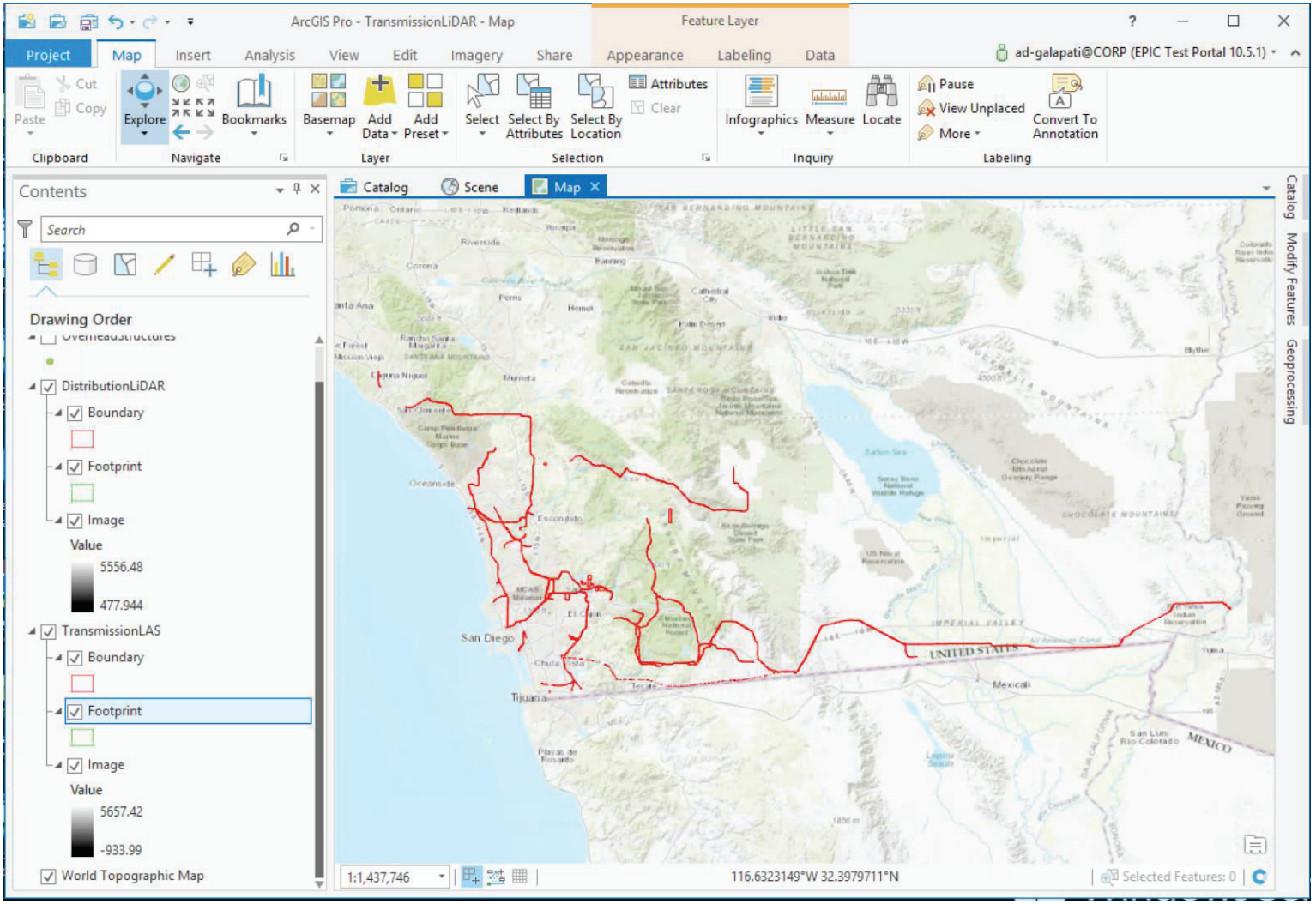


Figure 2-60. LiDAR Data Extent (red lines are boundaries of LiDAR extent)

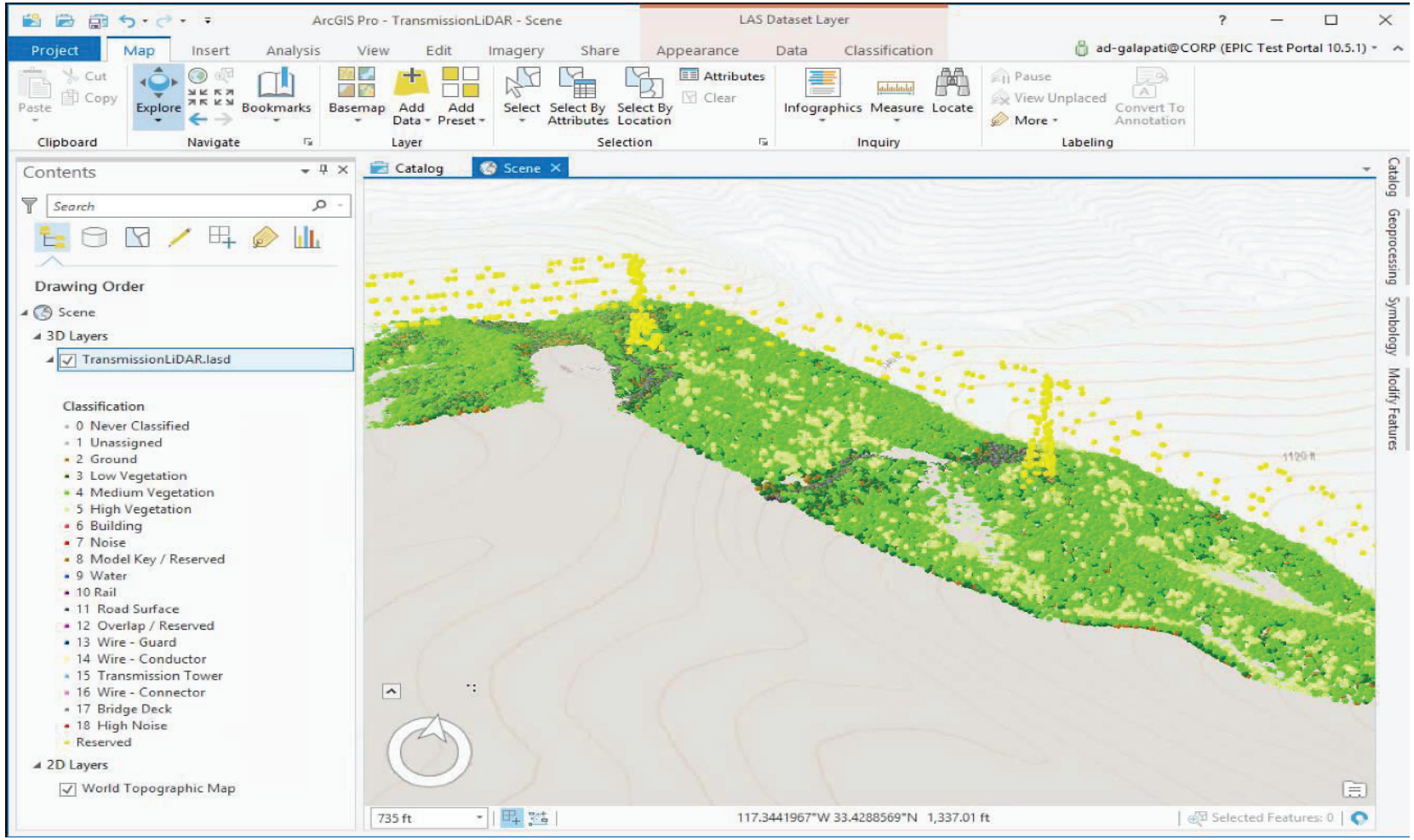


Figure 2-61. LiDAR Data in 3D in ArcPro

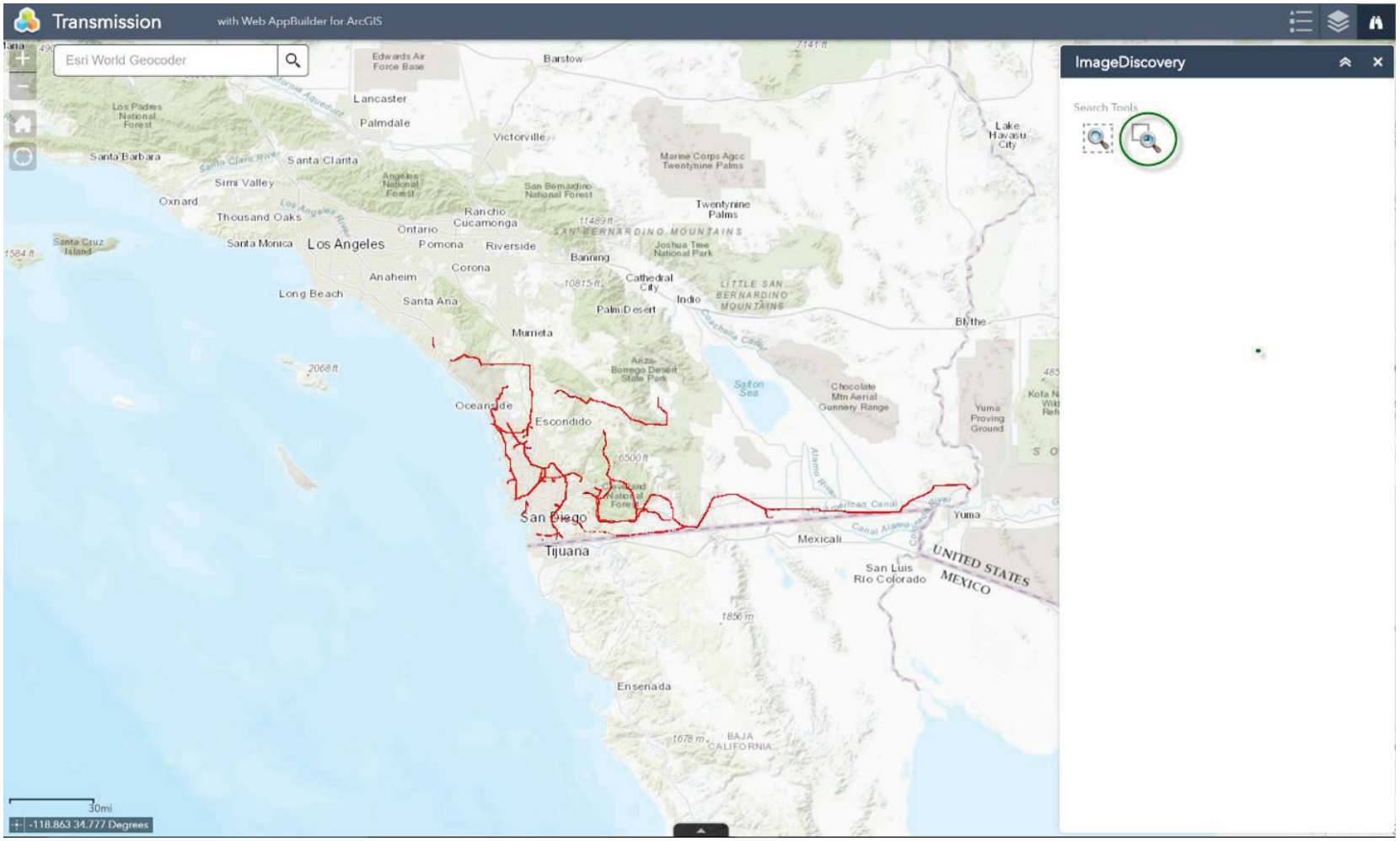


Figure 2-62. Search Tool with Search by Area Extent Circled

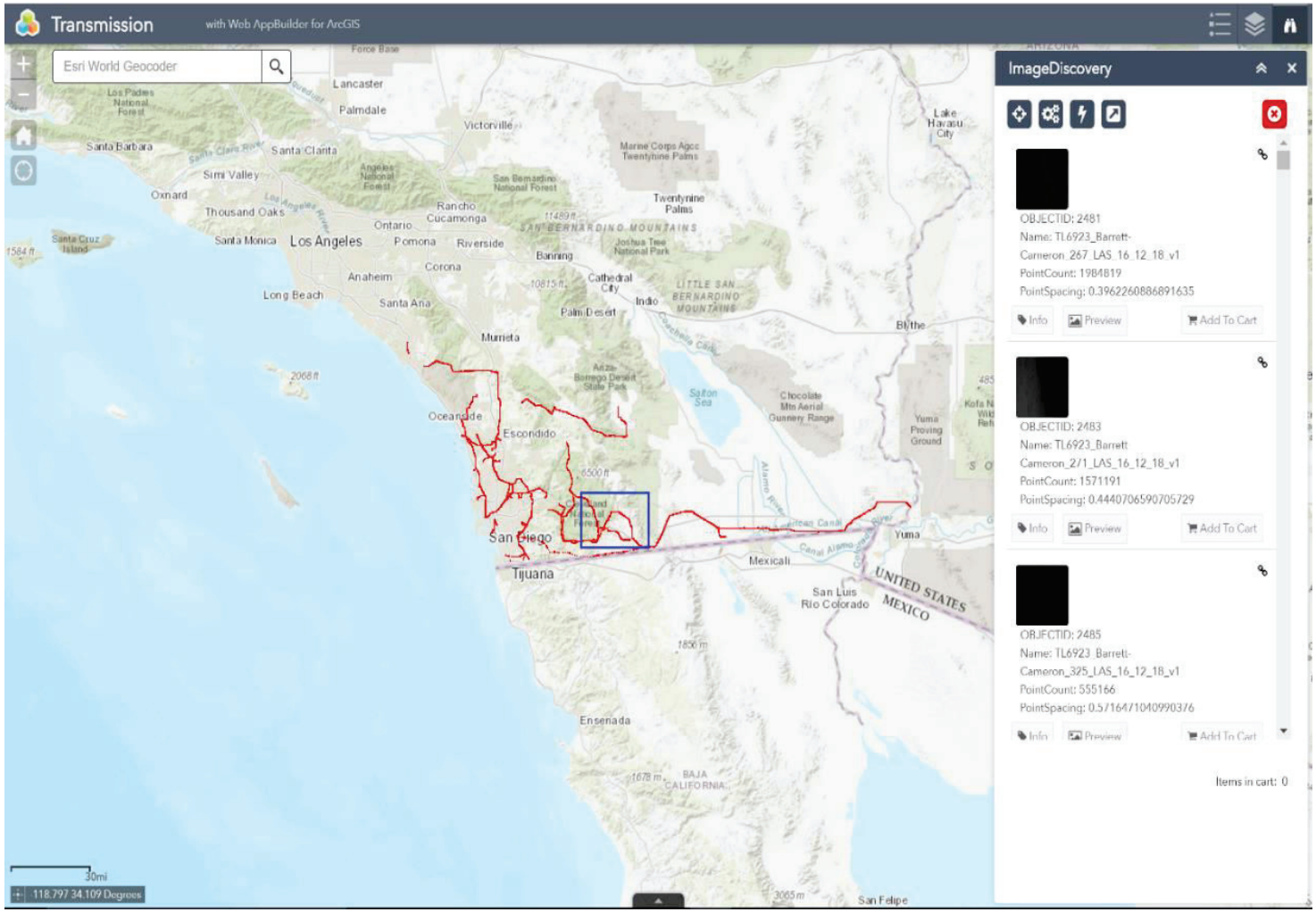


Figure 2-63. Selection of Image Files Based on Area of Interest

From here, the user can preview and download a file of interest by clicking on the file icon of interest.

In addition, the capability to search by Facility, Tieline, or Circuit ID, as well as filter output on specific dates or date ranges, is also provided, all with a look and feel similar to the other query forms.

2.7.6 Observations, Challenges, and Lessons Learned

Challenges and Resolutions

- Multiple vendors (five) work with different SDG&E departments and use about 20 different image data types. Metadata for images is not standard for all the vendors (or across departments). Development of a way to visualize through a consistent interface is a challenge
- Data cleanup is necessary to use the data in a GIS workflow. This is a laborious process. Also, the archived data obtained from different vendors often does not have labels or any references between the Image and the Transmission data. Where missing, this type of data needs to be constructed to achieve better performance, which, again, is a laborious process.
- Obtaining data access and finding the right data owners and data took significant time. Processing the imagery datasets requires dedicated hours for the task, anywhere from 5 to 12 hours, depending on the size of data. If the datasets are not processed properly, the downloads cannot be accomplished.

2.7.6.1 Current Limitations for Data Access

- Looking for new image data in source folders takes significant amount of time.
- Permissions to add all users to secured data locations does involve potential risks

2.7.6.2 Solved Issues

- Having data on a common NAS drive and accessing it through a website application mitigates the risks associated with granting permissions for access. In this case, the portal website is the only place to track access and downloads.
- Although the data is in a common NAS folder, different applications can be spawned to use the same data according to the specific requirements, which simplifies the task of managing what application can be shared with which user groups. For example, it is possible to have Distribution data and Transmission data accessible via two different applications; similarly, it is possible to have LiDAR and TIFF data in one application, and JPG and imagery in another application. By managing which applications are being shared by what users, one manages the permissions for data access.
- PDF, CSV, Excel, and all metadata supporting the imagery can be attached and viewed as attachments to the GIS features that serve as reference for Images.
- The application does not allow anyone to access bulk amounts of data; a user can only download a few files at a time depending on the size of data. The application limits the download size of data. The limit can be varied when needed.

2.7.6.3 Future Work

- Add more data and data types within the set supported by Esri
- Maintenance of applications and development enhancements as required by the users

Recommendations

- Identify the right data owners
- Develop an SDG&E standard for image metadata

2.8 GIS Visualization Infrastructure Modernization (UC #8)

2.8.1 Background

The GIS technologies currently implemented for visualizing assets and electrical connectivity as 2D circuit maps and schematics are over 10 years old. Over the same time span, the visualization infrastructure used at SDG&E has seen only incremental improvements through patches and upgrades, with no major changes in the core software stack and data components. Furthermore, the underlying electrical circuits connectivity models and the corresponding data currently supporting various SDG&E visualization needs are physically separated by domains such as transmission, distribution, structural, telecom, and others; in addition, the models have a limitation on the amount of asset details they can capture.

Meanwhile, and especially over the last several years, the GIS-specific technologies, but also broader technologies with a potential to impact GIS visualization, have seen significant transformation. The most notable of these changes are:

- More expressive utility network modeling capabilities that allow for a more comprehensive details capture, as well as more powerful and functional engines that process these models
- Hardware virtualization
- GPU processing
- Software component interfaces via Web Service architecture
- Web browser functionality for viewing, editing, and tracing electric networks
- 3D maps that can support augmented and mixed reality consumption
- Real-time data from drones, Internet of Things (IoT), and smart devices
- Open source technologies
- Machine learning

It is inevitable that at least some of these advancements will find a way to improve GIS visualization capabilities in the industry at large, and at SDG&E in particular. With a view toward inevitability of improvements in the SDG&E GIS capabilities through accommodations of more advanced GIS and GIS-related technologies, SDG&E envisions a need to research and identify those modernizations in the industry (including hardware, software, data model, connectivity, and databases) that can help to better support SDG&E visualization of asset maps and schematic diagrams, both in the office and in the field. The specific modernizations of interest are:

- **Hardware:** Modernize CPU with GPU processor
- **Virtualization:** Modernize Citrix with VM Ware
- **Software:** Modernize 32-bit ArcMap with 64-bit ArcGIS Pro
- **Architecture**: Modernize direct database transactions with services-based transactions

- **Data Model:** Modernize the current Electric data model with Utility Network data model
- **Data Content:** Modernize asset content by reducing abstraction from field and as-built conditions
- **Connectivity:** Modernize Geometric Network with Utility Network
- **Database:** Modernize Oracle with Postgres
- **Apps:** Modernize front-end Web technology with Node.JS-based technology

These examinations will require significant effort, spread over time. Examinations within this use case constitute a beginning of this examination effort, and have as its objective a subset of the required activities as listed in the next section.

2.8.2 Objective

The objective of Use Case #8 is to conduct an initial investigation of hardware and GPU virtualization, as well as options to modernize the front-end Web technology.

2.8.3 Users

- GBS – GIS Business Solutions
- T&D Engineering
- Electric T&D Construction

2.8.4 Solution Components, and Approach

2.8.4.1 Solution Components

- Three widgets
  - Display Manger
  - URL Navigator
  - Net Explorer
- GIS Portal

2.8.4.2 Solution Approach

As part of the EPIC technology demonstration, SDG&E used ArcGIS Pro and Esri beta Utility Network (UN) together with a Hypervisor hardware/software appliance equipped with NVIDIA GRID technology. In other words, a virtual desktop and virtual application approach was used to provision the new GIS and network utility model.

The Hypervisor is a powerful server that is used for running Virtual Machines (VM) to deliver the ArcGIS Pro application to the end users. At SDG&E, desktop GIS users use the VMware ESXi 6.0. At the Hypervisor Operating System level, the VMware ESXi is an operating system running its own kernel that manages the desktop VM. A VMware product known as vSphere allows for an administrator to provision and manage the VM. In vSphere, administrators can configure and allocate vGPU (virtual Graphics Processing Unit) for the VM pool.

For the EPIC demonstration project, SDG&E is acquiring two Tesla M60s to make up the NVIDIA GRID GPU portion of the Hypervisor appliance, allowing for a total of 16 GB of DDR5 VRAM (Video RAM) (8 GB's per GPU). NVIDIA's GRID vGPU Manager allows administrators to create 1-GB, 2-GB, 4-GB, or 8-GB vGPU's for the Virtual Desktop pools.

For load testing, the following ratios are estimated: 1 GB = 16 Virtual Machines, 2 GB = 8 Virtual Machines, 4 GB = 4 Virtual Machines and 8 GB = 2 Virtual Machines. Using the various profiles, SDG&E plans to obtain performance metrics to help understand user density optimizations. For the EPIC demonstration, the configuration applies to the VMware products ESXi, vSphere, and Horizon View.

At a high level, the diagram (Figure 2-64) from NVIDIA illustrates how it works.

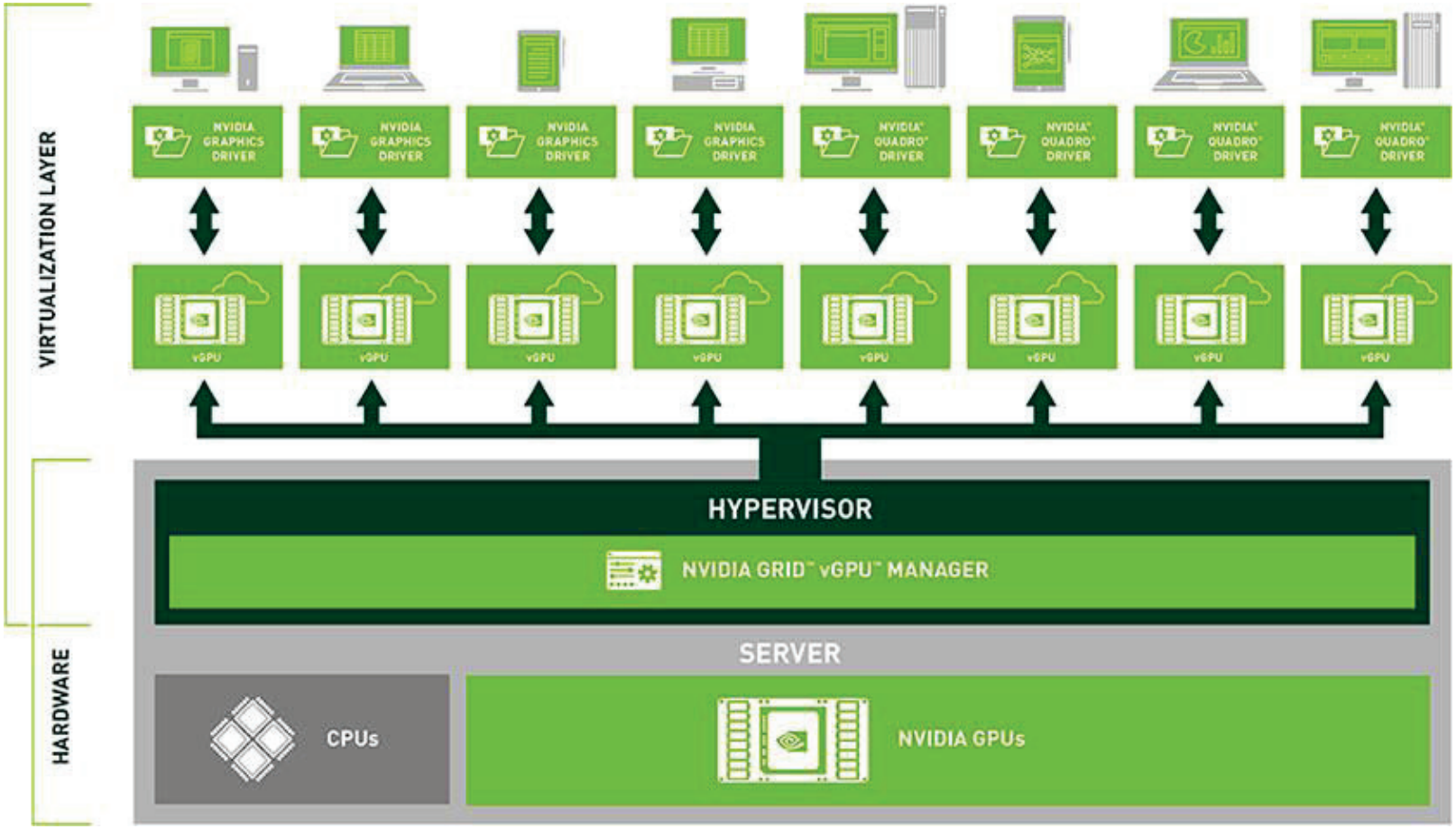


Figure 2-64. Virtualization of GPUs

VDI versus Terminal Services Discussion

As noted, the GPU server Hypervisor servers can also be supported on the VMware or the comparable Citrix environments (XenServer and XenDesktop). Currently at SDG&E, the electric GIS desktop is deployed using a Citrix XenApp (terminal services) approach. From the business user's perspective, they are accustomed to using several applications at the same time. For productivity, their preference is to access multiple applications using the same virtual desktop window. To satisfy this need, using the XenDesktop approach would require the various applications that would require a different Virtual Desktop images. Additionally, they would need different Virtual Desktop pool deployments to support the different application licensing. With XenApp, it is not possible to simply add all applications into one image to meet each of the user needs.

From an IT perspective, the preference is also to deploy a desktop using the Citrix XenApp application virtualization rather than XenDesktop (VDI). The XenApp allows the teams to rapidly deploy GIS updates. From the Citrix administration standpoint, dealing with the client image management and non-GIS applications users' need is of less of concern.

For the EPIC technology demonstration, the focus was on VDI deployment. Via discussions with the technology vendors, it was found that using XenApp paired with ArcPro resulted in reduced application performance. This was not a Citrix limitation or an issue with ArcGIS Pro but rather the Server Operating System (Microsoft Windows). In a XenApp scenario, one typically assigns a vGPU to a Virtual Server. When a user launches an instance of ArcGIS Pro via XenApp, a session is created on the Virtual Server with no resource allocation guarantee for users. Essentially, what ends up happening is, as users spin up sessions on the Virtual Server via XenApp, the Frame Buffer (a portion of the VRAM for storing bitmaps which make up screen display to the user) runs out of memory. After about 4 users, XenApp Server reaches a state of not-so-great performance.

This will be something that SDG&E needs to consider in the future because the current deployment relies on XenApp. With the expected production deployment of ArcPro and Esri Utility Network several years away, it is hoped that there will be sufficient time to design a strategy to deliver Virtual Desktops to GIS users that present them with a good experience.

2.8.4.3 New Widgets

The three widgets from Avineon that demonstrate an opportunity to modernize Silverlight technology as a part of this effort are *Display Manager*, *URL Navigator*, and *Net Explorer*. A brief description of each follows:

1. Display Manager

The DisplayManager™ widget (Figure 2-65) provides functionality to easily filter map content across multiple layers for user-specified values. This widget also provides capability to apply filters on related features such as feature linked annotation. The typical use of this widget is to display all features associated with a work order or perhaps of a particular status. The widget configuration screen provides the ability to choose the layers and fields to apply the filter on. Figure 2-65 illustrates the display of features for a selected facility (in this case Facility ID = P235245). Figure 2-66 illustrates the use of Display Manager to display features filtered by Owner (SDG&E). An example of what details can be selected are shown in Figure 2-67.

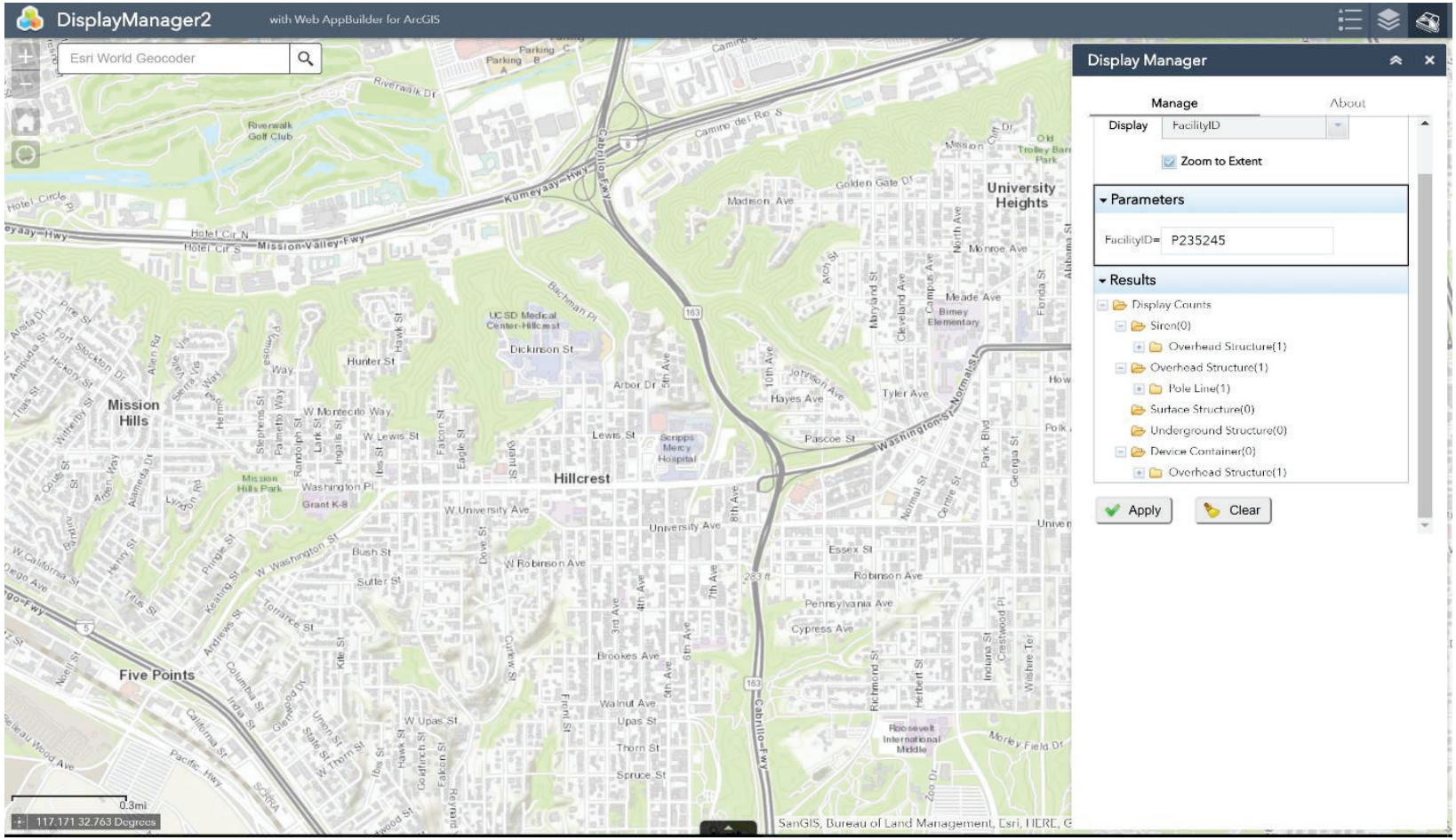


Figure 2-65. Custom Widget: Display Manager, Selection by Parameter

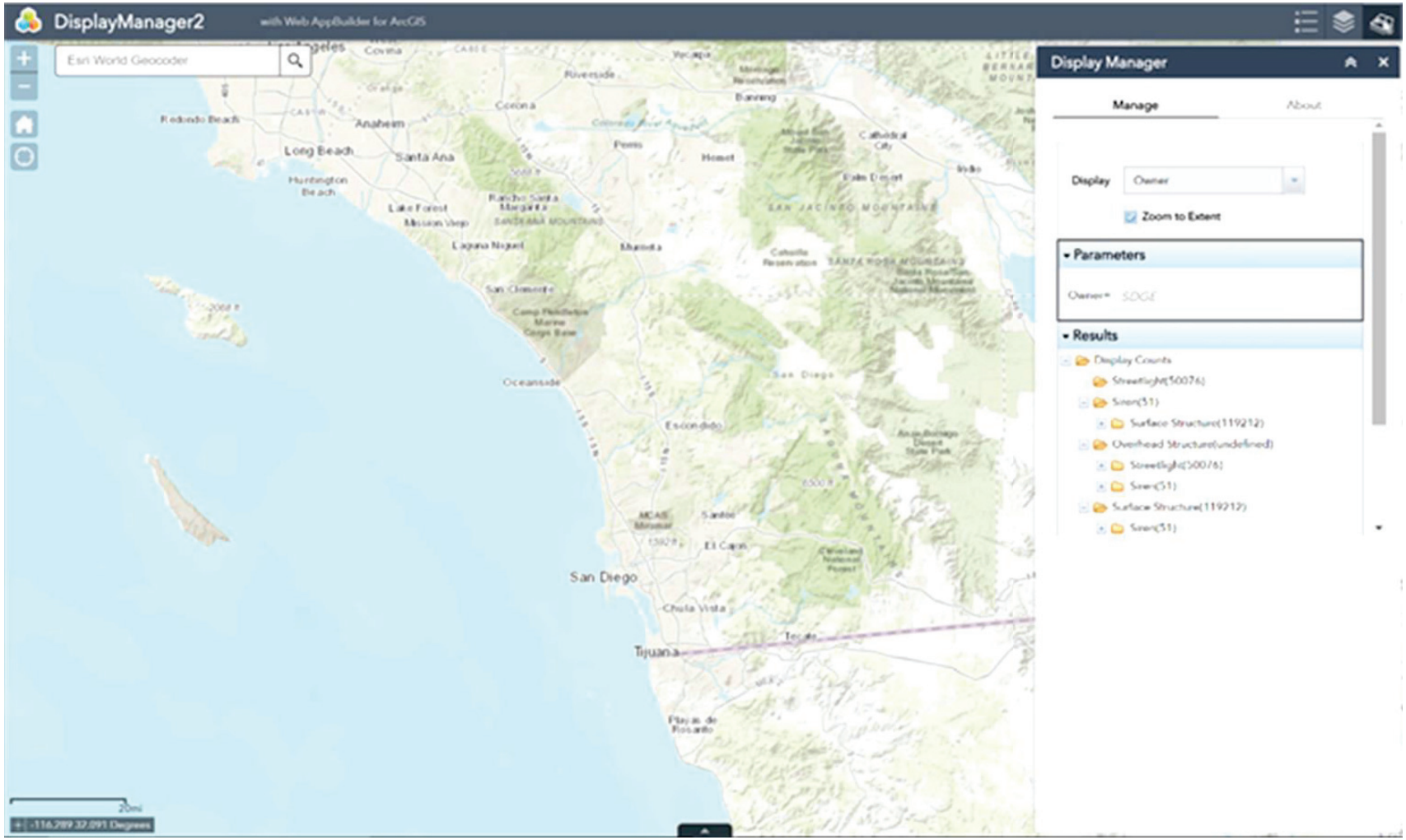


Figure 2-66: Custom Widget: Display Manager, Selection by Owner (SDG&E)

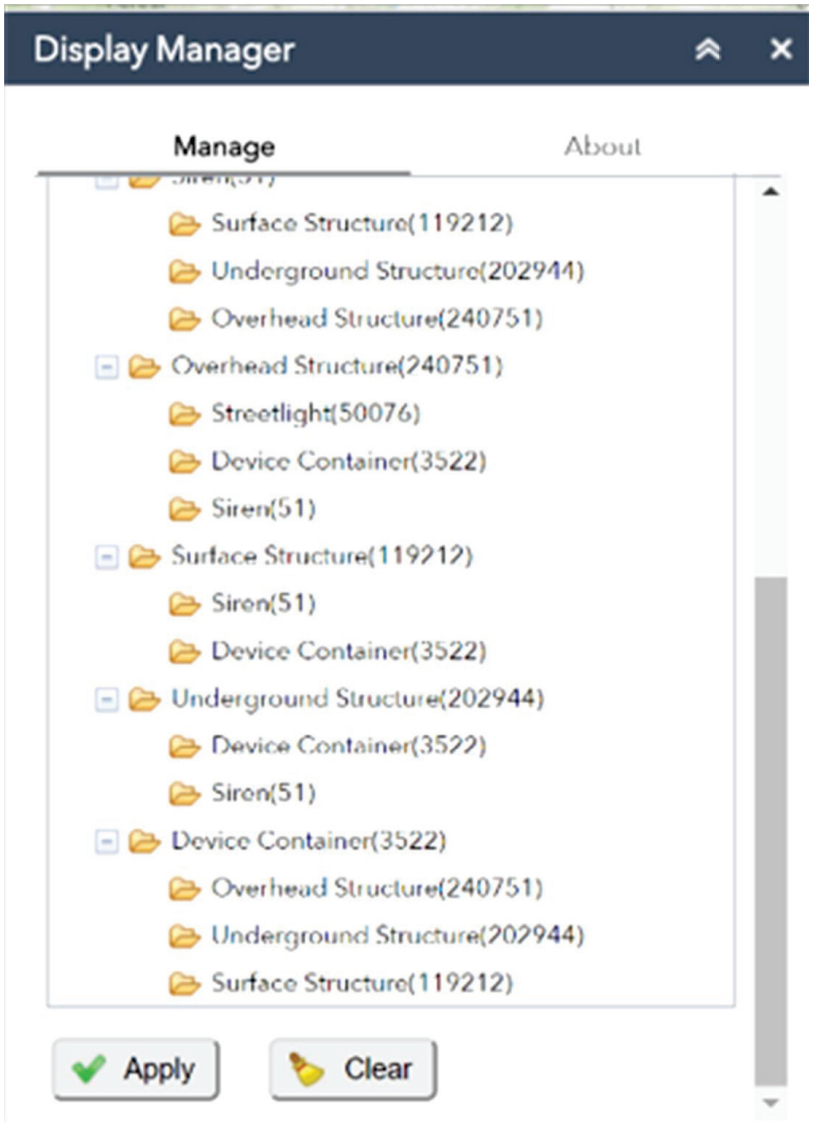


Figure 2-67: Features Available when Owner Selected

2. URL Navigator

   The URL Navigator widget displays clickable links for features selected in the map. By clicking on these links, users can open the target web pages either in a new tab or new browser window. The links (URLs) to target pages are constructed by the widget based on the features class, fields, and values specified in the widget configuration and selection screens.

   The key capabilities of this widget are:

   i) Add New URL Navigator (the URL links for the selected features are displayed in the URL Navigator widget)
      (1) Parameter Details
      (2) Types of Parameters
         (a) Add Parameter
            (i) Parameter with Text
            (ii) Parameter with Field Value
            (iii) Parameter with Subtype/Domain
            (iv) Parameter with Coordinates
      (3) Edit Parameter
      (4) Delete Parameter
   ii) Edit URL Navigator
   iii) Delete URL Navigator

An example of the LiveStreet link is shown in Figure 2-71; the Google Maps example link is shown in Figure 2-72.

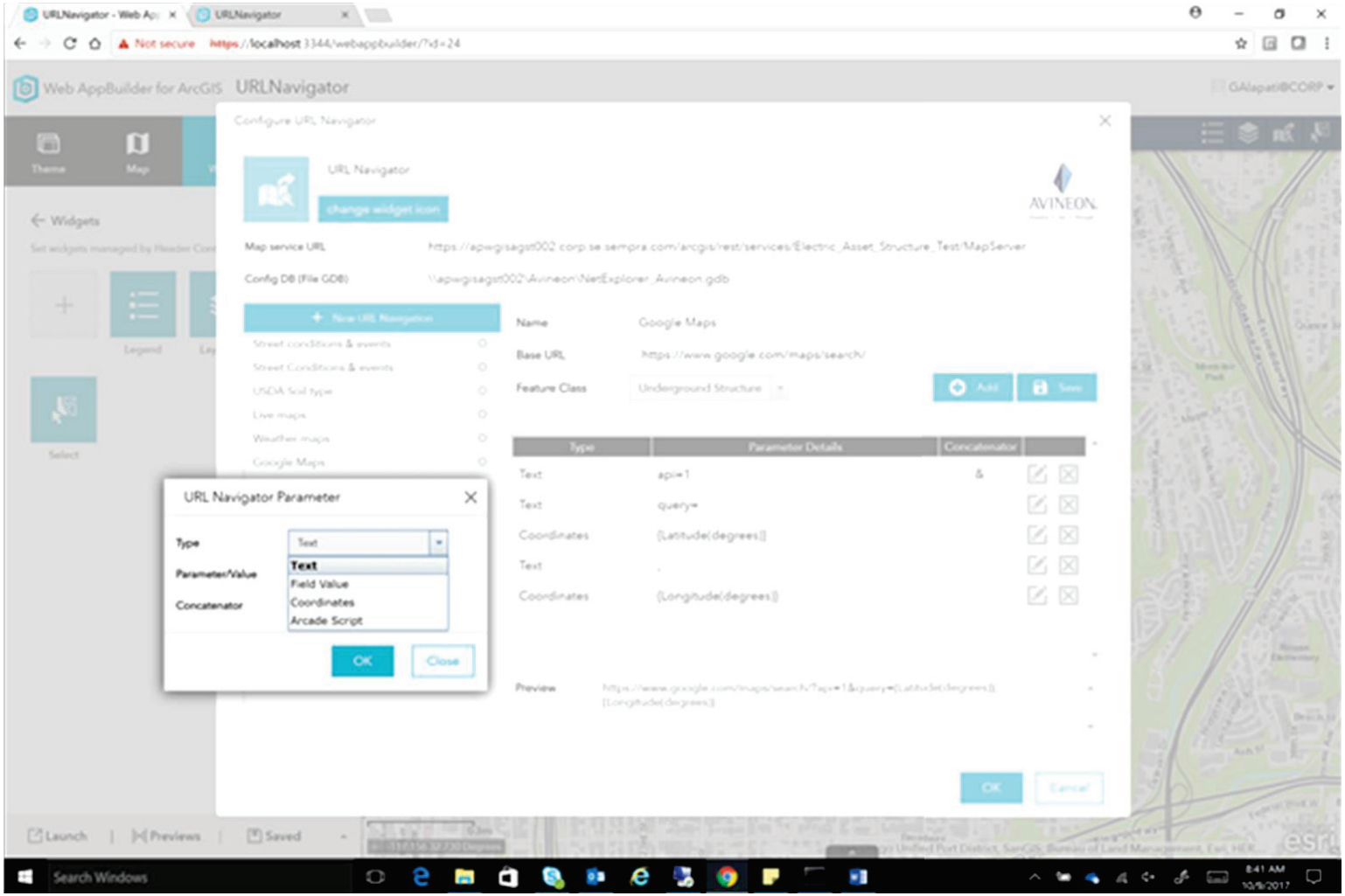


Figure 2-68. UI for URL Formation

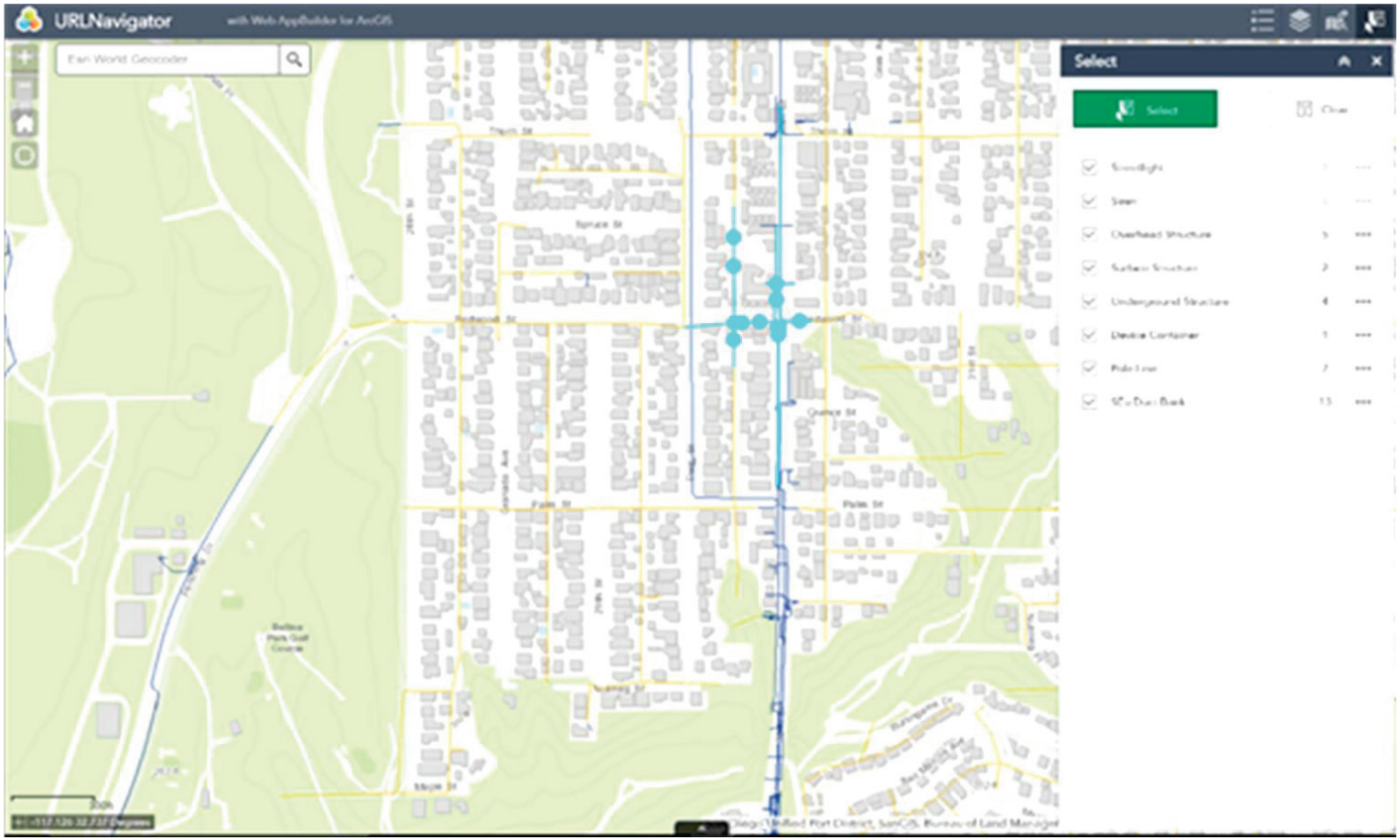


Figure 2-69. Select Desired Features to Display via URL

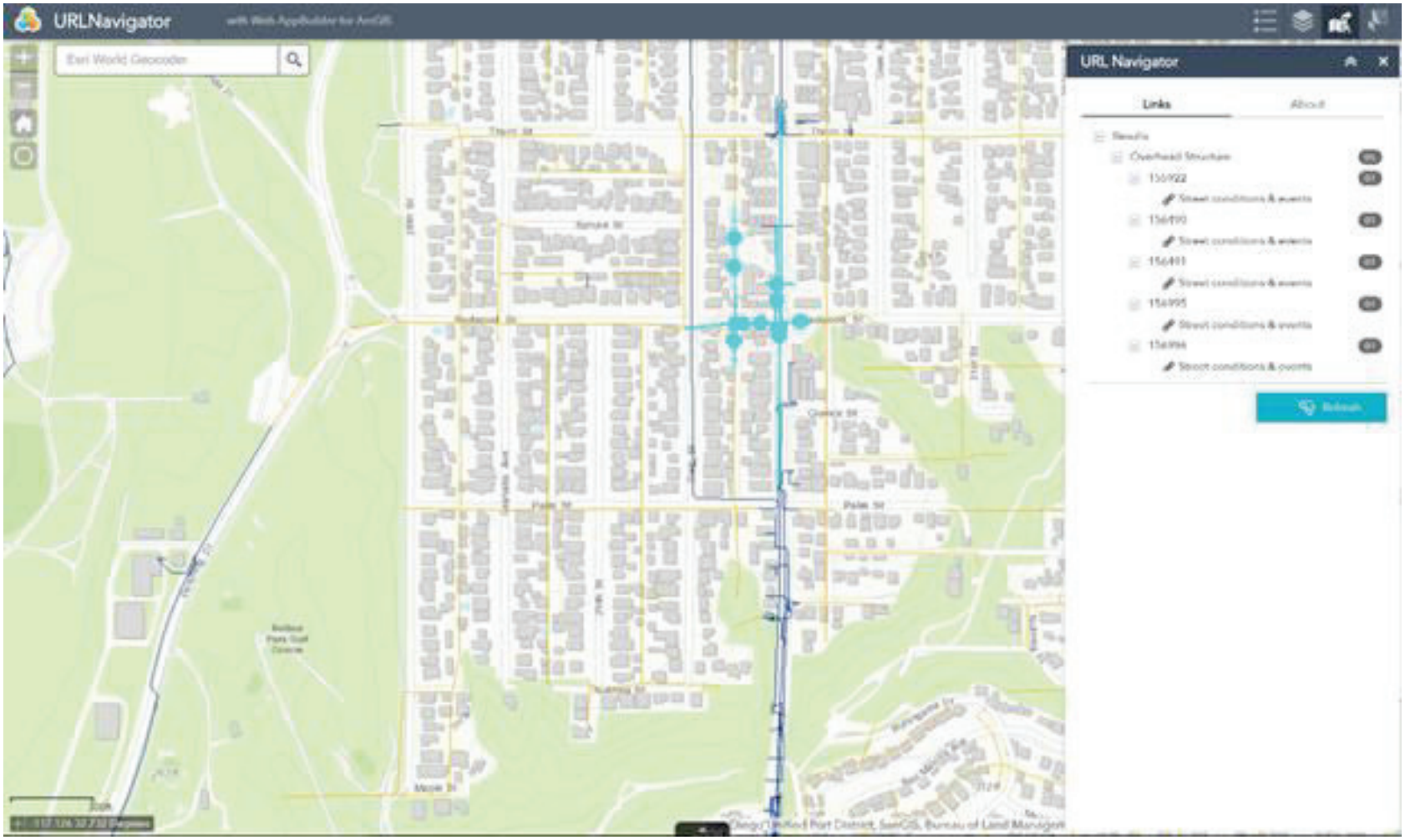


Figure 2-70. Example of Created URLs

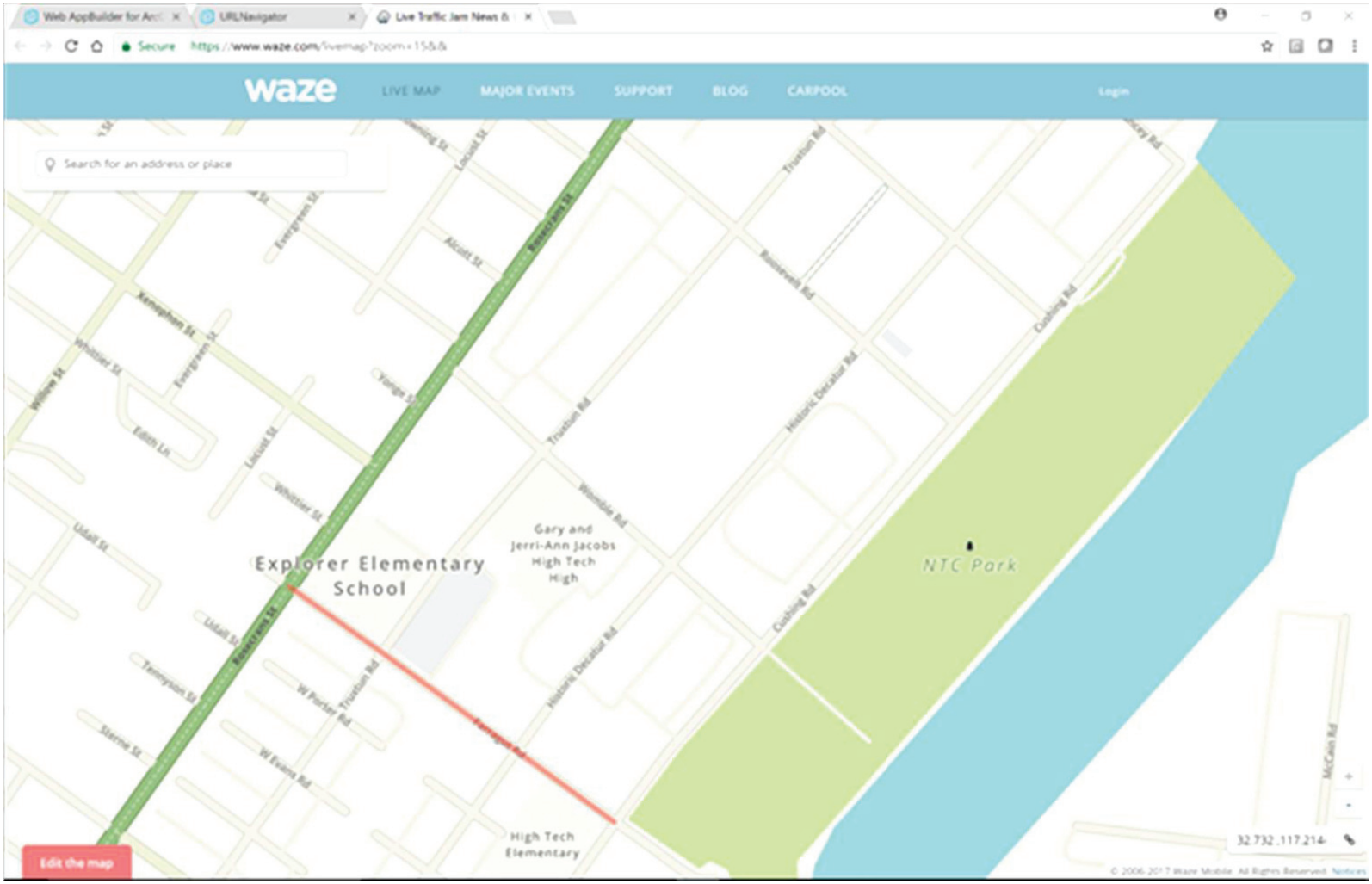


Figure 2-71. Example URL to LiveStreet

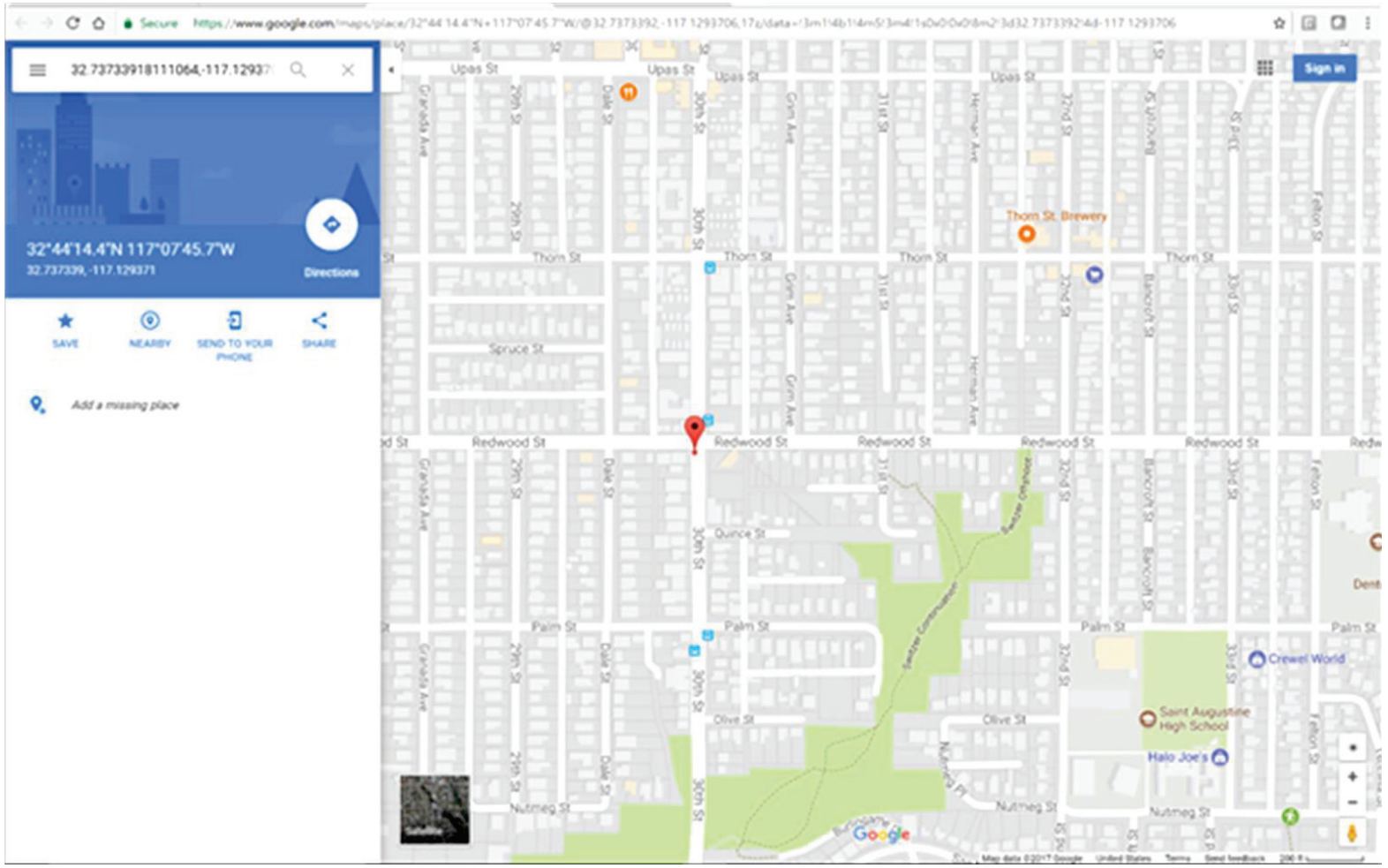


Figure 2-72. Example URL to Google Maps

3. Net Explorer

   NetExplorer is an easy-to-use widget to trace and report on electric networks within GIS using a web browser.

   Similar to the tracing functionality available in desktop GIS, this web widget provides intuitive functionality for users to specify starting points and stopping points (optional), run traces, and report on asset connectivity. Users can see trace results displayed on the map and also summarized by each GIS layer. The trace results are also available for deeper interrogation and analysis. This configurable widget can be made available to end users in **Basic** and **Advanced** modes. The basic mode is highly suitable for GIS end users and requires little-to-no training.

   The key capabilities of this widget are:

   1. Select Trace to Run
   2. Key In Parameters
   3. Select Stopping Points (optional)
   4. Run the Trace
   5. View Summary of Trace Results
   6. Summarize Trace Results By Fields of Interest
   7. Interact with Trace Results
   8. Save Trace Inputs for Reuse

   The advanced mode is suitable for business analysts and users that need more choices and flexibility when tracing networks and provides following additional capabilities:

   1. Select Network to Trace
   2. Specify Trace Task
   3. Specify Starting Points for the Trace
   4. Specify Trace Options

An example of a display to configure Trace to run is shown in Figure 2-73, and the results are shown in Figure 2-74 and Figure 2-75. Show Related on Output tab shows customer information for the selection.

In the “Details” tab, there is an option to display related records by features. When selected, an output, like that shown in Figure 2-76, will be obtained, where customer information is part of features.

The results can be saved with a name and shared with other users. This particular trace is saved as ‘AssetsOffSwitch’.

The ‘Exclude’ option on Input can be used to exclude certain features from the trace results. A difference between including and excluding certain features is illustrated by Figure 2-77 and Figure 2-78.

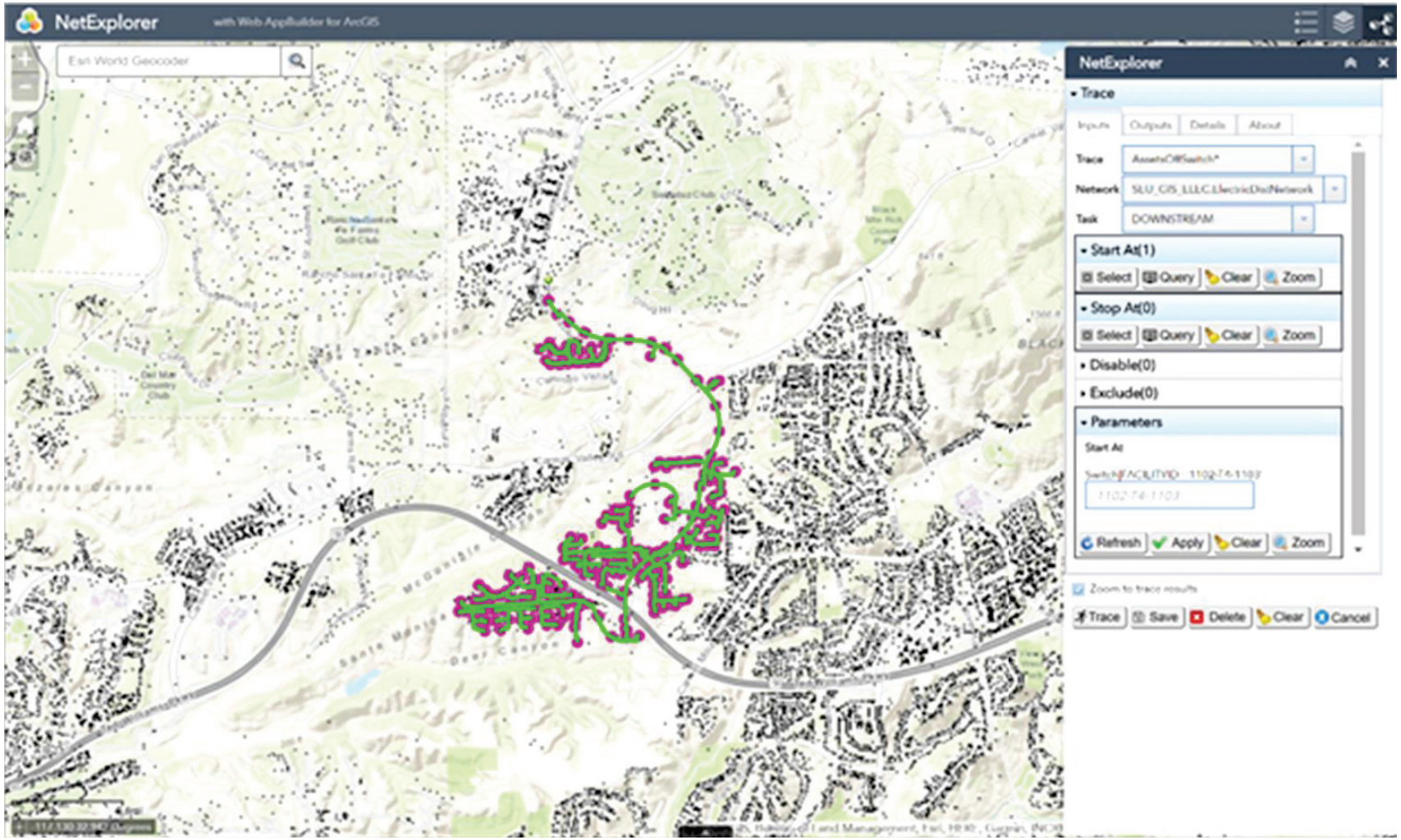


Figure 2-73. NetExplorer Trace Configuration Display

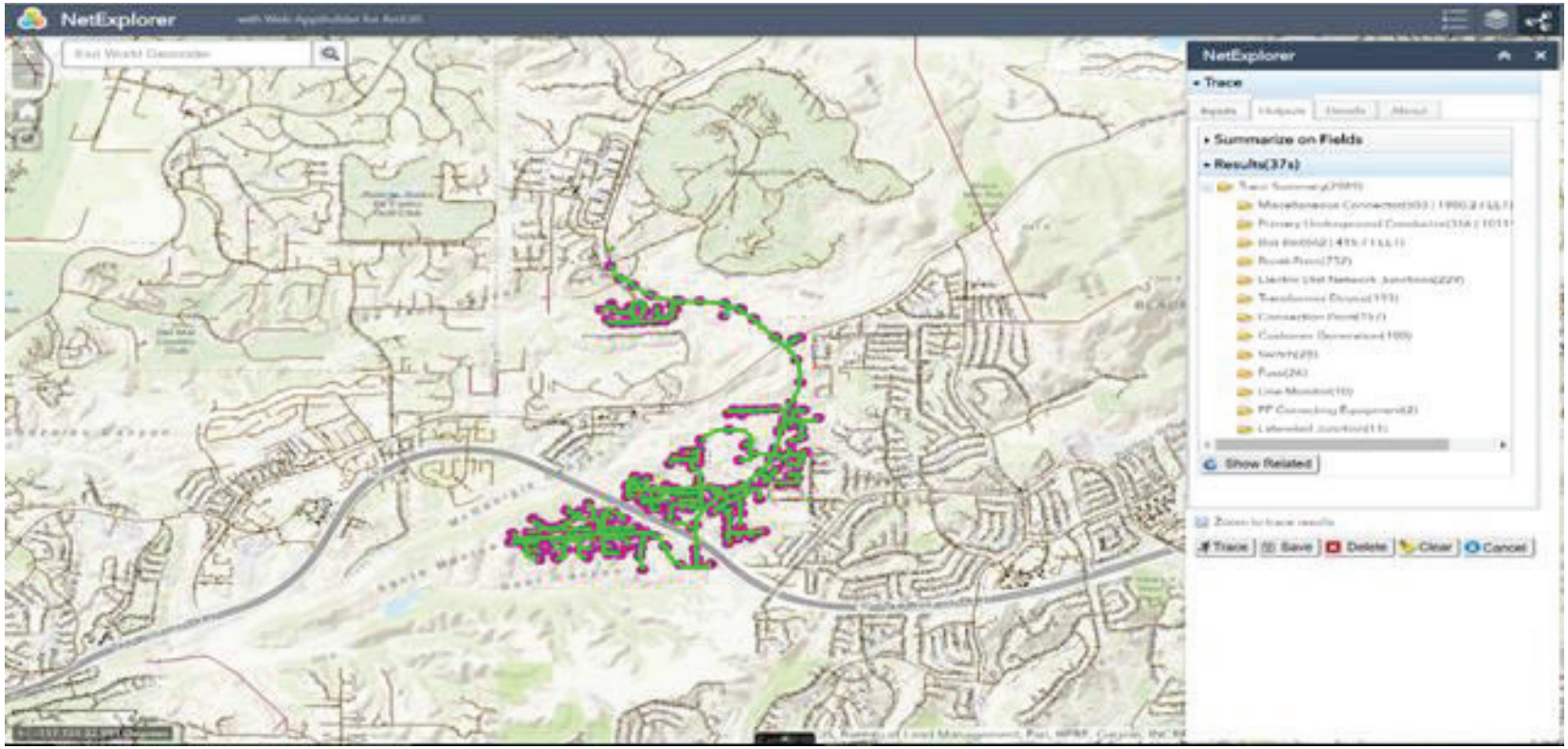


Figure 2-74. A NetExplorer Trace Output

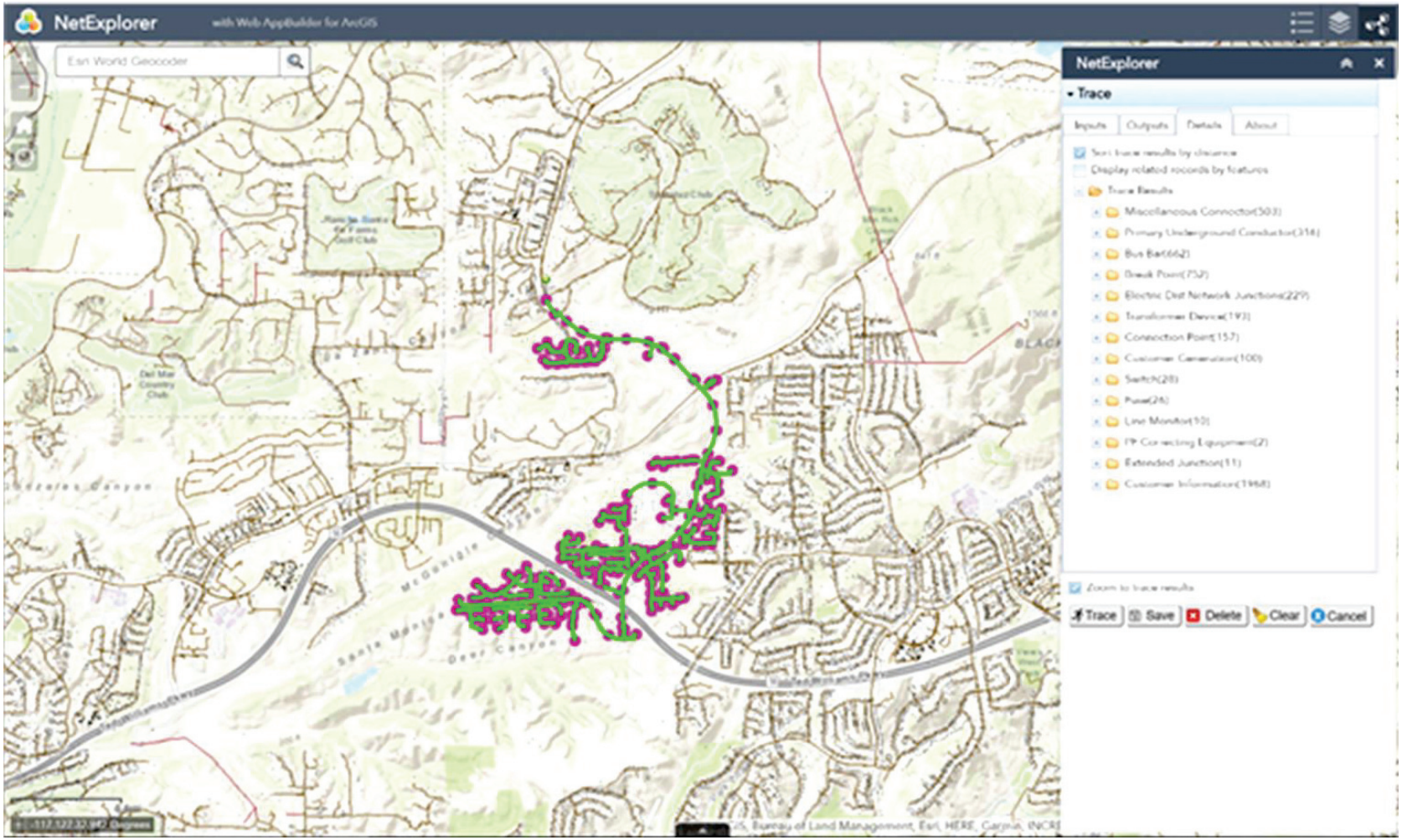


Figure 2-75. Details of the Trace (on Details tab)

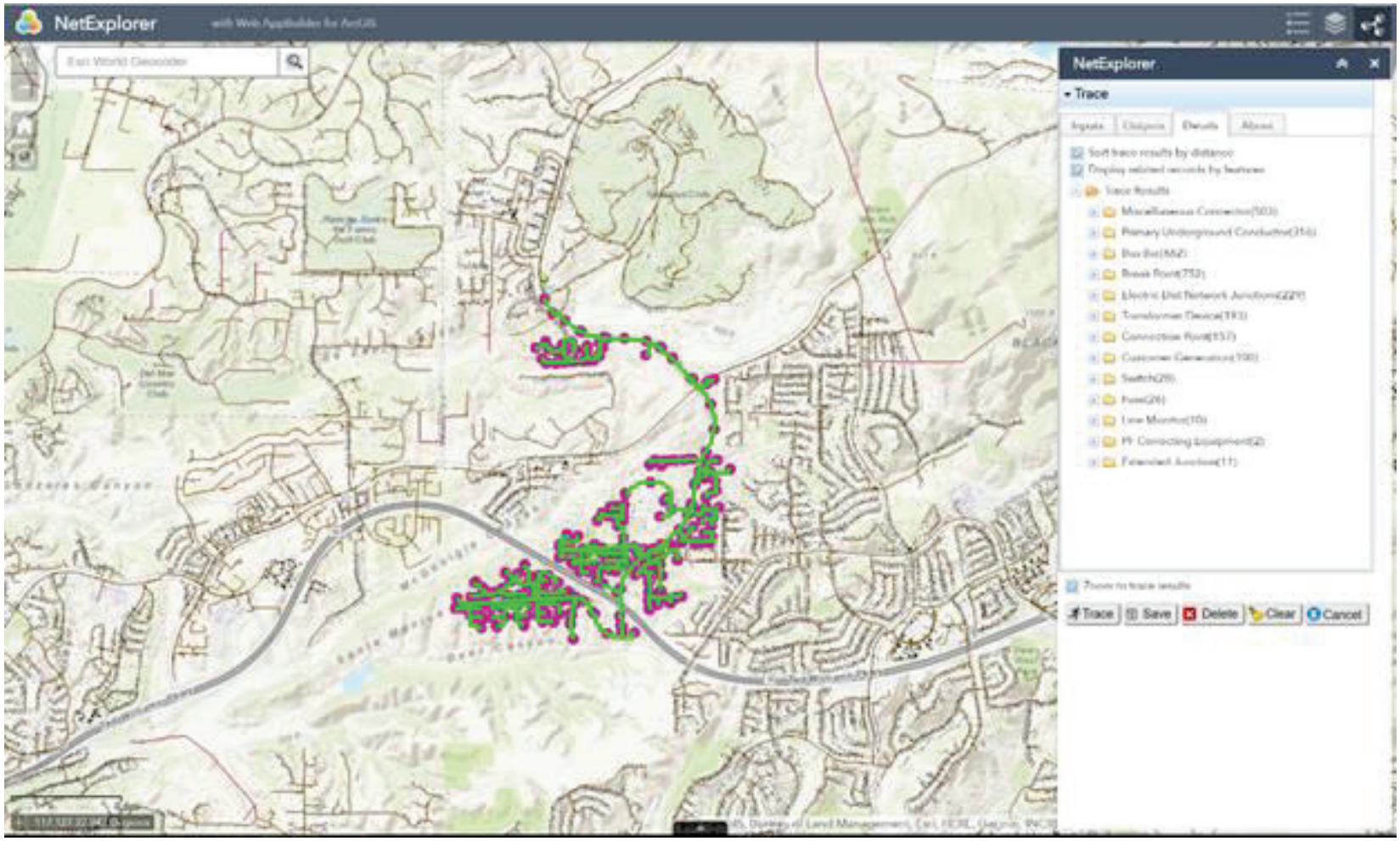


Figure 2-76. Display Related Records by Features

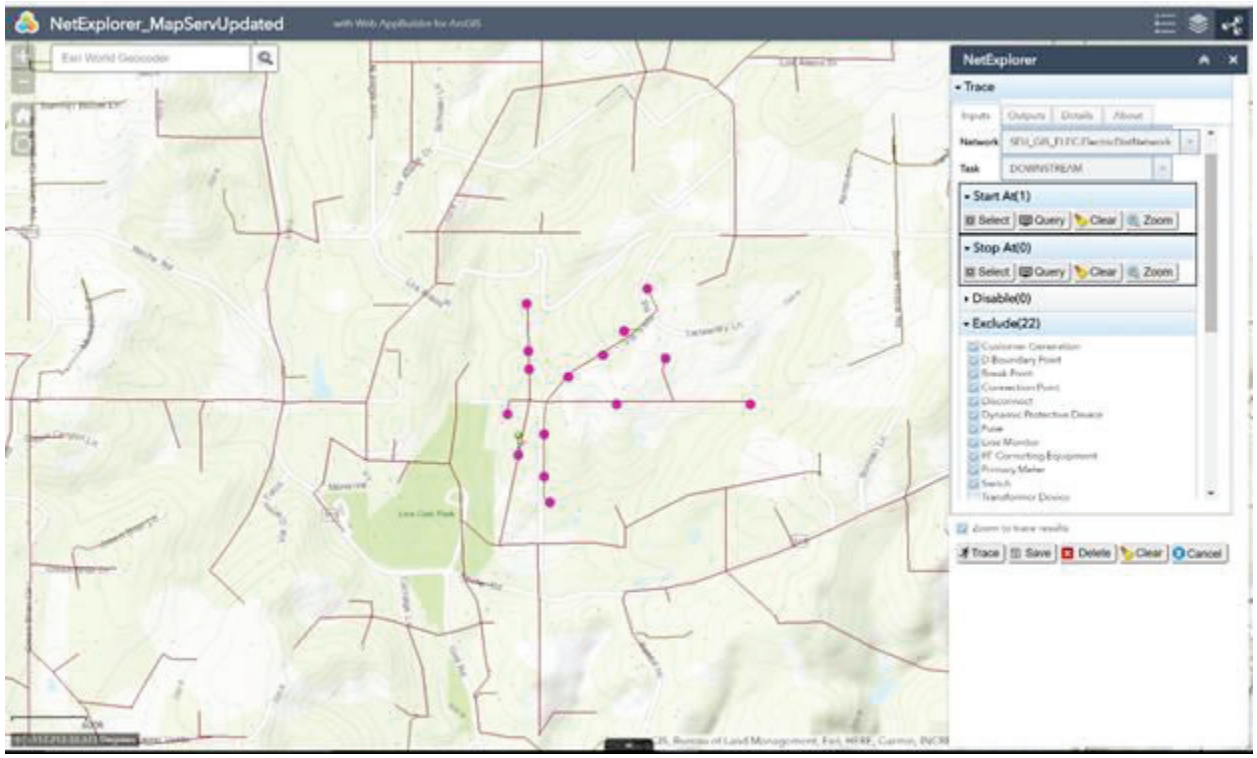


Figure 2-77. Display with Excluded Features

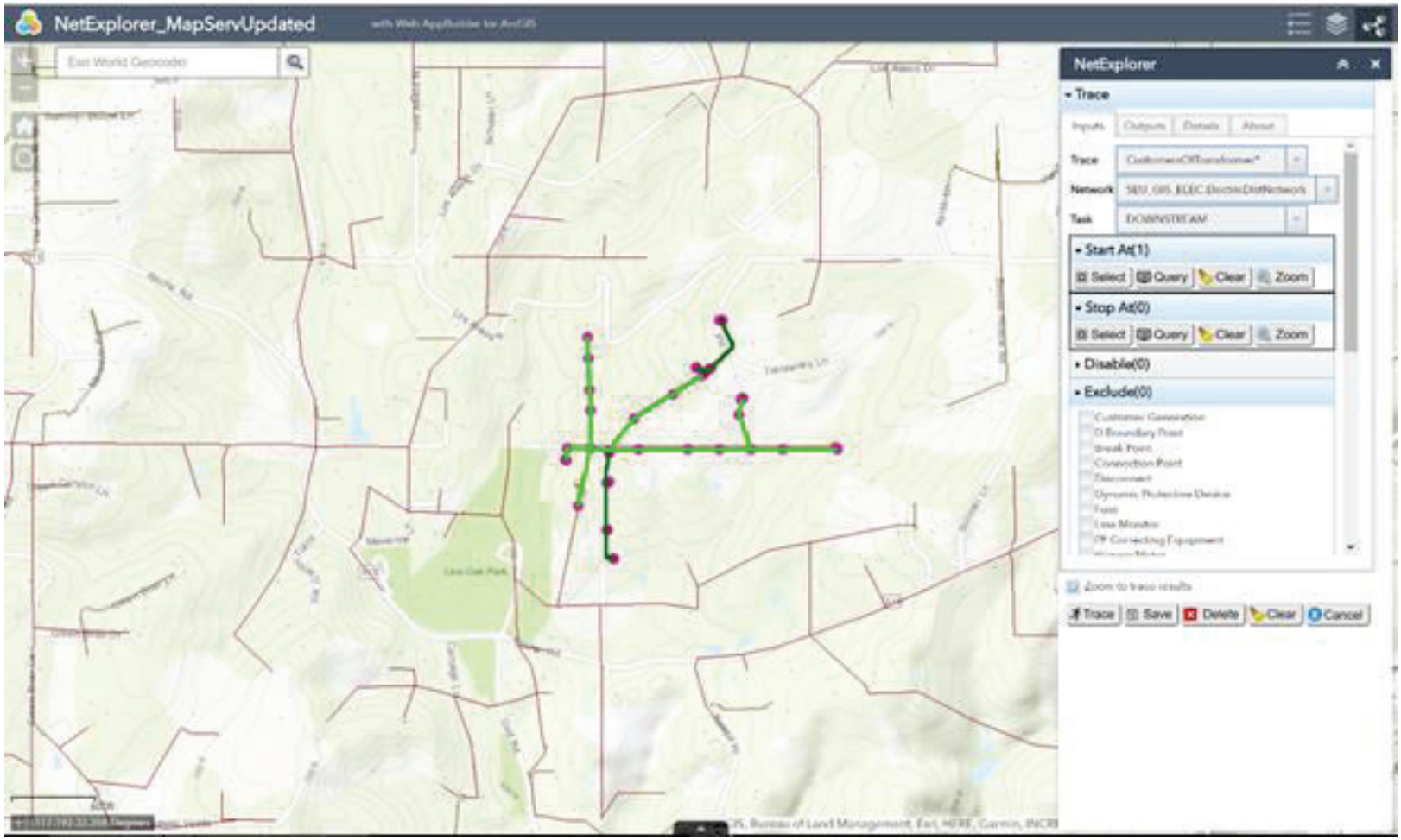


Figure 2-78. Same Display with Included Features (no exclusions)

While saving the trace results (for sharing with other users), the ‘Exclude’ options are also saved.

‘Basic’ users can view trace results created and saved in ‘Advanced’ mode. In the ‘Basic’ mode, the users can select start/stop by clicking on a map and view the trace results, but cannot apply advanced filters and exclude and disable feature classes.

The available Input, Output, and Detail options for ‘Basic’ mode users are illustrated by Figure 2-79, Figure 2-80, and Figure 2-81.

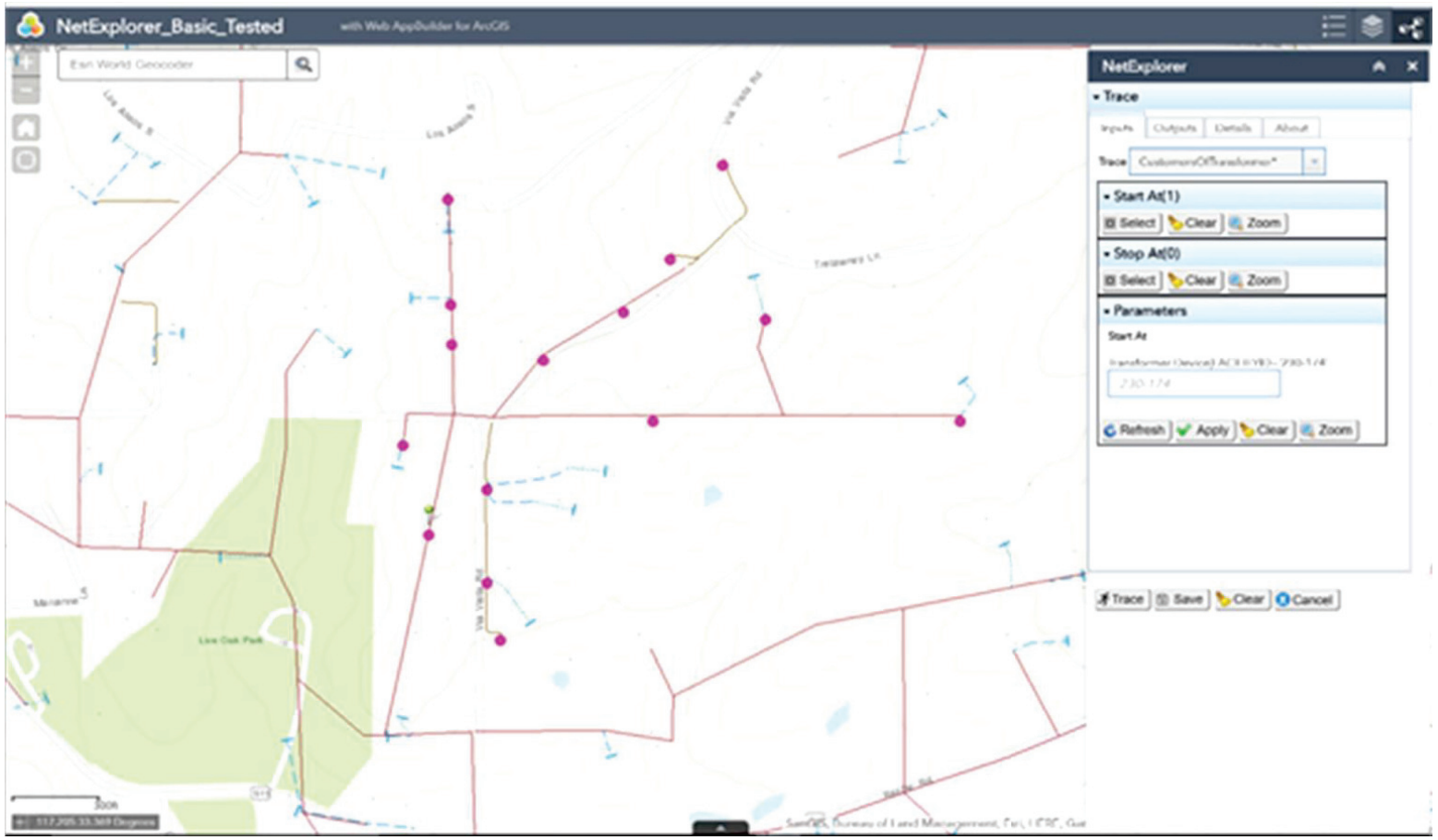


Figure 2-79. Basic Mode Trace Input Options

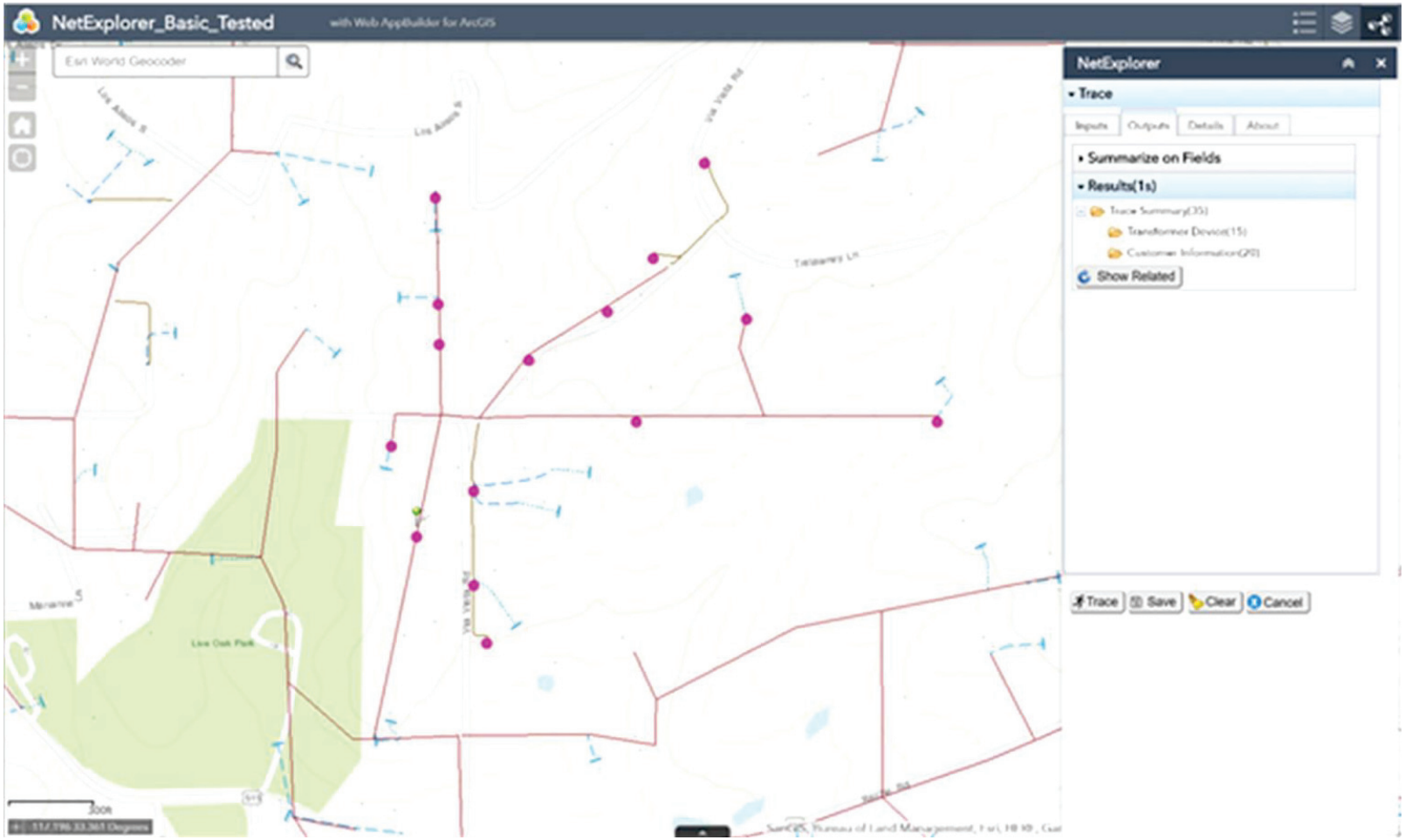


Figure 2-80. Basic Mode Trace Output Options

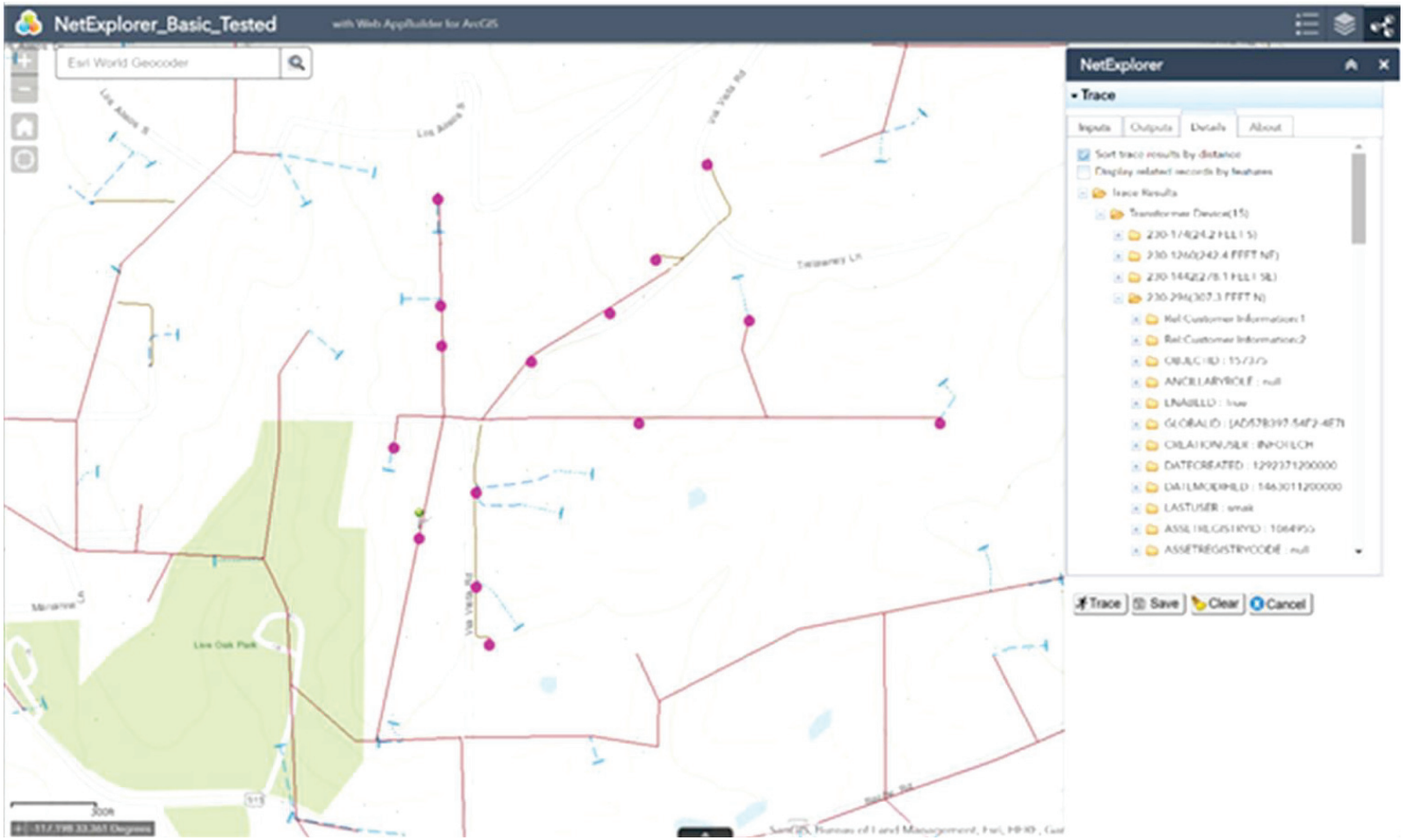


Figure 2-81. Basic Mode Trace Details Options

2.8.5 Observations, Challenges, and Lessons Learned

Challenges and Resolutions

- Extracting data from the existing system and converting the existing models into the new model by both leveraging the capabilities of the new (and different) modeling structure while maximizing the reuse of the useful information from the existing models. This process is time consuming and involves an assessment of whether there are benefits to reformulating the network model within the new framework; the performed work marks only the beginning of what will be a long and an ongoing process to carefully evaluate all aspects of this process on a few pilot circuit implementations before undergoing a full scale transition.
- Currently, geoprocessing is slow when the new full-facility models are used (some other use cases within this project even used simplifications of the existing, old asset models to speed up rendering to an acceptable level for those use cases, and the new models are significantly more complex, with the corresponding effect on rendering speed). Therefore, an objective of this use case was to assess if and what new virtualization-based HW platform improvements are required to be able, in the future, to configure an environment for SDG&E users with sufficient performance for GIS rendering of new models.
- The solutions exercised in this use case are based on brand new components (e.g., some of the components are in beta release), with little experience in the industry to draw from.

- This is still a work in progress relative to the larger scope of modernizing SDG&E GIS infrastructure, but the completed results of this use case have produced initial observations and experiences that will be leveraged in the ongoing efforts on this subject.

3 KEY ACCOMPLISHMENTS AND RECOMMENDATIONS

3.1 Key Accomplishments

With the solutions demonstrated in the project, the SDG&E project team has made significant improvements over the state-of-the-art approaches at SDG&E in each of the areas addressed by the eight use cases. The following lists some of the key accomplishments of these efforts:

- Real-time feature updates on maps based on the time varying data from PI has been successfully resolved by the use of OSISoft PI Integrator for Esri ArcGIS and Esri GeoEvent Extension for Server products. This mechanism is reusable and has been extensively used across multiple use cases.
- The team has successfully integrated standard and custom PowerBI widgets within various maps, in combination with other feature layers. In the course of the widget development, the emphasis was placed on the widgets' reuse, resulting in a reuse on multiple use cases.
- Electrical circuits layers are extensively used in some of the use cases. The team has found a way of simplifying the asset models of electrical circuits for an improved (better than an order of magnitude) rendering speed of electrical circuits' layers. Where it was taking in excess of 20 seconds to render circuit layers at the beginning of the project, it now takes an acceptable (sub-seconds) time for the same task.
- All use cases have solutions that produce map updates at speeds compatible with expectations of interactive users.
- SDG&E has successfully used GIS processing technologies and GIS analytics to aid in preparation of certain SDG&E mandatory and ad-hoc reports. The process has led to a substation automation of previously manually intensive steps, with savings in the overall processing time measured in days. It is expected that the approach will be extended in the future to cover additional reports.
- SDG&E has completed an initial set of GIS-based applications to help with SDG&E imagery management. Consolidation (in terms of access) of the many imagery sources should help with more effective use and management of these valuable resources in the future.
- SDG&E has begun explorations of 3D utility network modeling for SDG&E and of the associated computing infrastructures needed to support eventual widespread use of this more advanced modeling approach. This new modeling approach has the potential to unify some of the stove pipes GIS models necessitated by the capabilities of the previous GIS technology.

SDG&E is planning to continue with further refinements and extensions of the developed solutions, especially in response to feedback from operational use. Although the basic architectural solutions are believed to be solid, future developments will need to include periodic assessments of the architecture, a search for more robust implementations where possible, and training of future users.

3.2 Recommendations and Insights

Based on the outcomes of pre-production demonstrations, the results for use cases 1, 2, 4, 5, and 6 are recommended for production implementation. Results of use cases 7 and 8 (Imagery Management and GIS Visualization Infrastructure Modernization) have met the narrow objectives set for each of those use cases; however, in both instances, the efforts are just an initial step towards what is required for a more extensive development and investigation (i.e., the cumulative results of use cases 7 and 8 are not ready for production).

Use Case #3 has successfully demonstrated the capability of third-party analytics, in combination with the core GIS system, to substantially automate the process of producing certain time-consuming quarterly reports. Furthermore, the approach is such that it can be generalized, with additional work, to the production of other reports. Ultimately, SDG&E has decided, based on licensing, installation, and training considerations, that a similar outcome can be achieved using products SDG&E already has a license for, and its developers have more familiarity. It is on this basis that the team does not recommend a production implementation at SDG&E at this time.

For the use cases recommended for production implementation, the effort to transition to production is minimal, measured in fractions of FTE, and generally consists of moving the artifacts from the test to QA environments, engineering review, and customer acceptance. In one case (Visualization of Customer-owned DER), no additional work is required beyond what was necessary for the pre-production demonstration.

In the course of implementation, each of the use case teams had to overcome certain challenges, and each has gained valuable insights from doing so. The most notable insights for each use case follow.

UC 1: Transmission Fault Location

- The labor to create the initial reference layers of electric circuits is pretty significant and should be planned for.
- There is a need to setup a process to “re-digitize” electrical circuit lines any time there is a reconfiguration, or to digitize new lines, with an associated process to reflect the changes in PI.

UC 2: Load Curtailment

- From a development perspective, a replacement for the scraping of web pages with a more direct interface would be desirable.
- From a usage standpoint, the development team is expecting quite a bit of feedback from the managers of Emergency Operations Center after a planned demonstration of the function is presented in the near future.

UC 3: Self Service EGI BI Reports

- An investment in terms of time, effort, and training is needed to master Spatial Eye queries and setup of Spatial Eye projects.

UC 4: History Playback

- This insight underscores one of the basic tenets of effective software development – the most important starting point is to collect and formulate solid user requirements
- For effective integration of dispersed data, there is a need to continuously communicate with various stakeholders and data owners
- Widget development is envisioned as a continuous process in order to serve the evolving needs of end customers

UC 5: AMI for Operations

- Design custom widgets to be as generic as possible. In this project, that approach has proven to be very helpful, and such an approach is expected to continue to be helpful in future projects

- Allowing the application to be customizable by end-users helps better match system functionality with user needs, and ultimately it helps with adoption of the function

UC 6: Customer-Owned DER Visualization

- Ideas for converting PV nameplate data to actual data: use an existing nearby solar plant for which there is a real-time data, and apply the same scaling factor between the nameplate capacity and the actual output to rooftop PV outputs in the vicinity of the PV plant. Also, consider use of models, nameplate capacity and metered irradiation data in the vicinity of PVs.
- For batteries, a dashboard similar to the one currently used (e.g., with real time prices to display Day-ahead market prices).

UC 7: Imagery Management

- With data sources spread out over many data owners and locations, one of the key challenges of this use case was identification of the correct data owners
- One of the key efforts to systematize access to imagery is development of an SDG&E standard for image metadata

UC 8*: *Visualization Infrastructure Modernization

- The experiences gained through the project, due to the novel nature of what was being demonstrated, should be very useful both for SDG&E and the industry at large.

3.3 Technology Transfer Plan for Applying Results into Practice

A primary benefit of the EPIC program is the technology and knowledge sharing that occurs both internally within SDG&E and across other IOUs and the CEC, and the wider industry. In order to facilitate this knowledge sharing, SDG&E has been sharing the results of the EPIC SDG&E Visualization and Situational Awareness Demonstrations project at suitable industry workshops and conferences.

The project team believes that visualization and situational awareness solutions developed in this project will be useful beyond SDG&E, and, therefore, the solution ideas and lessons learned will continue to be shared with other stakeholders, to promote further advancements of the integration and visualization solutions initiated in this project.

This final report and all other public papers and presentations on this project will continue to be posted on SDG&E's EPIC public website at *www.sdge.com/epic*.

4 CONCLUSIONS

This project examined how data currently unexploited and separately processed at SDG&E can be integrated and visually presented for strategic use by system operators. The project also demonstrated technical solutions at a pre-commercial level for how data collected from sensors and devices can be processed, combined, and presented to system operators in a way that enhances grid monitoring and situational awareness.

Enhanced monitoring and situational awareness is achieved by providing a geospatial context for a wide variety of operational, historical, and metering data. Consequently, through the numerous use cases undertaken within this project, it has illustrated how the data commonly used to support diverse business needs at SDG&E can be combined with geospatial data to significantly enhance insights and situational awareness.

The project has successfully achieved all of its key objectives. In the process, the project team and other SDG&E stakeholders have gained valuable experience and a solution framework that can be reused to speed up future developments in the area of situational awareness and integration of real-time and geospatial data.

5 METRICS AND VALUE PROPOSITION

5.1 Project Metrics

The project tracking metrics included the milestones in the project plan. Technical project metrics included the completion of the initial specification for a visualization and situational awareness system, the demonstration of a system display mock-up, and the specifications and recommendations regarding adoption by SDG&E.

Also, major project results were submitted in technical papers and presentations for consideration by major technical conferences and publications.

This section provides more information about the metrics and benefits of the project. The most important benefits are in areas of:

Safety, power quality, and reliability

a. Ability to monitor, visualize, and analyze visualization information can help reduce number of outages, as well as their frequency and duration. Transmission fault location use case is particularly useful for this purpose.
b. Public safety improvement and hazard exposure reduction can also be accomplished by advanced visualization tools.
c. Utility worker safety improvement and hazard exposure reduction

Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy

a. Description of the issues, project(s), and the results or outcomes
b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)
c. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)

Effectiveness of information dissemination

a. The visualization platform enables the creation of numerous reports and fact sheets for various users, not only within SDG&E but also on a wider basis, via preparation of conference presentations, papers, and other relevant material.

Adoption of EPIC technology, strategy, and research data/results by others

a. The technology developed and demonstrated during the course of the project provides a promising basis for building upon and for development of a production version of the monitoring and visualization platform that can be effectively utilized by various stakeholders both at SDG&E and beyond.

After further development of all presented use cases and additional testing, it would be beneficial to prepare a comprehensive description and documentation of the technology that could help with obtaining approvals from the California Energy Commission for further proposals, thereby enabling wide-spread adoption of the technology, first at California IOUs and, eventually, beyond.

5.2 Value Proposition: Primary and Secondary Guiding Principles

The value proposition is to address how the project met the EPIC principals.

Table 1.1 summarizes the specific primary and secondary EPIC Guidelines Principles advanced by the Visualization and Situational Awareness Project.

Table 5.1: EPIC Primary and Secondary Guiding Principles

Primary Principals			Secondary Principals				
Reliability	Lower Costs	Safety	Loading Order	Low-Emission Vehicles / Transportation	Safe, Reliable & Affordable Energy Sources	Economic Development	Efficient Use of Ratepayers Monies
✓	✓	✓					

The Visualization and Situational Awareness Project covers the following primary EPIC principals:

- **Reliability:** This project developed tools that give the ability to monitor, visualize, and analyze information which help reduce number of outages, as well as their frequency and duration, giving a higher reliability. Transmission fault location use case is particularly useful for this purpose.

- **Lower Costs:** Given the ability to visualize occurring events in near real time to operators, helps deploy maintenance crews more efficiently and effectively. The imagery management use case, for example, aim is to be able to see the data sources visually, in a geographic context, as opposed to searching for the data via file and folder names. This should save time and effort in organizing huge amounts of data.

- **Safety:** As mentioned, the ability to monitor events and historical trends, like transmission faults or voltage issues, gives the departments and crews that depend on this information, to have a better assessment on how to approach an occurring issue, or based on trends, evaluate on how to safely plan a future activity.

6 APPENDIX: FOUNDATIONAL COMPONENTS

6.1 Esri GIS Components

This section provides very basic information about the Esri GIS components that have been used in this project. The source of the information is largely from Esri's extensive web-help site http://resources.arcgis.com/en/help/ (following the contained links).

Esri provides various solutions to meet its clients' GIS needs. Figure 6-1 shows the main components of ArcGIS Enterprise, which is the version used by SDG&E in this project. The diagram shows the main functional groups of components. Subsequent sections contain a brief summary of these groups.

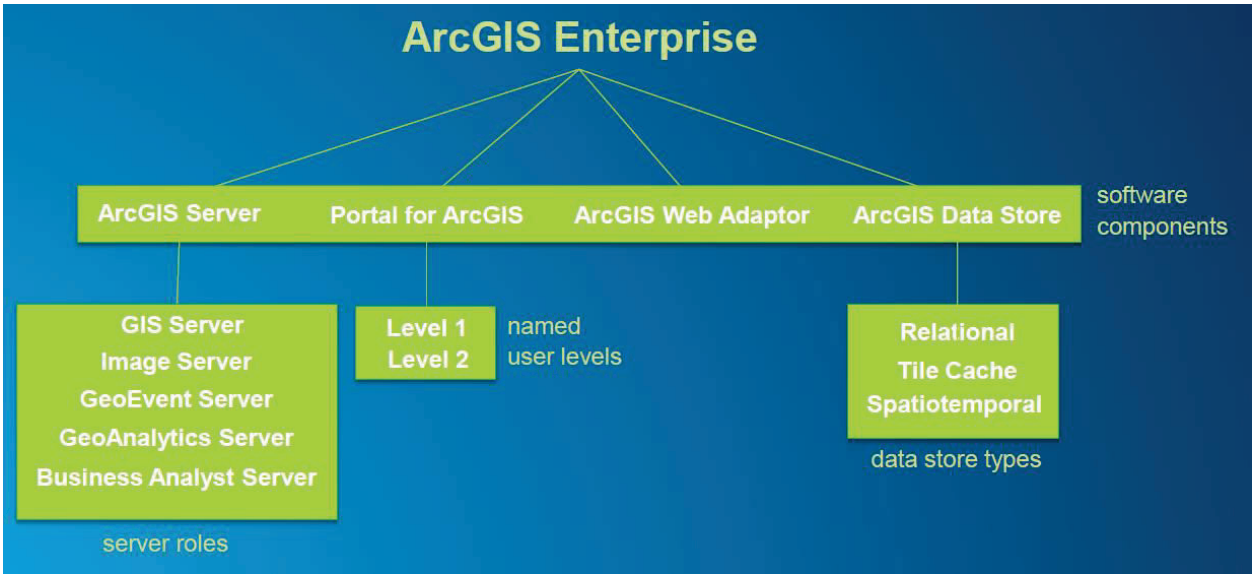


Figure 6-1. Esri ArcGIS Enterprise Components

In the following subsections, each of the functional groups of the ArcGIS Enterprise suite of applications is briefly overviewed based on the information provided on the Esri Web Site.

6.1.1 ArcGIS Servers

There are five different kinds of servers: GIS Server, Image Server, GeoEvent Server, GeoAnalytics Server, and Business Analyst Server. A brief overview of each of these servers is provided in the following subsections.

6.1.1.1 Image Server

ArcGIS Image Server provides serving, processing, analysis, and extracting business value from collections of imagery, rasters, and remotely sensed data. Figure 6-2 shows, pictorially, Esri's depiction of the main roles of its Image Server. In this project, Image Server is primarily used to support Use Case #7, Imagery Management.

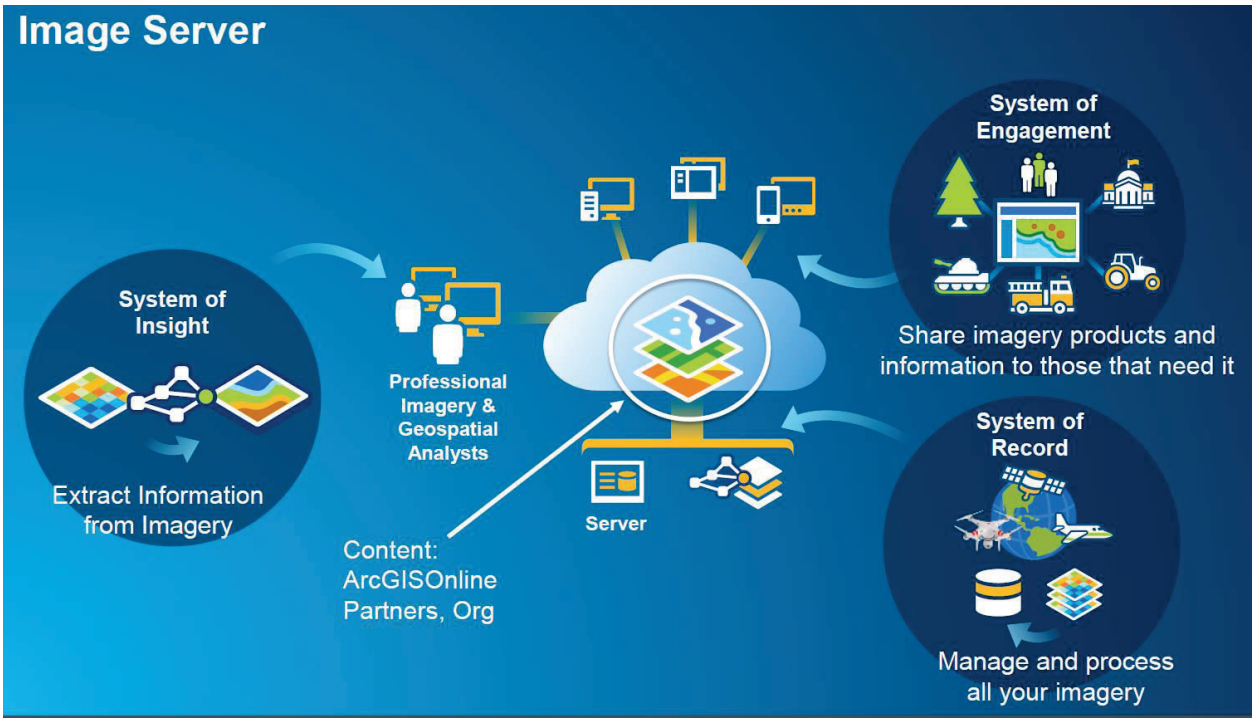


Figure 6-2. Esri Image Server

6.1.1.2 GeoEvent Server

The main role of GeoEvent Server (Figure 6-3) is to facilitate updates of geospatial feature of GIS maps based on dynamic data. Within this project, the role of providing dynamic data updates is filled by OSISoft PI Esri Integrator for the dynamic data that resides in PI Historians, and by GeoEvent Server for all other kinds of dynamic data (e.g., weather, fire, etc.).

6.1.1.3 GeoAnalytics Server and Insights

GeoAnalytics Server (Figure 6-4) supports Big Data analytics on the server side.

Insights (Figure 6-5) provides visual programming capabilities to end-users, allowing them to specify sophisticated data analysis and display results on maps within portal for ArcGIS. Insights blends spatial and non-spatial data to bring together spreadsheets, databases, and ArcGIS data.

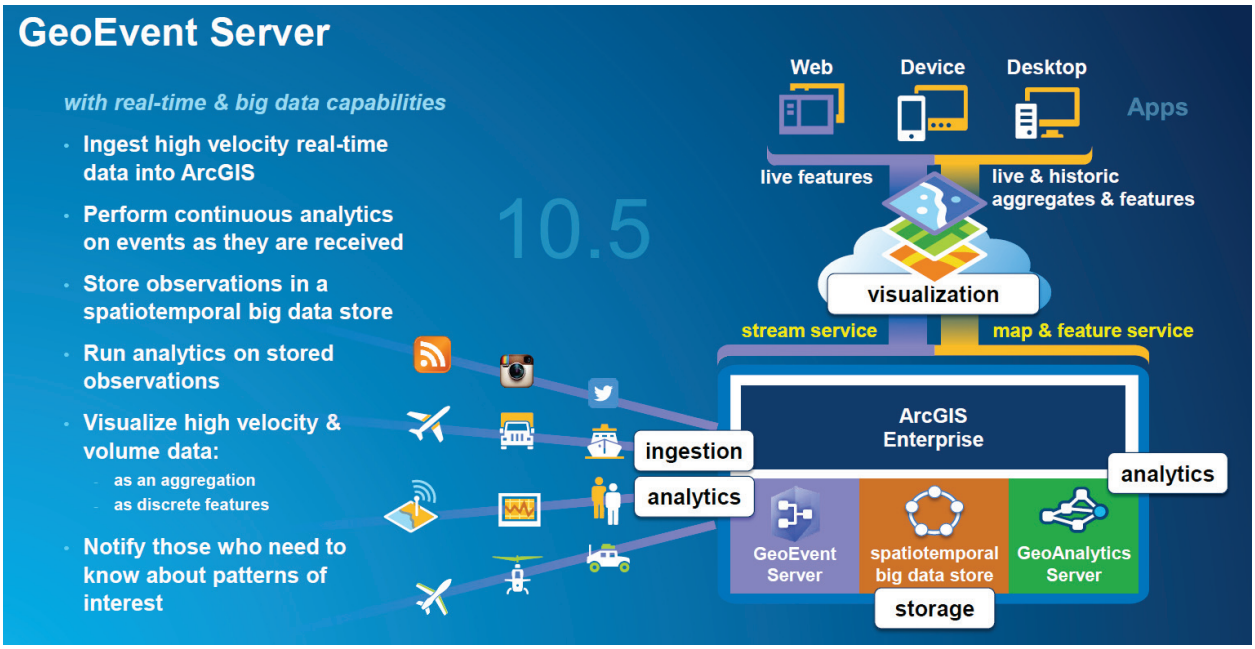


Figure 6-3. Esri GeoEvent Server

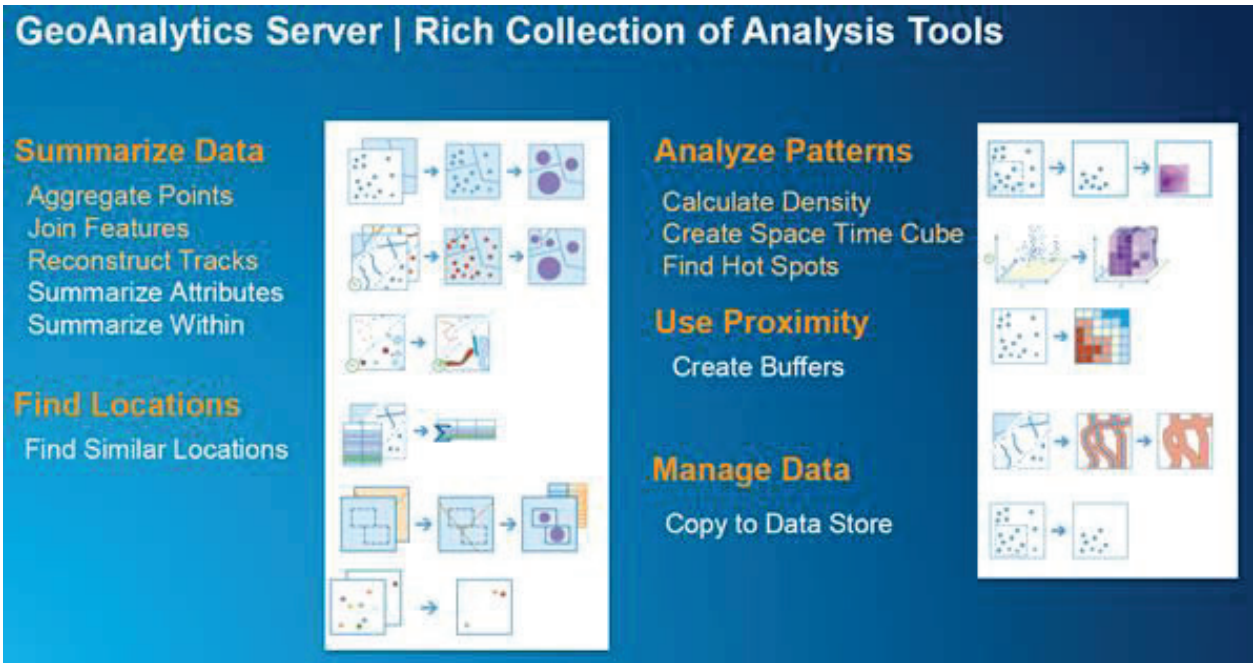


Figure 6-4. Esri GeoAnalytics Server

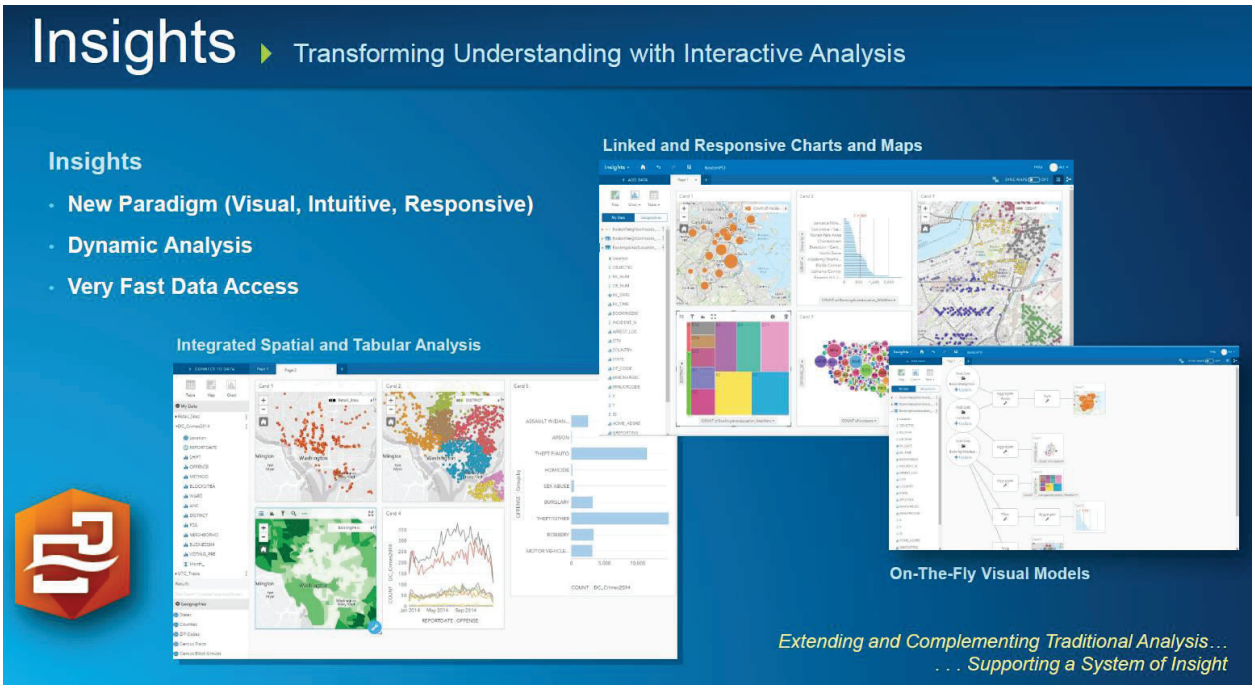


Figure 6-5. Esri Insights

6.1.2 Portal for ArcGIS

This components was heavily used in this project. Portal for ArcGIS allows sharing of maps, scenes, apps, and other geographic information with other people in the organization. The shareable content is delivered through a website. The website can be customized to the organization's visual standards.

Portal for ArcGIS brings together all the geographic information in the ArcGIS platform, and it shares it throughout the organization. For example, with Portal for ArcGIS it is possible to:

- Create, save, and share web maps and scenes.
- Create and host web mapping apps.
- Search for GIS content within the organization.
- Create groups for sharing GIS information with coworkers.
- Share links to GIS apps.
- Share map and layer packages to use in ArcGIS Desktop.

Portal for ArcGIS includes geographic viewers designed for those who are just beginning with GIS. Experienced GIS users can connect to Portal for ArcGIS from ArcGIS Desktop, developer APIs, and other applications.

6.1.3 ArcGIS Web Adapter

The Web Adaptor provides the following features:

- Allows integration of *Portal for ArcGIS* with the organization's existing web server. Inclusion of a web server with ArcGIS Web Adapter provides the ability to host web applications that use GIS services.
- The organization's identity store and security policies can be used at the web-tier level. For example, when using IIS, it is possible to use Integrated Windows Authentication to restrict who enters the portal. It is also possible to use Public Key Infrastructure (PKI) or any other identity store for which the web server has built-in or extensible support. This allows provision of a single sign-on or other custom authentication experience when logging in to use services, web applications, and Portal for ArcGIS.
- Portal for ArcGIS functions can be exposed through a site name other than the default ArcGIS.

The Web Adaptor is platform independent of Portal for ArcGIS, and hence, the Web Adaptor does not have to match the operating system platform of the portal. For example, if the portal is running on Linux, it is possible to deploy ArcGIS Web Adaptor (IIS) or (Java Platform) to work with Portal for ArcGIS. Conversely; if the portal is running on Windows, an ArcGIS Web Adaptor (Java Platform) on Linux can work with the Portal for ArcGIS.

After installing and configuring the Web Adaptor, the URL used to access the portal will be in the format https://webadaptor.domain.com/arcgis/home. For example, if the machine hosting the Web Adaptor is named *webadapter* with the domain *sdgeorg.net*, and the portal is named *arcgisportal*, the portal is accessed using the URL https://webadapter.sdgeorg.net/arcgisportal/home.

6.1.4 ArcGIS Desktop and Server

ArcGIS for Desktop – Comprehensive software used by GIS professionals on Windows PCs for a range of GIS activities including data compilation, mapping, modeling, spatial analysis, and geoprocessing. ArcGIS for Desktop extensions provide additional functionality such as 3D visualization, network analysis, schematics, and geostatistics. Desktop is the starting point and foundation for deploying GIS in organizations. It is used by professional GIS staff for desktop mapping, reporting, and analysis. It is also used by data compilation staff to create and maintain critical foundational data layers that fuel other GIS applications. This role for data stewardship is quite significant.

ArcGIS for Server – GIS back-office software that enables centralized, enterprise-level geodatabase management and server-based publication of maps and geographic information services throughout the enterprise and on the Internet as web services. ArcGIS Server supports the leading enterprise database management systems (DBMS): Oracle, SQL Server, DB2, Informix, and PostgreSQL. It is available on Windows or Linux servers on-site or in cloud configurations. This project uses on premises installations.

ArcGIS Server provides the core technology for implementing large-scale GIS in organizations and businesses worldwide.

6.1.5 ArcGIS Data Store

ArcGIS Data Store is an application supporting configuration of data stores for hosting and for federated servers used with the Portal. The following different types of data stores can be configured:

- Relational data store: stores Portal's hosted feature layer data, including hosted feature layers created as output from spatial analysis tools running in the portal
- Tile cache data store: stores caches for Portal's hosted scene layers

- Spatiotemporal big data store: archives real-time observation data that can be used with an ArcGIS Server running ArcGIS GeoEvent Server that is federated with the portal; also stores the results generated using ArcGIS GeoAnalytics Server tools

A more comprehensive list of ArcGIS Data Store features includes:

- Publish large numbers of hosted feature layers.
- When publishing large numbers (thousands) of feature layers to Portal, it is recommended to use ArcGIS Data Store to create a relational data store. Hosted feature layers that rely on the relational data store require a smaller memory footprint to run, making it possible to publish many services with fewer hardware resources.
- Publish hosted scene layers to the Portal.
- When the Portal's hosting server is registered with a Tile Cache Data Store, it is possible to publish hosted scene layers from ArcGIS Pro to Portal.
- Publishing hosted scene layers also creates a hosted feature layer. Esri recommends use of ArcGIS Data Store to create a relational data store to support this functionality; other managed databases registered with the hosting server can be used instead if preferred.
- Archiving
- High volume, real-time observation data
- When using ArcGIS GeoEvent Extension to stream high volumes of real-time data, it is possible to create a Spatiotemporal Big Data Store to archive the GeoEvent observation data in it
- Create automatic backups of relational data stores
- Backups support recovery of feature data in the event of a disaster such as data corruption or hardware failure
- Configure a failover data stores for feature layer data and scene caches
- ArcGIS Data Store allows a setup of primary and standby relational data store machines, and primary and standby tile cache machines. Hosted feature layer and hosted scene layer tile cache data is replicated from the primary machines to the standby machines
- Configure highly available spatiotemporal Big Data stores
- Configure multiple spatiotemporal big data stores to balance data loads over multiple machines and ensure availability of spatiotemporal data in the event of a machine failure.
- Analyze the Portal for ArcGIS map viewer
- Spatial analysis functionality in Portal requires that the portal hosting servers use an ArcGIS Data Store relational data store
- GeoAnalytics Tools require the hosting server to be configured with a spatiotemporal big data store.

6.2 OSIsoft PI

OSIsoft PI was originally developed to efficiently capture and store real-time data, especially time series data. Through addition of functions, and a widespread deployment in the industry, it has grown to now include a comprehensive set of functions to capture, process, analyze, store, and visualize any form of real-time data. PI is used extensively at SDG&E.

The key elements of the PI platform are shown in Figure 6-6. A standard installation is shown in Figure 6-7.

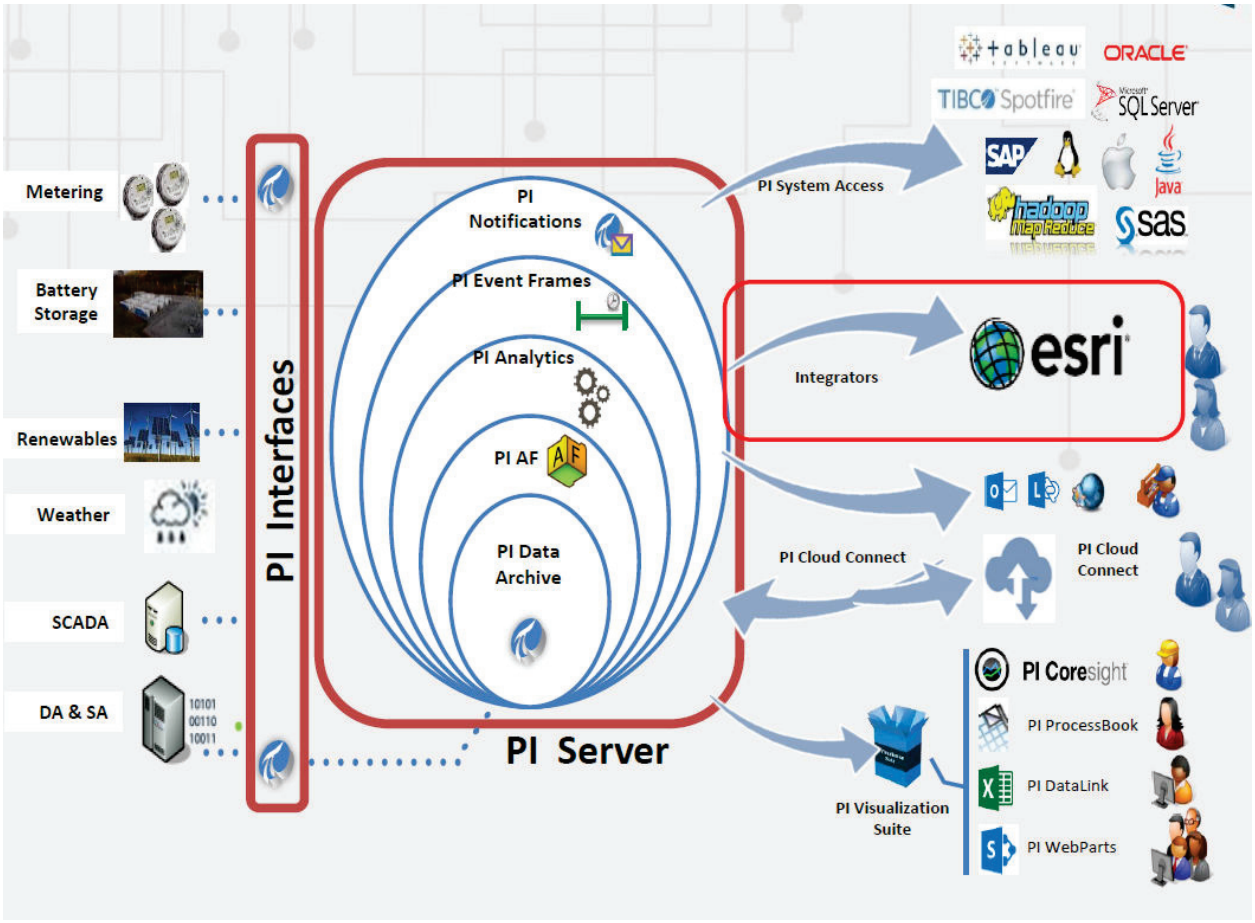


Figure 6-6. OSISoft PI System Components

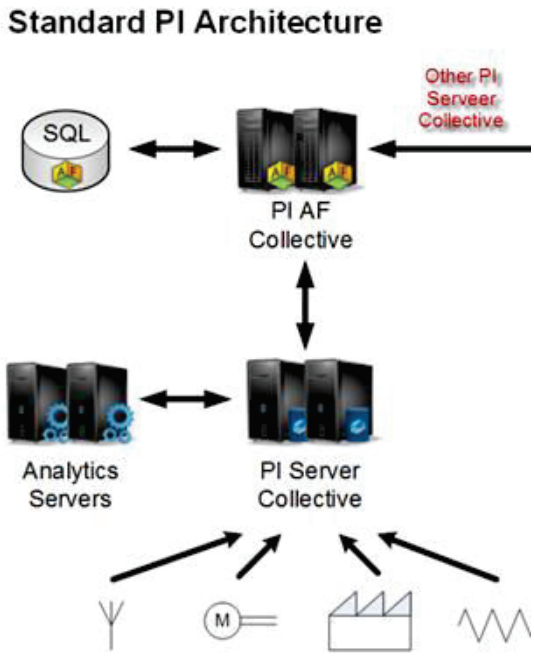


Figure 6-7. OSISoft Standard PI Architecture

A generic on-premises installation of PI systems in combination with ArcGIS is shown in Figure 6-8, and the specific configuration at SDG&E is shown towards the beginning of this document in Figure 1-1.

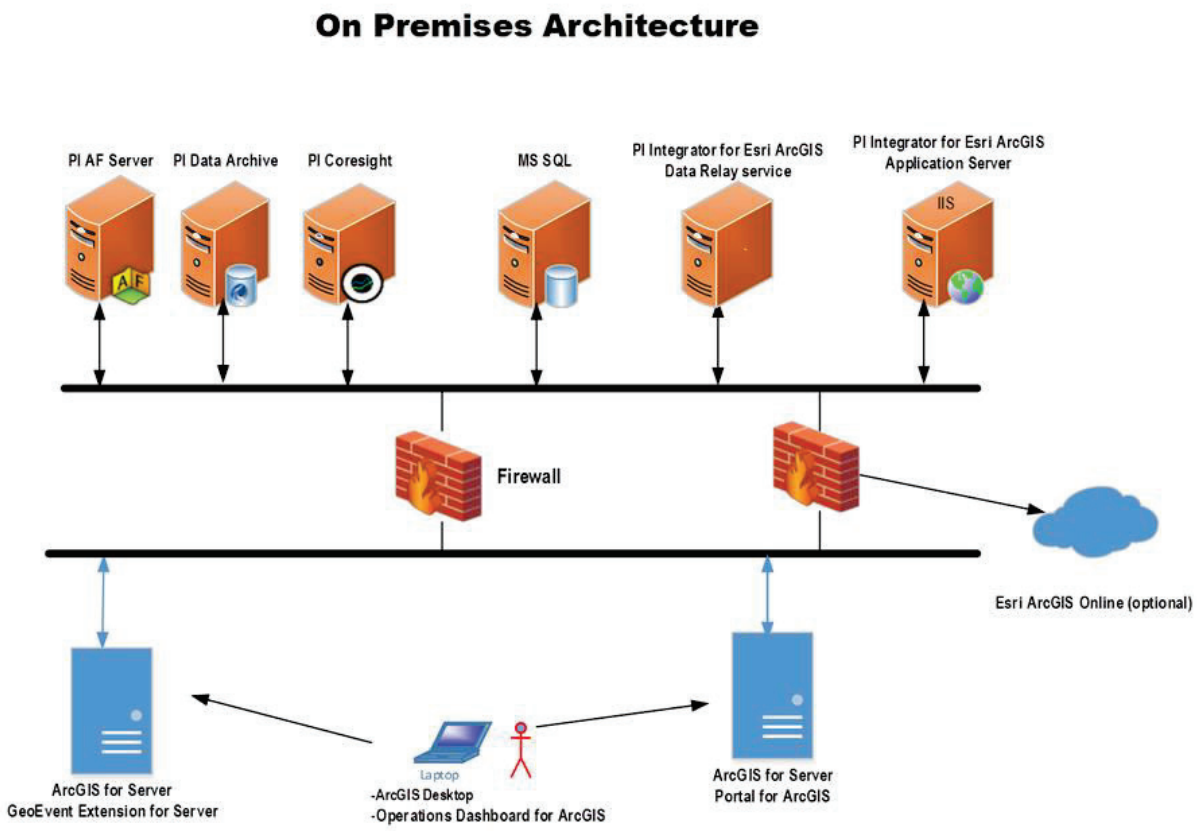


Figure 6-8. OSISoft Generic On-Premises Architecture

6.2.1 PI Integrator for Esri® ArcGIS® Overview

PI Integrator for Esri® ArcGIS® is the OSISoft product that enables a PI System to be connected with an ArcGIS Platform to first define geospatial feature services and layers in ArcGIS, and once defined, to dynamically update these with the data from PI.[6] The whole process of dynamically updating ArcGIS feature services and layers requires two components from Esri and two components from OSISoft:

- Esri
  - Esri ArcGIS for Server: manages feature services and layers
  - GeoEvent Extension for Server: provides GeoEvent Service to update real-time data, as well as Input and Output (the difference between the input and output is that additional processing can be performing on Input data within the GeoEvent Service, e.g., filtering, processing, geofencing, to produce Output)
- OSISoft
  - PI Server, containing PI Data Archive and PI Asset Framework data stores
  - PI Integrator for Esri ArcGIS, containing Application Server and Data Relay

[6] https://www.youtube.com/watch?v=7iTPdVHZkWM

The integration process starts by using Application Server wizards to setup GeoEvent Services and Inputs and Outputs in GeoEvent Extension for Server. A simple setup is when Output = Input, but manual changes in GeoEven Extension for Server can be made to institute additional transformation of Input data to Output. Here, one service is defined for each PI AF Template used.

Once the GeoEven Service is defined, at certain periodicity, the service issues HTTP (or HTTPS) to Application Server, which in turn relies on Data Relay to retrieve data from PI Data Archive referenced by an AF Template, provides it to Application Server, which in turn responds to GeoEvent Service with the requested data, which then traverses through Input to Output within GeoEvent Extension for Server, and finally updates the Feature Service on ArcGIS for Server.

The Data Relay component sends metadata and real-time information to Application Server of Esri ArcGIS.

6.3 Power BI

Power BI is a Microsoft suite of tools for efficient data analysis, which enables users to connect with many data sources to extract, analyze, and visualize the extracted data in many different ways. Once a connection to data sources is established, even the end users – without any programming skills – can specify through a Graphical User Interface (GUI) the type of analysis to be performed, and how to visualize the data and the results. Enhanced capabilities for these tasks are also available through high-level languages supported by the various Power BI sub-components.

Esri provides a component that enables display of Power BI results on geo-spatial maps, giving additional options for presenting results in addition to Excel-like tables and graphs that are available in the Power BI itself. This component, however, does not work in mixed environments, where EsriArc products run on premises and PowrBI in the cloud, as is the case at SDG&E. To overcome this difficulty, SDG&E resorted to writing its own Java-based code to allow Power BI widgets to be displayed on geospatial maps.

Major sub-components of Power BI (with yes/no indication of if used in this project):

- Power Query (yes): Data mash up and transformation tool.
- Power Pivot (yes): In-memory tabular data modelling tool
- Power View (yes): Data visualization tool
- Power Map (no): 3D Geo-spatial data visualization tool
- Power Q&A (no): Natural language question and answering engine
- Power BI Desktop (yes): A development tool for building Power BI reports and dashboards

There are other components, such as PowerBI.com Website that is used to share Power BI data analysis as cloud services; and Power BI Mobile Apps on Android, Apple, and Windows mobile devices.

Appendix 3

EPIC-1, Project 3: Distributed Control for Smart Grids

San Diego Gas & Electric Company

EPIC Final Report

Program	**Electric Program Investment Charge (EPIC)**
Administrator	**San Diego Gas & Electric Company**
Project Number	**EPIC-1, Project 3**
Project Name	**Distributed Control for Smart Grids**
Date	**December 31, 2017**

Attribution

This comprehensive final report documents the work done in this EPIC project.

The project team for this work included the following individuals, listed alphabetically by last name:

SDG&E Staff

Kelvin Ellis
Aksel Encinas
Frank Goodman
Molham Kayali
Amin Salmani

Quanta Technology, LLC

Farid Katiraei
Bahman Koosha
Ahmad Momeni
Douglas Proudfoot
Baharak Soltani
Amin Zamani

Advanced Control Systems (ACS)

Gary Ockwell
Jim Sutterfield
Xihui Yan

EXECUTIVE SUMMARY

The objective of this project was to demonstrate a prototype distribution system control capability that could manage and dispatch higher penetrations of smart devices in the distribution systems by using local control of circuits as part of a hierarchical control strategy under the distribution management system. This project was intended to help San Diego Gas & Electric Company (SDG&E) and other utilities make strategic choices concerning distributed control systems.

As the distribution system complexity increases and more intelligent electronic and power generation/conditioning devices are deployed at circuit levels, controls need to be distributed and implemented closer to the end devices. These new, fast response, control requirements result in the need for substation-to-feeder and feeder-to-feeder controls, in a truly distributed fashion.

Work on the project was divided into four main tasks. The first task involved an assessment of trends in distribution system modernization and control. A comprehensive list of distribution automation applications was compiled and eight selected for further scrutiny. To allow utilities to gauge the maturity level of their own distribution automation implementations, four different levels of functionality were defined for each of the applications.

The second task examined the requirements of the proposed advanced distributed control system. It started by contrasting the two different schools of thought in the industry on centralized versus decentralized control methodologies and then explored what additional architectural enhancements might be considered in comparison to conventional approaches. The requisite functional, technical, standards, information technologies and security requirements for the enhanced architecture were enumerated. The concept of a regionally based master controller, distinct from the traditional centralized supervisory control and data acquisition (SCADA) system, was introduced and became one of the core elements in the test system configuration. Finally, three use cases were identified that best allowed the testing and demonstration of the application, and merits of, a decentralized control approach.

The third task leveraged the earlier work to construct a test system capable of demonstrating the use cases in as realistic a fashion as possible, and to provide a platform to contrast the performance of the conventional approach to system control with that of the new approach. Rather than construct an entirely artificial test platform, the decision was made to pick two SDG&E substations that met specific requirements and model these. The selection criteria included the requirement that the two substations be electrically connected through a tie switch or breaker, and that they possess circuits with a high penetration level of Distributed Energy Resources (DERs), with lower than average reliability (system average interruption duration index (SAIDI)) and with issues related to performance and/or power quality. The resultant two-substation system was modeled using a combination of actual Intelligent Electronic Devices (IEDs), actual DERs and the remainder simulated in a real time digital simulator that allowed power hardware in the loop testing.

The final task involved conducting extensive tests on the system, beginning with factory acceptance testing and culminating with system acceptance testing and a final pre-commercial demonstration of the operation and performance of the system at SDG&E's Integrated Test Facility (ITF). The results of those tests and the comparison between the different approaches were documented and used to formulate findings and conclusions.

Conclusions and Findings:

The results provided quantifiable evidence that the distributed control of system resources could achieve benefits when compared to a conventional approach. Major benefits identified included:

- Increase the utilization and contribution of DERs
- Reduce and even prevent unintentional reverse power flow
- Produce a flatter voltage profile over the length of a circuit
- Bring voltage profiles back inside the permissible range after a system event
- Reduce system electrical losses
- Improve the power factor of a circuit
- Reduce the number of operations of controllable assets like capacitor banks, voltage regulators and load tap changers
- Dynamically adjust protection settings to increase system reliability

The tests demonstrated that the greatest benefits were obtained when the control system was able to coordinate the control of two adjacent substations and when the regionally-based master controller was controlling the system, because it provided more possibilities for system optimization.

Additional tests demonstrated that a purely substation-based control scheme was still able to provide benefit, although not to the same extent as when the master controller was present, due to the inability to coordinate and therefore optimize between the two substations.

The demonstrated benefits of the distributed control approach in the areas of DER integration, improved grid stability, reliability and power quality and better utilization of controllable assets certainly warrants additional research, as well as inclusion into the technology roadmap of any utility facing an expansion in DER and IED devices on the distribution system.

Recommendations and next steps:

The main recommendations of the project are:

- Development of a strategic plan and roadmap for incorporating distributed control architecture as part of future deployment of advanced distribution automation systems.
- To achieve distributed controls, the focus should be on identifying certain Advanced Distribution Management System (ADMS) functions, similar to the use cases explored in the project, which can be deployed in the field through substation and field controllers that are supervised and coordinated through the ADMS at the control center.
- Further investigation focused on the standardization and expansion of field area communications as a key enabler for deployment of distributed control systems in the field.

TABLE OF CONTENTS

EXECUTIVE SUMMARY ..... **III**
1 INTRODUCTION **1**
1.1 Objective 1
1.2 Issue/problem being addressed 1
1.3 Project description, tasks, and deliverables produced 2
1.4 How to read this report 4
2 PROJECT APPROACH **5**
2.1 Distributed control system review and assessment 5
2.1.1 Grid modernization trends 5
2.1.2 Distribution automation applications 9
2.1.3 Distribution automation maturity model 10
2.2 Distributed control system design 15
2.2.1 Centralized approach 15
2.2.2 Decentralized approach 18
2.2.3 Centralized versus decentralized - pros and cons 21
2.2.4 Components of a distributed control system 22
2.2.5 System requirements - general 23
2.2.6 System requirements - layers of controls and requisite speed 25
2.2.7 Use case selection 26
2.3 Distributed control system test platform construction 28
2.3.1 Substation selection 28
2.3.2 Test platform design 32
2.3.3 Test platform construction 35
2.4 Distributed control system pre-commercial demonstration 42
2.4.1 Test plans 42
2.4.2 Data collection 43
2.4.3 Communications Tests 43
2.4.4 Use case 1: Automatic Resource Control 51
2.4.5 Use case 2: Synchronized Load Transfer 76
2.4.6 Use case 3: Automatic protection setting changes 86
2.4.7 Distributed control functions 92
3 KEY FINDINGS **96**
3.1 Automatic Resource Control 96
3.2 Synchronized Load Transfer 97
3.3 Automatic Protection Setting Change 98
4 RECOMMENDATIONS AND NEXT STEPS **99**

4.1 Technology/Knowledge transfer plan for applying results into practice 99
5 METRICS AND VALUE PROPOSITION 100
5.1 Project Metrics 100
5.2 Value Proposition: Primary and Secondary Guiding Principles 101
6 REFERENCES 102
7 LIST OF ACRONYMS AND ABBREVIATIONS 103
8 APPENDIX A – ADDITIONAL USE CASE RESULTS 105
8.1 Use Case 1: Automatic Resource Control Test Results 110
8.1.1 Test Case 1.1 110
8.1.2 Test Case 1.2 111
8.1.3 Test Case 1.3 112
8.1.4 Test Case 1.4 113
8.1.5 Test Case 1.5 114
8.1.6 Test Case 1.6 115
8.1.7 Test Case 1.7 116
8.1.8 Test Case 1.8 117
8.1.9 Test Case 1.9 118
8.1.10 Test Case 1.15 119
8.1.11 Test Case 1.16 120
8.1.12 Test Case 1.17 121
8.1.13 Test Case 1.18 122
8.1.14 Test Case 1.19 123
8.1.15 Test Case 1.20 124
8.1.16 Test Case 1.21 125
8.1.17 Test Case 1.22 126
8.1.18 Test Case 1.23 127
8.1.19 Test Case 1.24 128
8.1.20 Test Case 1.25 129
8.1.21 Test Case 1.26 130
8.2 Use Case 2: Synchronized Load Transfer 131
8.2.1 Test Case 2.4 131
8.2.2 Test Case 2.5 132
8.2.3 Test Case 2.6 133
8.2.4 Test Case 2.7 134
8.2.5 Test Case 2.8 135
8.2.6 Test Case 2.9 136

1 INTRODUCTION

1.1 Objective

The objective of this project was to demonstrate a prototype distribution system control capability that could manage and dispatch higher penetrations of smart devices in the grid by using local control of circuits as part of a hierarchical control strategy under the distribution management system. This project was intended to help San Diego Gas & Electric Company (SDG&E) make strategic choices concerning distributed control systems.

The chosen focus of this pre-commercial demonstration project included:

- Understand preferred operational responsibilities and control characteristics of numerous distribution system resources that can be controlled by a distributed control system infrastructure.
- Develop and test methods of communicating and coordinating control across multiple resources to ensure that devices operate in a complementary manner to optimize distribution system performance.
- Identify distributed control methods and approaches to control resources and integrate as part of a unified control scheme that is compatible with other utility control systems such as Supervisory Control and Data Acquisition (SCADA), Advanced Distribution Management System (ADMS), Distributed Energy Resource Management System (DERMS) and Demand Response Management System (DRMS).
- Demonstrate distributed control concepts that fill gaps in traditional control system infrastructure, and are compatible with it.
- Assess the scalability and performance of the control schemes against distribution system optimization objectives, using metrics such as circuit electrical efficiency, stability, reliability, frequency control, voltage support, asset health maintenance, and operating costs.

1.2 Issue/problem being addressed

A multitude of new types of controllable devices are being introduced in the power distribution system. The new devices have inherent functional capabilities whose operation needs to be coordinated and managed, in coordination with the existing devices, to derive maximum value from the available functions and improve distribution system electrical efficiency, reliability, power quality and operational costs.

The utility distributed control system must be able to interact with these controllable devices, and process the large amount of system status information coming from these devices, sensors, and monitoring nodes. The distributed control system must also coordinate and dispatch these controllable devices in a strategic, fast and automated manner.

While the control of individual elements within an electric power distribution system is fairly well known, there is not a commonly-accepted model available for the control of the whole distribution system. The existing control strategies for the distribution system have been developed in the context of the 20th century circuit design, which are being widely changed for the distribution grid of the future.

For instance, distributed energy resources (DERs)[1] play a key role in industry trend, as utilities are moving towards a future where DERs penetrate the distribution system at unprecedented levels. It is worth noting that while concerns about impact of increasing level of DERs in distribution system on control and operation of the distribution system remain unanswered, interconnection policies are resolving the deployment challenges with the development of strict standards for more utility controls and interaction with DERs. Therefore, the ability to accurately determine mitigation actions and remotely control the system is gaining more attention by utilities.

1.3 Project description, tasks, and deliverables produced

This project demonstrated a distributed control system capable of utilizing both conventional and new types of actively controllable devices in the distribution system in response to dynamically changing operating conditions.

This unified control platform, referred to as the Advanced Distributed Control System (ADCS), was expected to be compatible with conventional distribution control system technologies, including DERMS, DRMS, ADMS, distribution automation and substation automation, as well as to have the ability to effectively manage and coordinate the resources and devices at the distribution substation and distribution feeder interacting with retail and third-party-owned resources, for example, aggregators.

After formation of the project team and development of the project plan, the project was executed over the four major task areas illustrated in Figure 1-1 below.

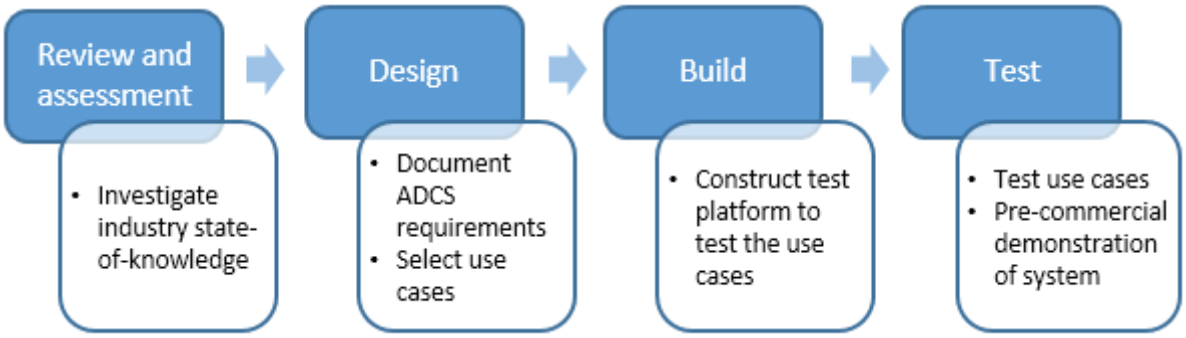


Figure 1-1. Primary project task areas

The sections that follow briefly outline the scope of work of each task and the deliverables produced.

Distributed control system review and assessment

This task documented trends in grid modernization and control based on a literature review from publicly available documents. A comprehensive list of distribution automation (DA) applications was compiled and eight selected for further scrutiny. To allow utilities to gauge the maturity level of their

[1] According to California Public Utilities Code Section 769, energy efficiency, electric vehicles, demand response, renewable resources, and energy storages are considered as distributed resources.

own DA implementations, four different levels of functionality were defined – from "Traditional" to "Trendsetter."

Distributed control system design

This task examined the requirements of the proposed advanced Distributed Control System. It started by contrasting the two different schools of thought in the industry on centralized versus decentralized control methodologies.

As the distribution system complexity increases and more intelligent electronic and power generation/conditioning devices are deployed at circuit levels, controls need to be distributed and implemented closer to the end devices. These new, fast response, control requirements result in the need for substation-to-feeder and feeder-to-feeder controls, in a truly distributed fashion. This could ultimately include peer-to-peer communications utilizing, for example, the IEC 61850 communication standard, but that falls outside the scope of this particular project.

With this basis, the project examined what additional architectural enhancements might be considered in comparison to conventional approaches. The requisite functional, technical, standards, information technologies and security requirements for the enhanced architecture were enumerated. Finally, three use cases were identified that best allowed the testing and demonstration of the application, and merits of, a decentralized control approach.

Distributed control system test platform construction

This task leveraged the work from previous tasks to design a test system capable of demonstrating the use cases in as realistic a fashion as possible and providing a platform to contrast the performance of the conventional approach to system control with that of the new approach.

The test system was constructed using a digital system simulator and the demonstration circuits were modeled after actual SDG&E distribution circuits. The selected circuits were picked because they possessed the unique characteristics that have historically proven challenging for the integration of new distribution circuit features – including high penetration of solar photovoltaic (PV) systems, presence of sensitive loads, and customers with premium power quality requirements.

Distributed control system pre-commercial demonstration

This task created a series of factory and site acceptance test procedures intended to test the use cases on the test platform, after which the pre-commercial demonstration was performed and the results captured. The demonstration was performed on the digital system simulator in conjunction with Hardware-in-Loop (HIL) and Software-in-Loop (SIL) testing at SDG&E's Integrated Test Facility (ITF) in Escondido, CA.

1.4 How to read this report

The table below provides a quick reference guide on the primary content areas of the report and the page number where each starts.

Table 1.1. Navigating the document

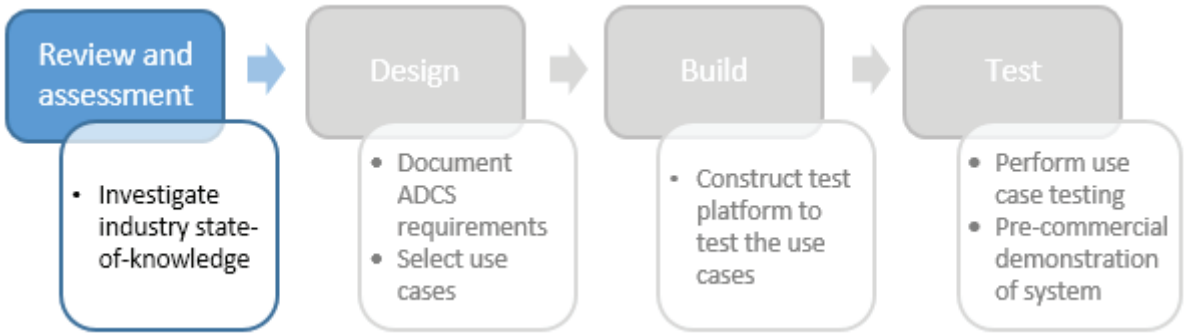
Item	Description	Starts on page
	**Task 1: Review and assess** Documents trends in grid modernization and control based on a literature review from publically available documents. Defines a distribution automation maturity model based on eight distribution automation applications.	5
	**Task 2: Design** Designs a test system and selects use cases capable of contrasting the performance of the conventional approach to system control with that of a distributed approach.	15
	**Task 3: Build** Creates factory and site acceptance test procedures and constructs a test system.	28
	**Task 4: Test** Details the test case(s) and results for each of the three use cases	42
	Findings Summarizes the results	96
	Recommendations and next steps Where to from here	99
	Appendix A – Additional use case results Provides the results for any test cases that were not described in the task 4	105

2 PROJECT APPROACH

The project started with several brainstorming sessions with stakeholders from various groups, including Growth & Technology Integration, Electric System Planning & Grid Modernization, Distribution Operations and Asset Management. These discussions were used to baseline the current state of distribution system control at SDG&E and provide a point of reference for the work that followed.

The subsections that follow provide details on the approach and results from the work performed on the four major project tasks.

2.1 Distributed control system review and assessment



The main objective of this task was to provide a summary of industry discussions and state of knowledge on advanced control and automation practices.

2.1.1 Grid modernization trends

The challenges associated with the control of the future grids as well as concerns for safe, reliable, and cost-effective operation of the grid have triggered many utilities to start planning for modernization of their electric grid. The grid modernization strategy must address challenges prompted by grid transformation drivers and take advantage of emerging opportunities. The major drivers for the grid transformation include:

- Extreme weather conditions
- Aging infrastructure/workforce
- Critical infrastructure
- Renewable surges
- Distributed energy resources

In particular, grid modernization programs should prepare the next-generation electric grid for comprehensive integration of DERs. Some of the relevant initiatives include microgrids, data analytics, smart cities, and new distribution system operator (DSO) models.

2.1.1.1 Features of a modern power distribution system

The strategy of a utility for effective operation of its power distribution system heavily depends on the changing landscape of the utility industry. Regardless, the grid modernization strategy should ensure the following feature of the electric power distribution system:[2]

- **Safety**: Grid safety minimizes exposure of personnel (crews and public) to energized equipment. In addition, potential hazards and modified operating practices caused by implementation of new technologies must be carefully studied.
- **Reliability**: Avoiding/minimizing outage times for critical/all customers is the main objective of a reliable grid design. For example, Fault Location, Isolation, and Service Restoration (FLISR) is an automation application that can reduce response time to outages. This, however, requires communication between central locations and the field in addition to new software tools that interact with field automation.
- **Resiliency**: Grid resiliency should ensure proactive/reactive response of the grid to mitigate voltage violation, system overloads, and power quality issues. It should allow for interaction with customer equipment to manage two-way power flows caused by DERs. Advanced voltage control schemes can help with realization of these goals, albeit at the cost of using automated equipment to respond more rapidly than current systems.
- **Flexibility**: Flexibility should ensure that new grid technologies can be integrated into the grid, if upgrades to existing equipment are required. For example, modular automation designs that allow for "plug and play" upgrades position the utility to keep pace with technology advancements.
- **Cost-Effectiveness**: A modern grid is not exclusively the one with best technology, but also one that is reasonable in cost for the utility's ratepayers. It is important make investments that consider the financial needs of customers, while maximizing equipment life cycle.

2.1.1.2 Capabilities of a modern power distribution system

Several new capabilities should be developed to modernize a utility's power distribution system. As discussed above, the goal of a modernization plan is to improve safety, reliability, and the associated cost in the electricity delivery. This is achieved by a wide range of investment in grid assets, technologies, and telecommunications overhaul upgrade.

These capabilities can be categorized into three main functionalities, namely, "Monitoring", "Prediction and Forecasting", and "Protection and Control."[3] [1] A number of examples in each category are listed in the following figure.

[2] "Grid Modernization: Modernizing SCE's Grid to Ensure Safety and Reliability While Preparing for Increased Levels of Distributed Energy Resources," A white paper by Southern California Edison (SCE), 2015.

[3] "Grid Modernization: Modernizing SCE's Grid to Ensure Safety and Reliability While Preparing for Increased Levels of Distributed Energy Resources," A white paper by Southern California Edison (SCE), 2015.

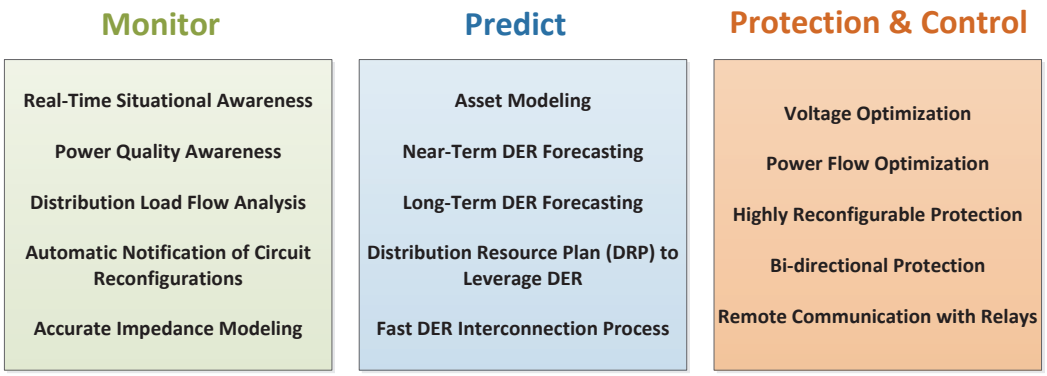


Figure 2-1. Summary of grid modernization capabilities

2.1.1.3 Grid modernization strategies

Three different business models can be envisioned for grid modernization: traditional, proactive, and aggressive.[4] [1] The selection of each business model depends on a number of external factors, including market conditions, DER adoption trends, and the regulatory policies. Further, each business model has its own set of assumptions. These assumptions are summarized in the following table.

Table 2.1. Scenario assumption in three grid modernization business models

Scenario #	Business model	Assumptions
1	Traditional	DER integration grows at a gradual rate; Undetermined policy in interaction with users and DER infrastructure; No knowledge of the technologies that will be deployed moving forward; Wider telemetry for informed decisions.
2	Proactive	DER integration grows at an increasing rate. Necessity of interaction with users and DERs in the next 10 years; Going forward with some technologies while looking forward for others to develop.
3	Aggressive	DER integration grows at a drastic rate; Regulations enforce more comprehensive interaction with users and DERs in the next 1-3 years; Utilities tend to take risks on unproven/unknown technologies.

The aforementioned future scenarios require different levels of investment – these are tabulated below. Telecommunication architecture and infrastructure, energy management solutions, and DER controls are some examples of the areas in which investments can be made.

[4] "Grid Modernization: Modernizing SCE's Grid to Ensure Safety and Reliability While Preparing for Increased Levels of Distributed Energy Resources," A white paper by Southern California Edison (SCE), 2015; "Smart Metering (SM) and Distribution Automation (DA) Program: Functional Benchmarking Report," a presentation by Booz | Allen | Hamilton (BAH) Inc., Nov. 2015.

Table 2.2. Investment measures in three grid modernization business models

Scenario #	Business model	Investments
1	Traditional	Fewer automation capabilities with telecommunication expansion; Slow energy management system modernization; Update on planning, design, and operations procedures/tools using proven technologies; No acceleration on implementation plans.
2	Proactive	Further investments on control of utility-owned assets & DERs; Modern technologies to enhance advancement of energy management systems; Additional upgrade on telecommunications infrastructure.
3	Aggressive	Grid assets modernization with a higher aggressive investment; Wide telecommunications network overhaul; Partnership with software developers to greatly scale up advanced control functions.

The associated level of risk to these three business models would vary from low to high, going from traditional approach to aggressive approach. The risk level of each modernization scenario is described in the following table.

Table 2.3. Risk levels in three grid modernization business models: traditional, proactive, and aggressive

Scenario #	Business model	Risk Level
1	Traditional	Low risk, watching to follow the winning solution; High risk of loss if DER integration accelerates.
2	Proactive	Moderate risk, the risk of stranded investment; Perhaps not prepared for emerging technology deployment, but the process can be scaled up as necessary.
3	Aggressive	High risk, the significant risk of stranded investments in modern technologies; The risk of developing advanced technologies at a higher cost.

In each future scenario, utilities will be required to adapt their resources to fulfill the requirements of the corresponding modernization plan. The resource impact is compared between the three business models in Table 2.4.

Table 2.4. Resource impact in three grid modernization business models

Scenario #	Business model	Resource Impact
1	Traditional	Using the current organizational capabilities
2	Proactive	More resources are required to manage the added advanced functionalities
3	Aggressive	Aggressive resource hiring; On-going training to keep the skill level up-to-date.

2.1.2 Distribution automation applications

Distribution Automation (DA) can be defined as "any automation used in the planning, engineering, construction, operation, and maintenance of the distribution power system, including interactions with the transmission system, DERs, and end-users."[5] A large variety of DA applications and technologies have been reported in technical literature. In general, the applications can be of either Primary type or Secondary type. Primary DA applications are those that directly benefit the performance of the SDG&E distribution system. Secondary DA applications, on the other hand, are those that support the improved performance of the SDG&E system using the data provided by the primary DA functions.

The project reviewed publicly available information to identify all potential DA applications and use cases. These were grouped into the following five categories based on their approach for improving the distribution system performance:

- Operation and Control
- Planning and Assessment
- DER Integration and Management
- Monitoring and Diagnostics
- Protection and Automation

While each application and the available technology for its implementation depends on a number of factors that will vary by utilities,[6] the aforementioned five categories represent the main types of applications identified in SDG&E. Figure 2-2 provides a shortened version of the master DA application list identified in this study.

[5] Xanthus Consulting International, "Benefit and Challenges of Distribution Automation (DA): Use Cases Scenarios and Assessment of DA Functions," A report prepared for California Energy commission, 2009.

[6] Energy & Environmental Economics Inc. and EPRI Solution Inc., "Value of Distribution Automation Applications," A report prepared for California Energy commission, 2007

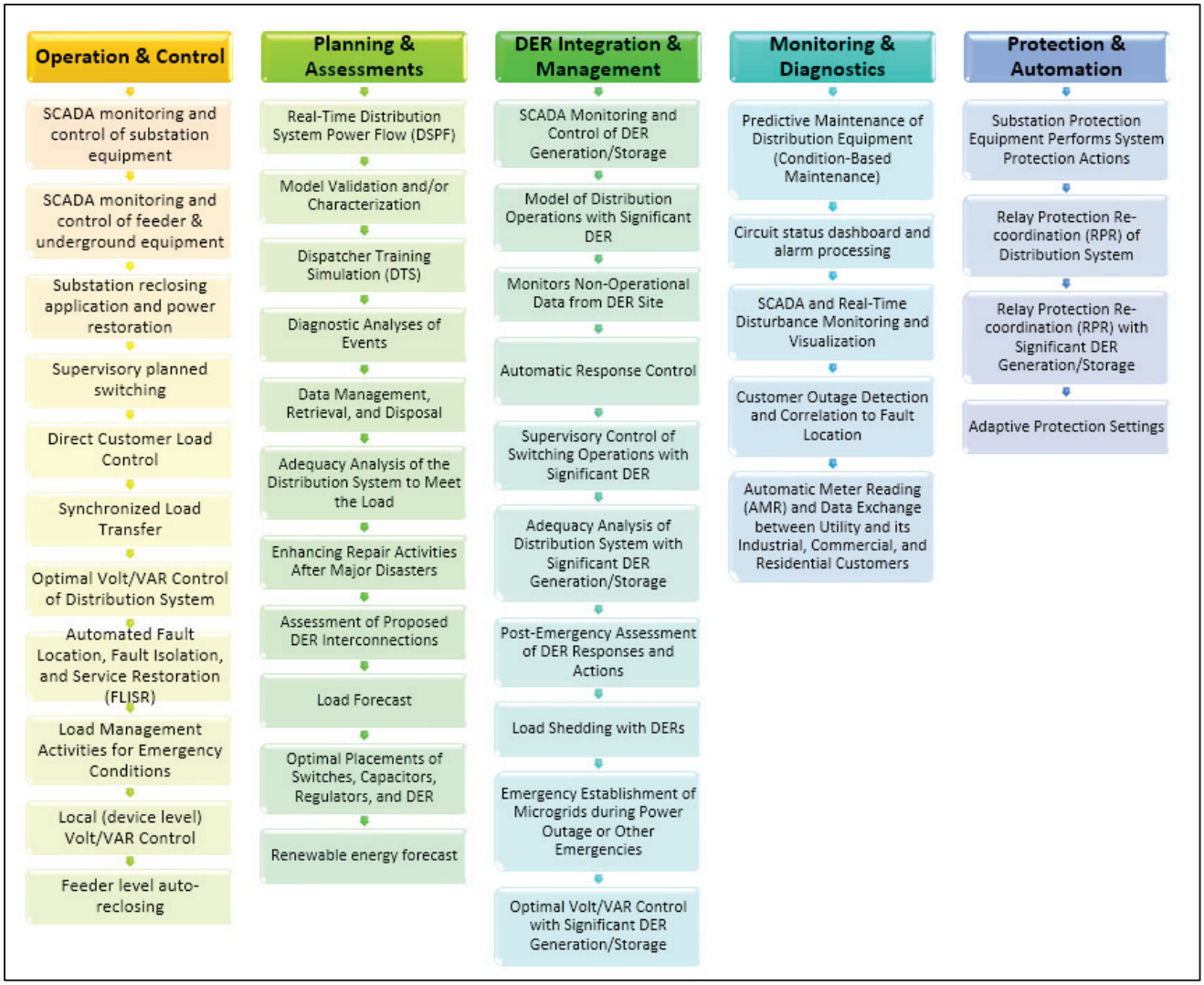


Figure 2-2. An overview of DA applications

2.1.3 Distribution automation maturity model

The objective of this section was to review some commonly implemented distribution automation (DA) applications and to define different implementation levels to allow utilities to benchmark themselves.

Eight (8) major DA applications were considered and four (4) maturity levels defined, ranging from "Traditional" to "Trendsetter". Table 2.5 provides a list of DA applications reviewed in this study along with the definition of the maturity levels.

Table 2.5. Reviewed DA applications and their maturity level

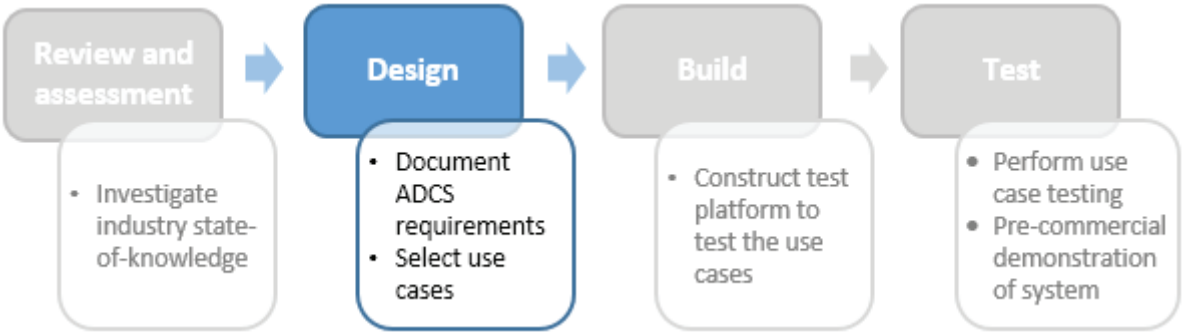
Application	Level 1 – Traditional	Level 2 – Basic	Level 3 – Advanced	Level 4 – Trendsetter
Fault Location and Service Restoration	No information on status of various devices in the distribution system is available to the operator. There is no direct way to find out about the outages. Thus, the dispatchers depend on telephone calls from customers or a sudden change in power flow at a metered location. Technician then identifies the open device responsible for the outage and locates the cause of the outage. In some cases, overhead fault indicators can give indication of the direction of the fault to speed the location of the problem. Damage is cleared and isolated section is restored	Customer calls are cataloged and analyzed by the outage management system (OMS). The call pattern data predict the most likely device initiating the outage. Single Point status sensors may be available to confirm major device status (feeder breaker or recloser) in OMS. Technician travels to predicted device and confirms/corrects outage model. Restoration is modeled in OMS as technician manually updates progress.	Advanced methods require installation of sensors on feeders and customer-ends. Such an approach requires recording the time of interruption. The data is processed using a statistical technique to determine outage locations. Once the location is known, the faulted section is isolated with the help of remotely controlled switches, if the protective devices have not already isolated the fault. Subsequently, remote switching can be done to restore power to healthy parts of the system. The OMS, combined with SCADA and fault data, can accurately locate the faults. Some switching operations can be performed to partially restore service from the control center utilizing SCADA switches.	Combination of SCADA controlled devices and fault sensors allow for local or centrally managed location of faults, automatic isolation switching, and restoration where possible. This is commonly referred to as the FLISR (fault location, isolation and service restoration). The status of the switches that operated under the FLISR scheme are reported back to the OMS, and the information is provided to the technician. The technician then travels directly to the faulted area of circuit, clears the trouble, and requests the control room to return the circuit to normal. The OMS then returns the circuitry to normal operating conditions.
Feeder Reconfiguration and Transformer Load Balancing	Manual system reconfiguration is done on a seasonal basis. Distribution planners perform offline analysis on a circuit-by-circuit basis to determine the best circuit configuration for seasonal loading. Since such reconfiguration may require several manual switching	Circuit analysis is performed using recorded peak loading conditions captured by load recorders. Circuits' peak capacity are flagged for reconfiguration and the analysis is only performed on select circuits. Reconfiguration of the system for reliability and loss reduction	Some circuits/substations are analyzed in DMS through loading scenarios, and switching/reconfiguration suggestions are made to the operator. These suggestions can be performed using only remotely-controlled devices or a blend of remotely and locally controllable switches.	Optimization modules run on a predefined frequency to attain target goals (voltage profile, losses, CVR, etc.), and DMS recommendations are implemented immediately in the field utilizing remote switches. An operator/engineer would be notified of configuration changes and be able to override reconfiguration in the cases of

Application	Level 1 – Traditional	Level 2 – Basic	Level 3 – Advanced	Level 4 – Trendsetter
	operations, it is not feasible to do it frequently.	can be done using the same switches which are used for fault isolation and service restoration. Switching is mainly performed in the field, with some remote switching via SCADA. Efficacy of load transfer is monitored via SCADA and Distribution Management System (DMS).	Since the system can operate sectionalizers remotely, system reconfiguration can be done as frequently as the operator desires.	emergency response or planned clearances.
Transformer Life Extension	Manual process: the dispatcher relies on trial-and-error to get proper level of loading. The dispatcher would close a switch to supply additional load with an expectation that the total load would be less than a certain value. But if the load is higher than expected, he would have to open the switch, drop a few feeders, and then close the switch again. The process would have to be repeated until the load is at a desired level. The switching of the load can stress the transformer significantly and, thus, reduce its total life.	It is similar to Traditional level, but there is some data monitoring including oil and transformer temperature using conventional SCADA. This level still needs few switching operations, but it is less than Traditional level.	Transformer oil level and winding temperature are monitored. Also, equipment for monitoring the health of the transformer based on dissolved gas analysis are available, as well as measurements from the feeder to which the transformer is connected. Since the feeder can be accessed by DMS, the balance between the desired loading and the feeder load can be monitored to control transformer overloading without additional switching. Thus, stress on the transformers can be avoided and its life will be extended. Fault Oscillography is available at the transformer bus to record through faults seen by the transformer.	Fully integrated and optimized within DMS system, to minimize stress on the transformers. Fault Oscillography is analyzed by DMS to evaluate I^2t exposure by substation transformer. Also, DMS alarms trigger for excessive fault duty or excessive cumulative fault exposure
Recloser and Breaker Monitoring and Control	Manual process: no remote monitoring and control is available. Recloser and relay settings are changed locally. In case of pole mounted reclosers,	Recloser/breaker statuses are monitored via SCADA, but their settings are adjusted manually. Monitoring helps to maintain recloser and breaker contact	Recloser/Breaker statuses are monitored and controlled via SCADA. The control functions include status change (Trip/Close), automatic reclosing	Advanced DMS/OMS with fully automated monitoring and control, health monitoring, and maintenance initiation is in place. Secured engineering access to

Application	Level 1 – Traditional	Level 2 – Basic	Level 3 – Advanced	Level 4 – Trendsetter
	it is very time consuming to change settings. Further, since no monitoring is available, time-based maintenance is used for reclosers and breakers even if it not is necessary.	when needed. Number of operations can be recovered from SCADA to improve maintenance strategy based on operation frequency. In addition, load currents per phase, control battery voltage, and line voltage may be reported to SCADA.	enable/disable, ground relay enable/disable, and setting group change. This allows for better control of the system when the system configuration changes. This can be done via SCADA or DMS.	controls and configure relay settings is available so that operational profiles can be changes without requiring a technician to visit the control in the field. Fault data are captured to improve maintenance programs in DMS.
Capacitor Switching for Volt/Var Control	Installed capacitor banks cannot be monitored remotely. They are controlled locally, by sending the crew to the site or through local control (voltage, time of day, load current inputs, etc.)	Some of the installed capacitors may be remotely monitored via SCADA, while some of them are remotely controllable. The voltage regulation settings are determined based on assumed load curves, historical data, and offline analysis.	Capacitors are remotely monitored and controlled via SCADA or dedicated controllers. These controllers can be programmed to use a combination of several factors for capacitor switching. In some cases, the controllers can communicate with the central station. However, the controllers respond to local conditions and, thus, they do not provide the most optimal capacitor configuration. In other words, they cannot consider the network-wide impacts of capacitor switching, leading to potential overvoltage scenarios.	Advanced DMS applications (Loss optimization, Volt/Var Optimization, CVR, etc.) enable optimal capacitor switching for different load conditions. Meters measure V, I, P, and Q at different locations. The metered data as well as status of capacitors are sent to the DMS to determine optimal capacitor switching for the prevailing system conditions. AMI data is also used to support this functionality. DMS looks into the network and prohibits a device from closing into an overvoltage. Voltage exceptions not identified by DMS are flagged in DMS for follow-up.
Regulator Operation for Voltage Control	There is no voltage regulators in place.	The regulator is controlled based on local line voltage and maintaining a band-center setpoint with a proper voltage tolerance bandwidth. In advanced cases, line drop compensation is used to overcome large distances	Regulator voltage is monitored and controlled in DMS. Regulator voltage, tap position, and settings are fully configurable/controllable through DMS.	Operation of regulators is coordinated with capacitor switching to reduce losses and/or obtain better voltage profile under different load conditions. Regulator settings are controlled dynamically based on advanced DMS applications.

Application	Level 1 – Traditional	Level 2 – Basic	Level 3 – Advanced	Level 4 – Trendsetter
		between the regulator and the load center.		
Transformer LTC Control	Manually or Locally controlled Load Tap Changer (LTC)	Tap position and LTC output voltage are monitored by SCADA. The control is normally done manually or as a function to load changes. The control is not typically implemented inside DMS/SCADA, but a separate control system.	Operation has supervision and control of the LTC through SCADA. Settings and positions are controlled through DMS.	The LTC is used as a part of the Volt/Var optimization, loss optimization, and/or CVR application. DMS prioritizes device operations based on operational objectives and impacts.
Distribution System Monitoring	Basic SCADA: Status indications of major equipment (circuit breakers and IEDs), No control and coordination with OMS exist; there is only basic local controls for Volt/Var equipment.	SCADA with basic DMS: Feeder circuit breakers and some three phase reclosers, capacitor banks, and line regulators are monitored and controlled. Load and voltage data can be monitored through DMS.	SCADA and DMS/OMS in place: Feeder circuit breakers, three phase reclosers, and Volt/Var equipment are monitored and controlled. Additional aerial and pad mounted sectionalizing device are also controlled. Status points are integrated with OMS model to instantly verify outages.	Full monitoring and control system, integrated with SCADA, DMS, and OMS Advanced applications with DERs integration, AMI/MDM, enterprise back office applications, and demand response Latest interface standards, communication protocols and cyber security in place

2.2 Distributed control system design



This task examined the architectural considerations for the proposed distributed control system using the findings from the previous task as a point of departure. It began by contrasting two different approaches to distribution control system design: centralized versus decentralized and finished by selecting three uses cases suitable for testing and demonstrating the proposed system.

2.2.1 Centralized approach

Conventional distribution control systems tend to be centralized in nature. As shown in Figure 2-3 below, a central control center communicates with an array of substation and field-based Intelligent Electronic Devices (IEDs) – polling them on a periodic basis to extract digital and analog data, and issuing commands to control primary apparatus and reconfigure the system, as and when human operators deem it necessary.

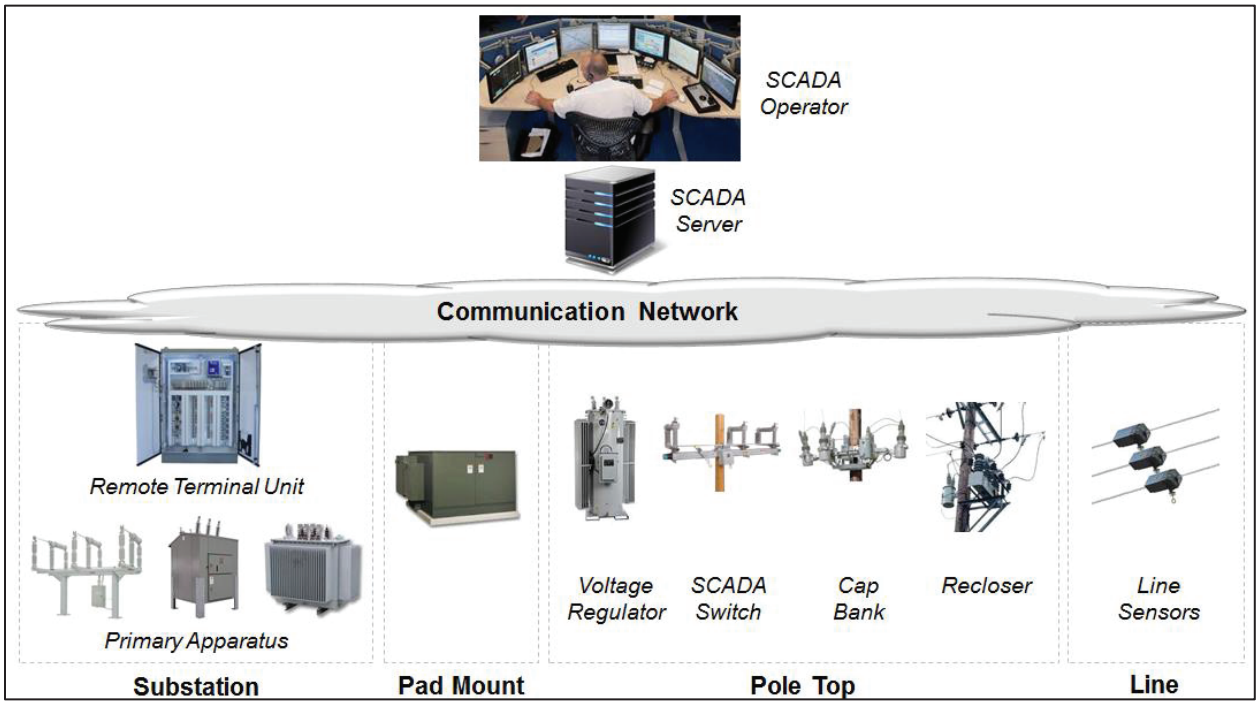


Figure 2-3. Simplistic representation of conventional distribution control system

The frequency with which the control center communicates with the IEDs is dependent on:

- The capabilities of the SCADA server in the control center and the presence, and number of, front-end-processors
- The type and speed of the communication network
- The communication protocol(s) in use
- The turn-around time of the IEDs
- The control mode: whether automatic or operator advisory

In most cases, round-robin data acquisition times of several seconds are the norm. Should an event occur on the power system that requires it to be re-configured, the time taken to do so is dependent on the capabilities of the operator to process the incoming data, determine the appropriate response and issue the necessary commands. Speed of response is typically measured in minutes, as illustrated below.

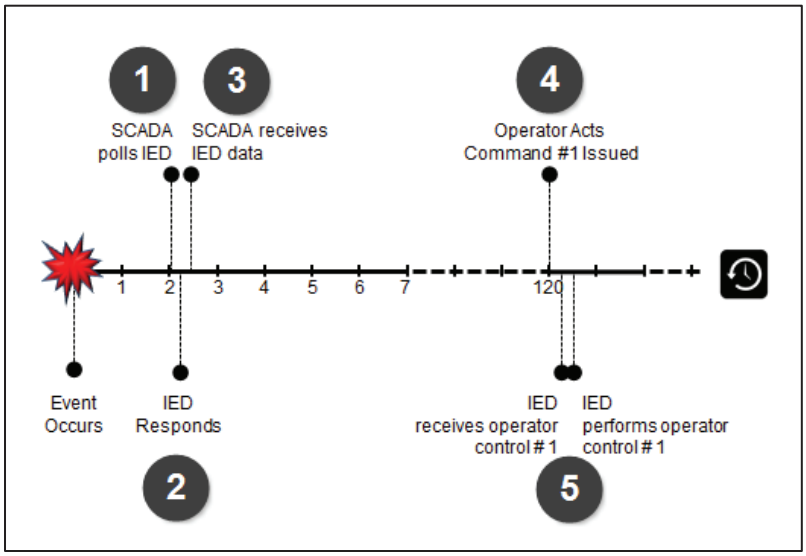


Figure 2-4. Sample event-to-action timeline – centralized design under operator control

Hypothetical sequence of actions showing manually generated operator controls:

- SCADA polls IED (assuming 2 second poll rate)
- IED responds (within 100 – 500 ms depending on IED vintage)
- SCADA receives IED data (dependent on communications baud rate. For example, it takes ~50 ms for a maximum length DNP 3.0 message at 64 kbps to be received at the SCADA, whereas the same message will take 2.64 seconds on a 1200 bps line)
- Operator acts (highly variable, and dependent on Operator's experience, type of event, amount of data, etc.)
- IED receives the first operator initiated control command and performs the requisite action. The time between receipt of message and initiation of the control is IED dependent, but in newer generation devices, largely negligible

It is possible to improve the speed of response by automating the decision tree and sequence of actions the operator undertakes for a given system event. A typical application for this type of automation is

Fault Location Isolation and Service Restoration (FLISR). Machine intelligence is deployed at the control center to detect fault scenarios, process the incoming data and follow a series of pre-programmed steps to isolate the fault and restore service to the maximum number of customers as quickly as possible. This is illustrated in Figure 2-5 below.

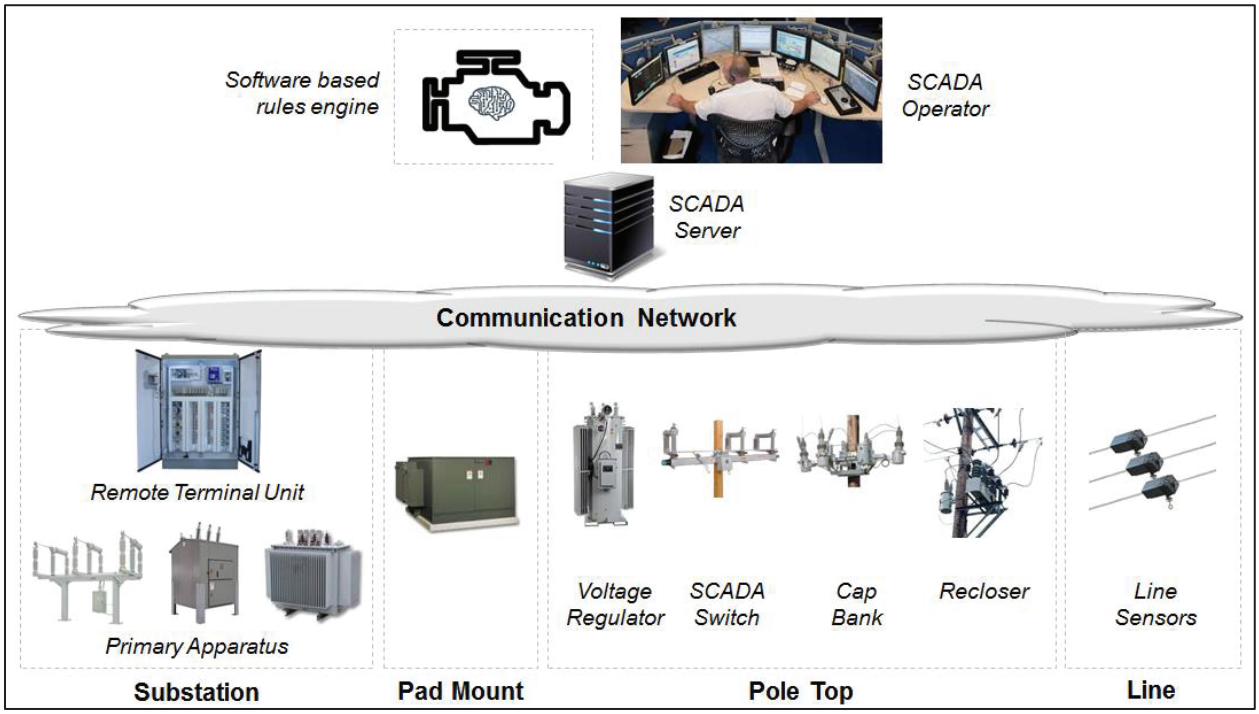


Figure 2-5. Simplistic representation of distribution control system with centralized automation

The equivalent event-to-action timeline is shown in

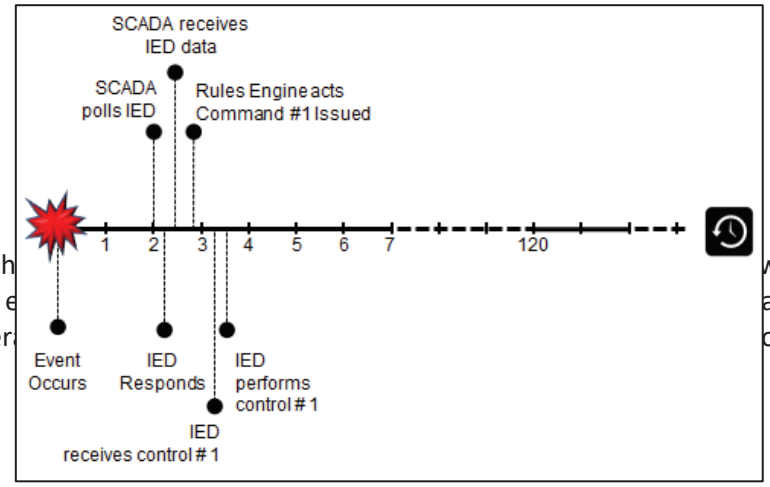


Figure 2-6 below, wh with a machine response. The rules e a fraction of the time it takes an oper onds.

Figure 2-6. Sample event-to-action timeline – centralized design under automatic control

The example above assumes that control commands are prioritized and the normal polling schedule is interrupted to send out-of-sequence communications to the IED that needs to be controlled. It is worth noting that for some applications the rapid response depicted above is neither necessary nor desirable. Certain delays may be required, for example, to allow reclosers to retry the requisite number of times before locking-out, and then only initiate the isolation actions. In these instances, the delays can be programmed into the rules engine and the response times, repeatability and quality of control decisions is guaranteed – **making automation an ideal way to improve the performance of a centralized system**.

2.2.2 Decentralized approach

The key premise of the decentralized approach is that decision making is driven to the lowest level possible and as close to the initiating event as feasible. The speed at which various control functions are performed can vary significantly depending on the control requirements and type of events with much less dependency on SCADA communications. In this case, the control center's role is that of a "supervisory systems", allowing high speed and time speed controls to be performed closer to the point of action.

Several technology advancements have made this decentralized approach possible:

- The advent of newer generation of IEDs with more processing power and communications ability
- The introduction of newer generation of communication protocols that allow for peer-to-peer communications
- The availability of IP-enabled, substation hardened communication equipment that have facilitated the gradual convergence of utility information technology and operational technologies (IT/OT)

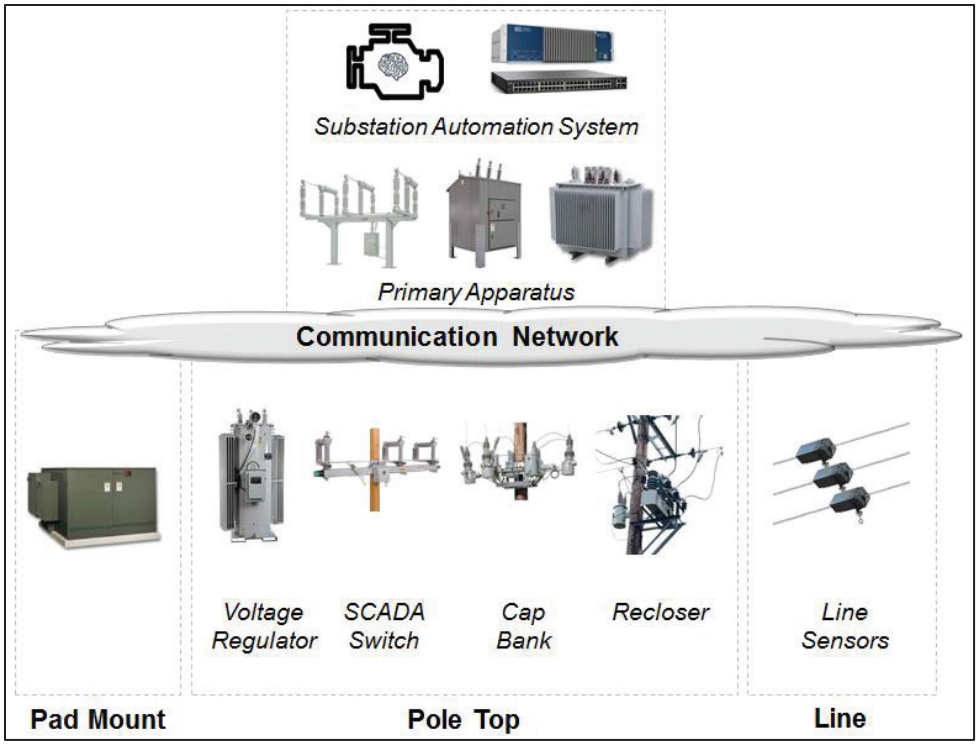


Figure 2-7. Substation-centric decentralized design

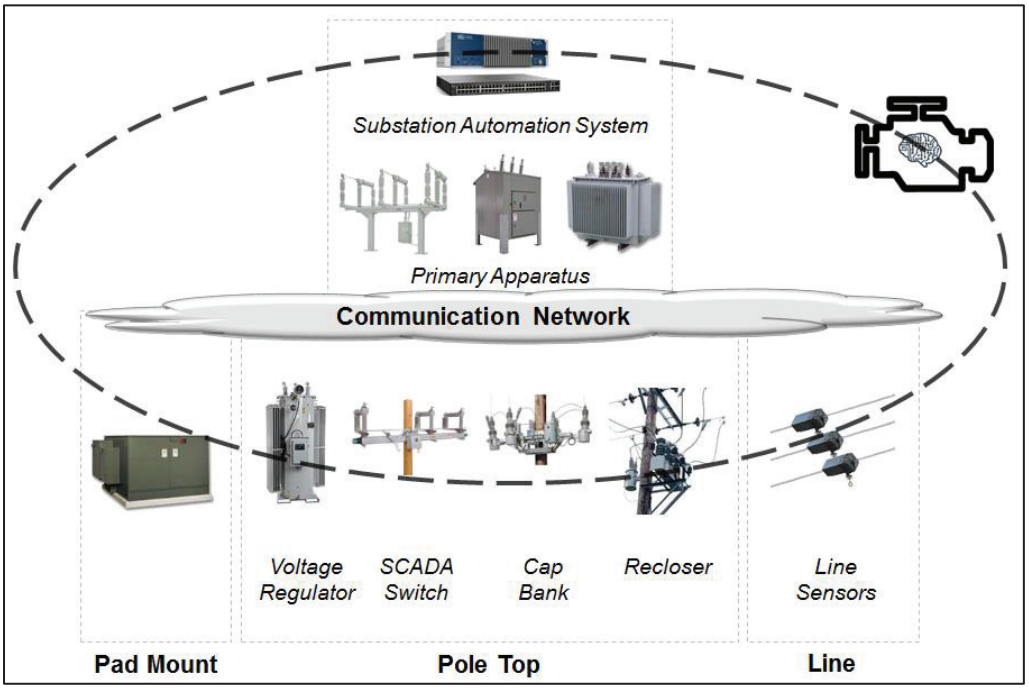


Figure 2-8. Peer-to-peer based decentralized design

Figure 2-7 and Figure 2-8 above illustrate two different approaches. The more conventional is the substation centric design where the processing power of the substation automation systems that are gradually replacing remote terminal units (RTUs) are used to provide a computing platform for the automation applications. It mirrors the centralized approach in that all data flows upstream to a single device – in this case the substation automation system – decisions are made and then distributed to the required IEDs. The associated event time line will look something like Figure 2-9:

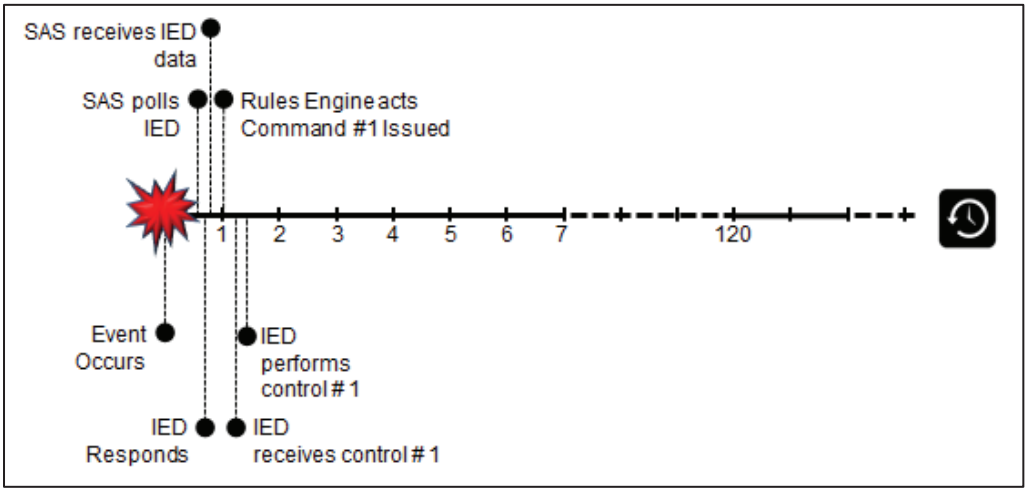


Figure 2-9. Sample event-to-action timeline – decentralized substation-centric design

Data acquisition times are reduced since there are less downstream devices that need to be serviced, so response times are faster than the SCADA-centric automated equivalent and measured in a couple of seconds. In contrast, the peer-to-peer approach is truly decentralized, and there is no central decision making rules engine. Requisite data are published to all devices that have registered to receive them and decision are made by the IEDs, all of which are required to have sufficient processing power to implement portions of the rules-engine.

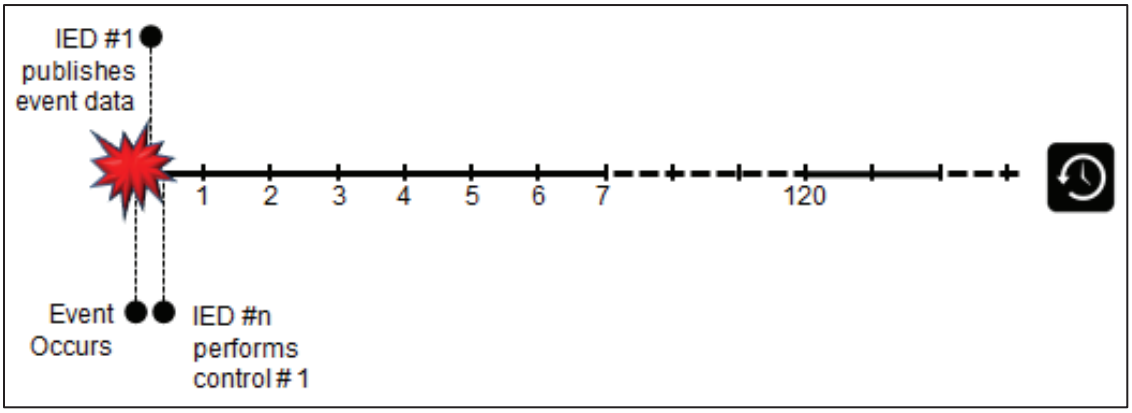


Figure 2-10. Sample event-to-action timeline – decentralized peer-to-peer design

The timeline is even more compressed and sub-second response times are now possible. As noted previously, there are some applications where this high-speed response can be fully utilized and others not.

2.2.3 Centralized versus decentralized - pros and cons

There are advantages and disadvantages to both centralized and decentralized approaches – summarized below:

Table 2.6. Comparison between centralized and decentralized control approaches

Parameter	Centralized	Decentralized
Situational awareness	Comprehensive The as-switched status of every system component is available (subject to whatever restrictions apply from communications connectivity and update times) The advantage of the centralized man-in-the-loop is the ability preview the situation before changes are made	Limited Restricted to the local area - substation or lower. Any information from neighboring substations has to be fed downstream from the control center in a convoluted manner – possible, but inelegant – that is unless a peer-to-peer connection can be made.
Speed of response	Low As discussed	High As discussed
Accuracy	Restricted The delays imposed by the "man-in-the-loop" may limit the accuracy of the selected solution, because changes during the decision process may require a new decision or approval cycle	Optimal The solution is implemented as soon as possible following an event, minimizing the likelihood that the solution is invalidated by another event. Once the solution is implemented, the system is armed for the next event as soon as possible
Resiliency	Very heavily dependent on communication infrastructure and any interruptions in service halt all transactions	For the most part can act autonomously from the control center so status of upstream communications has no impact on ability to operate
Maintainability	Easy from the perspective that all logic is managed in one location. However, depending on the vintage of the system, the entire model may require updating, making the process cumbersome and time consuming	The logic is present in multiple locations which can require more steps to make modifications. However, it does have the advantage that the model can be updated incrementally without impacting other non-affected parts, making updates simpler and faster
Personnel safety	More reliant on human intervention and therefore more susceptible to human error	Faster response times and deterministic behavior should improve personnel safety

Parameter	Centralized	Decentralized
Scalability	Determined by the SCADA server capacity and capability, as well as communication infrastructure	Highly scalable, with less dependency on SCADA backbone
Physical and cyber security	Typically have better and comprehensive physical and cyber security postures than de-centralized control systems. Standards for protecting centralized systems are further evolved than standards for de-centralized systems. Unauthorized access to centralized systems puts more assets in jeopardy than in a de-centralized system	More access points and commensurate increase in complexity to protect
Technological enhancement	Has to be implemented in steps and at some point may require a complete overhaul of the SCADA backbone, which increases the capital cost investment	Gradual and continuous, requiring lower capital investment
Dependent on	Access to a reliable and high speed / high bandwidth communication system with high resiliency. Redundant SCADA servers and fast and seamless fail-over mechanisms to prevent SCADA downtime	Local processing capabilities in the IEDs and peer-to-peer communications for some applications

2.2.4 Components of a distributed control system

The main components of a distributed control systems are:

1. Control platform that is a combination of logic/algorithms programed in hardware devices and software programs
2. Control applications: a series of applications that target specific objectives and/or coordinated actions
3. Communications system: a mix of hardwired and/or wireless methods for transferring data and commands between the components of the control platform
4. Database (on a server or a cloud) for data gathering and data sharing among the applications
5. End devices:
    - Feeder level devices, including: SCADA switches, reclosers, capacitors, voltage regulators,

- DER devices: energy storage systems (ESS), PV systems, power conditioning units, other distributed generation (DG) units

6. Measurement sources:
   - Non-SCADA measurement devices (*e.g.*, advanced metering infrastructure (AMI))
   - Measurement from SCADA devices on the circuits
   - Measurements through RTU devices at the substation

2.2.5 System requirements - general

The main functional requirements for a distributed control system irrespective of target applications and/or end-devices as part of the control are tabulated below:

Table 2.7. Functional requirements for a distributed control system

Parameter	Functional requirements
Proven and innovative solution	A distributed control system (DCS) technology should be proven in the most demanding automation environments. It should also offer innovative solutions vital to improved system operations in a fiercely competitive climate. Major areas to apply innovative and proven solutions are: • Proven communication networks for fault tolerance, performance and security • Stable and time-tested controllers and device-level interface design • Versatile and robust control environment with proven control algorithms • Pre-built template and rich function libraries enabling rapid implementation of best practices • Built-in function blocks specific for power applications and distribution system automations • Advanced batch file control capability
Built-in redundancy	True redundancy is required in all levels of the system from the I/O all the way up through the I/O link, the controllers, the network and the servers. There should be no single point of failure in the entire process. In addition, fail safe consideration should incorporate transferring of the controls and commands to alternative devices and/or platforms to maintain certain level of autonomous operation, as long as there are no drastic change in operating conditions.
Integrated platform environment	The DCS platform should allow direct access to controllers for process data, alarms and messages for constant view and control of the process. Also, the integrated platform facilitate data exchange and utilization freely among various players and components.
One data ownership	By sharing a singular database across controllers and human machine interfaces (HMIs), it helps maintain global data consistency while enabling greater usability and operability.
Simple configuration and use of	Distributed controls in the new environment heavily rely on advancement of monitoring and visualization to assist the operators in area awareness and making inform decisions. Hence, the higher focus should be given to the HMI capabilities and features, such as:

Parameter	Functional requirements
visualization system	• Standardized display library • Multi-level hierarchy windows with single click navigation • Pre-built equipment templates for easy configuration and maintenance • Bulk configuration tools that eliminate repetitive manual tasks • Dynamic alarm suppression that simplifies plant operations • Trending and playback capabilities for forensic analysis
Flexibility to expand control	The control platform should be able to easily handle integration of new devices and control processes without imposing unnecessary limitations. Distribution systems are evolving with the fast pace of changes occurring in the underlying technology and customer expectations. The controllers should be able to: • Grow to fit the emerging needs • Implement control where it is necessary

2.2.6 System requirements - layers of controls and requisite speed

For the purposes of defining the requirements of the proposed advanced distributed control system, the system elements were assigned to different functional levels as illustrated below. One of the primary differentiating characteristics between the layers, in addition to attributes like applicable industry standards, security, redundancy requirements, etcetera, was the speed of control performance. The applicable time domains of control performance are included below.

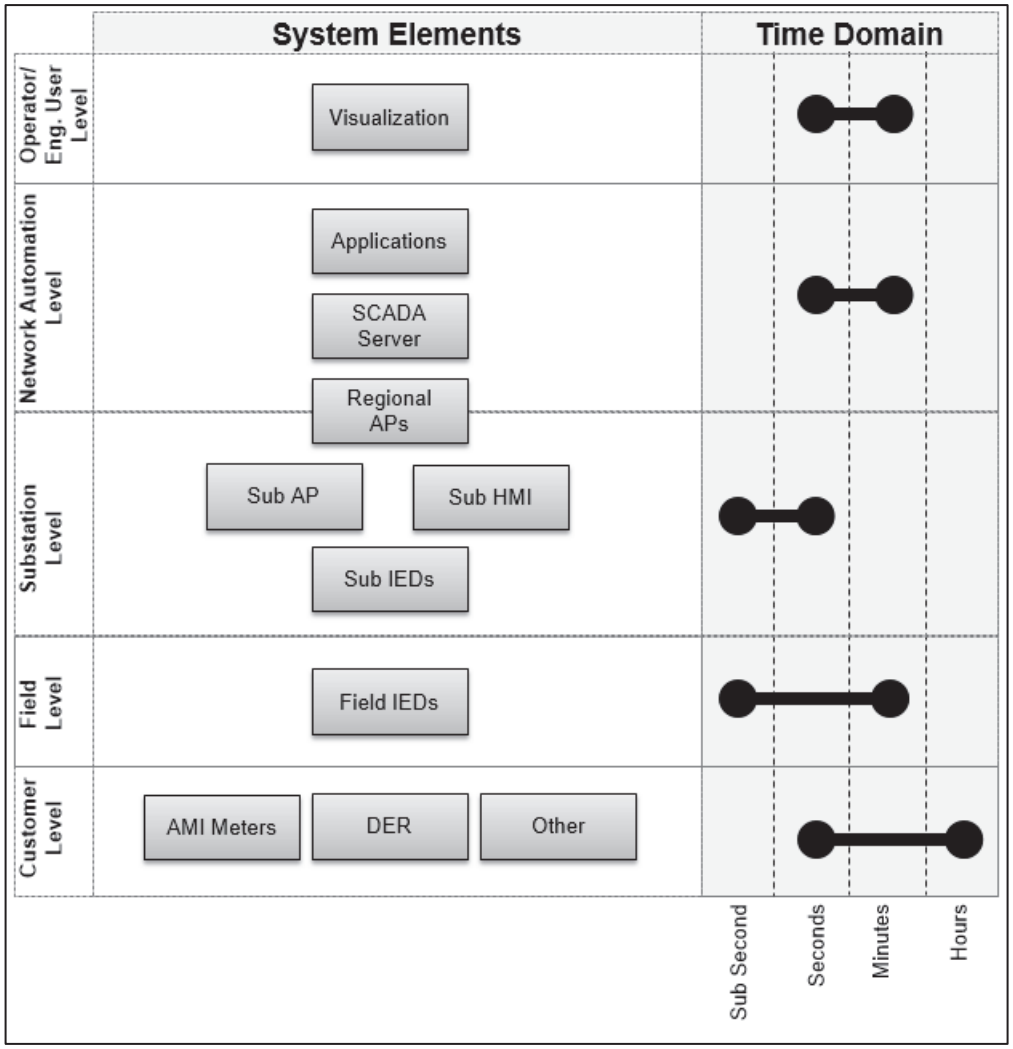


Figure 2-11. System elements at the various levels

Most of the system elements are self-explanatory and have been introduced in the preceding discussions (*e.g.*, the various types of IEDs, SCADA Server, etc). One new element that forms the basis for the ability to truly distribute control and automation functionality is the Application Processor (AP). This is a generic term for an automation engine that has the ability to interface with other devices, extract data from them, make high-speed autonomous decisions and communicate the results as commands and notifications. As shown, this could take the form of a substation-based AP, responsible for managing the operation of the substation and associated feeders, or it could be a Regional AP,

responsible for managing the operation of multiple substations in a region. The ability to distribute the logic and adjust the extent of the area under control is key to creating a system that can scale and be future proof and forward compatible.

2.2.7 Use case selection

As part of Distributed control system review and assessment task, the project reviewed the publicly available information to identify all potential DA applications and use cases. After discussions with project stakeholders, a short list of three use cases were selected that best allowed for the comprehensive validation and testing of the proposed distribution control architecture – these are identified below, and described in more detail in the sections that follows:

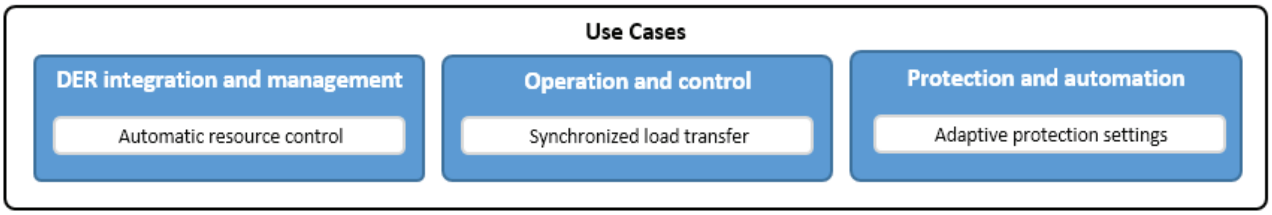


Figure 2-12. Selected use cases

Use case 1 - Automatic response control

Advanced distributed control techniques in distribution systems require close coordination amongst all the controllable equipment, including but not limited to DERs, capacitor banks, tap changers, voltage regulators, etc. With the proliferation of DERs, and the advent of advanced distribution automation applications, the operating principles of distribution systems are challenged. One method to address these challenges is to control controllable field equipment as well as dispatchable DERs such that system performance criteria including circuit loading, voltage profile, and losses are met. In particular, fine tuning/control of DER output powers (real and/or reactive power) can significantly reduce unnecessary stresses on system assets. The Automatic Response Control (ARC) application is used to reduce electric feeder losses and to flatten the Voltage profile of the feeder while maximizing the injection capability of the renewable devices, despite there being multiple feeder injection points.

Advanced strategies are needed to mitigate the adverse impacts of DERs on the distribution system while harnessing the benefit offered by them. The general philosophy is that DERs should generate at unity power factor (*i.e.*, no reactive power contribution). However, smart inverters offer advanced functionalities (including real- and reactive-power control) that can potentially improve grid stability and voltage regulation. Further, coordinated control of field devices such as load tap changers, voltage regulators, and capacitor banks can optimize the performance of the power system and facilitate integration of DERs into the electric grid.

Use case 2 - Synchronized load transfer for renewables

The effects of DERs on the performance of the distribution system may no longer be adequately managed by conventional approaches. The Synchronized Load Transfer (SLT) function, capable of changing circuit configuration through corrective automated switching actions, is one of the new control techniques that can help with integrating DERs into the electric grid.

The main objective of the SLT is to achieve the optimal configuration of distribution circuit(s) in order to improve operating conditions such as voltage profile, load balance, losses, overloading, and/or to prevent excessive reverse power flow from local distributed generation (*e.g.*, PV production). Under normal conditions, the SLT is performed when the circuit operating conditions cannot be improved through the automatic resource control (*i.e.*, control of load tap changers, voltage regulators, capacitor banks, and/or distributed generators).

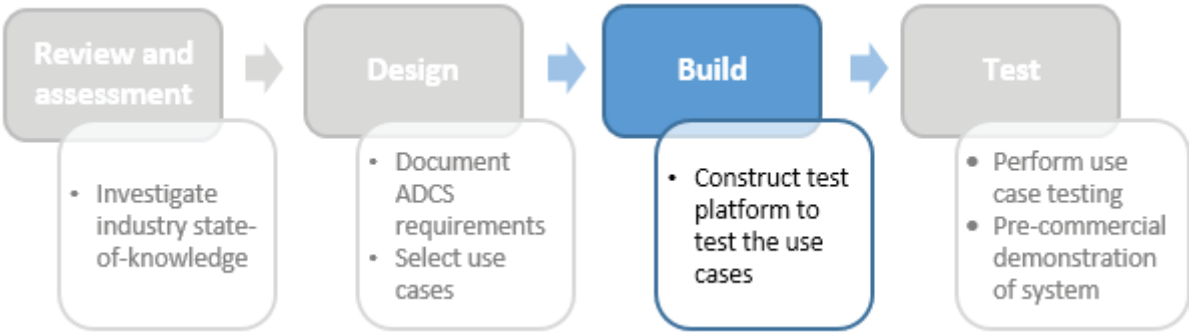
Use case 3 - Adaptive protection settings

The effect of distribution system changes on the protection system is traditionally managed by determining the relay settings for worst-case scenarios. With the high penetration of DERs and advent of distribution automation applications, this approach will no longer be adequate. Therefore, automatic protection setting change capable of changing protection setting groups based on the system topology can improve the protection system reliability.

The Automatic Protection Setting (APS) is a near-real-time activity that automatically modifies the protection setting groups in response to a change in system conditions or (forecasted) configuration in a timely manner by means of externally generated signals or control actions. It is a distributed control application that requires access to the state of switching device, protective devices, and Intelligent Electronic Devices (IEDs). Based on the state of the switching devices received from IEDs or other changes in the system configuration, the APS will change protective setting groups in one or more relays to prevent protection mal-operation and/or mis-coordination.

The main objective of the APS is to adapt the protection system to change in the power system condition and/or topology in order to improve the reliability and quality of service while incorporating advanced capabilities for optimal management of the distribution system.

2.3 Distributed control system test platform construction



2.3.1 Substation selection

Rather than constructing an entirely artificial test platform, the decision was made to pick two substations that met the selection criteria and then model these. The following attributes were considered during the selection process:

- Two substations that could be electrically connected through a Tie switch or breaker to investigate the impact of distribution automation applications
- Circuits with a high penetration level of DERs
- Circuits with lower than average reliability (SAIDI)
- Circuits with issues related to performance (losses, circuit loading, etc.) and/or power quality (voltage quality issues, etc.)

After evaluating these criteria, Substation "A" and Substation "B" best met the criteria for the reasons enumerated in the table below.

Table 2.8. Substation selection rationale

Criteria	Characteristics
Substation proximity	The selected substations were fairly close to each other with tie switches between them. Furthermore, there were tie switches between the circuits of each substation that provided the potential for implementation of distribution automation functions.
DER penetration level	Substation A and Substation B were among the 20 substations with the highest level of DER penetration. • Substation A had the highest level of DERs in its circuits • Substation B had the second highest energy storage system installation
System reliability	Substation A and Substation B were among the 10 substations with the highest SAIDI and system average interruption frequency index (SAIFI) values
Circuit performance	Substation A and Substation B were among the 10 substations with the highest level of capacitor failures. The main reasons for capacitor failure are normally

Criteria	Characteristics
	overheating, over-voltages, and voltage imbalances, all of which indicate performance issues.
Power quality	Substation A and Substation B were among the 10 substations with the highest level of highest level of voltage imbalance – possibly as a result of the high DER penetration level as well as load diversity in the circuits fed by these substations.

A simplified version of the resulting system single line diagram of the two substations and the respective feeders that are tied together via a tie breaker are represented in the following figure.

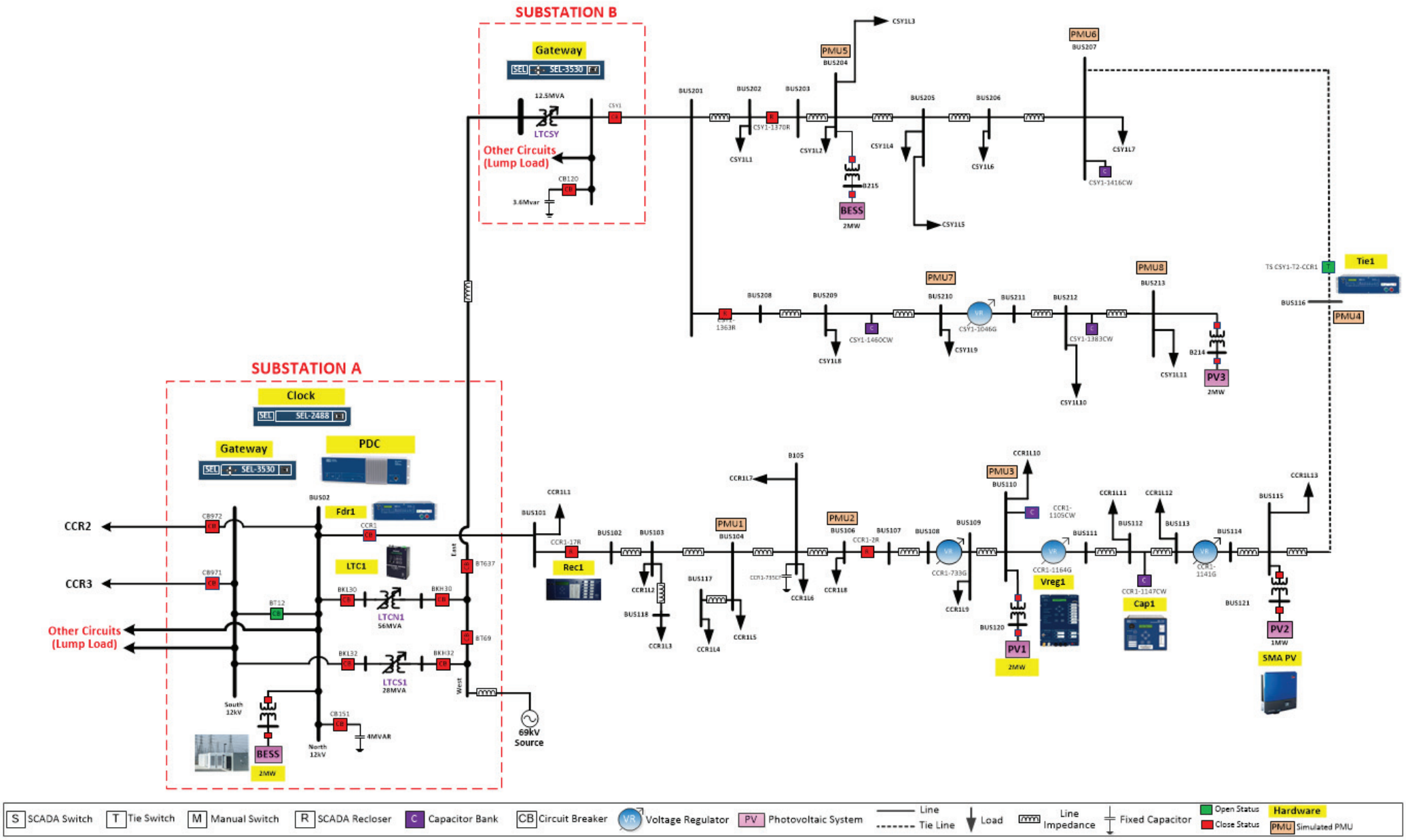


Figure 2-13. Single Line Diagram (SLD) of distributed control system test platform

The power components included in the model are listed in the table below.

Table 2.9. Power components of circuits CCR1 and CSY1

Item	Device	Quantity of Components in	
		Substation A (Circuit CCR1)	Substation B (Circuit CSY1)
1	LTC	2	1
2	Circuit Breakers	10	1
3	Line Recloser	2	2
4	Voltage Regulators	3	1
5	PV system	2	1
6	Shunt Capacitors	2	3
7	Tie Switch	1	N/A
9	Battery energy storage system	1	1

While much of the system was modelled in the digital simulator, extensive use was made of actual hardware devices – both IEDs and DERs. These are indicated in yellow in the Figure 2-13 above, as well as listed in the table below:

Table 2.10. Physical hardware IEDs included in the test setup

Item	Device	Location		Abbreviation
		Substation A	Substation B	
1	Feeder Protection Relay (CCR1)	x	-	Fdr1
2	LTCN1	x	-	LTC1
3	Recloser CCR1-17R	x	-	Rec1
4	Voltage Regulator CCR1-1164G	x	-	VReg1
5	CAP CCR1-1147CW	x	-	Cap1
6	PV 2	x	-	PV2
7	Tie Switch TS CSY1-T2-CCR1	x	-	Tie1
8	BESS 1	x	-	BESS1
9	PDC	x	-	PDC

The capability of switching from simulated IED models to physical IEDs was also implemented in the design of the test system to compare the control functionalities of the system controllers in dealing with real hardware as well as simulated (simplified) devices.

Each hardware IED also had a simulated version modelled in the digital simulator. This allowed the project to run the system completely independent of the hardware units to test and verify the

communications interfaces and control logic without using any hardware-in-the-loop. Once the testing of the "all-simulated" base system was completed, individual hardware units could be brought on line to replace the simulated equivalent.

A simple, but elegant, mechanism was implemented to manage the switch-over from the simulated environment to the physical realm. The control and monitoring points associated with each IED were duplicated in the substation controller. A software toggle accessible from either the Local HMI or the master controller determined which data set was used for any local distributed logic, and fed upstream to the master controller.

2.3.2 Test platform design

The test platform architecture incorporated three layers of controls, namely:

- A master controller located in the control center which was used to perform optimization functions and coordinate the operation of field-based (lower level) controllers.
- Substation-based controllers – one in each substation – that acted as gateways for connecting substation and feeder IEDs to the control center and which were responsible for control logic specific to that substation and downstream feeders.
- Substation and Feeder IEDs that were the lowest-level controllers in the test system.

Figure 2-14 below shows how these three different control levels map to the conceptual distributed control architecture discussed previously. As shown, the master controller could be either a Regional Application Processor (AP) or a centralized SCADA Server plus applications. The substation controller represents the substation-based AP, and the local controllers are the substation and feeder based IEDs.

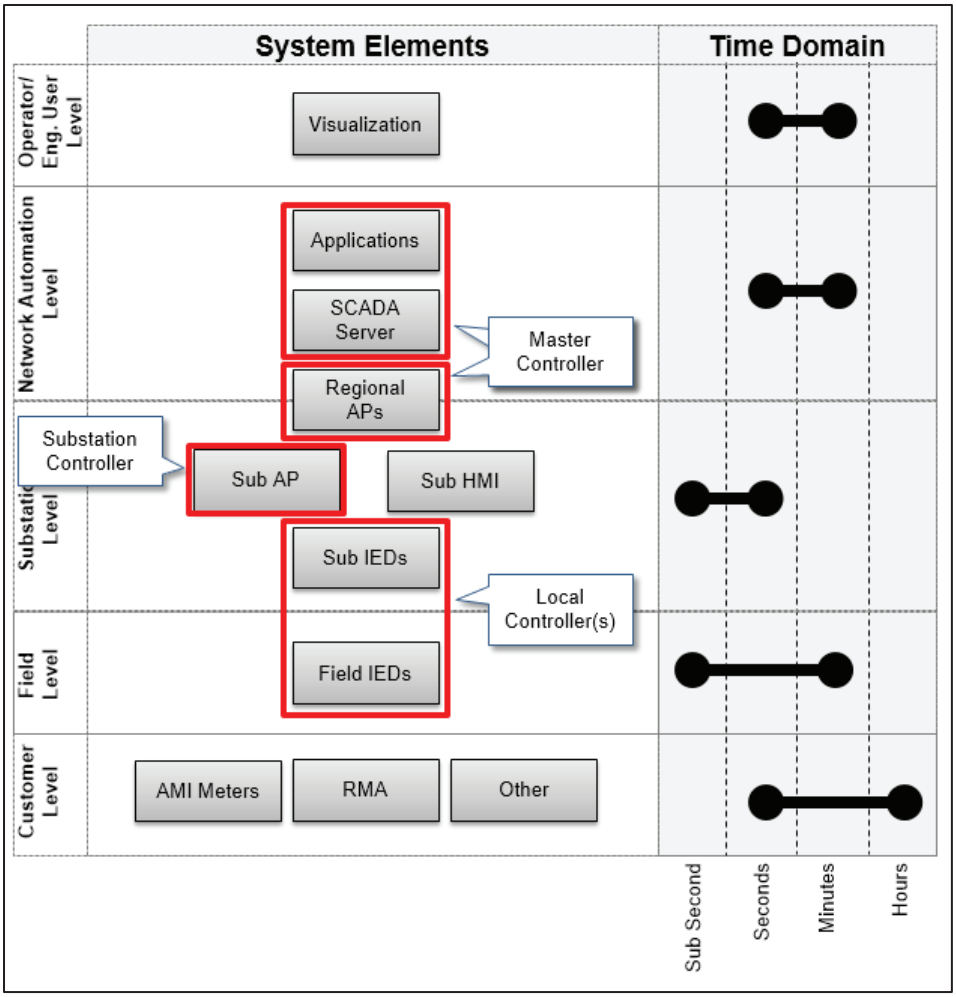


Figure 2-14. Three levels of control in the test system

Figure 2-15 below illustrates the interconnections between the various elements utilized in the test setup.

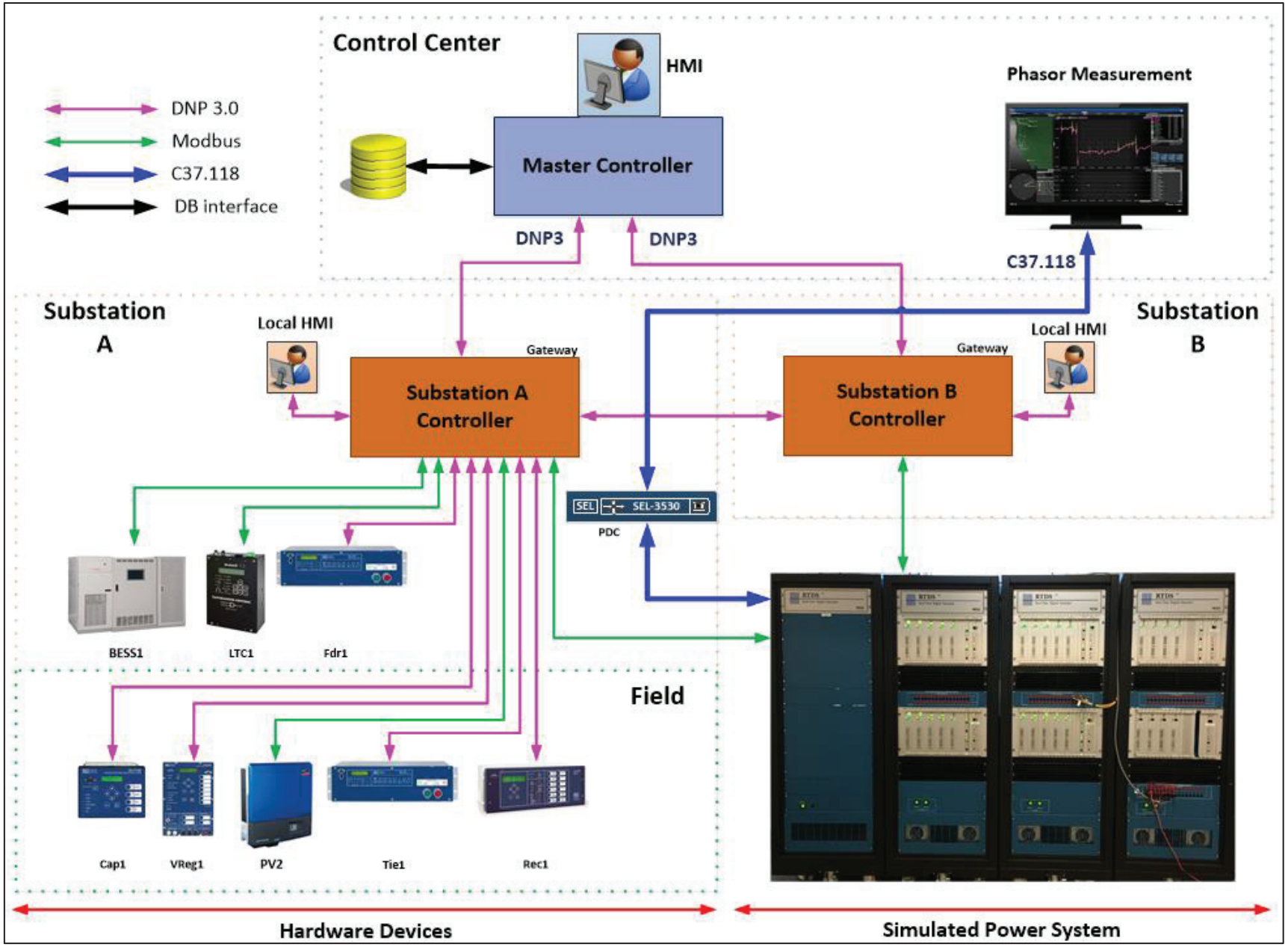


Figure 2-15. Communication architecture of distributed control system test platform

The table that follows provides a description of the functionality provided at the three different control levels.

Table 2.11. Key platform elements

Device	Description
Master controller	The master controller used a commercial SCADA package from Advanced Control Systems to run supervisory control functions for the entire test platform. Functionality included: • Acting as an automation engine for the control and automation functionality required to execute the requisite logic for the three use cases • Providing an operator interface from which control commands and setpoints could be issued to downstream devices • Providing an operator interface where digital, analog and accumulator data could be viewed, trended and alarmed upon. • Acting as a source for the data for the PI System, the primary repository for system data generated during the various use cases for later analysis • Acting as a secondary data repository
Substation controller	The two substation controllers were implemented on SEL RTACs. Functionality included: • Acting as automation engines for the control and automation functionality required to execute the distributed logic for the use cases for those instances where control responsibility was ceded to the Substation Controllers – either by operator command, or as a result of loss of communications between the substation and master controllers • Acting as data concentrators for both substation and feeder based IEDs • Acting as control and monitoring gateways between master controller and the substation and feeder based IEDs.
IED-level Controllers	The lowest control level was the individual IEDs, some of which possessed programmable logic functionality, although there were restrictions on the processing power available in specific IEDs that curtailed the extent of the logic that could be implemented. Functionality included: • Protection against overcurrent • Local (discrete) voltage adjustment (LTC and Cap Bank controller) • Local voltage tuning (through DER droop mode, if supported)

2.3.3 Test platform construction

The various hardware components were installed in two 19” racks as illustrated in the figure below.

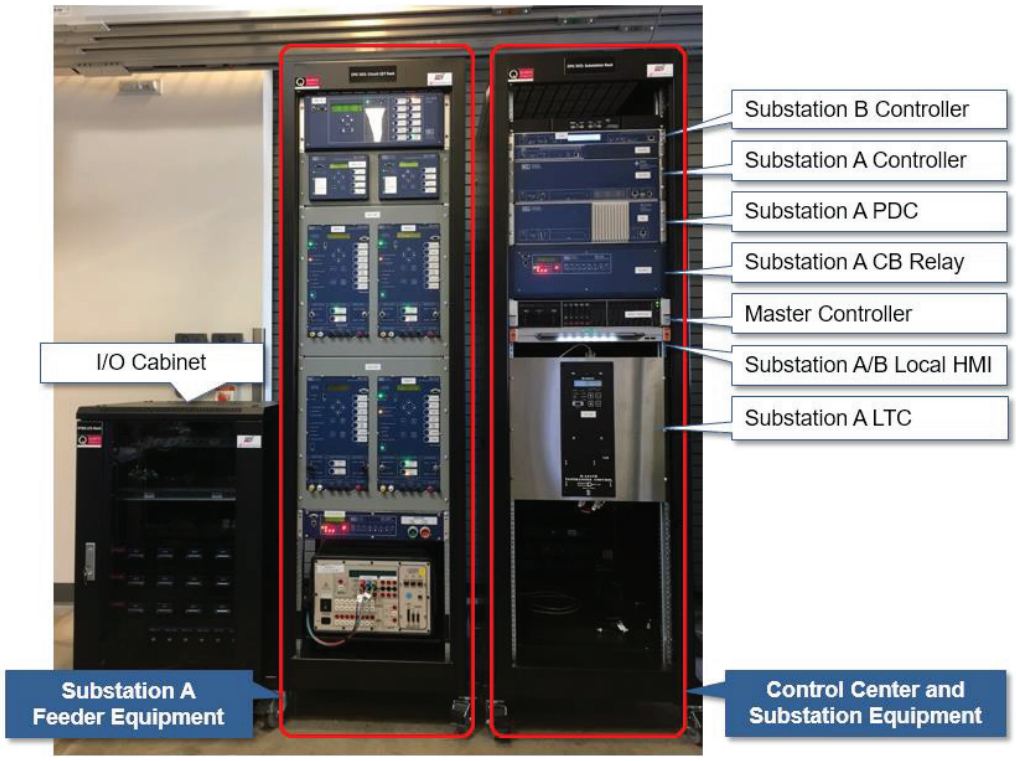


Figure 2-16. Test platform racks

The rack to the right in Figure 2-16 above was used to house the control center and substation equipment from both substations, while the one on the left was used for all of the IEDs on Substation A's CCR1 circuit. An additional, smaller, rack was provided to house the digital simulator I/O cards that were providing the hardwired inputs to the substation and feeder IEDs, as well as interfacing with the battery energy storage system (BESS) and smart inverter.



The master controller was equipped with an HMI that provided a graphical representation of the two substations as well as the various operator interfaces to control and monitor the substation and feeder equipment as shown in Figure 2-17 .

Figure 2-18 shows a typical HMI screen at the Master Controller.

Figure 2-17. Master Controller HMI (deployed)

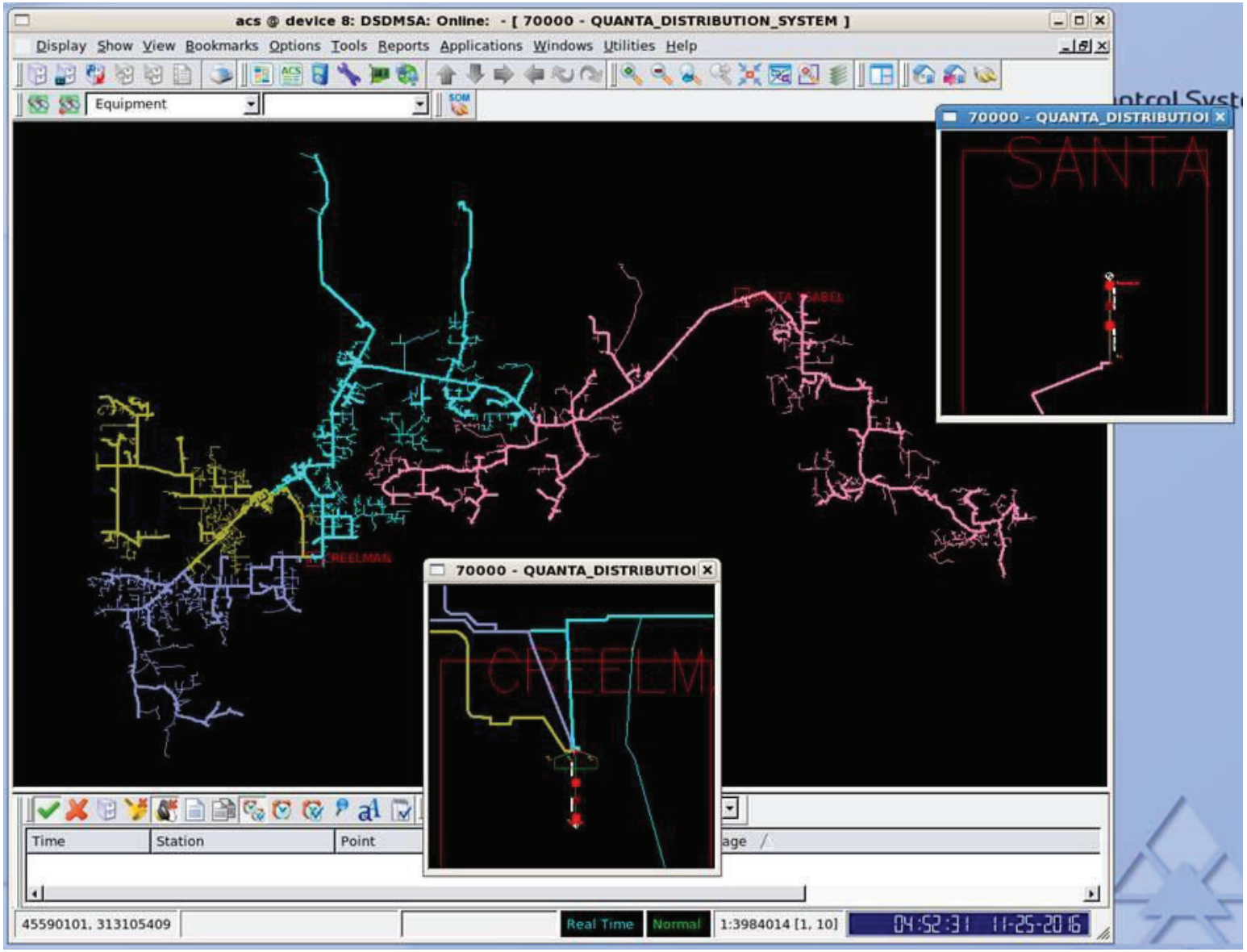


Figure 2-18. Sample HMI screen at the Master Controller

As illustrated in Figure 2-15, both of the Substation Controllers were equipped with local HMIs. These were web-based and accessible via a simple browser. Several examples of screens are presented in the figures that follow.

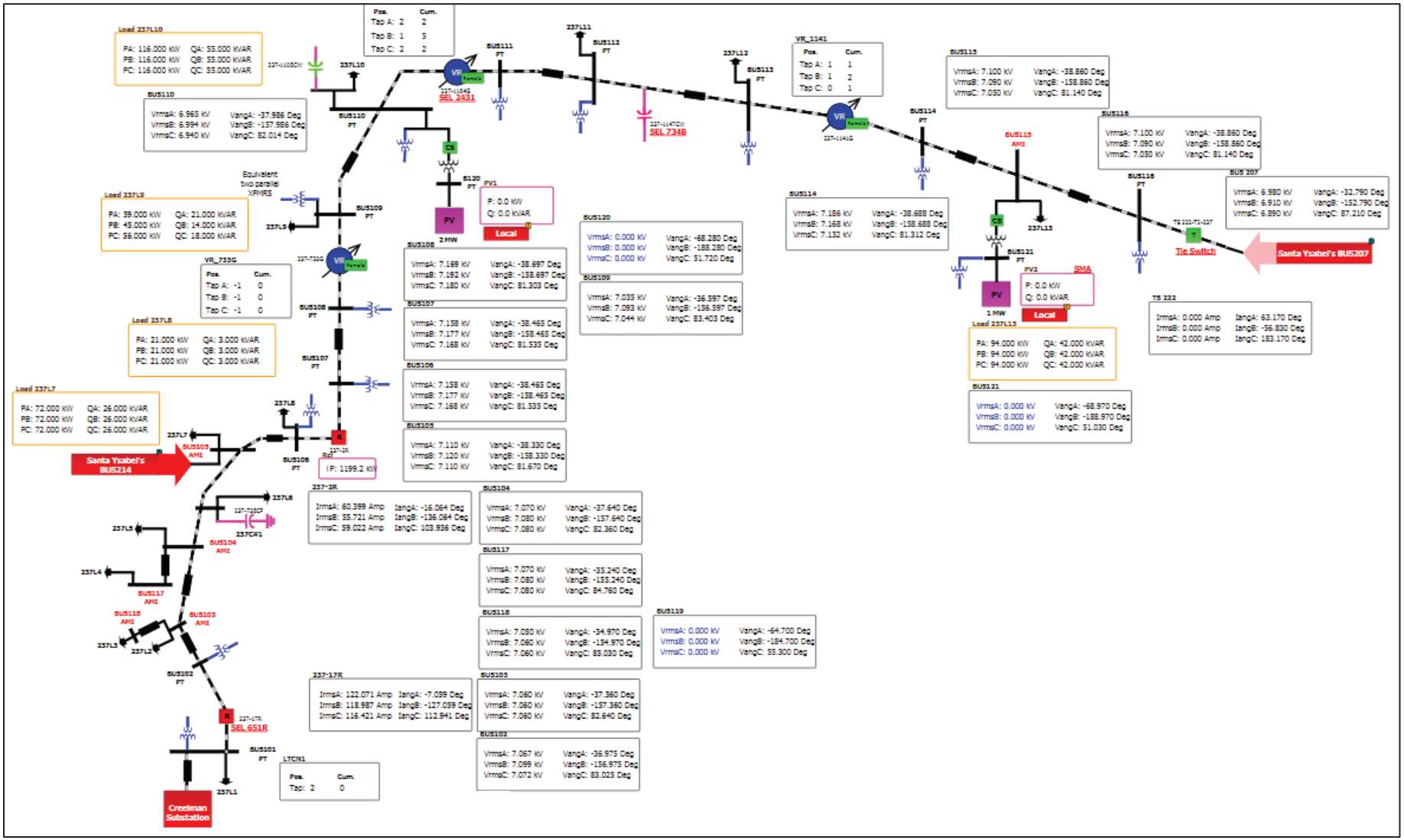


Figure 2-19. Substation A and circuit CCR1 topographic representation in the local HMI

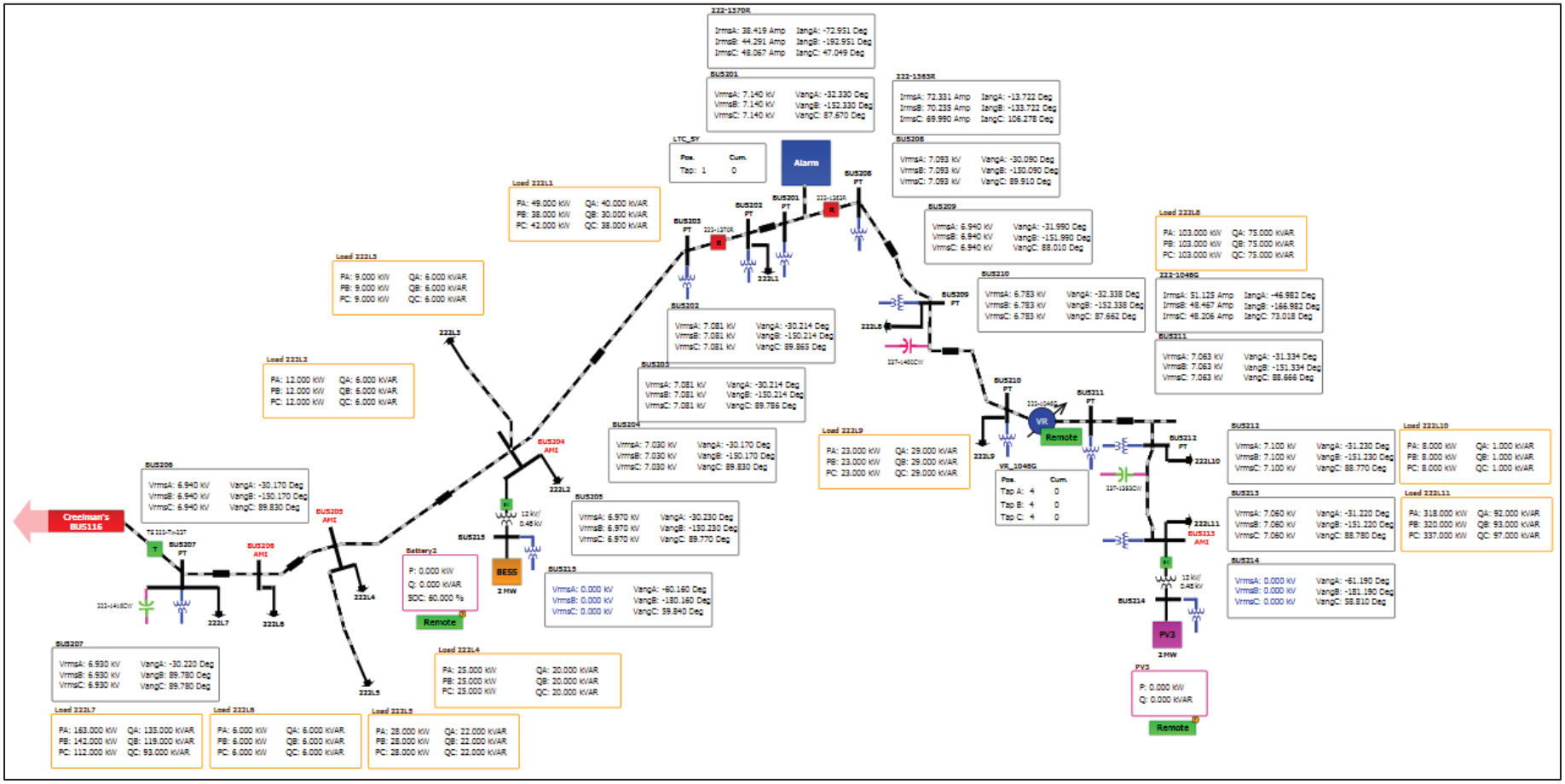


Figure 2-20. Substation B and circuit CSY1 topographic representation in the local HMI

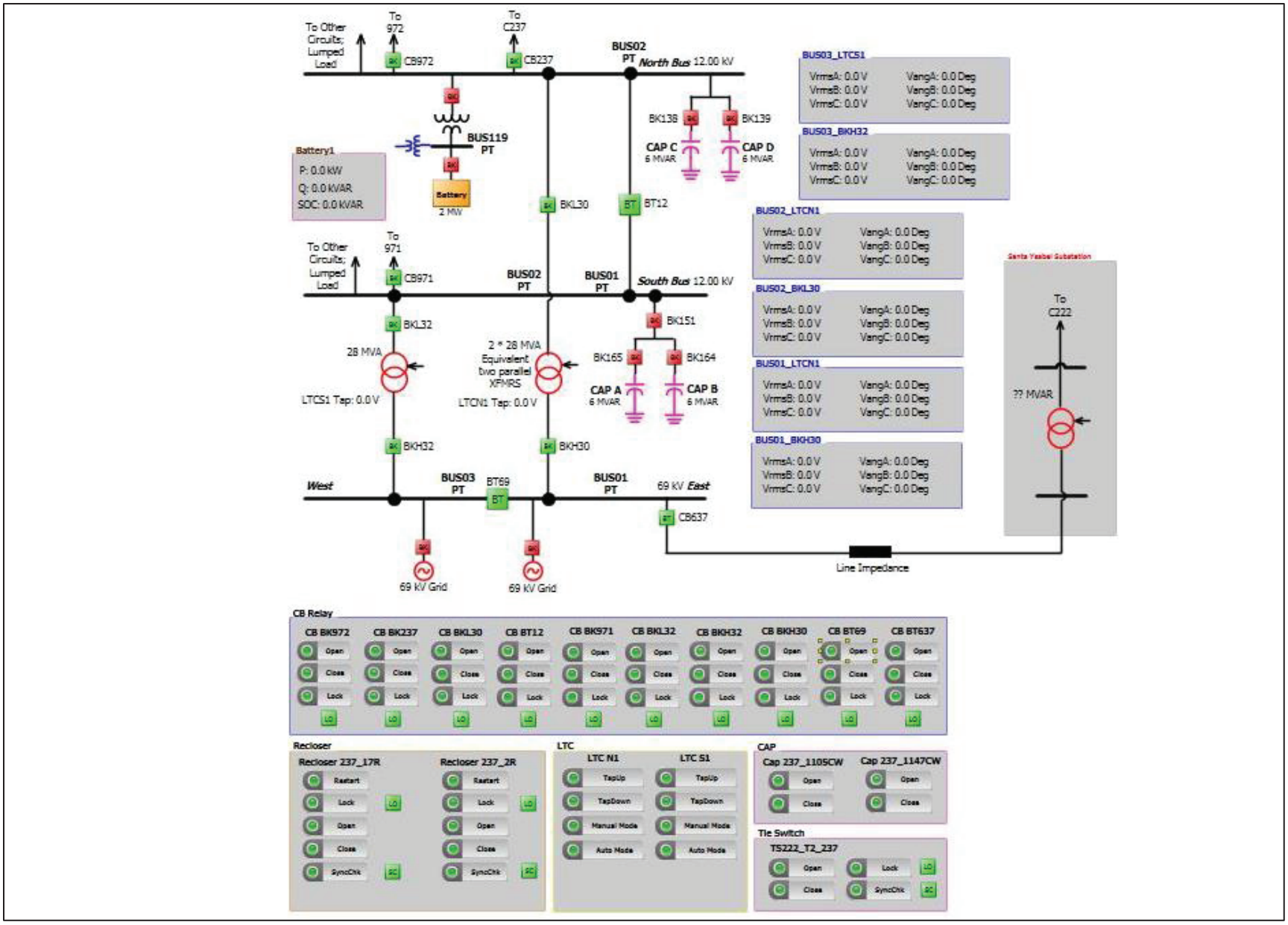


Figure 2-21. Substation A SLD in the local HMI

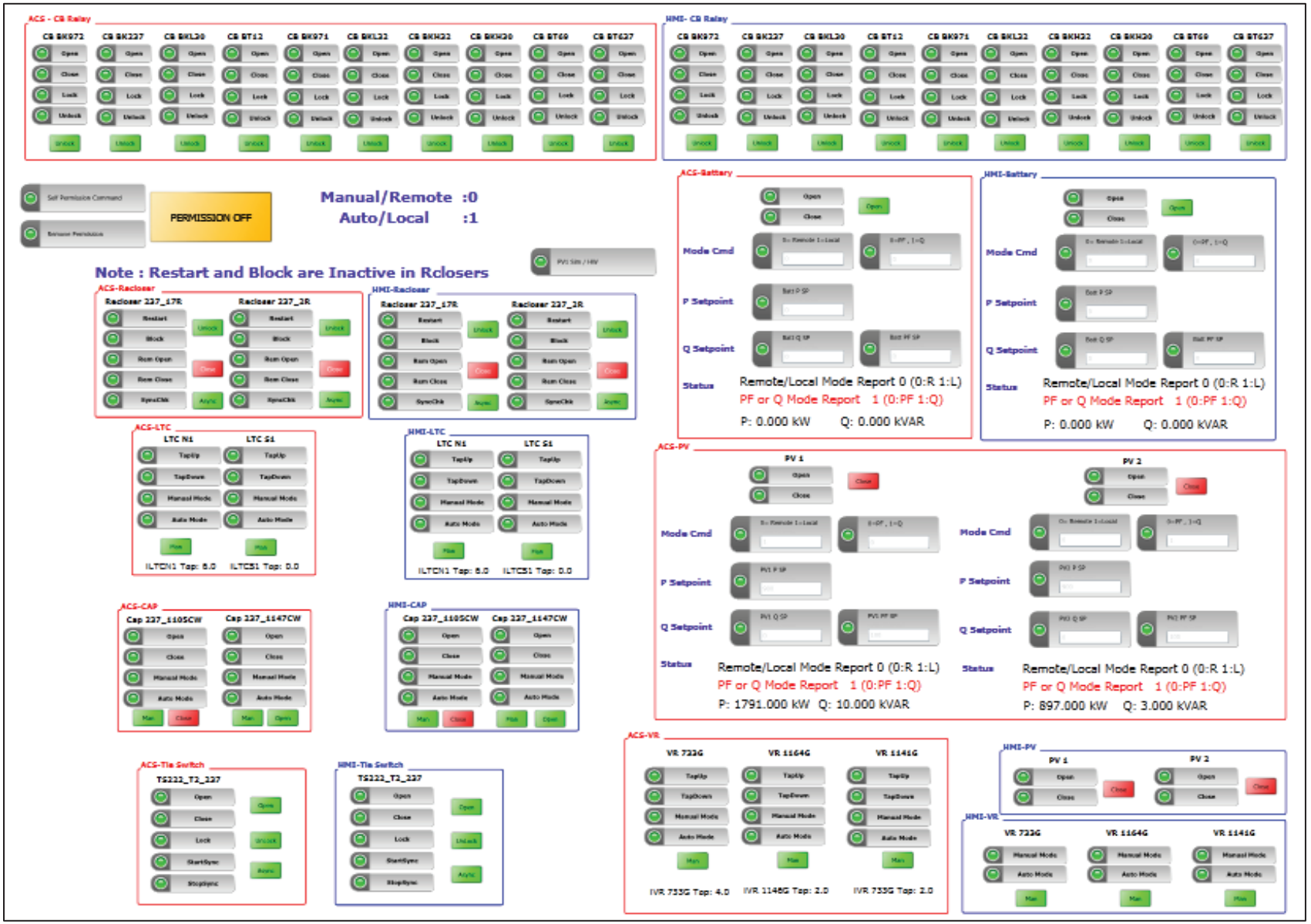
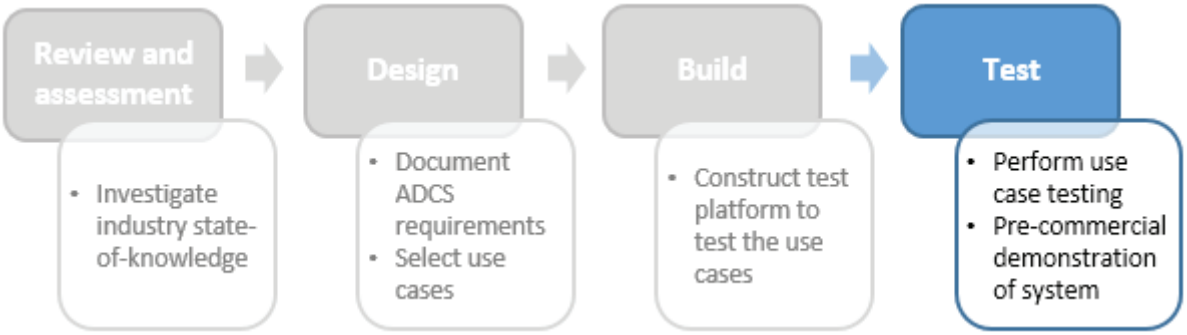


Figure 2-22. Monitoring the DER setpoints and other settings in the local HMI of substation A.

2.4 Distributed control system pre-commercial demonstration



Testing of the system was implemented in three separate phases:

- Factory acceptance testing of a simplified model consisting on a single circuit with limited hardware-in-the-loop
- Factory acceptance testing of a comprehensive model using two circuits with additional hardware-in-the-loop
- Site acceptance testing of the complete model using two circuits with extensive hardware-in-the-loop, including an actual Battery Energy Storage System and smart PV inverter.

An interesting side-note is that for much of the test platform development and initial testing, the Master Controller was physically located in Atlanta, GA at the headquarters of ACS, the SCADA platform provider, while the substation controllers, digital simulator and the hardware-in-the-loop IEDs were located in Toronto, ON at the Canadian office of Quanta Technology. The controllers were networked together over the public internet and system testing was performed on this distributed configuration for an extended period of time. The first time the master controller was in the same physical location as the rest of the equipment was when it was integrated into the hardware rack in the Toronto office just prior to shipping the equipment to ITF for the SAT.

2.4.1 Test plans

Test plans were created for each of the test phases. The test plan incorporated a comprehensive set of tests to evaluate the performance of the proposed automated distributed control system and to contrast it with a conventional control scheme.

Two baseline systems were used for comparison:

- Baseline System 1: system with no DER and local/automatic controls for individual devices (with no coordination) in the field.
- Baseline System 2: system with DER (penetration depends on the test case) and local/automatic controls for individual devices (with no coordination) in the field.

The test cases and performance comparisons for each of the use cases is discussed in sections 2.4.4.2 to 2.4.6.2.

2.4.2 Data collection

In order to analyze the performance of the system, it was essential to collect measurements, statuses, setpoints, and commands during each test. Therefore, the project considered two separate paths for archiving test data with an acceptable resolution:

1. The master controller was continuously saving a list of desired parameters during each test; the variables of interest included but were not limited to bus voltages, breaker powers, switch statuses, DER outpour powers, tap changer position, voltage regulator tap position, Cap bank statuses, etc.
2. The PI historian interfaced with the test setup and archived all the analog and binary values reported from the system to the master controller. The digital simulator sent a comprehensive list of measurements and statuses to the master controller (and subsequently to the PI). The time resolution for archiving these data was adjustable in PI, and was set to a time resolution of 10 seconds, which was deemed sufficient for post-mortem data analysis.

In addition to these two paths, phasor measurement unit (PMU) measurement data were also able to be retrieved from the SynchroWave Central/Historian. These PMU measurements were mainly intended for monitoring purposes although they were also available for later extraction and analysis purposes if required.

2.4.3 Communications Tests

The purpose of this test category was to verify proper communications amongst various components of the test setup as a precondition for performing use case testing. As such, several tests were performed to verify communications between:

- Field (digital simulator or hardware device) and substation; and
- Substation and control center (master controller)

2.4.3.1 Field and Substation Communications

Table 2.12 provides a list of major tests executed (or steps taken) for verifying communications between field devices (digital simulator/hardware) and the substation controller.

Table 2.12. Communication test cases

Case#	Test Case	Description
1	IP/Port number verification	Ensure that digital simulator and Substation Controller could ping each other
2	Analogue input (measurements) reading by substation controller	Change the power flow of the circuit and verify that the changes were reflected in the HMI
3	Analogue output (setpoints) writing by substation controller	Issue setpoints and/or curtailment signals to the substation BESS and/or PV systems and verify that they were applied correctly
4	Binary input (status) reading by substation controller	Change the status of switching devices and verify that the changes were reflected in the HMI
5	Binary output (commands) writing by substation controller	Send open/close command to switching devices (or issue tap up/down commands to the VR) and verify that it was applied properly

One of the screens created for the local HMIs provided a communications status overview. The absence of communications with any of the devices would be reflected in the screens and visible to the user. A sample screen is shown in Figure 2-23 below.

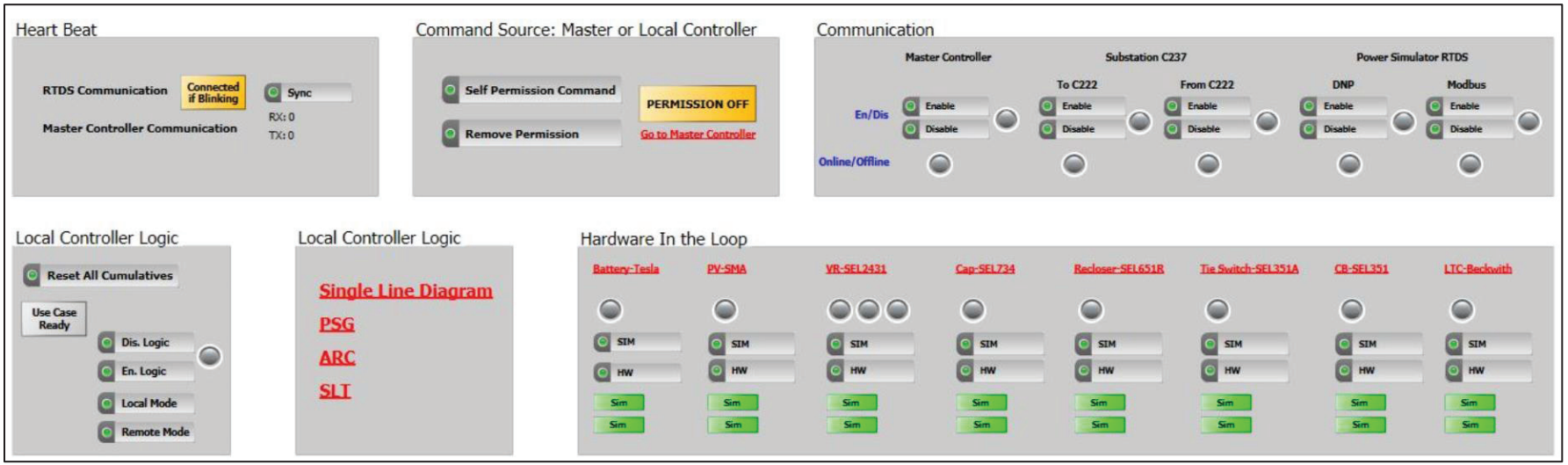
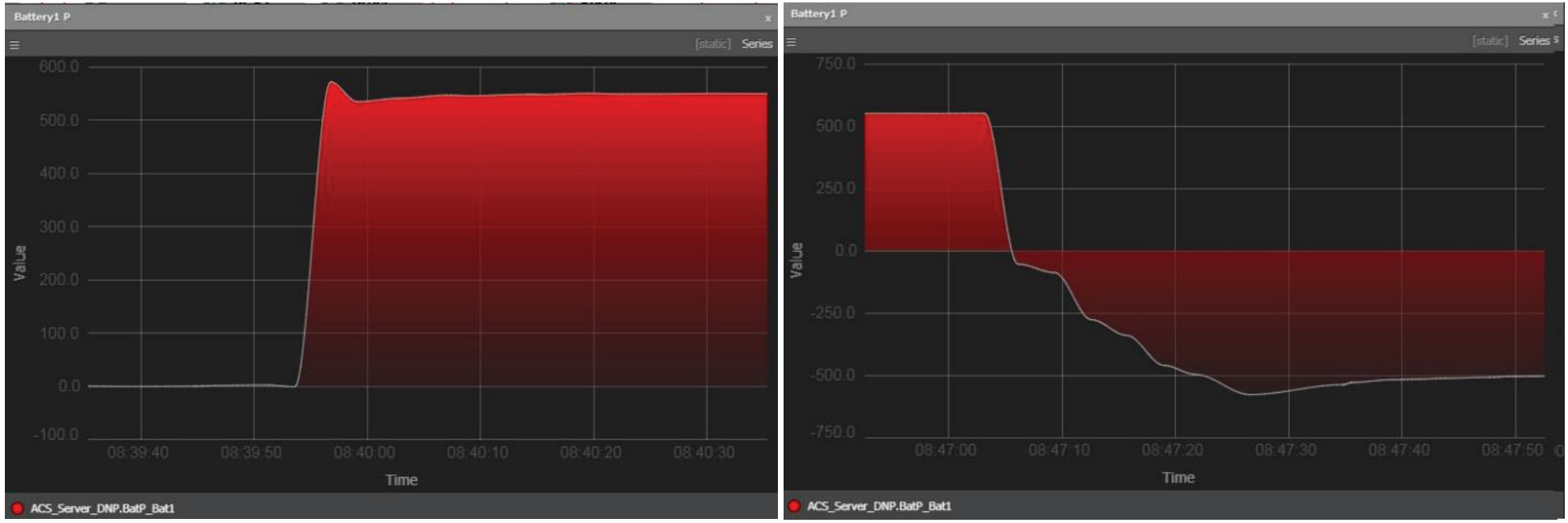


Figure 2-23. Communications testing – Communications status display on Local HMI of Substation A

As a part of communication tests, real and reactive power setpoints (P and Q) were sent from substation controller to the battery, and the battery response was confirmed. Figure 2-24 and Figure 2-25 shows the response of the battery to the following sequence of real and reactive power commands:

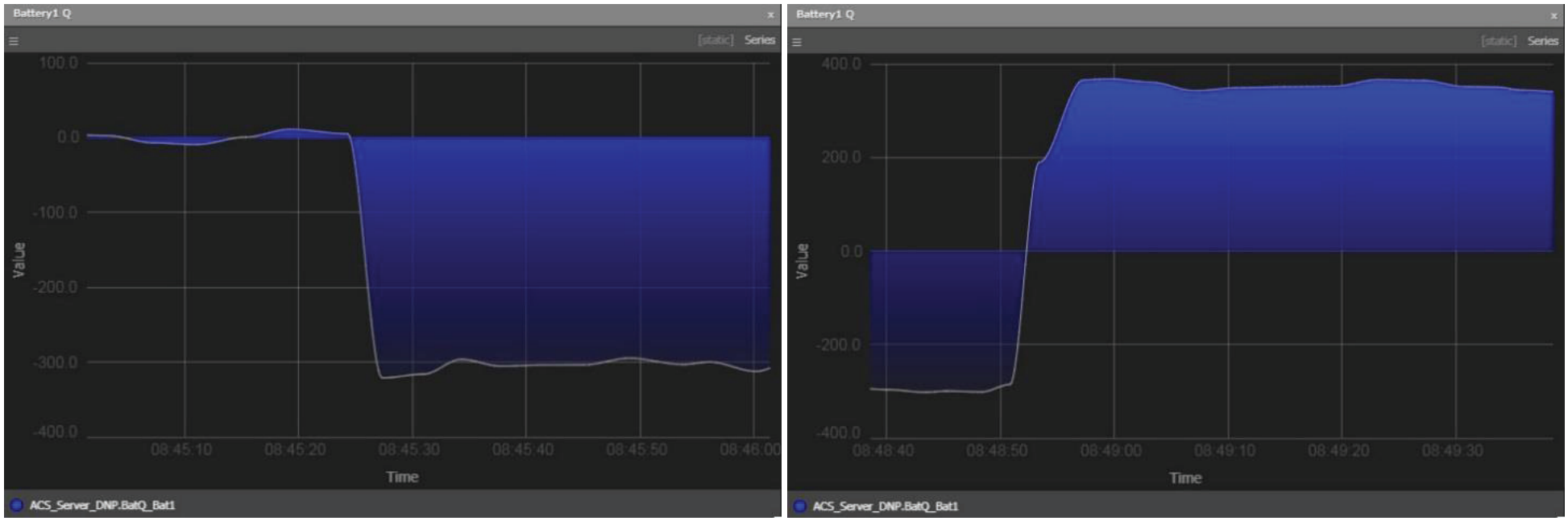
- Initially real and reactive powers of the battery were (almost) zero.
- First, real power setpoint of P_{SP}=550kW[7] was sent to the battery (Figure 2-24 (a))
- While P=550kW, a reactive power setpoint of Q_{SP}=–300kW was issued to the battery (Figure 2-25 (a))
- Then the battery was taken to the charging mode by P_{SP}=–500kW (Figure 2-24 (b))
- Finally, the reactive power setpoint of Q_{SP}=350kW was issued to the battery (Figure 2-25 (b))



(a) **(b)**

Figure 2-24. Communications testing - Response of the battery to P commands issued from the Local HMI

[7] A scaling factor of 10 was used to integrate a 200kW inverter as a 2MW battery energy storage system into the simulated power system.



(a) **(b)**

Figure 2-25. Communications testing - Response of the battery to Q commands issued from the Local HMI

2.4.3.2 Substation and control center communications

Several tests were executed to verify the DNP 3.0 communications between the substation controller and the master controller. Table 2.13 lists the major test cases used to verify proper establishment of this communication.

Table 2.13. Substation and control center communications test cases

Case#	Test Case	Description
1	IP/Port number verification	Ensure that substation controller and master controller could ping each other
2	Analogue input (measurements) reading by master controller	Change the power flow of the circuit and verify that the changes were reflected in the HMI
3	Analogue output (setpoints) writing by master controller	Issue setpoints and/or curtailment signals to the substation BESS and/or PV systems and verify that they were applied correctly
4	Binary input (status) reading by master controller	Change the status of switching devices and verify that the changes were reflected in the HMI
5	Binary output (commands) writing by master controller	Send open/close command to switching devices (or tap up/down a VR) and verify that it was applied properly

All setpoints and commands were tested to ensure proper control actions would be taken when needed. Figure 2-26 and Figure 2-27 show snapshots of the master controller screens for the steady-state conditions of Baseline System 1.

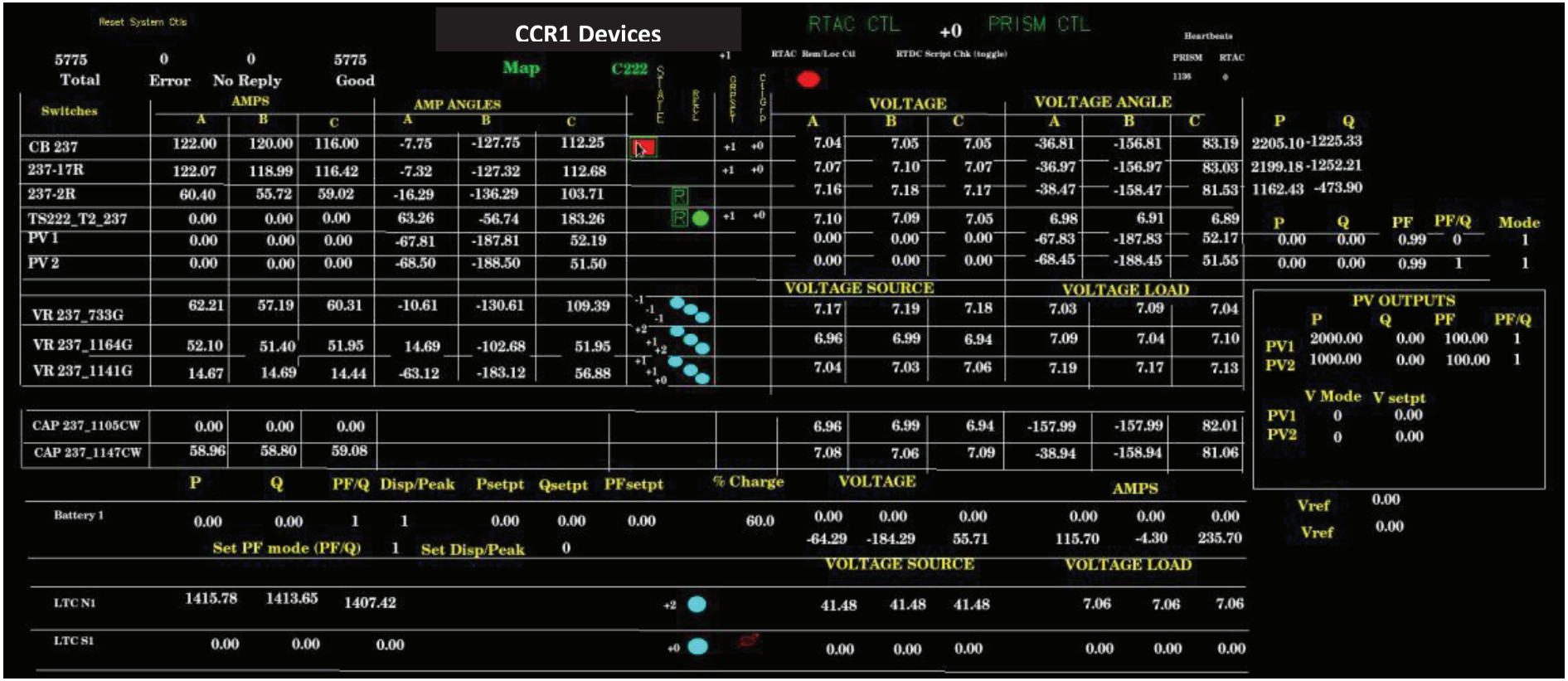


Figure 2-26. Snapshot of the master controller HMI (CCR1 – Baseline System 1)

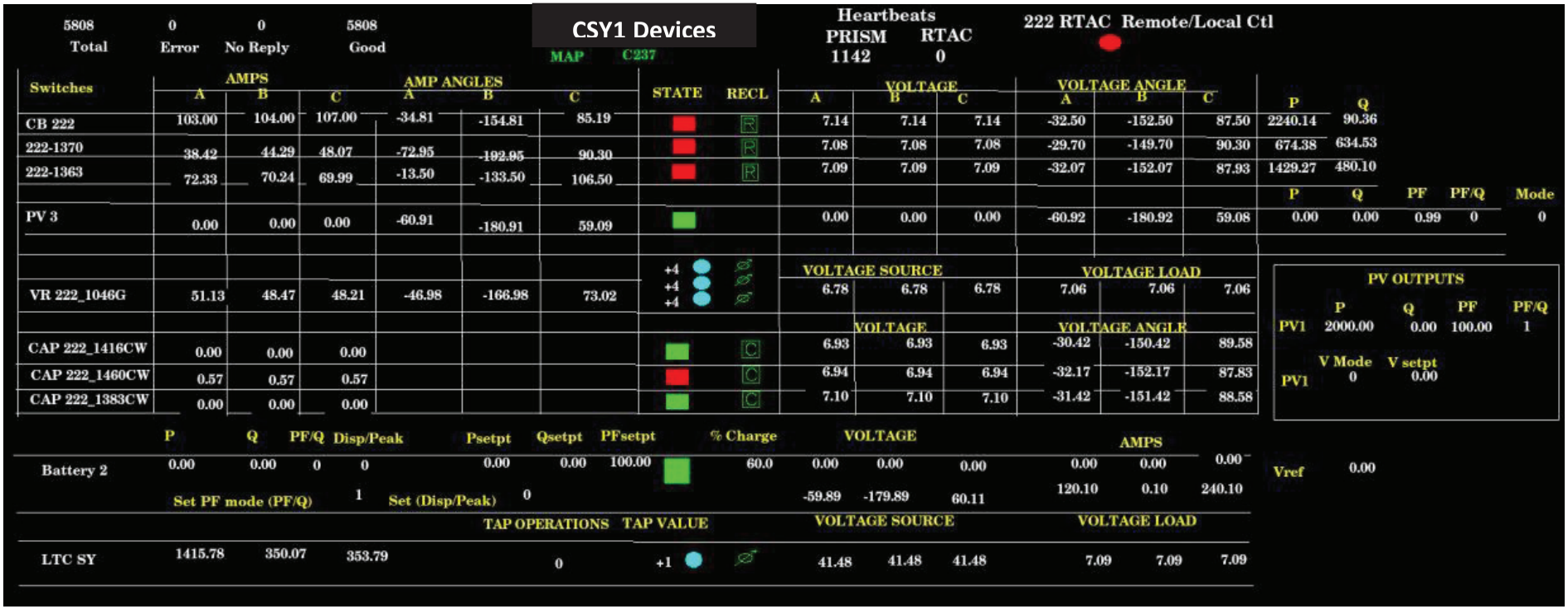
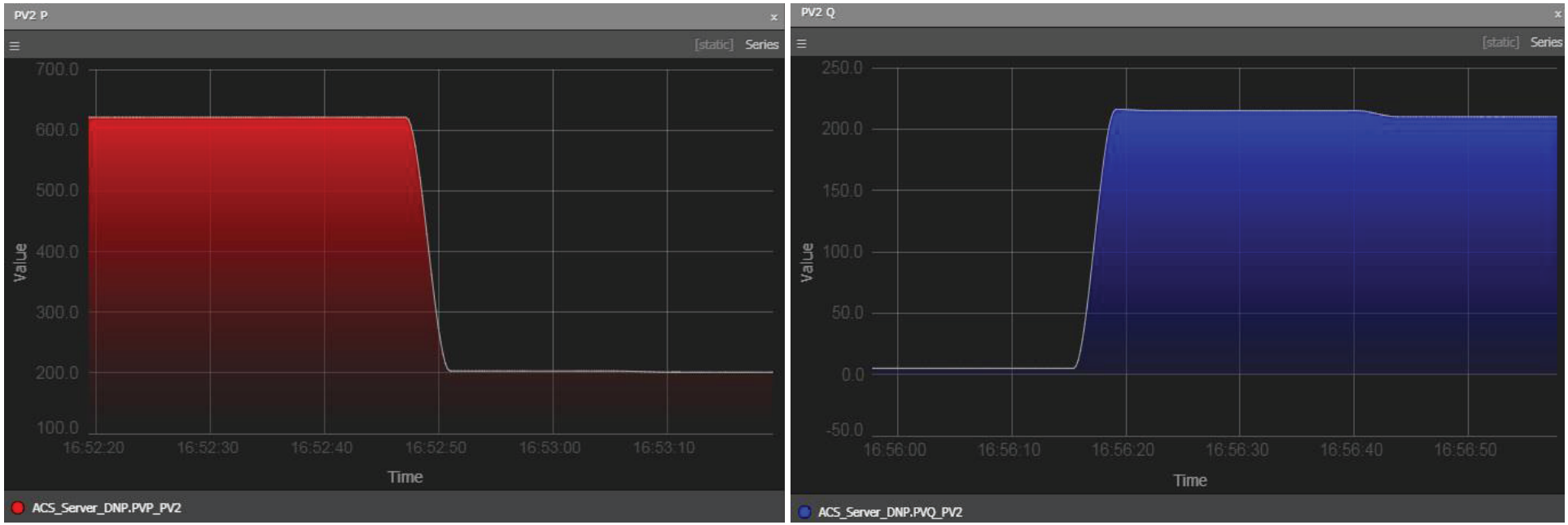


Figure 2-27. Snapshot of the master controller HMI (CSY1 – Baseline System 1)

A set of curtailment and reactive commands were sent from the master controller to the SMA PV inverter in the field, and the inverter response was confirmed. Figure 2-28 shows the response of the SMA inverter to the following set of commands:

- Initially real and reactive powers of the inverter were 620kW[8] and zero, respectively.
- Real power of the inverter was curtailed to P_{SP}=200kW.
- While P=200kW, a reactive power setpoint of Q_{SP}=200kW was issued to the inverter.

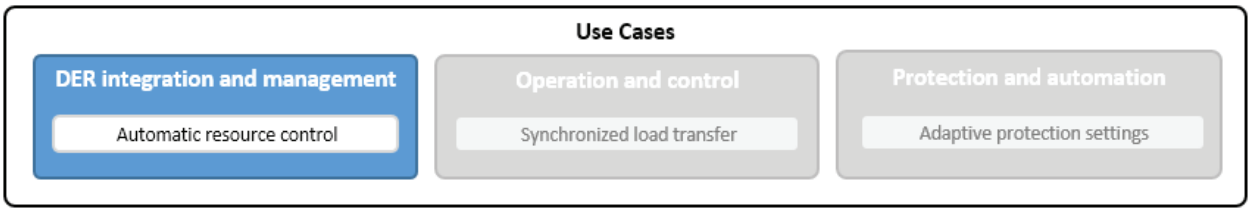


Active Power (P) **Reactive Power (Q)**

Figure 2-28. Response of the PV inverter to P and Q commands issued from the master controller

[8] A scaling factor of 100 is used to integrate a SMA 10kW inverter as a 1MW PV system into the simulated power system.

2.4.4 Use case 1: Automatic Resource Control



The main objective of the Automatic Resource Control (ARC) implemented on the test system was to achieve the optimal combination of LTC, VR, Cap Bank settings and output powers of controllable DERs in order to improve operating conditions such as voltage profile, losses, load balance, and overloading conditions, and/or to prevent excessive reverse power flow from local distributed generation (e.g., PV generation) by limiting the maximum DER generation.

ARC benefits were accomplished by minimizing the average voltage of all nodes and injection points at the point of common coupling to the feeder, while maintaining 'end of line' voltages within acceptable operating limits. ARC produced a solution, which minimized energy consumption and maximized energy transfer at the lowest cost.

The ARC application utilized two control blocks for its proper performance; these were:

- Feeder Injection Test (FIT) tool; and
- Near-Real-Time Power Flow (NRTPF) model

Access to real-time SCADA measurements was critical for the accurate performance of the ARC function. The Feeder Injection Test (FIT) tool determined whether there were circuit performance violation(s) that could not be corrected by automatic resource control. In the event that violations were detected, FIT used real-time field/SCADA data, load/generation forecast results, and the Near-Real-Time Power Flow Model to determine if the circuit violation could be resolved by resource control (DER dispatch and LTC/VR/Cap control).

The ARC function first located and identified LTCs, VRs, Cap banks, and DER assets. Then, the candidate ARC devices/inverters were identified to modify their settings/setpoints. Based on the results of the power flow analysis (NRTPF model), optimal control settings and/or setpoints were calculated and issued to the ARC devices and/or inverter assets to ensure desired system performance.

The ARC application performed the following functions:

- Utilized the results of the FIT tool or an operator request to trigger further action;
- Acquired information about
  - LTC settings and control modes;
  - VR settings and control modes;
  - Cap Bank controller settings and modes;
  - DER power/energy settings; and
  - Current status of ARC devise/inverters.

- Determined if the change in LTC/VR/Cap Bank setting or DER dispatch (ARC function) could improve system conditions (voltage quality, loading, etc.);
- Identified the ARC assets or DERs that needed to modify their settings/setpoints for optimal system performance;
- Calculated optimum settings/setpoint for selected devices/DERs;
- Sent the settings/setpoints to target ARC devices/DERs via DERMS (or another higher-level control platform);
- Received confirmation from ARC devices/DERs on the receipt of settings/setpoints and their activation;
- Triggered alarms if:
  - Automatic resource control could not resolve the circuit violation;
  - Automatic resource control could not be accomplished due to the current state of ARC devices/DERs or other limitations;
  - Communication network had failed;
  - Communication with the target ARC device/DER had failed; and
  - The target device/DER was not responded properly to the setting/setpoint change command.
- Sent ARC confirmation signal to Distributed Energy Resource Management System (DERMS) or Distribution Management System (DMS) indicating that the device/DER setpoints/settings were changed.

Three-pass optimization

ARC used a three-pass iterative approach to control from 'course' control to 'fine' control.

1. The first pass minimized the var losses by controlling the feeder capacitors.
2. The second pass flattened the line drop voltage after the impact of the capacitor switching in the first layer was calculated. The second pass controlled the LTC and voltage regulators.
3. The third pass applied fine control of the voltage based on the ability of the inverter to affect the voltage at the point of common coupling / injection points. Many smart Inverters can be issued a voltage set point directly from ARC based on an optimum target calculated for the entire scope of the feeder. Other inverters offer real and reactive power (P/Q) set-point control which is used to drive an optimum voltage at the point of common coupling (PCC).

Table 2.14 provides more details on the three-pass optimization layers of the ARC use case. The sequence diagram for the ARC application is also shown in Figure 2-29.

Table 2.14. Three-pass optimization

Pass	Characteristics
Pass 1: Load flow optimized var minimization	ARC ran an Unbalanced Distribution Load Flow optimization in order to determine an optimum control strategy and to avoid control 'hunting'. The load flow was run in real-time to determine reactive power requirements at each injection point and capacitor bank location for the entire feeder. If a significant amount of lagging reactive power flow was observed on the feeder at various nodes, the reactive contribution provided by the capacitor bank(s) needed to

Pass	Characteristics
	be engaged. Likewise, if there was a large amount of leading reactive power flow on the feeder breaker, the capacitor bank(s) needed to be decoupled from the feeder. The decision was made through a series of load flow calculations. To verify if a given capacitor operation violated any Voltage constraints, the changes in Voltage and power factor were calculated for the entire feeder considering the effect of the capacitor operation. The analysis considered the operable capacitors on the feeder which were located first by topology tracing from the feeder breaker downstream. Feeder loads were estimated by Load estimator using a combination of static load curves of load behavior modified by real-time measurements of actual to calculate Voltage, branch flows, and power factors. The branch flows at device locations were analyzed so that the capacitor banks were sorted in descending order based on their branch reactive power flows. The capacitor with the largest branch reactive power was selected as a control candidate. Its impact on feeder Voltages was calculated and checked against the limits and if no limit was exceeded, a control command was issued to operate this capacitor bank. If any constraint was violated, the capacitor bank would be passed over and the next capacitor processed. The above process was repeated until distribution loss was minimized or no capacitor was available for control.
Pass 2: Load flow optimized voltage reduction	The second step in the control cycle after the capacitor settings were made was to evaluate the feeder Voltage. When capacitors are added they raise Voltages contrary to the objective of Voltage reduction and increase energy usage. This mandated the need to coordinate kvar control with Voltage control. Once capacitor bank statuses were determined, a load flow calculation was performed to find the highest and lowest Voltages in the feeder assuming all devices took the expected control actions (either on or off). The Voltage regulation optimization which includes down line regulators was managed using a layer approach starting from the source. Voltage regulators on each phase were adjusted based on the Voltages on the other two phases to achieve balanced three phase Voltages. The solution ensured that no end of line Voltage violations took place. The regulator settings were sent out in steps as ARC verified the effect of the control action. Typically, the substation LTC is set to automatic mode which makes changes at the bus level thereby affecting all feeders. Based on the real-time transformer data ARC would operate dynamically to adjust the optimum LTC setting. If the substation LTC couldn't be adjusted or if it was set manually, it was desirable to know the optimum setting. A bus Voltage target set point could be entered, which ARC will provide a recommended setting either in advisory mode or through a control point if it is available. In summary, the optimum control settings for capacitors regulators and LTCs are adjusted such that the lowest Voltage is maintained above the low Voltage limit.
Pass 3: Load flow optimized voltage regulation	After the regulator tap settings were implemented, the optimum calculated Voltage at the PCC was assigned as a set point to the PV smart inverters. The inverters would then assign the necessary P/Q to maintain the assigned Voltage. In the event that inverters were not "smart", the ARC had the ability to set the P & Q set points to achieve the desired Voltage at the PCC.

Pass	Characteristics
	If an emergency limit was exceeded, for example due to unexpected load switching from one feeder to another, the ARC would close or open capacitors as necessary to reduce the violation before altering the regulator settings.

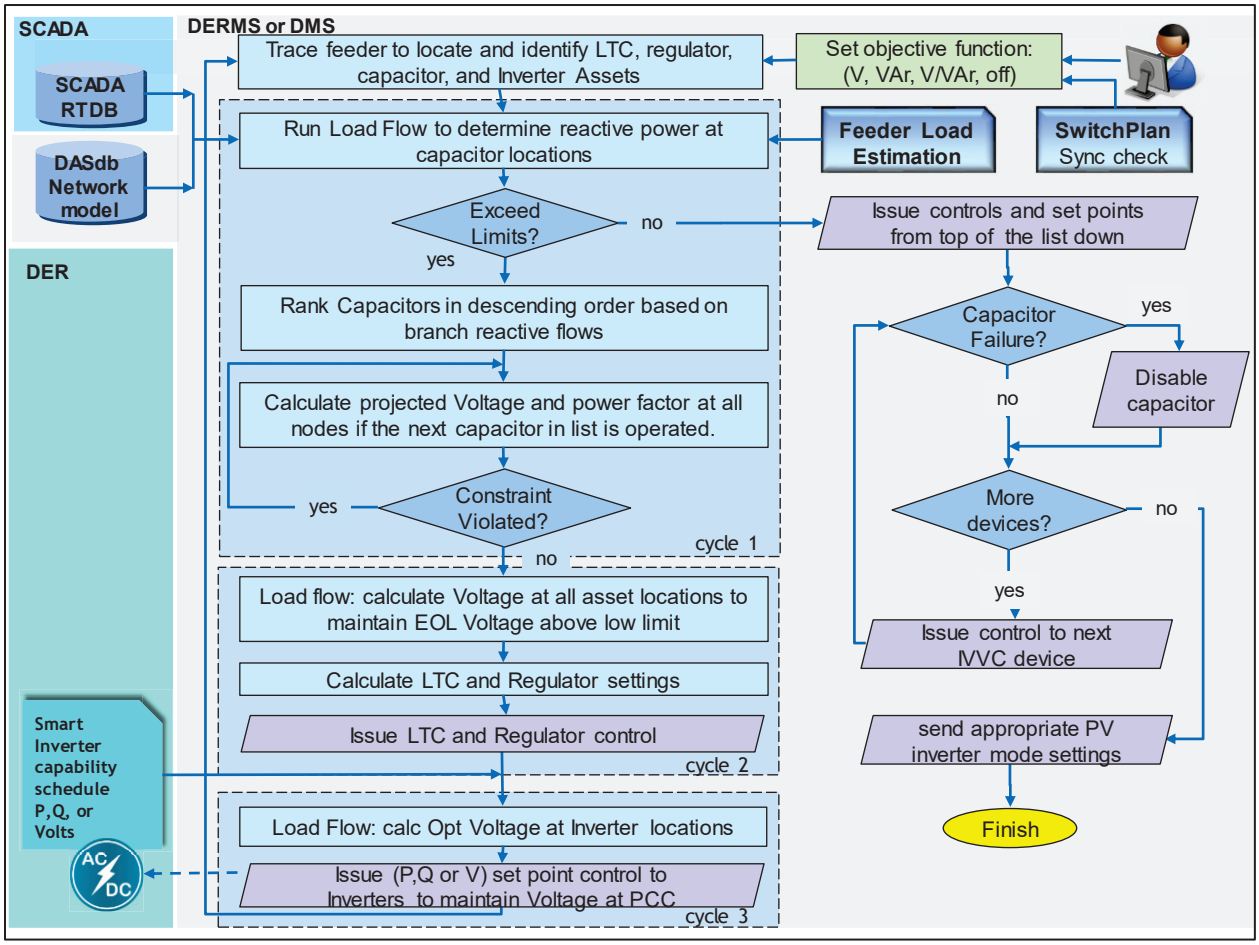


Figure 2-29. ARC logic control of the network devices and DER

2.4.4.1 Performance criteria

The following criteria were used to evaluate successful operation of the control system for ARC use cases:

- Voltage profile: standard deviation and out-of-range values/durations were used to examine the performance of the control function.
- Power loss (P_{loss}): reduced power loss was considered as one of the objectives of the central ARC. The following equation was used to calculate power loss at the substation level

$$P_{loss} = P_{grid} + P_{DER} - P_{loads}$$

- DER involvement/contribution: this was evaluated based on the power drawn from the grid or substation transformer (P_{grid}). Higher DER involvement was equivalent to less power drawn

from the grid. It is noted that DER reactive power contribution to voltage improvement was preferred over the utilization of other assets.

- Power factor at the circuit level ($pf = \cos[tan^{-1}(Q_{grid}/P_{grid})]$: improved power factor was considered as one of the objectives of the central ARC.
- Number of capacitor bank (Cap bank) operation (n_{cap}): optimal operation of Cap banks was one of the objectives of the ARC
- Number of voltage regulator (VR) operation (n_{VR}):optimal operation of voltage regulators was one of the objectives of the ARC
- Number of load tap changer (LTC) operation (n_{LTC}):optimal operation of load tap changers was one of the objectives of the ARC

Table 2.15 provides a summary of the factors used for the ARC evaluation.

Table 2.15. Performance criteria for ARC use case

Criteria	Parameter	Remark
Voltage profile	ΔV_P, ΔV_t, σ	Out-of-range value, Out-of-range duration, Standard deviation
Power loss	P_{loss}	
DER involvement	P_{grid}, P_{DERs}, Q_{DERs}	DER and grid power values
Power factor at circuit level	$P_{CB-feeder}$, $Q_{CB-feeder}$	
Number of Cap bank operation	n_{Cap}	
Number of voltage regulator operation	n_{VR}	
Number of LTC operation	n_{LTC}	

2.4.4.2 Test Results

The purpose of this test category was to verify that master controller and substation controllers were able to automatically control the system resources (i.e., controllable assets and DERs) in order to maintain the operating parameters of the system within the acceptable ranges specified by SDG&E. Several test cases were considered in this use case to ensure proper operation of the ARC function under various load, generation, and system operating conditions. Table 2.16 lists the major test cases that were run. The test cases were selected to enable the evaluation of system performance under three control scenarios:

- Scenario 1 (CS 1): Only device local controls were in place (no remote control available)
- Scenario 2 (CS 2): Master controller was in charge of resource control
- Scenario 3 (CS 3): Substation controller was in charge of resource control

The location of the devices referenced in the Test Condition column in Table 2.16 are highlighted in the figure below.

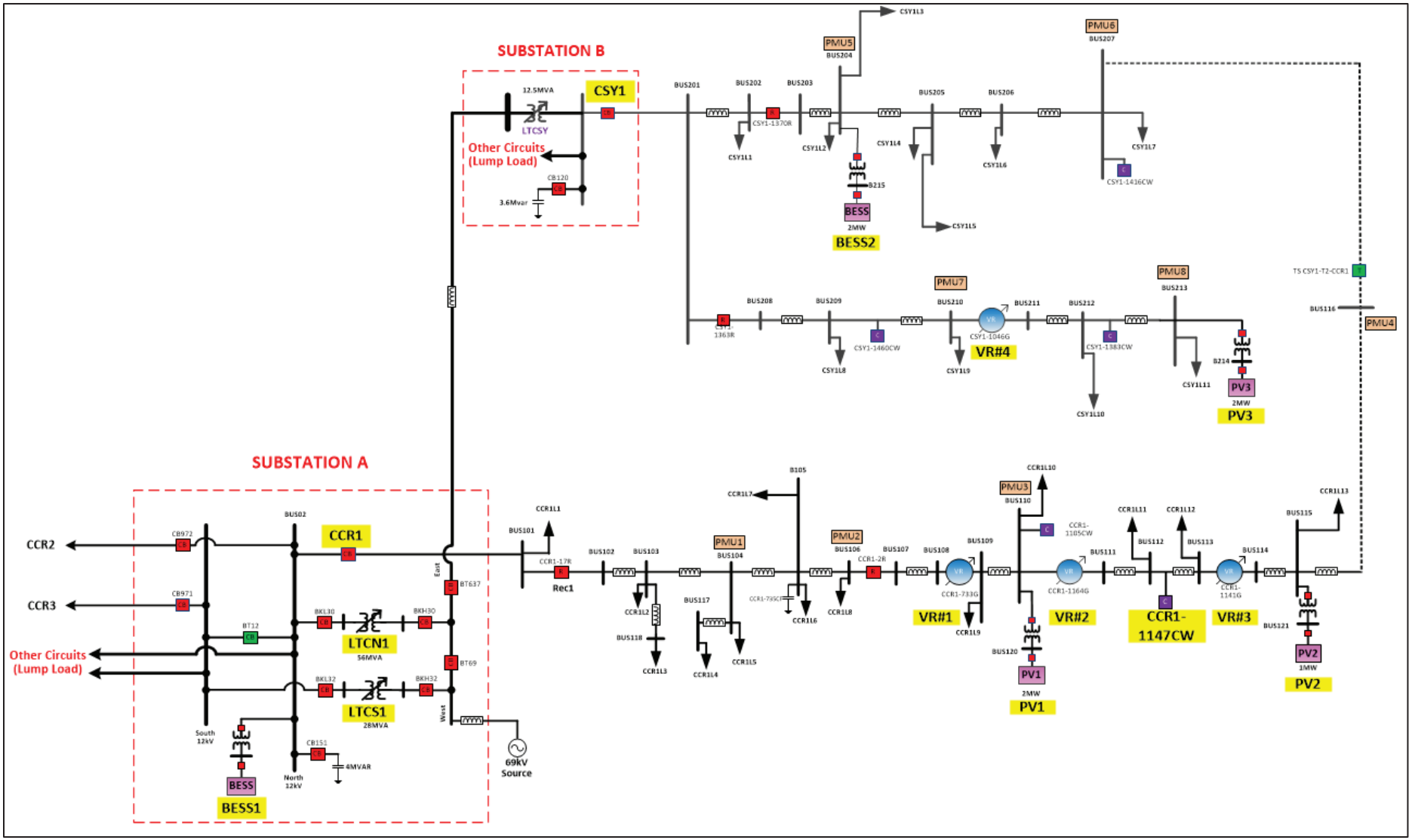


Figure 2-30. Identification of devices referenced in use case 1 test cases

It is worth mentioning that when the substation control assumes responsibility for controlling resources, it would first change the control mode of all controllable assets to “Local”. Then, based on the level of control that the substation controller was able to offer, it would change the control mode of corresponding devices to “Remote” in order to remotely control them. The control functions of the substation controller depended on various parameters including utility requirements, controller programming capability, controller communication capability, etc. For the purpose of this study, the substation controller mainly utilized DERs to improve system operating conditions and, thus, had limited control functionality when compared to the master controller.

Table 2.16. ARC Test Cases

Case#	Test Conditions	Description	Remark
1.1	CCR1: Pload=7.2MW, PPV1=0, PPV2=0, PBESS1=0 CSY1: Pload=5.7MW, PPV3=0, PBESS2=0 Initial Conditions: LTCN1_tap=4, LTCSY_tap=4, VR#1_tap=0, VR#2_tap=1, VR#3_tap=5, VR#4_tap=0, all Cap banks in CCR1 are ON, all Cap banks in CSY1 are OFF, tie switches are open.	High load (fix), no DER	Baseline System 1 (No DER with all controllable devices in Local/Auto mode)
1.2	CCR1: Pload=7.2MW, PPV1=0, PPV2=0, PBESS1=0 CSY1: Pload=5.7MW, PPV3=0, PBESS2=0 Initial Conditions: LTCN1_tap=4, LTCSY_tap=4, VR#1_tap=0, VR#2_tap=1, VR#3_tap=5, VR#4_tap=0, all Cap banks in CCR1 are ON, all Cap banks in CSY1 are OFF, tie switches are open.	High load (fix), no DER	Master controller was responsible to take actions through ARC/IVVC algorithm.
1.3	CCR1: Pload=2.2MW, PPV1=0, PPV2=0, PBESS1=0 CSY1: Pload=2.3MW, PPV3=0, PBESS2=0 Initial Conditions: LTCN1_tap=4, LTCSY_tap=4, VR#1_tap=0, VR#2_tap=1, VR#3_tap=5, VR#4_tap=0, all Cap banks in CCR1 are ON, all Cap banks in CSY1 are OFF, tie switches are open.	Low load (fix), no DER	Baseline System 1 (No DER with all controllable devices in Local/Auto mode)
1.4	CCR1: Pload=2.2MW, PPV1=0, PPV2=0, PBESS1=0 CSY1: Pload=2.3MW, PPV3=0, PBESS2=0 Initial Conditions: LTCN1_tap=4, LTCSY_tap=4, VR#1_tap=0, VR#2_tap=1, VR#3_tap=5, VR#4_tap=0, all Cap banks in CCR1 are ON, all Cap banks in CSY1 are OFF, tie switches are open.	Low load (fix), no DER	Master controller was responsible to take actions through ARC/IVVC algorithm.
1.5	CCR1: Pload=7.2MW, PPV1=0.4MW, PPV2=0.2MW, PBESS1=0 CSY1: Pload=5.7MW, PPV3=0.4MW, PBESS2=0 Initial Conditions: Steady state of case 1.1	High load (fix), Low PV (fix)	Baseline System 2 (all controllable devices were in Local/Auto mode)
1.6	CCR1: Pload=7.2MW, PPV1=0.4MW, PPV2=0.2MW, PBESS1=0 CSY1: Pload=5.7MW, PPV3=0.4MW, PBESS2=0 Initial Conditions: Steady state of case 1.1	High load (fix), Low PV (fix)	Master controller was responsible to take actions through ARC/IVVC algorithm.

Case#	Test Conditions	Description	Remark
1.7	CCR1: Pload=7.2MW, PPV1=0.4MW, PPV2=0.2MW, PBESS1=0 CSY1: Pload=5.7MW, PPV3=0.4MW, PBESS2=0 Initial Conditions: Steady state of case 1.1	High load (fix), Low PV (fix)	Substation controller was responsible to take actions through permission or communication loss (prior to event)
1.8	Case 1.5, trip CCR1-1147CW (e.g., fault) after the system gets to the steady state condition.	High load (fix), Low PV (fix)	Baseline System 2 (all controllable devices were in Local/Auto mode)
1.9	Case 1.6, tripCCR1-1147CW (e.g., fault) after the system gets to the steady state condition.	High load (fix), Low PV (fix)	Master controller was responsible to take actions through ARC/IVVC algorithm.
1.10	CCR1: Pload=7.2MW, PPV1=1.8MW, PPV2=0.9MW, PBESS1=0 CSY1: Pload=5.7MW, PPV3=1.8MW, PBESS2=0 Initial Conditions: Steady state of case 1.1	High load (fix), High PV (fix)	Baseline System 2 (all controllable devices were in Local/Auto mode)
1.11	CCR1: Pload=7.2MW, PPV1=1.8MW , PPV2=0.9MW, PBESS1=0 CSY1: Pload=5.7MW, PPV3=1.8MW, PBESS2=0 Initial Conditions: Steady state of case 1.1	High load (fix), High PV (fix)	Master controller was responsible to take actions through ARC/IVVC algorithm.
1.12	CCR1: Pload=7.2MW, PPV1=1.8MW , PPV2=0.9MW, PBESS1=0 CSY1: Pload=5.7MW, PPV3=1.8MW, PBESS2=0 Initial Conditions: Steady state of case 1.1	High load (fix), High PV (fix)	Substation controller was responsible to take actions through permission or communication loss (prior to event)
1.13	Case 1.10 (PBESS1= PBESS2=0), trip PV 1 after the system gets to the steady state condition.	High load (fix), High PV (fix)	Baseline System 2 (all controllable devices were in Local/Auto mode)
1.14	Case 1.11 (PBESS1= PBESS2=0), trip PV 1 after the system gets to the steady state condition.	High load (fix), High PV (fix)	Master controller was responsible to take actions through ARC/IVVC algorithm.
1.15	CCR1: Pload=2.2MW, PPV1=0.4MW, PPV2=0.2MW, PBESS1=0 CSY1: Pload=2.3MW , PPV3=0.4MW, PBESS2=0 Initial Conditions: Steady state of case 1.3	Low load (fix), Low PV (fix)	Baseline System 2 (all controllable devices were in Local/Auto mode)
1.16	CCR1: Pload=2.2MW , PPV1=0.4MW, PPV2=0.2MW, PBESS1=0 CSY1: Pload=2.3MW , PPV3=0.4MW, PBESS2=0 Initial Conditions: Steady state of case 1.3	Low load (fix), Low PV (fix)	Master controller was responsible to take actions through ARC/IVVC algorithm.
1.17	CCR1: Pload=2.2MW , PPV1=0.4MW, PPV2=0.2MW, PBESS1=0 CSY1: Pload=2.3MW , PPV3=0.4MW, PBESS2=0 Initial Conditions: Steady state of case 1.3	Low load (fix), Low PV (fix)	Substation controller was responsible to take actions through permission or communication loss (prior to event)

Case#	Test Conditions	Description	Remark
1.18	CCR1: Pload=2.2MW, PPV1=1.8MW , PPV2=0.9MW, PBESS1=0 CSY1: Pload=2.3MW , PPV3=1.8MW , PBESS2=0.5MW Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix)	Baseline System 2 (all controllable devices were in Local/Auto mode)
1.19	CCR1: Pload=2.2MW, PPV1=1.8MW , PPV2=0.9MW, PBESS1=0 CSY1: Pload=2.3MW, PPV3=1.8MW , PBESS2=0MW Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix)	Master controller was responsible to take actions through ARC/IVVC algorithm.
1.20	CCR1: Pload=2.2MW, PPV1=1.8MW , PPV2=0.9MW, PBESS1=0 CSY1: Pload=2.3MW, PPV3=1.8MW , PBESS2=0.5MW Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix)	Substation controller was responsible to take actions through permission or communication loss (prior to event)
1.21	Case 1.15, trip PVs after the system gets to the steady state condition.	Low load (fix), High PV (fix)	Baseline System 2 (all controllable devices were in Local/Auto mode)
1.22	Case 1.16, trip PVs after the system gets to the steady state condition.	Low load (fix), High PV (fix)	Master controller is responsible to take actions through ARC/IVVC algorithm.
1.23	CCR1: Load Profile = High/Summer, PV Profile = High/11am CSY1: Load Profile = High/Summer, PV Profile = High/11am Initial Conditions: Steady state of case 1.1 (45-min run)	High load profile (real), High PV profile (real)	Baseline System 2 (all controllable devices were in Local/Auto mode)
1.24	CCR1: Load Profile = High/Summer, PV Profile = High/11am CSY1: Load Profile = High/Summer, PV Profile = High/11am Initial Conditions: Steady state of case 1.1 (45-min run)	High load profile (real), High PV profile (real)	Master controller was responsible to take actions through ARC/IVVC algorithm.
1.25	CCR1: Load Profile = Low/Winter, PV Profile = Low/4pm CSY1: Load Profile = Low/Winter, PV Profile = Low/4pm Initial Conditions: Steady state of case 1.3 (45-min run)	Low load profile (real), Low PV profile (real)	Baseline System 2 (all controllable devices were in Local/Auto mode)
1.26	CCR1: Load Profile = Low/Winter, PV Profile = Low/4pm CSY1: Load Profile = Low/Winter, PV Profile = Low/4pm Initial Conditions: Steady state of case 1.3 (45-min run)	Low load profile (real), Low PV profile (real)	Master controller was responsible to take actions through ARC/IVVC algorithm.

For the sale of brevity, only the results of a selected number of test cases are detailed in the following paragraphs. The test data and analysis results for all cases are available in Appendix A. For the selected test cases, this report provides a comparative analysis of test results for all control scenarios (*i.e.*, Control Scenarios 1, 2, and 3) to provide the reader with a better understanding of the advantages and disadvantages associated with each control scenario.

2.4.4.3 High load and high PV condition

In this subsection, the performance of the control system under high load and high PV profiles were examined. To that end, while the system was operating under high-load condition, the PV generation was suddenly increased to study the system reaction to such a drastic change. It is acknowledged that the likelihood of such an event occurring in the real world is slight; however, the goal was to compare system performance for such extreme cases under various control scenarios. The three test cases selected for further analysis were:

- Test Case 1.10 – All controllable devices were in Local/Auto mode, i.e. neither master controller nor substation controller active (CS 1).
- Test Case 1.11 – Master controller was responsible to take actions through ARC algorithm (CS 2).
- Test Case 1.12 – Substation controller was responsible to take actions either because permission had been granted by the master controller, or communications had been lost to the latter (CS 3).

2.4.4.3.1 Voltage profile

Figure 2-31(a) through Figure 2-31(c) show the voltage profile of circuit CCR1 for the test case with high load and high PV generation under the three control scenarios described above. This report primarily focuses on the analysis of the results obtained for circuit CCR1 because this circuit included all hardware devices including relays, voltage regulators, load tap changes and DERs. As such, the results of circuit CCR1 were more realistic, incorporating the inherent response time of actual controllable devices in the field. Similar results were also collected and analyzed for the fully simulated circuit CSY1, but are not discussed further in this report – they are however available as an electronic addendum to this report.

In Figure 2-31, three bus voltages were selected to represent the voltage profile of the feeder during the test. Voltage of Bus 103 represented the voltage at beginning of the feeder, voltage of Bus 110 indicated the voltage at middle of the feeder, and voltage of Bus 115 represented the end of the line (EOL) voltage (see Figure 2-13 to view the test system SLD). Comparing the voltage profiles for all three control scenarios[9], one can observe that the control response time was considerably faster in control scenario 2 (CS 2). In addition, both the voltage out-of-range value and voltage out-of-range duration were smaller when the master controller was in charge (CS 2). The color code used in Figure 2-31 for different voltage ranges is as follows:

- Green: Permissible range (system was allowed to work in this range for extended period of time)
- Orange: Moderate range (system was allowed to work in this range for certain time period – several minutes)
- Red: Excessive range (system was allowed to work in this range for a short period of time – several seconds)

A summary of main parameters related to the system voltage performance is presented in Table 2.17. The table shows that the majority of voltage-related criteria are improved when the master controller is operating. Moreover, although the performance of the system in control scenario 3 was not as good as

[9] A comprehensive set of data (with 10s resolution) was extracted from PI historian for analysis.

control scenario 2, it was still better than control scenario 1. It is worth noting that due to the location of PV systems, the voltage of the feeder end experienced a greater increase.

Table 2.17. Voltage-related criteria for three control scenarios (high load, high PV case)

Parameter		Value		
		CS 1	CS 2	CS 3
Maximum voltage magnitude (rms)		8.04kV (1.16pu)	7.44kV (1.074pu)	7.67kV (1.107pu)
Maximum out-of-range value with respect to maximum allowable voltage (rms)		765.4V (0.11pu)	165.4V (0.024pu)	395.3V (0.057pu)
Out-of-range duration (seconds)		115	25	80
Standard deviation	Bus 103 (beginning)	0.02412	0.01075	0.02135
	Bus 110 (middle)	0.18041	0.09328	0.19340
	Bus 115 (EOL)	0.40579	0.12152	0.37322
Average	Bus 103 (beginning)	7.096	7.078	7.044
	Bus 110 (middle)	7.046	7.088	7.037
	Bus 115 (EOL)	7.251	7.095	6.991

Figure 2-32 and Figure 2-33 show the voltage profile along the both tested circuits (*i.e.*, CCR1 and CSY1) at the steady-state condition subsequent to the test. As can be observed in these figures, under CS 2, the voltage profile of both circuits are more flat which is desirable. Further, the steady-state average voltage value is lower under CS 2 (while within the limit).

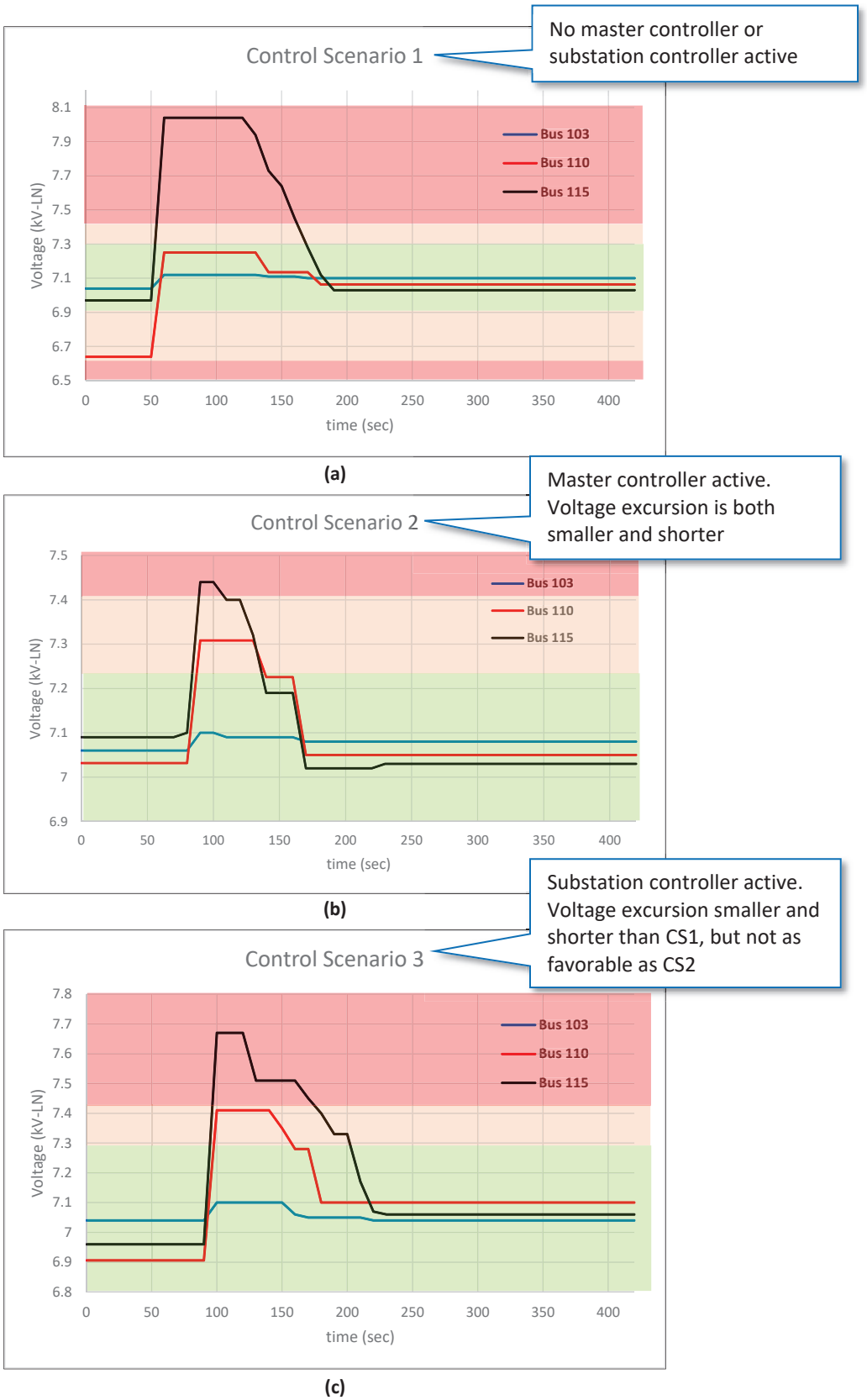


Figure 2-31. Voltage profile of circuit CCR1 for (a) Case 1.10, (b) Case 1.11, and (c) Case 1.12

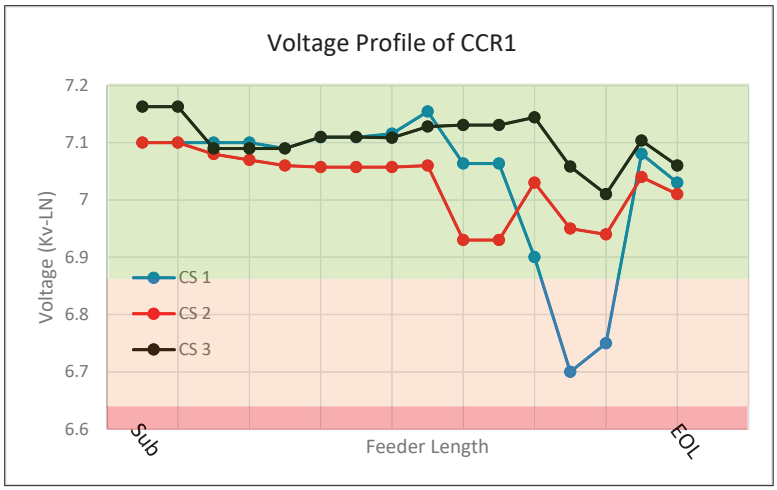
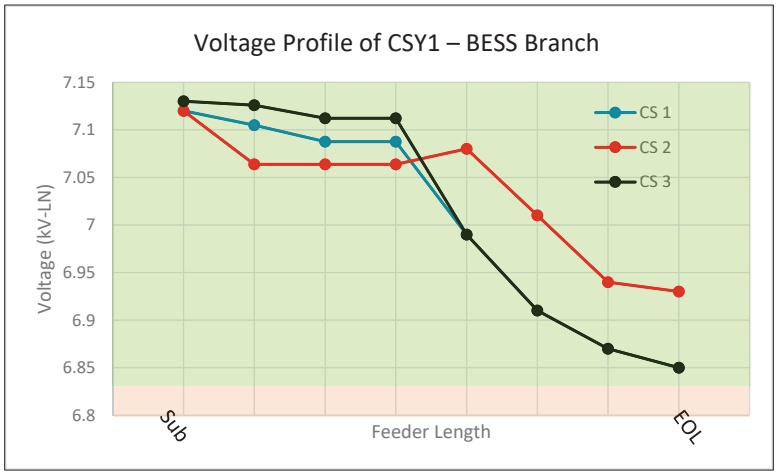
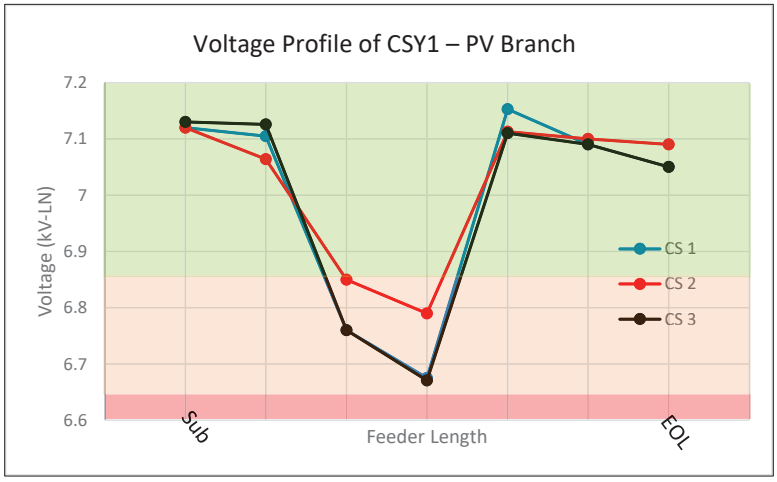


Figure 2-32. Steady-state voltage profile along circuit CCR1 under various control scenarios



(a)



(b)

Figure 2-33. Steady-state voltage profile along circuit CSY1 under various control scenarios: (a) BESS branch and (b) PV branch

2.4.4.3.2 Power losses

Figure 2-34 shows the power loss calculated for Substation "A" when the system operated under the three control scenarios (see Section 2.4.4.1 for power loss equation). As shown in this figure, the power loss generally decreased once the PV generation/injection started (at different instants); this is because some loads were supplied locally through PV systems (DERs). In addition, the amount of loss reduction was higher when the system operated under control scenario 2 and 3 (CS 2 and CS 3). This was mainly due to the fact that the master and substation controllers utilized more DERs to address system violations (as compared to local controllers). More specifically, battery energy storage systems made a greater contribution to the enhanced system performance (see Section 2.4.4.3.3), when the Master/Substation controller was in place.

Table 2.18 reports the power loss reduction for Substation A for the three control scenarios under study. As shown in this table, with no DERs, the total power loss was about 1.5MW (4.4% of the total substation load). However, with the DER contribution, the power loss decreased to 1.04MW, 0.77MW, and 0.86MW under CS 1, CS 2, and CS 3, respectively.

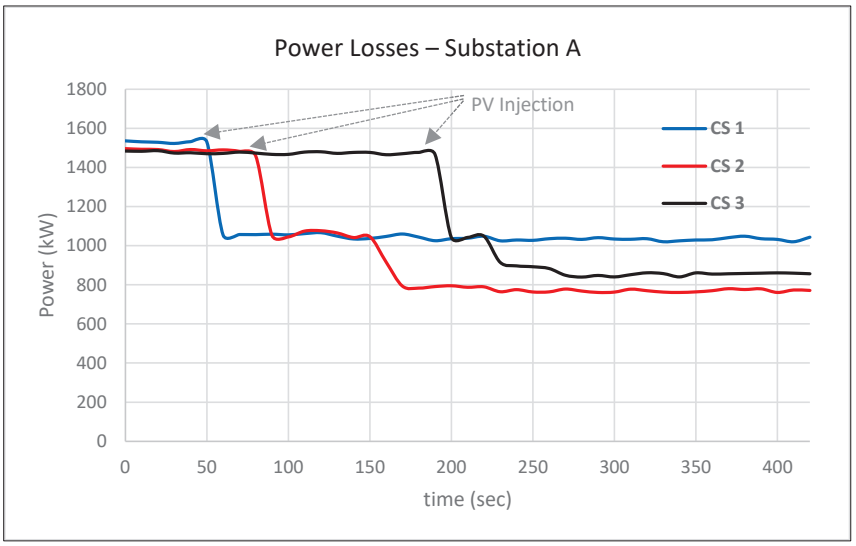


Figure 2-34. Power losses for Substation A (Cases 1.10, 1.11, and 1.12)

Table 2.18. Power loss reduction under three control scenarios

Control Scenario	Power Loss		
	Before	After	Enhancement
CS 1	1535.9kW (4.40%)	1043.5kW (3.04%)	1.36%
CS 2	1496.1kW (4.36%)	771.1kW (2.25%)	2.11%
CS 3	1493.9kW (4.36%)	856.4kW (2.50%)	1.86%

2.4.4.3.3 DER involvement/contribution

As the penetration of DERs increases, it is essential to utilize them effectively in the control process of distribution systems. Therefore, enhanced DER involvement was one of the key factors for the evaluation of the effectiveness of a control strategy. In this project, both DER output power and grid power were used as means to examine DER involvement. Figure 2-35 shows the grid power (only for Substation A) during the conducted test for each control scenario. As shown, the power drawn from the grid was reduced for CS 2 and CS 3, which is the main reason that the overall power loss decreased.

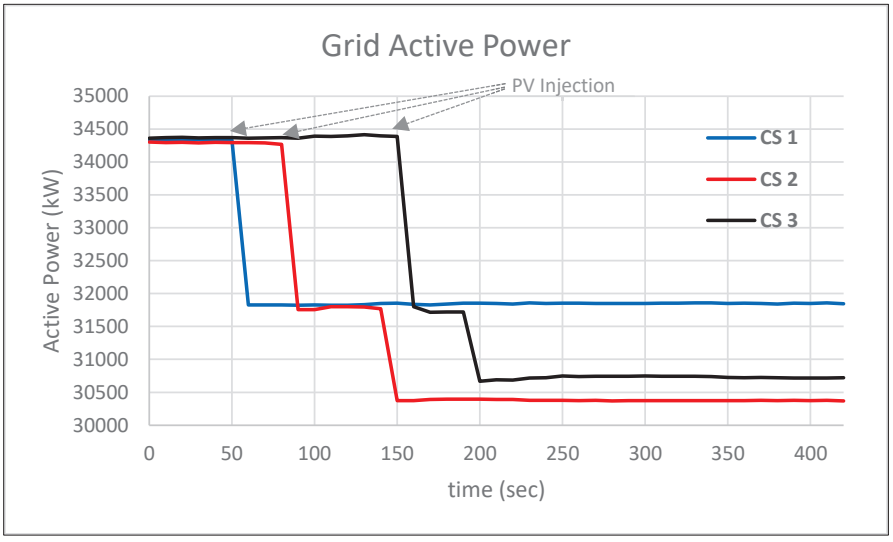


Figure 2-35. Grid power (Substation A) for high load, high PV case

The reactive power contributions (absorption) of DERs for each control scenario are plotted in Figure 2-36. Similarly, it is observed that DERs contributed more to the voltage correction under Control Scenarios 2 and 3. One interesting point is that, under CS 3, the DER reactive power contribution was even greater than that of CS2. This is because the substation controller was regulating the power factor (at the substation level) by controlling the reactive power of the substation battery (see BESS1 in Figure 2-40). This will be discussed further in the subsection that follows.

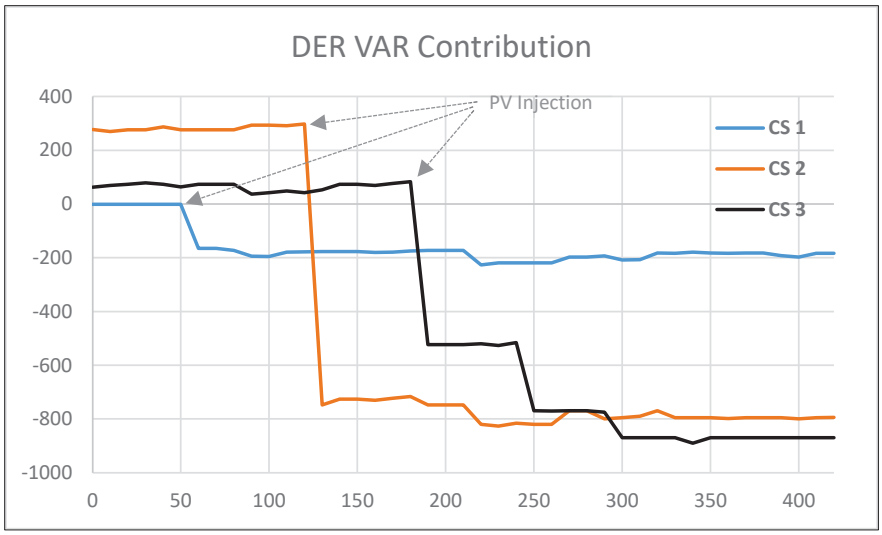


Figure 2-36. Reactive power contribution of DERs (Substation a) for high load, high PV case

2.4.4.3.4 Power factor

Figure 2-37 shows the reactive power flowing through Circuit Breaker CCR1 (CB CCR1 in Figure 2-13) for high load with high PV generation. Although the overall reactive power under normal condition was insignificant (both feeder capacitor banks located at circuit CCR1 are ON), the improvement under CS 2 and CS 3 was still observable. In other words, both master controller and substation controller tried to maintain power factor of the circuit at unity. This is evident in Figure 2-37 where the circuit reactive power was around zero under CS 2 and CS 3 (note the dash box). It should be noted that the accurate adjustment (fine tuning) of power factor is only achievable through the effective utilization/control of distributed energy resources (DERs).

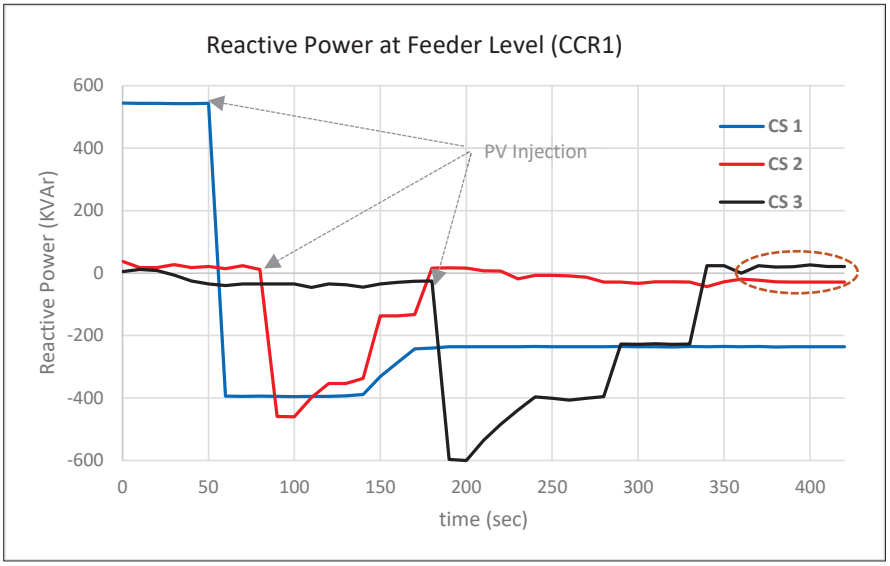


Figure 2-37. Reactive power at the feeder level for high load, high PV case

2.4.4.3.5 Asset operation

The last item studied for the evaluation of the ARC use case in the proposed control architecture was the number of operation of controllable assets. Ideally, it is expected that a central controller reduces the number of operation of Cap banks, voltage regulators, and tap changers. This should be achieved with efficient utilization of DERs for voltage regulation. However, it was observed that in some test cases there was no or little improvement in the cumulative number of asset operation. This was a result of the master controller trying to optimize the feeder voltage profile, which normally required more operations of some switchable devices.

Table 2.19 lists the cumulative numbers of operation for each controllable device employed in circuit CSY1 and circuit CCR1. Figure 2-38 identifies the location of each of these controllable devices on the SLD. For this test case, it was observed that the total operation of assets decreased under CS 2. This was mainly because of the enhanced DER involvement. It should be pointed out that, under CS 3, the total number of operation increased because: (i) substation controller tried to regulate voltage at best possible values and (ii) substation controller did not remotely control feeder capacitor banks (out of scope of this project).[10] It is also worth noting that the substation controller can provide the same functionality as the master controller, assuming proper logic capability and reliable communications with the field devices exist.

Table 2.19. Total number of operation of controllable devices (high load, high PV case)

Device	Total number of operation		
	CS1	CS2	CS3
Cap. CSY1_1383CW	1	1	0
Cap. CSY1_1416CW	0	0	0
Cap. CSY1_1460CW	0	0	0
Cap. CCR1_1105CW	0	0	0
Cap. CCR1_1147CW	0	0	0
VR CSY1-1046G_PhaseA	7	3	6
VR CSY1-1046G_PhaseB	8	3	6
VR CSY1-1046G_PhaseC	7	3	4
VR CCR1-733G_PhaseA	2	2	4
VR CCR1-733G_PhaseB	1	3	2
VR CCR1-733G_PhaseC	2	2	3
VR CCR1-1164G_PhaseA	5	4	4
VR CCR1-1164G_PhaseB	6	2	6
VR CCR1-1164G_PhaseC	4	3	5
VR CCR1-1141G_PhaseA	3	2	4

[10] Capacitor Banks have a minimum start times of 5 minutes (in Local mode) and, thus, before they get a chance to operate, the control of other devices may bring the voltage within the acceptable level (albeit at the price of higher operation number). However, the central controller can send close/trip commands to Cap Banks in Remote mode, knowing the operation history.

Device	Total number of operation		
	CS1	CS2	CS3
VR CCR1-1141G_PhaseB	3	3	5
VR CCR1-1141G_PhaseC	2	3	5
LTCN1	0	0	1
LTCSY	1	0	0
TOTAL	**52**	**34**	**55**

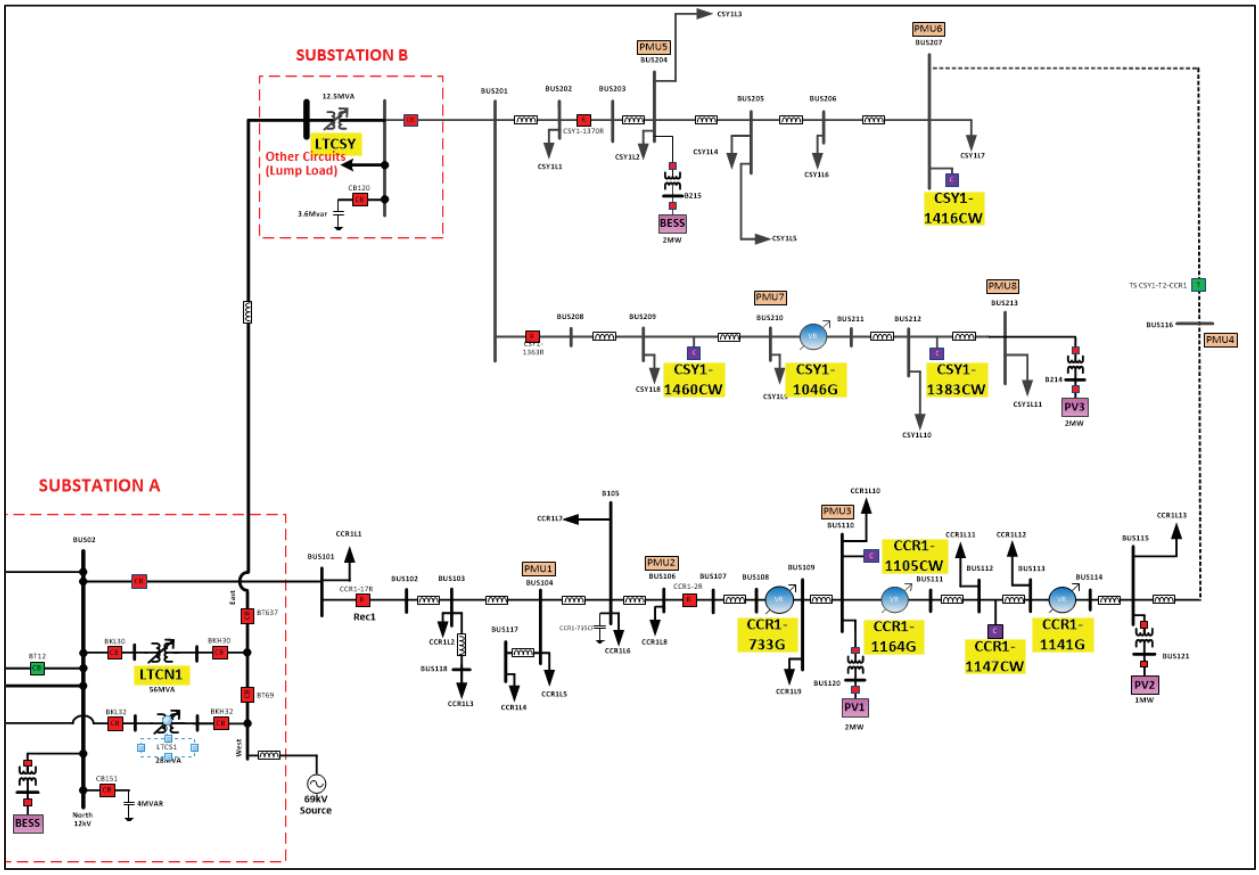
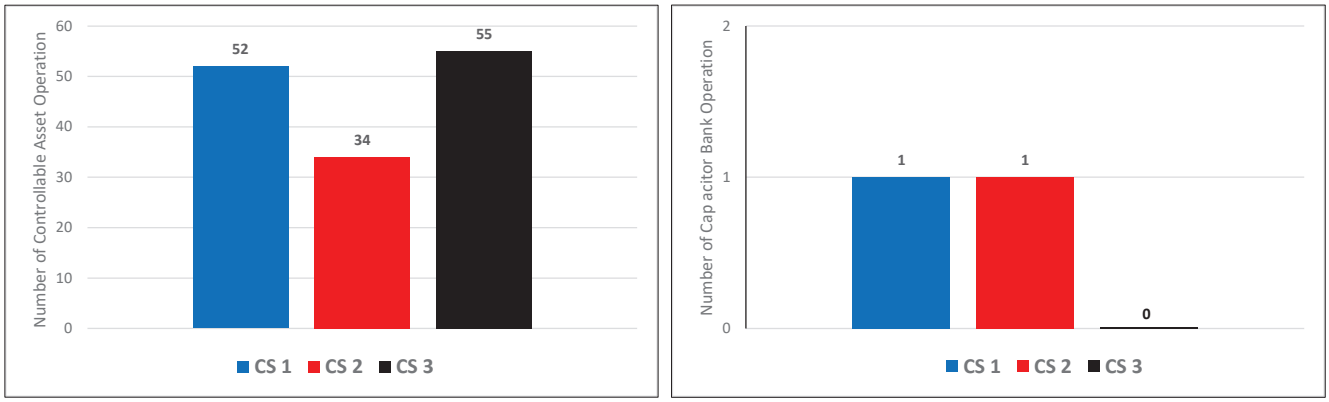


Figure 2-38. Device identifier of controllable devices.

Figure 2-39 represents an illustrative comparison between the total numbers of asset operation (and capacitor bank operation). Although there was not an improvement for the third control scenario (for the sake of optimal voltage values), the number of operation improved by about 35% for CS 2.



(a) **(b)**

Figure 2-39. Number of controllable device operations under different control scenarios: (a) total numbers of operations and (b) capacitor bank operation.

In summary, the analysis of results for ARC use case shows that, with a central ARC (CS 2 or CS 3), the system performance improved significantly. Although the results of CS 3 were not as good as CS 2, it should be borne in mind that the substation controller can offer the same functionality as the master controller if (i) it has adequate analysis capability and (ii) it can communicate with all required controllable field devices.

2.4.4.4 Trip PV 1 (high load and high PV profile)

This section provides the results of a more realistic case that can potentially occur in real life. In this case, while the system was in the steady-state condition (with high load profile[11] and high PV generation profile),[12] PV1 was tripped (*e.g.*, due to a fault) causing the system to lose approximately 1800kW of generation. The load and PV profiles were obtained based on the analysis of historical data.

Figure 2-40 shows a simplified single-line diagram of the study system with the location of PV1 highlighted. After running the system for about 30 minutes with actual load and PV profiles, PV1 was suddenly tripped. For such a contingency case, the system performance was analyzed under two control scenarios, *i.e.*, CS 1 (Case 1.13 in Table 2.16) and CS 2 (Case 1.14 in Table 2.16), and the results are presented and briefly discussed in the following subsections.

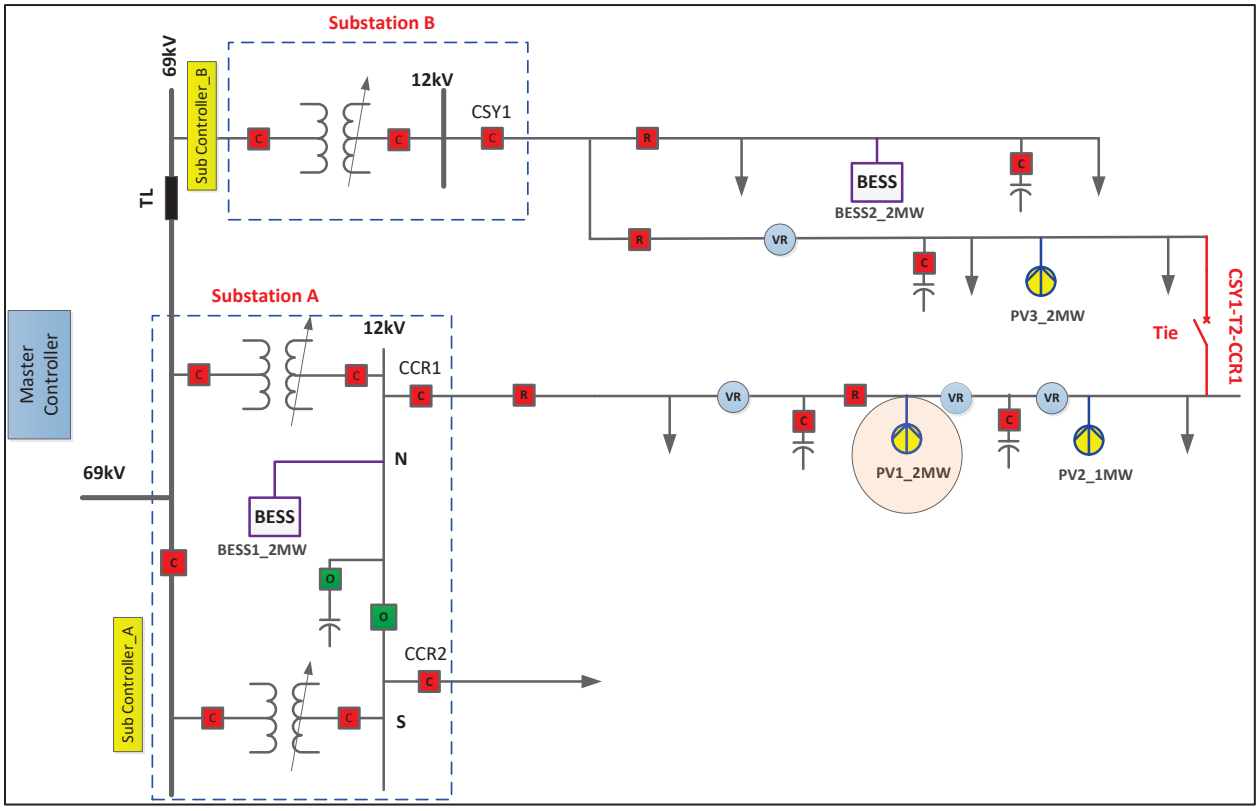


Figure 2-40. Simplified SLD of the study system

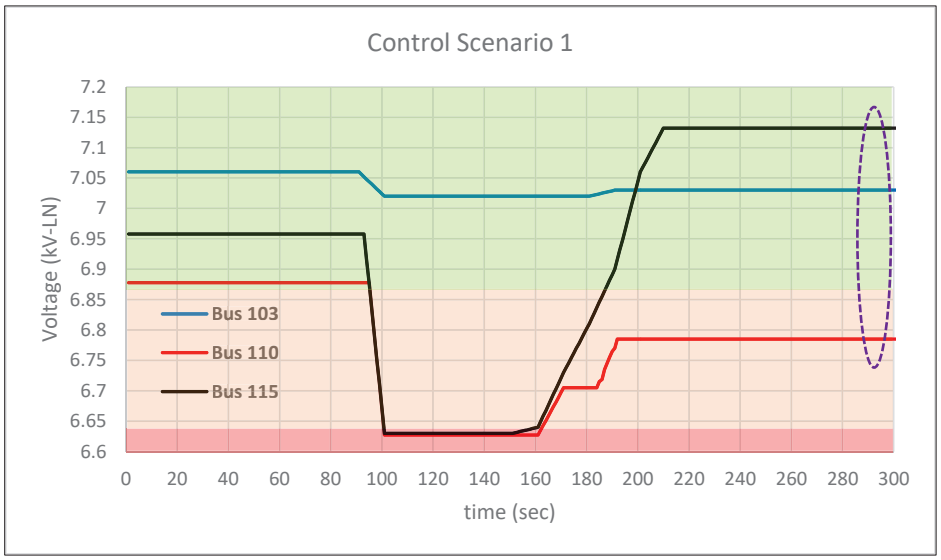
2.4.4.4.1 Voltage profile

Figure 2-41 (a) and Figure 2-41 (b) show the voltage profile of Circuit CCR1 for Cases 1.13 and 1.14, respectively. The figures clearly show that, under Control Scenario 2 (CS 2), the system reacted quickly

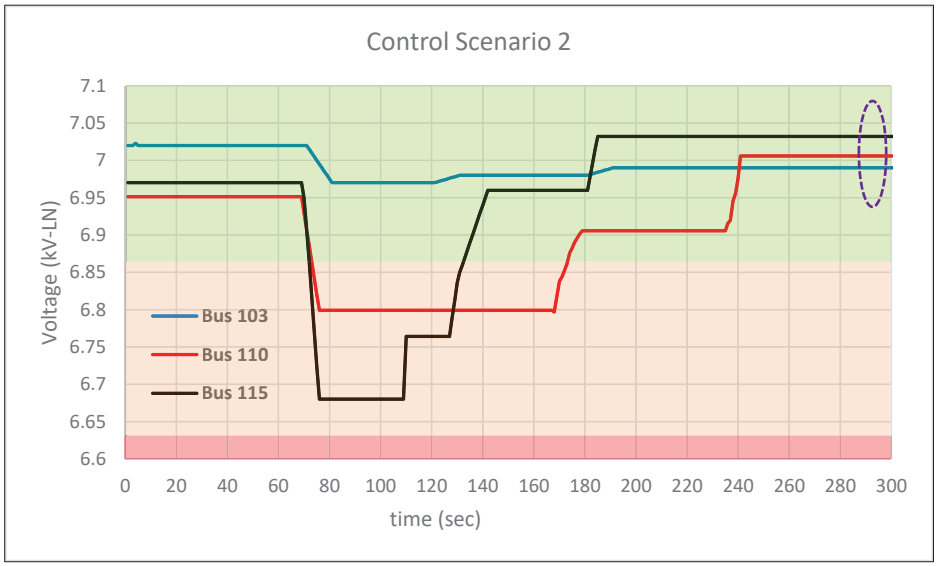
[11] High load profile is selected based on the analysis of historical load data, which is a summer day. Similarly, low load profile data is a winter day.

[12] High PV generation is selected based on the analysis of historical solar radiation data, which is 11am to 1pm of a sunny day. Similarly, low PV profile is 4pm to 6pm of a regular day.

to the DER trip, way before the voltage could go below the permissible threshold (see Figure 2-41 (b)). In contrast, under Control Scenario 1 (CS 1), the system voltage entered the excessive range for about 60 seconds before the first control action was taken. Further, under CS 1, the steady-state voltage of Bus 110 stayed in the moderate range.



(a)



(b)

Figure 2-41. Voltage profile of circuit CCR1 for (a) Case 1.13 (CS 1) and (b) Case 1.14 (CS 2)

It is important to note that steady-state voltage values had a much flatter profile under CS 2 when compared to the same voltages values under CS 1 (see dash circled areas in Figure 2-41 (a) and Figure 2-41 (b) above). This is further illustrated in Figure 2-42, where the steady-state voltage value of some busses stayed in the moderate range (orange) under CS 1 while the same values were in the acceptable range under CS 2. This re-emphasized that ineffective/insufficient contribution of DERs in local mode caused significant voltage drop at the end of the line for CS 1 (see blue line in Figure 2-42).

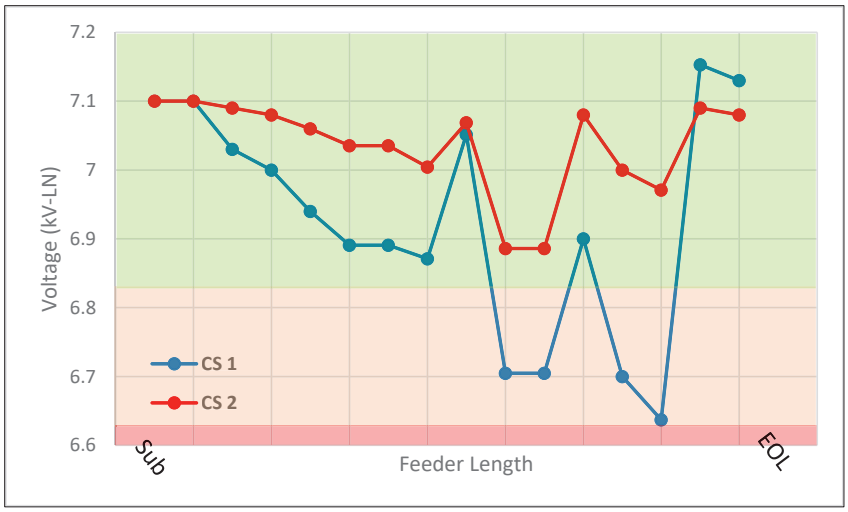


Figure 2-42. Steady-state voltage profile along Circuit CCR1 under various control scenarios

2.4.4.4.2 Power losses

Figure 2-43 shows the power loss calculated for Substation A for Case 1.13 (CS 1) and Case 1.14 (CS 2) (see Section 2.4.4.1 for power loss equation). As indicated in the figure, the power loss generally increased subsequent to the PV trip (taking place at different instants for each case); this was due to the fact that less loads were supplied locally when a DER unit (~1800kW) tripped. Figure 2-43 also shows that the amount of loss reduction was higher when the system operated under Control Scenario 2 (steady state), as compared with Control Scenario 1. In this case, the reactive power support of DERs played a role in the loss reduction for the overall substation. Since DERs have more reactive power contribution in Case 1.14 (CS 2), the power loss reduction was higher for this case (also see Section 2.4.4.4.3).

The results of these tests showed that the steady-state power losses under CS 1 and CS 2 were 1120.4kW (3.27%) and 1022.5kW (2.98%), respectively. Therefore, there was 0.29% improvement in power loss when the system operated under Control Scenario 2.

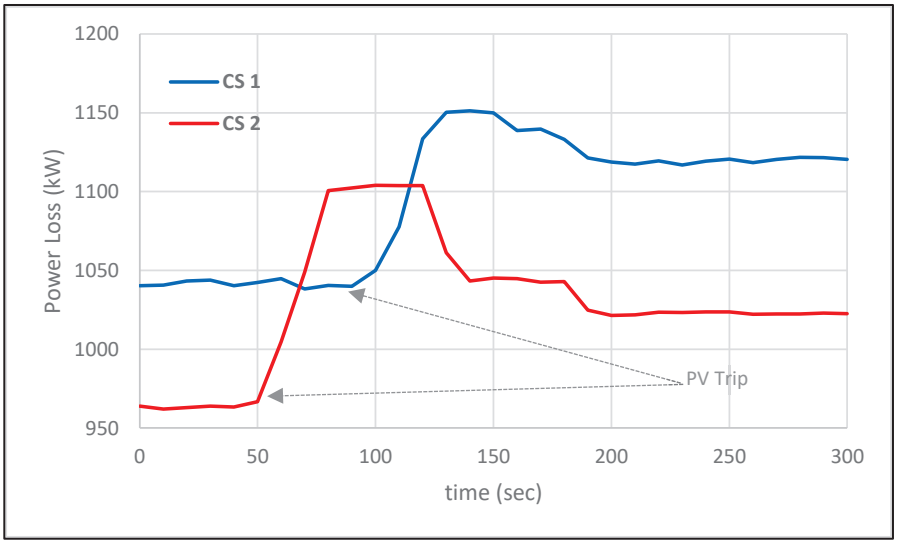


Figure 2-43. Power losses for Substation A substation (cases 1.13 and 1.14)

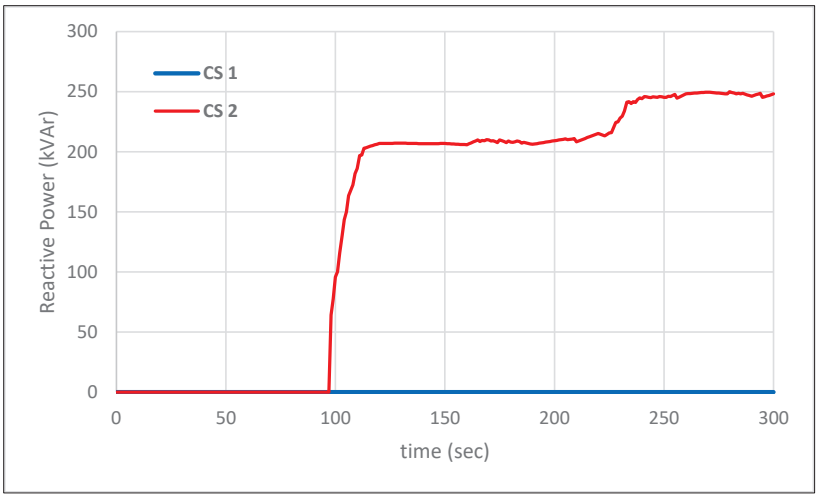
2.4.4.4.3 DER involvement/contribution

The reactive power contributions of all DERs in Circuit CCR1 are plotted in Figure 2-44(a), (b), and (c) for both control scenarios. It can be observed in these figures that all DERs injected more reactive power to the circuit under Control Scenarios 2 (CS 2) in order to regulate feeder voltage or adjust the circuit power factor. For example, Figure 2-44(a) shows that the battery energy storage system at the substation (BESS 1 in Figure 2-13) did not inject any reactive power to the grid under CS 1. However, with the ARC algorithm activated (CS 2), the reactive power contribution of BESS 1 was adjusted by the ARC engine (master controller in this case) such that it supported the grid by injecting about 250 kvar reactive power in the steady-state condition.

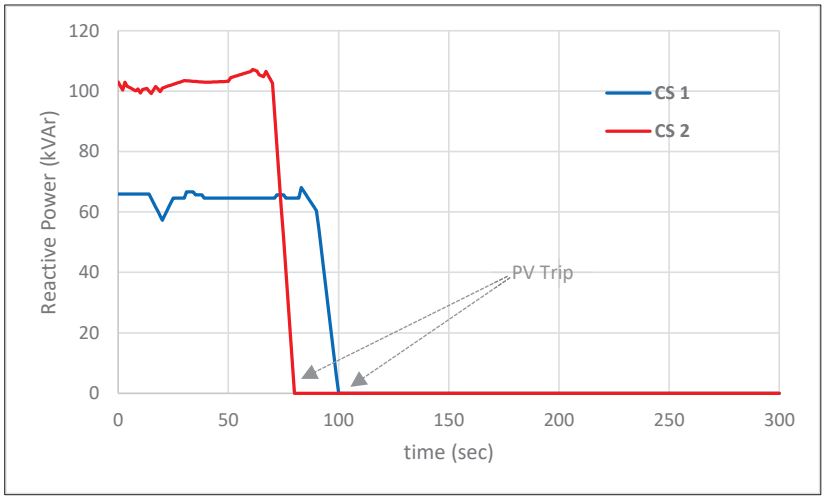
A comparison of total reactive power injection by DERs on Circuit CCR1 showed that they injected around 480 kvar more reactive power to the circuit under CS 2 (relative to CS 1). It should, however, be acknowledged that part of this var contribution by DERs was to adjust power factor at the circuit/feeder level.

2.4.4.4.4 Power factor

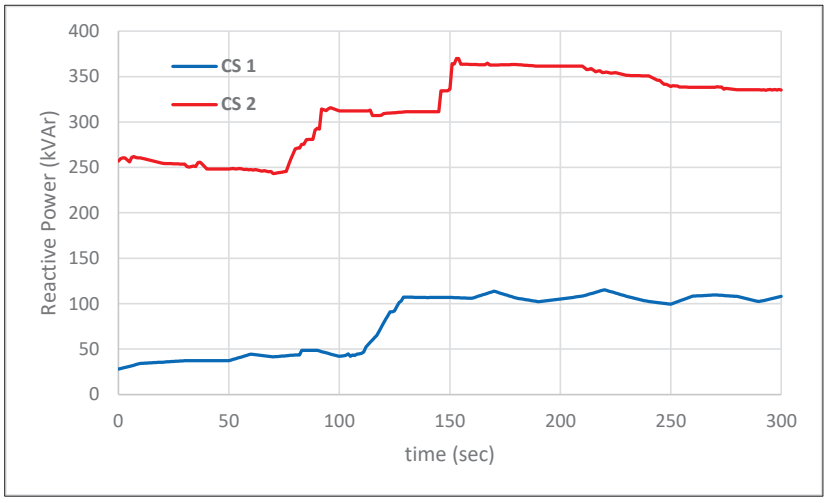
Figure 2-45 shows the reactive power flowing through Circuit Breaker CCR1 (CB CCR1 Figure 2-13) before and after the PV trip, for a 5-minute time frame. As indicated in this figure, under the second control scenario with ARC in place (CS 2), the reactive power flow at the feeder level was close to zero. This is because one of the objectives of the ARC algorithm is to improve overall system power factor through the regulation of reactive power. In other words, the master controller tried to maintain power factor of the circuit at unity. This is evident in Figure 2-45 where the circuit var value was around zero under CS 2 (green band in Figure 2-45). It should also be pointed out that the accurate adjustment of power factor was achieved through the effective control of DERs.



(a)



(b)



(c)

Figure 2-44. Reactive power contribution of DERS (in Substation A) for cases 1.13 (CS 1) and 1.14 (CS 2): (a) Substation BESS reactive power, (b) PV1 reactive power, and (c) PV2 reactive power

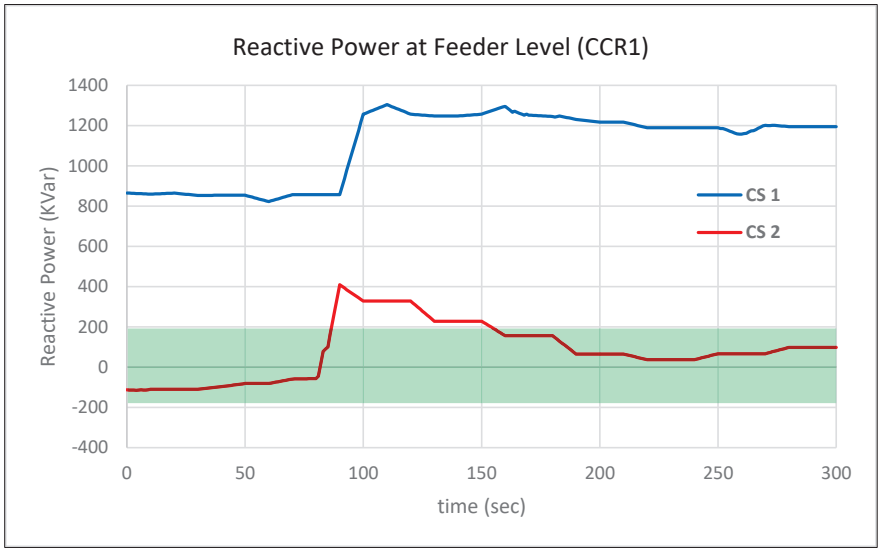


Figure 2-45. Reactive power at the feeder level for cases 1.13 and 1.14 (PV trip)

2.4.4.4.5 Asset operation

Figure 2-46(a) and Figure 2-46(b) respectively show the cumulative numbers of device operation and number of capacitor bank operation for Case 1.13 and Case 1.14. It is evident from the figures that the cumulative number of operation of controllable assets was reduced by about 26% with the master controller in charge (i.e., CS 2). In addition to the enhanced DER contribution, switching on the capacitor bank CSY1-1383CW avoided additional operation of other controllable assets. It should be noted that, as opposed to local mode control that had a minimum start time for capacitor bank energization, the master controller could quickly send the close/trip commands to the capacitor bank (in remote mode), knowing its operation history.

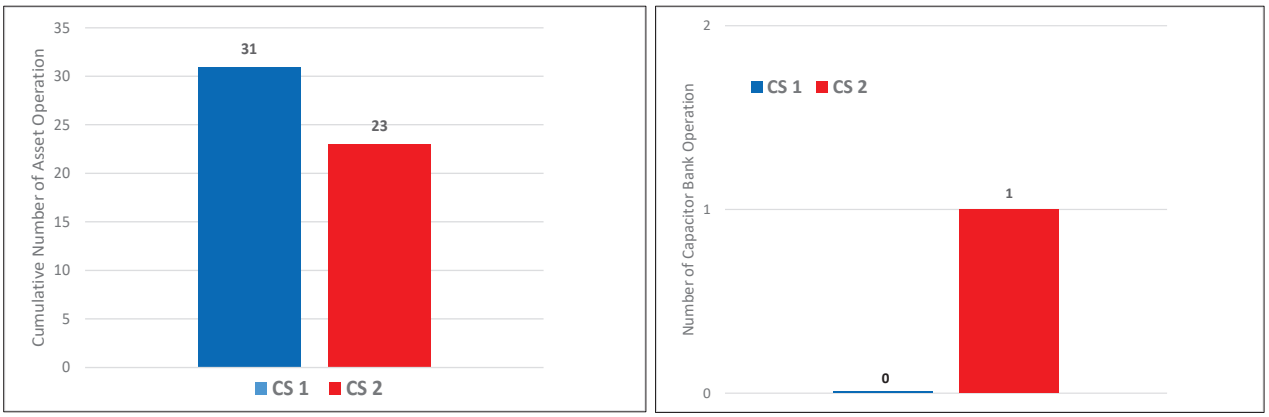
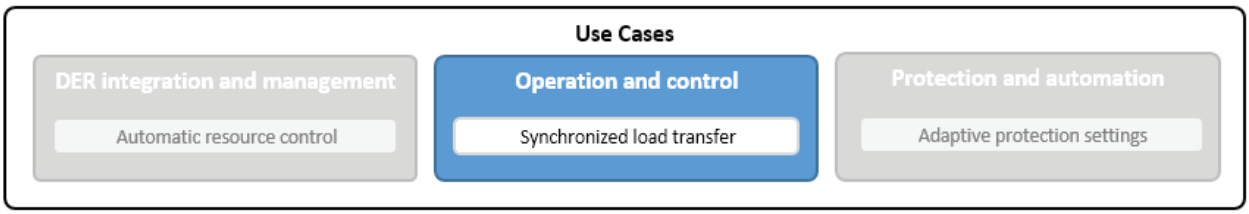


Figure 2-46. Number of controllable device operations for case 1.13 (CS 1) and case 1.14 (CS 2): (a) cumulative numbers of operations and (b) capacitor bank operation.

2.4.5 Use case 2: Synchronized Load Transfer



The Synchronized Load Transfer (SLT) application utilized four control blocks in various levels to optimize circuit reconfiguration:

- Feeder Injection Test (FIT) tool
- Near-Real-Time Power Flow (NRTPF) model
- Real-time SCADA measurements
- Synchronization check function

The Feeder Injection Test (FIT) tool determined whether there were circuit performance violation(s) that should be corrected by Synchronized Load Transfer (SLT). In the event that violations were detected, FIT used real-time field/SCADA data, load/generation forecast results, and the Near-Real-Time Power Flow Model (NRTPF) to determine if the circuit violation needed to be addressed by the load transfer (rather than resource control). Both FIT and NRTPF blocks were located at the control-center level in the master controller.

For all test cases, the SLT function identified the switches to operate for the desired system reconfiguration. Since the load transfer was executed while the system was energized (without any power interruption), a synchronization check had to be performed. The voltages on both sides of the tie switch (magnitude, phase angle, and frequency) were checked to ensure they were synchronized. If this condition was not met, Load Tap Changer (LTC) settings, capacitor bank controller settings, and/or DER outputs were controlled to achieve synchronization.[13] Once voltage synchronization was established by the SLT, the tie switch was closed, followed by opening of the upstream isolating switch(s) to complete the transfer. The synchronization check was performed through the collaboration of field and substation devices.

The SLT application performed the following functions:

- Utilized the results of the FIT tool or an operator request to trigger further action
- Acquired information about all tie and isolating switches in the distribution system, including their current status
- Determined if the load transfer could improve system condition (power quality, loading, etc.) using FIT and NRTPF models
- Identified the tie and isolating switches that needed to be operated for optimal system reconfiguration
- Checked synchronization between two parts of the distribution network (voltages on both sides of the tie switch)

[13] It should be pointed out that the frequency and phase angle of the voltages (on both sides of the tie switch) were in the acceptable synchronization range for distribution systems.

- If the voltage phasors were not synchronized, it would change LTC settings, capacitor bank controller settings, and/or DER output powers to synchronize the voltages (magnitude, phase angle, and frequency)
- Sent trip/open commands to tie/isolating switch(s) via SCADA
- Received synchronization confirmation signal (and closure confirmation) from the tie switch
- Triggered alarms if:
  - Load transfer couldn't resolve the circuit violation
  - Load transfer couldn't be accomplished due to the current state of switching devices
  - Communication network failed
  - Communication with the target switch failed
  - The target switch failed to operate
- Sent SLT completion confirmation to higher control level *i.e.*, Distributed Energy Resource Management System (DERMS) or Distribution Management System (DMS) or SCADA.

Figure 2-47 provides the sequence diagram of the SLT applications, showing the interaction between the ARC and SLT applications. As illustrated, once the application determined the ARC was unable to resolve the circuit violtion (e.g. excessive reserve power flow), the SLT application would check the possibility of the load transfer without system interruption (green box in Figure 2-47).

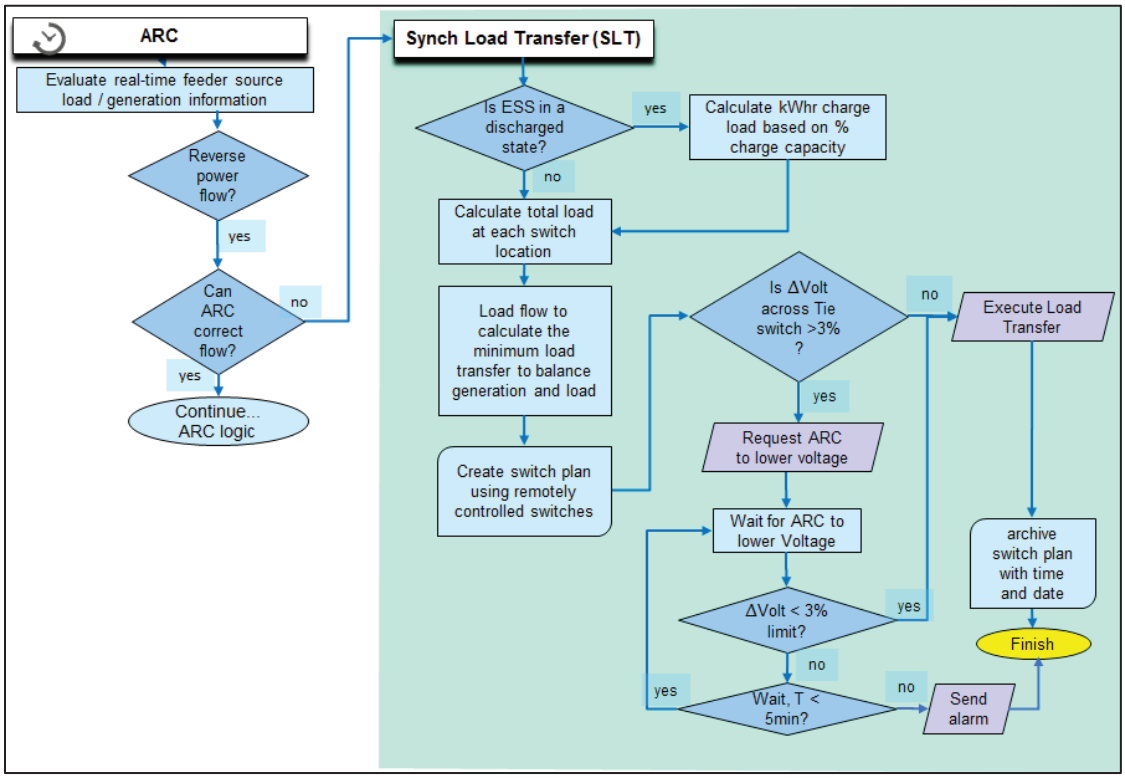


Figure 2-47. Synchronized Load Transfer

2.4.5.1 Performance criteria

The main objectives of the SLT use case was to prevent unintentional excessive reverse power flow within distribution circuits or at the substation level. The SLT function should transfer some part of a circuit to another one in order to avoid reverse power flow in the circuit. It should be noted that the SLT use case would only function if the ARC was not capable of optimally addressing the situation. Therefore, if the reverse power flow was reduced as a results of the SLT application, it was considered as successful test. The successful completion of the function also required the transfer be done in a synchronized manner.

2.4.5.2 Test results

The purpose of this test category was to verify that the master controller and substation controllers could collectively perform load transfer between two circuits (from two different substations) when such a need arose. The main criterion for performing a load transfer was excessive reverse power flow measured along the feeder, *e.g.*, when the DER penetration/injection was high. Under such a scenario, it was very unlikely that the ARC function would be able to address circuit violation without any curtailment. As a result, the possibility of SLT was evaluated through proper coordination between ARC and SLT engines.

It is emphasized that the salient feature of the SLT is that the transfer is executed in a synchronized manner, meaning it will be performed only if the voltage phasors on both sides of the tie switch are cophasal and of almost equal magnitude (the instantaneous voltage across the tie switch should be adequately small). If the synch-check signal is not received from the tie switch relay, the transfer cannot be accomplished. In such a case, the SLT function will adjust the settings of controllable assets to bring the voltage magnitude across the tie to an acceptable range. As soon as this happens, the tie switch relay will issue the synch-check signal such that the SLT can be initiated and completed.

Several test cases were considered in this category to ensure proper operation of the SLT application (both security and dependability). Figure 2-48 lists major test cases conducted for the evaluation of the SLT application. Similar to the ARC use case, the test cases were designed to examine system performance under three control scenarios described in Section 2.4.4.2 (CS 1, CS2, and CS 3); the results of selected test cases are presented and discussed in this section.

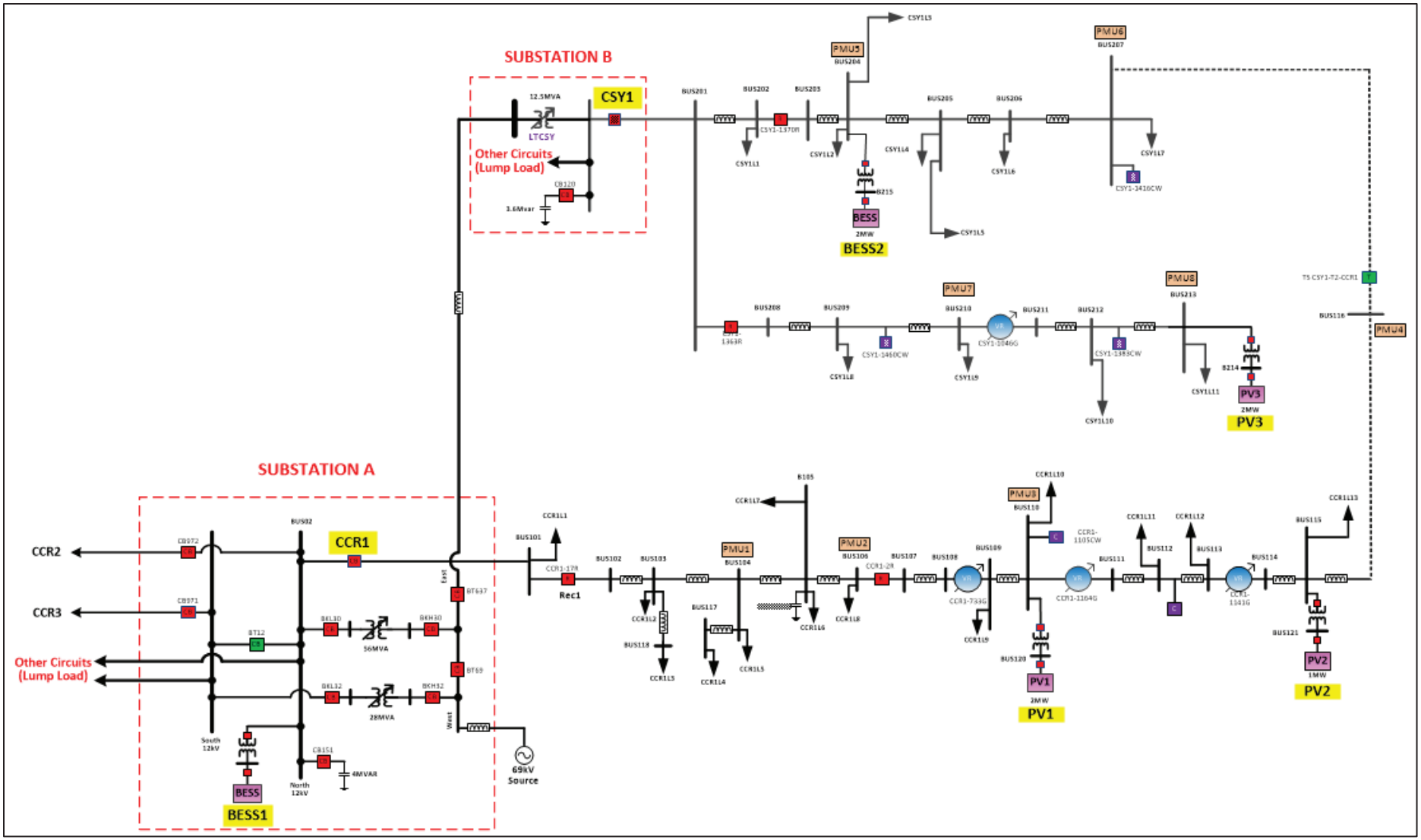


Figure 2-48. Identification of devices referenced in use case 2 test cases

Table 2.20. SLT test cases

Case#	Test Condition	Description	Remark
2.1	CCR1: PLoad=2.1MW, PPV1=2MW, PPV2=1MW, PBESS1=0 CSY1: PLoad =2.3MW, PPV3=0 (PV was not available), PBESS2=0 Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix), PV3 tripped	Baseline System 2 (all controllable devices were in Local/Auto mode)
2.2	CCR1: PLoad =2.1MW, PPV1=2MW, PPV2=1MW, PBESS1=0 CSY1: PLoad =2.3MW , PPV3=0 (PV was not available), PBESS2=0 Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix), PV3 tripped	Master controller was responsible to take actions through SLT/IVVC algorithm.
2.3	CCR1: Pload=2.1MW, PPV1=2MW, PPV2=1MW, BESSOutput=0 CSY1: Pload=2.3MW, PPV3=0 (PV was not available), PBESS2=0 Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix), PV3 tripped	Sub controller was responsible to take actions through permission of communication loss (prior to event)
2.4	CCR1: PLoad =2.1MW, PPV1=1MW, PPV2=0.5MW, PBESS1=0 CSY1: PLoad =2.3MW, PPV3=1.0MW, PBESS2=0 Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix)	Baseline System 2 (all controllable devices were in Local/Auto mode)
2.5	CCR1: PLoad=2.1MW, PPV1=1MW, PPV2=0.5MW, PBESS1=0 CSY1: PLoad=2.3MW, PPV3=1.0MW, PBESS2=0 Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix)	Master controller was responsible to take actions through SLT/IVVC algorithm.
2.6	CCR1: Pload=2.1MW, PPV1=1MW, PPV2=0.5MW, PBESS1=0 CSY1: Pload=2.3MW, PPV3=1MW, PBESS2=0 Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix)	Sub controller was responsible to take actions through permission of communication loss (prior to event)
2.7	CCR1: PLoad=3.6MW, PPV1=1.6MW, PPV2=0.8MW, PBESS1=0 CSY1: PLoad=1.2MW, PPV3=1.4MW, PBESS2=0MW Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix)	Baseline System 2 (all controllable devices were in Local/Auto mode)
2.8	CCR1: PLoad=3.6MW, PPV1=1.6MW, PPV2=0.8MW, PBESS1=0 CSY1: PLoad=1.2MW, PPV3=1.4MW, PBESS2=0MW Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix)	Master controller was responsible to take actions through SLT/IVVC algorithm.
2.9	CCR1: Pload=2.1MW, PPV1=2MW, PPV2=1MW, PBESS1=0 CSY1: Pload=2.3MW, PPV3=1.4, PBESS2=0 Initial Conditions: Steady state of case 1.3	Low load (fix), High PV (fix)	Sub controller was responsible to take actions through permission of communication loss (prior to event)

For scenarios where the system is lightly loaded and the PV generation is high (e.g., test cases 2.1, 2.2, and 2.3 in Table 2.20), it is very likely that power flows through some of the protective devices along the circuit become negative. The reverse power flow can significantly impact the operation of protection and control equipment, which is not desirable. For example, when the solar radiation is suddenly increased in a light load condition (cases 2.1, 2.2, and 2.3), the direction of the active power flowing through devices on circuit CCR1 changes. Figure 2-49 shows the active power flow through two reclosers before and after the solar radiation increase. The figure indicates that the increase in the solar radiation (from 10% to 80%) could cause significant reverse power flow through the two reclosers.

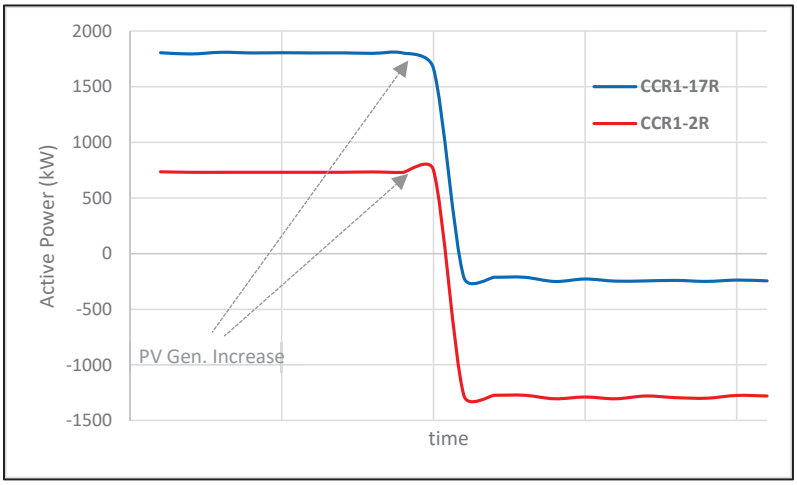


Figure 2-49. Active power flow through CCR1-2R and CCR1-17R

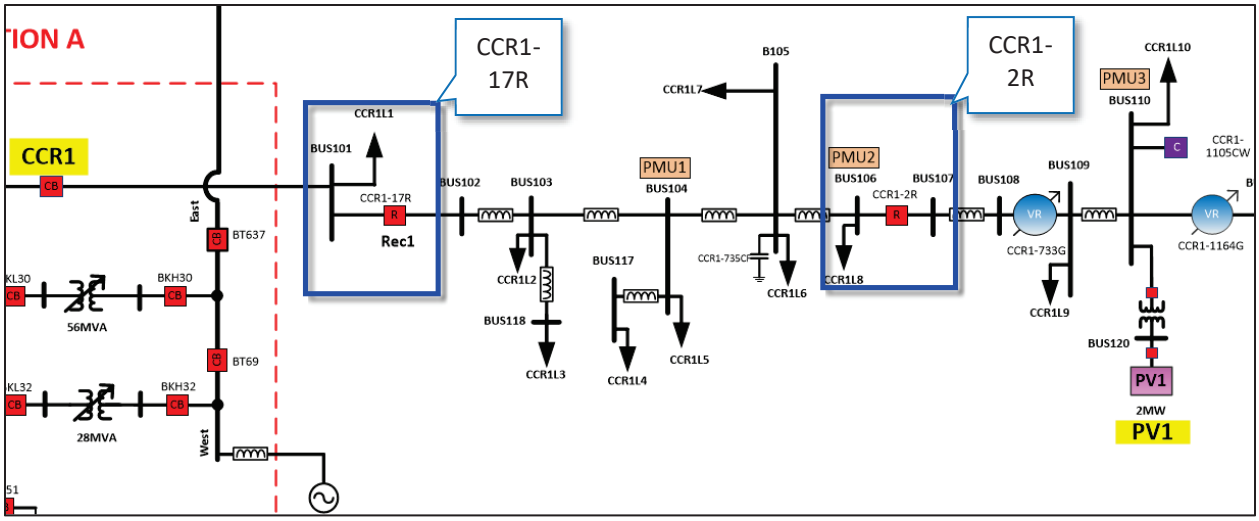


Figure 2-50. Location of CCR1-2R and CCR1-17R on SLD

Under control scenario 1 (*i.e.*, when all individual devices are in Local mode), it would be very difficult, if not impossible, to effectively manage reverse power flow while maximizing the power generation from renewable energy resources. Figure 2-51 shows the voltage profile of circuit CCR1 for control scenario 1 (CS 1), with no PV curtailment. As shown in this figure, the steady-state values of bus voltages did not settle in the permissible range. In other words, without any power curtailment, both reverse power

issue and overvoltage issue could not be successfully resolved for low-load, high-generation conditions. The power of the tie switch and reclosers CCR1-2R and CCR1-17R during the entire test is plotted in Figure 2-53. It can be observed that the tie switch remains open during the test.

On the other hand, under control scenario 2 (*i.e.*, when ARC/SLT function is run in the master controller), the reverse power flow along the circuit was detected by the master controller. Since the ARC could not fully resolve the circuit violations without power curtailment, the possibility of the synchronized load transfer was evaluated by the SLT function. Once the SLT engine confirmed the load transfer could be executed, the close command was issued to the tie switch. Once the voltages on both sides of the tie switch were synchronized (*i.e.*, the synch-check command was received from the tie switch relay), the close command was applied, followed by opening the upstream isolating switch.

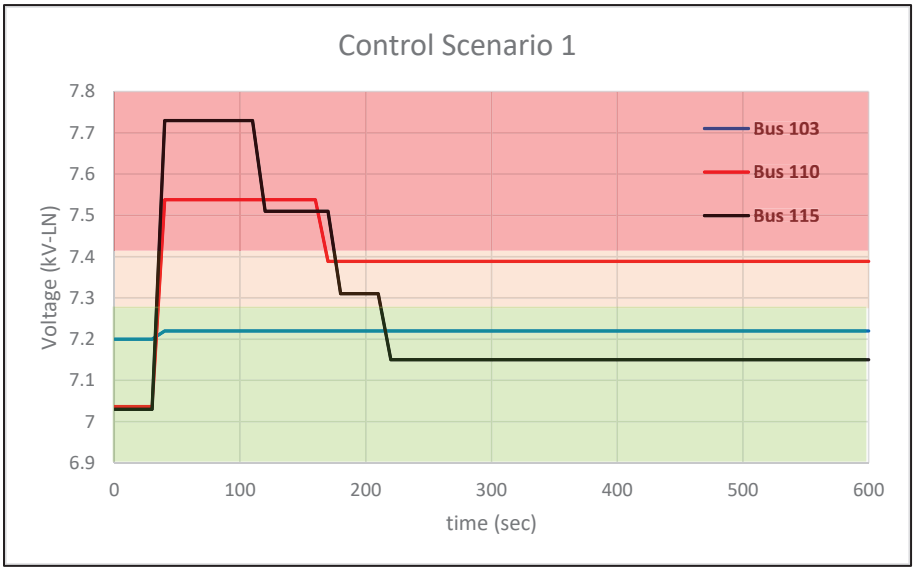


Figure 2-51. Voltage profile of circuit CCR1 for case 2.1 (CS 1) without power curtailment

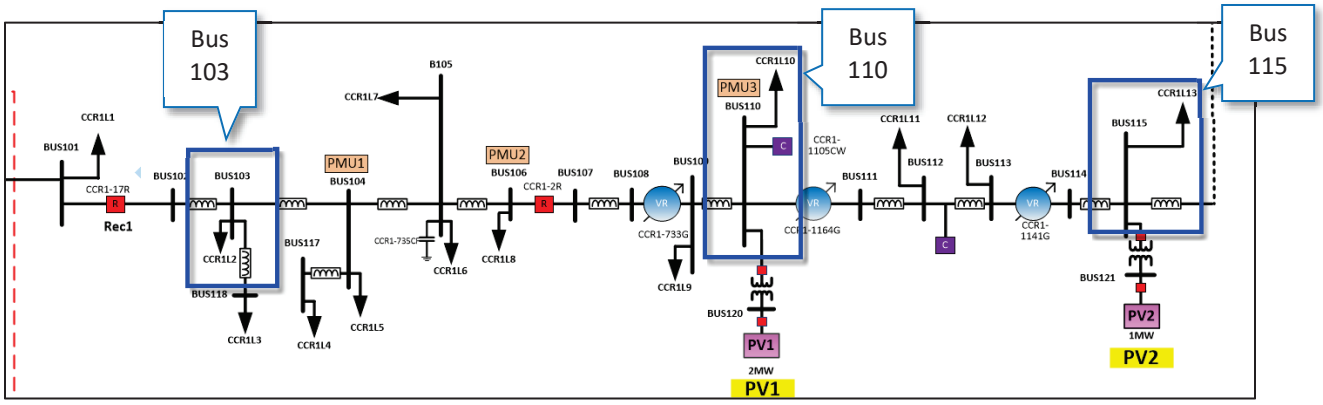


Figure 2-52. Location of Bus 103, 11, and 115 on circuit CCR1 on the SLD

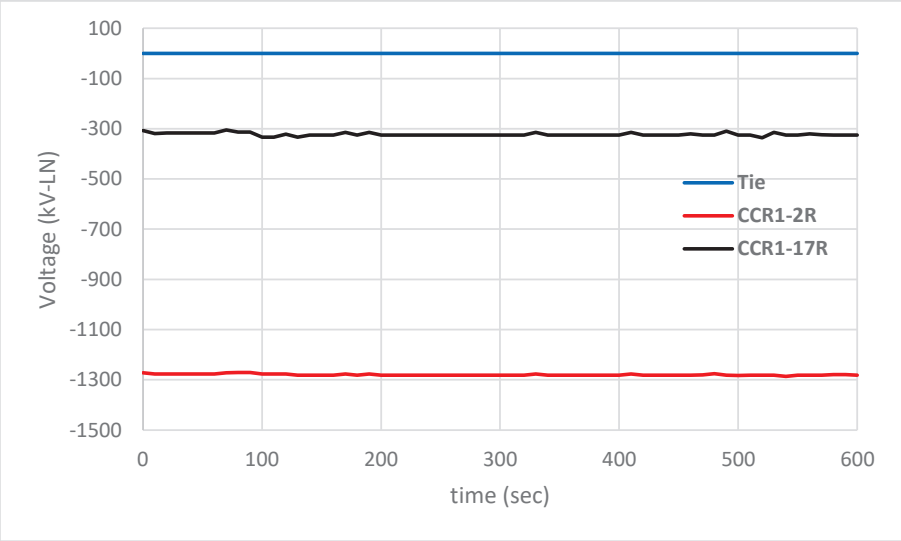


Figure 2-53. Power flow through tie switch and reclosers CCR1-2R and CCR1-17R under CS 1 (Case 2.1)

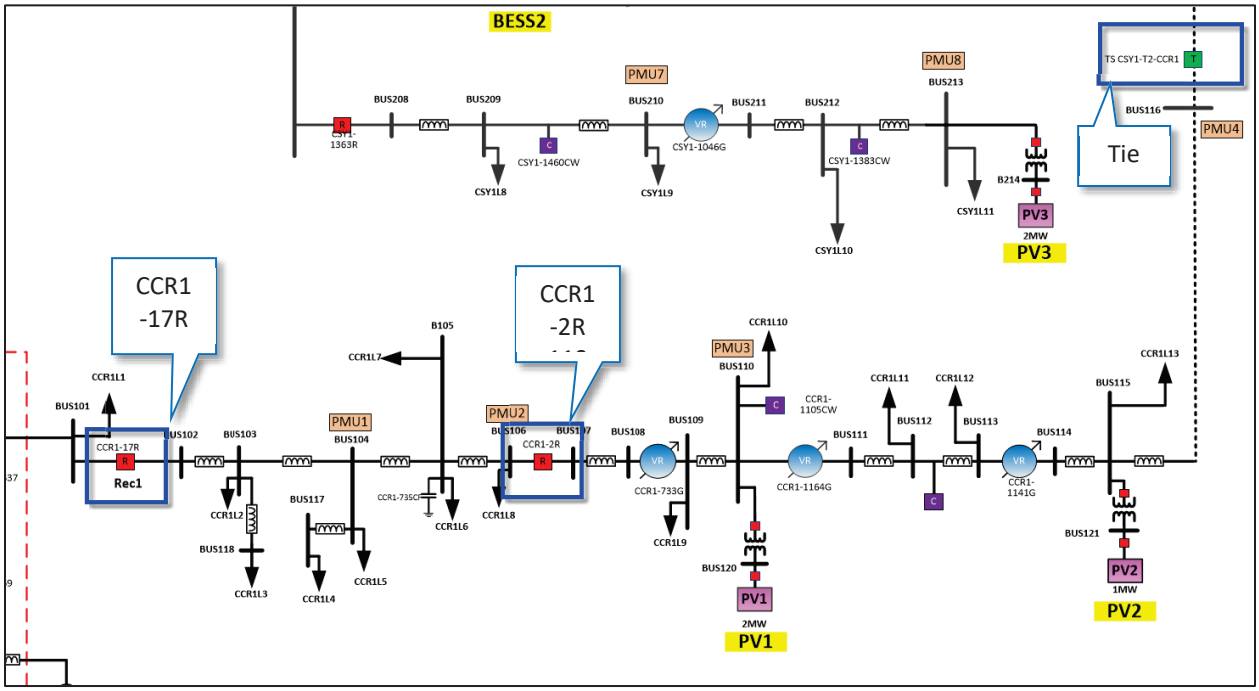


Figure 2-54 shows the voltage profile of circuit CCR1 for case 2.2 (control scenario 2). The instant at which the SLT was performed is also illustrated in the figure. As can be observed in Figure 2-54, the steady-state values of bus voltages stayed in the permissible range after the load transfer. Further, the load transfer resolved the reverse power flow issue in circuit CCR1. The power flow through the tie switch, recloser CCR1-2R and recloser CCR1-17R are plotted in Figure 2-55 before and after the SLT. It is evident that, subsequent to the SLT, the active power flowing through both reclosers became zero/positive.

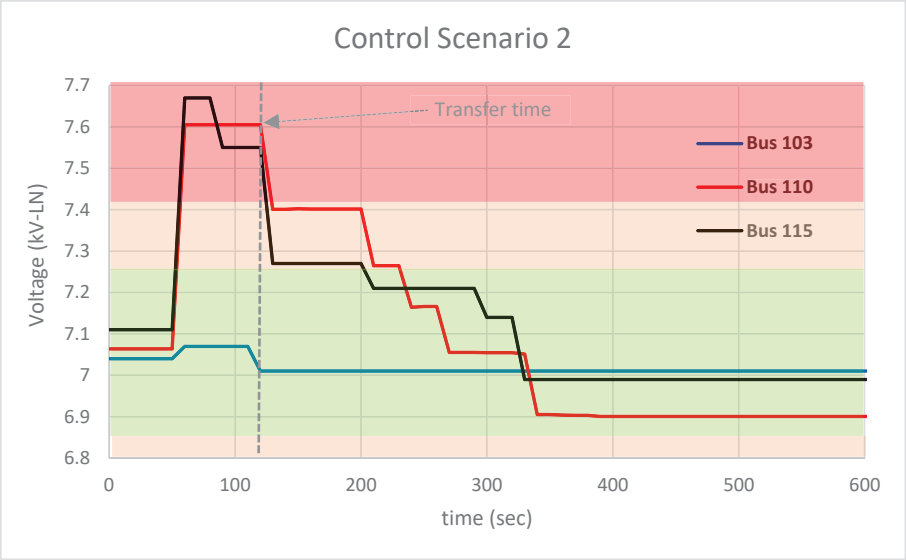


Figure 2-54. Voltage profile of circuit CCR1 for case 2.2 (CS 2)

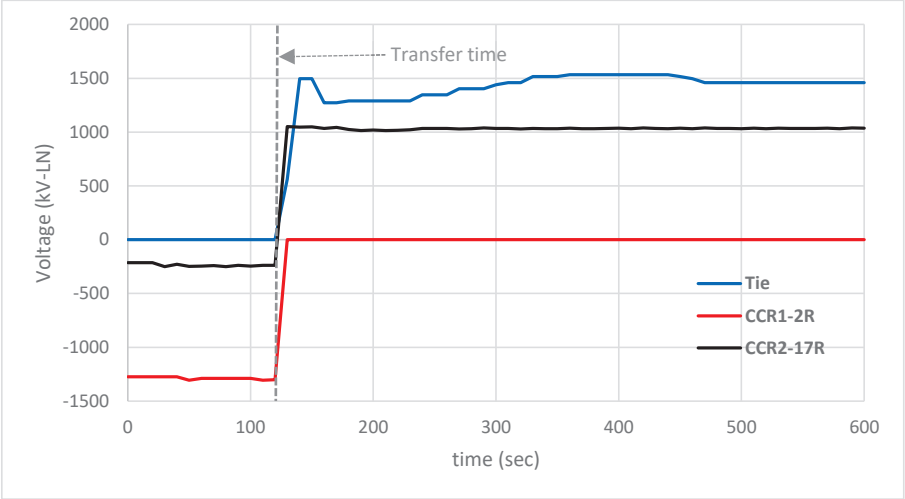


Figure 2-55. Power flow through tie switch and reclosers CCR1-2R and CCR1-17R under CS 2 (Case 2.2)

Figure 2-56 shows the voltage profile of circuit CCR1 for case 2.3 (control scenario 3). The instant at which the SLT was performed is also indicated in this figure. Similar to case 2.2, the steady-state values of bus voltages stayed in the permissible range after the load transfer (see Figure 2-56). However, compared to Case 2.2, the accumulative number of asset operation increased under CS 3 as the substation controller did not has the same observability/access as the master controller.

In addition to the voltage profile, the load transfer resolved the reverse power flow issue in circuit CCR1. Figure 2-57 shows the power flow through the tie switch, recloser CCR1-2R, and recloser CCR1-17R under control scenario 3, before and after the SLT. As shown in the figure, subsequent to the SLT, the active power flowing through both reclosers became zero/positive.

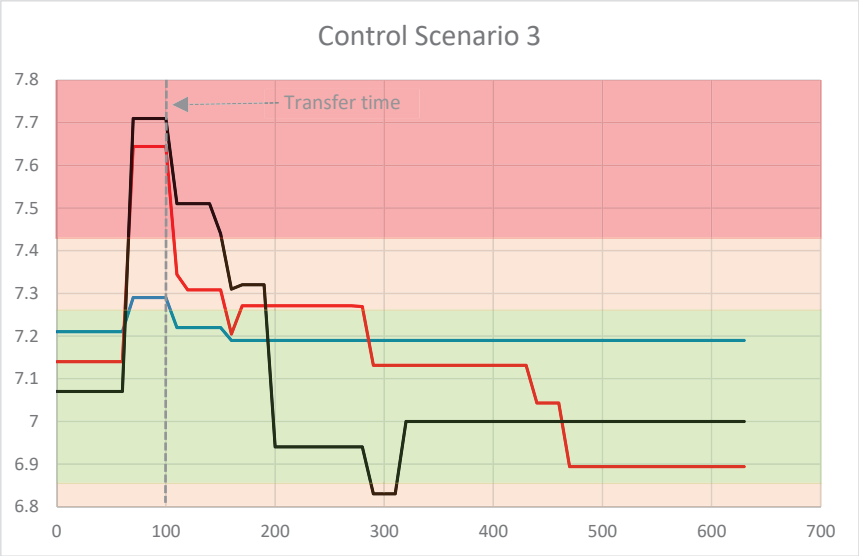


Figure 2-56. Voltage profile of circuit CCR1 for case 2.3 (CS 3)

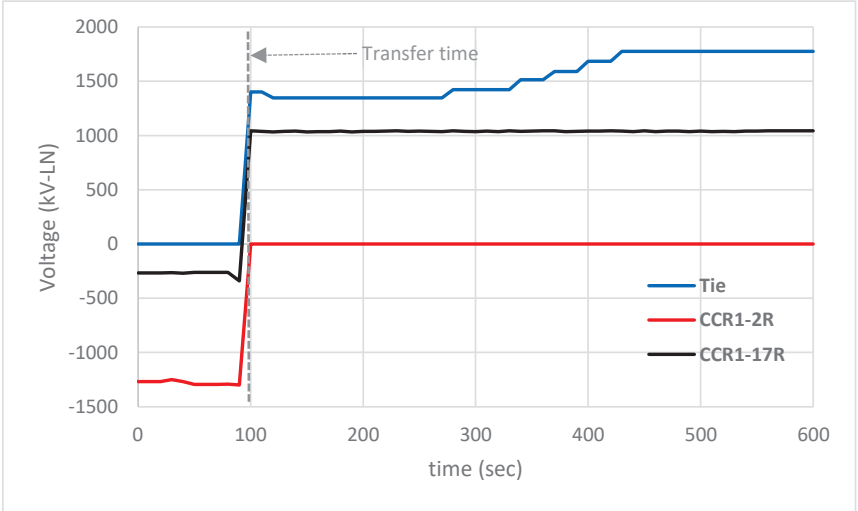
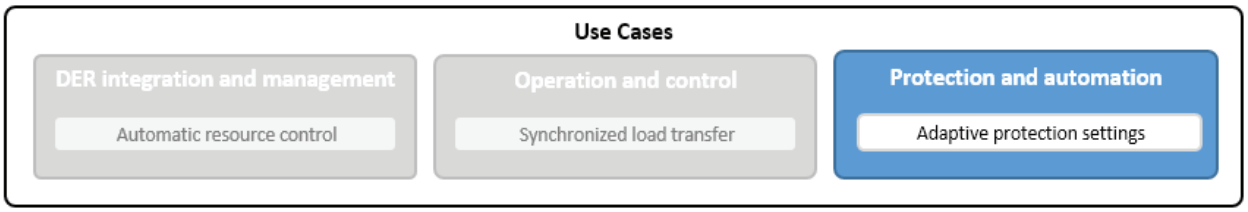


Figure 2-57. Power flow through tie switch and reclosers CCR1-2R and CCR1-17R under CS 3 (case 2.3)

The test cases listed in Table 2.20 were executed, and the SLT was performed successfully when it was necessary. The results show that the SLT could help with reverse power flow management in distribution circuits with high penetration of DERs. Further modifications are possible to ensure a smooth transition, by making corrective actions prior to the SLT initiation (beyond the scope of this project).

2.4.6 Use case 3: Automatic protection setting changes



The APS was tasked with determining if the forecasted or real-time distribution system condition/topology required changing protection setting groups. It would then determine the correct protection setting groups based on the prevailing system condition/configuration. The APS would finally send commands to appropriate protective devices or IEDs in order to change protection settings.

The APS provided the following functionalities:

- Dynamically received state of switching devices for any changes in system;
- Determined the global topology of the system based on the received data;
- Determined whether or not the protection setting groups should change for the new system condition/configuration;
- Identified appropriate protection setting groups for the new system condition/configuration (from the setting-topology database);
- As required, sent protection setting changes to the corresponding protective devices;
- Received confirmation on active protection settings from protective devices or IEDs; and
- Defaulted to safe condition in the event of failures.

In the event of a circuit reconfiguration, the APS would immediately evaluate the new configuration, determine the proper setting group, and request the changes if necessary. The APS processing occurred centrally which required visibility and access to protective devices, IEDs, and switching devices. Topology algorithm in the APS processor dynamically determined the electric configuration of the distribution system. Every time a change of state of a switching device was indicated, the topology algorithm was run to determine if there was a need for protection setting change. Thus, the APS system required the current state of switching devices and protection IEDs to detect changes in system configuration and to trigger the protection setting changes, if it was necessary.

Once the need for a protection setting change was established, commands would be sent to specific protective devices or IEDs to change their setting group. When a protective device or IED received the command to change its setting, it was required to send back confirmation indicating that a change had occurred as well as the active protection setting group in place. The APS would trigger alarms or flag an issue if:

- Security and/or dependability of the protection system (fault detection, isolation, and coordination) was fully/partially violated due to the system changes;
- Communication network had failed;
- Communication with a specific protective device(s) or IED(s) had failed; and
- Target settings could not be applied.

Entities requesting the APS service included the APS Processor (automatically) or the System Operator (manually). It should be noted that, in the test system architecture, the control was distributed within the system, and the Substation Controller was responsible for executing some control functions. Therefore, in the case of a single processor failure (e.g., communication failure to central controller) the lower-level distributed controllers could manage the execution of some control functions to ensure fail-safe functions.

2.4.6.1 Performance criteria

Subsequent to a system reconfiguration (*e.g.*, due to a load transfer), the APS function was tasked with changing the protection setting group of specified protective devices if it was essential to do so. The APS function was continuously monitoring the status of the distribution system and would change the setting group based on the defined lookup table. The defined topologies/configurations for the system under study are shown in Table 2.21. For each topology, a set of protection setting group was also defined for specified protective assets as shown in Table 2.22. As soon as one of the system topologies was sensed by the logic, proper protection setting group were communicated to the corresponding protective device.

Table 2.21. Defined topologies for the test system

Configuration #	Configuration name	Switch/breaker status				
		TSCSY1-T2-CCR1	TSCCR1-T1-972	CCR1-17R	CCR1-2R	CSY1-1370R
1	Normal	Open	Open	Closed	Closed	Closed
2	Transfer 1	Closed	Open	Closed	Open	Closed
3	Transfer 2	Closed	Open	Closed	Closed	Open
4	Transfer 3	Open	Closed	Open	Closed	Closed
5	Transfer 4	Closed	Closed	Open	Open	Closed

Table 2.22. Defined protection setting group for each system topology

Protection setting group							
CB CCR1	CB CSY1	TS CSY1-T2-CCR1	TS CCR1-T1-972	CCR1-17R	CCR1-2R	CSY1-1370R	CB972
1	1	as is (1)	as is (1)	1	1	1	1
2	2	1	as is (1)	2	as is (1)	2	1
3	3	2	as is (1)	3	2	as is (1)	1
1	1	as is (1)	1	as is (1)	1	1	2
1	2	1	2	as is (1)	as is (1)	2	3

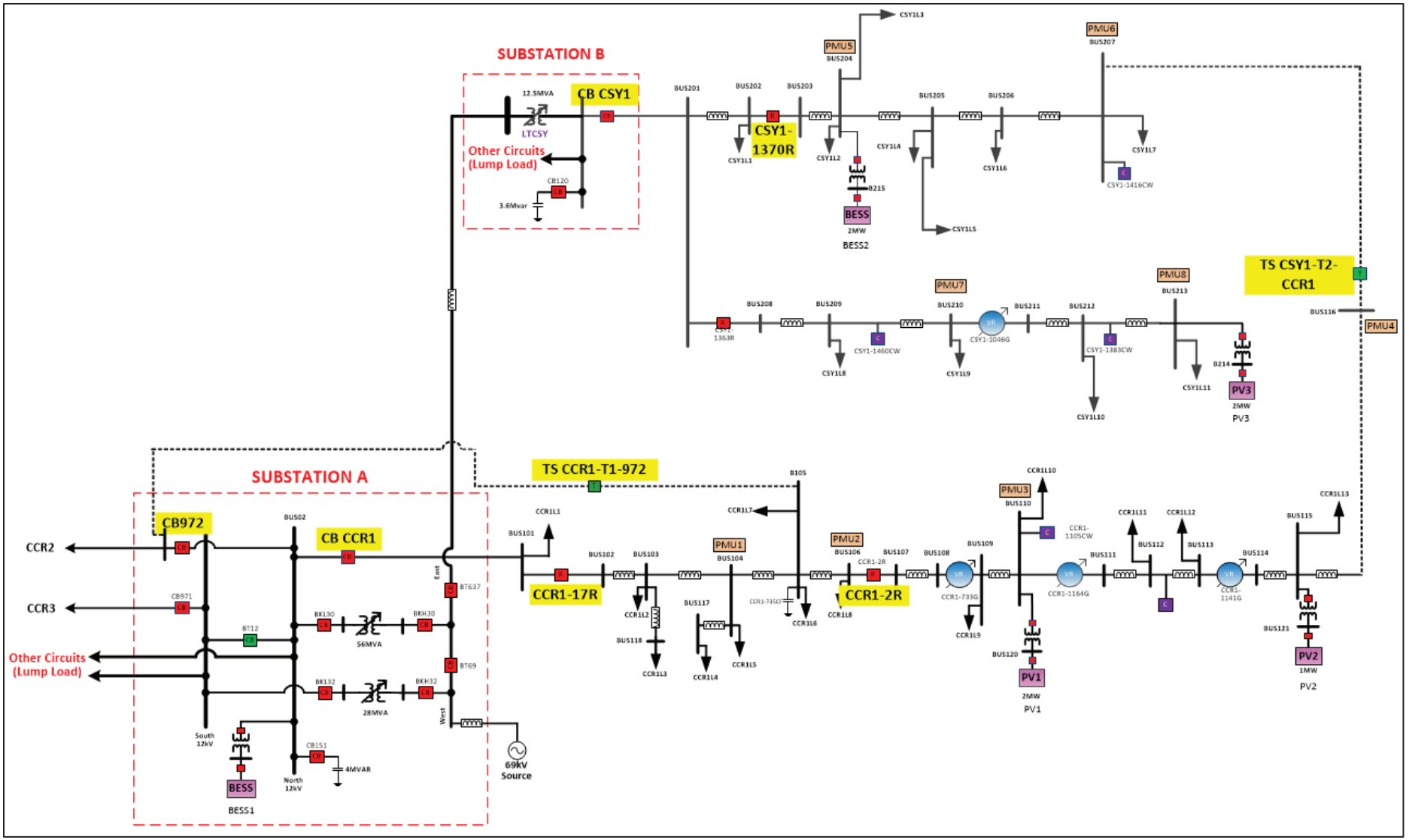
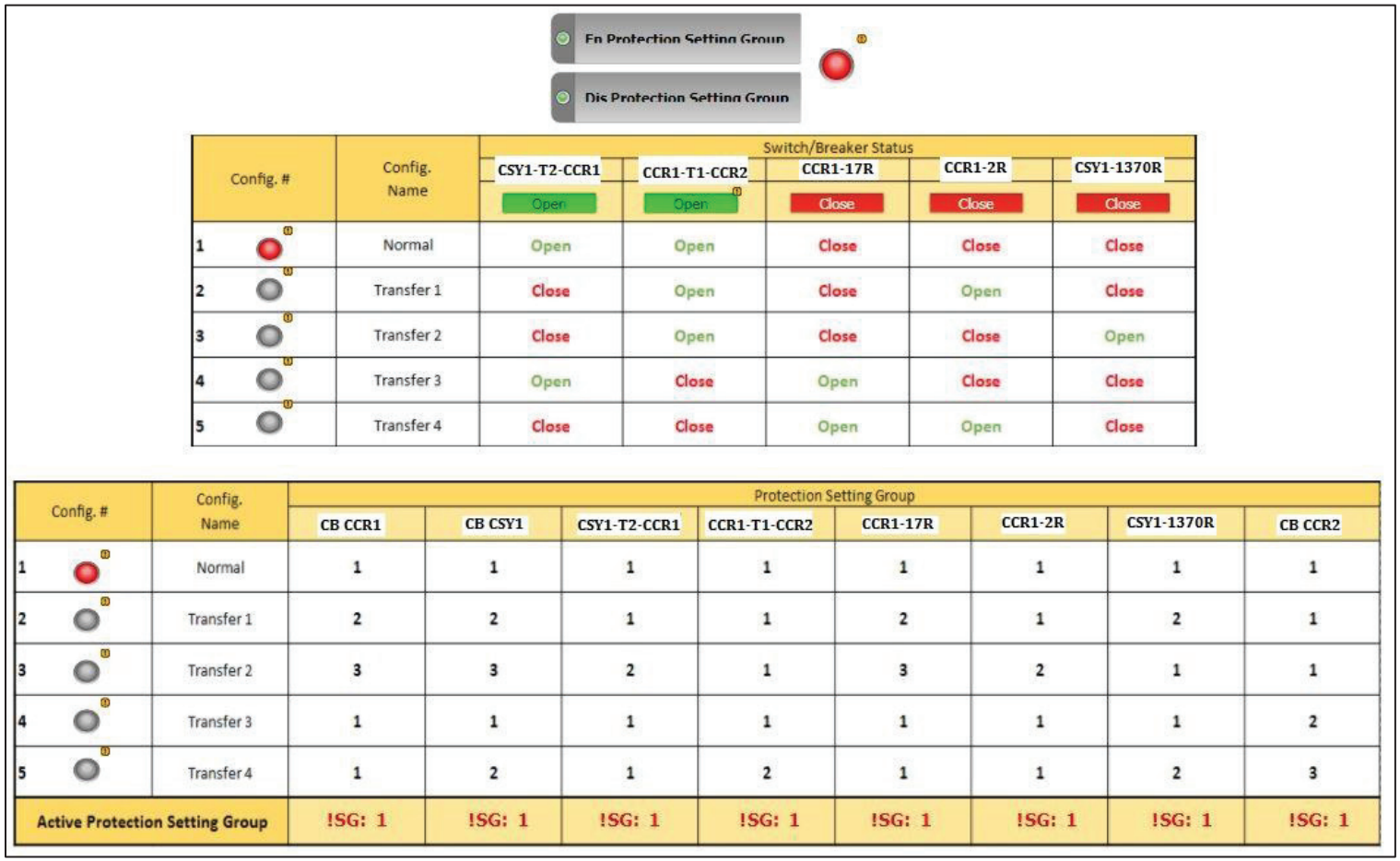


Figure 2-58. Identification of devices referenced in use case 3 test cases

2.4.6.2 Test results

The purpose of this test category was to verify that the master controller and substation controllers would take proper action in response to the system reconfiguration and/or alarms. In particular, it was expected that the protection setting group of certain protective devices would change when the system configuration changed (e.g., due to a load transfer). The performance of the APSC function was evaluated for the same test cases as those considered for the SLT function to ensure proper operation of the application (see Table 2.20 for a list of test cases).

Under normal system configuration (*i.e.*, when all tie switches are open and circuit reclosers are closed), the protection setting groups of all protective relays were set to be at Group 1. This is shown in the first row of both lookup tables in Figure **2-59**. This figure shows that all meaningful system configurations/topologies are listed in a lookup/event table along with the proper protection setting groups for each configuration/topology14. The APSC function was continuously monitoring the states of (major) switching devices in both circuits and performing a real-time matching to determine the most appropriate setting group for the protective devices. For the majority of the test cases of Table 2.20, the system operated with its normal configuration and, thus, the setting group of all devices remained at 1 as shown in Figure 2-59.



Config. #	Config. Name	Switch/Breaker Status				
		CSY1-T2-CCR1	CCR1-T1-CCR2	CCR1-17R	CCR1-2R	CSY1-1370R
		Open	Open	Close	Close	Close
1	Normal	Open	Open	Close	Close	Close
2	Transfer 1	Close	Open	Close	Open	Close
3	Transfer 2	Close	Open	Close	Close	Open
4	Transfer 3	Open	Close	Open	Close	Close
5	Transfer 4	Close	Close	Open	Open	Close

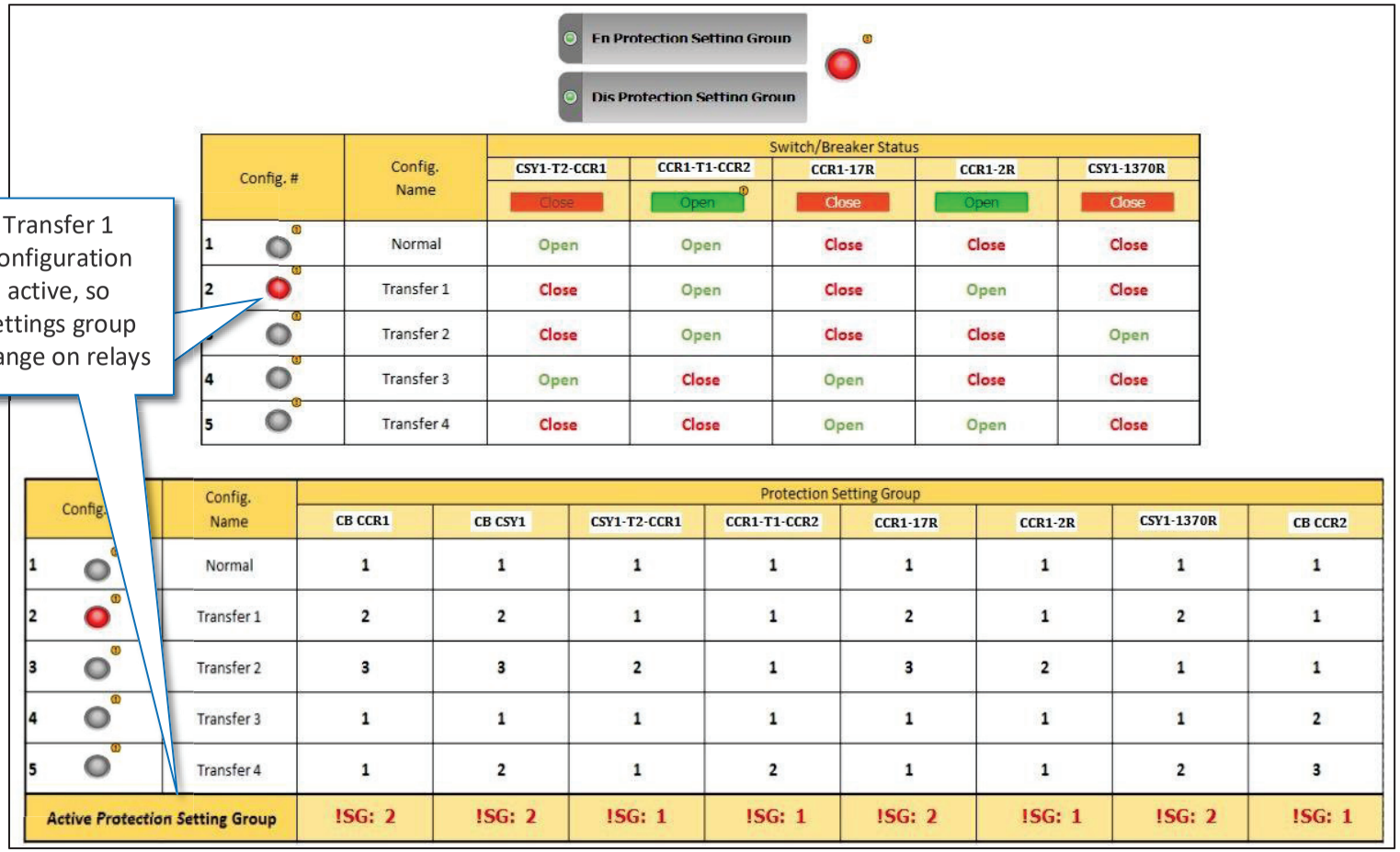
Config. #	Config. Name	Protection Setting Group							
		CB CCR1	CB CSY1	CSY1-T2-CCR1	CCR1-T1-CCR2	CCR1-17R	CCR1-2R	CSY1-1370R	CB CCR2
1	Normal	1	1	1	1	1	1	1	1
2	Transfer 1	2	2	1	1	2	1	2	1
3	Transfer 2	3	3	2	1	3	2	1	1
4	Transfer 3	1	1	1	1	1	1	1	2
5	Transfer 4	1	2	1	2	1	1	2	3
Active Protection Setting Group		!SG: 1	!SG: 1	!SG: 1	!SG: 1	!SG: 1	!SG: 1	!SG: 1	!SG: 1

[14] The determination of suitable protection settings for each system topology/configuration is done through a set of off-line fault and protection coordination analyses.

Figure 2-59. Protection setting group of CCR1 and CSY1 devices under normal system configuration (as displayed on Master Controller HMI)

When the system topology/configuration changed (*e.g.*, when the SLT function performed a load transfer and changed the states of some switching devices), the change was detected by the APSC function. This function then found the most appropriate protection setting group for each protective device through a search of the lookup table.

Figure 2-60 shows the selected protection setting group for the system configuration/topology subsequent to the SLT. The figure shows that when the system configuration changed to Transfer 1 (due to the change in the status of CSY1-T2-CCR1 and CCR1-2R), the protection setting group of four protective devices (i.e., CB CSY1, CB CCR1, CCR1-17R, and CSY1-1360R) changed from 1 to 2. It is worth noting that the protection setting group change can also be triggered by a system operator command, *e.g.*, during fire season (not shown in Figure 2-60).



Config. #	Config. Name	Switch/Breaker Status				
		CSY1-T2-CCR1	CCR1-T1-CCR2	CCR1-17R	CCR1-2R	CSY1-1370R
		Close	Open	Close	Open	Close
1	Normal	Open	Open	Close	Close	Close
2	Transfer 1	Close	Open	Close	Open	Close
3	Transfer 2	Close	Open	Close	Close	Open
4	Transfer 3	Open	Close	Open	Close	Close
5	Transfer 4	Close	Close	Open	Open	Close

Config.	Config. Name	Protection Setting Group							
		CB CCR1	CB CSY1	CSY1-T2-CCR1	CCR1-T1-CCR2	CCR1-17R	CCR1-2R	CSY1-1370R	CB CCR2
1	Normal	1	1	1	1	1	1	1	1
2	Transfer 1	2	2	1	1	2	1	2	1
3	Transfer 2	3	3	2	1	3	2	1	1
4	Transfer 3	1	1	1	1	1	1	1	2
5	Transfer 4	1	2	1	2	1	1	2	3
Active Protection Setting Group		!SG: 2	!SG: 2	!SG: 1	!SG: 1	!SG: 2	!SG: 1	!SG: 2	!SG: 1

Figure 2-60. Protection setting group of CCR1 and CSY1 devices for transfer 1 configuration (as displayed on master controller HMI).

2.4.7 Distributed control functions

For as long as the master controller was active, the substation controllers were working as gateways, collecting data from downstream IEDs and sending them to the master controller, as well as processing control commands from the master controller and sending them to the downstream IEDs.

However, if the master controller stopped functioning, communications were lost, or control permission was toggled to local control, the substation controllers assumed the control responsibility for their own local area, including the associated substation and the circuits. The logic diagrams for the main control functions for each substation are illustrated in Figure 2-61.

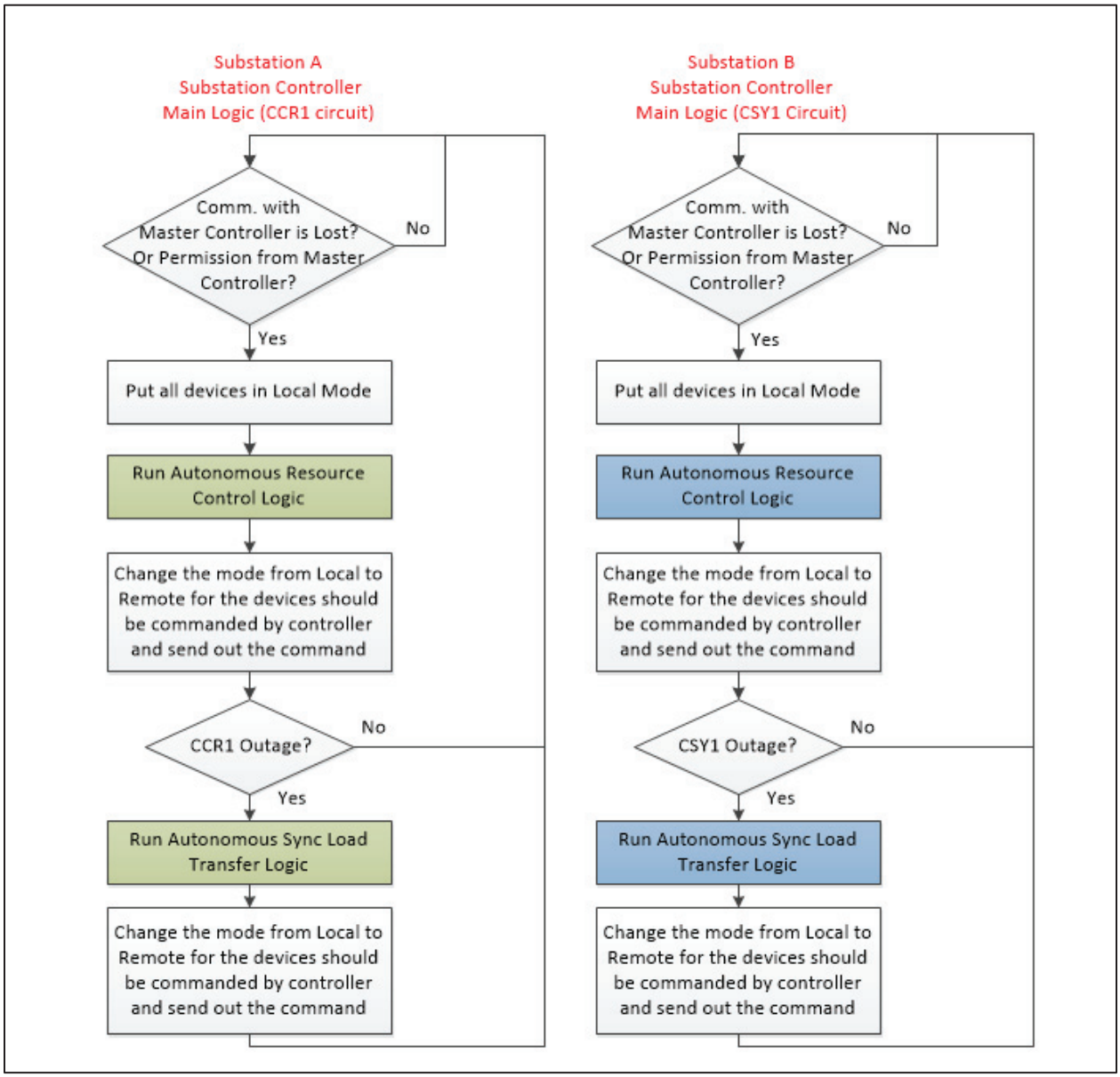


Figure 2-61. Main logic diagrams for each substation controller

Similar to the master controller, there were three control functions in each substation:

- Autonomous Automatic Resource Control (AARC)
- Autonomous Synchronized Load Transfer (ASLT)
- Autonomous Automatic Protection Setting Change (AAPSC)

Since the AAPSC was executed in a very similar manner to the APS (except being performed in substation level), it is not explained again. The following two subsections provides more details on the first two autonomous functions, *i.e.*, AARC and ASLT.

2.4.7.1 Autonomous Automatic Resource Control

Figure 2-62 shows the AARC scheme. In the event of the Master Controller being unavailable, or having issued the appropriate permissions to the substation controllers, logic was initiated in the substation controllers to adjust the active and reactive power generation of the DERs for proper load management.

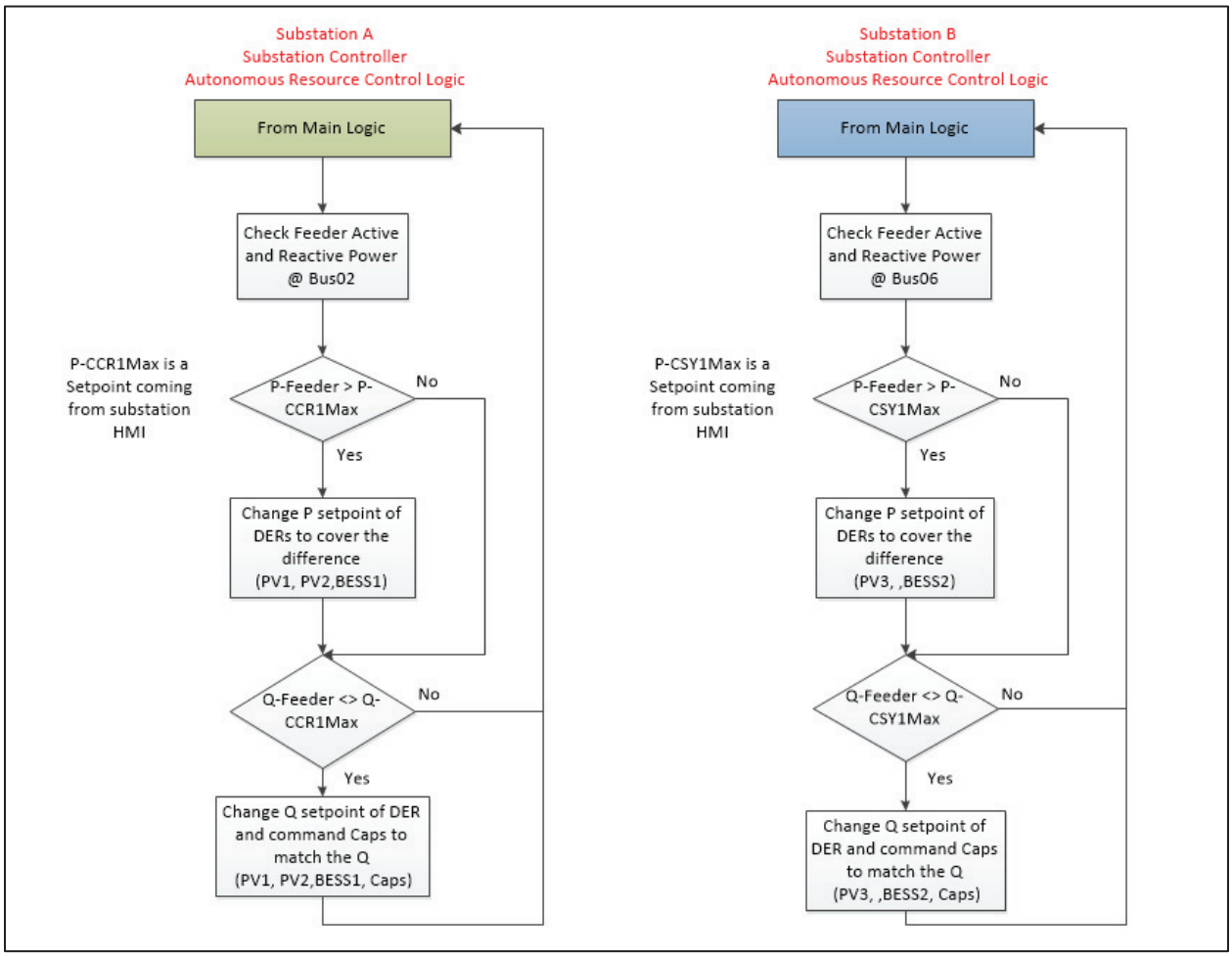


Figure 2-62. Substation Autonomous ARC Logic

The Substation Controllers compared the active and reactive power of the feeder against the maximum active and reactive power setpoints (which could be modified via the Local HMI).

- If the active power of the feeder was more than the maximum power set point, the optimal setpoints for the configured distributed energy resources for each circuit were calculated and transmitted to the appropriate IED controller.
- Reactive power of the feeder was also checked and if different from the Q setpoint, the Q setpoints of the distributed energy resources were changed. The scheme also controlled substation shunt capacitor banks to adjust the reactive power, if needed, in order to maintain power factor at the circuit level.

2.4.7.2 Autonomous Synchronous Load Transfer

Figure 2-63 shows the ASLT logic for each circuit. This logic was designed to serve the loads by monitoring the power flow of recloser R2 and recloser R3 and, if necessary, triggering a load transfer to manage reverse power flow in both circuits.

To perform the load transfer, the Substation Controller sends the sync check command to the tie switch and then waits for a response.

- If the voltages on both sides of the tie switch were in sync, the tie switch controller would close the switch. Subsequently, the upstream isolating switch would be closed by the Substation Controller as soon as the closure confirmation was received from the tie switch.
- If not, the substation controller would receive a sync error message from the tie switch controller. In the event of receiving an unsuccessful sync message from the tie switch, or not hearing back from tie switch within a specific time period, the substation controller would run additional logic to curtail DER resources to prevent reverse power flow, if needed.

It is worth noting that the substation controller would not provide the same level as control as the master controller, mainly due to the limited visibility over the entire system. However, if an adequate communication infrastructure is available and the substation controller has sufficient processing power, it should be able to provide the same control functionality as the master controller.

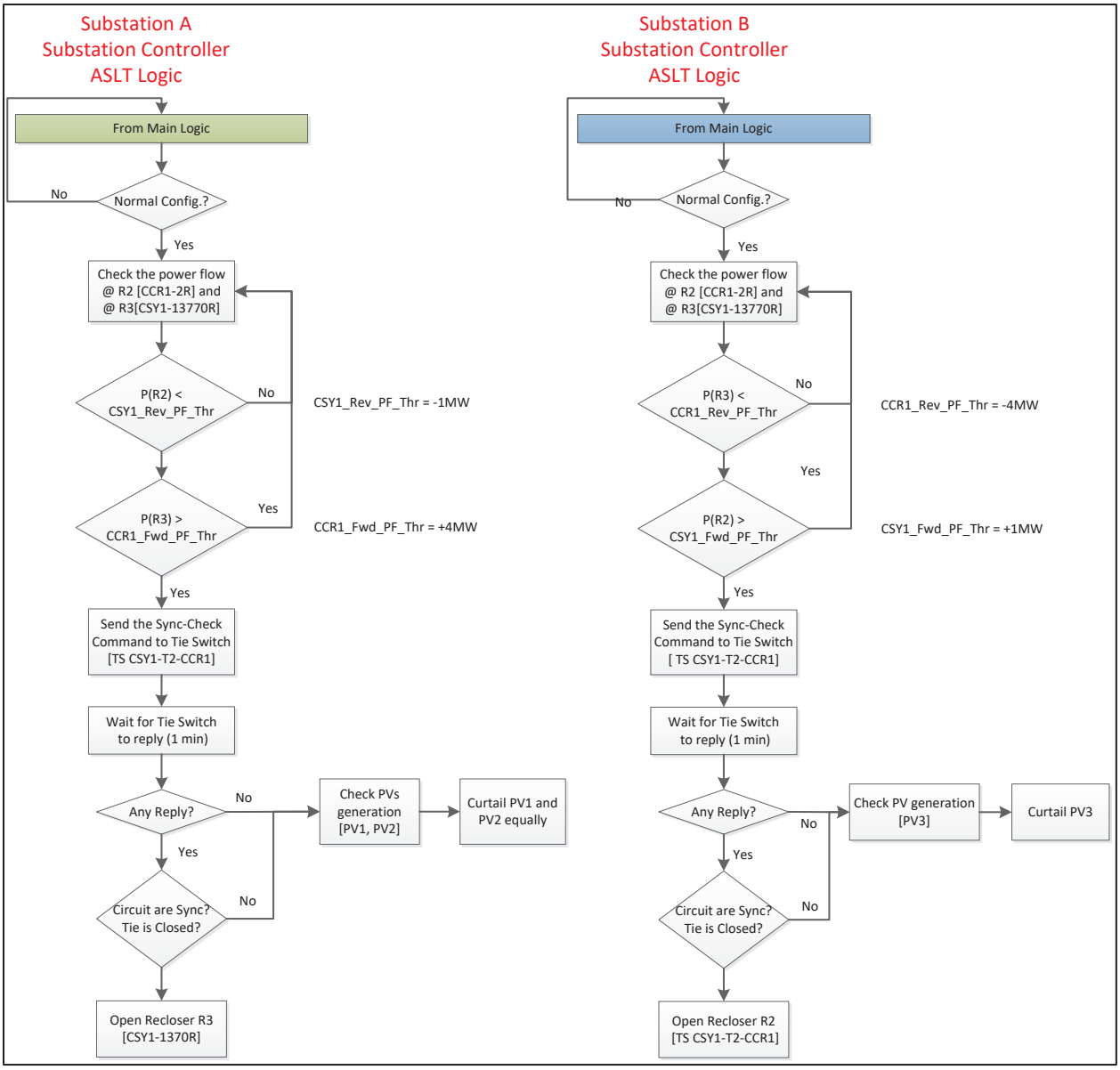


Figure 2-63. Substation Autonomous SLT Logic

3 KEY FINDINGS

This pre-commercial demonstration investigated the implementation of three advanced distribution automation (ADA) applications in a distributed control architecture. The performance of these three ADA applications (use cases) was evaluated through a comprehensive set of tests with actual protection, control, and power hardware devices. To ensure the accuracy of conclusions, three sets of system performance data were analyzed for the assessment of the proposed control architecture. These sets of data were collected for three control scenarios as follows:

- Control scenario 1 (CS 1): No remote control of distribution system resources was available, i.e., capacitor banks, voltage regulators, load tap controllers, smart inverters, and other resources were all working autonomously and in isolation to optimize the portions of the system they could monitor.
- Control scenario 2 (CS 2): Distribution system resources were intelligently controlled by a master controller capable of monitoring and controlling the resources at the two substations modelled in the test system.
- Control scenario 3 (CS 3): Distribution system resources were intelligently controlled by the substation controllers for each of the substations, autonomously and with limited access to each other.

The results of this project showed that although a multi-tiered control architecture is required for a distributed control system, such a design offers several advantages over conventional control schemes commonly used in distribution systems. The following paragraphs discuss a summary for the three different use cases.

3.1 Automatic Resource Control

The test results for ARC use case proved conclusively that intelligent control of distribution system resources improves system performance. They demonstrated that a master controller with the ability to control and monitor multiple substations that are electrically interconnected provides the greatest amount of benefit (CS 2). They furthermore confirmed that even when the control is limited to a single substation and downstream distribution system resources (CS 3), significant improvements in system performance are recognized in contrast to the case where there is no remote control (CS 1).

Several performance criteria were defined and analyzed to accurately evaluate the performance of a distributed control approach. The following conclusion was made throughout the course of this study:

- The response time of the control system significantly improves when the distribution controllable resources can be remotely controlled by an engine embedding an optimal (or semi-optimal) control logic, *i.e.*, CS 2 and CS 3.
- In almost all cases, the system voltage profile was improved under CS 2 and CS 3. In particular, the voltage profile can be regulated more precisely through fine tuning of DER setpoints.
- Optimized remote control of DERs (CS 2 and CS 3) can reduce the system losses through enhanced contribution of DERs.
- Under CS 2 and CS 3, DERs provide more reactive power support which, in turn, enables accurate adjustment of the power factor (e.g., close to unity) at the circuit or substation level.
- The cumulative number of controllable asset operation decreases under CS 2 and CS 3, due to the increased contribution of DERs as well as enhanced system observability (control coordination). However, since master/substation Controller aims at optimal voltage regulation, there were some test cases that show minimum or no improvement in the total asset operations.

- With CS 2 and CS 3 in place, DER integration into distribution system can be facilitated. In other words, intelligent remote control of DERs can address some of the challenges associated with high penetration of DERs.
- Implementing a distributed control approach requires a minimum communication infrastructure being available to enable remote control of distribution resources. In addition, the distribution voltage regulators, capacitor bank controllers, IEDs, etc. should support a standard communication protocol. These are considerations that need to be taken into account for developing a distributed control architecture in distribution systems.
- Some of the existing DERs in the field do not support smart inverter features and control modes. As an example, the battery used in this study does not support remote power factor adjustment and V-Q droop modes. In the proposed control architecture, it is essential that certain DERs to support specific control modes.

Table 3.1 below provides a summary of findings for test cases 1.10, 1.11 and 1.12, which were explained in Section 2.4.4.2. The dark cells show improvement while the lighter shaded cells indicate no enhancement. The results for the remaining test cases are captured in Appendix A.

Table 3.1. Summary of ARC test results

Parameter	Scenario 1 Result	Delta between Scenarios 1 and 2	Delta between Scenarios 1 and 3
Maximum voltage magnitude (rms)	8.04 kV (1.16pu)	7% less	5% less
Maximum out-of-range value with respect to maximum allowable voltage (rms)	765.4 V (0.11pu)	78% less	48% less
Out-of-range duration (seconds)	115 seconds	78% less	30% less
Power Loss	1.04MW	26% less	17% less
Active Power (DER Involvement/Contribution)	31.8 kW	4% less	3% less
Asset Operations	52 operations	35% less	6% more

Improvement
No improvement

3.2 Synchronized Load Transfer

The Synchronized Load Transfer (SLT) is a unique ADA application that can help with load and power flow management in distribution systems dominated with DERs. Conventional control techniques in distribution systems cannot manage reverse power flow without curtailing renewable DERs. The SLT provide the possibility of transferring the partial load/generation to another circuit while the maximum energy is extracted from renewable resources.

The SLT tests were able to show that the master controller and substation controllers could collectively perform load transfer between two circuits from two different substations when excessive reverse power flow was

measured along the feeder, *e.g.*, when the DER penetration/injection was high. More importantly, the transfer is performed while the system is energized, that is, with no customer interruption. The following is the main findings and recommendations for the SLT use case:

- SLT is an effective solution to reverse power flow management under high penetration of DERs, with the maximum power being obtained from renewable resources.
- SLT will resolve the reverse power issue without any interruption being imposed to customers.
- The SLT requires the voltage on both sides of the tie switch to be cophasal. If this condition is not met, the SLT can command some of the controllable assets to bring the voltages (magnitudes) to an acceptable range. However, the control of voltage phase angles is not an easy task and, in some cases, it is impossible. Nonetheless, it is acknowledged that the synchronization criterion for voltage phase angle in distribution systems is most of the time met (no violation was observed during the course of this project).
- To ensure a smooth transition during a transfer, it is recommended that the master/substation controller takes some corrective actions prior to the SLT initiation, based on the Near-Real-Time Power flow analysis. This was not systematically studied in this project (beyond the project scope), but try and error showed potential for further improvement during the transition.

3.3 Automatic Protection Setting Change

The requirements for performance improvement of the protection system under different system conditions and/or configurations has led to the idea of Automatic Protection Setting Change (APSC). The APSC tests demonstrated that protection settings could be dynamically changed to adapt to changing system configurations triggered by unplanned system events or ARC and SLT system re-configurations. The following is the main findings and recommendations for the SLT use case:

- The APSC can ensure that the system is always protected regardless of the system topology, DER penetration level, and prevailing DER statuses.
- The real-time matching algorithm of the APSC is easily and fully implementable in both master controller and substation controller.
- The proposed APSC algorithm need offline studies to be run for all meaningful system configurations/conditions in order to calculate proper protection settings. This may potentially become a time-consuming task, considering that new system configurations/conditions will be frequently introduced to the system with the increasing penetration of DERs and application of new ADA applications.
- Fuses, electromechanical relays, and standard solid-state relays that are common in distribution systems do not provide the flexibility of changing protection settings, limiting the efficiency of the APSC. Digital (microprocessor-based) relays with flexible protection settings as well as communication capabilities are required for the APSC. The trend of utilizing of advanced digital relays is expected to address this concern in the future.

4 RECOMMENDATIONS AND NEXT STEPS

As detailed in the preceding sections, the use cases comprehensively demonstrated that real, quantifiable benefits are achieved when a distributed control scheme is implemented that allows high-speed, localized control of IEDs and DER in substations and feeders.

As such, the concept deserves additional investigations in the field and real-world environment. It is recommended that SDG&E plan and implement a pilot project to test real-world performance of the distributed controls as the next step. Although not part of this project, the use of the IEC 61850 communication standard holds the promise of allowing data exchange between substations without central SCADA intervention, thereby offering additional opportunities for system optimization. The pilot project should be planned such that sufficient time exists to work through any real-world and interoperability issues. Aside from exploring the deployment of the technology, the pilot project should have several other objectives:

- Quantify costs and benefits, and then develop a cost-benefit analysis for wide scale deployment
- Examine what changes to standard operating procedures are necessary to fully leverage the benefit of the distributed control system design.
- Use the pilot project as a training platform for engineering and operational personnel

The integration of feeder-based IEDs and DERs is more complex than for those inside the substation boundary, and high-speed and reliable communications are a prerequisite.

Hence, it is recommended that the pilot project also explorer various communication technologies and allow for real-world testing. Additional testing on a carefully selected substation and feeder combination and the results analyzed over a period of time will ensure the maturity of the technology is such that system performance is consistent and reliable.

The project provided a good platform for SDG&E personnel to increase their familiarity with the different technologies. It is recommended that as far as possible, the same team remain engaged in the pilot projects to build upon the experience gained to date.

It is recommended that this project be followed by the development of a strategic roadmap for deployment of distributed controls which identifies ADMS functions that can be implemented in substation and feeder based controllers.

4.1 Technology/Knowledge transfer plan for applying results into practice

During the course of the project, several workshops and project demonstration sessions were held with the involvement of SDG&E stakeholders to share the project approach, major findings and to showcase the specific use cases.

SDG&E plans to communicate the results of the project with the industry at large. It is therefore recommended that appropriate venues such as conferences and industry events be selected for paper submission and presentation to summarize and share the key findings with the industry. By doing so, the experience gained on this project can be shared with as many stakeholders as possible – which includes anyone dealing with the need to integrate DERs and other IEDs on the distribution system. SDG&E will also widely announce the availability of this final report.

5 METRICS AND VALUE PROPOSITION

5.1 Project Metrics

The project tracking metrics included the milestones in the project plan. Technical metrics for this project were based on comparing the performance of distribution system operations when various new control schemes are in place with the performance of the same operations when the control schemes are not in place. These performance metrics included measures of power quality, electrical loss reductions, asset health maintenance, and adaptability to new device types in the distribution system.

Also, major project results were submitted as technical papers and presentations for consideration by major technical conferences and publications.

The following metrics were identified for this project:

- **Economic benefits:**
    a. Reduction in electrical losses in the transmission and distribution system.
    b. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear.
    c. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management.

- **Safety, Power Quality, and Reliability (Equipment, Electricity System):**
    a. Outage number, frequency and duration reductions.
    b. Forecast accuracy improvement.
    c. Reduced flicker and other power quality differences.
    d. Increase in the number of nodes in the power system at monitoring points.

- **Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy:**
    a. Description of the issues, project(s), and the results or outcomes.
    b. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)
    c. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360).

- **Effectiveness of information dissemination:**
    a. Number of information sharing forums held.
    b. Stakeholders attendance at workshops.
    c. Technology transfer.

- **Adoption of EPIC technology, strategy, and research data/results by others**
    a. Description/documentation of projects that progress deployment, such as Commission approval of utility proposals for wide spread deployment or technologies included in adopted building standards.

5.2 Value Proposition: Primary and Secondary Guiding Principles

The value proposition was to address how the project met the EPIC principals.

Table 5.1 summarizes the specific primary and secondary EPIC principles advanced by the Distributed Control for Smart Grids Project:

Table 5.1: EPIC Primary and Secondary Guiding Principles

Primary Principals			Secondary Principals				
Reliability	Lower Costs	Safety	Loading Order	Low-Emission Vehicles / Transportation	Safe, Reliable & Affordable Energy Sources	Economic Development	Efficient Use of Ratepayers Monies
✓		✓					

The Distributed Control for Smart Grids Project covers the following primary EPIC principals:

- **Reliability:** The results of this project demonstrates several scenarios and options that dynamically adjust protection settings to increase reliability. The demonstrated benefits of the distributed control approach in the areas of DER integration, improved grid stability, reliability and power quality and better utilization of controllable assets.

- **Safety:** The project focuses on a decentralized control approach, which gives for faster response times and deterministic behavior improves personnel safety, since there will be less intervention and therefore less room for human error.

6 REFERENCES

[1] "Grid Modernization: Modernizing SCE's Grid to Ensure Safety and Reliability While Preparing for Increased Levels of Distributed Energy Resources," A white paper by Southern California Edison (SCE), 2015.

[2] "Smart Metering (SM) and Distribution Automation (DA) Program: Functional Benchmarking Report," a presentation by Booz | Allen | Hamilton (BAH) Inc., Nov. 2015.

[3] Xanthus Consulting International, "Benefit and Challenges of Distribution Automation (DA): Use Cases Scenarios and Assessment of DA Functions," A report prepared for California Energy commission, 2009.

[4] Energy & Environmental Economics Inc. and EPRI Solution Inc., "Value of Distribution Automation Applications," A report prepared for California Energy commission, 2007

[5] Richard E. Brown, Electric Power Distribution Reliability, Second Edition

[6] R. Billinton and R.N. Allan, Reliability Evaluation of Power Systems, 2nd Ed, New York, Plenum Press, 1996.

[7] R. Billinton and P. Wang, "Teaching Distribution System Reliability Evaluation Using Monte Carlo Simulation", IEEE Transactions on Power Systems, Vol. 14, No. 2, pp. 397-403, May.1999.

[8] "Reliability of Electric Utility Distribution Systems: EPRI White Paper", October 2000.

[9] J. R. Agüero, J. Wang and J. J. Burke, "Improving the reliability of power distribution systems through single-phase tripping," IEEE PES T&D 2010, New Orleans, LA, USA, 2010, pp. 1-7.

7 LIST OF ACRONYMS AND ABBREVIATIONS

AAPSC	Autonomous Automatic Protection Setting Change
AARC	Autonomous Automatic Resource Control
ADA	Advanced Distribution Automation
ADCS	Advanced Distributed Control System
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
AP	Application Processor
APS	Automatic Protection Setting
APSC	Automatic Protection Setting Change
ARC	Automatic Response Control
ASLT	Autonomous Synchronized Load Transfer
BESS	Battery Energy Storage System
CT	Current Transformer
DA	Distribution Automation
DCS	Distributed Control System
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
D-SCADA	Distribution SCADA
DMS	Distribution Management System
DRMS	Demand Response Management System
DSO	Distribution System Operator
EMS	Energy Management System
EPIC	Electric Program Investment Charge
ESS	Energy Storage Systems
FAT	Factory Acceptance Test
FIT	Feeder Injection Test
FLISR	Fault Location, Isolation, and Service Restoration
HIL	Hardware-in-Loop
HMI	Human Machine Interfaces
IEC	International Electrotechnical Corporation
IED	Intelligent Electronic Device
ITF	SDG&E's Integrated Test Facility
kW	Kilowatt
LTC	Load Tap Changer
NRTPF	Near-Real-Time Power Flow

OMS	Outage Management System
PCC	Point of Common Coupling
PHIL	Power Hardware in the Loop
PMU	Phasor Measurement Unit
PT	Potential Transformer (aka Voltage Transformer)
PV	Photovoltaic
RFP	Request for Proposal
RTDS	Real Time Digital Simulator
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAT	Site Acceptance Test
SCADA	Supervisory Control and Data Acquisition
SDG&E	San Diego Gas & Electric
SIL	Software-in-Loop
SLD	Single Line Diagram
SLT	Synchronized Load Transfer
VR	Voltage Regulator

8 APPENDIX A – ADDITIONAL USE CASE RESULTS

Both Use Case 1 and Use Case 2 involved several test cases, but for the sake of brevity, only a representative sample of these were evaluated in the preceding sections. Appendix A documents the results of those test cases that were omitted from the earlier sections. While the test results are not explained in detail in this section, they enable the interested reader to observe the difference between various control scenarios.

The figures that follow illustrate the locations of the various SLD elements referenced in the test cases, as well as the mapping on how values like the P and Q contributions of the DER on the two circuits are constructed.

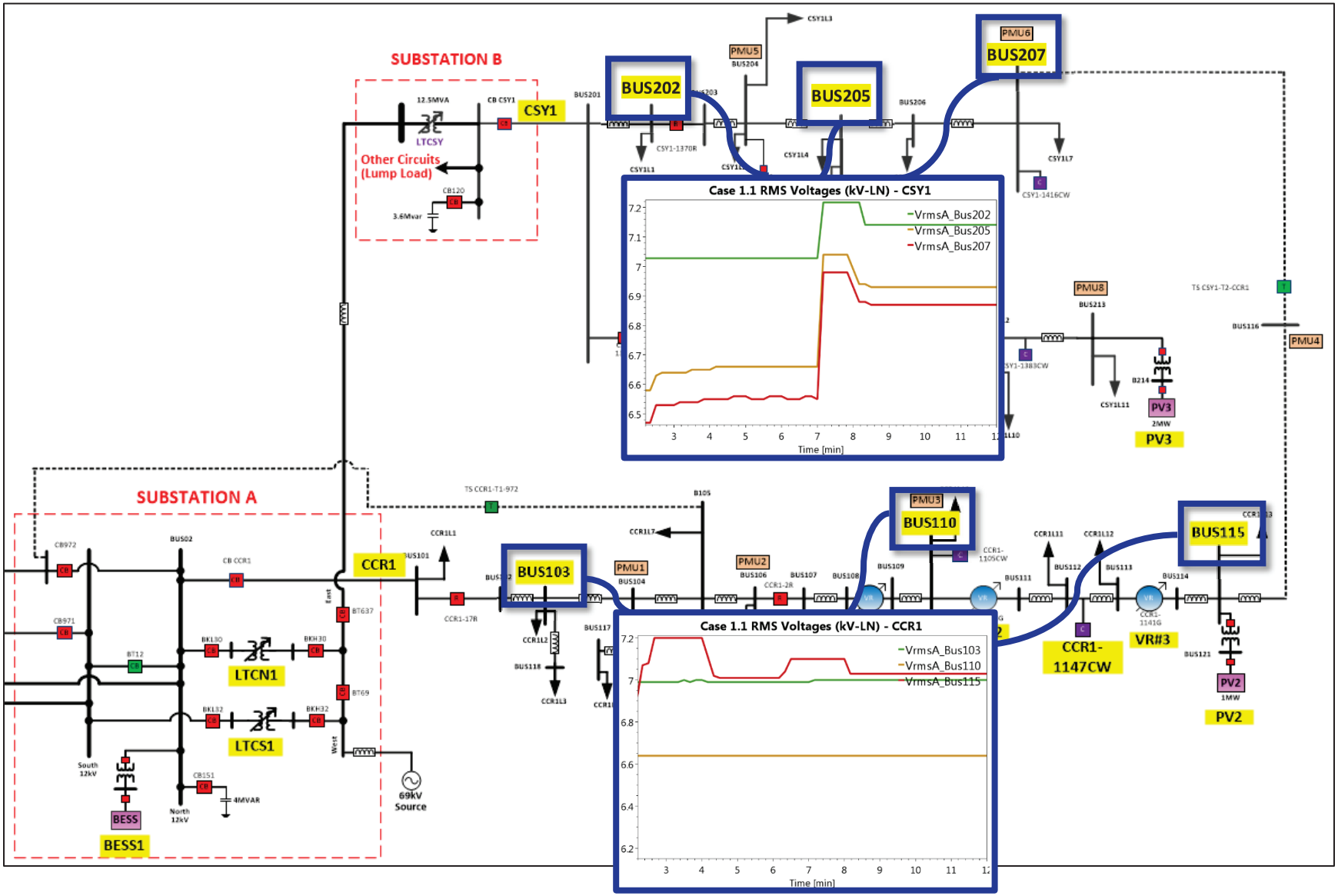


Figure 8-1. Mapping of SLD elements to test case charts (RMS Voltage)

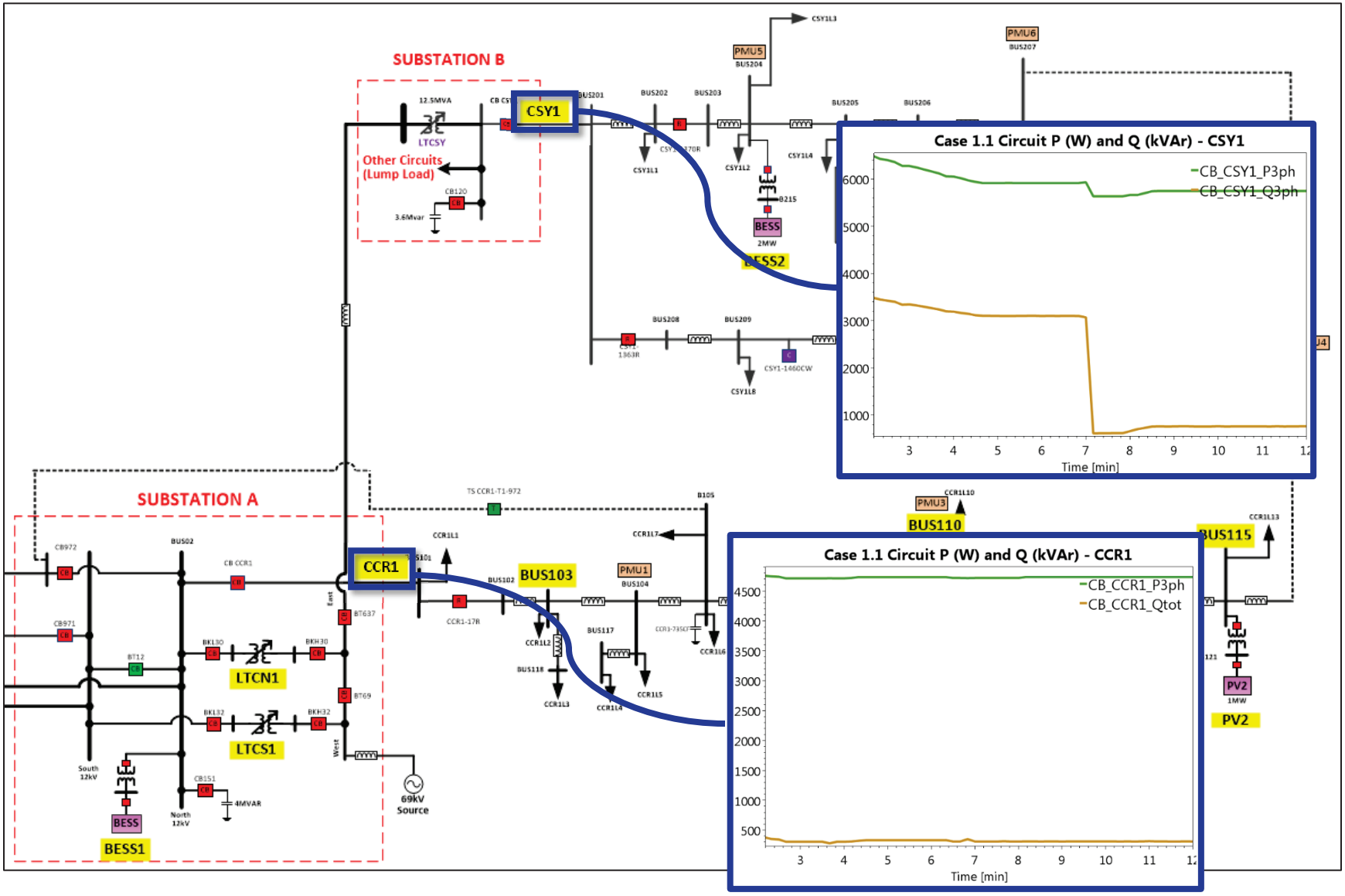


Figure 8-2. Mapping of SLD elements to test case charts (Reactive power)

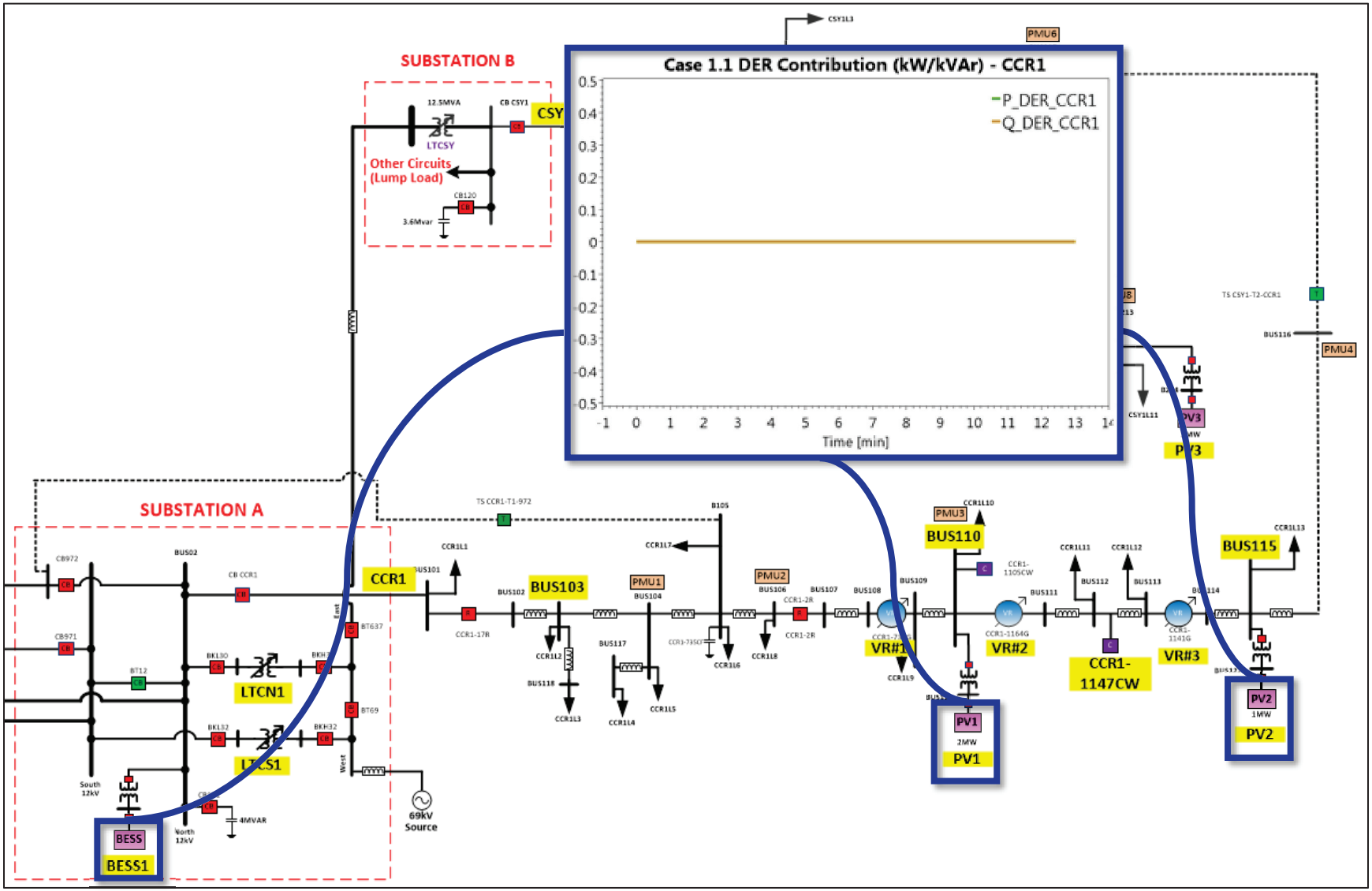


Figure 8-3. Mapping of SLD elements to test case charts (DER on CCR1)

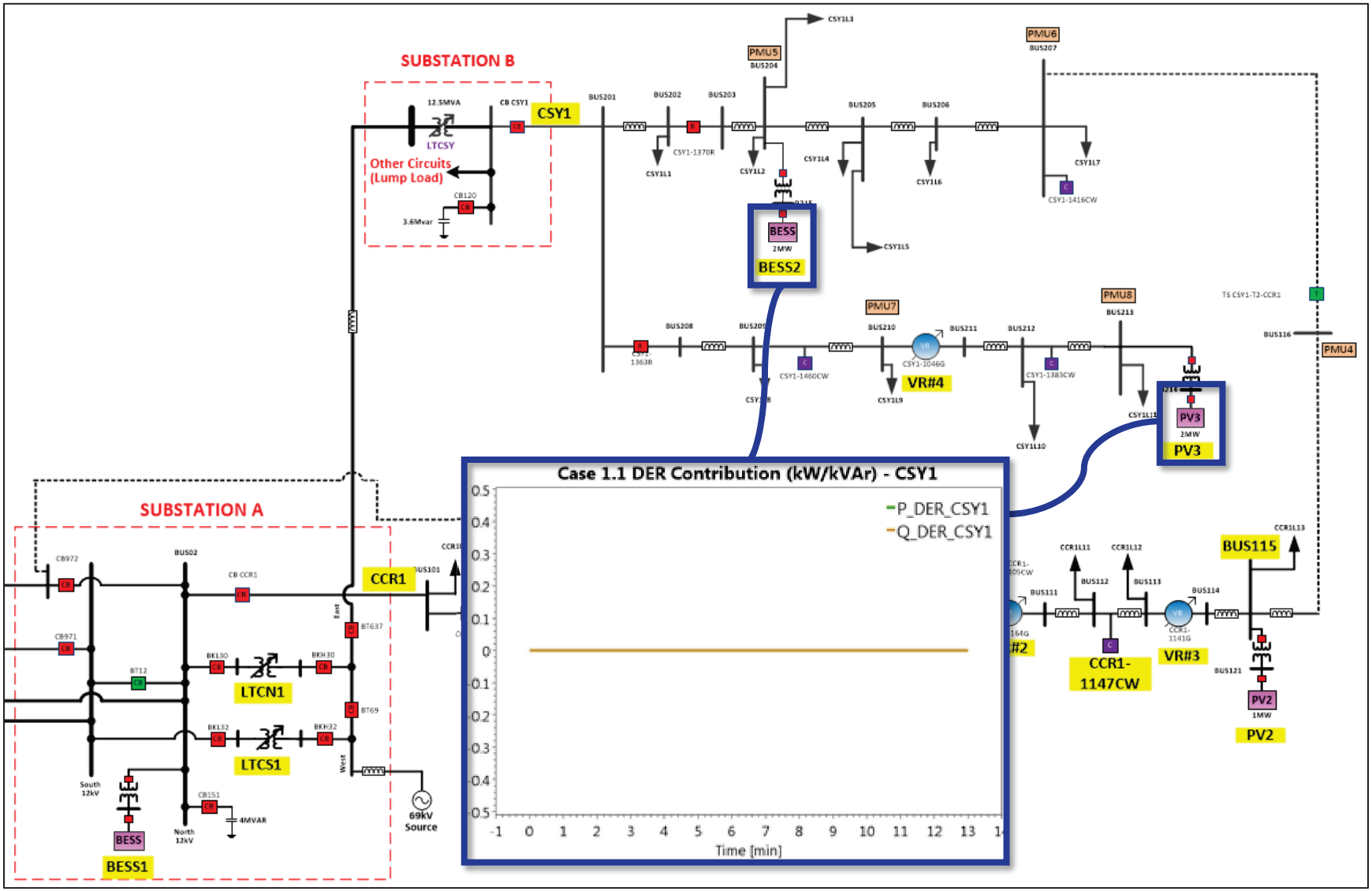


Figure 8-4. Mapping of SLD elements to test case charts (DER on CSY1)

8.1 Use Case 1: Automatic Resource Control Test Results

8.1.1 Test Case 1.1

Table 8.1. Test condition for Case 1.1

Case#	Test Conditions	Remark
1.1	High load (fix), no DER, with following initial conditions: LTCN1_tap=4, LTCSY_tap=4, VR#1_tap=0, VR#2_tap=1, VR#3_tap=5, VR#4_tap=0, all Cap banks in CCR1 are ON, all Cap banks in CSY1 are OFF, tie switches are open.	Baseline System 1 (No DER with all controllable devices in Local/Auto mode)

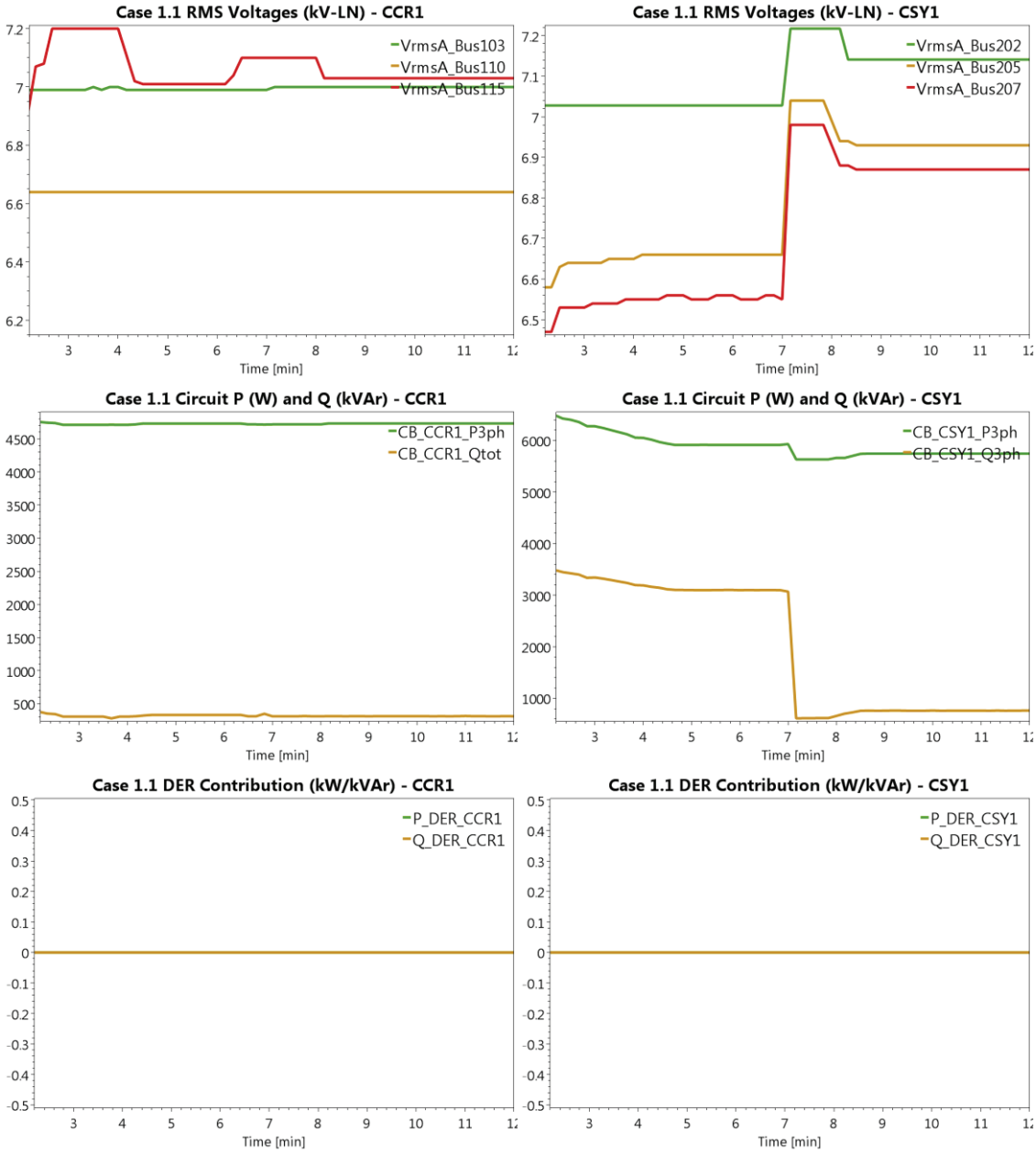


Figure 8-5. Voltage profiles, circuit powers, and DER contributions for Case 1.1

It can be observed in Figure 8-5 that, under CS1 (Local Control Scenario), BESSs do not contribute to the regulation of the voltage profile.

8.1.2 Test Case 1.2

Table 8.2. Test condition for Case 1.2

Case#	Test Conditions	Remark
1.2	High load (fix), no DER, with following initial conditions: LTCN1_tap=4, LTCSY_tap=4, VR#1_tap=0, VR#2_tap=1, VR#3_tap=5, VR#4_tap=0, all Cap banks in CCR1 are ON, all Cap banks in CSY1 are OFF, tie switches are open.	Master controller was responsible to take actions through ARC/IVVC algorithm.

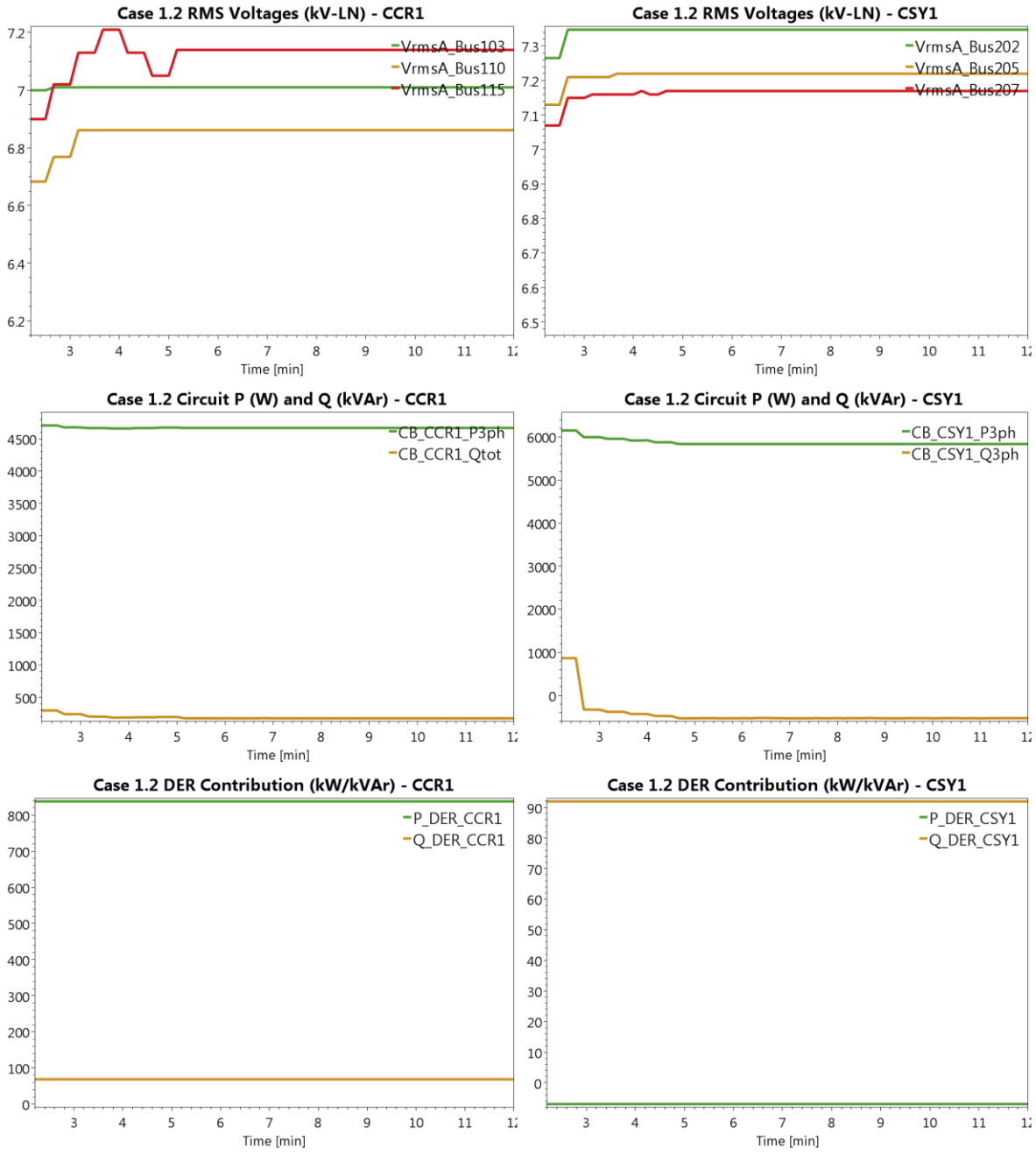


Figure 8-6. Voltage profiles, circuit powers, and DER contributions for Case 1.2

Figure 8-6 shows that the master controller involves BESSs in the adjustment of bus voltages (CS2), thereby leading to an improved voltage regulation and circuit power factor (as compared to Case 1.1).

8.1.3 Test Case 1.3

Table 8.3. Test condition for Case 1.3

Case#	Test Conditions	Remark
1.3	Low load (fix), no DER, with following initial conditions: LTCN1_tap=4, LTCSY_tap=4, VR#1_tap=0, VR#2_tap=1, VR#3_tap=5, VR#4_tap=0, all Cap banks in CCR1 are ON, all Cap banks in CSY1 are OFF, tie switches are open.	Baseline System 1 (No DER with all controllable devices in Local/Auto mode)

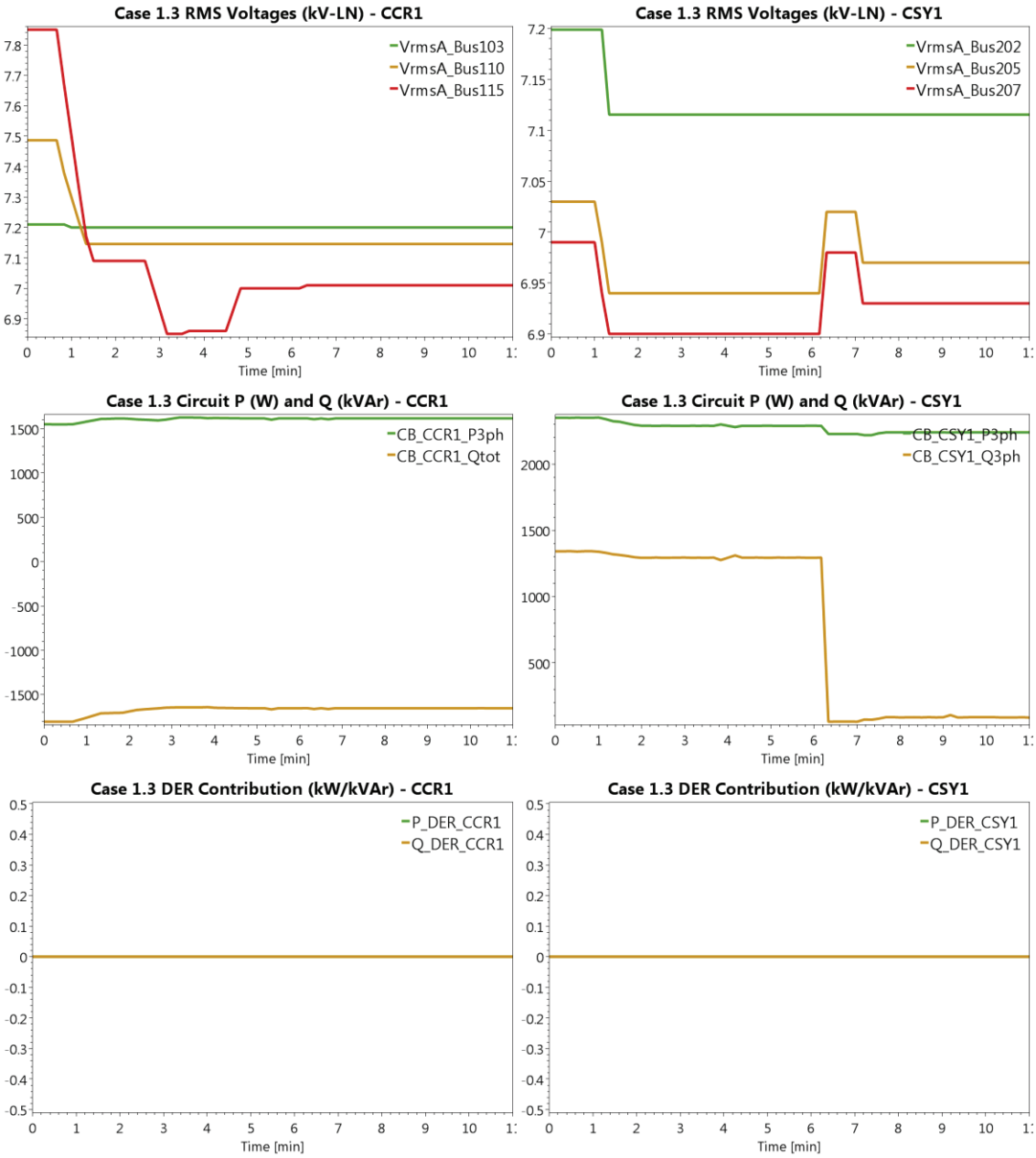


Figure 8-7. Voltage profiles, circuit powers, and DER contributions for Case 1.3

Similar to Case 1.1, BESSs are not involved in the voltage regulation and, thus, the bus voltages experience a jump as shown in Figure 8-7. This may cause unintentional operation of some of the protective equipment. Further, the circuit power factors are not improved.

8.1.4 Test Case 1.4

Table 8.4. Test condition for Case 1.4

Case#	Test Conditions	Remark
1.4	Low load (fix), no DER, with following initial conditions: LTCN1_tap=4, LTCSY_tap=4, VR#1_tap=0, VR#2_tap=1, VR#3_tap=5, VR#4_tap=0, all Cap banks in CCR1 are ON, all Cap banks in CSY1 are OFF, tie switches are open.	Master controller was responsible to take actions through ARC/IVVC algorithm.

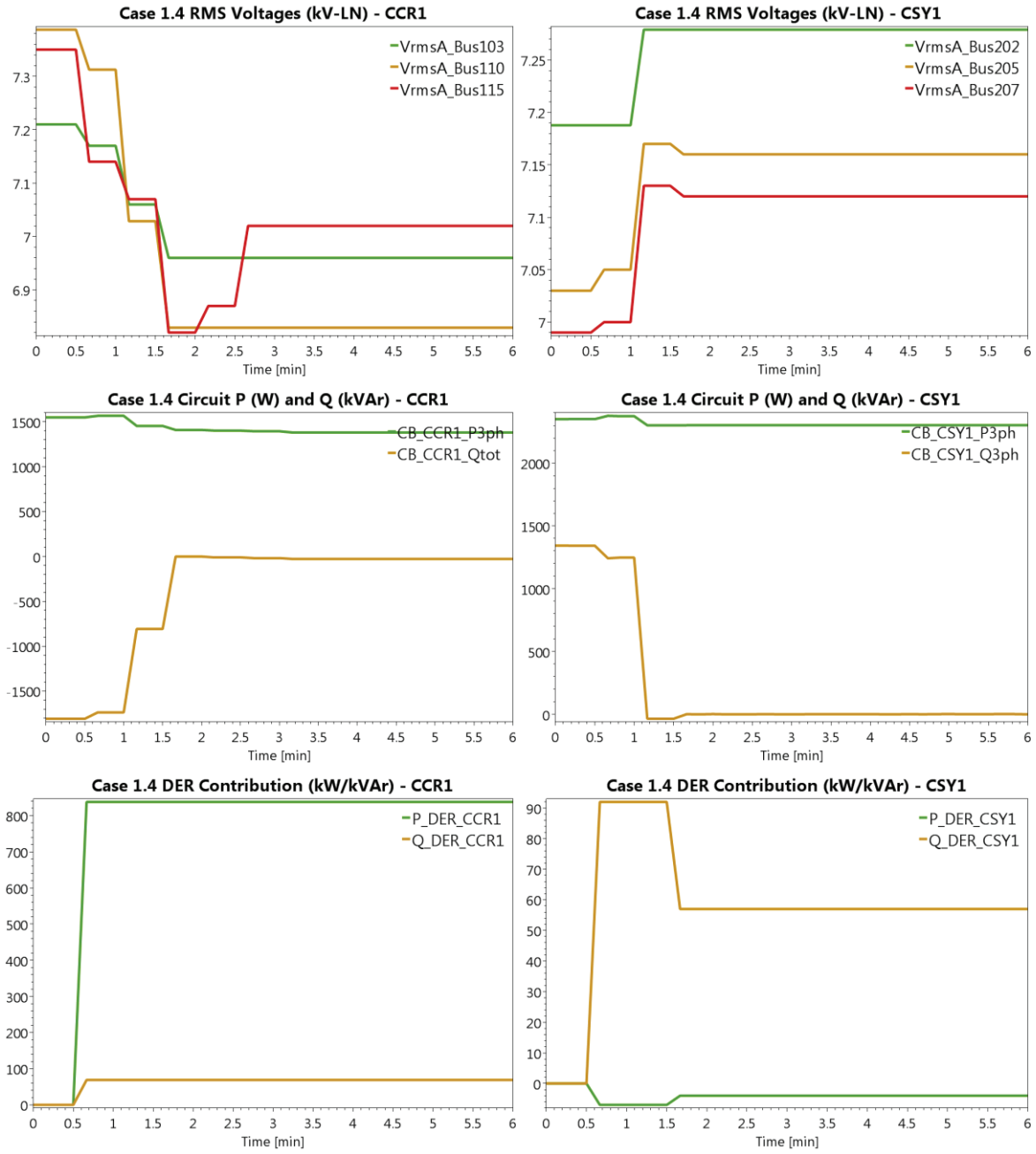


Figure 8-8. Voltage profiles, circuit powers, and DER contributions for Case 1.4

The master controller utilizes BESSs for system performance improvement. As such, besides the fine tuning of bus voltages, the increased contribution of DERs improves system efficiency and power factor.

8.1.5 Test Case 1.5

Table 8.5. Test condition for Case 1.5

Case#	Test Conditions	Remark
1.5	High load (fix), Low PV (fix) Initial Conditions: Steady state of case 1.1	Baseline System 2 (all controllable devices were in Local/Auto mode)

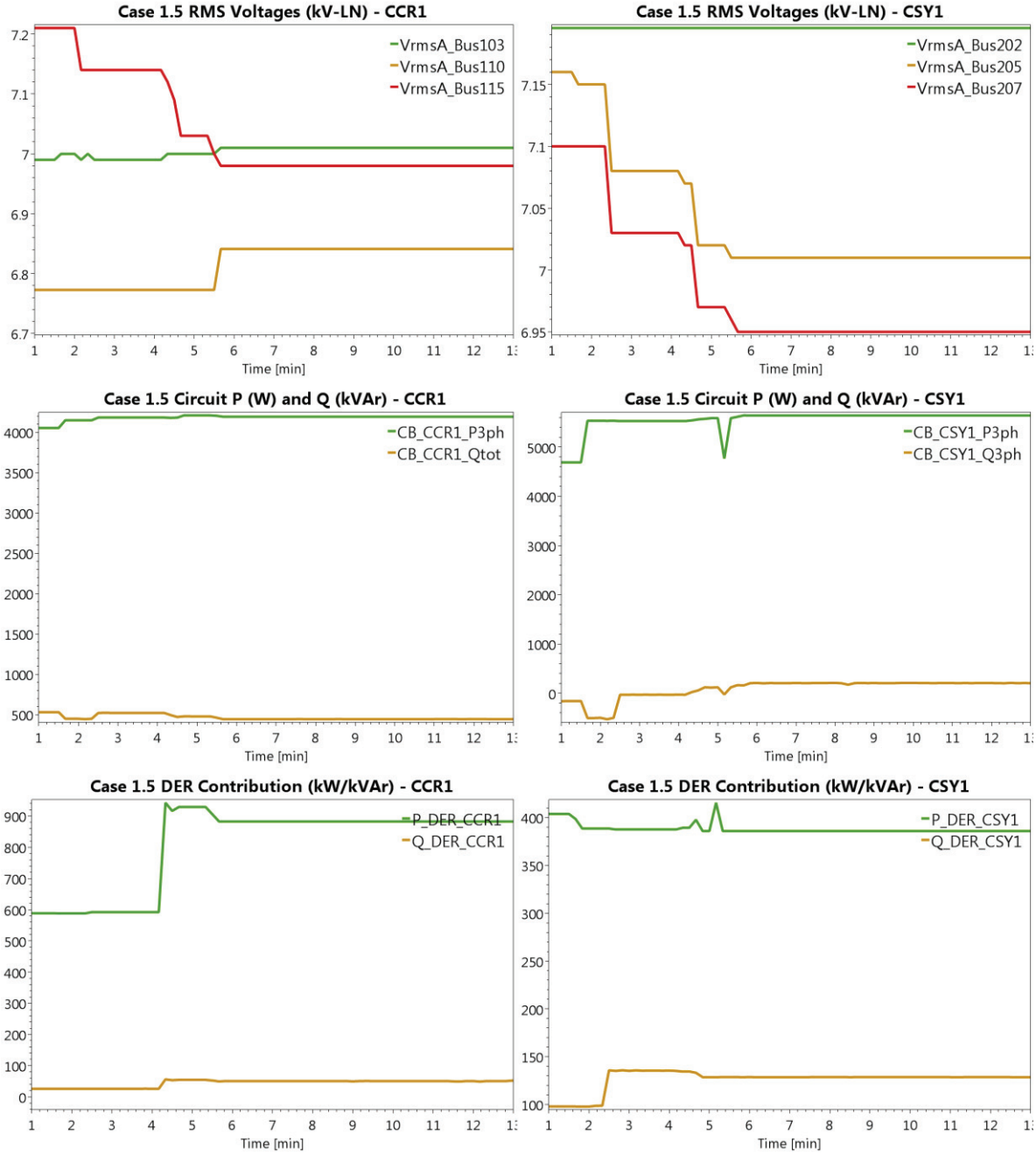


Figure 8-9. Voltage profiles, circuit powers, and DER contributions for Case 1.5

Figure 8-9 shows that the substation BESS has generated some real power based on its local peak shaving functionality.

8.1.6 Test Case 1.6

Table 8.6. Test condition for Case 1.6

Case#	Test Conditions	Remark
1.6	High load (fix), Low PV (fix) Initial Conditions: Steady state of case 1.1	Master controller was responsible to take actions through ARC/IVVC algorithm.

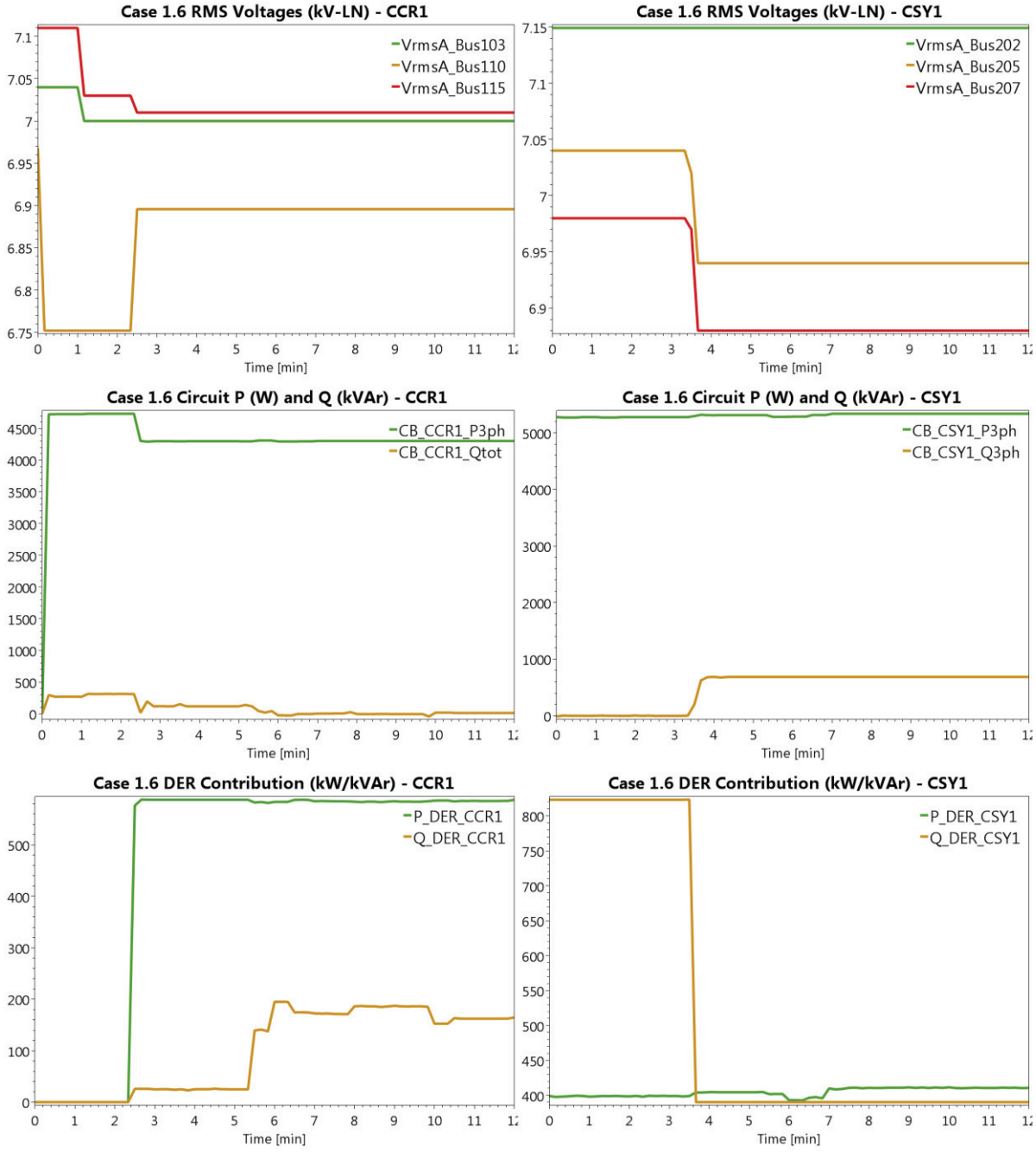


Figure 8-10. Voltage profiles, circuit powers, and DER contributions for Case 1.6

Compared to Case 1.5, the voltage profile has been improved due to the effective utilization of DERs. It is also noted that voltage control has had more priority over the feeder power factor regulation.

8.1.7 Test Case 1.7

Table 8.7. Test condition for Case 1.7

Case#	Test Conditions	Remark
1.7	High load (fix), Low PV (fix) Initial Conditions: Steady state of case 1.1	Sub controller was responsible to take actions through permission or communication loss (prior to event)

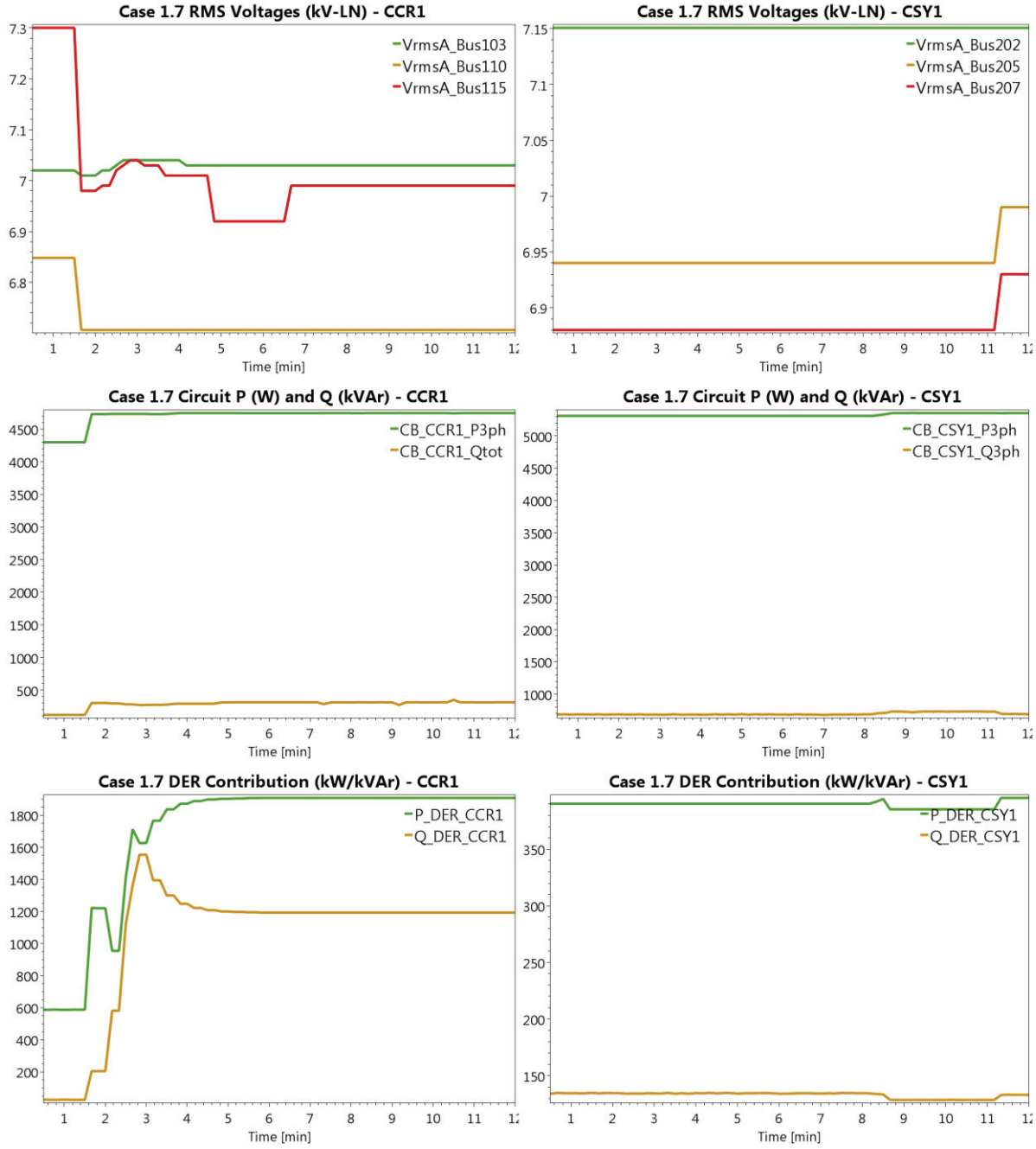


Figure 8-11. Voltage profiles, circuit powers, and DER contributions for Case 1.7

The results of Figure 8-11 shows that, for this test case, the substation controller is able to regulate the bus voltages and feeder power factor almost similar to the master controller (Case 1.6).

8.1.8 Test Case 1.8

Table 8.8. Test condition for Case 1.8

Case#	Test Conditions	Remark
1.8	Case 1.5: High load (fix), Low PV (fix) Trip CCR1-1147CW after the system gets to the steady state condition.	Baseline System 2 (all controllable devices were in Local/Auto mode)

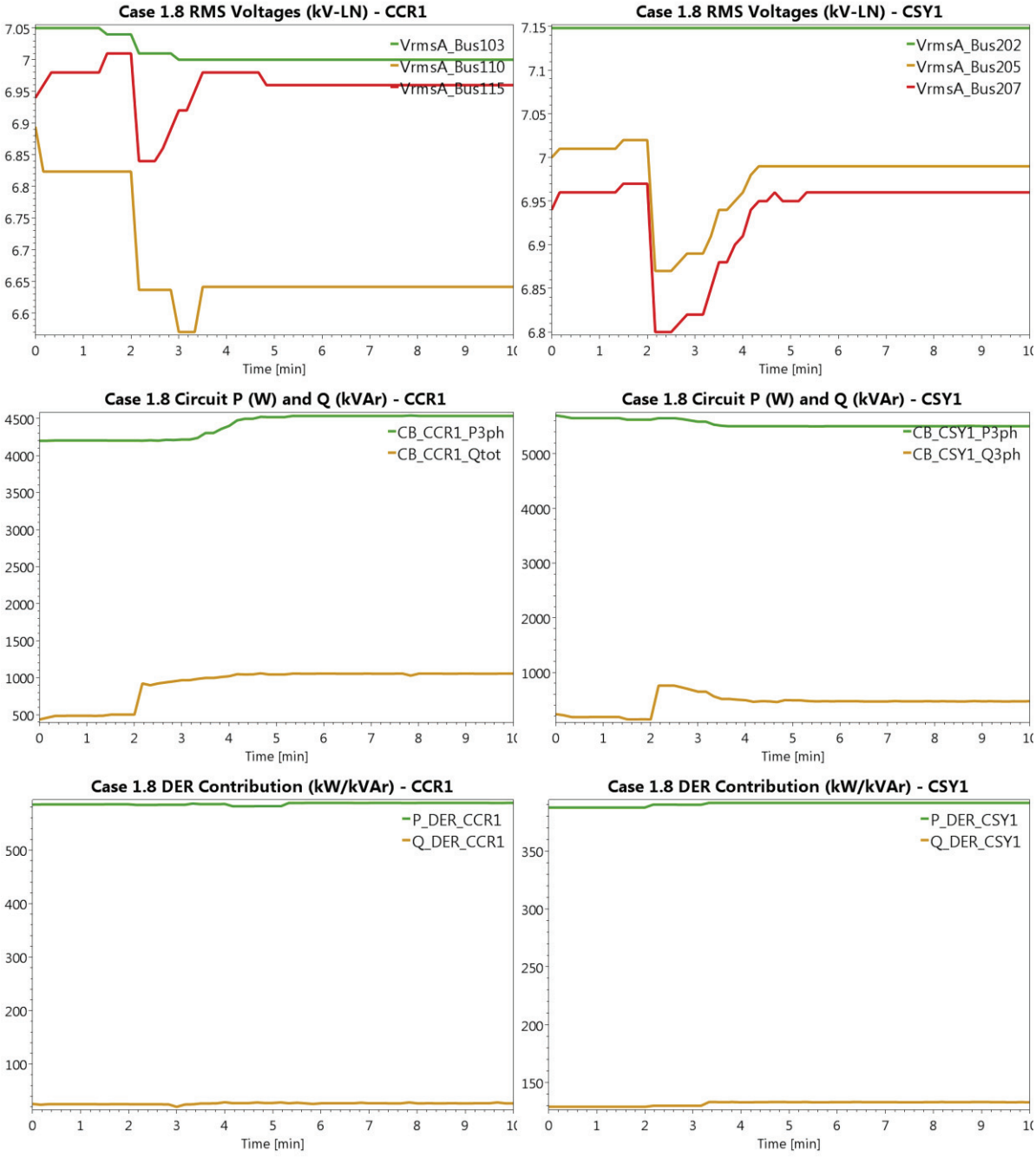


Figure 8-12. Voltage profiles, circuit powers, and DER contributions for Case 1.8

As can be seen in Figure 8-12, following the cap bank trip, the local controllers cannot bring back the voltage of Bus 110 to the acceptable range. It is also observed that DERs have minimal involvement.

8.1.9 Test Case 1.9

Table 8.9. Test condition for Case 1.9

Case#	Test Conditions	Remark
1.9	Case 1.6: High load (fix), Low PV (fix) TripCCR1-1147CW after the system gets to the steady state condition.	Master controller was responsible to take actions through ARC/IVVC algorithm.

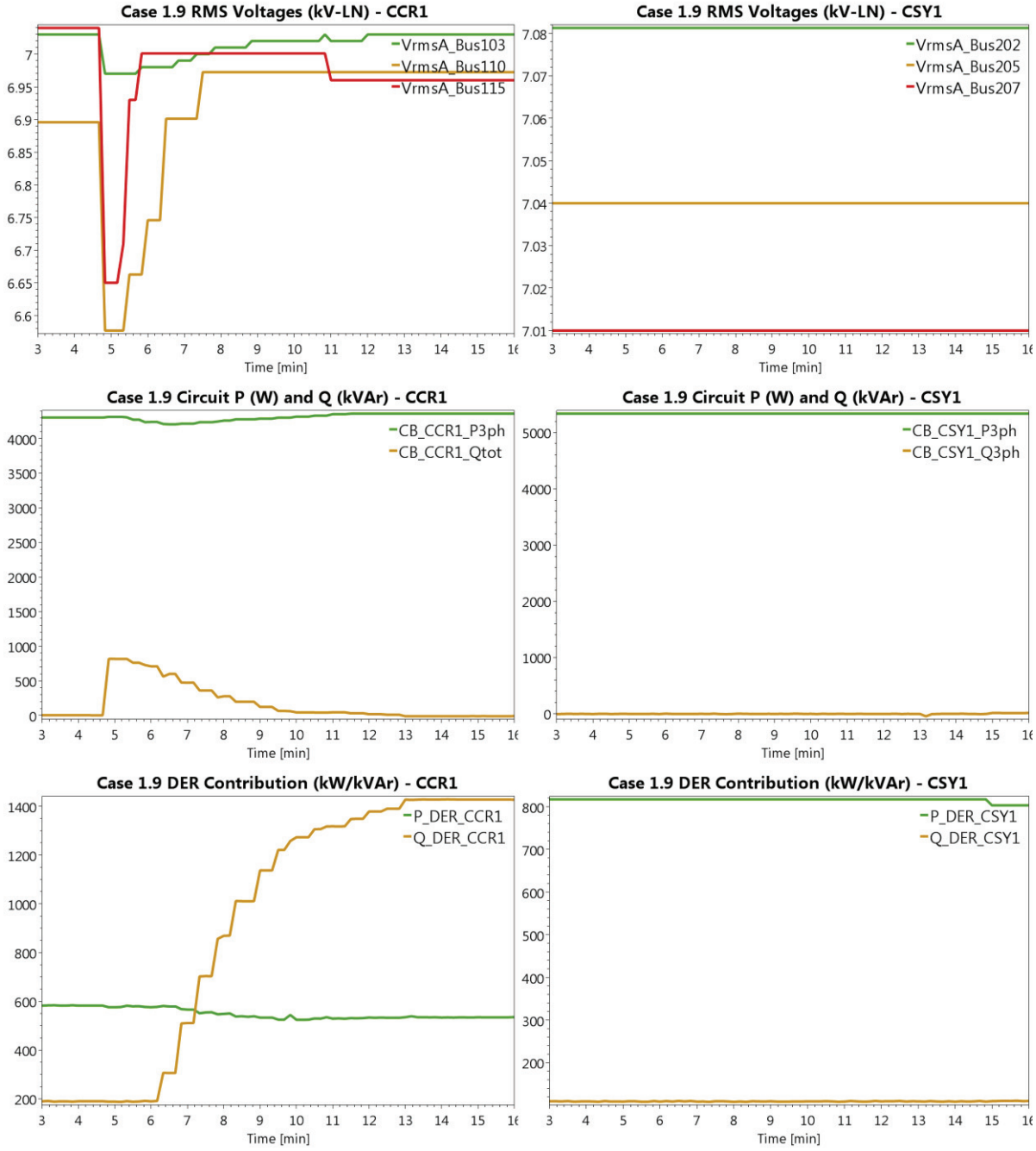


Figure 8-13. Voltage profiles, circuit powers, and DER contributions for Case 1.9

As opposed to Case 1.8, the master controller effectively utilizes DERs to regulate voltage profile and improve power factor, while minimizing the renewable energy curtailment.

8.1.10 Test Case 1.15

Table 8.10. Test condition for Case 1.15

Case#	Test Conditions	Remark
1.15	Low load (fix), Low PV (fix) Initial Conditions: Steady state of case 1.3	Baseline System 2 (all controllable devices were in Local/Auto mode)

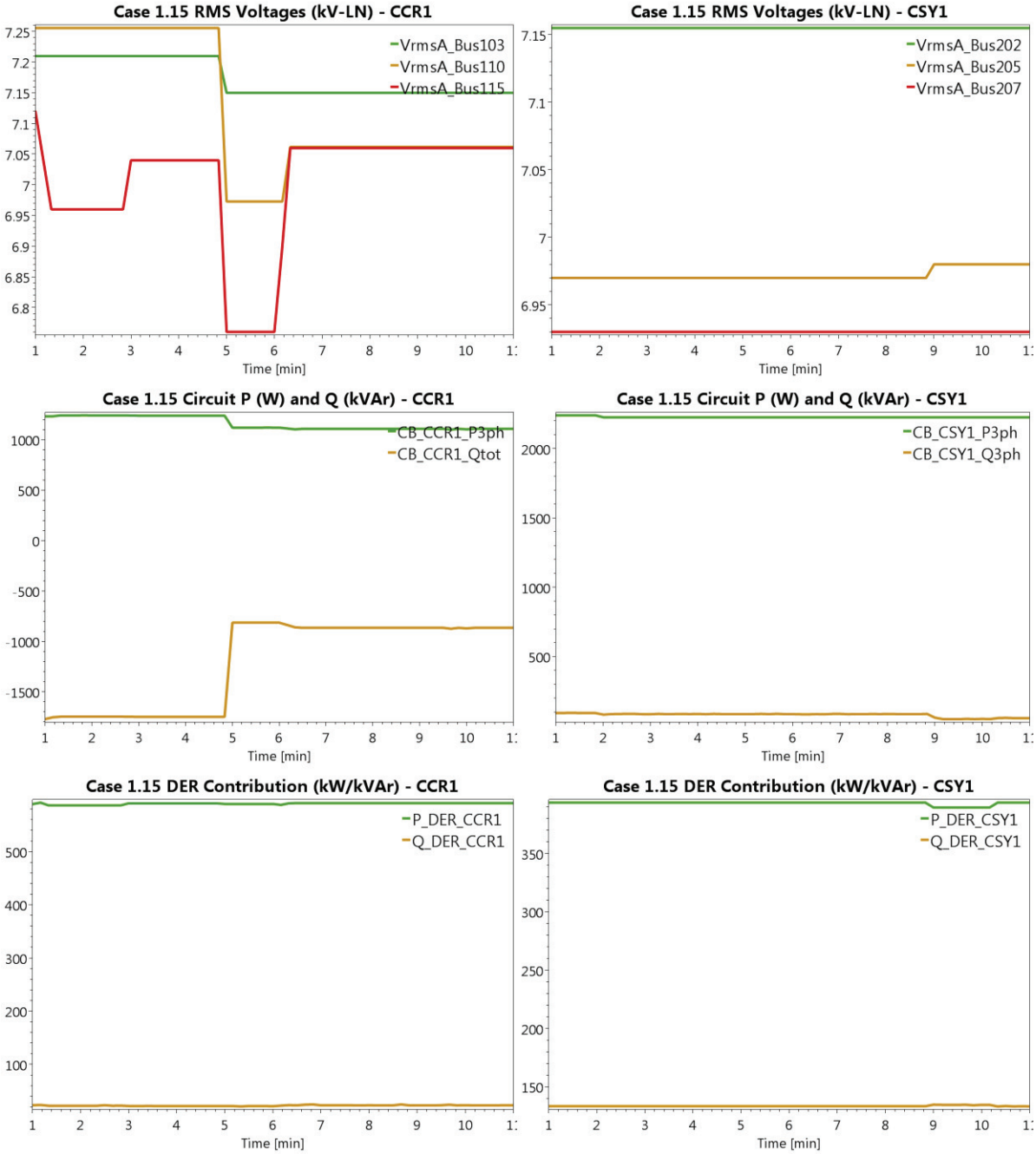


Figure 8-14. Voltage profiles, circuit powers, and DER contributions for Case 1.15

As shown in Figure 8-14, due to the lack of coordination among local controllers, the voltage of buses fluctuate considerably. Also, the capacitor bank has operated late (about 5 min after the PV profile change).

8.1.11 Test Case 1.16

Table 8.11. Test condition for Case 1.16

Case#	Test Conditions	Remark
1.16	Low load (fix), Low PV (fix) Initial Conditions: Steady state of case 1.3	Master controller was responsible to take actions through ARC/IVVC algorithm.

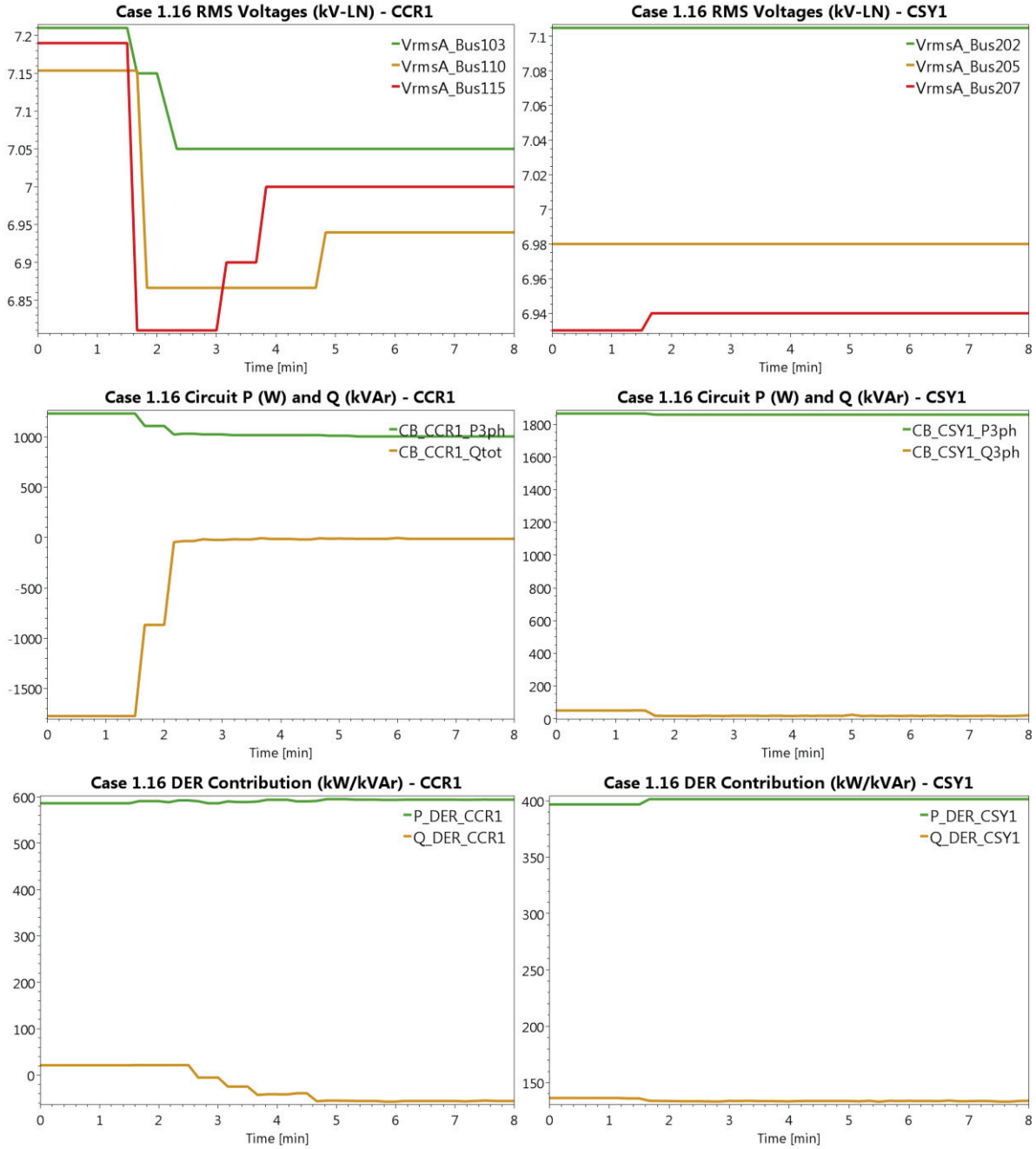


Figure 8-15. Voltage profiles, circuit powers, and DER contributions for Case 1.16

Figure 8-15 shows that the master controller trips a capacitor bank to improve both feeder power factors, while keeping the bus voltages within the acceptable range (enhanced DER involvement).

8.1.12 Test Case 1.17

Table 8.12. Test condition for Case 1.17

Case#	Test Conditions	Remark
1.17	Low load (fix), Low PV (fix) Initial Conditions: Steady state of case 1.3	Sub controller was responsible to take actions through permission or communication loss (prior to event)

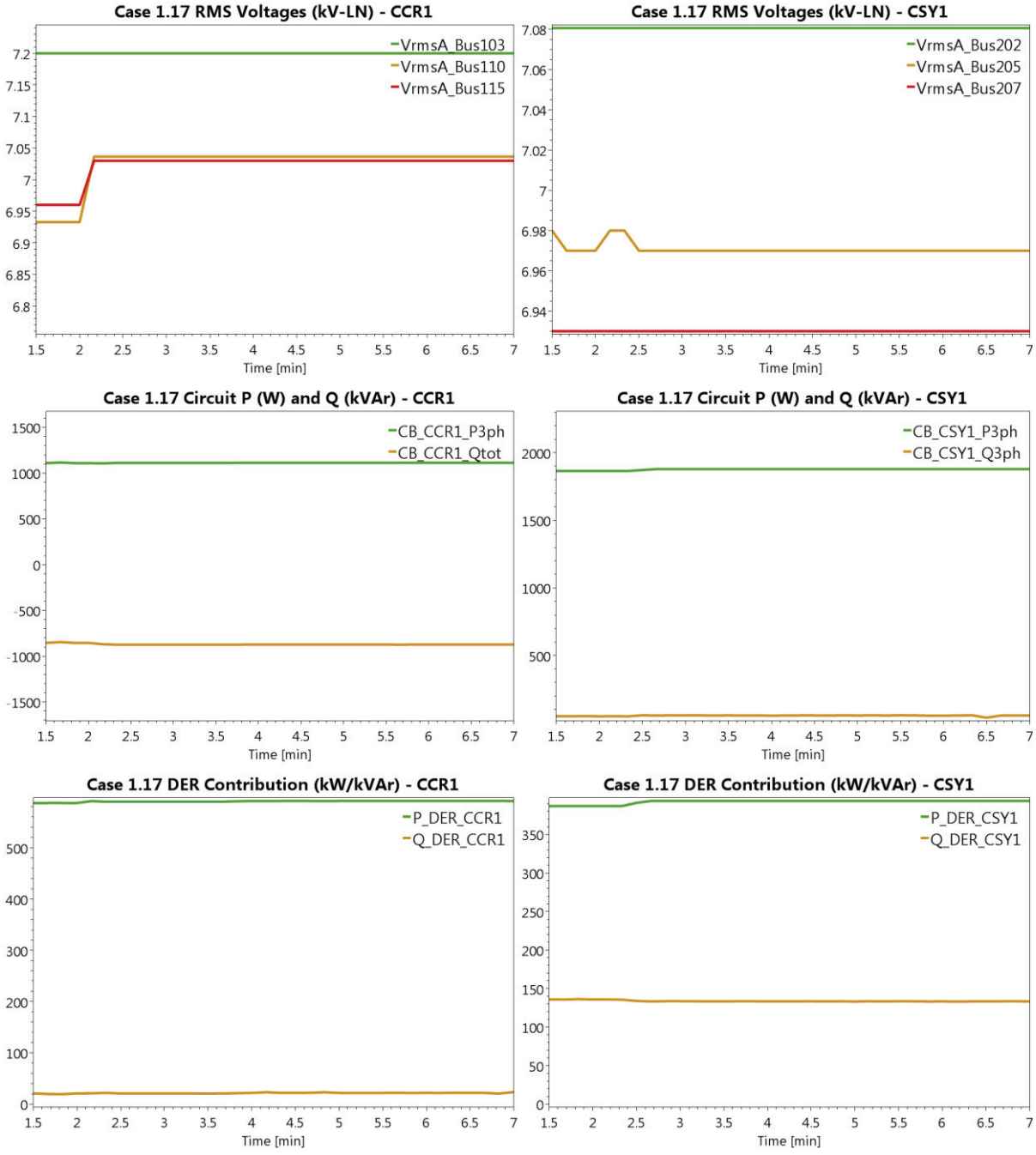


Figure 8-16. Voltage profiles, circuit powers, and DER contributions for Case 1.17

Under CS3 (substation controller in charge), the voltage profiles are improved (compare to Case 1.15), but the feeder power factors are not as good as Case 1.16 (master controller in charge).

8.1.13 Test Case 1.18

Table 8.13. Test condition for Case 1.18

Case#	Test Conditions	Remark
1.18	Low load (fix), High PV (fix) Initial Conditions: Steady state of case 1.3	Baseline System 2 (all controllable devices were in Local/Auto mode)



Figure 8-17. Voltage profiles, circuit powers, and DER contributions for Case 1.18

Figure 8-17 shows that, subsequent to the PV profile change, the system undergoes severe transients due to uncoordinated actions of various controllers (including local control of DERs).

8.1.14 Test Case 1.19

Table 8.14. Test condition for Case 1.19

Case#	Test Conditions	Remark
1.19	Low load (fix), High PV (fix) Initial Conditions: Steady state of case 1.3	Master controller was responsible to take actions through ARC/IVVC algorithm.

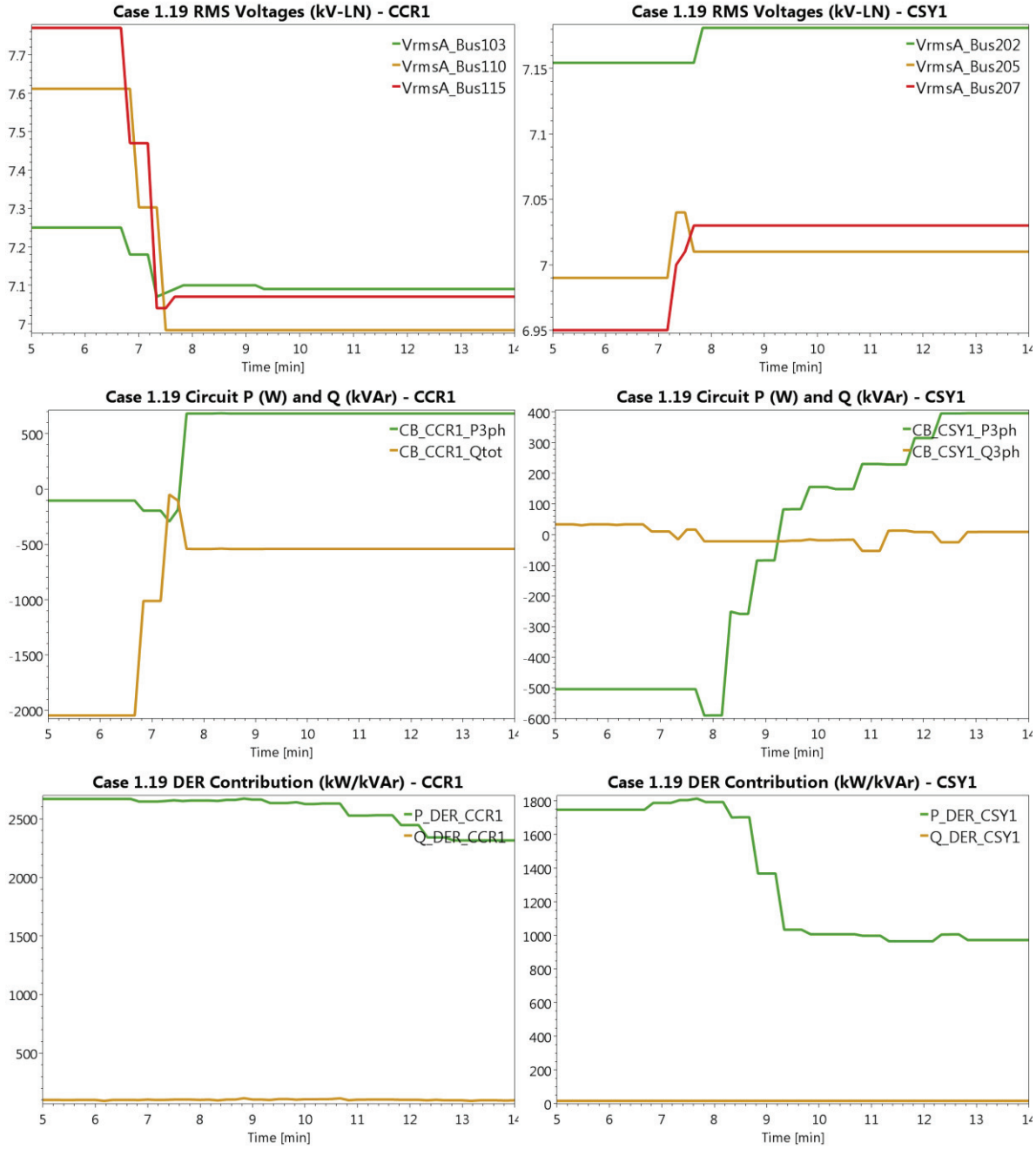


Figure 8-18. Voltage profiles, circuit powers, and DER contributions for Case 1.19

Compared to Case 1.18, the master controller has been able to effectively stabilize the system operating conditions while managing reverse power flow at the feeder circuit breakers.

8.1.15 Test Case 1.20

Table 8.15. Test condition for Case 1.20

Case#	Test Conditions	Remark
1.20	Low load (fix), High PV (fix) Initial Conditions: Steady state of case 1.3	Sub controller was responsible to take actions through permission or communication loss (prior to event)

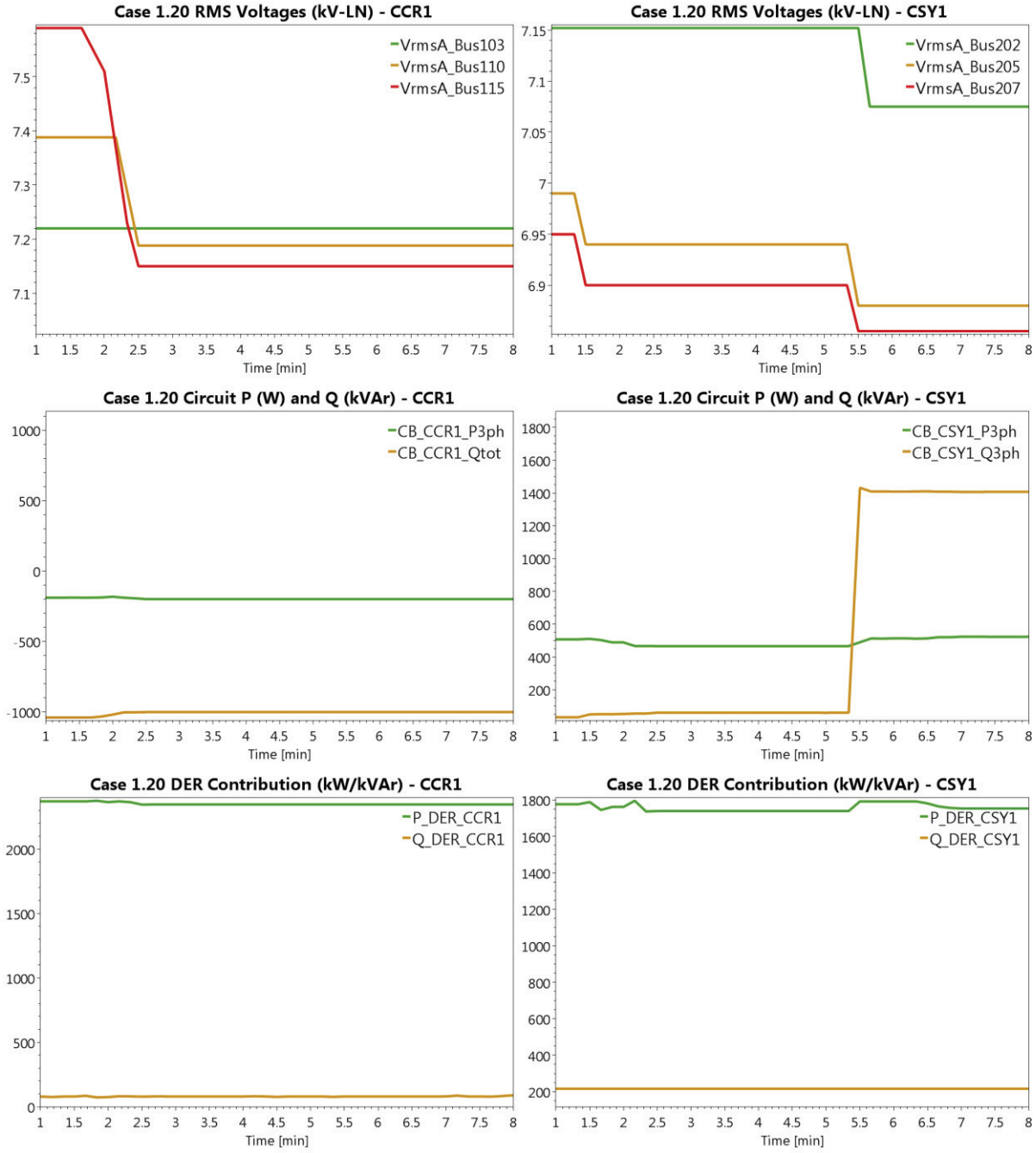


Figure 8-19. Voltage profiles, circuit powers, and DER contributions for Case 1.20

While the voltage profiles are improved in this case (compare to CS1 – Case 1.18), the substation control cannot effectively enhance DER contributions to improve both system efficiency and power factor.

8.1.16 Test Case 1.21

Table 8.16. Test condition for Case 1.21

Case#	Test Conditions	Remark
1.21	Case 1.15: Low load (fix), High PV (fix) Trip PVs after the system gets to the steady state condition.	Baseline System 2 (all controllable devices were in Local/Auto mode)

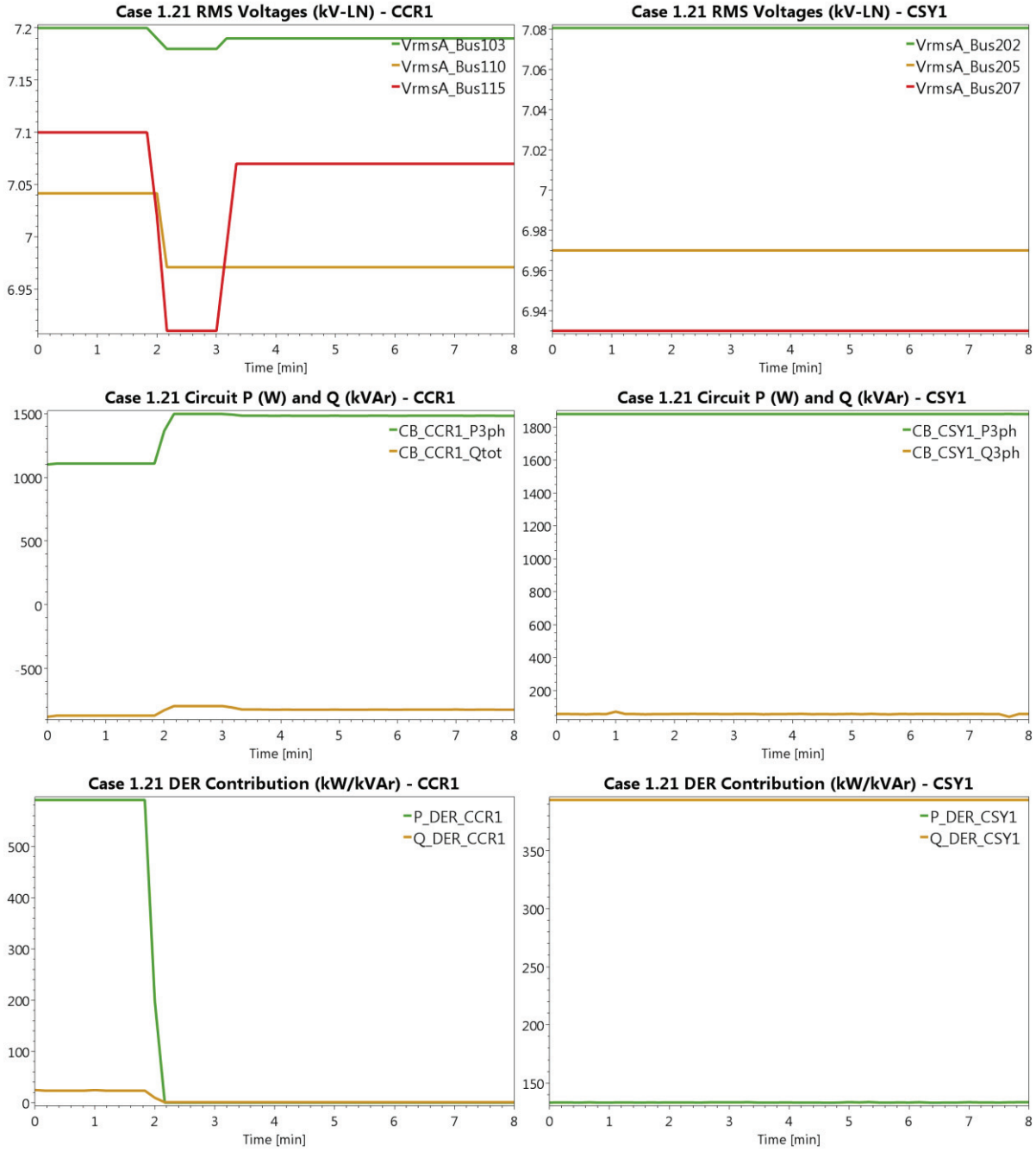


Figure 8-20. Voltage profiles, circuit powers, and DER contributions for Case 1.21

Figure 8-20 shows that the PV trips did not impact the voltage profile significantly. However, the local controllers could not optimize the feeder power factors.

8.1.17 Test Case 1.22

Table 8.17. Test condition for Case 1.22

Case#	Test Conditions	Remark
1.22	Case 1.16: Low load (fix), High PV (fix) Trip PV 1 after the system gets to the steady state condition.	Master controller is responsible to take actions through ARC/IVVC algorithm.

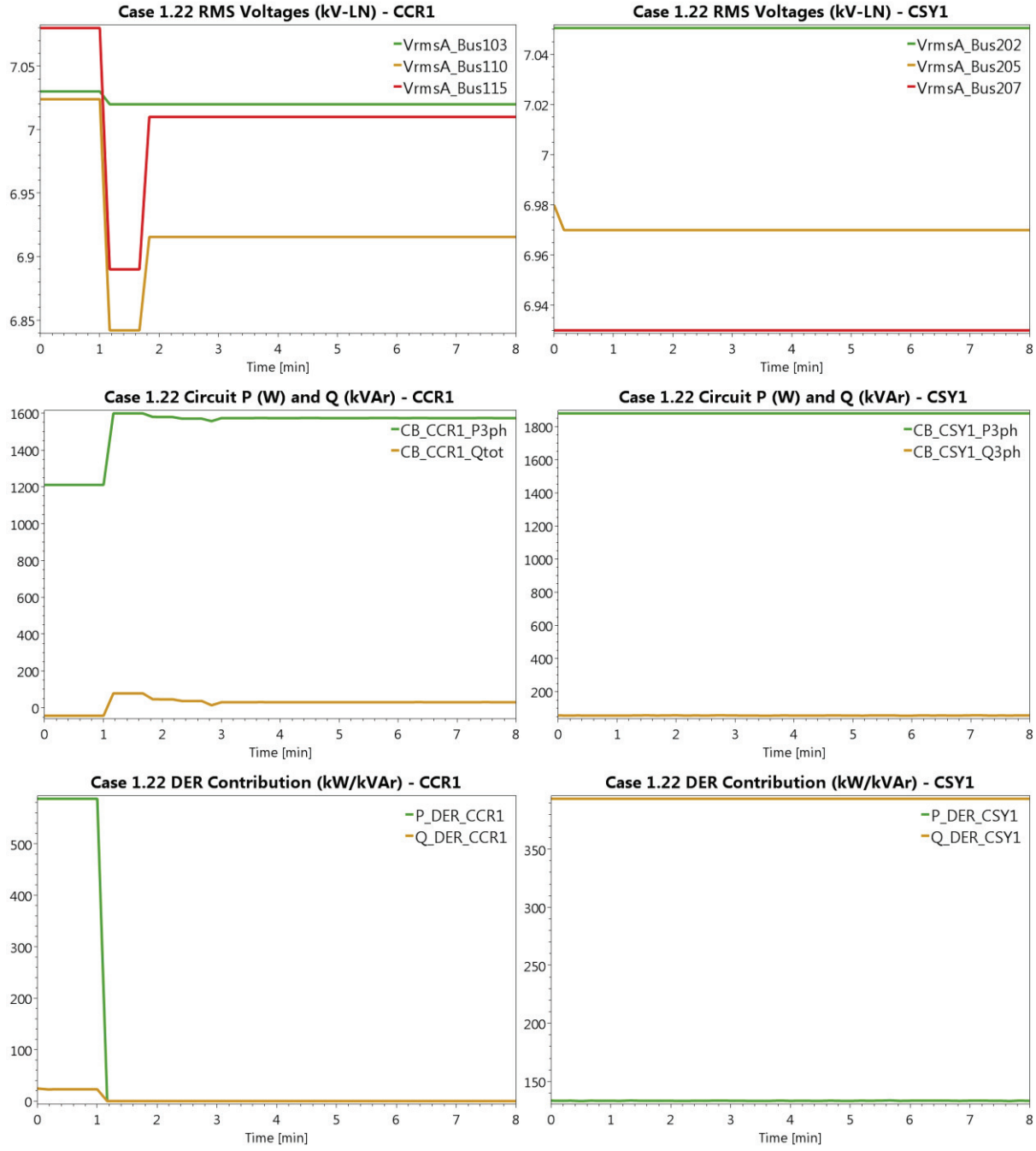


Figure 8-21. Voltage profiles, circuit powers, and DER contributions for Case 1.22

The main feature of the central control (as opposed to local control – Case 1.21) is the improved circuit reactive power regulations.

8.1.18 Test Case 1.23

Table 8.18. Test condition for Case 1.23

Case#	Test Conditions	Remark
1.23	CCR1: Load Profile = High/Summer, PV Profile = High/11am CSY1: Load Profile = High/Summer, PV Profile = High/11am Initial Conditions: Steady state of case 1.1 (45-min run)	Baseline System 2 (all controllable devices were in Local/Auto mode)

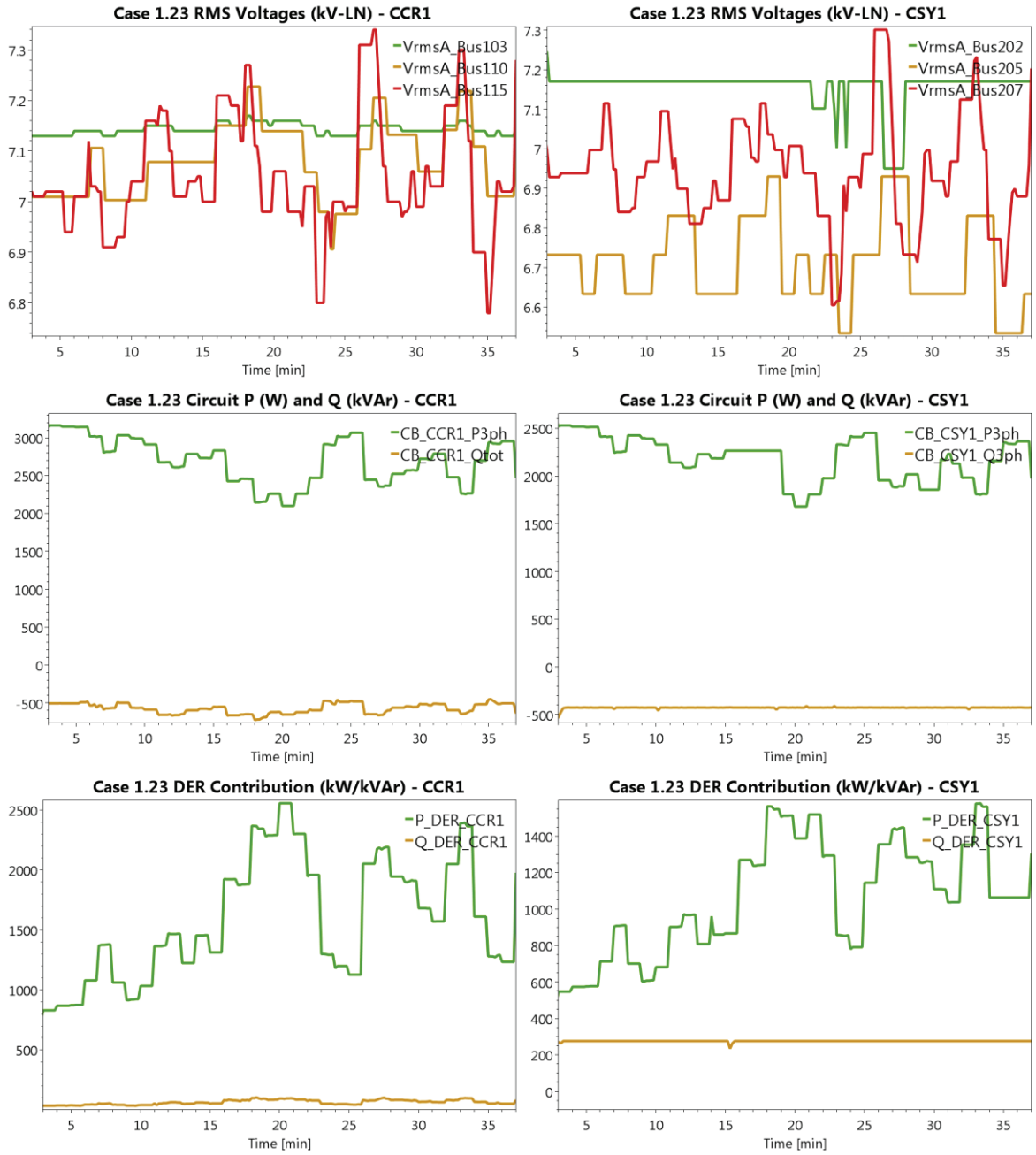


Figure 8-22. Voltage profiles, circuit powers, and DER contributions for Case 1.23

In this case that represents a realistic situation, it is observed that the voltage profile of circuit CSY1 is not properly managed and, in some cases, the voltage values are out of range (under CS1).

8.1.19 Test Case 1.24

Table 8.19. Test condition for Case 1.24

Case#	Test Conditions	Remark
1.24	CCR1: Load Profile = High/Summer, PV Profile = High/11am CSY1: Load Profile = High/Summer, PV Profile = High/11am Initial Conditions: Steady state of case 1.1 (45-min run)	Master controller was responsible to take actions through ARC/IVVC algorithm.

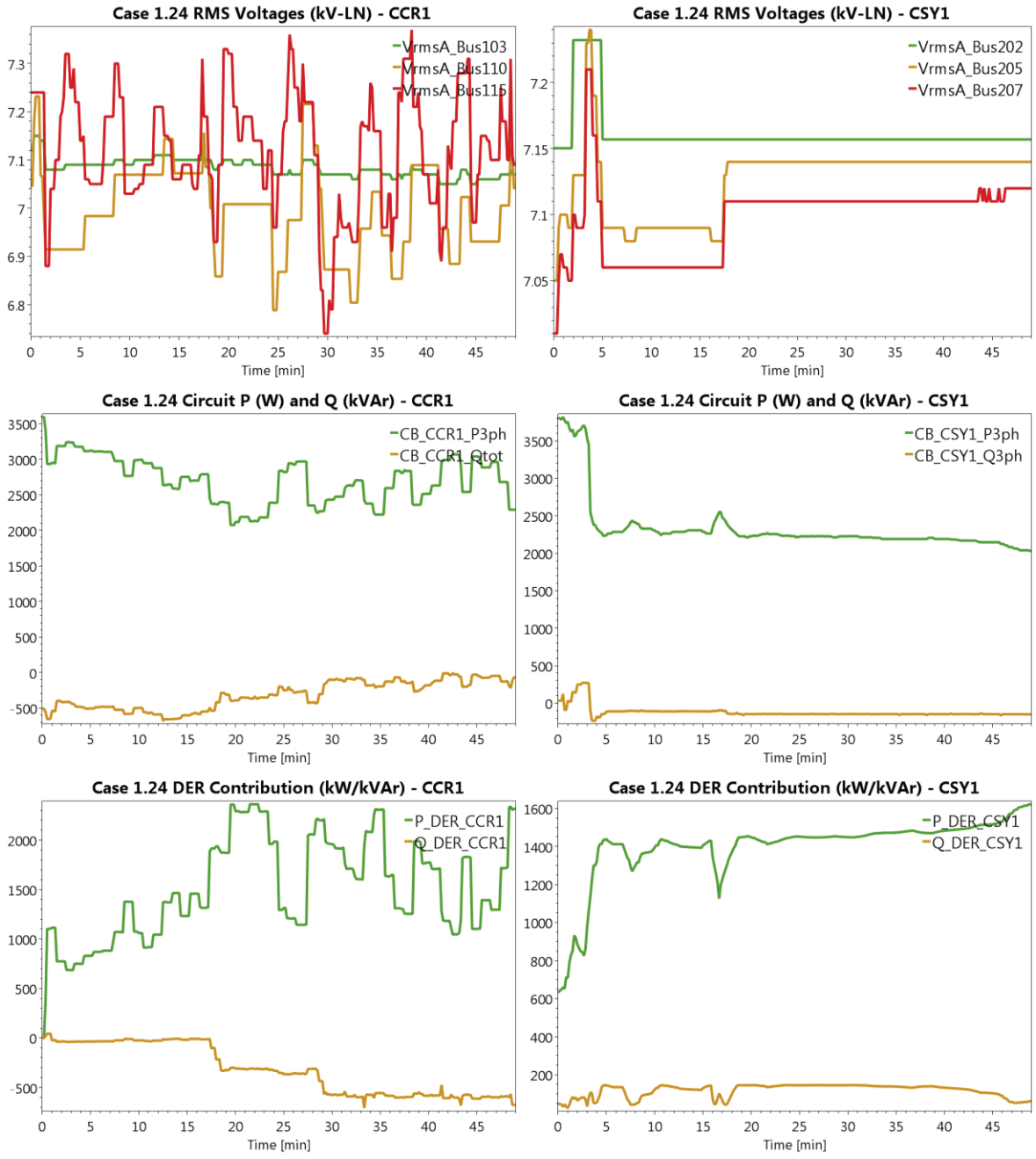


Figure 8-23. Voltage profiles, circuit powers, and DER contributions for Case 1.24

Under CS2, both the voltage profile and the feeder (reactive) power is properly regulated (compare Figure 8-23 with Figure 8-22).

8.1.20 Test Case 1.25

Table 8.20. Test condition for Case 1.25

Case#	Test Conditions	Remark
1.25	CCR1: Load Profile = Low/Winter, PV Profile = Low/4pm CSY1: Load Profile = Low/Winter, PV Profile = Low/4pm Initial Conditions: Steady state of case 1.3 (45-min run)	Baseline System 2 (all controllable devices were in Local/Auto mode)

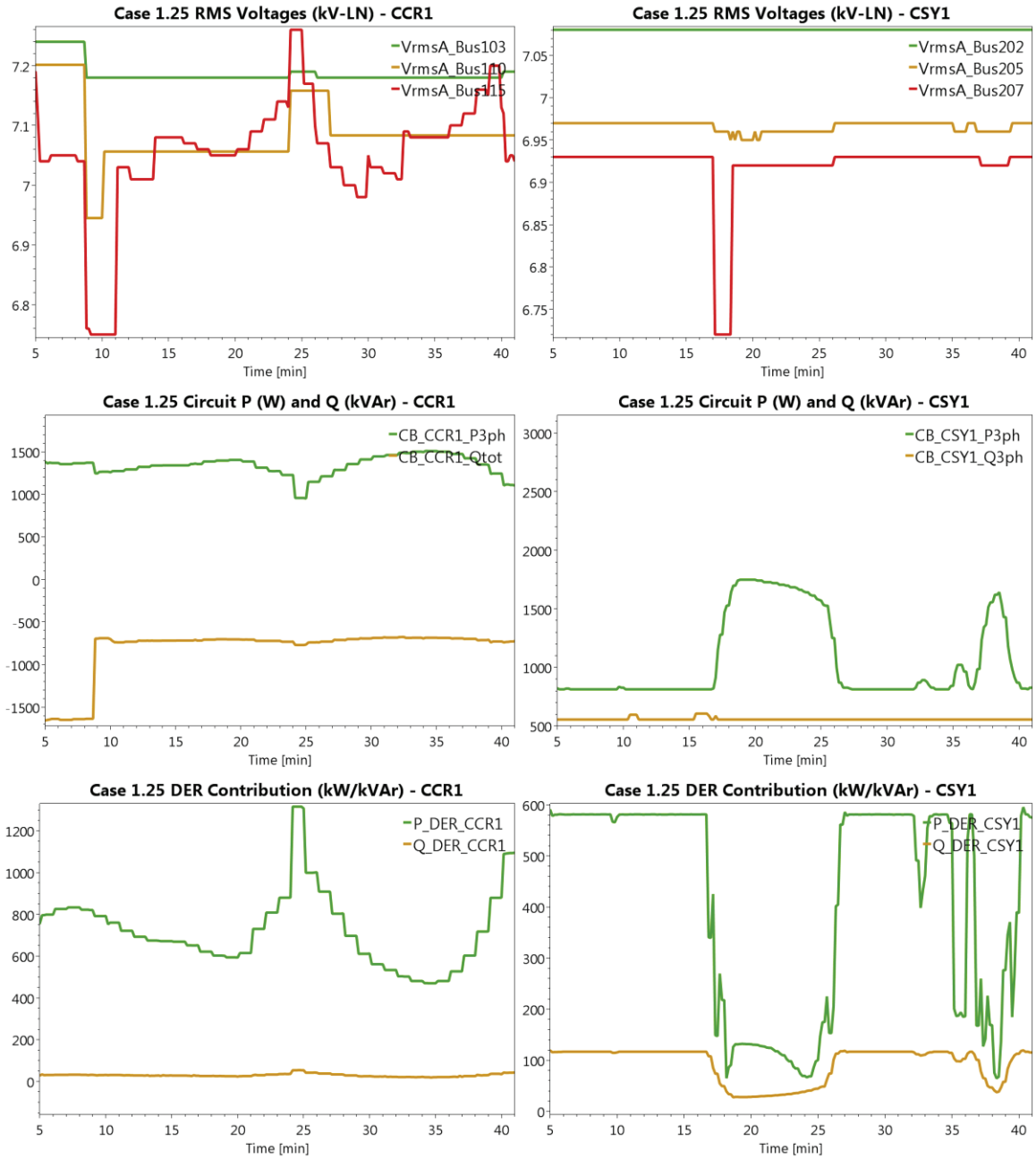


Figure 8-24. Voltage profiles, circuit powers, and DER contributions for Case 1.25

As can be observed in Figure 8-24, Under CS1, the bus voltage occasionally goes out of range. Furthermore, the feeder power is not regulated properly.

8.1.21 Test Case 1.26

Table 8.21. Test condition for Case 1.26

Case#	Test Conditions	Remark
1.26	CCR1: Load Profile = Low/Winter, PV Profile = Low/4pm CSY1: Load Profile = Low/Winter, PV Profile = Low/4pm Initial Conditions: Steady state of case 1.3 (45-min run)	Master controller was responsible to take actions through ARC/IVVC algorithm.

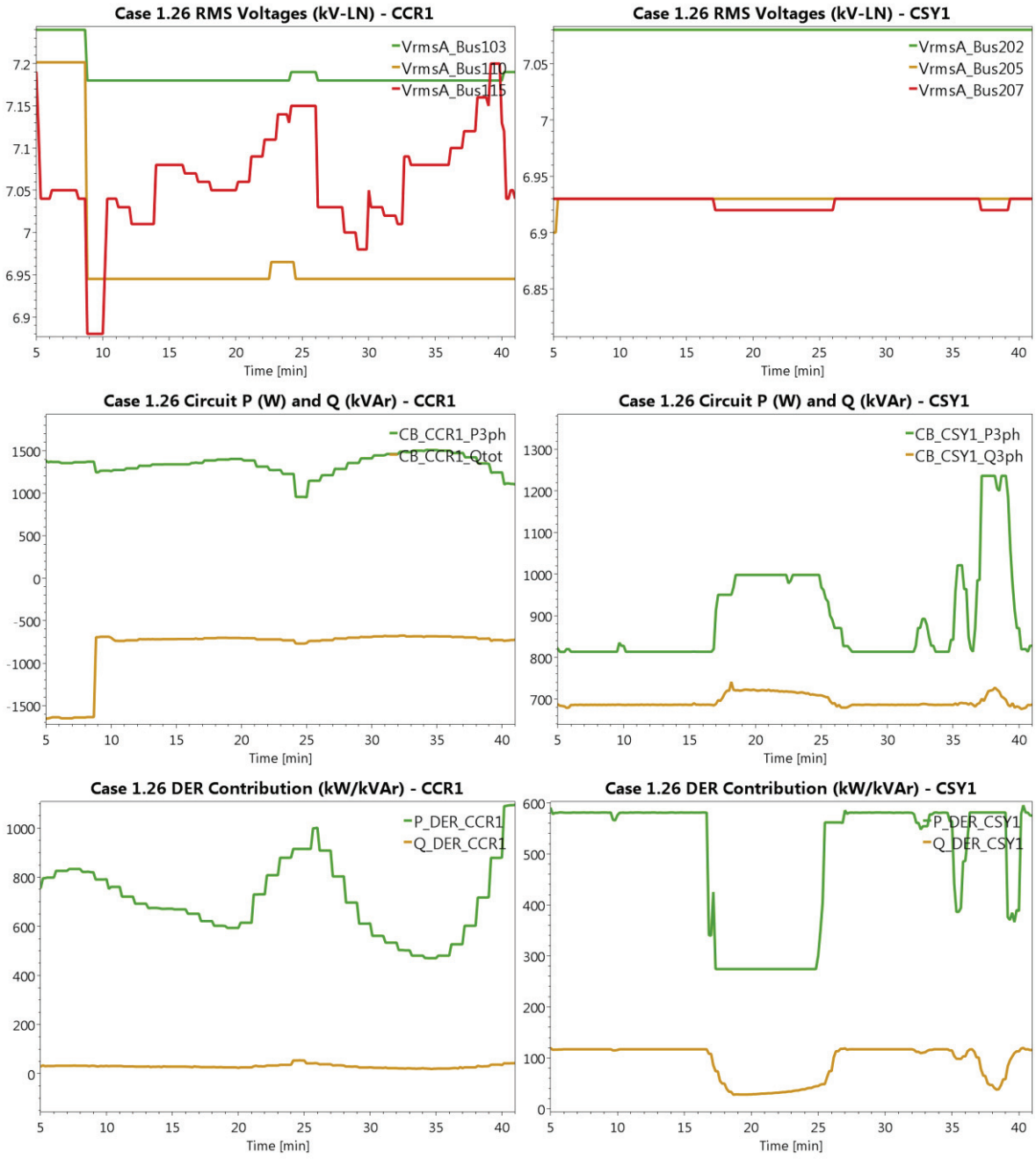


Figure 8-25. Voltage profiles, circuit powers, and DER contributions for Case 1.26

Compared to Case 1.25 (CS1), it is observed in this case (CS2) that the voltage values are always within the acceptable range and circuit powers experience less fluctuations due to the DER involvements.

8.2 Use Case 2: Synchronized Load Transfer

8.2.1 Test Case 2.4

Table 8.22. Test condition for Case 2.4

Case#	Test Condition	Remark
2.4	Low load (fix), High PV (fix) Initial Conditions: Steady state of case 1.3	Baseline System 2 (all controllable devices were in Local/Auto mode)

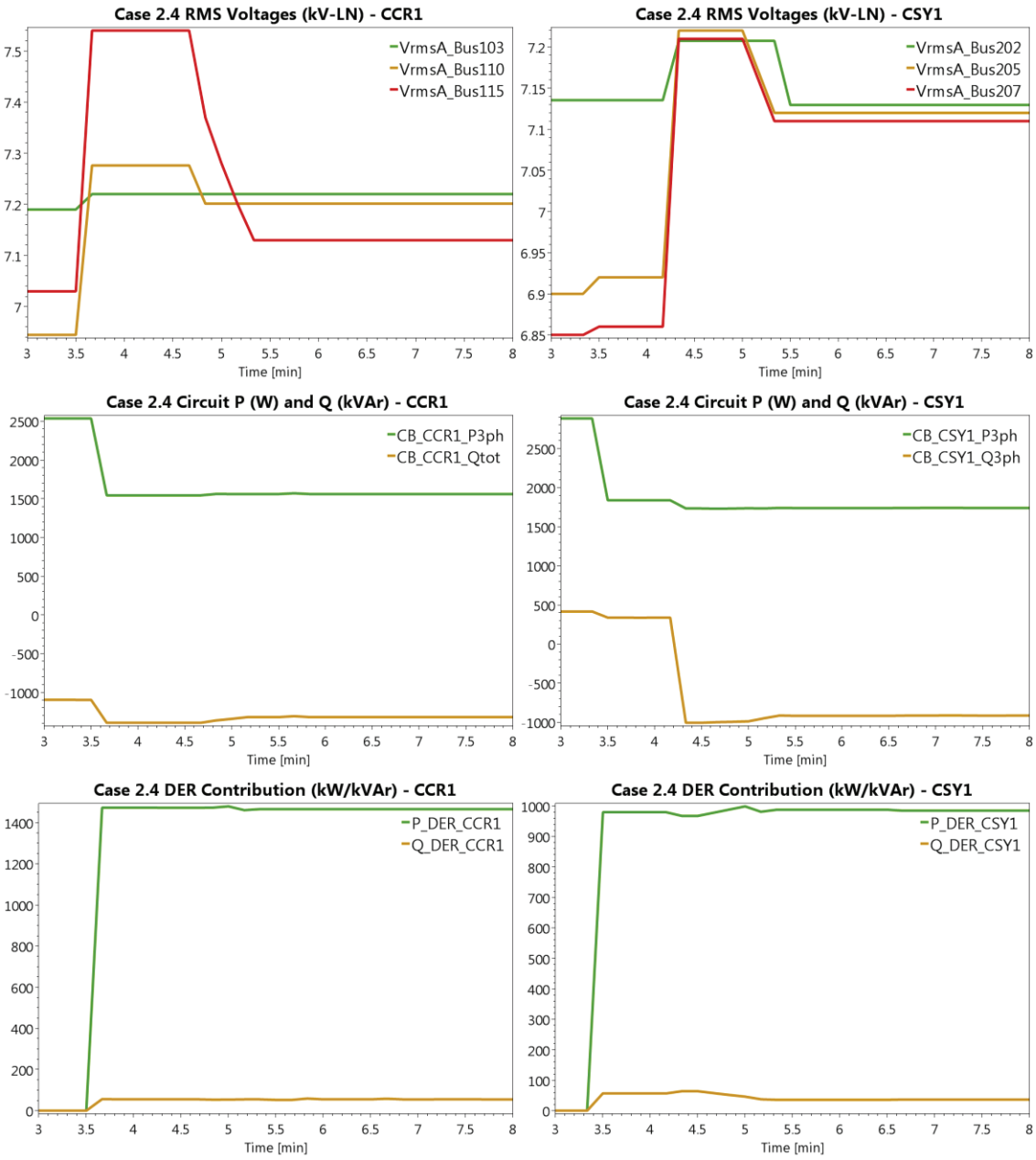


Figure 8-26. Voltage profiles, circuit powers, and DER contributions for Case 2.4

In this case, while there is no reverse real power flowing through feeder breakers, it has taken a relatively long time for local controllers to adjust the bus voltages after the PV profile change.

8.2.2 Test Case 2.5

Table 8.23. Test condition for Case 2.5

Case#	Test Condition	Remark
2.5	Low load (fix), High PV (fix) Initial Conditions: Steady state of case 1.3	Master controller was responsible to take actions through SLT/IVVC algorithm.

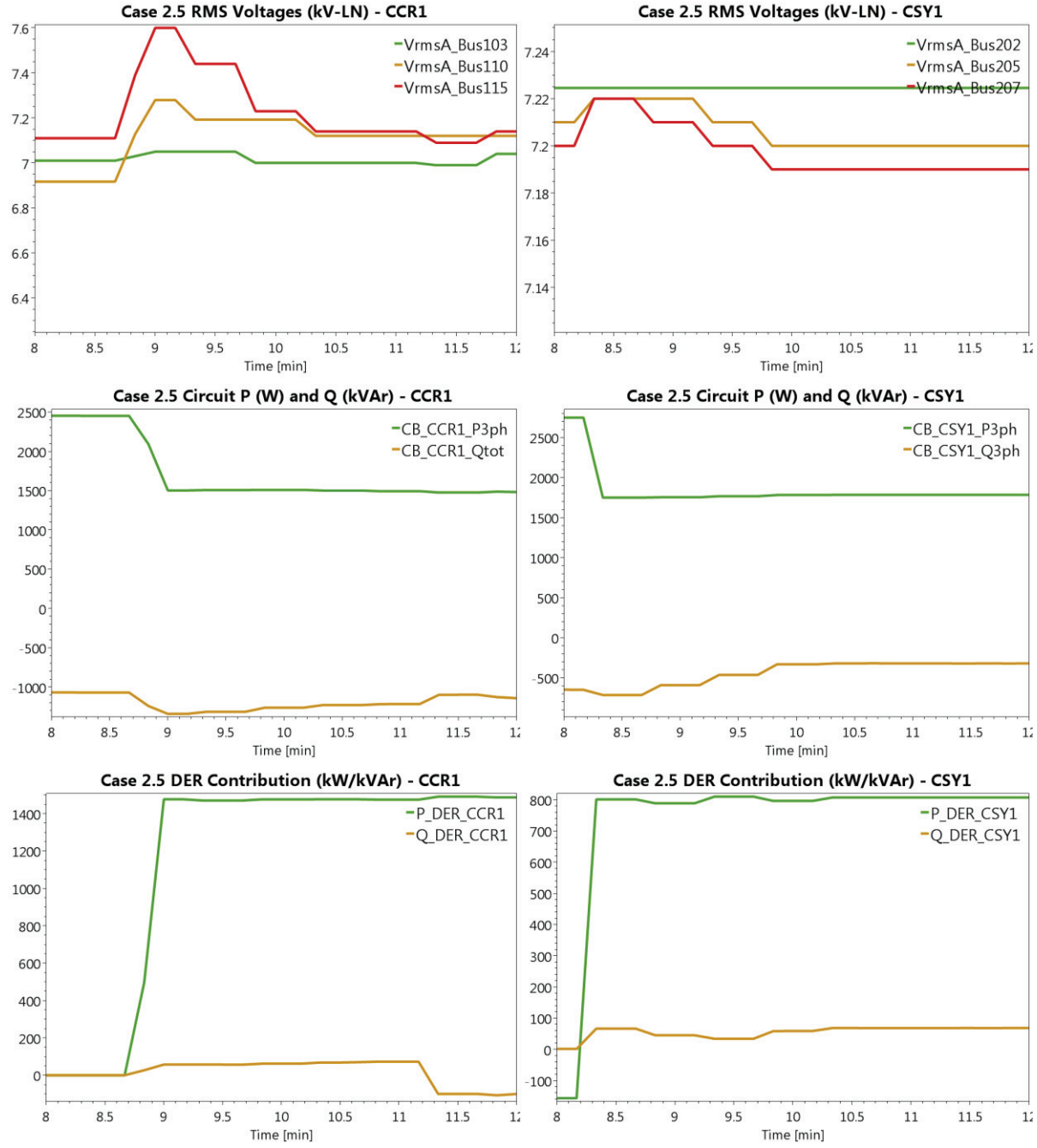


Figure 8-27. Voltage profiles, circuit powers, and DER contributions for Case 2.5

Similar to Case 2.4, no reverse power flow was detected by the SLT engine and, thus, no load transfer was initiated. However, the response times for voltage regulation are faster in this case.

8.2.3 Test Case 2.6

Table 8.24. Test condition for Case 2.6

Case#	Test Condition	Remark
2.6	Low load (fix), High PV (fix) Initial Conditions: Steady state of case 1.3	Sub controller was responsible to take actions through permission of communication loss (prior to event)

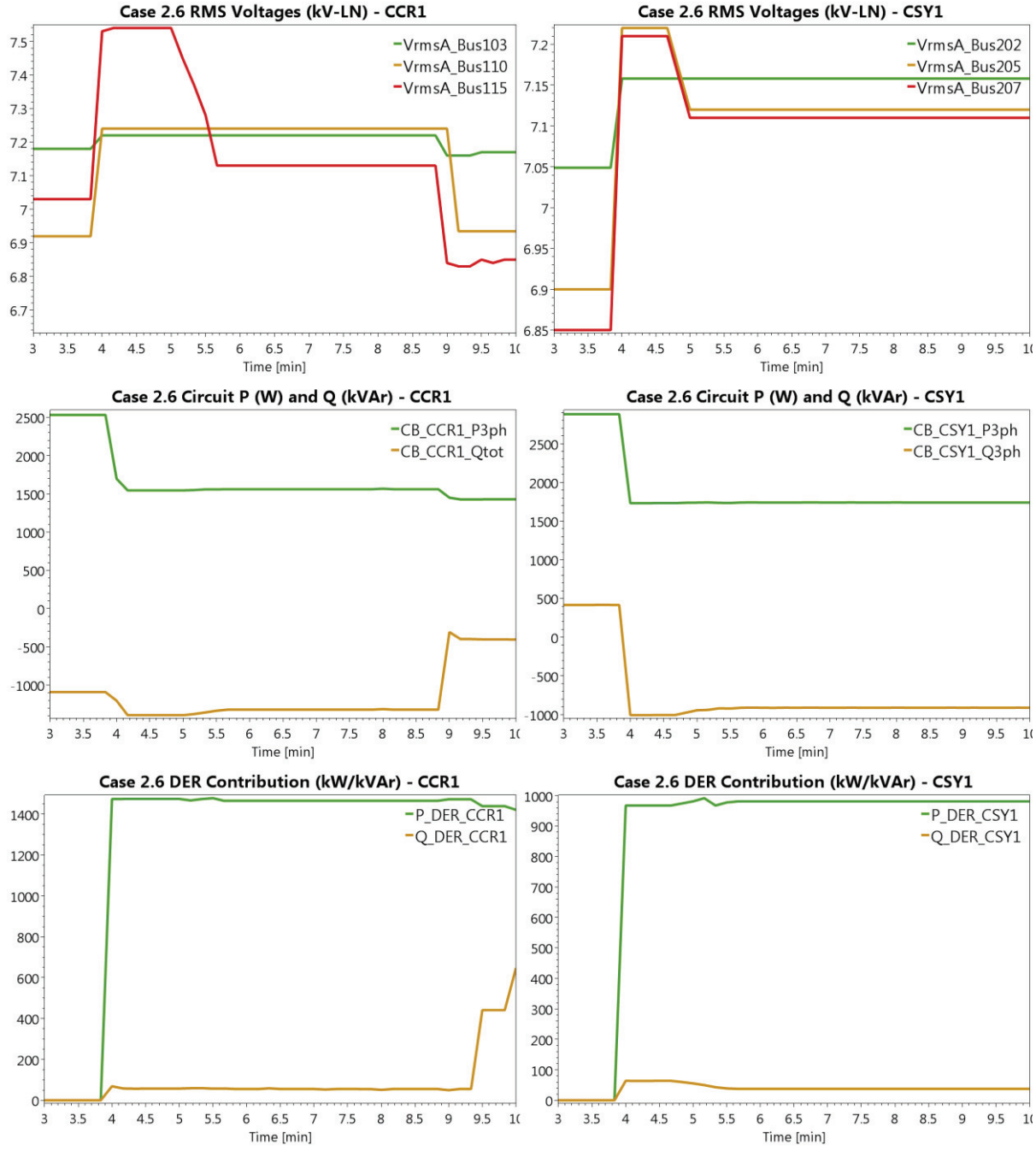


Figure 8-28. Voltage profiles, circuit powers, and DER contributions for Case 2.6

In this case (CS3), the response times are not as good as Case 2.5, but are better than Case 2.4. Additionally, the substation controller uses the substation BESS to improve circuit power factor.

8.2.4 Test Case 2.7

Table 8.25. Test condition for Case 2.7

Case#	Test Condition	Remark
2.7	Low load (fix), High PV (fix) Initial Conditions: Steady state of case 1.3	Baseline System 2 (all controllable devices were in Local/Auto mode)

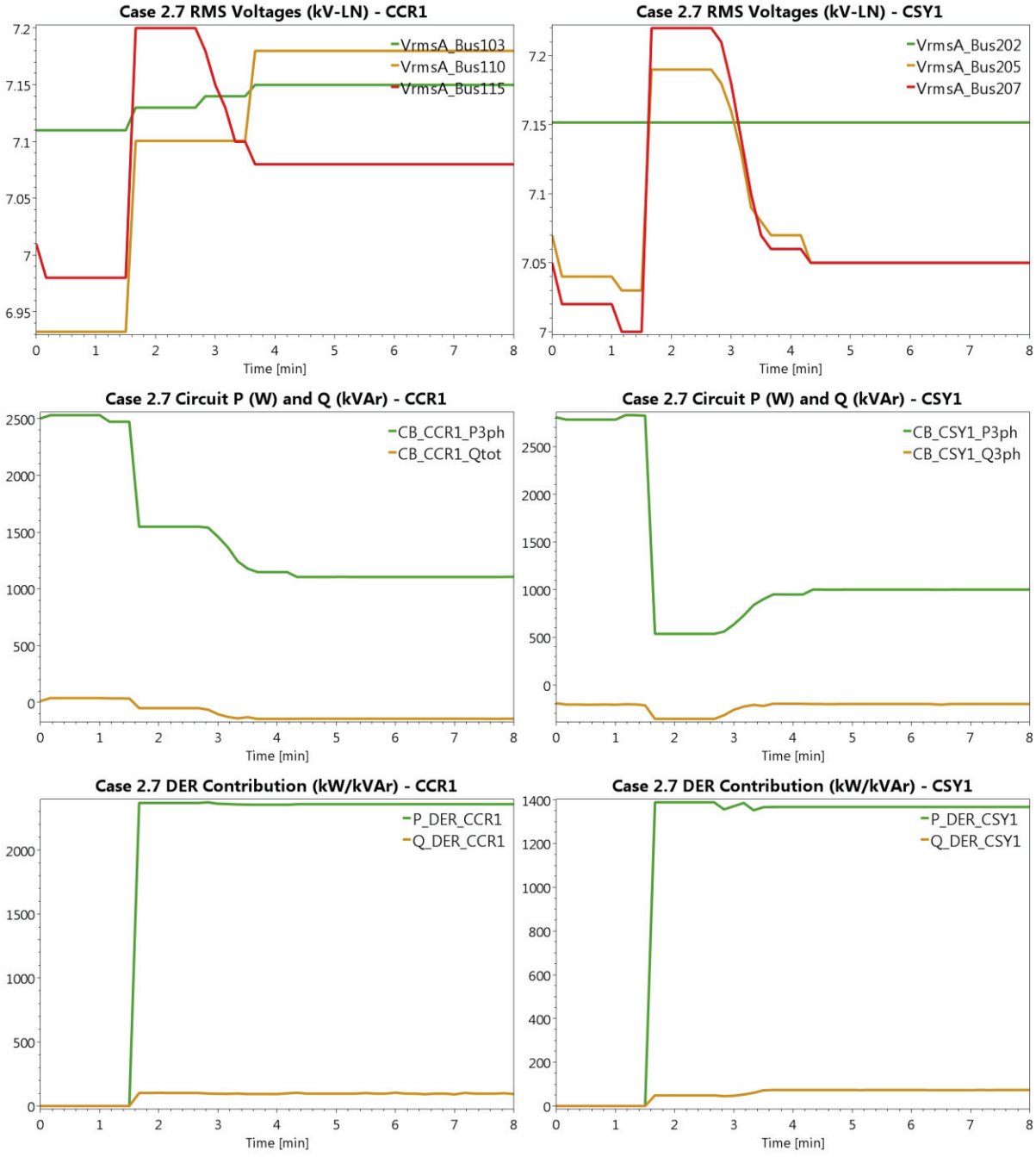


Figure 8-29. Voltage profiles, circuit powers, and DER contributions for Case 2.7

In this case, there is no reverse power issue that requires load transfer. The voltage profiles are also acceptable, but are not optimized (compare with next case, Case 2.8).

8.2.5 Test Case 2.8

Table 8.26. Test condition for Case 2.8

Case#	Test Condition	Remark
2.8	Low load (fix), High PV (fix) Initial Conditions: Steady state of case 1.3	Master controller was responsible to take actions through SLT/IVVC algorithm.

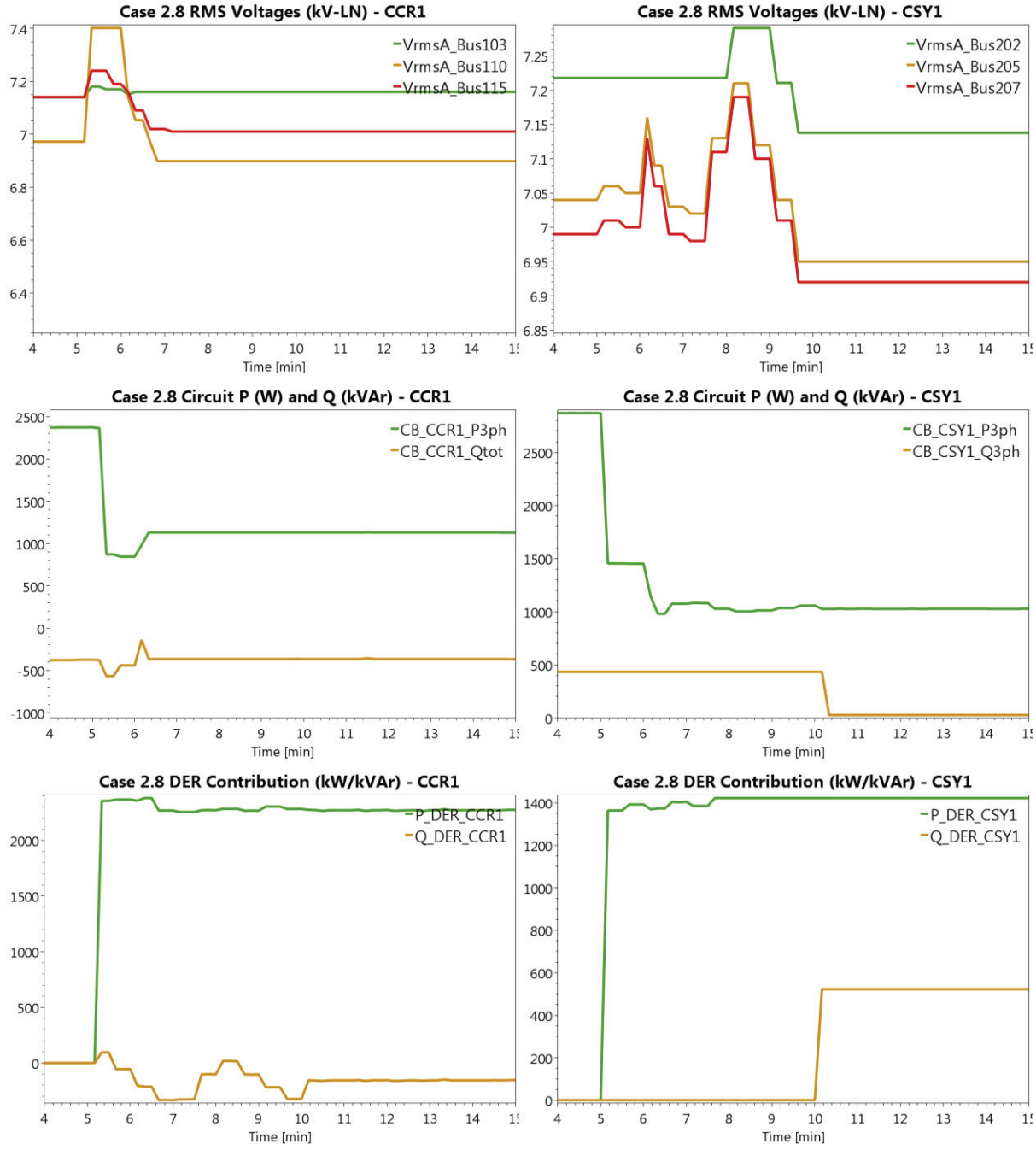


Figure 8-30. Voltage profiles, circuit powers, and DER contributions for Case 2.8

The SLT engine did not detect reverse power flow to initiate a transfer. However, the master controller optimized the voltage profiles as compared to previous case (Compare Figure 8-29 with Figure 8-30)

8.2.6 Test Case 2.9

Table 8.27. Test condition for Case 2.9

Case#	Test Condition	Remark
2.9	Low load (fix), High PV (fix) Initial Conditions: Steady state of case 1.3	Sub controller was responsible to take actions through permission of communication loss (prior to event)

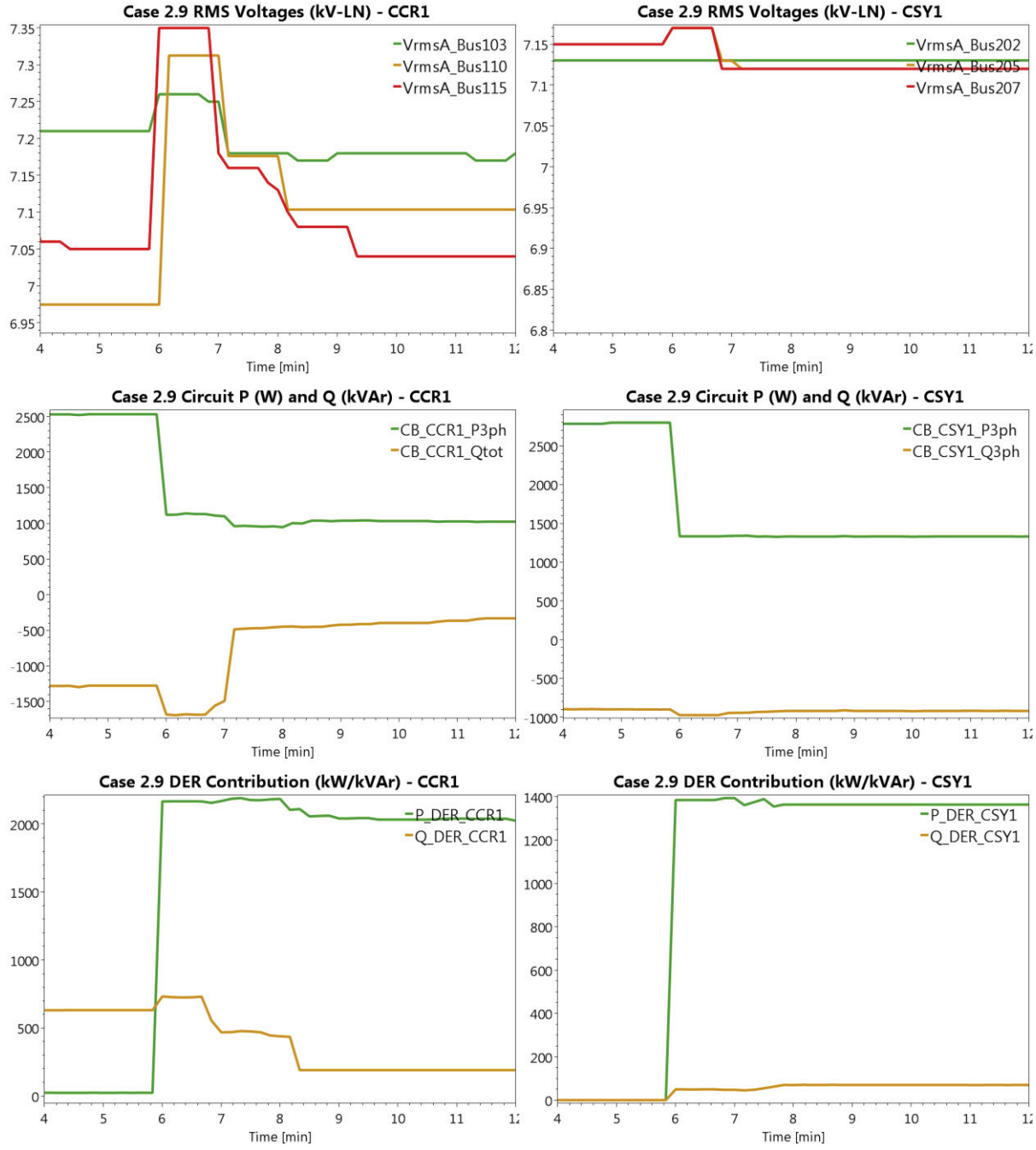


Figure 8-31. Voltage profiles, circuit powers, and DER contributions for Case 2.9

The substation controller cannot regulate the bus voltages as effective as the master controller (Case 2.8), but has the capability to perform the SLT if such a need arises (as opposed to CS1).

Appendix 4

EPIC-1, Project 4, Module 1: Demonstration of Grid Support Functions of Distributed Energy Resources – Pre-Commercial Demonstration and Value Assessment



EPIC Final Report

Program	**Electric Program Investment Charge (EPIC)**
Administrator	**San Diego Gas & Electric Company**
Project Number	**EPIC-1, Project 4**
Project Name	**Demonstration of Grid Support Functions of Distributed Energy Resources (DER)**
Project Focus	**Module 1, Pre-Commercial Demonstration and Value Assessment**
Date	**December 31, 2017**

Attribution

This comprehensive final report documents the work done in this EPIC project.

The project team for this work included the following individuals.

Internal SDG&E Staff

Kahveh Atef

Frank Goodman

Molham Kayali

Zoltan Kertay

Prajwal Raval

Amin Salmani

Aung Thant

Schweitzer Engineering Laboratories, Inc

Kamal Garg

Milind Malichkar

Jenny Hitch

Cassie Reimer

Kim Sarff

EXECUTIVE SUMMARY

The objective of EPIC-1, Project 4, Demonstration of Grid Support Functions of Distributed Energy Resources (DER) was to demonstrate grid support functions of DER, which can improve distribution system operations. The chosen sub-projects and modules quantified the value of specific grid support functions in specific application situations and provided a basis for San Diego Gas & Electric Company (SDG&E) to determine which functions it wants to pursue commercially in the development of its smart grid. This project consists of three modules: value assessment of grid support functions of DER, communication standards for grid support functions of DER, and demonstration and comparison of the Electric Power Research Institute (EPRI) and SDG&E DER hosting capacity analysis tools. This executive summary addresses the module on value assessment of grid support functions of DER, especially to demonstrate and determine the viability of specific DER functions and to identify that, if any, grid support functions of DER and application situations (use cases) should be pursued in advance distribution system automation.

A distribution circuit that includes renewable energy sources such as photovoltaic (PV) and the energy storage system (ESS) was selected as a demonstration circuit to conduct this assessment. A test device (a bi-directional ESS inverter) was interfaced with the Real Time Digital Simulator (RTDS®) in the control and power hardware-in-the-loop (PHIL) experiments. The rating of the test device was 50 KVA, which was scaled up in the RTDS to 1 MW in the distribution circuit. This additional DER was interfaced in the circuit in such a way that it could be moved and connected at different locations. A grid simulator and a battery/load emulator was used to supply AC and DC power to the inverter. The test circuit and device were tested in a variety of scenarios, based on the location of the DER in the system with different operating modes on the inverter under different system conditions. This report presents the recommendations on operating the DER systems in different functional modes under different conditions and discusses their benefits and success in meeting the grid support objectives and challenges.

The DER grid support functions are summarized as follows:

1. The volt-VAR control provides seamless voltage regulation in the event of an under-voltage and overvoltage in the system. This function effectively provided the grid support during disturbances by injecting more reactive power into the system. With proper coordination among capacitor banks and voltage regulators, the ESS can provide fast, seamless voltage regulation.
2. The frequency-watt control provides seamless frequency regulation in the event of an under and over-frequency in the system created by events such as load switching. The frequency droop and the dead-band settings should be coordinated if multiple DER are operating in parallel to control the contribution from each DER. The hysteresis characteristics of the function provides stability and prevents oscillations or hunting.
3. The advanced, multifunction inverters could be implemented with a function to black start an island or a microgrid, providing voltage and frequency support in addition to feeding the load. Black start functionality enables the formation of an island (microgrid) in the event of distribution system loss, once the island is sustained, additional generation and/or storage resources can be brought online.
4. The load leveling function provides the ESS the ability to follow the load and the generation on the feeder and to maintain the active power import at the point of common coupling (PCC) within a specified range. The peak shaving function supplies the additional load if it goes beyond the peak shaving limit and the base loading function consumes active power during the low loading condition.
5. The volt-watt mode provides the ESS with the ability to curtail the active power output so that it can mitigate the overvoltage condition on the feeder when multiple DER are online. Because of the high penetration of the DER, the overall voltage on the feeder tends to rise beyond a value

that would prevent other DER to come online until the local voltage is within the safe operation limits.

6. The ESS may function in some situations as an efficient and economical alternative to spinning reserve for limited time durations. The ESS can operate in the idle mode for a long time without significant loss of charge. The ESS can supply the peak demand until the generation plant can be brought online, thereby reducing the idle time of the conventional generators.

The increasing penetration of DER in utility power systems has increased the complexity of the design and operation of the power systems. These generation sources are considered mostly as negative loads that are expected to disconnect from the rest of the system, which further aggravates the disturbance. With the implementation of the advanced, multifunction inverter functions, DER can play an active role in supporting the distribution systems operations.

Recommendations

The following recommendations for utilization of different DER functions are made based on the results of pre-commercial demonstrations in the lab.

- Volt-VAR function: In the demonstrations, DER performed voltage regulation successfully in different test scenarios to maintain the system voltage. The DER was a faster device in terms of response time during the disturbance compared to voltage regulating devices such as capacitor banks. This function contributed to the system stability autonomously and helped the grid sustain the disturbance. It prevents frequent operation of the capacitor banks and the voltage regulators by providing the dynamic voltage regulation. In a distribution system, which has multiple DER, this function can efficiently provide voltage stability to the grid. It is recommended to pursue this function commercially in the DER inverters.

- Frequency-Watt function: The frequency-watt function of the DER provided smooth active power regulation for the frequency disturbances during the demonstrations. The DER provided the active power to the system to maintain the frequency. This function is recommended to use in the distribution circuit that has a large amount of intermittent generation. The frequency-watt function mitigates the frequency fluctuations caused by these sources. The location of the DER does not impact the operation of the frequency-watt function. This function complements the volt-VAR function, in that both functions can operate independently at the same time and provide voltage and frequency regulation. It is highly recommended to pursue these grid support functions in the commercial DER inverter.

- Load leveling function: The load leveling function maintained the power import from the PCC within the specified dead band during the demonstrations. During heavy and light loading periods, the DER supplied and absorbed the deficit and surplus power. The DER supported the load fluctuation by keeping the power import at the PCC constant under different scenarios. This function smooths out the load fluctuations on the feeder and makes the load forecasting simpler for distribution system operators. When used with an ESS, this function provides both peak shaving and base loading because the ESS can supply, as well as absorb, active power. It will be beneficial to implement this function in the commercial DER inverter.

- Black start function: The results of this demonstration show the effectiveness of using the ESS to black start the system, just like the conventional generation source, to bring the system online in the increment of loads and generations. Once the grid breaker opens, causing the system to enter a blackout, the ESS enters VSI mode creating reference for voltage and frequency. With the ESS in VSI mode, additional load and generation sources can be connected in the system in the subsequent steps. The DER, like the PV system, needs a voltage reference from the ESS to

initiate the startup process to feed the load. It is highly recommended to pursue black start functionality commercially to be used in the distribution system microgrids.

- Spinning reserve function: The results of this demonstrations proved that the ESS is quite effective in sustaining loads during periods of under-frequency, providing voltage and frequency support within a short period. In addition to being a fast spinning resource, the ESS also proves to be more effective in terms of cost and efficiency and better in terms of environmental factors and ease of operation and maintenance. The ESS reacted to the undervoltage and underfrequency in the system during a generation outage by acting as a source of spinning reserve providing voltage and frequency support to feed the local loads in the affected region. It is recommended to implement this function in the commercial ESS inverter. The ESS can run in the idle mode with minimal loss of charge to provide spinning reserve.

- DER monitoring and control function: DER monitoring allows system operators visibility into DER operation, which enables efficient use of the DER. All the important status points should be relayed to the remote management system. For the ESS, information such as state of charge, online/offline status, power output, and so on, is necessary to make control decisions. The availability of this information aids the control actions such as connecting and disconnecting the DER, updating voltage and frequency ride-though settings. The ability of DER to communicate with the remote management system to allow monitoring and control is highly desirable to make informed decisions about system operation. It is recommended that this function be implemented in the DER.

- Volt-Watt function: The volt-watt function curtails the active power output of the DER during the overvoltage in the system. This function has a very narrow applicability in terms of grid support. The voltage regulation is best carried out by the volt-VAR function which provides reactive power support instead of active power. Because of the high penetration of the DER, the overall voltage on the feeder tends to rise beyond a value that would prevent other DER to turn online until the local voltage is within safe operation limits. The volt-watt function curtails the active power output of the online DER so that other DER can be turned on. This function is not recommended to use in the steady state where, to correct the low voltage, the feeder needs the reactive power to be fed into the circuit instead of the active power. This is more useful in the overvoltage scenario that prevents energization of the DER.

Table of Contents

Executive Summary ..... **iii**

Acronyms and Abbreviations ..... **xvi**

Section 1 Introduction **1**

Project Objective 1

Project Approach 1

Major Tasks 2

Report Outline 2

Section 2 Demonstration System Development **3**

Data Extraction and RTDS Model Developed From Synergi 3

Equivalent Source 3

Feeder Transformer 4

Distribution Line Model 5

Feeder Loads 6

Capacitor Banks 7

Distributed Energy Resources 7

PV System Model 7

Distributed Energy Storage System Model 8

Wind Energy System Model 8

Validation Using Synergi Model 9

Section 3 Pre-commercial Demonstration of Grid Support Functions of DER **11**

Introduction to Distributed Energy Resource Grid Support Functions 11

Active Power DER Functions 11

Reactive Power DER Functions 12

Frequency Support DER Functions 13

Power-Hardware-in-the-Loop (PHIL) Test Setup 14

Hardware Setup Description 14

RTDS Setup 16

Test Scenarios 20

Scenario 1: DER Close to a Substation 20

Scenario 2: DER on a Complex Circuit with a Multitude of Controllable Devices 21

Scenario 3: DER at the End of a Long Feeder 21

Scenario 4: Multiple Diverse Types of DER on the Same Circuit 22

Table of Tests 23
Test Results 24
Test 1 – Limit Maximum Active Power Output 24
Test 2 – Schedule Active Power Output 27
Test 3 – Volt-Watt 34
Test 4 – Volt-VAR 42
Test 5 – Frequency-Watt 57
Test 6 – DER Response to Emergencies 72
Test 7 – Spinning Reserve 74
Test 8 – Black Start 79
Test 9 – Load Leveling 87
Section 4 Project Results and Findings 92
Detailed Technical Results and Findings 92
Limiting Maximum Active Power Output 92
Schedule Active Power Output 93
Volt-Watt 94
Volt-VAR 95
Frequency-Watt 96
DER Response to Emergencies 97
Spinning Reserve 98
Black Start 98
Load Leveling 99
Recommendations 100
Volt-VAR Function 100
Frequency-Watt Function 100
Load Leveling Function 100
Black Start 100
Spinning Reserve 101
DER Monitoring and Control 101
Volt-Watt Function 101
Technology Transfer Plan 101
Section 5 Metrics and Value Proposition 102
Metrics 102
Value Proposition 103

Limit Maximum Active Power Output 103
Schedule Active Power Output 103
Volt-Watt Function 103
Volt-VAR Function 104
Frequency-Watt Function 104
DER Response to Emergencies 105
Spinning Reserve 105
Black Start 105
Load Leveling 106
Section 6 References 107
Appendix A Software Simulation Testing 109
Device Under Test 109
Test 3 – Volt-Watt 110
Scenario 1: DER Close to a Substation 111
Scenario 3: DER at the End of a Long Feeder 118
Scenario 4: Multiple Diverse Types of DER on the Same Circuit 125
Test 4 – Volt-VAR 132
Scenario 1: DER Close to a Substation 133
Scenario 2: DER on a Complex Circuit with a Multitude of Controllable Devices 142
Scenario 3: DER at the End of a Long Feeder 150
Test 5 – Frequency-Watt 158
Scenario 2: DER on a Complex Circuit with a Multitude of Controllable Devices 159
Scenario 3: DER at the End of a Long Feeder 170
Scenario 4: Multiple Diverse Types of DER on the Same Circuit 180
Test 7 – Spinning Reserve 190
Test Procedure 190
Conclusion 192
Test 8 – Black Start 195
Test Procedure and Results 195
Conclusion 200
Appendix B Dynamic Reduced Model Analysis 202
Building the Model 202
Test Results 202
Test 2 – Schedule Active Power Output 203

Test 4 – Volt-VAR 208
Test 5 – Frequency-Watt 212
Test 7 – Spinning Reserve 216

List of Figures

Figure 2.1: Simplified Single-Line Diagram of the Distribution Circuit 3
Figure 2.2: Feeder Transformer Information 4
Figure 2.3: Feeder Transformer Information from ASPEN OneLiner 4
Figure 2.4: Conversion of Synergi Section Data into the RTDS PI Model 5
Figure 2.5: Conversion of Synergi Load Data into the RTDS Dynamic Load Model 6
Figure 2.6: PV Inverter Model in the RTDS 7
Figure 2.7: ESS Model in the RTDS 8
Figure 2.8: DFIG Model on the RTDS 9
Figure 2.9: Synergi Software Power Flow Results 10
Figure 2.10: RTDS Model Power Flow Results 10
Figure 3.1 Limit Maximum Active Power Output Function 11
Figure 3.2: Volt-Watt Function 12
Figure 3.3: Volt-VAR Function 12
Figure 3.4: Frequency-Watt Function 13
Figure 3.5: Load-Leveling Function 14
Figure 3.6: Test Circuit Schematic with Inverter at the DER Lab 15
Figure 3.7: PHIL Test Setup Showing Hardware Interface in RSCAD® 15
Figure 3.8: ESS RTDS Analog Output 17
Figure 3.9: ESS RTDS Analog Input 19
Figure 3.10: DER Close to Substation (Typical) 20
Figure 3.11: DER on a Complex Circuit with a Multitude of Controllable Devices (Typical) 21
Figure 3.12: DER at the End of a Long Feeder (Typical) 22
Figure 3.13: Multiple Diverse Types of DER on the Same Circuit (Typical) 22
Figure 3.14: System Response for Test 1.1 25
Figure 3.15: System Response for Test 1.2 26
Figure 3.16: System Response for Test 2.1.1 28
Figure 3.17: System Response for Test 2.1.2 29
Figure 3.18: System Response for Test 2.1.3 30

Figure 3.19: System Response for Test 2.1.4 31
Figure 3.20: System Response for Test 2.1.5 32
Figure 3.21: System Response for Test 2.1.6 33
Figure 3.22: System Response for Test 3.1.1 35
Figure 3.23: System Response for Test 3.1.4 37
Figure 3.24: System Response for Test 3.3.4 39
Figure 3.25: System Response for Test 3.4.4 41
Figure 3.26: System Response for Test 4.1.1 43
Figure 3.27: System Response for Test 4.1.2 44
Figure 3.28: System Voltage Profile for Test 4.1.3 45
Figure 3.29: System Response for Test 4.1.3 46
Figure 3.30: System Response for Test 4.1.4 47
Figure 3.31: System Response for Test 4.1.5 48
Figure 3.32: System Response for Test 4.2.1 49
Figure 3.33: System Response for Test 4.2.2 50
Figure 3.34: System Response for Test 4.2.3 51
Figure 3.35: System Response for Test 4.2.4 52
Figure 3.36: System Response for Test 4.3.1 53
Figure 3.37: System Response for Test 4.3.2 54
Figure 3.38: System Response for Test 4.3.3 55
Figure 3.39: System Response for Test 4.3.4 56
Figure 3.40: System Response for Test 5.2.1 58
Figure 3.41: System Response for Test 5.2.2 59
Figure 3.42: System Frequency Profile for Test 5.1.8 60
Figure 3.43: System Response for Test 5.2.3 61
Figure 3.44: System Response for Test 5.2.4 62
Figure 3.45: System Response for Test 5.2.5 63
Figure 3.46: System Response for Test 5.3.1 64
Figure 3.47: System Response for Test 5.3.2 65
Figure 3.48: System Response for Test 5.3.3 66
Figure 3.49: System Response for Test 5.3.4 67
Figure 3.50: System Response for Test 5.3.5 68
Figure 3.51: System Response for Test 5.4.1 69
Figure 3.52: System Response for Test 5.4.2 70
Figure 3.53: System Response for Test 5.4.3 71

Figure 3.54: Inverter Startup Transients 73
Figure 3.55: System Response for Test 7.1 75
Figure 3.56: System Response for Test 7.2 76
Figure 3.57: System Response for Test 7.3 77
Figure 3.58: System Response for Test 7.4 78
Figure 3.59: Starting the DER in VSI ISO Mode to support a local load 80
Figure 3.60:Adding a Ramp Load to the Inverter in VSI ISO Mode 81
Figure 3.61:Black Start Application of the DER – Island Load Step 82
Figure 3.62: Starting the DER in VSI VF Mode to support a local load 83
Figure 3.63:Adding a Ramp Load to the Inverter in VSI VF Mode 84
Figure 3.64:Adding a Ramp Load to the Inverter in VSI VF Mode 85
Figure 3.65:Unintentional Tripping of the Inverter 86
Figure 3.66: Load and DER Output Profile for Test #9 87
Figure 3.67: System Response for Test 9.1.1 88
Figure 3.68: System Response for Test 9.1.2 89
Figure 3.69: System Response for Test 9.3.1 90
Figure 3.70: System Response for Test 9.3.2 91
Figure 4.1: Limit Maximum Active Power Function 92
Figure 4.2: Schedule Active Power Output Function 93
Figure 4.3: Volt-Watt Function 94
Figure 4.4: Volt-VAR Function 95
Figure 4.5: Frequency-Watt Function 97
Figure 4.6: Inverter Startup Transients 97
Figure 4.7: Load Leveling Function 99
Figure A.1: DER Test Inverter Model 108
Figure A.2: System Response for Test 3.1.1 110
Figure A.3: System Response for Test 3.1.2 111
Figure A.4: System Response for Test 3.1.3 112
Figure A.5: System Response for Test 3.1.4 113
Figure A.6: System Response for Test 3.1.5 114
Figure A.7: System Response for Test 3.1.6 115
Figure A.8: System Response for Test 3.1.7 116
Figure A.9: System Response for Test 3.3.1 117
Figure A.10: System Response for Test 3.3.2 118
Figure A.11: System Response for Test 3.3.3 119

Figure A.12: System Response for Test 3.3.4 120
Figure A.13: System Response for Test 3.3.5 121
Figure A.14: System Response for Test 3.3.6 122
Figure A.15: System Response for test 3.3.7 123
Figure A.16: System Response for Test 3.4.1 124
Figure A.17: System Response for Test 3.4.2 125
Figure A.18: System Response for Test 3.4.3 126
Figure A.19: System Response for Test 3.4.4 127
Figure A.20: System Response for Test 3.4.5 128
Figure A.21: System Response for Test 3.4.6 129
Figure A.22: System Response for Test 3.4.7 130
Figure A.23: System Response for Test 4.1.1 132
Figure A.24: System Response for Test 4.1.2 133
Figure A.25: System Response for Test 4.1.3 134
Figure A.26: System Response for Test 4.1.4 135
Figure A.27: System Response for Test 4.1.5 136
Figure A.28: System Voltage Profile for Test 4.1.6 137
Figure A.29: System Response for Test 4.1.6 138
Figure A.30: System Response for Test 4.1.7 139
Figure A.31: System Response for Test 4.1.8 140
Figure A.32: System Response for Test 4.2.1 141
Figure A.33: System Response for Test 4.2.2 142
Figure A.34: System Response for Test 4.2.3 143
Figure A.35: System Response for Test 4.2.4 144
Figure A.36: System Response for Test 4.2.5 145
Figure A.37: System Response for Test 4.2.6 146
Figure A.38: System Response for Test 4.2.7 147
Figure A.39: System Response for Test 4.2.8 148
Figure A.40: System Response for Test 4.3.1 149
Figure A.41: System Response for Test 4.3.2 150
Figure A.42: System Response for Test 4.3.3 151
Figure A.43: System Response for Test 4.3.4 152
Figure A.44: System Response for Test 4.3.5 153
Figure A.45: System Response for Test 4.3.6 154
Figure A.46: System Response for Test 4.3.7 155

Figure A.47: System Response for Test 4.3.8 156
Figure A.48: System Response for Test 5.2.1 158
Figure A.49: System Response for Test 5.2.2 159
Figure A.50: System Response for Test 5.2.3 160
Figure A.51: System Response for Test 5.2.4 161
Figure A.52: System Response for Test 5.2.5 162
Figure A.53: System Response for Test 5.2.6 163
Figure A.54: System Response for Test 5.2.7 164
Figure A.55: System Response for Test 5.2.8 166
Figure A.56: System Response for Test 5.2.9 167
Figure A.57: System Response for Test 5.2.10 168
Figure A.58: System Response for Test 5.3.1 169
Figure A.59: System Response for Test 5.3.2 170
Figure A.60: System Response for Test 5.3.3 171
Figure A.61: System Response for Test 5.3.4 172
Figure A.62: System Response for Test 5.3.5 173
Figure A.63: System Response for Test 5.3.6 174
Figure A.64: System Response for Test 5.3.7 175
Figure A.65: System Response for Test 5.3.8 176
Figure A.66: System Response for Test 5.3.9 177
Figure A.67: System Response for Test 5.3.10 178
Figure A.68: System Response for Test 5.4.1 179
Figure A.69: System Response for Test 5.4.2 180
Figure A.70: System Response for Test 5.4.3 181
Figure A.71: System Response for Test 5.4.4 182
Figure A.72: System Response for Test 5.4.5 183
Figure A.73: System Response for Test 5.4.6 184
Figure A.74: System Response for Test 5.4.7 185
Figure A.75: System Response for Test 5.4.8 186
Figure A.76: System Response for Test 5.4.9 187
Figure A.77: System Response for Test 5.4.10 188
Figure A.78: Idle Grid Connected System With Frequency-Watt and Volt-VAR Modes 190
Figure A.79: System Response for DER Operating as Spinning Reserve Following Underfrequency Due to Islanding 191
Figure A.80: DER at the End of a Long Feeder (Typical) 194

Figure A.81: System Response for Step 1 195
Figure A.82: System Response for Step 2 196
Figure A.83: System Response for Step 3 197
Figure A.84: System Response for Step 4 198
Figure A.85: System Response for Step 5 199
Figure B.86: Simplified Dynamic Equivalent Model of the Carmel Valley Circuit 201
Figure B.87: System Response for Test 2.1 202
Figure B.88: System Response for Test 2.2 203
Figure B.89: System Response for Test 2.3 204
Figure B.90: System Response for Test 2.4 205
Figure B.91: System Response for Test 2.5 206
Figure B.92: System Response for Test 4.1a 207
Figure B.93: System Response for Test 4.1b 208
Figure B.94: System Response for Test 4.2a 209
Figure B.95: System Response for Test 4.2b 210
Figure B.96: System Response for Test 5.1a 211
Figure B.97: System Response for Test 5.1b 212
Figure B.98: System Response for Test 5.2a 213
Figure B.99: System Response for Test 5.2b 214
Figure B.100: System Response for Test 7.1a 215
Figure B.101: System Response for Test 7.1b 216
Figure B.102: System Response for Test 7.2a 217
Figure B.103: System Response for Test 7.2b 218

List of Tables

Table 3.1: DER Modes for Demonstrations 23
Table 3.2: DER Maximum Active Power Output Limiting Test Cases 24
Table 3.3: DER Active Power Output Scheduling Test Cases 27
Table 3.4: DER Volt-Watt Test Cases 34
Table 3.5: DER Volt-VAR Test Cases 42
Table 3.6: DER Frequency-Watt Test Cases 57
Table 3.7: DER Emergency Response Test Cases 72
Table 8. EPIC metrics for grid support functions of DER 102

Table A.1: DER Volt-Watt Test Cases 110
Table A.2: DER Volt-VAR Test Cases 132
Table A.3: DER Frequency-Watt Test Cases 158

ACRONYMS AND ABBREVIATIONS

AC	Alternating current
DC	Direct current
DER	Distributed energy resource(s)
DFIG	Doubly fed induction generator
DQ	Direct quadrature
EPIC	Electric Program Investment Charge
ESS	Energy storage system(s)
GSC	Grid side control
HMI	Human-machine interface
LHFRT	Low-/high-frequency ride-through
LHVRT	Low-/high-voltage ride-through
PCC	Point of common coupling
PHIL	Power hardware-in-the-loop
PLC	Programmable logic controller
PU	Per unit
PV	Photovoltaic
RSC	Rotor side control
RTDS®	Real-Time Digital Simulator
SDG&E	San Diego Gas & Electric Company
SIWG	Smart Inverter Working Group
SOC	State of charge
VSC	Voltage source converter
VSI	Voltage source inverter
ISO	Isochronous
KVAR	Kilovolt-ampere reactive
kW	Kilowatt

This page intentionally left blank

SECTION 1 INTRODUCTION

PROJECT OBJECTIVE

The objective of EPIC-1, Project 4, Demonstration of Grid Support Functions of Distributed Energy Resources (DER) was to demonstrate grid support functions of DER, which can improve distribution system operations. The chosen sub-projects and modules quantified the value of specific grid support functions in specific application situations and provided a basis for SDG&E to determine which functions it wants to pursue commercially in the development of its smart grid. This EPIC project consists of three modules: value assessment of grid support functions of DER, communication standards for grid support functions of DER, and demonstration and comparison of the EPRI and SDG&E DER hosting capacity analysis tools.

Focus of this report is on the first module where the objectives are to demonstrate and determine the viability of specific DER functions and to identify which grid support functions of DER and use cases should be pursued in advance distribution system automation. Furthermore, this module consisted of pre-commercial demonstration of grid support DER functions: to observe how well specific grid support functions work in specific locational and operational situations; to determine the requirements of the grid support functions for interconnection and interoperability; to identify any gaps in meeting those requirements; and to determine operational requirements for control and dispatch of specific grid support functions in viable application situations.

DER are being widely deployed in California and elsewhere. There is increasing interest in using DER for grid support functions to add value beyond their primary function of being local energy resources. The California Public Utilities Commission (CPUC) is preparing a set of guidelines for implementing the autonomous functions in the inverters for photovoltaic and energy storage systems (ESS), which may provide a regulatory basis to guide adoption of DER grid support functions. However, there remains a void in understanding in which situations these DER functions provide sufficient value to warrant adoption. This EPIC project addresses this knowledge gap. The autonomous functions include volt/VAR, frequency/watt and volt/watt support, among others, that improve the operability of the DER systems. This report presents the approach and results for pre-commercial demonstration of DER grid support functions to assess their value in specific applications situations. The report also presents the findings and recommendations based on the test results and observations.

PROJECT APPROACH

A distribution circuit that includes renewable energy sources such as photovoltaic (PV) and the ESS was selected as a demonstration circuit to conduct this assessment. A test device (a bi-directional ESS inverter) was interfaced with the Real Time Digital Simulator (RTDS®) in the control and power hardware-in-the-loop (PHIL) fashion. The rating of the test device was 50 KVA, which was scaled up in the RTDS to 1 MW in the distribution circuit. This additional DER was interfaced in the circuit in such a way that it could be moved and connected at different locations. A grid simulator and a battery/load emulator was used to supply AC and DC power to the inverter. The test circuit and device were tested in a variety of scenarios, based on the location of the DER in the system with different operating modes on the inverter under different system conditions. This report presents the recommendations on operating the DER systems in different functional modes under different conditions and discusses their benefits and the success in meeting the grid support objectives and challenges.

MAJOR TASKS

During this project, the following major tasks were performed for the pre-commercial demonstrations of grid support function of DER. An RTDS model was developed for a typical distribution circuit to connect the DER inverter for the PHIL demonstration. PHIL testing using a hardware inverter was conducted in the DER lab to demonstrate the response of an actual small-scale inverter in the lab. Different use cases were tested in the PHIL setup to conduct the overall assessment, and the test results, observations, and recommendations were recorded. A final report documenting all the findings, value propositions for each grid support function, and recommendations regarding commercial pursuit of DER grid support functions was submitted to SDG&E as a final deliverable.

REPORT OUTLINE

This report is divided into five sections:

- Section 1 presents the project summary, including the project scope.
- Section 2 describes the modeling of different circuit components of SDG&E's distribution circuit into the RTDS system. The calculations and the assumptions for each component are provided.
- Section 3 presents the results of the power hardware-in-the-loop (PHIL) testing conducted in the DER lab, including the descriptions of the various PHIL tests that were performed along with the scenarios under which they were developed.
- Section 4 contains the summary of results, observations, recommendations and value proposition of each functional test.
- Appendix A presents the test results and findings for the software testing conducted with software simulation of the inverter.
- Appendix B presents the tests results for the PHIL testing conducted on the reduced distribution circuit model with dynamics.

SECTION 2 DEMONSTRATION SYSTEM DEVELOPMENT

This section describes the test circuit modeling in the RTDS. The distribution circuit shown in Figure 2.1 was modeled in the RTDS software to obtain the equivalent model and was validated against the actual model for power flow analysis. The information contained in the following subsections for modeling of this circuit was provided in the form of a Synergi circuit model.

DATA EXTRACTION AND RTDS MODEL DEVELOPED FROM SYNERGI

Figure 2.1 shows a simplified single-line diagram of the distribution circuit. This circuit includes three-phase PV inverters and an energy storage system (ESS). The two single-phase PV inverters in the system are ignored for modeling purposes because of their small ratings. The circuit contains the load and line section information along with the various components, such as the source feeder, capacitor banks, distributed energy resources (DER), and ESS. The fuses in the circuit are ignored in the model, and the open points are modeled as the open circuit breaker points in the circuit. The switches are modeled as individual breakers for each line connected to the switch.

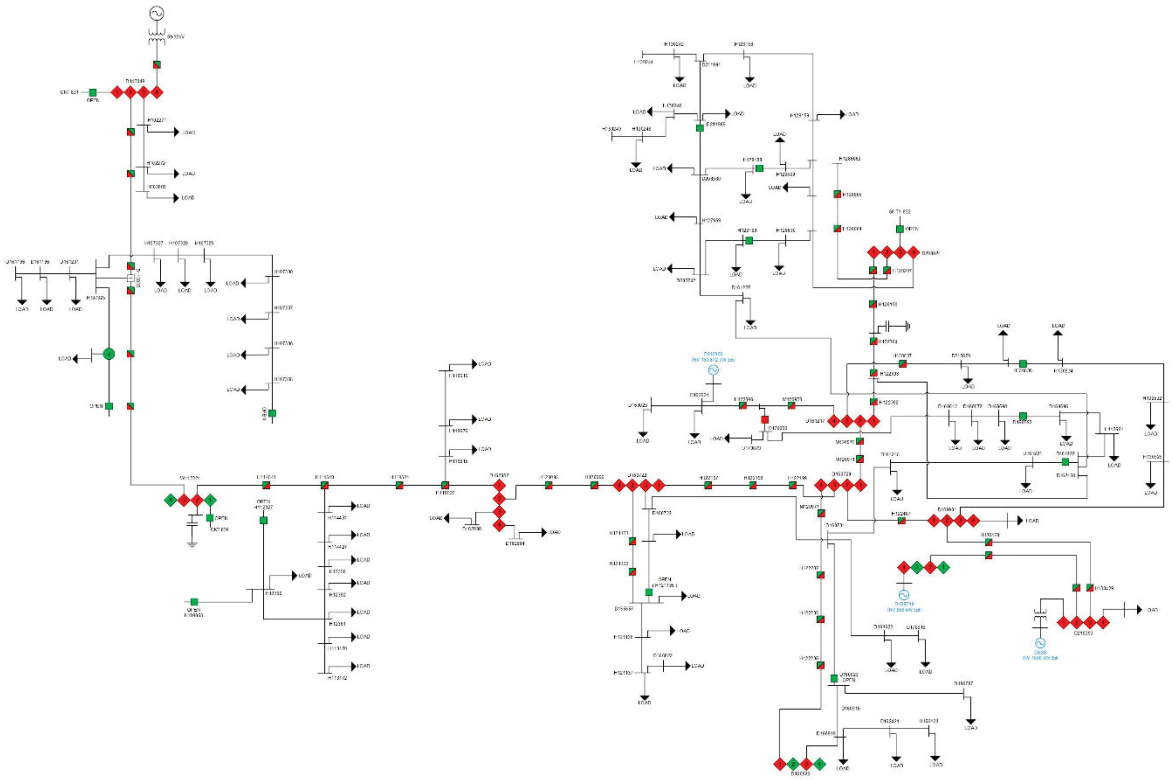


Figure 2.1: Simplified Single-Line Diagram of the Distribution Circuit

EQUIVALENT SOURCE

The source impedance is calculated from the ASPEN model of the reduced SDG&E system [1]. The Synergi model combines the source impedance and the transformer impedance to form a single-source model with equivalent impedance on a 12 kV base.

The per-unit zero- and positive-sequence impedance at 69 kV/100 MVA is calculated as follows:

$$Z_{Base} = \frac{(kV)^2}{MVA} = \frac{(69)^2}{100} = 47.62\,\Omega$$

$$Z_1 = (0.00593 + 0.04722j) \bullet Z_{Base} = 2.265\angle 82.84°\Omega$$

$$Z_0 = (0.01703 + 0.14254j) \bullet Z_{Base} = 6.834\angle 83.18°\Omega$$

FEEDER TRANSFORMER

The feeder transformer data obtained from the ASPEN model are shown in Figure 2.2 and Figure 2.3.

Bank:	30	31				Total:
Firm Capacity:	30	30				60
% Z Adj Rating:	30.0	30.0				60.0
Impedence:	7.40	7.40				Graph Peak
MVA Base:	15	15				
% Load Share:	50%	50%				Comments

Figure 2.2: Feeder Transformer Information

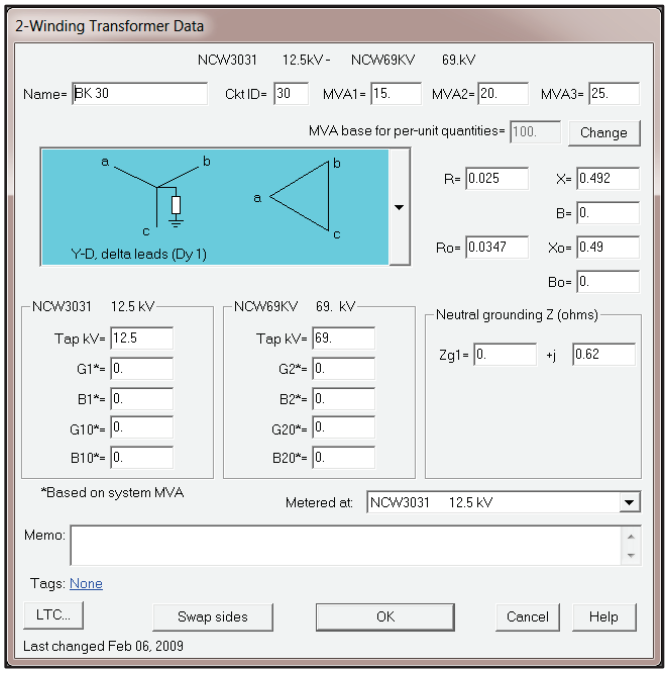


Figure 2.3: Feeder Transformer Information from ASPEN OneLiner

DISTRIBUTION LINE MODEL

The RTDS model information for the different line sections was obtained from Synergi by combining multiple small sections to one equivalent PI model to simplify and evaluate the circuit effectively. Single-phase lines leading to individual residences were ignored for modeling purposes, and the net losses from these lines were incorporated into the connected loads to account for them. The various steps taken to covert the Synergi line section data into a PI section model in the RTDS are shown in Figure 2.4.

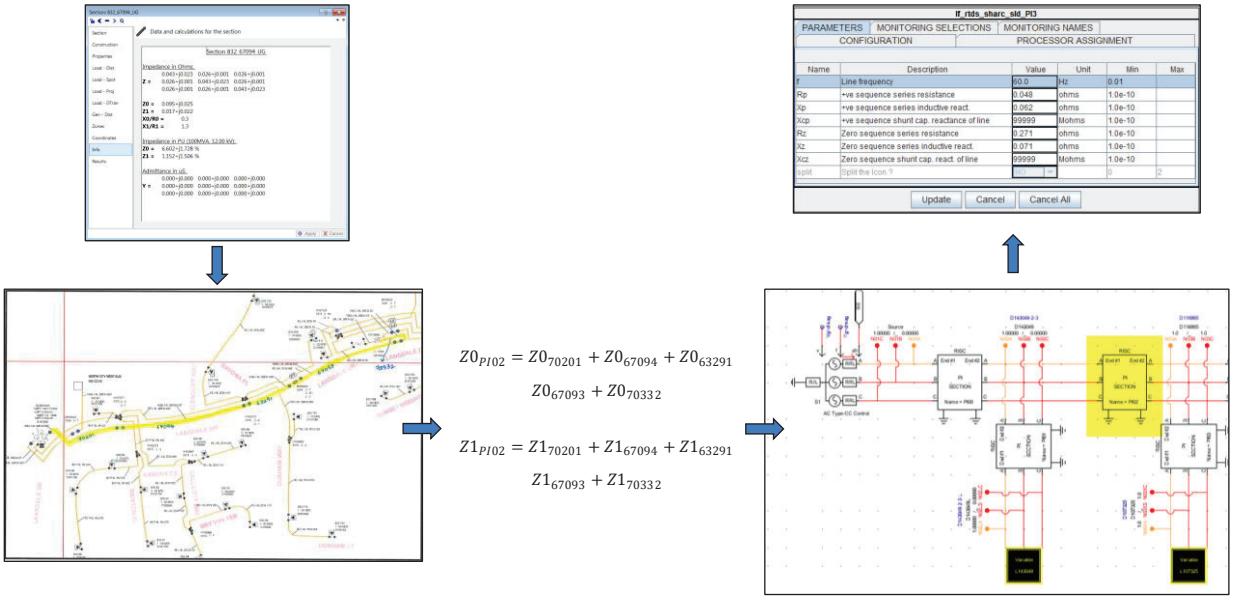
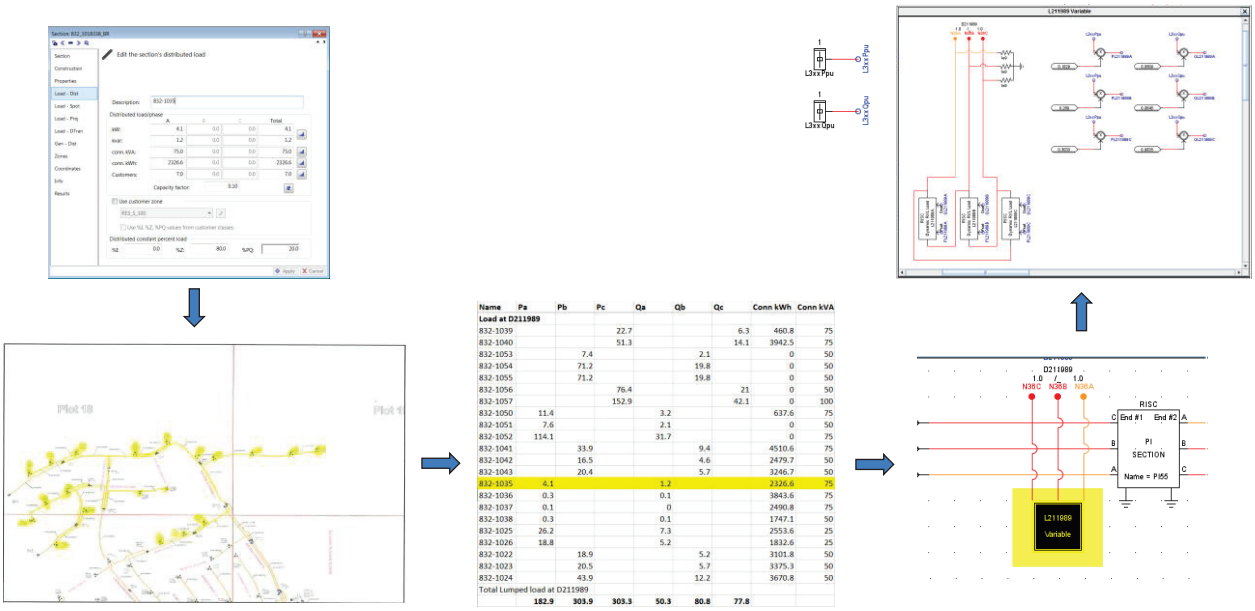


Figure 2.4: Conversion of Synergi Section Data into the RTDS PI Model

FEEDER LOADS

The single-phase and three-phase loads across a node were merged into a consolidated three-phase load, which can be dynamically controlled using sliders and/or schedulers to simulate a load demand curve. These connected loads were validated with the load flow to verify the accuracy of the simplification. Figure 2.5 shows the conversion of a load model from Synergi to RTDS.



Name	Pa	Pb	Pc	Qa	Qb	Qc	Conn kWh	Conn kVA
Load at D211989								
832-1039			22.7			6.3	460.8	75
832-1040			51.3			14.1	3942.5	75
832-1053		7.4			2.1		0	50
832-1054		71.2			19.8		0	50
832-1055		71.2			19.8		0	50
832-1056			76.4			21	0	50
832-1057			152.9			42.1	0	100
832-1050	11.4			3.2			637.6	75
832-1051	7.6			2.1			0	50
832-1052	114.1			31.7			0	75
832-1041		33.9			9.4		4510.6	75
832-1042		16.5			4.6		2479.7	50
832-1043		20.4			5.7		3246.7	50
832-1035	4.1			1.2			2326.6	75
832-1036	0.3			0.1			3843.6	75
832-1037	0.1			0			2490.8	75
832-1038	0.3			0.1			1747.1	50
832-1025	26.2			7.3			2553.6	25
832-1026	18.8			5.2			1832.6	25
832-1022		18.9			5.2		3101.8	50
832-1023		20.5			5.7		3375.3	50
832-1024		43.9			12.2		3670.8	50
Total Lumped load at D211989								
	182.9	**303.9**	**303.3**	**50.3**	**80.8**	**77.8**		

Figure 2.5: Conversion of Synergi Load Data into the RTDS Dynamic Load Model

CAPACITOR BANKS

There are two capacitor banks of 400 kVAR per phase each. These banks are located near the substation and at the far end of the feeder, respectively. The capacitance of these banks is calculated in the next equation to be 22.1 μF per phase. The switching of these capacitor banks is controlled automatically based on the system voltage level. The system voltage levels are maintained between 10.8 kV and 13.2 kV for system stability.

$$C = \frac{(kVAr)}{2\pi f \bullet V_{L-N}{}^2} = \frac{(400\ kVAr)}{2\pi f \bullet \left(\frac{12\ kV}{\sqrt{3}}\right)^2} = 22.1\ \mu F$$

DISTRIBUTED ENERGY RESOURCES

PV System Model

The two three-phase PV systems with 471 kW and 485 kW capacities were merged together in the RTDS to form a single three-phase 956 kW PV inverter system for ease of modeling. The two single-phase PV inverters were ignored, and their generation was accounted for in the circuit power flow. The three-phase PV system at Circuit Node D210906 is modeled as a constant current source with a power output of 165 kW. The RTDS model is shown in Figure 2.6.

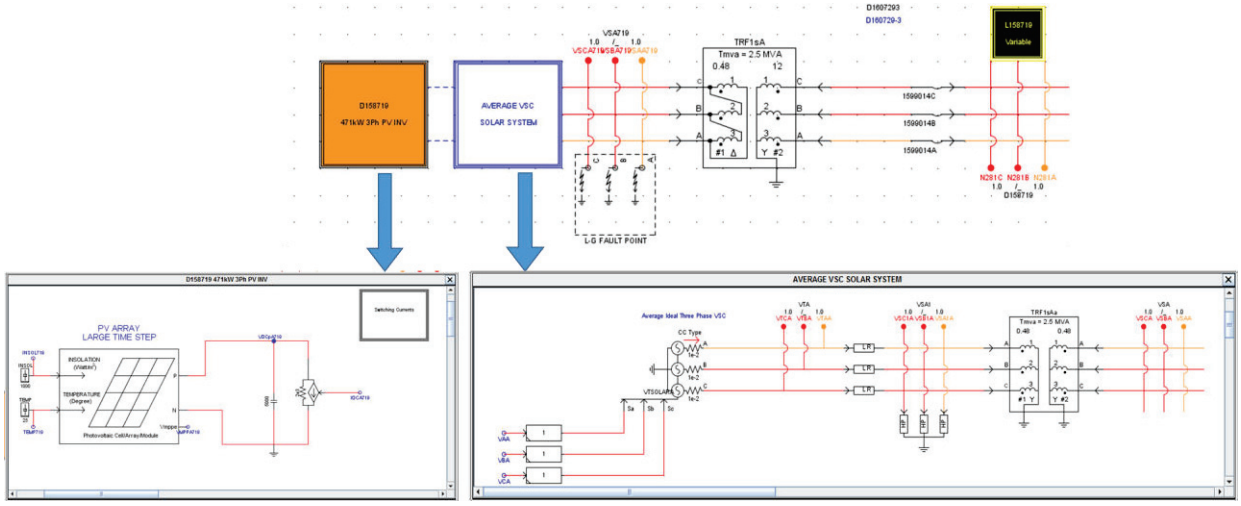


Figure 2.6: PV Inverter Model in the RTDS

The PV system was modeled as an average value model with mathematical control systems. The AC side of the bridge was modeled as a controllable voltage source based on the reference voltage waveform from the controller. The DC side of the bridge was designed as a controllable current source based on the power balance equation on the AC and DC sides. The voltage output can be controlled by defining various parameters and modes.

The flow of control is as follows:

Step 1. Calculate the line current and voltage across the AC side, and change it to a direct-quadrature (DQ) frame using Park's transformation.
Calculate the updated line currents in the DQ frame using the following control operations.
The different operational controls on the PV inverter are:

a. Active power output control – This control determines the active power output of the PV inverter based on the radiation (INSOL) and temperature (TEMP) levels. The INSOL and TEMP levels are controlled using sliders in the model.
b. Reactive power dispatch control – This control determines the reactive power output of the PV battery and is controlled by specifying the reactive power directly using a slider in the model.
c. MPPT algorithm – The maximum power point tracking algorithm (MPPT) is either estimated from the PV array indirectly or calculated using the MPPT block in the RSCAD software from the DC voltage obtained from the PV array.
d. Voltage control – The AC voltage can be controlled by regulating the DQ frame reference (DC voltage) of the line voltage and controlling the reactive current (Isq).

Step 2. The updated currents in the DQ frame are converted to A-B-C line voltages and fed into the voltage controlled source on the AC side.

Step 3. The A-B-C frame currents calculated from the DQ frame DC are averaged to obtain the DC reference from the controlled DC source current.

Distributed Energy Storage System Model

The ESS has four 250 kW batteries that are merged to represent one 1 MW battery in the RTDS model. The ESS is modeled similarly to the PV inverter model (Figure 2.7).

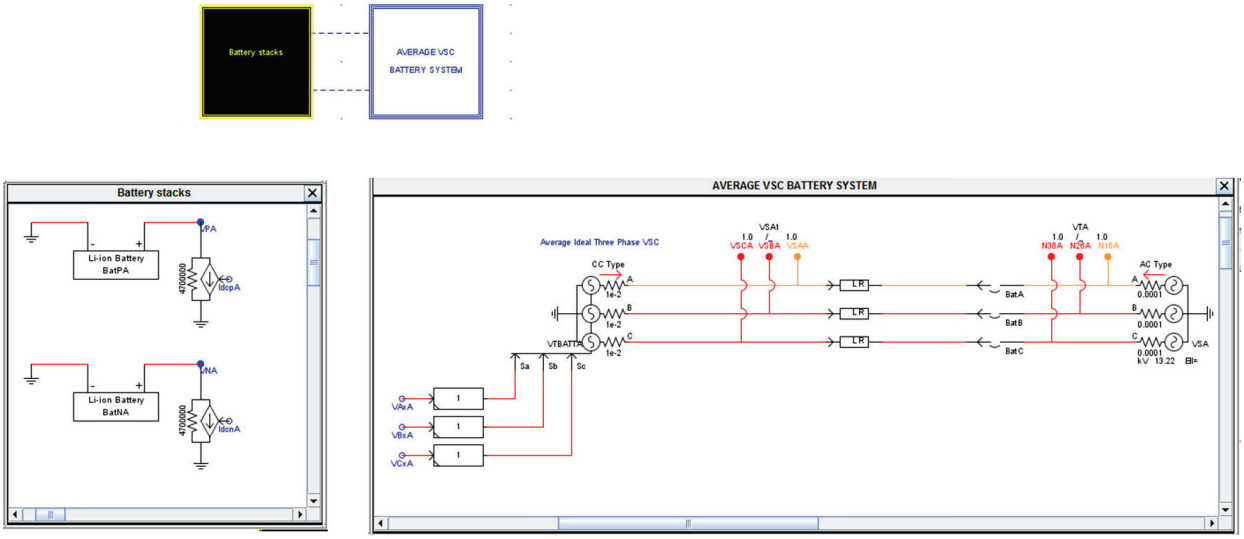


Figure 2.7: ESS Model in the RTDS

The control philosophy of the ESS is like that of the PV system—the AC side of the bridge is modeled as a controllable voltage source based on the reference voltage waveform from the controller. The DC side of the bridge is designed as a controllable current source based on the power balance equation on the AC and DC sides. The real and reactive power outputs of the ESS are controlled using sliders. Both the PV inverter and the ESS have common voltage and frequency ride-through controllers.

Wind Energy System Model

The model has a wind system in the distribution circuit to simulate the effects of wind energy penetration in the grid and the interaction with the test inverter. Thus, a wind energy system is incorporated into the grid with a 2.0 MW capacity as a Type 2 doubly fed induction generator (DFIG) system. The DFIG

model is an average value model where the small signal DC-AC converter is replaced by mathematical controls to create a DC link across the bridge.

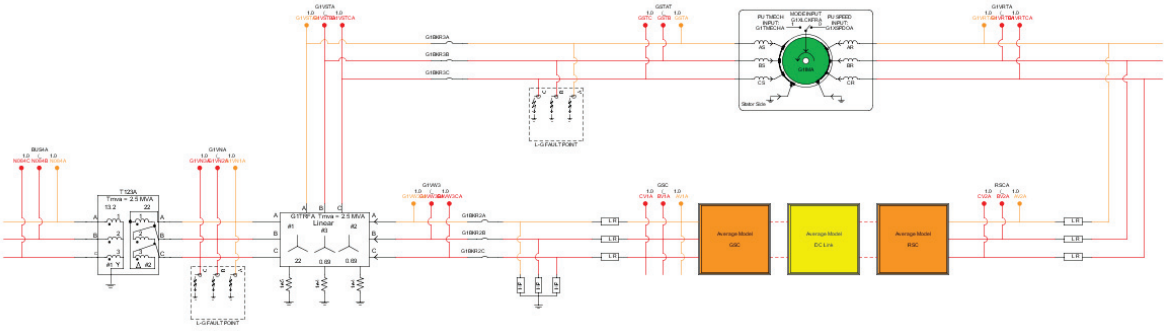


Figure 2.8: DFIG Model on the RTDS

The controls for the DFIG system are divided into four major systems:

- Rotor axis control – The rotor side control (RSC) is modeled using a controllable voltage source on the rotor side that applies voltage to the rotor windings of the DFIG and controls the rotor currents. The control voltage is obtained by converting the three-phase line currents into a DQ frame using Park's transformation. The updated DQ voltages from various control parameters are converted into the three-phase voltage waveforms and are injected into the controllable current source at slip frequency. The reactive power output of the RSC can be controlled using sliders.
- Grid side control (GSC) – The GSC regulates the voltage of the DC bus capacitor and absorbs or generates reactive power for voltage support. The GSC has one control parameter that is the reactive power absorbed from or injected into the grid.
- Rotor and multi-mass control – This block manages the pitch control for the turbine. The mechanical model for the wind turbine is combined with the DFIG and the multi-mass model. Mechanical torque is calculated in the wind turbine and speed in multi-mass and electrical torque is calculated by the DFIG.
- DC link capacitance – This stores the energy between the GSC and RSC and transfers energy across the link. This is the equivalent of the voltage source converter (VSC) bridge modeled mathematically.

VALIDATION USING SYNERGI MODEL

The RTDS model was validated using the Synergi model for the system power flow. A few changes were made to the connected loads to account for the line losses in the single-phase lines that connect to residences. The changes were usually in the order of ±1 to 2 kW. A comparison of the power flow results on the Synergi model versus the RTDS model is shown in Figure 2.9 and Figure 2.10. The power flows shown in the figures do not consider the generation from the DER and the capacitor reactive power generation.

Load Type	Total		A		B		C	
	kVA	pf	kVA	pf	kVA	pf	kVA	pf
Distributed	12440	96.37	4134	96.35	4165	96.35	4142	96.41
Spot	0	100.00	0	100.00	0	100.00	0	100.00
Large Customer	0	100.00	0	100.00	0	100.00	0	100.00
Capactor	0	100.00	0	100.00	0	100.00	0	100.00
Generator	0	100.00	0	100.00	0	100.00	0	100.00
Losses	377	64.01	123	60.87	118	64.81	137	66.06
Total Load	12752	95.91	4233	95.87	4263	95.93	4257	95.93
Demand	12391	95.66	4124	95.64	4135	95.66	4133	95.67
Connected loads								
Connected kVA	27091		9199		9039		8854	
Connected Customers	2478		928		834		715	
Conneced kWH	1087801		367887		381431		338483	

Figure 2.9: Synergi Software Power Flow Results

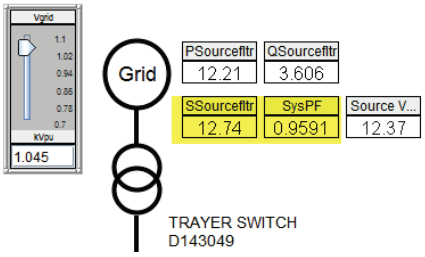


Figure 2.10: RTDS Model Power Flow Results

SECTION 3 PRE-COMMERCIAL DEMONSTRATION OF GRID SUPPORT FUNCTIONS OF DER

This section describes various tests that were conducted on the DER system and provides the test results. The grid support functionalities of the DER (ESS for this demonstration) were tested in various conditions of the circuit including load fluctuations and changes in voltage and frequency. A background on the grid support functions and the PHIL concept is provided before the test result for reference.

INTRODUCTION TO DISTRIBUTED ENERGY RESOURCE GRID SUPPORT FUNCTIONS

The following grid support functions have been demonstrated for their value assessment.

Active Power DER Functions

LIMIT MAXIMUM ACTIVE POWER OUTPUT

This function recommends implementing the maximum limit on the active power of the DER by the grid operator. With this limit in place, DER can operate in any other regulation mode without exceeding active power beyond this limit. The change in the limit occurs at a specified ramp rate. The characteristics for this function is shown in the Figure 3.1 below.

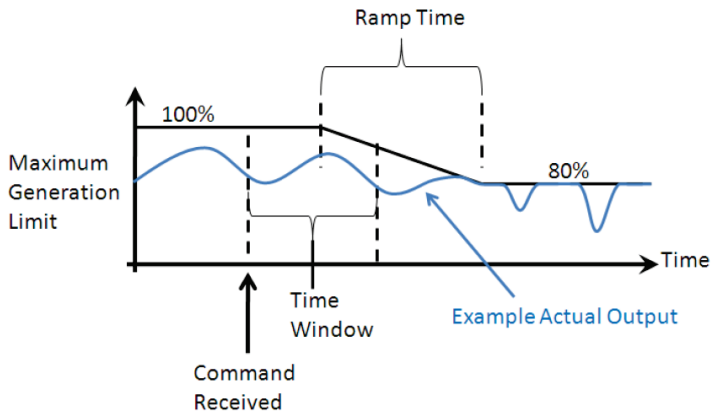


Figure 3.1 Limit Maximum Active Power Output Function

SCHEDULE ACTIVE POWER OUTPUT

This function enables the utility to schedule the output at the PCC during certain times and conditions. This operation establishes the base, or known, generation level on the feeder without the need for constant monitoring, which provides important information about the operational planning and it minimizes the output during low-load conditions, while allowing a higher output during peak load time periods. The power output of the DER is specified to be a constant value. The power grid manages an increase or decrease in load while the power output of the DER remains unchanged.

VOLT-WATT FUNCTION

This function was identified for use as compensation for the voltage variability that results from intermittent renewable sources or other loads. Volt-watt is intended to provide a flexible mechanism through which inverters may be configured to dynamically provide voltage stabilization. This function involves the dynamic production of active power (watts) to resist variations in the voltage at the PCC. The

objective is to counter any changes in the voltage by varying the output power. When the DER is set in volt-watt control mode, it tries to maintain the voltage of the system to 1 per unit (pu) by curtailment of the active power output. Figure 3.2 shows the volt-watt function model with a ramp rate.

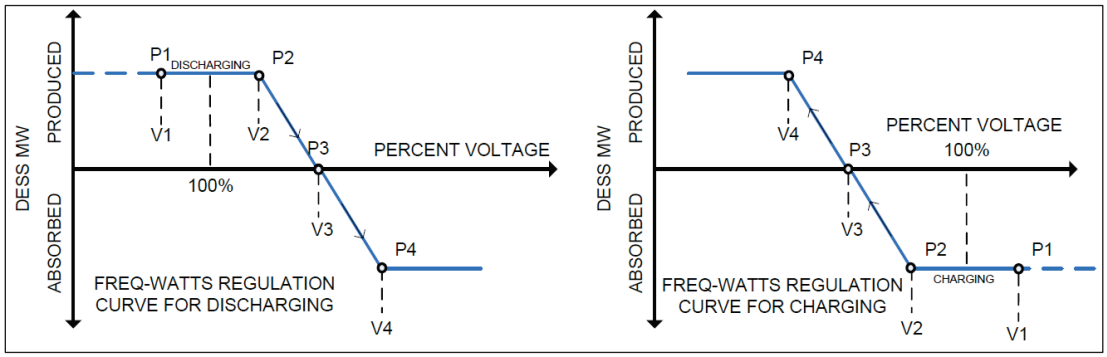


Figure 3.2: Volt-Watt Function

The objective of the tests performed under this section is to study the feasibility of the DER volt-watt function under different locational scenarios and topology.

Reactive Power DER Functions

VOLT-VAR FUNCTION

This function is intended to provide a mechanism through which a DER may be configured to manage its own VAR output in response to a fluctuation in the local service voltage. This function involves the dynamic production of reactive power (VARs) to resist variations in the voltage at the PCC. The objective is to counter any changes in the voltage by varying the output reactive power. When the DER is set in volt-VAR mode, it tries to maintain the voltage of the system to reference value by regulation of the reactive power output. The volt-VAR mode regulates the voltage at specified ramp rate, and the characteristics for this function is shown in Figure 3.3.

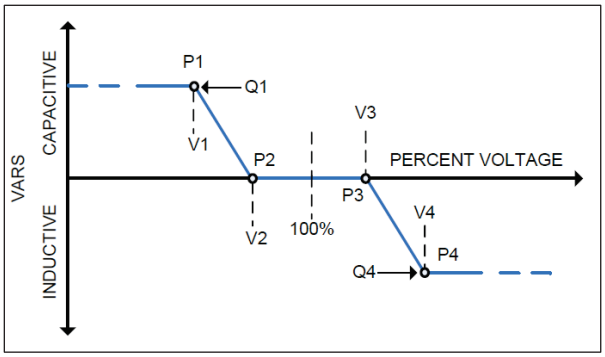


Figure 3.3: Volt-VAR Function

The objective of the tests performed under this section is to study the capability of the DER volt-VAR function under different locational scenarios and topology.

Frequency Support DER Functions

FREQUENCY-WATT FUNCTION

This function is intended to provide a mechanism through which a DER may be configured to manage its own active power output in response to the fluctuations in the system frequency. This function involves the dynamic production of active power to resist variations in the system frequency. The objective is to counter any changes in the frequency by varying the output power. When the DER is in frequency-watt mode, it tries to maintain the frequency of the system to 60 Hz by regulating active power. The characteristics for this function is shown in Figure 3.4.

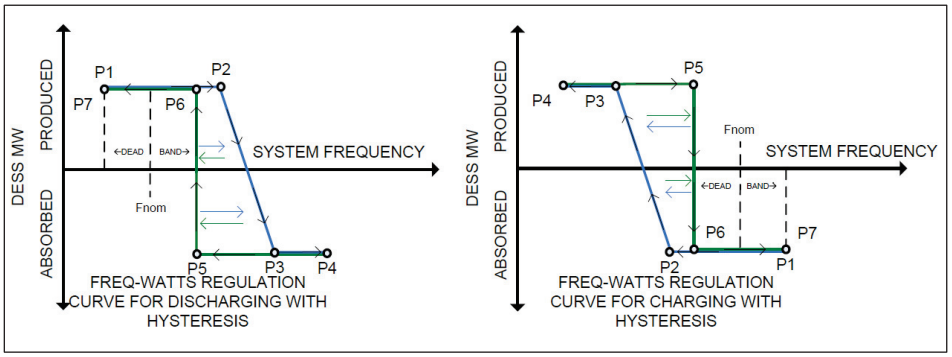


Figure 3.4: Frequency-Watt Function

The objective of the tests performed under this section is to study the capability of the DER frequency-watt function under different locational scenarios and topology.

DER RESPONSE TO EMERGENCIES

These functionalities are part of Phase 3 Rule 21 recommendations by the Smart Inverter Working Group (SIWG). Although not related to the grid supporting DER functions, these functions demonstrate the ability of the DER to respond to different emergency situations or commands from the utility, such as:

- Issue disconnect or reconnect commands to the DER system from the utility.
- Update voltage ride-through curves to change anti-islanding settings.
- Update frequency ride-through curves to change anti-islanding settings.
- Request notification from the DER system about the status of microgrid connection.
- Request notification from the DER system about the spinning reserve.

SPINNING RESERVE

The objective of this test is to assess the benefits of the battery storage system in functioning as a spinning reserve in different system conditions compared to traditional sources, such as diesel generators. The DER system is compared against the traditional backup diesel generator as a source of spinning reserve in terms of response time, standby losses, durability of support, and availability.

BLACK START

The battery storage system can be used to black start the system after complete system outage. The battery can operate in voltage source inverter (VSI) mode to provide voltage and frequency support during the black start. Once the nominal voltage and frequency are established in the island, the loads can

be picked up slowly and other renewable generation sources can be brought online to support the load on the feeders.

LOAD LEVELING

The load-leveling function is like peak shaving in that it involves the cycle of charging and discharging during different loading conditions. Therefore, it is most relevant when the DER is a storage device. During the periods of high-load demand, the DER can supply energy into the grid and it can charge while the load is low. This helps reduce the load on less economical peak generating plants. The source level is determined and is limited within the capacity of the DER. The increase and decrease in load is handled by the DER by injecting or absorbing power from the grid. Figure 3.5 shows the characteristics load-leveling function of the DER.

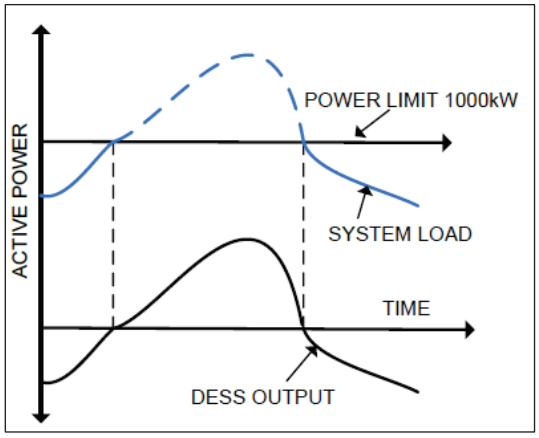


Figure 3.5: Load-Leveling Function

The objective of this test is to assess the economic benefits of using the DER to supply clean and emission-free energy, while reducing the use of less economical generation plants during high-load demands.

POWER-HARDWARE-IN-THE-LOOP (PHIL) TEST SETUP

A hardware inverter was used as a device under test for the assessment of the grid support functions. This hardware device is an additional DER introduced in the distribution circuit for demonstrations purpose. The DER that exist in the circuit presently are modeled in the RTDS simulation as mentioned in Section 2. This section describes the PHIL setup used for the testing in the lab.

Hardware Setup Description

A bidirectional inverter, with grid support functionalities, was installed and commissioned at the DER lab in the PHIL configuration, along with other equipment, such as the grid simulator, battery/load simulator. The PHIL concept brings together software simulation and hardware testing in a closed-loop circuit to evaluate the response of hardware to real-world scenarios in a controlled lab environment. Using the PHIL setup, a small-scale inverter is interfaced with the distribution circuit simulation to produce 1 MW of power at full device rating.

The hardware connection to be implemented is outlined in Figure 3.6. The inverter AC voltage is supplied by the grid simulator, which is controlled by a low-level analog representation of a node voltage in the RTDS model. The power loop is closed by bringing the inverter AC current feedback into the RTDS

using low-level voltage signals delivered by current transformer (CT) clamps to the analog input (Giga-Transceiver Analogue Input [GTAI]) card. These current signals are introduced into the simulation using a current injector model, as shown in Figure 3.7. This current injector component can be moved around the circuit to simulate different source penetration points in the system.

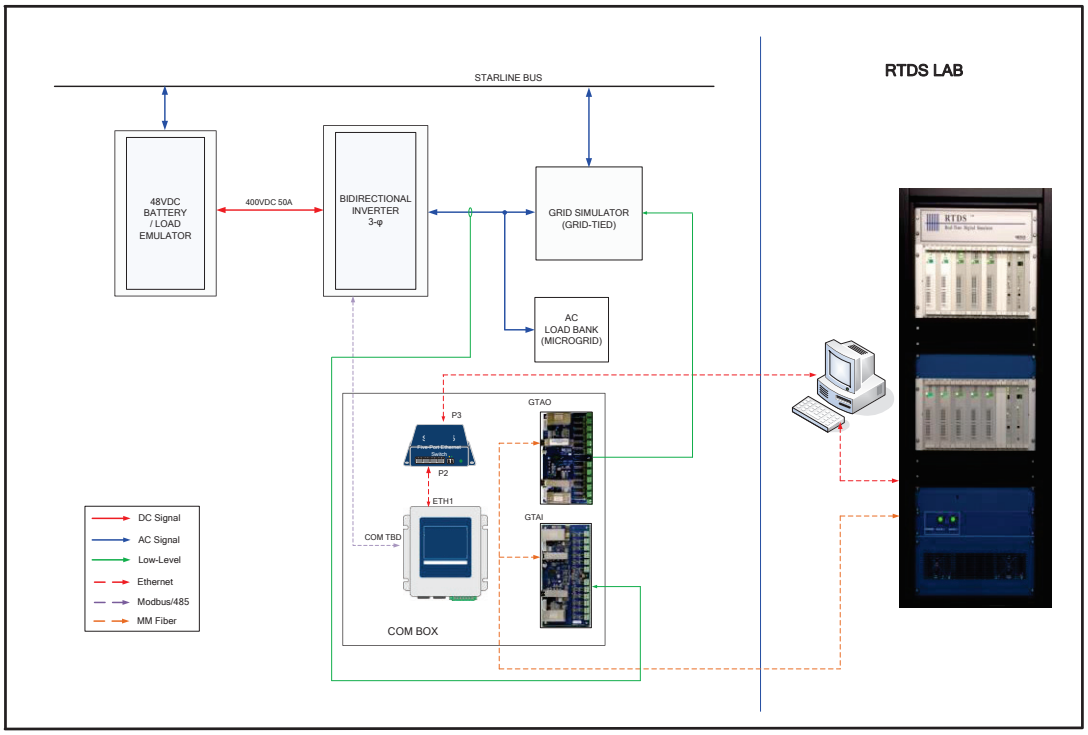


Figure 3.6: Test Circuit Schematic with Inverter at the DER Lab

The typical PHIL test setup modeled in the RSCAD® software is shown in Figure 3.7.

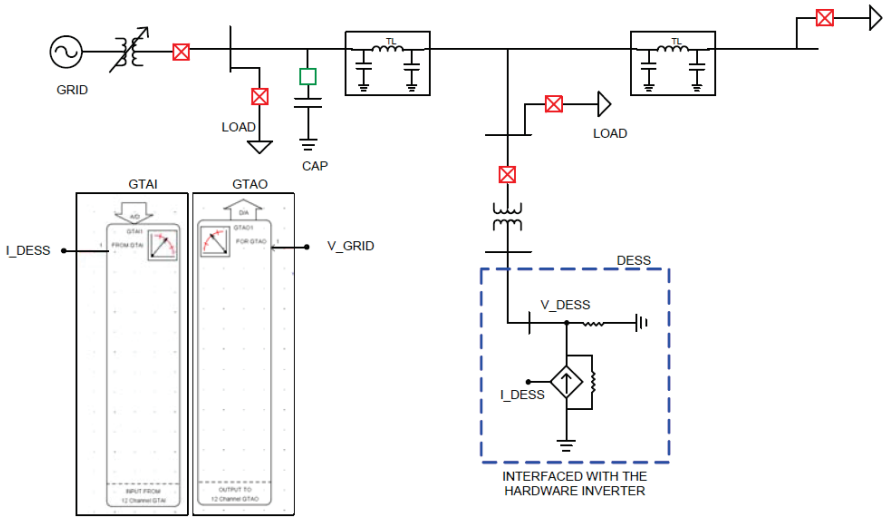


Figure 3.7: PHIL Test Setup Showing Hardware Interface in RSCAD®

RTDS Setup

OUTPUT VOLTAGE SIGNAL

The circuit begins with the translation of the voltage signals from the software model in to the hardware via low-level analog outputs. The software voltage signal is scaled down from the software model level, 12kV for the ESS, to the voltage level of the grid simulator at 277V_{L-N}. Figure 3.8 shows this process in the RTDS model.

Note: All the signal labels mentioned here are generic names given to the signals in the Figure 3.8 and are not standard acronyms.

Following the signal out through the ESS model.

1. VPCCVA is the label for the voltage at the point of common connection (PCC) between the point in the ESS model being evaluated and the voltage signal sent to the grid simulator. This method allows us to change the PCC location in the model in the future. For the ESS circuit, the PCC is 1MW battery. The line to neutral voltage measured at this point is approximately 6.928kV.
2. Since RTDS base units for voltage are in kV, VPCCVA will come in as 6.928 kV. Point 2 scales this up to be 6928V.
3. Point 3 then scales the voltage down to the 480V_{L-L} (or 277 V_{L-N}) level required at the inverter. (12000/25 = 480 or 6928/25 = 277)
4. Point 4 scales 277 V_{L-N} down by the gain of the inverter. The gain was calculated (300/7 = 42.85) as well as verified by measurement. The RS-90 has a maximum output of 300 V_{L-N} and a maximum low-level external input of 7 Vrms. Therefore, the voltage signal at VPA2 = 277/42.85 = 6.46V (for 6.928 kV_{L-N} input). (Note: 7 Vrms at the low level external input of the grid simulator produces 300 V_{L-N} at the output)
5. VPCCLIMA is the voltage signal that is sent through the analog output (GTAO) to the external input of the grid simulator. For 6.928kV input the output is 6.46V. The highlighted symbol is a signal limiter that limits VPCCLIMA to 10 Vpk (7 Vrms) regardless of the signal magnitude of VPA2. If VPA2 is greater than 10 Vpk, the outgoing signal will be clipped to10 Vpk.

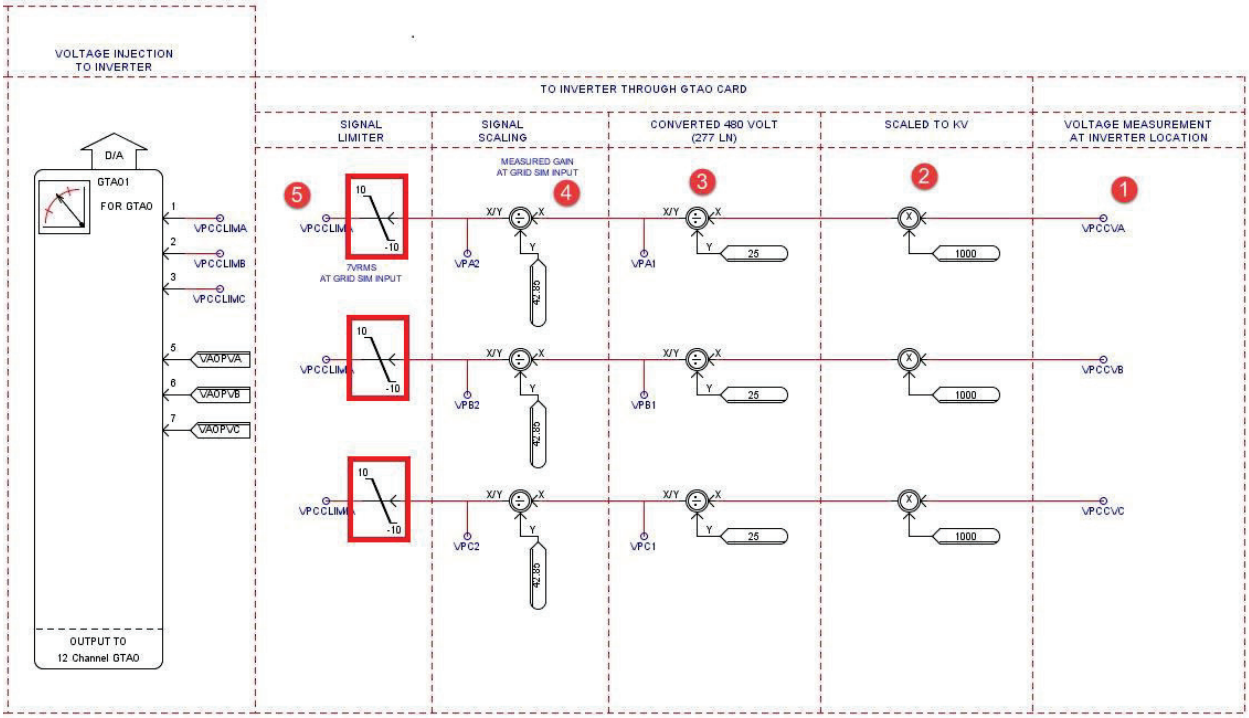


Figure 3.8: ESS RTDS Analog Output

INPUT CURRENT SIGNAL

The feedback loop is closed when the current signal is brought back in to the RTDS model as a low-level voltage signal. The signal brought back in is the current between the grid simulator and the inverter (see Figure 3.9).

Note: All the signal labels with acronyms mentioned here are generic names given to the signals in the Figure 3.9 and are not standard acronyms.

Following the ESS current in from the GTAI:

1. INA is the raw analog signal that is brought in from the CTs through the GTAI card. The CT ratio of the clamps used is 1V input per 10A measured. At 1MW at unity power factor the current is ~60A, this equates to a voltage input of 6V at INA. INA then passes through a low-pass filter with a cutoff frequency of 500Hz and a scalable gain to filter out undesired harmonics introduced by measurement. The gain not only scales up from the CT Ratio but also accounts for magnitude attenuation incurred at the filter. The scaling factor will be chosen to amplify the ESS capacity to 1 MW.
2. The switch PHILON is used to change between open-loop and closed-loop. When PHILON is off, the zero at point A is fed in to the circuit. When PHILON is on INFA is fed in to the circuit. INFA is the filtered and input (INA) that has been scaled back to the original signal magnitude.
3. Another limiter is implemented here to prevent a current signal outside expected values from propagating into the RTDS model and cause circuit instability. (The 85Apk limit corresponds to the 60Arms expected value.)
4. The scaling at point 4 corresponds to the opposite of the down scale at point 2 in the GTAO to account for the change in unit, see Figure 3.9. (1/1000 = .001)
5. The scaling at point 5 corresponds to the opposite of the down scale at point 3 in the GTAO to account for the change in voltage level, see Figure 3.9. (1/25 = .04)
6. A gain setting of 20 was used to scale the inverter (50kVA) to 1 MW for the demonstrations.

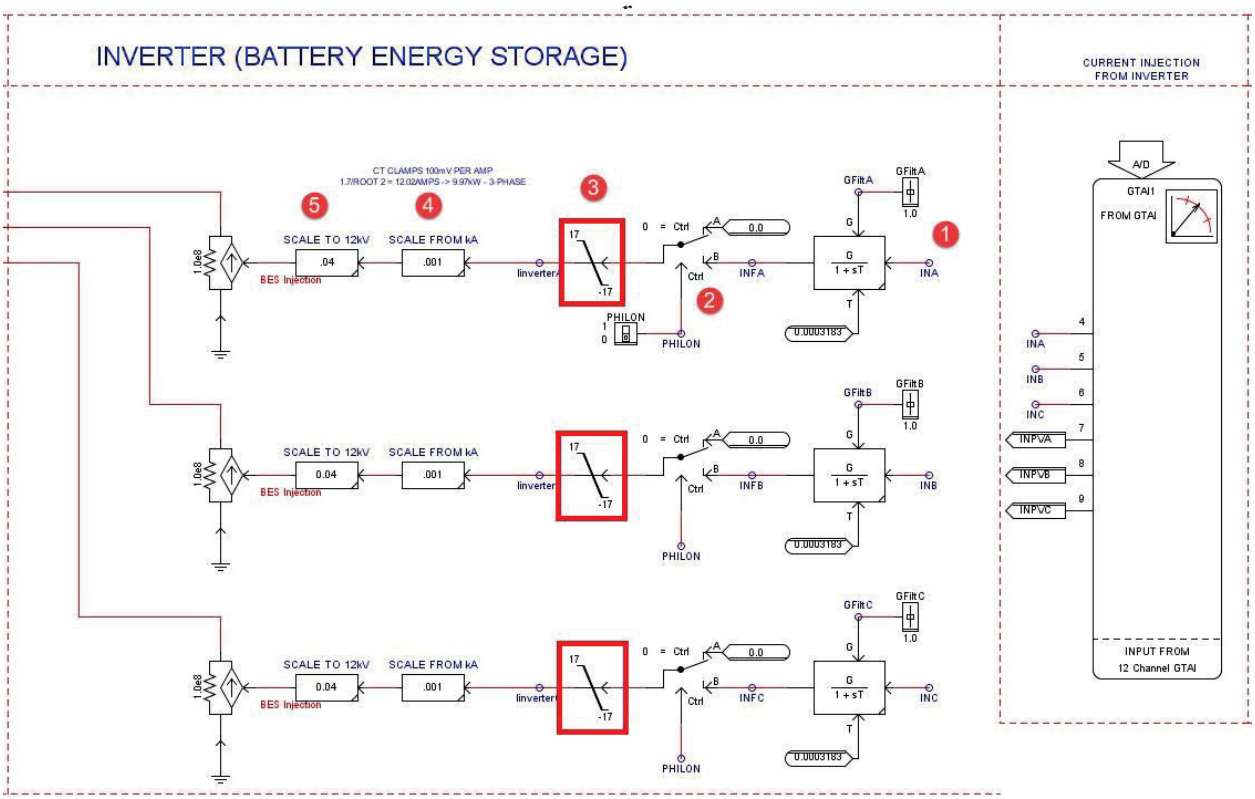


Figure 3.9: ESS RTDS Analog Input

COMMUNICATION WITH THE INVERTER USING THE GATEWAY

The RTDS communicated with the inverter controller using a communication gateway. The RTDS communicates with the gateway using a DNP session. The gateway communicates with the inverter using Modbus session. The register numbers for the various parameters used are mentioned in the inverter manuals. This communication interface is used to control the inverter remotely, to start/stop, to change the modes and set points on the inverter.

TEST SCENARIOS

The components of the DER under test are modeled generically so they can be moved to different locations within the circuit to simulate different source penetration points. The following distribution circuit scenarios are studied for the DER placements.

Scenario 1: DER Close to a Substation

Under this scenario, the DER is placed close to the substation on the low side of the feeder transformer. The Voltage at the substation is set at 1.032pu to have a 1pu voltage at the end of the feeder. This in turn, causes the voltage at the DER to be at 1.025pu. The DFIG system is turned off for studying the effects of the DER on the grid. The capacitor bank is switched on or off using the automatic switching control where they are switched based on the system voltage. Under this scenario, the tests for understanding the functions of the DER are simulated:

Test 1 – Limit the Maximum Power Output
Test 2 – Schedule Active Power Output
Test 3 – Volt-Watt
Test 4 – Volt-VAR
Test 5 – Frequency-Watt
Test 9 – Load Leveling

The simplified circuit of scenario 1 is shown in Figure 3.10.

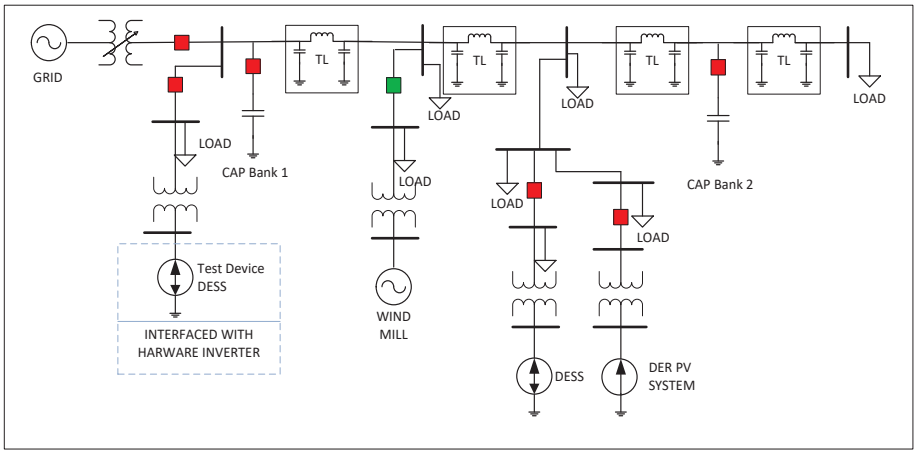


Figure 3.10: DER Close to Substation (Typical)

Scenario 2: DER on a Complex Circuit with a Multitude of Controllable Devices

Under this scenario, the DER under test is placed near the middle of the circuit close to the DFIG system with the DFIG system turned off for the scenario. The Voltage at the DER is at 1.018pu. The DFIG system is turned off for studying the effects of the DER on the grid. The capacitor bank is switched on or off using the automatic switching control where they are switched based on the system voltage. Under this scenario, the tests for understanding the functions of the DER are simulated:

Test 1 – Limit the Maximum Power Output
Test 2 – Schedule Active Power Output
Test 3 – Volt-Watt
Test 4 – Volt-VAR
Test 5 – Frequency-Watt
Test 9 – Load Leveling

The simplified circuit of scenario 2 is shown in Figure 3.11

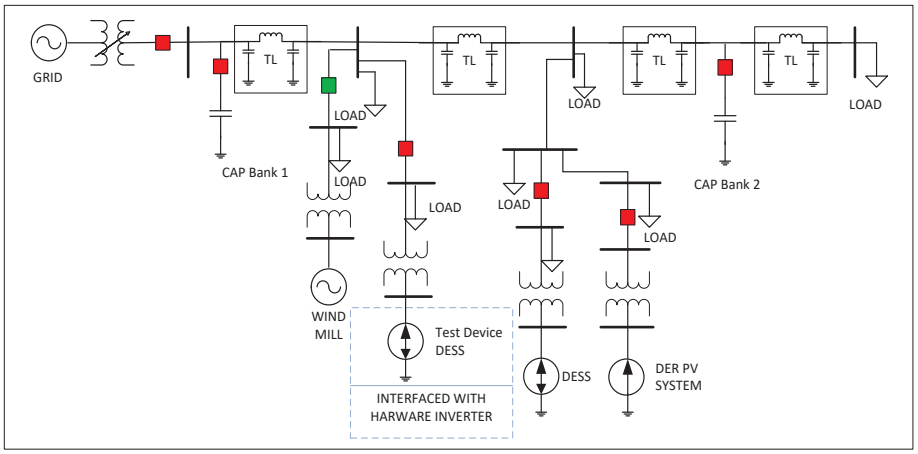


Figure 3.11: DER on a Complex Circuit with a Multitude of Controllable Devices (Typical)

Scenario 3: DER at the End of a Long Feeder

The ESS is placed at the extreme end of the feeder to study the voltage regulation and other functionality of DER under test. The DFIG system is turned off for studying the effects of the ESS on the grid. Under this scenario all the tests except the ESS response to emergencies are simulated. This is because, DER being at the end of feeder, functions effectively for the voltage based tests as the voltage is the lowest at the end of the feeder. The voltage at the Scenario 3 is exactly around 1pu. The capacitor banks are controlled using automatic switching for all the tests except for the black start test where they are turned off. Figure 3.12 shows the simplified circuit of Scenario 3.

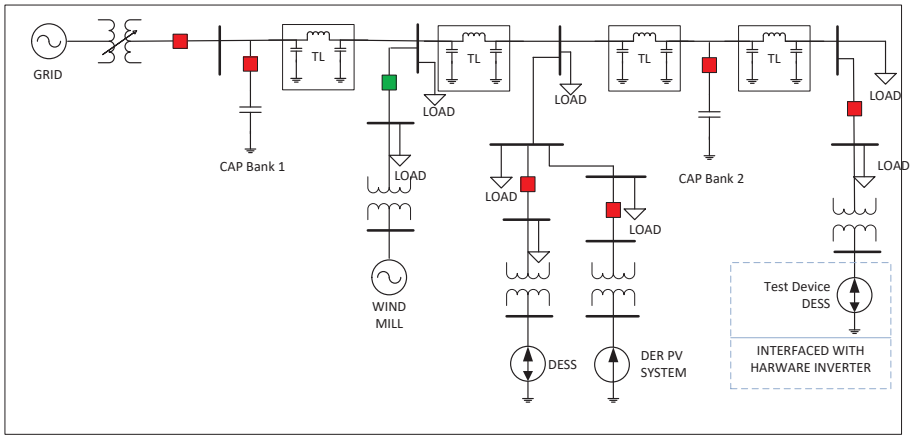


Figure 3.12: DER at the End of a Long Feeder (Typical)

Scenario 4: Multiple Diverse Types of DER on the Same Circuit

Under this scenario, multiple DER are feeding the loads in the system. This scenario is to understand the interaction between the different renewable sources and the DER under test. There is a PV, ESS and a DFIG system in the circuit in addition to the DER under test. The DER is located near the DFIG, like Scenario 2, except that the DFIG is switched on in this scenario to study the interaction. The voltage profile in that case is 1.015pu like the scenario 2. The capacitor banks are switched on or off using the automatic switching control where they are switched based on the system voltage. Figure 3.13 shows simplified circuit of the Scenario 4.

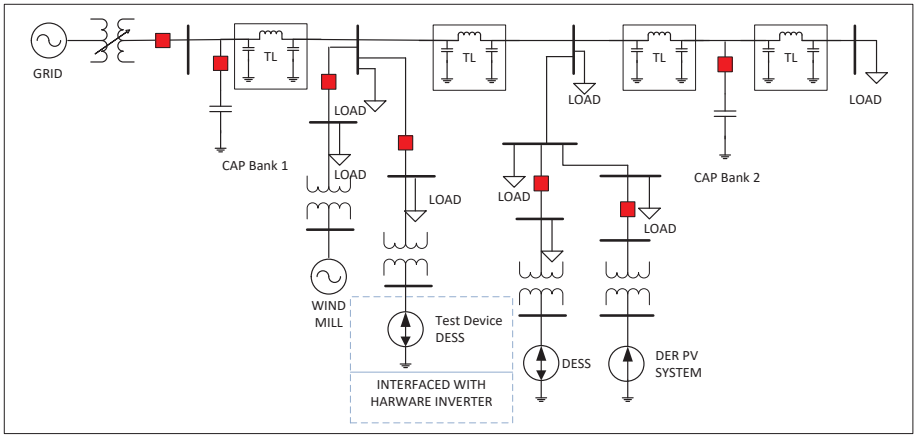


Figure 3.13: Multiple Diverse Types of DER on the Same Circuit (Typical)

TABLE OF TESTS

Table 3.1 lists the DER modes during each of the tests described in the previous sections.

Table 3.1: DER Modes for Demonstrations

Test	Test Name	DER Mode	DER Location	Variable to Change
Test 1	Limit maximum active power output	Active power control mode	DER near the substation	Voltage, frequency
			DER on the complex circuit	
			DER at the end of feeder	
			DER with other diverse DER	
Test 2	Scheduled active power output	Active power control mode	DER near the substation	Voltage, frequency
			DER on the complex circuit	
			DER at the end of feeder	
			DER with other diverse DER	
Test 3	Volt-watt	Volt-watt mode	DER near the substation	Voltage, frequency
			DER on the complex circuit	
			DER at the end of feeder	
			DER with other diverse DER	
Test 4	Volt-VAR	Volt-VAR mode	DER near the substation	Voltage, frequency
			DER on the complex circuit	
			DER at the end of feeder	
			DER with other diverse DER	
Test 5	Frequency-watt	Frequency-watt mode	DER near the substation	Voltage, frequency
			DER on the complex circuit	
			DER at the end of feeder	
			DER with other diverse DER	
Test 6	DER emergency response	NA	DER near the substation	Voltage, frequency
			DER on the complex circuit	
			DER at the end of feeder	
			DER with other diverse DER	
Test 7	Spinning reserve	Standby mode	DER at end of feeder	NA
Test 8	Black Start	VSI mode	DER at end of feeder	NA
Test 9	Load leveling	Active power control mode	DER near the substation	Load
			DER on the complex circuit	
			DER at end of feeder	
			DER with other diverse DER	

TEST RESULTS

The performance of the distributed energy resource (DER) was demonstrated under different system topologies, including the various DER locations and the diverse types of DER in the system for each of the following functions. A qualitative analysis has been conducted for the reliability and the economic benefits that each of the functions provides under different situations and is presented in Section 4.

Test 1 – Limit Maximum Active Power Output

Enable the phase 3 function "Limit maximum active power output" of the DER upon a direct command from the controller. In the RTDS model, use the nominal settings for the voltage, frequency, and for the distribution equipment on a typical SDG&E feeder, including tap changers and any capacitor switches, reclosers, and voltage regulators.

The procedure for testing was as follows:

- Issue the command to limit active power output of the DER to a specific value.
- Change the load or other distribution equipment settings to determine if the DER system correctly performs the function.
- Record the circuit measurements, the behavior of the DER system, and behavior of the distribution equipment via a Sequence of Events (SOE) recorder to log all time-stamped results.
- Repeat the previous steps after sending a command for different active power limit values.
- Establish different circuit settings for alternate SDG&E circuit scenarios, so that the value of the function can be judged for different scenarios.
- Record the circuit measurements, the behavior of the DER system, and behavior of the distribution equipment via an SOE recorder to log all time-stamped results.
- Assess the results and determine whether there are any areas of concern.

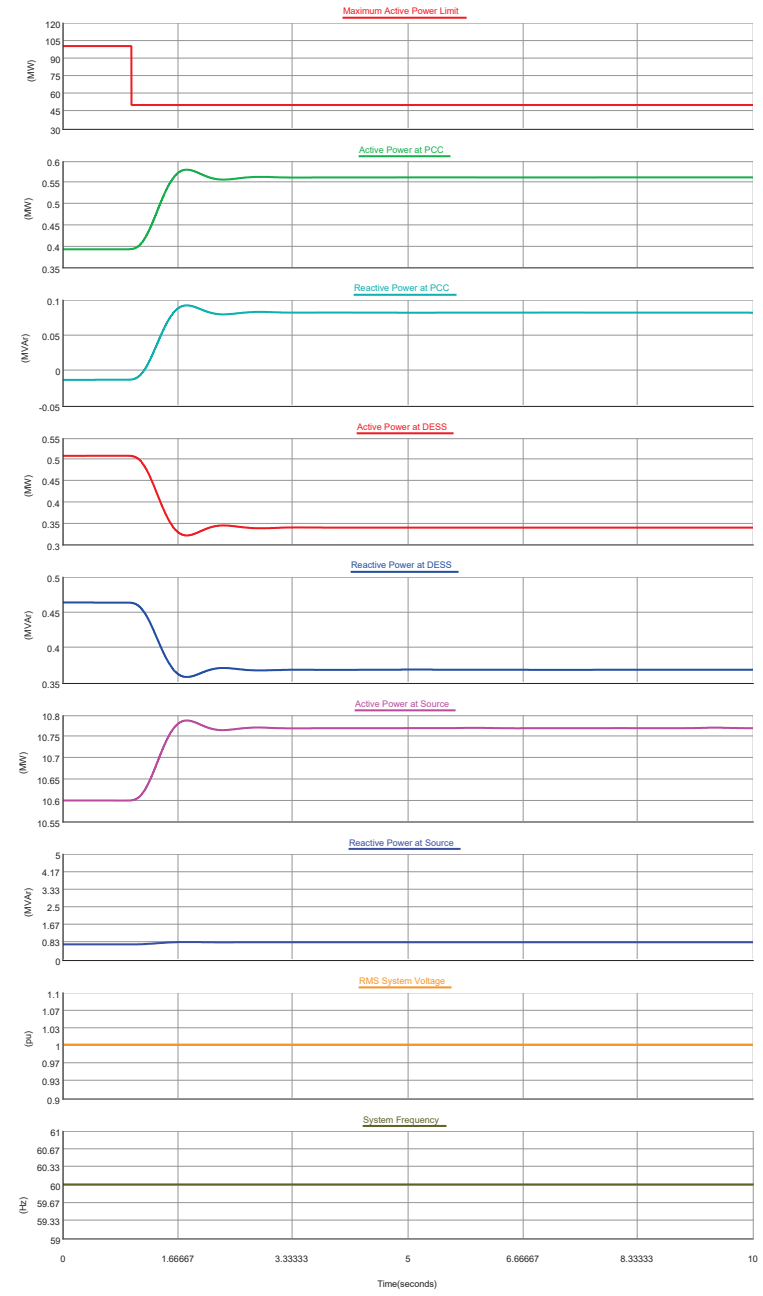
Table 3.2: DER Maximum Active Power Output Limiting Test Cases

Test	Test Description	Expected Response
Test 1.1	Change the maximum active power limit of the DER from 100% to 50% of its rated capacity with the schedule output set at 70% of rated capacity	DER output decreases to 50% when the limit decreases
Test 1.2	Change the scheduled output of the DER from 50% to 90% of rated capacity with the maximum active power limit set at 80% of its rated capacity	DER output increases to 80% instead of 90% as the limit is set to 80%

This test was conducted only in one scenario (Scenario 1) as the response does not depend on the location on the DER in the circuit.

TEST #1.1 CHANGE THE MAXIMUM ACTIVE POWER LIMIT OF THE DER FROM 100% TO 50% WITH THE SCHEDULE OUTPUT SET AT 70%

On decreasing the maximum active power generation limit to 50% from 100%, the DER active power dispatch reduced from 500kW to 340kW to stay within the generation limit. This caused more active power to be imported across the PCC to compensate for the reduced active power from the DER which increased the active power generation from the source as well. The reactive power output of the DER did not get affected which resulted in the reactive power across the PCC and the source to remain the same. The system voltage and frequency remained unaffected by the change.



r

Figure 3.14: System Response for Test 1.1

TEST #1.2 CHANGE THE SCHEDULED OUTPUT OF THE DER FROM 50% TO 90% WITH THE MAXIMUM ACTIVE POWER LIMIT SET AT 80%

On increasing the DER active power dispatch from 50% to 90%, the DER output was limited at 80% due to the generation set limit at 80%. Because of this limit, the DER output did not increase beyond 600kW even though the DER set point is at 900kW. The active power dispatch of the source decreased by 300kW to compensate for the generation by the DER and this reduced the active power import across the PCC. The reactive power across the DER, PCC and the source got affected marginally. The system voltage and frequency did not get affected by the changes in the DER active power dispatch.

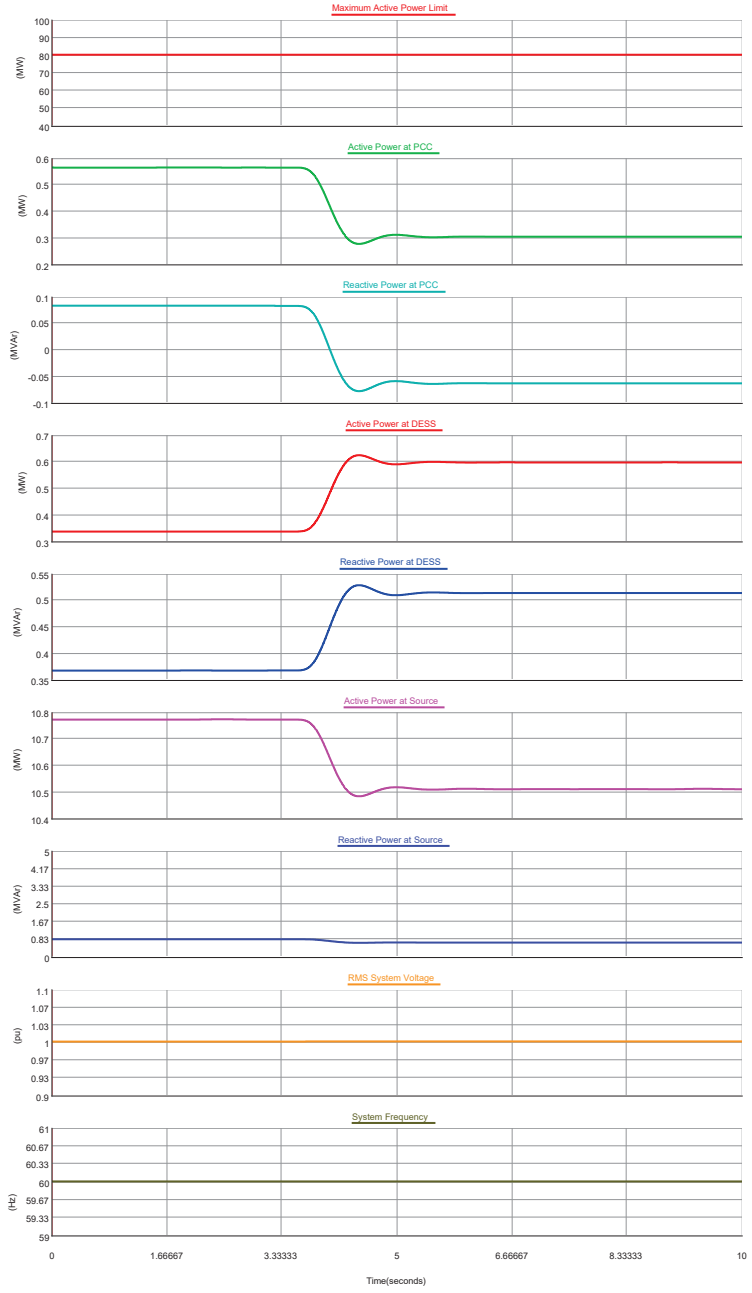


Figure 3.15: System Response for Test 1.2

Test 2 – Schedule Active Power Output

Enable the Phase 3 function "Schedule active power output at the PCC." In the RTDS model, use the default settings for the nominal voltage and for the distribution equipment on a typical SDG&E feeder, including tap changers and any capacitor switches, reclosers, and voltage regulators.

The procedure for testing was as follows:

- Send a schedule of different active power output values (ensuring the DER system can meet those values).
- Change the load or other distribution equipment settings to determine if the DER system correctly performs the function.
- Record the circuit measurements, the behavior of the DER system, and behavior of the distribution equipment via an SOE recorder to log all time-stamped results.
- Repeat the previous steps after sending a command for different active power limit values.
- Establish different circuit settings for alternate SDG&E circuit scenarios so that the value of the function can be judged for different scenarios.
- Record the circuit measurements, the behavior of the DER system, and behavior of the distribution equipment via an SOE recorder to log all time-stamped results.
- Assess the results and determine whether there are any areas of concern.

Table 3.3 lists the tests that were conducted.

Table 3.3: DER Active Power Output Scheduling Test Cases

Test	Test Description	Expected Response
Test 2. x.1	Mode activation with active power set point of 500 kW scheduled at the PCC	DER dispatches 500 kW at steady state
Test 2. x.2	Change active power set point to 800 kW schedule	DER dispatches 800 kW at steady state
Test 2. x.3	Increase the system load by 500 kW	DER dispatches 500 kW at steady state
Test 2. x.4	Increase the system voltage by 5%	DER dispatches 500 kW at steady state
Test 2. x.5	Increase the system frequency by 0.5 Hz for 1 s	DER dispatches 500 kW at steady state
Test 2. x.6	Increase the system frequency by 0.5 Hz for 5 s	DER dispatches 500 kW at steady state

Note: "x" denotes the scenario under test.

SCENARIO 1: DER CLOSE TO A SUBSTATION

TEST 2.1.1: MODE ACTIVATION WITH 500 KW ACTIVE POWER SET POINT SCHEDULED AT THE PCC

Before the DER was set to schedule active power mode, the DER active power dispatch was set at 0 kW. The initial set point was set at 500 kW at the DER. This caused the power flow to shift in such a way that the DER provided 500 kW of the 900 kW active power load, while the rest was fed by the grid through the PCC. The reactive power at the DER and PCC, the system frequency and the voltage remained unaffected by the change across the PCC.

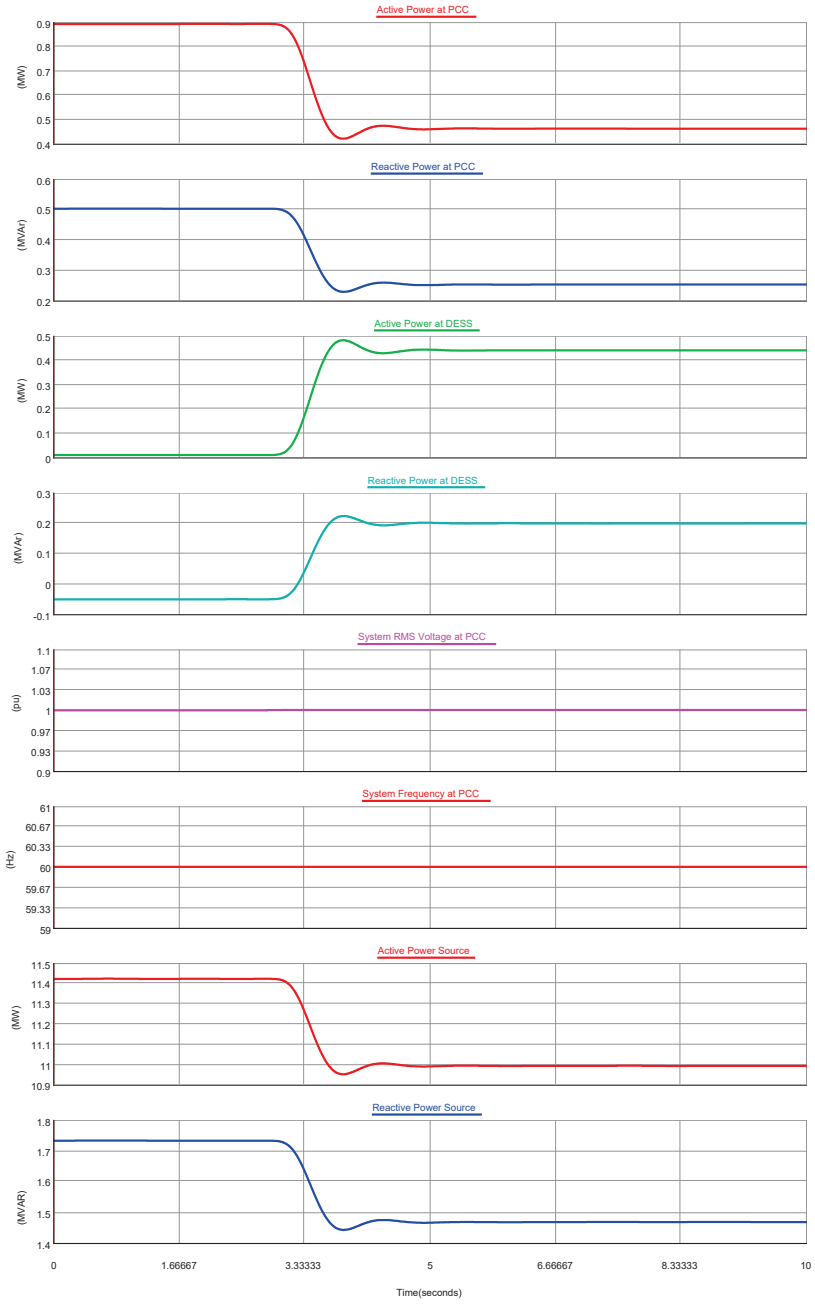


Figure 3.16: System Response for Test 2.1.1

TEST 2.1.2: CHANGE ACTIVE POWER SET POINT TO 800 KW SCHEDULED

On increasing the set point for active power output of the DER to 800 kW, the power import across the PCC reduced to 100 kW, while the active power at the DER settled to 800 kW. The reactive power across the PCC and DER changed marginally, while the system voltage and frequency remained unaffected by the change in the set point.

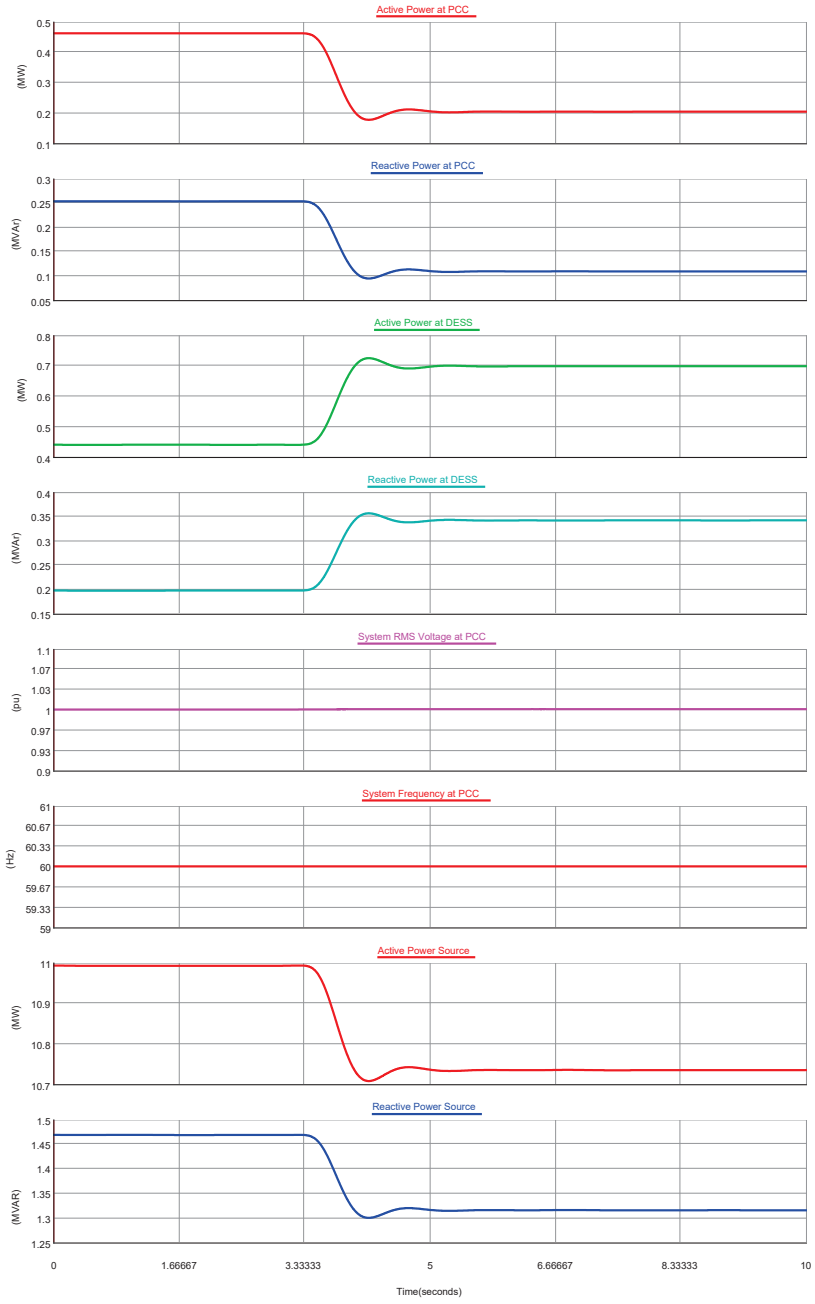


Figure 3.17: System Response for Test 2.1.2

TEST 2.1.3: INCREASE THE SYSTEM LOAD BY 500 KW

The active load connected to the DER was increased from 900 kW to 1400 kW. The DER remained at the prior set point of 500 kW at steady state, while the additional 500 kW was fed by the grid through the PCC. The reactive power, voltage, and frequency remained unaffected by the change in active load.

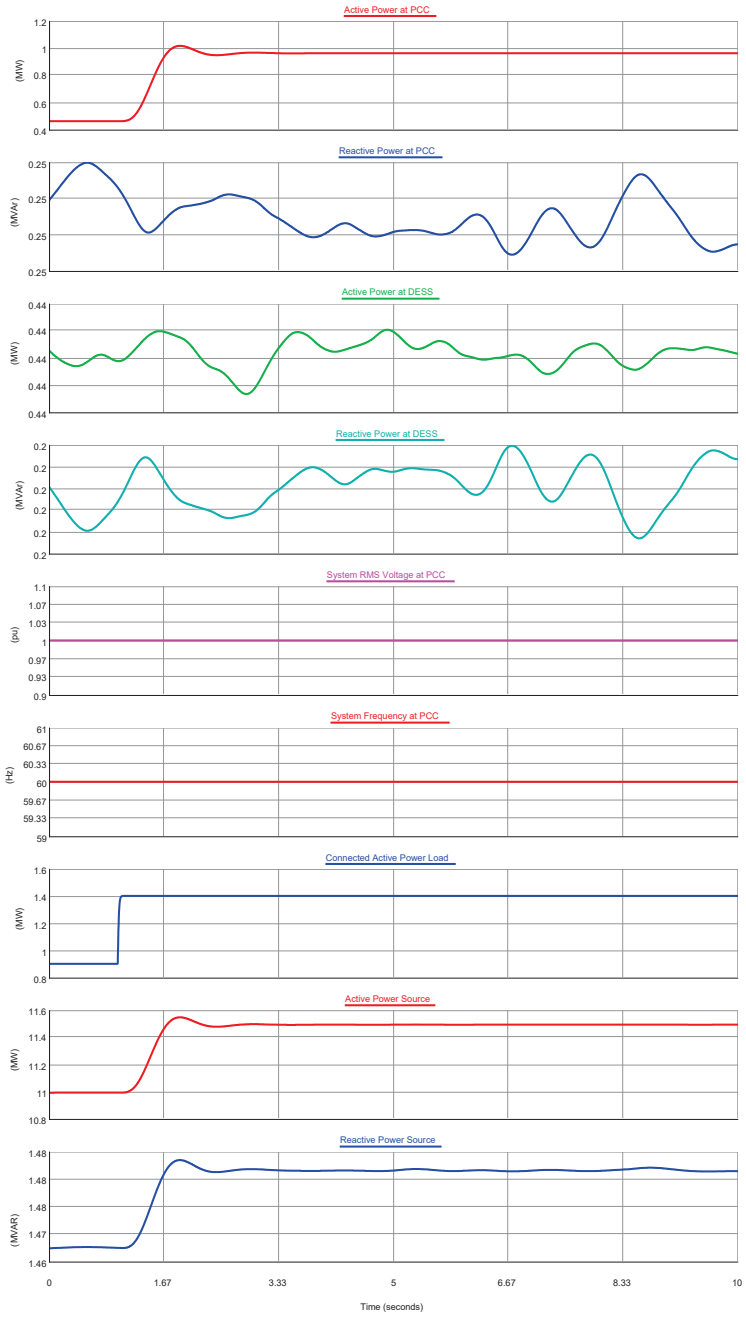


Figure 3.18: System Response for Test 2.1.3

TEST 2.1.4: INCREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On increasing the system pu voltage from 1 pu to 1.05 pu, the real power and the reactive power at the DER and PCC rode through the transient phase and settled at its previous set point at steady state. The increase in the reactive power generation by the source was due to the capacitor switching off because of increased voltage. This restricted the voltage at 1.045 pu instead of 1.05pu. The system frequency remained unaffected during this transition.

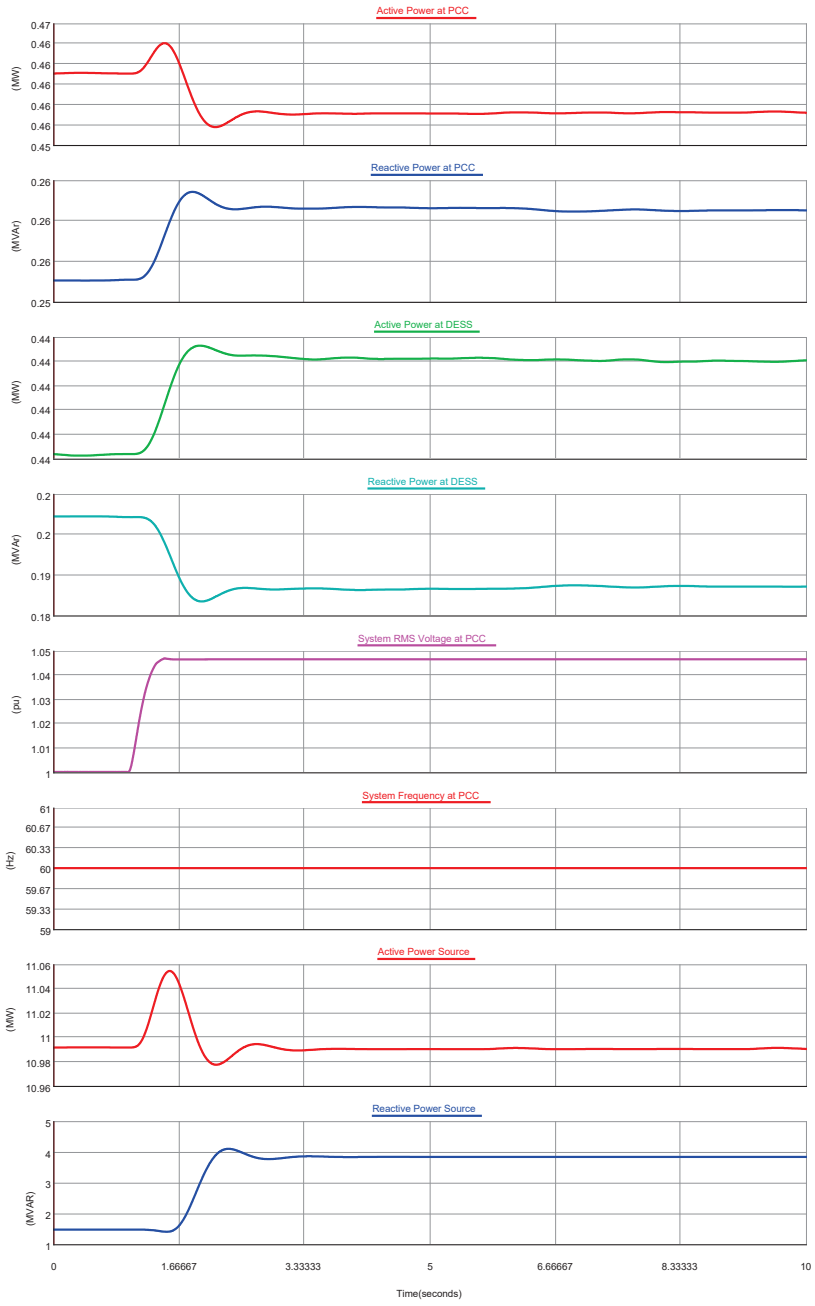


Figure 3.19: System Response for Test 2.1.4

TEST 2.1.5: INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was increased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER, in this mode, reacted to the change, rode through, and returned to steady state. The real and reactive power flows at the PCC and DER settled at their previous set points. The voltage remained unaffected by the frequency change.

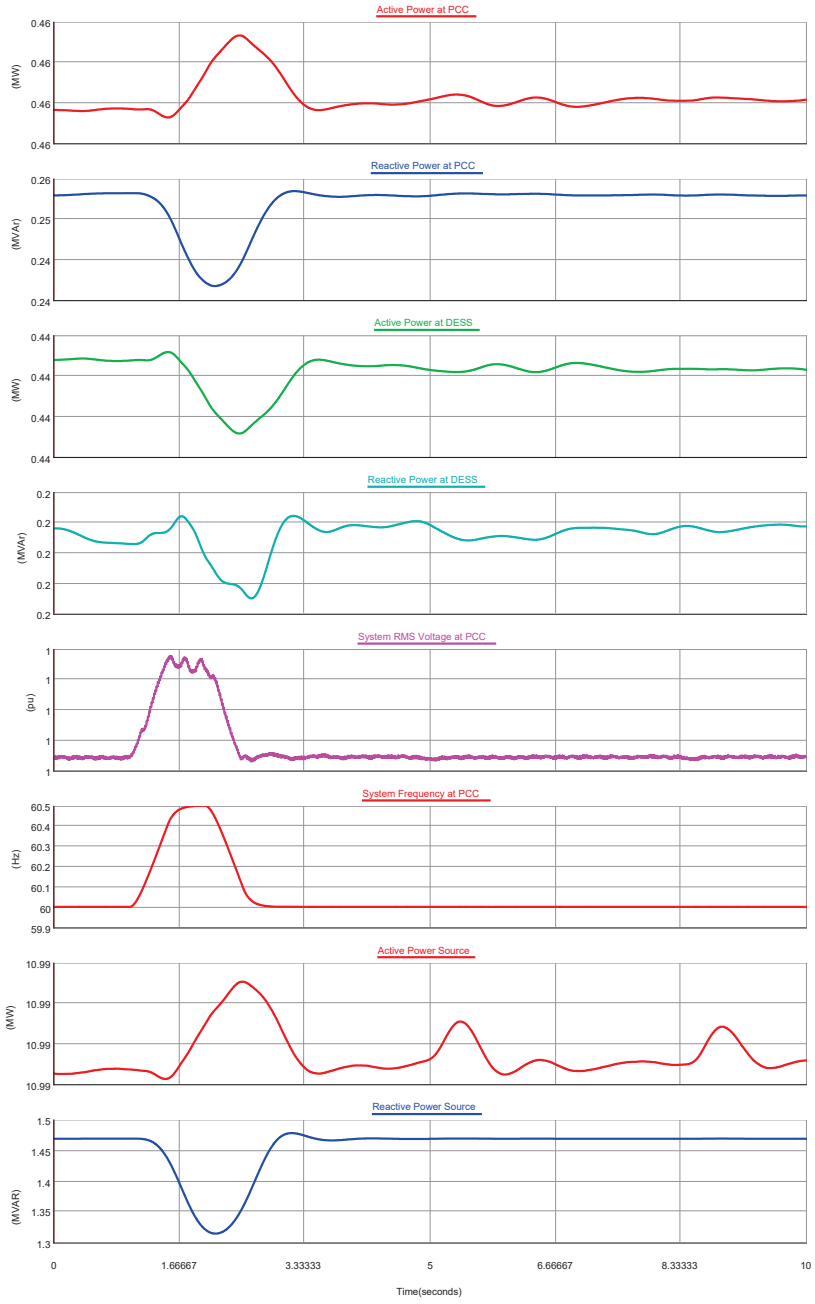


Figure 3.20: System Response for Test 2.1.5

TEST 2.1.6: INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ

Like Test 2.1.5, the DER rode through and settled into the previous set point at steady state.

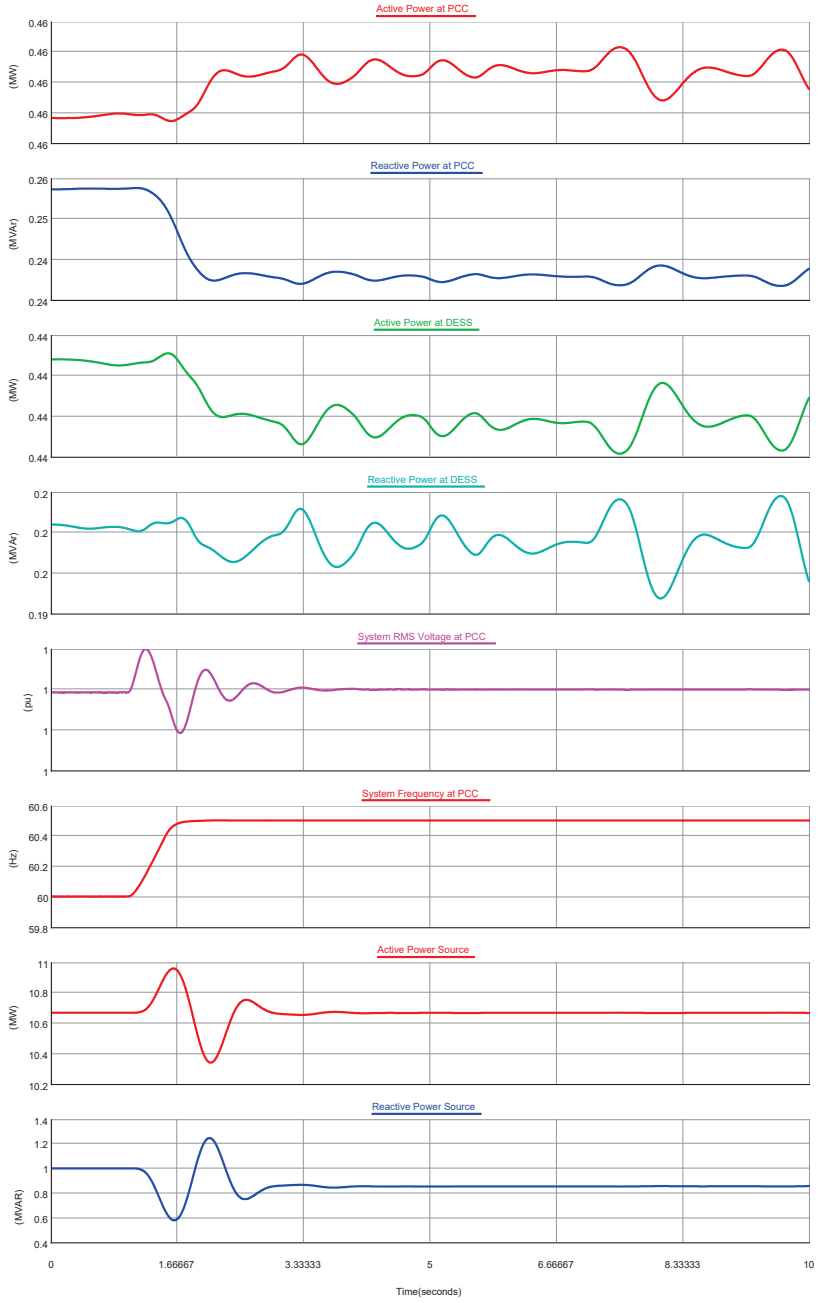


Figure 3.21: System Response for Test 2.1.6

Test 3 – Volt-Watt

This function was identified for use as compensation for the voltage variability that results from intermittent renewable sources or other loads. Volt-watt is intended to provide a flexible mechanism through which inverters may be configured to dynamically provide voltage stabilization. This function involves the dynamic production of active power (watts) to resist variations in the voltage at the PCC.

The objective is to counter any changes in the voltage by varying the output power. When the DER is set in volt-watt control mode, it tries to maintain the voltage of the system to 1 pu by curtailing the active power output.

The procedure for testing was as follows:

Step 1. Vary the system voltage beyond the nominal values in a stepped and/or transient manner to observe the behavior of the DER.

Step 2. Change the voltage by changing the load in steps or by changing the grid voltage (the DER should respond in such a way that the system voltage is maintained within the nominal values).

Step 3. Increase the output of the DER to its maximum capacity, which should lead to the voltage increase at the PCC bus (when the DER is put into volt-watt mode at this stage, the system voltage should revert into the nominal band because of the power curtailment by the function).

Compare the results with the baseline case and develop conclusions based on these findings.

Table 3.4 lists the tests that were conducted.

Table 3.4: DER Volt-Watt Test Cases

Test	Test Description	Expected Response
Test 3. x.1	Mode activation with active power set point of 500 kW	DER dispatches 500 kW at steady state
Test 3. x.2	Increase the system load by 500 kW	DER dispatches 500 kW at steady state
Test 3. x.3	Decrease the system load by 500 kW	DER dispatches 500 kW at steady state
Test 3. x.4	Increase the system voltage by 5%	DER decreases active power output to offset voltage increase

Note: “x” denotes the scenario under test.

SCENARIO 1: DER CLOSE TO A SUBSTATION

TEST 3.1.1: MODE ACTIVATION

The system local load was at 900 kW and 450 kVAR. On activating the volt-watt mode, the real and the reactive power at the DER and PCC settled at steady state. No visible disturbance was observed following mode activation. The voltage and frequency profile remained unaffected by the transition.

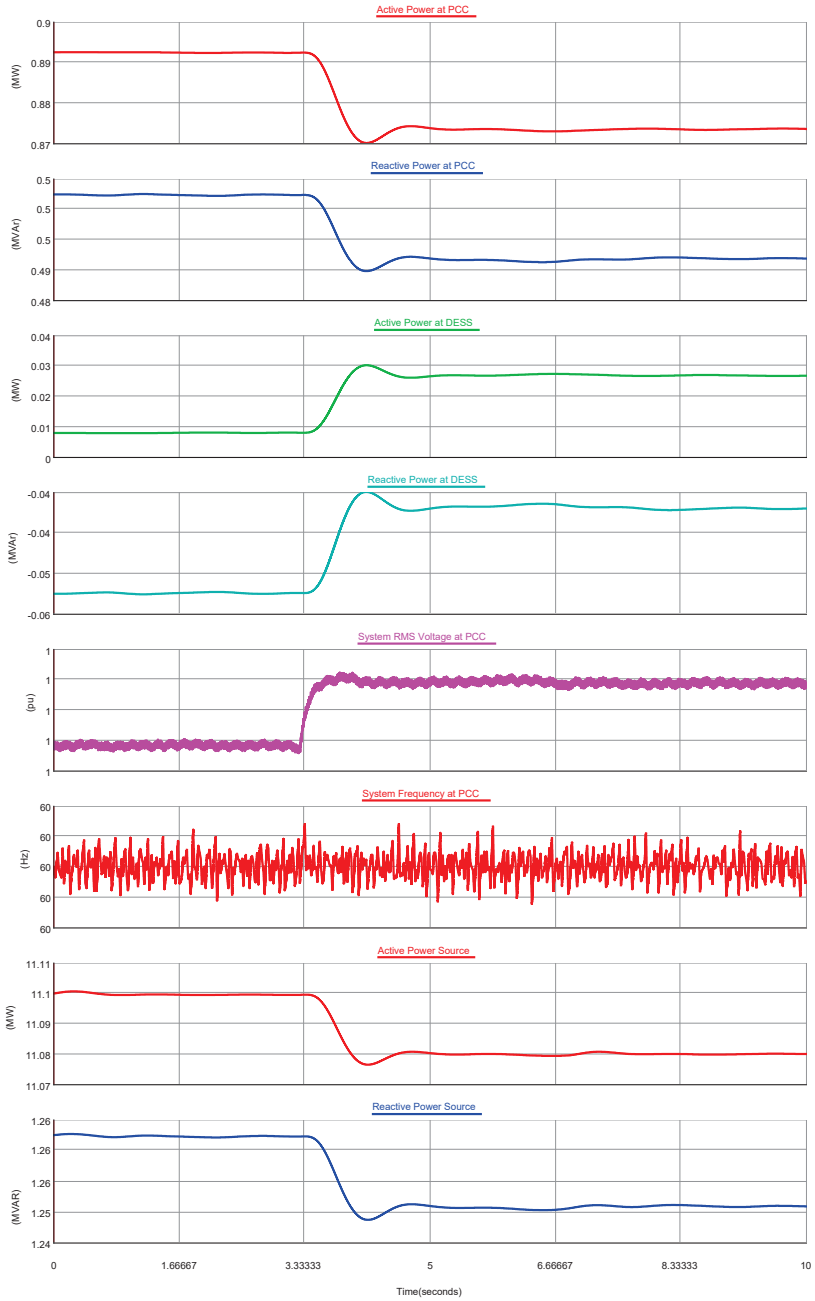


Figure 3.22: System Response for Test 3.1.1

TEST 3.1.2: INCREASE THE SYSTEM LOAD BY 500 KW

On increasing the active power load by 500 kW, the real power at the DER settled to steady state, while the additional load was supported by the grid through the PCC. The reactive power flow and system voltage and frequency were not affected.

TEST 3.1.3: DECREASE THE SYSTEM LOAD BY 500 KW

On decreasing the active power load by 500 kW, the real power at the DER settled to steady state, while the additional load was supported by the grid through the PCC. The reactive power flow and system voltage and frequency were not affected.

TEST 3.1.4: INCREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On increasing the system voltage by 5 percent from 1 pu to 1.05 pu, the active power at the DER fell so that more power was imported from the grid to keep the power import in the same direction. This balanced the power flow across the PCC to avoid reverse flow into the grid due to the increased voltage across the terminals. The reactive power returned to its prior set point during steady state, and the system frequency remained undisturbed during the transition. The increase in the reactive power generation by the source was due to the capacitor switching because of increased voltage, which restricted voltage to 1.045pu.

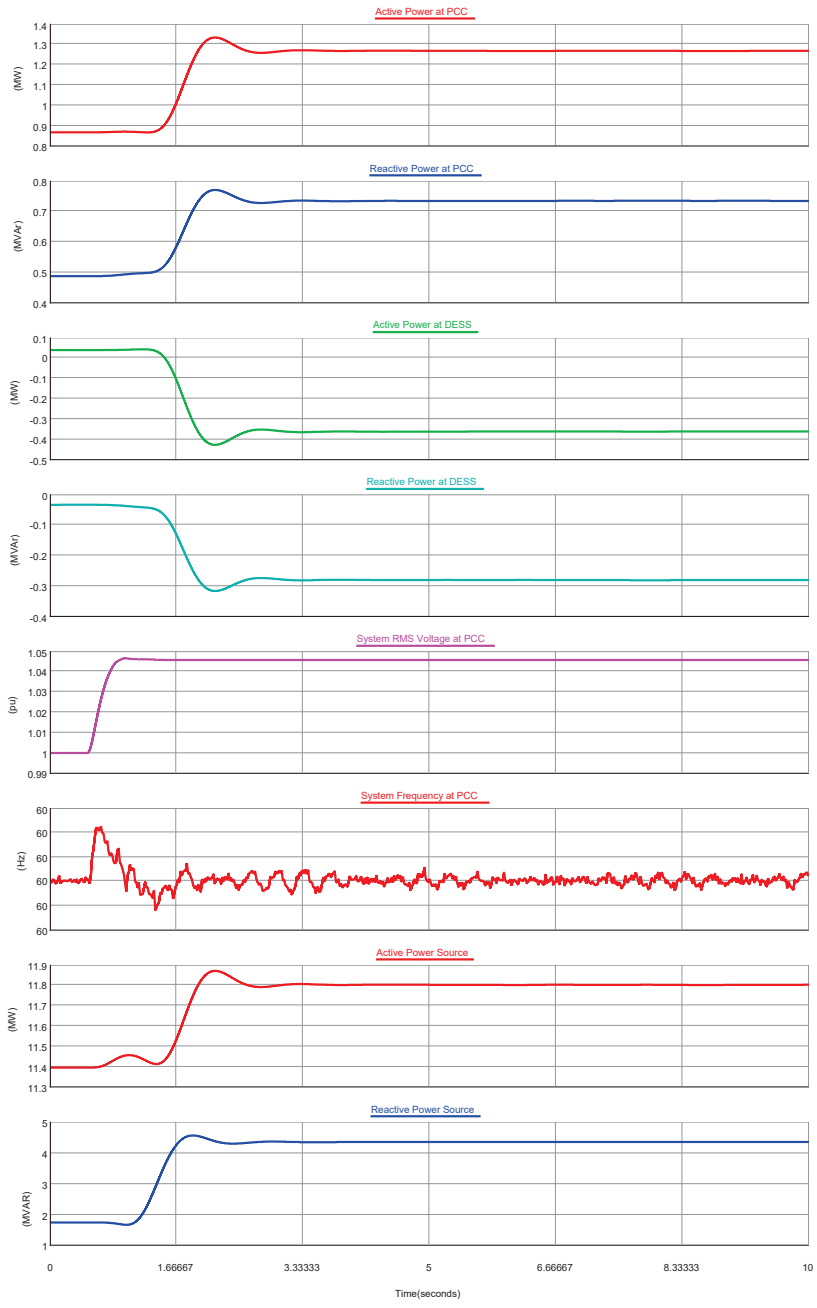


Figure 3.23: System Response for Test 3.1.4

SCENARIO 3: DER AT THE END OF A LONG FEEDER

TEST 3.3.1: MODE ACTIVATION

The system local load was at 900 kV and 450 kVAR. On activating the volt-watt mode, the real and the reactive power at the DER and PCC settled at steady state. No visible disturbance was observed following mode activation. The voltage and frequency profiles remained unaffected by the transition.

TEST 3.3.2: INCREASE THE SYSTEM LOAD BY 500 KW

On increasing the active power load by 500 kW, the real power at the DER settled to steady state, while the grid supported the additional load through the PCC. The reactive power flow and the system voltage and frequency were not affected.

TEST 3.3.3: DECREASE THE SYSTEM LOAD BY 500 KW

On decreasing the active power load by 500 kW, the real power at the DER settled to steady state, while the grid supported the additional load through the PCC. The reactive power flow and the system voltage and frequency were not affected.

TEST 3.3.4: INCREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On increasing the system voltage by 5 percent from 0.978 pu to 1.025 pu, the real power at the DER fell so that more power was imported from the grid to keep the power import in the same direction. This balanced the power flow across the PCC to avoid reverse flow into the grid due to the increased voltage across the terminals. The system frequency remained undisturbed during the transition.

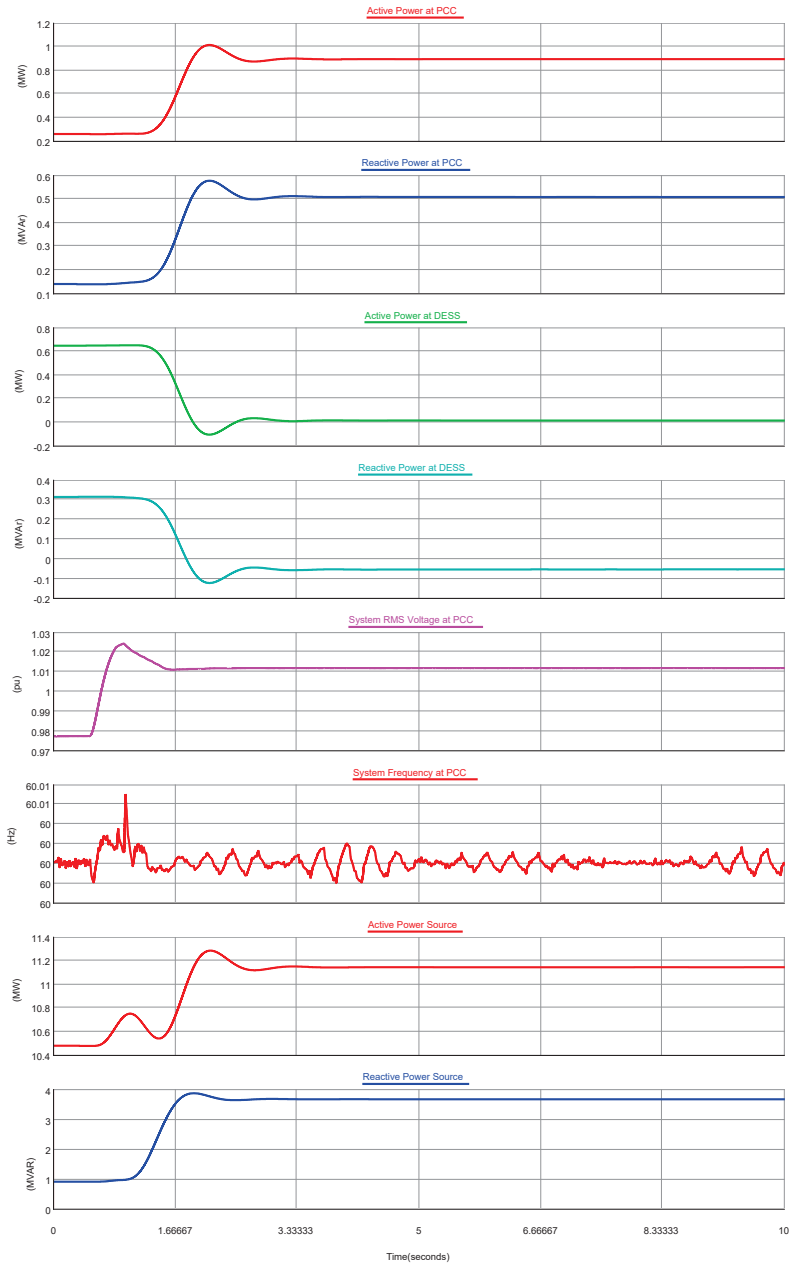


Figure 3.24: System Response for Test 3.3.4

SCENARIO 4: MULTIPLE DIVERSE TYPES OF DER ON THE SAME CIRCUIT

TEST 3.4.1: MODE ACTIVATION

The system local load was at 900 kV and 450 kVAR. On activating the volt-watt mode, the real and the reactive power at the DER and PCC settled at steady state. No visible disturbance was observed following mode activation. The voltage and frequency profiles remained unaffected by the transition.

TEST 3.4.2: INCREASE THE SYSTEM LOAD BY 500 KW

On increasing the active power load by 500 kW, the real power at the DER settled to steady state, while the additional load was supported by the grid through the PCC. The reactive power flow and the system voltage and frequency were not affected.

TEST 3.4.3: DECREASE THE SYSTEM LOAD BY 500 KW

On decreasing the active power load by 500 kW, the real power at the DER settled to steady state, while the additional load was supported by the grid through the PCC. The reactive power flow and the system voltage and frequency were not affected.

TEST 3.4.4: INCREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On increasing the system voltage by 5 percent from 1.0 pu to 1.05 pu, the real power at the DER fell so that more power was imported from the grid to keep the power import in the same direction. This balanced the power flow across the PCC to avoid reverse flow into the grid due to the increased voltage across the terminals. The reactive power returned to its prior set point during steady state, and the system frequency remained undisturbed during the transition. The increase in the reactive power generation by the source was due to the capacitor switching because of increased voltage, which restricts voltage to 1.045pu.

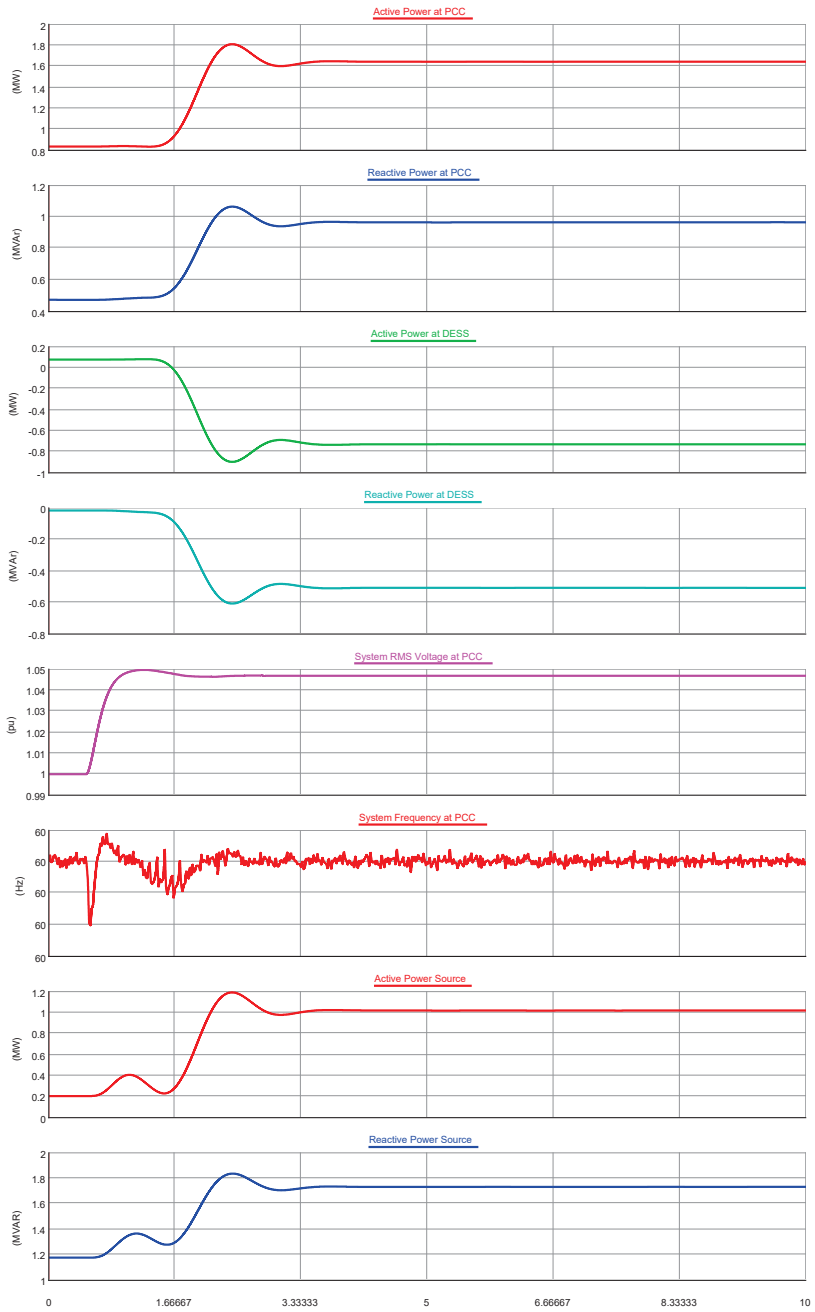


Figure 3.25: System Response for Test 3.4.4

Test 4 – Volt-VAR

This function is intended to provide a mechanism through which a DER may be configured to manage its own VAR output in response to a fluctuation in the local service voltage. This function involves the dynamic production of reactive power (VARs) to resist variations in the voltage at the PCC.

Using the different circuit scenarios, the DER is put into volt-VAR mode. The objective is to counter any changes in the voltage by varying the output reactive power. When the DER is set in volt-VAR mode, it tries to maintain the voltage of the system to 1 pu by regulating the reactive power output.

The procedure for testing was as follows:

Step 1. Vary the system voltage beyond the nominal values in a stepped and/or transient manner to observe the behavior of the DER (the DER should respond in such a way that the system voltage is maintained within the nominal values).
Step 2. Change the voltage by changing the load in steps or by changing the grid voltage (when the DER is put into volt-VAR mode, the system voltage should revert into the nominal band because of the DER reactive power regulation).
Step 3. Compare the results with the baseline case and develop conclusions based on these findings.

Table 3.5 lists the tests that were conducted.

Table 3.5: DER Volt-VAR Test Cases

Test	Test Description	Expected Response
Test 4. x.1	Increase the system voltage by 5%	DER decreases reactive power output to offset voltage increase
Test 4. x.2	Decrease the system voltage by 5%	DER increases reactive power output to offset voltage decrease
Test 4. x.3	a) Ramp up the system voltage to 109%, at the rate of 30% per minute, and hold it for 5 s b) Ramp down the system voltage to 90%, at the rate of 30% per minute, and hold it for 5 s c) Ramp up the system voltage, back to nominal voltage (refer to Figure 3.28)	DER decreases its reactive power output to offset voltage increases and following that DER increases its reactive power output to offset voltage decrease. DER settles back at 200 kVAR at steady state.
Test 4. x.4	Increase the system frequency by 0.5 Hz for 1 s	DER dispatches 200 kVAR at steady state
Test 4. x.5	Decrease the system frequency by 0.5 Hz for 1 s	DER dispatches 200 kVAR at steady state

Note: “x” denotes the scenario under test.

SCENARIO 1: DER CLOSE TO A SUBSTATION

TEST 4.1.1: INCREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On increasing the system voltage at the PCC from 1 pu to 1.05 pu, the reactive power output of the DER decreased and drew more reactive power from the grid through the PCC to maintain the node voltage at the PCC constant. The frequency and the real power at the PCC and DER remained unaffected. The capacitor switched off during the increase in system voltage due to which the reactive power output of the source increased drastically restricting the system voltage at 1.045pu.

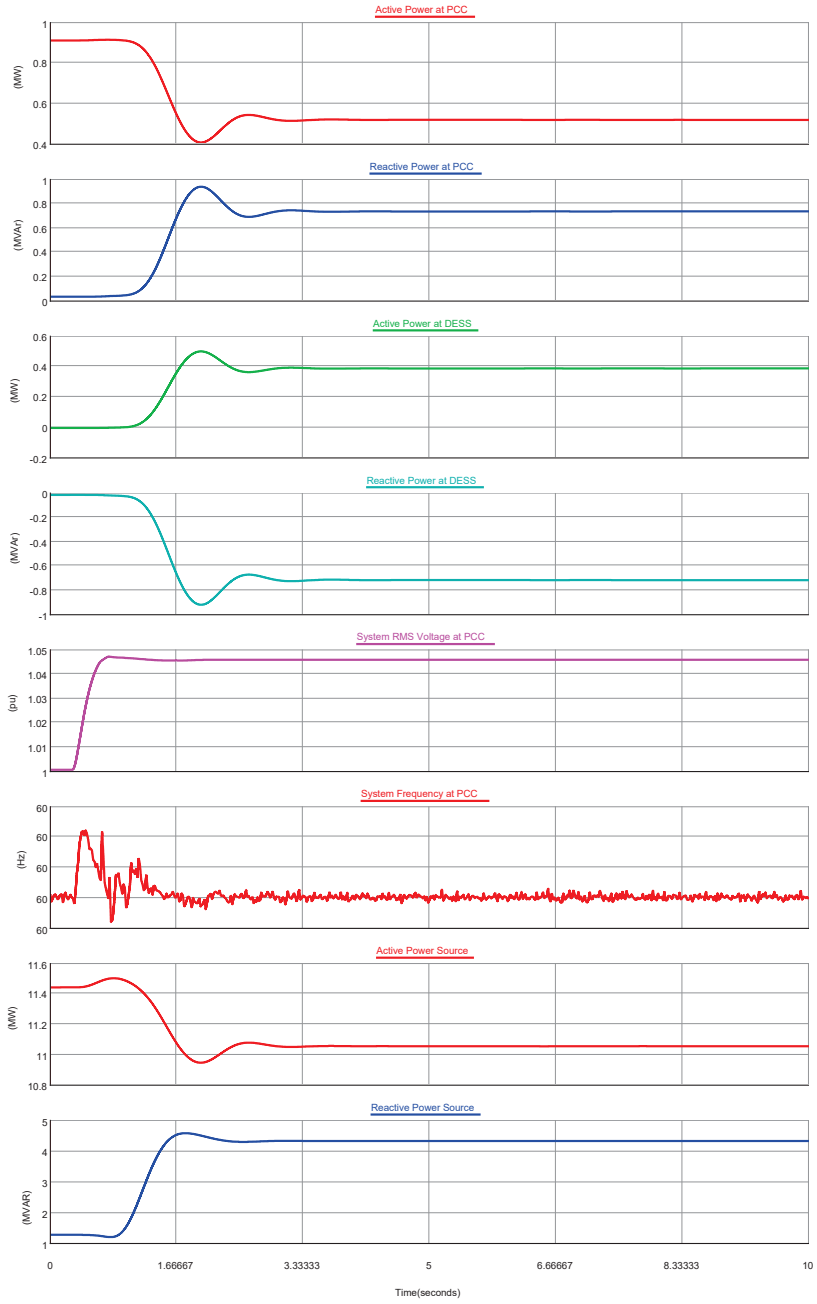


Figure 3.26: System Response for Test 4.1.1

TEST 4.1.2: DECREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On decreasing the system voltage at the PCC from 1 pu to 0.95 pu, the reactive power output of the DER increased and produced more reactive power maintain the node voltage at the PCC constant. The frequency remained unaffected by the change at steady state. The active power at the PCC and DER changed due to direction of the power flow.

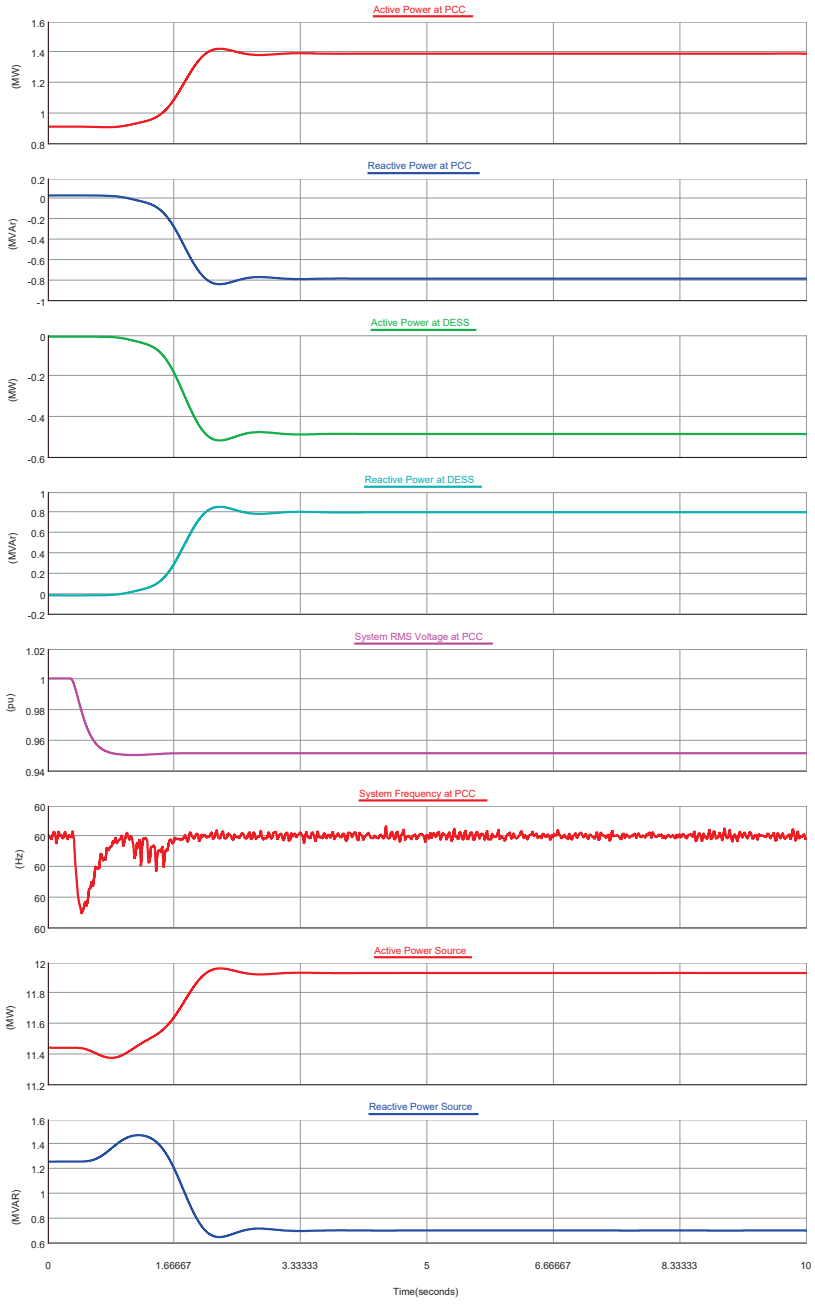


Figure 3.27: System Response for Test 4.1.2

TEST 4.1.3 VARY THE SYSTEM VOLTAGE

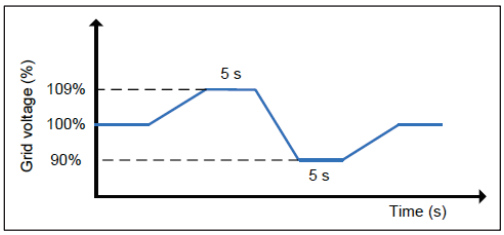


Figure 3.28: System Voltage Profile for Test 4.1.3

The voltage profile at the PCC was changed, as shown in Figure 3.28. On increasing the voltage to 109 percent, the DER reactive power output decreased, while the reactive power import from the grid increased. The increase in voltage caused both system capacitors to turn off during the rising edge of the voltage. This decrease in the DER reactive power output, along with the turning off the capacitor, caused the source reactive power to increase. Once the voltage reached 109 percent, it was held for 5 seconds. Then the voltage dropped from 109 percent to 90 percent, during which the reactive power output of the DER increased to maintain the node voltage constant. The reduction in voltage caused one of the capacitors near the end of the feeder to turn on, which supplemented the reactive power along with the DER, resulting in the reduction of reactive power import from the source. The real power and reactive power at the DER and PCC settled at its prior set point post the transition in the voltage. The system frequency remained unaffected by the change in voltage.

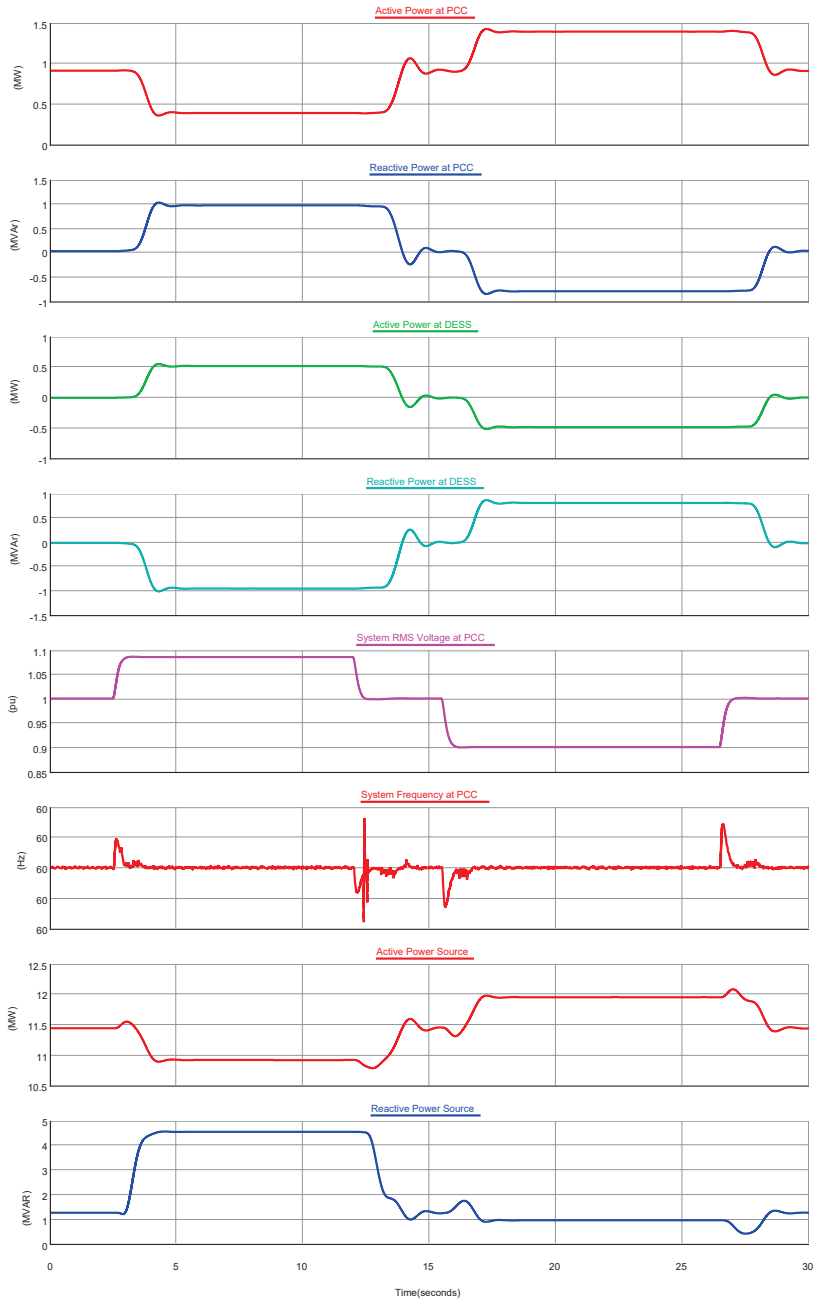


Figure 3.29: System Response for Test 4.1.3

TEST 4.1.4: INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was increased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER, in this mode, reacted to the change, rode through, and returned to steady state. The real and reactive power flows at the PCC and DER settled at their previous set points. The voltage was disturbed by the frequency change due to power flow but settled back to 1 pu in steady state.

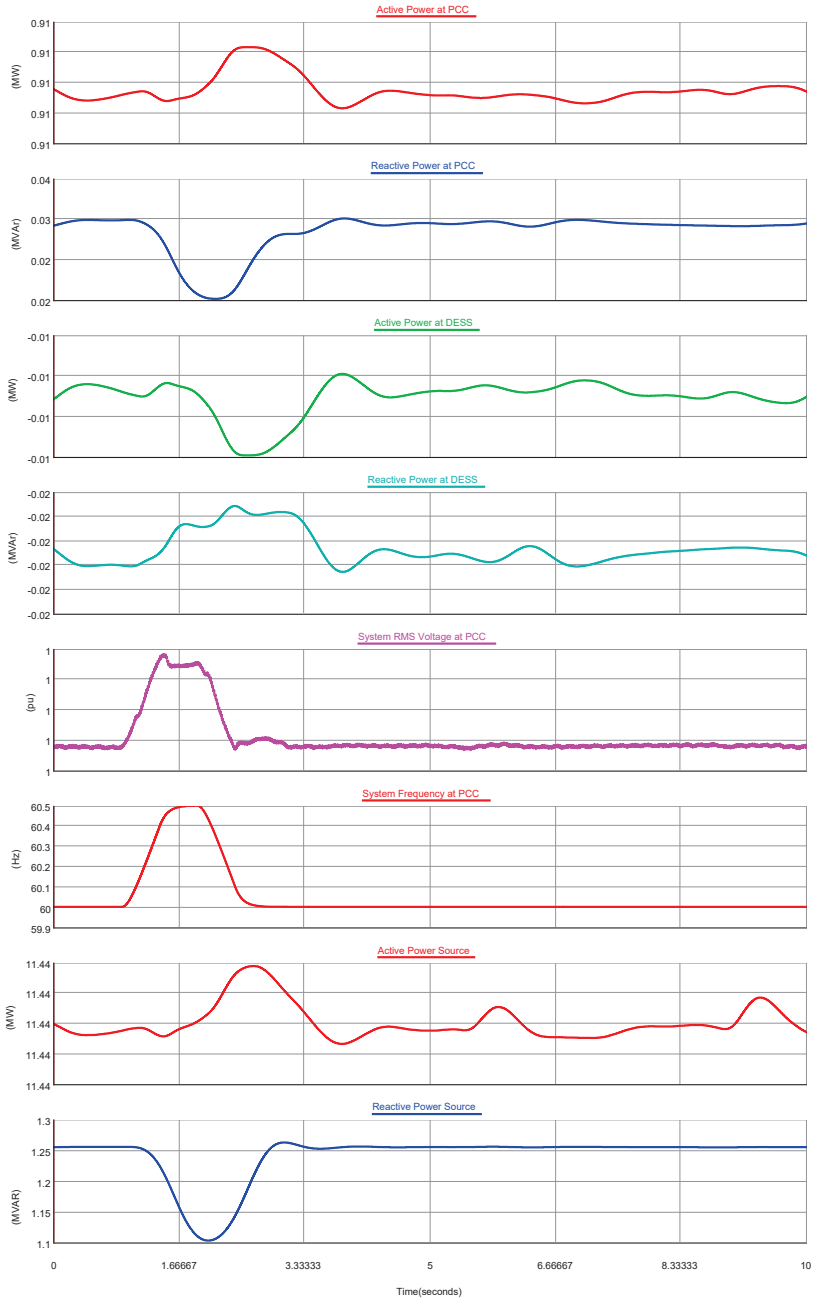


Figure 3.30: System Response for Test 4.1.4

TEST 4.1.5: DECREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was decreased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER, in this mode, it reacted to the change, rode through, and returned to steady state. The real and reactive power flows at the PCC and DER settled at their previous set points. The voltage was disturbed by the frequency change due to power flow but settled back to 1 pu in steady state.

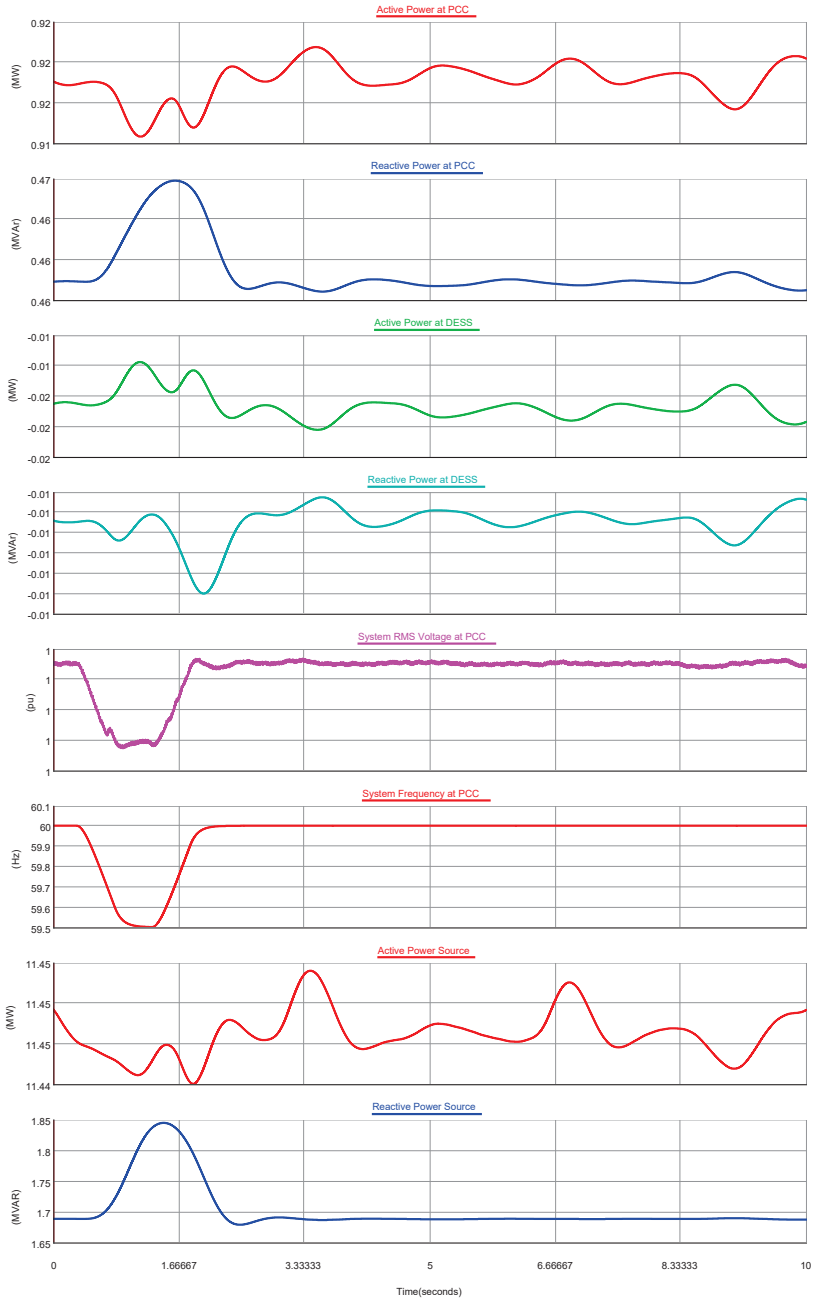


Figure 3.31: System Response for Test 4.1.5

SCENARIO 2: DER ON A COMPLEX CIRCUIT WITH A MULTITUDE OF CONTROLLABLE DEVICES

TEST 4.2.1: INCREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On increasing the system voltage at the PCC from 0.98pu to 1.038 pu, the reactive power output of the DER decreased and drew more reactive power from the grid through the PCC to maintain the node voltage at the PCC constant. The frequency and the real power at the PCC and DER remained unaffected by the change. The capacitor switched off during the increase in system voltage due to which the reactive power output of the source increased drastically restricting the system voltage at 1.025pu.

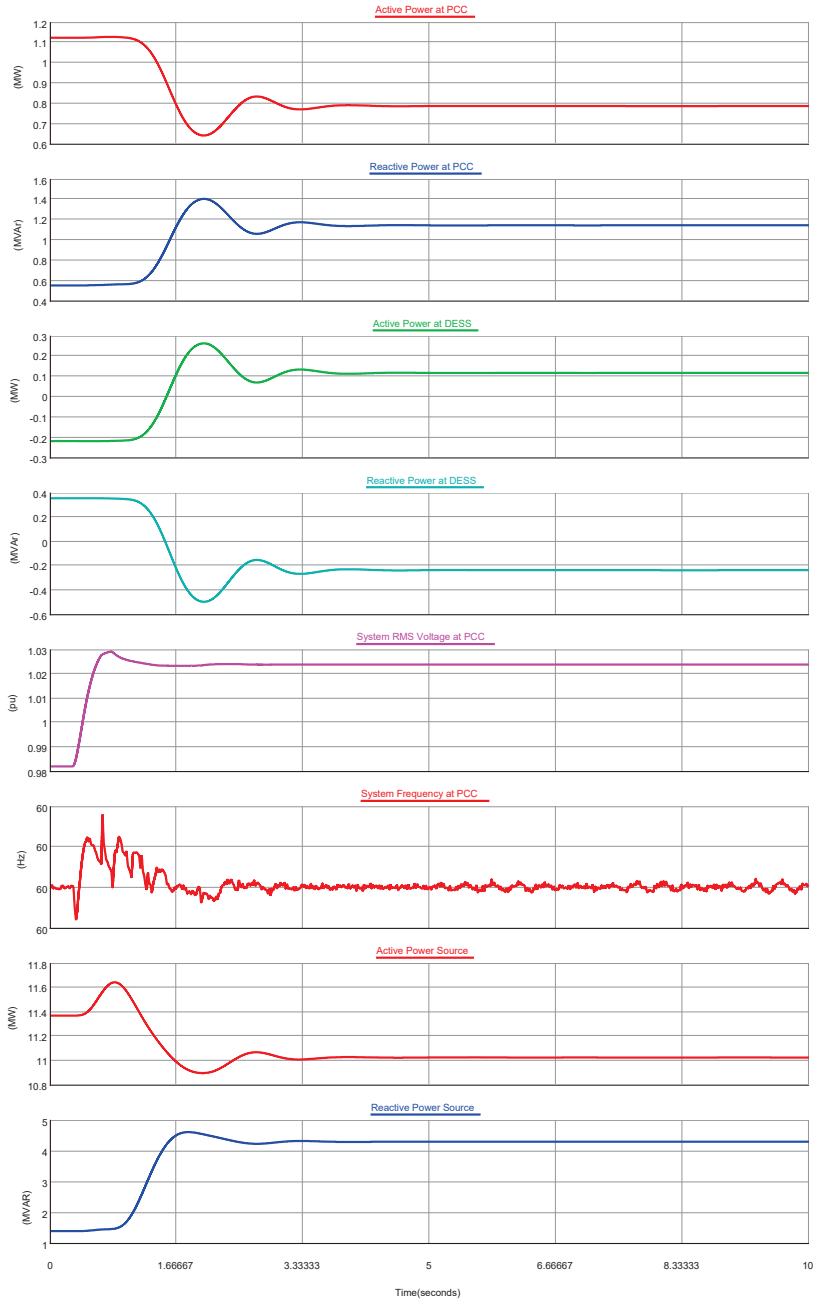


Figure 3.32: System Response for Test 4.2.1

TEST 4.2.2: DECREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On decreasing the system voltage at the PCC from 0.98 pu to 0.93 pu, the reactive power output of the DER increased and produced more reactive power to maintain the node voltage at the PCC constant. The frequency remained unaffected by the change at steady state. The active power at the PCC and DER changed due to direction of the power flow.

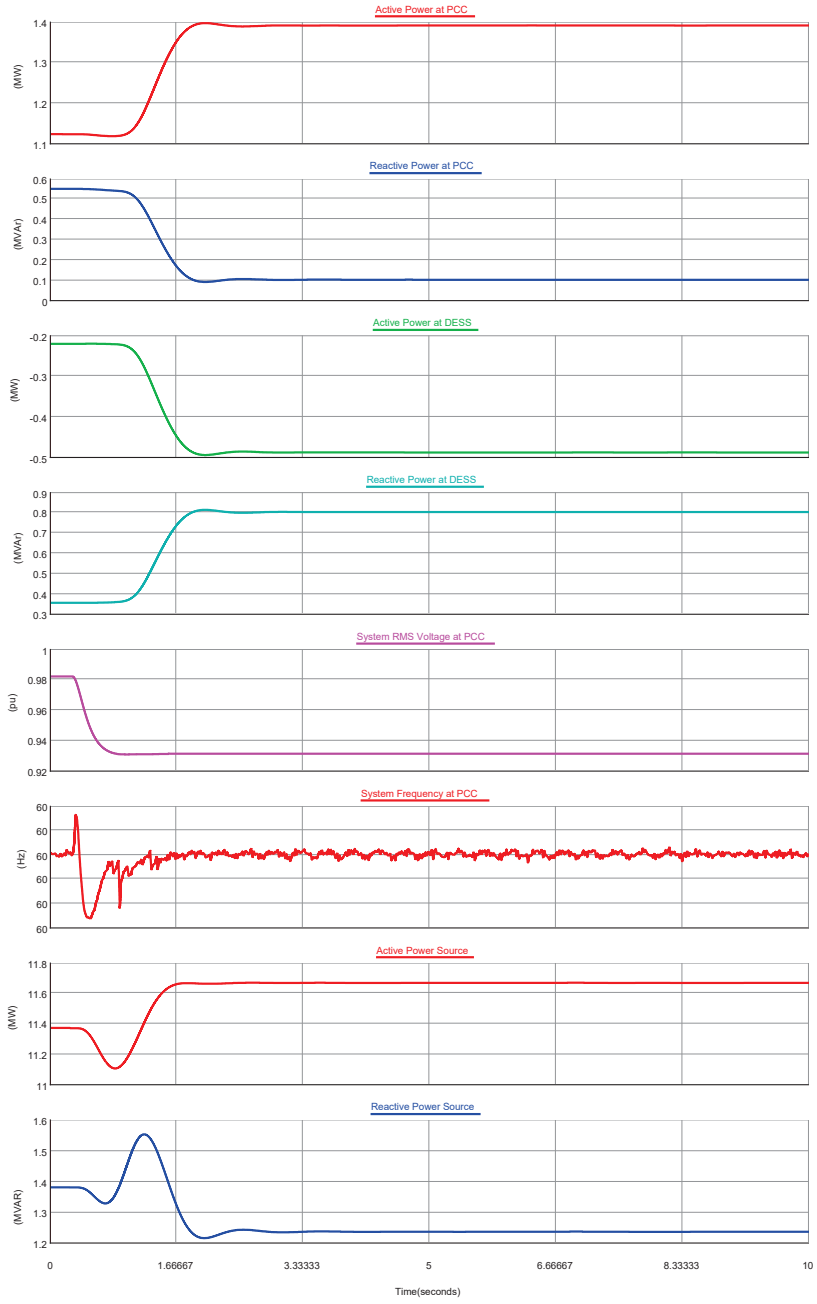


Figure 3.33: System Response for Test 4.2.2

TEST 4.2.3: VARY THE SYSTEM VOLTAGE

The voltage profile at the PCC was varied, as shown in Figure 3.28. The reduction in voltage caused one of the capacitors near the end of the feeder to turn on, which supplemented the reactive power along with the DER, resulting in the reduction of reactive power import from the source. The real power and reactive power at the DER and PCC settled at its prior set point post the transition in the voltage. The system frequency remained unaffected by the change in voltage.

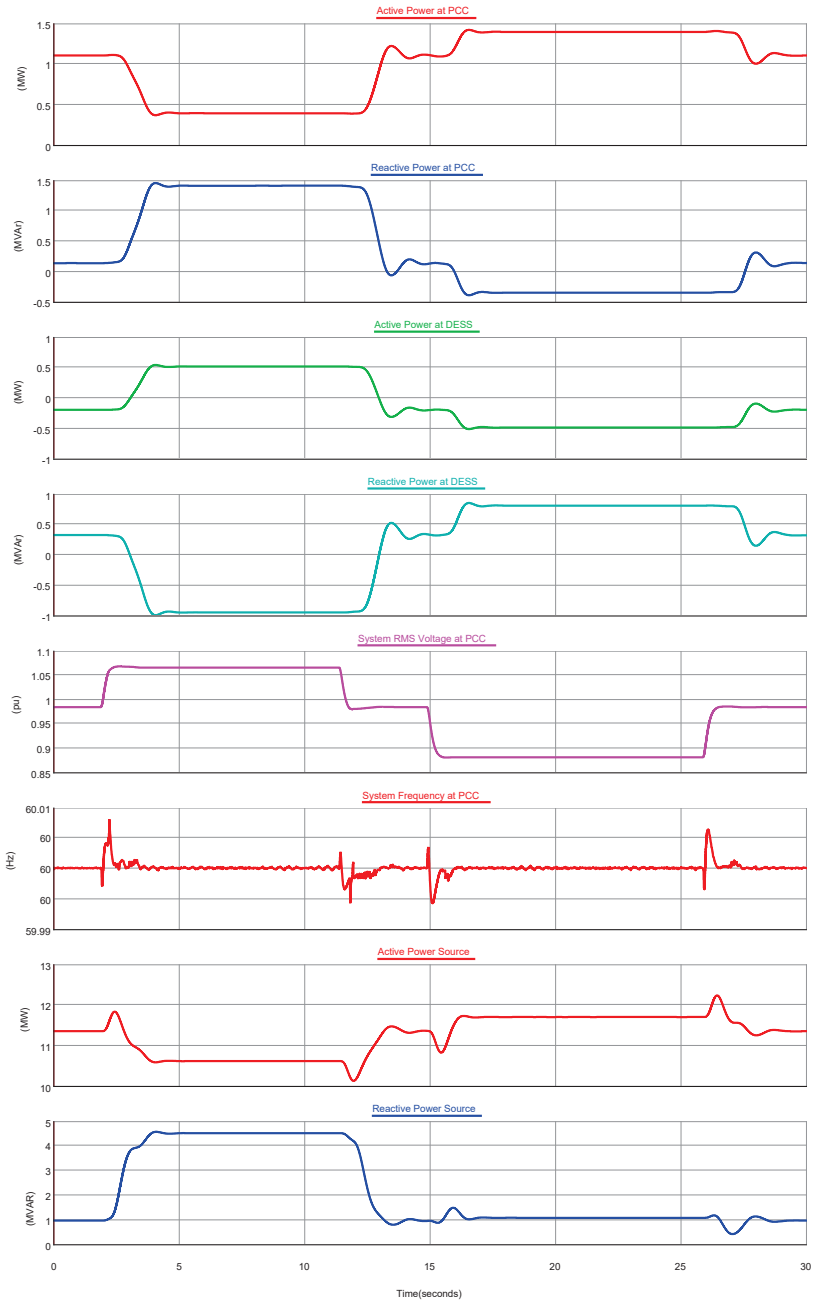


Figure 3.34: System Response for Test 4.2.3

TEST 4.2.4: INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was increased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER, in this mode, it reacted to the change, rode through, and returned to steady state. The real and reactive power flows at the PCC and DER settled at their previous set points. The voltage was disturbed by the frequency change due to the power flow but settled back to 1.018 pu in steady state.

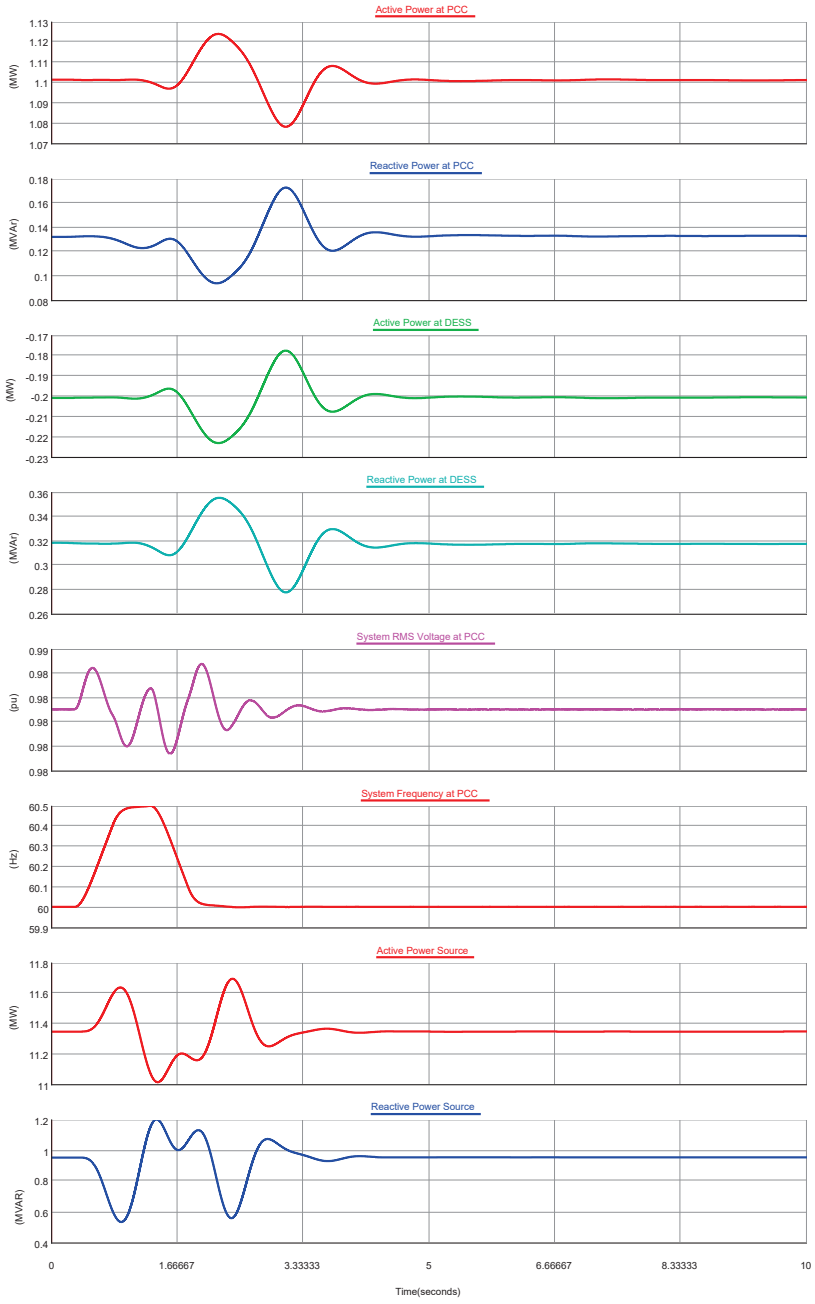


Figure 3.35: System Response for Test 4.2.4

SCENARIO 3: DER AT THE END OF A LONG FEEDER

TEST 4.3.1: INCREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On increasing the system voltage at the PCC from 0.978 pu to 1.025 pu, the reactive power output of the DER decreased and drew more reactive power from the grid through the PCC to maintain the node voltage at the PCC constant. The frequency and real power at the PCC and DER remained unaffected by the change. The capacitor switched off during the increase in system voltage because of which the reactive power output of the source increased drastically restricting the system voltage at 1.012pu.

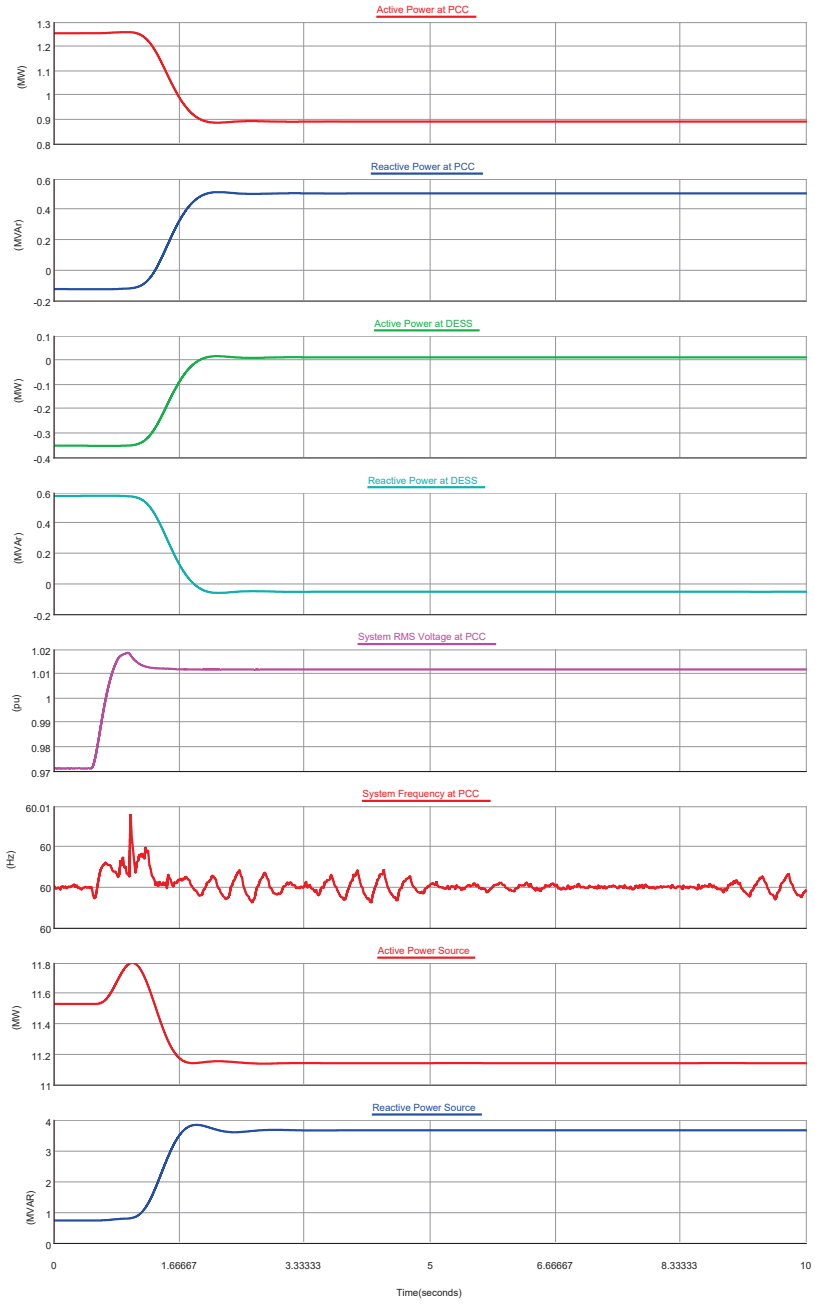


Figure 3.36: System Response for Test 4.3.1

TEST 4.3.2: DECREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On decreasing the system voltage at the PCC from 0.978 pu to 0.925 pu, the reactive power output of the DER increased and produced more reactive power maintain the node voltage at the PCC constant. The frequency remained unaffected by the change at steady state. The active power at the PCC and DER changed due to direction of the power flow.

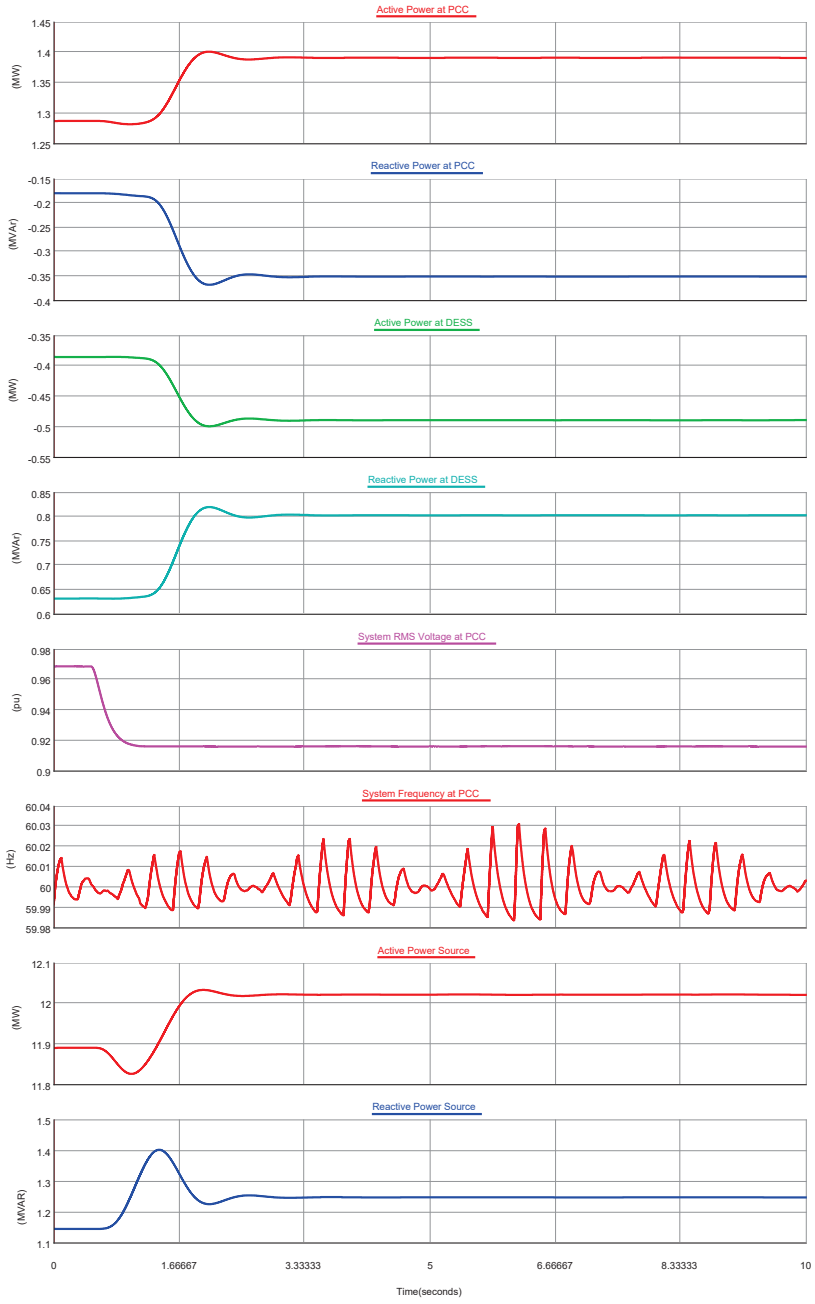


Figure 3.37: System Response for Test 4.3.2

TEST 4.3.3: VARY THE SYSTEM VOLTAGE

The voltage profile at the PCC is varied, as shown in Figure 3.28. The real power and reactive power at the DER and PCC settled at its prior set point post the transition in the voltage. The system frequency remained unaffected by the change in voltage.

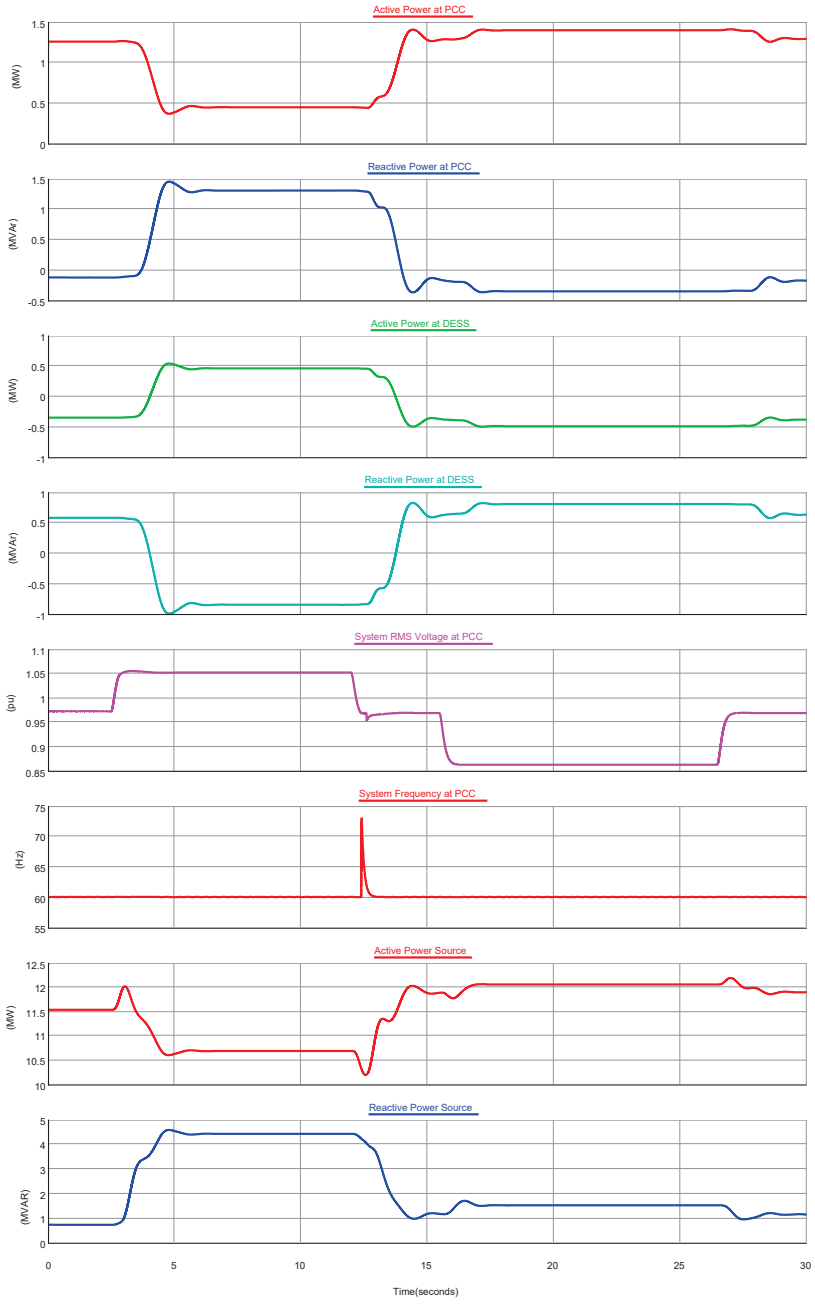


Figure 3.38: System Response for Test 4.3.3

TEST 4.3.4: INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was increased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER, in this mode, reacted to the change, rode through, and returned to steady state. The real and reactive power flows at the PCC and DER settled at their previous set points. The voltage was disturbed by the frequency change due to power flow but settled back to 0.978 pu in steady state.

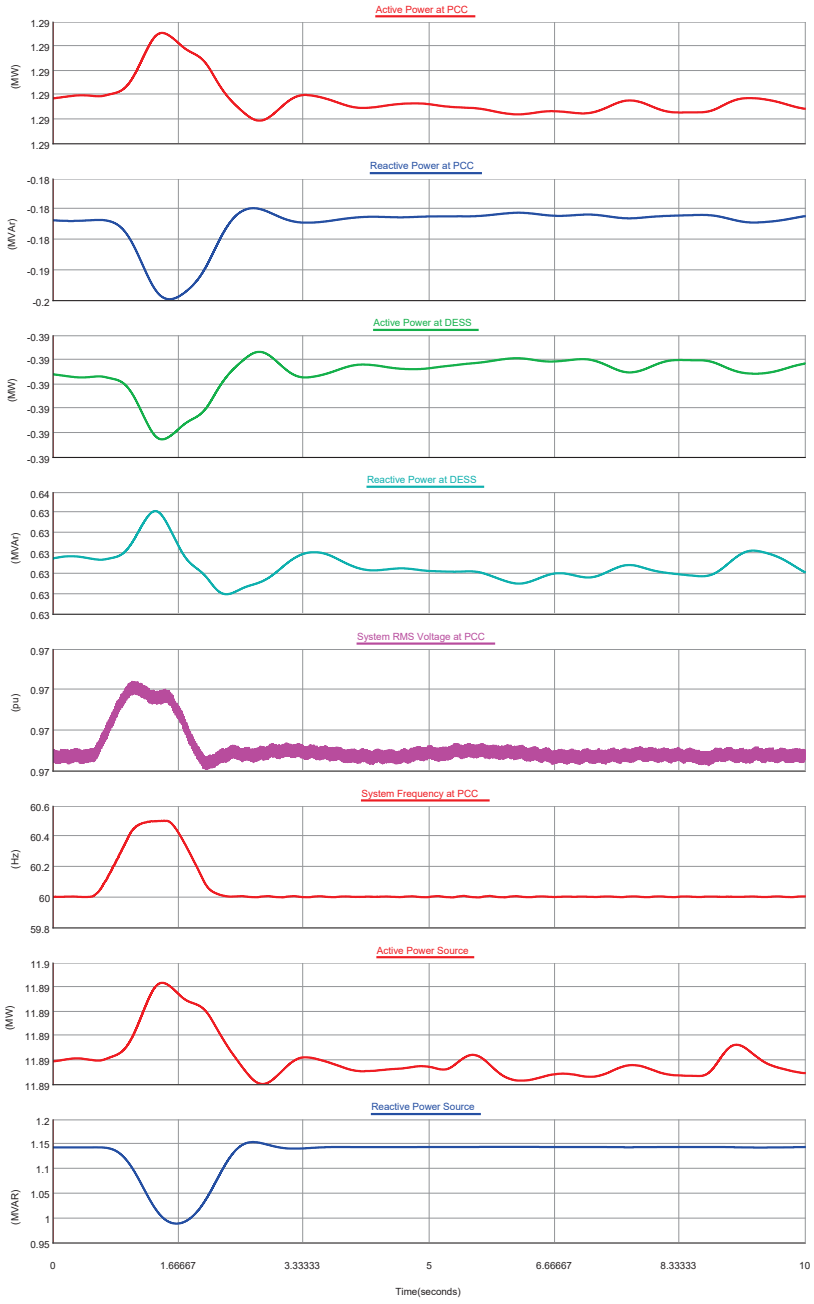


Figure 3.39: System Response for Test 4.3.4

Test 5 – Frequency-Watt

This function is intended to provide a mechanism through which a DER may be configured to manage its own active power output in response to the fluctuations in the system frequency. This function involves the dynamic production of active power to resist variations in the system frequency.

The objective is to counter any changes in the frequency by varying the output power. When the DER is in frequency-watt mode, it tries to maintain the frequency of the system to 60 Hz by regulating active power.

The procedure for testing was as follows:

Step 1. Vary the system frequency beyond the nominal values in a stepped and/or transient manner to observe the behavior of the DER (the DER should respond in such a way that the system frequency is maintained within the nominal values).

Step 2. Change the system frequency by changing the load in steps or by changing the grid frequency (when the DER is put into frequency-watt mode, the system frequency should revert to the nominal band because of the DER active power regulation).

Step 3. Compare the results with the base line case and develop the conclusions based on these findings.

Table 3.6 lists the tests that were conducted.

Table 3.6: DER Frequency-Watt Test Cases

Test	Test Description	Expected Response
Test 5. x.1	Increase the system frequency by 0.5 Hz for 1 s	DER decreases active power output to offset frequency increase. DER dispatches 500 kW at steady state.
Test 5. x.2	Decrease the system frequency by 0.5 Hz for 1 s	DER increases active power output to offset frequency decrease. DER dispatches 500 kW at steady state
Test 5. x.3	a) Ramp up the system frequency to 60.5 Hz at the rate of 0.1 Hz per second, and hold it for 5 s b) Ramp down the system frequency to 59.7 Hz at the rate of 0.1 Hz per second, and hold it for 5 s)	DER decreases its active power output to offset frequency increases and following that DER increases its active power output to offset frequency decrease. DER settles back at 500 kW at steady state.
Test 5. x.4	Increase the system frequency by 0.5 Hz for 5 s	DER decreases active power output to offset frequency increase
Test 5. x.5	Decrease the system frequency by 0.5 Hz for 5 s	DER increases active power output to offset frequency decrease

Note: "x" denotes the scenario under test.

SCENARIO 2: DER ON A COMPLEX CIRCUIT WITH A MULTITUDE OF CONTROLLABLE DEVICES

TEST 5.2.1: INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was increased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER responded to the change in frequency by increasing its active power output correspondingly and settled at its prior set point at steady state. The reactive power flow at the PCC and DER settled at its prior set point. The voltage was disturbed by the frequency change due to power flow but settles back to 1.01 pu in steady state.

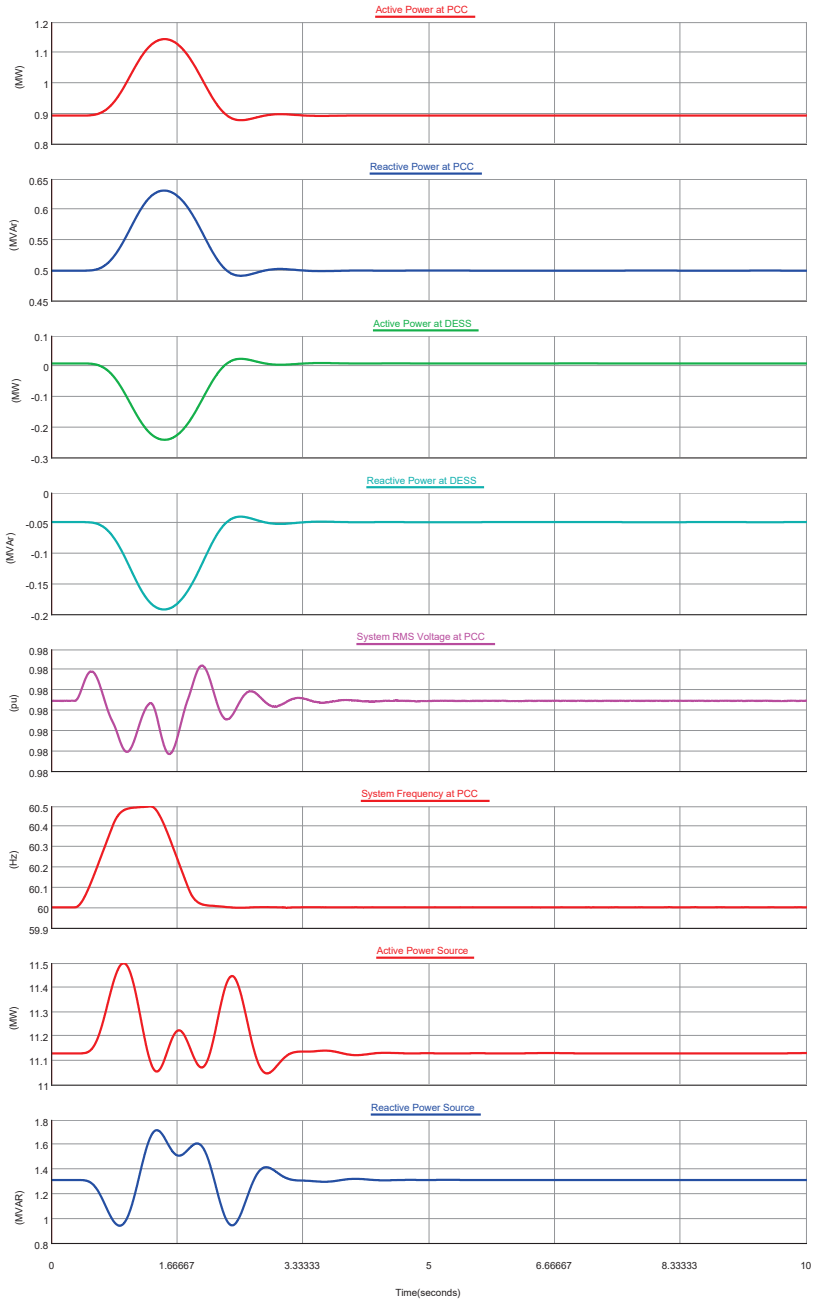


Figure 3.40: System Response for Test 5.2.1

TEST 5.2.2: DECREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was decreased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER responded to the change in frequency by increasing its active power output correspondingly and settled at its prior set point at steady state. The reactive power flow at the PCC and DER settled at its prior set point. The voltage was disturbed by the frequency change due to power flow but settled back to 1.01 pu in steady state.

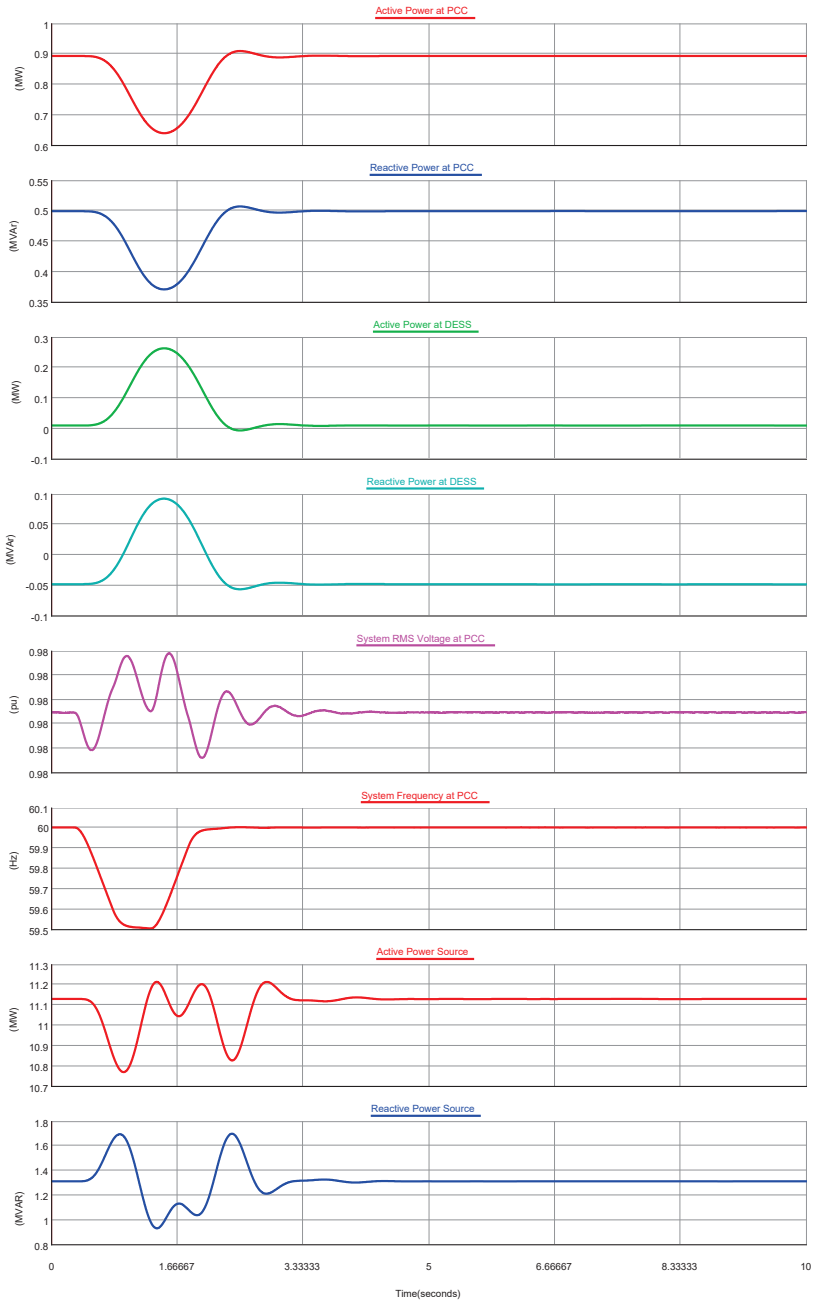


Figure 3.41: System Response for Test 5.2.2

TEST 5.2.3: VARY THE SYSTEM FREQUENCY

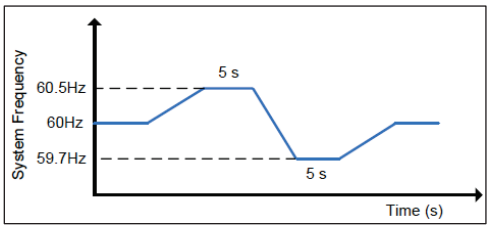


Figure 3.42: System Frequency Profile for Test 5.1.8

On increasing the system frequency to 60.5 Hz at a ramp rate of 0.1 Hz per second (as shown in Figure 3.42), the real power across the DER reduced, while the active power import across the PCC increased. The frequency was held at 60.5 Hz for a period of 5 seconds, during which the active power across the PCC and DER began to settle. Once the frequency started decreasing from 60.5 Hz to 59.7 Hz and was held for another 5 seconds, the active power output of the DER increased and the import across the PCC reduced. The active power settled at its previous set point of 500 kW during steady-state conditions following the disturbances. The reactive power was disturbed during this transition and settled at its previous set point during steady-state conditions. The system voltage was affected during this transition but returned to 1.01 pu during steady-state conditions.

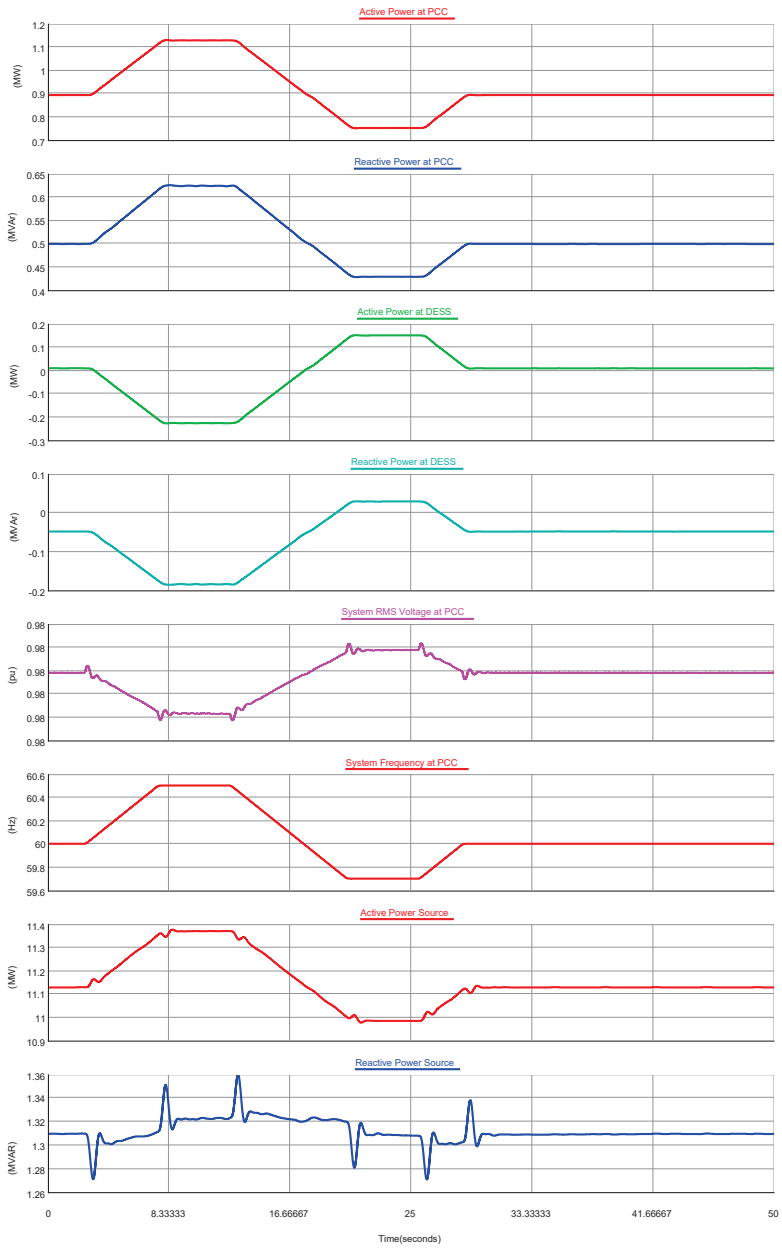


Figure 3.43: System Response for Test 5.2.3

TEST 5.2.4: INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ

On increasing the system frequency by 0.5 Hz, the DER responded to the frequency change by reducing its power output and settled at a new set point per the frequency-watt droop of the inverter. This caused more active power to be drawn from the grid. The reactive power across the DER and PCC remained the same, while the system voltage settled into 1 pu at steady state.

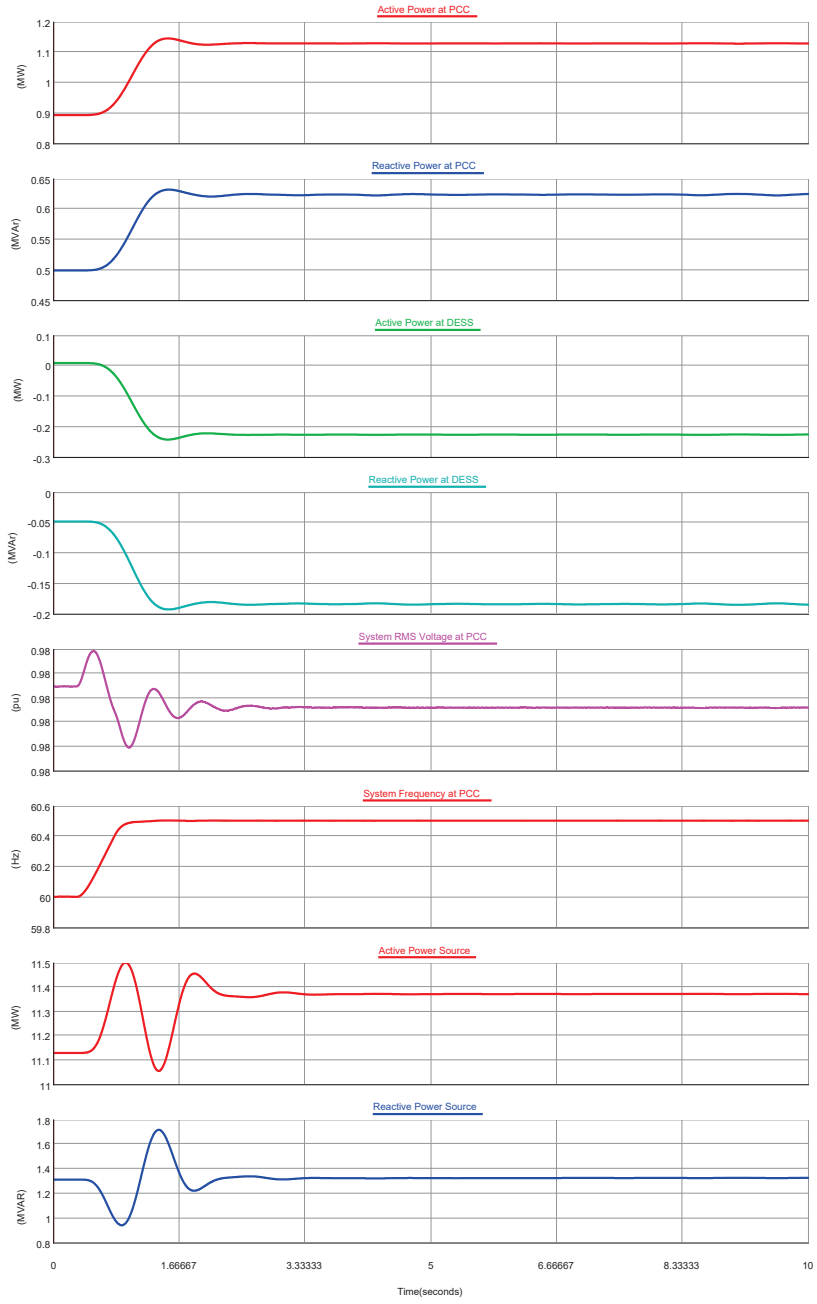


Figure 3.44: System Response for Test 5.2.4

TEST 5.2.5: DECREASE THE SYSTEM FREQUENCY BY 0.5 HZ

On decreasing the system frequency by 0.5 Hz, the DER responded to the frequency changes by increasing its power output and settled at a new set point per the frequency-watt droop of the inverter. This reduced the active power import from the grid through the PCC. The reactive power across the DER and PCC remained the same, while the system voltage settled into 1 pu at steady state.

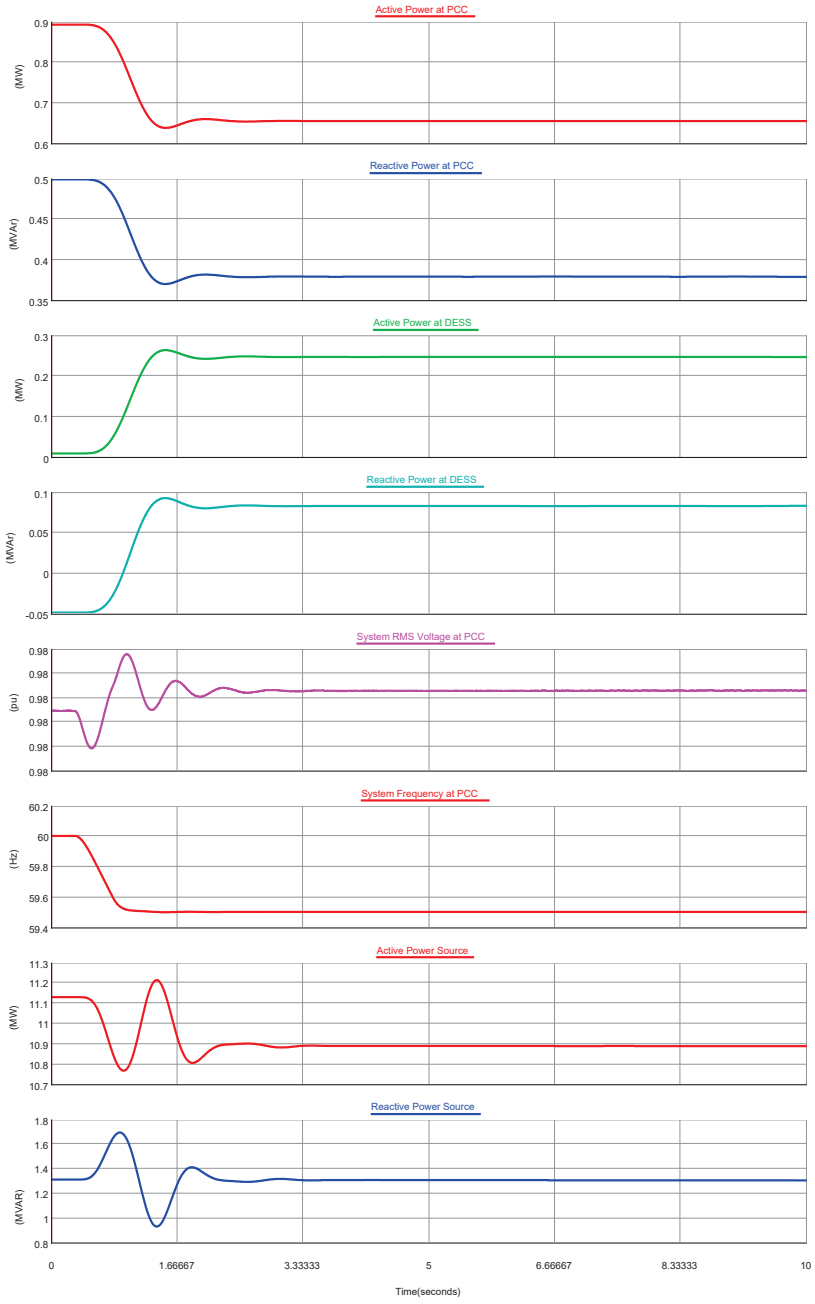


Figure 3.45: System Response for Test 5.2.5

SCENARIO 3: DER AT THE END OF A LONG FEEDER

TEST 5.3.1: INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was increased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER responded to the change in frequency by increasing its active power output correspondingly and settled at its prior set point at steady state. The reactive power flow at the PCC and DER settled at its prior set point. The voltage was disturbed by the frequency change due to power flow but settled back to 0.978 pu in steady state.

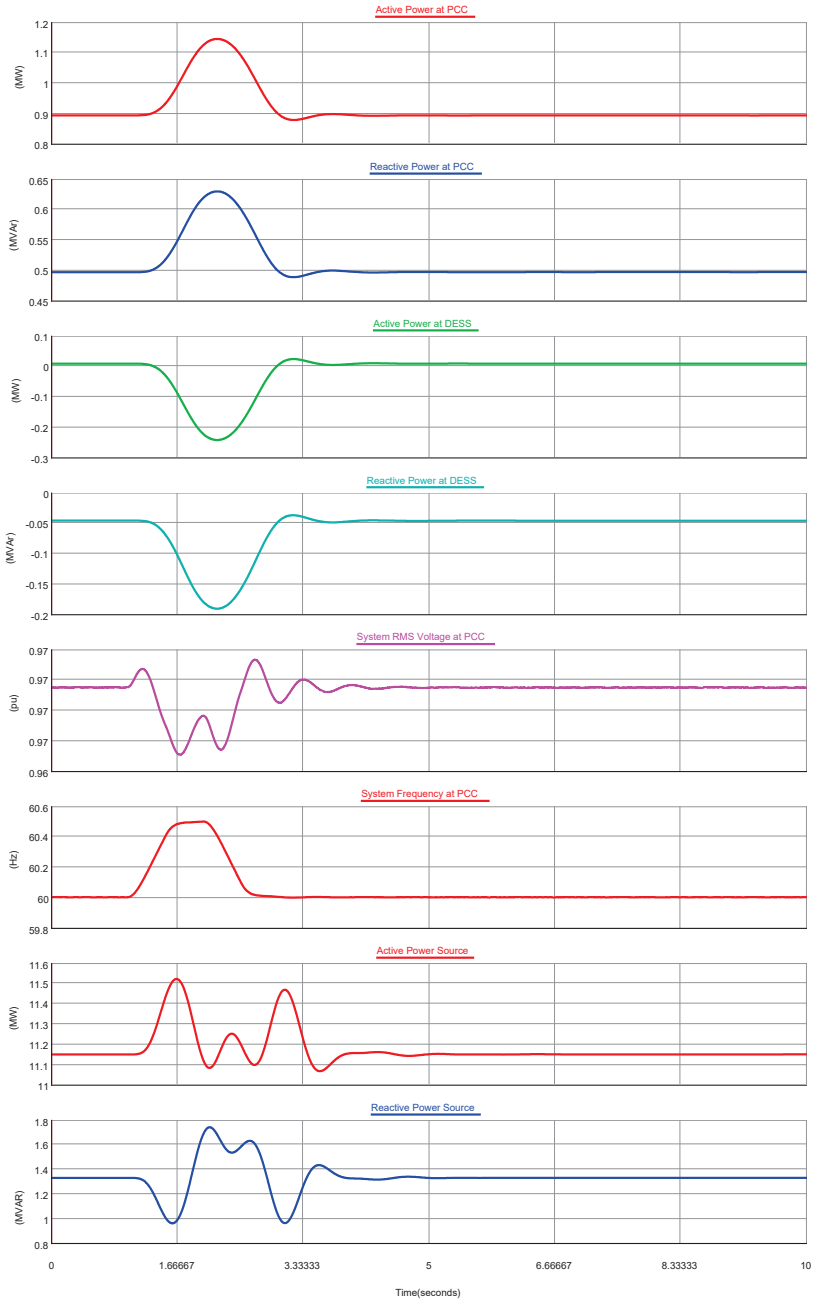


Figure 3.46: System Response for Test 5.3.1

TEST 5.3.2: DECREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was decreased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER responded to the change in frequency by increasing its active power output correspondingly and settled at its prior set point at steady state. The reactive power flow at the PCC and DER settled at its prior set point. The voltage was disturbed by the frequency change due to power flow but settled back to 0.978 pu in steady state.

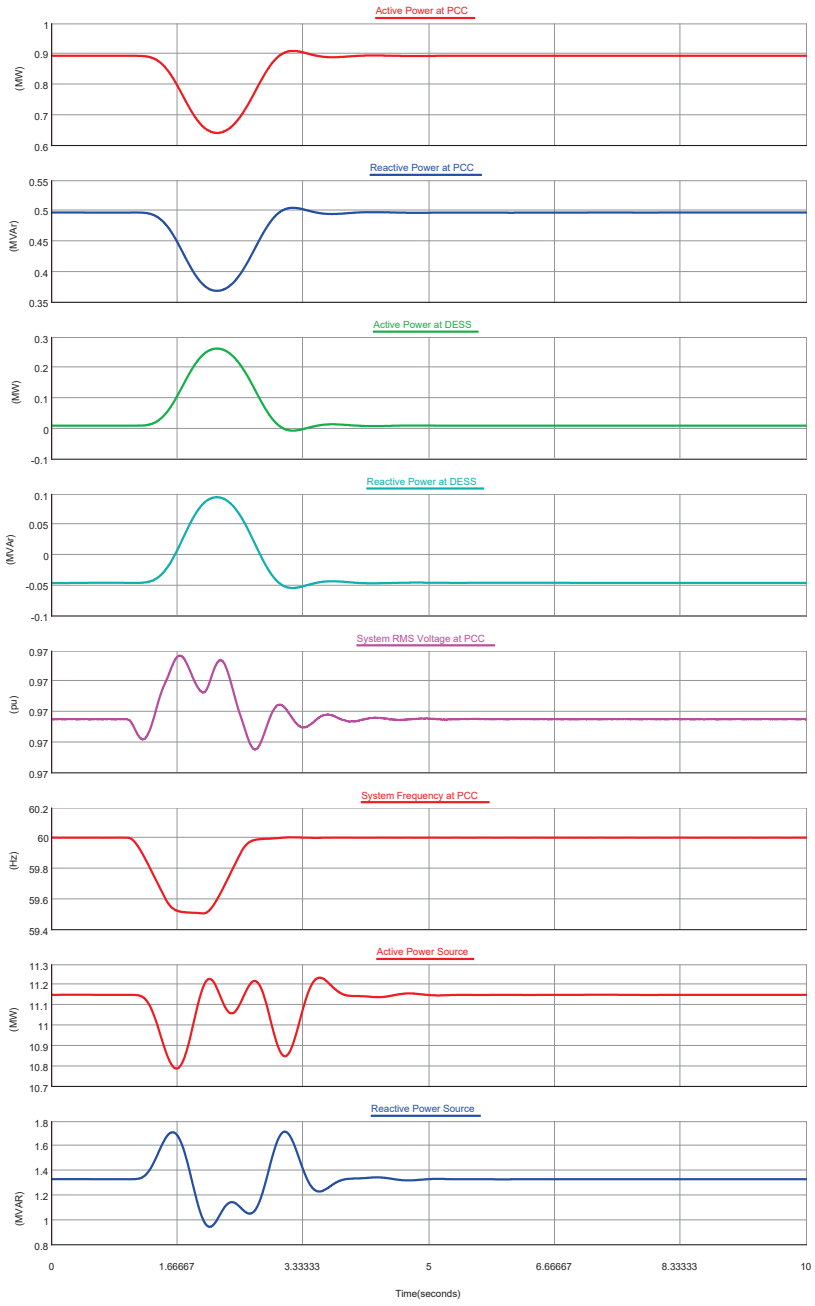


Figure 3.47: System Response for Test 5.3.2

TEST 5.3.3: VARY THE SYSTEM FREQUENCY

The system frequency was changed as shown in Figure 3.42. The reactive power is disturbed during this transition and settles at its previous set point during steady-state conditions. The system voltage is affected during this transition but returns to 0.978 pu during steady-state conditions.

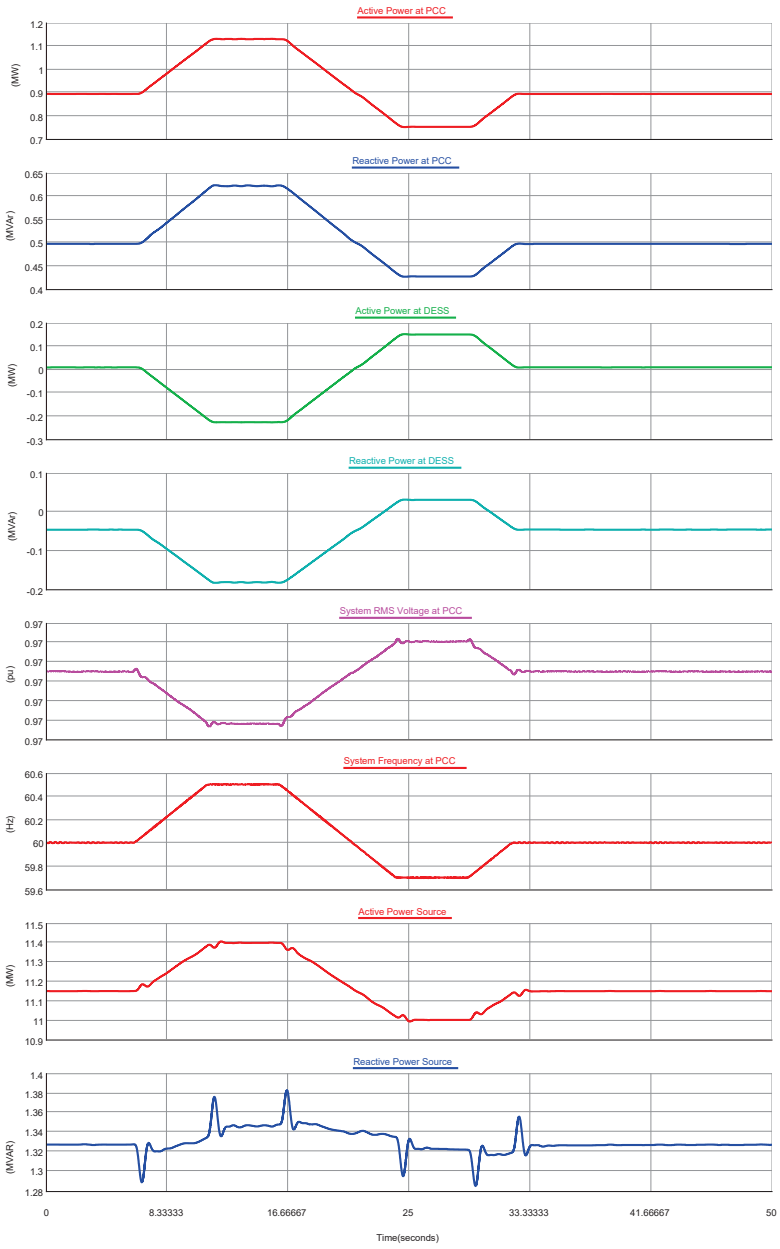


Figure 3.48: System Response for Test 5.3.3

TEST 5.3.4 INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ

On increasing the system frequency by 0.5 Hz, the DER responded to the frequency changes by reducing its power output and settled at a new set point per the frequency-watt droop of the inverter. This caused more active power to be drawn from the grid. The reactive power across the DER and PCC remained the same, while the system voltage settled into 1 pu at steady state.

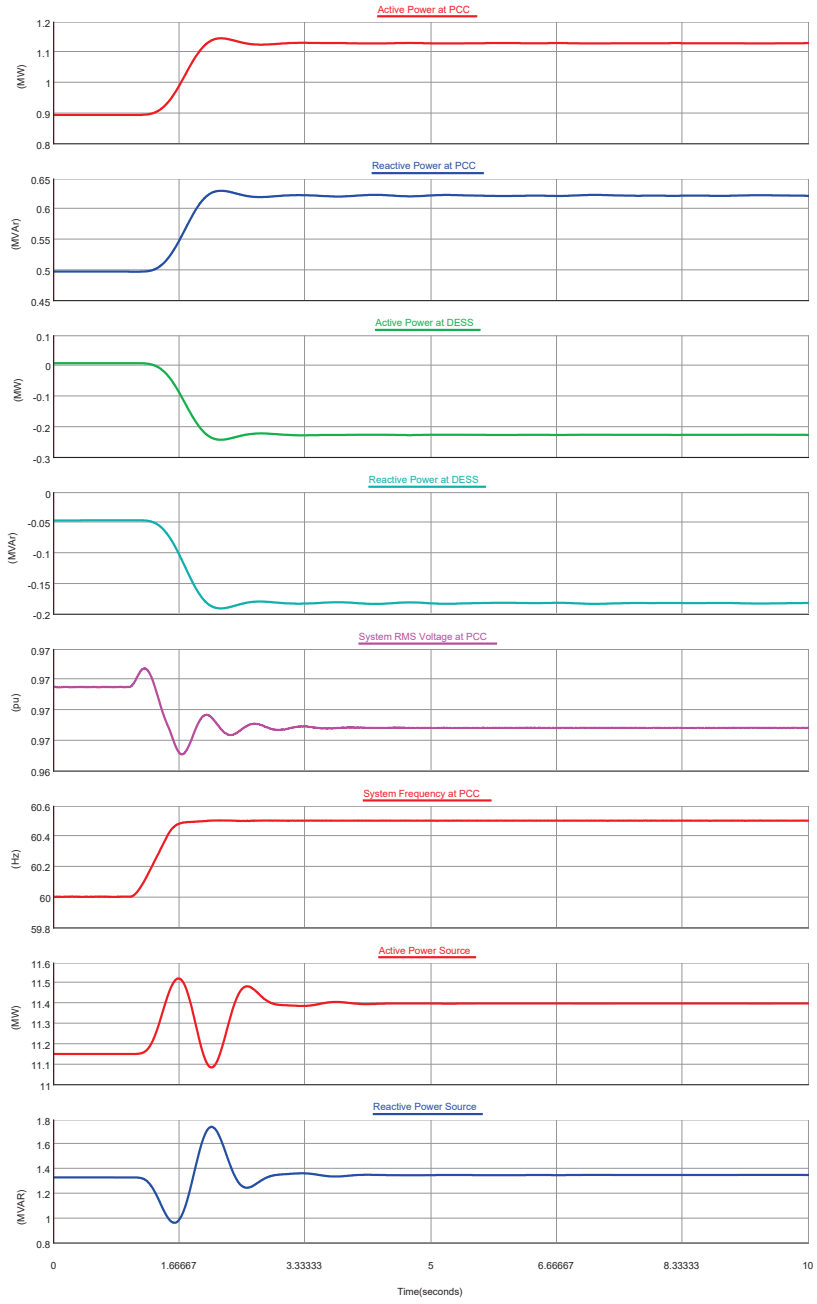


Figure 3.49: System Response for Test 5.3.4

TEST 5.3.5: DECREASE THE SYSTEM FREQUENCY BY 0.5 HZ

On decreasing the system frequency by 0.5 Hz, the DER responded to the frequency changes by increasing its power output and settled at a new set point per the frequency-watt droop of the inverter. This reduced the active power import from the grid through the PCC. The reactive power across the DER and PCC remained the same, while the system voltage settled into 1 pu at steady state.

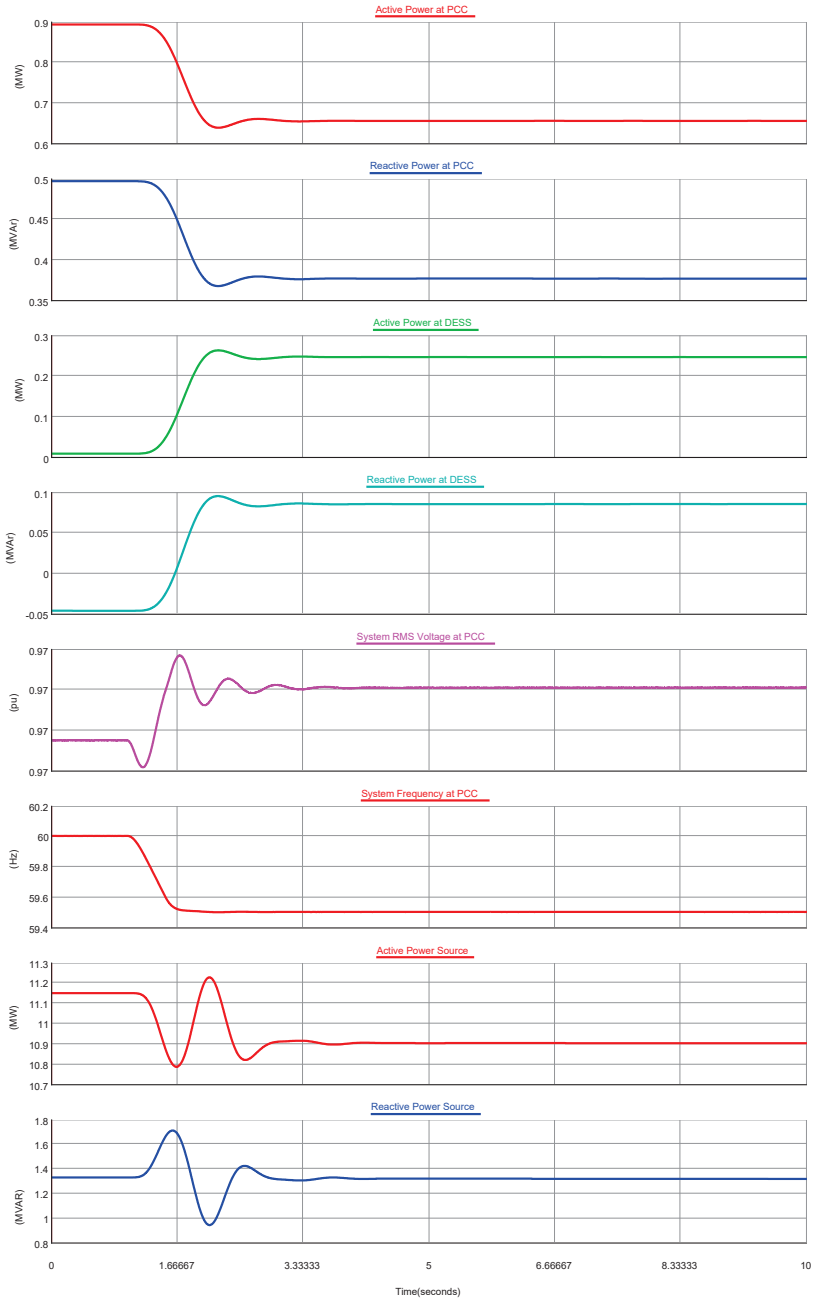


Figure 3.50: System Response for Test 5.3.5

SCENARIO 4: MULTIPLE DIVERSE TYPES OF DER ON THE SAME CIRCUIT

TEST 5.4.1 INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was increased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER responded to the change in frequency by increasing its active power output correspondingly and settled at its prior set point at steady state. The reactive power flow at the PCC and DER settled at its prior set point. The voltage was disturbed by the frequency change due to power flow but settled back to 1.01 pu in steady state.

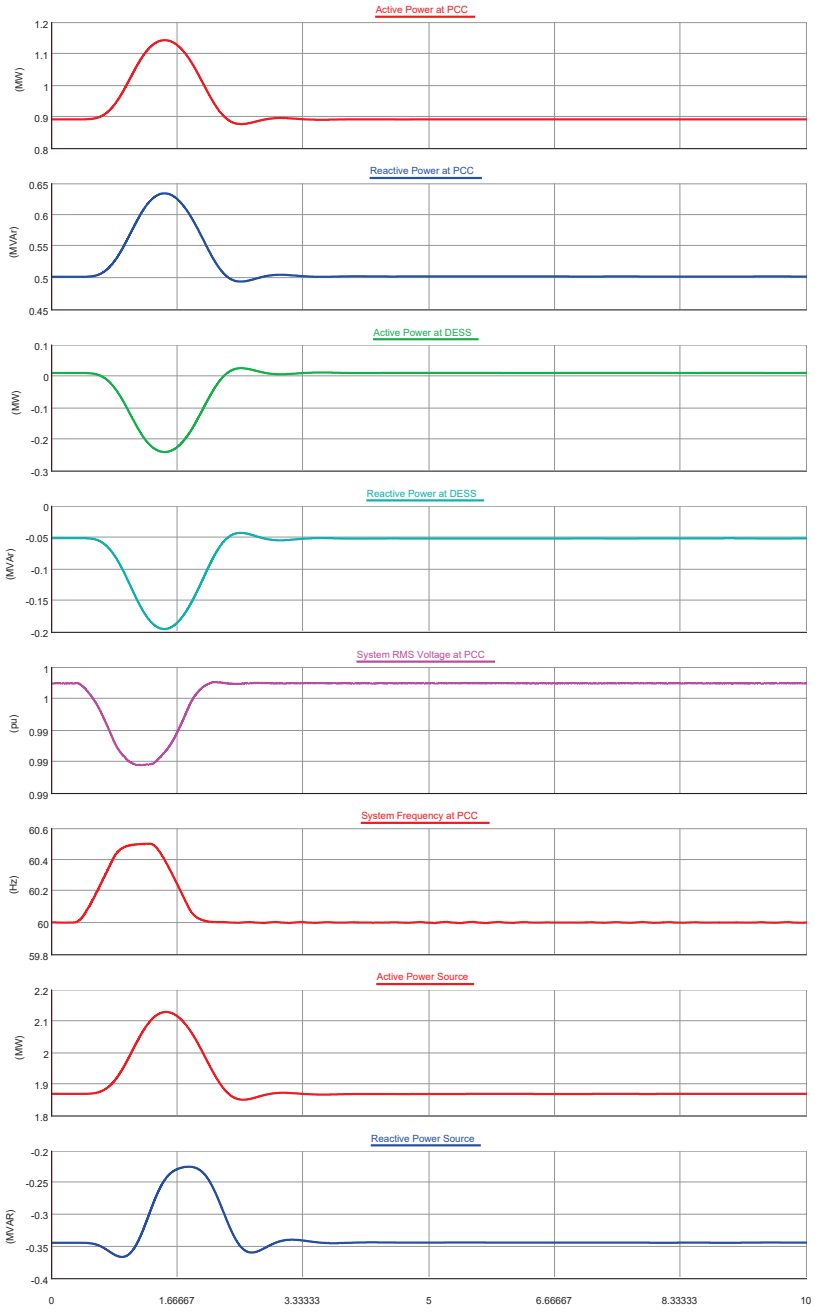


Figure 3.51: System Response for Test 5.4.1

TEST 5.4.2: DECREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was decreased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER responded to the change in frequency by increasing its active power output correspondingly and settled at its prior set point at steady state. The reactive power flow at the PCC and DER settled at its prior set point. The voltage was disturbed by the frequency change due to power flow but settled back to 1.0 pu in steady state.

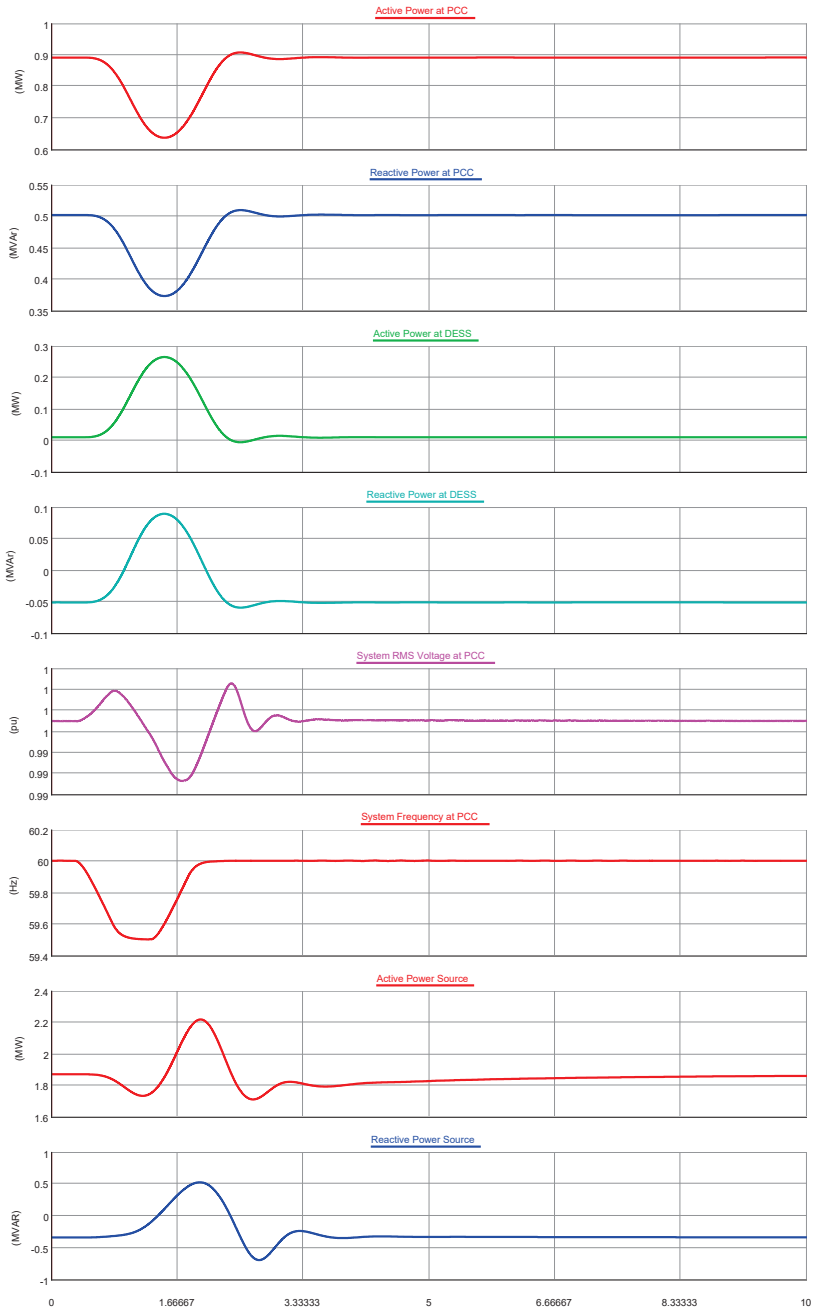


Figure 3.52: System Response for Test 5.4.2

TEST 5.4.3: VARY THE SYSTEM FREQUENCY

The system frequency was changed as shown in Figure 3.42. The reactive power was disturbed during this transition and settled at its previous set point during steady-state conditions. The system voltage was affected during this transition but returned to 1.0 pu during steady-state conditions.

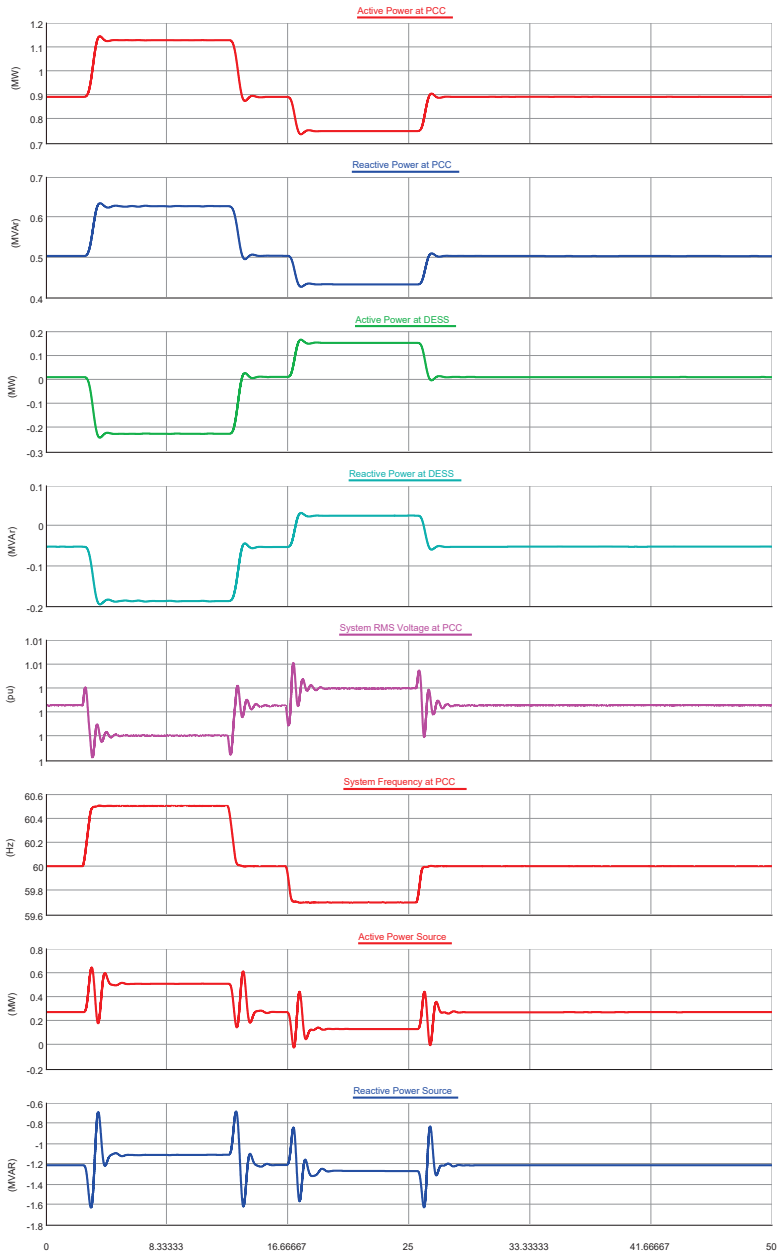


Figure 3.53: System Response for Test 5.4.3

Test 6 – DER Response to Emergencies

In this test, the DER system was subjected to various emergency situations and the action taken by the utility is sending specific commands to the DER. The response of the DER system is recorded for analysis.

The objective of this test was to demonstrate and analyze the operability of the DER system with a utility's DER management system, which performs manual or autonomous functions remotely. The DER system should have the provisions in the inverter to send status signals and respond to the commands and settings from the utility DER management system.

Table 3.7 lists the tests that were conducted.

Table 3.7: DER Emergency Response Test Cases

Test	Test Description	Expected Response	Actual Response
Test #6.1	Issue disconnect or reconnect commands to the DER system from the utility	Connect/ Disconnect	Connect/ Disconnect
Test #6.2	Update voltage ride-through curves to change anti-islanding settings	Update the ride-through curves	Curves are hard set locally
Test #6.3	Update frequency ride-through curves to change anti-islanding settings	Update the ride-through curves	Curves are hard set locally
Test #6.4	Request notification from the DER system about the status of microgrid connection	-	-
Test #6.5	Request notification from the DER system about the spinning reserve	-	-

These tests examined the capability of the inverter to communicate the information with the utility management system for more operational flexibility. Following are some of the emergency commands and requests that are exchanged between the utility and the DER managements system.

- Issue disconnect or reconnect commands to the DER system from the utility.

  A start and stop command can be sent remotely over Modbus to the DER controller for connecting and disconnecting the DER from the system. The startup process took up to 4 seconds after the start command is issued to the controller. Figure 4.6 shows the startup transient during the inverter AC breaker closing. Once the DER is online, different mode commands can be sent with the required active and reactive power set points.

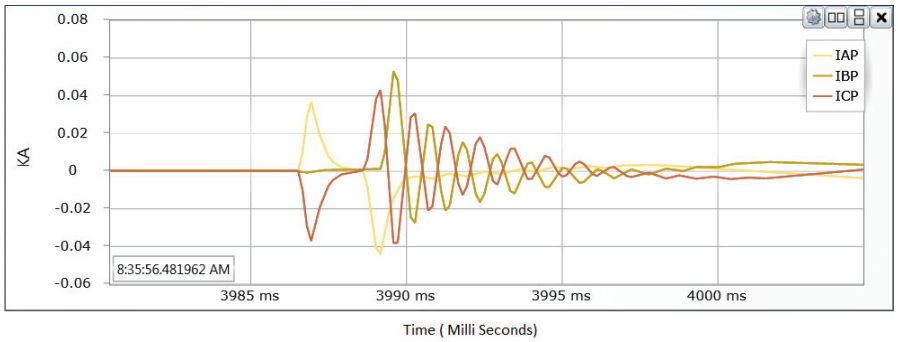


Figure 3.54: Inverter Startup Transients

- Update voltage ride-through curves to change anti-islanding settings.

  The voltage ride-through settings on the tested DER can only be set via the HMI since this setting in not available in the Modbus register.

- Update frequency ride-through curves to change anti-islanding settings.

  The frequency ride-through settings on the tested DER can only be set via the HMI since this setting is not available in the Modbus register.

- Request notification from the DER system about the status of microgrid connection.

  The tested DER continuously broadcast its status to the remote managements system via Modbus, indicating if the DER was online or offline. Along with this status information, the DER also sent the power output information. Based on this information utility operator can take operations decisions during different periods of the day.

- Request notification from the DER system about the spinning reserve.

  The tested DER sent the present state of charge to the remote management system via Modbus, which aids the utility operator with load and generation forecast.

Test 7 – Spinning Reserve

The objective of this test was to assess the benefits of the DER in functioning as a spinning reserve in different system conditions, compared to traditional sources, such as diesel generators. The DER is compared against the traditional backup diesel generator as a source of spinning reserve in terms of response time, standby losses, durability of support, and availability.

The procedure for testing was as follows:

Step 1. Place the DER into the idle mode with the state of charge (SOC) of the battery at the full level.
Step 2. Create a contingency where a source of generation (Grid) is taken offline to simulate an under-frequency situation in the system.
Step 3. Set the DER in to voltage and frequency regulation modes after approximately 5 seconds to produce the deficit active and reactive power to support the rest of the system during this event. Bring the additional backup generation online, in the meantime.
Step 4. Perform a comparative analysis in terms of economic benefits in fuel savings, ease of operation, response time, and reliability.
Step 5. Document the results of the testing for analysis.

To analyze the response of the system more accurately, a reduced dynamic model of the distribution circuit was developed and is described and the results are presented in Appendix B.

TEST 7.1 MODE ACTIVATION

The DER was initiated into the spinning reserve mode by activating the frequency and the voltage regulation functions. This caused the active and reactive to shift to support the system voltage and frequency. This caused the voltage and the frequency to settle down at 1 pu and at 60 Hz respectively.

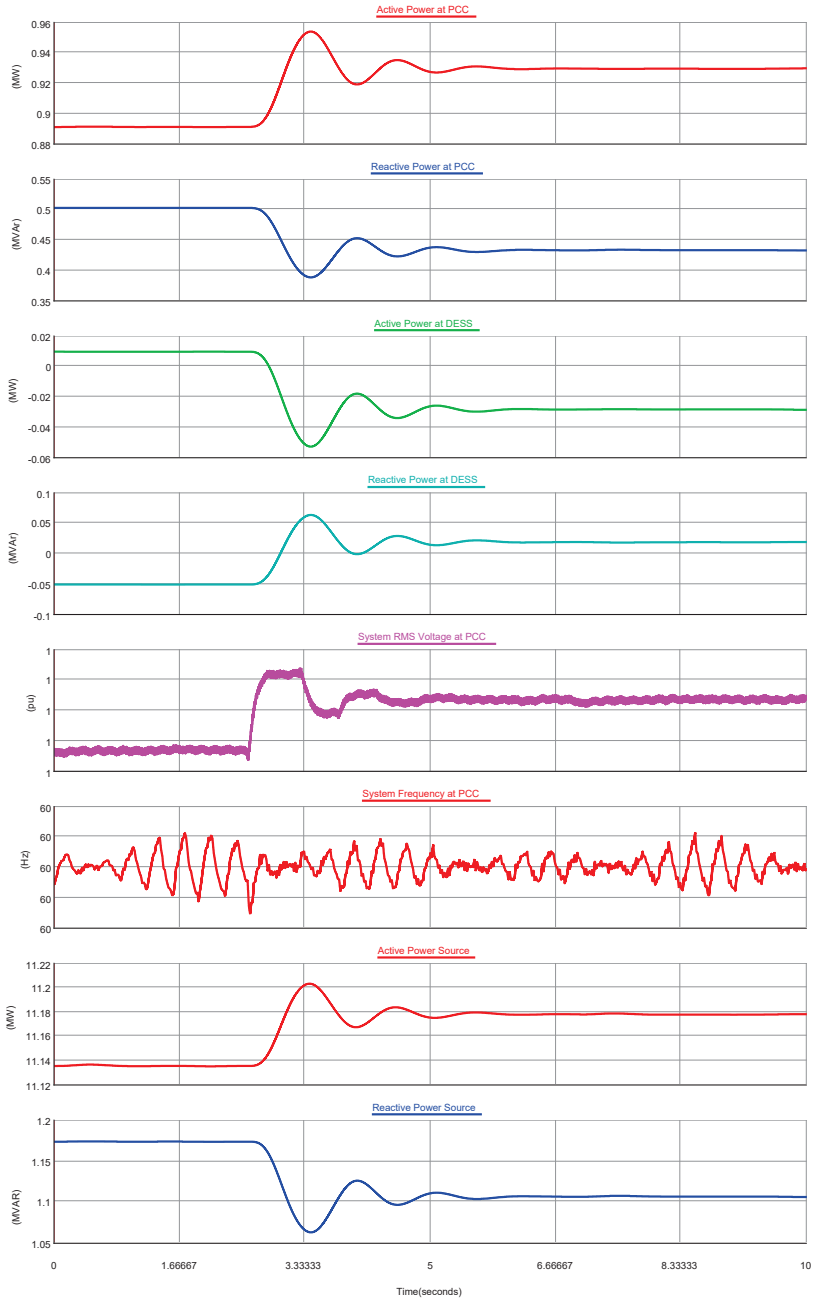


Figure 3.55: System Response for Test 7.1

TEST 7.2 OPENING THE BREAKER ACROSS THE DER

On creating an under-frequency situation by opening the breaker, the generation from the source across the PCC dropped to zero. The DER acted as spinning reserve and picked up/supported the local load. This caused the voltage and frequency to drop temporarily across the terminals of the PCC. The active and reactive power generation from the source dropped as the load across the DER was supported by the DER. The frequency at steady state was lesser than 60Hz because the DER was operating near its maximum capacity.

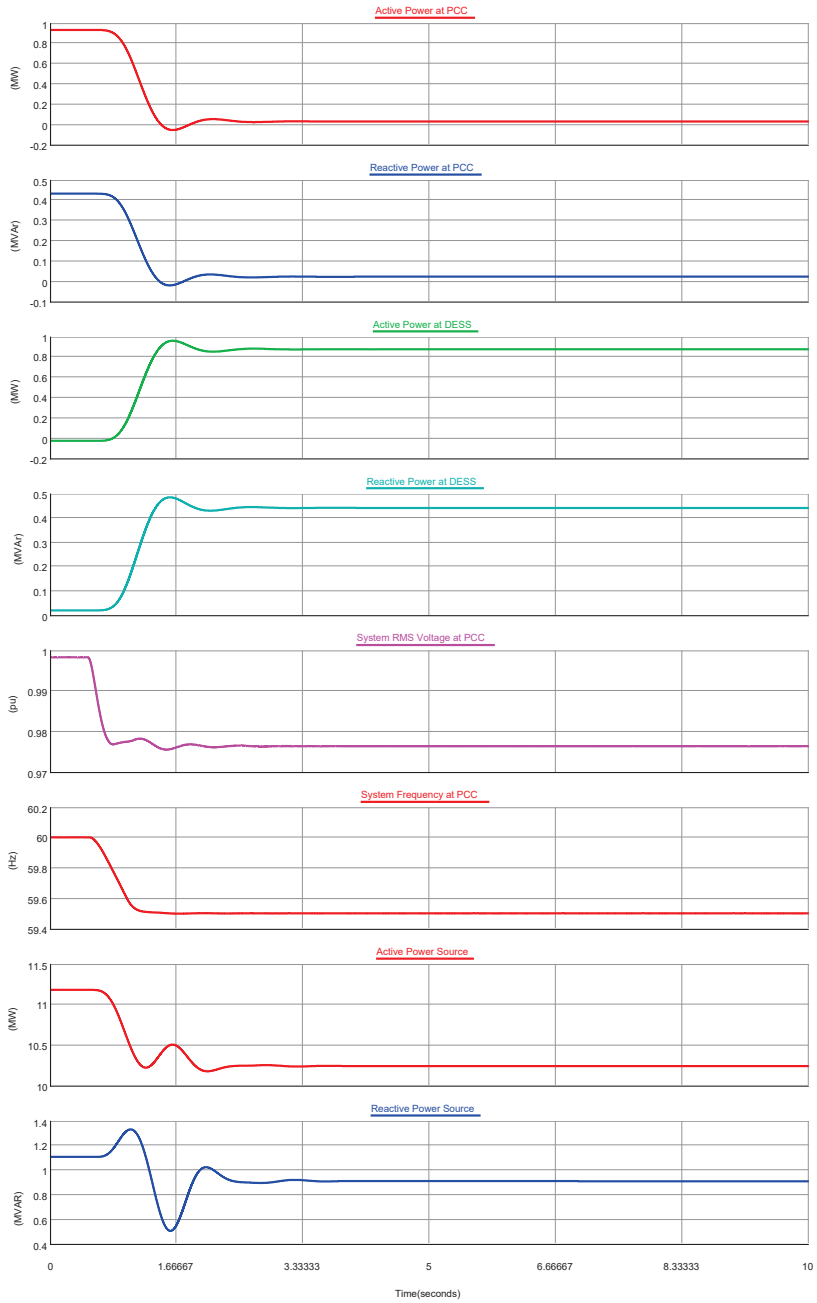


Figure 3.56: System Response for Test 7.2

TEST 7.3 CREATING UNDER-FREQUENCY FOR 1 SECOND

An under-frequency situation was created by decreasing the frequency by 0.5Hz for 1second. On decreasing the frequency, the DER rode through and settled at its prior set point in the steady state.

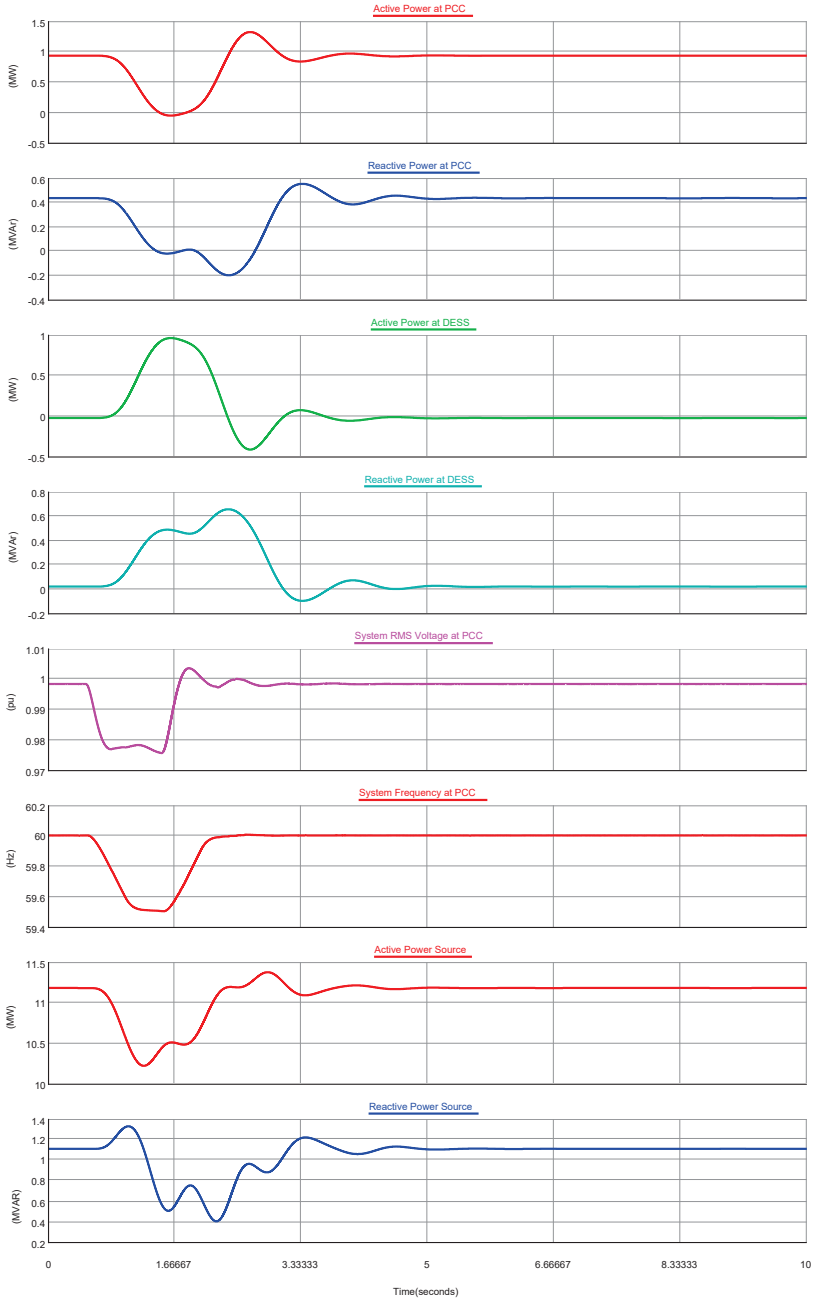


Figure 3.57: System Response for Test 7.3

TEST 7.4 CREATING A TEMPORARY FAULT

Creating a temporary fault caused the DER to react to the transition and return to its steady state once the fault was cleared. The temporary fault caused the voltage to drop and the frequency to increase drastically for which the DER reacted by regulating the active and reactive power output. Once the fault was cleared, the DER returned to its zero value at the steady state.

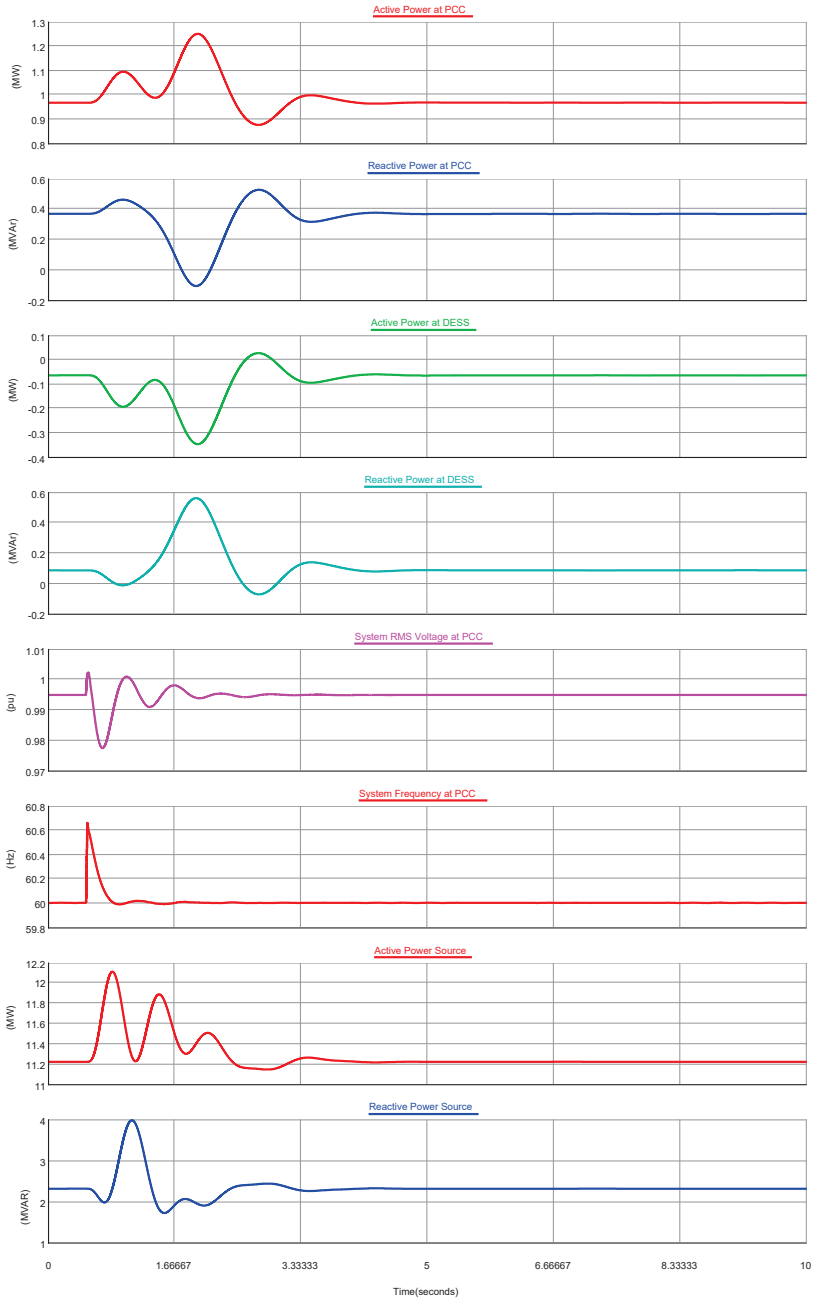


Figure 3.58: System Response for Test 7.4

Test 8 – Black Start

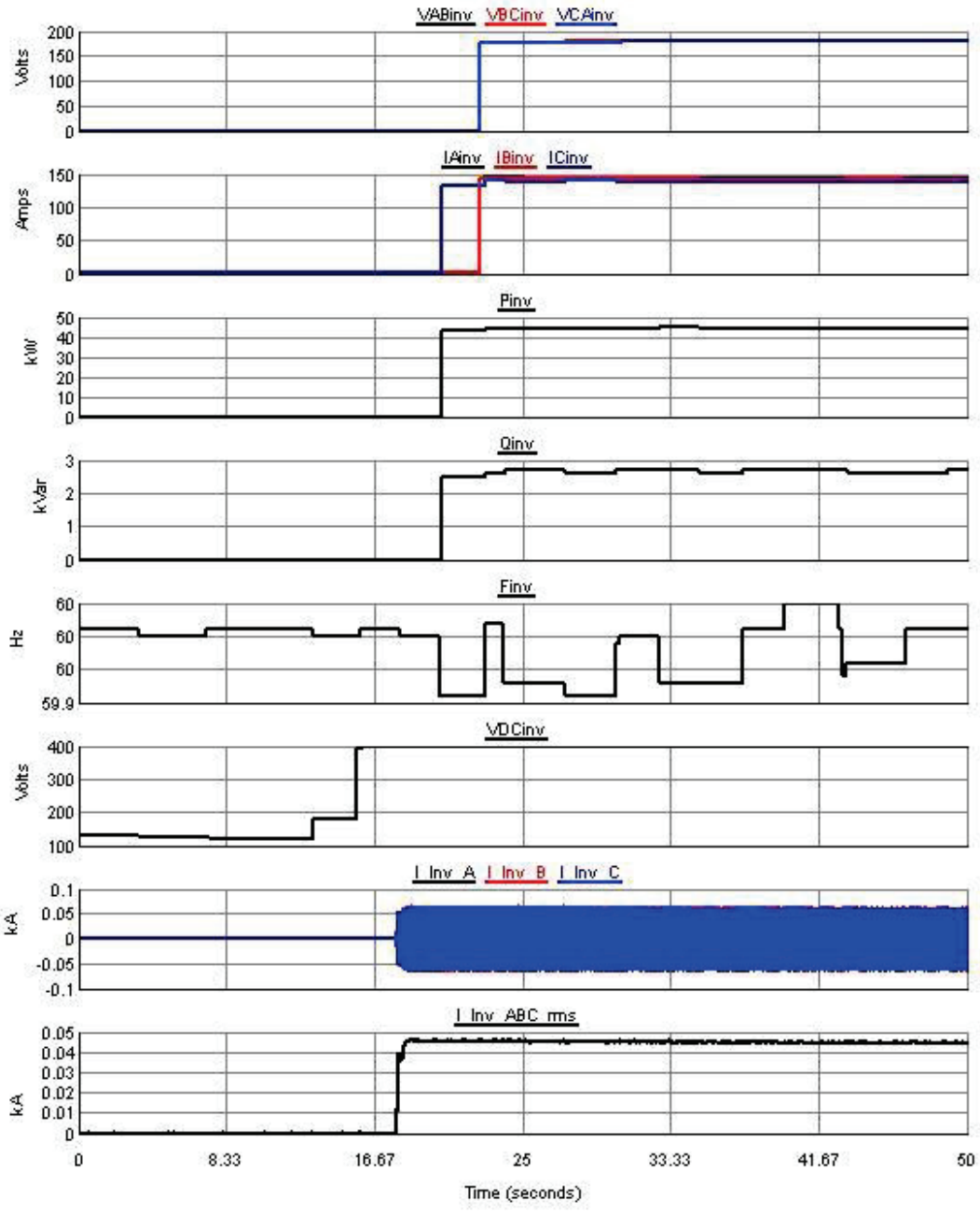
The ESS can be used to black start the system after complete system outage. The DER can operate in VSI mode to provide voltage and frequency support during the black start. Once the nominal voltage and frequency are established in the island, the loads can be picked up slowly and other renewable generation sources can be brought online to support the islanded load on the feeders. For the PHIL testing a load bank was used to connect to the DER to establish an island. The DER in the VSI ISO mode could sustain the island and feed the load bank.

Step 1. Record the system voltage and frequency during the steps performed for black-start operation.
Step 2. Document the black start and load restoration procedure for analysis.

VSI ISO mode regulates the voltage and frequency at the inverter terminals with regards to the voltage and frequency set points but unlike VSI VF does not accept droop set points. The inverter operates like a grid forming generator keeping the grid frequency and voltage as close as possible to the set points. This mode is used for islanded operation when the inverter system is the only source of generation or is the largest source of generation. If the load exceeds the capacity of the ESS the grid parameters will fall out of range.

TEST 8.1A: BLACK START 44 KW

on switching the inverter on in VSI ISO Mode, the inverter provided reference for the voltage and frequency and operates as a primary source. In this mode, once the DER was switched on, the DER supported the active and reactive power load. The frequency was set at 60Hz and the system voltage was set to 400V. The inverter current started flowing when the load was connected.



r

Figure 3.59: Starting the DER in VSI ISO Mode to support a local load

TEST 8.2A: ISLAND LOAD RAMP

On decreasing the connected load across the terminals of the inverter using a sliding ramp, the DER current reduced and the generated active and reactive power of the inverter reduced as well. The change did not affect the voltage and frequency. The DER current increased with the increasing island load, while the voltage and frequency remained unaffected by the change. The generated active power and reactive power also increased to provide for the local connected load.

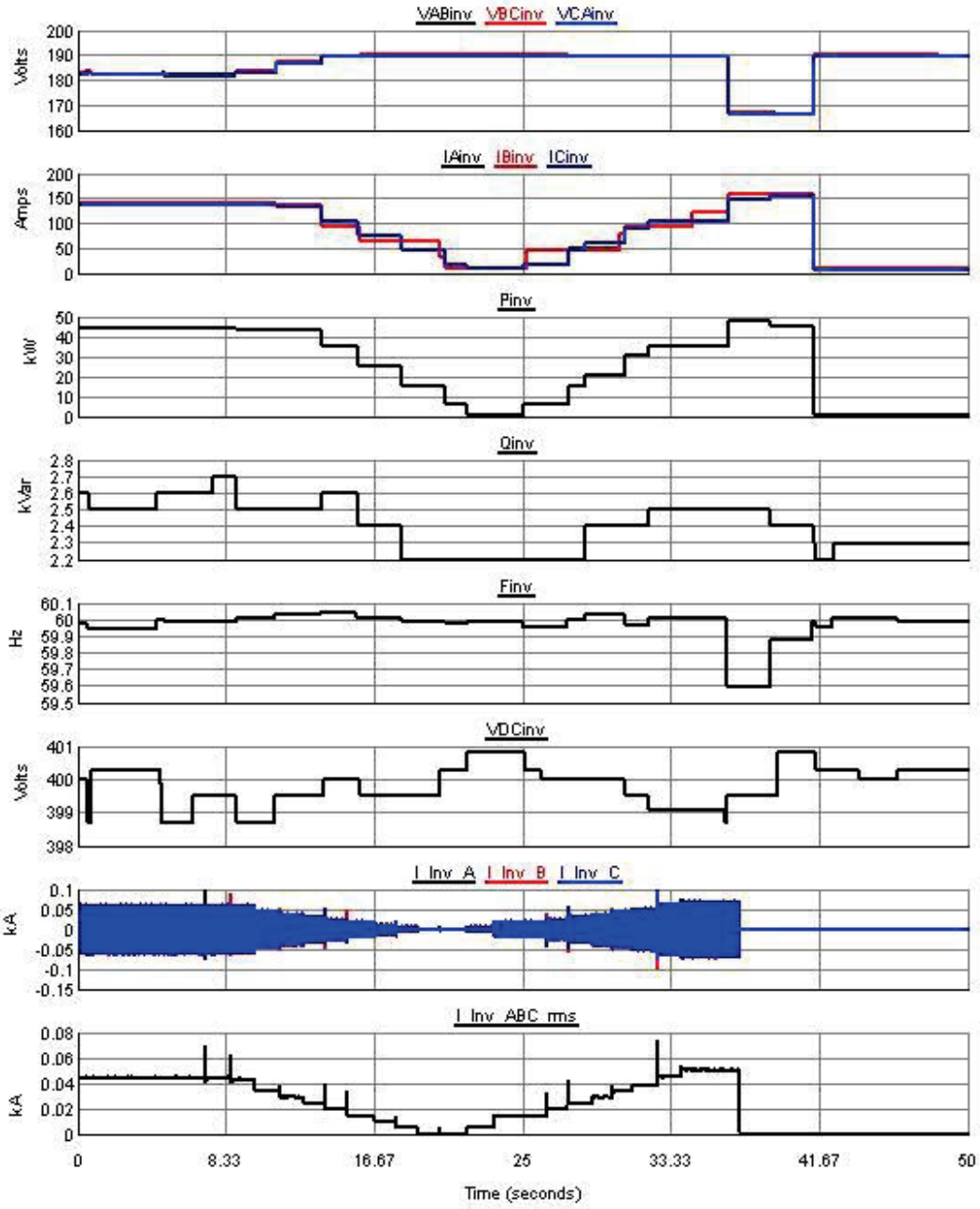
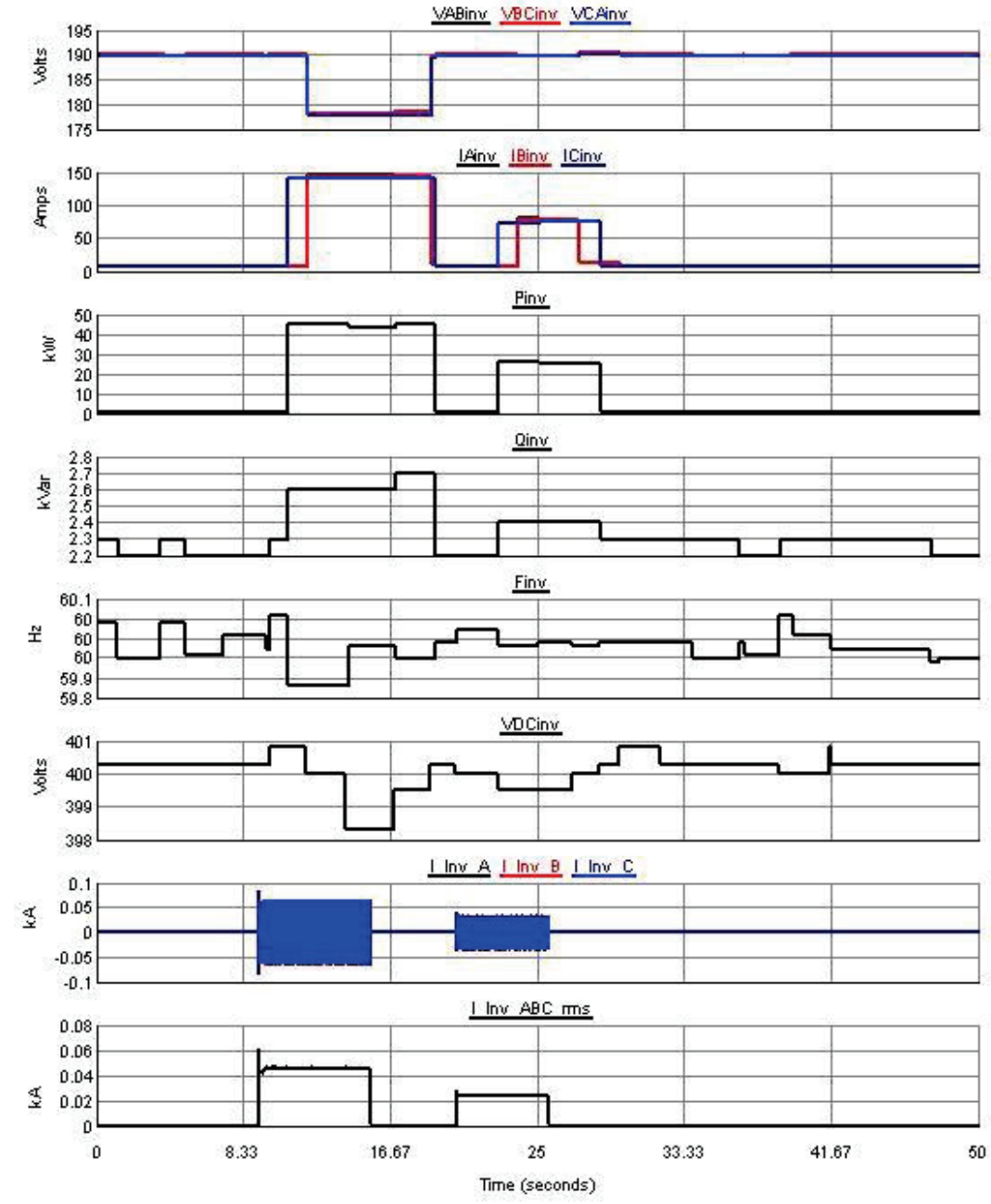


Figure 3.60:Adding a Ramp Load to the Inverter in VSI ISO Mode

TEST 8.3A: ISLAND LOAD STEP

When the DER was connected to a load using step method, the current increased and dropped along with the load. The real power switched to zero right after the step load was removed from the circuit from the inverter. However, due to shift in power flow caused by the increased flow of the current from the inverter, the reactive power of the inverter increased when the inverter supported the load but reduced slowly back to its previous output set point. This change occurred even without any change in the reactive load. The system frequency and voltage remained unaffected during the steady state.



r

Figure 3.61:Black Start Application of the DER – Island Load Step

VSI VF MODE

VSI VF mode regulate the voltage and frequency at the inverter terminals per voltage and frequency set points. The response is characterized by the voltage and frequency droops.

TEST 8.1B: BLACK START 44 KW VSI VF

On switching the inverter on in VSI VF Mode, the inverter provided reference for the voltage and frequency and operated as a primary source. In this mode, once the DER was switched on, the DER supported the active and reactive power load. The frequency was set at 60Hz and the system voltage was set to 400V. The inverter current started flowing when the load was connected.

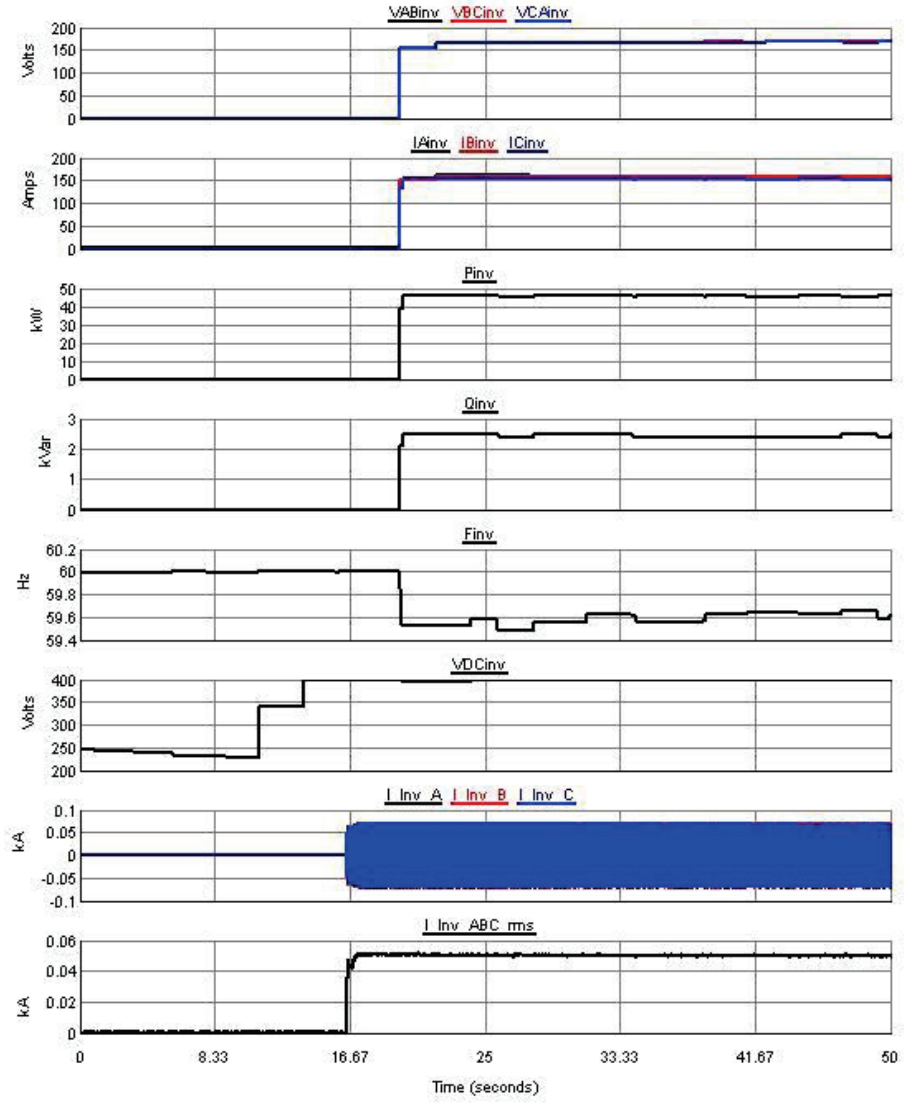


Figure 3.62: Starting the DER in VSI VF Mode to support a local load

TEST 8.2B: ISLAND LOAD RAMP VSI VF

In the VF mode, the inverter responded to the load changes by changing the output voltage and frequency. On decreasing the connected active power load, the DER active power and the reactive power output also reduced, due to the reduction in the current which caused the system frequency to increase (due to a large change in the active power output). The change in voltage was not significant since the reactive power reduces minimally. Similarly, when the active power load increased gradually, causing the system frequency to reduce. The increase in current caused the reactive power to increase, which reduced the system voltage marginally.

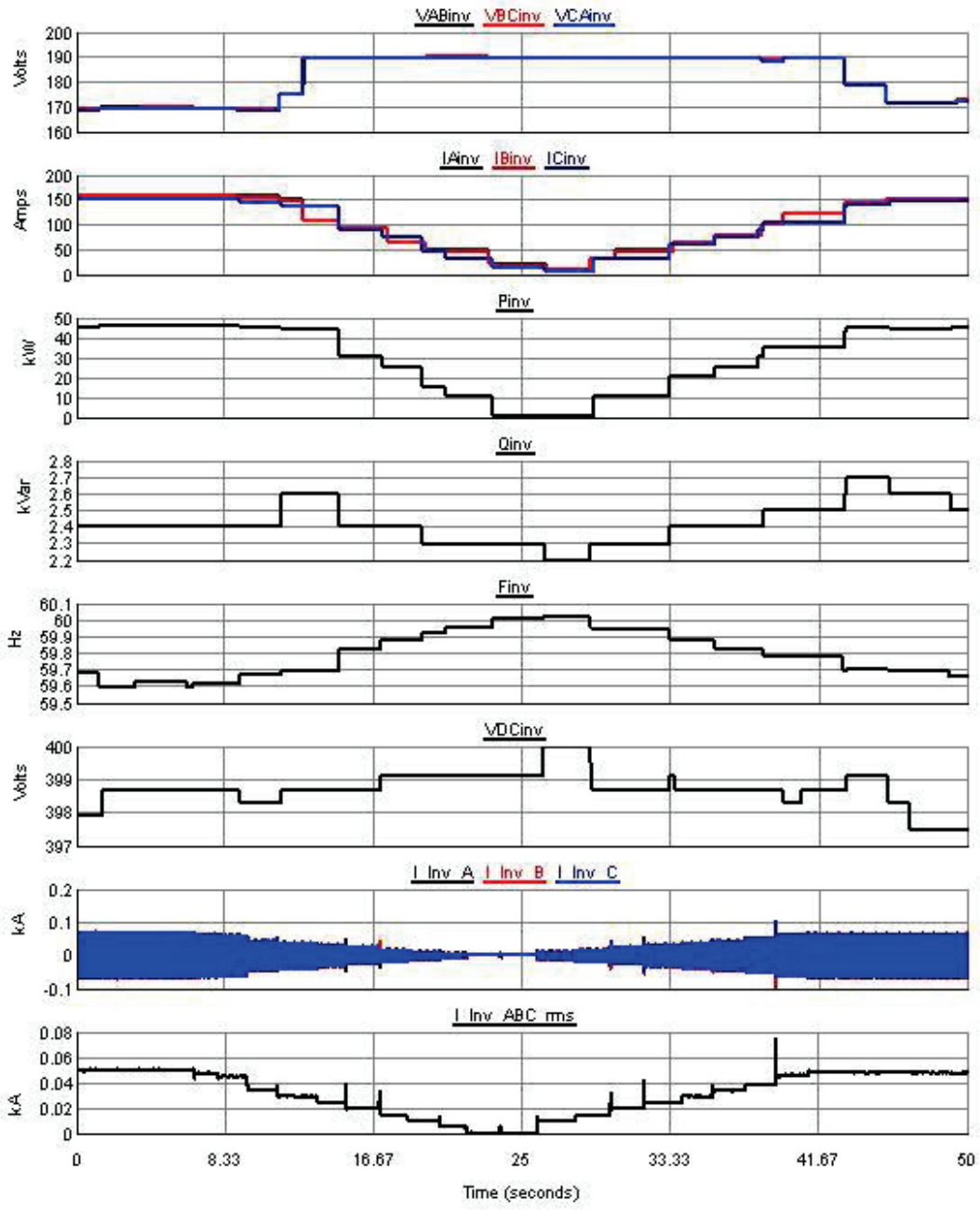


Figure 3.63:Adding a Ramp Load to the Inverter in VSI VF Mode

TEST 8.3B: ISLAND LOAD STEP VSI VF

On changing the load as a step, the system frequency changed as a response to the active power load. The voltage responded to the changes in the reactive power output of the inverter. The voltage and frequency response of the inverter was much more dynamic in the VF mode compared to the ISO Mode.

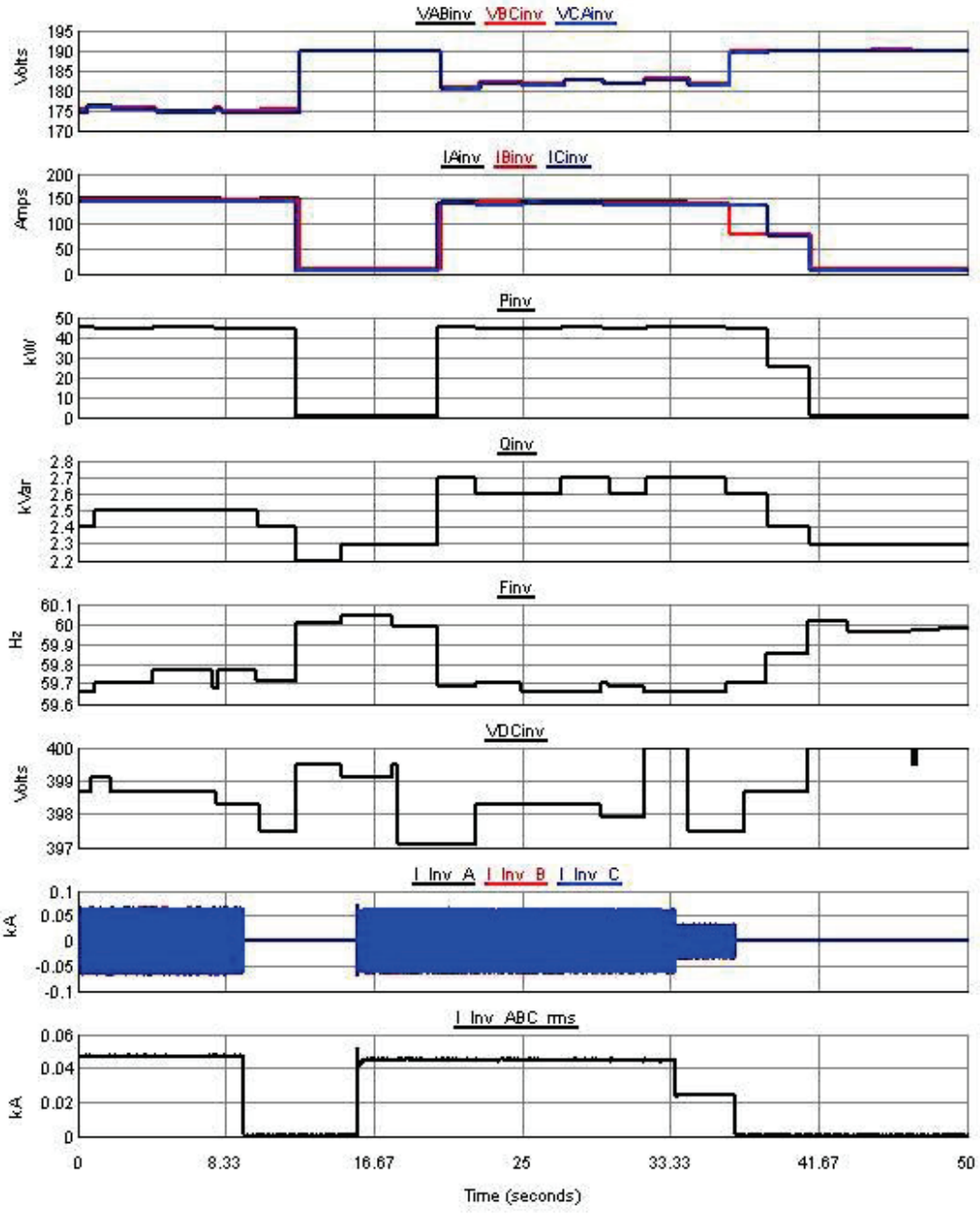


Figure 3.64:Adding a Ramp Load to the Inverter in VSI VF Mode

BLACK START UNINTENTIONAL TRIP

The inverter tripped unintentionally during the sudden drop of the load.

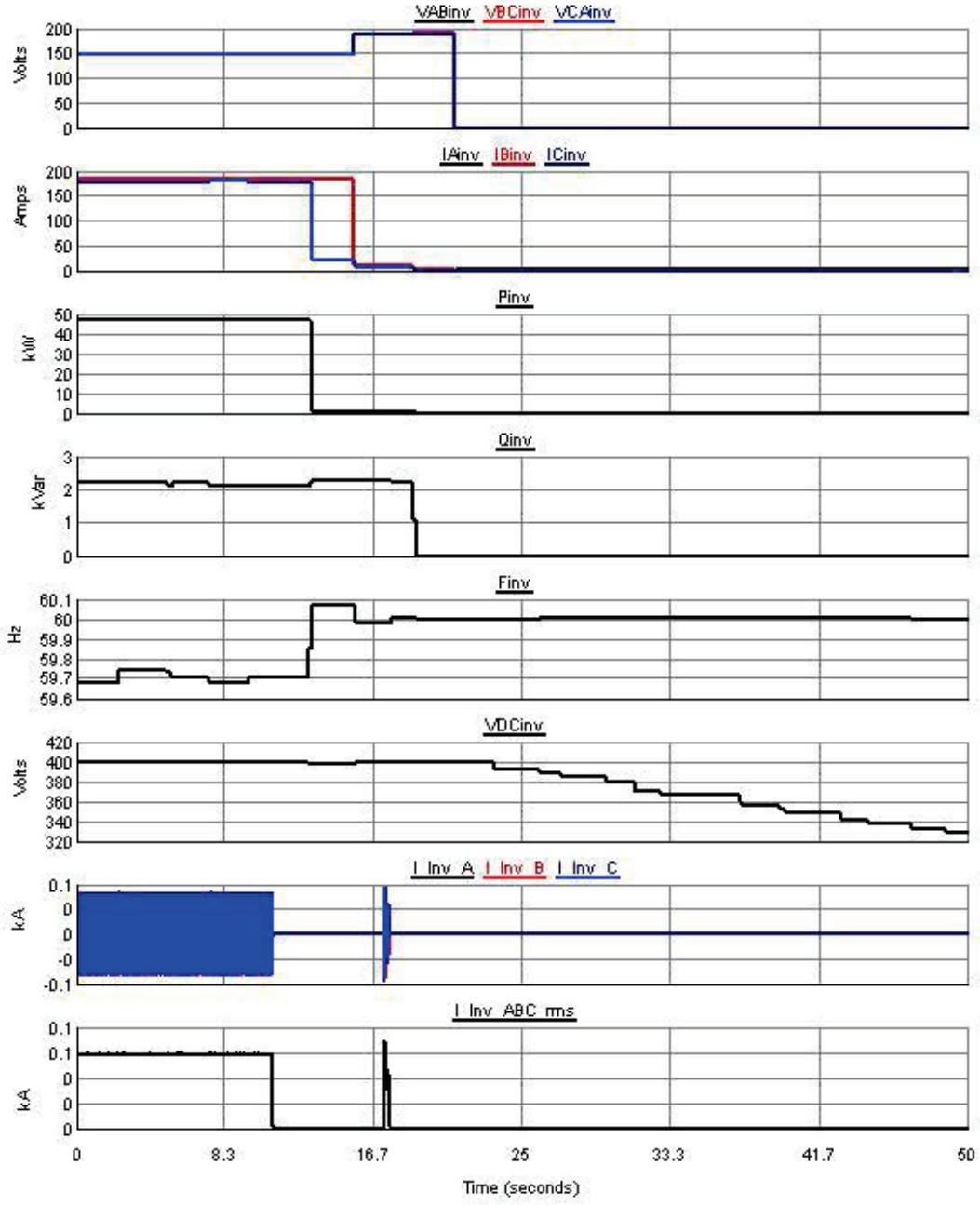


Figure 3.65: Unintentional Tripping of the Inverter

Test 9 – Load Leveling

The load-leveling function is like peak shaving in regard to the cycle of charging and discharging during different loading conditions. During the periods of high load demand, the DER can supply energy into the grid and it can charge while the load is light. This helps in reducing the load on less economical peak generating plants.

The objective of this test was to assess the economic benefits of using the DER to supply clean and emission-free energy, while reducing the use of less economical generation plants during high load demands

The procedure for testing was as follows:

- Set the DER output to constant power in the base mode operation.
- Starting with the base load, vary the local load in cyclic fashion of repeating crest and trough so that the load active power changes from 1200 kW to 800 kW. Make sure that the DER supplies constant power of 800 kW throughout these load changes.
- Activate the load-leveling mode on the DER with a set point of 1000 kW at the PCC that will maintain the power flow of 1000 kW (import) across the PCC and the rest of the power will be delivered by the DER.
- Record the DER power output during this event and analyze the behavior in following the variation in the load.
- Figure 3.66 shows a typical load profile to be used for this test.

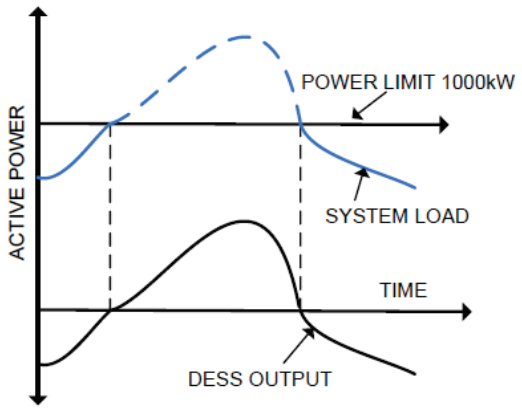


Figure 3.66: Load and DER Output Profile for Test #9

SCENARIO 1: DER CLOSE TO A SUBSTATION

TEST 9.1.1: WITHOUT LOAD LEVELING

On varying the system load by activating the DER in the schedule active power mode, the power output of the DER was maintained constant at 500 kW, while the fluctuations in the load were managed by the grid, which was reflected in the active power imported from the grid across the PCC and the increase in the active power generation of the source. The reactive power output did not change across the PCC, DER, or source.

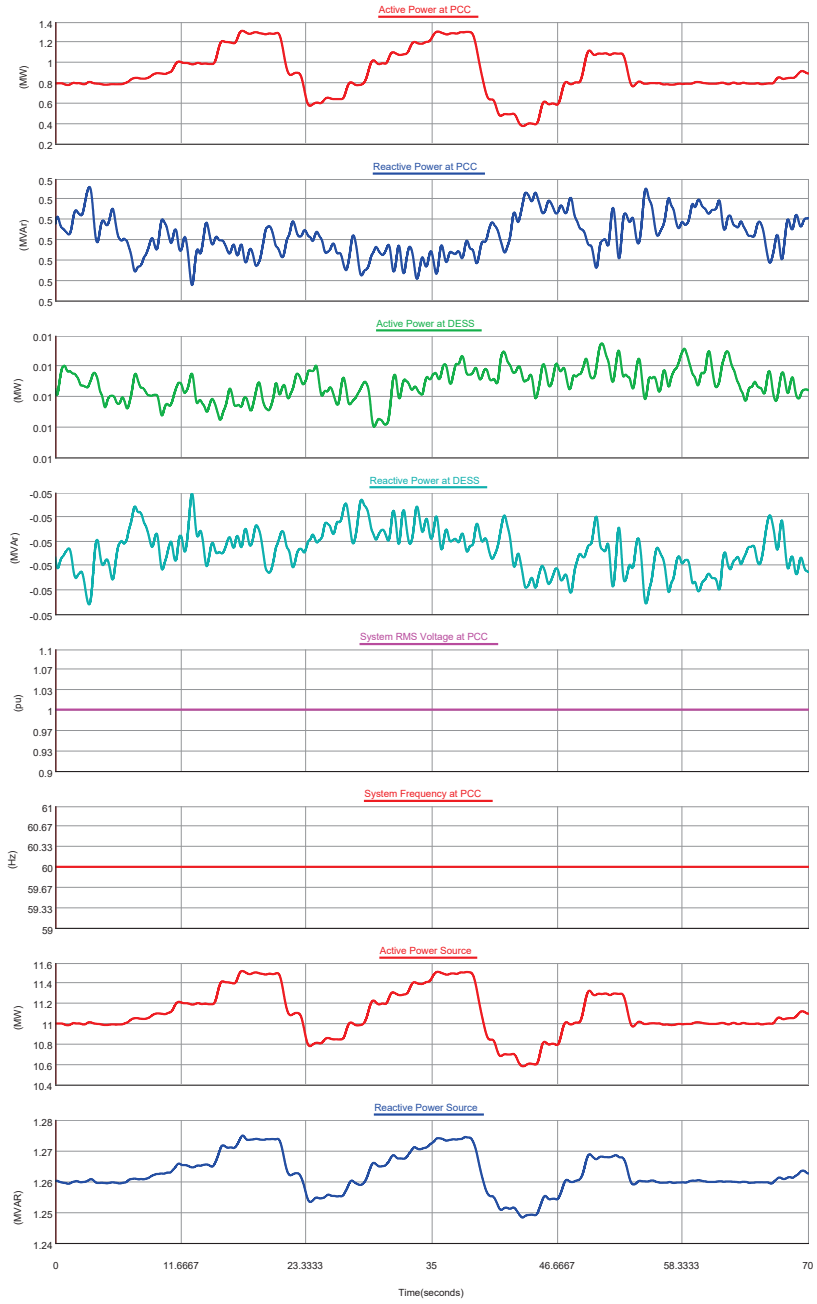


Figure 3.67: System Response for Test 9.1.1

TEST 9.1.2: LOAD LEVELING

Activating the load-leveling mode on the DER with a set point of 1000 kW at the PCC would maintain the power flow of 1000 kW (import) across the PCC. Fluctuations in the load were managed by the DER, which provided the required power during periods of heavy load and drew the excess power generated during periods of light loads. This ensured that the active power generated by the source remained constant and did not cause reverse power flow into the utilities during light load condition.

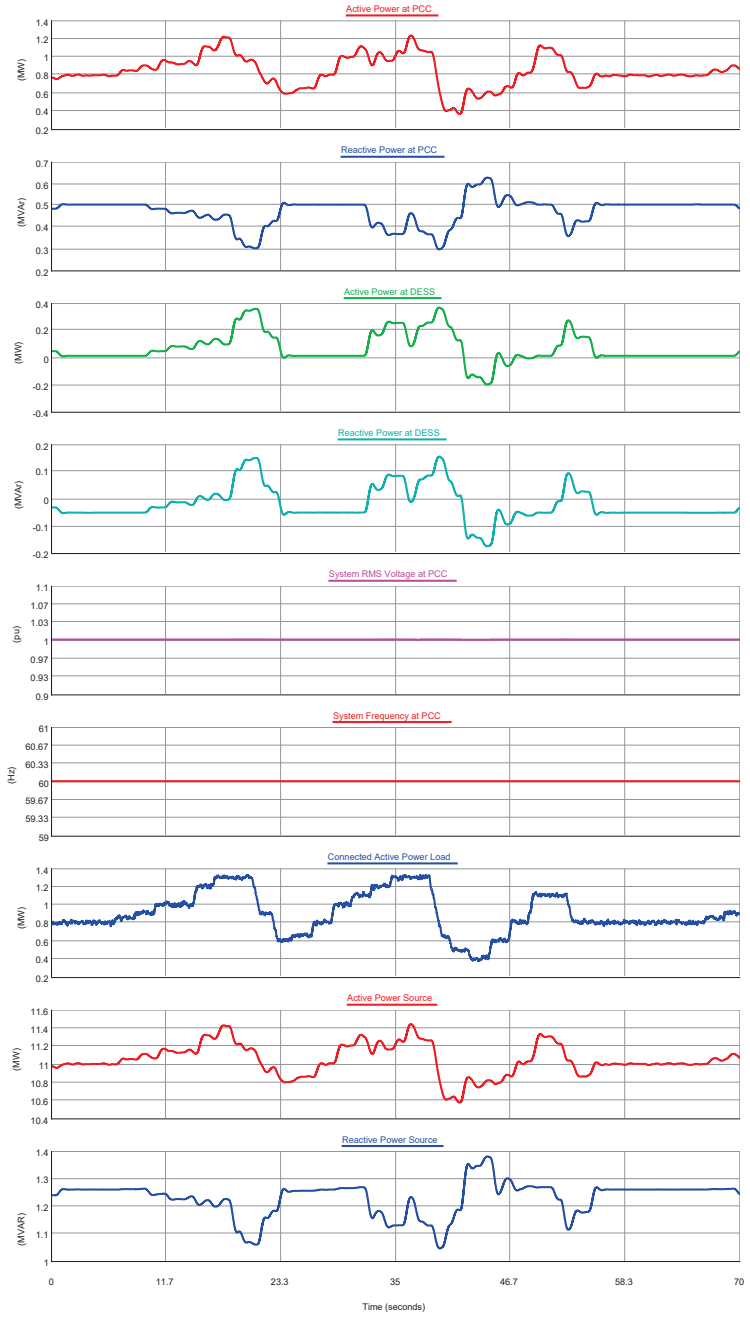


Figure 3.68: System Response for Test 9.1.2

SCENARIO 3: DER AT THE END OF A LONG FEEDER

TEST 9.3.1: WITHOUT LOAD LEVELING

On varying the system load by activating the DER in the schedule active power mode, the power output of the DER was maintained constant at 500 kW, while the fluctuations in the load were managed by the grid, which was reflected in the active power imported from the grid across the PCC and the increase in the active power generation of the source. The reactive power output did not change across the PCC, DER, or source.

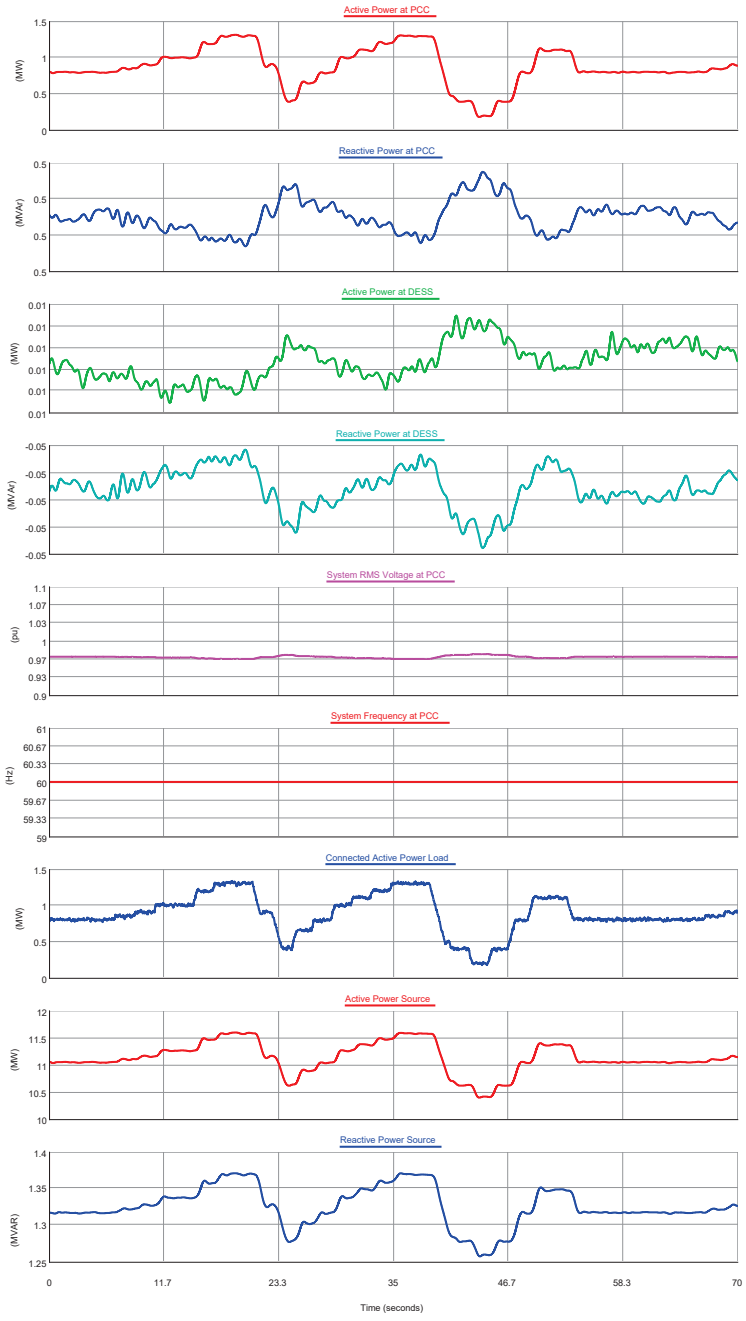


Figure 3.69: System Response for Test 9.3.1

TEST 9.3.2: LOAD LEVELING

Activating the load-leveling mode on the DER with a set point of 1000 kW at the PCC would maintain the power flow of 1000 kW (import) across the PCC. Fluctuations in the load were managed by the DER, which provided the required power during periods of heavy load and drew the excess power generated during periods of light loads. This ensured that the active power generated by the source remains constant and did not cause reverse power flow into the utilities during light load condition.

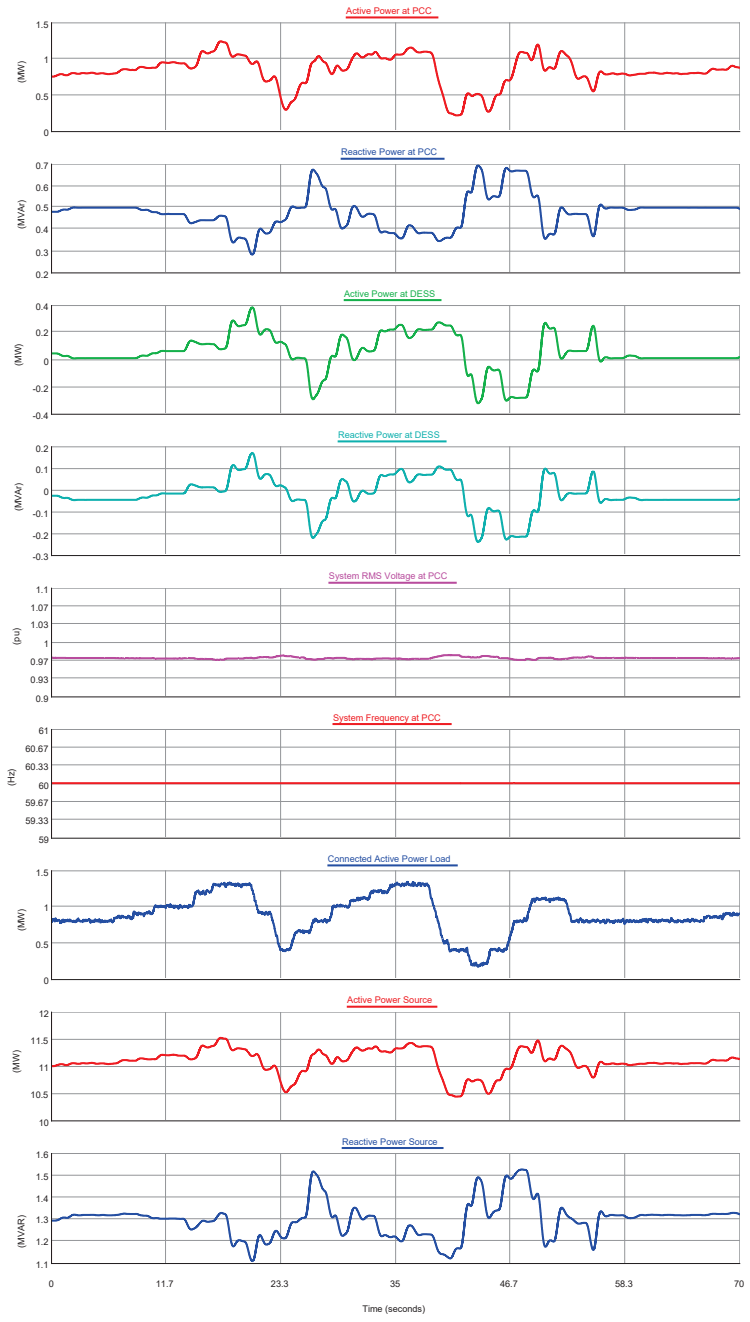


Figure 3.70: System Response for Test 9.3.2

SECTION 4 PROJECT RESULTS AND FINDINGS

This section discusses the test results obtained from the testing, presents findings and makes recommendations regarding commercial adoption of DER grid support functions. It also discusses the technical issues in terms of implementation and provide the value proposition.

DETAILED TECHNICAL RESULTS AND FINDINGS

This section discusses the summary of test results, functions of the DER inverter that are in line with the CPUC Rule 21 guidelines, the differences and areas that needs development. The smart inverter and the battery storage system are collectively referred to as the distributed energy storage system (ESS) and the inverter is referred to as a device under test (DUT). In this effort, an ESS was used as a DER to conduct the demonstrations.

Limiting Maximum Active Power Output

Per the Rule 21, the utility operator should be able to set the maximum limit on the DER output remotely. The maximum limit on the output could only be changed via local HMI on DUT. The change in the maximum active power limit was instantaneous and not ramped with a settable ramp rate.

For the demonstrations, the active power limit on the DER was changed manually from the HMI and the plot was recorded in the RTDS. Because of the limitation on the remote control of this function, the time delay could not be determined. Overall, the DER could limit its active power output successfully as specified by the user irrespective of the circuit power flow changes. If the DER receives an active power set point of more than the maximum limit set point, the output of the DER is held at the maximum limit set point. On the other hand, if the maximum limit set point is changed so that it is lower than the present active power output of the DER, the active power is reduced to the new maximum limit. The operation of this function is unaffected by the location of the DER in the circuit and yields similar results in all the scenarios. Figure 4.1 shows the change in active power when the maximum limit is reduced to 50%.

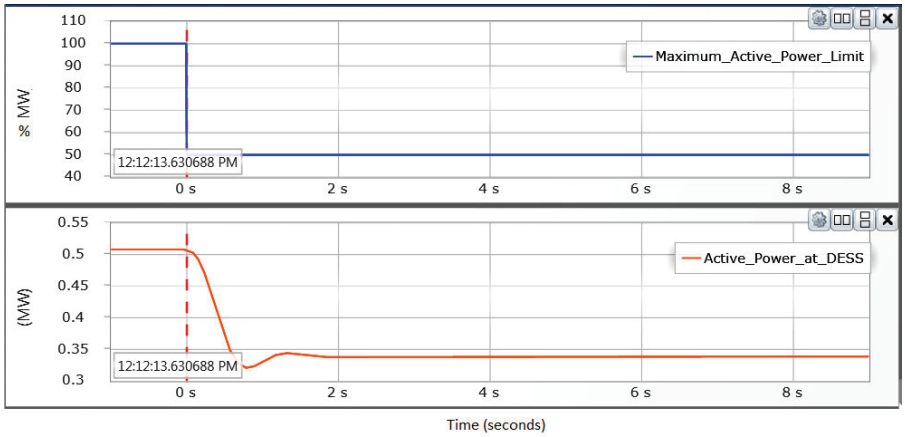


Figure 4.1: Limit Maximum Active Power Function

The main objective of this function is to provide a safety limit on the DER. The DER can still be used to perform other functions such as frequency-watt, but the active power regulates between the set positive and negative limits. The active power output of the DER can be limited to a value that keeps the current from exceeding current rating of the cables or overhead lines connecting to the utility system while allowing the DER to take part in the active power regulation.

Schedule Active Power Output

This function lets the operator schedule the active power output on the DER. The DUT has to be set in the active and reactive power schedule mode to execute the active power set point. Along with the active power set point, a positive and a negative ramp rate has to be provided to set the time response of the step change. For this testing, a ramp rate of +/- 100 kW per second was used. The rule 21 has marked the guidelines of this function as optional one in the regards that the maximum active power limit function can be used to set the active power for the energy storage systems such that the limit value indicates the active power set point as well. The DUT had a weekly scheduling function, wherein the active power dispatch can be scheduled during particular hours on a particular day of the week.

Varieties of tests were performed to validate this function on the test distribution circuit. The location of the DER in the circuit did not affect the performance of the DER in this mode, and it was effective under all the scenarios. The variations in load and voltage do not alter steady-state active power output. Overall, DER could provide the scheduled active power output as specified by the user within its rated capacity. Figure 4.2 shows that the change in loading on the circuit did not alter the output of the DER.

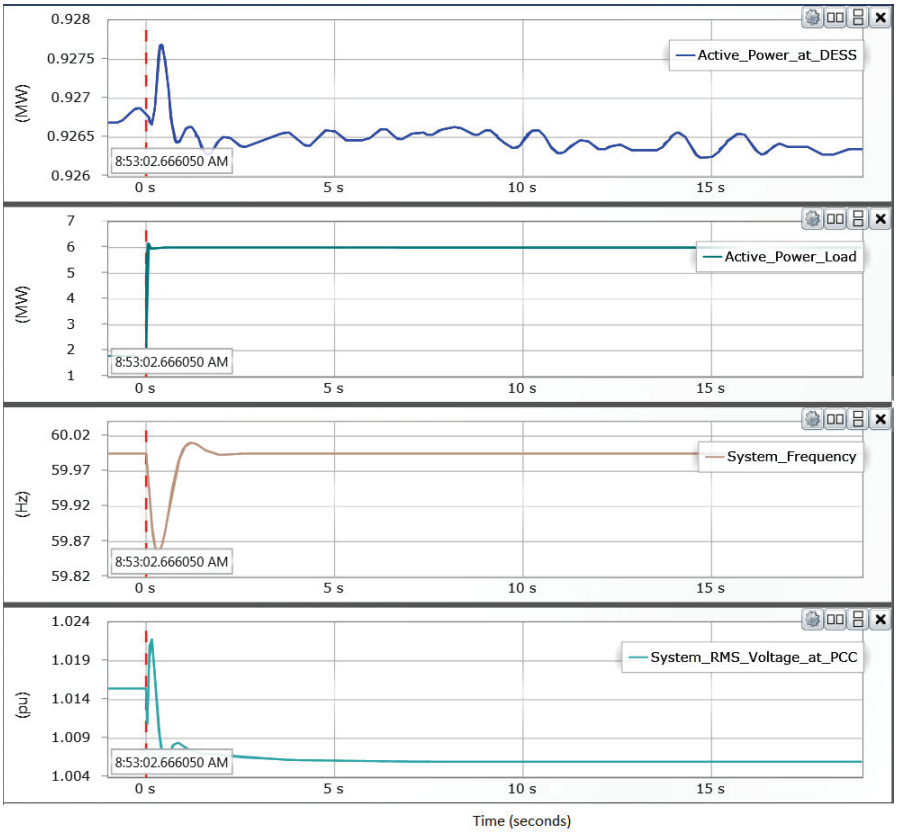
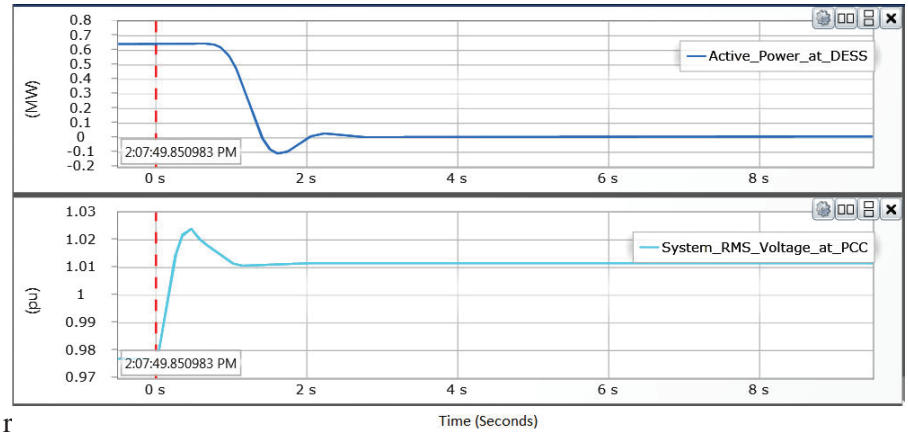


Figure 4.2: Schedule Active Power Output Function

The active power scheduling function helps establishing the base generation level on the distribution feeder, which helps the utility in load-demand-response management. Fixed active power output of the DER does not provide any significant value based on its location, however when operated in the fixed power factor mode, the reactive power contribution at the end of the circuit would help to improve overall voltage profile. The ability of changing the output ramp rates provides an advantage when operating with the traditional inertia based generation to offer smooth transition of power flow.

Volt-Watt

Volt-watt function enables the DER to manage its active power dispatch in response to the voltage of the system. The objective is to counter any changes in the voltage by varying the output active power to maintain the nominal voltage. When the DER is set in volt-watt control mode, it attempts to maintain the voltage of the system at reference value by curtailing the active power output. The DUT has settings for the voltage reference, dead band and the under and overvoltage droop to program the characteristics of the volt-watt function. For these testing a voltage droop setting of 6% was used. This function only regulates the active power of the DER therefore other high-level controls that operate on reactive power can be used simultaneously. Figure 4.3 shows the plot of active power in response to the rising voltage at the PCC, the increase in the system voltage is because of disconnection of the load on the feeder.



r

Figure 4.3: Volt-Watt Function

The results of this test show that the DER active power output is at the highest (approximately 600 kW) in Scenario 3: DER at the End of a Long Feeder and its lowest in Scenario 1: DER Close to a Substation. This shows that this mode is much more effective in Scenario 3 because it maintains the voltage at reference value at the end of the feeder. The fluctuations in the frequency do not affect the DER operation in this mode in steady state.

This function is useful in the circuit where multiple DER devices are connected in the proximity. Because of the high penetration of the DER, the overall voltage on the feeder tends to rise beyond a value that would prevent other DER to turn online until the local voltage is within the safe operation limits. The volt-watt function curtails the active power output of the online DER so that other DER can be turned on. This function is not recommended to be used otherwise in the steady state where, to correct the low voltage, the feeder needs the reactive power fed in to the circuit instead of the active power. This is more useful in the overvoltage scenario that prevents energization of the DER. The voltage droop and the dead band settings of different DER depend on many factors in a particular distribution circuit; such as the ratings of the DER; number of DER in closed proximity and the location. In this particular circuit, the voltage at the far end of the feeder was about 0.97 pu with full load on the circuit, in this case the DER would not curtail the active power since the voltage is already below nominal value and overvoltage condition does not exist. By analyzing Figure 4.3, it can be noted that the droop settings can be set less than the present setting of 6% so that more output is curtailed for the same amount of change in the voltage and the voltage is settled back in to the dead band.

Volt-VAR

This function provides an ability to the DER to regulate the reactive power in the system to maintain the bus voltage to the reference value. The DUT had settings for the voltage reference, dead band and the under and overvoltage droop to program the characteristics of the volt-VAR function. The Rule 21 proposes having pre-programmed volt-VAR curves in the device memory so that operator can select it based on the system condition during particular time of the day. The DUT allows changing the droop settings (kVAR per percentage volt) of the controller to vary the reactive power contribution of the DER for 1% change in system voltage from the reference value. This creates a challenge for the operator to come up with a droop setting in different scenarios as compared to selecting from a set of per-programmed curves. CPUC also recommends the hysteresis function may be used on the volt-VAR curve for more flexibility; the controller on the DUT lacked the hysteresis function. For these tests, a voltage droop setting of 6% and a dead band of 1% was used.

The DER responded to fluctuations in voltage by increasing its reactive power dispatch at low voltage condition and decreasing its reactive power dispatch during high-voltage conditions. The results of this test show that this mode is very effective in Scenario 3: DER at the End of a Long Feeder) because the voltage is the lowest at the end of the feeder, and hence the reactive power dispatch is the highest. The location of the DER near the feeder transformer (Scenario 1: DER Close to a Substation) is not as effective because the DER reduces its reactive power output to maintain the voltage at 1 pu because the voltage is close to or above nominal near the substation. DER responded to the voltage, load, and generation changes to by regulating the reactive power in the system. Figure 4.4 shows the plot of reactive power output of the DER in response to the system voltage during the disturbance. Note that the spike in the voltage at about 12 seconds' mark is because of the capacitor bank switching after a set time delay. At this instance, the reactive power is supplied by the capacitor bank and the DER backs up on its output since the overall voltage is in the dead band.

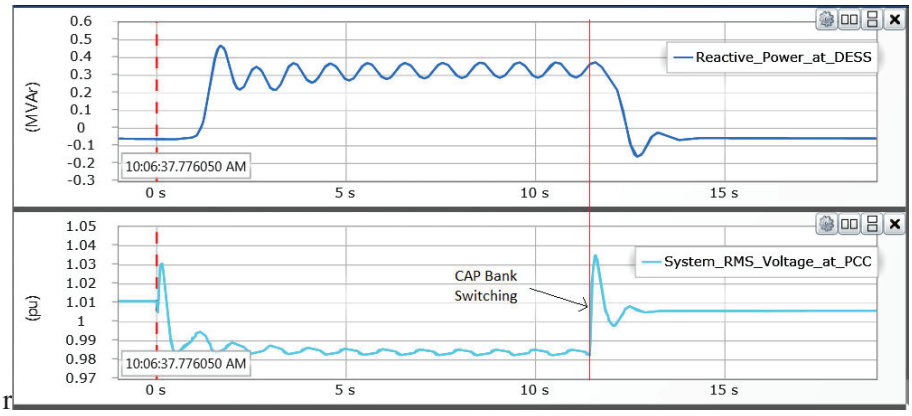


Figure 4.4: Volt-VAR Function

This highlights an interesting point about the need of coordination between the reactive power regulating devices when they are located close by to interact each other's performance. The DER is the faster device to react to the voltage disturbance in comparison to other devices such as capacitor banks (time delayed) and voltage regulators etc. The volt-VAR operation of the DER should be coordinated with the capacitor bank such that in the steady state when DER reaches its rating, the capacitor bank should switch on and take off the reactive power load from the DER. In this manner, the DER is only used for transient changes while the slower devices provide support during the steady state; this improves the overall system reliability without overburdening the DER. At the farthest end of the feeder, the DER was found to be producing more reactive power even in the steady state because of the poor voltage profile. This provides

a good measure to system planners for installing a fixed capacitor bank for continued use instead of a DER.

In the distribution circuit where multiple DER are present near, it will be necessary coordinate their droop settings such that the devices with the higher ratings contribute more reactive power during the disturbance. This will prevent overloading and distribute the load efficiently among all the DER devices. A weighted droop setting based on the DER rating should be a good approach to the coordination.

One of the flexibility of this function is that, irrespective of the location of the DER, it can regulate the voltage at different points of interconnections (PCC) along the distribution circuit. This can be done by supplying measured voltage of that particular connection node to the DER. However, this posed a limitation with the DUT, in a way that this connection was hardwired to the power quality meter on the inverter control panel from AC side of the device. This provided no flexibility and the ease of use to test the volt -VAR regulation at variable PCC's. In a circuit where it necessitates that different PCC's be used for voltage regulation, the measured voltage signal can be transmitted via communication channel to the inverter controller (Modbus, DNP3 etc.)

Frequency-Watt

This function provides an ability to the DER to regulate the active power output in the system to maintain the system frequency to the reference value.

The DUT had settings for the frequency reference, dead band and the under and over frequency droop to program the characteristics of the Frequency-Watt function. The DUT allows changing the droop (kW per percentage frequency) of the controller to vary the active power contribution of the DER for 1% change in system frequency from the reference value. Per CPUC Rule 21 guidelines, the hysteresis function may to be used on the Frequency-Watt curve for more flexibility, the controller on the DUT lacked the hysteresis function. For these tests, a frequency droop setting of 6% nominal frequency and a dead band of 0.1 Hz had been used.

The test was conducted for all the scenarios and the various system conditions including load variations and the frequency, voltage fluctuations. The results of this test show that the location of the test DER does not affect the performance of the DER in frequency-watt mode. The DER responded to fluctuations in frequency by increasing its active power dispatch at low frequency condition and decreasing its active power dispatch during high-frequency conditions. The voltage variations did not have any significant impact on the active power dispatch of the DER. The Figure 4.5 below shows the plot of active power output of the DER during a frequency disturbance in the system. The dip in the frequency is caused by the energization of the load in the system and the DER increase its output to supply additional active power in the system until the traditional generation responds to the change.

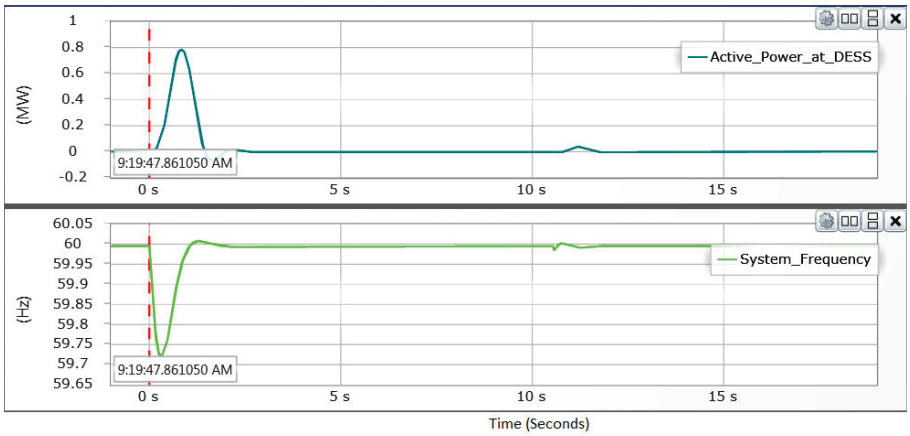


Figure 4.5: Frequency-Watt Function

In the distribution circuit where multiple DER are present in the proximity, it will be necessary to coordinate their droop settings such that the devices with the higher ratings contribute more active power during the disturbance. This will prevent overloading and distribute the load efficiently among all the DER devices. The DER, when operated in this mode can provide the frequency support when other DER such as photovoltaic systems start to ramp down towards the end of the day while the conventional generation is still trying to ramp up. When the system frequency is in the stable band DER can be used to run in other control mode such as peak shaving, SOC management etc. Since frequency-watt affects only the active power output of the DER, the control modes that operate on reactive power can be used simultaneously.

DER Response to Emergencies

This test examined the capability of the inverter to communicate the information with the utility management system. Following are some of the emergency commands and requests that are exchanged between the utility and the DER managements system.

ISSUE DISCONNECT OR RECONNECT COMMANDS TO THE DER SYSTEM FROM THE UTILITY

A start and stop command can be sent remotely over Modbus to the DER controller for connecting and disconnecting the DER from the system. The startup process takes up to 4 seconds after the start command is issued to the controller. Figure 4.6 shows the startup transient during the inverter AC breaker closing. Once the DER is online, different mode commands can be sent with the required active and reactive power set points.

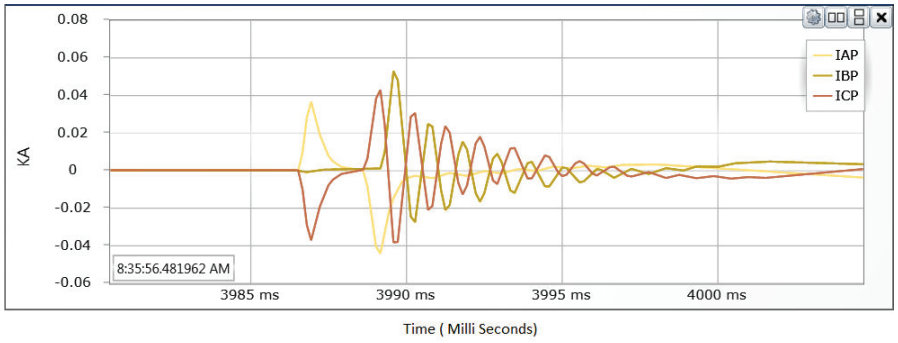


Figure 4.6: Inverter Startup Transients

UPDATE VOLTAGE RIDE-THROUGH CURVES TO CHANGE ANTI-ISLANDING SETTINGS

The voltage ride-through settings on the tested DER can only be set via the HMI, since this setting in not available in the Modbus register. Therefore, it could not be tested in this effort.

UPDATE FREQUENCY RIDE-THROUGH CURVES TO CHANGE ANTI-ISLANDING SETTINGS

The frequency ride-through settings on the tested DER can only be set via the HMI, since this setting is not available in the Modbus register. Therefore, it could not be tested in this effort.

REQUEST NOTIFICATION FROM THE DER SYSTEM ABOUT THE STATUS OF MICROGRID CONNECTION

The tested DER continuously broadcasts its status to the remote managements system via Modbus, indicating if the DER is online or offline. Along with this status information, the DER also sends the power output information. Based on this information utility operator can take operations decisions during different periods of the day.

REQUEST NOTIFICATION FROM THE DER SYSTEM ABOUT THE SPINNING RESERVE

The tested DER sends the present state of charge to the remote management system via Modbus, which aids the utility operator with load and generation forecast.

Spinning Reserve

The purpose of this test was to assess the benefits of using the DER an alternative to spinning reserve to provide the active power support during different system conditions as compared to conventional diesel generators in terms of response time, standby losses, durability of support, and availability. The DER is connected near the end of the feeder (Scenario 3) in this test. The results of this test proved that the DER is quite effective in sustaining loads during periods of under-frequency, providing voltage and frequency support within a short period. In addition to being a fast spinning resource, it also proves to be more effective in terms of cost and efficiency and better in terms of environmental factors and ease of operation and maintenance. The DER reacted to the under-voltage and under-frequency in the system during generation outage by acting as a source of spinning reserve providing voltage and frequency support to feed the local loads in the affected region.

Black Start

The purpose of this test is to assess the benefits of using the DER to black start the system after a complete system outage. The result of this test shows the effectiveness of using the DER to black start the system just like the traditional generation to bring the system online in the increment of loads and generations on the circuit. Once the grid breaker opens, causing the system to enter a blackout, the DER enters VSI mode creating reference for voltage and frequency. With the DER in VSI mode, additional load and generation sources can be connected in the system in the subsequent steps. The DER, like the PV system, need a voltage reference from the DER to initiate the startup process to feed the load. The only difference of using the DER as a black start source as opposed to the traditional generators is that the DER offers no inertia to the system.

The DER responded successfully by operating in VSI mode providing voltage and frequency support during the black start.

Load Leveling

The load-leveling function is like load and generation following in the manner that it involves the cycle of charging and discharging during different loading conditions. During periods of high-load demand, the DER can supply energy into the grid and charge while the load is light. This helps reduce the load on less economical peak generating plants. The DUT has a setting for peak shaving and the base loading active power limits. These two settings create a band envelope such that if the load at the PCC changes above or below this limit, the DER produces or absorbs the active power. The controller needs to monitor the active power flow through the PCC for this mode to function. This supervised active power signal is transmitted to the controller over Modbus.

The purpose of this function is to ensure that the import of active power across the grid remains the same throughout the periods of load fluctuations. This reduces the load on less economical peak generation plants. The results of this test on different scenarios had similar and effective impact on the system throughout. While the DER responded to the load fluctuations, the power import across the PCC remained constant, which maintained the active power imported from the source at a constant value. Figure 4.7 below shows the active power output of the DER responding to the changing power flow at the PCC. For this test, the peak shaving limit was set to 1000 kW and the base loading limit was set to 600 kW. When the active power at the PCC was within the band of peak shaving and base loading the DER output was zero as indicated by the dead band in the plot below.

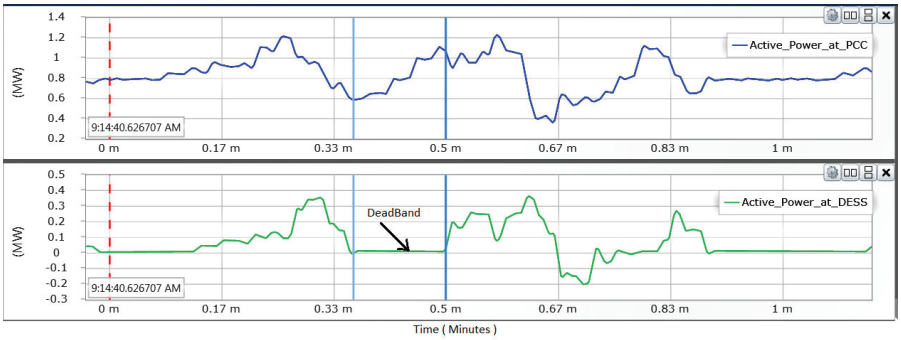


Figure 4.7: Load Leveling Function

The objective of this test was to assess the economic benefits of using the DER to supply clean and emission-free energy, while reducing the use of less economical generation plants during high-load demands. The peak shaving and base loading settings should be set based on the loading conditions on the feeder throughout the day; maximum deviation of the base load over a period of time and the rating of the DER that is going to feed the deficit power and absorb the surplus power. Overall, The DER mitigated the impact of the load fluctuation by keeping the power import at the PCC constant under different scenarios.

RECOMMENDATIONS

The following recommendations are made based on the results of the pre-commercial demonstrations in the laboratory. For more details on the application situations where the recommended commercial adoption would provide the greatest value, see the discussions in previous sections.

Volt-VAR Function

In the demonstrations, DER performed voltage regulation successfully in different test scenarios to maintain the system voltage. The DER was a faster device in terms of response time during the disturbance compared to traditional voltage regulating devices such as capacitor banks. This function contributed to the system stability autonomously and helped the grid sustain the disturbance. It prevents frequent operation of the capacitor banks and the voltage regulators by providing the dynamic voltage regulation. In a distribution system, which has multiple DER, this function can efficiently provide voltage stability to the grid. It is recommended to pursue this function commercially in the DER inverters.

Frequency-Watt Function

The frequency-watt function of the DER provided the smooth active power regulation for the frequency disturbances during the demonstrations. The DER provided the active power to the system to maintain the frequency. This function is recommended to be used in the distribution circuit which has a large amount of intermittent generation. The frequency-watt function mitigates the frequency fluctuations caused by these sources. The location of the DER does not impact the operation of the frequency-watt function. This function complements the volt-VAR function, in regards that both functions can operate independently at the same time and provide voltage and frequency regulation. It is highly recommended to pursue these grid support functions in the commercial DER inverter.

Load Leveling Function

Load leveling function maintained the power import form the PCC within the specified dead-band during the demonstrations. During heavy and light loading periods, the DER supplied and absorbed the deficit and surplus power. The DER supported the load fluctuation by keeping the power import at the PCC constant under different scenarios. This function smooths out the load fluctuations on the feeder and makes the load forecasting simpler for distribution system operators. Load leveling concept is common in other types of DER such as diesel generators, which is called peak shaving. When used with ESS, it provides both peak shaving and base loading, since ESS can supply as well as absorb active power. It will be beneficial and is recommended to implement this function in the commercial DER inverter.

Black Start

The results of this demonstration show the effectiveness of using the ESS to black start the system just like the conventional generation source to bring the system online in the increment of loads and generations on the circuit. Once the grid breaker opens, causing the system to enter a blackout, the ESS enters VSI mode creating reference for voltage and frequency. With the ESS in VSI mode, additional load and generation sources can be connected in the system in the subsequent steps. The DER, like the PV system, need a voltage reference from the ESS to initiate the startup process to feed the load. It is highly recommended to pursue black start functionality commercially to be used in the microgrids in the distributions system.

Spinning Reserve

The results of this demonstrations proved that the ESS is quite effective in sustaining loads during periods of under-frequency, providing voltage and frequency support within a short period. In addition to being a fast spinning resource, it also proves to be more effective in terms of cost and efficiency and better in terms of environmental factors and ease of operation and maintenance. The ESS reacted to the under-voltage and under-frequency in the system during generation outage by acting as a source of spinning reserve providing voltage and frequency support to feed the local loads in the affected region. It is recommended to have this function implemented in the commercial ESS inverter. The ESS can run in the idle mode with minimal loss of charge to provide spinning reserve.

DER Monitoring and Control

DER monitoring allows system operator visibility into DER operation that enables efficient use of DER. All the important status points should be relayed to the remote management system. For the ESS, the information like state of charge, online/offline status, power output etc. is necessary to make control decisions. The availability of this information aids the control actions such as connecting/disconnecting the DER, updating voltage and frequency ride-though settings. The ability of DER to communicate with the remote system and to allow DER monitoring and control is highly desirable with increasing penetration of DER in the system to make informed decision about the operation of the system. It is recommended that this function be implemented in the DER.

Volt-Watt Function

The volt-watt function curtails the active power output of the DER during the overvoltage in the system. This function has a very narrow applicability in terms of grid support. The voltage regulation is best carried out by the volt-VAR function, which provides reactive power support instead of active power. Because of the high penetration of the DER, the overall voltage on the feeder tends to rise beyond a value that would prevent other DER to turn online until the local voltage is within the safe operation limits. The volt-watt function curtails the active power output of the online DER so that other DER can be turned on. This function is not recommended to be used otherwise in the steady state where, to correct the low voltage, the feeder needs the reactive power fed in to the circuit instead of the active power. This is more useful in the overvoltage scenario that prevents energization of the DER.

TECHNOLOGY TRANSFER PLAN

A primary benefit of the EPIC program is the technology and knowledge sharing that occurs both internally within SDG&E and across the industry. To facilitate this knowledge sharing, SDG&E will share the results of this project by widely announcing the availability of this report to industry stakeholders on its EPIC website, by submitting papers to technical journals and conferences, and by presentations in EPIC and other industry workshops and forums. Additionally, presentations will be given to internal stakeholders at SDG&E.

SECTION 5 METRICS AND VALUE PROPOSITION

METRICS

The following metrics (shown in Table 8) were identified for this project as potential project benefits at larger scale deployment. Given the pre-commercial nature of this EPIC project, these metrics would apply in future scenarios after widespread commercial adoption. The following metrics are potential benefits that are concluded from different tests cases performed in this effort:

Table 8. EPIC metrics for grid support functions of DER

D.13-11-025, Attachment 4. List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation)
1. Potential energy and cost savings
b. Total electricity deliveries from grid-connected distributed generation facilities
e. Peak load reduction (MW) from summer and winter programs
f. Avoided customer energy use (kWh saved)
g. Percentage of demand response enabled by automated demand response technology
3. Economic benefits
c. Reduction in electrical losses in the transmission and distribution system
e. Non-energy economic benefits
f. Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management
5. Safety, power quality, and reliability (equipment, electricity system)
a. Outage number, frequency, and duration reduction
f. Reduced flicker and other power quality differences
7. Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy
b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)

VALUE PROPOSITION

The purpose of EPIC funding is to support investments in R&D projects that benefit the electricity customers of California IOUs. The primary principles of EPIC are to invest in technologies and approaches that promote greater reliability, lower costs, and increased safety. This section discusses each of the functions in detail in terms of the value it provides to the overall system operation. Primary and secondary benefits are presented wherever applicable to demonstrate the value of the function for commercial adoptability.

Limit Maximum Active Power Output

In this mode, the active power output of the DER is restrained by a maximum specified limiting value. This function can be used to prevent the localized overvoltage conditions by curtailing DER output. This test is conducted under different scenarios and under different system conditions including load. Because of the changing load conditions and varying operating set points the DER operates as controlled by the system operator within the specified maximum limit. If the DER receives an active power set point of more than the maximum limit set point, the output of the DER is held at the maximum limit set point. On the other hand, if the maximum limit set point is changed so that it is lower than the present active power output of the DER, the active power is reduced to the new maximum limit. The operation of this function is unaffected by the location of the DER in the circuit and yields similar results in all the scenarios.

Primary Principles: The limit on the active power act as an additional safety measure, to protect the equipment from unintended operation, when an undesirable set point is issued by the grid operator. This limit can be set once considering the rating of the equipment and can only be changed if needed. This improves the reliability of the system when operating in the grid support mode with active power regulation. Although this function is integral part of most inverters, having an ability to control this limit remotely by the grid operator, gives more operational flexibility.

Schedule Active Power Output

In this mode, the DER is set at a constant active power dispatch and the DER tries to limit its active power output at that value. This test was conducted for all the four scenarios. The location of the DER in the circuit did not affect the performance of the DER in this mode, and it was effective under all the scenarios. The variations in load and voltage do not alter steady-state active power output. The frequency fluctuations do not affect the DER in any condition.

Primary Principles: In this mode, the inverter operates in the base mode, where it supplies or consumes the active power depending on the operational needs. A schedule can be implemented during the day for the output of the inverter based on the cost of electricity and other environmental factors. This enables the operator to dispatch clean energy at lower costs. This also takes the load off peak generating stations during high load demand periods. The overall redistribution of power improves the reliability of the grid.

Secondary Principles: The ability to control and schedule power on these renewable assets provides more transparency to the grid operator for load generation forecasting by making efficient use of the resources.

Volt-Watt Function

Volt-watt mode enables the DER to manage its active power dispatch in response to the voltage of the system. The objective is to counter any changes in the voltage by varying the output active power to maintain the nominal voltage. When the DER is set in volt-watt control mode, it attempts to maintain the voltage of the system at reference value by curtailing the active power output. The results of this test

show that the DER active power output is at the highest in Scenario 3: DER at the End of a Long Feeder and its lowest in Scenario 1: DER Close to a Substation. This shows that this mode is much more effective in Scenario 3 because it maintains the voltage at reference value at the end of the feeder, which improves the overall circuit voltage profile. The fluctuations in the active power load and frequency do not affect the DER operation in this mode in steady-state conditions.

Primary Principles: This function is particularly important, when multiple DER are connected on the same feeder, which tends to rise the voltage on the feeder beyond a nominal value that energizing further DER cannot be achieved because of the high voltage. In this scenario, when the online DER if set in the volt-watt mode, would curtail the output so that voltage falls within the acceptable limit. This enables reliable operation of the microgrid with operational flexibility since it can control the output of the DER to maintain the voltage on the feeder. It increases equipment and personnel safety by maintaining the voltage at a nominal value.

Secondary Principles: This function allows for multiple DER operate in parallel by maintaining the voltage within nominal limit to offer more affordable renewable energy services to the customers. More penetration of the renewable energy reduces negative environmental impact.

Volt-VAR Function

Volt-VAR mode enables the DER to manage its reactive power dispatch in response to the voltage fluctuations. The test was conducted for all the four scenarios and the various system conditions including load variations and the frequency, voltage fluctuations. The DER responded to fluctuations in voltage by increasing its reactive power dispatch at low voltage condition and decreasing its reactive power dispatch during high-voltage conditions. The results of this test show that this mode is very effective in Scenario 3: DER at the End of a Long Feeder because the voltage is the lowest at the end of the feeder, and hence the reactive power dispatch is the highest. The location of the DER near the feeder transformer in Scenario 1: DER Close to a Substation is not as effective because the DER reduces its reactive power output to maintain the voltage at 1 pu because the voltage is close to or above nominal near the substation. The change in frequency did not affect the DER in this mode during steady-state conditions. The change in reactive load caused minimal change in voltage.

Primary Principles: The volt-VAR function provides seamless voltage regulation on the feeder which provides benefit over the stepped capacitor banks. The inverter in this mode provides voltage support during transient and steady state. With proper coordination, multiple devices can be operated in parallel to have the efficient voltage regulation. This provides greater reliability of operation by improving the voltage profile on the feeder compared to slow acting voltage regulating devices such as voltage regulators and capacitor banks. The volt-VAR function involves no switching or the tap change operations like traditional device, which reduces periodic maintenance and improves service life of equipment.

Frequency-Watt Function

Frequency-watt mode enables the DER to manage its active power dispatch in response to frequency fluctuations. The test is conducted for all the four scenarios and the various system conditions including load variations and the frequency, voltage fluctuations. The results of this test show that the location of the test DER does not affect the performance of the DER in frequency-watt mode. The DER responded to fluctuations in frequency by increasing its active power dispatch at low frequency condition and decreasing its active power dispatch during high-frequency conditions. The voltage or load variations did not have any significant impact on the active power dispatch of the DER.

Primary Principles: The frequency watt function provides seamless regulation during the event of under-frequency caused by events such as load switching. This function provides reliability when the other intermittent sources renewable sources of energy reduce output because of cloud cover or lack of wind, the DER provides additional output to counter the changes in the DER output. The regulation can also occur in a manner that DER can operate in the charging mode to absorb the excess output in the system, which may occur during the light load condition. Since DER acts as quick reacting source to mitigate these frequency fluctuations, it takes load off the conventional generations. This leads to efficient and low-cost operations of the grid.

DER Response to Emergencies

A start and stop command can be sent remotely over Modbus to the DER controller for connecting and disconnecting the DER from the system. The startup process takes up to 4 seconds after the start command is issued to the controller. Once the DER is online, different mode commands can be sent with the required active and reactive power set points. The voltage ride-through settings on the tested DER can only be set via the HMI since this setting in not available in the Modbus register. The frequency ride-through settings on the tested DER can only be set via the HMI since this setting is not available in the Modbus register. The tested DER continuously broadcasts its status to the remote managements system via Modbus, indicating if the DER is online or offline. Along with this status information, the DER also sends the power output information. Based on this information utility operator can take operations decisions during different periods of the day. The tested DER sends the present SOC to the remote management system via Modbus to assist the utility operator with load and generation forecast.

Primary Principles: The ability of the DER inverter to communicate to relay the status information and receive the control commands from the remote managements system, provides operational flexibility to the grid operator, which aids the operator to make sound decisions based on the overall system condition. A DER inverter can be started and stopped to connect and disconnect from the rest of the system. The output can be modified and the ramp rates can be changed depending on the need. In addition, the ramp rates and gains for the volt-VAR, frequency-watt and volt-watt functions can be changed to suit different scenarios. Overall, this flexibility provides reliable operation with increased safety.

Spinning Reserve

The purpose of this test is to assess the benefits of using the DER a source of spinning reserve to provide the active and reactive power support during different system conditions as compared to conventional diesel generators. The DER is connected near the end of the feeder (Scenario 3) in this test. The results of this test proved that the DER is quite effective in sustaining loads during periods of under-frequency, providing voltage and frequency support within a short period.

Primary Principles: The DER can remain in idle mode with minimal loss of charge unlike the conventional diesel generators, which consumes fuel even when it is not outputting the power. Because of this benefit, storage system is more cost effective as a source of spinning reserve. It is more efficient and reliable source to provide the grid support during the disturbance or the outage. It provides clean energy and enhances environmental sustainability and provides ease of operation and maintenance. The detailed cost benefit analysis is provided in Appendix A.

Black Start

The purpose of this test is to assess the benefits of using the DER to black start the system after a complete system outage. The result of this test shows the effectiveness of using the DER to black start the system just like the traditional generation to bring the system online in the increment of loads and generations on the circuit. Once the grid breaker opens, causing the system to enter a blackout, the DER

enters VSI mode creating reference for voltage and frequency. With the DER in VSI mode, additional load and generation sources can be connected in the system in the subsequent steps. The DER, like the PV system, need a voltage reference from the DER to initiate the startup process to feed the load. The only difference of using the DER as a black start source as opposed to the traditional generators is that the DER offers no inertia to the system.

Primary Principles: With the black start functionality, the DER can be used to power up the microgrid during the system outage, to feed the local load. In addition, other types of renewables can be paralleled once the microgrid is formed. This provides reduced outage duration for the microgrid, once the grid is back online, microgrid can be synchronized without interrupting the load. The storage system operating in parallel with the PV system is an ideal example of renewable microgrid operating at a very low cost without any negative environmental impact.

Load Leveling

The purpose of this function is to ensure that the import of active power across the grid remains the same throughout the periods of load fluctuations. This reduces the load on less economical peak generation plants. The results of this test on different scenarios had similar and effective impact on the system throughout. While the DER responded to the load fluctuations, the power import across the PCC remained constant, which ensured that the active and reactive power imported from the source remained constant as well.

Primary Principles: With the load levelling, the DER system can be set to follow the load, which means, it responds to load changes during high as well as low loading conditions. The load demand for the utility at the PCC remains constant throughout, which helps offset stress from the economical peak generating plants. This leads to lower cost of operation with improved reliability.

SECTION 6 REFERENCES

[1] ASPEN Model of the SDG&E System.

[2] IEEE 1547a-2014, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.

[3] T. Fenimore, A. Gould, and L. Wright, "Implementing a Microgrid Using Standard Utility Control Equipment," proceedings of the Power and Energy Automation Conference, Spokane, WA, March 2016.

[4] A. Yazdani and P. P. Dash, "A Control Methodology and Characterization of Dynamics for a Photovoltaic (PV) System Interfaced with a Distribution Network," IEEE *Transactions on Power Delivery*, Vol. 24, No. 3, July 2009.

This page intentionally left blank

APPENDIX A SOFTWARE SIMULATION TESTING

Software testing, with the test inverter simulated in the RTDS, was conducted prior to the PHIL testing with the hardware inverter. A software simulation of demonstration DER was used for this assessment. The objective of the software tests was same as the PHIL tests. This section presents the results of the software testing. Only core functions of the DER were demonstrated in the software testing.

DEVICE UNDER TEST

The device under test was modeled as a DER with a capacity of 1 MW and 1500 kWh. The DER had an average value model of control system that was like the photovoltaic (PV) control from Section 2—A controllable AC voltage source and a controllable DC source. The control was achieved by controlling the line currents and voltages and converting them into a direct-quadrature (DQ) frame using Park's transformation. The various control parameters were real power output and reactive power output, which were controllable through sliders. Figure A.1 shows the DER model.

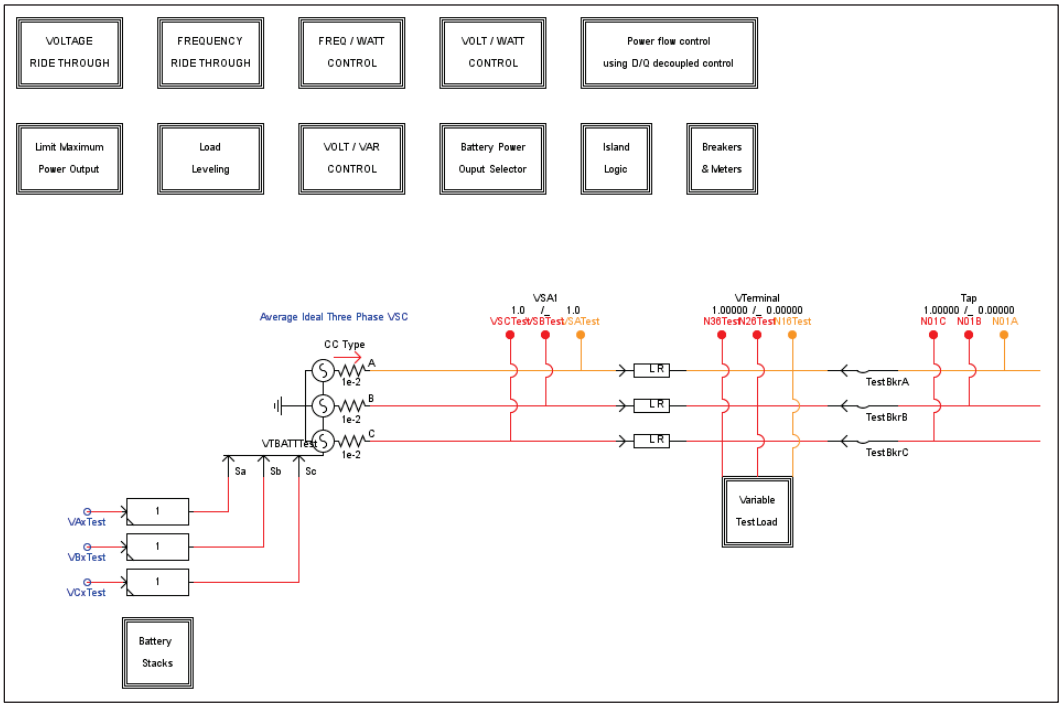


Figure A.1: DER Test Inverter Model

The DER is modeled generically such that it can be moved around in the circuit without affecting the functionality of the device to simulate multiple testing locations for penetration points. The DER provides the grid support functions and the ride-through protection functions.

TEST 3 – VOLT-WATT

This function was identified for use as compensation for the voltage variability that results from intermittent renewable sources or other loads. volt-watt is intended to provide a flexible mechanism through which inverters may be configured to dynamically provide voltage stabilization. This function involves the dynamic production of active power (watts) to resist variations in the voltage at the PCC.

The objective is to counter any changes in the voltage by varying the output power. When the DER is set in volt-watt control mode, it tries to maintain the voltage of the system to 1 pu by curtailing the active power output.

The procedure for testing was as follows:

Step 1. Vary the system voltage beyond the nominal values in a stepped and/or transient manner to observe the behavior of the DER.
Step 2. Change the voltage by changing the load in steps or by changing the grid voltage (the DER should respond in such a way that the system voltage is maintained within the nominal values).
Step 3. Increase the output of the DER to its maximum capacity, which should lead to the voltage increase at the PCC bus (when the DER is put into volt-watt mode at this stage, the system voltage should revert into the nominal band because of the power curtailment by the function).
Step 4. Compare the results with the baseline case and develop conclusions based on these findings.

Table A.1 lists the tests that were conducted.

Table A.1: DER Volt-Watt Test Cases

Test	Test Description	Expected Response
Test 3. x.1	Mode activation with active power set point of 500 kW	DER dispatches 500 kW at steady state
Test 3. x.2	Increase the system load by 500 kW	DER dispatches 500 kW at steady state
Test 3. x.3	Decrease the system load by 500 kW	DER dispatches 500 kW at steady state
Test 3. x.4	Increase the system voltage by 5%	DER decreases active power output to offset voltage increase
Test 3. x.5	Decrease the system voltage by 5%	DER increases active power output to offset voltage decrease
Test 3. x.6	Increase the system frequency by 0.5 Hz for 1 s	DER dispatches 500 kW at steady state
Test 3. x.7	Decrease the system frequency by 0.5 Hz for 1 s	DER dispatches 500 kW at steady state

Note: “x” denotes the scenario under test.

Scenario 1: DER Close to a Substation

TEST 3.1.1: MODE ACTIVATION WITH ACTIVE POWER SET POINT OF 500 KW

The system was initially operating in the schedule active power mode where the active and reactive power set points were at 500 kW and 200 kVAR, respectively. The system local load was at 900 kW and 450 kVAR. On activating the volt-watt mode, the real and the reactive power at the DER and PCC settled at steady state. No visible disturbance was observed following mode activation. The voltage and frequency profile remained unaffected by the transition.

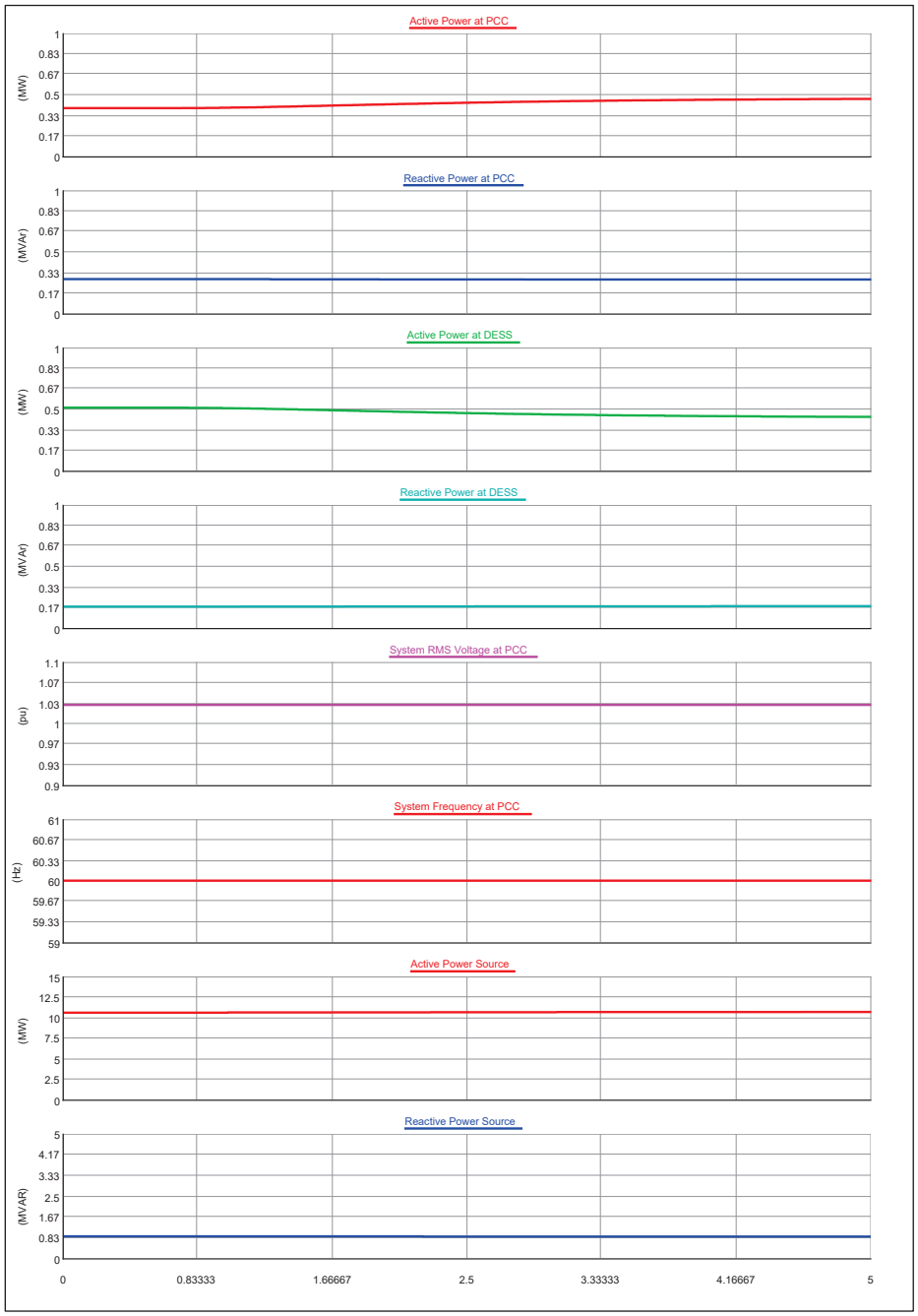


Figure A.2: System Response for Test 3.1.1

TEST 3.1.2: INCREASE THE SYSTEM LOAD BY 500 KW

On increasing the active power load by 500kW, the real power at the DER settled to steady state, while the additional load was supported by the grid through the PCC. The reactive power flow and system voltage and frequency were not affected.

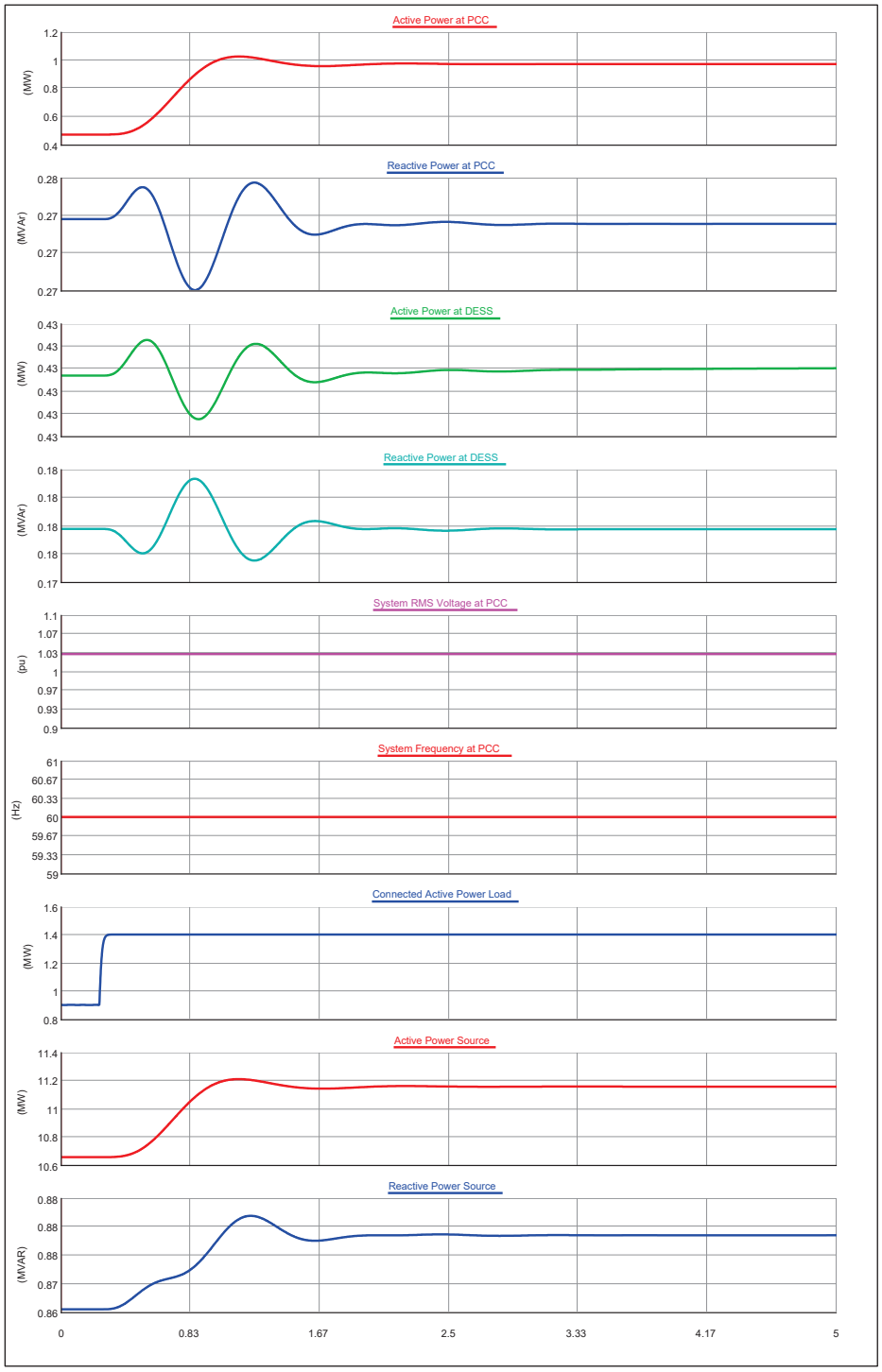


Figure A.3: System Response for Test 3.1.2

TEST 3.1.3: DECREASE THE SYSTEM LOAD BY 500 KW

On decreasing the active power load by 500 kW, the real power at the DER settled to its steady state, while the additional load was supported by the grid through the PCC. The reactive power flow and system voltage and frequency were not affected.

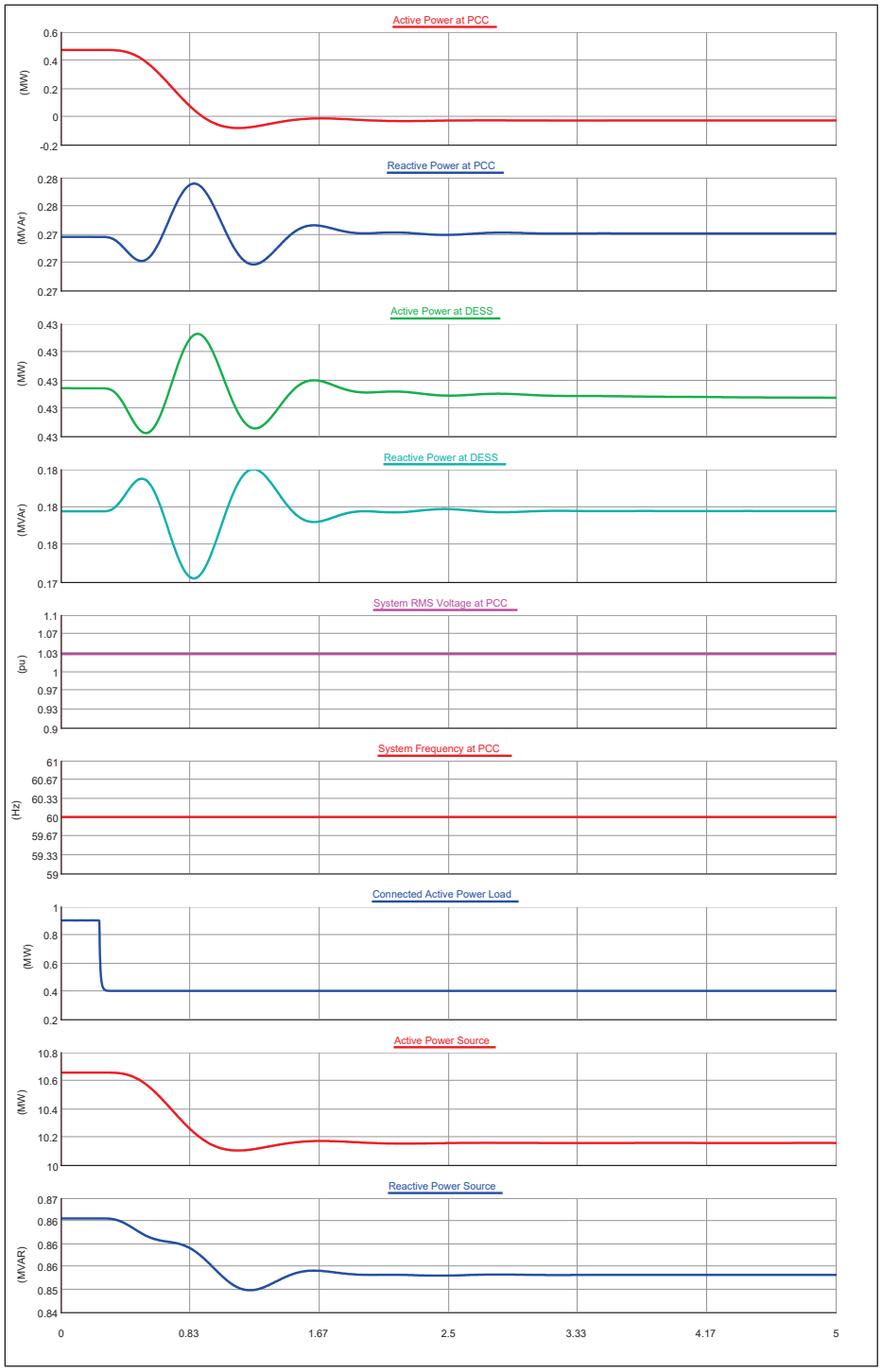


Figure A.4: System Response for Test 3.1.3

TEST 3.1.4: INCREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On increasing the system pu voltage by 5 percent from 1.025 pu to 1.075 pu, the active power at the DER fell so that more power was imported from the grid to keep the power import in the same direction. This balanced the power flow across the PCC to avoid reverse flow into the grid due to the increased voltage across the terminals. The reactive power returned to its prior set point during steady state, and the system frequency remained undisturbed during the transition.

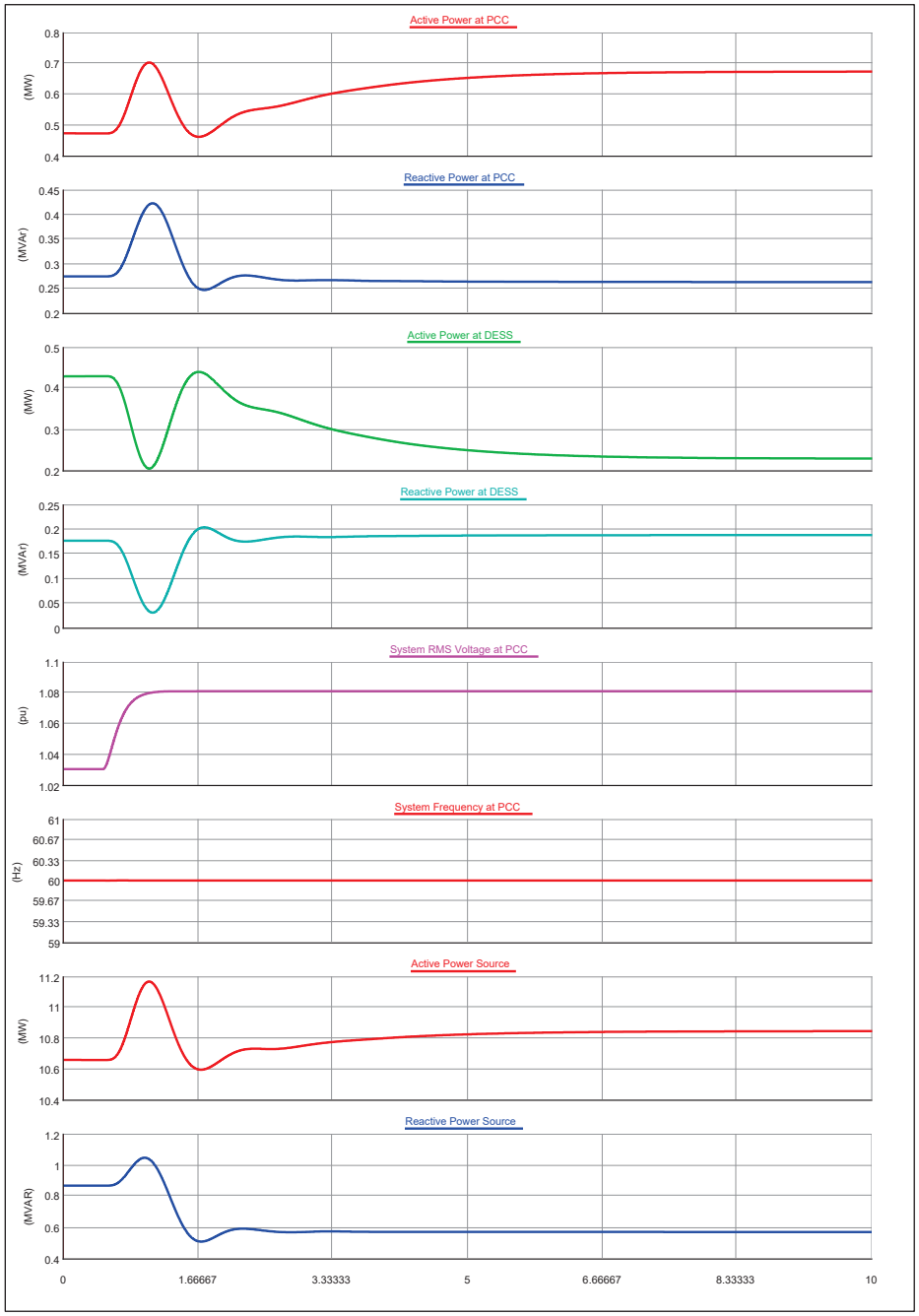


Figure A.5: System Response for Test 3.1.4

TEST 3.1.5: DECREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On decreasing the system pu voltage by 5 percent from 1.025 pu to 0.975 pu, the real power at the DER increased so that more power was imported from the grid to keep the power import in the same direction. This balanced the power flow across the PCC to avoid additional power import from the grid due to the voltage drop across the terminals. The reactive power returned to its prior set point during steady state, and the system frequency remained undisturbed during the transition.

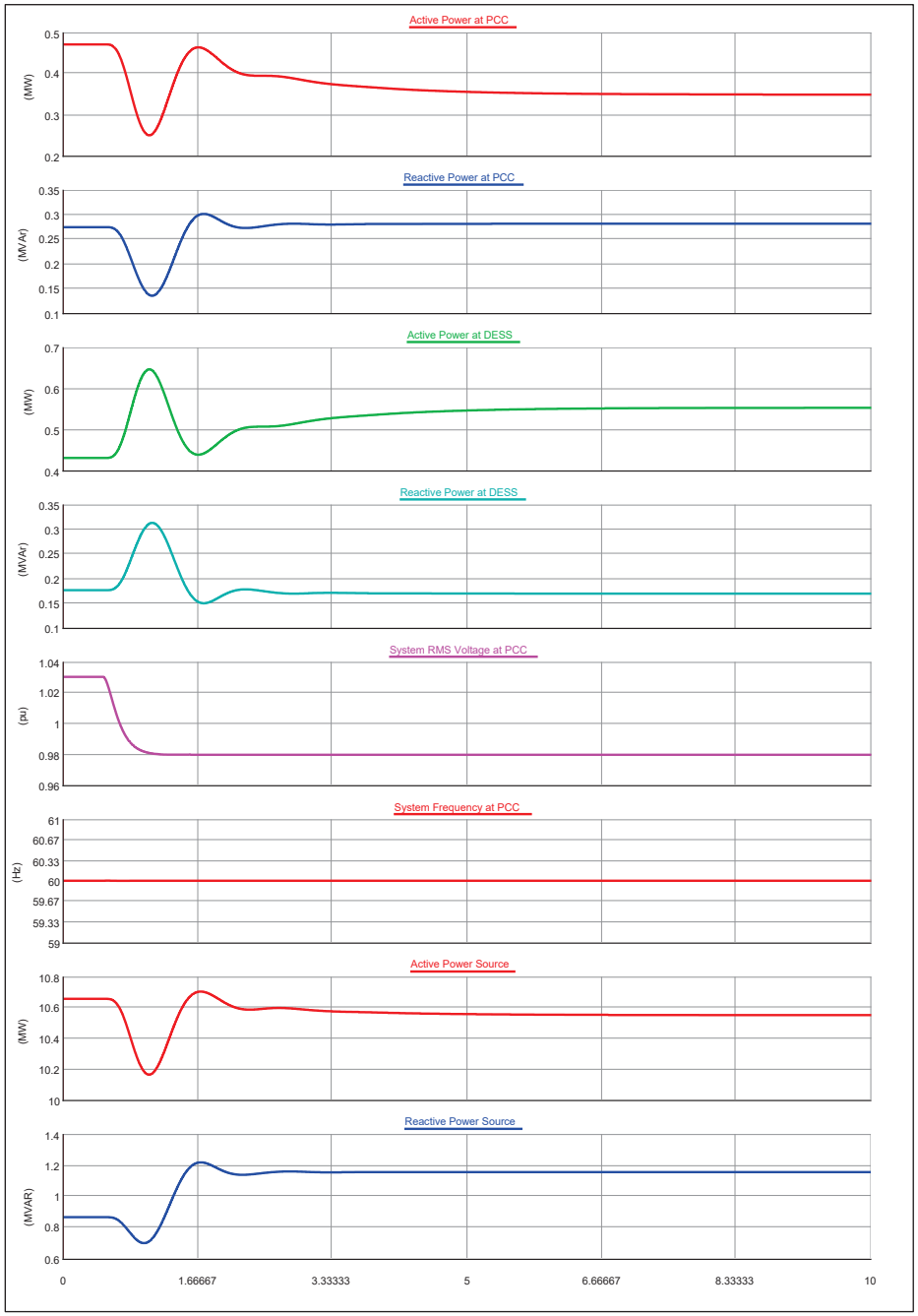


Figure A.6: System Response for Test 3.1.5

TEST 3.1.6: INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was increased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER, in this mode, reacted to the change, rode through, and returned to steady state. The real and reactive power flow at the PCC and DER settled at their previous set points. The voltage was disturbed by the frequency change due to power flow but settled back to 1.025 pu in steady state.

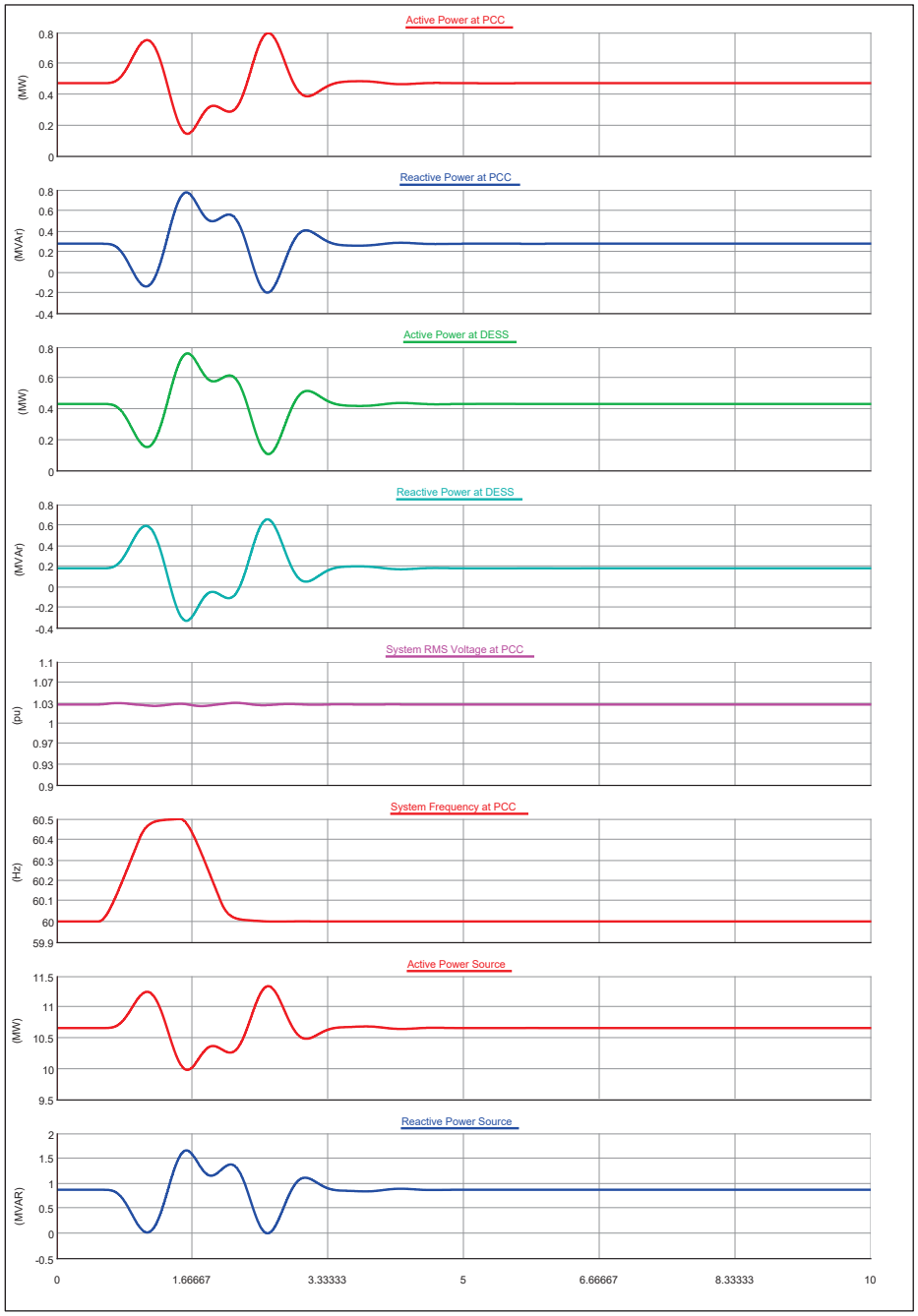


Figure A.7: System Response for Test 3.1.6

TEST 3.1.7: DECREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was decreased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER, in this mode, reacted to the change, rode through, and returned to steady state. The real and reactive power flow at the PCC and DER settled at their previous set points. The voltage was disturbed by the frequency change due to power flow but settled back to 1.025 pu in steady state.

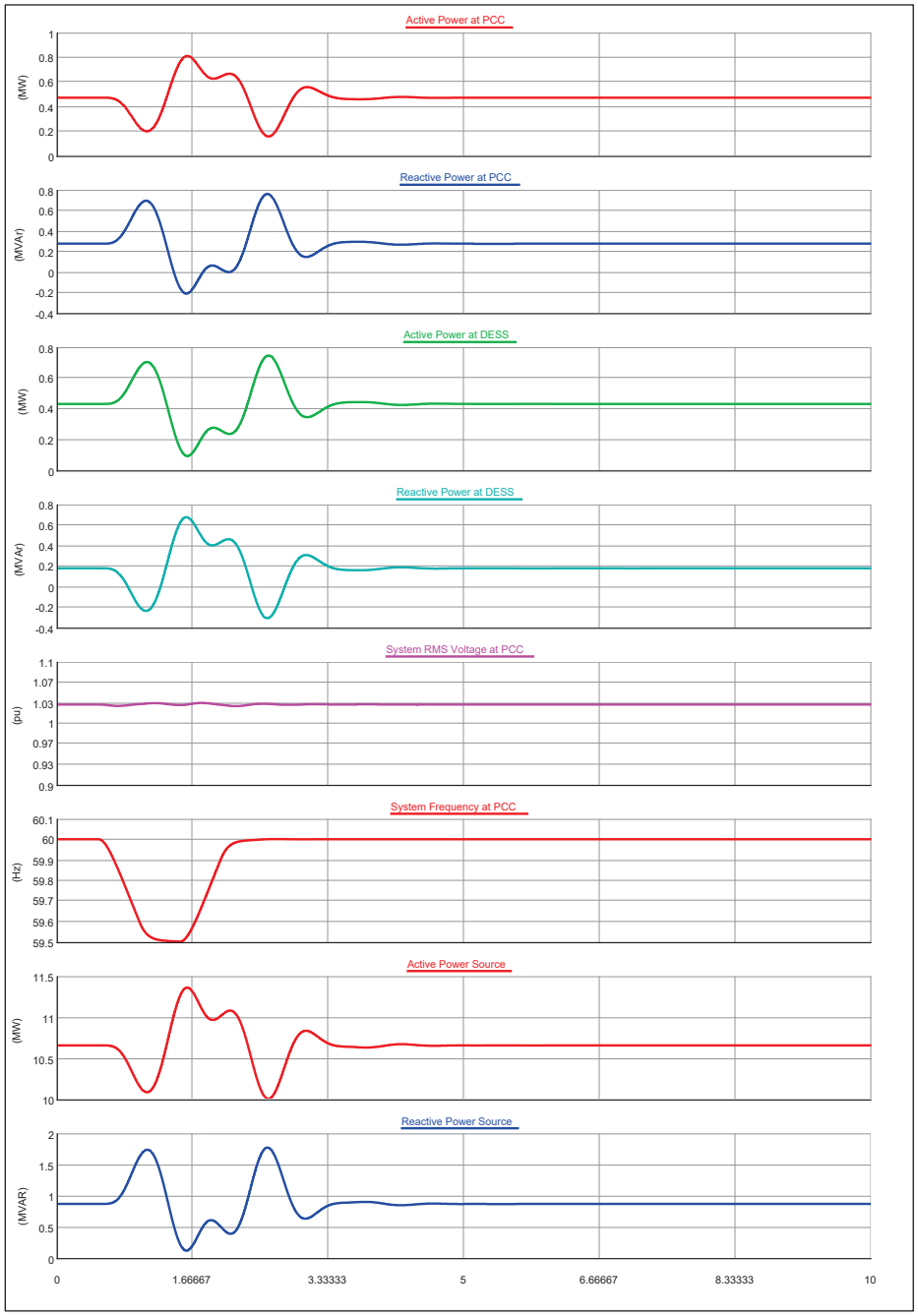


Figure A.8: System Response for Test 3.1.7

Scenario 3: DER at the End of a Long Feeder

TEST 3.3.1: MODE ACTIVATION WITH ACTIVE POWER SET POINT OF 500 KW

The system was initially operating in the schedule active power mode where the active and reactive power set points were at 500 kW and 200 kVAR, respectively. The system local load was at 900 kW and 450 kVAR. On activating the volt-watt mode, the real and the reactive power at the DER and PCC settled at steady state. No visible disturbance was observed following mode activation. The voltage and frequency profiles remained unaffected by the transition.

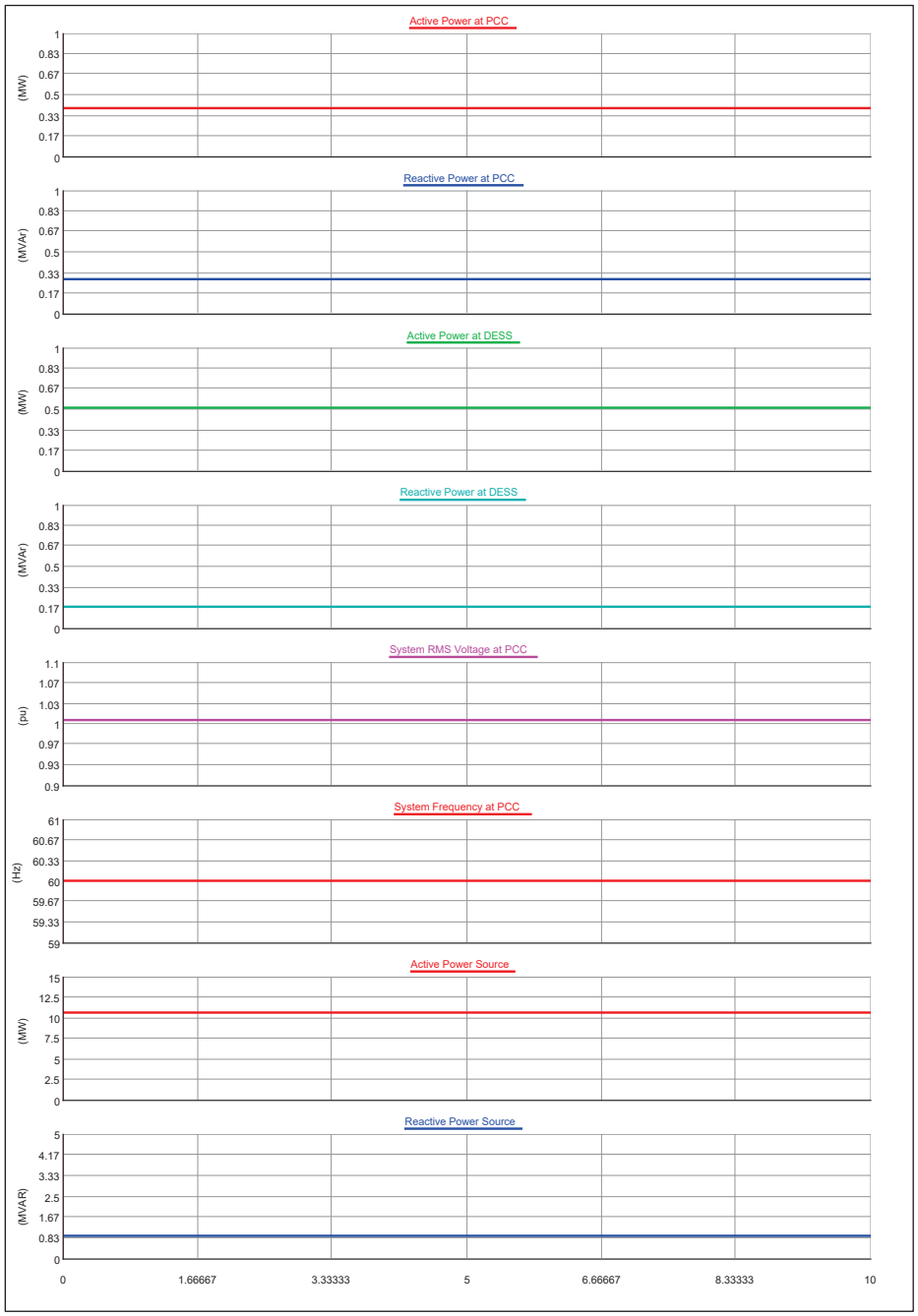


Figure A.9: System Response for Test 3.3.1

TEST 3.3.2: INCREASE THE SYSTEM LOAD BY 500 KW

On increasing the active power load by 500 kW, the real power at the DER settled to steady state, while the additional load was supported by the grid through the PCC. The reactive power flow and the system voltage and frequency were not affected.

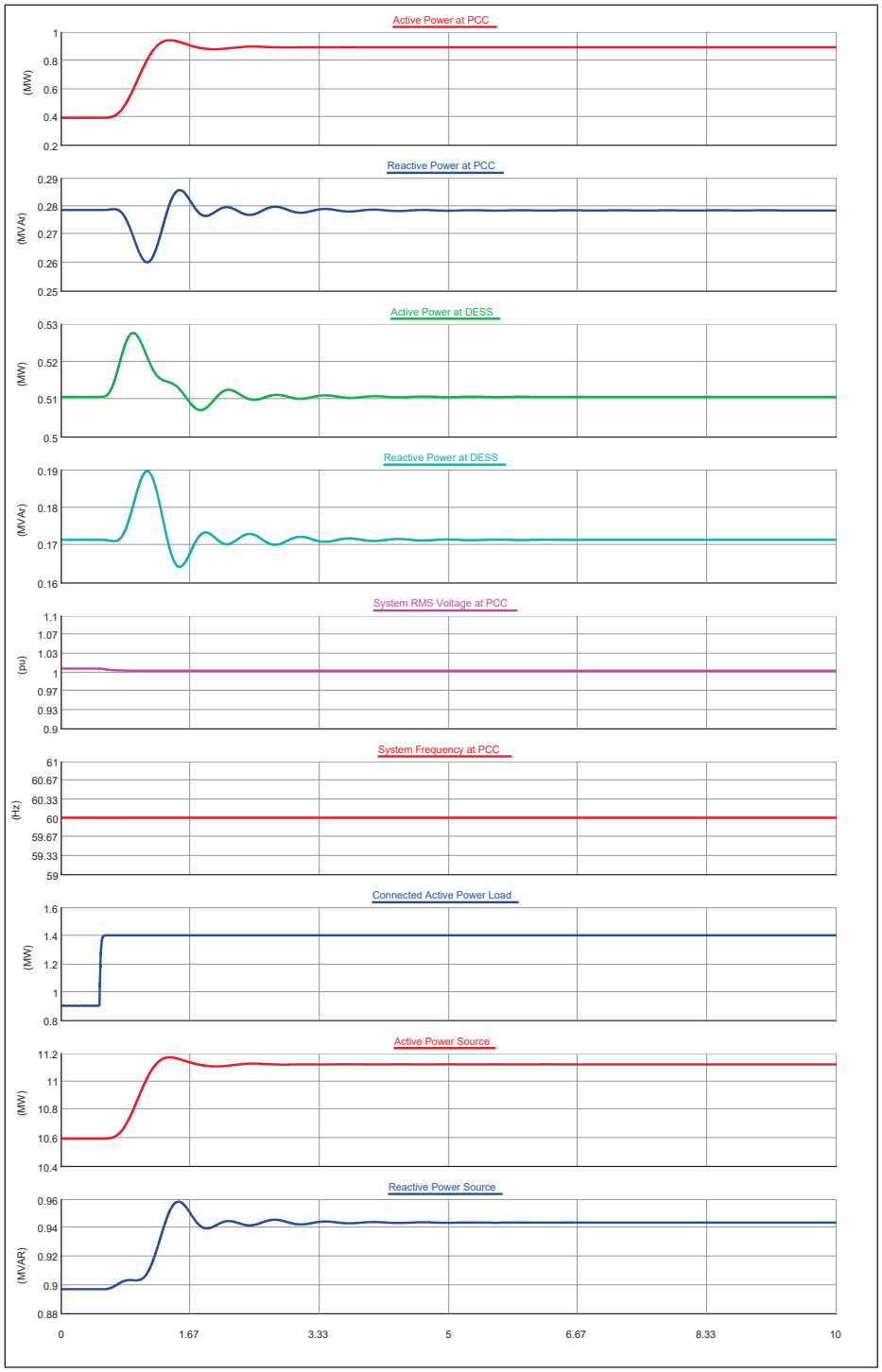


Figure A.10: System Response for Test 3.3.2

TEST 3.3.3: DECREASE THE SYSTEM LOAD BY 500 KW

On decreasing the active power load by 500 kW, the real power at the DER settled to its steady state, while the additional load was supported by the grid through the PCC. The reactive power flow and the system voltage and frequency were not affected.

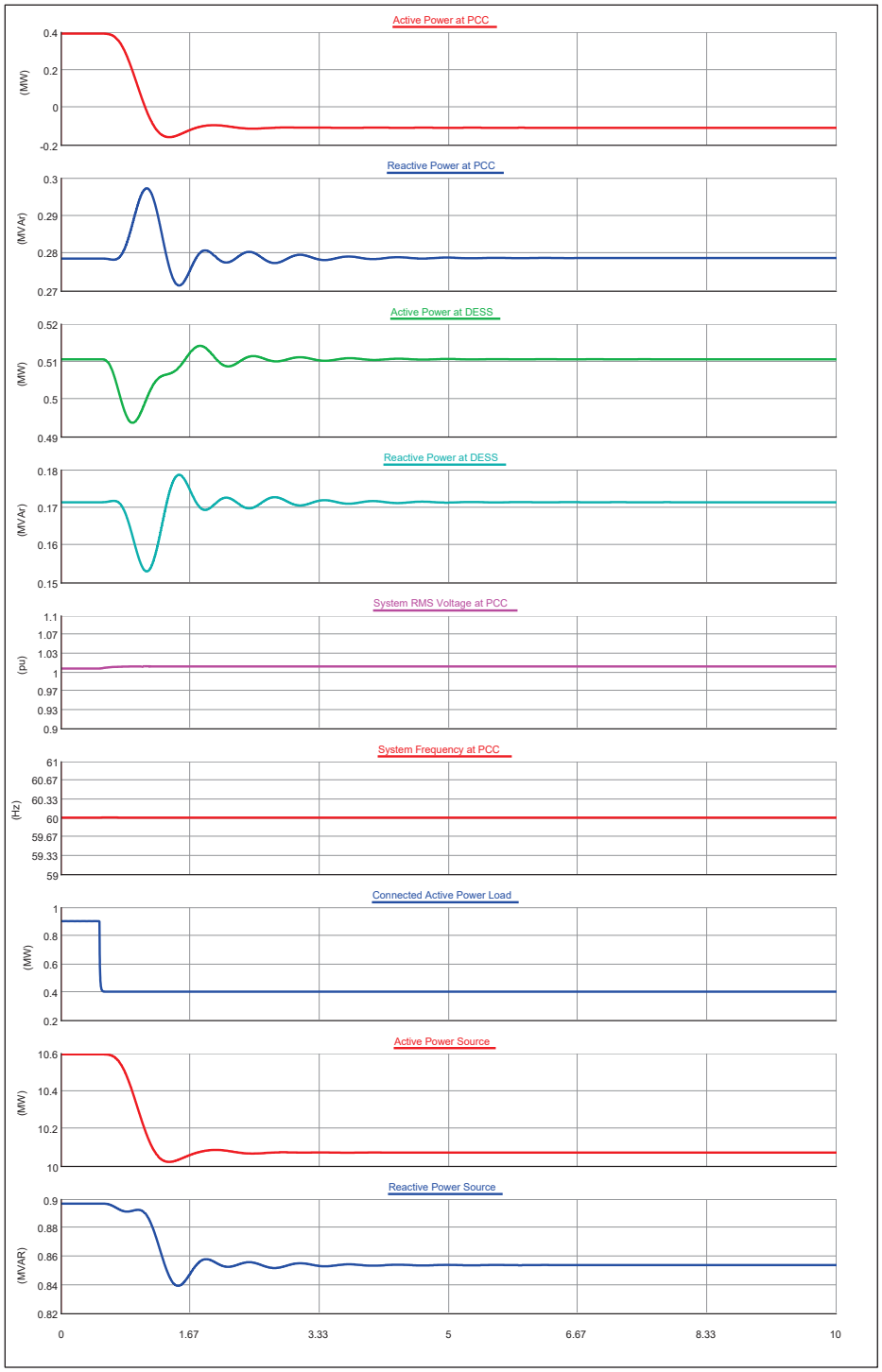


Figure A.11: System Response for Test 3.3.3

TEST 3.3.4: INCREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On increasing the system pu voltage by 5 percent from 1.002 pu to 1.052 pu, the real power at the DER fell so that more power was imported from the grid to keep the power import in the same direction. This balanced the power flow across the PCC to avoid reverse flow into the grid due to the increased voltage across the terminals. The reactive power returned to its prior set point during steady state, and the system frequency remained undisturbed during the transition.

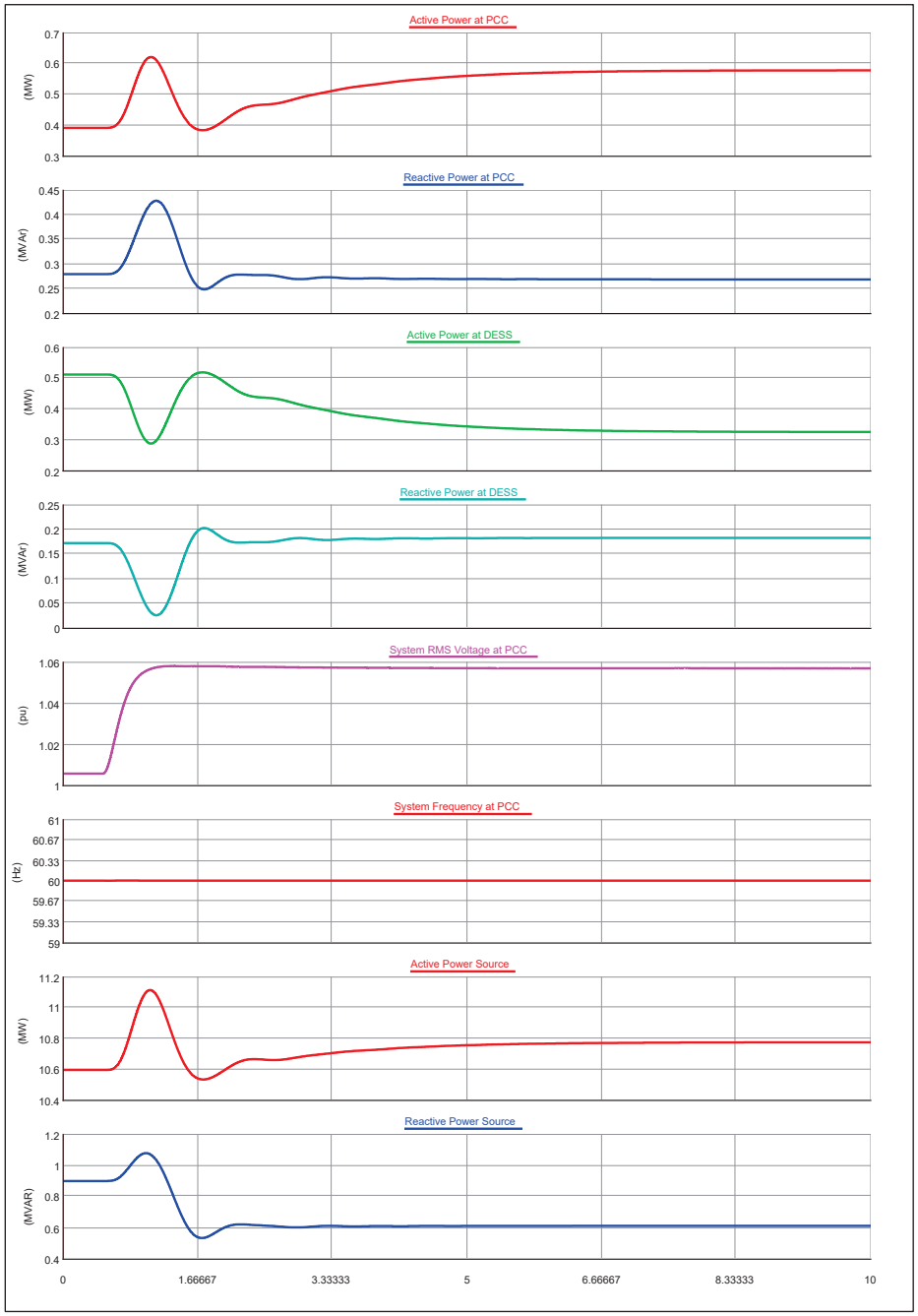


Figure A.12: System Response for Test 3.3.4

TEST 3.3.5: DECREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On decreasing the system pu voltage by 5 percent from 1.002 pu to 0.952 pu, the real power at the DER increased so that more power was imported from the grid to keep the power import in the same direction. This balanced the power flow across the PCC to avoid additional power import from the grid due to the voltage drop across the terminals. The reactive power returned to its prior set point during steady state, and the system frequency remained undisturbed during the transition.

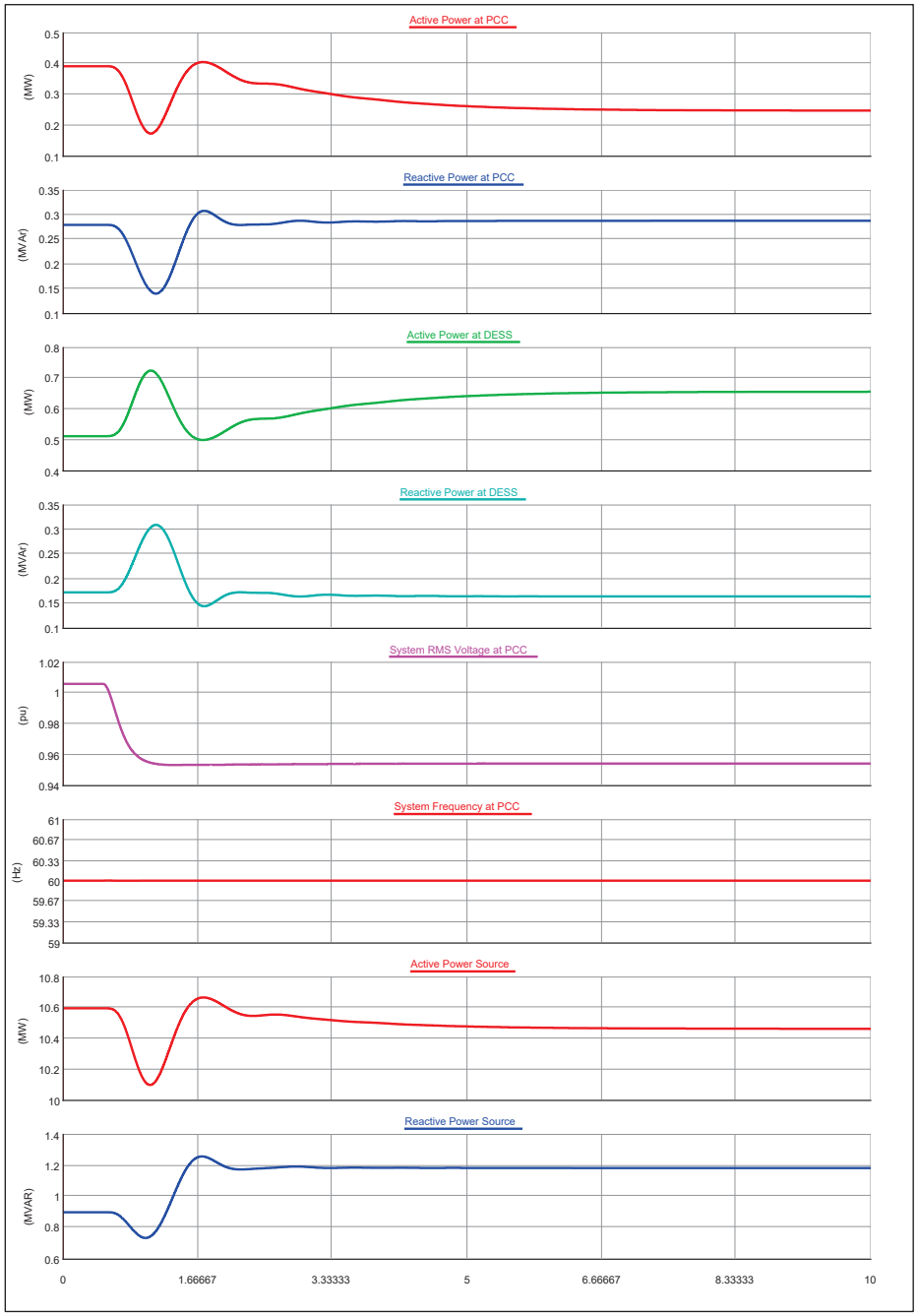


Figure A.13: System Response for Test 3.3.5

TEST 3.3.6: INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was increased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER, in this mode, reacted to the change, rode through, and returned to steady state. The real and reactive power flow at the PCC and DER settled at their previous set points. The voltage was disturbed by the frequency change due to power flow but settled back to 1.002 pu in steady state.

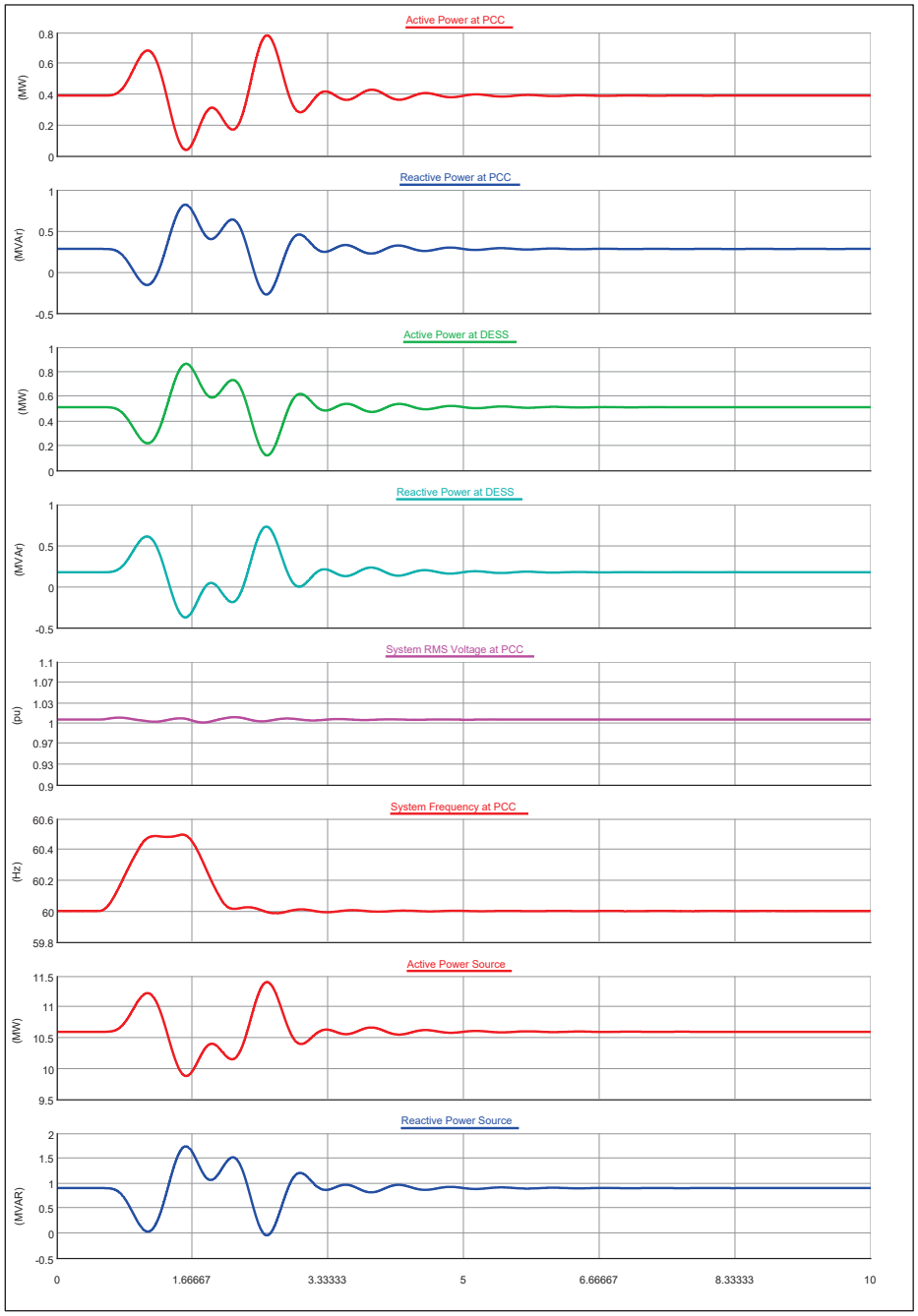


Figure A.14: System Response for Test 3.3.6

TEST 3.3.7: DECREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was decreased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER, in this mode, reacted to the change, rode through, and returned to steady state. The real and reactive power flow at the PCC and DER settled at their previous set points. The voltage was disturbed by the frequency change due to power flow but settled back to 1.002 pu in steady state.

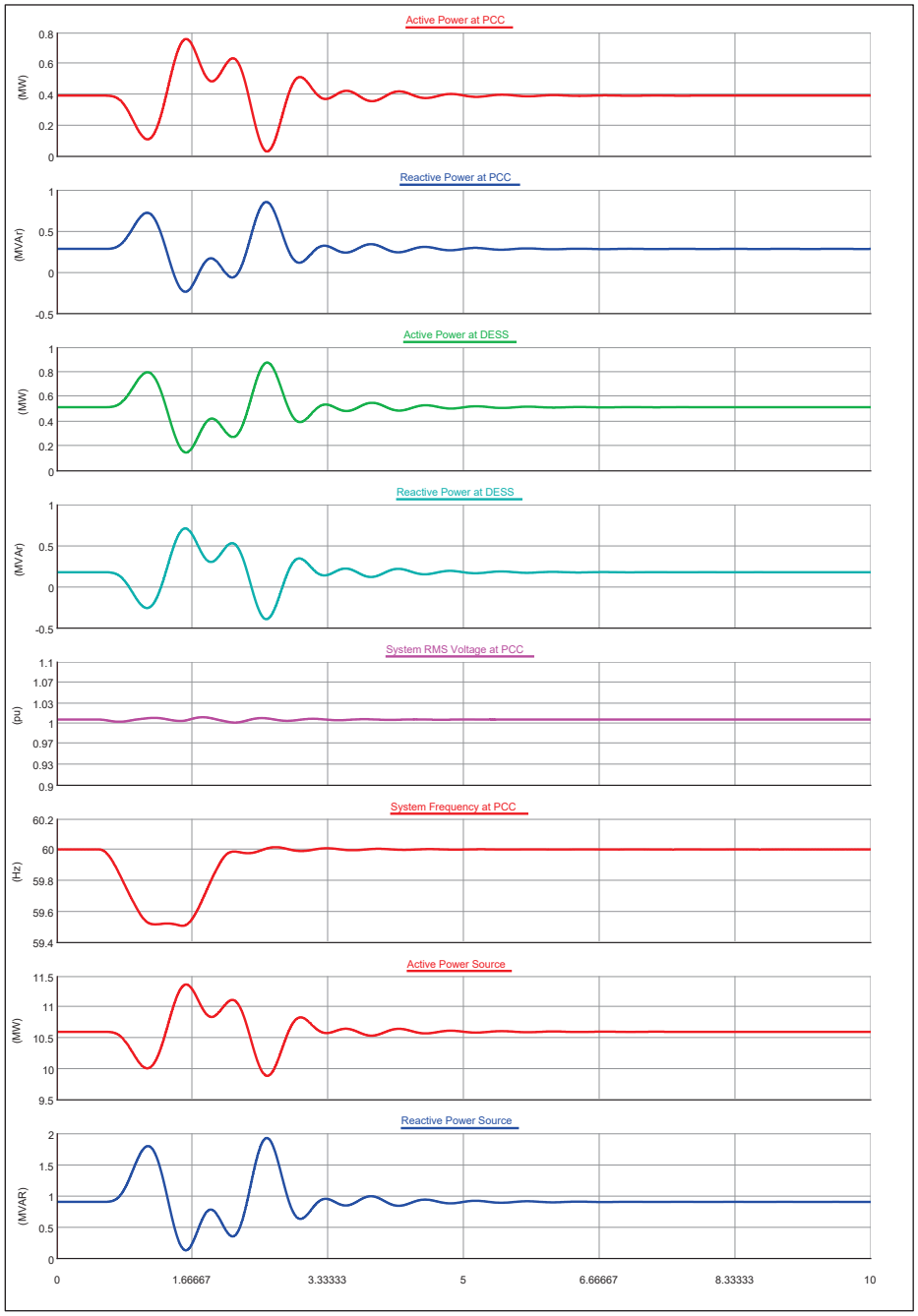


Figure A.15: System Response for test 3.3.7

Scenario 4: Multiple Diverse Types of DER on the Same Circuit

TEST 3.4.1: MODE ACTIVATION WITH ACTIVE POWER SET POINT OF 500 KW

The system was initially operating in the schedule active power mode where the active and reactive power set points were at 500 kW and 200 kVAR, respectively. The system local load was at 900 kW and 450 kVAR. On activating the volt-watt mode, the real and the reactive power at the DER and PCC settled at steady state. No visible disturbance was observed following mode activation. The voltage and frequency profiles remained unaffected by the transition.

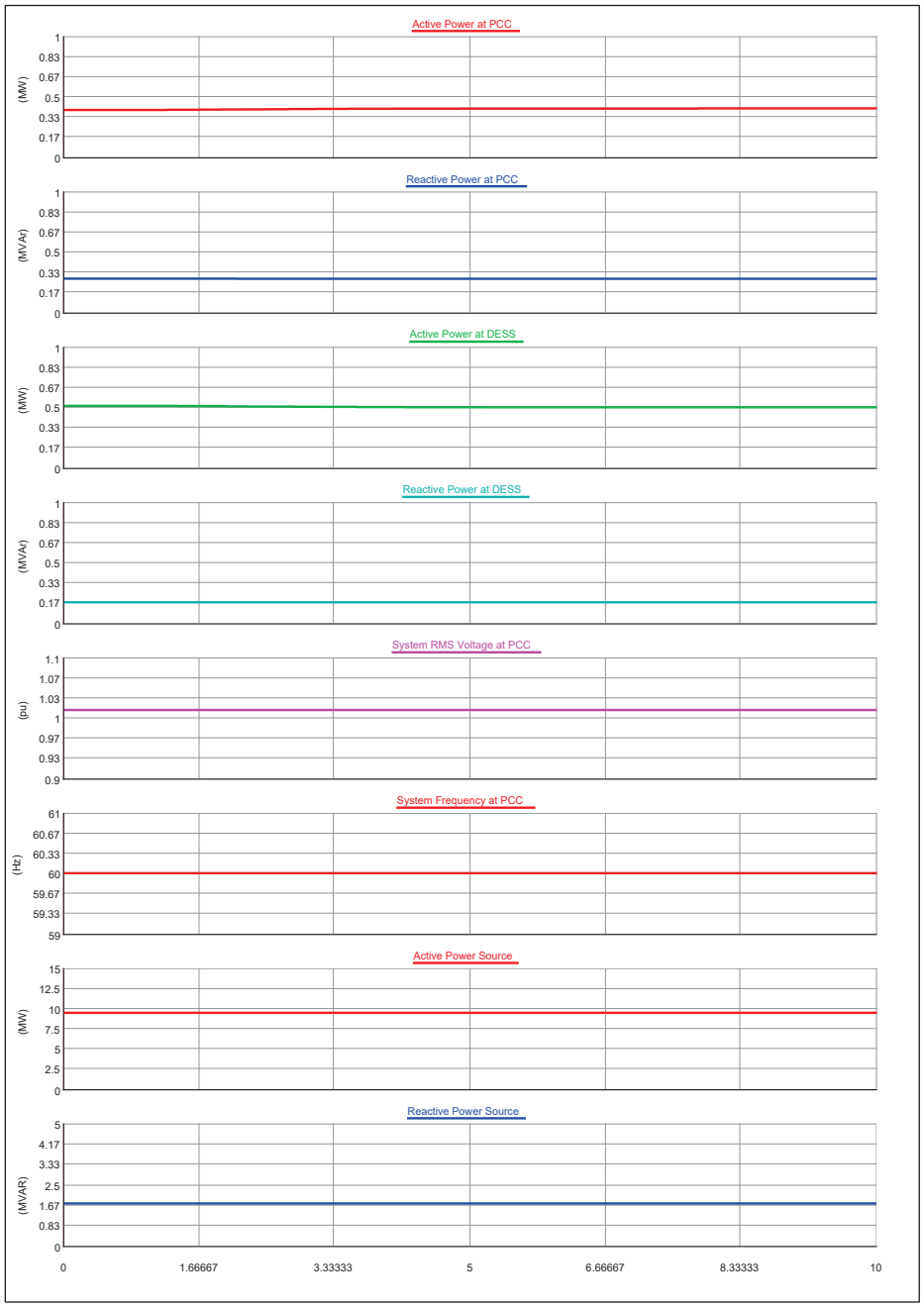


Figure A.16: System Response for Test 3.4.1

TEST 3.4.2: INCREASE THE SYSTEM LOAD BY 500 KW

On increasing the active power load by 500 kW, the real power at the DER settled to steady state, while the additional load was supported by the grid through the PCC. The reactive power flow and the system voltage and frequency were not affected.

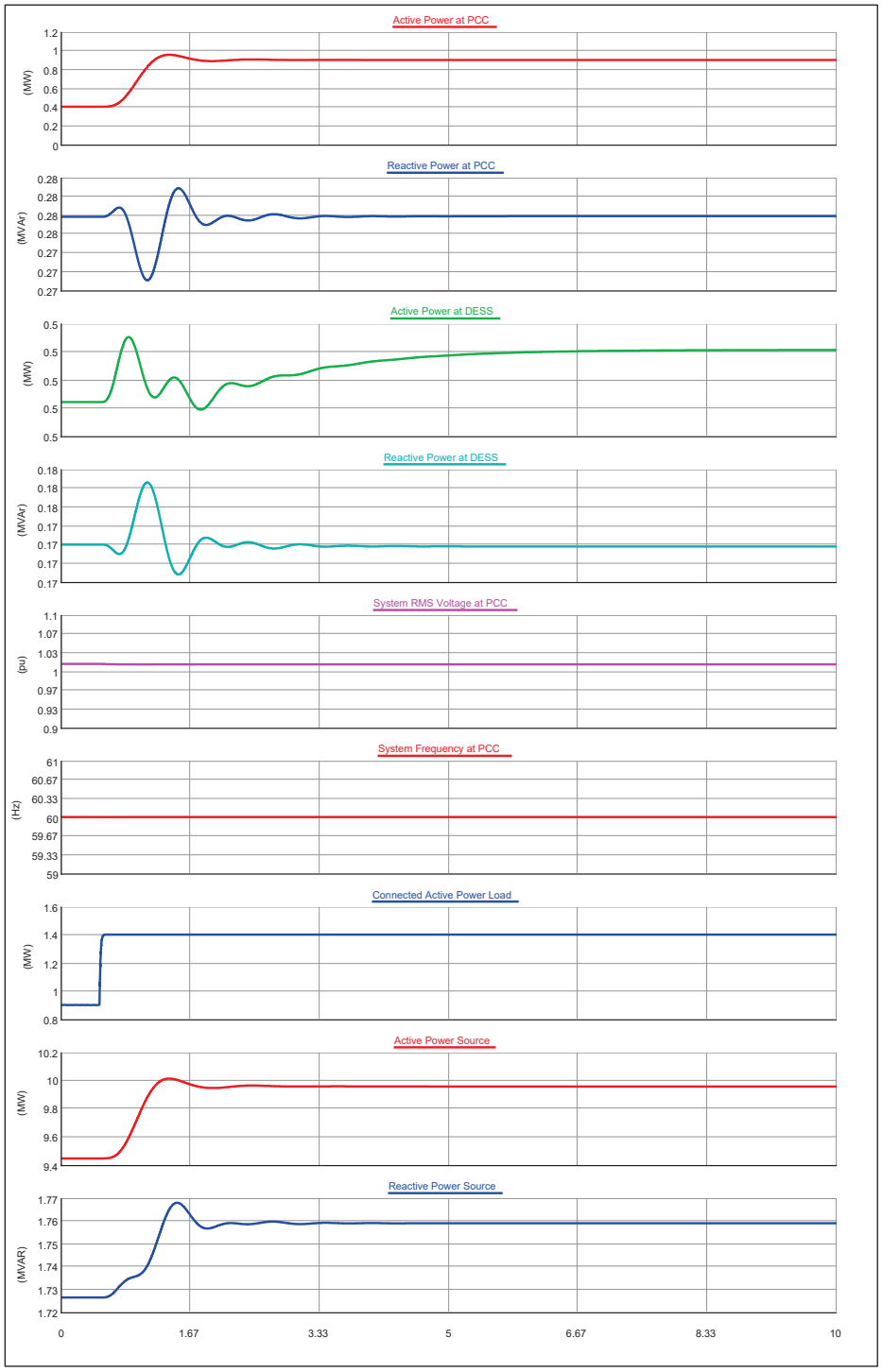


Figure A.17: System Response for Test 3.4.2

TEST 3.4.3: DECREASE THE SYSTEM LOAD BY 500 KW

On decreasing the active power load by 500 kW, the real power at the DER settled to steady state, while the additional load was supported by the grid through the PCC. The reactive power flow and the system voltage and frequency were not affected.

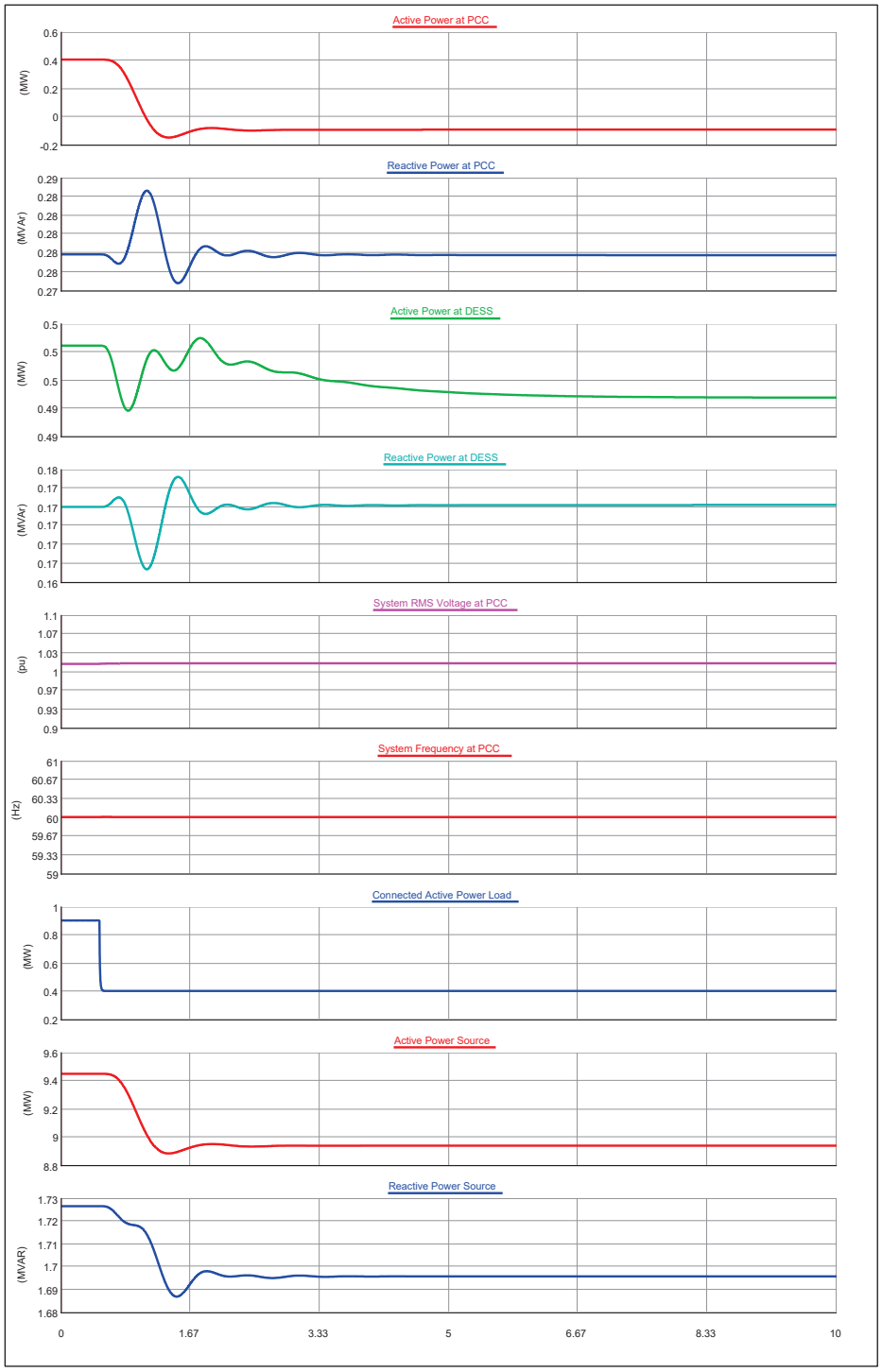


Figure A.18: System Response for Test 3.4.3

TEST 3.4.4: INCREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On increasing the system pu voltage by 5 percent from 1.018 pu to 1.068 pu, the real power at the DER fell so that more power was imported from the grid to keep the power import in the same direction. This balanced the power flow across the PCC to avoid reverse flow into the grid due to the increased voltage across the terminals. The reactive power returned to its prior set point during steady state, and the system frequency remained undisturbed during the transition.

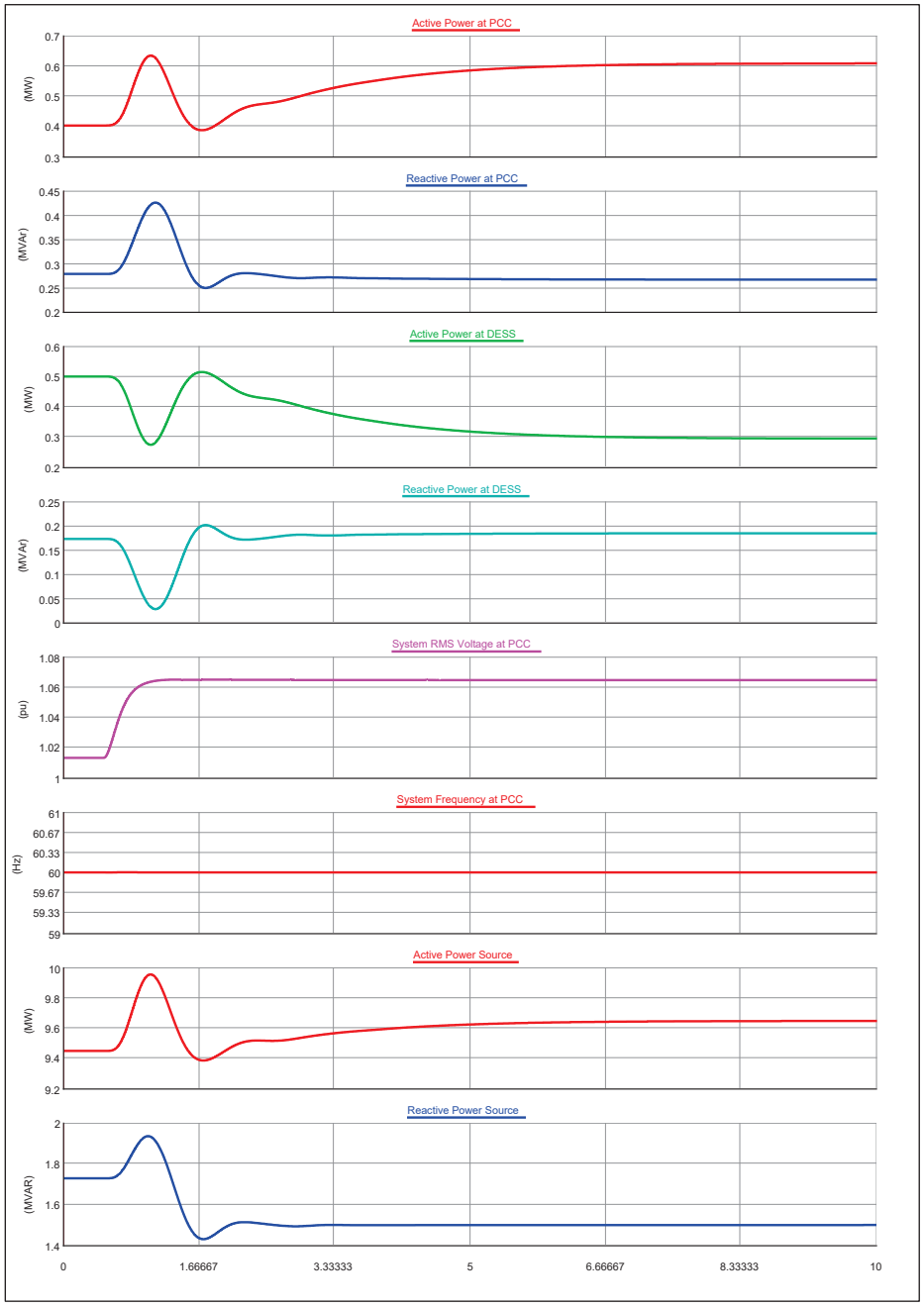


Figure A.19: System Response for Test 3.4.4

TEST 3.4.5: DECREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On decreasing the system pu voltage by 5 percent from 1.018 pu to 0.968 pu, the real power at the DER increased so that more power was imported from the grid to keep the power import in the same direction. This balanced the power flow across the PCC to avoid additional power import from the grid due to the voltage drop across the terminals. The reactive power returned to its prior set point during steady state, and the system frequency remained undisturbed during the transition.

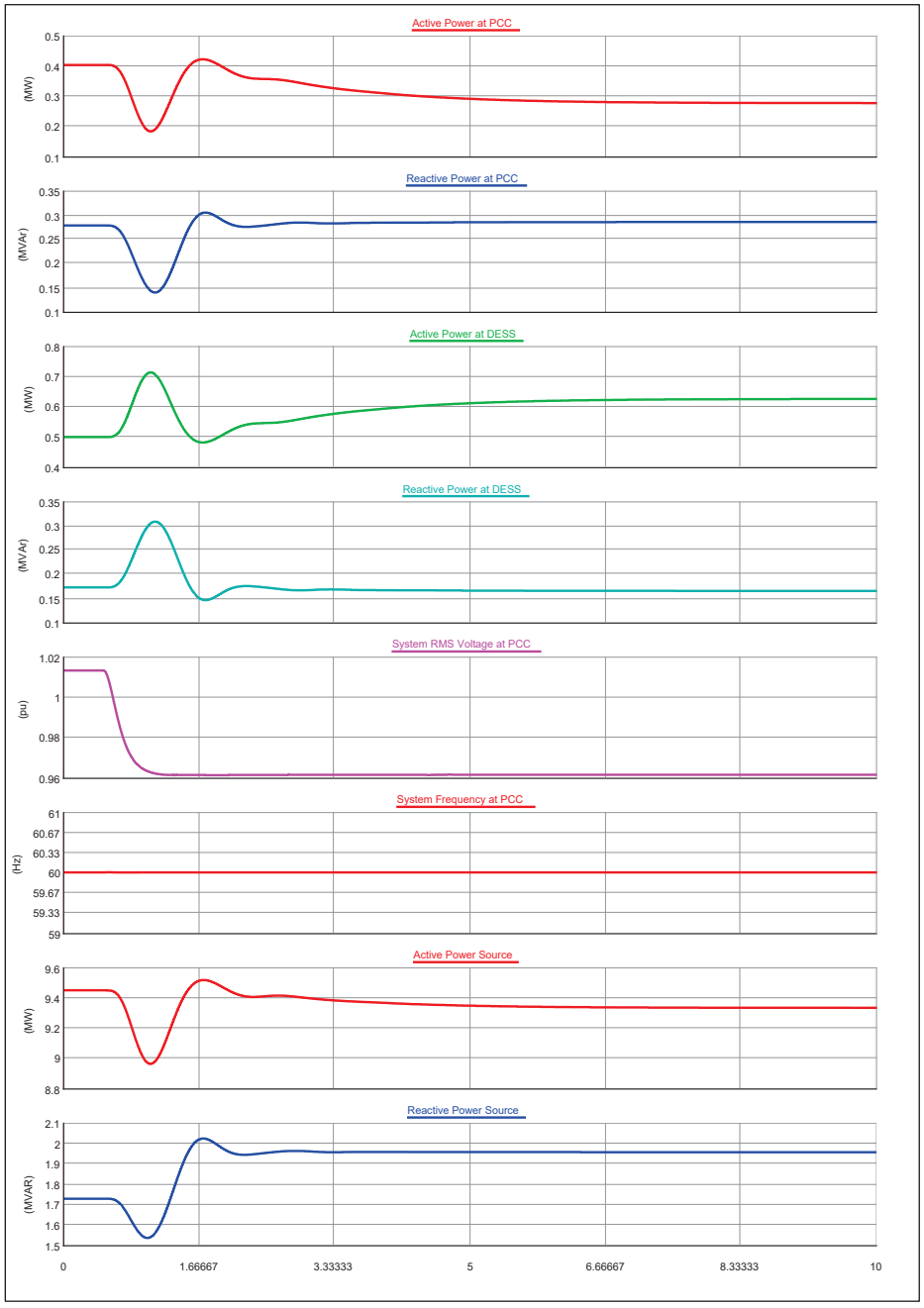


Figure A.20: System Response for Test 3.4.5

TEST 3.4.6: INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was increased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER, in this mode, reacted to the change, rode through, and returned to steady state. The real and reactive power flow at the PCC and DER settled at their previous set points. The voltage was disturbed by the frequency change due to power flow but settled back to 1.018 pu in steady state.

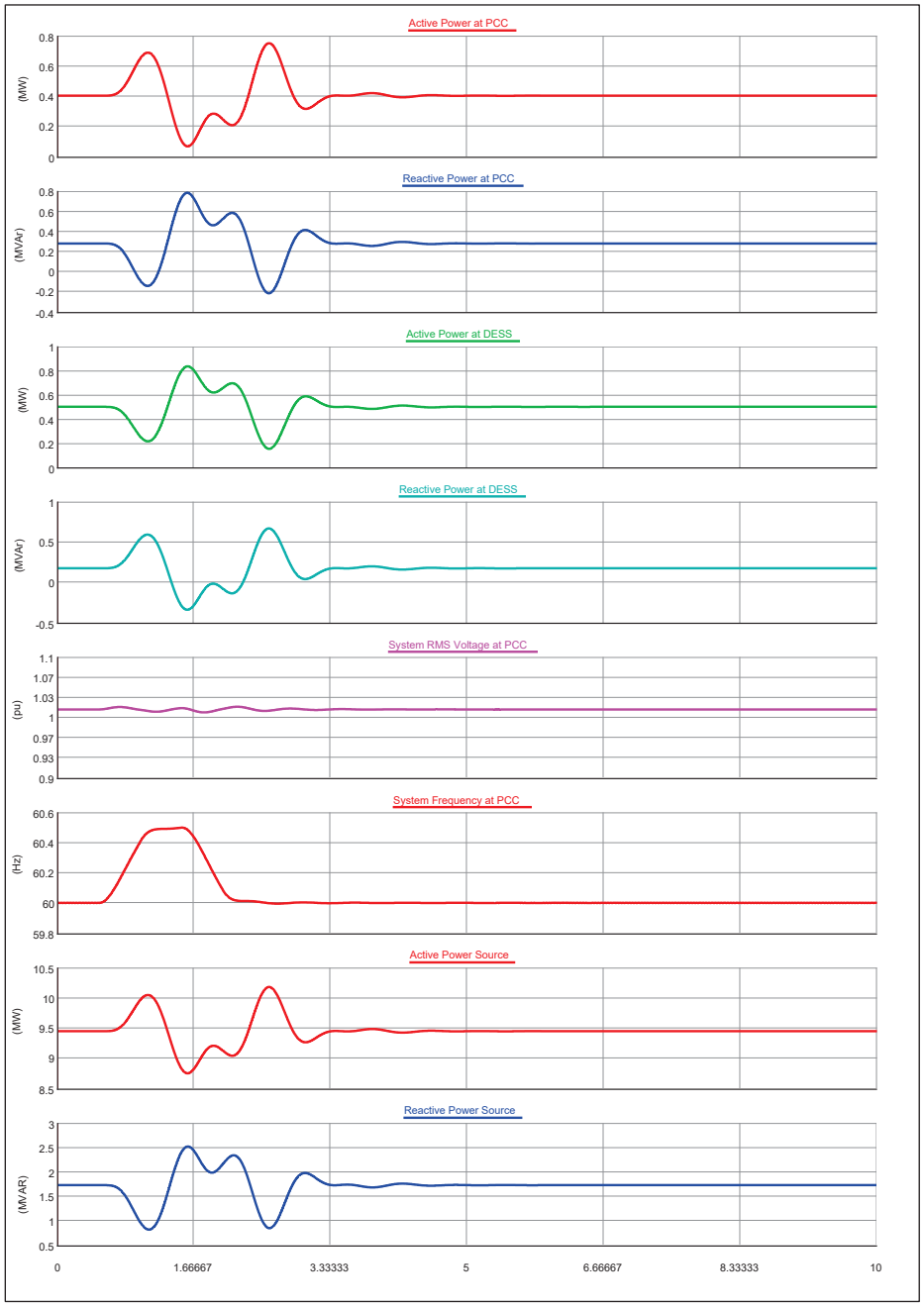


Figure A.21: System Response for Test 3.4.6

TEST 3.4.7: DECREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was decreased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER, in this mode, reacted to the change, rode through, and returned to steady state. The real and reactive power flow at the PCC and DER settled at their previous set points. The voltage was disturbed by the frequency change due to power flow but settled back to 1.018 pu in steady state.

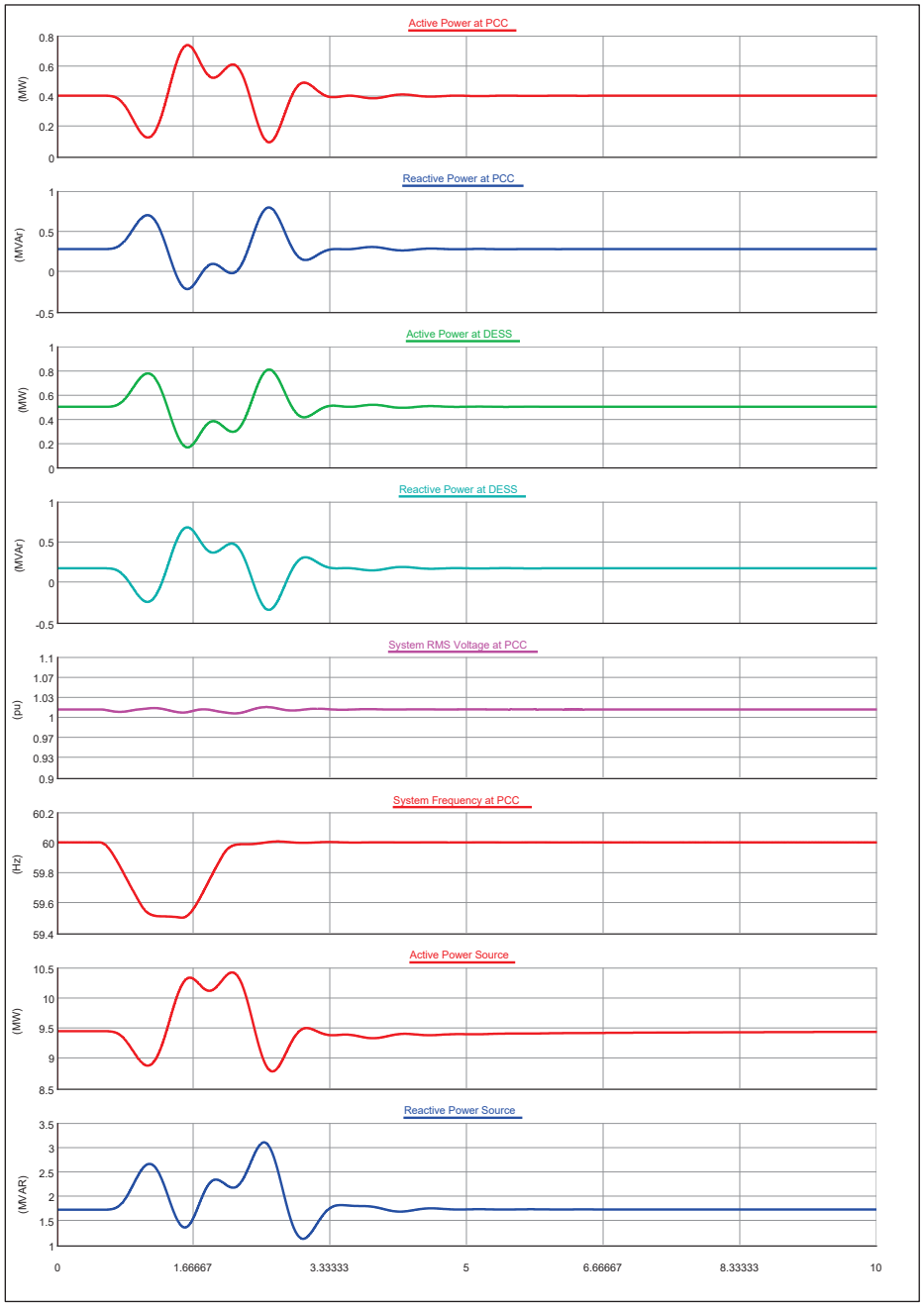


Figure A.22: System Response for Test 3.4.7

TEST 4 – VOLT-VAR

This function is intended to provide a mechanism through which a DER may be configured to manage its own VAR output in response to a fluctuation in the local service voltage. This function involves the dynamic production of reactive power (VARs) to resist variations in the voltage at the PCC.

Using the different circuit scenarios, the DER is put into volt-VAR mode. The objective is to counter any changes in the voltage by varying the output reactive power. When the DER is set in volt-VAR mode, it tries to maintain the voltage of the system to 1 pu by regulating the reactive power output.

The procedure for testing was as follows:

Step 1. Vary the system voltage beyond the nominal values in a stepped and/or transient manner to observe the behavior of the DER (the DER should respond in such a way that the system voltage is maintained within the nominal values).
Step 2. Change the voltage by changing the load in steps or by changing the grid voltage (when the DER is put into volt-VAR mode, the system voltage should revert into the nominal band because of the DER reactive power regulation).
Step 3. Compare the results with the baseline case and develop conclusions based on these findings.

Table A.2 lists the tests that will be conducted.

Table A.2: DER Volt-VAR Test Cases

Test	Test Description	Expected Response
Test 4. x.1	Mode activation with active power set point of 200 kVAR	DER dispatches 200 kVAR at steady state
Test 4. x.2	Increase the system load by 500 kVAR	DER dispatches 200 kVAR at steady state
Test 4. x.3	Decrease the system load by 500 kVAR	DER dispatches 200 kVAR at steady state
Test 4. x.4	Increase the system voltage by 5%	DER decreases reactive power output to offset voltage increase
Test 4. x.5	Decrease the system voltage by 5%	DER increases reactive power output to offset voltage decrease
Test 4. x.6	a) Ramp up the system voltage to 109%, at the rate of 30% per minute, and hold it for 5 s b) Ramp down the system voltage to 90%, at the rate of 30% per minute, and hold it for 5 s c) Ramp up the system voltage, back to nominal voltage (refer to Figure 3.28)	DER decreases its reactive power output to offset voltage increases and following that DER increases its reactive power output to offset voltage decrease. DER settles back at 200 kVAR at steady state.
Test 4. x.7	Increase the system frequency by 0.5 Hz for 1 s	DER dispatches 200 kVAR at steady state
Test 4. x.8	Decrease the system frequency by 0.5 Hz for 1 s	DER dispatches 200 kVAR at steady state

Note: "x" denotes the scenario under test.

Scenario 1: DER Close to a Substation

TEST 4.1.1: MODE ACTIVATION WITH REACTIVE POWER SET POINT OF 200 KVAR

The initial set points of the DER were at 500 kW and 200 kVAR. The active and reactive power load were at 900 kW and 550 kVAR respectively. When the mode was activated, the reactive power input of the DER dropped to 99 kVAR as the voltage at the PCC was greater than 1.025 pu; hence, the DER reduced its reactive power output to maintain the terminal voltage at the same value. The active power dispatch of the DER remained unaffected and therefore did not change across the PCC and the source. The system voltage and frequency did not change with the activation of the mode.

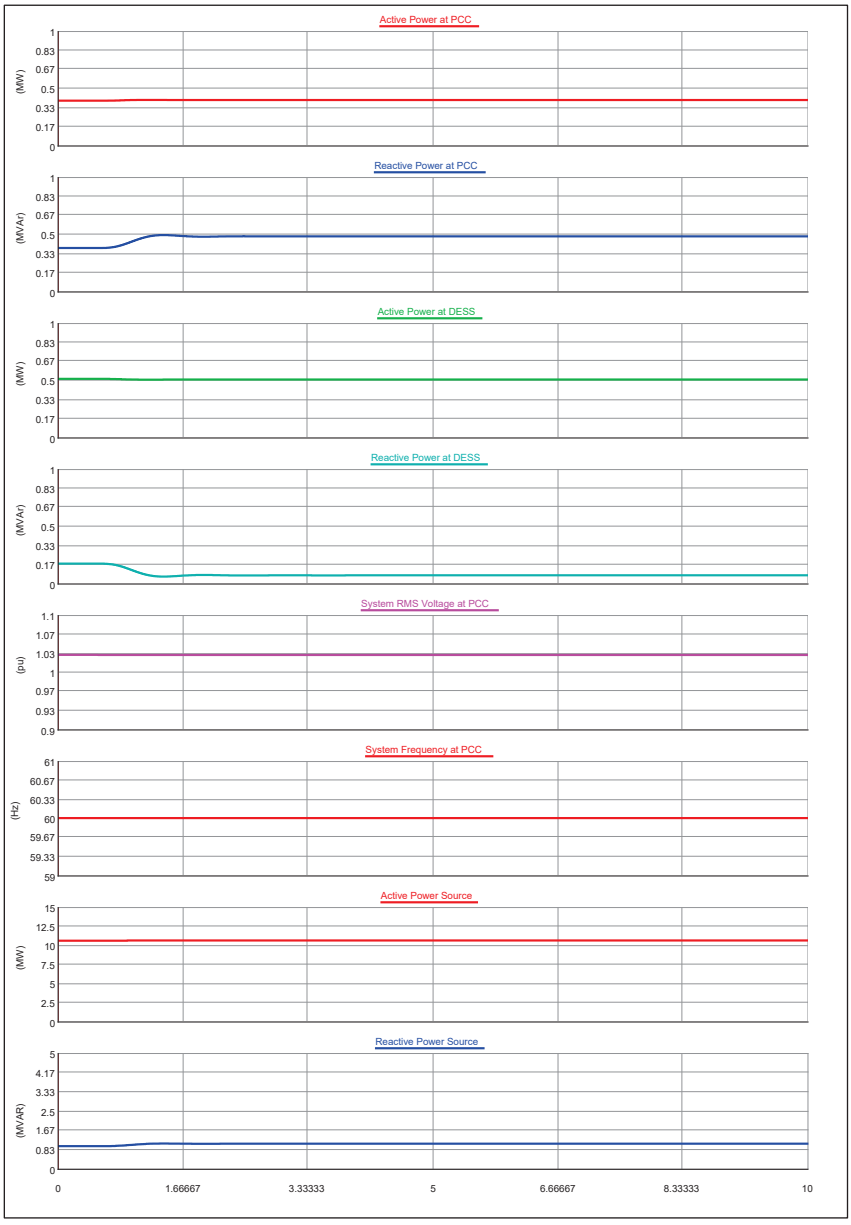


Figure A.23: System Response for Test 4.1.1

TEST 4.1.2: INCREASE THE SYSTEM LOAD BY 500 KVAR

On increasing the reactive power load by 500 kVAR to 1050 kVAR at the PCC, the reactive power at the DER remained unchanged at steady state because the reactive power set point at the DER was determined by the system voltage, which was not affected significantly during the load variation. The system voltage decreased minimally because of the inflow of the reactive power from the grid. The additional reactive power load was supported by the PCC to keep the node voltage constant. The frequency and the real power at the DER and PCC remained unaffected as well.

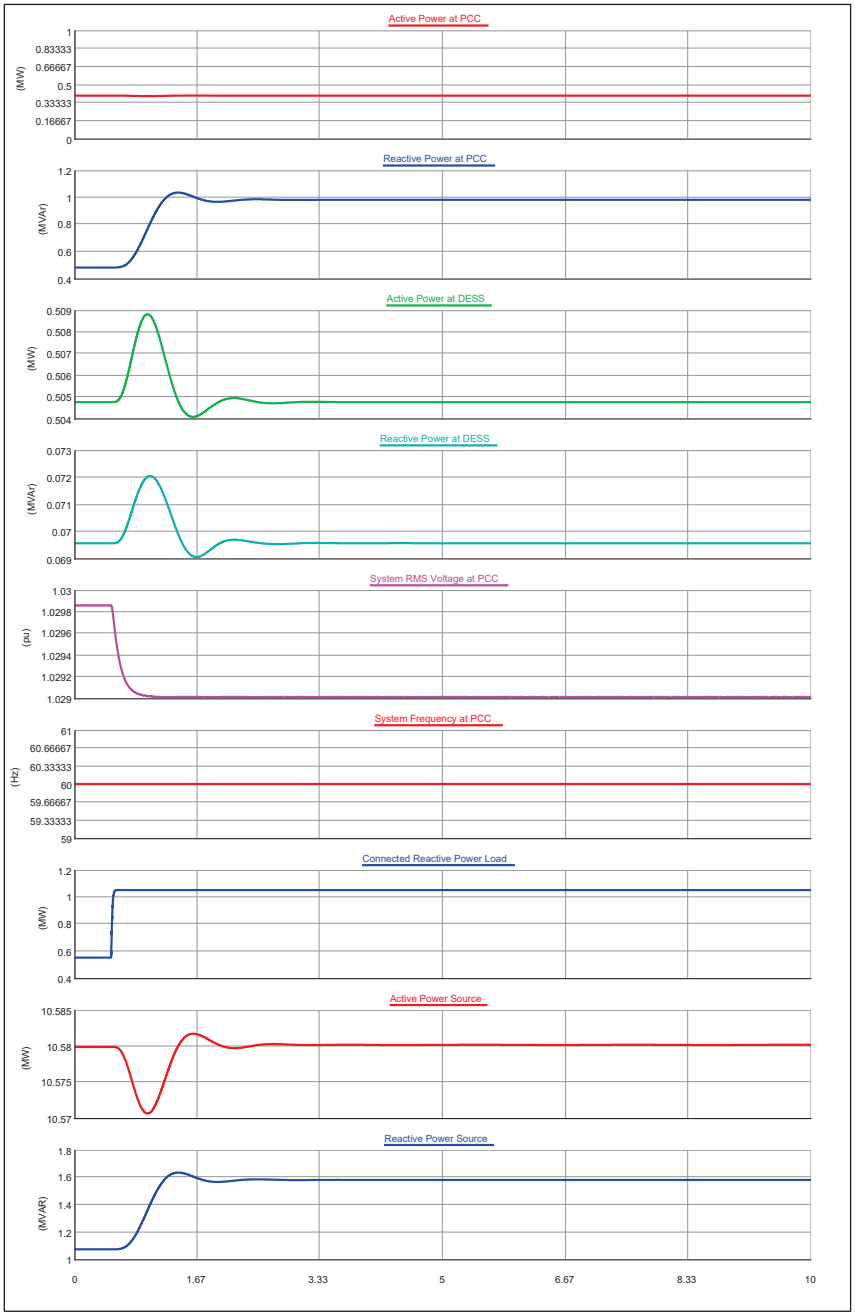


Figure A.24: System Response for Test 4.1.2

TEST 4.1.3: DECREASE THE SYSTEM LOAD BY 500 KVAR

On decreasing the reactive power, the load decreased from 550 kVAR to 50 kVAR. Like the observations for Test 4.1.2, the reactive power at the DER remained unaffected, while the grid drew power from the DER to maintain the load voltage at the PCC constant. The real power and frequency remained unaffected by the VAR changes, while the system voltage increased slightly because of the excess reactive power generated that was injected into the grid through the PCC.

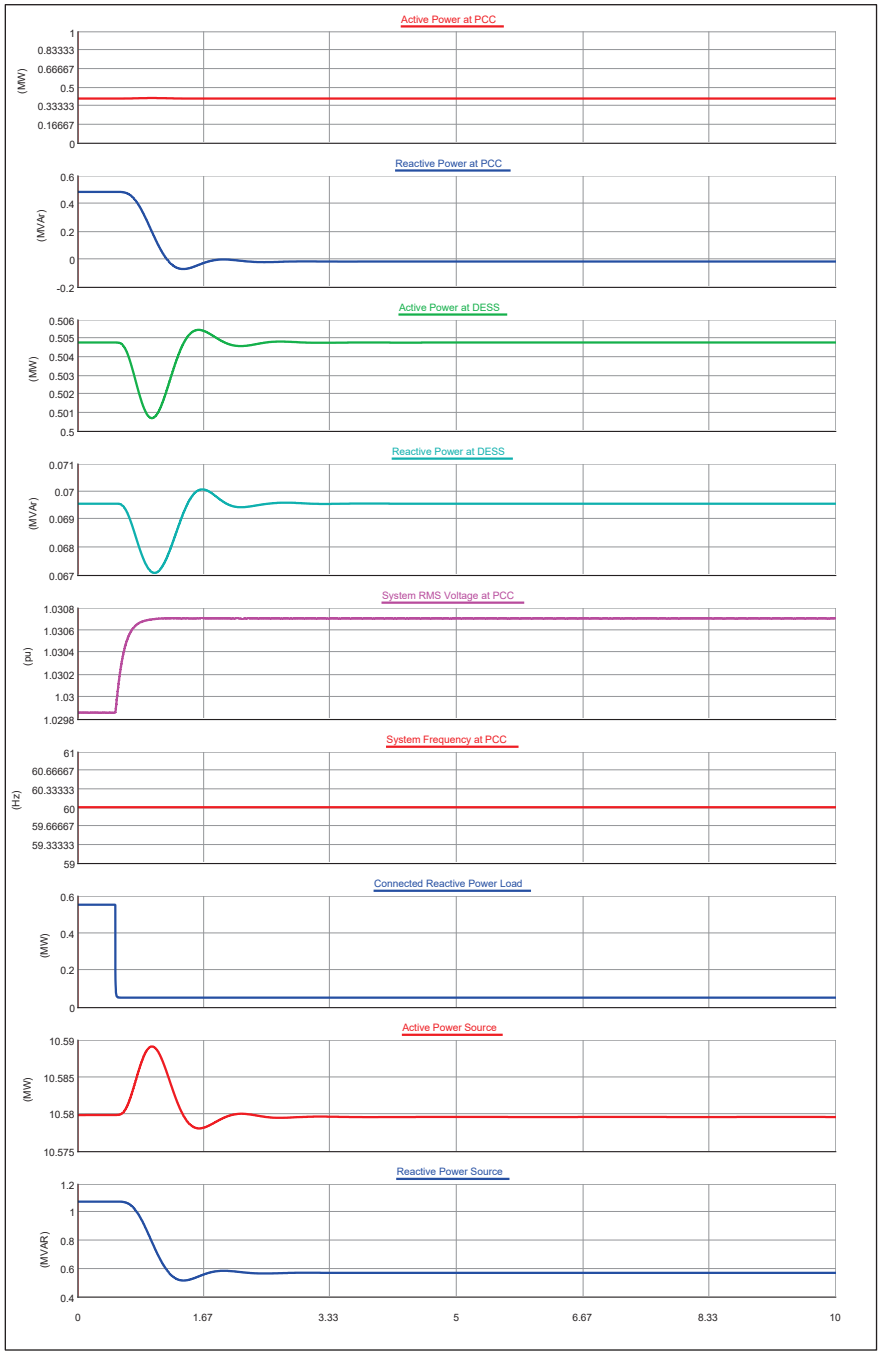


Figure A.25: System Response for Test 4.1.3

TEST 4.1.4: INCREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On increasing the system voltage at the PCC from 1.025 pu to 1.075 pu, the reactive power output of the DER decreased and drew more reactive power from the grid through the PCC to maintain the node voltage at the PCC constant. The frequency and the real power at the PCC and DER remained unaffected.

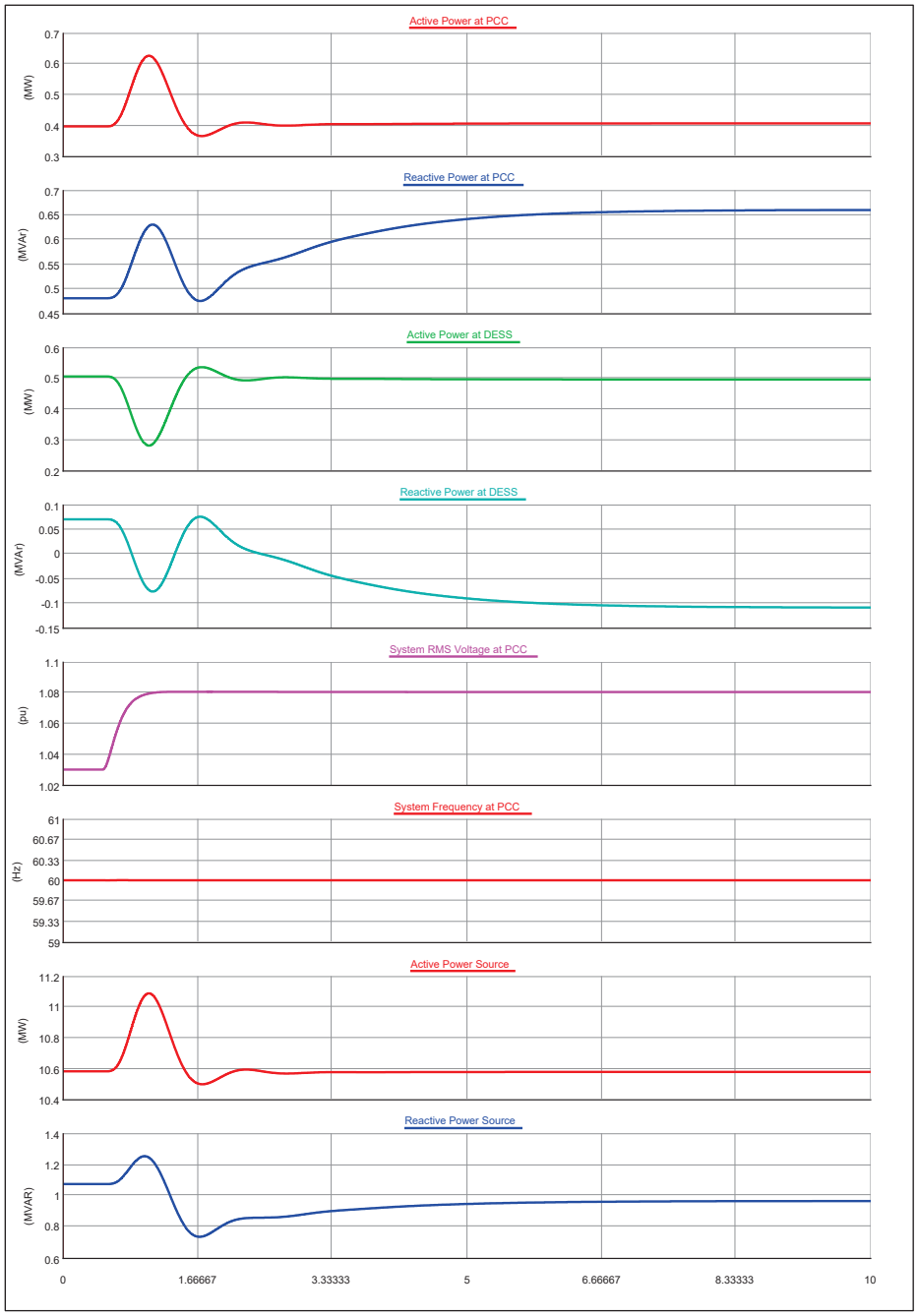


Figure A.26: System Response for Test 4.1.4

TEST 4.1.5: DECREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On decreasing the system voltage at the PCC from 1.025 pu to 0.975 pu, the reactive power output of the DER increased and produced more reactive power maintain the node voltage at the PCC constant. The frequency and the real power at the PCC and DER remained unaffected by the change at steady state.

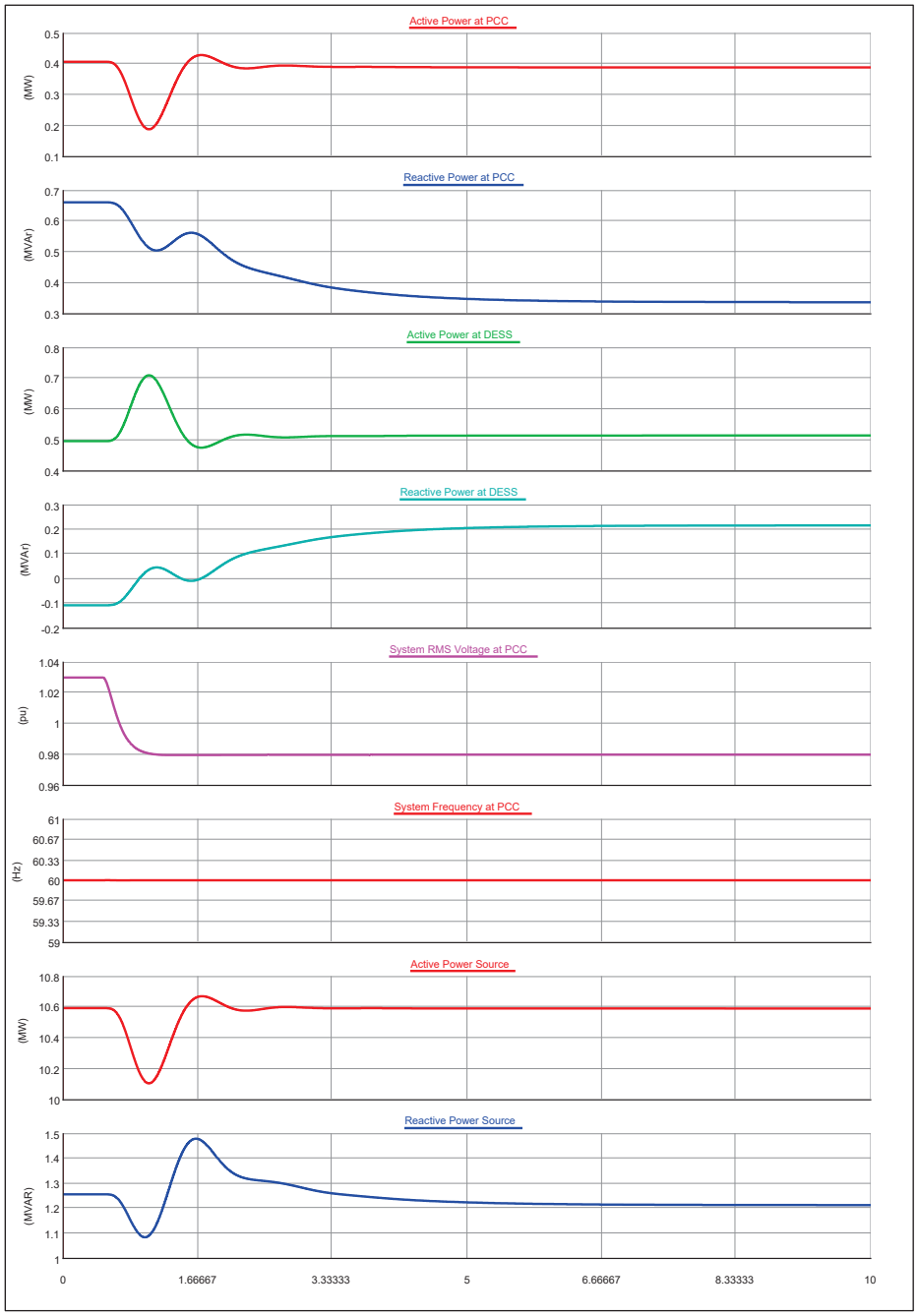


Figure A.27: System Response for Test 4.1.5

TEST 4.1.6 VARY THE SYSTEM VOLTAGE

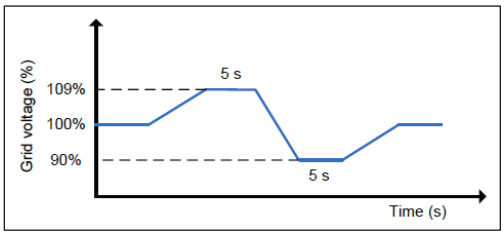


Figure A.28: System Voltage Profile for Test 4.1.6

The voltage profile at the PCC was varied, as shown in Figure A.28 . On increasing the voltage to 109 percent at a ramp rate of 0.02 volts per unit per second, the DER reactive power output decreased, while the reactive power import from the grid increased. The increase in voltage caused both system capacitors to turn off during the rising edge of the voltage. This decrease in the DER reactive power output, along with the turning off the capacitor, caused the source reactive power to increase. The active power at the DER and PCC changed minimally during this transition; however, it did not reach the steady-state value. Once the voltage reached 109 percent, it was held for 5 seconds. Then the voltage dropped from 109 percent to 90 percent, during which the reactive power output of the DER increased and the power import from the PCC reduced to maintain the node voltage constant. The reduction in voltage caused one of the capacitors near the end of the feeder to turn on, which supplemented the reactive power along with the DER results, resulting in the reduction of reactive power import from the source. The real power and reactive power at the DER and PCC settled at its prior set point post the transition in the voltage. The system frequency remained unaffected by the change in voltage.

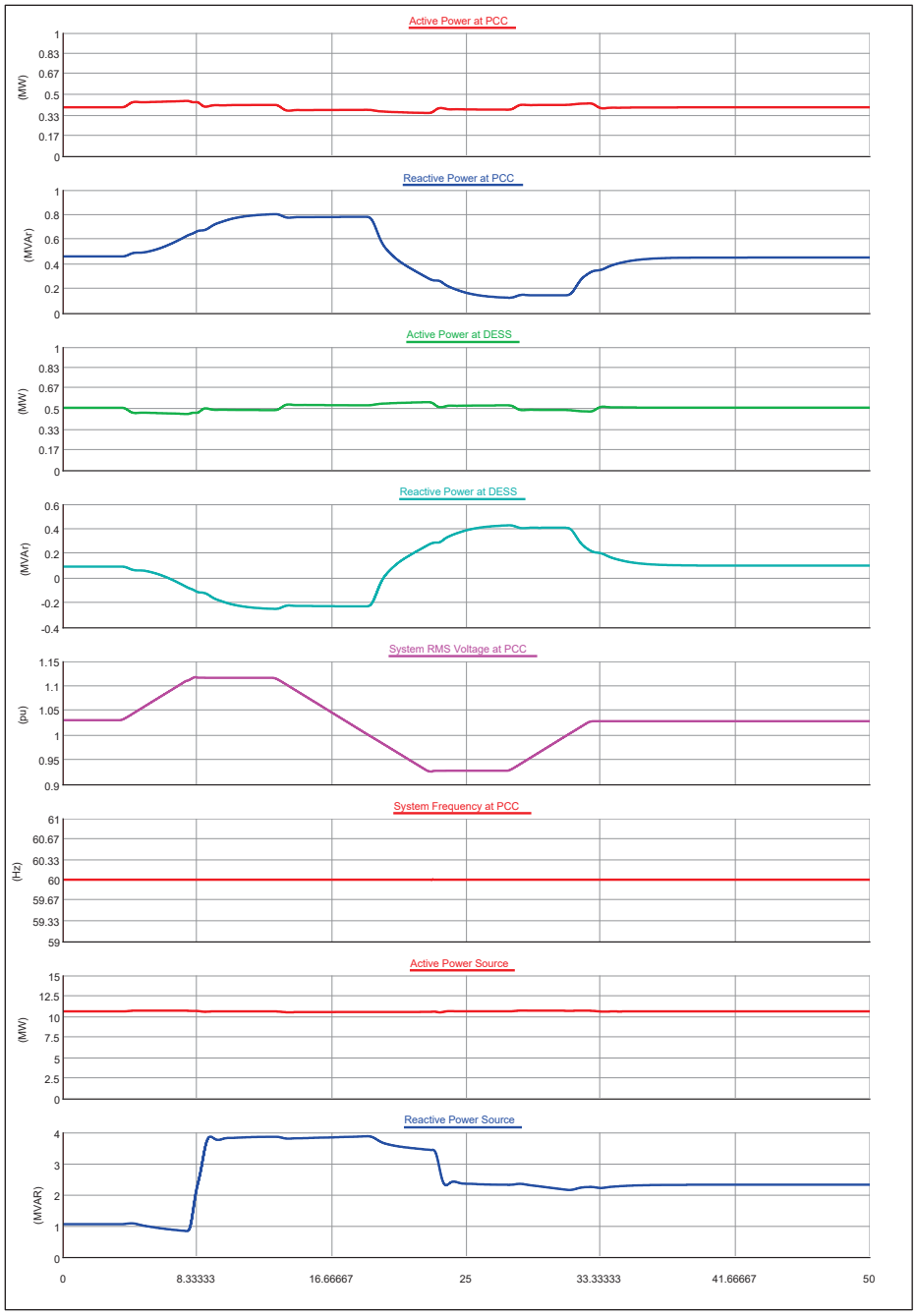


Figure A.29: System Response for Test 4.1.6

TEST 4.1.7: INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was increased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER, in this mode, reacted to the change, rode through, and returned to steady state. The real and reactive power flow at the PCC and DER settled at their previous set points. The voltage was disturbed by the frequency change due to power flow but settled back to 1.025 pu in steady state.

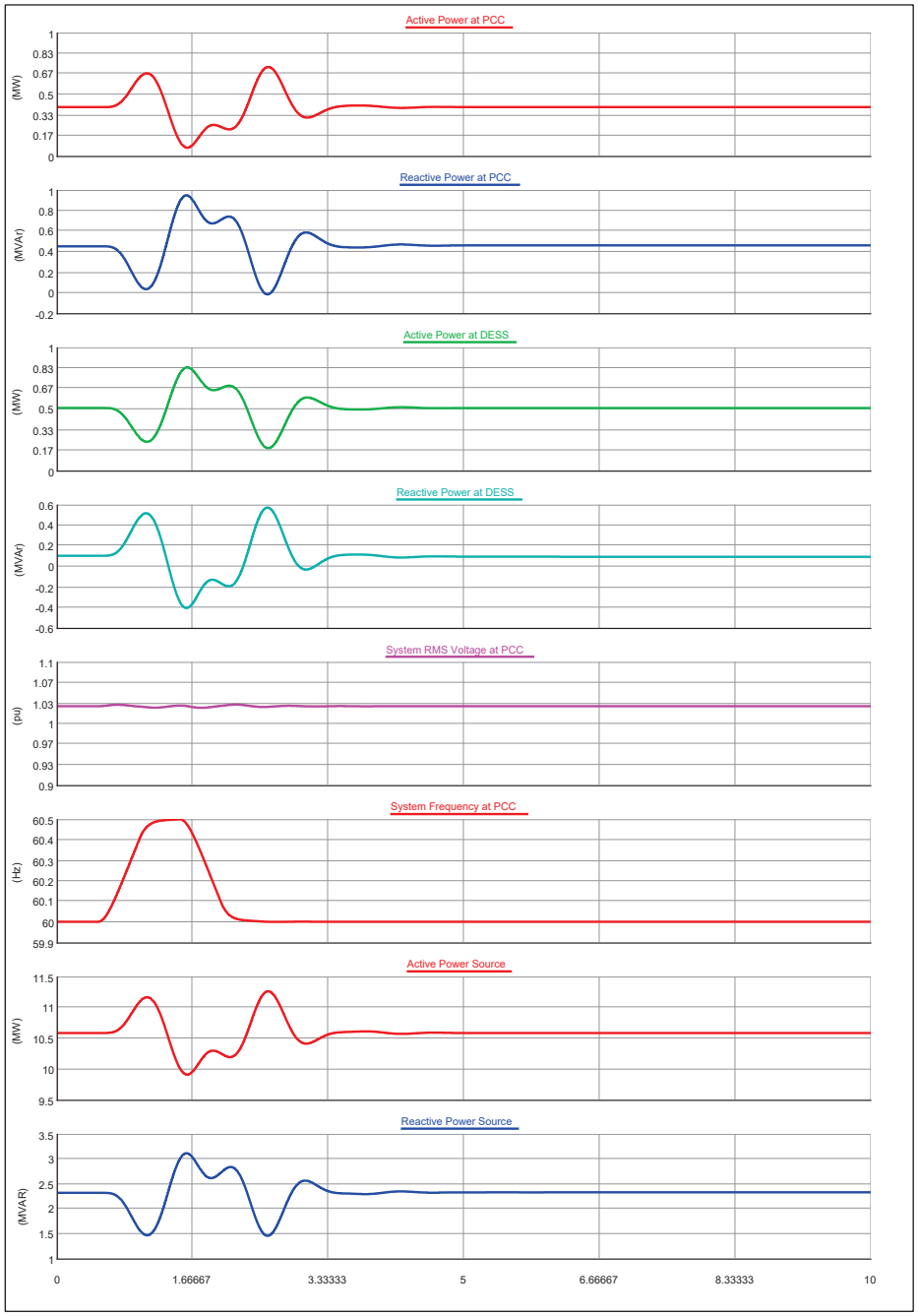


Figure A.30: System Response for Test 4.1.7

TEST 4.1.8: DECREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was decreased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER, in this mode, reacted to the change, rode through, and returned to steady state. The real and reactive power flow at the PCC and DER settled at their previous set points. The voltage was disturbed by the frequency change due to power flow but settled back to 1.025 pu in steady state.

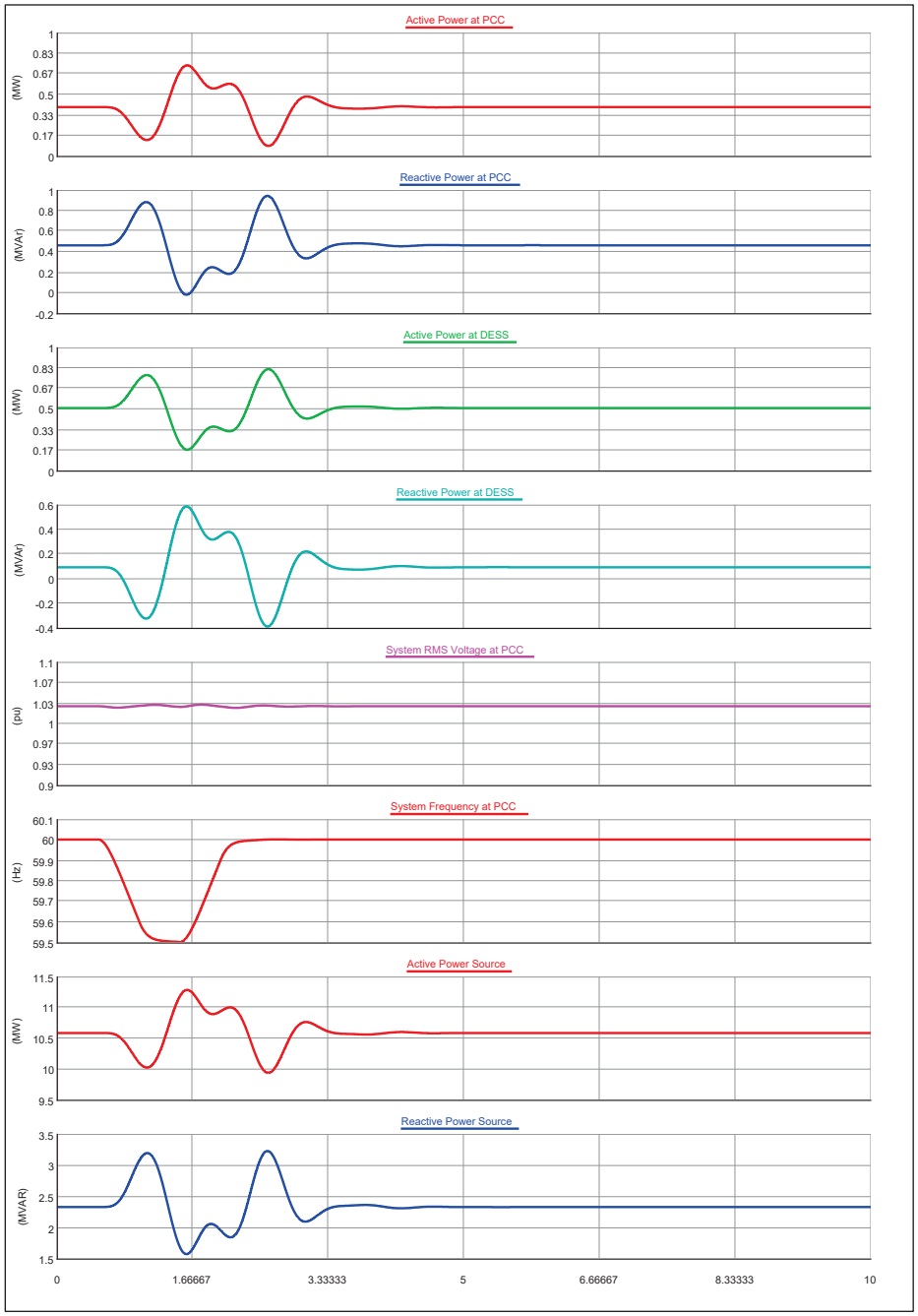


Figure A.31: System Response for Test 4.1.8

Scenario 2: DER on a Complex Circuit with a Multitude of Controllable Devices

TEST 4.2.1: MODE ACTIVATION WITH REACTIVE POWER SET POINT OF 200 KVAR

The initial set point of the DER was at 500 kW and 200 kVAR. The active and reactive power load were at 900 kW and 550 kVAR, respectively. When the mode was activated, the reactive power input of the DER dropped to 136 kVAR as the voltage at the PCC was greater than 1.018 pu; hence, the DER reduced its reactive power output to maintain the terminal voltage at the same value. The active power dispatch of the DER remained unaffected and therefore did not change across the PCC and the source. The system voltage and frequency did not change with the activation of the mode.

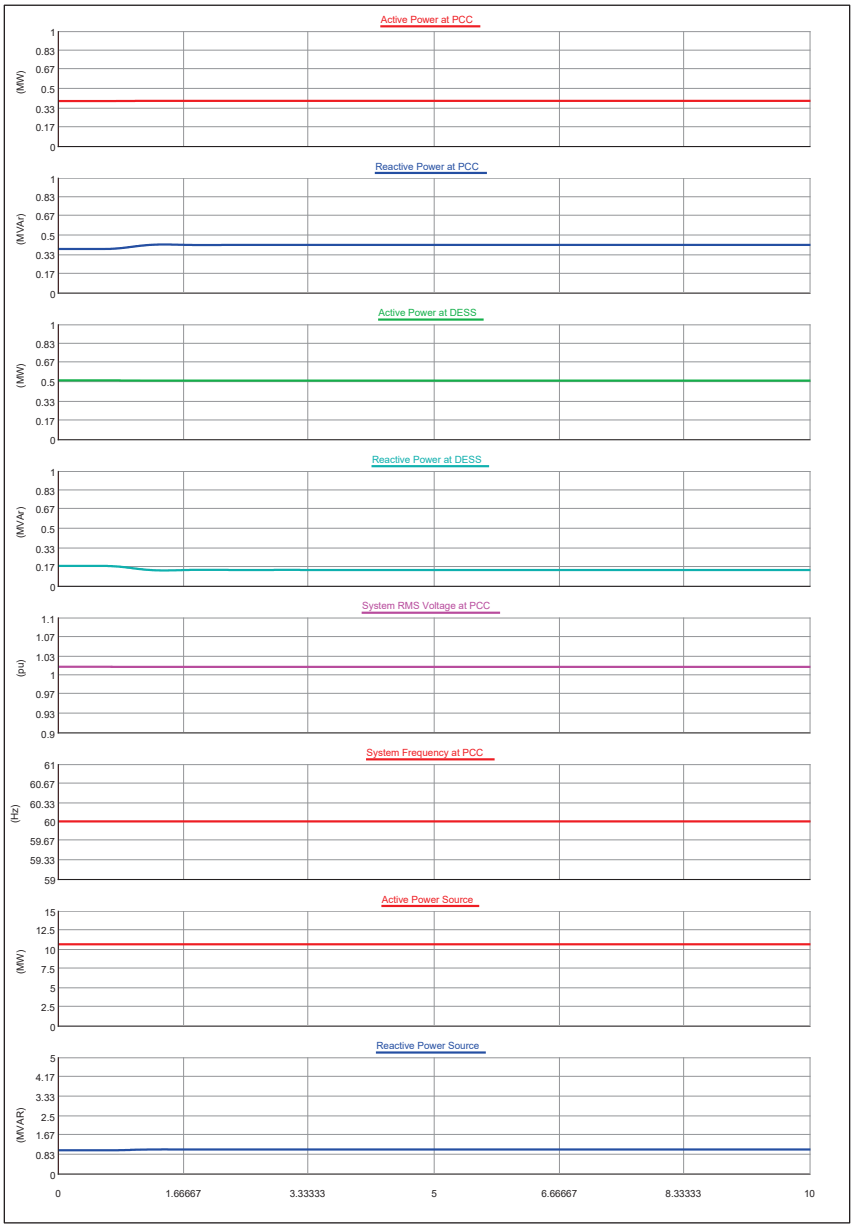


Figure A.32: System Response for Test 4.2.1

TEST 4.2.2: INCREASE THE SYSTEM LOAD BY 500 KVAR

On increasing the reactive power load by 500 kVAR to 1050 kVAR at the PCC, the reactive power at the DER remained unchanged at steady state because the reactive power set point at the DER was determined by the system voltage, which was not affected significantly during the load variation. The system voltage decreased minimally because of the inflow of the reactive power from the grid. The additional reactive power load was supported by the PCC to keep the node voltage constant. The frequency and the real power at the DER and PCC remained unaffected as well.

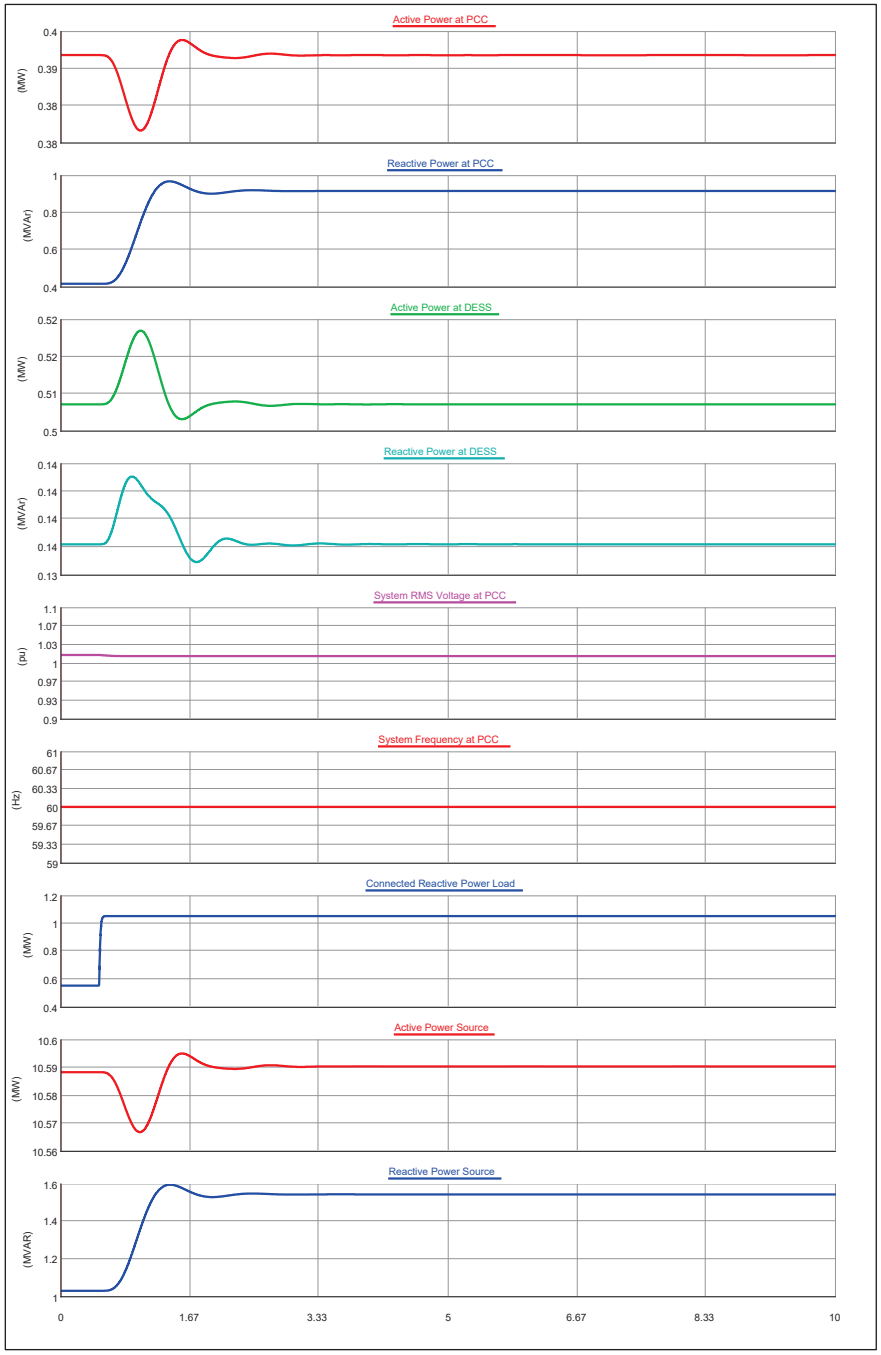


Figure A.33: System Response for Test 4.2.2

TEST 4.2.3: DECREASE THE SYSTEM LOAD BY 500 KVAR

On decreasing the reactive power, the load decreased from 550 kVAR to 50 kVAR. Like the observations from Test 4.2.2, the reactive power at the DER remained unaffected, while the grid drew power from the DER to maintain the load voltage at the PCC constant. The real power and frequency remained unaffected by the VAR changes, while the system voltage increased slightly because of the excess reactive power generated that was injected into the grid through the PCC.

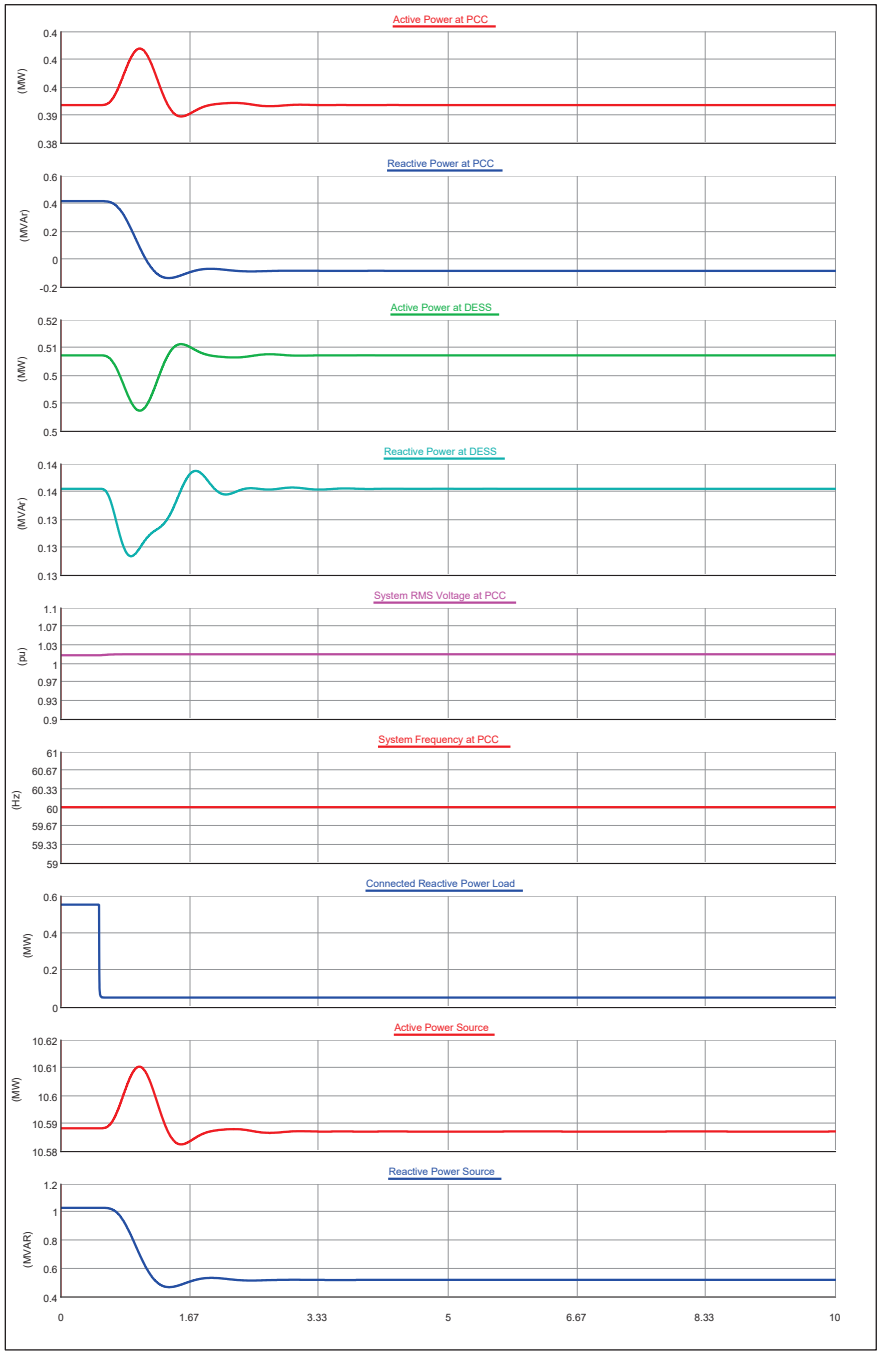


Figure A.34: System Response for Test 4.2.3

TEST 4.2.4: INCREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On increasing the system voltage at the PCC from 1.018 pu to 1.068 pu, the reactive power output of the DER decreased and drew more reactive power from the grid through the PCC to maintain the node voltage at the PCC constant. The frequency and the real power at the PCC and DER remained unaffected by the change.

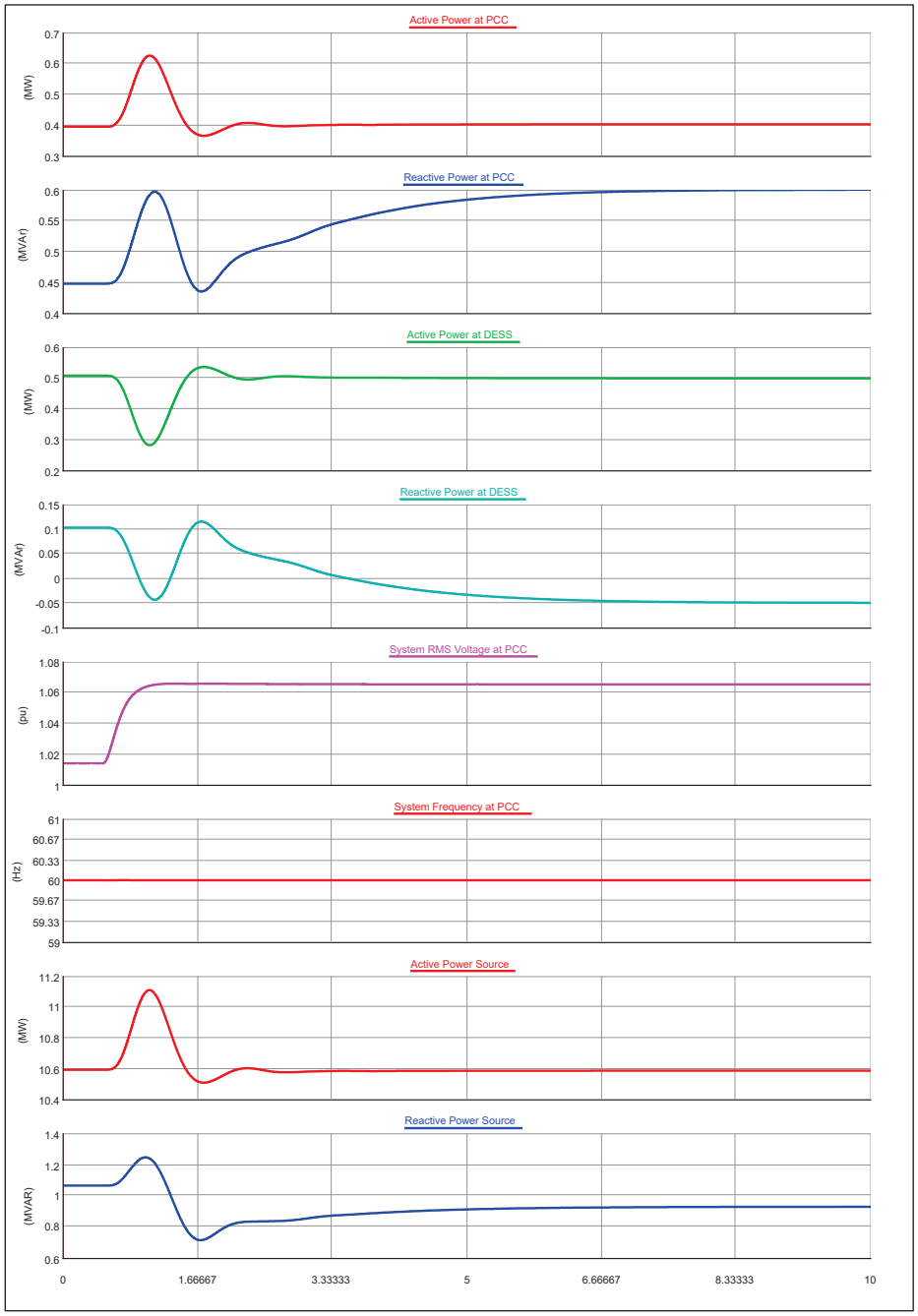


Figure A.35: System Response for Test 4.2.4

TEST 4.2.5: DECREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On decreasing the system voltage at the PCC from 1.018 pu to 0.968 pu, the reactive power output of the DER increased and produced more reactive power to maintain the node voltage at the PCC constant. The frequency and the real power at the PCC and DER remained unaffected by the change at steady state.

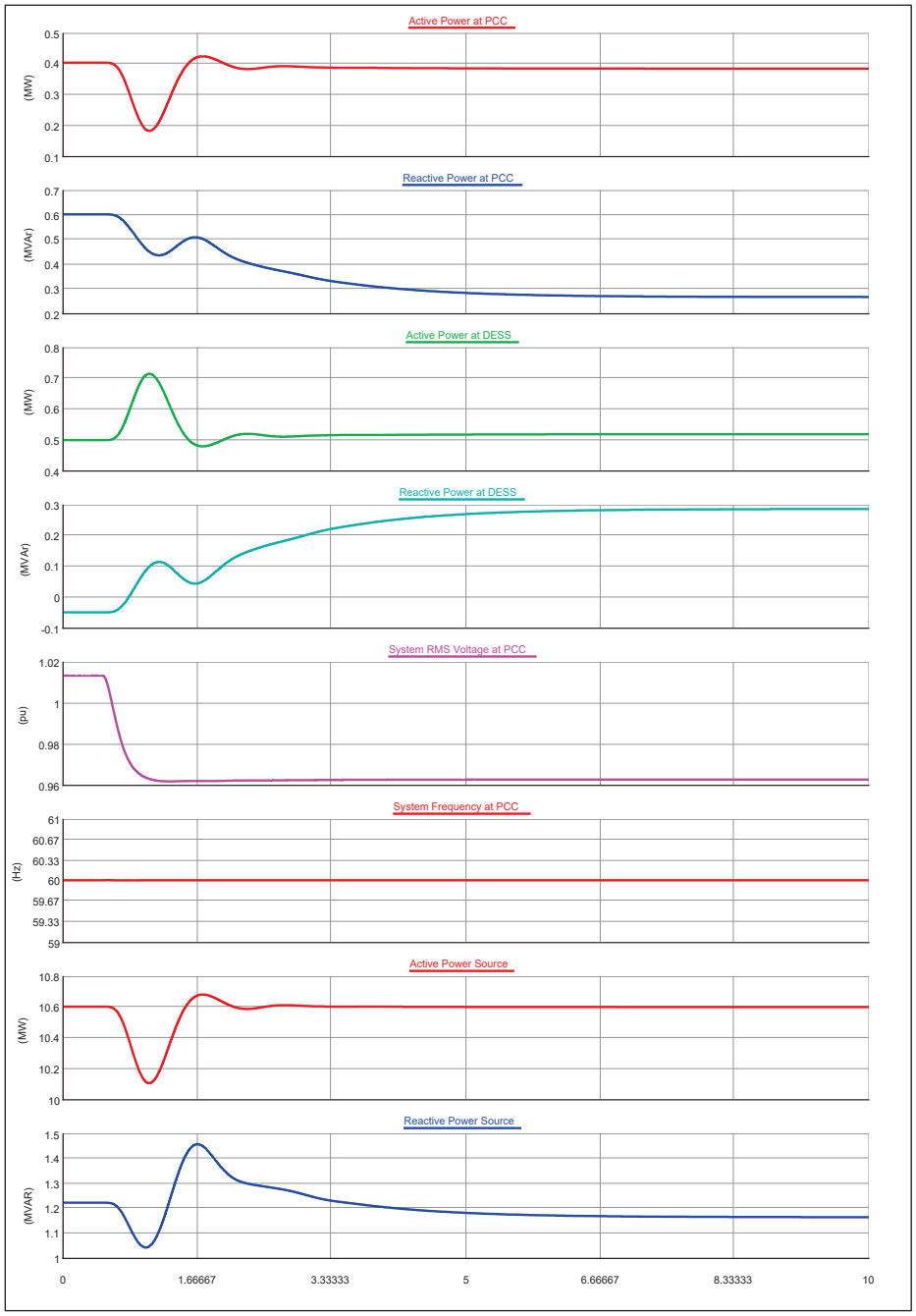


Figure A.36: System Response for Test 4.2.5

TEST 4.2.6: VARY THE SYSTEM VOLTAGE

The voltage profile at the PCC was varied, as shown in Figure A.28. The real power and reactive power at the DER and PCC settled at its prior set point post the transition in the voltage. The system frequency remained unaffected by the change in voltage.

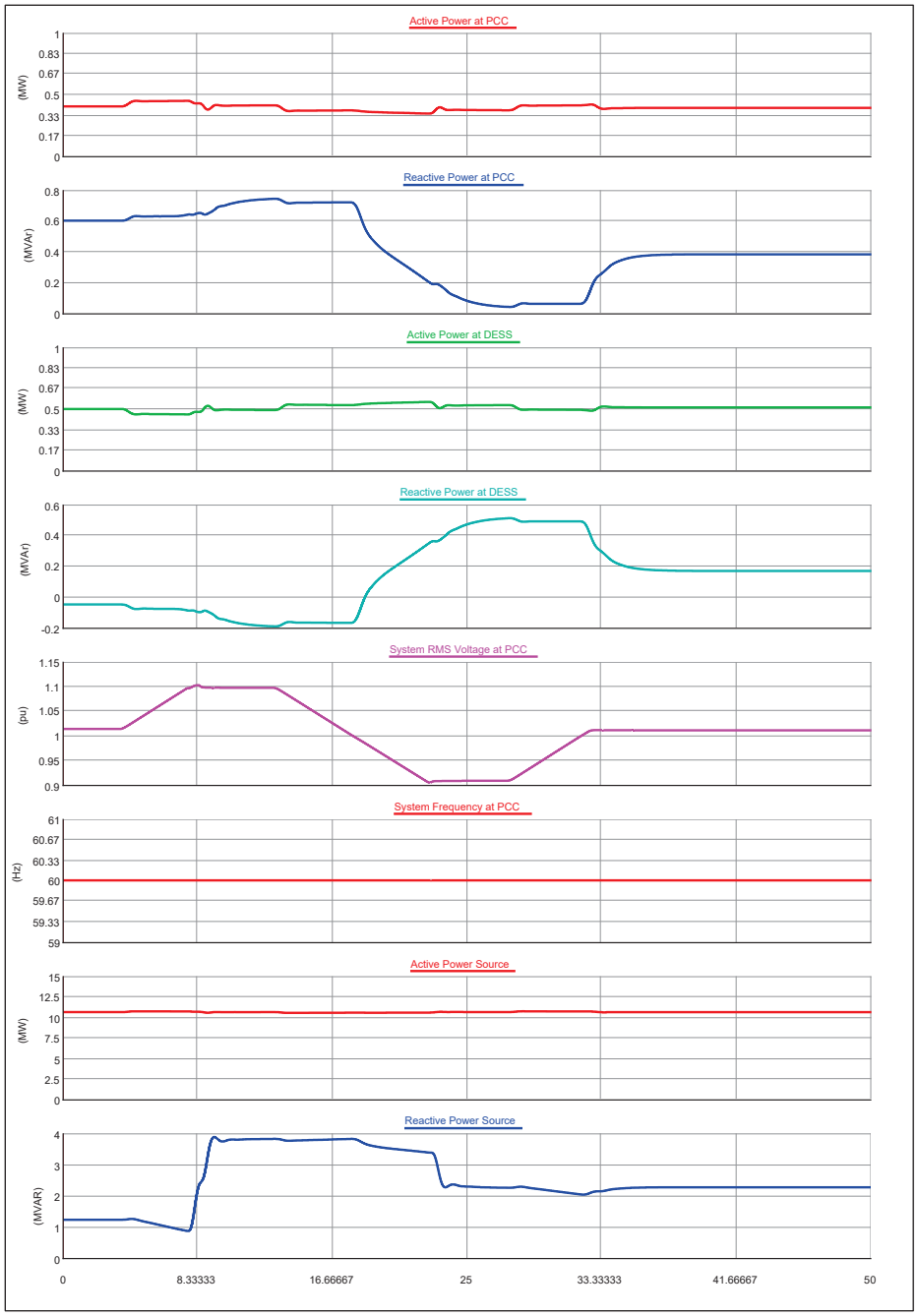


Figure A.37: System Response for Test 4.2.6

TEST 4.2.7: INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was increased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER, in this mode, reacted to the change, rode through, and returned to steady state. The real and reactive power flow at the PCC and DER settled at their previous set points. The voltage was disturbed by the frequency change due to the power flow but settled back to 1.018 pu in steady state.

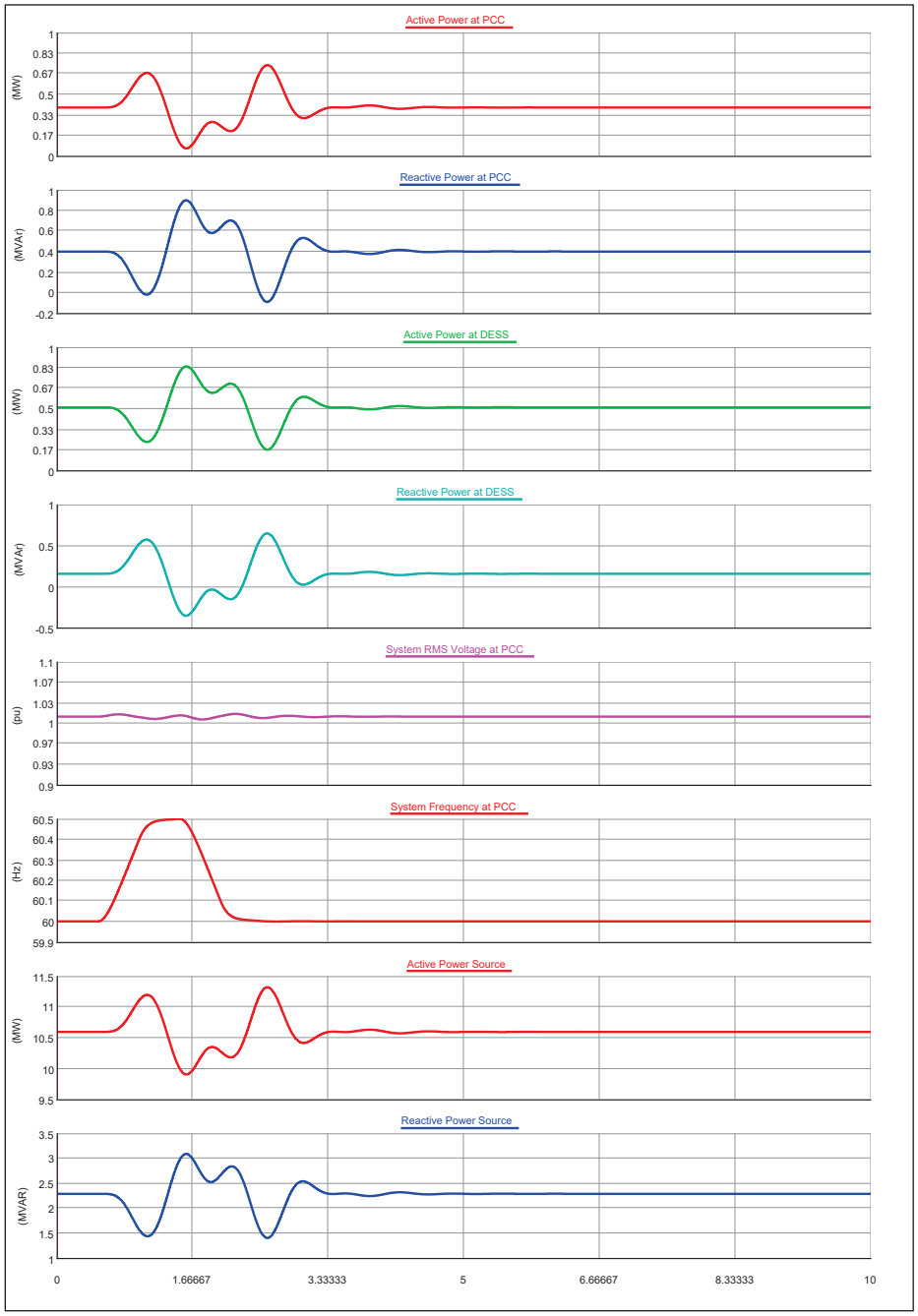


Figure A.38: System Response for Test 4.2.7

TEST 4.2.8: DECREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was decreased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER, in this mode, reacted to the change, rode through, and returned to steady state. The real and reactive power flow at the PCC and DER settled at their previous set points. The voltage was disturbed by the frequency change due to power flow but settled back to 1.018 pu in steady state.

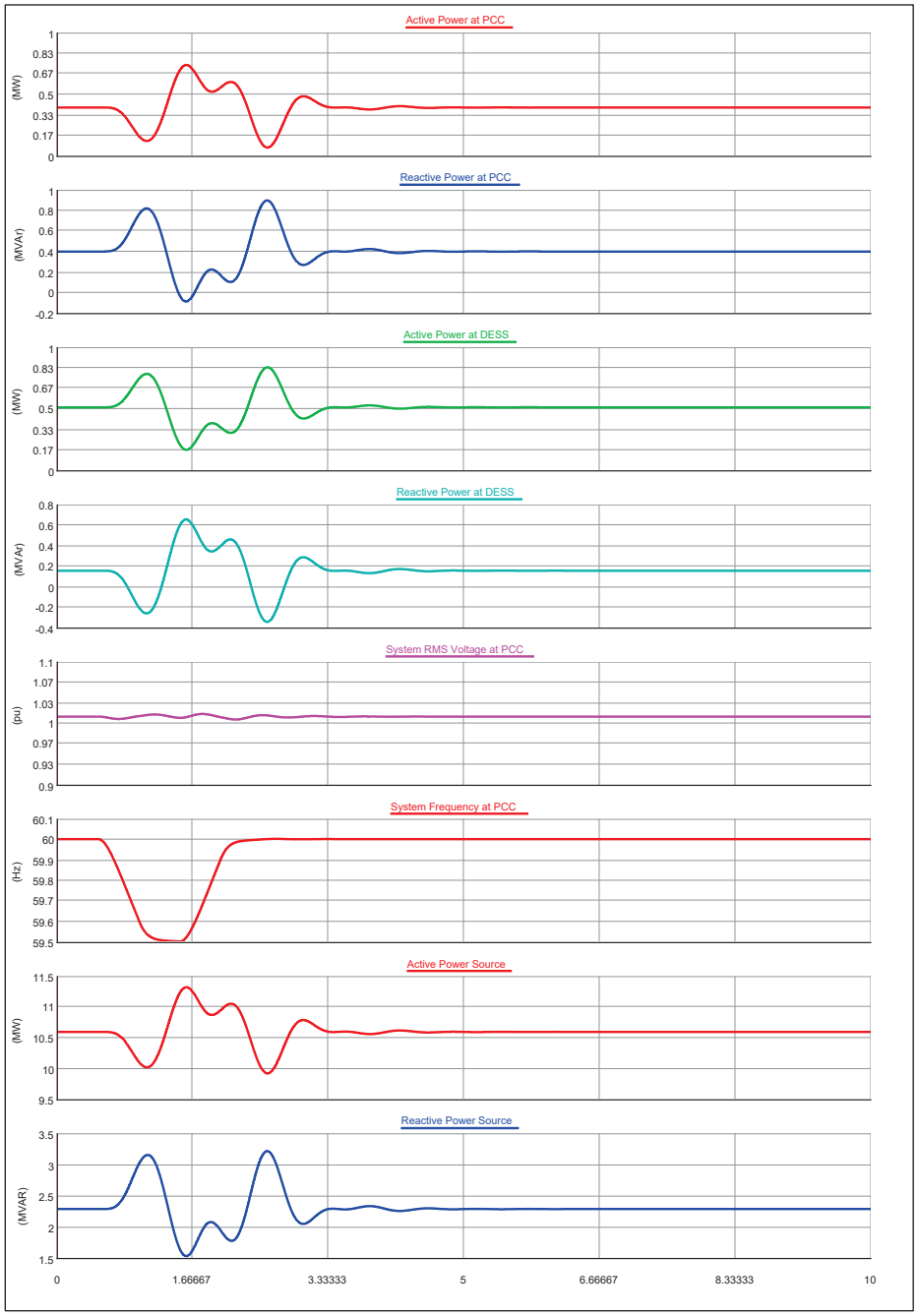


Figure A.39: System Response for Test 4.2.8

Scenario 3: DER at the End of a Long Feeder

TEST 4.3.1: MODE ACTIVATION WITH REACTIVE POWER SET POINT OF 200 KVAR

The initial set point of the DER was at 500 kW and 200 kVAR. The active and reactive power load were at 900 kW and 550 kVAR, respectively. When the mode was activated, the reactive power input of the DER did not change because the voltage at the PCC is at 1.002 pu, and therefore the DER maintained its reactive power output to maintain the terminal voltage at the same value. The active power dispatch of the DER remained unaffected, and hence it did not change across the PCC and the source. The system voltage and frequency did not change with the activation of the mode.

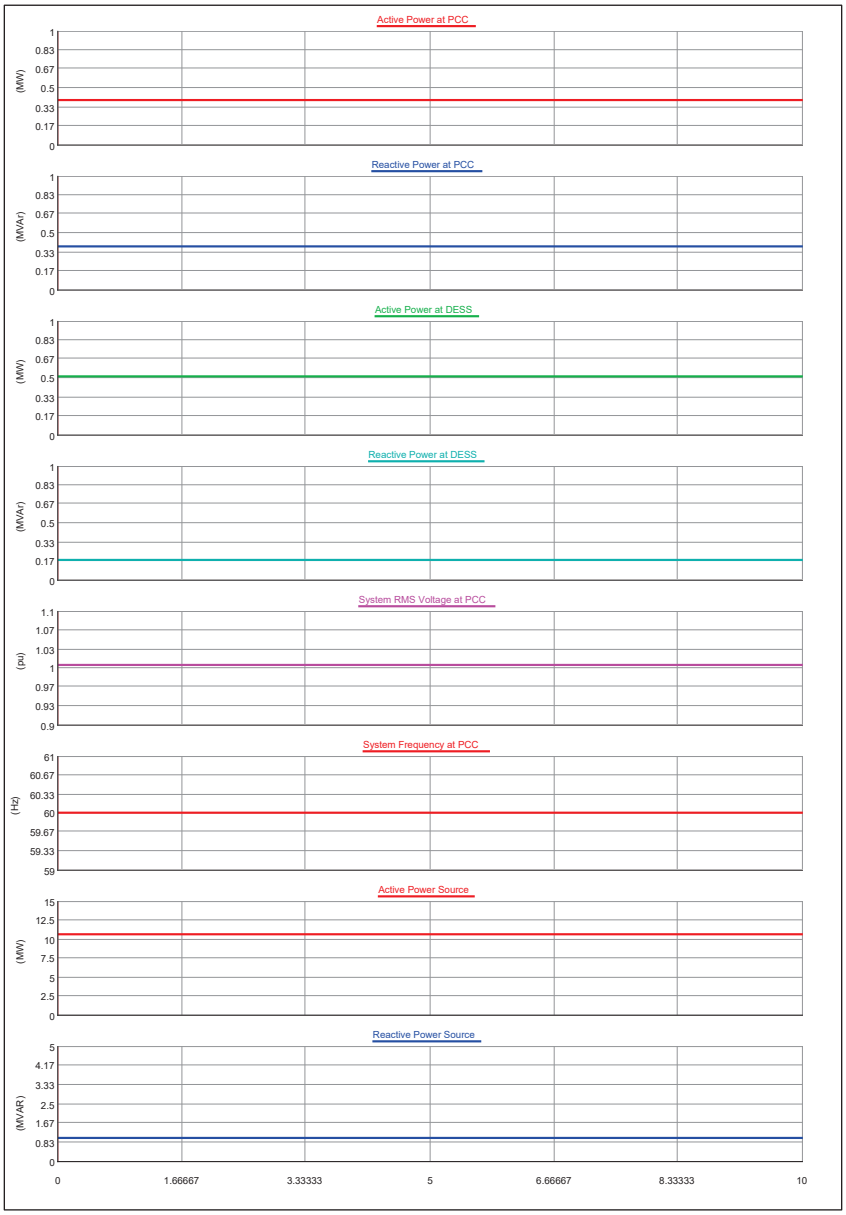


Figure A.40: System Response for Test 4.3.1

TEST 4.3.2: INCREASE THE SYSTEM LOAD BY 500 KVAR

On increasing the reactive power load by 500 kVAR to 1050 kVAR at the PCC, the reactive power at the DER remained unchanged at steady state because the reactive power set point at the DER was determined by the system voltage, which was not affected significantly during the load variation. The system voltage decreased minimally because of the inflow of the reactive power from the grid. The additional reactive power load was supported by the PCC to keep the node voltage constant. The frequency and the real power at the DER and PCC remained unaffected as well.

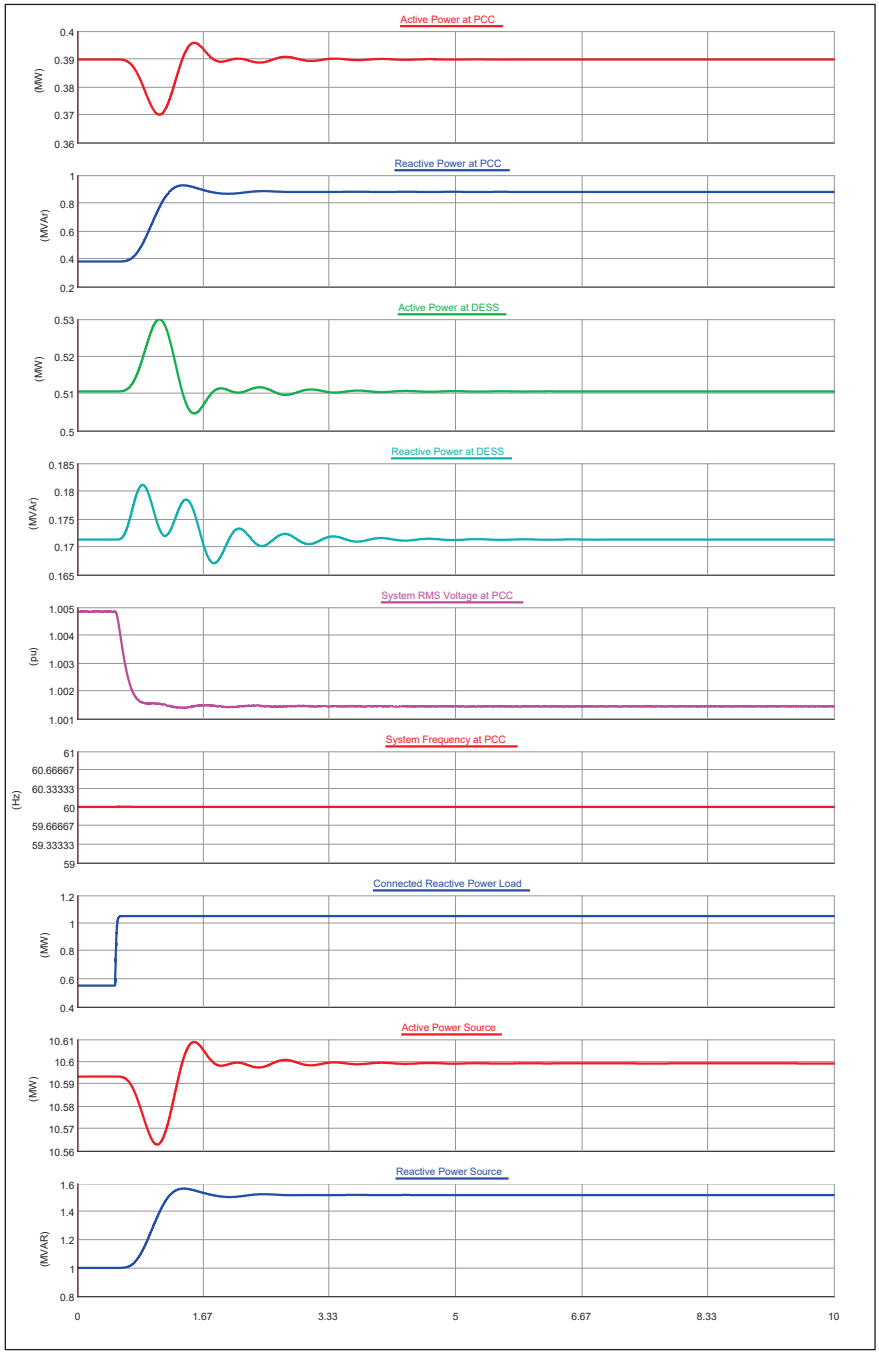


Figure A.41: System Response for Test 4.3.2

TEST 4.3.3: DECREASE THE SYSTEM LOAD BY 500 KVAR

On decreasing the reactive power, the load decreased from 550 kVAR to 50 kVAR. Like the observations from Test 4.3.2, the reactive power at the DER remained unaffected, while the grid drew power from the DER to maintain the load voltage at the PCC constant. The real power and frequency remained unaffected by the VAR changes, while the system voltage increased slightly because of the excess reactive power being generated that was injected into the grid through the PCC.

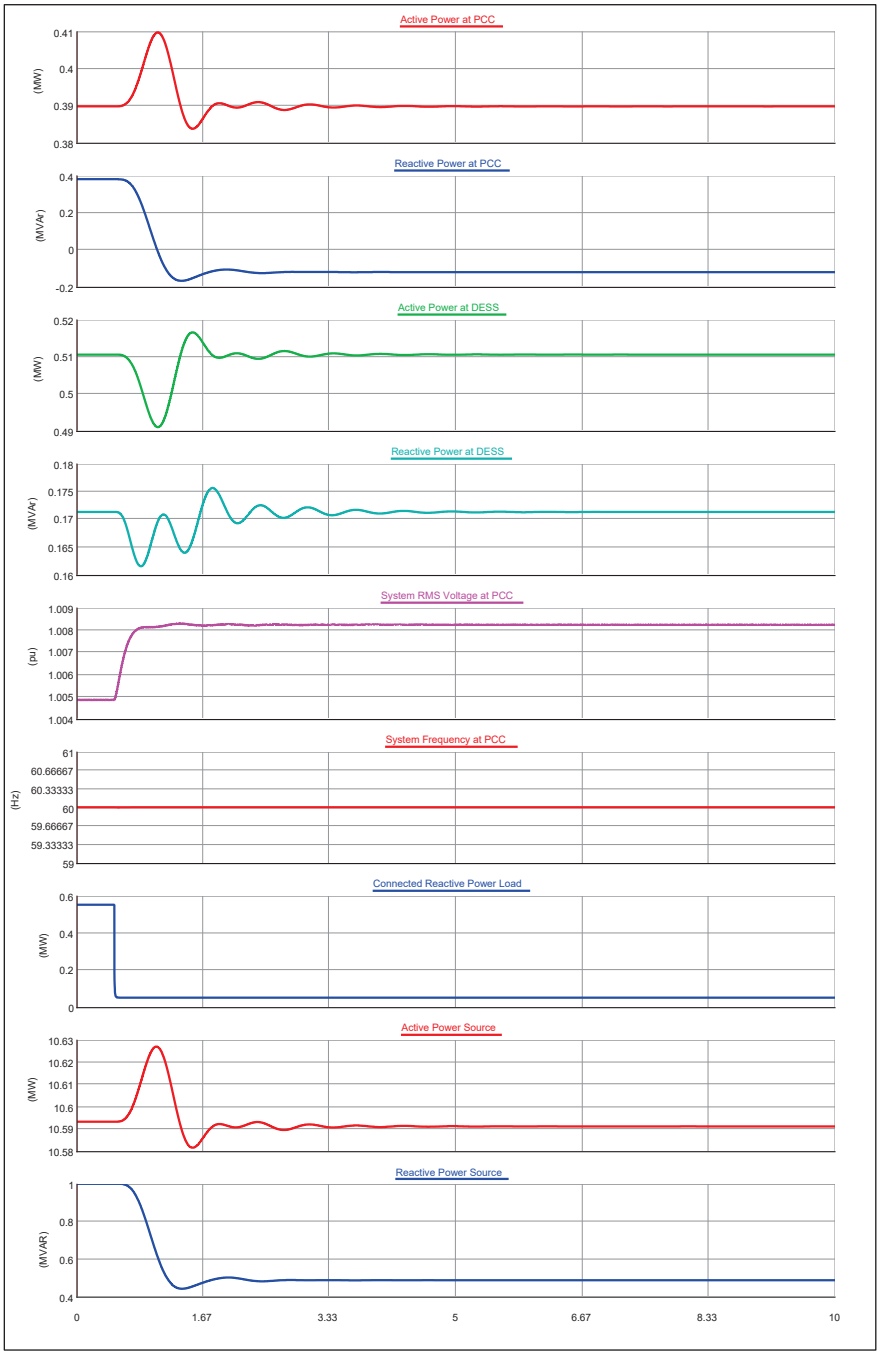


Figure A.42: System Response for Test 4.3.3

TEST 4.3.4: INCREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On increasing the system voltage at the PCC from 1.002 pu to 1.052 pu, the reactive power output of the DER decreased and drew more reactive power from the grid through the PCC to maintain the node voltage at the PCC constant. The frequency and real power at the PCC and DER remained unaffected by the change.

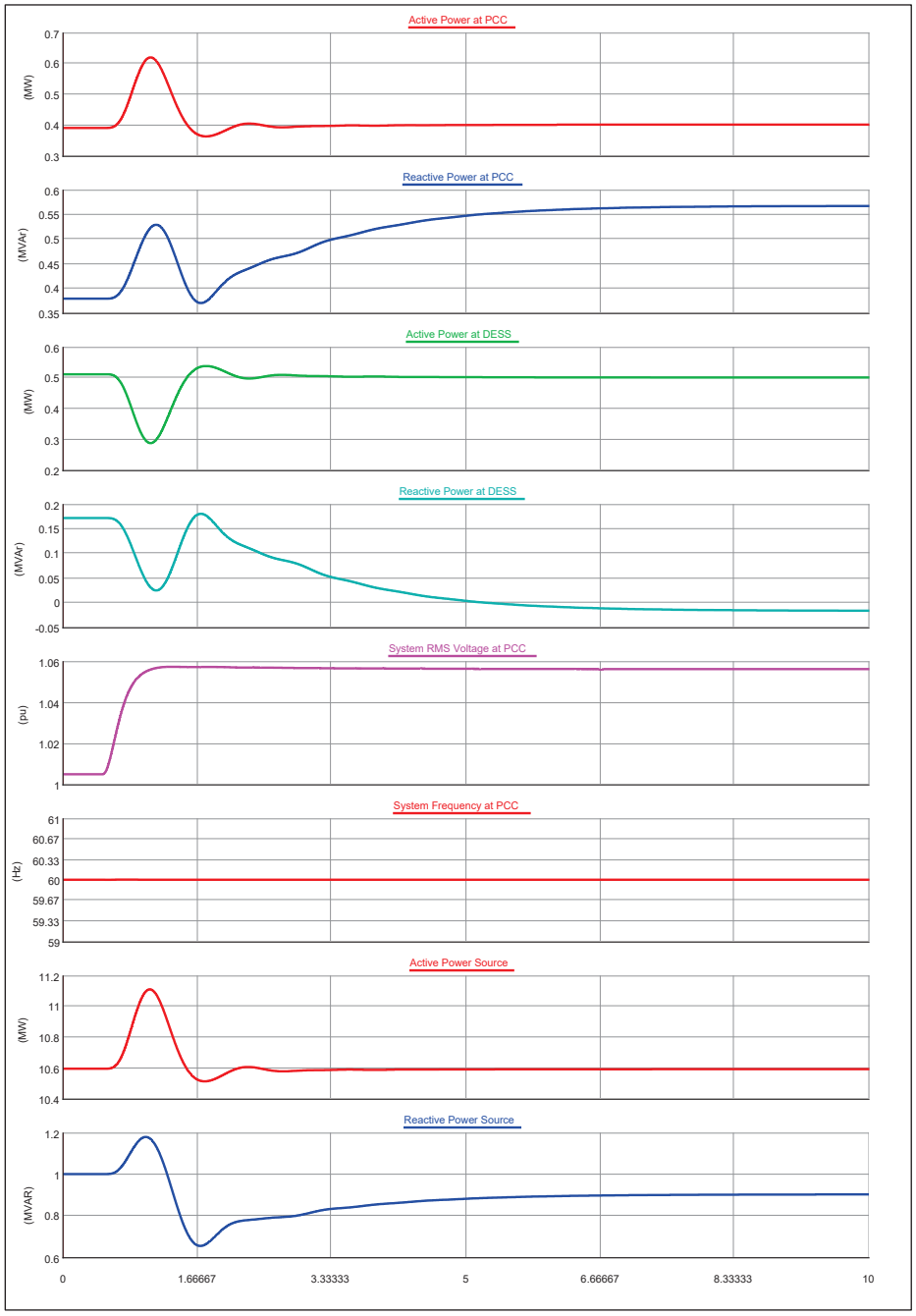


Figure A.43: System Response for Test 4.3.4

TEST 4.3.5: DECREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On decreasing the system voltage at the PCC from 1.002 pu to 0.952 pu, the reactive power output of the DER increased and produced more reactive power maintain the node voltage at the PCC constant. The frequency and the real power at the PCC and DER remained unaffected by the change at steady state.

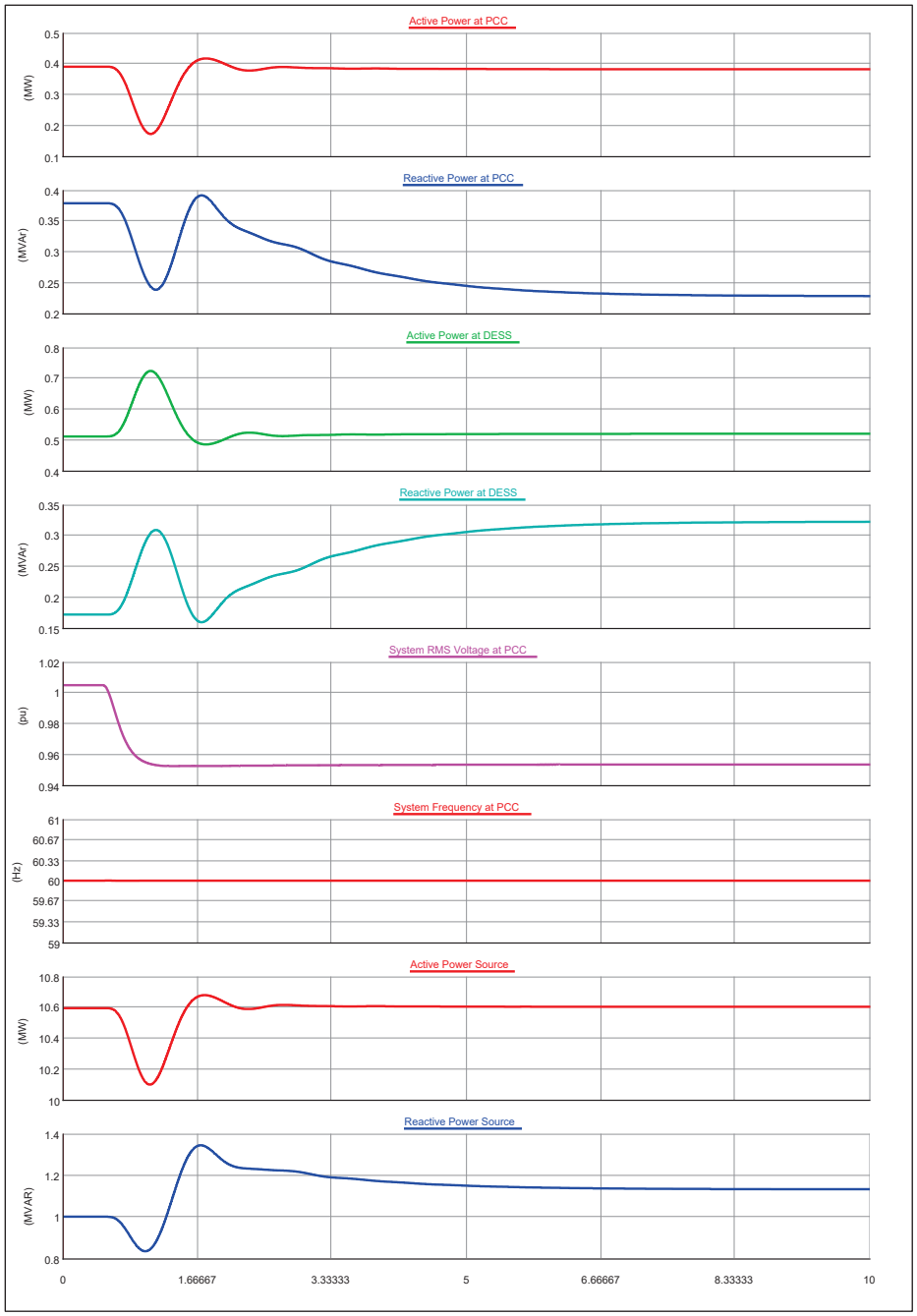


Figure A.44: System Response for Test 4.3.5

TEST 4.3.6: VARY THE SYSTEM VOLTAGE

The voltage profile at the PCC was varied, as shown in Figure A.28. The real power and reactive power at the DER and PCC settled at its prior set point post the transition in the voltage. The system frequency remained unaffected by the change in voltage.

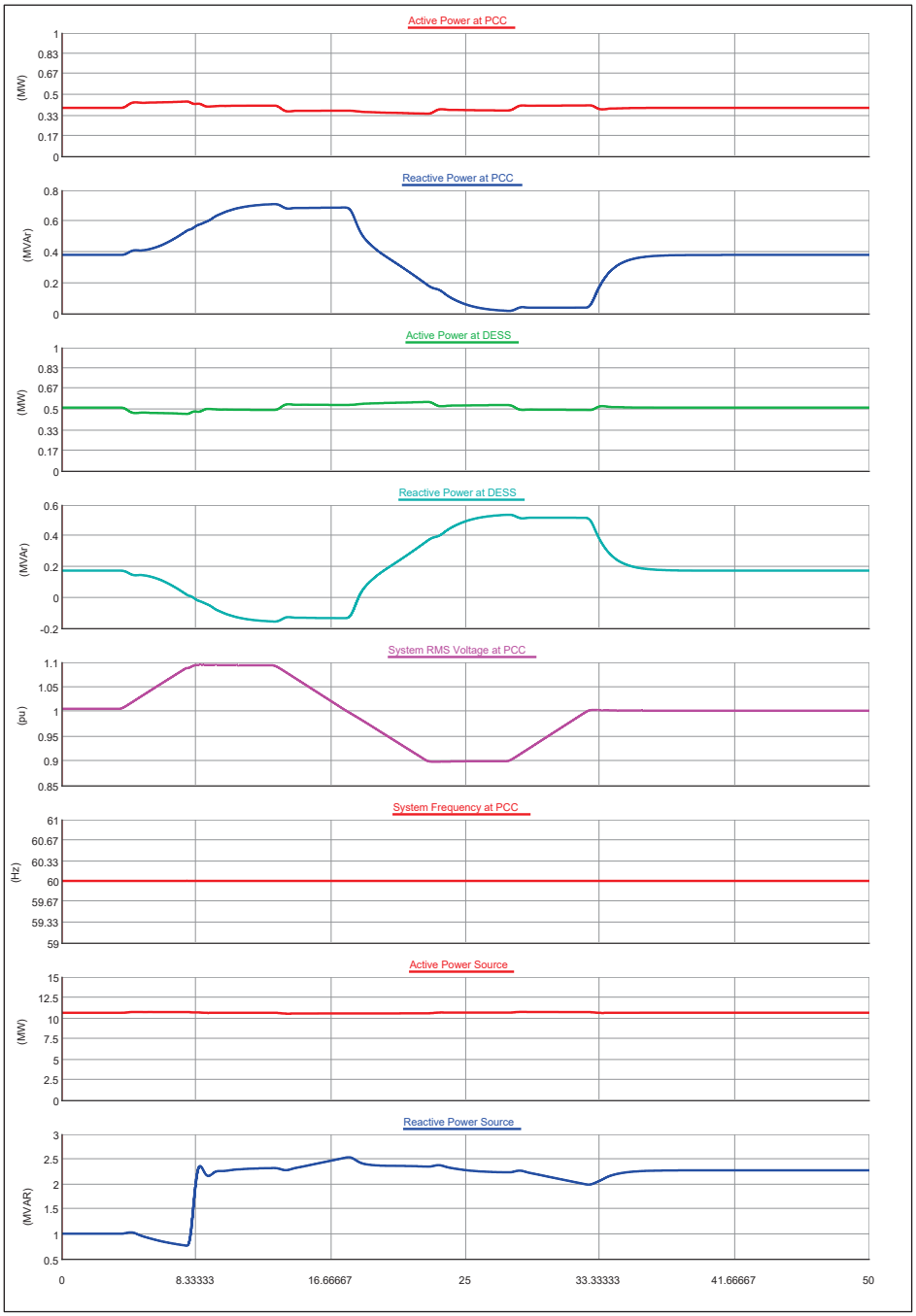


Figure A.45: System Response for Test 4.3.6

TEST 4.3.7: INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was increased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER, in this mode; hence, reacted to the change, rode through, and returned to steady state. The real and reactive power flow at the PCC and DER settled at their previous set points. The voltage was disturbed by the frequency change due to power flow but settled back to 1.002 pu in steady state.

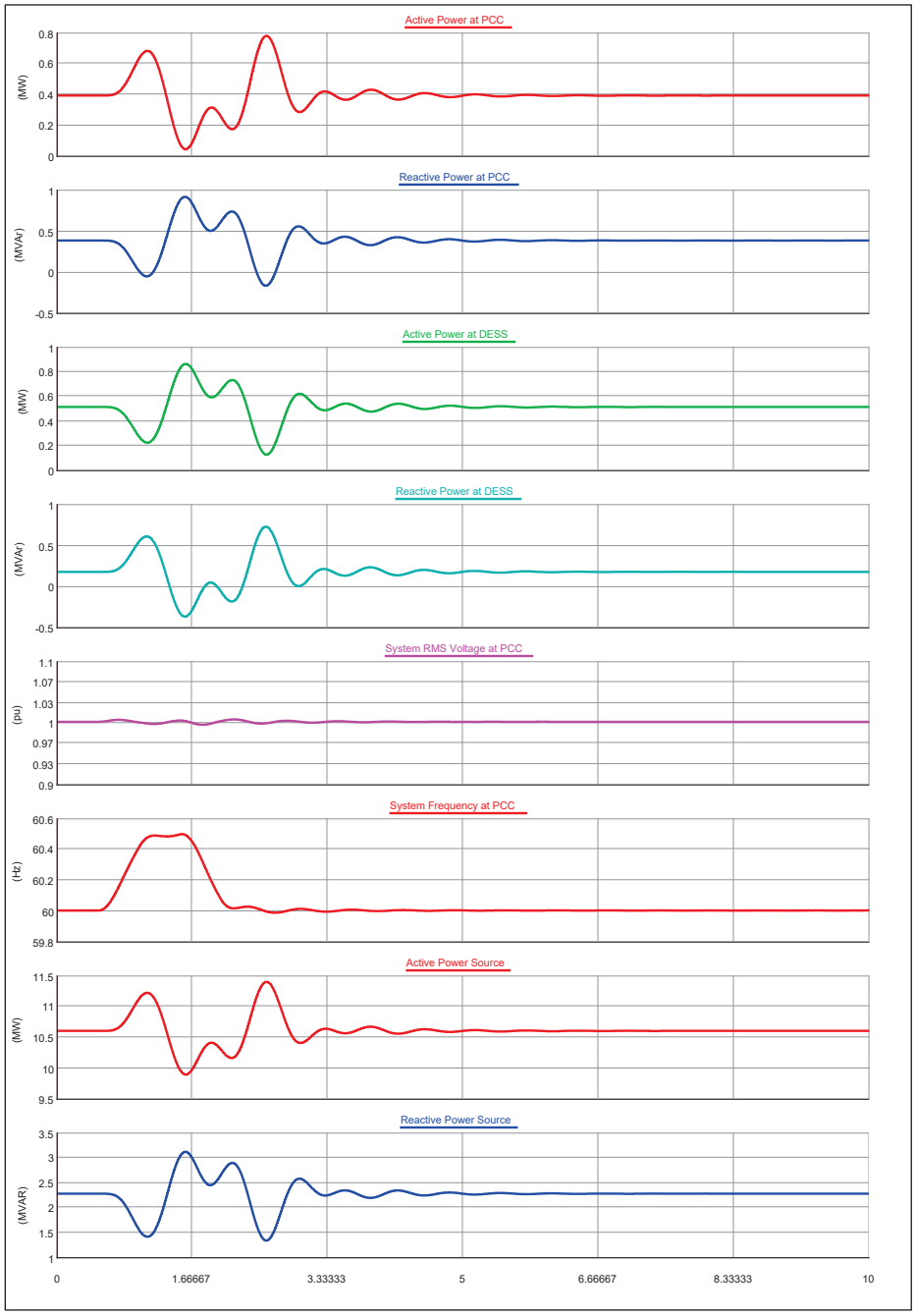


Figure A.46: System Response for Test 4.3.7

TEST 4.3.8: DECREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was decreased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER, in this mode, reacted to the change, rode through, and returned to steady state. The real and reactive power flow at the PCC and DER settled at their previous set points. The voltage was disturbed by the frequency change due to power flow but settled back to 1.002 pu in steady state.

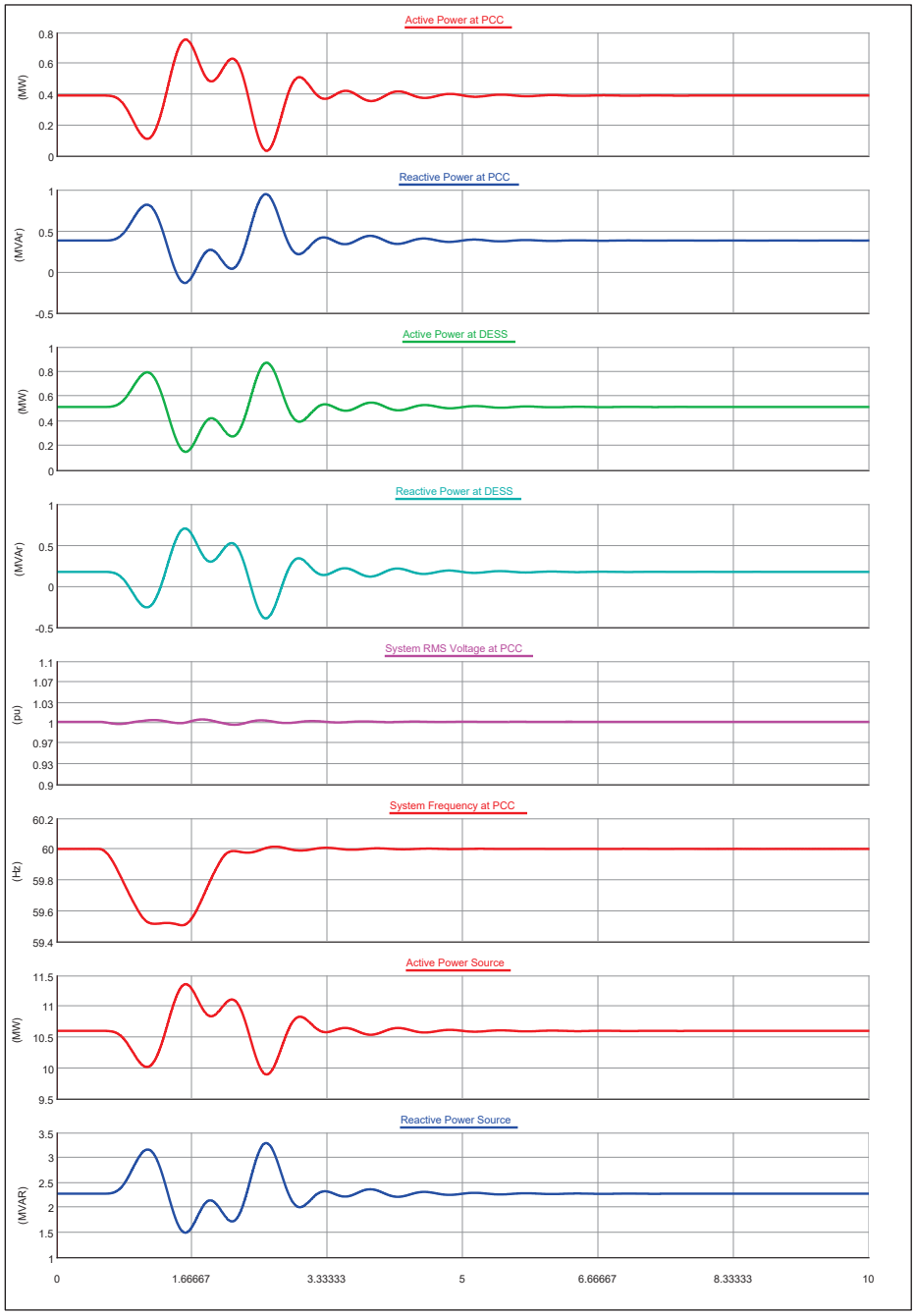


Figure A.47: System Response for Test 4.3.8

TEST 5 – FREQUENCY-WATT

This function is intended to provide a mechanism through which a DER may be configured to manage its own active power output in response to the fluctuations in the system frequency. This function involves the dynamic production of active power to resist variations in the system frequency.

The objective is to counter any changes in the frequency by varying the output power. When the DER is in frequency-watt mode, it attempts to maintain the frequency of the system to 60 Hz by regulating active power.

The procedure for testing was as follows:

Step 1. Vary the system frequency beyond the nominal values in a stepped and/or transient manner to observe the behavior of the DER (the DER should respond in such a way that the system frequency is maintained within the nominal values).

Step 2. Change the system frequency by changing the load in steps or by changing the grid frequency (when the DER is put into frequency-watt mode, the system frequency should revert in to the nominal band because of the DER active power regulation).

Compare the results with the baseline case and develop the conclusions based on these findings.

Table A.3 lists the tests that will be conducted.

Table A.3: DER Frequency-Watt Test Cases

Test	Test Description	Expected Response
Test 5. x.1	Mode activation with active power set point of 500 kW	DER dispatches 500kW at steady state
Test 5. x.2	Increase the system load by 500 kW	DER dispatches 500kW at steady state
Test 5. x.3	Decrease the system load by 500 kW	DER dispatches 500kW at steady state
Test 5. x.4	Increase the system voltage by 5%	DER dispatches 500kW at steady state
Test 5. x.5	Decrease the system voltage by 5%	DER dispatches 500kW at steady state
Test 5. x.6	Increase the system frequency by 0.5 Hz for 1 s	DER decreases active power output to offset frequency increase. DER dispatches 500kW at steady state.
Test 5. x.7	Decrease the system frequency by 0.5 Hz for 1 s	DER increases active power output to offset frequency decrease. DER dispatches 500kW at steady state
Test 5. x.8	a) Ramp up the system frequency to 60.5 Hz at the rate of 0.1 Hz per second, and hold it for 5 s b) Ramp down the system frequency to 59.7 Hz at the rate of 0.1 Hz per second, and hold it for 5 s)	DER decreases its active power output to offset frequency increases and following that DER increases its active power output to offset frequency decrease. DER settles back at 500kW at steady state.
Test 5. x.9	Increase the system frequency by 0.5 Hz for 5 s	DER decreases active power output to offset frequency increase
Test 5. x.10	Decrease the system frequency by 0.5 Hz for 5 s	DER increases active power output to offset frequency decrease

Note: "x" denotes the scenario under test.

Scenario 2: DER on a Complex Circuit with a Multitude of Controllable Devices

TEST 5.2.1: MODE ACTIVATION WITH ACTIVE POWER SET POINT OF 500 KW

The active and reactive power dispatch of the DER were set at 500 kW and 200 kVAR, respectively. On activating the frequency-watt mode, there was no change on the graph because the system frequency is maintained at 60 Hz.

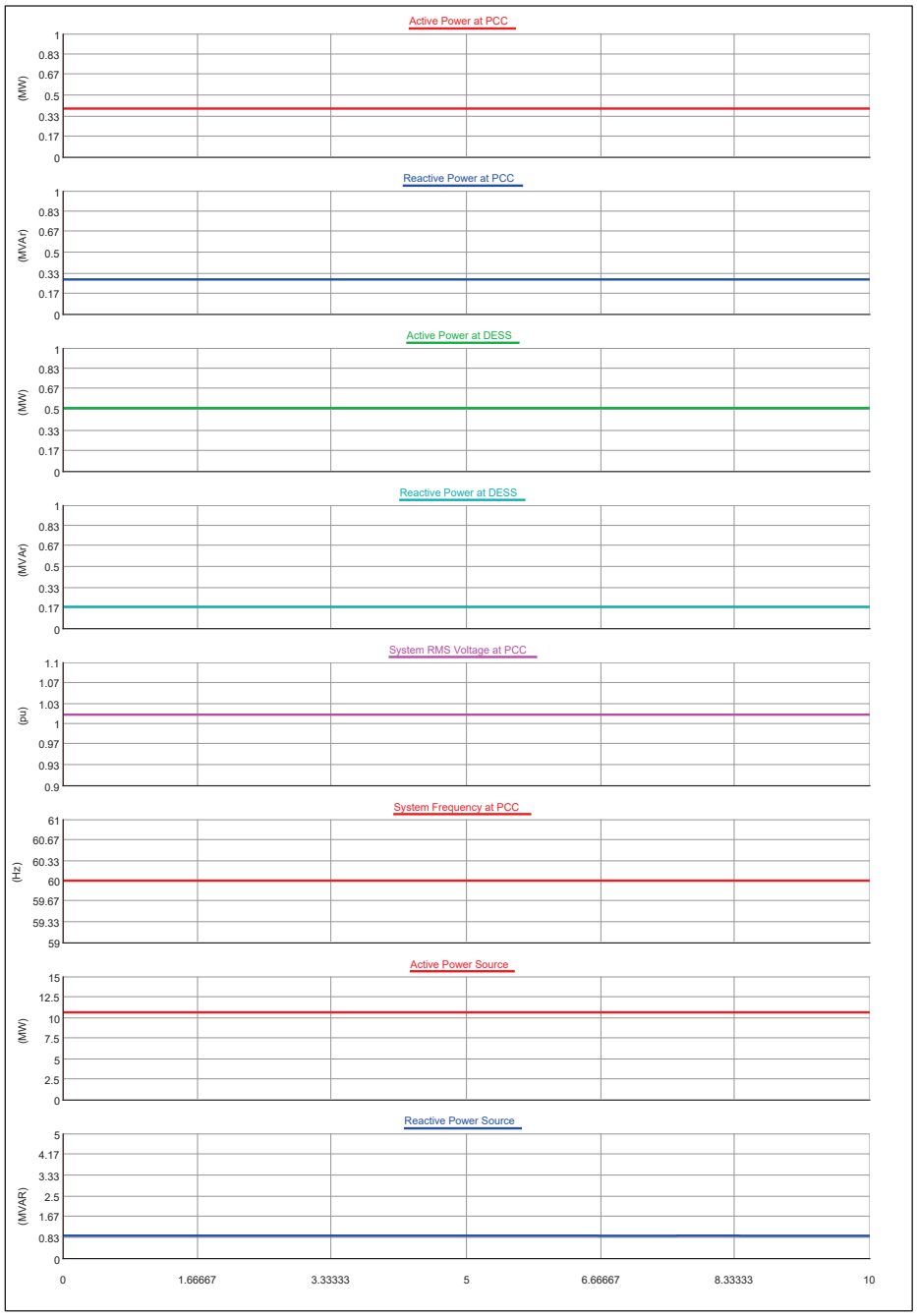


Figure A.48: System Response for Test 5.2.1

TEST 5.2.2 INCREASE THE SYSTEM LOAD BY 500 KW

On increasing the active power load by 500 kW, the real power output of the DER remained constant at 500 kW, while the additional load was fed by the grid through the PCC. The reactive power from the DER and across the PCC settled to their prior set points at steady state, while the system frequency and voltage were not affected by the change.

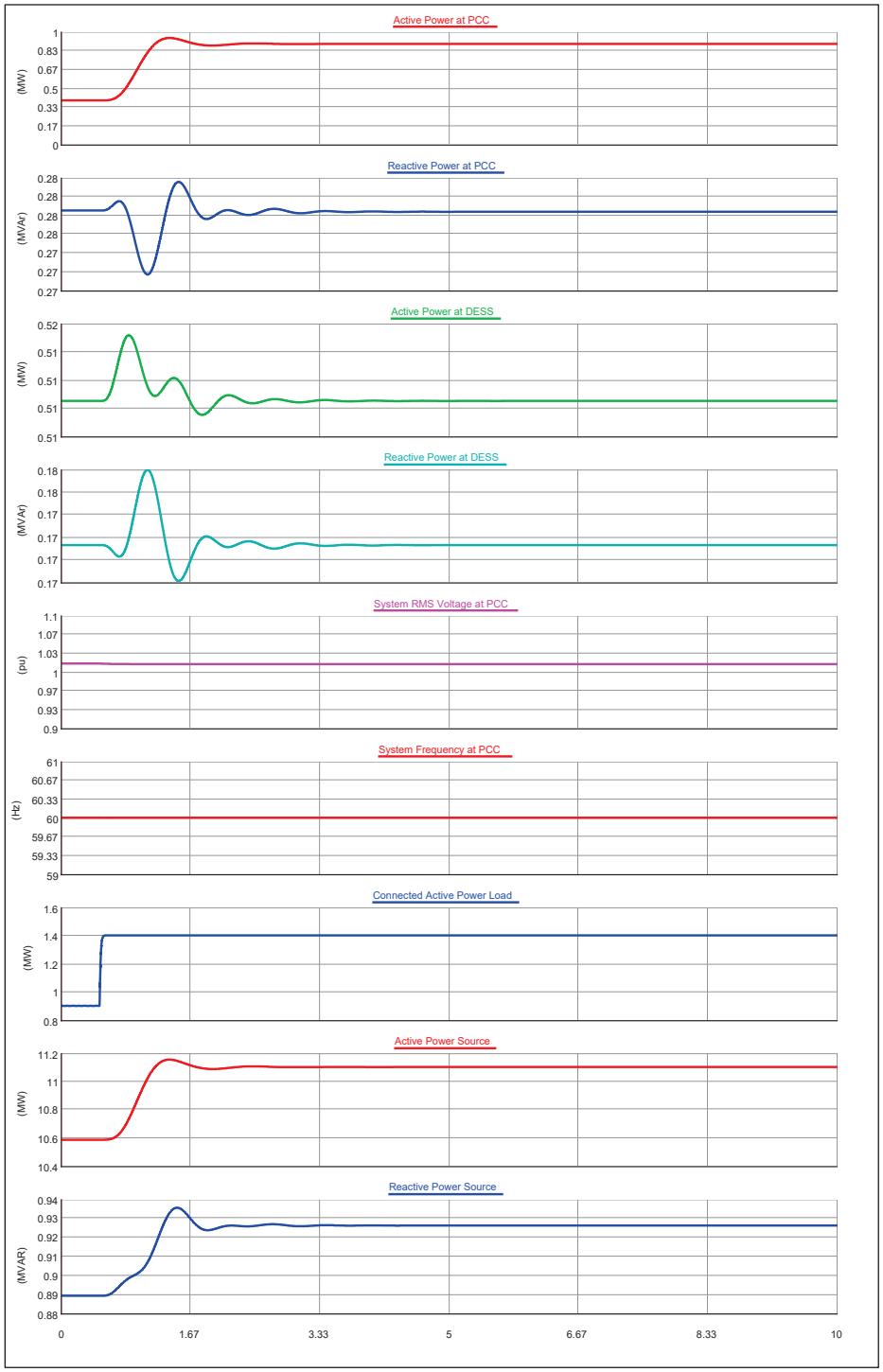


Figure A.49: System Response for Test 5.2.2

TEST 5.2.3: DECREASE THE SYSTEM LOAD BY 500 KW

On decreasing the active power load by 500 kW, the real power output of the DER remains constant at 500 kW, while the load is balanced by sending more active power into the grid through the PCC. The reactive power from the DER and across the PCC settled to their prior set points at steady state, while the system frequency and voltage were not affected by the change.

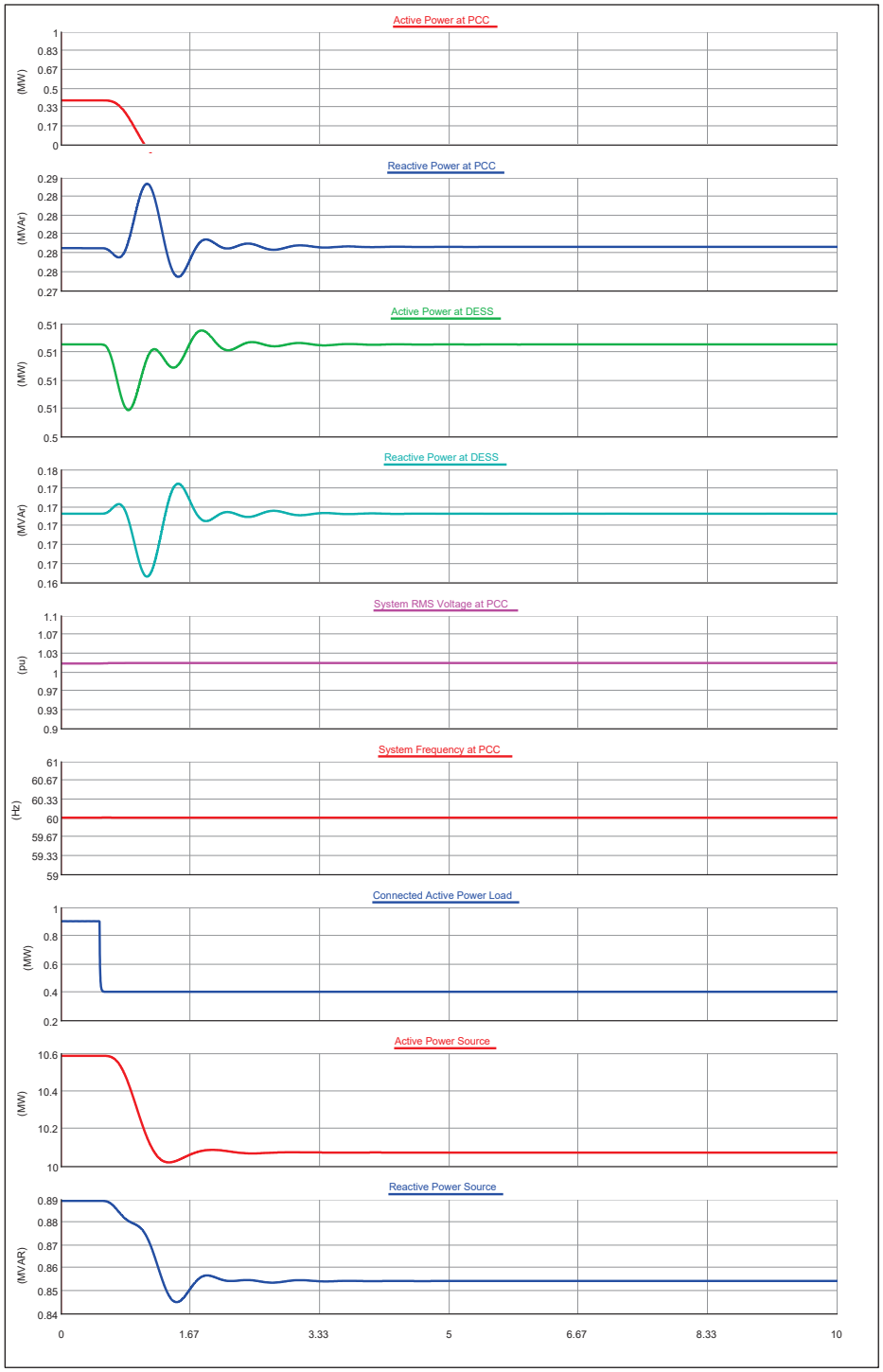


Figure A.50: System Response for Test 5.2.3

TEST 5.2.4: INCREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On increasing the system voltage by 5 percent from 1.018 pu to 0.968 pu, the DER rode through the disturbance. The real power and reactive power at the DER and PCC did not change at steady state, while the system frequency was unaffected.

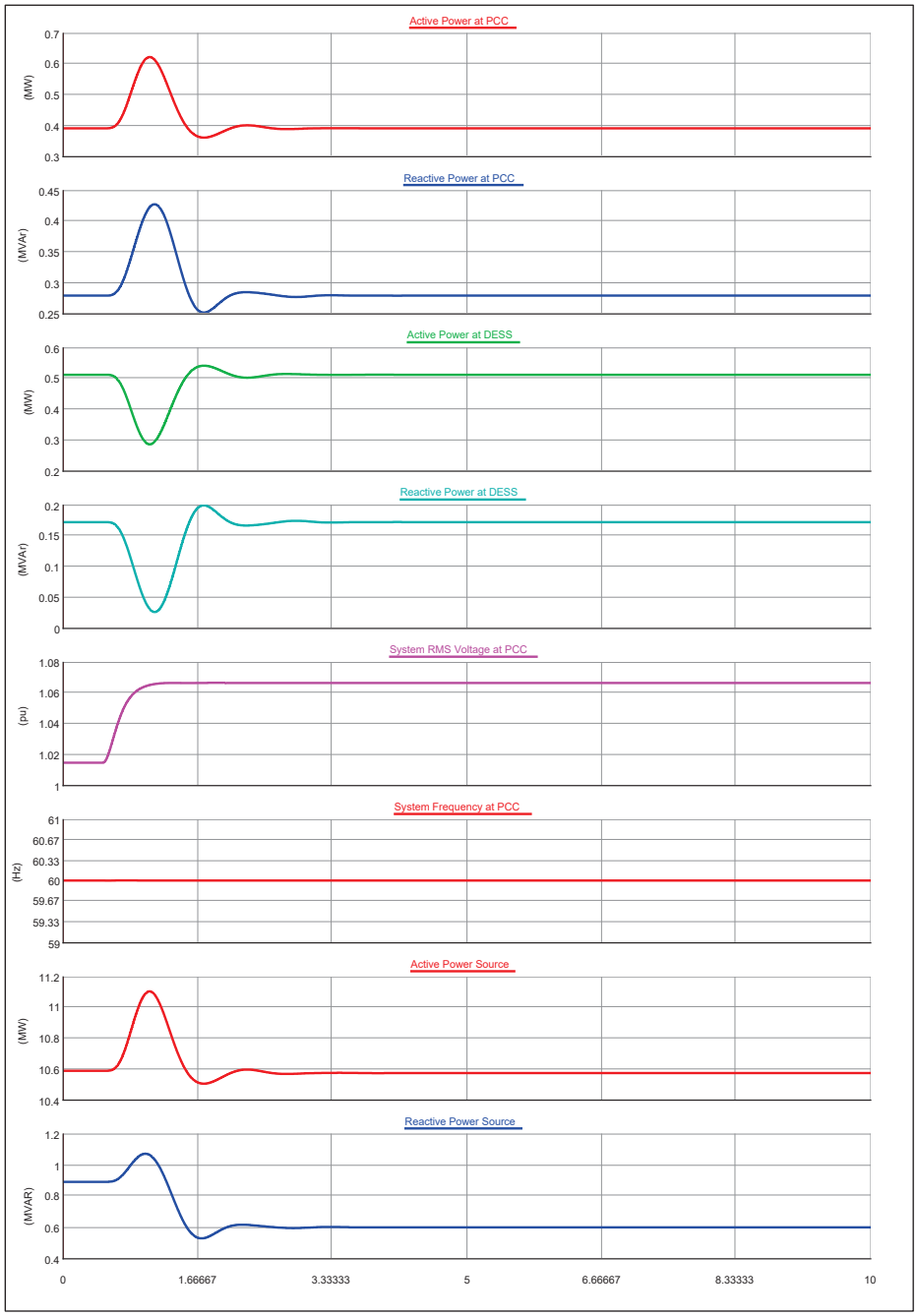


Figure A.51: System Response for Test 5.2.4

TEST 5.2.5: DECREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On decreasing the system voltage by 5 percent from 1.01 pu to 0.96 pu, the DER rode through the disturbance. The real power and reactive power at the DER and PCC did not change at steady state, while the system frequency was unaffected.

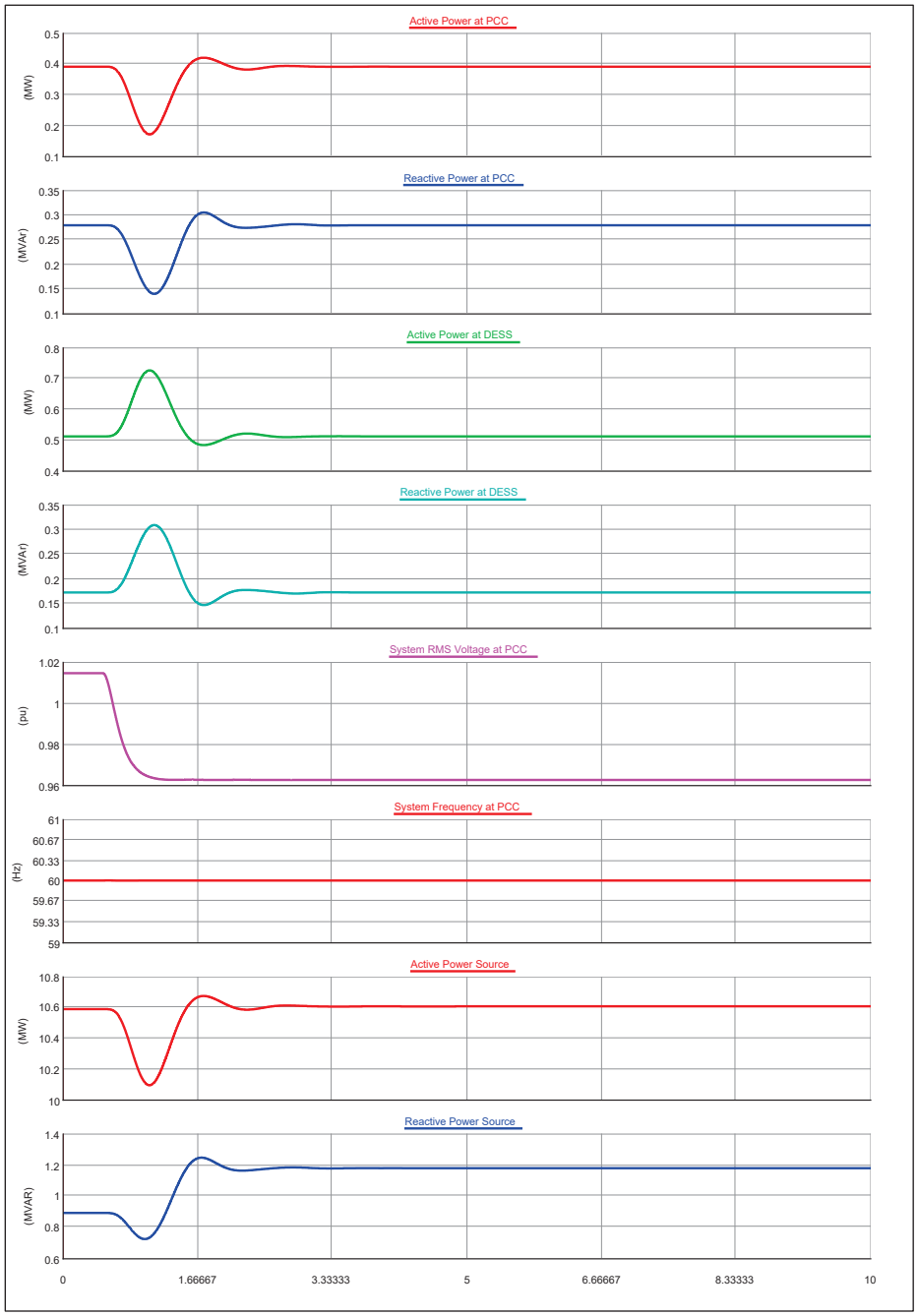


Figure A.52: System Response for Test 5.2.5

TEST 5.2.6: INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was increased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER responded to the change in frequency by increasing its active power output correspondingly and settled at its prior set point at steady state. The reactive power flow at the PCC and DER settled at its prior set point. The voltage was disturbed by the frequency change due to power flow but settled back to 1.01 pu in steady state.

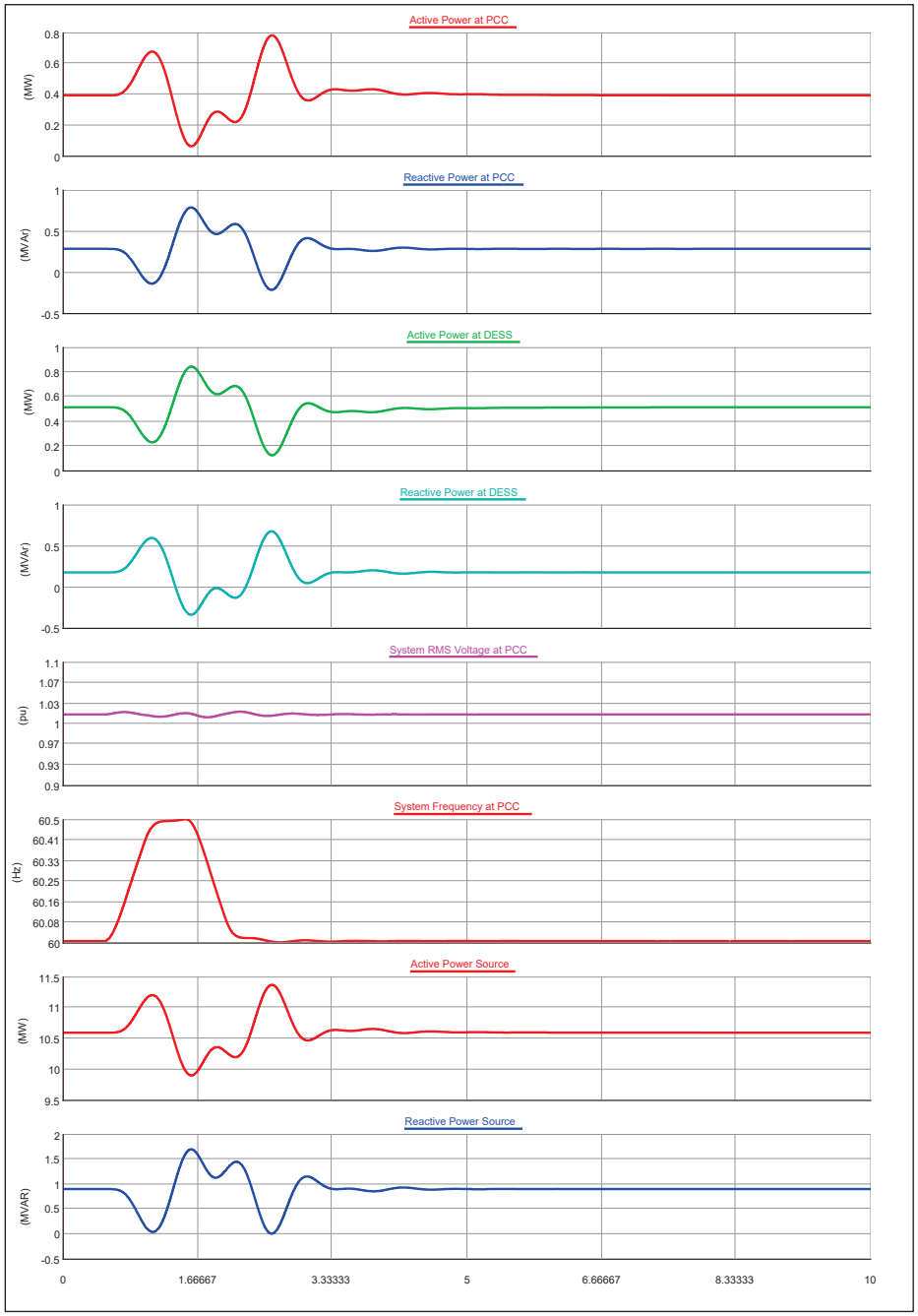


Figure A.53: System Response for Test 5.2.6

TEST 5.2.7: DECREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was decreased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER responded to the change in frequency by increasing its active power output correspondingly and settled at its prior set point at steady state. The reactive power flow at the PCC and DER settled at its prior set point. The voltage was disturbed by the frequency change due to power flow but settled back to 1.01 pu in steady state.

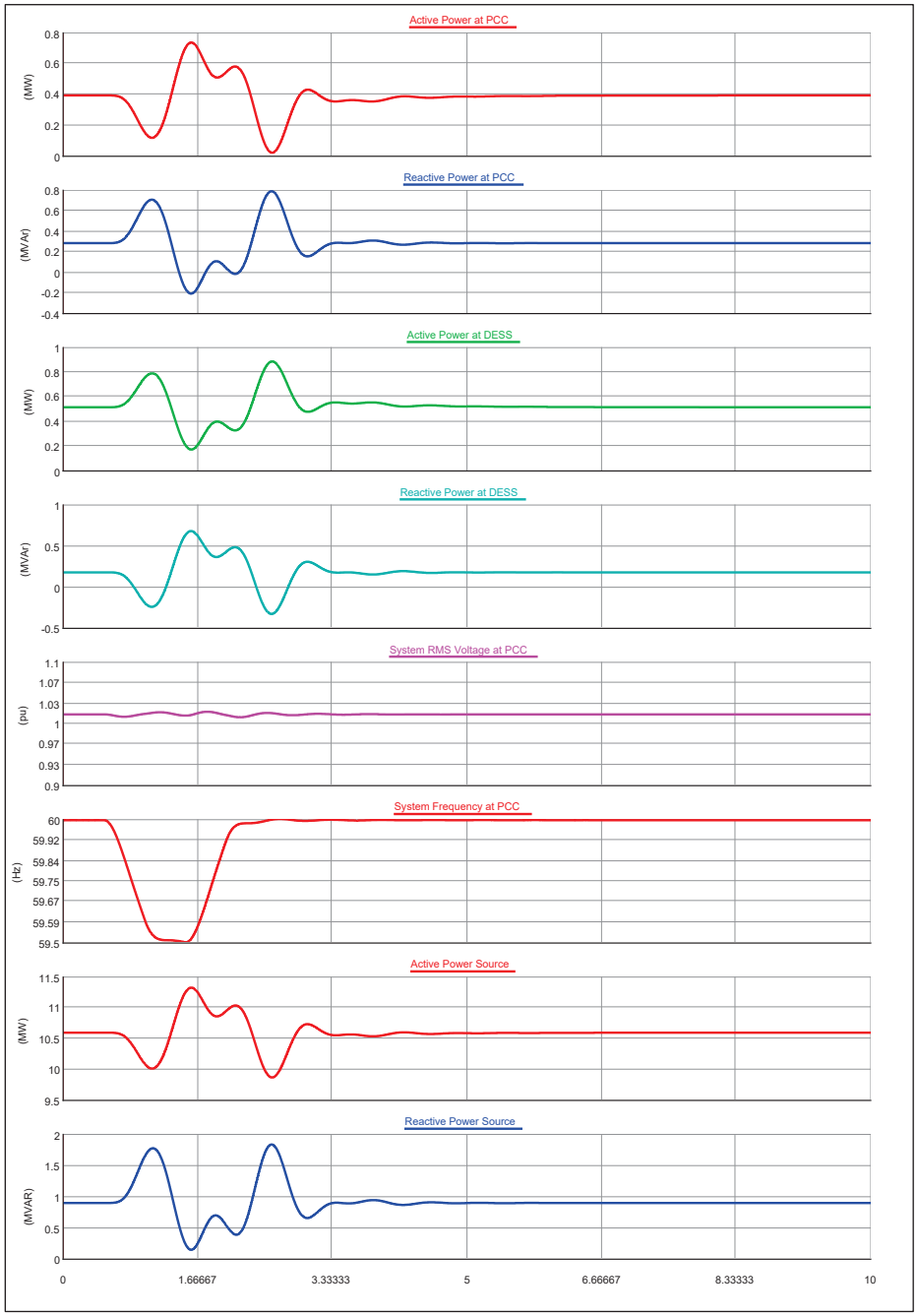


Figure A.54: System Response for Test 5.2.7

TEST 5.2.8: VARY THE SYSTEM FREQUENCY

On increasing the system frequency to 60.5 Hz at a ramp rate of 0.1 Hz per second (as shown in Figure 3.42), the real power across the DER reduced, while the active power import across the PCC increased. The frequency was held at 60.5 Hz for a period of 5 seconds, during which the active power across the PCC and DER began to settle. When the frequency began decreasing from 60.5 Hz to 59.7 Hz and was held for another 5 seconds, the active power output of the DER increased and the import across the PCC reduced. The active power settled at its previous set point of 500 kW during steady-state conditions following the disturbances. The reactive power was disturbed during this transition and settled at its previous set point during steady-state conditions. The system voltage was affected during this transition but returns to 1.01 pu during steady-state conditions.

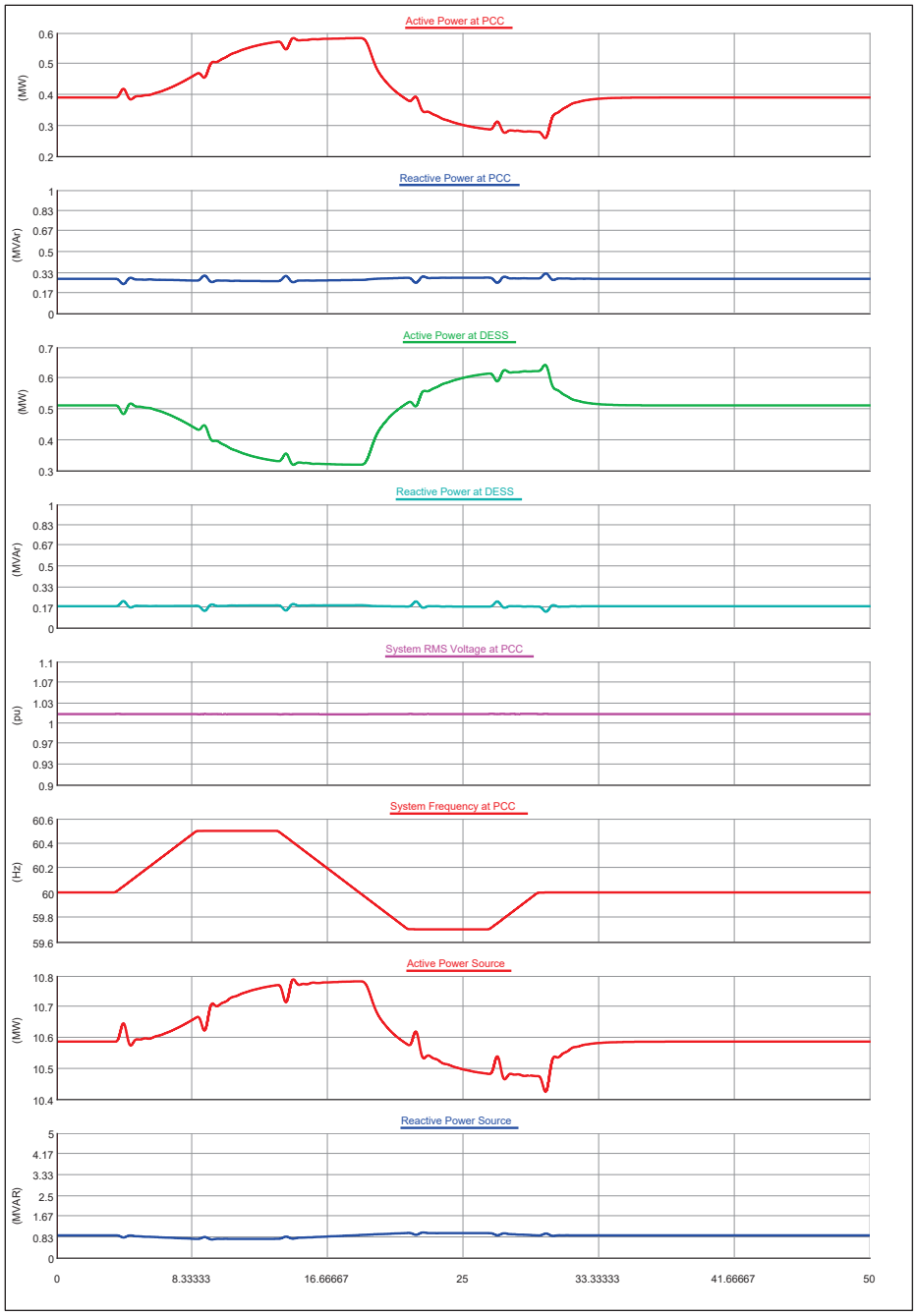


Figure A.55: System Response for Test 5.2.8

TEST 5.2.9: INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ

On increasing the system frequency by 0.5 Hz, the DER responded to the frequency changes by reducing its power output and settled at a new set point per the frequency-watt droop of the inverter. This caused more active power to be drawn from the grid. The reactive power across the DER and PCC remained the same, while the system voltage settled into 1.025 pu at steady state.

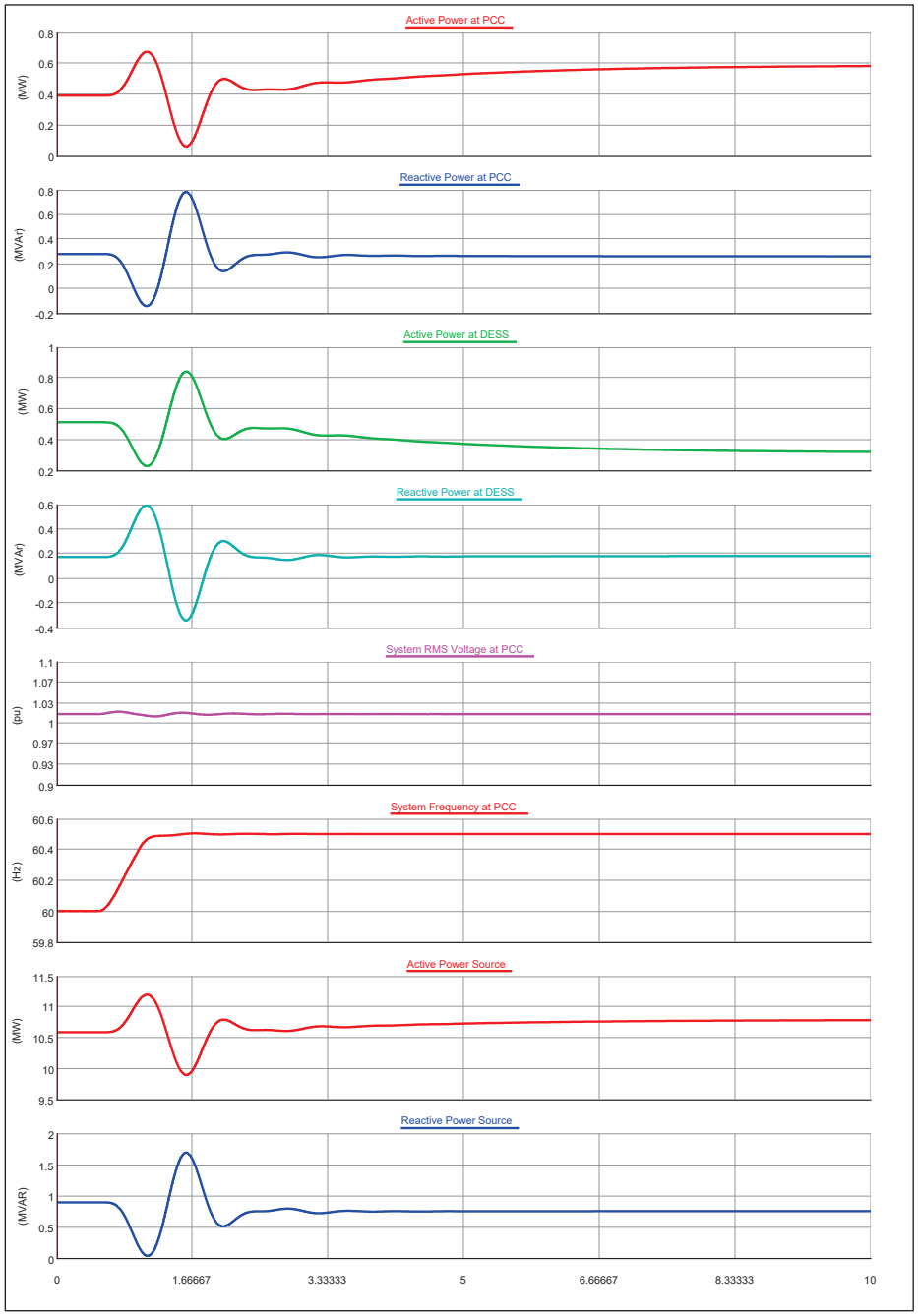


Figure A.56: System Response for Test 5.2.9

TEST 5.2.10: DECREASE THE SYSTEM FREQUENCY BY 0.5 HZ

On decreasing the system frequency by 0.5 Hz, the DER responded to the frequency changes by increasing its power output and settled at a new set point per the frequency-watt droop of the inverter. This reduced the active power import from the grid through the PCC. The reactive power across the DER and PCC remained the same, while the system voltage settled into 1.025 pu at steady state.

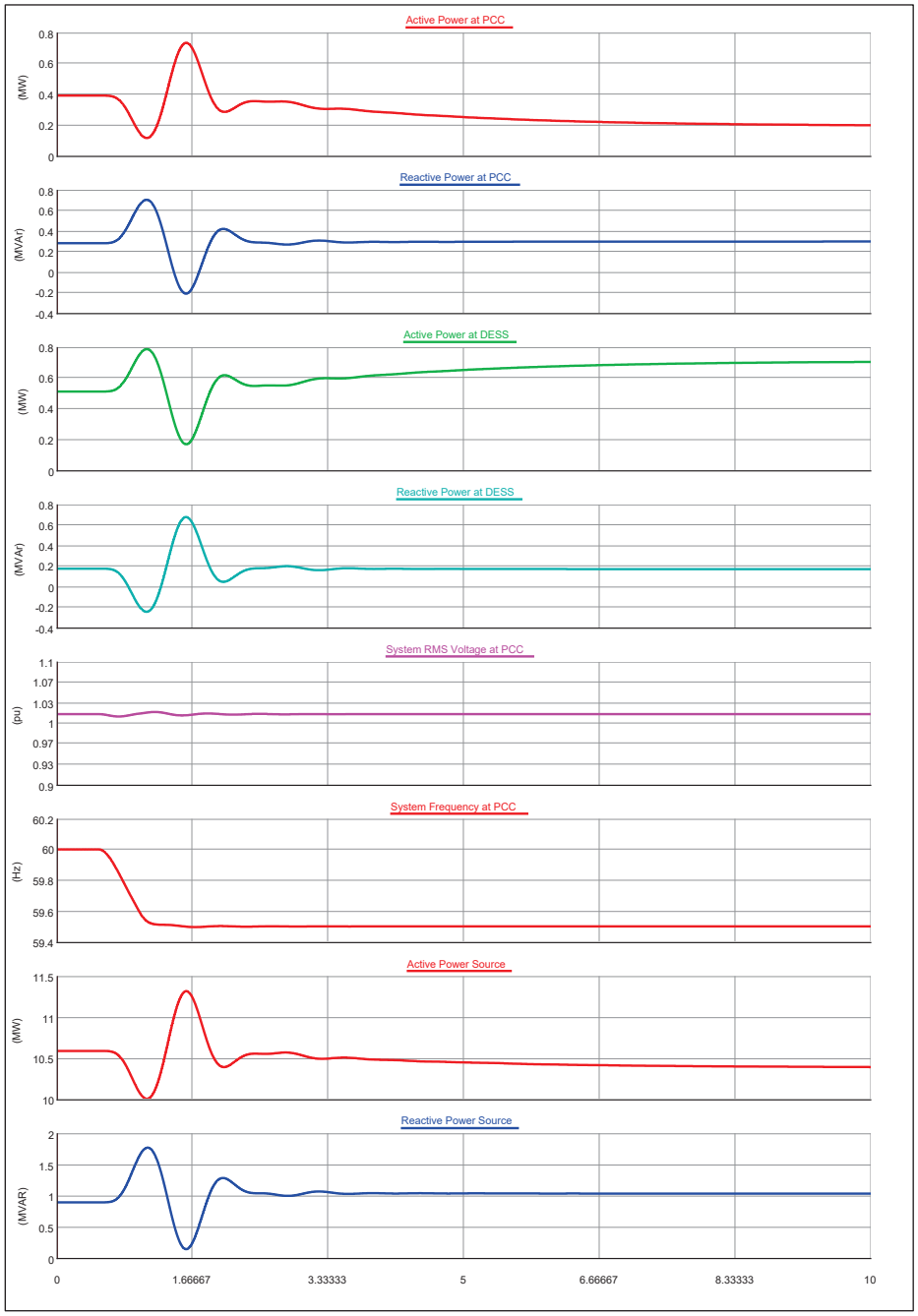


Figure A.57: System Response for Test 5.2.10

Scenario 3: DER at the End of a Long Feeder

TEST 5.3.1: MODE ACTIVATION WITH ACTIVE POWER SET POINT OF 500 KW

The active and reactive power dispatch of the DER were set at 500 kW and 200 kVAR, respectively. On activating the frequency-watt mode, there was no change on the graph because the system frequency was maintained at 60 Hz.

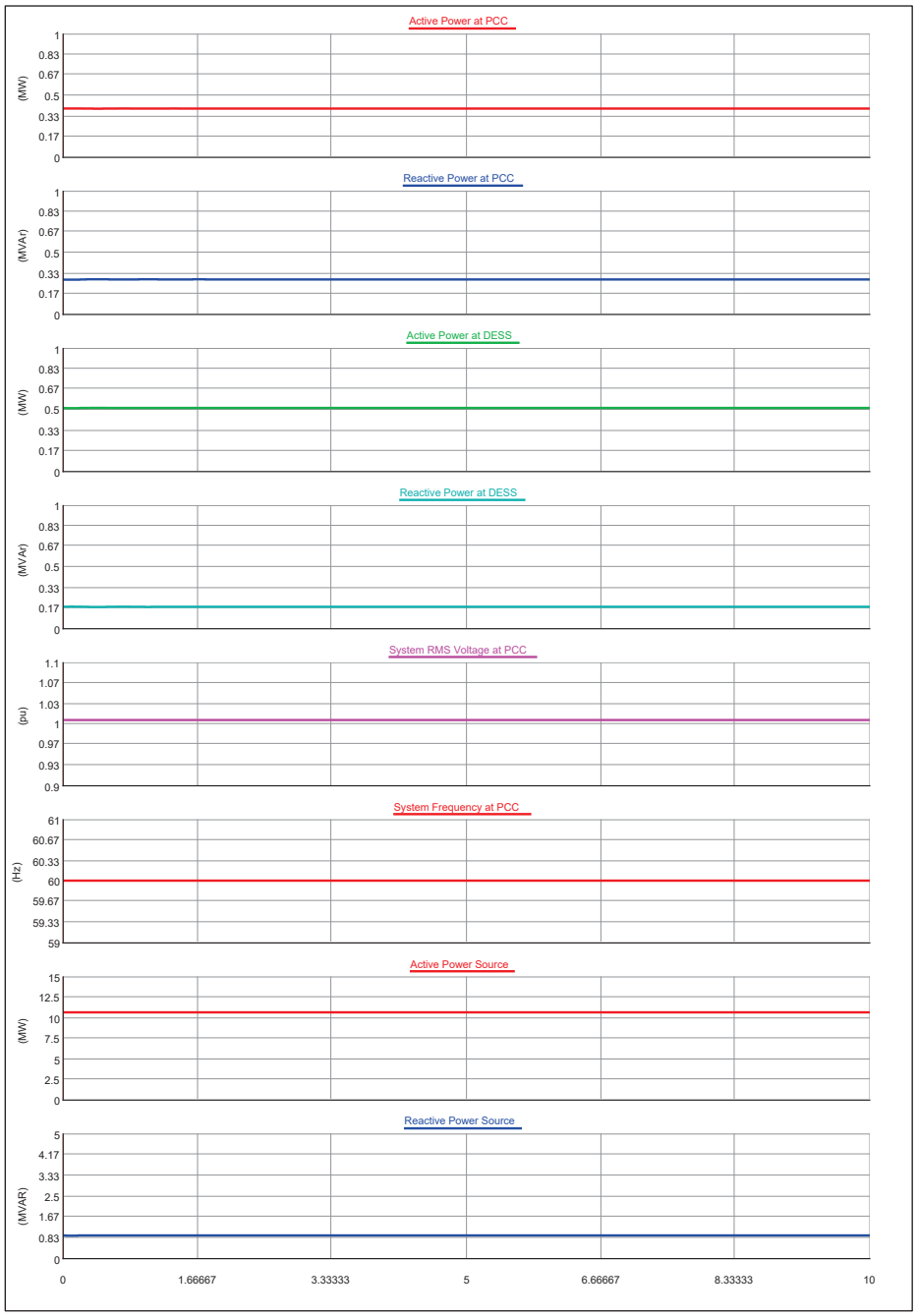


Figure A.58: System Response for Test 5.3.1

TEST 5.3.2: INCREASE THE SYSTEM LOAD BY 500 KW

On increasing the active power load by 500 kW, the real power output of the DER remained constant at 500 kW, while the additional load was fed by the grid through the PCC. The reactive power from the DER and across the PCC settled to their prior set points at steady state, while the system frequency and voltage were not affected by the change.

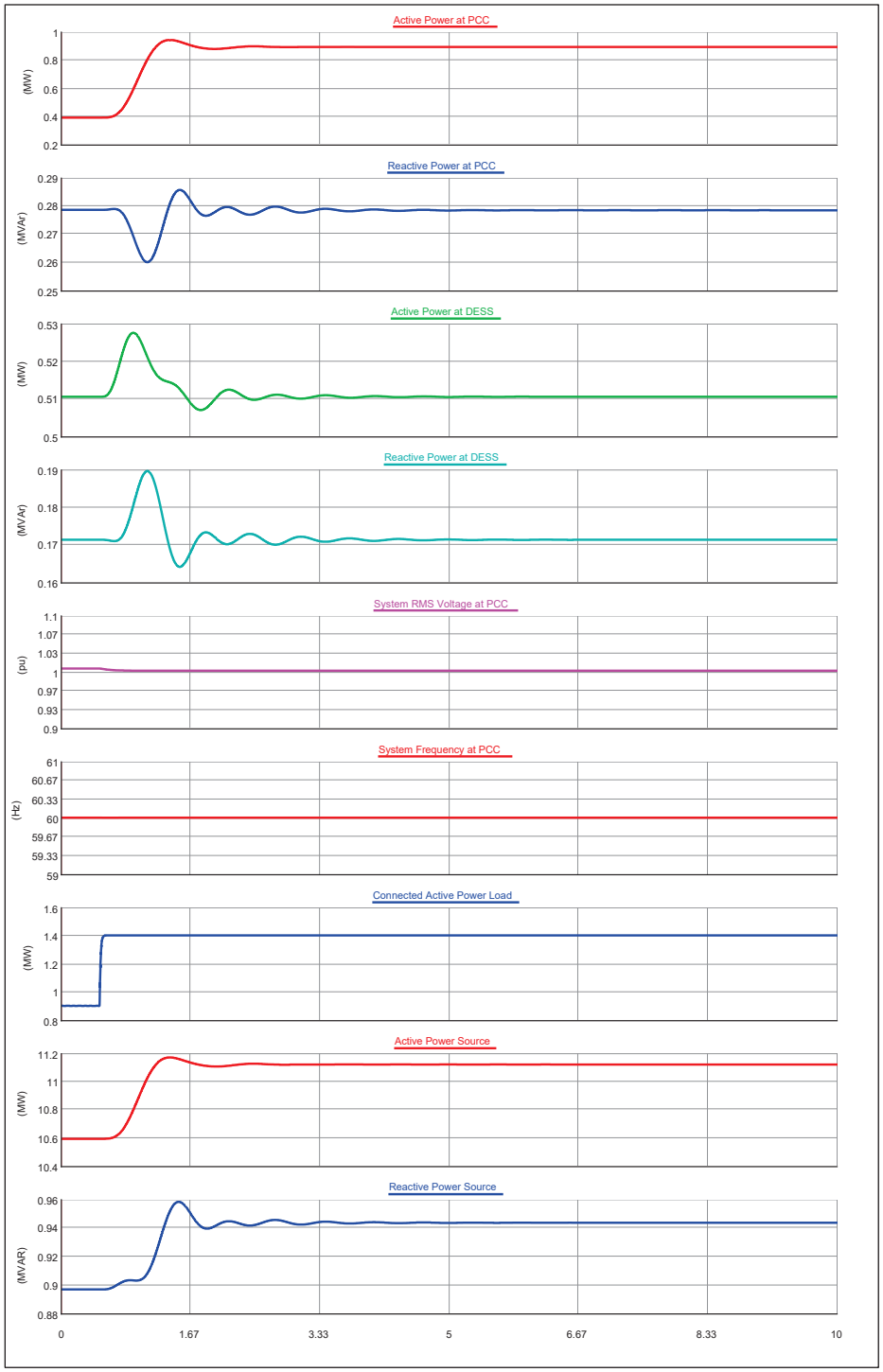


Figure A.59: System Response for Test 5.3.2

TEST 5.3.3: DECREASE THE SYSTEM LOAD BY 500 KW

On decreasing the active power load by 500 kW, the real power output of the DER remained constant at 500 kW, while the load was balanced by sending more active power into the grid through the PCC. The reactive power from the DER and across the PCC settled to their prior set points at steady state, while the system frequency and voltage were not affected by the change.

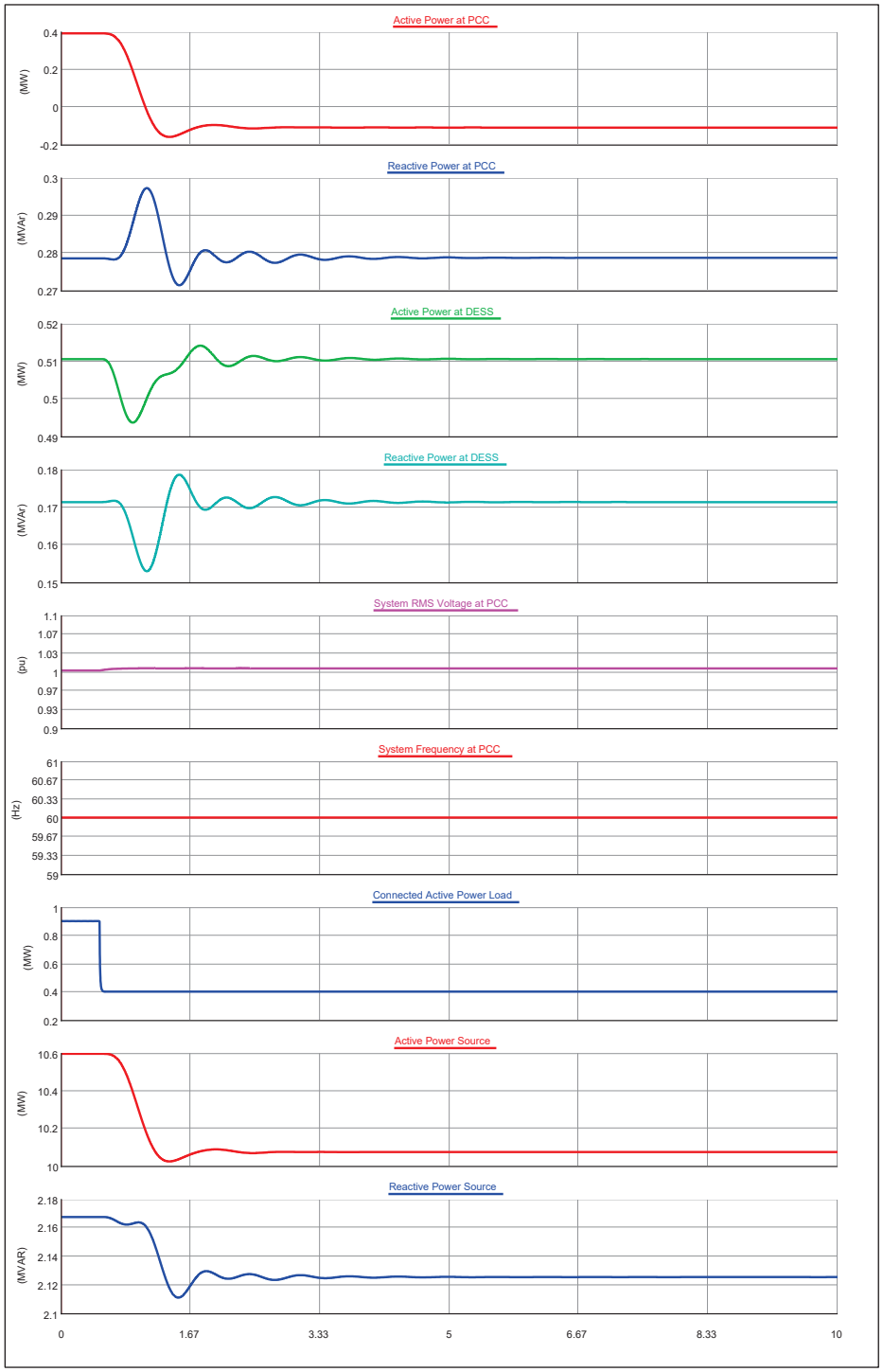


Figure A.60: System Response for Test 5.3.3

TEST 5.3.4: INCREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On increasing the system voltage by 5 percent from 1.002 pu to 0.952 pu, the DER rode through the disturbance. The real power and reactive power at the DER and PCC did not change at steady state, while the system frequency was unaffected.

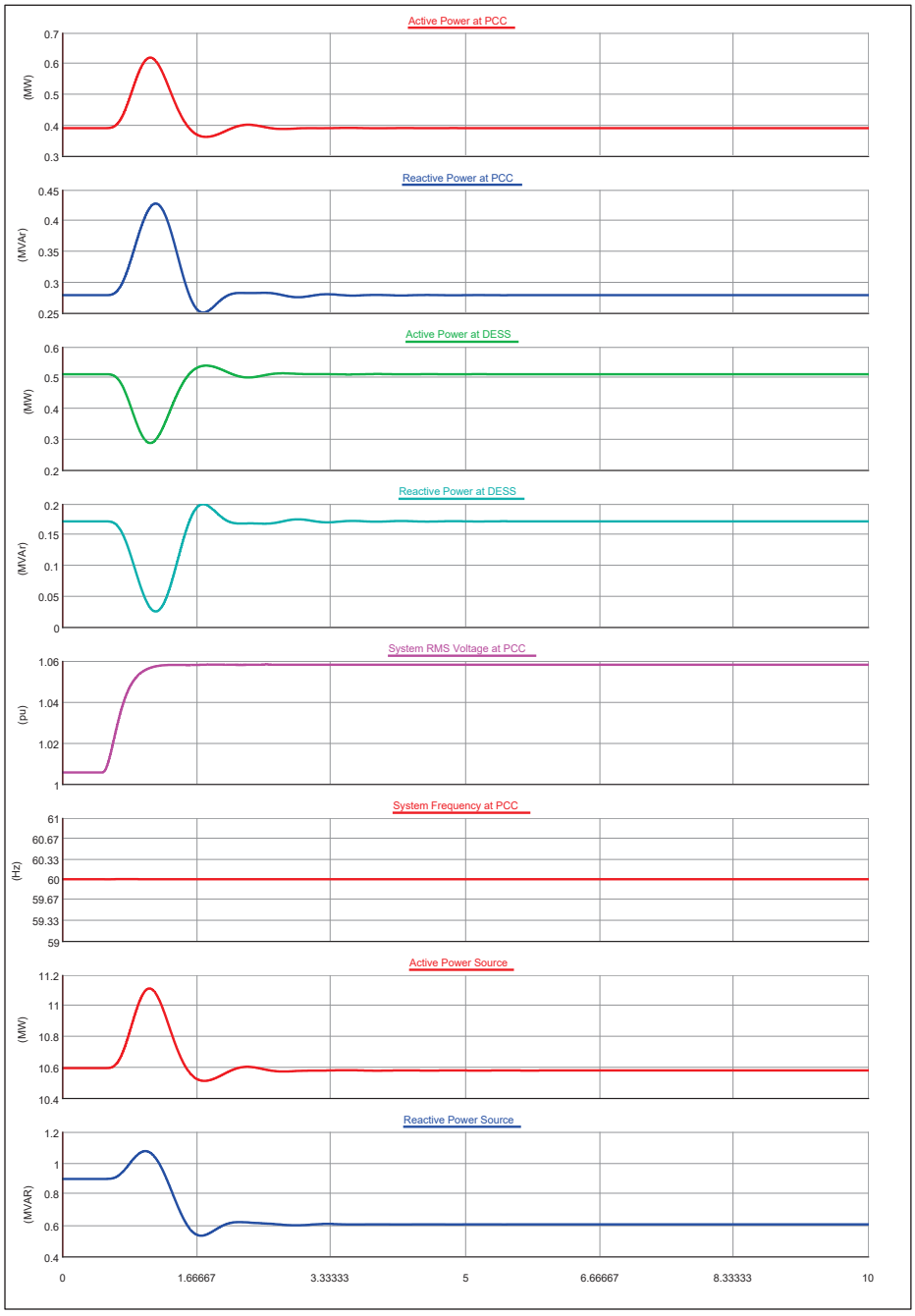


Figure A.61: System Response for Test 5.3.4

TEST 5.3.5: DECREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On decreasing the system voltage by 5 percent from 1.002 pu to 0.952 pu, the DER rode through the disturbance. The real power and reactive power at the DER and PCC did not change at steady state, while the system frequency was unaffected.

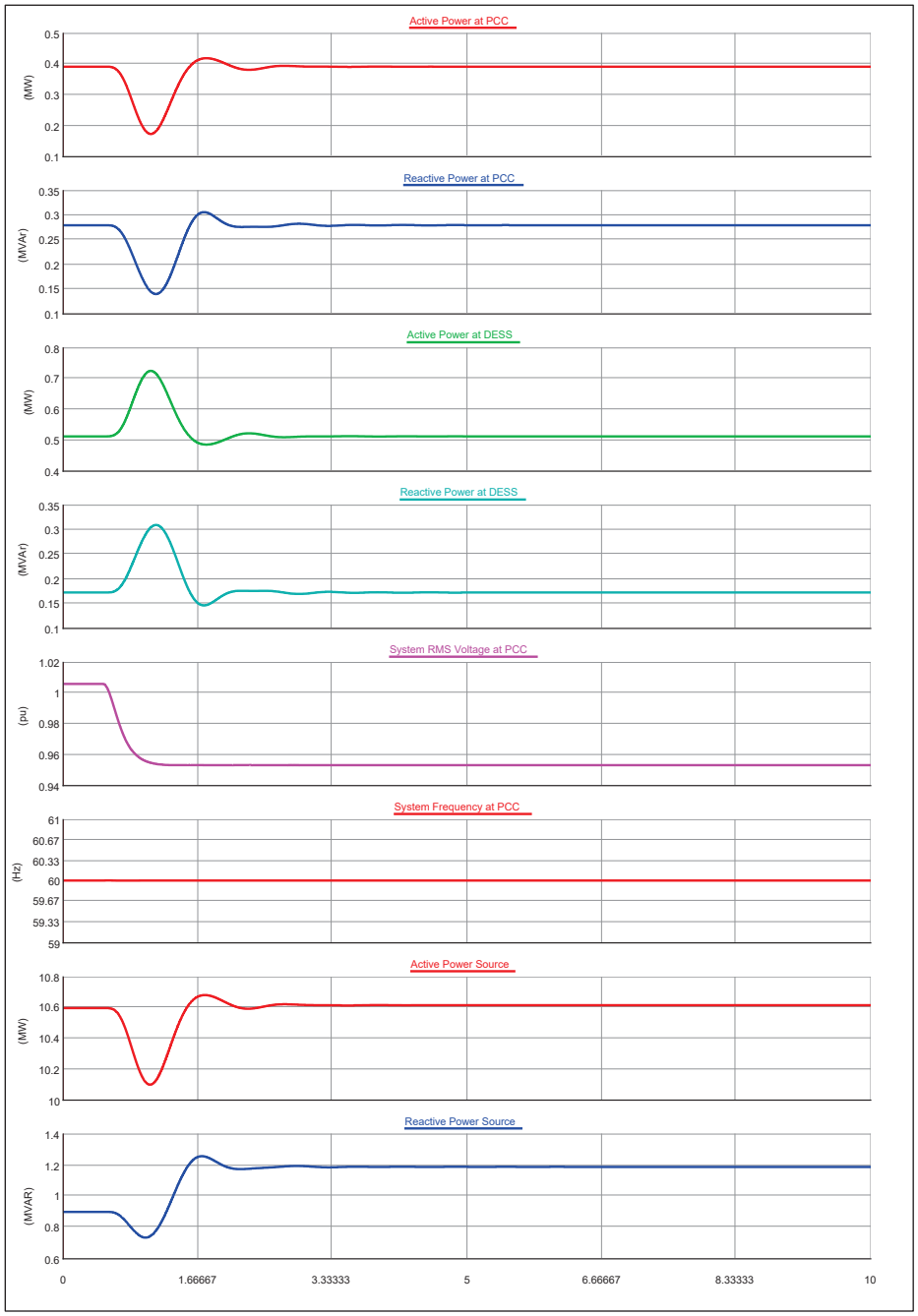


Figure A.62: System Response for Test 5.3.5

TEST 5.3.6: INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was increased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER responded to the change in frequency by increasing its active power output correspondingly and settled at its prior set point at steady state. The reactive power flow at the PCC and DER settled at its prior set point. The voltage was disturbed by the frequency change due to power flow but settled back to 1.002 pu in steady state.

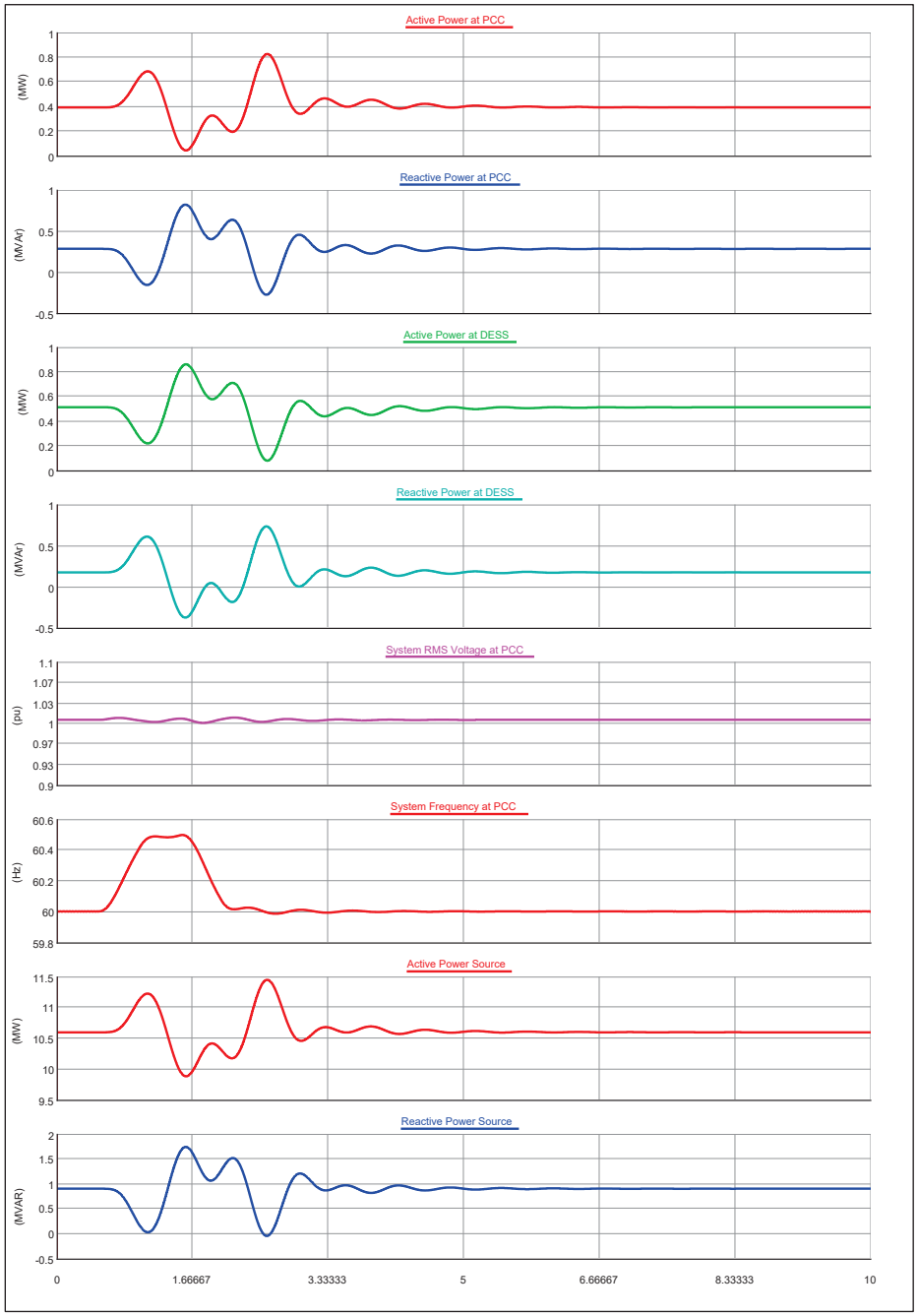


Figure A.63: System Response for Test 5.3.6

TEST 5.3.7: DECREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was decreased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER responded to the change in frequency by increasing its active power output correspondingly and settled at its prior set point at steady state. The reactive power flow at the PCC and DER settled at its prior set point. The voltage was disturbed by the frequency change due to power flow but settled back to 1.002 pu in steady state.

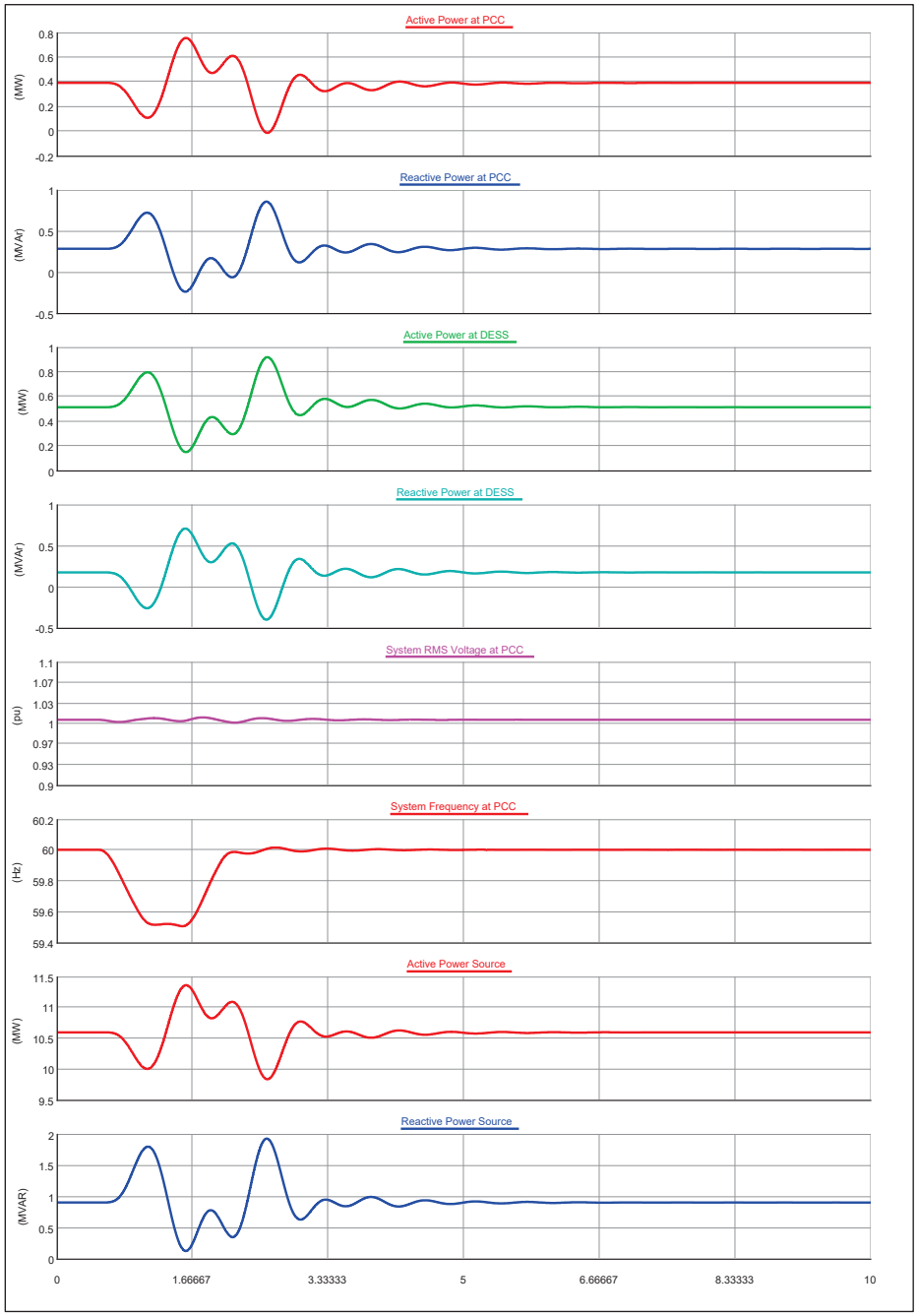


Figure A.64: System Response for Test 5.3.7

TEST 5.3.8: VARY THE SYSTEM FREQUENCY

The system frequency was changed as shown in Figure 3.42. The reactive power was disturbed during this transition and settled at its previous set point during steady-state conditions. The system voltage was affected during this transition but returned to 1.002 pu during steady-state conditions.

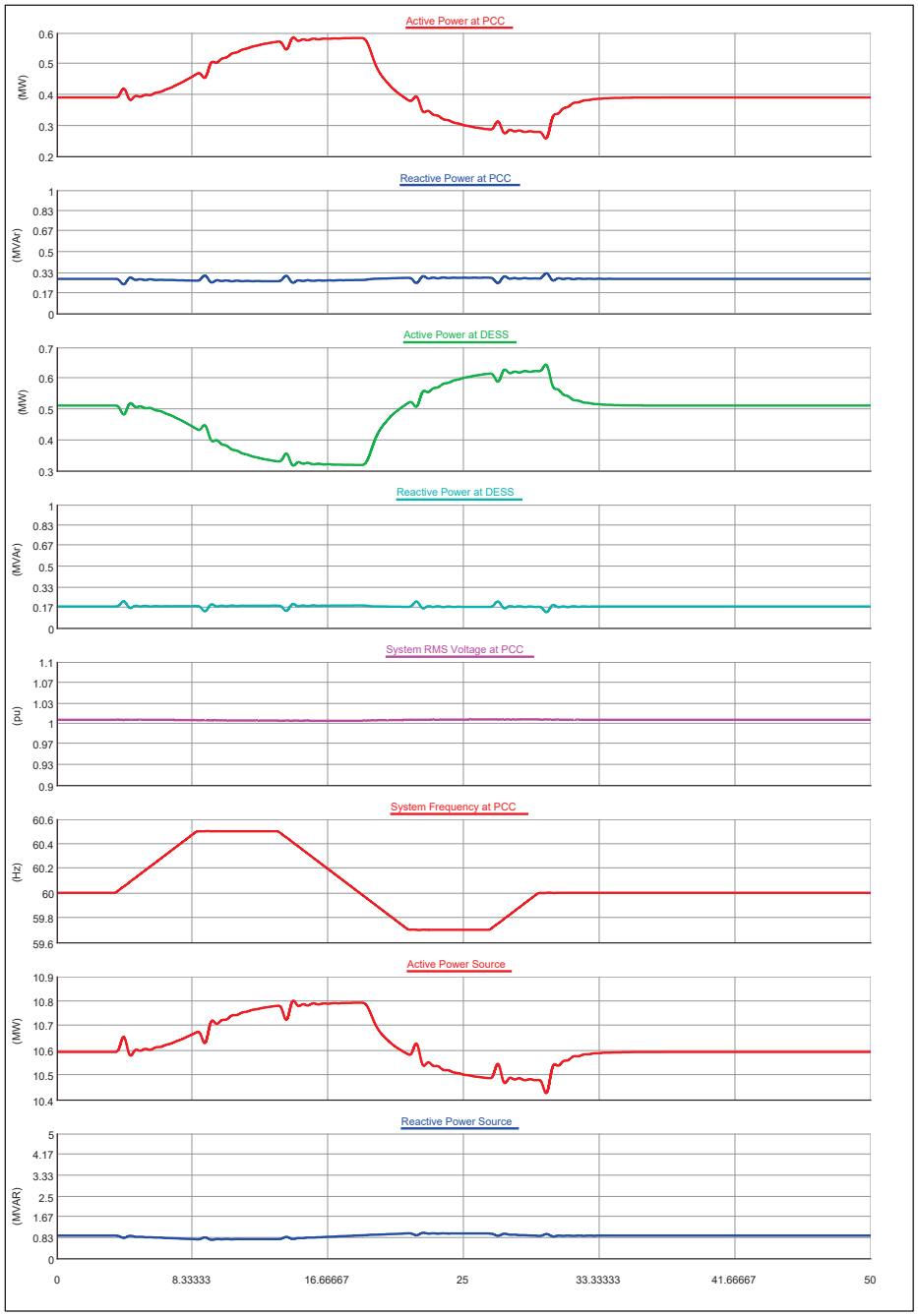


Figure A.65: System Response for Test 5.3.8

TEST 5.3.9 INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ

On increasing the system frequency by 0.5 Hz, the DER responded to the frequency changes by reducing its power output and settled at a new set point per the frequency-watt droop of the inverter. This caused more active power to be drawn from the grid. The reactive power across the DER and PCC remained same, while the system voltage settled into 1.025 pu at steady state.

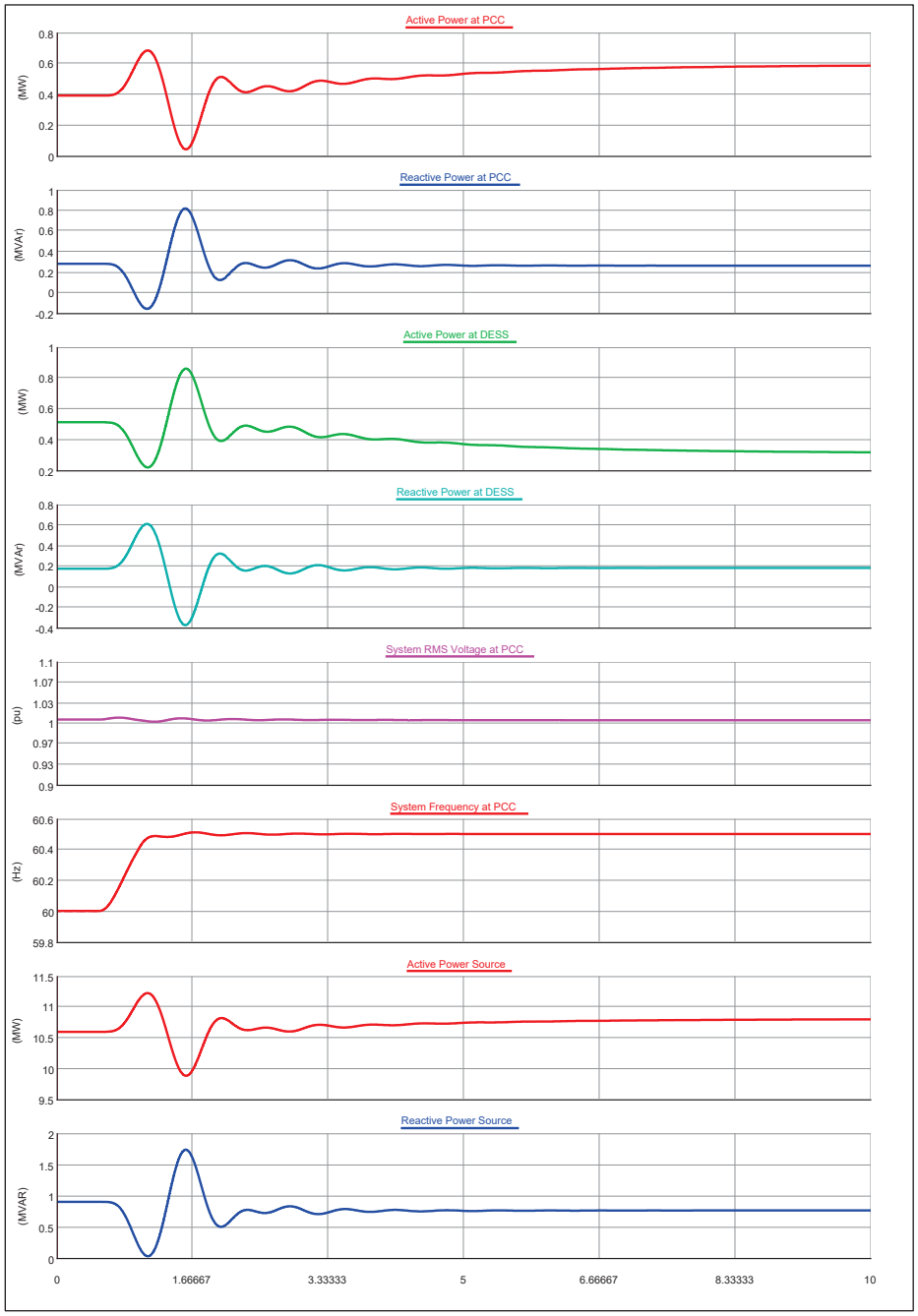


Figure A.66: System Response for Test 5.3.9

TEST 5.3.10: DECREASE THE SYSTEM FREQUENCY BY 0.5 HZ

On decreasing the system frequency by 0.5 Hz, the DER responded to the frequency changes by increasing its power output and settled at a new set point per the frequency-watt droop of the inverter. This reduced the active power import from the grid through the PCC. The reactive power across the DER and PCC remained same, while the system voltage settled into 1.025 pu at steady state.

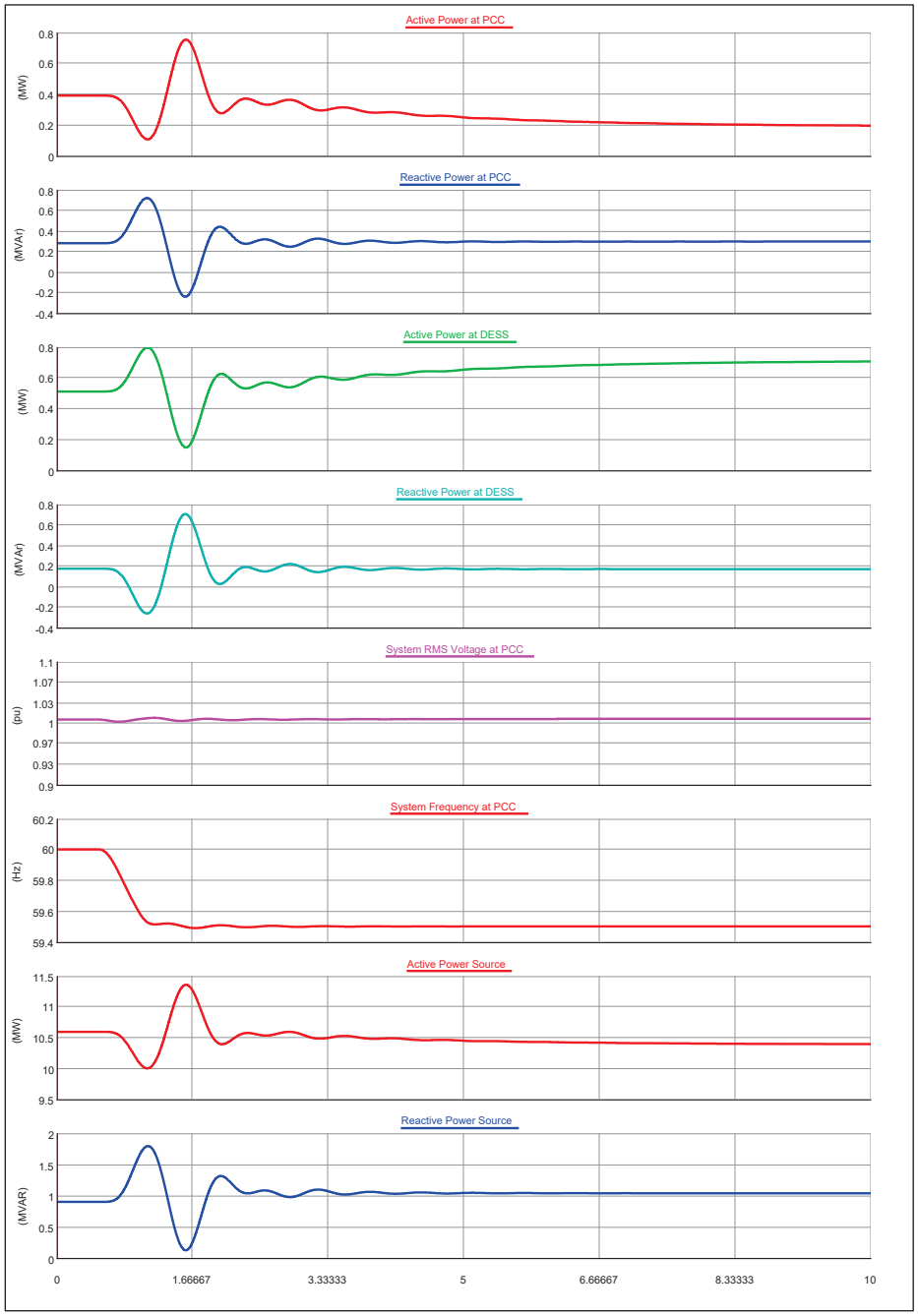


Figure A.67: System Response for Test 5.3.10

Scenario 4: Multiple Diverse Types of DER on the Same Circuit

TEST 5.4.1: MODE ACTIVATION WITH ACTIVE POWER SET POINT OF 500 KW

The active and reactive power dispatch of the DER were set at 500 kW and 200 kVAR, respectively. On activating the frequency-watt mode, there was no change on the graph because the system frequency was maintained at 60 Hz.

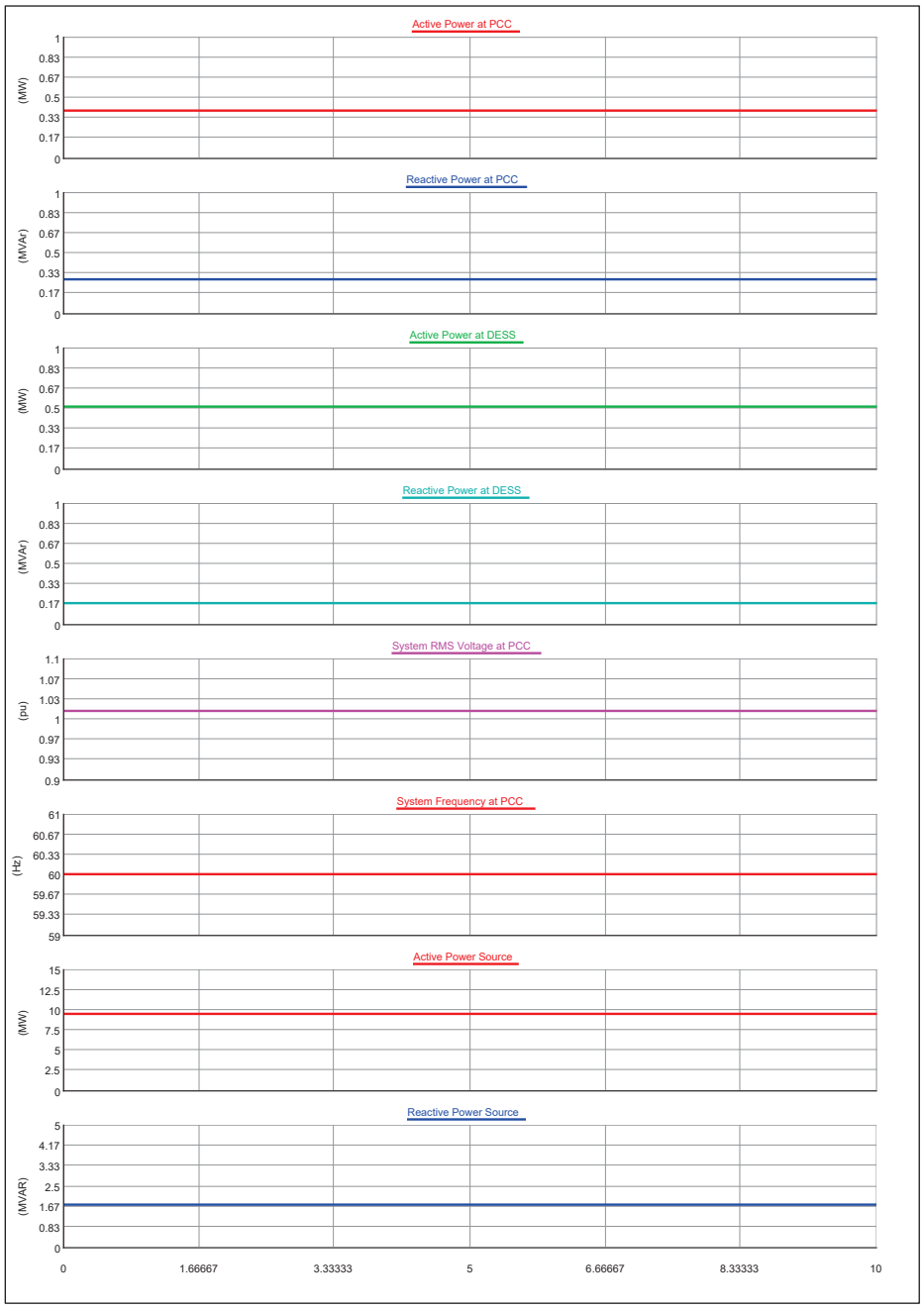


Figure A.68: System Response for Test 5.4.1

TEST 5.4.2: INCREASE THE SYSTEM LOAD BY 500 KW

On increasing the active power load by 500 kW, the real power output of the DER remained constant at 500 kW, while the additional load was fed by the grid through the PCC. The reactive power from the DER and across the PCC settled to their prior set points at steady state, while the system frequency and voltage were not affected by the change.

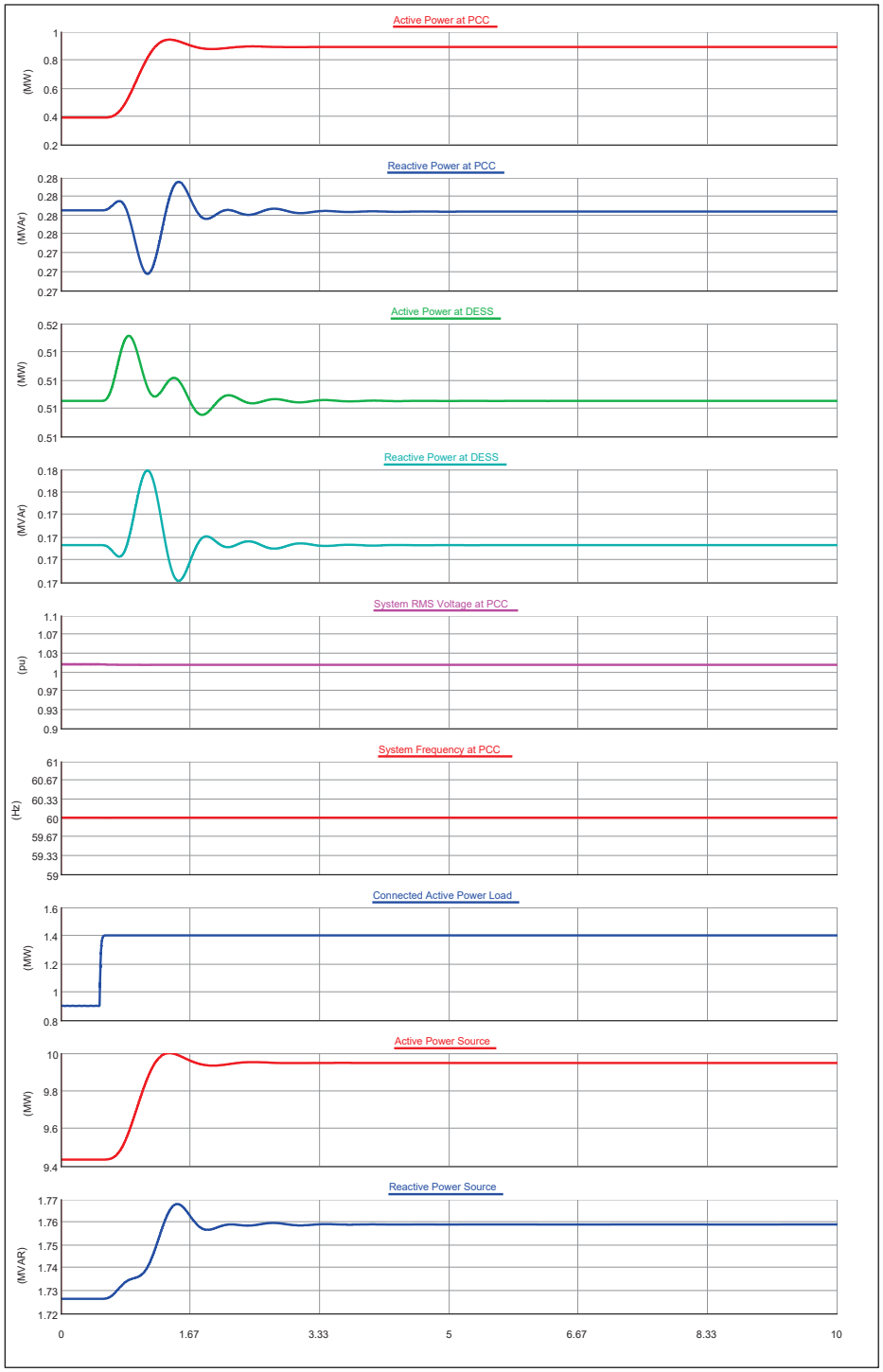


Figure A.69: System Response for Test 5.4.2

TEST 5.4.3: DECREASE THE SYSTEM LOAD BY 500 KW

On decreasing the active power load by 500 kW, the real power output of the DER remained constant at 500 kW, while the load was balanced by sending more active power into the grid through the PCC. The reactive power from the DER and across the PCC settled to their prior set points at steady state, while the system frequency and voltage were not affected by the change.

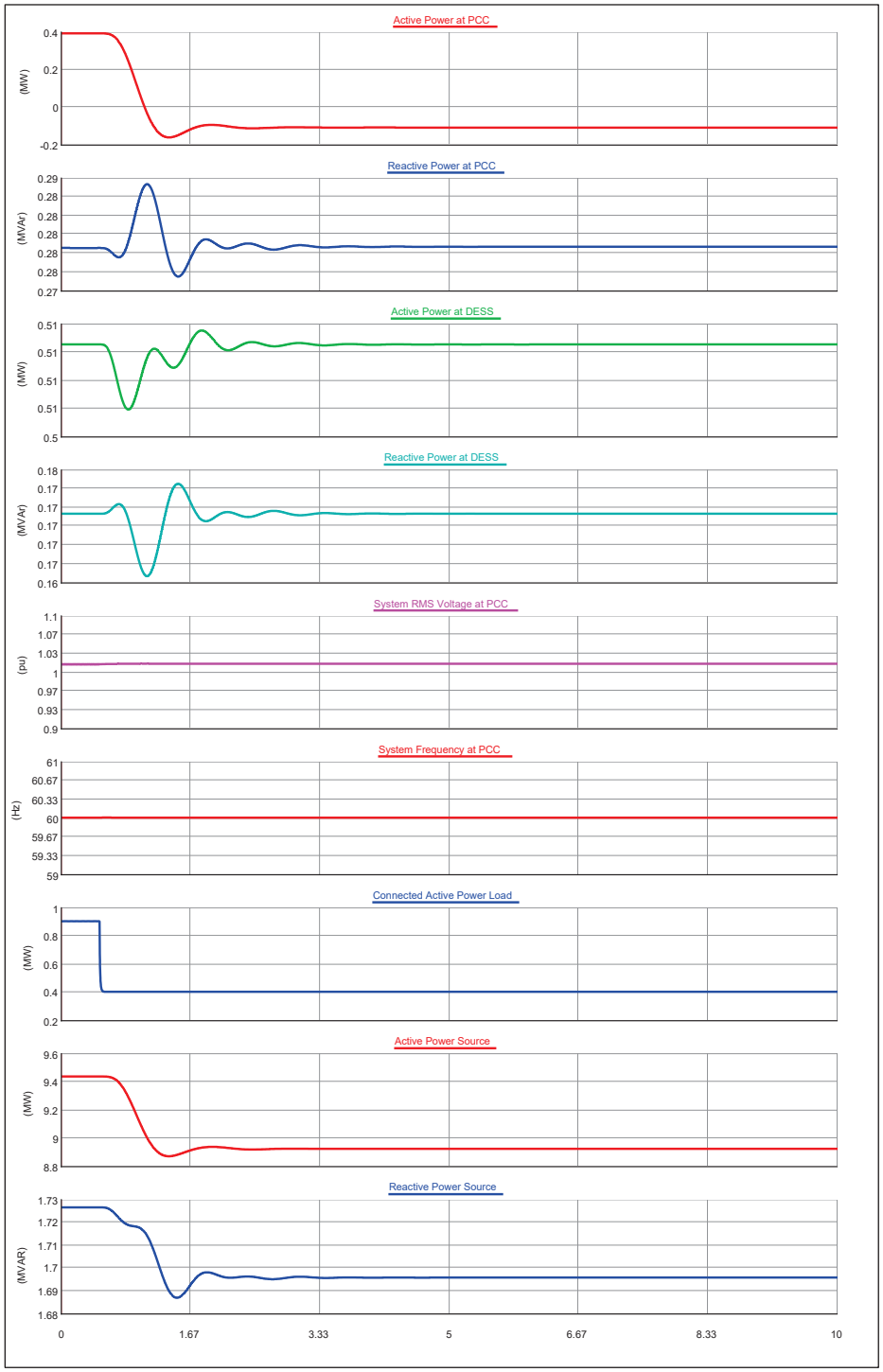


Figure A.70: System Response for Test 5.4.3

TEST 5.4.4: INCREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On increasing the system voltage by 5 percent from 1.01 pu to 0.96 pu, the DER rode through the disturbance. The real power and reactive power at the DER and PCC did not change at steady state, while the system frequency was unaffected.

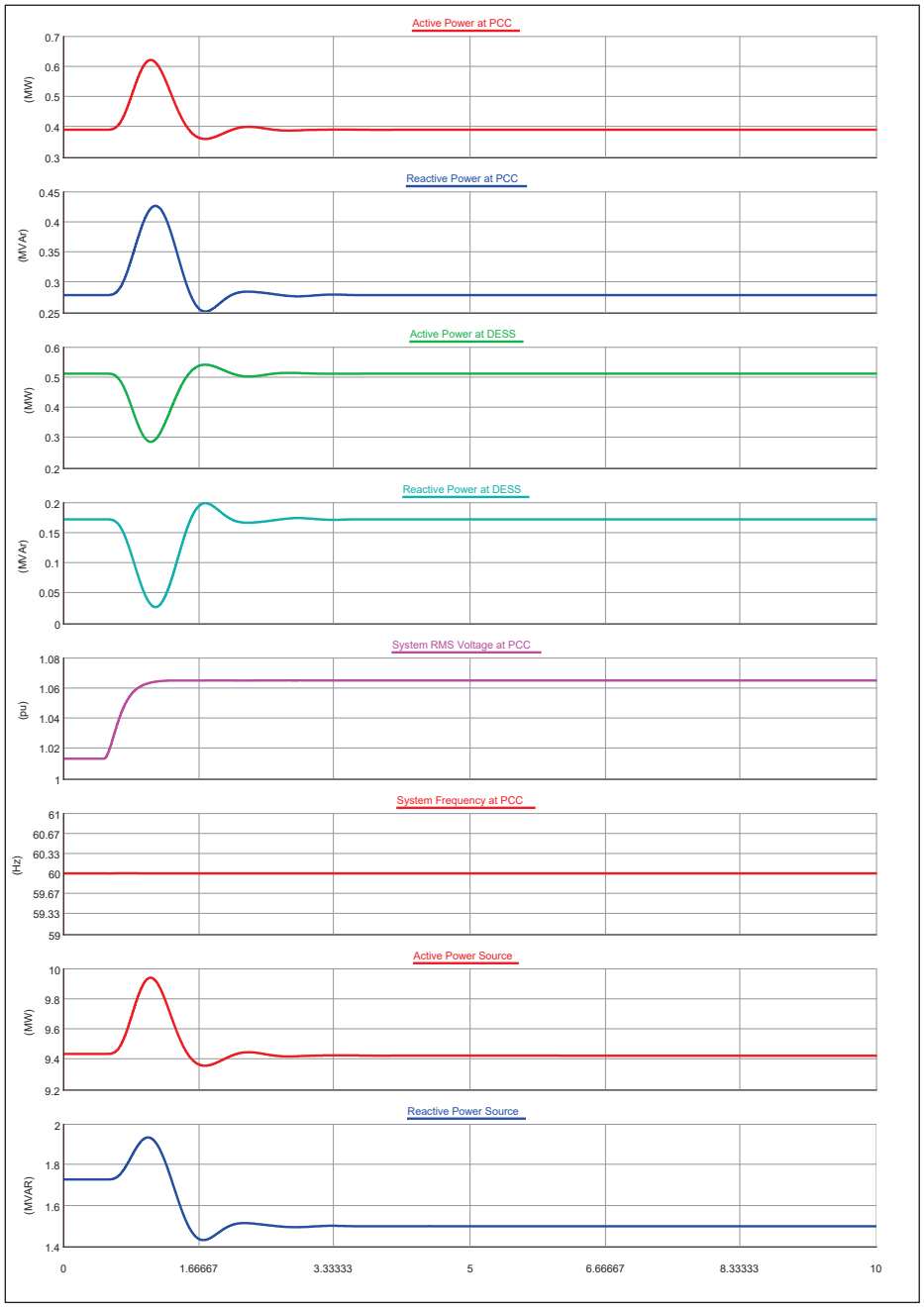


Figure A.71: System Response for Test 5.4.4

TEST 5.4.5: DECREASE THE SYSTEM VOLTAGE BY 5 PERCENT

On decreasing the system voltage by 5 percent from 1.01 pu to 0.96 pu, the DER rode through the disturbance. The real power and reactive power at the DER and PCC did not change at steady state, while the system frequency was unaffected.

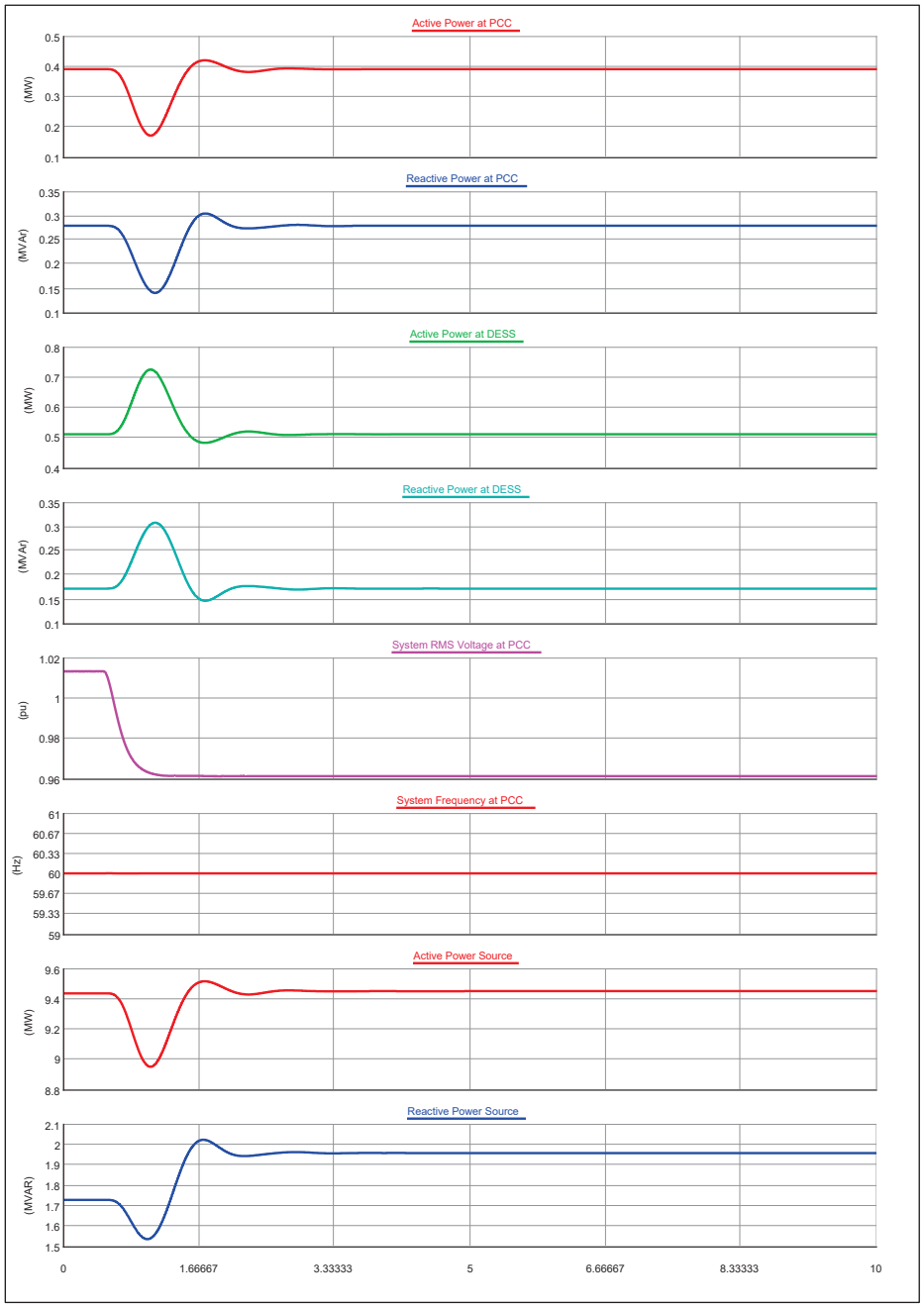


Figure A.72: System Response for Test 5.4.5

TEST 5.4.6 INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was increased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER responded to the change in frequency by increasing its active power output correspondingly and settled at its prior set point at steady state. The reactive power flow at the PCC and DER settled at its prior set point. The voltage was disturbed by the frequency change due to power flow but settled back to 1.01 pu in steady state.

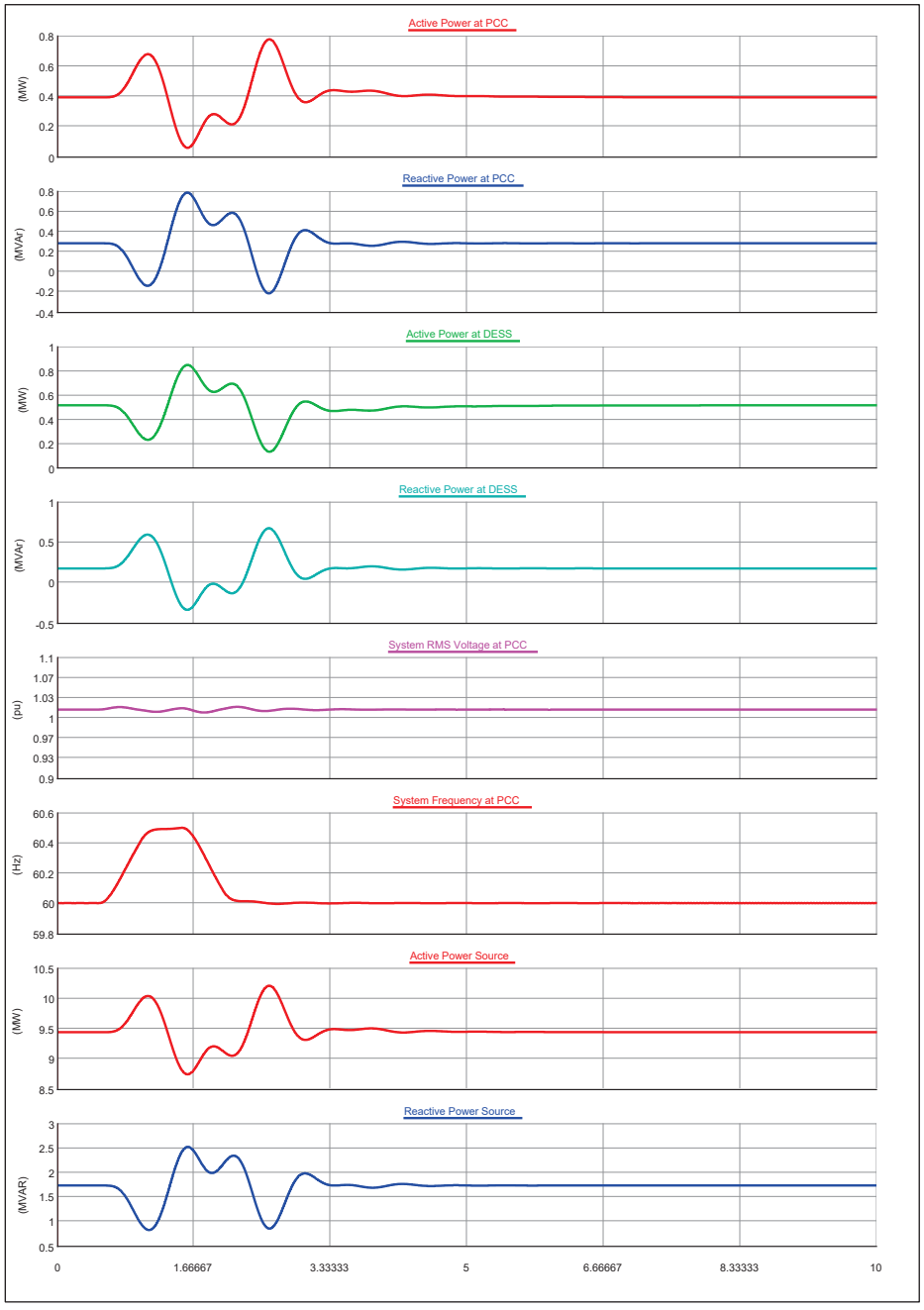


Figure A.73: System Response for Test 5.4.6

TEST 5.4.7: DECREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 1 SECOND

The system frequency was decreased by 0.5 Hz for 1 second at a ramp rate of 1 Hz per second. The DER responded to the change in frequency by increasing its active power output correspondingly and settled at its prior set point at steady state. The reactive power flow at the PCC and DER settled at its prior set point. The voltage was disturbed by the frequency change due to power flow but settled back to 1.01 pu in steady state.

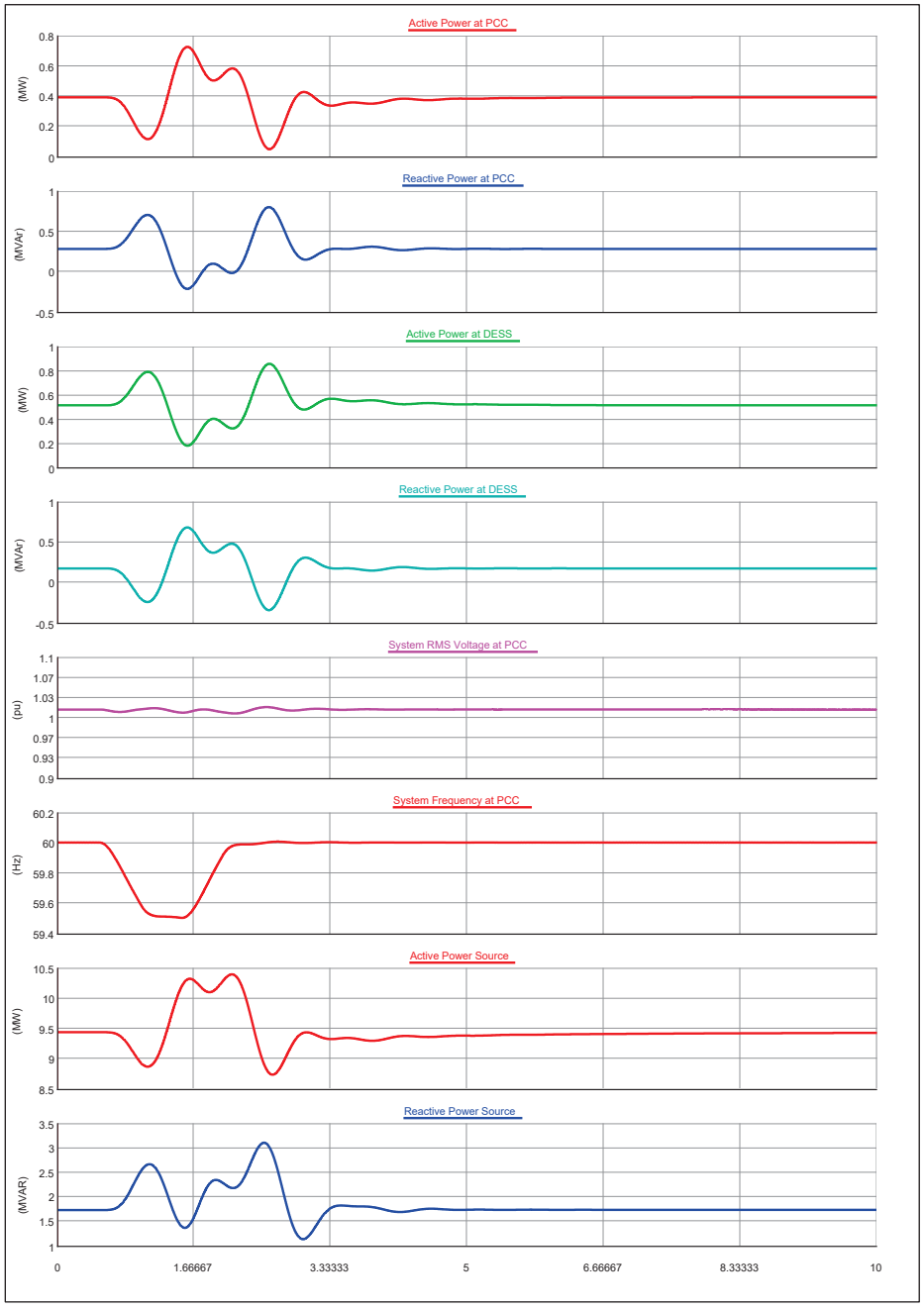


Figure A.74: System Response for Test 5.4.7

TEST 5.4.8: VARY THE SYSTEM FREQUENCY

The system frequency was changed as shown in Figure 3.42. The reactive power was disturbed during this transition and settled at its previous set point during steady-state conditions. The system voltage was affected during this transition but returned to 1.01 pu during steady-state conditions.

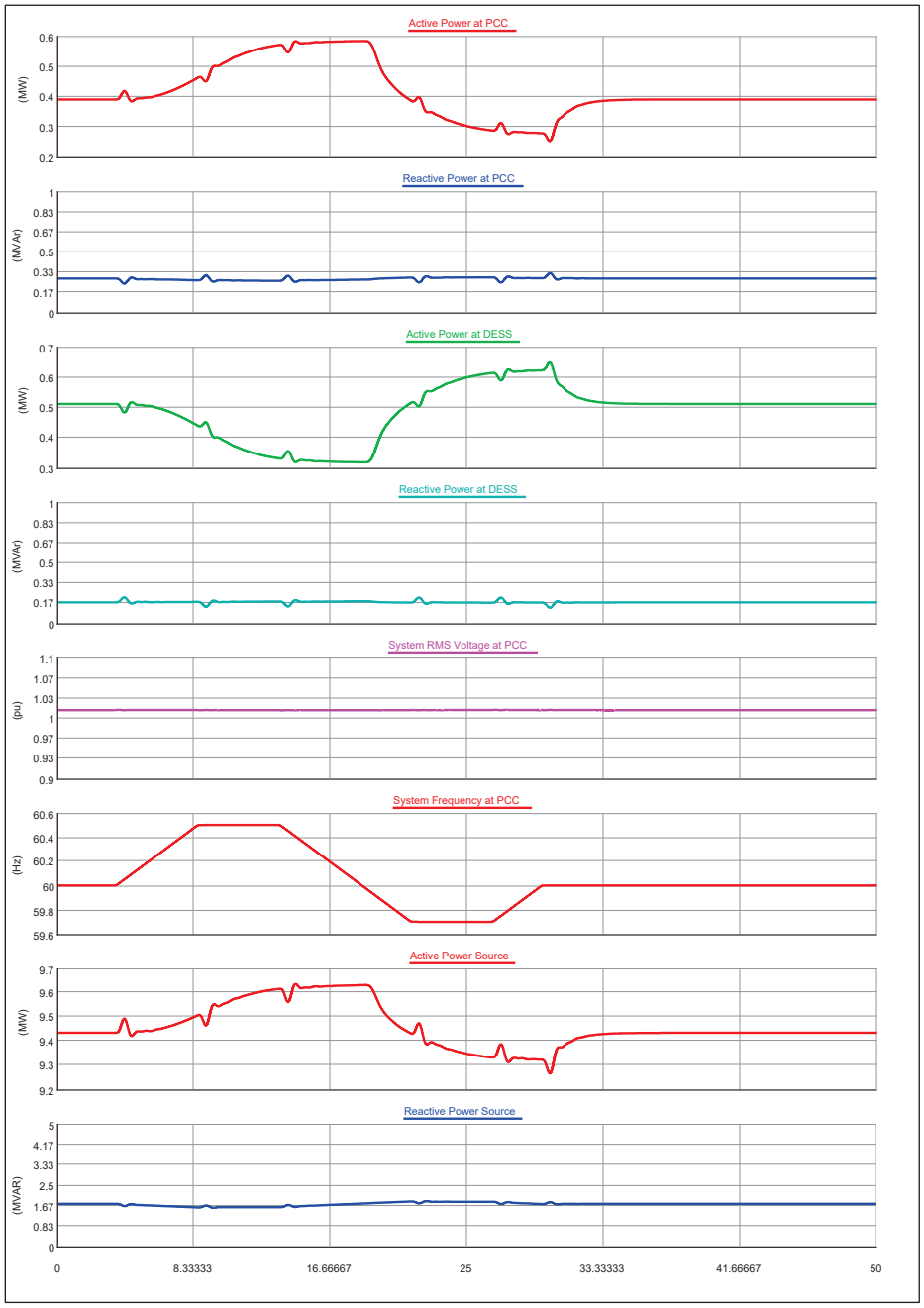


Figure A.75: System Response for Test 5.4.8

TEST 5.4.9: INCREASE THE SYSTEM FREQUENCY BY 0.5 HZ

On increasing the system frequency by 0.5 Hz, the DER responded to the frequency changes by reducing its power output and settled at a new set point per the frequency-watt droop of the inverter. This caused more active power to be drawn from the grid. The reactive power across the DER and PCC remained same, while the system voltage settled into 1.025 pu at steady state.

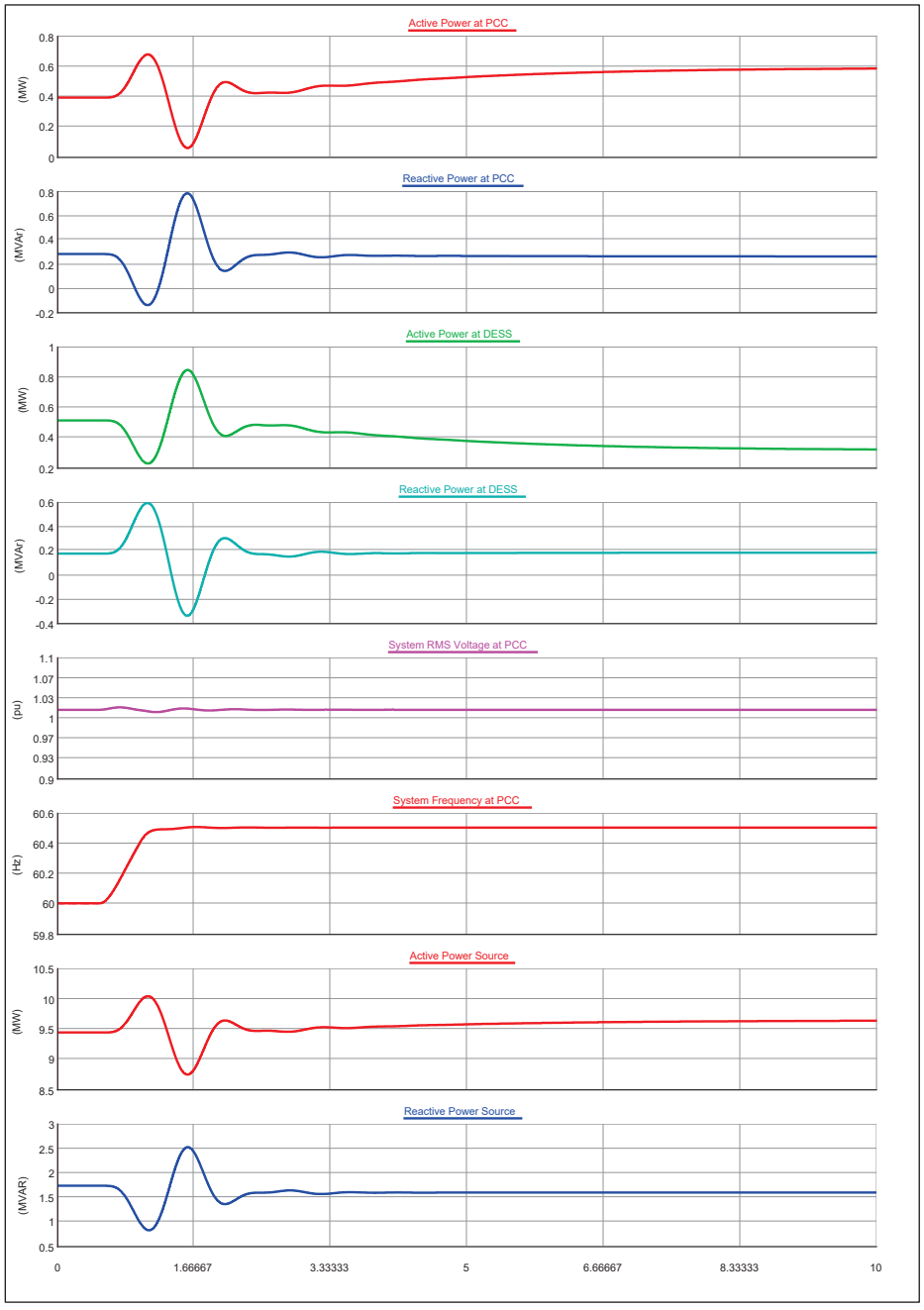


Figure A.76: System Response for Test 5.4.9

TEST 5.4.10: DECREASE THE SYSTEM FREQUENCY BY 0.5 HZ FOR 5 SECONDS

On decreasing the system frequency by 0.5 Hz, the DER responded to the frequency changes by increasing its power output and settled at a new set point per the frequency-watt droop of the inverter. This reduced the active power import from the grid through the PCC. The reactive power across the DER and PCC remained the same, while the system voltage settled into 1.025 pu at steady state.

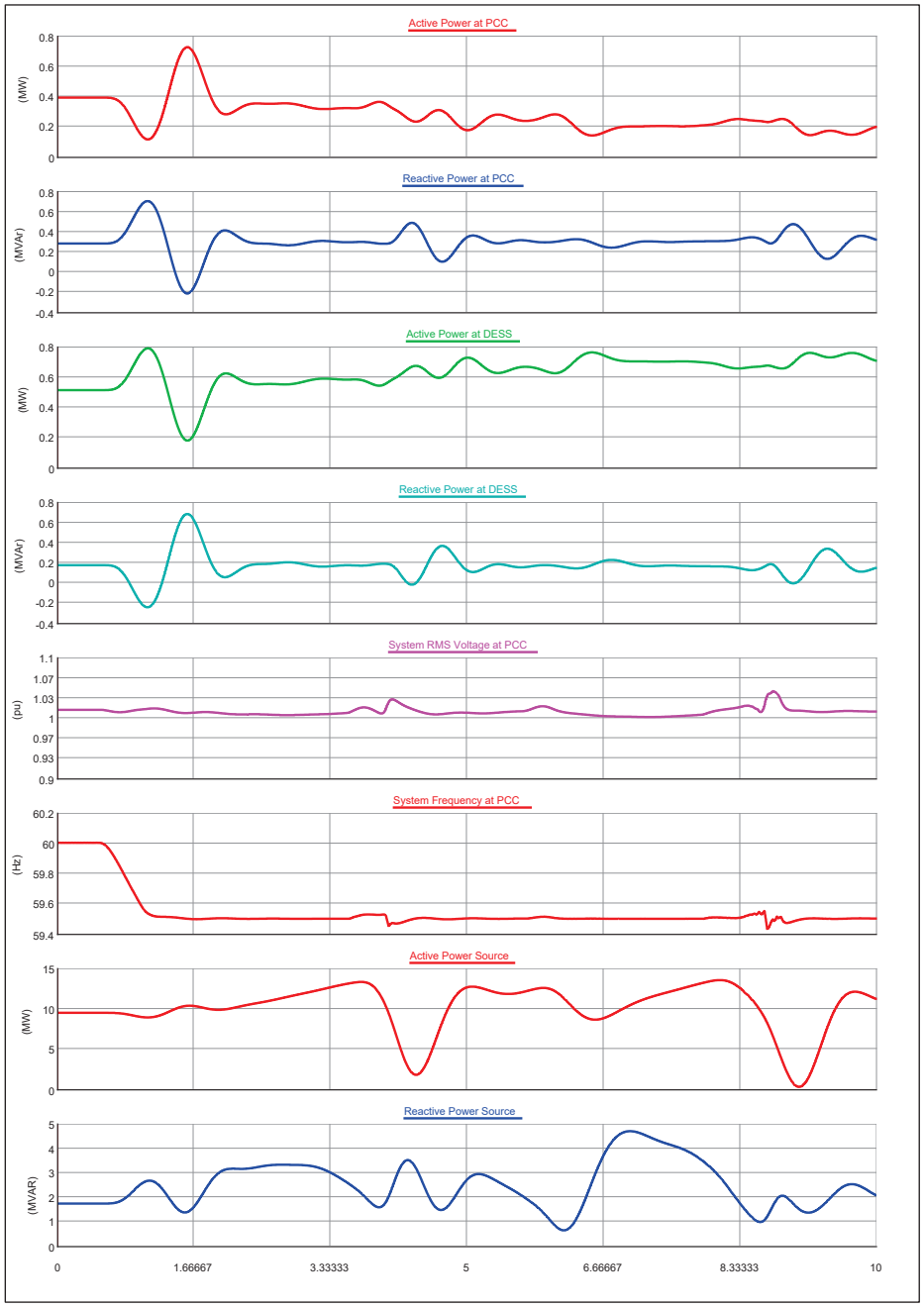


Figure A.77: System Response for Test 5.4.10

TEST 7 – SPINNING RESERVE

The objective of this test is to assess the benefits of the battery storage system in functioning as a spinning reserve in different system conditions, compared to traditional sources, such as diesel generators. The DER will be compared against the traditional backup diesel generator as a source of spinning reserve in terms of response time, standby losses, durability of support, and availability.

Test Procedure

The DER used for testing is modeled as a frequency-watt controlled and volt-VAR controlled DER when it is connected to the grid, and it works as a volt-frequency controlled device in island condition. Thus, the voltage and frequency of the DER is controlled during the grid connected mode as well as during island mode. The DER acts as a spinning resource providing support for the grid during periods of fluctuation in system voltage and/or frequency.

The procedure for testing was as follows:

Step 1. Place the DER into idle mode with the state of charge (SOC) of the battery at the full level. During Idle mode, the DER does not generate or absorb active or reactive power from the grid.

Step 2. Create a contingency where a grid source is taken offline to simulate an under-frequency situation in the rest of the system connected by the DER. Set the DER in to voltage and frequency regulation modes after approximately 5 seconds to produce the deficit active and reactive power to support the rest of the system during this event. In the meantime, bring the additional backup generation online.

Step 3. On opening the Region 1 (Rgn1) breaker, the DER enters island mode, regulates the voltage and frequency across the islanded portion of the grid, and restores balance in the portion of the circuit isolated from the main circuit within few seconds. The net load in the region is supported by the DER completely if the system load is within its capacity. The active power dispatch of the DER is 845 kW, and the reactive power dispatch is 310 kVAR. One observation in Figure A.79 is that the frequency of the DER shoots up to 4000 Hz and more. This can be attributed to the metering error of the software, which creates random values for frequency of those nodes that have been opened.

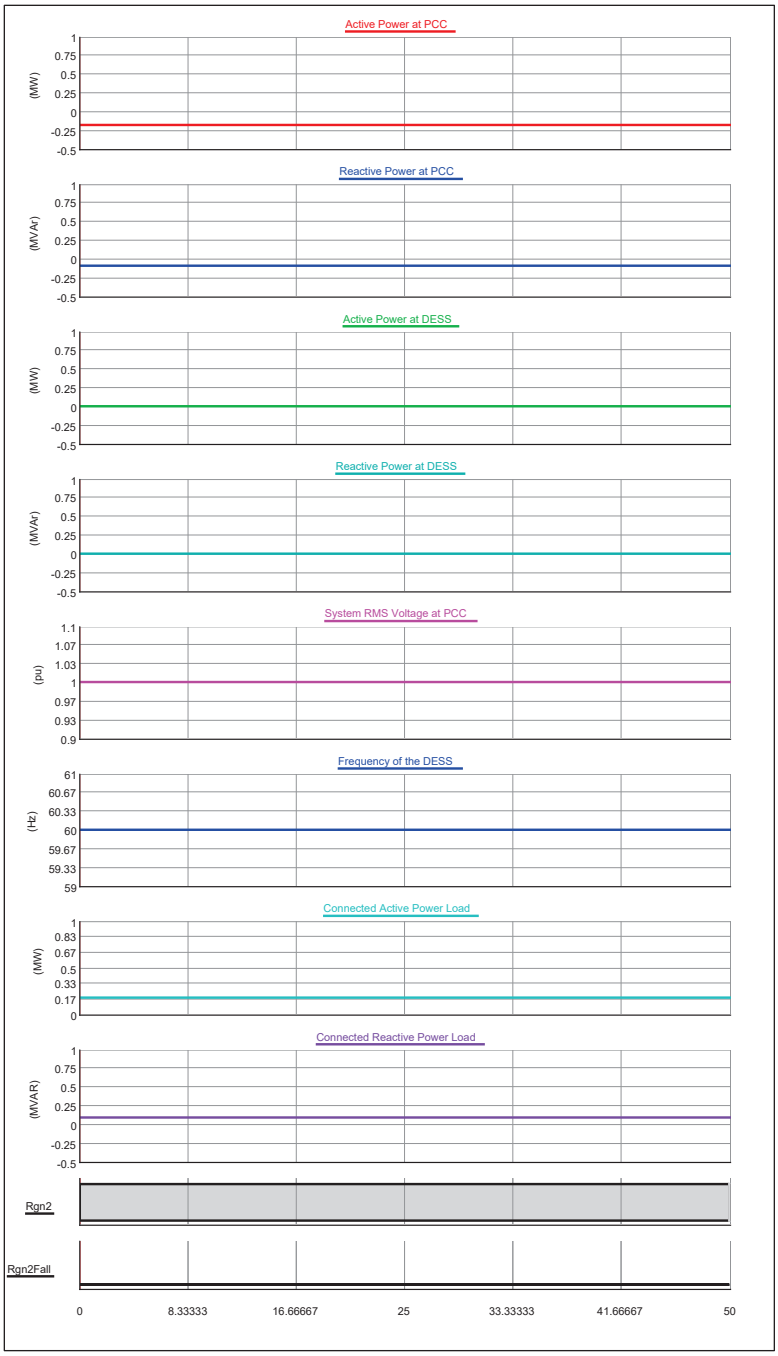


Figure A.78: Idle Grid Connected System With Frequency-Watt and Volt-VAR Modes

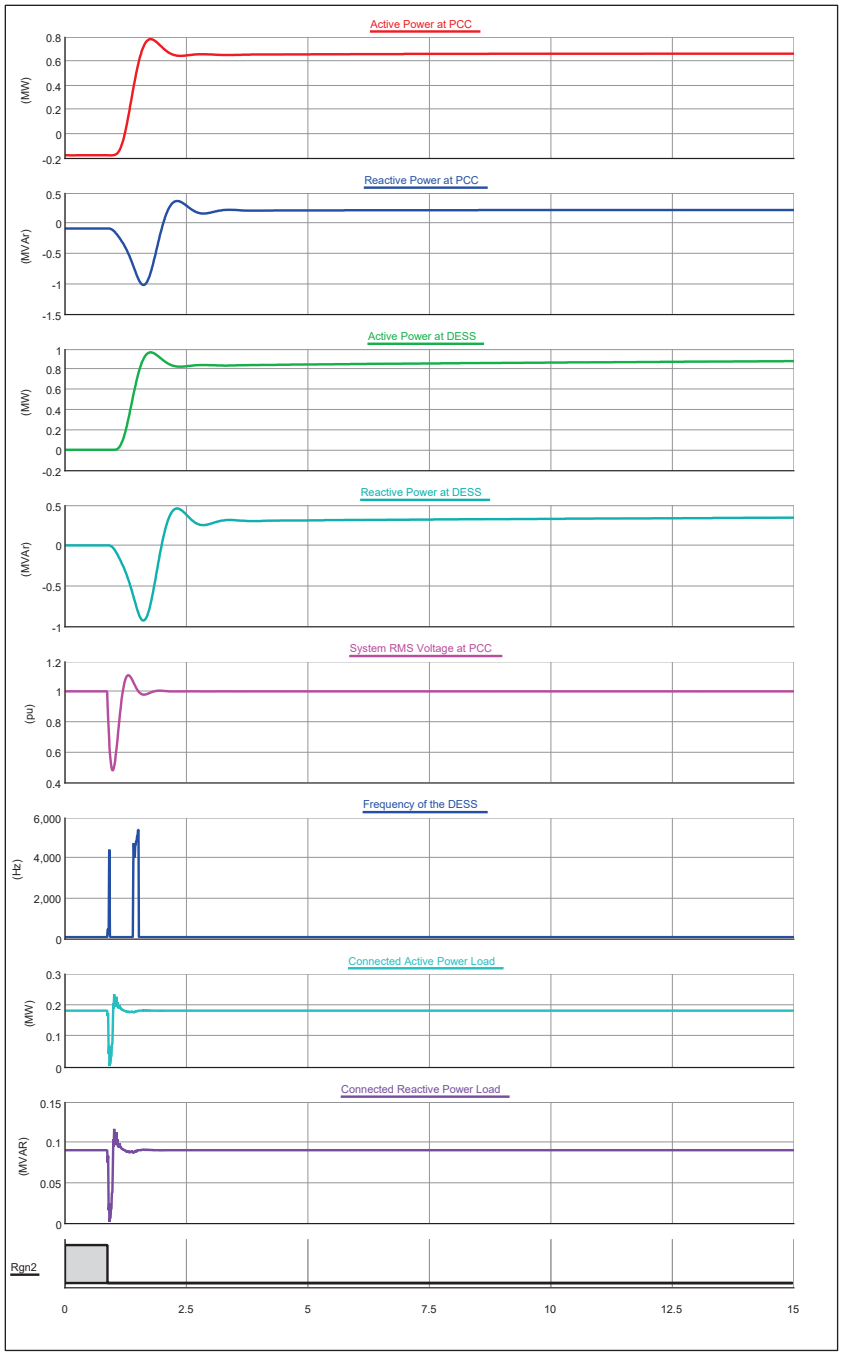


Figure A.79: System Response for DER Operating as Spinning Reserve Following Underfrequency Due to Islanding

Conclusion

On performing a comparative analysis in terms of economic benefits in fuel savings, ease of operation, response time, and reliability, it is evident that the use of a DER over diesel generators is considerably more beneficial, in terms of both cost and operation. The results from the comparative study in terms of various aspects are presented below.

COST

The capital cost of installing the DER is the only major cost involved in the battery storage system because the overall operation cost along with the idle charge losses is negligible. There is no fuel that needs to be replenished frequently as in a diesel generator, and hence the operational cost is considerably lower.

Compare the performance of the diesel generator of a similar rating of 1 MW, whose approximate fuel flow rate is specified as:

$$\text{Fuel flow (GPH)} = 1.1312 \bullet \text{MW (\% of the rated MW)} + 10.01$$

The total cost of the diesel generator based on the average cost of diesel of $2.562 per gallon.

Fuel cost during idle period for a period of 1 hour:

$$\text{Fuel cost} = \text{fuel flow (gallons per hour)} \bullet 1 \text{ hour} \bullet \frac{\$2.562}{\text{gallon}}$$

$$\text{Fuel cost} = 10.01 \bullet \$2.562 = \$25.62$$

The fuel cost for a generation of 845.6 kW (0.8456 MW) for a period of 1 hour is calculated as follows:

$$\text{Fuel cost} = (1.1312 \bullet 0.8456 + 10.01) \bullet 1 \text{ hour} \bullet \frac{\$2.562}{\text{gallon}} = \$28.096$$

$$\text{Total fuel cost} = \$53.71$$

The timelines considered here are solely for comparison; however, the actual idle runtime can exceed more than an hour, which increases the cost of operation rapidly. This cost is considerably higher than a negligible operational cost of the DER system, and hence a DER system is an economic source of spinning reserve than a diesel generator system because the idle loss of the diesel generator is almost half of the operation cost incurred by it.

RESPONSE TIME

The battery responds to changes in frequency and voltage due to islanding faster than a diesel generator. The response time of the battery to switch from grid connected mode to island mode was a period of 5 to 6 cycles, which is considerably faster than a diesel generator switching whose default ramp rate is around 40 percent of its rated capacity per minute, which means for an active power load of 85 percent of its rated capacity, the response is expected to be more than 120 seconds. This makes a DER an obvious choice for fast response.

OPERATION AND MAINTENANCE

A DER is relatively easier to operate and environmentally cleaner source compared to a diesel generator, which needs to be monitored frequently for changing operation and causes environmental pollution. Furthermore, a DER requires little or no maintenance compared to a traditional diesel generator, which needs frequent maintenance. This makes a DER an obvious choice of spinning reserve over diesel generators.

SPINNING RESERVE TEST RESULTS:

The purpose of this test is to assess the benefits of using the DER a source of spinning reserve to provide the active power support during different system conditions as compared to conventional diesel generators. The DER is connected near the end of the feeder (Scenario 3) in this test. The results of this

test proved that the DER is quite effective in sustaining loads during periods of underfrequency, providing voltage and frequency support within a short period. In addition to being a fast spinning resource, it also proves to be more effective in terms of cost and efficiency and better in terms of environmental factors and ease of operation and maintenance.

TEST 8 – BLACK START

The battery storage system can be used to black start the system after complete system outage. The battery can operate in VSI mode to provide voltage and frequency support during the black start. Once the nominal voltage and frequency are established in the island, the loads can be picked up slowly and other renewable generation sources can be brought online to support the islanded load on the feeders.

The simplified test circuit for Scenario 3 for black start is shown in Figure A.80.

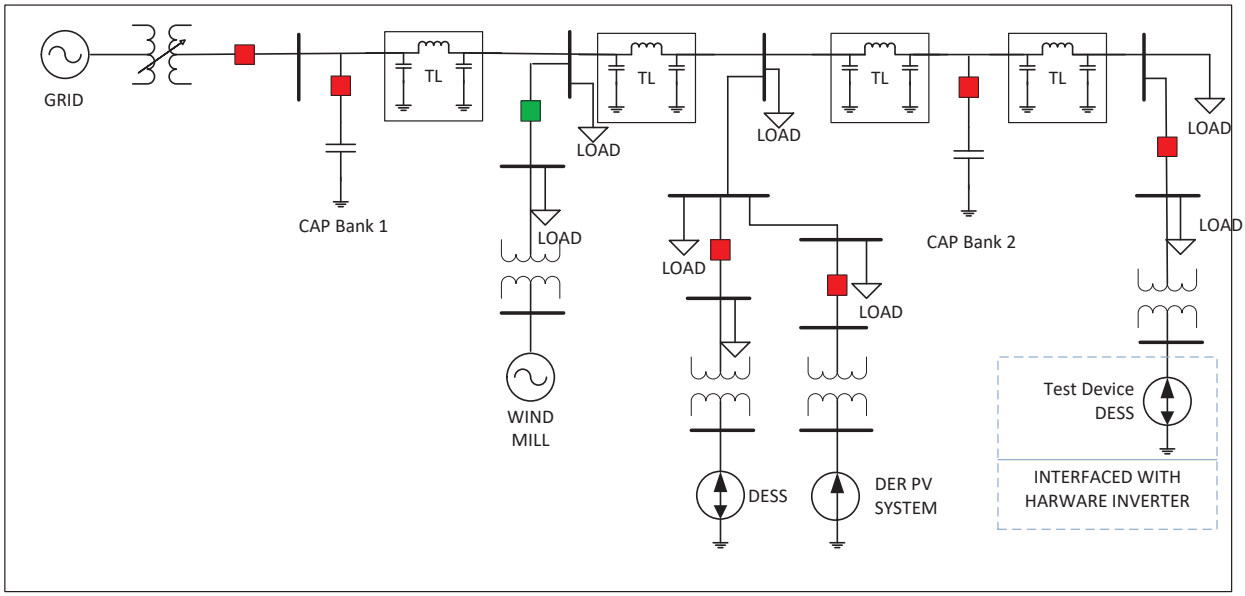


Figure A.80: DER at the End of a Long Feeder (Typical)

For the software testing, follow these steps:

Step 1. While the system is running in steady-state conditions, open the grid circuit breaker, which should lead to a blackout in the system.

Step 2. Identify the DER that can be used as a source to create an island. Disconnect the loads from the system so that the DER can feed enough load within its capacity without collapsing when brought online.

Step 3. Once the island is formed, close the breakers connecting to other renewable sources in the system, such as the PV system and wind turbines.

Step 4. Keeping in mind the available generation capacity, start closing the load breakers one by one.

Step 5. Record the system voltage and frequency during the steps performed for the black start operation. Document the black start and load restoration procedure for analysis.

Test Procedure and Results

STEP 1: CLOSE THE TEST DER BREAKER TESTBKR

The grid breaker was opened, which caused a complete blackout in the system. All loads and DER were disconnected from the circuit. The total load of the system was brought down to 2 MW, which was within the capacity of the two DER put together. The circuit and the test the DER supplied active and reactive power to their local load in their respective islands. When the test inverter breaker (TESTBKR) was closed, the test DER was brought into the circuit. No loads were connected yet because the load breakers

were still open, and hence the active and reactive power output of the test inverter and the circuit DER were not changed. The frequency and system voltage remained unaffected during this switching, while the power import across the PCC did not change as well.

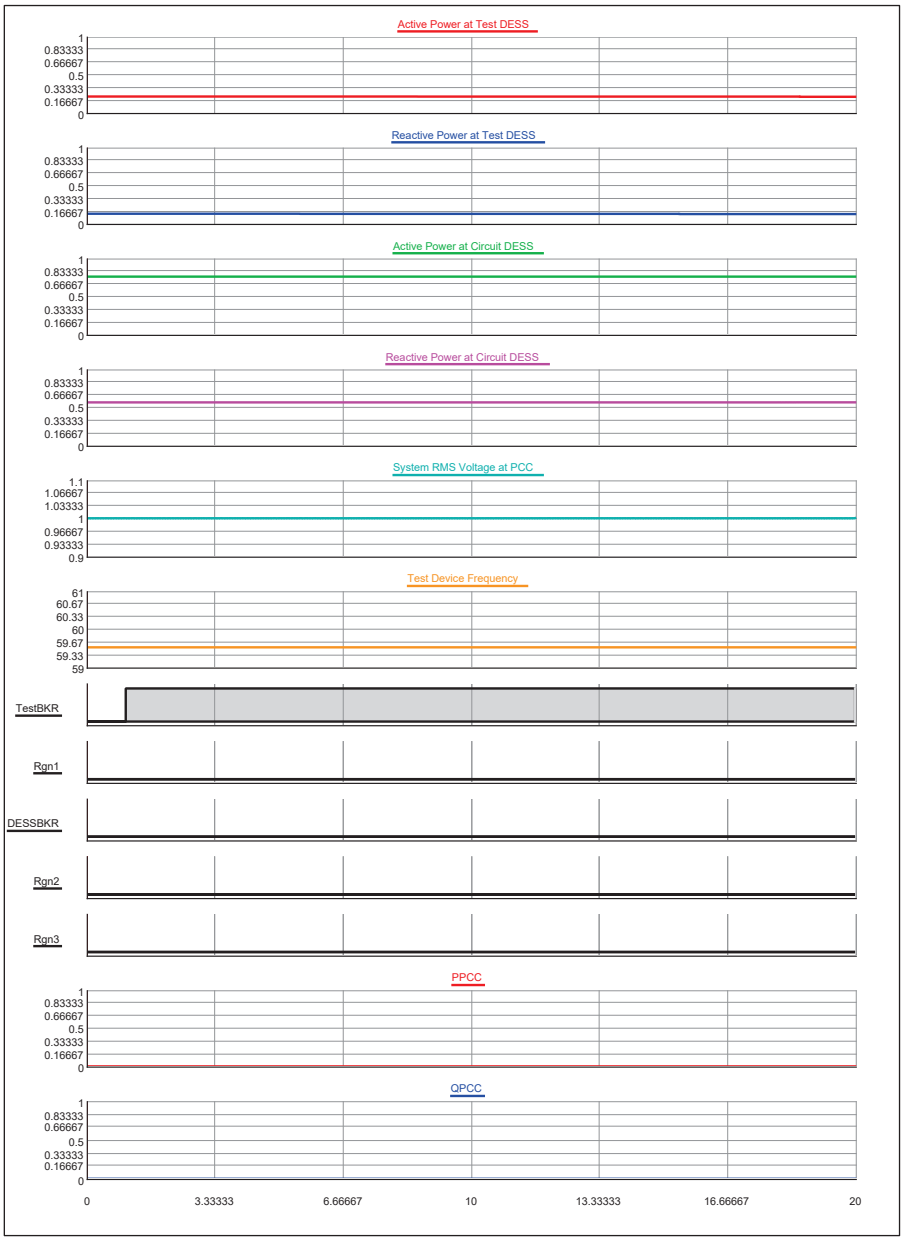


Figure A.81: System Response for Step 1

STEP 2: CLOSE THE LOAD REGION 1 BREAKER

When the load breaker for load Region 1 closed, the net load connected to the test DER increased, causing the active and reactive power output of the test DER to increase. This changes the power transfer across the PCC, which supplied power into the grid. The frequency across the DER had a minor fluctuation because of the switching transients but settled into the previous value during steady-state conditions. The active and reactive power output of the circuit DER did not change because it was still in its island mode and disconnected from the rest of the grid. The voltage remained unaffected by the change and was maintained approximately at 1 pu.

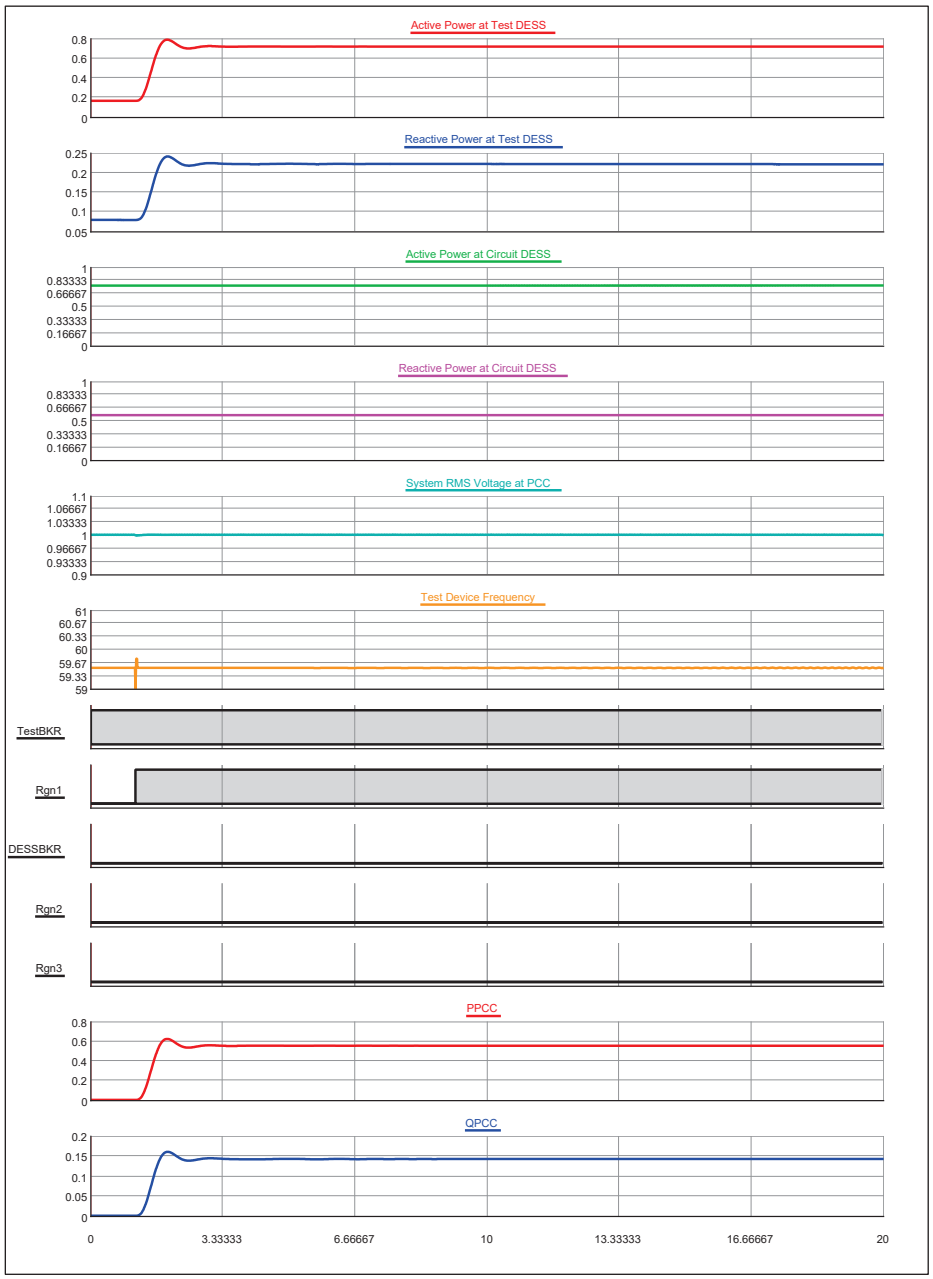


Figure A.82: System Response for Step 2

STEP 3: CLOSE THE CIRCUIT DER BREAKER (DESSBKR)

When the circuit DER was brought into the grid by closing the DESSBKR circuit breaker, the circuit DER output increased while the test DER output decreased to balance the existing loads in Region 1 between the two DER. This shift in power flow caused the power export across the PCC to reduce, resulting in the real and reactive power across the PCC to decrease. The system voltage and the frequency remained unaffected by the change.

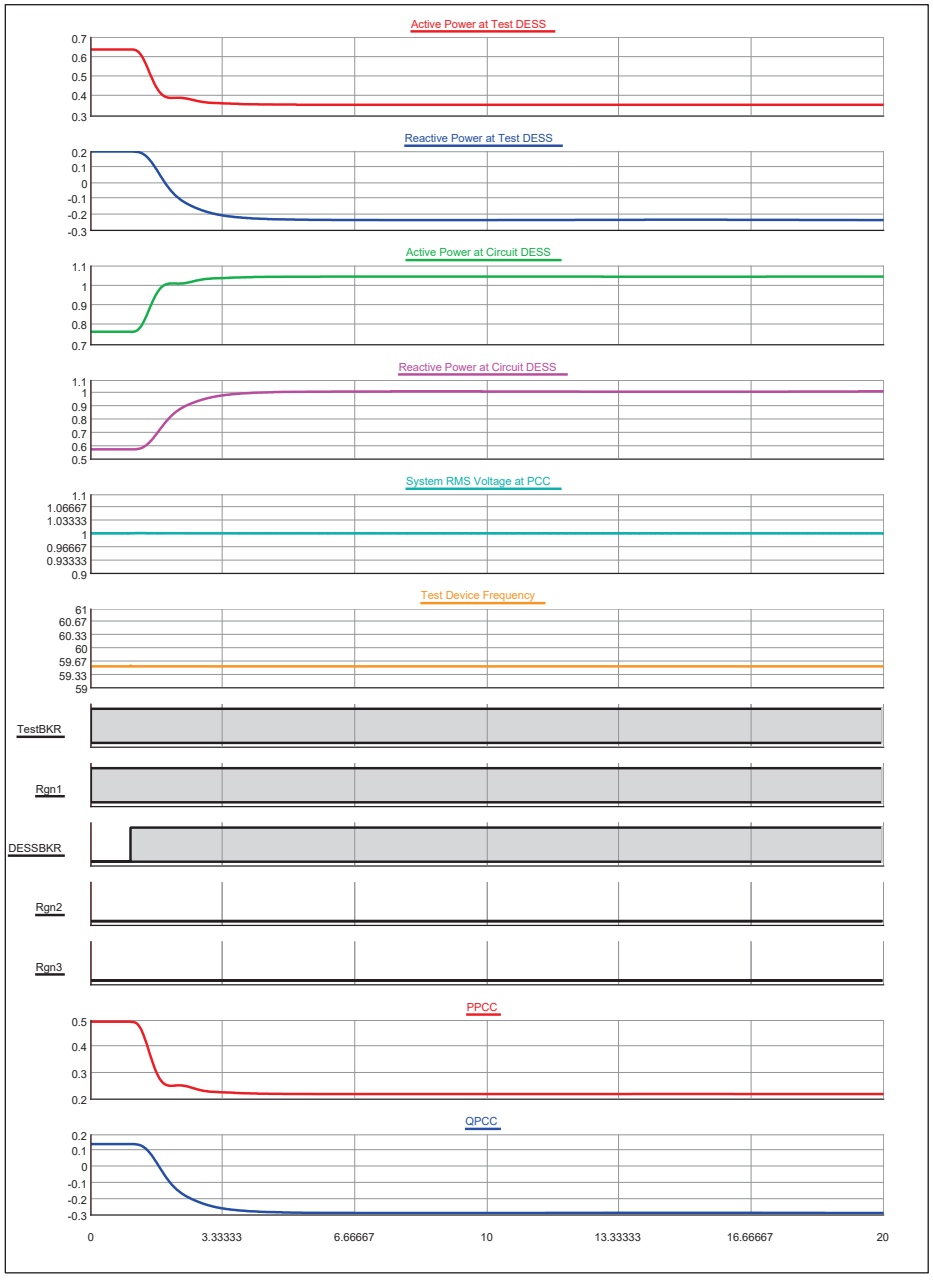


Figure A.83: System Response for Step 3

STEP 4: CLOSE LOAD REGION 2 BREAKER

When the load Region 2 breaker (Rgn2) closed, another set of loads were connected into the circuit fed by the two DER. This caused the active power output of both the test DER and circuit DER to increase, creating a shift in the reactive power output due to the shift in the load flow. The frequency and voltage had a minor disturbance but immediately settled back into steady-state conditions following the disturbance.

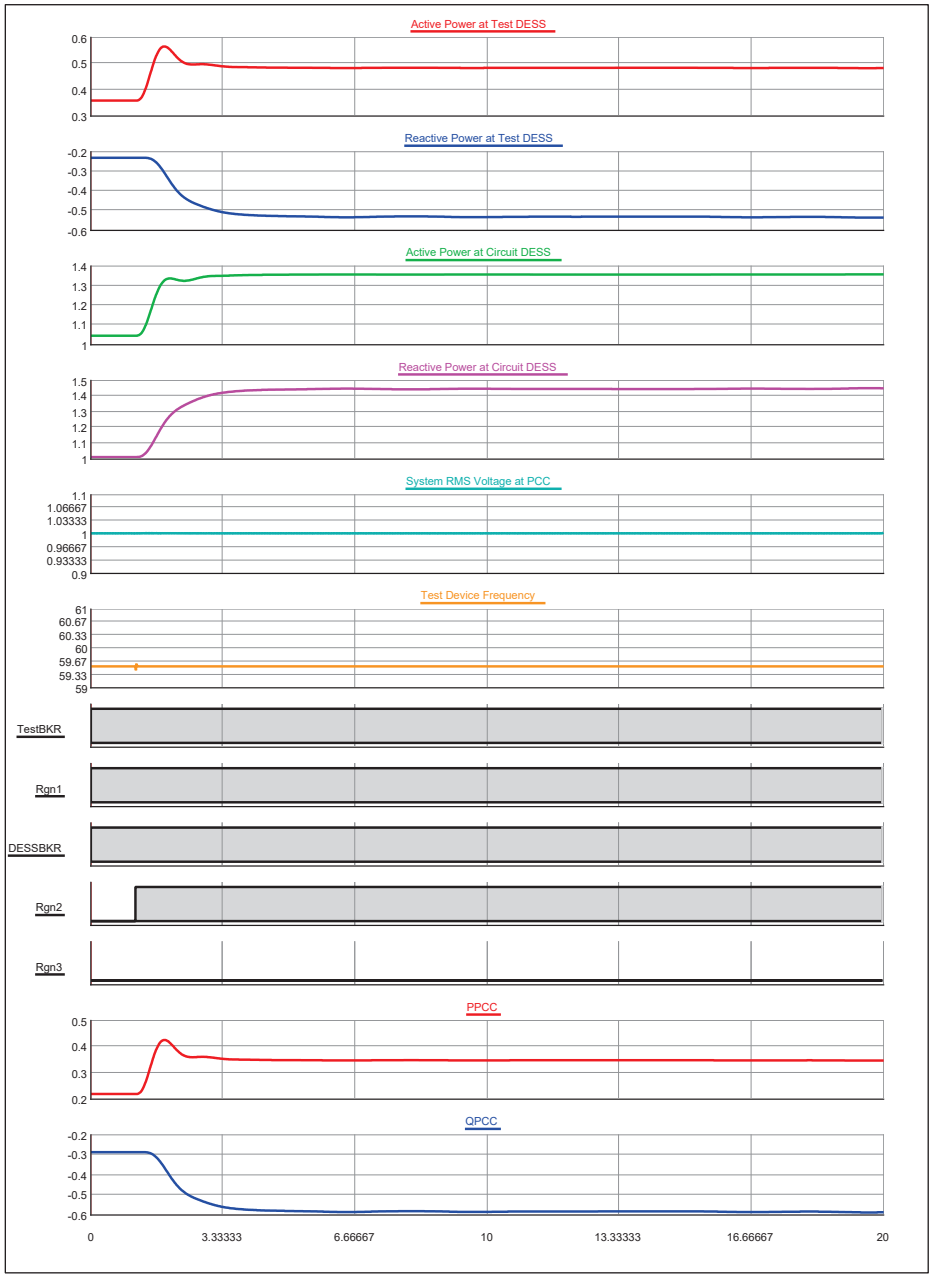


Figure A.84: System Response for Step 4

STEP 5: CLOSE LOAD REGION 3 BREAKER

When the load Region 3 breaker (Rgn3) closed, the last set of loads were connected into the rest of the circuit. This caused the active power output of both the test DER and circuit DER to increase, creating a shift in the reactive power output due to the shift in the load flow. The frequency and voltage had a minor disturbance but immediately settled back into steady-state conditions following the disturbance.

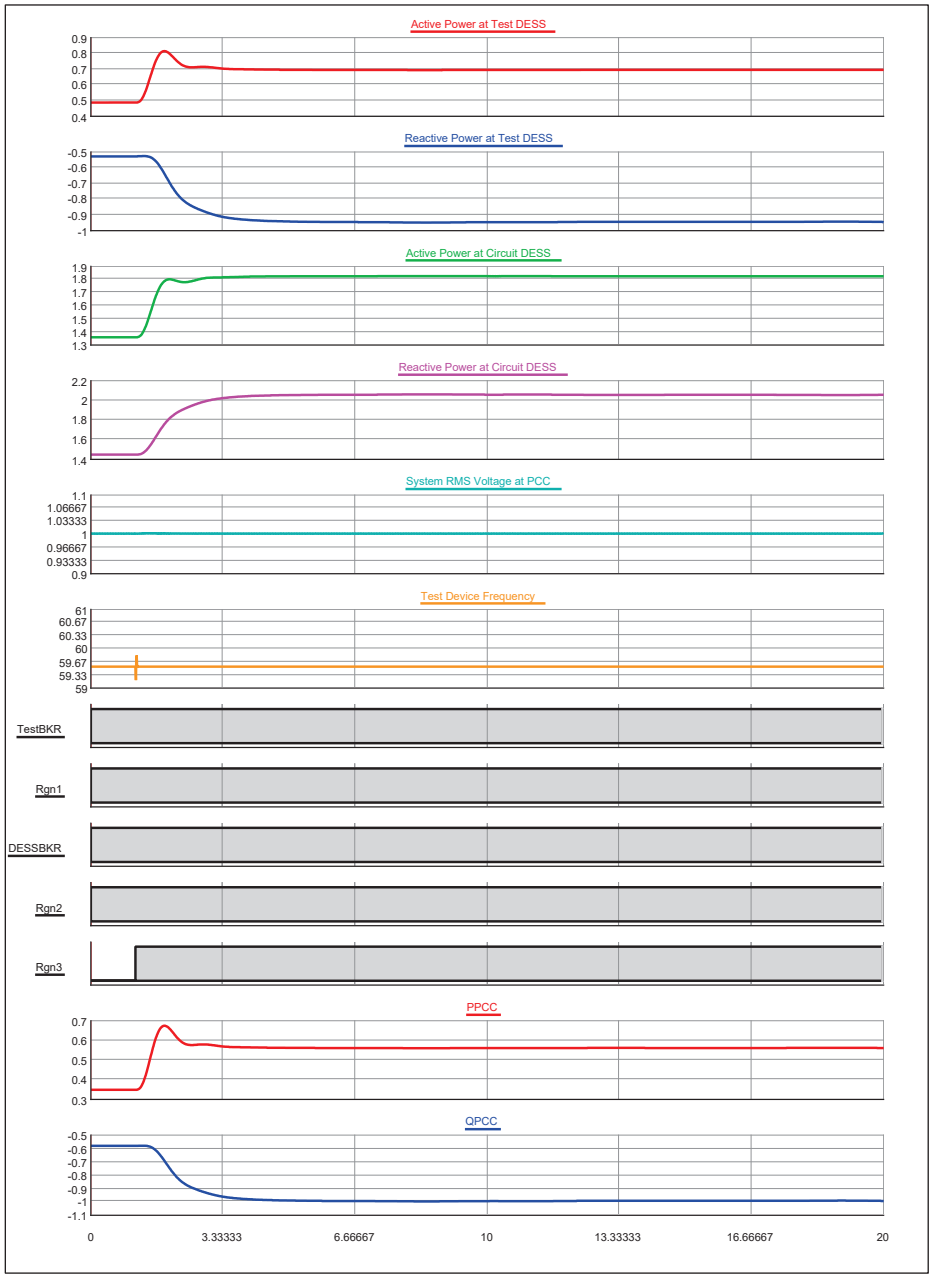


Figure A.85: System Response for Step 5

Conclusion

The purpose of this test is to assess the benefits of using the DER to black start the system after a complete system outage. The result of this test shows the effectiveness of using the DER to black start the

system just like the traditional generation to bring the system online in the increment of loads and generations on the circuit. Once the grid breaker opens, causing the system to enter a blackout, the DER enters VSI mode creating reference for voltage and frequency. With the DER in VSI mode, additional load and generation sources can be connected in the system in the subsequent steps. The DER, like the PV system, need a voltage reference from the DER to initiate the startup process to feed the load. The only difference of using the DER as a black start source as opposed to the traditional generators is that the DER offers no inertia to the system.

APPENDIX B DYNAMIC REDUCED MODEL ANALYSIS

A dynamic model of the distribution circuit is an equivalent reduced circuit with a synchronous source, transformer, load and the DER under test. This model was developed to study the actual response of the synchronous generator to load, voltage and frequency changes and its interaction with the test DER in PHIL environment. These tests served the same objective as that of software and PHIL tests conducted on the detailed model. Only core functions of the DER were demonstrated in this testing.

BUILDING THE MODEL

The source is replaced by the Synchronous generator with governor and exciter control models. The overall line load of the line is simplified to obtain an equivalent line impedance through equivalent impedance calculations. The dynamic model is a representation of the Scenario 3 of the test circuit. The tap changer is modeled as such. The net loads of the circuit are lumped together and is represented by a variable load changed using sliders. The two capacitors are lumped together to create one shunt capacitance.

The test DER is connected to the end of the feeder to study the interaction between the DER, synchronous source and the shunt capacitance for balancing the node voltage at the point of common coupling.

r

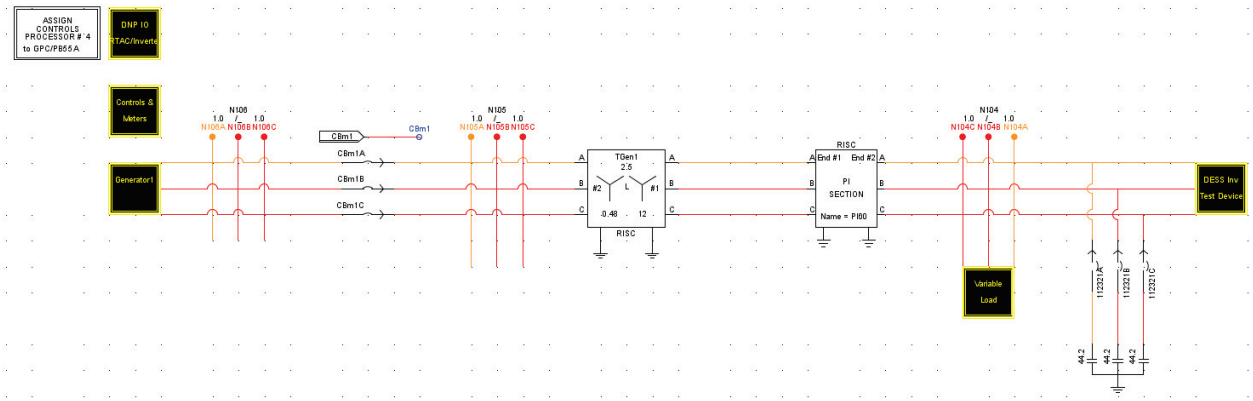


Figure B.86: Simplified Dynamic Equivalent Model of the Carmel Valley Circuit

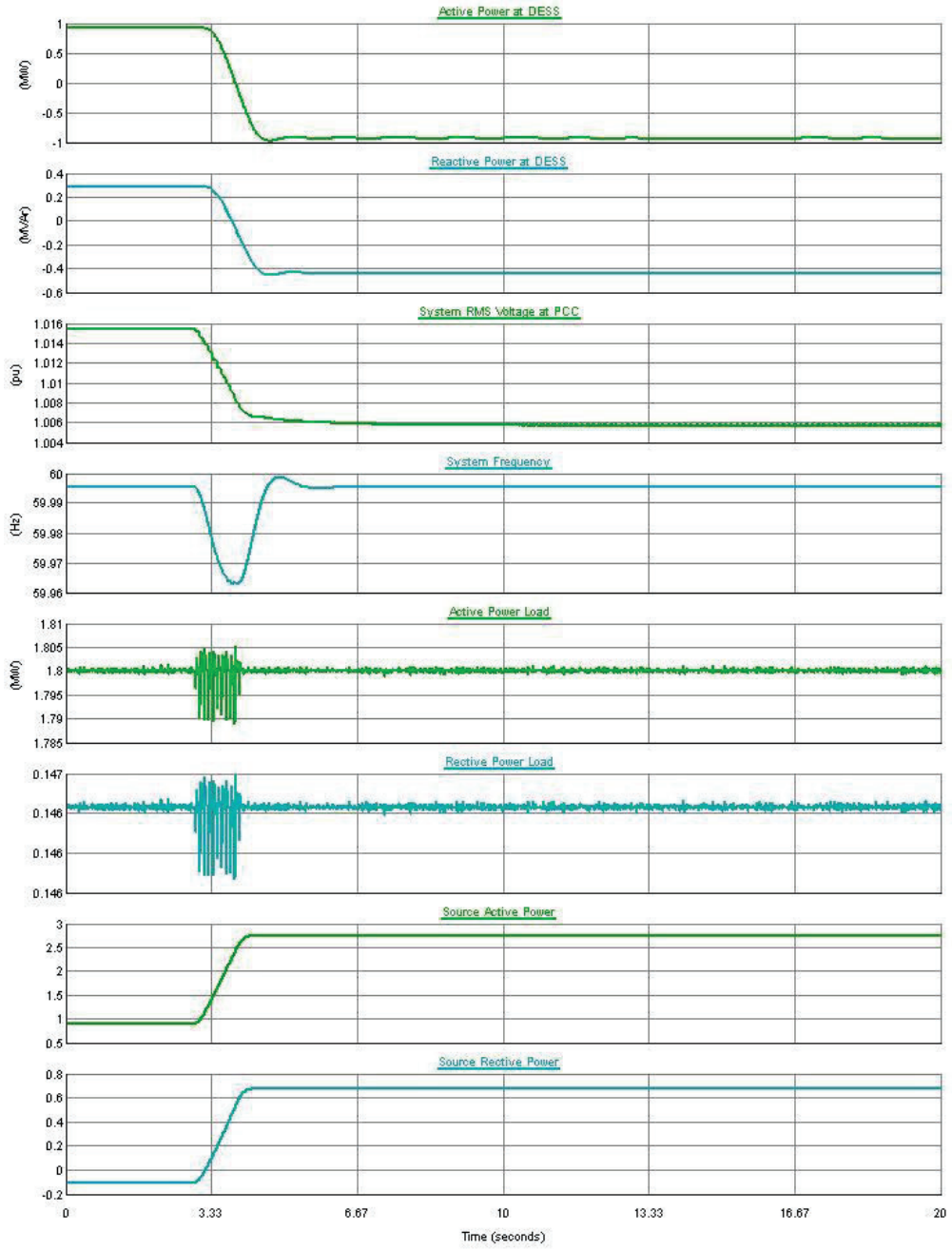
TEST RESULTS

The dynamic model is particularly tested for the voltage and frequency based tests to test the more realistic response of the synchronous generator. The tests that are conducted with the dynamic model and the system responses are shown in this section:

Test 2 – Schedule Active Power Output

TEST 2.1: CHANGING THE ACTIVE POWER DISPATCH FROM 1MW TO -1MW

On changing the active power set point, the DER absorbed 1MW instead of producing a 1MW active power dispatch. This change in DER output affected the source generator output because of which it increased the active power dispatch. Because of increased megawatt production by the synchronous generator, the system frequency fell momentarily but stabilized in the steady state. The system voltage dropped minimally due to the increased power output from the generator.

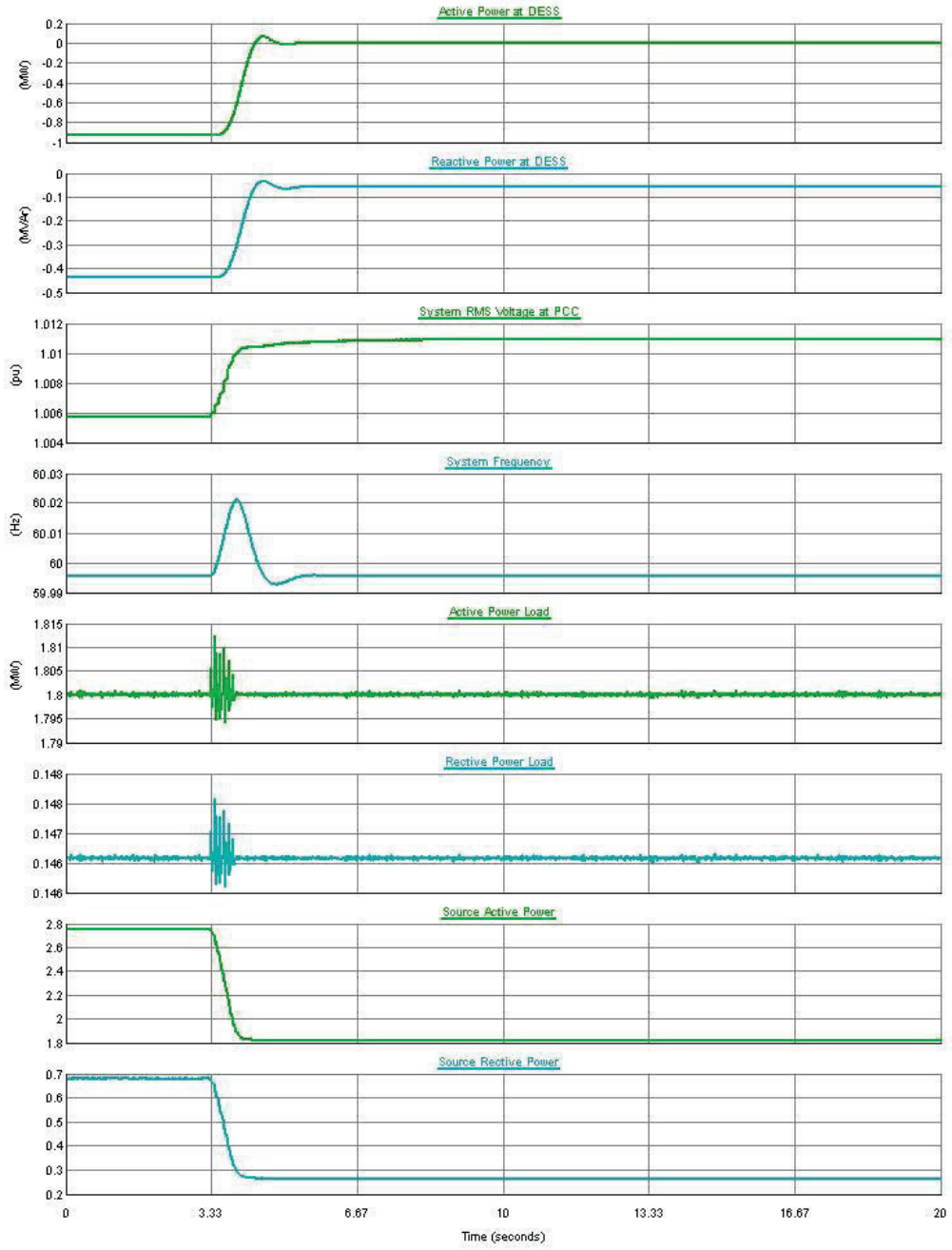


r

Figure B.87: System Response for Test 2.1

TEST 2.2: CHANGING THE ACTIVE POWER DISPATCH FROM -1MW TO 0MW

On increasing the DER active power set point to 0MW from -1MW, the load reduced at the generator, because of which the voltage across the terminals of the generator increased. The system frequency remained unaffected by the transition.



r

Figure B.88: System Response for Test 2.2

TEST 2.3: INCREASING THE ACTIVE POWER LOAD BY 4MW

On increasing the connected active power load by 4MW, the DER stayed at the scheduled set point of 1MW while the additional load was supplied by the source.

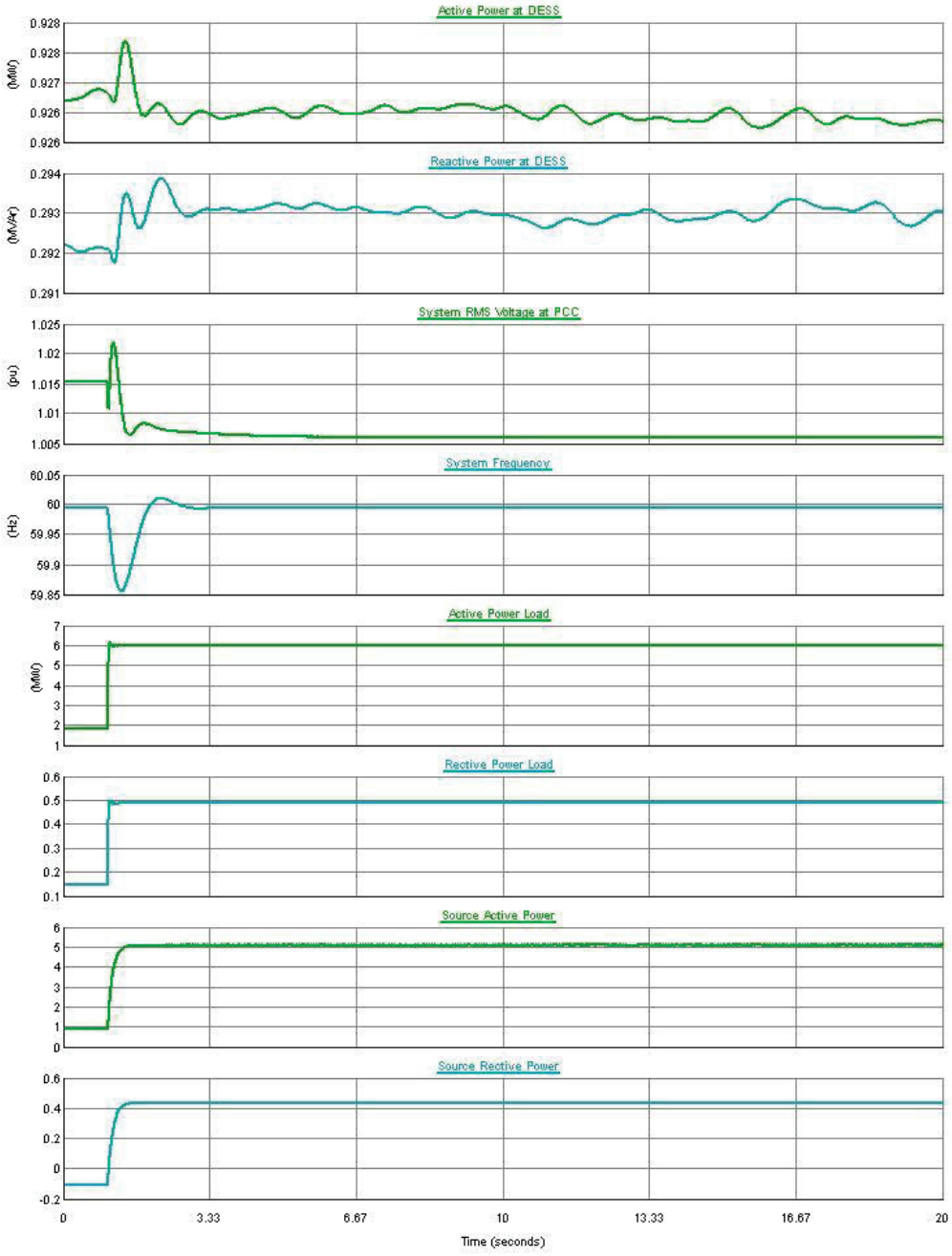


Figure B.89: System Response for Test 2.3

TEST 2.4: INCREASING THE REACTIVE POWER LOAD BY 800 KVAR

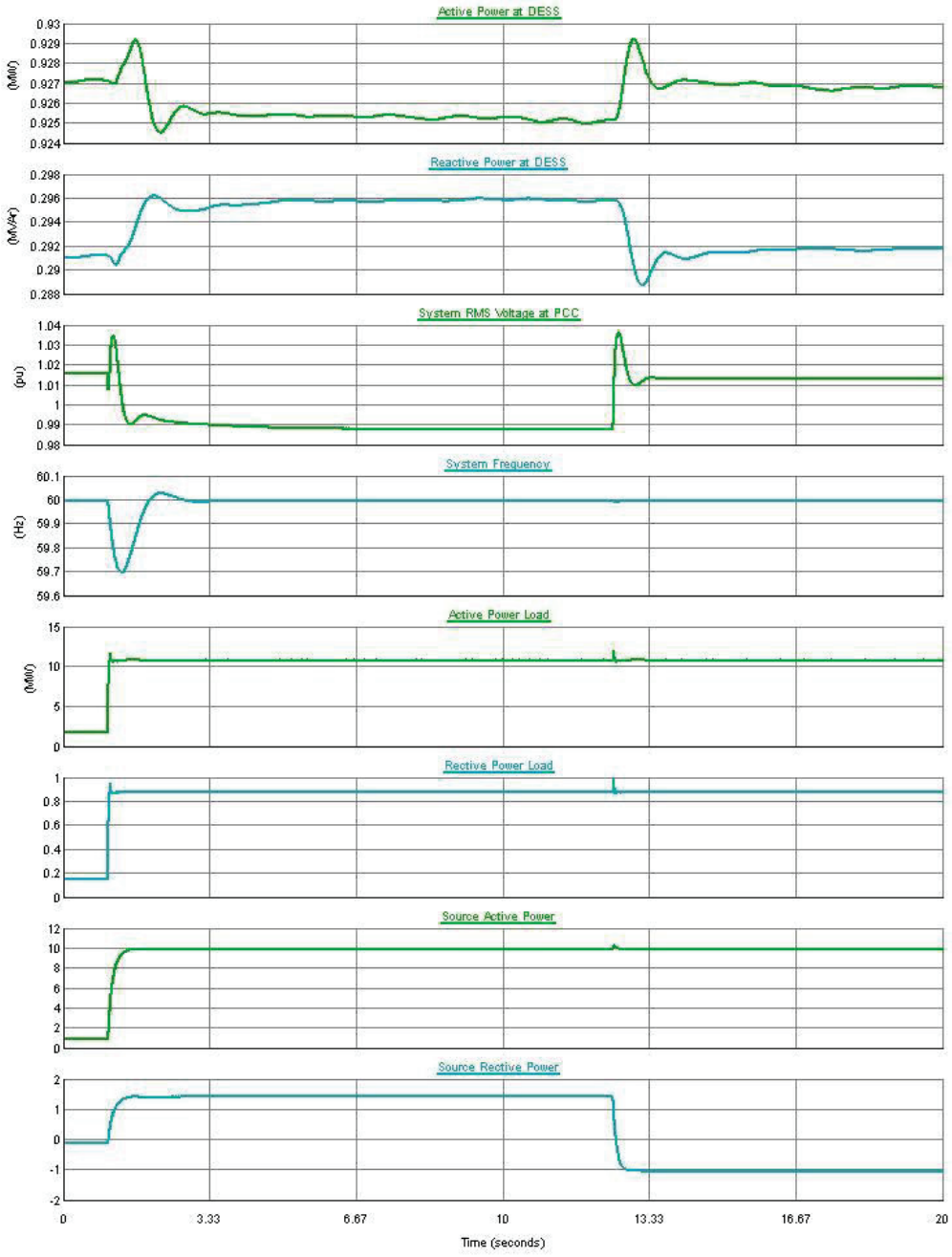


Figure B.90: System Response for Test 2.4

TEST 2.5: INCREASING THE REACTIVE AND ACTIVE POWER LOAD BY 9MW AND 700 KVAR RESPECTIVELY

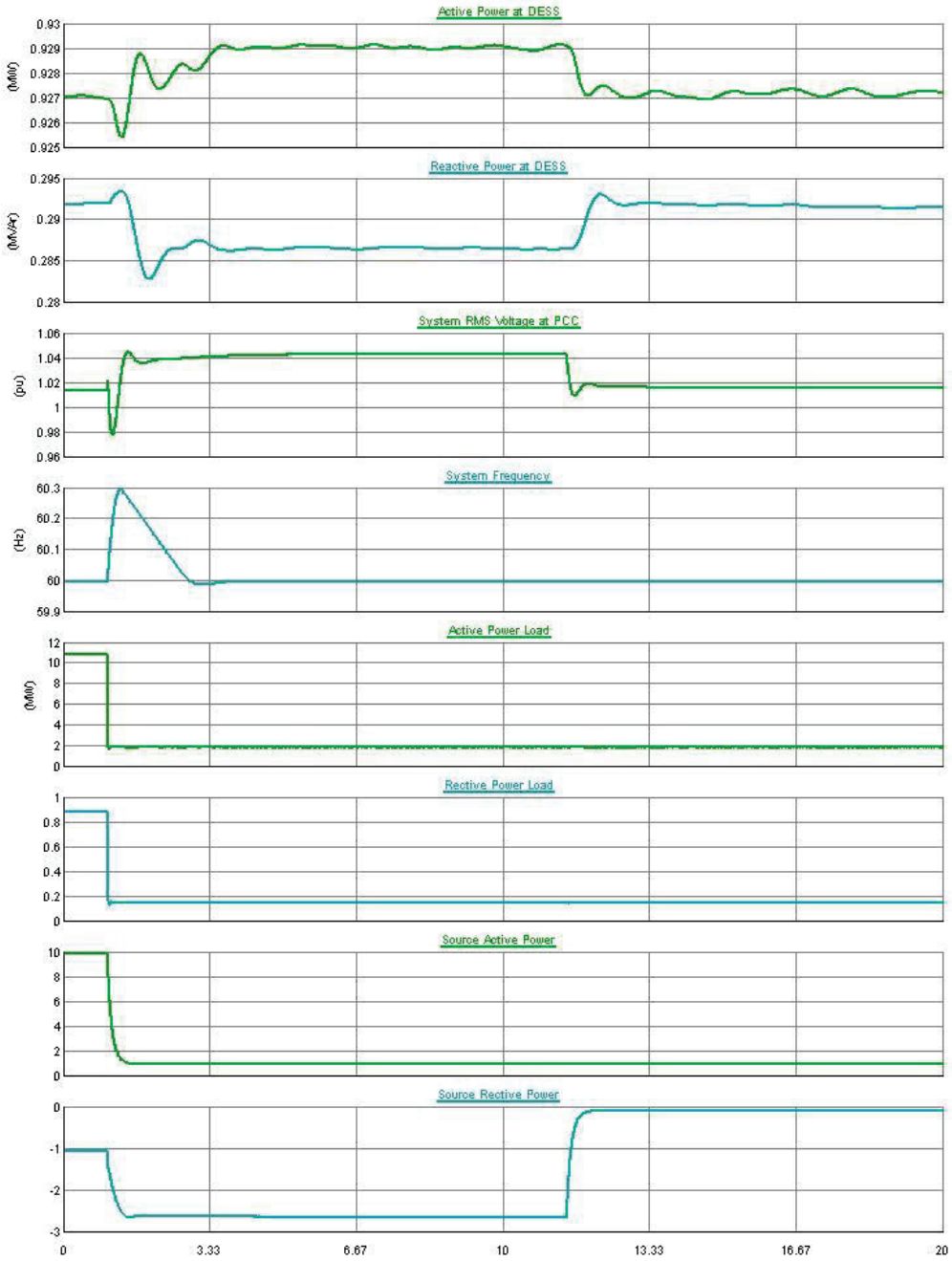


Figure B.91: System Response for Test 2.5

Test 4 – Volt-VAR

TEST 4.1A: INCREASING THE ACTIVE AND REACTIVE POWER LOAD BY 9MW AND 700 KVAR

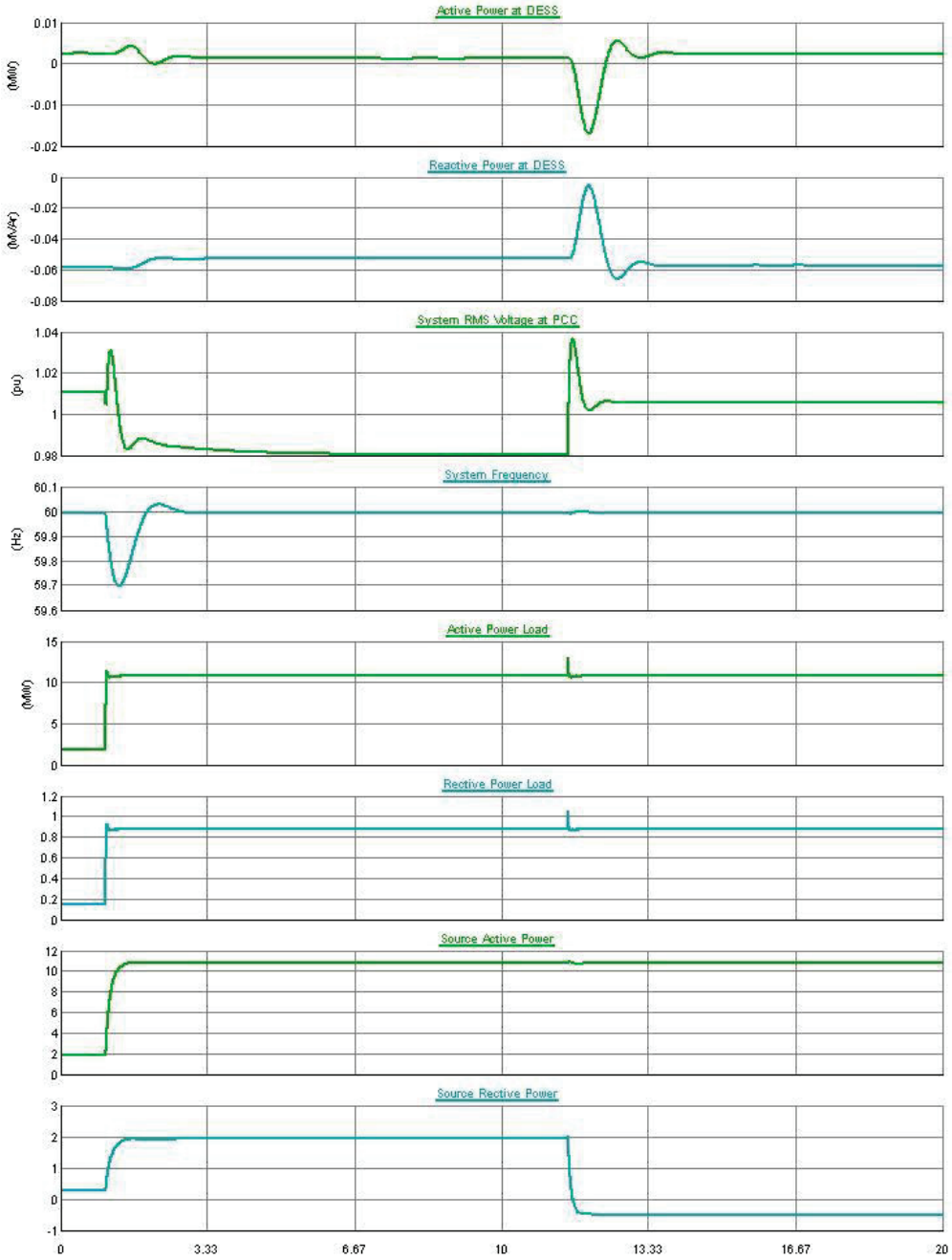


Figure B.92: System Response for Test 4.1a

TEST 4.1B: INCREASING THE ACTIVE AND REACTIVE POWER LOAD BY 9MW AND 700 KVAR

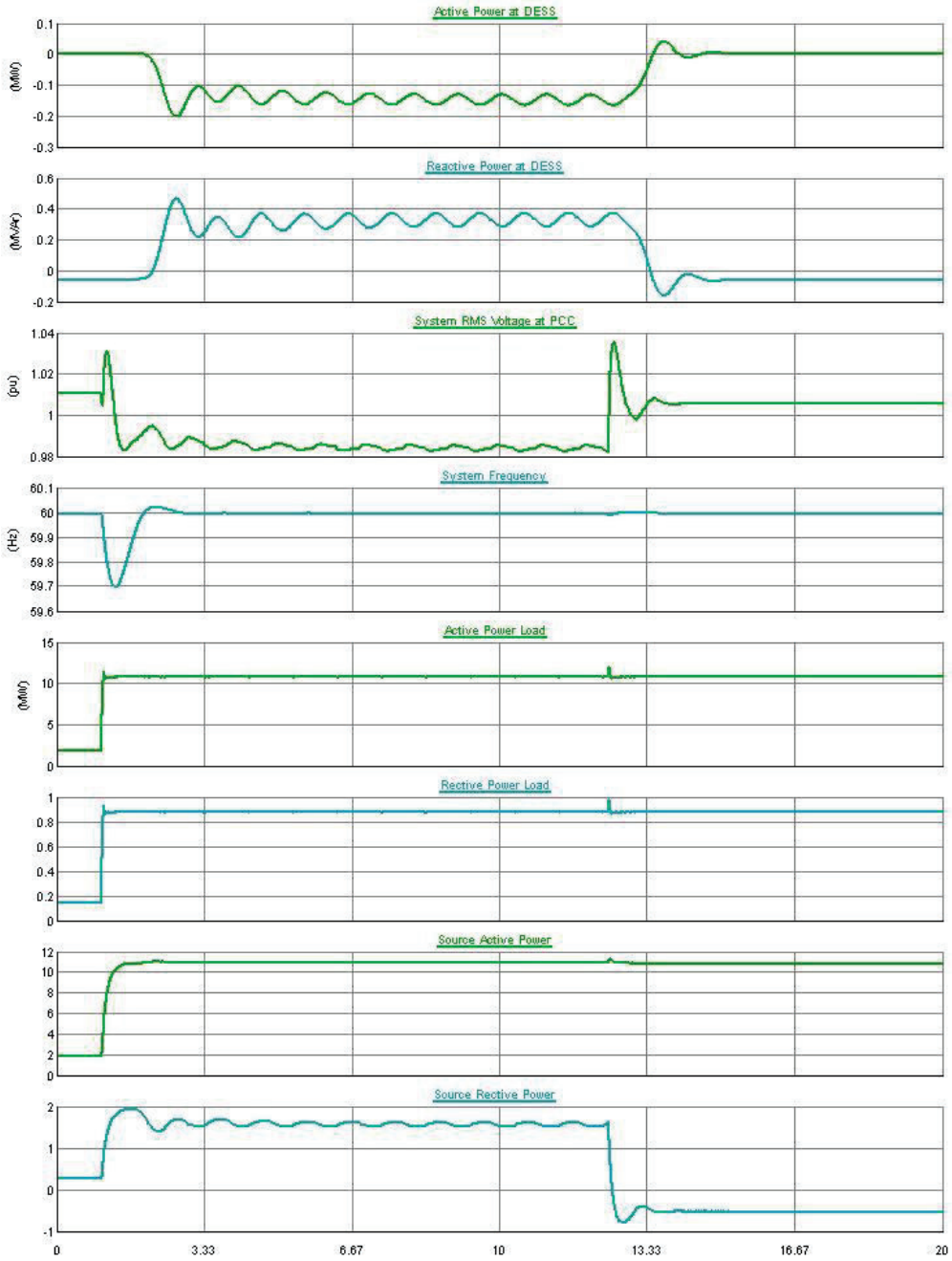


Figure B.93: System Response for Test 4.1b

TEST 4.2A: DECREASING THE ACTIVE AND REACTIVE POWER LOAD BY 9MW AND 700 KVAR

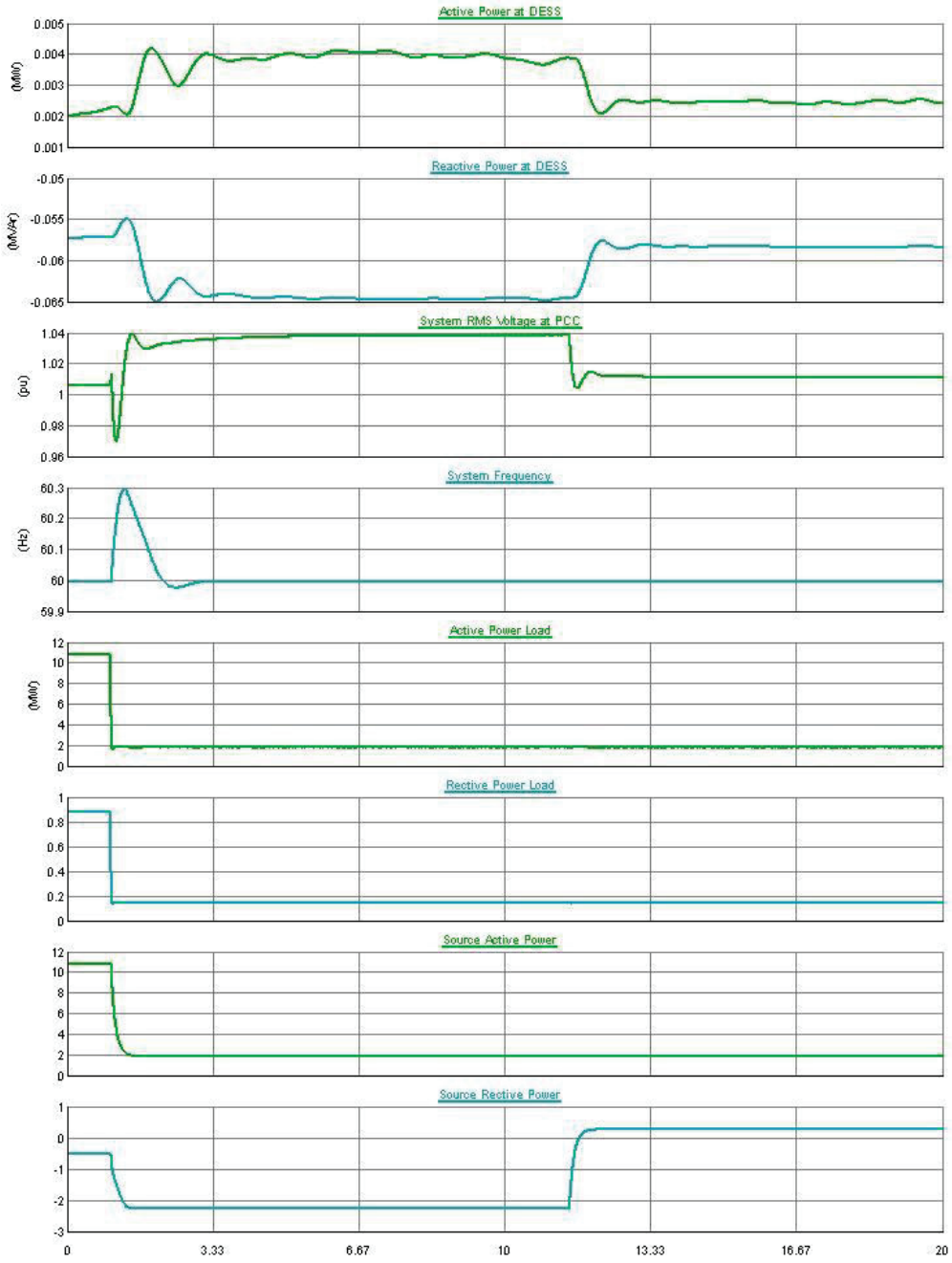


Figure B.94: System Response for Test 4.2a

TEST 4.2B: DECREASING THE ACTIVE AND REACTIVE POWER LOAD BY 9MW AND 700 KVAR

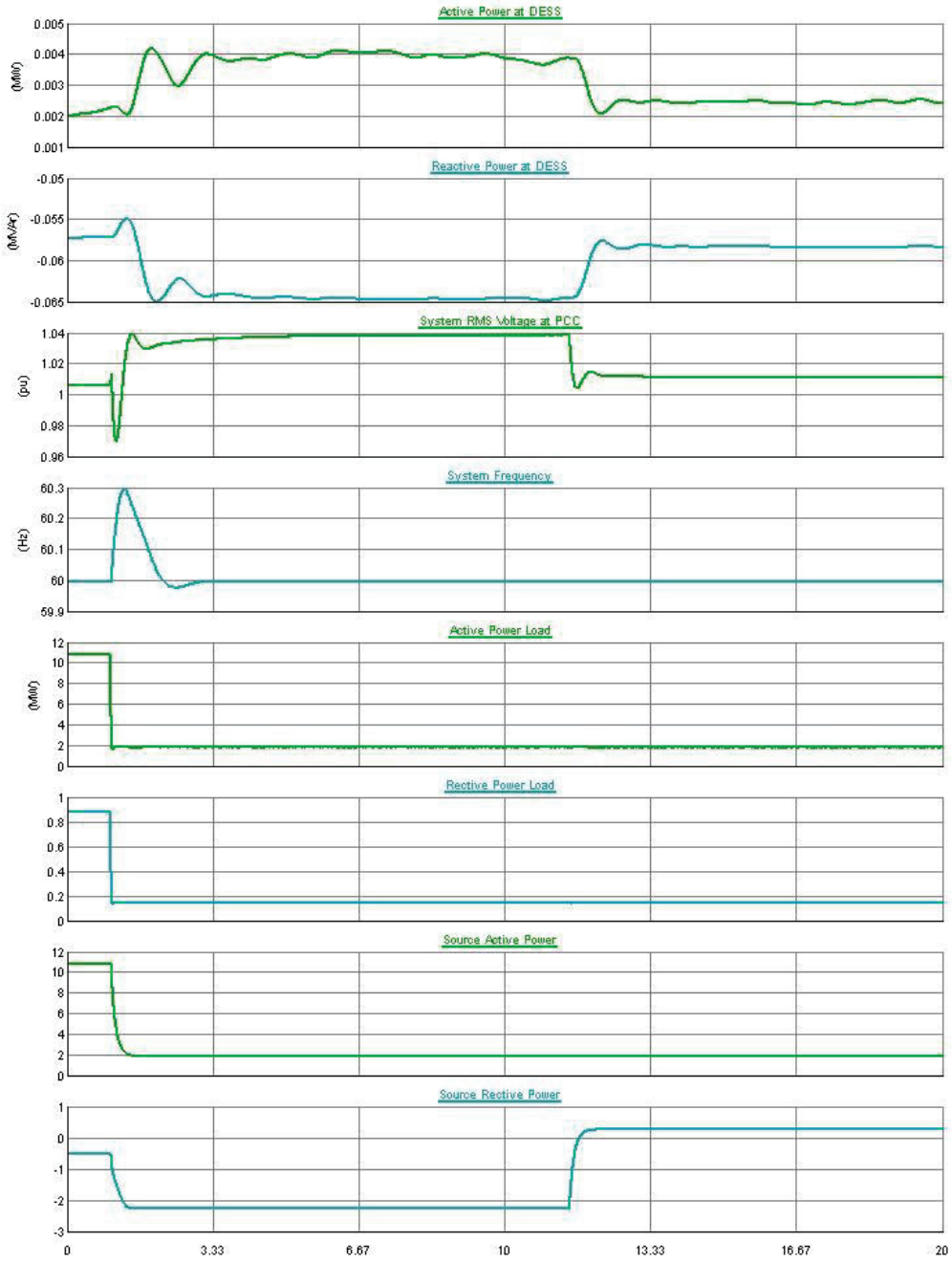


Figure B.95: System Response for Test 4.2b

Test 5 – Frequency-Watt

TEST 5.1A: INCREASING THE ACTIVE AND REACTIVE POWER LOAD BY 9MW AND 700 KVAR

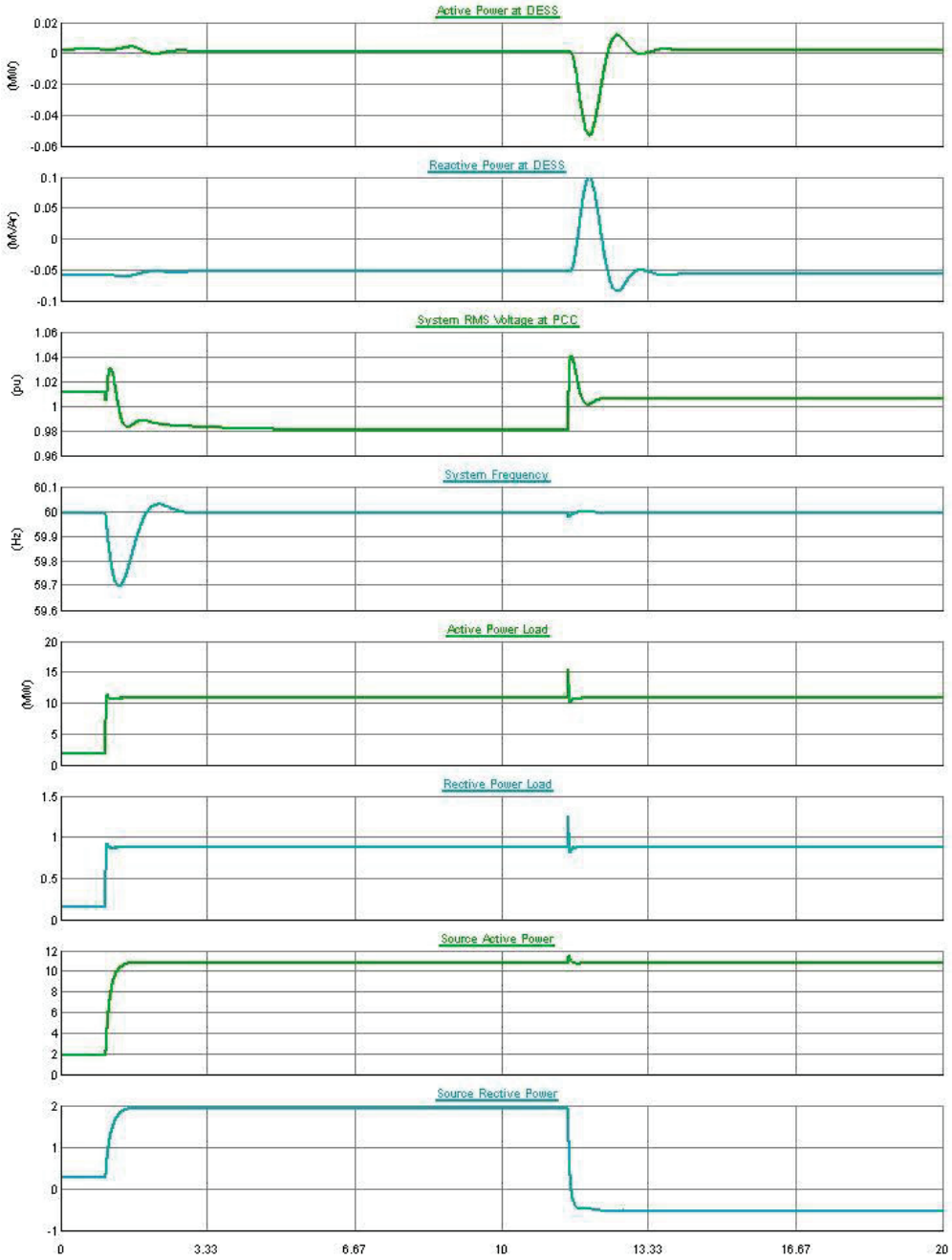


Figure B.96: System Response for Test 5.1a

TEST 5.1B: INCREASING THE ACTIVE AND REACTIVE POWER LOAD BY 9MW AND 700 KVAR

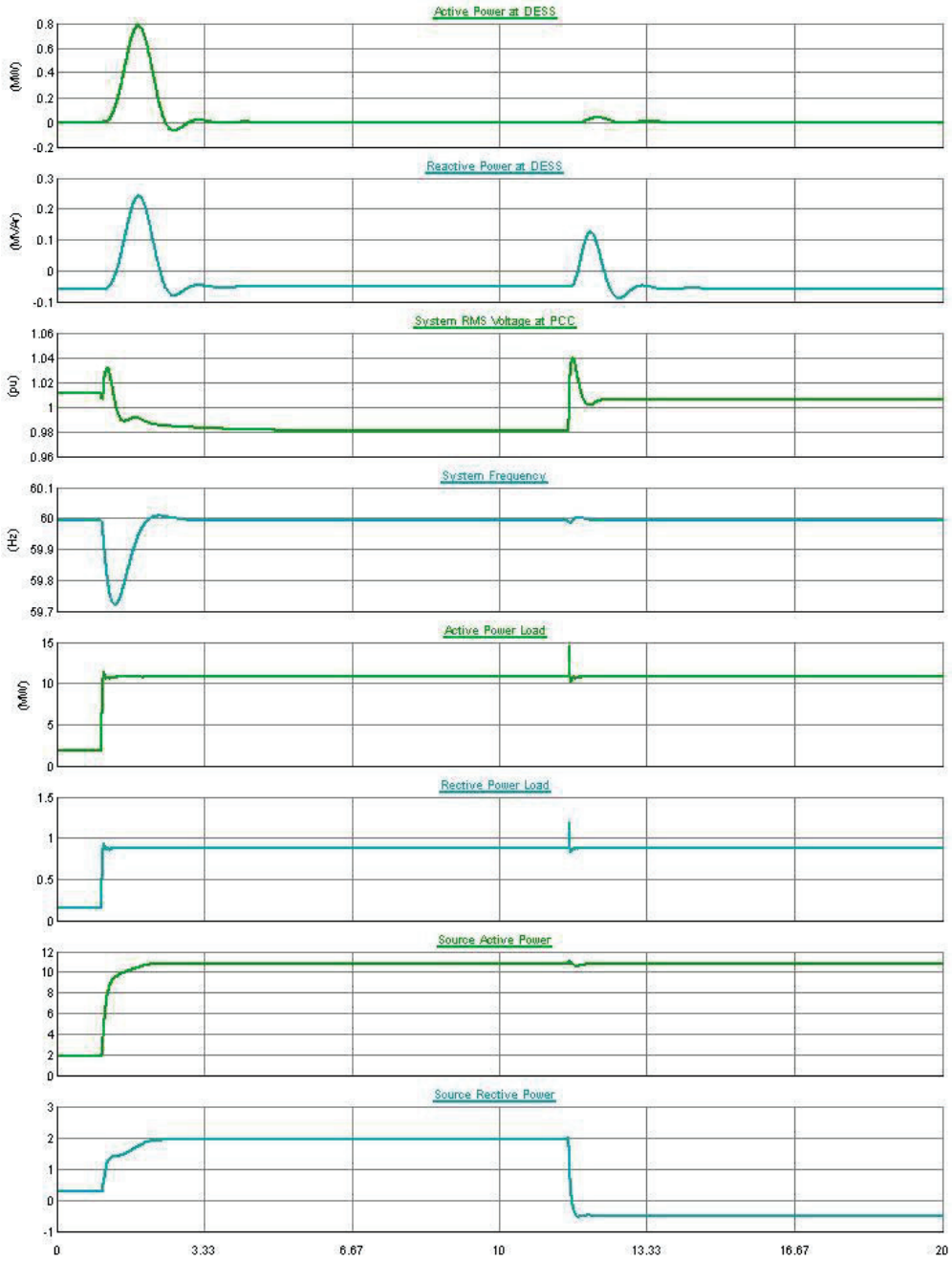


Figure B.97: System Response for Test 5.1b

TEST 5.2A: DECREASING THE ACTIVE AND REACTIVE POWER LOAD BY 9MW AND 700 KVAR

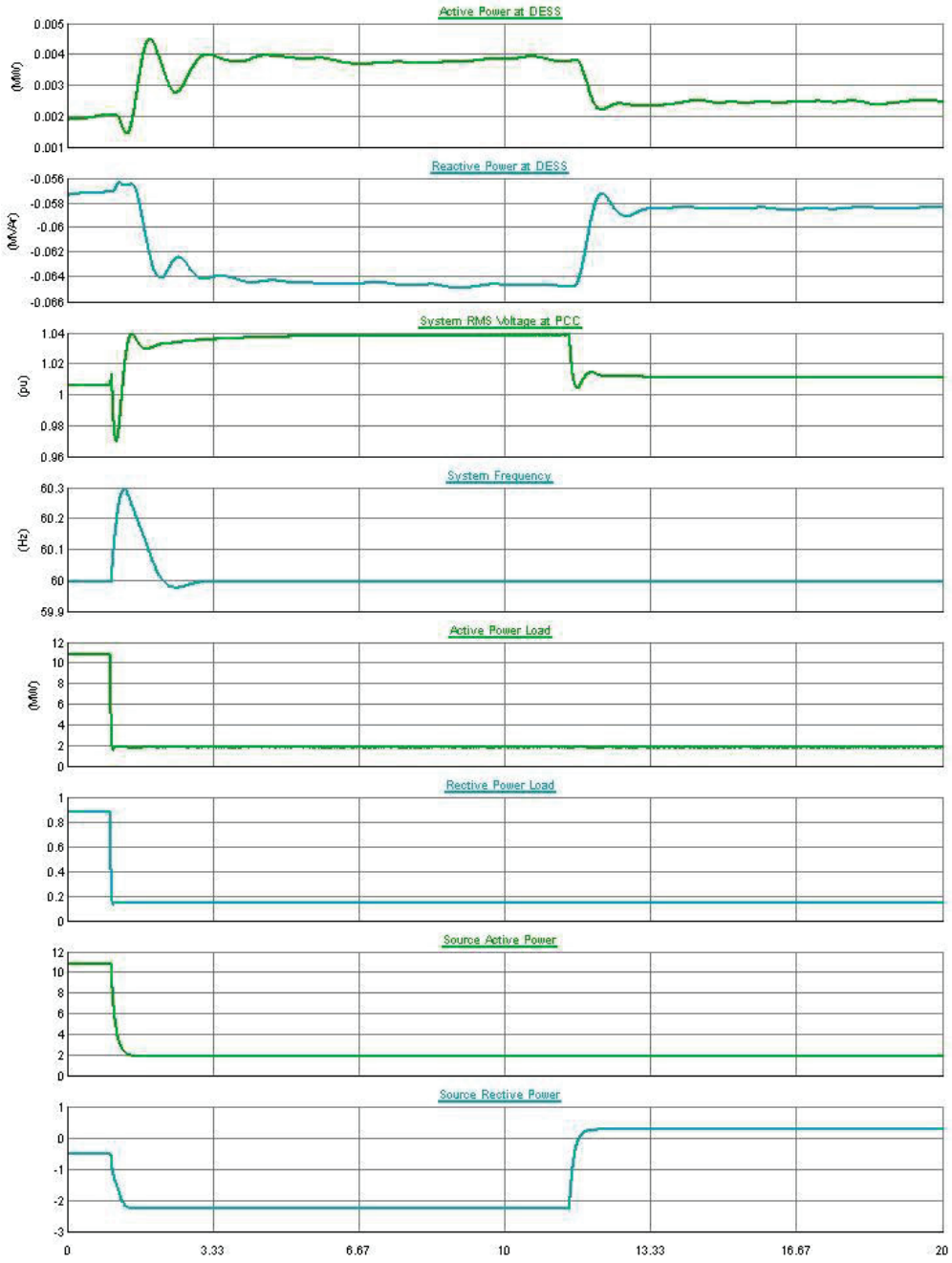


Figure B.98: System Response for Test 5.2a

TEST 5.2B: DECREASING THE ACTIVE AND REACTIVE POWER LOAD BY 9MW AND 700 KVAR

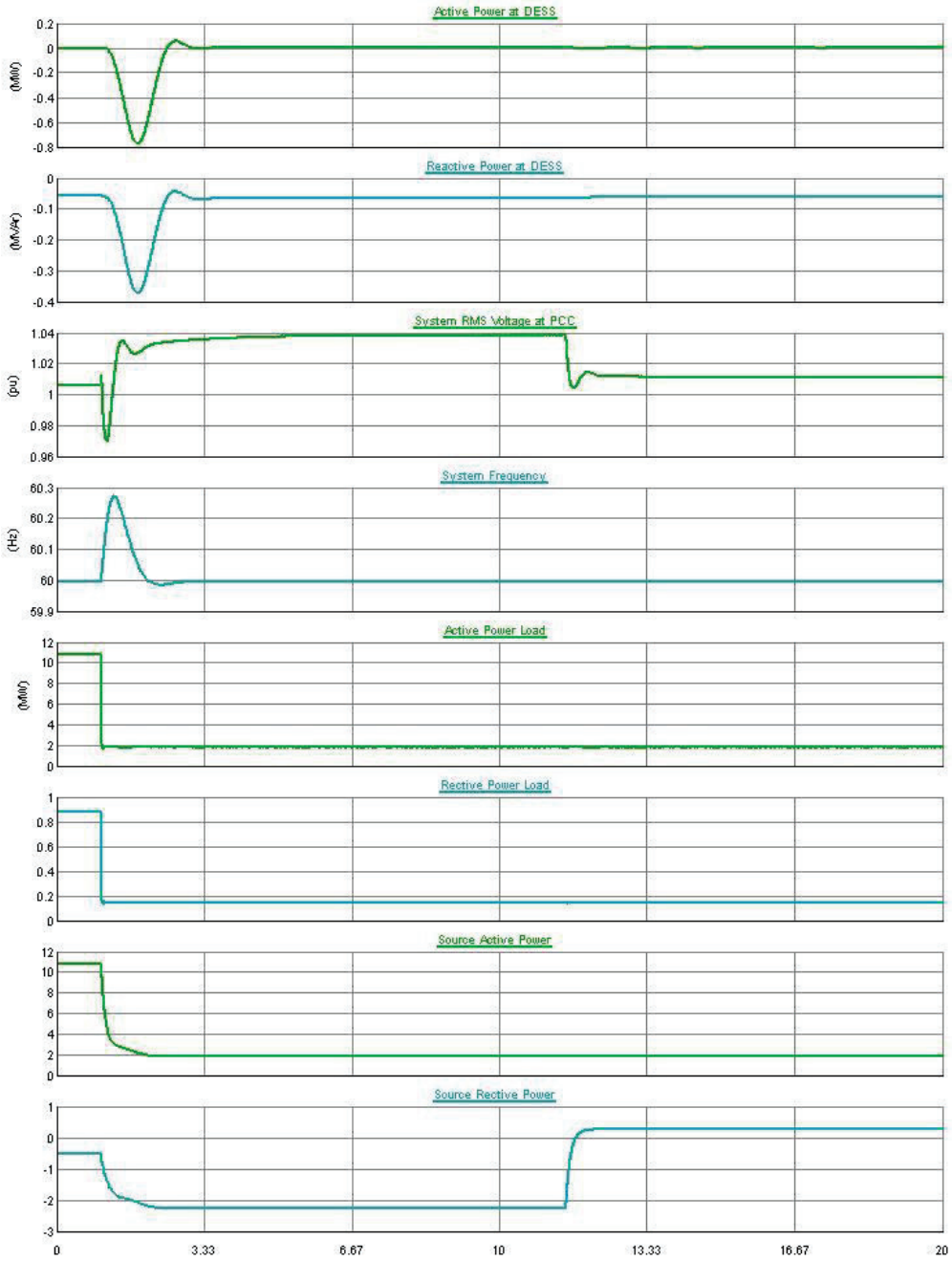


Figure B.99: System Response for Test 5.2b

Test 7 – Spinning Reserve

TEST 7.1A: INCREASING THE ACTIVE AND REACTIVE POWER LOAD BY 9MW AND 700 KVAR

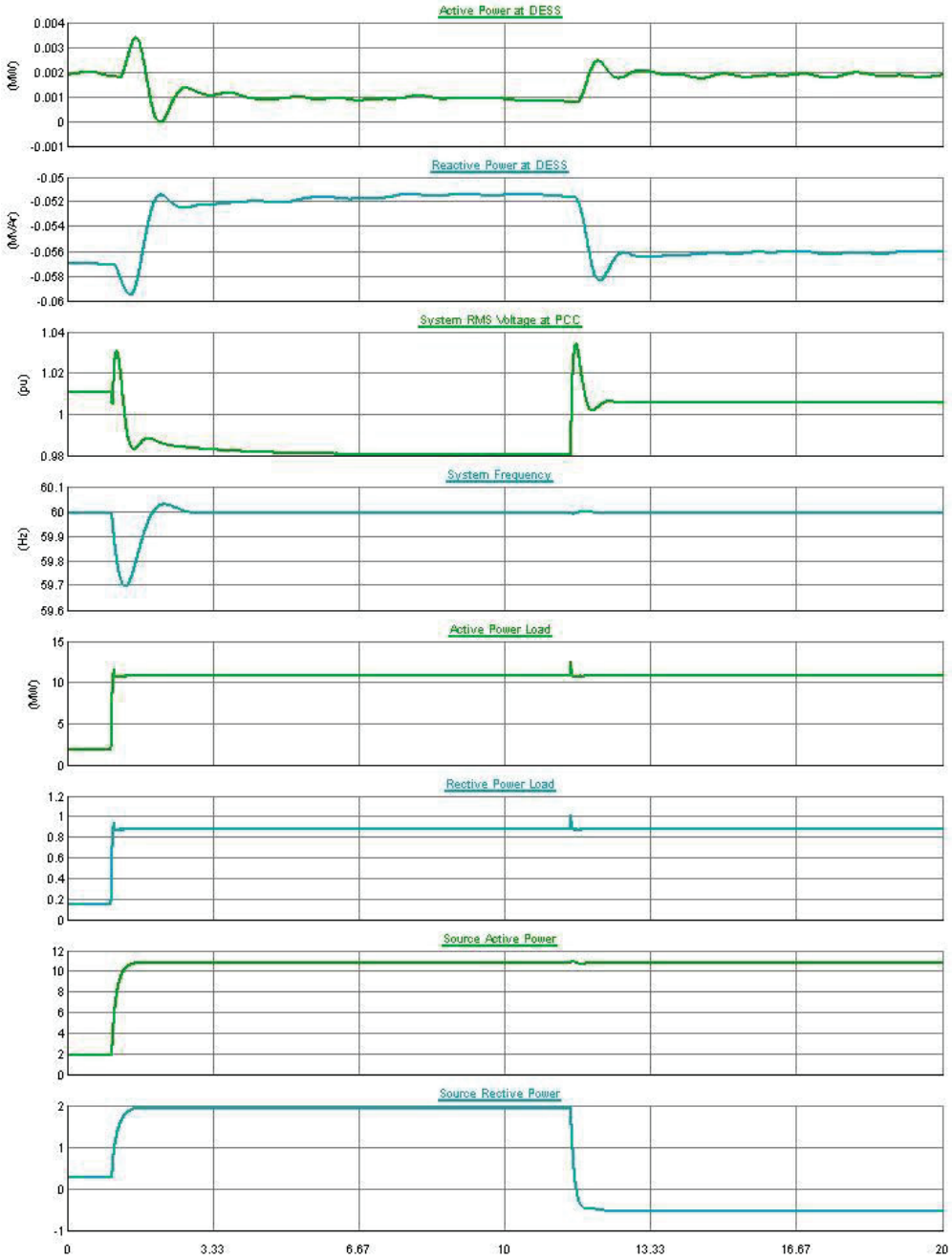


Figure B.100: System Response for Test 7.1a

TEST 7.1B: INCREASING THE ACTIVE AND REACTIVE POWER LOAD BY 9MW AND 700 KVAR

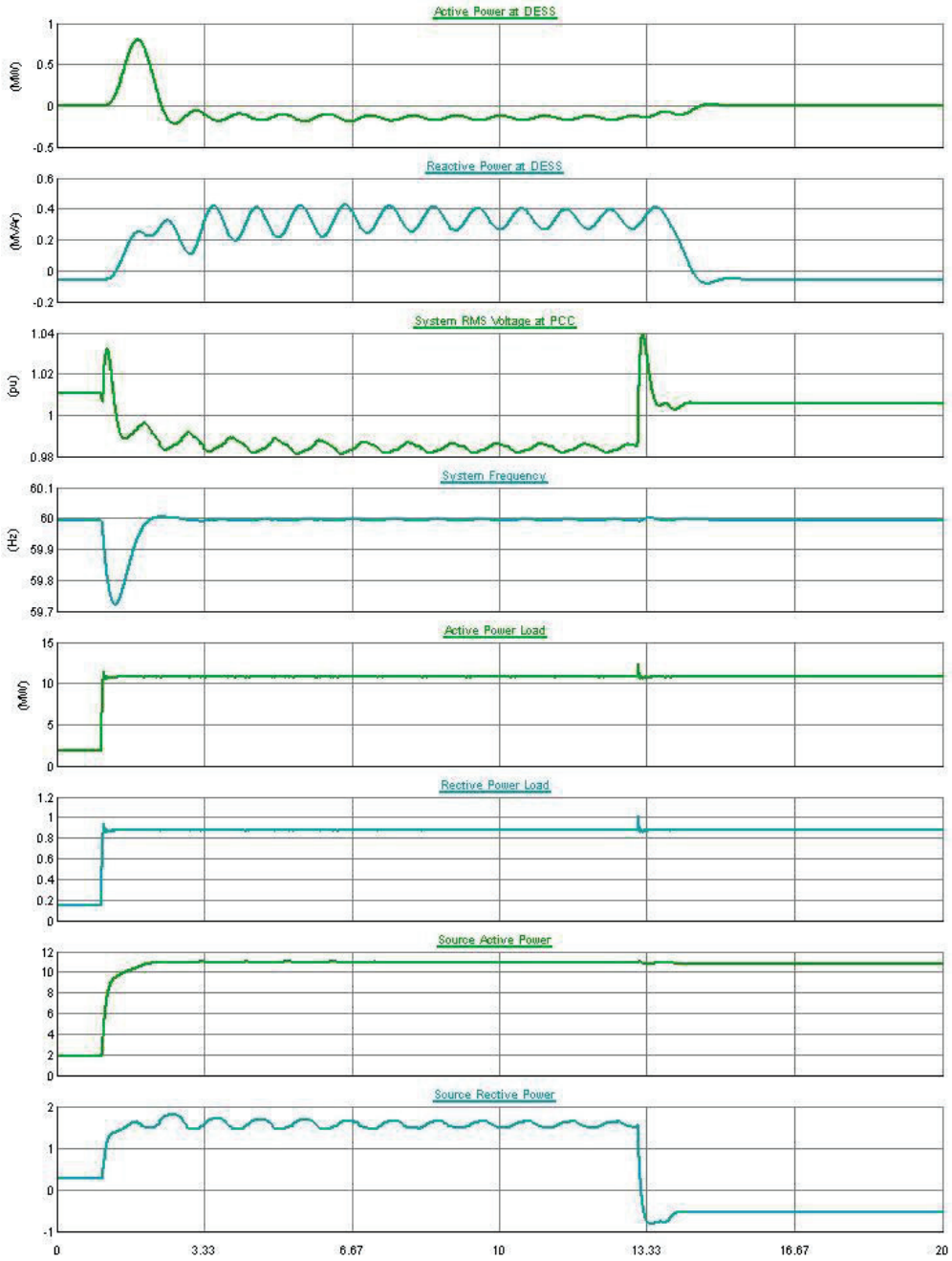


Figure B.101: System Response for Test 7.1b

TEST 7.2A: DECREASING THE ACTIVE AND REACTIVE POWER LOAD BY 9MW AND 700 KVAR

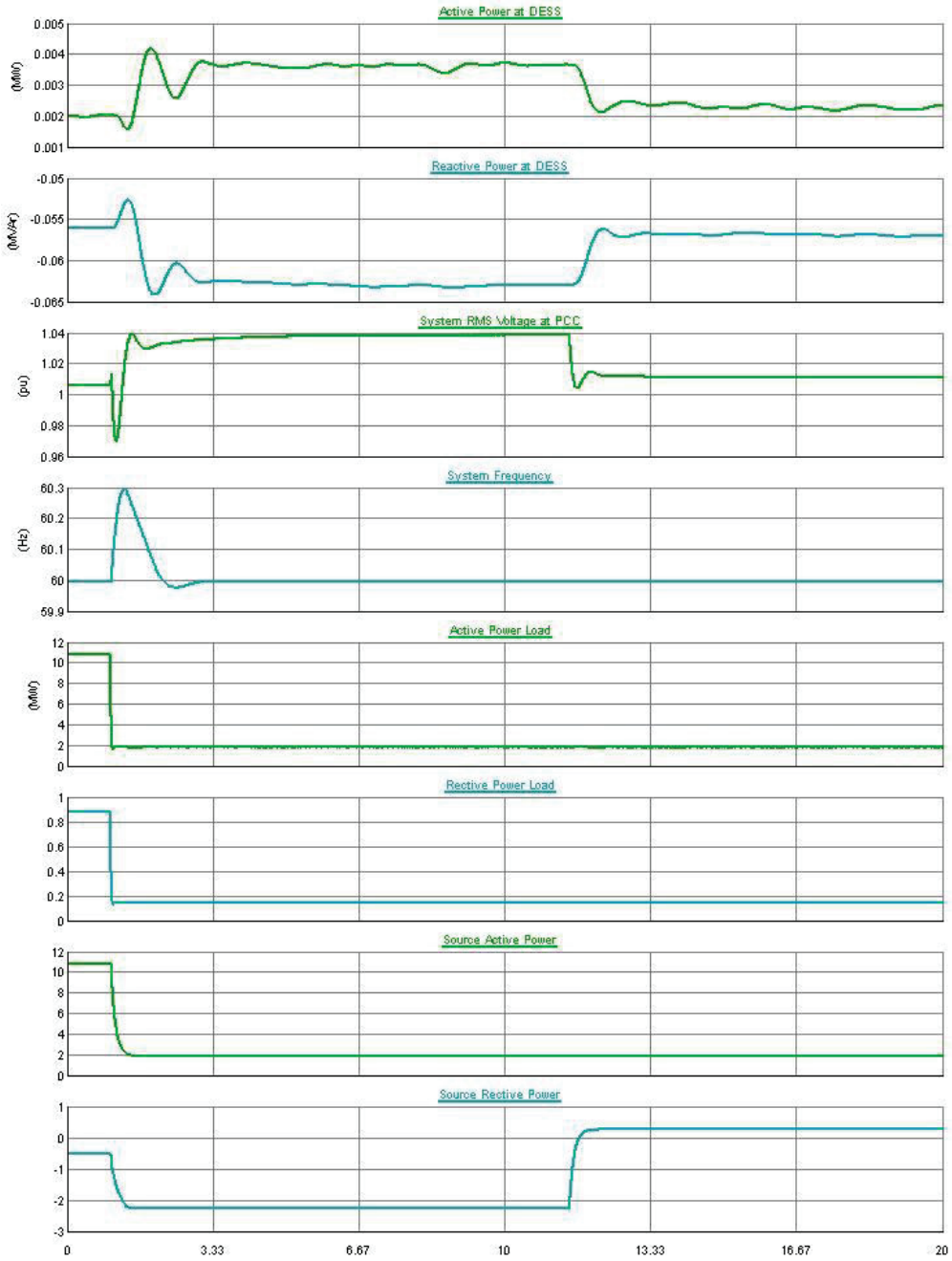


Figure B.102: System Response for Test 7.2a

TEST 7.2B: DECREASING THE ACTIVE AND REACTIVE POWER LOAD BY 9MW AND 700 KVAR RESPECTIVELY

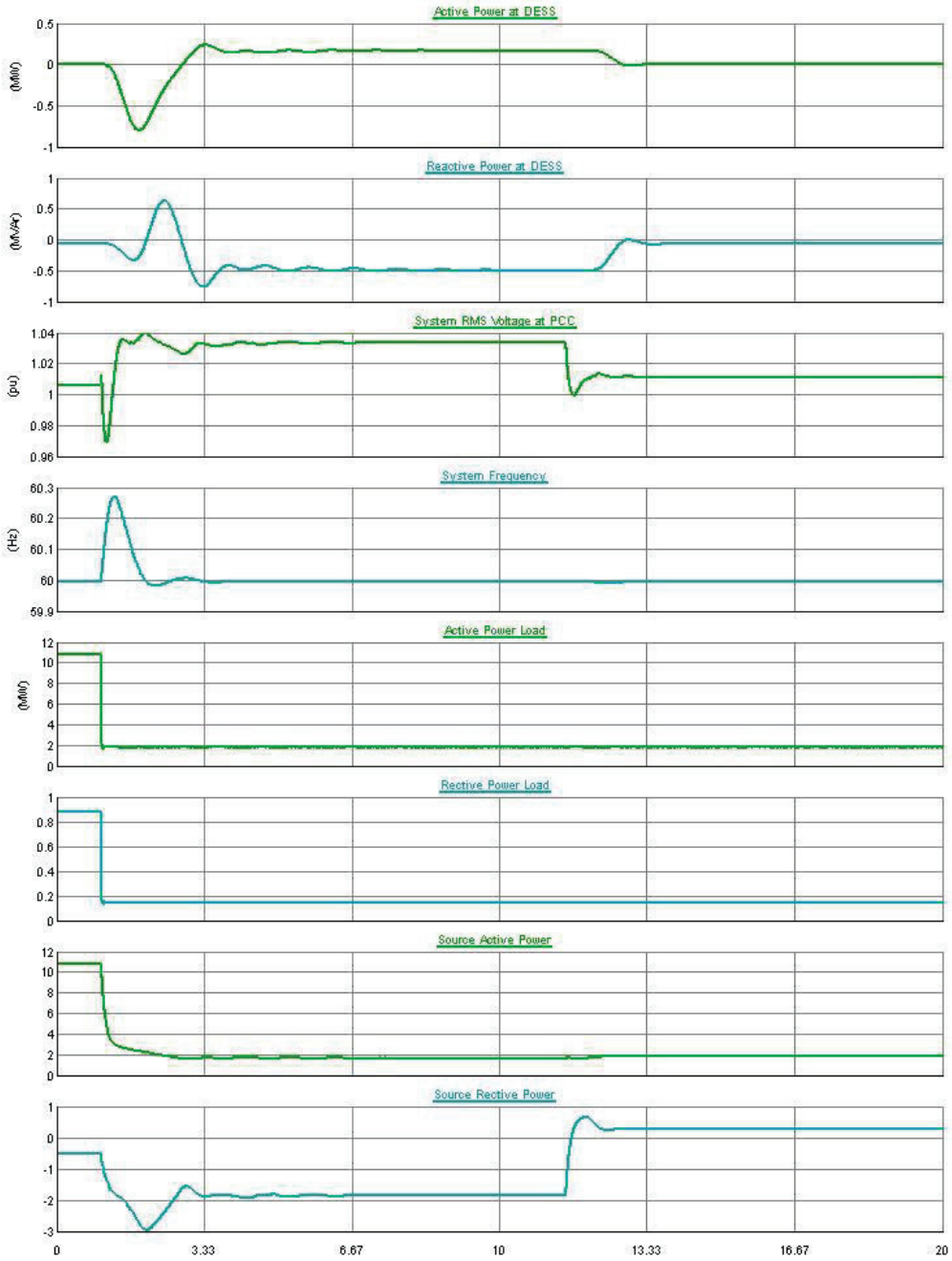


Figure B.103: System Response for Test 7.2b

Appendix 5

EPIC-1, Project 4, Module 2: Demonstration of Grid Support Functions of Distributed Energy Resources – Pre-Commercial Demonstration of Communications Standards for DER



EPIC Final Report

Program	**Electric Program Investment Charge (EPIC)**
Administrator	**San Diego Gas & Electric Company**
Project Number	**EPIC-1, Project 4**
Project Name	**Demonstration of Grid Support Functions of Distributed Energy Resources (DER)**
Module Name	**Module 2, Pre-Commercial Demonstration of Communication Standards for DER**
Date	**December 31, 2017**

Attribution

This comprehensive final report documents the work done in this EPIC project.

The project team for this work included the following individuals:

Internal SDG&E Staff

Frank Goodman

Zoltan Kertay

Prajwal Raval

Amin Salmani

Aung Thant

Kitu Systems, Inc.

Gordon Lum

Executive Summary

The objective of EPIC-1, Project 4, Demonstration of Grid Support Functions of Distributed Energy Resources (DER) was to demonstrate grid support functions of DER, which can improve distribution system operations. The chosen sub-projects and modules quantified the value of specific grid support functions in specific application situations and provided a basis for San Diego Gas & Electric Company (SDG&E) to determine which functions it wants to pursue commercially in the development of its smart grid. This project consists of three modules: value assessment of grid support functions of DER, communication standards for grid support functions of DER, and demonstration and comparison of the Electric Power Research Institute (EPRI) and SDG&E DER hosting capacity analysis tools. This executive summary addresses the module on pre-commercial demonstration of communication standards for grid support functions of DER.

With the proliferation of residential solar and storage systems, the CPUC is in the process of updating California Electric Tariff Rule 21 (CA Rule 21) governing the interconnection of generation and storage resources to utility distribution systems. As part of the update to CA Rule 21, the Smart Inverter Working Group (SIWG) has generated recommendations regarding DER grid support functions, the ability to modify and control these functions, and the needed communication standards. The CA Rule 21 update has been partitioned into 3 phases, with Phase 1 addressing the implementation of autonomous functions that operate without the need for communications, Phase 2 addressing communications to control Phase 1 and Phase 3 functions, and Phase 3 addressing advanced functions.

At this time, Phase 1 functions are well defined, Phase 2 default communications protocol has been chosen, and Phase 3 functions will be designed to align with Institute of Electrical and Electronics Engineers (IEEE) 1547 (the IEEE standard for interconnecting distributed resources with electric power systems, which is also currently being updated).

Although IEEE 2030.5-2013 was chosen as the default communications protocol for CA Rule 21, the current standard (2013) does not fully support all the Phase 1 and Phase 3 functions. A revision to the IEEE 2030.5 specification to support all Phase 1 and Phase 3 functions is currently in process and may be ready for adoption in early 2018. In the long term, it cannot be known at this time what the communication protocol specified in CA Rule 21 will be.

This EPIC pre-commercial demonstration tested the communications performance of the IEEE 2030.5 protocol (also known as SEP 2.0) on testable Phase 1 functions. The objective was to determine the impact of protocol selection on the viability and value of DER grid support functions. The testable Phase 1 control commands includes connect/disconnect, power factor, volt-VAr, and real power output. The demonstration system consisted of an IEEE 2030.5 server on the internet that creates and stores Phase 1 control actions, a cellular gateway and Wi-Fi access point for providing internet connectivity, an IEEE 2030.5 DER protocol translator for converting IEEE 2030.5 controls to Modbus controls, and a DER Device that acts on the translated Phase 1 controls. IEEE 2030.5 security was applied to secure the communications.

All the testable Phase 1 functions were successfully sent from the IEEE 2030.5 server, received by the IEEE 2030.5 DER protocol translator, and executed by the DER device. In addition, metrology data (e.g., real and reactive power output) was successfully read from the DER device over Modbus, translated and sent by the IEEE 3020.5 DER protocol translator, and received by the IEEE 2030.5 server.

Analyzing the IEEE 2030.5 protocol shows that a polling model is used, whereby the DER protocol translator periodically polls the IEEE 2030.5 server for new control actions. This polling mechanism introduces a latency on the order of 10's of seconds, so the IEEE 2030.5 protocol is well suited for "quasi-real-time" systems on the order of 10's of seconds to minutes. Thus, it is not suited for system response times of seconds or sub-seconds.

The demonstration successfully showed that the IEEE 2030.5 protocol could successfully communicate Phase 1 functions. Some recommendations for future steps are:

1. Although this pre-commercial demonstration could only test a subset of the CA Rule 21 Phase 1 functions, IEEE 2030.5 appears to be the protocol of choice for providing quasi-real-time DER grid support services in the foreseeable future. Many stakeholders from the SIWG, standards organizations, equipment manufacturers, and utilities are actively working on harmonizing IEEE 2030.5 with CA Rule 21 and IEEE 1547. No other communications protocol is at this advanced stage of development. At this time, both the IEEE 2030.5 protocol and the Phase 3 functions are being revised and updated. As the protocols for the CA Rule 21 standard or for international standards change from time to time, the successful performance of the intended functions for the new protocols should be re-demonstrated for certification by a qualified organization to validate the suitability of the new standard each time. This validation process should verify that the updated IEEE 2030.5 protocol (or any other alternative that may be adopted in CA Rule 21 or international standards) could successfully transport all Phase 1 and Phase 3 functions. SDG&E is not a certification organization.
2. The IEEE 2030.5 security model uses a power cipher suite that cannot be easily broken even for desired functions like packet inspection. IT security departments should be aware of this fact and design/modify their IT infrastructure accordingly.
3. The DER device in this demonstration used a proprietary Modbus control map. For large-scale deployments, a standardized DER Modbus model needs to be used.

Table of Contents

Executive Summary iii
1.0 Introduction 1
1.1 Statement of Project Objective 1
1.2 Project Approach 1
1.3 Test System Architecture 2
1.4 Test Terminology and Other Information 2
2.0 Use Cases 3
2.1 Test #1 – Register the DER System 3
2.2 Test #2 – Monitor the Output of the DER System 3
2.3 Test #3 – Issue Control Commands to the DER System 3
2.4 Test #4 – Issue Set-Point Update to the DER System 3
2.5 Test #5 – Activation and Deactivation Commands to the DER System 3
2.6 Test #6 – Simulate Multiple DER Systems 4
3.0 Project Results 4
3.1 Test #1 – Register the DER System 4
3.1.1 Definitions 4
3.1.2 Description 5
3.1.3 Procedure 5
3.1.4 Results 5
3.2 Test #2 – Monitor the Output of the DER system 7
3.2.1 Description 7
3.2.2 Procedure 7
3.2.3 Results 7
3.3 Test #3, #4 – Issue Control Commands, Issue Set Point Updates 10
3.3.1 Description 10
3.3.2 Fixed Power-Factor Procedure 10
3.3.3 Results 11
3.3.4 Volt-VAr Procedure 15
3.3.5 Results 15
3.4 Test #5 – Activation and Deactivation Mode Commands 19
3.4.1 Description 19
3.4.2 Connect/Disconnect and Real Power Output Procedure 19

3.4.3 Results 19
3.5 Test #7 – Cyber Security Tests 23
3.5.1 Description 23
3.5.2 Basic TLS Handshake 24
3.5.3 Results 24
3.5.4 Bad TLS Handshake 28
3.5.5 Results 28
4.0 Conclusions and Recommendations 30
4.1 Conclusions 30
4.1.1 Test #1 – Registration 30
4.1.2 Test #2 – Monitor of the Output of the DER System 30
4.1.3 Test #3 – Issue Control Commands, Test #4 Issue Set-Point Update 30
4.1.4 Test #5 – Issue Activation and Deactivation 30
4.1.5 Test #7 – Cybersecurity 30
4.1.6 Learning from Success 30
4.2 Recommendations 30
4.2.1 Evaluation of the IEEE 2030.5 Protocol 31
4.2.2 Recommendations Associated with the IEEE 2030.5 Protocol 31
4.2.3 Evaluation of IEEE 2030.5 Security in Production 31
4.2.4 Recommendations Associated with Security 32
4.2.5 Evaluation of DER Device Interoperability 32
4.2.6 Recommendations Associated with DER Device Interoperability 32
5.0 Technology Transfer Plan 32
6.0 Metrics and Value Proposition 33
6.1 Metrics 33
6.2 Value Proposition 33
7.0 References 34

List of Figures

Figure 1 – Test System Architecture 2
Figure 2 - Server Registration 6
Figure 3 - Client Registration 6
Figure 4 - Reported Real Power prior to Event Start 7
Figure 5 - Reported Reactive Power prior to Event Start 8
Figure 6 - Reported Real Power after Event Start 9
Figure 7 - Reported Reactive Power after Event Start 10
Figure 8 - Reported Real Power prior to Event Start 11
Figure 9 - Reported Reactive Power prior to Event Start 12
Figure 10 - DER Control, Real and Reactive 13
Figure 11 - Real Power output during DER Control Event 14
Figure 12 - Reactive Power output during DER Control Event 15
Figure 13 - Reported Reactive Power prior to Event Start 16
Figure 14 - Volt-VAr Curve DER Event 17
Figure 15 - Reported Reactive Power during Voltage Disturbance 18
Figure 16 - Reported Real Power prior to Event Start 20
Figure 17 - Reported Reactive Power prior to Event Start 21
Figure 18 - Reported Real Power after Event Start 22
Figure 19 - Reported Real Power after Event Completion 23
Figure 20 - TLS Handshake 25
Figure 21 - TLS Client Hello 26
Figure 22 - TLS Server Hello 27
Figure 23 - TLS Bad Certificate 29

Acronyms and Abbreviations

AES	Advanced Encryption Standard
CA Rule 21	California Electric Tariff Rule 21
CBC	Cipher Block Chaining
CPUC	California Public Utilities Commission
CSIP	Common Smart Inverter Profile
DC	Direct Current
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DMZ	De-militarized Zone
DRLC	Demand Response Load Control
EPIC	Electric Program Investment Charge
EPRI	Electric Power Research Institute

ESS	Energy Storage System
IEEE	Institute of Electrical and Electronics Engineers
IOUs	Investor-Owned Utilities
IT	Information Technology
mRID	Master Resource Identifier
NSA	National Security Agency
PC	Personal Computer
PV	Photovoltaic
SDG&E	San Diego Gas & Electric Company
SIWG	Smart Inverter Working Group
SEP	Smart Energy Profile
SEP 2.0	Smart Energy Profile 2.0 (synonymous with IEEE 2030.5)
SFDI	Short Form Device Identifier
T&D	Transmission & Distribution
TLS	Transport Layer Security
WAF	Web Application Firewall

1.0 Introduction

1.1 Statement of Project Objective

The objective of EPIC-1, Project 4, Demonstration of Grid Support Functions of Distributed Energy Resources (DER) was to demonstrate grid support functions of DER, which can improve distribution system operations. The chosen sub-projects and modules quantified the value of specific grid support functions in specific application situations and provided a basis for SDG&E to determine which functions it wants to pursue commercially in the development of its smart grid. This project consists of three modules: value assessment of grid support functions of DER, communication standards for grid support functions of DER, and demonstration and comparison of the EPRI and SDG&E DER hosting capacity analysis tools. This final report addresses the second module on pre-commercial demonstration of communication standards for grid support functions of DER.

The California Public Utilities Commission (CPUC) initiated a rulemaking proceeding to review and, if necessary, revise the rules and regulations governing interconnecting generation and storage resources to the electric distribution systems. This proceeding is generally referred to as updates to Electric Tariff Rule 21 (CA Rule 21), and the Smart Inverter Working Group (SIWG) has been tasked with generating recommendations for this proceeding.

As a result of the SIWG work, CA Rule 21 has been divided into 3 phases:

- Phase 1 – Addresses autonomous functions that smart inverters must support. Autonomous means these functions must exist and work without the need for communications.
- Phase 2 – Addresses communications to change and/or control Phase 1 and Phase 3 functions. The default protocol for communications is IEEE 2030.5 (also known as SEP 2.0).
- Phase 3 – Addresses advanced smart inverter functions.

The focus of this module of the EPIC project was to perform a pre-commercial demonstration of IEEE 2030.5-2013 as a protocol to communicate CA Rule 21 DER grid support functions. Supported Phase 1 functions were tested. Phase 3 functions were not tested, because the list of advanced functions have not been finalized and current inverters do not yet support many of these advanced functions.

The IEEE 2030.5 protocol was chosen because it provides the most support for communicating with the DER controls required by CA Rule 21. IEEE 2030.5 was initially developed as Smart Energy Profile 2.0 (SEP 2.0). The purpose of SEP 2.0 was to provide an IP based protocol for communication smart energy functions like demand response load control (DRLC), metering, pricing, and DER. Subsequently, SEP 2.0 was formally ratified in 2013. Shortly after ratification, ownership and maintenance of the standard was transferred to IEEE, and the protocol was renamed IEEE 2030.5 and the adopted version was renamed IEEE 2030.5-2013. Therefore, SEP 2.0 and IEEE 2030.5 are the same protocols. The name “SEP 2.0” is now deprecated in favor of the name “IEEE 2030.5”.

1.2 Project Approach

For this pre-commercial demonstration, a test system was set up to perform the tests. The test system architecture is described in the next section. Seven test cases were tested. The description of each use case is described in the “Use Cases” section. For each test case, DER grid support controls were first created on the IEEE 2030.5 Server. The DER Protocol Translator, the DER Device, and the DER System Simulator were then started. All the IEEE 2030.5 communications were recorded for later analysis.

1.3 Test System Architecture

The test system architecture is shown in Figure 1. The system consists of the following components:

- **IEEE 2030.5 Server** – This server is the "front-end" of the utility Distributed Energy Resource Management System (DERMS). It can be thought of as an "IEEE 2030.5 protocol translator" that converts commands from the utility DERMs to IEEE 2030.5 format. For this demonstration, a real DERMS was not used. Instead, a human operator created the controls that DERMS would normally provide. These controls were entered via webpages linked to the IEEE 2030.5 internet server.
- **Cellular Gateway** – This device provides internet connectivity to the local DER test site.
- **Wi-Fi Access Poin**t – This device uses the Cellular Gateway to provide Wi-Fi internet access to devices at the DER test site.
- **DER Protocol Translator** – This device translates the IEEE 2030.5 protocol information to Modbus register controls for the DER. Physically, this device is a computer module running the IEEE 2030.5 DER client code. Logically, this device acts as IEEE 2030.5 client when interfacing to the IEEE 2030.5 server, and acts as Modbus master when interfacing with the DER Modbus slave. In this report, the term DER client will be used to refer to the DER protocol translator.
- **DER Device** – The DER device used in this system is an 88-kW Energy Storage System (ESS) that has been widely utilized in the SDG&E DER sites.
- **DER System Simulator** – The DER System Simulator consists of a real-time power system simulation, grid simulator (as power amplifier), smart inverter, direct current (DC) power supply to provide DC source as battery or photovoltaic (PV).
- **Ethernet Sniffer** – This is a personal computer (PC) monitoring Ethernet traffic between the Cellular Gateway and the Wi-Fi Access Point. At this location, the sniffer can monitor all traffic between the IEEE 2030.5 Server and the DER Protocol Translator.

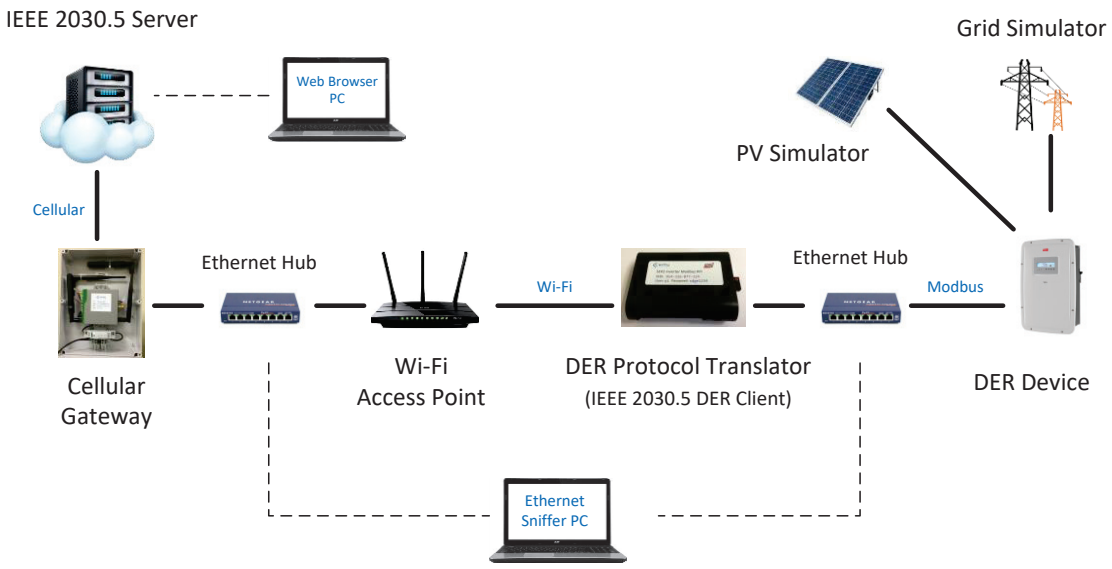


Figure 1 – Test System Architecture

1.4 Test Terminology and Other Information

This report uses information and terminology associated with the IEEE 2030.5 protocol. This section briefly explains some terms and information that will appear in this report.

- **Events** – In IEEE 2030.5, controls (e.g., real and reactive power settings) are events. An event is an IEEE 2030.5 resource that has a start time (in UTC), a duration (in seconds), and some control value.
- **mRID** – In IEEE 2030.5, an mRID is a 128-bit number that servers as a unique identifier of a resource on the server.
- Control values like real and reactive power settings are expresses as a percentage of the device's nameplate maximum settings. The DER Device used in this report has a real power output maximum setting of 50 kW and a reactive power output maximum of 50 kVAr. The units are in 0.01 percent (i.e., a value of 1 represents 0.01 percent, and a value of 10000 represents 100 percent). For example, to set the real power output to 90% of its nameplate maximum setting, a setting of 9000 is used.
- The DER Protocol Translator returns meter readings (e.g., real and reactive power output) read from the DER Device's Modbus registers. In IEEE 2030.5, meter readings have a value and a power of 10 multiplier. For all of the tests discussed in this report, the power of 10 multiplier was set to -1, so the unit of measure for real power is 0.1 watts and the unit of measure for reactive power is 0.1 VArs. For example, a reported power level of 500000 represents 50 kW.

2.0 Use Cases

This pre-commercial demonstration will test seven use cases. Each use case focuses on one or more DER functions that are expected to be important for grid support services.

2.1 Test #1 – Register the DER System

Registration is an important part of any production system as it provides a means of identifying and managing devices on the system. This test case will verify the Registration capabilities of the IEEE 2030.5 protocol.

2.2 Test #2 – Monitor the Output of the DER System

Many grid support services need to monitor the real and reactive power output of DER Devices. This information is important for evaluating the effectiveness of current controls and to forecast future controls. This test will verify the reporting capabilities of the IEEE 2030.5 protocol by measuring the real and reactive power outputs of the DER Device prior to and during an active DER control.

2.3 Test #3 – Issue Control Commands to the DER System

Many grid support services need to issue control commands to change the behavior of the DER Device. This test will verify the transmission of control commands using the IEEE 2030.5 protocol. The DER Device output (e.g., real and reactive power) will be measured prior to and during a control command to verify the command was properly executed.

2.4 Test #4 – Issue Set-Point Update to the DER System

Many grid support services need to change a set point of the DER device. This test will verify the transmission of set points using the IEEE 2030.5 protocol. The DER device output (e.g., real and reactive power) will be measured prior to and during a control command to verify the set point was properly executed.

2.5 Test #5 – Activation and Deactivation Commands to the DER System

Many grid support services need to activate/deactivate a DER Device. This test will verify the transmission of an activate/deactivate command using the IEEE 2030.5 protocol. The DER Device output (e.g., real and reactive power) will be measured prior to and during a control command to verify the activate/deactivate command was properly executed.

2.6 Test #6 – Simulate Multiple DER Systems

The performance of a system when connected to multiple DER Devices needs to be tested and analyzed. This data is needed to estimate system performance as the system is scaled to production levels. This test will verify the performance of the system when connected to multiple DER Devices that are simultaneously polling for DER controls and posting metrology data.

3.0 Project Results

SIWG has defined California Rule 21 Phase 1 functions to be:

1. High/Low Voltage Ride Through
2. High/Low Frequency Ride Through
3. Ramp Rate
4. Connect/Disconnect
5. Fixed Power Factor
6. Volt-Var Control
7. Real Power Output Control

Ideally, all Phase 1 functions should be demonstrated, but the DER Device utilized in this test system did not support all the Phase 1 functions. To be more specific, this DER device supported the ride through functions and ramp rate control, but these settings cannot be changed over Modbus. Therefore, the subset of testable Phase 1 functions were:

1. Connect/Disconnect
2. Fixed Power Factor
3. Volt-Var Control
4. Real Power Output Control

3.1 Test #1 – Register the DER System

3.1.1 Definitions

To understand IEEE 2030.5 registration, the definitions of a few terms may be helpful:

- **EndDevice** – An EndDevice is a resource on the Server that represents a unique physical client device. For this project, the physical client device is the DER client (i.e., the DER Protocol Translator). Information about the client device and specific commands to a client device are realized using this resource. An EndDevice is uniquely identified using its short-form device identifier (SFDI) that is unique to the device.
- **SFDI** (Short-Form Device Identifier) – Each EndDevice is uniquely identified by its SFDI. The SFDI is a 12-digit decimal number derived from hashing the device's unique Device Certificate. For these tests, the IEEE 2030.5 DER Protocol Translator contains the unique Device Certificate. The SFDI of this Device Certificate, which is used in all the tests, is "14336077324".
- **Device Certificate** – In IEEE 2030.5, all client devices must have a unique device certificate. For all tests in this report, the device certificate is in the IEEE 2030.5 DER Protocol Translator. The device certificate is an X.509 digital certificate that chains back to the Root Certificate Authority. The device certificate is used to authenticate the identity of the client device. The SFDI is derived from the device certificate. It is computed by taking the first 36-bits of the SHA-256 Hash of the device certificate.
- **Registration** – In IEEE 2030.5, there are two sides to registration
    - **Server Registration** – Server registration refers to the creation of the EndDevice resource for "registered" devices. This is an out-of-band process where the client information (e.g., SFDI) is used to

create the corresponding EndDevice resource on the IEEE 2030.5 server. In the project, server registration is performed using the “create inverter” function on the server webpage.

- **Client Registration** – Client registration occurs when the DER client device finds its EndDevice information on the server and verifies the registration PIN is correct. If registration is confirmed, the DER client continues with normal operation. If registration is not-confirmed, the DER client ceases operation with the server.

- **Registration PIN** – The registration PIN is a resource associated with the EndDevice entry. It contains a 6-digit code that the DER client uses to verify registration. This code is shared between the server and DER client via an out-of-band process. In this project, the PIN that is used is “111115” and is provisioned into the server and DER client prior to the start of testing.

3.1.2 Description

Registration is an important step in managing and controlling DER devices. In IEEE 2030.5, server registration is used to maintain a list of authorized EndDevices, and client registration is used to verify that a specific EndDevice is permitted to access the server. To verify server and client registrations, the initial communications between the server and DER client was captured and analyzed to confirm the DER client successfully retrieved its EndDevice resource and verified the registration PIN.

3.1.3 Procedure

The test procedure was:

1. Configure the DER client to use unencrypted HTTP to allow for Ethernet sniffer captures.
2. Start the Ethernet sniffer trace.
3. Start the DER client.
4. Wait 2 minutes.
5. Stop the DER client.
6. Stop the Ethernet sniffer trace.

3.1.4 Results

The full trace is captured in the Ethernet sniffer file: “Real-80.pcapng”

The packet in Figure 2 shows the EndDevice instance of the DER device containing the correct SFDI value of 14336077324. This verifies server registration.

```
GET /sep2/edev HTTP/1.1
Accept: application/sep+xml
Host: 52.35.96.64:8080

HTTP/1.1 200 OK
Access-Control-Allow-Origin: *
Access-Control-Allow-Methods: GET,PUT,POST,DELETE, OPTIONS
Access-Control-Allow-Headers: Content-Type, Authorization
Access-Control-Expose-Headers: Location
Content-Type: application/sep+xml; charset=utf-8
Content-Length: 544
Date: Wed, 16 Aug 2017 21:55:02 GMT
Connection: keep-alive

<EndDeviceList href="/sep2/edev" subscribable="1" all="1" results="1" xmlns="http://zigbee.org/sep"
xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance">
        <EndDevice href="/sep2/edev/31" subscribable="1">
                <sFDI>14336077324</sFDI>
                <RegistrationLink href="/sep2/edev/31/rg"/>
                <DERListLink href="/sep2/edev/31/der" all="1"/>
                <LogEventListLink href="/sep2/edev/31/lel" all="0"/>
                <SubscriptionListLink href="/sep2/edev/31/sub" all="0"/>
                <FunctionSetAssignmentsListLink href="/sep2/fsagrp/22/fsa" all="1"/>
        </EndDevice>
</EndDeviceList>
```

Figure 2 - Server Registration

The packet in Figure 3 shows the correct registration PIN of 111115 is retrieved. This verifies Client Registration.

```
GET /sep2/edev/31/rg HTTP/1.1
Accept: application/sep+xml
Host: 52.35.96.64:8080

HTTP/1.1 200 OK
Access-Control-Allow-Origin: *
Access-Control-Allow-Methods: GET,PUT,POST,DELETE, OPTIONS
Access-Control-Allow-Headers: Content-Type, Authorization
Access-Control-Expose-Headers: Location
Content-Type: application/sep+xml; charset=utf-8
Content-Length: 210
Date: Wed, 16 Aug 2017 21:55:03 GMT
Connection: keep-alive

<Registration href="/sep2/edev/31/rg" xmlns="http://zigbee.org/sep"
xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance">
        <dateTimeRegistered>1502495010</dateTimeRegistered>
        <pIN>111115</pIN>
</Registration>
```

Figure 3 - Client Registration

3.2 Test #2 – Monitor the Output of the DER system

3.2.1 Description

This purpose of this test is to verify the reporting of the output of the DER system. The DER device is capable of reporting real power and reactive power. This test verifies the reporting of this data. The DER device is configured to post real and reactive power readings roughly every 10 seconds. This test is run using a fixed power-factor control to enable both real and reactive power output.

3.2.2 Procedure

Test procedure was:

1. Configure the DER device to use unencrypted HTTP to allow for Ethernet sniffer captures.
2. Start the Ethernet sniffer trace.
3. Start the DER client.
4. Schedule a fixed power-factor control for 2 minutes.
5. Wait 3 minutes.
6. Stop the DER client.
7. Stop the Ethernet sniffer trace.

3.2.3 Results

The full trace is captured in the Ethernet sniffer file: “PF-90-30.pcapng”

Verify that the DER client is periodically reporting real and reactive power. The relevant packets are shown below.

The packet in Figure 4 shows the reported real power output prior to the start of the DER control event. The reported value is **-999** which indicates the DER device is disconnected (i.e., no real power exported).

```
POST /sep2/mup/4 HTTP/1.1
Content-Length: 418
Content-Type: application/sep+xml
Host: 52.35.96.64:8080

<MirrorMeterReading
     xmlns="http://zigbee.org/sep"
     xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance">
    <mRID>055731E34571F7501D00000000009182</mRID>
    <description>Real Power(W)</description>
    <Reading>
        <timePeriod>
            <duration>0</duration>
            <start>1502920333</start>
        </timePeriod>
        <value>-999</value>
    </Reading>
</MirrorMeterReading>
HTTP/1.1 204 No Content
Access-Control-Allow-Origin: *
Access-Control-Allow-Methods: GET,PUT,POST,DELETE, OPTIONS
Access-Control-Allow-Headers: Content-Type, Authorization
Access-Control-Expose-Headers: Location
Location: /sep2/upt/4/mr/26
Date: Wed, 16 Aug 2017 21:52:15 GMT
Connection: keep-alive
```

Figure 4 - Reported Real Power prior to Event Start

The packet in Figure 5 shows the reported reactive power output prior to the start of the DER control event. The reported value is **-999** which indicates the DER device is disconnected (i.e., no reactive power exported).

```
POST /sep2/mup/4 HTTP/1.1
Content-Length: 424
Content-Type: application/sep+xml
Host: 52.35.96.64:8080

<MirrorMeterReading
     xmlns="http://zigbee.org/sep"
     xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance">
    <mRID>055731E34571F7501A00000000009182</mRID>
    <description>Reactive Power(VAr)</description>
    <Reading>
        <timePeriod>
            <duration>0</duration>
            <start>1502920333</start>
        </timePeriod>
        <value>-999</value>
    </Reading>
</MirrorMeterReading>
HTTP/1.1 204 No Content
Access-Control-Allow-Origin: *
Access-Control-Allow-Methods: GET,PUT,POST,DELETE, OPTIONS
Access-Control-Allow-Headers: Content-Type, Authorization
Access-Control-Expose-Headers: Location
Location: /sep2/upt/4/mr/29
Date: Wed, 16 Aug 2017 21:52:16 GMT
Connection: keep-alive
```

Figure 5 - Reported Reactive Power prior to Event Start

The packet in Figure 6 shows the reported real power output after the start of the DER control event. The reported value is **443000** which represents 44,300 Watts.

```
POST /sep2/mup/4 HTTP/1.1
Content-Length: 420
Content-Type: application/sep+xml
Host: 52.35.96.64:8080

<MirrorMeterReading
     xmlns="http://zigbee.org/sep"
     xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance">
    <mRID>055731E34571F7501D00000000009182</mRID>
    <description>Real Power(W)</description>
    <Reading>
        <timePeriod>
            <duration>0</duration>
            <start>1502920383</start>
        </timePeriod>
        <value>443000</value>
    </Reading>
</MirrorMeterReading>
HTTP/1.1 204 No Content
Access-Control-Allow-Origin: *
Access-Control-Allow-Methods: GET,PUT,POST,DELETE, OPTIONS
Access-Control-Allow-Headers: Content-Type, Authorization
Access-Control-Expose-Headers: Location
Location: /sep2/upt/4/mr/26
Date: Wed, 16 Aug 2017 21:53:05 GMT
Connection: keep-alive
```

Figure 6 - Reported Real Power after Event Start

The packet in Figure 7 shows the reported reactive power output after the start of the DER control event. The reported value is **150000** which is 15,000 VArs.

```
POST /sep2/mup/4 HTTP/1.1
Content-Length: 426
Content-Type: application/sep+xml
Host: 52.35.96.64:8080

<MirrorMeterReading
     xmlns="http://zigbee.org/sep"
     xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance">
    <mRID>055731E34571F7501A00000000009182</mRID>
    <description>Reactive Power(VAr)</description>
    <Reading>
        <timePeriod>
            <duration>0</duration>
            <start>1502920383</start>
        </timePeriod>
        <value>150000</value>
    </Reading>
</MirrorMeterReading>
HTTP/1.1 204 No Content
Access-Control-Allow-Origin: *
Access-Control-Allow-Methods: GET,PUT,POST,DELETE, OPTIONS
Access-Control-Allow-Headers: Content-Type, Authorization
Access-Control-Expose-Headers: Location
Location: /sep2/upt/4/mr/29
Date: Wed, 16 Aug 2017 21:53:06 GMT
Connection: keep-alive
```

Figure 7 - Reported Reactive Power after Event Start

3.3 Test #3, #4 – Issue Control Commands, Issue Set Point Updates

3.3.1 Description

In IEEE 2030.5, there is no distinction between “control commands” and “set point updates”. Both are considered a DER control in IEEE 2030.5 parlance, so test case #3 and test case #4 are the same tests with different control commands. A DER control is an IEEE 2030.5 event that has a start time, duration, and a control value. Prior to a control event, the control is either “off” or operating under a default control value. At the start time of the event, the control is enabled at a certain set point value for the specified duration. Once the duration has expired, the control reverts to “off” or its default control value. The following Phase 1 functions were tested: Fixed Power-Factor and Volt-Var.

3.3.2 Fixed Power-Factor Procedure

The purpose of this test was to verify that a fixed power factor DER control function was successfully communicated to the DER device. The DER device under test did not directly support the fixed power factor function, so the server converts the power factor setting to a real and reactive power setting based on the nameplate power rating. In this test, the nameplate power setting is 50000 Watts. The test sequence was:

1. Configure the DER client to use unencrypted HTTP to allow for Ethernet sniffer captures.
2. Start the Ethernet sniffer trace.
3. Start the DER client.
4. Schedule a power factor control for 2 minutes.
5. Wait 3 minutes.
6. Stop the DER client.
7. Stop the Ethernet sniffer trace.

3.3.3 Results

The full trace is captured in the Ethernet sniffer file: “PF-90-30.pcapng”. The relevant packets from that file are provided below.

The packet in Figure 8 shows the reported real power output prior to the start of the DER control event. The reported value is **-999** which indicates the DER device is disconnected (i.e., no real power exported).

```
POST /sep2/mup/4 HTTP/1.1
Content-Length: 418
Content-Type: application/sep+xml
Host: 52.35.96.64:8080

<MirrorMeterReading
     xmlns="http://zigbee.org/sep"
     xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance">
    <mRID>055731E34571F7501D00000000009182</mRID>
    <description>Real Power(W)</description>
    <Reading>
        <timePeriod>
            <duration>0</duration>
            <start>1502920318</start>
        </timePeriod>
        <value>-999</value>
    </Reading>
</MirrorMeterReading>
HTTP/1.1 204 No Content
Access-Control-Allow-Origin: *
Access-Control-Allow-Methods: GET,PUT,POST,DELETE, OPTIONS
Access-Control-Allow-Headers: Content-Type, Authorization
```

Figure 8 - Reported Real Power prior to Event Start

The packet in Figure 9 shows the reported reactive power output prior to the start of the DER control event. The reported value is **-999** which indicates the DER device is disconnected (i.e., no reactive power exported).

```
POST /sep2/mup/4 HTTP/1.1
Content-Length: 424
Content-Type: application/sep+xml
Host: 52.35.96.64:8080

<MirrorMeterReading
     xmlns="http://zigbee.org/sep"
     xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance">
    <mRID>055731E34571F7501A00000000009182</mRID>
    <description>Reactive Power(VAr)</description>
    <Reading>
        <timePeriod>
            <duration>0</duration>
            <start>1502920318</start>
        </timePeriod>
        <value>-999</value>
    </Reading>
</MirrorMeterReading>
HTTP/1.1 204 No Content
Access-Control-Allow-Origin: *
Access-Control-Allow-Methods: GET,PUT,POST,DELETE, OPTIONS
Access-Control-Allow-Headers: Content-Type, Authorization
Access-Control-Expose-Headers: Location
Location: /sep2/upt/4/mr/29
Date: Wed, 16 Aug 2017 21:52:01 GMT
Connection: keep-alive
```

Figure 9 - Reported Reactive Power prior to Event Start

The packet in Figure 10 shows the DER control event. The "opModFixedW" is the real power output control and the "opModFixeVAr" is the reactive power control. Real power output is set to 90% (**9000**) of its rated value and the reactive power output is set to 30% (**3000**) of its rated value. The rated value for the DER device in this test is 50000 Watts, so the target real output level is 45,000 Watts and the target reactive output power level is 15,000 VArs.

```
GET /sep2/derp/20/derc HTTP/1.1
Accept: application/sep+xml
Host: 52.35.96.64:8080

HTTP/1.1 200 OK
Access-Control-Allow-Origin: *
Access-Control-Allow-Methods: GET,PUT,POST,DELETE, OPTIONS
Access-Control-Allow-Headers: Content-Type, Authorization
Access-Control-Expose-Headers: Location
Content-Type: application/sep+xml; charset=utf-8
Content-Length: 763
Date: Wed, 16 Aug 2017 21:52:43 GMT
Connection: keep-alive

<DERControlList href="/sep2/derp/20/derc" subscribable="1" all="1" results="1"
xmlns="http://zigbee.org/sep" xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance">
  <DERControl href="/sep2/derp/20/derc/77" subscribable="1">
    <mRID>150292036095</mRID>
    <description>PF</description>
    <creationTime>1502920359</creationTime>
    <interval>
      <duration>90</duration>
      <start>1502920368</start>
    </interval>
    <EventStatus>
      <currentStatus>0</currentStatus>
      <dateTime>1502920361</dateTime>
      <potentiallySuperseded>false</potentiallySuperseded>
    </EventStatus>
    <DERControlBase>
      <opModFixedVAr>
        <refType>0</refType>
        <value>3000</value>
      </opModFixedVAr>
      <opModFixedW>9000</opModFixedW>
    </DERControlBase>
  </DERControl>
</DERControlList>
```

Figure 10 - DER Control, Real and Reactive

The packet in Figure 11 shows the reported real power output during to the DER control event. The reported value is **443000**, which is close to the targeted real output level of 45,000 Watts. At the time the power reading was captured, the DER device was still ramping up its output to match the target set point, which is why the reading is a little less that the target value.

```
POST /sep2/mup/4 HTTP/1.1
Content-Length: 420
Content-Type: application/sep+xml
Host: 52.35.96.64:8080

<MirrorMeterReading
     xmlns="http://zigbee.org/sep"
     xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance">
    <mRID>055731E34571F7501D00000000009182</mRID>
    <description>Real Power(W)</description>
    <Reading>
        <timePeriod>
            <duration>0</duration>
            <start>1502920383</start>
        </timePeriod>
        <value>443000</value>
    </Reading>
</MirrorMeterReading>
HTTP/1.1 204 No Content
Access-Control-Allow-Origin: *
Access-Control-Allow-Methods: GET,PUT,POST,DELETE, OPTIONS
Access-Control-Allow-Headers: Content-Type, Authorization
Access-Control-Expose-Headers: Location
Location: /sep2/upt/4/mr/26
Date: Wed, 16 Aug 2017 21:53:05 GMT
Connection: keep-alive
```

Figure 11 - Real Power output during DER Control Event

The packet in Figure 12 shows the reported reactive power output during to the DER control event. The reported value is **150000**, which is exactly matches the targeted reactive output level of 15,000 VArs.

```
POST /sep2/mup/4 HTTP/1.1
Content-Length: 426
Content-Type: application/sep+xml
Host: 52.35.96.64:8080

<MirrorMeterReading
     xmlns="http://zigbee.org/sep"
     xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance">
    <mRID>055731E34571F7501A00000000009182</mRID>
    <description>Reactive Power(VAr)</description>
    <Reading>
        <timePeriod>
            <duration>0</duration>
            <start>1502920383</start>
        </timePeriod>
        <value>150000</value>
    </Reading>
</MirrorMeterReading>
HTTP/1.1 204 No Content
Access-Control-Allow-Origin: *
Access-Control-Allow-Methods: GET,PUT,POST,DELETE, OPTIONS
Access-Control-Allow-Headers: Content-Type, Authorization
Access-Control-Expose-Headers: Location
Location: /sep2/upt/4/mr/29
Date: Wed, 16 Aug 2017 21:53:06 GMT
Connection: keep-alive
```

Figure 12 - Reactive Power output during DER Control Event

3.3.4 Volt-VAr Procedure

The objective of this test was to verify the Volt-VAr function was successfully communicated to the DER device using IEEE 2030.5. IEEE 2030.5 uses a curve-based model for specifying reactive power behavior based on voltage. The DER device uses a voltage-droop model. The DER client translates IEEE 2030.5 curve-based parameter to voltage-droop parameters. The test procedure was:

1. Configure the DER client to use unencrypted HTTP to allow for Ethernet sniffer captures.
2. Start the Ethernet sniffer trace.
3. Start the DER client.
4. Schedule a Volt-VAr control for 2 minutes.
5. After the start of the Volt-VAr control, create a voltage disturbance and observe the resulting reactive power behavior.
6. Stop the DER client.
7. Stop the Ethernet sniffer trace.

3.3.5 Results

The full trace is captured in the Ethernet sniffer file: “volt-var.pcapng”. The relevant packets from that file are provided below.

The packet in Figure 13 shows the reported reactive power output prior to the start of the DER control event. The reported value is **-999** which indicates the DER device is disconnected (i.e., no reactive power exported).

```
POST /sep2/mup/4 HTTP/1.1
Content-Length: 424
Content-Type: application/sep+xml
Host: 52.35.96.64:8080

<MirrorMeterReading
     xmlns="http://zigbee.org/sep"
     xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance">
    <mRID>055731E34571F7501A00000000009182</mRID>
    <description>Reactive Power(VAr)</description>
    <Reading>
        <timePeriod>
            <duration>0</duration>
            <start>1502922283</start>
        </timePeriod>
        <value>-999</value>
    </Reading>
</MirrorMeterReading>
HTTP/1.1 204 No Content
Access-Control-Allow-Origin: *
Access-Control-Allow-Methods: GET,PUT,POST,DELETE, OPTIONS
Access-Control-Allow-Headers: Content-Type, Authorization
Access-Control-Expose-Headers: Location
Location: /sep2/upt/4/mr/29
Date: Wed, 16 Aug 2017 22:24:45 GMT
Connection: keep-alive
```

Figure 13 - Reported Reactive Power prior to Event Start

The packet in Figure 14 shows the DER control event. The "opModVoltVAr" is the Voltage-VAr curve control. The DER client will translate this control to a Voltage-Droop control for the DER device.

```
GET /sep2/derp/20/derc HTTP/1.1
Accept: application/sep+xml
Host: 52.35.96.64:8080

HTTP/1.1 200 OK
Access-Control-Allow-Origin: *
Access-Control-Allow-Methods: GET,PUT,POST,DELETE, OPTIONS
Access-Control-Allow-Headers: Content-Type, Authorization
Access-Control-Expose-Headers: Location
Content-Type: application/sep+xml; charset=utf-8
Content-Length: 679
Date: Wed, 16 Aug 2017 22:24:57 GMT
Connection: keep-alive

<DERControlList href="/sep2/derp/20/derc" subscribable="1" all="1" results="1"
xmlns="http://zigbee.org/sep" xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance">
  <DERControl href="/sep2/derp/20/derc/81" subscribable="1">
    <mRID>150292228620</mRID>
    <description>vv</description>
    <creationTime>1502922284</creationTime>
    <interval>
      <duration>210</duration>
      <start>1502922299</start>
    </interval>
    <EventStatus>
      <currentStatus>0</currentStatus>
      <dateTime>1502922286</dateTime>
      <potentiallySuperseded>false</potentiallySuperseded>
    </EventStatus>
    <DERControlBase>
      <opModVoltVAr href="/sep2/dc/29"/>
    </DERControlBase>
  </DERControl>
</DERControlList>
```

Figure 14 - Volt-VAr Curve DER Event

The packet in Figure 15 shows the reported reactive power output during a voltage disturbance. The reported value is **286000**, which translates to 28,600 VArs. The reported value matched the value displayed on the DER device's front-panel screen.

```
POST /sep2/mup/4 HTTP/1.1
Content-Length: 426
Content-Type: application/sep+xml
Host: 52.35.96.64:8080

<MirrorMeterReading
     xmlns="http://zigbee.org/sep"
     xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance">
    <mRID>055731E34571F7501A00000000009182</mRID>
    <description>Reactive Power(VAr)</description>
    <Reading>
        <timePeriod>
            <duration>0</duration>
            <start>1502922405</start>
        </timePeriod>
        <value>286000</value>
    </Reading>
</MirrorMeterReading>
HTTP/1.1 204 No Content
Access-Control-Allow-Origin: *
Access-Control-Allow-Methods: GET,PUT,POST,DELETE, OPTIONS
Access-Control-Allow-Headers: Content-Type, Authorization
Access-Control-Expose-Headers: Location
Location: /sep2/upt/4/mr/29
Date: Wed, 16 Aug 2017 22:26:47 GMT
Connection: keep-alive
```

Figure 15 - Reported Reactive Power during Voltage Disturbance

3.4 Test #5 – Activation and Deactivation Mode Commands

3.4.1 Description

There is no explicit “Activation/Deactivation” command in either IEEE 2030.5 or the Phase 1 functions. However, the Phase 1 connect/disconnect control serves the same purpose as Activation/Deactivation, so it will be used for this test.

The Phase 1 connect/disconnect control verifies the DER system exports zero power when commanded to disconnect. However, zero power does not mandate a physical disconnect – just no power exported. Therefore, this connect/disconnect control is already an inherent part of the real power output control. When the real power output control is not active, it is already in the zero power (disconnected) state. The bottom line is that the real power output control demonstrates both the connect/disconnect function and the real power output function.

Therefore, the purpose of this test was to verify the connect/disconnect DER control function was successfully communicated to the DER device by using the real power output control.

3.4.2 Connect/Disconnect and Real Power Output Procedure

The test procedure was:

1. Configure the DER client to use unencrypted HTTP to allow for Ethernet sniffer captures.
2. Start the Ethernet sniffer trace.
3. Start the DER client.
4. Schedule a real power output control for 2 minutes.
5. Wait 3 minutes.
6. Stop the DER client.
7. Stop the Ethernet sniffer trace.

3.4.3 Results

The full trace is captured in the Ethernet sniffer file: “Real-80.pcapng”. The relevant packets from that file are provided below. The packet in Figure 16 shows the reported real power output prior to the start of the DER control event. The reported value is -999 which indicates the DER device is disconnected (i.e., no real power exported).

```
POST /sep2/mup/4 HTTP/1.1
Content-Length: 418
Content-Type: application/sep+xml
Host: 52.35.96.64:8080

<MirrorMeterReading
     xmlns="http://zigbee.org/sep"
     xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance">
    <mRID>055731E34571F7501D00000000009182</mRID>
    <description>Real Power(W)</description>
    <Reading>
        <timePeriod>
            <duration>0</duration>
            <start>1502920542</start>
        </timePeriod>
        <value>-999</value>
    </Reading>
</MirrorMeterReading>
HTTP/1.1 204 No Content
Access-Control-Allow-Origin: *
Access-Control-Allow-Methods: GET,PUT,POST,DELETE, OPTIONS
Access-Control-Allow-Headers: Content-Type, Authorization
Access-Control-Expose-Headers: Location
Location: /sep2/upt/4/mr/26
Date: Wed, 16 Aug 2017 21:55:45 GMT
Connection: keep-alive
```

Figure 16 - Reported Real Power prior to Event Start

The packet in Figure 17 shows the DER control event. This "opModFixedW" control is the real power output control that sets the real power output level to 80% (**8000**) of its rated value. The rated value for the DER device in this test is 50000 Watts, so the target output level is 40,000 Watts.

```
GET /sep2/derp/20/derc HTTP/1.1
Accept: application/sep+xml
Host: 52.35.96.64:8080

HTTP/1.1 200 OK
Access-Control-Allow-Origin: *
Access-Control-Allow-Methods: GET,PUT,POST,DELETE, OPTIONS
Access-Control-Allow-Headers: Content-Type, Authorization
Access-Control-Expose-Headers: Location
Content-Type: application/sep+xml; charset=utf-8
Content-Length: 679
Date: Wed, 16 Aug 2017 21:56:27 GMT
Connection: keep-alive

<DERControlList href="/sep2/derp/20/derc" subscribable="1" all="1" results="1"
xmlns="http://zigbee.org/sep" xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance">
        <DERControl href="/sep2/derp/20/derc/78" subscribable="1">
                <mRID>150292055895</mRID>
                <description>Real W</description>
                <creationTime>1502920557</creationTime>
                <interval>
                        <duration>90</duration>
                        <start>1502920569</start>
                </interval>
                <EventStatus>
                        <currentStatus>1</currentStatus>
                        <dateTime>1502920569</dateTime>
                        <potentiallySuperseded>false</potentiallySuperseded>
                </EventStatus>
                <DERControlBase>
                        <opModFixedW>8000</opModFixedW>
                </DERControlBase>
        </DERControl>
</DERControlList>
```

Figure 17 - Reported Reactive Power prior to Event Start

The packet in Figure 18 shows the reported real power output during to the DER control event. The reported value is **394000**, which translates to 39,400 W and is close to the targeted output level of 40,000 W.

```
POST /sep2/mup/4 HTTP/1.1
Content-Length: 420
Content-Type: application/sep+xml
Host: 52.35.96.64:8080

<MirrorMeterReading
     xmlns="http://zigbee.org/sep"
     xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance">
    <mRID>055731E34571F7501D00000000009182</mRID>
    <description>Real Power(W)</description>
    <Reading>
        <timePeriod>
            <duration>0</duration>
            <start>1502920619</start>
        </timePeriod>
        <value>394000</value>
    </Reading>
</MirrorMeterReading>
HTTP/1.1 204 No Content
Access-Control-Allow-Origin: *
Access-Control-Allow-Methods: GET,PUT,POST,DELETE, OPTIONS
Access-Control-Allow-Headers: Content-Type, Authorization
Access-Control-Expose-Headers: Location
Location: /sep2/upt/4/mr/26
Date: Wed, 16 Aug 2017 21:57:02 GMT
Connection: keep-alive
```

Figure 18 - Reported Real Power after Event Start

The packet in Figure 19 shows the reported real power output after to the DER control event has completed. The reported value is **-999** which indicates the DER device is back to the disconnected (i.e., no real power exported).

```
POST /sep2/mup/4 HTTP/1.1
Content-Length: 418
Content-Type: application/sep+xml
Host: 52.35.96.64:8080

<MirrorMeterReading
     xmlns="http://zigbee.org/sep"
     xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance">
    <mRID>055731E34571F7501D00000000009182</mRID>
    <description>Real Power(W)</description>
    <Reading>
        <timePeriod>
            <duration>0</duration>
            <start>1502920665</start>
        </timePeriod>
        <value>-999</value>
    </Reading>
</MirrorMeterReading>
HTTP/1.1 204 No Content
Access-Control-Allow-Origin: *
Access-Control-Allow-Methods: GET,PUT,POST,DELETE, OPTIONS
Access-Control-Allow-Headers: Content-Type, Authorization
Access-Control-Expose-Headers: Location
Location: /sep2/upt/4/mr/26
Date: Wed, 16 Aug 2017 21:57:48 GMT
Connection: keep-alive
```

Figure 19 - Reported Real Power after Event Completion

3.5 Test #7 – Cyber Security Tests

3.5.1 Description

Security is an important part of any communications system. For grid support services, security is especially important as breaches can lead issues with grid safety, stability, and reliability. This test examines and tests the cyber security features of the system. Cyber security is based on the underlying security of the IEEE 2030.5 protocol. IEEE 2030.5 uses the following cipher suite to protect communications between end points: *TLS_ECDHE_ECDSA_WITH_AES_128_CCM_8*. This cipher suite is compliant with NSA Suite B requirements for security at the SECRET level. It is helpful to understand the security components of the cipher suite.

- **TLS (Transport Layer Security)** – The TLS part of the cipher suite indicates that TLS is used. TLS is a well-known and well-supported security transport layer. For this cipher suite, the TLS version used is 1.2.
- **ECDHE** – The ECDHE part of the cipher suite indicates the key exchange algorithm used. ECDH stands for “elliptic-curve Diffie-Hellman”.
    - The “EC” part indicates that elliptic curve cryptography is used instead of RSA. For this cipher suite, the exact curve is the well-known NIST P-256 curve, with provides 128 bits of security protection.
    - The “DH” part indicates that the Diffie-Hellman algorithm, as applied to elliptic curves, is used to generate the shared secret between the client and the server.
    - The final “E” part indicates that ephemeral keys are used. This means that a new set of elliptic curve keys are generated for every new TLS session. This feature provides “perfect forward secrecy”, a property of secure communication protocols in which compromise of long-term keys does not compromise past session keys.

- **ECDSA** – This part indicates that elliptic-curve digital signatures are used for the authentication of certificates and other data. Each TLS end point contains a unique digital certificate for authentication.
- **AES_128** – This part indicates that the Advanced Encryption Standard (AES) algorithm is used for bulk traffic encryption using 128-bit keys derived from the Diffie-Hellman shared secret. The 128-bit AES key provides 128 bits of security protection.
- **CCM_8** – This part indicates the use of the cipher block chaining (CBC)-Counter Mode for the Message Authentication Check (MAC).

The secure channel is between the server and the DER client. They are the end points of the TLS protocol. With the Ethernet sniffer, you can capture the TLS handshaking prior to the switch to encrypted mode. Once this happens, the Ethernet sniffer trace only shows encrypted payload data.

3.5.2 Basic TLS Handshake

The purpose of this test was to verify the basic TLS handshake using the IEEE 2030.5 cipher suite. The test procedure was:

1. Configure the DER client to use encrypted HTTPS to capture the TLS transactions. The TLS port is 8443.
2. Start the Ethernet sniffer trace. The TLS port is 8443, so use this as an Ethernet sniffer filter
3. Start the DER client.
4. Schedule a real power output control for 2 minutes.
5. Wait 3 minutes.
6. Stop the DER client.
7. Stop the Ethernet sniffer trace.

3.5.3 Results

The full trace is captured in the Ethernet sniffer file: “Real-90-https.pcapng”. The screen capture in Figure 20 shows the TLS handshake between the client and server. Note that after the “Change Cipher Spec” packet, all subsequent packets are fully encrypted.

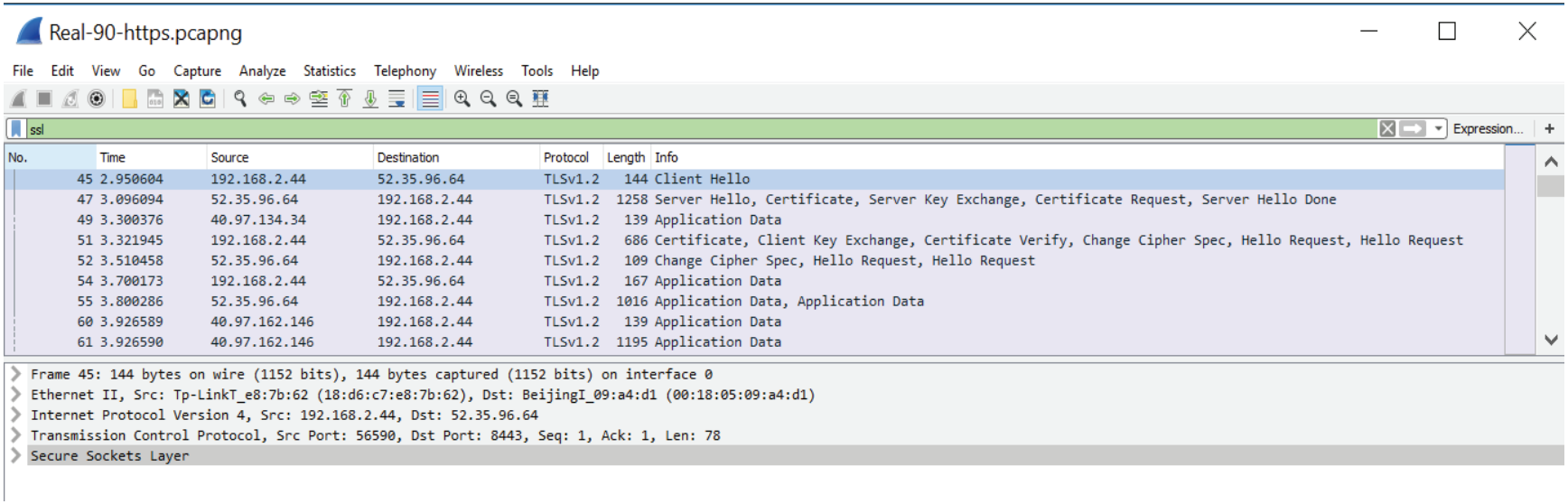


Figure 20 - TLS Handshake

The screen capture in Figure 21 shows the Client Hello packet in detail.

- Note that the client sets the Session ID to 0 to start a new session with new ephemeral keys.
- Note that the client offers to use the IEEE 2030.5 cipher suite.

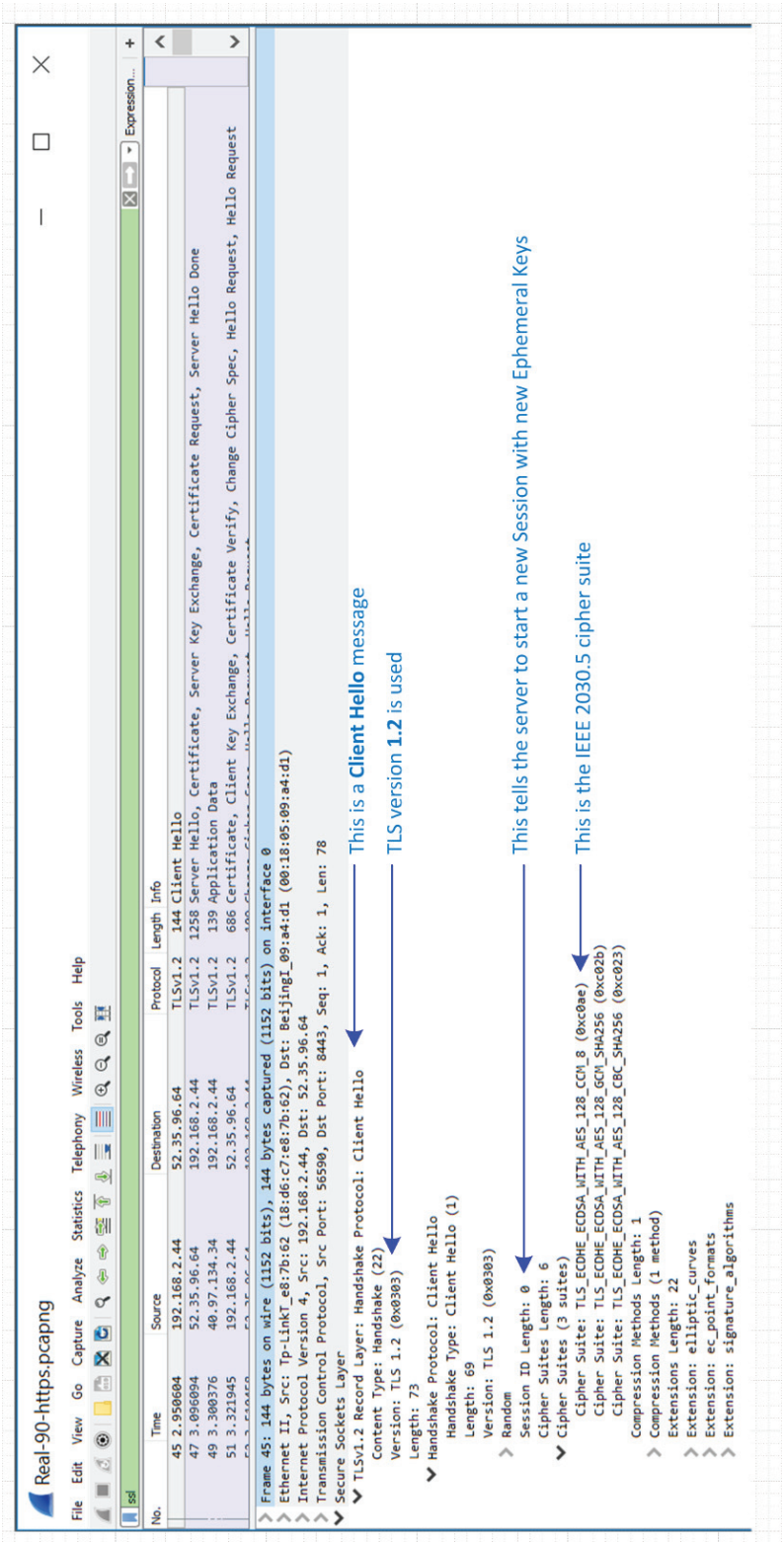


Figure 21 - TLS Client Hello

The screen capture in Figure 22 shows the Server Hello packet in detail.

- Note that the server sets the Session ID to a new random value to start a new session with new keys.
- Note that the server selects the IEEE 2030.5 cipher suite for this session.

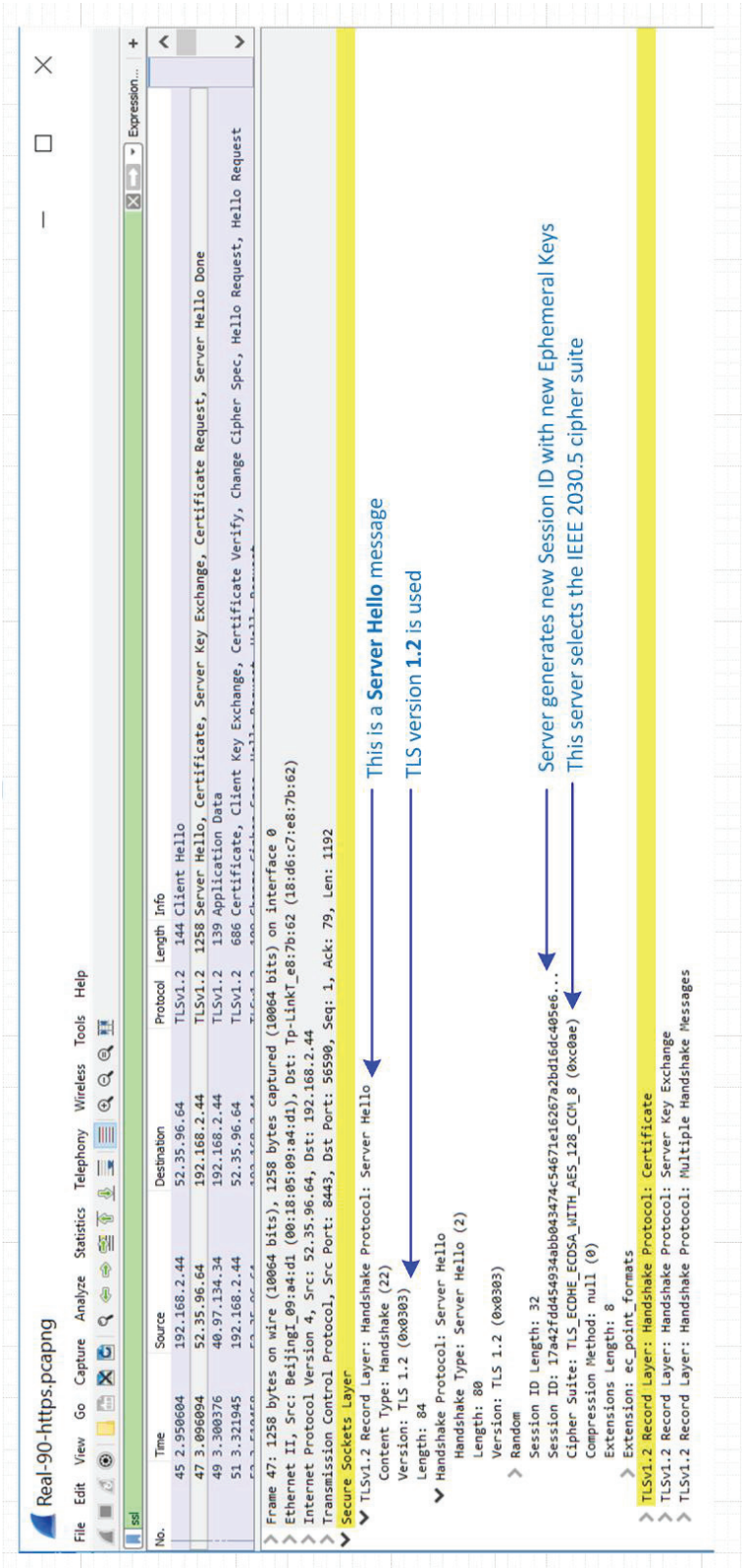


Figure 22 - TLS Server Hello

3.5.4 Bad TLS Handshake

This test verifies a bad certificate causes the TLS session to abort

1. Configure the DER client to use encrypted HTTPS to capture the TLS transactions. The TLS port is 8443.
2. Configure the DER client to use a certificate that chains to a different root CA than the server. The client will reject the Server's certificate during the TLS handshake.
3. Start the Ethernet sniffer trace. The TLS port is 8443, so use this as an Ethernet sniffer filter.
4. Start the DER client.
5. Schedule a real power output control for 2 minutes.
6. Wait 3 minutes.
7. Stop the DER client.
8. Stop the Ethernet sniffer trace.

3.5.5 Results

The full trace is captured in the Ethernet sniffer file: "bad-cert-https.pcapng". The screen capture in Figure 23 shows the TLS handshake between the client and server. Note that after receiving the Server's certificate, the client issues a "TLS Alert" indicating it has received a Bad Certificate.

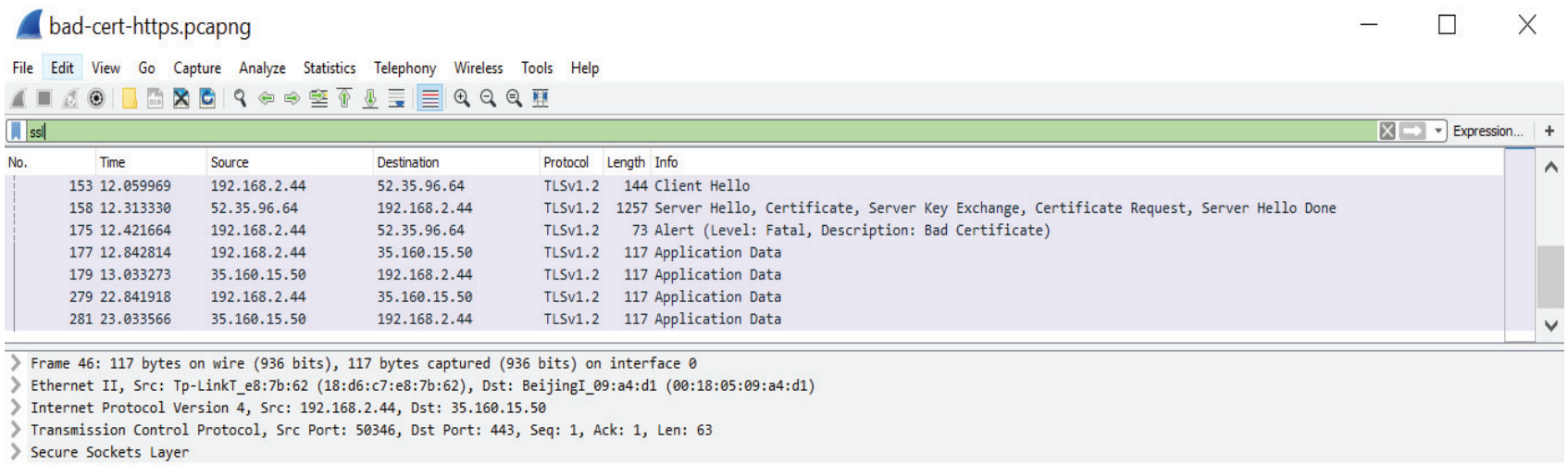


Figure 23 - TLS Bad Certificate

4.0 Conclusions and Recommendations

4.1 Conclusions

Following statements are concluded from different tests cases performed in this effort:

4.1.1 Test #1 – Registration

In this effort, correct registration of the DER device to the IEEE 2030.5 server, from both the client-side and the server-side, was demonstrated. Furthermore, successful client-side registration was verified by providing the DER device with the correct registration PIN. The DER device matched the PIN and continued with normal operation.

Server-side registration is the process where the server authenticates the DER device's certificate during a TLS exchange and authorizes the DER device to find and act upon the DER controls (control commands). Successful server-side registration is implicitly verified by the fact that the DER device was able to receive the DER controls and act upon them. Test case #7 (cybersecurity) provided a negative test for server-side registration. In this test, the DER device provided a bad certificate and the server successfully detected it and terminated the TLS session, thus denying access to the unauthenticated device.

4.1.2 Test #2 – Monitor of the Output of the DER System

The correct reporting of real and reactive output power of the DER System was verified prior to a DER control, during the DER control, and after the DER control for Test #3, Test #4, and Test #5. No issues were found using IEEE 2030.5 for monitoring.

4.1.3 Test #3 – Issue Control Commands, Test #4 Issue Set-Point Update

IEEE 2030.5 does not make any distinction between a control command and a set-point update – they are both DER controls. The correct operation of the fixed-power-factor and volt-VAr DER controls was verified. No issues were found using IEEE 2030.5 for these controls.

4.1.4 Test #5 – Issue Activation and Deactivation

Neither IEEE 2030.5 nor Phase 1 (SWIG) has an "Activation/Deactivation" command. Instead, the real output power control was used to achieve the same functionality. The correct operation of the real power output control was verified. No issues were found using IEEE 2030.5 for this control.

4.1.5 Test #7 – Cybersecurity

IEEE 2030.5 communications is secured using the *TLS_ECDHE_ECDSA_WITH_AES_128_CCM_8* cipher suite. The cipher suite provides end-to-end security between the IEEE 2030.5 server and the DER protocol translator. The Ethernet packet sniffer was utilized to verify the TLS handshake in normal operation. The Ethernet packet sniffer was used to verify that the TLS session generated a TLS alert when the DER protocol translator used an invalid certificate.

4.1.6 Learning from Success

The pre-commercial demonstration showed that IEEE 2030.5 can successfully send Phase 1 DER controls to DER devices and successfully monitor their output.

4.2 Recommendations

The objective of EPIC-1, Project 4, Demonstration of Grid Support Functions of Distributed Energy Resources (DER) was to demonstrate grid support functions of DER, which can improve distribution system operations. The chosen project modules quantified the value of specific grid support functions in specific application situations and provided a basis for SDG&E to determine which functions it wants to pursue commercially in advanced distribution system automation. This project module addressed pre-commercial demonstration of communication standards for grid support functions of DER. Recommendations for future commercial adoption are described in the following:

4.2.1 Evaluation of the IEEE 2030.5 Protocol

This pre-commercial demonstration proved that the IEEE 2030.5 protocol can successfully communicate Phase 1 functions. Thus, it is highly probable that it will be able to communicate Phase 3 functions, once those functions have been finalized.

At this time, the SIWG has agreed that the Phase 3 functions will be specified in the IEEE 1547 standards update. In conjunction, the IEEE 2030.5 standard is also being revised an updated to support all IEEE 1547, and therefore, all Phase 3 functions. When complete, CA Rule 21, IEEE 1547, and IEEE 2030.5 will be harmonized.

In parallel, the CSIP Implementation Guide version 2 is being revised to conform with the updated standards. The CSPI Implementation Guide is a document commissioned by the California IOUs that describes how to use the IEEE 2030.5 protocol to provide interoperable CA Rule 21 grid support functions. Version 1 of the CSIP Implementation Guide, based on the IEEE 2030.5-2013 was published in August 2016. Version 2 is expected in early 2018.

Also, in parallel, the CSIP Conformance Test Procedure document as well as a certification program is being developed to allow for certification of devices conforming to CSIP and IEEE 2030.5 specification. When complete, this certification program will insure the proper operation an interoperability of certified devices.

By early 2018, it is expected that the IEEE 2030.5 protocol will have:

1. A comprehensive specification supporting all IEEE 2030.5 and CA Rule 21 functions
2. An implementation guide explaining how to use IEEE 2030.5 for grid support services to promote interoperability across utilities
3. A test and certification process for validating functionality and interoperability

Although CA Rule 21 specifies IEEE 2030.5 as the default communications protocol, it does not preclude the use of other protocols. For example, DNP3 is being evaluated for real-time grid support applications. However, any proposed protocol, must provide support for the three criteria listed above. In the foreseeable future, IEEE 2030.5 is the only protocol that fully supports the three criteria.

4.2.2 Recommendations Associated with the IEEE 2030.5 Protocol

Some recommendations for future steps are:

1. At this time, this pre-commercial demonstration could only test a subset of the CA Rule 21 Phase 1 functions. When the standard updates have been completed, perform similar tests on all Phase 1 and Phase 3 functions.
2. For this pre-commercial demonstration, a single DER device was used. The performance of the IEEE 2030.5 protocol was not tested with a multitude of DER devices, so estimates on how the protocol would behave at production scale could not be determined. Lab tests with simulated devices or a field test with real devices would be useful in estimated performance at production scale.
3. As CA Rule 21 does not preclude the use of other protocols, and as the CA Rule 21 standard or international standards change from time to time, the successful performance of the intended functions for the new protocols should be re-demonstrated for certification by a qualified organization to validate the suitability of the new standard each time. This validation process should verify that the updated IEEE 2030.5 protocol (or any other alternative that may be adopted in CA Rule 21 or international standards) could successfully transport all Phase 1 and Phase 3 functions.

4.2.3 Evaluation of IEEE 2030.5 Security in Production

IEEE 2030.5 uses a powerful TLS cipher suite providing NSA SECRET level security. Normally, more security is desirable, but this TLS cipher suite uses ephemeral keys (which provides for perfect forward secrecy but may not play well with

existing firewalls and packet inspection tools). In many utility IT environments, inbound packets from the internet are required to be decrypted and inspected by a Web Application Firewall (WAF). The WAF normally has a copy of the server's static private key so that it can decrypt and inspect the inbound packets. With the use of ephemeral keys, the WAF can no longer decrypt the packet thus making the WAF useless.

For the reasons listed above, it is possible that a utility's information technology (IT) policy precludes the use of the IEEE 2030.5 TLS cipher suite. In the upcoming revision of the CSIP implementation guide, provisions are being made to allow for the use of a less secure but WAF-friendly cipher suite. When defined, this WAF-friendly cipher suite needs to be tested for cyber security vulnerabilities.

Another cybersecurity consideration is the end points of the TLS connection. In this pre-commercial demonstration, the end points were the IEEE 2030.5 server and the DER protocol translator. The IEEE 2030.5 server exists on the internet and the DER protocol translator was located deep inside the utility lab. In a production environment, IT policy may require TLS connections to terminate at a demilitarized-zone (DMZ) at the edge of the utility network. If this is the case, there is a need for a proxy-like device to terminate the TLS connection in the DMZ and create a new TLS connection from the proxy to the DER protocol translator. If there are multiple security zones, the use of proxies and firewalls may need to be repeated.

4.2.4 Recommendations Associated with Security

In general, designing for security is very sophisticated topic to address. Many factors come into play from the cipher suite used, to compatibility with existing equipment, to IT security policies. There is no one size fits all, and the proper security architecture may be site dependent. Providing general recommendations is difficult, but some recommendations for future steps are:

1. If an alternate cipher suite is required because of IT policy, re-evaluate the overall security of the entire system.
2. If the use of a TLS proxy is required because of IT policy, test the overall system performance as adding a proxy will necessarily increase the latency of the system.

4.2.5 Evaluation of DER Device Interoperability

The DER device in this pre-commercial demonstration used a proprietary Modbus register map for control and status. For single-device testing, this is acceptable, but for large-scale multi-vendor commercial deployments, the DER protocol translator cannot be expected to have to communicate with an unbounded number of proprietary DER device control protocols. Instead, DER devices should all conform to a single, standardized, control protocol (e.g., Modbus), and an open and standardized information model (e.g., SunSpec Alliance Models).

4.2.6 Recommendations Associated with DER Device Interoperability

1. Promote the standardization of a common DER device control mechanism. The SunSpec Alliance's DER Models appears the most suitable, but there may be others.
2. For large-scale deployments (i.e., utility scale), it is recommended that all DER devices implement a standardized DER Modbus model.

5.0 Technology Transfer Plan

A primary benefit of the EPIC program is the technology and knowledge sharing that occurs both internally within SDG&E and across the industry. To facilitate this knowledge sharing, SDG&E will share the results of this project by widely announcing the availability of this report to industry stakeholders on its EPIC website, by submitting papers to technical journals and conferences, and by presentations in EPIC and other industry workshops and forums. Additionally, presentations will be given to internal stakeholders at SDG&E.

6.0 Metrics and Value Proposition

6.1 Metrics

The following metrics (discussed in Table 1) were identified for this project as potential project benefits at larger scale deployment. Given the pre-commercial nature of this EPIC project, these metrics would apply in future scenarios after widespread commercial adoption. The following statements are potential benefits that are concluded from different tests cases performed in this effort:

Table 1. EPIC metrics for pre-commercial demonstration of communications performance of the IEEE 2030.5 protocol

D.13-11-025, Attachment 4. List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation)
1. Potential energy and cost savings
b. Total electricity deliveries from grid-connected distributed generation facilities
e. Peak load reduction (MW) from summer and winter programs
f. Avoided customer energy use (kWh saved)
g. Percentage of demand response enabled by automated demand response technology (e.g. Auto DR)
3. Economic benefits
b. Maintain/reduce operations and maintenance costs
c. Reduction in electrical losses in the transmission and distribution system
5. Safety, power quality, and reliability (equipment, electricity system)
a. Outage number, frequency, and duration reductions
b. Electric system power flow congestion reduction
7. Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy
b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)
c. Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360)
d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360)

6.2 Value Proposition

The purpose of EPIC funding is to support investments in R&D projects that benefit the electricity customers of California IOUs. The primary principles of EPIC are to invest in technologies and approaches that promote greater reliability, lower costs, and increased safety. Table 2 represents the value that "pre-commercial demonstration of EPRI DRIVE DER hosting capacity" project provides to the overall system operation. Primary and secondary benefits are presented wherever applicable to demonstrate the value of the function for commercial adoptability.

As it is shown in Table 2 and was discussed in the result and conclusion section of this report, pre-commercial demonstration of communications performance of the IEEE 2030.5 protocol primarily can enhance systems reliability by enabling dynamic optimization of grid operations and resources. Furthermore, this could be utilized by appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security. Additionally, it can contribute to optimized and cost-effective integration of DER to distribution system.

Table 2. Value proposition (primary and secondary) for pre-commercial demonstration of EPRI DRIVE DER hosting capacity tool

Primary Principals			Secondary Principals					
Reliability	Affordability	Safety	Societal Benefits	GHG Emissions Mitigation / Adaptation	Loading Order	Low-Emission Vehicles / Transportation	Economic Development	Efficient Use of Ratepayers Monies
X								X

7.0 References

[1] IEEE Adoption of Smart Energy Profile 2.0 Application Protocol Standard," in IEEE Std 2030.5-2013, vol., no., pp.1-348, Nov. 11 2013.

[2] IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," in IEEE Std 1547-2003, vol., no., pp.1-28, July 28 2003.

[3] IEEE 2030.5 Common California IOU Rule 21 Implementation Guide for Smart Inverters, California Smart Inverter Implementation Working Group, August 31, 2016.

Appendix 6

EPIC-1, Project 4, Module 3: Demonstration of Grid Support Functions of Distributed Energy Resources – Pre-Commercial Demonstration of the EPRI DRIVE Tool



EPIC Final Report

Program	**Electric Program Investment Charge (EPIC)**
Administrator	**San Diego Gas & Electric Company**
Project Number	**EPIC-1, Project 4**
Project Name	**Demonstration of Grid Support Functions of Distributed Energy Resources (DER)**
Module Name	**Module 3, Pre-Commercial Demonstration of the EPRI DRIVE Tool**
Date	**December 31, 2017**

Attribution

This comprehensive final report documents the work done in this EPIC project.

The project team for this work included the following individuals:

Internal SDG&E Staff

John Baranowski

Frank Goodman

Amin Salmani

Catarino Vargas

Electric Power Research Institute

Matt Rylander

Lindsey Rogers

Jeff Smith

Executive Summary

The objective of EPIC-1, Project 4, Demonstration of Grid Support Functions of Distributed Energy Resources (DER) was to demonstrate grid support functions of DER, which can improve distribution system operations. The chosen sub-projects and modules quantified the value of specific grid support functions in specific application situations and provided a basis for San Diego Gas & Electric Company (SDG&E) to determine which functions it wants to pursue commercially in the development of its smart grid. This project consists of three modules: value assessment of grid support functions of DER, communication standards for grid support functions of DER, and demonstration and comparison of the Electric Power Research Institute (EPRI) and SDG&E DER hosting capacity analysis tools. This executive summary addresses the module on pre-commercial demonstration of EPRI's Distribution Resource Integration and Value Estimation (DRIVE) tool, in comparison to SDG&E's Iterative Integration Capacity Analysis (ICA) tool.

Utilities are faced with making decisions on how to consider the growing penetration of DER on their system. With this challenge in mind, utilities across the country are beginning to look at how to meet the new requirements with analytical methods to identify impacts of distributed resources in the electric system. A foundational element of planning in the future is the capability to assess how much DER capacity the distribution system can "host." ***Hosting capacity is defined as the amount of DER that can be accommodated without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades.***

In California, the requirement to assess DER has come in the form of the California Legislature Assembly Bill (AB) 327, California Public Utilities Code (PUC) Section 769.[1] In response to this legislation, each investor owned utility (IOU) submitted a Distribution Resource Plan (DRP) that includes hosting capacity.[2] Pacific Gas and Electric Company (PG&E) responded with a "streamlined" hosting capacity approach, while SDG&E and Southern California Edison (SCE) responded with an "iterative" method. Table 3 summarizes the current methods used both in California and other jurisdictions.

Table 1. Hosting Capacity Methods

Method	Approach	Computation Time	Recommended Use Case	Industry Adoption
Stochastic	+Increase DER randomly +Run power flow for each solution	Hours	DER planning	PEPCO ComEd
Iterative (Integration Capacity Analysis)	+Increase DER at specific location +Run power flow for each solution	Hours*	Inform screening process and developers	SCE SDG&E
Streamlined	+Limited number of power flows +Utilizes combination of power flow and algorithms	Minutes	Inform screening process and developers	PG&E
DRIVE	+Limited number of power flows +Utilizes combination of power flow and algorithms	Minutes	DER planning, inform screening process and developers	>25 utilities worldwide

* ICA Iterative hosting capacity analysis has been previously stated as 27 hours per feeder

To date, industry adoption of these methods has been broad. Utilities are using hosting capacity as a foundational element to perform mapping, interconnection, system planning, and locational value studies.[3]

This activity is an element of the SDG&E Electric Program Investment Charge (EPIC) 1 - Project 4 on "Demonstration of Grid Support Functions of DER." The overall objective of the EPIC project is to validate the viability of specific DER functions and to identify which, if any, grid support functions of DER and application situations should be pursued commercially.

[1] http://www.cpuc.ca.gov/General.aspx?id=5071

[2] The term hosting capacity and integration capacity are interchangeable. This report will use the industry adopted terminology.

[3] Defining a Roadmap to Successful Implementation of a Hosting Capacity Roadmap in NY State. EPRI. Palo Alto, CA: 2016. 3002008848.

The focus of this portion of the project was to perform a demonstration of EPRI's Distribution Resource Integration and Value Estimation (DRIVE) tool for determining the DER hosting capacity capabilities of distribution feeders. The resulting hosting capacity values provide a comparison to understand how similar the results are to the SDG&E iterative ICA. This project provides insights into two different methods and provides the first comparative analysis between the SDG&E Iterative method and DRIVE.

The demonstration is applied on five SDG&E feeders while considering voltage and thermal impacts.[4] The results of the iterative method align very closely to the results of DRIVE (See Figure 1 for sample results). This comparison, similar to the one done as part of the CA DRP Demo, provides a relative precision[5] to a third approach.

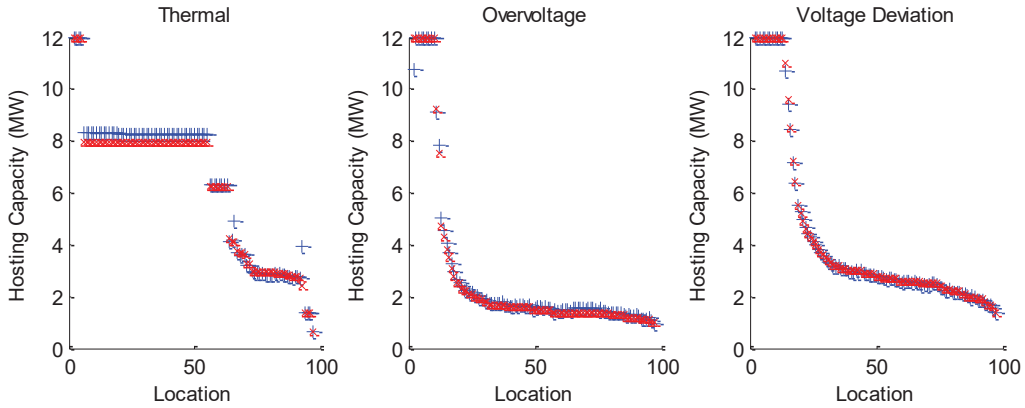


Figure 1. Comparative Results for One Feeder (Blue +: Iterative Analysis, Red x: DRIVE Analysis)

The comparative analysis also points to differences and areas that require continued improvement in both approaches as well as areas for further investigation as described in Table 2.

Table 2. Areas on Improvement/Understanding in Hosting Capacity Methodologies

Iterative	DRIVE
Further examination of inconsistencies in thermal analysis	Further examination of impedances used in voltage analysis
Consider including locking regulation equipment in voltage analysis	Incorporate branch analysis in voltage analysis
Further examination of inconsistencies in voltage deviation analysis	Further examination of impact of losses in voltage deviation analysis
Further examination of applied pre-existing violations	Consider inclusion of adjacent feeders at substation

This project demonstrated the use of the DRIVE tool for doing hosting capacity assessments on five selected SDG&E feeders. The results found both opportunities for implementation and challenges that require further investigation.

Key findings and recommendations are as follows:

Findings: Different hosting capacity methods can provide similar results; similar hosting capacity results can be derived more efficiently; hosting capacity methods will continue to evolve and improve.
Recommendations: SDG&E should keep DRIVE available as one of the tools it can use in future hosting capacity analyses; SDG&E should monitor the future advances in DRIVE and the emergence of other tools, to be able to make the best choices for specific future assessment needs.

[4] Protection impact analysis is excluded from the comparative study as this is not currently performed using the ICA module in the Synergi power flow tool which SDG&E uses for voltage and thermal analysis.
[5] Comparative analysis to date has assessed relative precision in producing similar results. This is different than accuracy.

Table of Contents

1.0 Introduction 1
1.1 Statement of project objective 1
1.2 Summary of the project scope of work 1
1.3 Description of major tasks, milestones, and deliverables 3
2.0 Project Approach 5
2.1 Methods for Comparison 5
2.1.1 SDG&E Iterative ICA Method 5
2.1.2 EPRI DRIVE Method 8
2.2 Implementation Considerations 11
2.3 Detailed technical results 13
2.3.1 Single-Hour Comparison 14
2.3.2 Annual Comparison 19
2.4 Applying the results 24
3.0 Findings and Conclusions 24
3.1 Was the project objective accomplished? 24
3.2 Description of measurement and verification results 24
3.3 Conclusion 25
3.3.1 Findings 25
3.3.2 Recommendations 25
4.0 Technology Transfer Plan 27
5.0 Metrics and Value Proposition 28
5.1 Metrics 28
5.2 Value Proposition 28

List of Figures

Figure 1. Comparative Results for One Feeder (Blue +: Iterative Analysis, Red x: DRIVE Analysis) iv
Figure 2. Simplified Diagram of the Iterative Method 6
Figure 3. Illustration of Layered Abstraction Process 7
Figure 4. Components of DRIVE 9
Figure 5. Simplistic Illustration of Centralized DER Analysis 10
Figure 6. Simplistic Illustration of Distributed DER Analysis 10
Figure 7. Definition of Node and Section 12
Figure 8. Feeders for Comparison a) A1 b) A2 c) B1 d) C1 e) C2 14
Figure 9. Single-Hour Thermal Hosting Capacity Comparison (Blue +: Iterative Analysis, Red x: DRIVE Analysis) 15
Figure 10. Single-Hour Overvoltage Hosting Capacity Comparison (Blue +: Iterative Analysis, Red x: DRIVE Analysis) 16
Figure 11. Single-Hour Overvoltage Hosting Capacity Comparison after DRIVE Analysis Overvoltage Algorithm Update. (Blue +: Iterative Analysis, Red x: DRIVE Analysis) 17
Figure 12. Single-Hour Voltage Deviation Hosting Capacity Comparison (Blue +: Iterative Analysis, Red x: DRIVE Analysis) 18
Figure 13. Illustration of Error in Iterative Hosting capacity result 18
Figure 14. Annual Thermal Hosting Capacity Comparison (Blue +: Iterative Analysis, Red x: DRIVE Analysis) 19
Figure 15. Annual Overvoltage Hosting Capacity Comparison (Blue +: Iterative Analysis, Red x: DRIVE Analysis) 20
Figure 16. Annual Voltage Deviation Hosting Capacity Comparison (Blue +: Iterative Analysis, Red x: DRIVE Analysis) 21
Figure 17. Annual Voltage Deviation Hosting Capacity Comparison when Ignoring the Impact of Losses in DRIVE (Blue +: Iterative Analysis, Red x: DRIVE Analysis) 21
Figure 18. Iterative Voltage Deviation Hosting Capacity Comparison (Blue +: Annual Analysis, Green x: Single-Hour Analysis) 22
Figure 19. Annual Voltage Deviation Hosting Capacity Comparison with DRIVE Considering Aggregate Impact of Existing DER (Blue +: Iterative Analysis, Red x: DRIVE Analysis) 23

List of Tables

Table 1. Hosting Capacity Methods iii
Table 2. Areas on Improvement/Understanding in Hosting Capacity Methodologies iv
Table 3. Hosting Capacity Methods 1
Table 4 Relative Effect of Hosting Capacity Impact Factors 3
Table 5. Project Tasks, Objectives, and Deliverables 3
Table 6. ICA Hosting Capacity Metrics Determined per Location 7
Table 7. DRIVE Hosting Capacity Metrics Determined per Location 10
Table 8. Differences in Methodologies 11
Table 9. Hosting Capacity Metrics Compared 13
Table 10. Feeder Characteristics 14
Table 11. Annual Hosting Capacity Analysis Summary for All Analyzed Feeders and Nodes 23
Table 12. Differences in Annual Hosting Capacity Analysis for All Analyzed Feeder Nodes 24
Table 13. Areas on Improvement/Understanding in Hosting Capacity Methodologies 24
Table 14. EPIC metrics for pre-commercial demonstration of EPRI DRIVE DER hosting capacity tool 28
Table 15. Value proposition for pre-commercial demonstration of EPRI DRIVE DER hosting capacity tool 28

List of Acronyms

Assembly Bill (AB)
California Public Utilities Code (PUC)
Distributed Energy Resources (DER)
Distribution Resource Integration and Value Estimation (DRIVE)
Distribution Resource Plan (DRP)
Electric Power Research Institute (EPRI)
Electric Program Investment Charge (EPIC)
Integration Capacity Analysis (ICA)
Investor Owned Utility (IOU)
Pacific Gas & Electric (PG&E)
San Diego Gas & Electric (SDG&E)
Southern California Edison (SCE)

1.0 Introduction

1.1 Statement of project objective

This activity is an element of San Diego Gas & Electric Company's (SDG&E's) EPIC 1 - Project 4 on Demonstration of Grid Support Functions of Distributed Energy Resources (DER). The overall objective of the EPIC project is to validate the viability of specific DER functions and to identify which, if any, grid support functions of DER and application situations should be pursued commercially. This activity is complementary to another activity already in progress, as part of this project.

The focus of this portion of the project was to perform a demonstration of the Electric Power Research Institute's (EPRI's) Distribution Resource Integration and Value Estimation (DRIVE) tool for determining the DER hosting capacity capabilities of distribution feeders. The hosting capacity values resulting from this demonstration provide a comparison to understand how similar the results are to the SDG&E iterative integration capacity analysis (ICA). This project provides insights into two different hosting capacity methods and provides the first comparative analysis between the iterative method used in SDG&E and that of DRIVE.

1.2 Summary of the project scope of work

Utilities are faced with making decisions on how to consider the growing penetration of DER on their system. The result is a new set of challenges for planning and operating the grid that serves these new resources. With this challenge in mind, utilities across the country are beginning to look at how to meet the new requirements with analytical methods to identify impacts of distributed resources in the electric system. A foundational element of planning the distribution system of the future is the capability to assess how much DER capacity the distribution system can "host."

Hosting capacity is defined as the amount of DER that can be accommodated without adversely affecting power quality or reliability under existing control configurations and without requiring infrastructure upgrades.

In California, the requirement to assess DER has come in the form of the California Legislature Assembly Bill (AB) 327, California Public Utilities Code (PUC) Section 769.[6] In response to this legislation, each investor owned utility (IOU) submitted a Distribution Resource Plan (DRP) that encompasses, among other items, hosting capacity.[7] Pacific Gas and Electric Company (PG&E) responded with a "streamlined" hosting capacity approach, while SDG&E and Southern California Edison (SCE) responded with what is referred to as an "iterative" method. Table 3 summarizes the current methods used to estimate hosting capacity both in California and in other jurisdictions including the advantages and disadvantages of each method.

Table 3. Hosting Capacity Methods

Method	Approach	Advantages	Disadvantages	Computation Time	Recommended Use Case	Industry Adoption
Stochastic	+Increase DER randomly +Run power flow for each solution	+Similar in concept to traditional interconnection studies +Becoming available in planning tools	+Computationally intensive +Limited scenarios	Hours	+DER planning	PEPCO ComEd
Iterative (Integration Capacity Analysis)	+Increase DER at specific location +Run power flow for each solution	+Similar in concept to traditional interconnection studies +Becoming available in planning tools	+Computationally intensive +Limited scenarios +Vendor-specific	Hours*	+Inform screening process +Inform developers	SCE SDG&E

[6] http://www.cpuc.ca.gov/General.aspx?id=5071

[7] The term hosting capacity and integration capacity are interchangeable. This report will use the industry adopted terminology of hosting capacity.

			implementations can vary			
Streamlined	+Limited number of power flows +Utilizes combination of power flow and algorithms	+Computationally efficient +Not vendor tool specific	+Novel approach to hosting capacity +Not well understood method +Limited scenarios +Not available in current planning tools	Minutes	+Inform screening process +Inform developers	PG&E
DRIVE	+Limited number of power flows +Utilizes combination of power flow and algorithms	+Computationally efficient +Many DER scenarios considered +Not vendor tool specific +Broad utility industry adoption and input +Becoming available in planning tools	+Novel approach to hosting capacity +Not well understood method +Lag between modifications/ upgrades and associated documentation	Minutes	+DER planning +Inform screening process +Inform developers	>25 utilities worldwide

* ICA Iterative hosting capacity analysis has been previously stated as 27 hours per feeder[8]

To date, industry adoption of these methods has been broad. Utilities are using hosting capacity as a foundational element to perform the following:[9]

- **Mapping:** Having a defined hosting capacity method gives developers/customers the ability to understand better/worse locations for DER on the system as an indicator of potential costs. Important considerations for this application are that maps only illustrate a point in time in a dynamic system – both as new applications are approved and the system operational requirements change.
- **Interconnections:** Hosting capacity information helps guide power systems engineers where detailed engineering studies are less likely to be required, improving efficiency of the process. There are some challenges in the frequency of updates to this data.
- **System Planning:** Hosting capacity analysis is also becoming a critical piece in the analytical framework and methodologies needed for integrated planning. Hosting capacity can be enhanced with load and DER forecasts to evaluate different planning scenarios on a feeder-by-feeder basis.
- **Locational Value:** The data, tools, and processes utilized in hosting capacity analysis can also help identify locations where benefit from DER can be maximized without incurring additional costs.

While these hosting capacity methods have advantages and disadvantages, most critical to the resulting values are the impact factors. Hosting capacity assessments should consider a wide range of impact factors including both DER and grid side impacts. The range of DER a feeder can host depends on the location and characteristics of both the feeder and DER. For DER impact factors, there are several characteristics that must be considered including location, type, control capabilities, aggregation of DER, and portfolios of different DER technologies. For grid impact factors, important characteristics to consider include voltage control, configuration, load, and phasing. Table 4 provides a summary of these impact factors with a relative ranking of importance in the impact they have on the resulting hosting capacity.

Given this landscape, this project demonstrated the DRIVE hosting capacity methodology on five SDG&E feeders to quantify the amount of DER each feeder can host without causing adverse impacts. The results of this analysis have been compared with the iterative method implemented by SDG&E in their DRP to better understand similarities and

[8] http://drpwg.org/wp-content/uploads/2016/07/R.14-08-013-DRP-Demos-A-B-Reports-SDGE.pdf

[9] Defining a Roadmap to Successful Implementation of a Hosting Capacity Roadmap in NY State. EPRI. Palo Alto, CA: 2016. 3002008848.

differences. This report summarizes the results of that demonstration and provides recommendations based on the findings.

Table 4 Relative Effect of Hosting Capacity Impact Factors

	Impact	Hosting Capacity Impact Factor
DER	High	Location
	High	Type/Technology
	High	Communication and Control
	High	Aggregation
	Medium	Efficiency
	Low	Vendor
	Low	Plant layout
	Medium	local weather patterns (renewables)
	Medium	Panel orientation (PV)
Distribution	High	Voltage control scheme
	High	Configuration
	High	Load
	High	Phasing
	Medium	Protection system design
	Medium	Granularity of MV models # of nodes)
	High	Grounding practices
Misc	High	Time
	Medium	service transformers
	Medium	Service drops
	Low	Planning software
	Medium	Transmission constraints
	Medium	Transmission grid configuration/dispatch

1.3 Description of major tasks, milestones, and deliverables

This project has six tasks with three major activities to meet the stated objectives. The main activities are Feeder Identification and Methodology Settings, Data Collection, and DRIVE demonstration for Hosting Capacity Assessment. Table 5 provides a brief summary of the project tasks and milestones. The text that follows provides details on approach and assumptions important to research findings.

Table 5. Project Tasks, Objectives, and Deliverables

Task	Objective
Task 1 Kickoff meeting, stakeholder consultations, and work plan review	Initiate the project, identify key stakeholders and to develop the detailed work plan for the project.
Task 2 Feeder Identification and Methodology Settings	Identify feeder models and settings for the demonstration and analysis.
Task 3 Data Collection	Obtain the necessary data for the demonstration.
Task 4 Demonstrate DRIVE for Hosting Capacity Assessment	Demonstrate DRIVE for hosting capacity analysis on selected use cases. Compare results to the SDG&E iterative analysis.
Task 5 Workshop	Conduct a workshop with SDG&E to review results, get feedback and input, and train SDG&E on using DRIVE.
Task 6 Comprehensive Final Report	Develop a comprehensive final report on the project work.

First, EPRI and SDG&E worked together to identify appropriate feeders for analysis. Five feeders were selected based upon their design configurations (long rural, short urban, heavy commercial/industrial). In order to compare hosting capacity methodologies, EPRI and SDG&E worked together to identify all analysis settings. To conduct a similar analysis, some settings were modified as necessary. These settings include items such as allowable feeder impact (like maximum allowable voltage) and DER characteristics (like resource variability).

Once feeders were selected and parameters set, SDG&E shared the model data for analysis. This included feeder models containing voltage regulation equipment and settings (LTC, line regulator, and switched capacitor) as well as existing DER.

EPRI and SDG&E both executed the hosting capacity analysis on the set of feeders with the agreed upon parameters - EPRI utilized the DRIVE hosting capacity analysis method and SDG&E utilized the Synergi[10] iterative method. The focus of the analysis was on the voltage and thermal impacts.[11] The results of this analysis were then compared and summarized in this report.

[10] https://www.dnvgl.com/services/power-distribution-system-and-electrical-simulation-software-synergi-electric-5005

[11] Protection comparison was not considered in this analysis as those calculations are currently not performed using the ICA module in the Synergi power flow tool which SDG&E uses for voltage and thermal analysis.

2.0 Project Approach

2.1 Methods for Comparison[12]

Given that different methods/tools are used, the hosting capacity results can be expected to be different. However, if hosting capacity analysis parameters, models, and impact factors used by the different tools are the same, one would expect the hosting capacity results to be similar. It is imperative that these factors are consistent in both methodologies when comparing the results to ensure any differences are based on methodology and not the input data or assumptions. To ensure this, EPRI and SDG&E ran the demonstration in parallel on the same set of feeders using the same models and inputs. The two methods used for the demonstration are further described below to provide context to the differences in approach, complexity, and time.

2.1.1 SDG&E Iterative ICA Method

The iterative method[13,14] used in SDG&E's ICA is a technique similar to that which has been used over the past few years to quantify the impacts of DER on distribution systems. DER is modeled directly at single locations, one at a time, while DER capacity is increased until issues occur on the system.

The iterative method essentially performs power flow simulations with DER at user-selected three-phase locations on the distribution system. Using this method, varying levels of DER are simulated at each location independently with power flow simulations iteratively performed to determine the maximum level of DER that can interconnect at these locations without exceeding thermal and voltage limits. Figure 2 depicts the iterative method technique in simplified diagram.

In addition to the power flow simulations, which are used primarily to evaluate thermal and steady state voltage conditions, fault flow simulations are also performed. The fault flow simulations are used to evaluate the protection criteria and to determine the DER level that can be interconnected to each node without hindering the protection devices' ability to detect fault conditions. Note, protection analysis was not included in this comparative study as this portion of the ICA is algorithm-based and does not leverage the Synergi-implemented iterative approach.

[12] *Methods and Considerations for Applying Hosting Capacity*. EPRI, Palo Alto, CA, 2017: 3002011009

[13] Southern California Edison Company's (U 338-E) Demonstration Projects A and B Final Reports, December 23, 2016

[14] Demonstration Projects A&B Final Reports of San Diego Gas & Electric Company (U 902-E), December 22, 2016

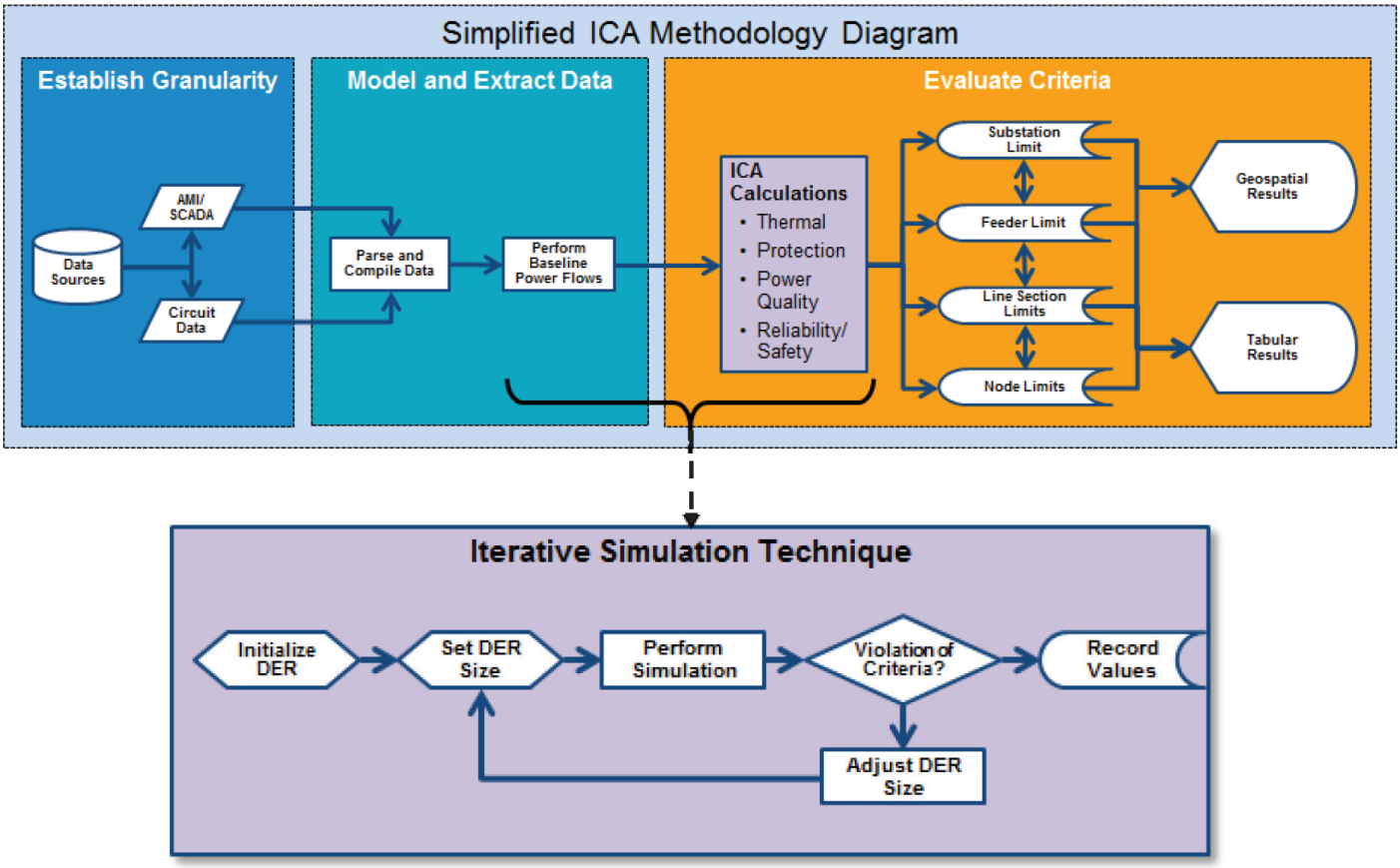


Figure 2. Simplified Diagram of the Iterative Method

This process is repeated for multiple time intervals (576 representative hours) to try to capture daily changes in load, DER, and regulation equipment, and observe their impacts on hosting capacity. This creates a form of time-based hosting capacity. The time series data needed to create these models are derived from 8760 hour DER and load forecasts leveraging historical smart meter data. The derived time series data consists of twenty-four sets (12 months x 2 days) of 24-hour profiles. For each month, there are 2 days that are derived as:

1. 90th percentile representing the high load scenario
2. 10th percentile representing the low load scenario

Evaluating all 576 unique load points is intended to understand the range of hosting capacities based on day and time. For the data to be leveraged into a time-series analysis where the voltage regulation and control from one time interval influences the next time period, the 576 load points are used as a single load profile. This time-series profile, however, is based on a discontinuous set of data as high load days do not transition directly into the low load days of each month. Therefore, the purpose of the time-series analysis, to capture accurate voltage regulation, should be further considered.

An important step in the process is the concept of layered abstraction representing divisions of the electric system in a top down fashion. The analysis looks at various layers of the system and ensures that the higher-level layers impact or limit the lower layers when applicable. By defining layers that represent the electric system hierarchy, explicit criteria calculations can be made within each layer independent of another layer's calculation. This helps organize the results in a way that can inform specific limitations to a single point of interconnection or broader limitation to a feeder or substation.

This point is illustrated in Figure 3 where the process of evaluation can be seen across the criteria at each layer. This approach is important to obtain results from node-specific limitations all the way to transmission-specific limitations. For instance, locational results can be limited by a higher-level constraint such as the thermal limitation of a substation

transformer, therefore limiting the total amount of possible DER that can be interconnected on the downstream feeders, nodes and line sections.

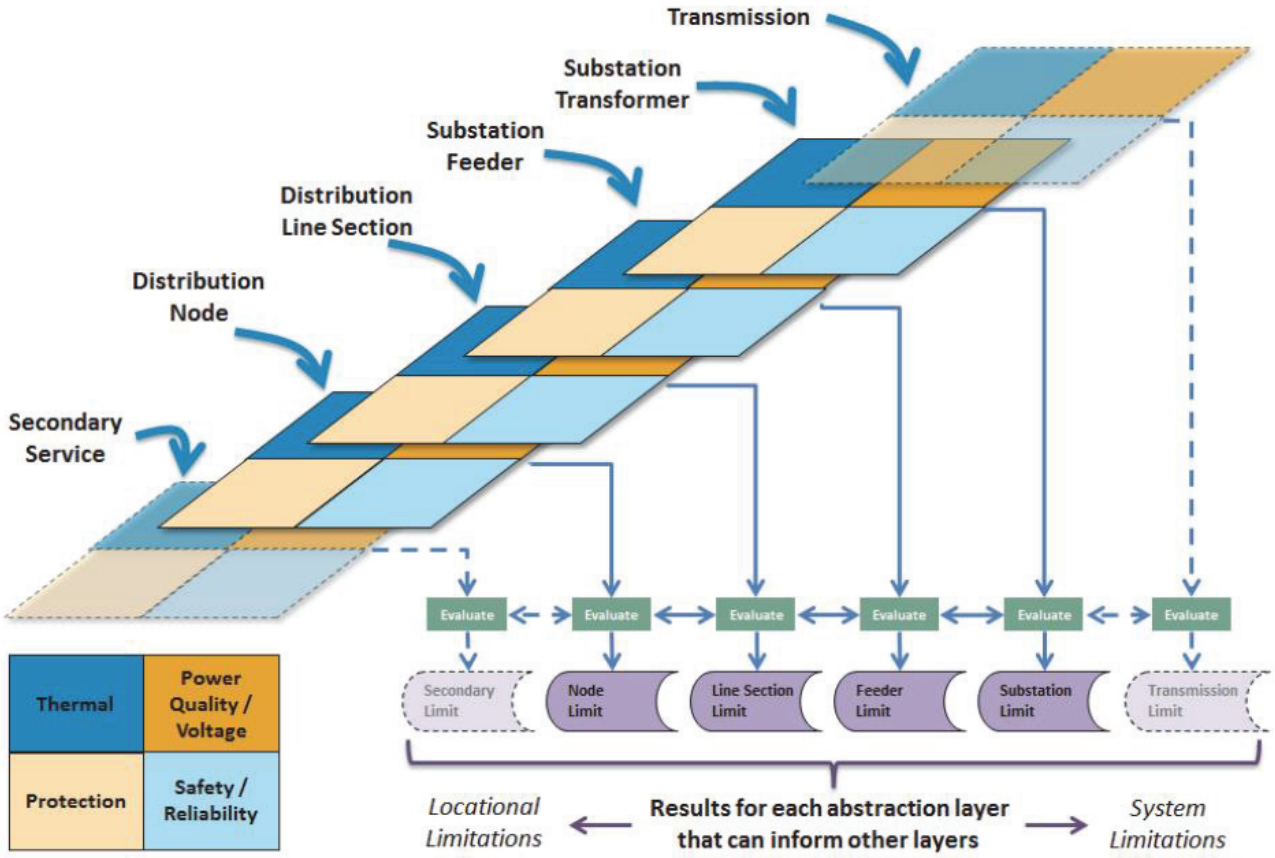


Figure 3. Illustration of Layered Abstraction Process

Once the layered abstraction approach is applied, time-based hosting capacity values for all 576 time intervals are derived resulting in what is referred to as an agnostic hosting capacity for the metrics identified in Table 6.

Table 6. ICA Hosting Capacity Metrics Determined per Location

Hosting Capacity Metrics	DER Scenario Allowing Reverse Power Flow	DER Scenario Limited by Reverse Power Flow
voltage due to generation	X	X
voltage due to load	X	X
voltage deviation due to generation	X	X
voltage deviation due to load	X	X
thermal due to generation	X	X
thermal due to load	X	X
reverse power flow		X
breaker reach	X	
additional fault current	X	
operational flexibility	X	

2.1.1.1 Assumptions

A number of assumptions are made within each method and the list below attempts to capture some of those pertinent to hosting capacity results. As methods further evolve over time, so will the associated assumptions.

- A DER agnostic hosting capacity can be determined and later decoupled into a DER specific hosting capacity portfolio
- Voltage regulation (LTC, line regulator, capacitor) is allowed to operate to adjust for DER impacts.[15]
- The impact of existing DER on voltage deviation is not considered. For example, voltage deviation calculations assume not all existing DER devices contribute to voltage changes (fixed output). In some cases, this can overestimate hosting capacity.
- Time series analysis captures accurate voltage regulation and control operations. The time-series profiles are based on a reduced set of discontinuous data as high load days do not transition directly into the low load days of each month. EPRI recommends the use of a reduced set of data, but it should be acknowledged that any reduction in data nevertheless streamlines the analysis.
- All ICA hosting capacity results are determined using the full detailed model and power/fault flow analyses. To reduce simulation times, some calculations may be performed using alternative methods to streamline the analysis.

2.1.2 EPRI DRIVE Method

The DRIVE hosting capacity method is the successor to the stochastic-based approach previously developed by EPRI. This method was developed to overcome the computation burden of stochastic and iterative-based approaches while still capturing critical grid responses for determining location-based hosting capacity.

Initially developed as a PV hosting capacity method,[16] this method has been further refined and updated as a DER technology neutral approach thus allowing other distributed technologies to be considered based on resource characteristics such as fault current contribution and output variability. The specific technology determines how the analysis is setup to properly quantify the unique impacts of the particular resource.

Working with a number of utilities throughout the world, further enhancements and refinements have been made to the initial approach to add new capabilities, improve overall accuracy, and increase efficiency.[17] A DRIVE User Group has been created to facilitate this process.

2.1.2.1 Overview

The method behind the DRIVE tool is similar to PG&E's streamlined method in concept - where a select number of power flow cases are used to characterize the feeder response, and then calculations are performed to determine DER scenario impacts and hosting capacities. However, the underlying approach and equations are different.[18]

There are two components in EPRI's DRIVE tool as shown in Figure 4. The first component is the Interface to the Planning Tool Module. In this component, each feeder is analyzed to extract information from the model via power flows and short circuit studies. The second component is the DRIVE Hosting Capacity Assessment Module where the extracted data from the first component is analyzed and examined for Hosting Capacity. More detail regarding the underlying method has previously been documented.[19]

[15] Allowing regulation equipment to operate can overestimate hosting capacity in some cases, particularly when the intermittent DER (solar, wind, storage) operates faster than regulation equipment. Quantifying this impact requires simulations to be ran in the 5-30 seconds timeframe rather than hourly as in the ICA. [Ref: Time Series Power Flow Analysis for Distribution Connected PV Generation, Sandia National Laboratory, SAND2013-0537, 2013]

[16] A New Method for Characterizing Distribution System Hosting Capacity for DER: A Streamlined Approach for PV. EPRI, Palo Alto, CA: 2014. 3002003278.

[17] *Distribution Resource Integration and Value Estimation (DRIVE) Tool: Advancing Hosting Capacity Methods to Include Existing DER and Reactive Power Control*. EPRI, Palo Alto, CA: 2016. 3002008293.

[18] Direct comparison of results from the two methods have not been performed to date.

[19] *Distribution Planning with DER: System-Wide Assessment*. EPRI, Palo Alto, CA: 2017. 3002010356

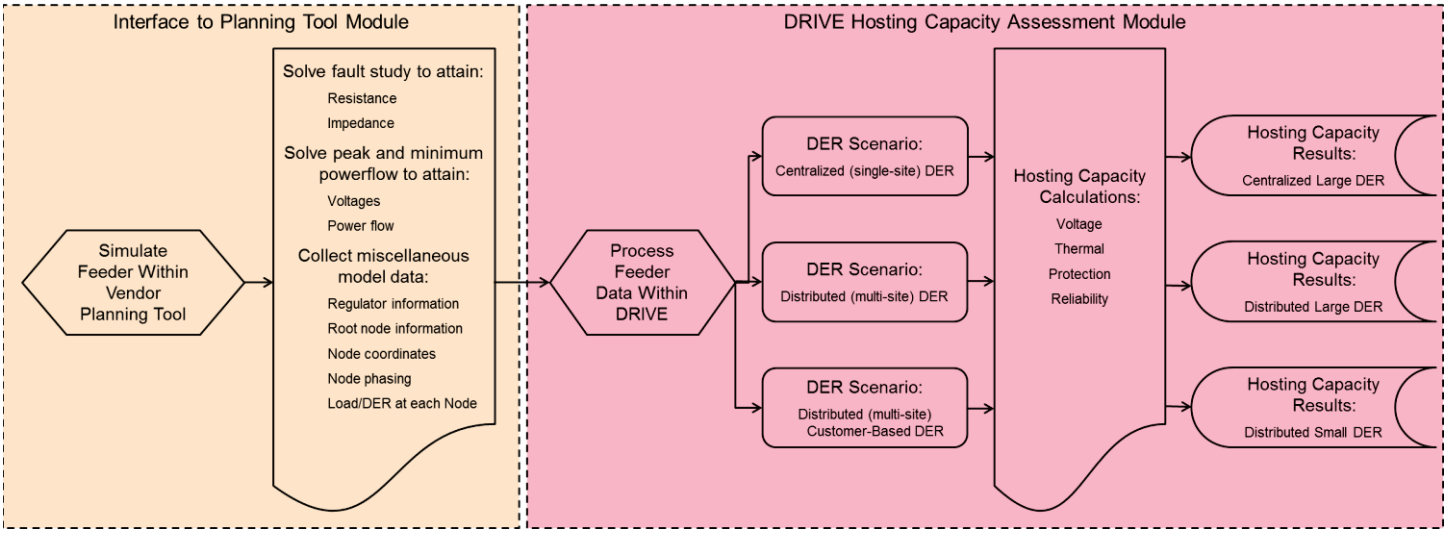


Figure 4. Components of DRIVE

2.1.2.2 Interface to Planning Tool Module

The interface to the planning tool module extracts important data out of the planning tool and models. These interfaces are compatible with a wide range of planning tools (CYME, Synergi, Milsoft, Powerfactory, OpenDSS, Gridlab-D, DEW, PVL, etc.).

The feeder models, exactly as the utility maintains, are analyzed with a limited set of power flows. These load levels are typically chosen based on peak and minimum. These two load levels create boundary conditions for the feeder, which are essential to the analysis of thermal and voltage impacts. For DER types such as photovoltaics, these load levels can be adjusted to daytime hours. The user ultimately has the capability to analyze more or less than two load levels for any one feeder.

The initial power flows are also conducted without any currently connected DER. This is done to determine the baseline operating point of each feeder without DER. Information about the connected/existing DER (if any) is extracted and sent to the Hosting Capacity Assessment where the user has the option to determine the feeder's total or remaining hosting capacity. Conditions might exist wherein the existing DER has direct control from the system operator and thus existing DER should not limit the remaining feeder hosting capacity. Conversely, the existing DER might significantly limit the feeders remaining hosting capacity. As such, the method by which existing DER is treated in the hosting capacity analysis is based on the characteristics of the DER.

Within the Interface to the Planning Tool, the detailed feeder model is analyzed with a series of power flow and fault flow studies. The power flow study provides voltages, element loading, load allocation, and connectivity of the model, while the fault study provides impedance/resistance/reactance data.

2.1.2.3 DRIVE Hosting Capacity Assessment Module

The DER assessments are then performed by applying various DER "scenarios" based on current injection. The hosting capacity is then determined based on whether the specific condition exceeds a user-defined threshold (voltage, protection, thermal). These scenarios consider centralized (single-site) and distributed (multiple-site) DER locations. Thousands of scenarios are examined when considering all potential locations, or "nodes", on the distribution feeder, and are broken down into three main categories:

- Centralized (single site) DER
- Distributed (multi-site) DER
- Distributed (multi-site) Customer-Based DER (e.g., rooftop PV)

Centralized (single-site) DER: The hosting capacity scenario depicts how much DER at a specific location can be accommodated as shown in Figure 5. When the hosting capacity analysis is performed, each node on the feeder is considered independently. This analysis provides insight to the feeder's ability to accommodate DER as well as each individual node on the feeder.



Figure 5. Simplistic Illustration of Centralized DER Analysis

Distributed (multi-site) DER: The hosting capacity scenario depicts how much distributed DER can be accommodated. The distribution applied has Weibull characteristics where its shape and scale are based on the nodes of the feeder. The distribution is continuous, as shown in Figure 6, thus an incremental amount of DER is considered at each node on the feeder. The use of this distribution was developed based on detailed stochastic analysis.[20] When the hosting capacity analysis is performed, each node on the feeder is used to adjust the shape and scale of the applied DER distribution. This analysis provides insight to the feeder's ability to accommodate various deployments of multi-site DER.

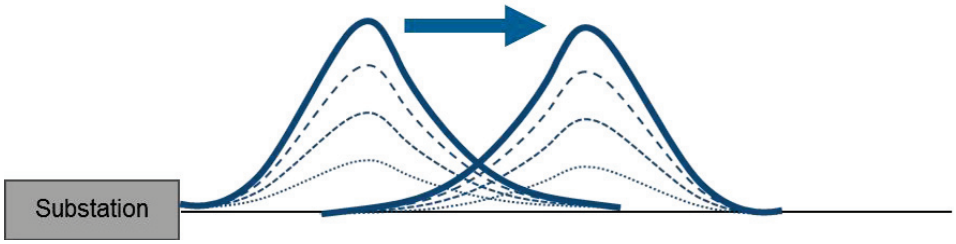


Figure 6. Simplistic Illustration of Distributed DER Analysis

Distributed (multi-site) Customer-Based DER: The hosting capacity scenario depicts how much distributed DER can be accommodated. The DER distribution is based on the location of existing customers and load on the feeder. The location of these customers are used to adjust the shape and scale of the applied DER distribution. Again, the use of this distribution was based on the detailed stochastic analysis previously referenced.

These scenarios make up the basis of the DER impact analysis. Each scenario results in a hosting capacity value and therefore there are multiple hosting capacities at each node – two based on Distributed DER and another based on Centralized DER. The metrics with hosting capacity results from the DRIVE analysis are shown in Table 7.

Table 7. DRIVE Hosting Capacity Metrics Determined per Location

Hosting Capacity Metrics	Centralized (single-site) DER	Distributed (multi-site) DER	Distributed (multi-site) Customer-Based DER
overvoltage due to generation	X	X	X
voltage deviation	X	X	X
regulator voltage deviation	X	X	X
undervoltage due to generation	X	X	X
undervoltage due to load	X	X	X

[20] *Stochastic Analysis to Determine Feeder Hosting Capacity for Distributed Solar PV.* EPRI, Palo Alto, CA: 2012. 1026640.

thermal due to generation	X	X	X
thermal due to load	X	X	X
reverse power flow	X	X	X
additional fault current	X	X	X
breaker reach	X	X	X
sympathetic feeder tripping	X	X	X
unintentional islanding	X	X	X

2.1.2.4 Assumptions

A number of assumptions are made within each method and the below list attempts to capture some of those pertinent to hosting capacity results. As methods further evolve over time, so will the associated assumptions.

- DER considered as a constant current injection, such that fault currents considered in the analysis can be higher than if dependent on impedance to the actual fault. Constant current injection also implies DER current does not change during DER induced voltage rise. This can result in underestimation of hosting capacity for extreme voltage-rise scenarios.
- Load magnitude does not change when DER changes voltage (loads are based on initial power flow). This can result in slightly different load currents and feeder losses which local DER can supply.
- Voltage regulation equipment does not operate to mitigate voltage rise due to DER. Allowing voltage regulation equipment to operate can mask the voltage issues that DER could cause in some cases. EPRI considers voltage regulation a solution to increase hosting capacity and therefore it is not part of DRIVE that calculates the baseline hosting capacity before mitigation solutions are assessed.
- Existing DER is considered in the hosting capacity analysis of every metric.

2.2 Implementation Considerations

As is shown in the previous section, no two hosting capacity methodologies are the same. Inputs, outputs, and assumptions vary. Therefore, a challenge in this project revolved around applying the pre-developed methodologies such that results from those methodologies could properly be compared. There are underlying assumptions and techniques that, if not addressed, would pose inconclusive results. The underlying assumptions can also depend on the tools used to conduct the analysis. Fortunately, both the iterative and DRIVE analyses can be performed on the same SDG&E feeders, modeled within Synergi Electric.[21] The iterative hosting capacity results are provided directly from Synergi Electric, while DRIVE is a standalone tool that has an interface to the Synergi Electric feeder model. Some of the unique aspects of the two tools used in the study are shown in Table 8. Comments on how to address those aspects are included in the table and discussed in the text below.

Table 8. Differences in Methodologies

	DRIVE	**ICA Iterative**	**Comments**
DER Locations Analyzed	All feeder locations	User selected feeder locations*	**DRIVE will compare results at locations selected in the iterative analysis**
DER Scenarios Analyzed	Distributed (multi-site) and Centralized (single-site) DER hosting capacity scenarios	Centralized (single-site) DER hosting capacity scenario	**Compare Centralized (single-site) DER hosting capacity scenario**

[21] https://www.dnvgl.com/services/power-distribution-system-and-electrical-simulation-software-synergi-electric-5005

Model Analyzed	Substation and Single Feeder Served	Substation and All Feeders Served	**Adjacent feeders on the substation bus will be aggregated to the substation bus for the DRIVE analysis. See following text.**
Load Level Considered	Two load conditions	576 load conditions	**DRIVE will analyze one load condition and those results will be compared to the same load condition of the iterative analysis.**
Hosting Capacity Metrics	Voltage, Thermal, Protection	Voltage and Thermal**	**Select voltage and thermal hosting capacities compared**

*Only 'Can Host DER' locations

**Protection is not calculated using the iterative approach

The most critical impact factor to a successful comparison is to have the same underlying feeder models. Besides the using the same underlying models in Synergi Electric, DRIVE processes feeder hosting capacity on a single feeder basis while the iterative method considers all feeders served off the substation bus simultaneously. Therefore, the iterative method might limit DER on the subject feeder due to impacts caused on the adjacent feeder. These adjacent feeder issues are commonly caused by allowing the voltage regulation to operate within the hosting capacity analysis. For instance, adding DER on the subject feeder might cause the LTC to tap down and cause an under voltage on the adjacent feeder. Again, as a fundamental component to DRIVE, voltage regulation adjustment is not considered in the analysis to establish baseline hosting capacity and voltage impacts to adjacent feeders are limited to the voltage impact at the point of common coupling (the substation bus). What should not be ignored, however, are the potential loading implications caused by the adjacent feeders. The load on the adjacent feeders will affect the LTC position and the total power flow through the substation transformer. To recognize this, the DRIVE analysis retains the aggregate load from the adjacent feeders at the substation bus.

The ICA iterative method produces hosting capacity results for 576 different time intervals. This equates to analyzing 576 different conditions for load and DER along with LTC and capacitor controls. To address this, the hosting capacity results for one time period of the iterative analysis was compared to the DRIVE results when analyzing only that same time intervals.

DRIVE automatically determines the Distributed and Centralized DER hosting capacities at every node/location on the feeder. A node is defined for each electrical section modeled in the feeder as shown in Figure 7. Since the iterative method results are for DER at the specific locations defined by the outward/downstream node of selected sections, the iterative results will be compared to the DRIVE results for Centralized DER at the same locations.

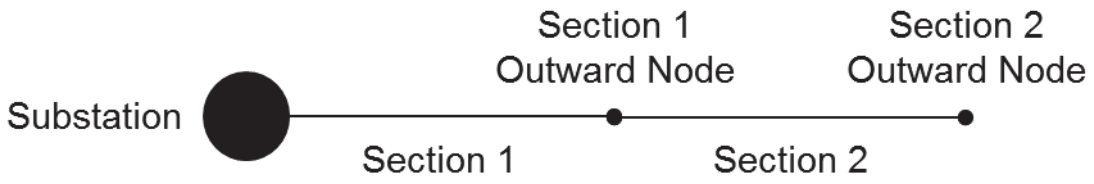


Figure 7. Definition of Node and Section

The Synergi ICA module used for voltage and thermal analysis currently does not support the determination of protection-based hosting capacity results (e.g., breaker reach, sympathetic tripping, etc.) that are performed in a full ICA

analysis[22]. The metrics that are compared in this study are stated in Table 9. For consistency, the DER characteristics for which the hosting capacity analysis is performed assumes DER is set for unity power factor with full 100% power output swings. The maximum penetration considered for hosting capacity is 12 MW.

Table 9. Hosting Capacity Metrics Compared

Category	Criteria	Thresholds
Voltage	Overvoltage	≥ 1.051 Vpu at primary node for non-CVR feeders ≥ 1.025 Vpu at primary node for CVR feeders
	Voltage Deviation	≥ 3% change at primary node
Thermal	Section Overload	≥ 100% normal rating

One final subtle difference is that the iterative method uses a time-based power flow solution at each time step while DRIVE uses snapshot power flow and fault-study. Although the power flow solution engines are the same, there may be slight differences in the final solution based on solution convergence and controls. The main implication here is that the final voltage profile and impedances of a feeder might be different which could lead to slightly different hosting capacity results.[23]

2.3 Detailed technical results

The schematics of the five feeders compared are shown in Figure 8. These are all 12 kV feeders with varying load levels, topology, and length as defined in Table 10.

[22] SDG&E uses separate calculations to meet the ICA requirements for protection-based results

[23] This phenomenon was also observed when comparing the Iterative implementation using different platforms (CYME/Synergi) per the Demo A/B reports published previously [Demonstration Projects A&B Final Reports of San Diego Gas & Electric Company (U 902-E), December 22, 2016]

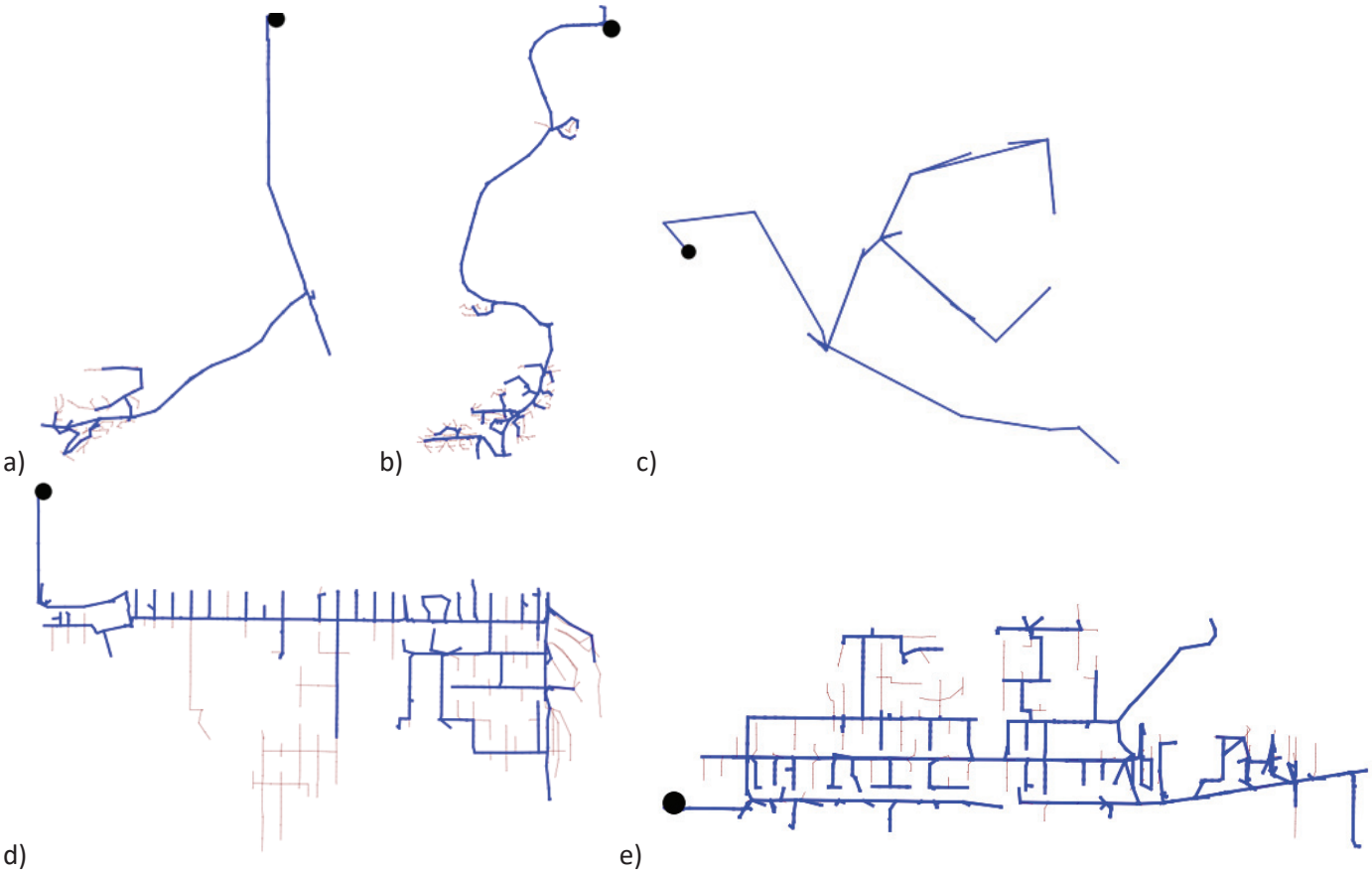


Figure 8. Feeders for Comparison a) A1 b) A2 c) B1 d) C1 e) C2

Table 10. Feeder Characteristics

Feeder	A1	A2	B1	C1	C2
Peak Hour Load (kW)	4360	7962	6441	10335	12336
Min Hour Load (kW)	294	234	3912	4330	4049
January Peak Day 1am Load (kW)	1783	2857	5369	5851	6058
DER (kW)	714	1997	0	861	985
Voltage Class (kV)	12	12	12	12	12
Furthest Point (ft)	27747	41532	4970	20700	16590
Furthest Electrical Distance (ohm)	3.46	1.86	0.50	2.34	1.38
Substation LTC	1	1	1	1	1
Switchable Substation Capacitors	2	2	1	1	1
Line Regulators	0	0	0	0	0
Switchable Line Capacitors	2	2	0	1	1

2.3.1 Single-Hour Comparison

The specific time period comparison uses the first time interval of the 576 point iterative analysis. This time interval simulates 1am of the peak load day in January. This hour was chosen for multiple reasons:

1) All control elements initialize during this hour (compared to hour 2 where control settings depend on the final control state of hour 1 after all DER hosting capacity metrics/locations are analyzed)

2) Existing DER output is zero during this hour (DER is primarily PV). Recall the differences previously noted regarding the application of existing DER in the iterative and DRIVE analyses

The iterative analysis is conducted for the January peak day to determine the 1am control settings. Those settings are then manually applied to create the January 1am peak load snapshot model. Due to differences in the time series power flow and the snapshot power flow algorithms in Synergi previously mentioned, the snapshot models are further refined to achieve a similar power flow solution. Once the power flow solutions matched, the DRIVE hosting capacity analysis is performed. The results from both methods are then compared.

2.3.1.1 Thermal Hosting Capacity

Overall, both methodologies produce similar thermal hosting capacity results as shown in Figure 9. However, there are some inconsistencies. Although results are sorted by descending DRIVE values, this should not imply that the iterative values are incorrect, but rather further examination is required.

Results on Feeders A1 and A2 indicate the inconsistency occurs in the iterative analysis when the section/node under consideration only serves a downstream capacitor. The inconsistencies on Feeders C1 and C2 occur in the iterative analysis when a fuse is located on the outward node of the section whose hosting capacity is being calculated. Further investigation regarding if alternative methods are used in the iterative method, should be considered. The iterative analysis is under further refinement at this time based on these findings.

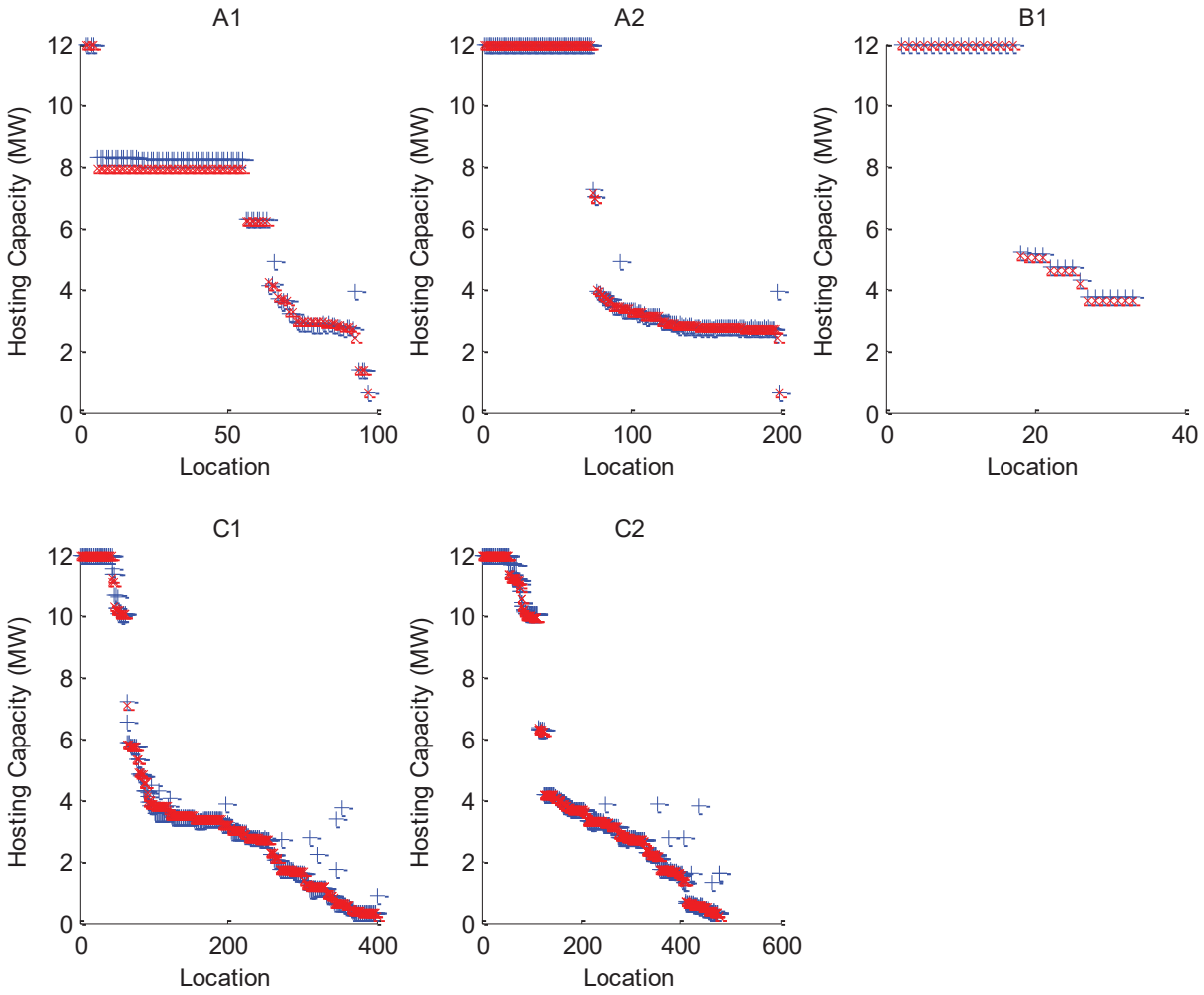


Figure 9. Single-Hour Thermal Hosting Capacity Comparison (Blue +: Iterative Analysis, Red x: DRIVE Analysis)

2.3.1.2 *Overvoltage Hosting Capacity*

The overvoltage hosting capacity comparison shown in Figure 10 is similar for all feeders except B1 and C2. The inconsistencies for Feeder B1 will be further explained in the next section on voltage deviation hosting capacity. Feeder C2 has a unique feature in that it contains long parallel branches within the feeder. The method by which DRIVE currently conducts the analysis does not consider the impacts that long parallel branches can provide when determining DER hosting capacity at a specific node. For efficiency reasons, the DRIVE analysis assumes that at minimum load, the voltage drop along any branch (short or long) will be minimal, even with long parallel branches. However, when not considering minimum load, as for this specific hour, and when the branches are long and the voltage drop along any particular branch is more significant, the DRIVE results match that of the lower hosting capacity branch (indicated by the DRIVE points matching the lower region of the iterative points). To consider a feeder and scenario with non-minimum load and long parallel branches, DRIVE has been updated and the new results provide a closer match as shown in Figure 11.

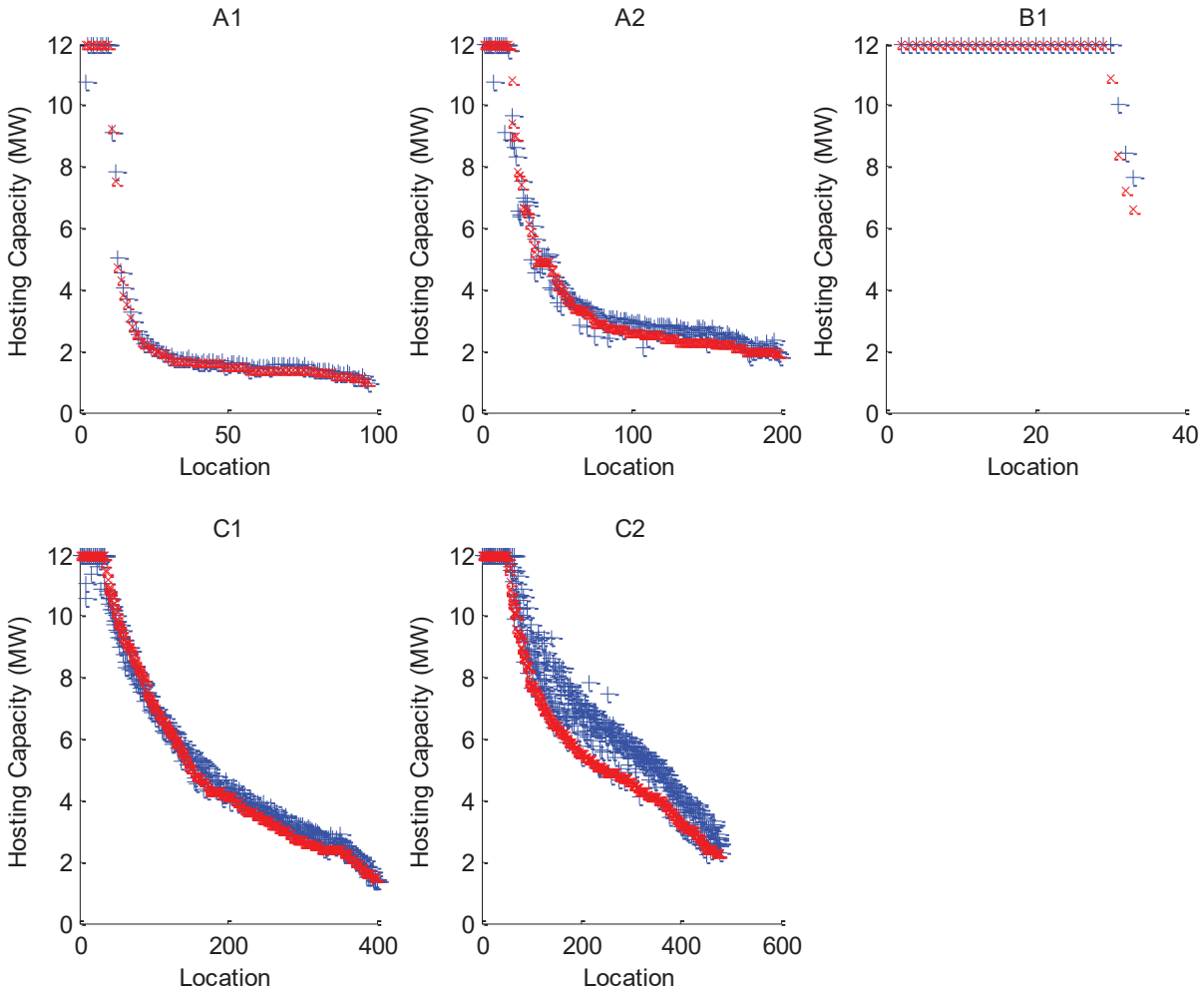


Figure 10. Single-Hour Overvoltage Hosting Capacity Comparison (Blue +: Iterative Analysis, Red x: DRIVE Analysis)

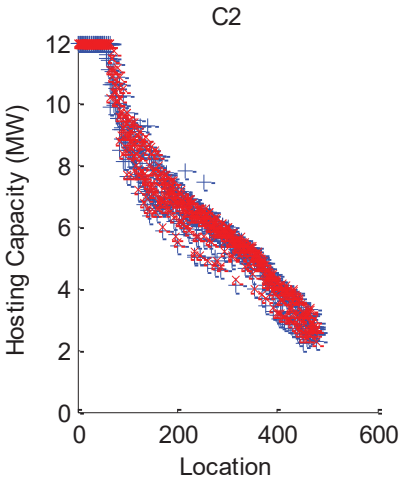


Figure 11. Single-Hour Overvoltage Hosting Capacity Comparison after DRIVE Analysis Overvoltage Algorithm Update. (Blue +: Iterative Analysis, Red x: DRIVE Analysis)

2.3.1.3 Voltage Deviation Hosting Capacity

As shown in

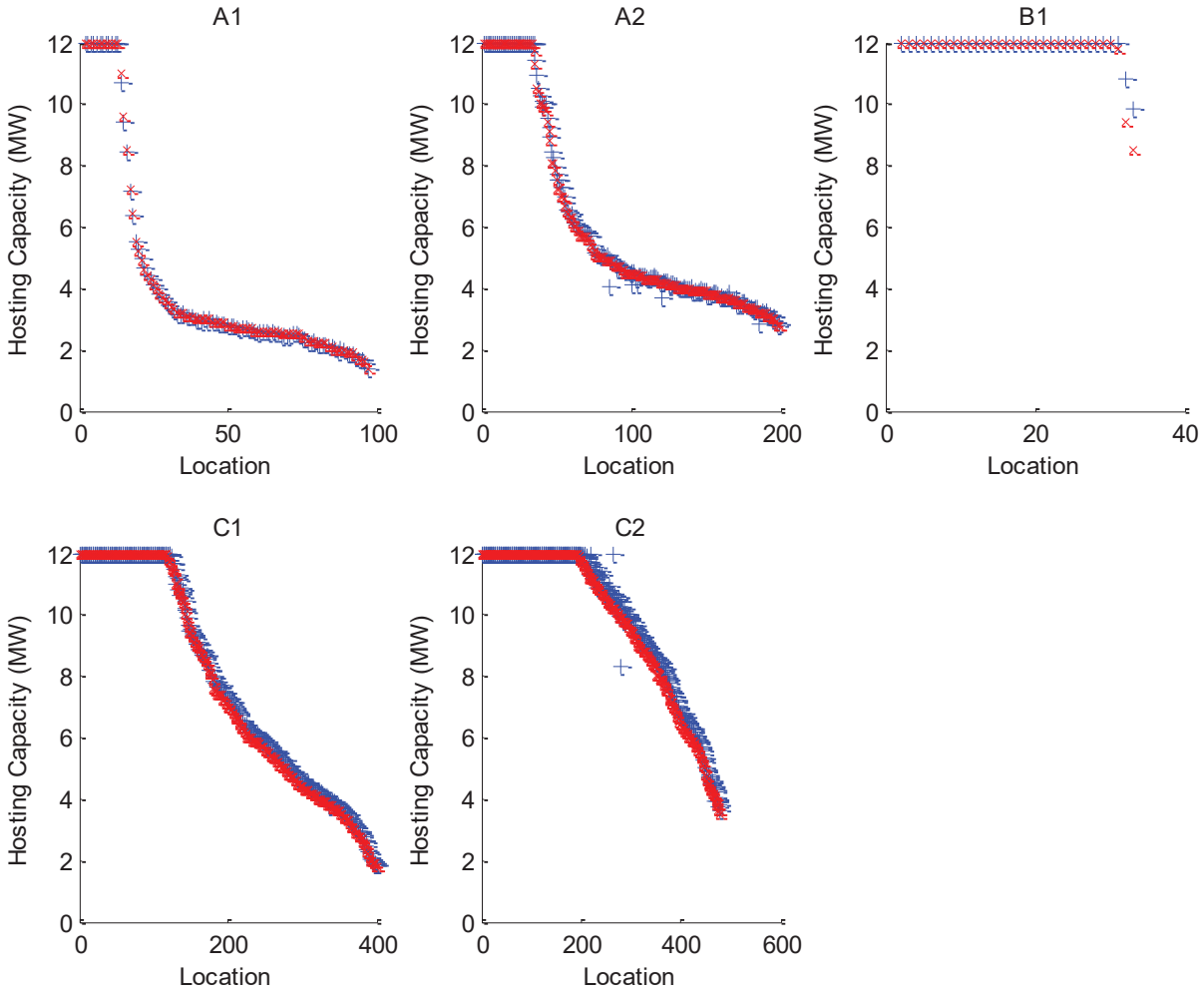


Figure 12, the voltage deviation hosting capacity comparison is very similar besides several inconsistencies for feeders A2, B1, and C2. The inconsistencies on feeder B1 are due to differences in the distribution system impedances used in the analysis. DRIVE uses Thevenin impedances derived from a short-circuit analysis, while the iterative analysis uses the phase impedances from the power flow. Although these values are typically similar, the Thevenin impedances are derived without loads, generators, and capacitors, while the power flow impedances account for the presence of these shunt devices. The difference in impedances also further explains the feeder B1 mismatch for overvoltage hosting capacity. The impact of the impedance used in the DRIVE analysis is under further investigation.

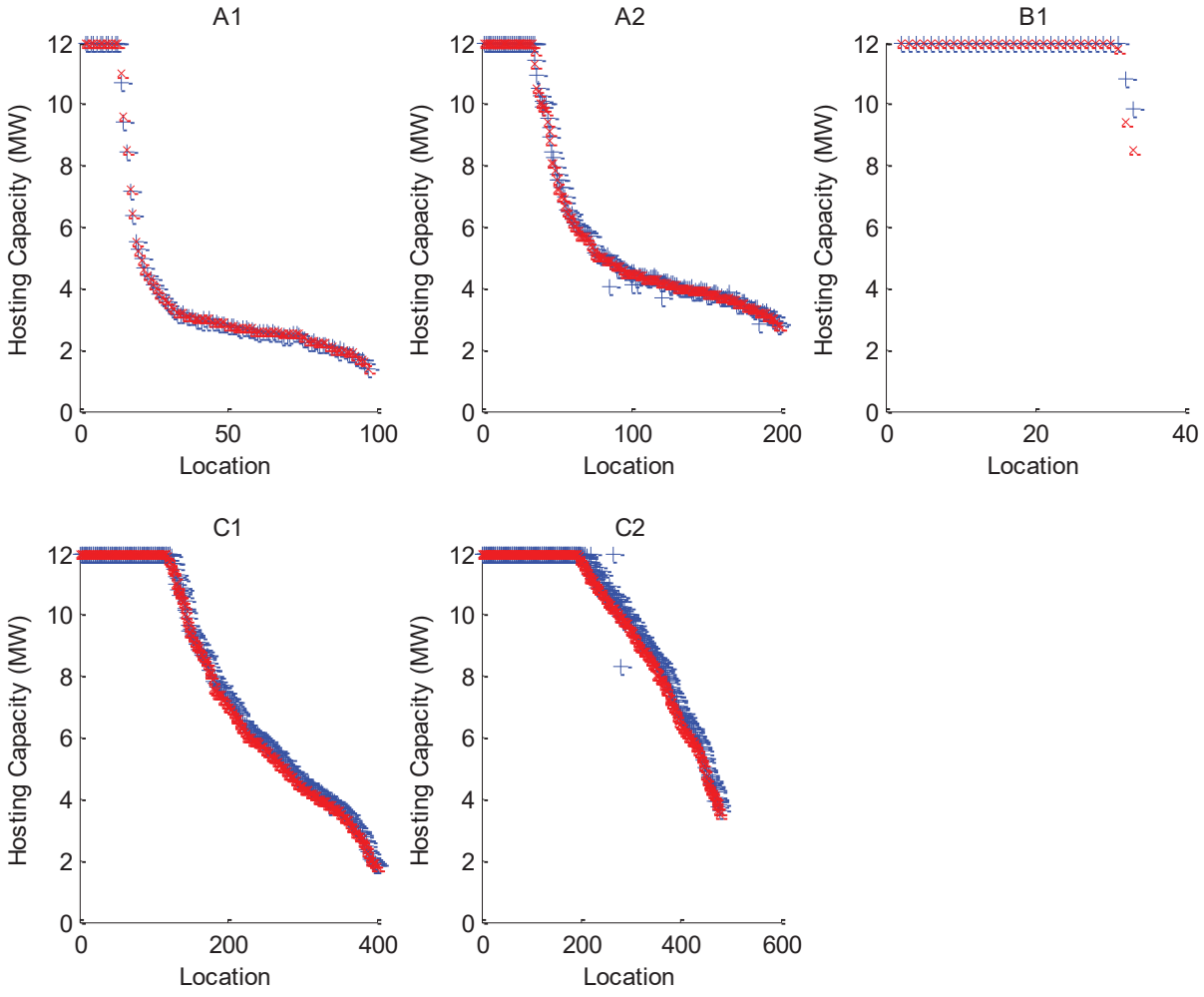


Figure 12. Single-Hour Voltage Deviation Hosting Capacity Comparison (Blue +: Iterative Analysis, Red x: DRIVE Analysis)

The results indicate that the iterative analysis outliers on Feeders A2 and C2 are an error based on the impedance to those locations. More specifically, the single iterative values shown that are significantly less than DRIVE on Feeders A2 and C2 occur at locations that should have a higher hosting capacity. This is illustrated in Figure 13 for the occurrence on Feeder C2. Note that higher impedances should result in lower voltage deviation hosting capacities. Similarly, the single iterative value shown that is significantly more than DRIVE on Feeder C2 occurs at a location that should have a lower hosting capacity. Further investigation should be considered to resolve these inconsistencies.

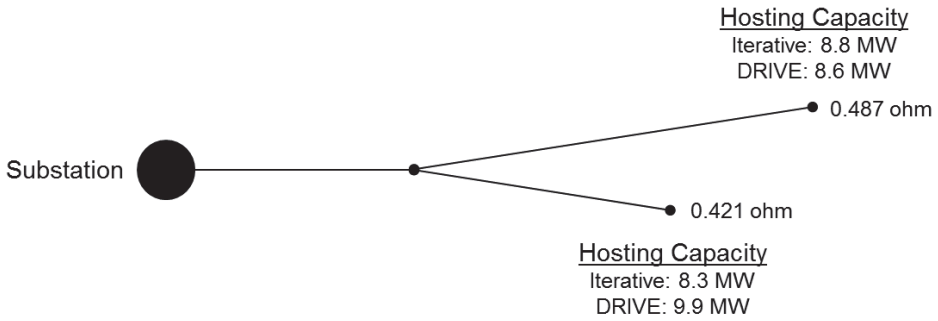


Figure 13. Illustration of Error in Iterative Hosting capacity result

2.3.2 Annual Comparison

The annual comparison goes beyond the specific hour analysis and compares the overall result of each method's full hosting capacity analysis. This will take all the results from the 576 point iterative analysis, find the minimum hosting capacity for each location, and compare those results to the DRIVE analysis conducted on two load conditions. For the DRIVE analysis, the additional level of scrutiny placed on matching the input power flow models is not applied. Rather, the DRIVE analysis scales the base model to the peak and minimum load levels. All existing DER is considered in the DRIVE analysis because peak and minimum load occur during daylight hours, during which time the iterative analysis would also have the DER resource online.

2.3.2.1 Thermal Hosting Capacity

The minimum thermal hosting capacities for each location are similar as shown in Figure 14 except for the discrepancies previously discussed that require further investigation (locations that have 100% reactive power loads downstream or locations with fuses on section's outward node). The overall similarity in results is expected based on the fact that the minimum load hour is analyzed in each methodology, and the minimum load hour sets the minimum thermal hosting capacity in each method.

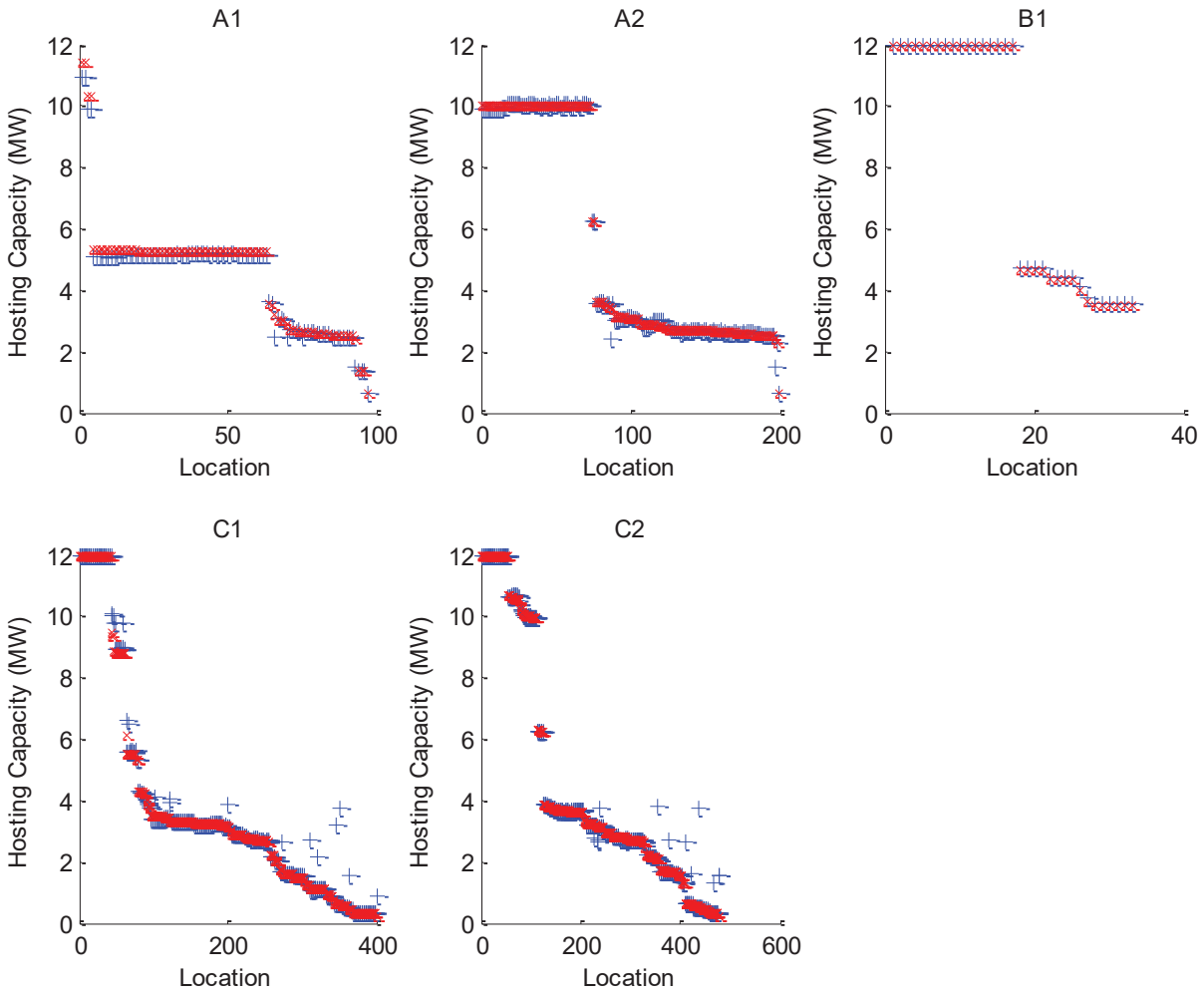


Figure 14. Annual Thermal Hosting Capacity Comparison (Blue +: Iterative Analysis, Red x: DRIVE Analysis)

2.3.2.2 Overvoltage Hosting Capacity

All four feeders with existing DER (A1, A2, C1, C2) showed voltage violations occurred in both the DRIVE and iterative analyses. Based on the DRIVE methodology, each of these four feeders cannot accommodate additional DER at any location until the voltage violation is mitigated. In the iterative methodology, however, three of the feeders with existing DER showed that some (not all) locations could still accommodate DER. These results indicate that the iterative methodology allows additional DER to mitigate the voltage violation and thus allows additional hosting capacity at some locations on the feeder. Currently, the iterative method is under further refinement to deal with pre-existing violations. Further investigation is needed before comparisons can be made.

The one feeder with no existing DER, Feeder B1, shows a significant mismatch in overvoltage hosting capacity as shown in Figure 15. Results indicate this mismatch is primarily due to intentional differences in the overvoltage methodology. Both methodologies use Synergi to run the baseline power flow, thus the voltage profiles used in both are valid for each hosting capacity analysis. However, DRIVE is based upon the premise that hosting capacity is defined as the amount of DER that can be accommodated without adversely affecting power quality or reliability under existing control configurations. As such, using existing voltage regulation to increase hosting capacity is considered a potential mitigation solution. Therefore, the DRIVE results indicate there exists a condition in which the feeder could experience overvoltage

at a lower hosting capacity than found in the iterative analysis. Further analysis comparing results to a full quasi-static time series analysis would shed light on this inconsistency.

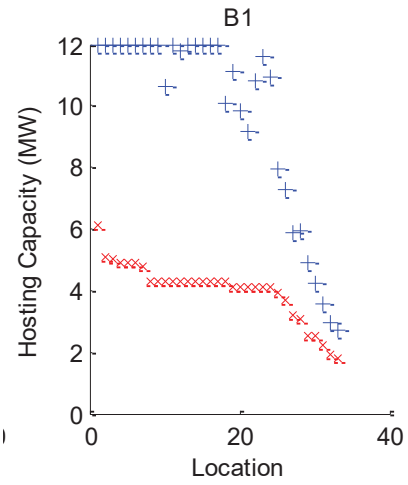


Figure 15. Annual Overvoltage Hosting Capacity Comparison (Blue +: Iterative Analysis, Red x: DRIVE Analysis)

2.3.2.3 Voltage Deviation Hosting Capacity

The voltage deviation hosting capacities between the iterative method and DRIVE analyses match relatively well for Feeders A1 and A2 as shown in Figure 16. The mismatch on Feeder B1 is again due to differences in the impedances used in each analysis. The most significant difference in results occurs on the highest loaded feeders (C1 and C2). The inconsistency is due to the way losses are incorporated in the analyses. Figure 17 illustrates how the comparison improves when the impact of losses is ignored in the DRIVE hosting capacity calculation. Results indicate that the DRIVE calculation to include the impact from losses may need further review, however, these feeders do have relatively high load (refer to Table 10) which typically correlates to higher loss impact. If DER output occurs at peak load, distribution feeder losses decrease, which increases feeder voltage further. Results therefore also indicate losses have insignificant impact in the iterative analysis which should be reviewed.

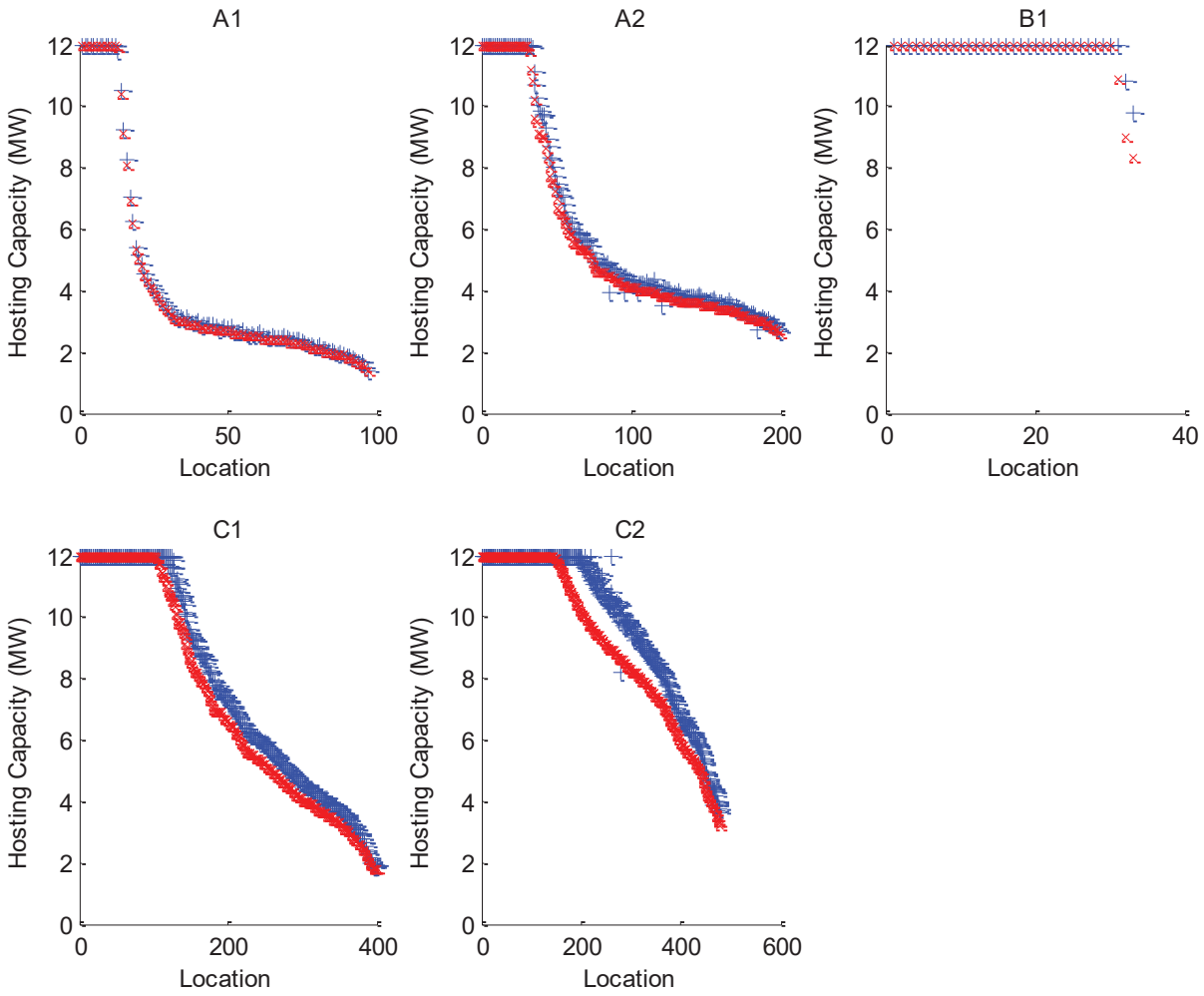


Figure 16. Annual Voltage Deviation Hosting Capacity Comparison (Blue +: Iterative Analysis, Red x: DRIVE Analysis)

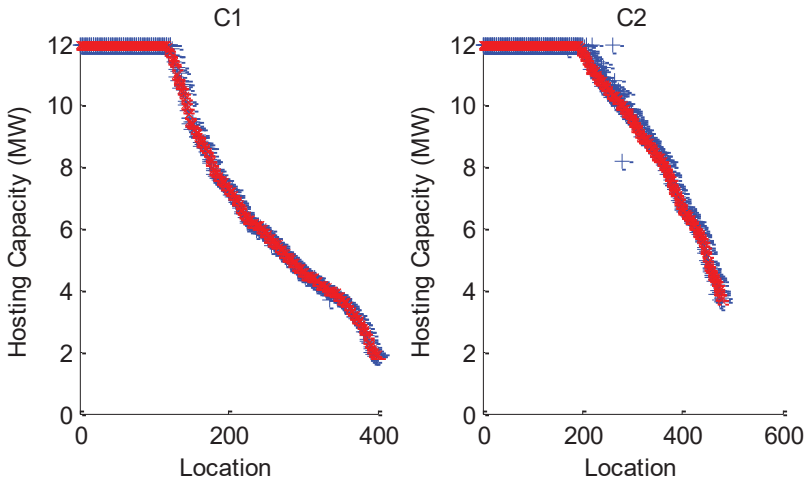


Figure 17. Annual Voltage Deviation Hosting Capacity Comparison when Ignoring the Impact of Losses in DRIVE (Blue +: Iterative Analysis, Red x: DRIVE Analysis)

Results show that the iterative method's voltage deviation hosting capacity values are relatively unchanged for all feeders between the specific-hour analysis and the annual analysis as shown in Figure 18. These results also indicate that the iterative method's voltage deviation hosting capacity is mostly independent of load and losses. Both methods require further investigation.

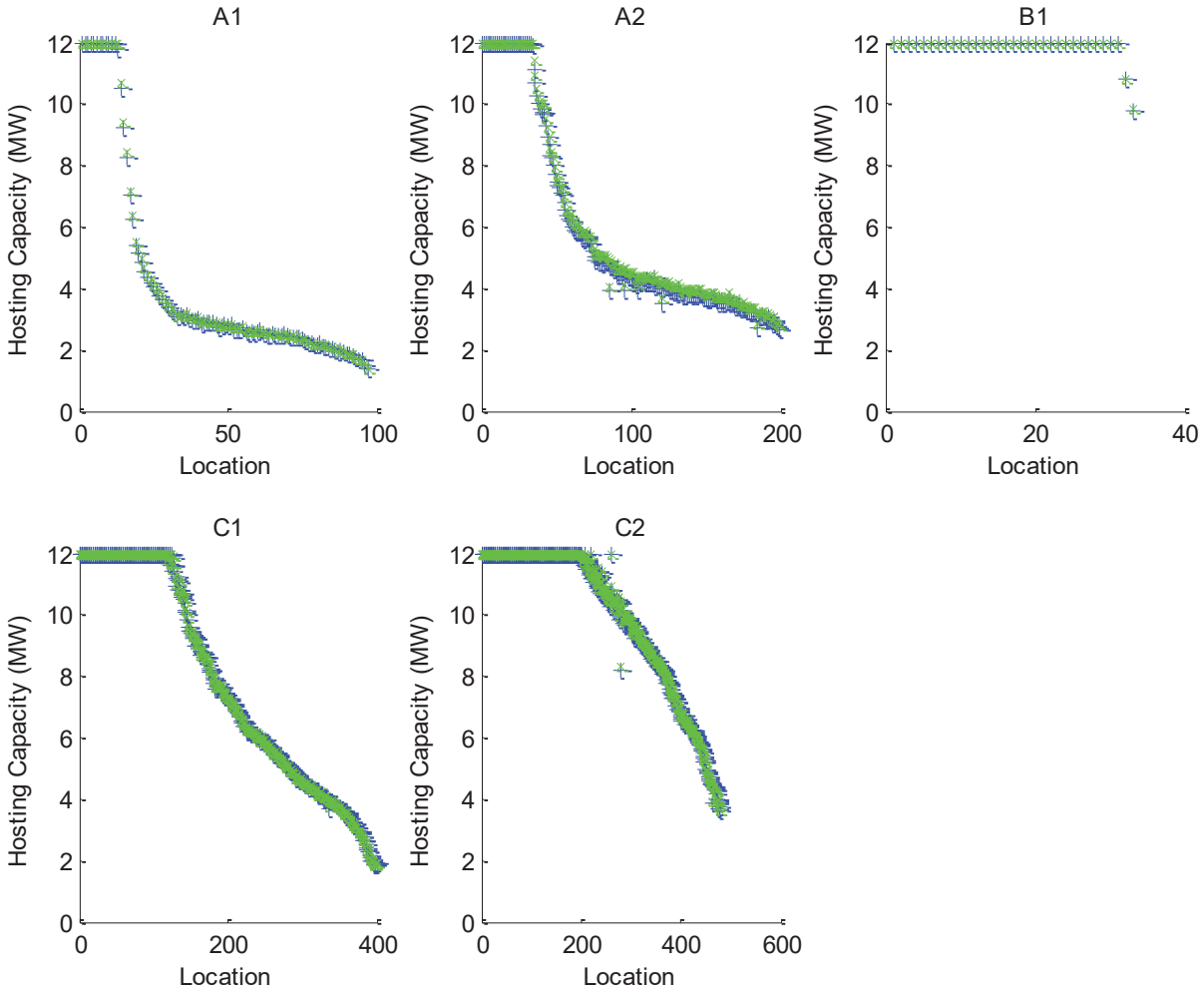


Figure 18. Iterative Voltage Deviation Hosting Capacity Comparison (Blue +: Annual Analysis, Green x: Single-Hour Analysis)

An additional variation in the two hosting capacity methods is that the iterative method does not consider the impact of existing DER on voltage deviation hosting capacity. DRIVE can consider this impact, and when it does, the remaining hosting capacity at each node would reduce from that shown in Figure 16 to that shown in Figure 19. In this case, the total change in voltage due to DER is underestimated in the iterative approach, thus overestimating hosting capacity for Feeders A1, A2, C1, and C2. Note Feeder B1 does not have any existing DER.

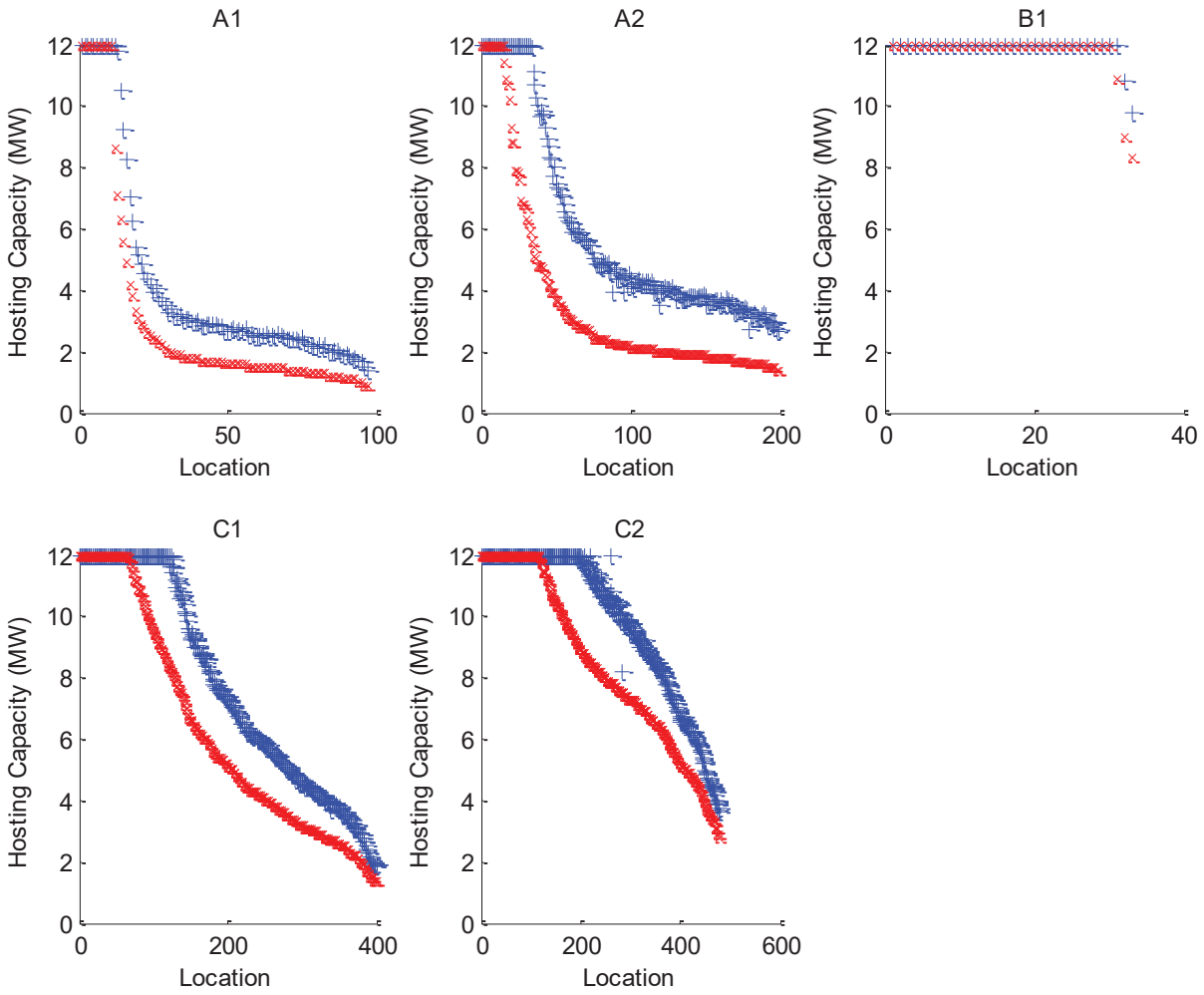


Figure 19. Annual Voltage Deviation Hosting Capacity Comparison with DRIVE Considering Aggregate Impact of Existing DER (Blue +: Iterative Analysis, Red x: DRIVE Analysis)

2.3.2.4 Annual Analysis Summary

Table 11**Error! Reference source not found.** summarizes the minimum hosting capacity value across all nodes from the previous annual analysis figures. Only the initial results are used and not the sensitivities discussed. Without knowing specific feeder location, the minimum hosting capacity values portray the greatest constraint on each feeder for each issue. Although DRIVE did not analyze the load for all 576 time intervals, the hosting capacities are almost identical except for Feeder B1, whose discrepancies were previously explained as a difference in simulated feeder impedance.

Table 11. Annual Hosting Capacity Analysis Summary for All Analyzed Feeders and Nodes

	Iterative ICA (MW)			**DRIVE (MW)**			**Difference (Iterative-DRIVE, MW)**		
Feeder	**Thermal**	**OV**	**Vdev**	**Thermal**	**OV**	**Vdev**	**Thermal**	**OV**	**Vdev**
A1	0.6	0.0	1.4	0.6	0	1.4	0.0	0.0	0.0
A2	0.6	0.0	2.6	0.6	0	2.6	0.0	0.0	0.0
B1	3.6	2.7	9.8	3.5	1.8	8.3	0.1	0.9	1.5
C1	0.3	0.0	1.8	0.2	0	1.8	0.1	0.0	0.0
C2	0.3	0.0	3.6	0.2	0	3.2	0.1	0.0	0.4

2.4 Applying the results

The results of this demonstration project point to opportunities in the future enhancement of hosting capacity analysis methods. These opportunities include the improvement of the underlying methods and the applicability of the results produced from those methods.

3.0 Findings and Conclusions

3.1 Was the project objective accomplished?

The objective of this activity was to perform a demonstration of the DRIVE tool for determining the hosting capacity of distribution feeders for DER. This objective was successfully accomplished on five SDG&E feeders with a range of designs and characteristics.

3.2 Description of measurement and verification results

The demonstration of the DRIVE tool provides insight to the hosting capacity on five SDG&E feeders when considering voltage and thermal impacts. Those results are useful in identifying existing barriers for adoption of DER. The results also provide information to customers and developers to enable more informed decisions on where to submit DER applications. By basing these decisions on hosting capacity information, there is an opportunity to reduce interconnection costs and reach the full hosting capacity potential on feeders.

The outcome of the demonstration points to a consistency in the results of two hosting capacity methods. As shown in Table 12, and discussed in the previous section, the results of the DRIVE demonstration align very closely to the results of the iterative analysis. This comparison, similar to the one done as part of the CA DRP Demos, provides a relative comparison to a third approach.

Table 12. Differences in Annual Hosting Capacity Analysis for All Analyzed Feeder Nodes

	Difference (Iterative-DRIVE)		
Feeder	**Thermal (MW)**	**Overvoltage (MW)**	**Voltage Deviation (MW)**
C1	0.1	0.0	0.0
C2	0.1	0.0	0.4
B1	0.1	0.9	1.5
A1	0.0	0.0	0.0
A2	0.0	0.0	0.0

The comparative analysis also points to differences and areas that require continued improvement in both approaches as well as areas for further investigation as described in Table 13. There are aspects of both analyses that may be unclear to the user. All users and stakeholders should acknowledge these aspects, and the internal functionality that drives them.

Table 13. Areas on Improvement/Understanding in Hosting Capacity Methodologies

Iterative	**DRIVE**
Further examination of inconsistencies in thermal analysis	Further examination of impedances used in voltage analysis
Consider including locking regulation equipment in voltage analysis	Incorporate branch analysis in voltage analysis
Further examination of inconsistencies in voltage deviation analysis	Further examination of impact of losses in voltage deviation analysis
Further examination of applied pre-existing violations	Consider inclusion of adjacent feeders at substation

3.3 Conclusion

This project demonstrates the use of the DRIVE tool for doing hosting capacity assessments on five selected SDG&E feeders. The results found both opportunities for implementation and challenges that require further investigation. While DRIVE has been adopted across the industry with more than 25 utilities worldwide, further refinements/enhancements to both DRIVE and the iterative methodology will continue to be made based on utility applications and demonstrations like that performed here.

Currently, the Iterative ICA analysis is based on the specific requirements within California. However, locking into one method without exploring alternative approaches will ultimately limit innovation in the future. Given this, it is recommended that alternative methods for determining hosting capacity should be considered. Alternative methods have been shown to produce similar results, though it should be noted that more work needs to be done to compare these results to detailed assessments. Alternative methods, based on the efficiencies they provide, would open the analysis to the exploration of impact factors and bring further accuracy to the results. Additionally, alternative methods may be needed as the system becomes more complex – smart inverter technologies, operational flexibility, etc.

What follows is a brief summary of findings, recommendations, and next steps based upon this effort.

3.3.1 Findings

1. **Different hosting capacity methods can provide similar results**
   As detailed in the findings, this project has shown that hosting capacity results of the iterative method are in line with results of the DRIVE hosting capacity analysis. While there were some minor variations noted, these inconsistencies have identified required improvements to one or both methodologies. Based on these results, there are opportunities for the industry to continue to refine and enhance multiple hosting capacity approaches while still achieving consistent results. Specifically, this finding indicates that utilizing DRIVE for SDG&E's ICA could be done with limited impact to results.
2. **Similar hosting capacity results can be derived more efficiently**
   The analysis has shown that the hosting capacity analysis can be performed in a fraction of the time without compromising accuracy of the results. This presents an opportunity for utilities to reduce computational burden and manpower needed to perform hosting capacity analysis. It is an important consideration as utilities are faced with decisions about frequency of the calculations, increased complexity of scenarios (e.g., operational flexibility, smart inverter controls, etc.), and the impact on different hosting capacity applications. Specifically, this finding indicates that SDG&E could save time and resources while achieving a similar result.
3. **Hosting capacity methods will continue to evolve and improve**
   As demonstrated throughout this effort, hosting capacity methods will continue to evolve. As noted, both methods are undergoing updates to improve precision. Likewise, both methods are undergoing further modifications to streamline the underlying algorithms and analysis approaches. While the industry has tried to draw a distinct line between "iterative" and "streamlined" approaches, in the future this will be irrelevant as there will likely be little means of distinction between the two.

3.3.2 Recommendations

1. **SDG&E should keep DRIVE available as one of the tools it can use in future hosting capacity analyses**
2. **SDG&E should monitor the future advances in DRIVE and the emergence of other tools, to be able to make the best choices for specific future assessment needs**
3. **Consider improvements to ICA requirements by reducing hours simulated**
   The results of this project also provided insight into potential opportunities to improve upon the required analysis approach of analyzing all 576 hourly load points per section. This project shows that similar results can be captured without analyzing all 576 hourly load points. It is recommended that further consideration be given

to reducing the number of hours simulated. It ensures a more cost-effective process and enables a more sustainable analysis approach for future complexity.

4. **Consider all potential DER locations in hosting capacity analyses**
   DER location is one of the primary factors impacting hosting capacity (more so than hourly changes in load[24]). As such, all possible DER locations should be evaluated. As noted in the results, only portions of the circuit locations were considered (two-phase and single-phase locations were excluded).
5. **Consider the aggregate impacts of all DER in hosting capacity analyses**
   At present, the current ICA does not consider the impact of existing DER on voltage deviation. Existing DER can contribute to voltage variations for intermittent resources and therefore should be considered in the analysis (currently existing DER is only considered for thermal and overvoltage analysis).
6. **Evaluate the use of regulation equipment for establishing baseline hosting capacity**
   The current ICA method calls for all regulation equipment to operate and therefore mitigate voltage rise from DER. Existing voltage regulation equipment can in some cases be used to mitigate voltage rise and increase hosting capacity, but at the same time, overregulation can lead to potential under-voltages and decreased hosting capacity. These impacts are examined by observing overvoltage and under-voltage simultaneously in the iterative analysis. DRIVE, however, calculates the DER-induced voltage rise prior to regulation equipment operation by considering all regulation equipment locked during the analysis. Caution is recommended when allowing regulation equipment to mitigate DER-induced voltage rise under high penetration scenarios, more specifically:
   i. Under conditions where regulation equipment is "bucking" to prevent DER-induced voltage rise, a sudden loss of generation due to a grid-related (fault) event or market signal could result in further under-voltage conditions for customers elsewhere on the feeder. These under-voltage conditions are not currently examined.
   ii. DER can operate faster than voltage regulation equipment and therefore cause voltage rise prior to regulation equipment operation. The current ICA method assumes existing regulation equipment can mitigate voltage rise, however different DER types can operate considerably faster than the existing regulation equipment (solar, wind, and storage).
   iii. Under-voltage due to overregulation is not specific to DER as it could also occur from by a sudden drop in load.

   Existing regulation equipment is considered adequate for existing load scenarios on the feeder, but the use of the regulation for DER is reserved as a potential solution to increase hosting capacity above baseline by mitigating DER-induced voltage rise. However, consideration as a mitigation solution warrants careful thought regarding the application and DER type. This can be particularly important as more advanced solutions, such as smart inverters, are deployed.
7. **Calculate the impacts of smaller-size DER within the ICA to prepare for future applications in planning**
   Current ICA analysis does not calculate the hosting capacity of smaller-size DER. However, prior analysis has shown that rooftop PV has a significant impact on hosting capacity results. It is recommended that including smaller-size DER analysis is critical when using hosting capacity for future applications like planning the distribution system.
8. **Perform detailed time-series analysis of DER impacts to compare ICA and DRIVE hosting capacity methods to assess accuracy**
   The comparison analyses performed to date in the industry are assessing the differences in results from one method to another but not assessing the accuracy of either. To evaluate accuracy, it is recommended that comparisons be performed with a detailed, time-series analysis of specific DER locations, technologies, etc. to better understand method accuracies. There is a certain level of implied precision and accuracy using a 576-

[24] Pacific Gas and Electric Company's (U 39 E) Demonstration Projects A and B Final Reports, December 27, 2016

hour approach that should be further investigated. This is of particular importance if ICA results begin being used more for interconnection assessment approval.

9. **Perform a more rigorous assessment of hosting capacity methods to better understand inconsistencies**
   Based on this initial comparison, it is clear there are benefits to doing a more in-depth comparison of the various hosting capacity methods and input assumptions. As noted, the results point to several items driving discrepancies, and it is recommended that the following be considered:
   - The use of voltage regulation equipment in mitigating voltage rise. As noted, the current ICA method calls for regulation equipment to operate and mitigate DER-induced voltage rise wherein DRIVE calculates the voltage rise prior to regulation operation.
   - Pre-existing conditions. As noted, the two approaches appear to handle pre-existing conditions (feeder violations prior to the hosting capacity calculation) differently and further investigation is needed to determine when and how this affects results.
   - Alternative methods for determining DER hosting capacity should be investigated.
   - Determine when model inconsistencies (such as inclusion of adjacent feeders on the substation, branches on the feeder under study, and variance in electrical characteristics) can significantly impact the hosting capacity results.
10. **Perform sensitivity analysis on DER and grid impact factors to improve accuracy**
    An important point frequently overlooked in discussions of hosting capacity methods is that the impact factors, not methods themselves, are the main driver to improve accuracy of results. Knowledge of these impact factors led to the consistency of analysis defined in section 2.2. There is an opportunity for the industry to better understand these impact factors and how they affect hosting capacity results. It is recommended that a sensitivity analysis be performed to understand the extent to which these drive accuracy, which in turn can inform what is most critical for analysis.
11. **Perform a protection impact assessment comparison**
    The iterative fault flow protection-based hosting capacity assessments are often significantly more time consuming and computationally difficult to perform. It is recommended that a similar assessment to that done in this project for power flow hosting capacity issues be performed for iterative protection-based methods.

4.0 Technology Transfer Plan

A primary benefit of the EPIC program is the technology and knowledge sharing that occurs both internally within SDG&E and across the industry. To facilitate this knowledge sharing, SDG&E will share the results of this project by widely announcing the availability of this report to industry stakeholders on its EPIC website, by submitting papers to technical journals and conferences, and by presentations in EPIC and other industry workshops and forums. Additionally, presentations will be given to internal stakeholders at SDG&E.

5.0 Metrics and Value Proposition

5.1 Metrics

The following metrics (discussed in Table 14) were identified for this project as potential project benefits at larger scale deployment. Given the pre-commercial nature of this EPIC project, these metrics would apply in future scenarios after widespread commercial adoption. The following metrics are potential benefits that are concluded from different tests cases performed in this effort:

Table 14. EPIC metrics for pre-commercial demonstration of EPRI DRIVE DER hosting capacity tool

D.13-11-025, Attachment 4. List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation)
1. Potential energy and cost savings
b. Total electricity deliveries from grid-connected distributed generation facilities
e. Peak load reduction (MW) from summer and winter programs
f. Avoided customer energy use (kWh saved)
i. Nameplate capacity (MW) of grid-connected energy storage
3. Economic benefits
b. Maintain/reduce capital costs
c. Reduction in electrical losses in the transmission and distribution system
4. Environmental benefits
a. GHG emissions reductions (MMTCO2e)
5. safety, power quality, and reliability (equipment, electricity system)
b. electric system power flow congestion reduction
7. Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy
d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360)

5.2 Value Proposition

The purpose of EPIC funding is to support investments in R&D projects that benefit the electricity customers of California IOUs. The primary principles of EPIC are to invest in technologies and approaches that promote greater reliability, lower costs, and increased safety. Table 15 represents the value that "pre-commercial demonstration of EPRI DRIVE DER hosting capacity" project provides to the overall system operation. Primary and secondary benefits are presented wherever applicable to demonstrate the value of the function for commercial adoptability.

Table 15. Value proposition (primary and secondary) for pre-commercial demonstration of EPRI DRIVE DER hosting capacity tool

Primary Principals			Secondary Principals					
Reliability	Affordability	Safety	Societal Benefits	GHG Emissions Mitigation / Adaptation	Loading Order	Low-Emission Vehicles / Transportation	Economic Development	Efficient Use of Ratepayers Monies
X				X				X

As it is shown in Table 15 and was discussed in the result and conclusion section of this report, pre-commercial demonstration of EPRI DRIVE DER hosting capacity primarily can enhance systems reliability by optimal DER placing and sizing. Furthermore, it can contribute to GHG emission reduction by finding and suggesting optimum number, size, and location of DER in a distribution system. These principles can eventually lead to efficient use of ratepayers' monies.

Appendix 7

EPIC-1, Project 5, Module 1: Smart Distribution Circuit Demonstrations – Demonstrations of Advanced Circuit Concepts and Devices



EPIC Final Report

Program	**Electric Program Investment Charge (EPIC)**
Administrator	**San Diego Gas & Electric Company**
Project Number	**EPIC-1, Project 5**
Project Name	**Smart Distribution Circuit Demonstrations**
Module Name	**Module 1, Demonstrations of Advanced Circuit Concepts and Devices**
Date	**December 31, 2017**

Attribution

This comprehensive final report documents the work done in this EPIC project.

The project team for this work included the following individuals, listed alphabetically by last name.

Internal SDG&E Project Technical Team

Aksel Encinas

Frank Goodman

Molham Kayali

Amin Salmani

Aung Thant

Internal SDG&E Stakeholder Review Panel

Laurence Abcede

Kahveh Atef

Michael Colburn

Jamie Exon

Christian Henderson

Karl Iliev

Greg Smith

Jade Thiemsuwan

Stacy Williams

Schweitzer Engineering Laboratories, Inc.

Alaap Anujan

Arvind Ayilliath

Tanushri Doshi

Kamal Garg

Jenny Hitch

Cassie Reimer

EXECUTIVE SUMMARY

Program Objective: The objective of SDG&E's EPIC-1, Project 5, on Smart Distribution Circuit Demonstrations, was to perform pilot demonstrations of smart distribution circuit features and associated simulation work to identify best practices for integrating new and existing distribution equipment in these circuits. The project was broken into two modules:

- Demonstration of Advanced Circuit Concepts
- Demonstration of Methodologies and Tools for Energy Storage System Assessment

This executive summary describes the work and results for the first module. The work on pre-commercial demonstration of advanced circuit concepts was broadly divided into three phases:

Phase 1 included evaluation of products and technologies currently available for improved distribution circuit design, system operation, and protection. It also assessed emerging distribution circuit solutions for maintaining reliable and uninterrupted energy delivery. Hardware evaluation covered topics such as time synchronization, protection and automation control, communication, and renewables and energy storage. Some of the distribution solutions investigated include advanced distribution automation control, dynamic feeder optimization, synchrophasor-based solutions, and fault location.

Phase 2 included the selection and modeling of three distribution circuits: coastal-residential, desert-rural, and urban. The circuit parameters provided by SDG&E in Synergi Electric format were converted to RTDS Power Simulation Software (RSCAD) and validated for accuracy. A pre-commercial demonstration plan was developed to validate the distribution circuit operation and equipment performance. A hardware setup was assembled for pre-commercial demonstration of the performance of individual smart devices in a laboratory. Algorithms were developed to study system voltage coordination on distribution circuits between distributed energy resource (DER) and voltage regulators (VR). The interaction between the two device types was made possible with a controller at a central level. Circuit performance was studied during load switching via simulations. The test observations and circuit performance were captured for further analysis.

Phase 3 included the analysis of the demonstration results carried out in Phase 2 and provided recommendations on the integration and coordination of multiple voltage correction devices on a larger system, controlled by a central master controller. It is demonstrated via simulations that the DER and VR can be controlled interactively to provide voltage support on distribution circuits. Practical implementation and expansion to include other voltage correction devices are discussed. Certain modern solutions including detection of downed conductors and power quality monitoring are discussed, offering insights on how to improve the existing distribution system.

The demonstration laid groundwork for commercial adoption of the demonstrated concepts. It is recommended that SDG&E pursue commercial adoption of some of the key concepts that were demonstrated. On larger distribution circuits with multiple voltage regulation devices, system-wide voltage coordination would be required for efficient and reliable service to the customers. This implementation would also aid in improving the lifespan of various distribution equipment, as well as lowering the associated maintenance costs. Some of the challenges associated with implementing this concept in larger circuits include bringing together devices from multiple vendors on one platform and the communication protocols supported by them. Adoption of a standardized communication architecture is recommended for this purpose. It is recommended that selected devices and communications protocols be carefully evaluated before commercial adoption. A technology transfer plan was created to include the recommended steps to bridge the gap between laboratory demonstration of improved distribution practices and its successful commercial and practical implementation in the field on larger distribution circuits.

Table of Contents

Executive Summary ..... **iii**
Abbreviations and Acronyms ..... **xviii**
1 Introduction **1**
2 Project Scope and Approach **3**
2.1 Project Initiation Meeting 3
2.2 Phase 1 Hardware and Circuit Evaluation 3
2.3 Phase 2 Circuit Simulation and Testing Evaluation 3
2.4 Phase 3 Smart Circuit Analysis and Recommendations 4
2.5 Project Deliverables 4
3 Hardware and Circuit Evaluation **5**
3.1 Time Synchronization 5
3.1.1 Network Time Protocol 5
3.1.2 Simple Network Time Protocol 5
3.1.3 IRIG-B Protocol 5
3.1.4 Precision Time Protocol 6
3.1.5 Applications 7
3.2 Protection, Automation, and Control 7
3.2.1 Dynamic Voltage Controller 7
3.2.1.1 Modes of Operation 8
3.2.1.1.1 Protection Mode 8
3.2.1.1.2 Standby Mode 9
3.2.1.1.3 Injection/Boost Mode 9
3.2.1.2 DVR Voltage Injection Methods 9
3.2.1.3 Dynamic Volt-Ampere Reactive Compensation Solution 9
3.2.1.4 D-VAR System Specifications 10
3.2.2 SCADA Capacitor 11
3.2.2.1 Vendor K Automatic Capacitor Controls 12
3.2.3 Voltage Regulator 13
3.2.3.1 Basic Operation of a Step-Voltage Regulator 14
3.2.3.2 Determining Voltage Regulator Type and Size 15
3.2.3.3 Vendor D Voltage Regulator 16
3.2.4 Reclosers 17

3.2.4.1 Types of Reclosers 17
3.2.4.1.1 Single-Phase Reclosers 17
3.2.4.1.2 Three-Phase Reclosers 17
3.2.4.1.3 Triple-Single Reclosers 17
3.2.4.2 Recloser Controls 17
3.2.4.2.1 Hydraulic Recloser Controls 18
3.2.4.2.2 Electronic Recloser Controls 18
3.2.4.3 Vendor G Three-Phase Reclosers 18
3.2.4.3.1 Operating Principle 18
3.2.4.4 Vendor L Advanced Recloser Control 18
3.2.5 Sectionalizers 19
3.2.5.1 Selection Criteria 19
3.2.6 Transformer Monitoring and Control 20
3.2.6.1 Thermal Monitoring 20
3.2.6.2 Dissolved Gas Analysis 20
3.2.6.3 Frequency Response Analysis 21
3.2.6.3.1 Impulse Frequency Response Analysis 21
3.2.6.3.2 Sweep Frequency Response Analysis 21
3.2.6.4 Partial Discharge Analysis 22
3.2.6.5 Microprocessor-Based Transformer Monitor 22
3.2.7 Micro-PMU 24
3.2.7.1 Components of a PMU 26
3.2.7.2 Need for PMUs 26
3.2.7.2.1 Oscillation Detection 26
3.2.7.2.2 Frequency Monitoring 26
3.2.7.2.3 Voltage Stability Monitoring 26
3.2.7.2.4 Disturbance Detection and Alarming 27
3.2.7.2.5 Resource Integration 27
3.2.7.2.6 Transmission Line Dynamic Rating and Congestion Management 27
3.2.7.3 MicroPMU 27
3.3 Communications 28
3.3.1 Communications Protocols Used in Substations 28
3.3.1.1 Distributed Network Protocol 28
3.3.1.1.1 Features of DNP3 28
3.3.1.2 IEC 61850 Standard 29

3.3.1.2.1 Features of IEC 61850 29
3.3.1.3 GOOSE Messaging 29
3.3.1.4 Modbus 30
3.3.2 Implementing SCADA Over Wireless Communications Networks 30
3.3.2.1 Wireless Network Topologies 30
3.3.2.2 Wireless Technologies 31
3.3.2.2.1 ZigBee 31
3.3.2.2.2 Wi-Fi 32
3.3.2.2.3 Worldwide Interoperability for Microwave Access 32
3.4 Renewables and Energy Storage 33
3.4.1 Multifunction Inverters 33
3.4.1.1 Vendor C Solar Inverter 33
3.4.2 Community Energy Storage (25–100 kW) 34
3.4.2.1 Introduction 34
3.4.2.2 Industrial Solutions and Products 34
3.4.2.2.1 Physical Layout 35
3.4.2.2.2 Operational Principle 36
3.4.2.2.3 Device Management 36
3.4.2.2.4 Relevant Standards Compliance 37
3.4.3 Commercial Electric Vehicle Supply Equipment Clusters 37
3.4.3.1 Introduction 37
3.4.3.2 Commercial EVSE Clusters 37
3.4.3.3 Charging Options 37
3.4.3.4 Electrical Assessment of Site Prior to Installation 38
3.4.3.5 Industrial Solutions and Products 40
3.4.3.5.1 Basic EVSE 40
3.4.3.5.2 Smart EVSE 40
3.4.3.6 Relevant Standards Compliance 40
3.4.4 Microgrid Solutions 41
4 Solutions Evaluation 42
4.1 Advanced Distribution Automation Control 42
4.1.1 Automatic Reconfiguration 43
4.1.1.1 Feeder Event Sequence 43
4.1.1.2 Feeder Return-to-Normal Sequence 44
4.1.1.3 Scheme Solution Sequence 44

4.1.1.4 Permanent Fault Condition 46
4.1.1.5 Open-Phase Condition 46
4.1.1.6 Overload Condition 46
4.1.2 Dynamic Feeder Optimization 47
4.1.2.1 Distribution Unit Control 47
4.1.2.2 DFO Sequence of Operation 48
4.1.2.3 Availability of Control Actions 49
4.1.2.4 Regulator Response 49
4.1.2.5 Capacitor Response 49
4.1.2.6 DFO and Device Control Modes 50
4.1.2.7 Capacitor Calibration 50
4.2 PMU-Enabled Solutions 50
4.2.1 Islanding Detection 51
4.2.2 Phase Identification 51
4.2.3 Load Characterization 51
4.2.4 System Monitoring 52
4.3 High-Impedance Fault Detection 52
4.4 Fault Location 53
4.5 Dynamic Line Rating in Distribution Circuits 54
4.6 Baseline Data 55
5 RTDS Modeling 56
5.1 Synergi to RTDS Conversion Process 56
5.1.1 Line Impedance Conversion – Synergi to RSCAD 56
5.1.1.1 Line Impedance Conversion 57
5.1.2 Load Impedance Conversion – Synergi to RSCAD 58
5.1.2.1 Load Impedance Conversion 59
5.2 RTDS Controller 60
5.2.1 RTDS Load Impedance Controller 60
5.2.1.1 Load Impedance Profile and Control 61
5.3 Results Capture 64
6 Voltage Regulator Control Tests 65
6.1 Test Setup 65
6.1.1 Voltage Regulator Control LED Definitions 65
6.1.2 Voltage Regulator Operator-Controlled Pushbuttons 66

6.1.3 Voltage Regulator Control I/O List 66
6.1.4 RTDS to Vendor B Amplifier Low-Level Test Interface 66
6.1.5 Vendor B Amplifier to Voltage Regulator Control Test Interface 70
6.2 Operating Modes 73
6.3 Test Procedure 73
6.4 Voltage Regulator Test 74
6.5 Voltage Regulator RTDS Model 76
6.6 Voltage Regulator Settings 79
6.7 RTDS Test Assumptions 80
6.8 Test Scenarios 81
6.8.1 Auto and Remote Toggle – From Local Control 81
6.8.2 Automatic Voltage Regulation – Voltage Raise/Lower Operation 83
6.8.3 Voltage High- and Low-Limit Scenarios – No Operation 91
6.8.4 Load Profile Operation 98
6.9 Recommendations 106
7 Capacitor Bank Controller 107
7.1 Test Setup 107
7.1.1 I/O List 107
7.1.2 Front-Panel Layout 108
7.1.3 Low-Level Test Interface 108
7.1.4 RTDS and Relay Interface 109
7.1.5 Tests Summary 112
7.1.6 Analog Thresholds 114
7.2 Test Scenarios and Results 115
7.2.1 SUPY and LOCAL Toggle 115
7.2.2 AUTO and MANUAL Toggle – From LOCAL Control 118
7.2.3 Automatic Voltage Control Operation 121
7.2.4 Automatic KVAR Control Operation 127
7.2.5 Time-of-Day Operation 135
7.2.6 Overvoltage Lockout 140
7.2.7 Voltage Imbalance Lockout 143
7.2.8 High-Current Condition 147
7.2.9 Hunting Lockout 150
7.2.10 Operations Counters 152

8 High-Impedance Fault Detection 154
8.1 Test Setup 156
8.1.1 RTDS Interface and I/O List 156
8.2 HIF Overview 159
8.2.1 HIF Detection 159
8.3 Test Procedure 161
8.4 Recloser Control Settings 162
8.5 Test Scenarios 164
8.5.1 Auto and Remote Toggle – From Local Control 164
8.5.2 High-Impedance Fault Detection 164
8.6 Recommendation 179
9 Power Quality in Islands 180
9.1 Island Configurations 180
9.2 Test Setup 184
9.2.1 Phasor Measurement Units 184
9.2.2 RTDS and PMU Interface 186
9.2.3 PMU Communications Architecture 186
9.3 Test Procedure and Results 187
9.3.1 Test 1 187
9.3.2 Test 2 190
9.3.3 Test 3 191
10 Voltage Support Coodination Tests 193
10.1 Circuit Selection 193
10.2 Test Setup 195
10.2.1 Distributed Energy Resource 195
10.2.2 Voltage Regulator 196
10.2.3 Voltage Controller 196
10.2.4 RSCAD RunTime 198
10.2.5 Hardware Implementation 199
10.3 Test Procedure 199
10.3.1 Load Switching 199
10.4 Test Results 201
10.4.1 Scenario 1 201
10.4.2 Scenario 2 204

11 Findings 207
11.1 Voltage Coordination Test Results Analysis 207
11.2 Voltage Regulator Location Analysis 207
12 Recommendations 210
12.1 System Voltage Coordination – Advanced Control 210
12.2 Downed Conductor Detection 213
12.3 Island Detection – Vector Shift Element 214
12.3.1 Vector Shift Element Logic 214
12.4 Island Detection – Fast Rate-of-Change-of-Frequency Protection 216
12.5 Fast Decoupling Schemes 216
12.5.1 Local Decoupling Protection Scheme 216
12.5.2 Synchrophasor-Based Decoupling Protection 217
12.5.2.1 Synchrophasor Protocol 217
12.5.2.2 Synchrophasor-Based Decoupling Protection 217
12.6 Power Quality Monitoring 218
12.6.1 Voltage Sag, Swell, and Interruption 218
12.6.2 Harmonics 218
12.6.3 Unbalance 218
13 Technology Transfer Plan 220
13.1 Introduction 220
13.2 Procedure for Commercial Implementation 220
13.2.1 Design and Review 220
13.2.2 In-house Testing and Validation 220
13.2.3 Field Implementation and Monitoring 220
13.3 Challenges 221
13.4 Resources 221
13.5 Conclusion 221
14 Overall Project Conclusions 222
15 Metrics And Value Proposition 223
15.1 Project Metrics 223
15.2 Value Proposition: Primary And Secondary Guiding Principles 224
16 References 225
Appendix A Circuit One-Line Diagram 228
Appendix B Load Profile 232

Appendix C Voltage Regulator Control Settings 245
Appendix D Recloser Settings Sheet 260

List of Figures

Figure 3.1: DVR General Configuration 9
Figure 3.2: Protection Mode 9
Figure 3.3: Standby Mode 10
Figure 3.4: Block Diagram of a SCADA-Controlled Metal-Enclosed Automatic Capacitor Bank 13
Figure 3.5: Step-Up Autotransformer (Boost Mode) 16
Figure 3.6: Step-Down Autotransformer (Buck Mode) 17
Figure 3.7: Connection of 32-Step and 4-Step Regulators 17
Figure 3.8: Microprocessor-Based Transformer Monitor I/O and Communications 26
Figure 3.9: PMU Used to Monitor Power Flowing Through Electrical Grid 28
Figure 3.10: PMUs Installed at Every Substation Monitoring the Power Grid 29
Figure 3.11: Block Diagram of a PMU 30
Figure 3.12: Simplified Representation of DEM Systems Supporting CES Fleet Systems 39
Figure 3.13: Simplified Circuit Representation of CES Units 40
Figure 3.14: Electrical Assessment Prior to EVSE Installation 43
Figure 4.1: Example of ADAC Implementation 48
Figure 4.2: Block Diagram of HIF Detection (Nonharmonic) 59
Figure 4.3: Balance Equation Schematic 61
Figure 5.1: Line Impedance Conversion From Synergi to RSCAD 64
Figure 5.2: Load Impedance Conversion From Synergi to RSCAD 66
Figure 5.3: Coastal-Residential Test Circuit – 24-Hour Field Load Profile 68
Figure 5.4: RSCAD Load Control 69
Figure 5.5: RSCAD Load Control HMI 70
Figure 6.1: Voltage Regulator Control Test Setup 72
Figure 6.2: RTDS to Vendor B Amplifier Interface 75
Figure 6.3: Raise, Lower, and Block Digital Input Wiring 76
Figure 6.4: Voltage Regulator External Connection Diagram 77
Figure 6.5: Voltage Regulator Internal Connection Diagram 78
Figure 6.6: Voltage Profile Plot of a Continual Raise Operation 79
Figure 6.7: Simplified One-Line Drawing of Desert-Rural Test Circuit 82
Figure 6.8: Voltage Regulator RTDS Block 84
Figure 6.9: Voltage Regulator Internal Logic 85
Figure 6.10: Voltage Regulator Voltage Band Setting 87

Figure 6.11: Test Scenario 3.7.1. Phase A Voltage Regulator SER 89
Figure 6.12: Test Scenario 3.7.1. Phase B Voltage Regulator SER....89
Figure 6.13: Test Scenario 3.7.1. Phase C Voltage Regulator SER....89
Figure 6.14: Test Scenario 3.7.2. Phase A Voltage Regulator Output Voltage Waveform 92
Figure 6.15: Test Scenario 3.7.2. Phase A Voltage Regulator SER 93
Figure 6.16: Test Scenario 3.7.2. Phase B Voltage Regulator Output Voltage Waveform 94
Figure 6.17: Test Scenario 3.7.2. Phase B Voltage Regulator SER....95
Figure 6.18: Test Scenario 3.7.2. Phase C Voltage Regulator Output Voltage Waveform 96
Figure 6.19: Test Scenario 3.7.2. Phase C Voltage Regulator SER....97
Figure 6.20: Test Scenario 3.7.3. Phase A Voltage Regulator Output Voltage Waveform 99
Figure 6.21: Test Scenario 3.7.3. Phase A Voltage Regulator SER 100
Figure 6.22: Test Scenario 3.7.3. Phase B Voltage Regulator Output Voltage Waveform 101
Figure 6.23: Test Scenario 3.7.3. Phase B Voltage Regulator SER....102
Figure 6.24: Test Scenario 3.7.3. Phase C Voltage Regulator Output Voltage Waveform 103
Figure 6.25: Test Scenario 3.7.3. Phase C Voltage Regulator SER....104
Figure 6.26: Test Scenario 3.7.4. Phase A Voltage Regulator Output Voltage Waveform – Normal Load Profile ..106
Figure 6.27: Test Scenario 3.7.4. Phase A Voltage Regulator SER – Normal Load Profile 107
Figure 6.28: Test Scenario 3.7.4. Phase A Voltage Regulator Output Voltage Waveform – Modified Load Profile108
Figure 6.29: Test Scenario 3.7.4. Phase A Voltage Regulator SER – Modified Load Profile....109
Figure 6.30: Test Scenario 3.7.4. Phase B Voltage Regulator Output Voltage Waveform – Modified Load Profile 110
Figure 6.31: Test Scenario 3.7.4. Phase B Voltage Regulator SER – Modified Load Profile....111
Figure 6.32: Test Scenario 3.7.4. Phase C Voltage Regulator Output Voltage Waveform – Modified Load Profile 112
Figure 6.33: Test Scenario 3.7.4. Phase C Voltage Regulator SER – Modified Load Profile....113
Figure 7.1: Controller Front-Panel Layout 115
Figure 7.2: Controller Low-Level Test Interface J2 115
Figure 7.3: CBC – Test Setup....116
Figure 7.4: RTDS and Controller Interface – Analog Inputs....117
Figure 7.5: RTDS and Controller Interface – Digital Inputs 118
Figure 7.6: RTDS and Controller Interface – Digital Outputs....118
Figure 7.7: CBC KVAR Operations – Quadrants I and IV 120
Figure 7.8: CBC SUPY Mode Enabled 124
Figure 7.9: CBC LOCAL Mode Enabled 125
Figure 7.10: CBC AUTO Mode Enabled 127
Figure 7.11: CBC MANUAL Mode Enabled....128
Figure 7.12: CBC High-Voltage Condition....130
Figure 7.13: CBC High-Voltage Switching Operation....131
Figure 7.14: CBC Low-Voltage Condition....133

Figure 7.15: CBC Low-Voltage Switching Operation....134
Figure 7.16: CBC Lead KVAR Condition – PQ Plot....136
Figure 7.17: CBC Lead KVAR Condition – Voltage Plot....137
Figure 7.18: CBC Lead KVAR Switching Operation....138
Figure 7.19: CBC Lag KVAR Condition – PQ Plot....140
Figure 7.20: CBC Lag KVAR Condition – Voltage Plot....141
Figure 7.21: CBC Lag KVAR Switching Operation....142
Figure 7.22: Circuit PQ Profile Over 24 Hours....144
Figure 7.23: CBC TOD Close Switching Operation at 14:00:00 Hours....145
Figure 7.24: CBC TOD Open Switching Operation at 05:00:00 Hours....147
Figure 7.25: CBC Overvoltage Condition....149
Figure 7.26: CBC Overvoltage Condition Lockout Operation....150
Figure 7.27: CBC Voltage Imbalance Condition....152
Figure 7.28: CBC Voltage Imbalance Percentage....153
Figure 7.29: CBC Voltage Imbalance Lockout Operation....154
Figure 7.30: CBC High-Current Condition....156
Figure 7.31: CBC High-Current Alarm Indication and Automatic Reset....157
Figure 7.32: CBC Hunting Lockout....159
Figure 7.33: CBC Operations Counter....161
Figure 8.1: Simplified One-Line Diagram With Fault Locations....163
Figure 8.2: HIF Detection Test Setup....164
Figure 8.3: Recloser RTDS Analog Output Signals....165
Figure 8.4: Recloser Trip and Close Digital Input Wiring....167
Figure 8.5: Block Diagram of HIF Detection in Recloser Control....168
Figure 8.6: HIF2 Algorithm Counting Parameters....169
Figure 8.7: HIF2 Algorithm Counting Regions....169
Figure 8.8: Test Setup....171
Figure 8.9: Scenario 1 – Event Report – 50GHIZ Pickup....176
Figure 8.10: Scenario 1 – C1215-32R Current A Magnitude – Single Spike....177
Figure 8.11: Scenario 1 – SER Report – 50GHIZ Pickup....178
Figure 8.12: Scenario 2 – Event Report – 50GHIZ and HIF2_A Pickup....180
Figure 8.13: Scenario 2 – Central C1215-32R Pickup....181
Figure 8.14: Scenario 2 – SER Report – 50GHIZ Picks Up 15 Times to Trigger HIF2_A....182
Figure 8.15: Scenario 3 – Central with 24-Hour Load Profile....184
Figure 8.16: Scenario 3 – SER Shows No Pickup on a 24-Hour Load Profile Cycle as Expected....185
Figure 8.17: Scenario 4 – Overcurrent Protection Pickups with No HIF Pickup....187
Figure 8.18: Scenario 4 – Central Single Spike Does Not Meet HIF Criteria....188

Figure 8.19: Scenario 4 – SER Shows Expected Overcurrent Pickups 189
Figure 9.1: Desert-Rural Test Circuit – Island 1 191
Figure 9.2: Desert-Rural Test Circuit – Island 2 192
Figure 9.3: Desert-Rural Test Circuit – Island 3 193
Figure 9.4: Locations of PMUs 195
Figure 9.5: RTDS and PMUs Interface 196
Figure 9.6: Synchrophasor Communications Architecture 197
Figure 9.7: Voltage Monitoring in Island 3 200
Figure 9.8: Frequency Monitoring in Island 3 203
Figure 10.1: Desert-Rural Test Circuit 205
Figure 10.2: Volt/VAR Mode Operation 206
Figure 10.3: Volt/VAR Controller Logic 206
Figure 10.4: Voltage Band Check 207
Figure 10.5: Controller On/Off Logic 208
Figure 10.6: Voltage Control – Scenario 1 208
Figure 10.7: Voltage Control – Scenario 2 209
Figure 10.8: DER Test RunTime Controls 209
Figure 10.9: Voltage Support Coordination Scenario Operation 212
Figure 10.10: Scenario 1 RunTime Plot 214
Figure 10.11: Scenario 2 RunTime Plot 217
Figure 11.1: Voltage Profile With Voltage Regulator In Service 220
Figure 12.1: Data Flow for Advanced Control of System Voltage Coordination 221
Figure 12.2: Energized Downed Conductor Causes Arcing – Potential Safety Hazard 223
Figure 12.3: Falling Conductor Detection and Isolation 224
Figure 12.4: Vector Shift Element Logic 225
Figure 12.5: 81RF Characteristics 226
Figure 12.6: Fast df/dt Logic 227
Figure 12.7: Power Quality Data Collection and Analysis 229
Figure A.1: Coastal-Residential Test Circuit One-Line Diagram 237
Figure A.2: Urban Test Circuit One-Line Diagram 238
Figure A.3: Desert-Rural Test Circuit One-Line Diagram 239
Figure B.1: Coastal-Residential Test Circuit – Actual Load Profile Over 24 Hours 241
Figure B.2: Coastal-Residential Test Circuit – Actual Load Profile Over 60 Minutes 242
Figure B.3: Coastal-Residential Test Circuit – Slider Position Over 60 Minutes 242
Figure B.4: Urban Test Circuit – Actual Load Profile Over 24 Hours 245
Figure B.5: Urban Test Circuit – Actual Load Profile Over 60 Minutes 246
Figure B.6: Urban Test Circuit – Slider Position Over 60 Minutes 246

Figure B.7: Desert-Rural Test Circuit – Actual Load Profile Over 24 Hours 249
Figure B.8: Desert-Rural Test Circuit – Actual Load Profile Over 60 Minutes 250
Figure B.9: Desert-Rural Test Circuit – Slider Position Over 60 Minutes 250

List of Tables

Table 3.1: Technical Specifications of the D-VAR System 10
Table 3.2: ANSI/IEEE C57.104 Standard for Dissolved Gas Analyses 20
Table 3.3: Comparison of Vendor I and Vendor B FRA Devices 22
Table 3.4: Transformer Monitor Analog and Digital I/O Monitoring Parameters 23
Table 3.5: SAE J1772TM-2011 Charging Configurations and Rating Terminology 37
Table 3.6: Vendor E EVSE Networking Specification 40
Table 6.1: Voltage Regulator Operation and Indication LED Definitions 65
Table 6.2: Voltage Regulator Operator-Controlled Pushbuttons 66
Table 6.3: Voltage Regulator Control I/O List 67
Table 6.4: Auto and Remote Toggle – Local Control 81
Table 6.5: High-Voltage Lower Tap Operation 83
Table 6.6: Low-Voltage Raise Tap Operation 84
Table 6.7: Voltage High- and Low-Limit Operations 91
Table 6.8: Load Profile Operation 98
Table 7.1: Controller I/O List 107
Table 7.2: Capacitor Bank Controller Analog Thresholds 114
Table 7.3: SUPY and LOCAL Toggle 115
Table 7.4: AUTO and MANUAL Toggle – LOCAL Control 118
Table 7.5: High-Voltage Open Operation 121
Table 7.6: Low-Voltage Close Operation 124
Table 7.7: Leading KVAR Open Operation (+P) 127
Table 7.8: Lagging KVAR Close Operation (+P) 131
Table 7.9: TOD Close Operation 135
Table 7.10: TOD Open Operation 138
Table 7.11: Overvoltage Lockout 140
Table 7.12: Voltage Imbalance Lockout 143
Table 7.13: High-Current Condition 147
Table 7.14: Hunting Lockout 150
Table 8.1: HIF Relay Word Bits 158
Table 8.2: Recloser Control I/O List 158
Table 8.3: Auto and Remote Toggle – Local Control 164
Table 8.4: 50GHIZ Overcurrent Pickup Element Test 165
Table 8.5: HIF Detection 169

Table 8.6: Recloser Response During Load Profile Operation 173
Table 8.7: Recloser Operation During Bolted Fault 176
Table 9.1: Desert-Rural Test Circuit – Load Distribution 180
Table 9.2: ANSI C84.1-2006 Standard Nominal System Voltages and Voltages Range – Service Voltage 188
Table 9.3: ANSI C84.1-2006 Standard Nominal System Voltages and Voltages Range – Utilization Voltage 188
Table 9.4: IEEE 519-2014 Maximum Harmonic Current Distortion in Percent of Current 190
Table 9.5: IEEE 519-2014 Maximum Harmonic Voltage Distortion in Percent 190
Table 10.1: Load Switching 200
Table 11.1: Desert-Rural Test Circuit Voltage Levels 208
Table 15.1: EPIC Primary and Secondary Guiding Principles 224
Table B.1: Load and Slider Position Value – Coastal-Residential Test Circuit 235
Table B.2: Load and Slider Position Value – Urban Test Circuit 239
Table B.3: Load and Slider Position Value – Desert-Rural Test Circuit 243

Abbreviations and Acronyms

ACSI	abstract communication service interface
ADC	analog-to-digital converter
ANSI	American national Standards Institute
AR	automatic reconfiguration
AVR	automatic voltage regulator
BCD	binary-coded decimal
BEV	battery electric vehicle
CBC	capacitor bank controller
CES	Community Energy Storage
CT	current transformer
CVR	conservation voltage reduction
DA	Distribution Automation
DAC	Distribution Automation Controller
ADAC	Advanced Distribution Automation Control
DCLS	dc level shift
DER	distributed energy resource
df/dt	rate-of-change-of-frequency
DFO	dynamic feeder optimization
DG	distributed generator
DGA	dissolved gas analysis
DNP3	Distributed Network Protocol
DST	daylight-saving time
D-VAR	dynamic volt-ampere reactive
DVR	dynamic voltage regulator
EPIC	Electric Program Investment Charge
EV	electric vehicle
EVSE	electrical vehicle supply equipment
FFT	fast Fourier transform
FRA	frequency response analysis
FTP	File Transfer Protocol
GFCI	ground-fault circuit interrupter
GOOSE	Generic Object-Oriented Substation Event
GPS	Global Positioning System
GSE	generic substation event
GSSE	generic substation status event
GTAO	gigabit transceiver analog output
GTFPI	gigabit transceiver front-panel interface
HIF	high-impedance fault
HIL	hardware-in-the-loop
HVRT	high-voltage ride-through
ICE	internal combustion engine
IEC	International Electrotechnical Commission
IED	intelligent electronic device
IEEE	Institute of Electrical and Electronics Engineers
IFRA	impulse frequency response analysis
IGBT	insulated-gate bipolar transistor
IIR	infinite impulse response
I/O	input/output
IP	Internet Protocol
IRIG-B	Inter-Range Instrumentation Group time code format B
ISM	industrial, scientific, and medical
ISO	International Organization for Standardization
KVAR	kilovolt-ampere reactive
LAN	local-area network
LED	light-emitting diode
LTC	load tap changer
LVRT	low-voltage ride-through
MAC	medium access control
ME	multiended
MMS	manufacturing message specification
NC	normally closed
NEC	National Electric Code
NO	normally open
NTP	Network Time Protocol
OCPP	Open Charge Point Protocol
OF	overfrequency
OLE	object linking and embedding
OLTC	on-load tap changer
OPC	OLE for Process Control
OSI	Open System Interface
OV	overvoltage
P	active power
PCC	point of common coupling
PCS	Power Conversion System
PDC	phasor data concentrator
PHEV	plug-in hybrid electric vehicle

PHY	physical layer
PID	proportional integral derivative
PLC	programmable logic controller
PMU	phasor measurement unit
ppm	parts per million
PT	potential transformer
PTP	Precision Time Protocol
pu	per unit
PV	photovoltaic
Q	reactive power
rms	root-mean-square
RSCAD	RTDS Power Simulation Software
RTAC	Real-Time Automation Controller
RTD	resistance temperature detector
RTDS	Real Time Digital Simulator
RTN	return-to-normal
RTU	remote terminal unit
SAE	Society of Automotive Engineers
SCADA	supervisory control and data acquisition
SDG&E	San Diego Gas & Electric Company
SDI	sum of difference current
SE	single ended
SER	Sequential Events Recorder
SFRA	sweep frequency response analysis
SMV	sampled measured value
SNTP	Simple Network Time Protocol
SOE	Sequence of Events
SOTF	switch onto fault
TCP	Transmission Control Protocol
THD	total harmonic distortion
THDI	total harmonic distortion, aggregated current
THDV	total harmonic distortion, aggregated voltage
TOD	time of day
TWFL	traveling-wave fault location
UCA	Utility Communications Architecture
UDP	User Datagram Protocol
UF	underfrequency
UL	Underwriters Laboratories
U.S.	United States
UTC	Coordinated Universal Time
UV	undervoltage
VAR	volt-ampere reactive
VFD	variable-frequency drive
VR	voltage regulator
VT	voltage transformer
WAN	wide-area network
WEP	Wired Equivalent Privacy
WiMAX	Worldwide Interoperability for Microwave Access
WPA	Wireless Protected Access
WPAN	Wireless Personal Area Network

1 INTRODUCTION

The objective of SDG&E's EPIC-1, Project 5, on Smart Distribution Circuit Demonstrations, was to perform pilot demonstrations of smart distribution circuit features and associated simulation work to identify best practices for integrating new and existing distribution equipment in these circuits. The project was broken into two modules:

- Demonstration of Advanced Circuit Concepts
- Demonstration of Methodologies and Tools for Energy Storage System Assessment

This report describes the work and results for the first module on pre-commercial demonstration of advanced circuit concepts.

The focus of this project module was to perform pilot demonstrations of smart distribution circuit features in a laboratory for a set of selected test circuits. Using simulations and hardware-in-the-loop (HIL) testing, the desired features and upgrades were tested in the selected circuits to assess their suitability for widespread adoption.

The test circuits studied in this project include:

- Coastal-residential
- Urban
- Desert-rural

This report is divided into the following sections:

- Hardware and Circuit Evaluation: This section includes documentation and evaluation of products and technologies available for improved circuit design, system operation, and protection.
- Solutions Evaluation: This section assesses emerging distribution circuit solutions and operational practices for maintaining reliable and uninterrupted energy delivery.
- RTDS Modeling: This section outlines the process involved in the modeling of circuits. The data, which includes the load, line, source, and other devices connected to the circuits, were provided in the format used by Synergi Electric, which was converted to RSCAD and validated for accuracy.
- Voltage Regulator Tests: This section describes the hardware setup for the voltage regulation operation with the test settings and procedures described in detail. Real Time Digital Simulator (RTDS) tests were carried out and recommendations are made based on the observations recorded.
- Capacitor Bank Controller Tests: The automatic capacitor controller application was evaluated to determine the best times to switch the capacitor bank in or out, based on the load and voltage profiles provided by SDG&E. This section describes the hardware setup of the capacitor bank controller and the RTDS modeling of the device. Tests were carried out on the RTDS and the observations and results recorded.
- High-Impedance Fault Detection: This section describes the hardware setup of a high-impedance fault detector, including settings involved in the high-impedance fault protection of a circuit. The high-impedance fault logic was tested for scenarios involving different fault impedances, fault locations, and responses during the load profile run.
- Power Quality in Islands: System parameters, such as voltage and frequency, were observed on pre- and post-islanded scenarios in a test circuit. This section describes the synchrophasor devices used to tabulate the results for power quality tests and their interface with the RTDS.

- Voltage Support Coordination Tests: This section describes tests that were performed on the selected test circuit to study the system response and participation of the distributed energy resource (DER) and voltage regulator (VR) in regulating the system voltage. Both devices were designed in the RTDS and master controller logic was developed to control the coordination of these voltage regulation devices. The section further describes the observations and results of the DER tests.
- Findings: This section analyzes the results of the pre-commercial demonstrations performed and provides recommendations based on the analyses. The analysis performed provides inputs for improving the existing circuits for better reliability and operability.
- Recommendations: Recommendations are provided on the integration and coordination of multiple voltage-correction devices on a larger distribution system, controlled via a central master controller. Certain modern concepts are also discussed, offering insights on how to improve the existing distribution system.
- Technology Transfer Plan: This section lays out the steps for commercial adoption of the best practices discussed in this report. The technology transfer plan describes the activities, equipment, resources involved and the required coordination between diverse groups to successfully implement the best practices commercially.

2 PROJECT SCOPE AND APPROACH

The goal of this project is to perform pilot demonstrations of smart distribution circuit features and associated simulations to analyze and identify best practices for integrating new and existing distribution equipment in a set of selected circuits. Using simulations and hardware testing, the desired features and upgrades are tested in the selected distribution circuits to assess their suitability for widespread adoption.

The following approach was adopted for successful completion of this project.

2.1 PROJECT INITIATION MEETING

A project initiation meeting was set up with the SDG&E stakeholders and the project team to review and finalize plans for the project including objectives, approach, deliverables, contractor staff, and existing SDG&E distribution design practices. The project was divided into three separate phases, interlinked to successfully achieve the tasks defined in the scope.

2.2 PHASE 1 HARDWARE AND CIRCUIT EVALUATION

Phase 1 includes the research, evaluation, and documentation of products and technologies available for improved distribution circuit design. It also includes selection of three SDG&E test circuits. Phase 1 is further divided into the following sub-tasks:

a. Identify, evaluate, and document existing products and technologies available for improved distribution circuit design, system operation, and protection. This includes diverse topics such as time synchronization, protection, automation and control, communication, and renewables and energy storage.

b. Assess and document emerging distribution circuit solutions for maintaining reliable and uninterrupted energy delivery. This includes topics such as advanced distribution automation control, synchrophasor-based applications, fault location, high-impedance fault detection, and dynamic line rating.

c. Select three different test circuits: coastal, desert-rural, and urban-residential.

2.3 PHASE 2 CIRCUIT SIMULATION AND TESTING EVALUATION

Phase 2 includes the following sub-tasks:

a. Convert the selected test circuits from Synergi Electric format into RSCAD and validate for accuracy. Hardware test racks were set up at the test facility.

b. Develop test plans to perform individual devices tests for voltage regulator, capacitor bank controllers, high-impedance fault detection, and power quality in islands.

c. Develop algorithms and a central controller-based system to perform system voltage coordination on distribution circuits between multiple voltage support devices, and the subsequent demonstration using RTDS. Additionally, recording test observations and results for all RTDS tests for further analysis.

2.4 PHASE 3 SMART CIRCUIT ANALYSIS AND RECOMMENDATIONS

Phase 3 includes the following sub-tasks:

a. Describe important findings from the circuit demonstrations.

b. Document possible enhancements to existing distribution circuits for improved circuit design and system operation.

c. Provide recommendations on the integration and coordination of multiple voltage correction devices on a larger distribution circuit, controlled via a central master controller.

d. Create a technology transfer plan to bridge the gap between the laboratory demonstration of improved distribution practices and its successful commercial and practical implementation in the field on larger distribution circuits.

e. Discuss modern solutions to improve the operational capabilities of existing distribution circuits.

2.5 PROJECT DELIVERABLES

The project deliverables were defined at the time of the project initiation meeting. The following list includes the project deliverables that were shared with the entire team for review and feedback at the task completion.

- Functional Design Specification – Describes the project scope and approach.
- Phase 1 interim report – At the completion of Phase 1.
- Phase 2 interim report – At the completion of Phase 2.
- Phase 3 interim report – At the completion of Phase 3.
- Real Time Digital Simulator (RTDS) test plans.
- Technology transfer plan.
- Final report – A comprehensive version of the above-mentioned deliverables.
- Selected circuits simplified one-line diagrams, and load and line sheets used for transferring data from Synergi Electric to RSCAD for the three selected circuits.
- RTDS models – Draft, RunTime, and load scheduler modules were used for the following three circuits modeled in RSCAD:
  - Coastal-residential
  - Urban
  - Desert-rural
- Project initiation meeting presentation.
- Phase 1 stakeholder presentation.
- Phase 2 stakeholder presentation.
- Phase 2 additional test results presentation.
- Phase 3/Final stakeholder presentation.
- Weekly/bi-weekly meeting minutes.

Bi-weekly meetings were conducted between the project teams to discuss the progress and concerns, if any. Face-to-face meetings were conducted at the end of each phase with SDG&E stakeholders and the project team members to review the completed tasks and discuss the remainder of the plan.

3 HARDWARE AND CIRCUIT EVALUATION

This section includes documentation and evaluation of products and technologies currently available for improved distribution circuit and design, system operation and protection. The broad discussion of available products in this section provides groundwork for the pre-commercial demonstrations in this project.

Note: Appendix E - Proprietary Information includes a look-up table for the vendors referred to in this report.

3.1 TIME SYNCHRONIZATION

Standard clock time is inherently inaccurate and presents added complexity in a distributed system in which several devices require precise synchronization with global time. Several protocols have been developed to control and monitor system time as the need for precise synchronization has increased across industries. The following protocols will be discussed:

- Network Time Protocol
- Simple Network Time Protocol
- Inter-Range Instrumentation Group time code format B
- Precision Time Protocol

3.1.1 Network Time Protocol

Network Time Protocol (NTP) synchronizes time across an internet protocol (IP) network. It uses Port 123 as source and destination, and runs over the User Datagram Protocol (UDP). The NTP network generally uses a time source device attached to the main time server that distributes time across the network. NTP works well over local-area networks (LANs) and wide-area networks (WANs). It requires little hardware and provides accuracies typically within a millisecond on LANs and a few milliseconds on WANs. NTP configurations typically use multiple redundant servers and diverse network paths to achieve accuracy and reliability. No more than one NTP transaction per minute is necessary to achieve a 1-millisecond synchronization on a LAN. For larger systems, NTP can routinely achieve 10-millisecond synchronization. Many NTP clients run on non-real-time operating systems such as Windows or Linux. On the Windows operating system, clock corrections of 10 to 50 milliseconds are common because the system is performing tasks deemed more important than time-keeping. Therefore, accuracy cannot be guaranteed.

3.1.2 Simple Network Time Protocol

Some devices support only Simple Network Time Protocol (SNTP), which is a simplified, client-only version of NTP. SNTP-enabled devices cannot be used to provide time to other devices; they can receive time only from NTP servers. The SNTP-enabled devices can achieve synchronization levels within 100 milliseconds.

3.1.3 IRIG-B Protocol

The Inter-Range Instrumentation Group time code format B (IRIG-B) was developed by the Inter-Range Instrumentation Group, which is the standards body of the Range Commanders Council of the United States (U.S.) military. The latest version of the IRIG-B standard was published in 2004. IRIG-B has a pulse rate of 100 per second with an index count of 10 milliseconds over its 1-second time frame. It contains time-of-year and year information in a binary-coded decimal (BCD) format, and seconds-of-day information in straight binary seconds. IRIG-B can achieve accuracy in the range of 1 to 10 microseconds.

Year information was not specified in the IRIG-B standard before the 2004 revision. The Institute of Electrical and Electronics Engineers (IEEE) previously adopted a standard (IEEE 1344, IEEE Standard for Synchrophasors for Power Systems) that included year data as part of the IRIG-B signal. This variation came to be known as IEEE 1344 extensions.

IEEE 1344 extensions use extra bits of the control functions portion of the IRIG-B time code. Within this portion of the time code, bits are designated for additional features, including:

- Calendar year (BCDYEAR)
- Leap seconds and leap seconds pending
- Daylight-saving time (DST) and DST pending
- Local time offset
- Time quality
- Parity
- Position identifiers

To use these bits of information, power system devices and other equipment receiving the time code must be able to decode them.

An IRIG-B time signal can be modulated (over a carrier signal) or unmodulated (no carrier signal), also known as dc level shift (DCLS) in the IRIG-B standard. In some manufacturers' literature, the term "demodulated" is used to describe a DCLS. However, in most cases it may be assumed the term is synonymous with unmodulated.

The IRIG-B protocol would appear the better choice, offering accuracy of 1 to 10 microseconds. Because IRIG-B systems use dedicated coaxial timing cabling between dedicated hardware clocks, the system has disadvantages. Most notable are the added expense of additional hardware and the increased time skew because of the additional physical infrastructure.

3.1.4 Precision Time Protocol

Since IEEE 1588-2008, the IEEE Standard for a Precision Clock Synchronization Protocol for Networked Measurement and Control Systems was established, Precision Time Protocol (PTP) has addressed the clock synchronization requirements of measurement and control systems by improving accuracy and reducing cost. Among the advantages of PTP is the protocol's use of the most readily available means for network connectivity: IP over Ethernet. Taking advantage of existing Ethernet infrastructure allows considerable reuse of in-place hardware and cabling, helping reduce costs for the physical layer. PTP eliminates Ethernet latency and jitter issues through hardware time-stamping to cancel out a measured delay between nodes at the physical layer of the network. Accuracy in the range of 10 to 100 nanoseconds can be achieved with this protocol.

IEEE 1588 specifies a protocol to synchronize independent clocks running on separate nodes of a distributed control system to a high degree of accuracy and precision. The clocks communicate with each other over a communications network. In its basic form, the protocol is intended to be administration free. The protocol generates a master-slave relationship among clocks in the system by determining which of the possible sources has the better accuracy. All clocks ultimately derive their time from a clock known as the grandmaster clock. Once all clocks in a control system are synchronized, events monitored in the control system can be time stamped to a very high degree of accuracy.

3.1.5 Applications

Most relays and devices used in the power system network typically support NTP, SNTP, and IRIG-B. PTP implementation in power system devices is at a relatively nascent stage, and most of them do not support the protocol. For applications in which time-stamping is critical, IRIG-B is preferable. For applications in which cost is a factor and time-stamping with microsecond accuracy is not a factor (e.g., data storage in a distribution system), NTP/SNTP may be used.

3.2 PROTECTION, AUTOMATION, AND CONTROL

3.2.1 Dynamic Voltage Controller

In the wake of an increased global demand for energy and the realization of the harmful effects (and scarcity) of fossil fuels, there have been advances in renewable energy technology. The steady increase in the amount of photovoltaic power stations and wind farms around the world is testament to the growth of renewable energy as a paradigm shift from the use of fossil fuels. However, renewable energy is still an emerging technology and is not free of issues. One such issue with several grid-tied renewable energy sources is the impact on power quality and system operation.

In an ideal world, power distribution companies should provide customers with a smooth sinusoidal voltage with a fixed amplitude and frequency. Unfortunately, the output power for most renewable energy sources is highly variable; wind generators can produce rated power only when the wind is blowing and the efficiency of photovoltaic solar installations are affected by the presence of clouds. These variations associated with these energy sources result in voltage fluctuations and decreases the power quality of the overall system.

In addition to grid-tied renewable energy sources, the rise of non-linear loads causes voltage sags, swells, and surges on utility lines that affect power quality. Of these voltage disturbances, voltage sags most commonly affect power quality. Voltage sags can cause damage to industrial devices such as variable-frequency drives (VFDs), robotics, controller power supplies, and control relays. Fortunately, these issues associated with voltage stability and power quality can be alleviated with proper voltage regulation.

The dynamic voltage regulator (DVR) is the most effective device for voltage regulation and improved power quality in a system. The DVR is a series compensator used to mitigate voltage sags and to restore the load voltage to its rated value. It is normally installed in a distribution system between the supply and a critical load feeder at the point of common coupling (PCC). Its primary function is to boost the load-side voltage in the event of a voltage sag to avoid power disruption to the load. The DVR can also have features such as line voltage harmonics compensation, reduction of transients in voltage, and fault current limitations.

The DVR is a power electronic converter-based device capable of protecting sensitive loads from most supply-side disturbances. The general configuration of a DVR is shown in Figure 3.1 [1].

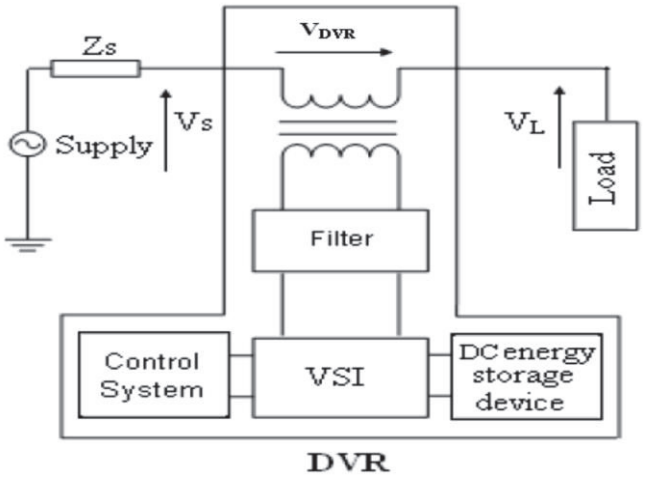


Figure 3.1: DVR General Configuration

3.2.1.1 MODES OF OPERATION

The DVR has three modes of operation:

2. Protection mode
3. Standby mode
4. Injection/Boost mode

3.2.1.1.1 PROTECTION MODE

If the current on the load side exceeds a permissible limit because of a short circuit on the load side or a large inrush current, the DVR will be isolated from the system by using bypass switches as shown in Figure 3.2 [1]. Switches S2 and S3 will open and S1 will be closed to provide an alternative path for the load current to flow.

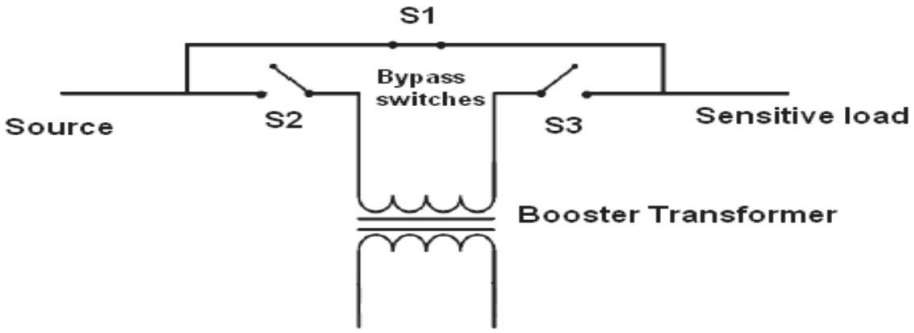


Figure 3.2: Protection Mode

3.2.1.1.2 STANDBY MODE

In Standby mode, the low-voltage winding on the booster transformer is shorted through the converter as shown in Figure 3.3 [1]. No switching of semiconductors occurs in this mode, and the full-load current will pass through the transformer primary.

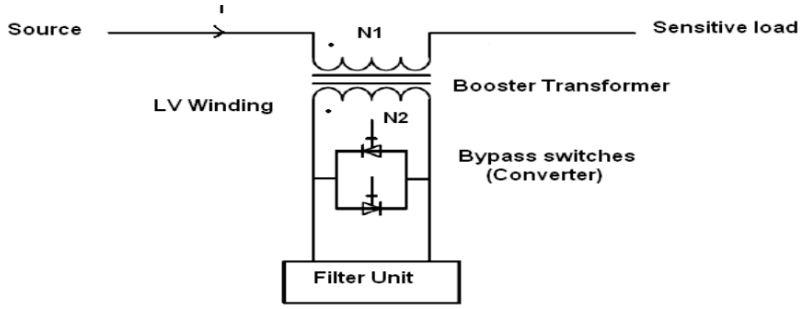


Figure 3.3: Standby Mode

3.2.1.1.3 INJECTION/BOOST MODE

In Injection/Boost mode, the DVR injects a compensating voltage through the booster transformer after the detection of a disturbance in the supply voltage.

3.2.1.2 DVR VOLTAGE INJECTION METHODS

The four methods of DVR voltage injection are discussed below. The choice of method depends on several limiting factors such as DVR power rating, load conditions, and voltage sag type.

- Pre-sag/dip compensation method: Tracks the supply voltage continuously for disturbances. If a disturbance is detected, the DVR will inject the difference in voltage between the voltage sag and the ideal prefault condition. The active power injected by the DVR cannot be controlled and is determined by external conditions such as the type of fault and load conditions.
- In-phase compensation method: The injected voltage is in phase with the point-of-contact voltage regardless of the load current and prefault voltage. The phase angles of the pre-sag and load voltage are different; however, attention is placed on maintaining a constant voltage magnitude on the load.
- In-phase advanced compensation method: Reduces the real power spent by the DVR by decreasing the power angle between the sag voltage and the load current. Active power is injected into the system by the DVR during disturbances; this active power is limited to the stored energy in the dc link of the DVR. The minimization of injected energy is achieved by making the injection voltage phasor perpendicular to the load current phasor.
- Voltage tolerance method: Voltage magnitude variations between 90 percent and 100 percent of the nominal voltage and phase angle variations between 5 percent and 10 percent of the normal state will not disturb the operation characteristics of loads. This method helps maintain the load voltage within the tolerance area with small changes in voltage magnitude.

3.2.1.3 DYNAMIC VOLT-AMPERE REACTIVE COMPENSATION SOLUTION

Vendor A dynamic volt-ampere reactive (D-VAR) was found to be a cost-effective way to provide continuous voltage regulation, improve voltage stability, meet interconnection requirements, and dynamically provide grid support where it is needed.

The main features of the D-VAR system include:

- High-speed response to voltage disturbances: D-VAR systems stabilize and regulate voltage and power factors on transmission and distribution networks and at industrial operations. The system detects and

rapidly compensates for voltage disturbances by injecting leading or lagging reactive power at key points on transmission and distribution grids. Each D-VAR system is tailored to meet specific customer requirements and accommodate changing grid conditions.

- Compliant with utility interconnection requirements: The D-VAR system can assist wind and solar generation plants in meeting utility interconnection requirements, including low-voltage ride-through (LVRT) and high-voltage ride-through (HVRT) regulation and power factor correction. The system helps reduce stress on equipment and extends its life by mitigating transient voltage events and by soft-switching capacitors and reactor banks with propriety and patented technology.
- Modular, scalable, compact, and flexible: D-VAR systems are highly modular and scalable by design. Each unit is compact to accommodate areas with space constraints. This allows utilities to install properly sized systems in the most effective power grid locations and quickly augment capability as demands increase.

3.2.1.4 D-VAR SYSTEM SPECIFICATIONS

The technical specifications of the D-VAR system (as listed on the datasheet) are shown in Table 3.1.

Table 3.1: Technical Specifications of the D-VAR System

Connection	Medium Voltage (up to 46 kV)
Frequency	50 or 60 Hz
Continuous rating	±2.0 to 100 s of MVAR
Transient overload rating	Three times continuous for up to 2 seconds
Response time	Subcycle
Inverter	Insulated-gate bipolar transistor (IGBT), 4 kHz switching frequency, rated at 1 MVAR, continuous duty
Output	Independent phase control
Harmonics	According to IEEE 519, IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems
System monitoring	Digital recording of system action, multiple inputs, alarms, and warning signals
Ambient temperature	–50°C to +50°C
Other features	– Mobile configuration for quick deployment – Minimal onsite installation – Compact installation for minimal footprint – Remote monitoring – Environmentally benign – Ambient air cooling – Robust operation during low-voltage conditions – Steady-state negative-sequence current injection to mitigate voltage unbalance

3.2.2 SCADA Capacitor

Many renewable energy systems (such as solar and wind) use dc-to-ac converters for electrical grid interconnections. During the dc-to-ac conversion, an inverter produces harmonics because of switching and a non-ideal power factor. Typically, a utility installs a capacitor bank on a distribution system for voltage and VAR support. The steps of the capacitors are automatically energized and de-energized with vacuum switches to regulate voltage, power factor, or VARs on distribution substations ranging in voltages from 4.16 kV to 34.5 kV. The banks are shipped fully assembled and ready for interconnection. All switching devices (including air-disconnect switches) and protection and control features are packaged into a single unit to allow for direct connection to the main bus of a distribution substation.

A SCADA-controlled bank offers the same benefits as conventional metal-enclosed banks; however, it goes one step further and allows for connection to a SCADA system. These SCADA-controlled banks provide the following key benefits [2]:

- Overrides automatic controls of the bank to provide voltage or VAR support to the distribution, subtransmission, and transmission systems.
- Alerts utility personnel of capacitor and fuse failures (this helps improve capacitor bank reliability).
- Reduces operating cost by reducing crew trips to the substation.
- Provides capability for remote monitoring of the status of all protection and control devices within the bank.
- Provides capability for remote monitoring of all power system parameters (harmonic distortion, voltage, power factor, etc.) associated with the capacitor bank.

A typical block diagram of a SCADA-controlled, metal-enclosed automatic capacitor bank is shown in Figure 3.4.

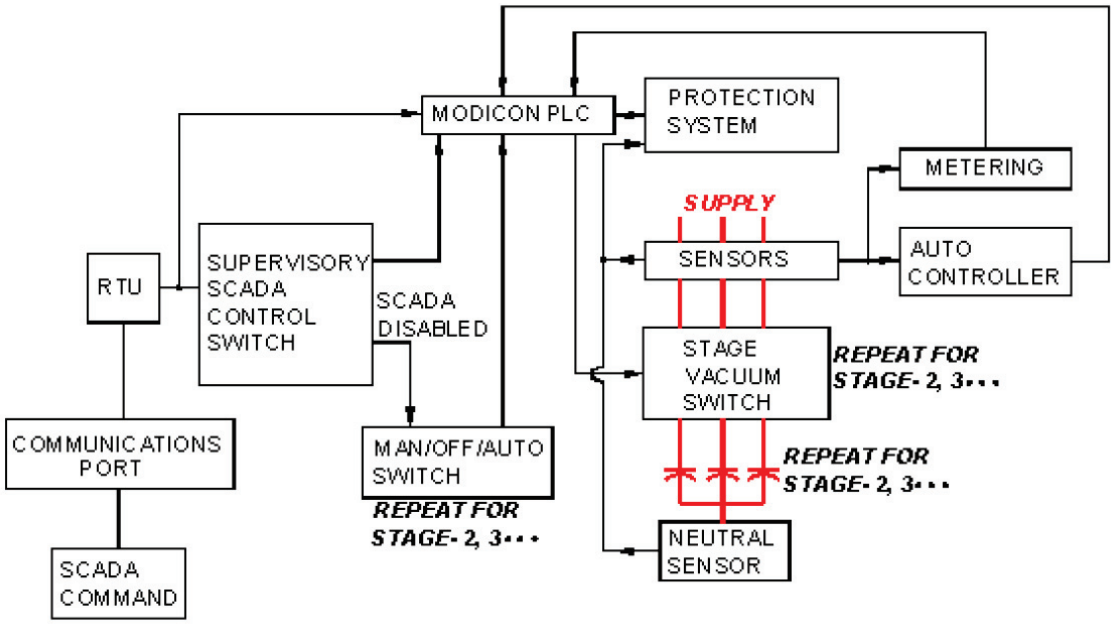


Figure 3.4: Block Diagram of a SCADA-Controlled Metal-Enclosed Automatic Capacitor Bank

The key elements in Figure 3.4 are:

- SUPERVISORY SCADA CONTROL SWITCH: This is typically located on the control panel of the metal-enclosed automatic capacitor bank. When the switch is in the Disabled position, all SCADA controls are disabled and the bank can be operated only from the control panel. The SCADA system will continue to receive indication of the capacitor bank, however, the controls received by the bank will be ignored. When the supervisory control switch is in the Enabled position, the bank can be controlled by the SCADA system, however, it will remain in Automatic Control mode until an override command is sent. Once an override command is received, the Automatic mode is disabled and complete capacitor bank control is based on commands received by the SCADA system.
- MAN/OFF/AUTO SWITCH: These are three-position switches that are functional only when the bank is not being controlled by the SCADA system. When in the ON position, the stage associated with the MAN/OFF/AUTO switch is turned on. When in the OFF position, the stage associated with the switch is turned off. When in the AUTO position, the bank is controlled by the power factor controller.
- Vendor H PLC: This controls many of the functional requirements of the SCADA control system.
- PROTECTION SYSTEM: This is composed of the neutral unbalance protection system, overcurrent relay(s), and overvoltage relay(s).
- SENSORS: These consist of the potential transformers (PTs), current transformers (CTs), and other devices required to provide SCADA and automatic control signals.
- STAGE VACUUM SWITCH: These are part of the capacitor bank and are responsible for energizing and de-energizing the capacitor bank.
- NEUTRAL SENSOR: These are located at the neutral point of most of the capacitor banks and will be either a CT or voltage transformer (VT). Their main purpose is to provide a voltage or current signal to the unbalance relay on the loss of a capacitor fuse.
- METERING: This monitors the power system parameters. These parameters are made available to the programmable logic controller (PLC) for detection of alarm and fault conditions, as well as to the remote terminal unit (RTU) for the SCADA system. A common communications protocol must exist among the RTU, metering devices, and the PLC.
- AUTO CONTROLLER: This module controls the capacitor bank stages based on system power factor, voltage, or VARs. The AUTO CONTROLLER can control the bank only if it is not being controlled by the SCADA system.

The automatic capacitor controller supported by Vendor K is a possible option for implementing SCADA capacitor controls in the system.

3.2.2.1 VENDOR K AUTOMATIC CAPACITOR CONTROLS

Vendor K supported capacitor controls are specifically designed to control pole-mounted and pad-mounted switched capacitor banks in electric distribution systems, to regulate reactive power or line voltage. With a one-way communications device installed, the capacitor controller operates in response to switching commands from SCADA or another centralized control. With a two-way communications device installed, local status information and feeder data are also available remotely, and remote configuration is possible.

With the normal standalone operation of automatic capacitor controls:

- A communications problem will not compromise VAR support.
- A problem at one capacitor bank will not affect other capacitor banks.
- Multiple contingencies are handled automatically.
- System changes and expansion do not require extensive programming.

With two-way communications equipped devices, there is no need for crews to periodically inspect the distribution capacitor banks and problems will be reported immediately. High-accuracy voltage and current inputs make it ideal for integration into advanced voltage optimization systems.

These capacitor controls offer a wide range of software-selectable functions:

- Voltage, time, temperature, time-biased voltage, and time-biased temperature control strategies.
- Voltage/temperature and SCADA override strategies.
- Automatic calculation of voltage change because of capacitor bank switching.
- Undervoltage and overvoltage protection.
- Daily limit on automatic switching operations.
- Optional neutral input sensing, which can lock out the capacitor bank if blown fuses or stuck switch poles are detected.

Other features of the capacitor controls include:

- Ease of installation: The device is available in convenient mounting types: four-jaw electric meter base, six-jaw electric meter base, pole-mounting bracket, and wall-mounting bracket. Prewired plugs are available for bracket-mounted controls, eliminating the need for field wiring. Vendor K capacitor controls accept a single-phase voltage signal from a VT, which is also used to derive control power. Models with VAR control and current control strategies also accept a single-phase current signal from a CT. When specified, the neutral input sensing feature accepts a signal from a VT, a Lindsey voltage sensor, or a current sensor.
- Ease of setup and configuration: The device can connect to a PC via USB link or an optional Wi-Fi module. Compatible software allows the operator to view real-time data, manage set points, troubleshoot problems, and download historical reports. The faceplate includes test points for the sensor inputs and a manual override switch. The system also supports remote firmware upgrades with a capable communications system.
- Extensive data access, logging, and graphing: The device provides real-time access to true root-mean-square (rms) line voltages and currents, kWs, kVAs, KVARs, power factor, temperature, and harmonics.
- Extensive data logging and graphing capabilities for optimizing performance. Parameters are logged at selected intervals and can be downloaded as tables or graphs. They include:
  - Temperature, voltage, current, power factor, KVAR, kW, and neutral current/voltage. Logging intervals can be adjusted from 1 to 60 minutes, for 2 to 120 days of voltage and temperature data.
  - Time and reason for the last 14 switching events, as well as the voltage (and VARs, if applicable) before and after bank switching. Other data include date and time of the last 15 power outages.
  - Daily minimum and maximum voltages, temperatures, currents, kWs, KVARs, power factors, neutral currents/voltages (if applicable), and number of switching cycles in the last month since installation.

3.2.3 Voltage Regulator

The main function of a utility is to supply power to its customers. With ever-increasing loads, power quality has become a critical issue for automated industries and sensitive load centers. The voltage quality is the most crucial factor that affects the power quality of a system. Voltage disturbances in the form of voltage sags, swells, and harmonics can cause damage to equipment and result in huge financial losses. Of these disturbances, voltage sags are the most common. Voltage sags can cause damage to industrial devices such as VFDs, robotics, controller power supplies, and control relays. Fortunately, issues associated with voltage stability and power quality can be alleviated with proper voltage regulation.

Voltage regulation is critical to users of electrical equipment and sensitive loads. Commercial, industrial, and residential applications require consistent voltage despite load current variations caused by expanding system demand and load profile fluctuations.

A voltage regulator is used when a steady, reliable voltage is required. Medium-voltage regulators are primarily used by the electric utilities to compensate for voltage drops in the feeders and distribution systems. The most common voltage regulators used by utilities are step-voltage regulators, which are commonly known as utility automatic voltage regulators (AVRs).

3.2.3.1 BASIC OPERATION OF A STEP-VOLTAGE REGULATOR

A step-voltage regulator is similar to an autotransformer. The step-voltage regulator has a high-voltage winding and a low-voltage winding that are connected in a way to aid or oppose the respective voltages. This means the output voltage could be the sum or the difference between the high-voltage winding and the low-voltage winding, based on the way these windings are connected.

For example, if the transformer had 10,000 V applied to the primary winding and a turns ratio of 10:1, the voltage at the secondary winding would be 1,000 V. If the primary winding and the secondary winding are connected such that the secondary winding voltage is the sum of the two windings (as shown in Figure 3.5), the secondary winding would be V_S = 11,000 V. If the primary winding and the secondary winding are connected such that the secondary winding voltage is the difference of the two windings (as shown in Figure 3.6), the secondary winding would be V_S = 9,000 V.

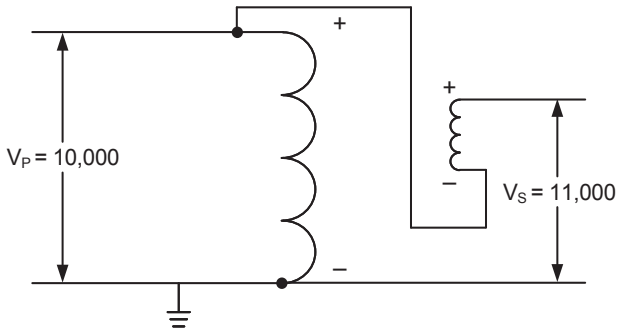


Figure 3.5: Step-Up Autotransformer (Boost Mode)

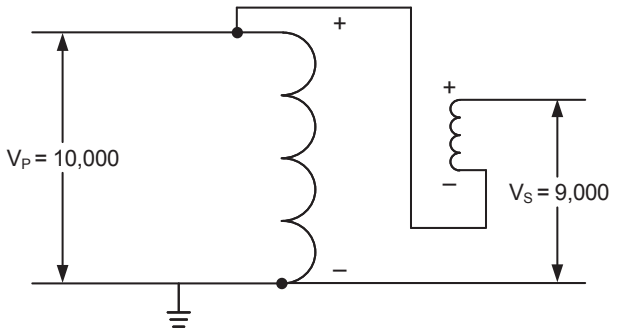


Figure 3.6: Step-Down Autotransformer (Buck Mode)

Conventional voltage regulators are the 32-step voltage regulator and the 4-step voltage regulator. The 32-step voltage regulator uses a reactor for switching and the 4-step voltage regulator uses resistors for switching. However, the basic operation of these voltage regulators is the same. The 32-step and 4-step voltage regulators are connected as shown in Figure 3.7.

This connection places the low-voltage winding on the source side of the high-voltage winding. The increase or decrease in voltage occurs ahead of the high-voltage winding. Therefore, the voltage measured across the high-voltage winding will be the final regulated voltage. In a voltage regulator, the low-voltage winding is called the series winding and the high-voltage winding is called the shunt winding. Taps can be added to the series winding for more versatility. There is an additional control winding that senses the load voltage and supplies this information to an automatic tap changer.

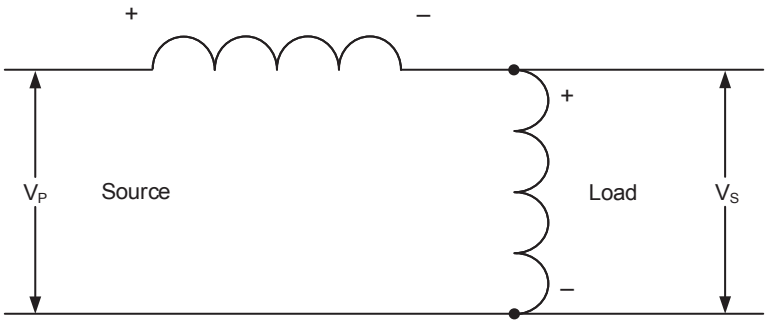


Figure 3.7: Connection of 32-Step and 4-Step Regulators

In terms of application, voltage regulators can be applied to the following circuits:

- A single-phase circuit
- One phase of a three-phase wye or delta circuit
- A three-phase, three-wire, wye or delta circuit
- A three-phase, four-wire, multigrounded wye circuit

3.2.3.2 DETERMINING VOLTAGE REGULATOR TYPE AND SIZE

The type of circuit (as previously listed) determines the type of voltage regulator to be used. However, the voltage regulator size can be determined using the circuit voltage, kVA rating, and the required amount of voltage regulation [3].

The method for calculating the required size of a voltage regulator is as follows:

1. Calculate the rated load current using the following formula:

$$I = \frac{\text{Three-phase } kVA \bullet 1{,}000}{\text{Line-to-line voltage} \bullet 1.732}$$

2. Calculate the desired voltage regulation range in kV:

$$\text{Range in kV} = \text{Voltage regulation range} \bullet \text{line-to-line voltage}$$

Note: Line-to-line voltage in kV is used for three-phase, three-wire wye or delta circuits. Line-to-neutral voltage in kV is used for three-phase, four-wire wye circuits.

3. Calculate voltage regulator rated kVA:

$$\text{Voltage regulator rated } kVA = I \bullet \text{Range in } kV$$

For example, consider a three-phase, three-wire circuit with a system voltage of 13.8 kV and a connected load of 2,000 kVA that requires a voltage correction of 10 percent. The size of the voltage regulator required for this application is calculated using the previous steps:

1. Rated load current for this application:

$$I = \frac{2{,}000 \bullet 1{,}000}{13{,}800 \bullet 1.732} = 83.7\ A$$

2. Range in voltage regulation:

$$\text{Range in } kV = 0.1 \bullet 13.8 = 1.38\ kV$$

3. Voltage regulator rated kVA:

$$\text{Voltage regulator rated } kVA = 83.7 \bullet 1.38 = 115.5\ kVA$$

For this application, a voltage regulator with a rated kVA of 115.5 should be selected.

Vendor D voltage regulator is a possible option to improve voltage quality in the system.

3.2.3.3 VENDOR D VOLTAGE REGULATOR

This single-phase step-voltage regulator is a tap-changing autotransformer that can regulate distribution line voltages from 10 percent raise to 10 percent lower in 32 steps of ⅝ percent each These voltage regulators are available from 2.4 kV to 34.5 kV for 60 Hz and 50 Hz systems.

The sealed-tank construction of the voltage regulator allows the use of a 65°C rise insulation, which provides an additional 12 percent capacity above the nameplate rating without loss of normal insulation life. The unit construction cover suspends the internal assembly for ease of inspection and maintenance. Other standard features include:

- Compliant with IEEE C57.15-2009, IEEE Standard Requirements, Terminology, and Test Code for Step-Voltage Regulators
- CL-7 control
- Tap changer with motor and power supply
- Position indicator with additional load capacity adjustment
- Two laser-etched nameplates
- Lifting lugs
- Oil drain valve and sampling device
- Upper filter press connection
- Oil sight gauge
- Mounting provisions for shunt arresters
- High-creep bushings with clamp-type connectors
- Bolt-down provisions
- Pole-type mounting brackets
- Substation base
- External series arrester
- Automatic pressure relief device
- Control cabinet with removable front panel
- Ratio correction transformer

- Conformally coated circuit boards

In addition, the voltage regulator includes a bypass arrester connected across the series winding and the load bushing. This bypass arrester helps limit the voltage developed across the series winding during switching surges, line faults, and lightning strikes.

The shunt winding can also be protected using a shunt arrester. The shunt arrester is connected between the load bushing and ground. However, a shunt arrester must be purchased as a separate accessory.

3.2.4 Reclosers

Modern power systems include reclosers along with conventional circuit breakers to provide enhanced reliability during transient events. It is a common convention to have reclosers installed at every major branch of a large power system. Because of their position in the network, they handle much less power when compared to circuit breakers at main feeders; therefore, they can trip at a lower fault threshold. This causes only a part of the system to be removed from the grid where the fault occurs. However, because of the transient nature of most faults that occur in a power system, a recloser aids in automatically reconnecting to the grid once the fault is cleared.

The most significant difference between a breaker and a recloser is that the recloser is defined as a self-controlled device. A breaker is designed for use with a separate relay/control scheme. A clear distinction between the circuit breaker and a recloser is defined in ANSI/IEEE C37.100-1981, IEEE Standard Definitions for Power Switchgear.

- Automatic circuit recloser: a self-controlled device for automatically interrupting and reclosing an alternating-current circuit, with predetermined sequence of opening and reclosing followed by resetting, hold closed, or lockout.
- Circuit breaker: a mechanical switching device capable of making, carrying, and breaking currents under normal circuit conditions and making, carrying for a specified time, and breaking currents under specified abnormal circuit conditions such as those of short circuit.

3.2.4.1 Types of Reclosers

3.2.4.1.1 Single-Phase Reclosers

Single-phase reclosers are used to protect single-phase lines, most commonly the branches or single-phase taps of a three-phase feeder system. They are also used in three-phase circuits where the load is predominantly single phase. In such applications, when a single-line-to-ground fault occurs, the faulted phase opens and locks out, while the other two-thirds of the system carries power.

3.2.4.1.2 Three-Phase Reclosers

Unlike the single-phase reclosers that operate only on one phase, the three-phase reclosers involve all three-phase contacts operating simultaneously during a trip event. There are a wide range of three-phase reclosers available, each to satisfy multiple applications at the most economical cost.

3.2.4.1.3 Triple-Single Reclosers

Triple-single reclosers combine the functionalities of single-phase and three-phase reclosers for multiple operating capabilities during faults. They have three modes of operation: three-phase trip/three-phase lockout, single-phase trip/three-phase lockout, and single-phase trip/single-phase lockout.

3.2.4.2 Recloser Controls

The recloser controls perform the calculations that help control the recloser operation. The recloser controller senses overcurrents, voltage abnormalities, recloser timing, and other recloser functions and subsequently communicates with the recloser to perform the necessary operations. There are two types of recloser controls: the internal hydraulic control and the external electronic control.

3.2.4.2.1 HYDRAULIC RECLOSER CONTROLS

The hydraulic recloser control forms an integral part of most single-phase reclosers and some three-phase reclosers. It has electromechanical controls and is mostly devoid of electronic components.

3.2.4.2.2 ELECTRONIC RECLOSER CONTROLS

Electronic controls are connected externally to the recloser and are usually housed in a separate cabinet and have electronic controls. When compared to the hydraulic controls, electronic controls are more flexible, better customized and programmed, and have increased functions such as advanced protection, metering, and automation capabilities.

The three-phase reclosers by Vendor G and advanced recloser control by Vendor L are discussed in the following sections.

3.2.4.3 VENDOR G THREE-PHASE RECLOSERS

Vendor G device is a solid dielectric, three-phase recloser controlled by an electronic recloser control The reclosers use epoxy-insulated vacuum interrupters, which provide excellent insulation while making the contacts fully shielded and void free. The reclosers are designed for three-phase automatic or manual trip operation, providing overcurrent protection for systems up to 38 kV, 800 A continuous, and 12.5 kA rms symmetrical interrupting.

3.2.4.3.1 OPERATING PRINCIPLE

Vendor G recloser consists of internal multiratio CTs and voltage sensors that monitor the circuit. The unit is powered by a 120 Vac or a 125 Vdc power source. In case of a power failure, the unit is powered using internal batteries in the control system.

The recloser has three distinct operating modes that provide maximum application flexibility:

- Three-phase trip/Three-phase lockout
- Single-phase trip/Three-phase lockout
- Single-phase trip/Single-phase lockout

The recloser control monitors the circuit parameters and controls recloser sequence operation, tripping, and overcurrent sensing functions. Each phase module consists of a magnetic actuator and a drive assembly. The magnetic actuators use permanent magnets to hold the solenoid plunger in a closed position while maintaining a charge on the opening spring. The trip/close operations are accomplished by energizing the trip coil, which generates a magnetic flux in the opposite direction and releases the trip spring. Manual trip operation is also made possible by a manual trip handle. Pulling the manual trip handle trips and locks the selected phase.

3.2.4.4 VENDOR L ADVANCED RECLOSER CONTROL

Vendor L Advanced Recloser Control is the recommended unit for the recloser. It provides the intelligence to allow reconfiguration of distribution systems and to maintain reliable service to as many subfeeders as possible in the event of a fault. The following are the features of the recloser control:

- Full line metering capabilities using voltage inputs from internal sensors.
- Six voltage inputs necessary for loop scheme designs.
- Proprietary programming for various functions such as recognizing seasonal loads and shift between Three-phase and Single-phase trip/close modes for optimal system efficiency.
- Programmable to act as a recloser for loop schemes, looking in either direction.
- Minimum trip for phase, ground, and sensitive earth faults.
- Capable of up to four shots to lockout.

- Sequence coordination.
- Harmonics up to the 15th order for total harmonic distortion (THD) analysis.
- Cold load pickup.

3.2.5 Sectionalizers

Sectionalizers provide an economical method of further improving protection of distribution lines already equipped with reclosers or circuit breakers. They are circuit-opening devices that isolate permanent faults and confine the power outage to a smaller section of the distribution system.

A sectionalizer has self-contained current-sensing transformers that power the control circuit and the circuit-opening mechanism. No auxiliary supply or external equipment or connections are required. It operates in conjunction with the source-side protection device. When the protective device de-energizes the circuit, the sectionalizer counts the number of overcurrent interruptions; when it goes beyond a preset threshold, it opens the contacts to isolate the circuit. It is not designed to interrupt fault current; therefore, it opens only during the open interval of the backup protection. Because the sectionalizer is not a time-current-based device, it can easily be added to the existing protection system without requiring a change in the coordination settings. It can be used in place of a fuse or between a fuse and a recloser.

Sectionalizers provide several advantages over fuse cutouts:

- The fault-closing capability of the sectionalizer greatly improves circuit testing after a permanent fault.
- The backup recloser can take care of power interruption if the fault is still present.
- Sectionalizers do not need replacements (contrary to fuse links). The line can be tested and service restored faster, more economically, and with more convenience.
- Sectionalizers do not open accidently under load because of a damaged link.
- Errors are eliminated in the selection of the correct fuse link size and type.

3.2.5.1 SELECTION CRITERIA

The selection of an appropriate sectionalizer is dependent on the following factors:

- System voltage: Sectionalizers are generally insensitive to the system voltage because they are not a factor upon which the device operates. However, the sole criterion to consider is that they meet the dielectric value and the appropriate voltage rating of the distribution system to which they are connected.
- Pickup current (actuating current): For reliable operation, the sectionalizer should be set to pick up current thresholds like the protective device upstream. The pickup should also be sensitive enough to register ground faults in the system, which in turn initiates automatic reclose operations.
- Inrush current restraint: One of the main causes of unwanted sectionalizer operation is inrush currents. The pickup current is a primary setting; however, depending on the position of the sectionalizer, it must be able to withstand possible transformer magnetizing inrush currents. The anti-magnetizing feature of the device ensures there is no operation if the positive and negative half cycles are below the pickup value. The inrush restraint feature thus prevents false counting and operation because of inrush currents during operation of the source-side protective device.
- Number of counts: The sectionalizers can operate for up to three recloser operation counts. For maximum reliability, the sectionalizer should be set to a count one less than the recloser upstream.
- Maximum fault current: The sectionalizer should be rated at a short-time withstand greater than or equal to the available fault current.
- Continuous current: The continuous current rating of the sectionalizer should be equal to or greater than the system load current.

- Reclaim time: The time that the memory of the sectionalizer retains prior to the counts. The duration varies with the value and duration of the fault current pulses.
- Overvoltage withstand: Sectionalizers must be able to withstand up to a 65 kA lightning surge current, as specified in IEEE C37.63, IEEE Standard Requirements for Overhead, Pad-Mounted, Dry-Vault, and Submersible Automatic Line Sectionalizers for Alternating Current Systems Up to 38 kV and IEEE C62.11, IEEE Standard for Metal-Oxide Surge Arresters for AC Power Circuits (> 1 kV).
- Load breaking: Sectionalizers are designed for dead-line operation only. Manual operation under live-line conditions will cause arcing between the contacts and can damage the device.
- Dead time: The time for a sectionalizer to drop to a safe isolating current level. To prevent the device from opening under live-load conditions, the upstream relay should have a dead-line time of not less than 0.5 seconds.

3.2.6 Transformer Monitoring and Control

Transformers are among the most expensive and critical equipment in a power system. The cost of repairing a transformer (to rectify energy not being delivered to the load because of the transformer unavailability and/or possible propagation of damages to equipment downstream of the transformer) is debilitating. It is essential that all transformer parameters be monitored for unexpected deviation from normal operating values.

Interruptions or failure of an in-service transformer usually results from dielectric breakdown, electrical faults or disturbances, winding distortion, insulation deterioration, lightning, improper maintenance, winding and magnetic hot spots, loose connections, or failure of components such as no-load tap changers or bushings. The first techniques developed for transformer monitoring were time-based monitoring solutions, which performed various offline tests to detect incipient problems. These tests could be performed only after a transformer outage or during scheduled maintenance. The time-based monitoring solutions are expensive and labor-intensive, and not entirely reliable because the monitoring is not in real time.

The present trend in the power industry is to move from time-based monitoring to a condition-based monitoring system. Condition-based monitoring can acquire and process information about a transformer in real time to determine corrective actions that may be needed to protect the transformer from overload. The following sections discuss the various aspects of condition-based monitoring of transformers.

3.2.6.1 THERMAL MONITORING

Thermal monitoring involves the development of a mathematical model that predicts the temperature profile of the power transformer using the principle of thermal analysis. The real-time temperature of the transformer is compared to the predicted operating temperature to detect abnormal operation. This is important in determining the insulation deterioration in the windings because of temperature rise. The thermal model is also used to determine the top oil temperature and the hot-spot temperature rise.

3.2.6.2 DISSOLVED GAS ANALYSIS

Gases in the transformer are produced by the degradation of transformer oil and solid insulating materials. Gases are produced at a much faster rate during electrical faults. There are three categories of faults that create gases: corona discharge, thermal heating, and arcing. By determining the quantities of hydrocarbon gases (hydrogen and carbon oxides present in the transformer), the exact fault can be detected. Table 3.2 is derived from the ANSI/IEEE C57.104-2008, IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers, which gives a good account on key gas concentrations and fault types.

Table 3.2: ANSI/IEEE C57.104 Standard for Dissolved Gas Analyses

Gas Description		Key Gas Concentration (ppm)		
Name	**Composition**	**Lower Limit***	**Higher Limit****	**Potential Fault Type**
Hydrogen	H_2	150	1,000	Corona, arcing

Gas Description		Key Gas Concentration (ppm)		
Name	**Composition**	**Lower Limit***	**Higher Limit****	**Potential Fault Type**
Methane	CH_4	25	80	Sparking
Acetylene	C_2H_2	15	70	Arcing
Ethylene	C_2H_4	20	150	Severe overheating
Ethane	C_2H_6	10	35	Local overheating
Carbon monoxide	CO	500	1,000	Severe overheating
Carbon dioxide	CO_2	10,000	15,000	Severe overheating
Total combustibles	TDCG	720	4,630	Severe overheating

* As the value exceeds this limit, sample frequency should be increased with consideration given to planned outage in near term for further evaluation.

** As value exceeds this limit, removal of transformer from service should be considered.

Vendor B supports a small encapsulated DGA monitor that can provide data in real time through the analysis of the insulating oil in the transformer. Some key features of the device are:

- Operates as a standalone device or in conjunction with monitoring software.
- Functions as a hydrogen monitor or is also available as a more advanced composite gas monitor.
- Contains optional pump for situations when there is poor oil circulation.
- Includes self-testing diagnostic to monitor its own performance, ensuring the device remains accurate.
- Has alarms and closing contacts for relays and digital and analog outputs.

3.2.6.3 FREQUENCY RESPONSE ANALYSIS

When a transformer is subjected to fault currents, the mechanical structure and windings are exposed to severe stresses, resulting in winding movement and structural deformations. The frequency response analysis (FRA) is a sensitive technique for detecting deformations and movement faults. It involves measuring the impedance of the windings at low voltage for a wide range of frequencies. The two FRA methods are described in the following subsections.

3.2.6.3.1 IMPULSE FREQUENCY RESPONSE ANALYSIS

The impulse frequency response analysis (IFRA) uses a single non-periodic voltage signal as an excitation or input, which is injected into one of the available transformer terminals. This excitation induces voltages on the remaining ends of the transformer. The properties of the reflected signal depend on the structure of the transformer and therefore are used to evaluate the condition of the transformer. The frequency spectrum of the input signal and the measured output signal are obtained through a fast Fourier transform (FFT) algorithm. The ratio between the two frequency spectra is obtained for analysis.

3.2.6.3.2 SWEEP FREQUENCY RESPONSE ANALYSIS

The sweep frequency response analysis (SFRA) is like the IFRA, except in the SFRA the excitation input is a low-voltage sinusoidal input (1 to 20 V_{rms} range) that is applied to the transformer terminal in a frequency sweep (Hz to mHz range). The transfer function is obtained for analysis from the ratio of output to input signal.

The FRA technique has certain limitations that prevent it from becoming a reliable transformer monitoring technique. The main limitation involves operating the FRA tests online while the transformer is connected to the power system and delivering load. The following are the drawbacks of applying the online FRA technique:

- Measurements are performed in the presence of sinusoidal high voltage that becomes more complex considering the voltage levels, personnel and equipment safety concerns, and electric noise.

- The transformer is electrically connected to the remaining elements in the power system such as the source, load, and switches. Therefore, the measurement is the response of the whole system, further complicating the interpretation of the results.
- The possible inclusion of elements in the transformer for the FRA measurement in the network could lead to vulnerabilities that may affect the power system operation.

There are FRA devices that can be used when a transformer is offline. Table 3.3 is a comparison of the analyzers supported by Vendor I and Vendor B.

Table 3.3: Comparison of Vendor I and Vendor B FRA Devices

Description	Vendor I FRA	Vendor B FRA
Frequency range	1 Hz to 30 MHz	10 Hz to 25 MHz
Output impedance	50 Ω	50 Ω
Voltage amplitude	10 V peak-to-peak	20 V peak-to-peak
Dynamic range	> 145 dB	> 90 dB
Accuracy	±0.5 dB	±1 dB

3.2.6.4 PARTIAL DISCHARGE ANALYSIS

Partial discharge or corona is a phenomenon that involves the local electric field exceeding its threshold value, causing a partial breakdown of the surrounding medium. It is caused by factors such as the main magnetic flux, stray flux, operative voltage, residual potential, and creeping discharge. Partial discharge occurs as sharp current spikes at the transformer terminals or certain winding stress points, depending on the winding insulation and nature of the winding, and can result in degradation of the insulation surrounding it. The level of degradation can be estimated by measuring these uneven current pulses.

The development of modern microprocessor-based relays with enhanced processing capabilities makes it is possible to perform transformer monitoring and control while ensuring fault protection. These relays use the thermal-based monitoring function to compare transformer internal temperatures and loss-of-life values with predefined limits. The relays are programmed to issue a warning if these limits are exceeded.

3.2.6.5 MICROPROCESSOR-BASED TRANSFORMER MONITOR

Transformer monitor is a device that performs transformer monitoring and protection. The transformer monitor works in conjunction with a resistance temperature detector (RTD) module and other sensors in the transformer core and coil for its monitoring function. For the protection function, it uses signals from the CT and VT connected to the power transformer. Figure 3.8 shows the device connection and how it monitors the transformer parameters.

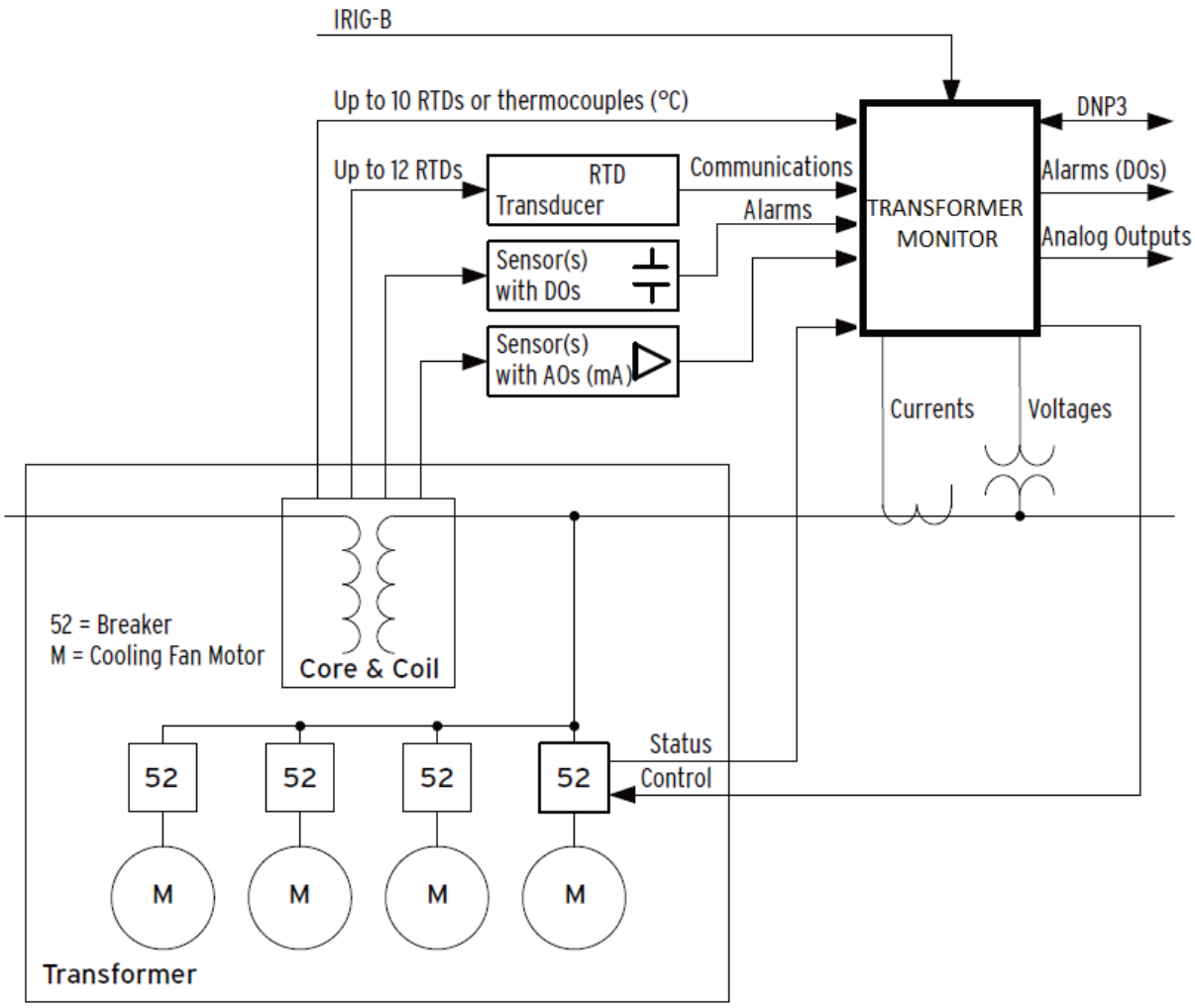


Figure 3.8: Microprocessor-Based Transformer Monitor I/O and Communications

The transformer monitor includes customizable input and output (I/O) cards that perform various functions based on the requirement. The digital inputs monitor critical transformer alarms and status points. The analog inputs measure pressure, oil level, temperature, tap position, and process-level signals (4–20 mA or 0–1 mA) from transducers. The digital and analog outputs originating from the transducers and the relay can be used to operate cooling fans, auxiliary equipment, and alarms, or provide indication. The device can also measure ac current and voltage to calculate three-phase power. In addition, it can calculate demand, generate oscillographic reports, and control automation processes (see Table 3.4).

Table 3.4: Transformer Monitor Analog and Digital I/O Monitoring Parameters

Inputs/Outputs	Status and Alarms
Digital inputs	Oil level (tank) [i]
	Oil level (conservator) [i]
	Pressure relief (tank) [i]
	Sudden pressure (Buchholz) [i]
	Gas accumulation (Buchholz) [i]

Inputs/Outputs	Status and Alarms
	Oil Flow 1 [i]
	Oil Flow 2 [i]
	Heat detector [i]
	Deluge monitor [i]
	Fan Pump 1 alarm [ii]
	Fan Pump 2 alarm [ii]
	Oil level (on-load tap changer [OLTC]) [iii]
Analog inputs	Ambient temperature [i]
	Top oil temperature [i]
	Hot-spot monitor [i]
	OLTC tank oil temperature [iii]
	Load voltage
	Load current
Digital outputs	Fan Bank 1 (on/off) [ii]
	Fan Bank 2 (on/off) [ii]
	Cooling lockout (inhibit) [ii]
	Breaker control (trip/close)
[i] Core and coil parameter [ii] Fan/pump bank parameter [iii] OLTC parameter	

In addition to the monitoring and control functions, the following are some of the features of the transformer monitor:

- Analyzes transformer Sequence of Events (SOE).
- Analyzes transformer event waveforms.
- Trends transformer temperatures and other analog inputs.
- Has through-fault event monitoring.
- Uses flexible control logic and integration features with compatibility over a wide range of communications protocols.

3.2.7 Micro-PMU

A phasor measurement unit (PMU) measures electrical waves to determine the health of the electrical distribution system using a common time source for synchronization (see Figure 3.9). Time synchronization allows synchronized real-time measurements of multiple remote points on the grid.

A PMU can be a dedicated device or can be incorporated into a protective relay or other devices. PMUs take measurements at 48 samples per second, with each measurement time-stamped to a common time reference. This allows PMUs at various locations and utilities to be synchronized.

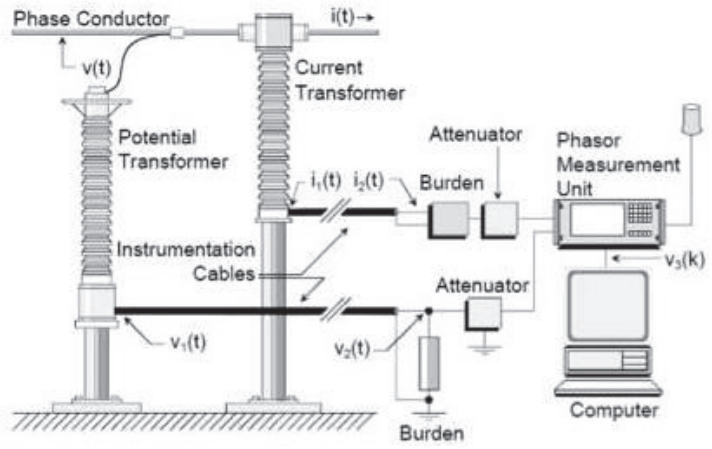


Figure 3.9: PMU Used to Monitor Power Flowing Through Electrical Grid

A single PMU cannot detect many errors in the grid. However, measuring phasors simultaneously from various PMUs at strategic locations in a system (as shown in Figure 3.10) and combining these data provides a precise and comprehensive view of the system.

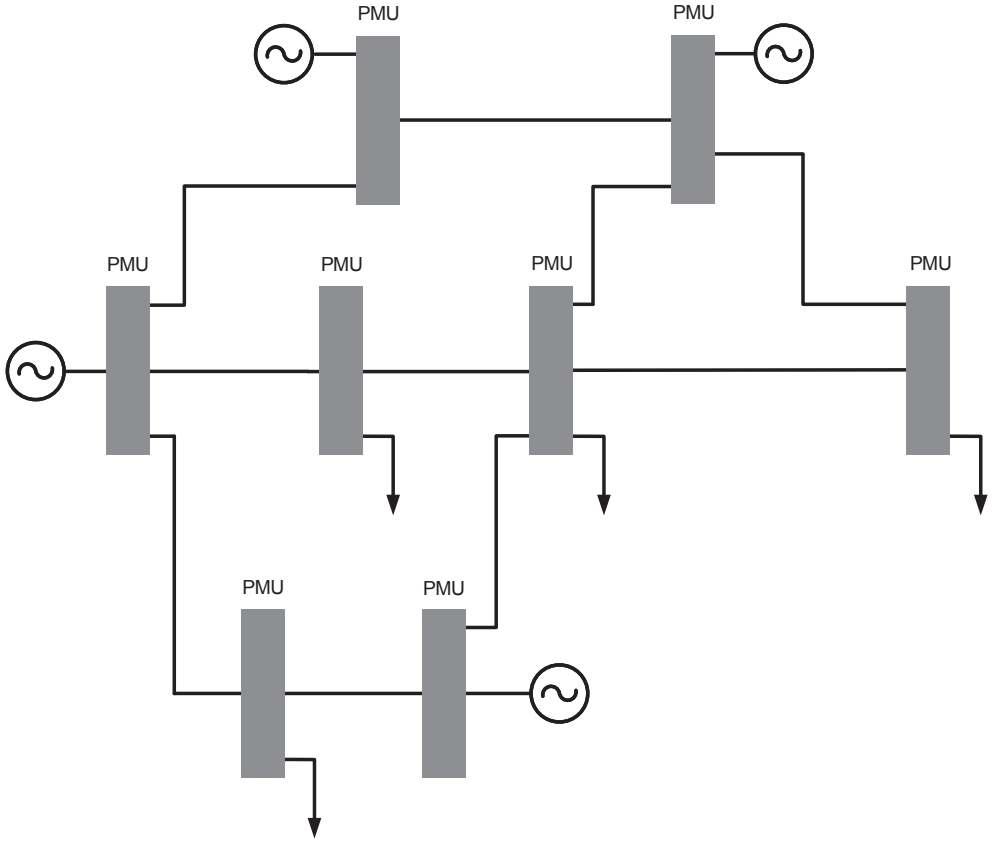


Figure 3.10: PMUs Installed at Every Substation Monitoring the Power Grid

3.2.7.1 COMPONENTS OF A PMU

From a design perspective, a PMU is a simple data collection circuit. It consists of the following components:

- A microprocessor or a microcontroller
- An analog-to-digital converter (ADC)
- A GPS receiver (to provide a precise, universal time base)
- A memory unit for storing the recorded synchrophasor data
- A communications interface to transfer the measured data back to the control room

In addition, analog inputs require a protection circuit to protect them from harmful voltages.

A simple block diagram of a PMU is shown in Figure 3.11.

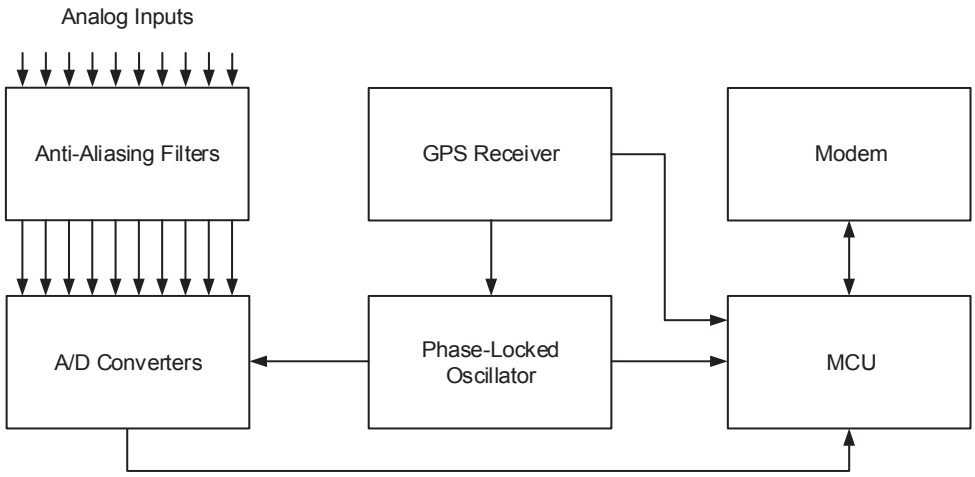


Figure 3.11: Block Diagram of a PMU

3.2.7.2 NEED FOR PMUS

3.2.7.2.1 OSCILLATION DETECTION

PMUs provide alerts to indicate levels of stress in a power grid. This stress can be in the form of low voltages, frequency oscillations, or differences in phase angles between two locations on the grid. With the increase in renewable energy generation plants connected to the grid, it is important to detect and isolate generators operating out of phase with other power stations because this can cause oscillations in the system and render the grid unstable.

3.2.7.2.2 FREQUENCY MONITORING

PMUs also help monitor the frequency in an electric power grid. Frequency fluctuates with imbalance between supply and demand of electric power. When demand is high, the frequency increases. When demand is low, the frequency decreases. If there is a rapid change in frequency, it indicates there is a loss of generation or load in the system. This kind of sudden event can cause oscillations in the grid and potentially lead to a blackout.

3.2.7.2.3 VOLTAGE STABILITY MONITORING

PMUs can help monitor, predict, and manage voltage on the transmission system of the power grid. In transmission systems, the voltage cannot exceed a certain limit without causing stability issues in the system. When voltage stability limits are exceeded, it can result in a voltage collapse.

3.2.7.2.4 DISTURBANCE DETECTION AND ALARMING

Phase angle differences between substations is a critical indicator of stress on a power system. Large phase angle differences are used for transmission operator alarms. PMUs compare the phase angles to the phase angle limits and warn the operators when stress on the system is increasing. This allows the operator to take necessary corrective measures to identify and mitigate the issue.

3.2.7.2.5 RESOURCE INTEGRATION

One of the main challenges with integrating distributed generation and renewable energy into the electric power grid is the ability to identify and respond to variability in the power generation. In a conventional system (without renewable energy), frequency is controlled by large central rotating generators. However, when more renewable energy is present in the system, it challenges the ability of the power system to control the system frequency because the change in frequency is much faster than in a conventional system. Large variations in frequency can adversely impact the stability performance of the grid. PMUs can provide real-time monitoring of frequency behavior and enable the operator to take necessary steps to maintain stability.

3.2.7.2.6 TRANSMISSION LINE DYNAMIC RATING AND CONGESTION MANAGEMENT

Dynamic rating is the ability to calculate the transmission line ratings based on environmental conditions. Typically, the ampacity of transmission lines is set at conservative values for various seasons based on a set of assumptions such as ambient temperature, wind speed, and solar heating input. However, with a combination of real-time phasor data of transmission lines and accurate local weather information, the actual ampacity of transmission lines can be calculated and would be much greater than the conservative seasonal rating. PMUs can aid in calculating the dynamic rating of transmission lines, which will help increase the throughput and relieve congestion on transmission lines.

PMUs are usually applied only at transmission systems or substations in an electric power grid. When PMUs are applied to smaller voltage levels, such as that of a distribution system, they are referred to as micro-PMUs. At the distribution level, phase angle differences are much smaller and change more rapidly than at the transmission level. This cannot be measured by traditional transmission level PMUs. Because micro-PMUs are intended to be used at the consumer voltage level, they can be created more economically, by an order of magnitude less, than the present commercial PMUs. The lower cost will allow many micro-PMUs to be deployed into the system, which will help provide a better data resolution of the distribution gird.

The micro-PMU can be connected to single-phase or three-phase secondary distribution circuits (up to 690 V line-to-line or 400 V line-to-neutral) through a PT or a standard outlet. It can also be connected to primary distribution circuits; however, the low-voltage installation is a simpler and more affordable option.

3.2.7.3 MICROPMU

The microPMU supported by Vendor J provides precise synchrophasor measurements for investigating stability and impedance issues on distribution grids and microgrids.

The microPMU measures 512 samples per nominal 50/60 Hz cycle. The measurement process adheres to IEEE C37.118, IEEE Standard for Synchrophasors for Power Systems; however, the module includes filters that are optimized for distribution and microgrid measurements. It also consists of three line-to-ground voltage measurement channels and three line current channels.

In addition, it includes 8 GB of onboard storage. This enables storage of measurements for up to 30 days.

Other features include:

- Provides up to 0.001° data resolution on voltage and current phase angles.
- Provides up to 2 parts per million (ppm) data resolution on voltage and current magnitudes.
- Supports PT connections up to 100 kV.

- Supports CT connections up to 6 kA.
- Is fully compatible with open phasor data concentrators (PDCs).
- Supports communication via Ethernet, File Transfer Protocol (FTP) file upload and download, and IEEE C37.118 streaming.
- Is able to connect to any power grid voltage with a frequency of 16.67/50/60/400 Hz and a voltage range of 100 V to 690 V, single phase or three phase.

3.3 COMMUNICATIONS

3.3.1 Communications Protocols Used in Substations

An electrical substation is a subsidiary station of the electric power system. A substation is the link between power generation and power transmission in a system. The step up of voltage for transmission or the step down of voltage for distribution and consumption takes place at an electrical substation. In addition to this critical purpose, the substation is responsible for control and monitoring of protection and power equipment, switchyard, revenue metering, and automation functions for energy management.

Substations employ protective relays and other devices to isolate system failures from affecting the entire system. SCADA systems are used to remotely monitor the status of these devices and to control system parameters when necessary. The communications protocol used by the SCADA system defines the architecture of the substation communications system.

The main task of a SCADA communications protocol is to transport digital and analog information from the substation to the control center and to allow remote control of operating parameters in the substation from the control center. The SCADA communications protocol may also be required to have the capability to access and download event files and oscillography. It should also have the ability to access devices in the substation.

The two main communications standards that have unique positions in the industry are:

- Distributed Network Protocol (DNP3)
- IEC 61850

3.3.1.1 DISTRIBUTED NETWORK PROTOCOL

DNP3 is an open and public SCADA protocol that was created by Vendor F in 1990 and is currently owned and supported by the DNP3 Users Group, which is composed of utilities and vendors who are using the protocol. DNP3 is the market leader in SCADA protocols used in the U.S.

DNP3 is based on the standards of the International Electrotechnical Commission (IEC) Technical Committee 57, Working Group 03, which has been working on an Open System Interface (OSI) Layer 3 “Enhanced Performance Architecture” protocol standard for tele-control applications. DNP3 was designed to optimize transmission of information and commands from one computer to another and is intended to be used for SCADA.

DNP3 works on serial interfaces (including RS232 and RS485), and fiber serial loop and fiber serial star configurations. DNP3 can also work over IP and Ethernet networks and is referred to as DNP3 over IP. The DNP3 protocol offers flexibility because it can be implemented over serial communication and Ethernet/IP. This allows serial devices and DNP3 over IP devices to coexist on the same network.

3.3.1.1.1 FEATURES OF DNP3

Some of the major features of DNP3 are:

- Time-stamped data
- Send and receive analog information

- Send and receive set points
- Time synchronization of data
- File download and upload capabilities
- Send and receive controls
- Report by exception (unsolicited reporting)
- Secure authentication
- Diagnostic information for each I/O point
- Communication to multiple masters
- High data integrity (no misinterpreted or corrupt data)

Being a non-proprietary standard, DNP3 has found great success in the electrical and water global sectors and has delivered significant success to the SCADA industry.

3.3.1.2 IEC 61850 STANDARD

IEC 61850 is a standard communications protocol developed by the IEC Committee 57, Working Group 10. IEC 61850 is a lower-layer, object-oriented protocol that is implemented over TCP/IP and Ethernet networks. It is based on the manufacturing message specification (MMS) that was developed by the International Organization for Standardization (ISO) Technical Committee.

More than a traditional SCADA protocol, IEC 61850 also provides information modes, abstract services, and configuration languages in substation communication.

3.3.1.2.1 FEATURES OF IEC 61850

Some of the major features of IEC 61850 are:

- Real-time information in the substation is translated into information models in the form of standard naming conventions and formats for easy information management.
- Abstract communication service interface (ACSI) allows applications and databases to remain unchanged with changes in communications protocols.
- Communications protocols are provided for TCP/IP-based SCADA, real-time Generic Object-Oriented Substation Event (GOOSE) and Generic Substation Status Event (GSSE), and real-time Sampled Measured Values (SMV).
- Substation wiring in the switchyard is reduced by converting CT and PT data into digital information.

IEC 61850 is a non-propriety communications protocol with multiple vendors that allows interoperation between devices and applications through standardized data models. It can simplify substation automation architecture with its flexible configuration of communications networks. With many vendors and customers using this communications protocol, IEC 61850 is futureproof. It can be implemented across numerous products from various manufacturers and meets a major utility requirement.

Some utilities have implemented IEC 61850 and taken advantage of an object-oriented, standardized approach to substation automation. With more vendor products that support IEC 61850 available on the market, IEC 61850 will continue to evolve.

3.3.1.3 GOOSE MESSAGING

Over the last three decades, devices in substations have evolved from electromechanical relays to digital relays with built-in communications capabilities. The advent of LAN technology has provided the capability for faster data

communication and flow of control between devices. Ethernet has become the most reliable technology for real-time applications.

IEC 61850 supports two groups of communications services between entities in a system. One group is based on the client-server model and supports services like reporting and remote switching. The other is based on the peer-to-peer model for Generic Substation Event (GSE), which provides fast and reliable communication between devices in a system and is used mainly for protection services. The GSE service also provides multicast/broadcast services, allowing the transmission of information to multiple devices.

The GSE model is divided into GOOSE and GSSE. GOOSE allows the exchange of a wide range of data organized by a data set. GSSE provides the capability to convey state-change information.

GOOSE messaging is an OSI Layer 2, broadcast/subscription Ethernet-based protocol that evolved from the Utility Communications Architecture (UCA) 2.0 GOOSE messaging protocol. This protocol is not as safe as other more common point-to-point protocols; however, it is still very useful in protection-type applications. It is particularly useful in load-shedding applications.

3.3.1.4 MODBUS

The Modbus protocol is a serial communications protocol based on the master-slave architecture. It is an open and public protocol developed by Vendor H for use with PLCs. Unlike DNP3 and IEC 61850, which are more specifically developed for applications in the power industry, Modbus is widely used across a variety of industries.

Modbus is mainly used to connect a supervisory computer to a RTU in SCADA application systems. In a standard Modbus network, there is one master unit and up to 247 slave units. Each slave unit will have a unique address. The master unit can write information to the slave units. Modbus is intended to be used as a request/reply protocol and to deliver services specified by function codes. Different versions of Modbus protocol exist for serial lines and for Ethernet applications.

One main limitation of the Modbus protocol is that it is intended to send only data and does not have the capability to send other parameters, such as point name, units, or resolution. Despite this limitation, the Modbus RTU is much easier to implement than other more modern protocols. It requires significantly lower memory than other communications protocols. With several vendor products supporting the Modbus communications protocol, it is still a dominant force in the marketplace. However, Modbus is one of the oldest communications methods and may not be a futureproof option for implementing substation automation like DNP3 and IEC 61850.

3.3.2 Implementing SCADA Over Wireless Communications Networks

Almost all substations employ SCADA systems to communicate with various intelligent electronic devices (IEDs) and other devices in the field for monitoring the system. Regular SCADA networks in substations are implemented over serial or Ethernet protocols, using copper wires or fiber-optic cables. However, copper wires and fiber-optic cables are expensive, and using them to implement SCADA in large substations will be costly and time consuming. A more cost-effective solution for implementing SCADA in large substations would be to consider implementing SCADA using wireless communications networks.

A SCADA system protocol uses polling schemes to gather information from the various devices in the field and report these data to a SCADA master. The SCADA master then makes necessary control decisions based on the information received from the devices in the field.

The polling rates of SCADA protocols can vary widely; however, typically they are not faster than once per second. The wireless communications network must account for this polling rate, protocol overhead, and number of devices in the field. To meet these requirements, the wireless communications network must have a high enough throughput. A throughput of 1 Mbps or greater will allow the wireless network to handle multiple devices regardless of the polling rate.

3.3.2.1 WIRELESS NETWORK TOPOLOGIES

There are a few network topologies to choose from when using wireless networks for SCADA applications:

- Point to point is the simplest wireless network topology. It contains only two devices. It is possible to set up multiple point-to-point networks in a single area to provide a pseudo point-to-multipoint network. However, a major drawback of this system is that if a single link in the network is compromised, it may lead to a loss in communication between the devices.
- Point to multipoint allows multiple terminal devices to communicate via a base station or access point. It allows data collection and wireless communication with multiple devices.
- Mesh allows each device to communicate with more than one device in the network. Two devices will communicate with each other directly if they are permitted to do so. Otherwise, they can use intermediary devices to relay information to each other or to a final destination. The mesh topology is a good option when devices do not have a line-of-sight to the access point. The presence of multiple links in the network ensures there will be no loss of communication if a single link is lost. However, having multiple links in the system increases the latency and lowers the throughput. Also, several devices are required to achieve path redundancy.

3.3.2.2 WIRELESS TECHNOLOGIES

This section discusses the various wireless technologies presently available on the market. Bluetooth® is based on IEEE 802.15.1, IEEE Standard for Telecommunications and Information Exchange Between Systems – LAN/MAN – Specific Requirements – Part 15. Wireless Medium Access Control (MAC) and Physical Layer (PHY) Specification for Wireless Personal Area Networks (WPANs). It is a wireless technology intended to be used for short-range applications. Bluetooth transmission hops from one frequency to another in a predetermined manner. If data transmitted over one channel are lost, they are retransmitted at a later time over a different channel. Bluetooth is popularly used for wireless audio applications. In Electric utilities, Bluetooth has mainly been used for serial port extension over wireless for commissioning devices and collecting data regarding events.

Some of the features of Bluetooth include:

- 2.5GHz design that is accepted in both the U.S. and internationally
- Range up to 300 feet
- Bandwidth of 2.1 Mbps (depending on the application)
- Pair with utility-grade serial-to-Bluetooth adapters
- Simple plug-and-play operation and provide support for laptops, smart phones, etc.

Security concerns, limited range, and support for only point-to-point communication may limit the possible application for Bluetooth in the power industry.

3.3.2.2.1 ZIGBEE

ZigBee is a wireless technology based on IEEE 802.15.4, IEEE Standard for Local and metropolitan area networks – Part 15.4: Low-Rate Wireless Personal Area Networks (LR-WPANs). It is usually used in lighting, traffic management systems, and industrial sensors. ZigBee supports low to moderate data throughput systems. Industrial radios based on this standard can handle SCADA data collection.

Some of the features of ZigBee include:

- Operates on 900 MHz (U.S.) and 2.4 GHz (U.S. and international).
- Covers a range of 300 feet to 1 mile.
- Uses low power consumption.
- Contains a bandwidth of 1.5 MHz.
- Supports application in point-to-point, point-to-multipoint, and mesh networks.
- Supports interoperability between devices.

ZigBee has potential for numerous applications in electric utilities; however, there are limited devices that support any application in this market. ZigBee has poor security features and is not secure.

3.3.2.2.2 WI-FI

Wi-Fi is a wireless technology based on IEEE 802.11, IEEE Standard for Information technology – Telecommunications and information exchange between systems Local and Metropolitan area networks – Specific requirements Part 11: Wireless LAN Medium Access Control (MAC) and Physical Layer (PHY) Specifications. It provides broadband communications access, which is desirable for industry and consumer applications. Wi-Fi devices have a link range of 300 feet and can be extended up to 1,000 yards with high-gain directional antennas.

Some of the features of Wi-Fi include:

- Operates on 2.4 GHz and 5.8 GHz (U.S. and international) industrial, scientific, and medical radio bands (ISM bands).
- Contains bandwidths of 5, 10, and 20 MHz.
- Covers a range of 300 feet (can be extended to 1,000 yards).
- Has better security options (WPA and WEP).
- Allows a higher throughput.
- Permits interoperability between devices.

Given its features, Wi-Fi represents the most promising option for implementing SCADA over wireless networks. However, it does have disadvantages. Because Wi-Fi is a popular technology used by industries and consumers, signal interference could be an issue. Although the range of Wi-Fi can be extended, it still has a limited range and its effectiveness will depend on the size of the facility or system. Another important criterion to be considered is that most Wi-Fi devices are not substation-hardened and may not meet the necessary standards required for being applied to substations.

3.3.2.2.3 WORLDWIDE INTEROPERABILITY FOR MICROWAVE ACCESS

Worldwide Interoperability for Microwave Access (WiMAX) is a group of wireless communications standards that implement IEEE 802.16, IEEE Standard for Local and metropolitan area networks Part 16: Air Interface for Broadband Wireless Access Systems, to provide up to 40 Mbps data rates. WiMAX was designed to provide high-speed broadband internet to devices over long distances.

WiMAX is often compared to Wi-Fi; however, there are key differences between them. WiMAX can provide a much wider wireless access than Wi-Fi. Unlike Wi-Fi, which is a networking technology that allows devices to connect to a network using the 2.4 GHz and 5 GHz ISM bands, WiMAX is a cellular technology that uses base stations and network infrastructure to allow devices to connect to a network. Access to the network is controlled by the base station. WiMAX supports multiple bandwidths ranging from 1.5 MHz to 28 MHz.

WiMAX gets its name from the WiMAX Forum, an industry group that promotes WiMAX use. The group was formed in 2001 and promotes conformity and interoperability.

Some of the features of WiMAX include:

- Covers a long range.
- Allows high data speeds (up to 40 Mbps).
- Contains better security (user authentication, device authentication, wireless encryption, and key management).

The major drawback of WiMAX is the cost associated with setting up base stations and network infrastructure. WiMAX is more suited to large utility systems and would not be a cost-effective choice for smaller systems.

3.4 RENEWABLES AND ENERGY STORAGE

3.4.1 Multifunction Inverters

Increases in solar power plants and distributed generation make it imperative for the grid to have infrastructure that is more intelligent and resilient to provide a stable and consistent flow of power.

The photovoltaic (PV) inverter, the basic building block of a solar power plant, could have the potential to aid the grid from being overwhelmed by the increasing number of renewable energy plants (which are mostly inverter based) connected to it. Unlike traditional inverters, a multifunction inverter (sometimes called smart inverter) has bidirectional communications capabilities and a robust software infrastructure.

A smart inverter can send and receive messages swiftly and share data with the owner and the utility. A smart inverter can be capable of the following functions:

- Connect/disconnect function. There are numerous possible reasons for disconnecting distributed devices from the grid. Unacceptable high-voltage levels, malfunctioning DER equipment, and maintenance requirements are among them. The utility can issue a "disconnect" command to disconnect DER devices from the system without loss of power to customers.
- Power factor control. Smart inverters allow control of reactive power by controlling the ratio of real power to reactive power.
- Maximum generation limit control. The smart inverter can control the real power output of a connected distributed generation device. This ensures the output from the distributed generation does not cause overvoltage conditions. This will in turn ensure devices such as transformers are not stressed by overvoltage conditions in the system.
- Intelligent volt/VAR control. The smart inverter can regulate voltage by modulating the reactive power output of the connected distributed generation device.
- Intelligent volt-real power control. Smart inverters can provide voltage regulation by modulating the real power output.
- Frequency control. Smart inverters allow DER systems to help with frequency regulation by modulating real power output.
- Power curtailment. Smart inverters can control the power output from a system by specifying an upper limit for the active power output from the system.
- Low- and high-voltage and frequency ride through. Smart inverters can adjust their output and remain connected to the grid under low- and high-voltage and low- and high-frequency conditions.

3.4.1.1 VENDOR C SOLAR INVERTER

Vendor C solar inverter incorporates PLCs, advanced VFDs, and protective relays. It has the intelligence to automate operations, commission, and shutdown procedures with minimal physical action.

This device is designed specifically for 480 Vac three-phase applications and 600 Vdc PV systems.

Some of the features and benefits include:

- Grid sensor-based vector control. Ensures precise synchronism and fast response to grid dynamics and ensures system stability.
- Advanced proportional integral derivative (PID) control. Precise synchronism to the grid enables finer current and power limits and better reactive power or power factor control.
- Large dc bus capacitors. Ensures better solar module operation with extremely low ripple current on the PV array.

- Advanced anti-islanding function. Ensures the operation of the inverter is prevented in the event of a utility outage.
- Dual storage 250 kW with hysteresis. Provides optimum efficiency in lower irradiance conditions. Improves inverter longevity with less stressful power-stage operation.
- Maximum power point. Fast response time reacts to sudden changes, improved current response for low-irradiance periods, sudden-onset shading, and grid outages.
- Remote monitoring interface. Compatible with third-party monitoring applications via Modbus/TCP with an RJ45 plug and a terminal block with additional I/O.

3.4.2 Community Energy Storage (25–100 kW)

3.4.2.1 INTRODUCTION

With the increasing presence of renewable energy generation, the need for large-scale energy storage units is indispensable. Grid-connected energy storage is essential to decrease the dependence on fossil fuel-based generation. It also helps in smoothing the variability of wind and other renewable sources of energy. Optimum integration of renewables in conjunction with grid-connected energy storage enables the power grid to better balance sources and loads while reducing carbon emissions.

Community Energy Storage (CES) systems can provide reliable local backup for communities, improve power quality, manage peak loads, and possibly improve power reliability indices. Energy storage will help reduce outages by swiftly dispatching power when grid power is unavailable. Existing industrial solutions for CES systems are discussed in the following sections.

3.4.2.2 INDUSTRIAL SOLUTIONS AND PRODUCTS

The Community Energy Storage System functions as an intelligent distributed energy storage system to help utilities meet their rapidly changing needs. By positioning discrete amounts of utility-controlled storage where required along the distribution circuit, the utilities can rapidly respond to changing electricity demand. Other applications that encourage the shift toward smart grid include: integration of renewables, managing the intermittent nature of renewable sources, managing peak loads including plug-in electric vehicles charging stations, and improving reliability indices by providing immediate backup power. High-speed transfer from grid to backup source makes the outage seem barely perceptible to customers.

Figure 3.12 shows a simplified illustration for using multiple energy storage units (CES fleet systems) to support a larger consumption. It essentially acts as a substitute for a peaking power plant. Vendor K supported Distributed Energy Management System offers the technology for smart management of multiple energy storage units. It offers the following features:

- Uses DNP3 communication
- Supports SCADA
- Allows real-time and archival data storage
- Integrates with central office systems
- Maintains system security with user authenticated login/logoff

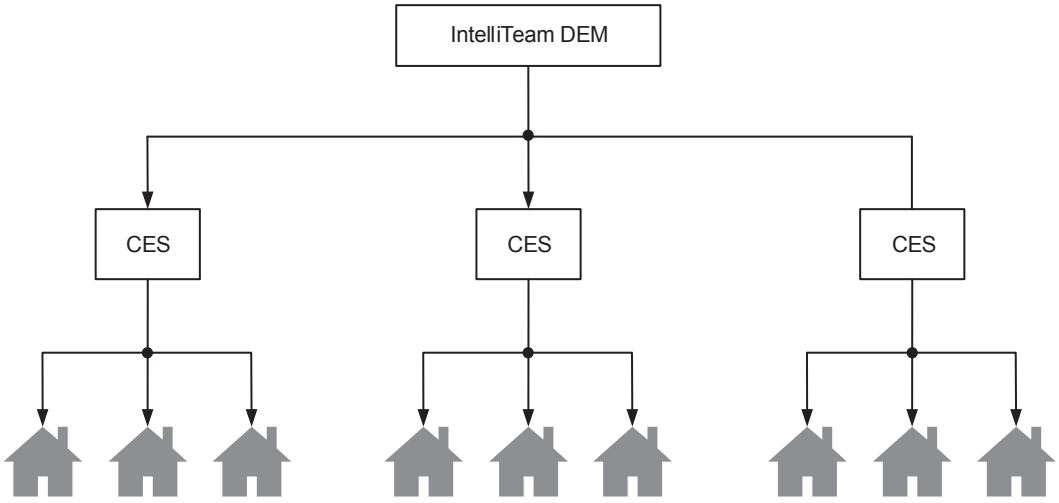


Figure 3.12: Simplified Representation of DEM Systems Supporting CES Fleet Systems

3.4.2.2.1 PHYSICAL LAYOUT

Vendor K supported CES consists of two main units as shown in Figure 3.13.

- Power Conversion System (PCS) Enclosure: Suitable for outdoor installation. It consists of an ac circuit breaker, an inverter, user-accessible ac termination area, user-accessible dc termination area, and user-accessible controls area.
  - AC circuit breaker: Automatically isolates the power unit from the utility source if the source is interrupted.
  - Inverter: If the ac circuit breaker is opened in response to interruption of the utility source, the inverter will provide the islanded load until service is resumed or energy in the battery pack is depleted.
  - DC breaker: Provides isolation of the battery pack, allowing maintenance to be performed on the PCS.
- Battery enclosure: An energy storage unit consisting of either a user-selected 25 kWh or 50 kWh lithium-ion battery pack suitable for installation underneath the PCS. The CES unit should be connected to the 120/240 Vac secondary of the outdoor utility distribution transformer at a frequency of either 50 Hz or 60 Hz.

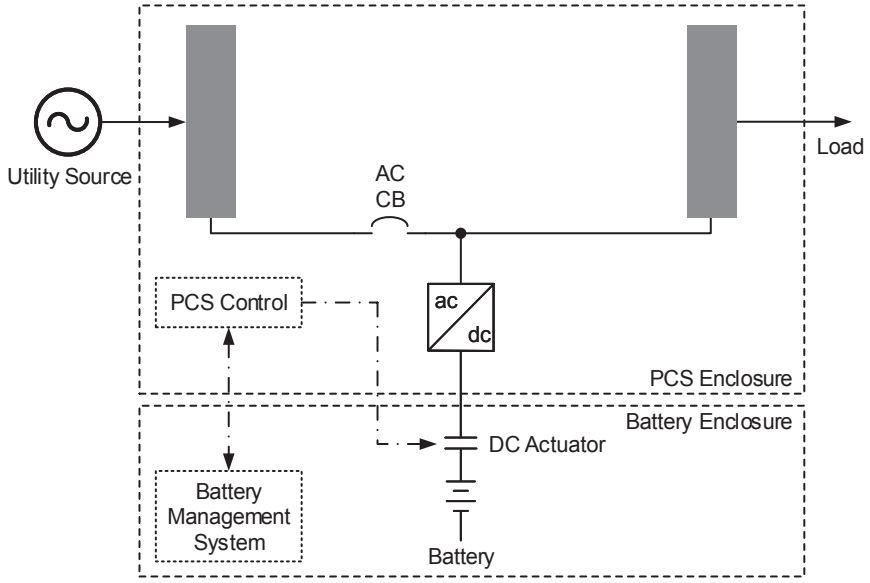


Figure 3.13: Simplified Circuit Representation of CES Units

3.4.2.2.2 OPERATIONAL PRINCIPLE

- Normal mode/utility connected: In normal operation, the CES operates in Current Source mode, providing functionalities such as voltage regulation, power factor correction, peak shaving, and load following.
- Island mode/utility disconnected: If the utility service is interrupted for any reason, the ac breaker in the unit will open, isolating and islanding the load from the utility service. The energy storage unit and inverter will then power the islanded load for a period depending on the battery bank capacity and the load. The energy storage unit will continue to support the load until utility service is resumed or the energy storage unit of the CES is depleted.

3.4.2.2.3 DEVICE MANAGEMENT

The operation, control, and monitoring of the CES can be done through the remote setup software. This program can be accessed by operators via secure Wi-Fi connection or WAN radio using a PC with compatible software. This software also works in conjunction with the IntelliTeam DEM system for CES fleet systems. The following features are offered by the IntelliLink program:

- Monitors the status of CES.
- Enables smart load management (load following function) that continuously adjusts the CES output to remain at or within the user-configured limits.
- Provides diagnostics, logging, and alarms.
- Schedules charge and discharge profiles for day of the week.
- Contains security settings.

3.4.2.2.4 RELEVANT STANDARDS COMPLIANCE

The following is a list of standards to which the CES units comply:

- IEEE 1547-2003 (R2008), IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.
- IEEE 1547.1-2005, IEEE Standard for Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems.
- IEEE 1547.3-2007, IEEE Guide for Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems.
- ANSI/IEEE C2-2007, National Electrical Safety Code.

3.4.3 Commercial Electric Vehicle Supply Equipment Clusters

3.4.3.1 INTRODUCTION

The electric vehicle (EV) is an automobile powered entirely or partially by electricity. Increased use of EVs provide multiple benefits, from reducing greenhouse gas emissions to minimizing dependence of petroleum. EVs are classified as follows:

- Battery electric vehicle (BEV): Propelled entirely by a battery-powered electric motor. Typically operates between 80 and 100 miles on a single charge.
- Plug-in hybrid electric vehicle (PHEV): Propelled by a combination of a battery-powered electric motor and a gas-powered internal combustion engine (ICE). It operates up to 40 miles on battery power, then switches to the ICE to propel the vehicle either directly or through the electric motor.

3.4.3.2 COMMERCIAL EVSE CLUSTERS

The electrical vehicle supply equipment (EVSE) is the electrical energy transfer device that conducts and regulates power from the electrical portal connection to the EV inlet. For EV use to become more widespread, it is required that reliable, efficient, and user-friendly infrastructure be developed. To achieve this, research in recognizing and identifying strong EVSE networks or "clusters" is essential. This identification is based on factors including the area's demographics and nature of potential EVSE location: publicly-owned or privately-owned, etc. Commercial clusters include areas like downtown, workplace, higher-education campus, leisure destinations, medical campus, and regional transit center. In a commercial setting, clustering refers to adjoining businesses that might install EVSE or multiple EVSE on one site.

3.4.3.3 CHARGING OPTIONS

According to the Society of Automotive Engineers SAE J1772TM-2011, "Standard for Electrical Connectors for Electric Vehicles," EVs can be charged via defined levels/rating of ac and dc power (see Table 3.5).

Table 3.5: SAE J1772TM-2011 Charging Configurations and Rating Terminology

Level	Rating	Estimated Charge Time
AC Level 1	120 V, 1.4 kW at 12 A	PHEV:7 hours BEV: 17 hours
	120 V, 1.9 kW at 16 A	
AC Level 2	240 V, 7.68 kW at 32 A	PHEV: 1.5 hours BEV: 3.5 hours
	240 V, 19.2 kW at 80 A	PHEV: 22 minutes BEV: 1.2 hours

Level	Rating	Estimated Charge Time
DC Level 1	200–450 V, up to 3 kW (80 A)	PHEV: 22 minutes BEV: 1.2 hours (Based on 20 kW)
DC Level 2	200–450 V, up to 90 kW (200 A)	PHEV: 10 minutes BEV: 20 minutes (Based on 45 kW)

Note: SAE J1772 is a North American standard for electrical connectors for EVs maintained by the SAE International. It covers the general physical, electrical, and communications protocols, and performance requirements for the EV conductive charge system and coupler.

3.4.3.4 ELECTRICAL ASSESSMENT OF SITE PRIOR TO INSTALLATION

Prior to implementation of an EVSE infrastructure, it is necessary to carry out a site assessment to evaluate the quantity and type of vehicles that will be charged, rate of turnover, electrical service availability, and physical space availability for charging. For this report, the focus is on electrical service assessment for a selected site. Figure 3.14 outlines the different steps for this assessment.

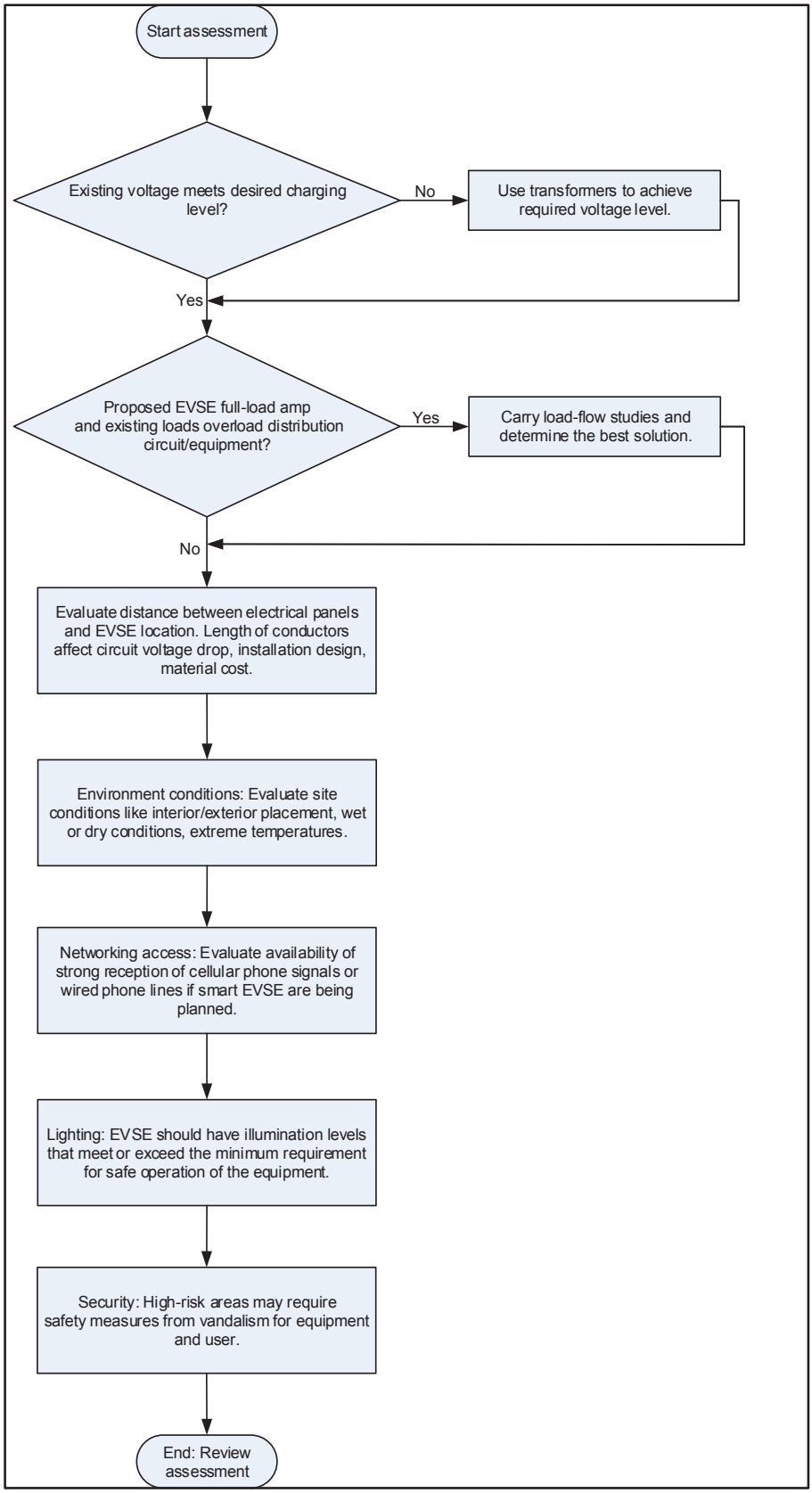


Figure 3.14: Electrical Assessment Prior to EVSE Installation

3.4.3.5 INDUSTRIAL SOLUTIONS AND PRODUCTS

EVSE are classified based on their networking capabilities as described in the following subsections.

3.4.3.5.1 BASIC EVSE

Basic EVSE, also referred to as a "Dumb" charger, communicates only with the vehicle. The handshake begins the charging process, and the process ends when the charge is complete or interrupted by the EVSE or uncoupling. A basic EVSE is simple to operate and maintain, and is generally less expensive than a smart EVSE. No other connection besides the electrical infrastructure is required. Models are available in both Level 1 and Level 2 charging, as explained in Table 3.5, and are manufactured for residential and commercial purposes.

3.4.3.5.2 SMART EVSE

The charger offers different levels of communication and networking with the end user, site host, utility grid, and the internet depending on the model type and manufacturer. It also offers the option of collecting a fee for the charging session and reporting capabilities.

Commonly available end-user features include accessibility through computers or smart phones, user verification, sales using credit cards, display of fee rates, rate of charging, cell phone or email notification of completed session, plug-out notification, internet location, availability, and reservation of EVSE with rates.

Commonly available reporting features include date, location, electricity use of each charging session, monthly reports, and fee totals. The site host can communicate with the smart EVSE to establish rates, determine usage, verify user identity, troubleshoot errors, and gather kWh consumption for analysis.

Vendor E EVSE provides 220 Vac and up to 30 A. It is designed according to the SAE J1772 requirements to meet all safety codes specified by UL and National Electric Code (NEC). The unit is engineered for commercial interior or exterior locations and comes in single, dual-wall, or pole-mounted versions. It is equipped with an automatic cable management system, which fully retracts and protects the 20-foot cable from weather-inflicted damages or vandalism.

The design is modular in nature and can be configured for simple on/off control, or provide the more sophisticated option of credit/debit and ID card processing. EVSE chargers are compatible with Open Charge Alliance charger networks. This ensures universal access to chargers without proprietary membership required. Table 3.6, documents the networking specifications.

Note: The Open Charge Alliance is an international standard for the development of charger networking based on an open versus proprietary architecture.

Table 3.6: Vendor E EVSE Networking Specification

Function	Specifications
Communications	Ethernet, cellular, and other radio communications, Wi-Fi
Networks	Web-based, LAN, WAN, cellular, Open Charge Point Protocol (OCPP)
Power monitoring	Integration with third-party monitoring systems
EV charge payment	EV charger kiosk or payment station integrated with current system

3.4.3.6 RELEVANT STANDARDS COMPLIANCE

The following are the standards to which the Vendor E EVSE units comply:

- UL 2231-1, Standard for Safety for Personnel Protection Systems for Electric Vehicle (EV) Supply Circuits: General Requirements.
- UL 2231-2, Standard for Safety for Personnel Protection Systems for Electric Vehicle (EV) Supply Circuits: Particular Requirements for Protection Devices for Use in Charging Systems.

3.4.4 Microgrid Solutions

A microgrid is a discrete energy system consisting of distributed energy sources (including demand management, storage, and generation) and loads capable of operating in parallel with, or independent from, the main power grid.

Microgrids can help reduce greenhouse gas emissions and lower stress on the transmission and distribution system by providing local, reliable, and affordable energy security for urban and rural communities while also providing solutions for commercial, industrial, and federal government consumers.

The primary driver for microgrids is the ability to deliver reliable, clean power to critical facilities during an extended period by islanding or operating independently of the utility grid. By controlling the demand and generation, dynamic stability, and optimizing control on a small scale, the microgrid can better manage the local power generation.

A microgrid connects to the grid at a PCC that maintains voltage at the same level as the main grid unless there is an issue on the grid. Microgrids can perform dynamic control over energy sources, enabling autonomous and automatic self-healing operations. Microgrids interoperate with existing power systems, information systems, and network infrastructure, and are capable of feeding power back to the larger grid during times of grid failure or power outages.

Microgrids are typically powered by renewable energy sources, diesel generator sets, fuel cells, and natural gas generators. However, PV and battery technologies are economically viable and can provide sustainable electricity and fuel growth for microgrid applications.

Some of the key features of the microgrid are:

- Operates in Island mode or Grid-connected mode.
- Connects to the main grid as a single controlled entity.
- Contains provisions to control the levels of power quality and reliability for end users.
- Accommodates total system energy requirements.
- Combines interconnected loads and co-located power generation sources.

Creating a successful microgrid is challenging. It involves understanding basic system requirements, accommodating unique operating characteristics of generation sources, managing and prioritizing power requirements, and seamlessly interfacing with the utility grid. A structured approach to microgrid implementation gives us the ability to support critical infrastructure, even in the event of a major power disruption. Extensive modeling and analysis must be performed to address the protection of the generation assets and subsystems.

Some technical challenges when implementing microgrids are:

- Management of large imbalance between load and generation.
- Use of different generation technologies.
- Presence of power electronic interfaces.
- Protection and safety for consumers and utility personnel.

Section 3 provides research and evaluation of products and technologies available for improved circuit performance and reliability. Products supported by a variety of vendors were considered for this analysis. This section aims at providing the groundwork for the options available for improved distribution circuits, to the reader. It also documents the basic features of the devices shortlisted and used in the demonstration of advanced circuits concepts through laboratory simulations.

4 SOLUTIONS EVALUATION

This section assesses emerging distribution circuit solutions and operation practices for maintaining reliable and uninterrupted energy delivery. It also highlights the baseline data which is used to understand the system characteristics under normal and abnormal conditions.

4.1 ADVANCED DISTRIBUTION AUTOMATION CONTROL

The Advanced Distribution Automation Control (ADAC) consists of a Distribution Automation Controller (DAC) that communicates with switch controls, recloser controls, feeder relays, and other IEDs.

The two main control objectives addressed by a ADAC are:

1. Automatic reconfiguration: Including or excluding a feeder from a scheme based on the evaluation of events by the ADAC.

2. Dynamic feeder optimization: Involves the continuous monitoring and control of tap-changing equipment and reactive power sources in the distribution system to improve voltage profiles and provide power factor correction.

The ADAC performs many functions, such as:

- Detecting open-phase and permanent fault conditions on the network and taking necessary steps to isolate the affected zone and restore power to the area.
- Detecting overload conditions in a system and taking necessary steps to mitigate effects by transferring load to adjacent feeders.
- Detecting loss-of-source and station events and taking necessary steps to isolate the event.
- Optimizing the operation of the distribution network by controlling voltage regulators and capacitors to improve the voltage profile and control power factor.
- Detecting the falling conductor.

The ADAC is implemented using a Real-Time Automation Controller (RTAC). The serial communications ports on the DAC are used to connect to reclosers, feeder relays, etc., to implement the required ADAC architecture. The DAC collects data and communicates with other IEDs using the DNP3 protocol. Each connected device is polled by the ADAC to ensure the device is healthy. The usual control commands sent by the ADAC include open and close commands, reset commands, and commands to change the settings group. More commands can be sent by the ADAC based on the way it is configured and the way it is connected to the external system.

Figure 4.1 shows a simple arrangement in which a ADAC is implemented using an automation controller that communicates with two relays via an RTU. The RTU is connected to serial communication Port 2 of the automation controller. These relays will, in turn, control the operation of circuit breakers in the system. Serial communications Port 1 is connected to a relay via radio. Serial communications Port 5 is used to communicate with SCADA.

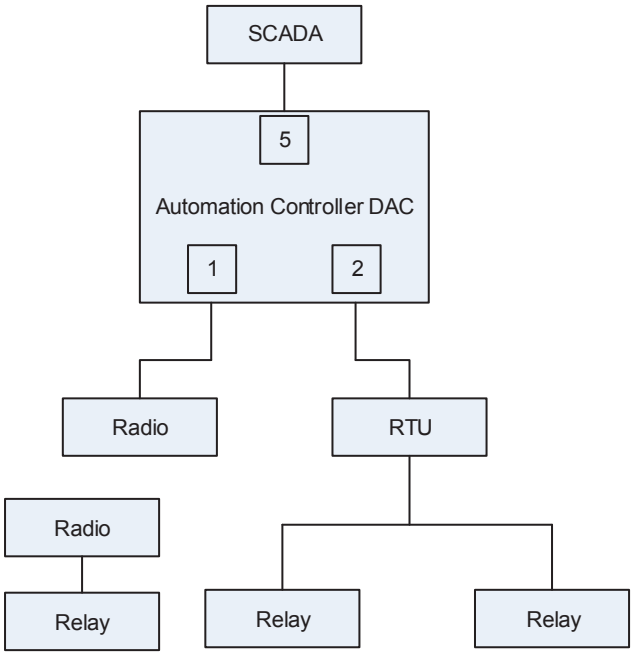


Figure 4.1: Example of ADAC Implementation

4.1.1 Automatic Reconfiguration

The ADAC is capable of automatic reconfiguration (AR) of radial and loop distribution feeders based on the required scheme of operation. A scheme is enabled or disabled by an operator. By default, all feeders are automatically included in a scheme. When a feeder is included in a scheme, it is considered armed. Once the feeder is armed, the ADAC will evaluate the events that may cause AR of this feeder.

The AR system is comprised of three separate sequences: feeder event, feeder return-to-normal, and scheme solution. A brief description of each of these sequences is provided in the following subsections.

4.1.1.1 FEEDER EVENT SEQUENCE

This scheme consists of four sequences: idle, update, analyze, and solution. The purpose of the Idle sequence is to verify whether a feeder is armed. When a feeder is included in a scheme, it is considered armed. When a feeder is not included in a scheme, it is not armed and is in the Idle sequence. The scheme will evaluate events on the feeder. When the feeder is armed and an event occurs on the feeder, the scheme detects this and the sequence transitions to the Update sequence. However, if the feeder is not armed, then the sequence remains in the Idle sequence.

In the Update sequence, an integrity poll of all connected devices is completed to ensure all the subsequent decisions are based on up-to-date information about the distribution network. The integrity poll also helps ensure each device is responsive. If a device is unresponsive, a communications alarm will be generated. The scheme will remain in the Update sequence until all the related devices have responded to the integrity poll. Once this condition is satisfied, the sequence transitions to the Analyze sequence.

The Analyze sequence determines whether a permanent fault, an open-phase condition, or an overload condition exists. This analysis is supervised to ensure the analysis is blocked when an abnormal condition exists in the system. Abnormal conditions are defined to include hot-line tags, nonreclose status, supervisory control disabled, or communications failures. Once the event has been confirmed, the system identifies the feeder sections to consider in the Solution sequence. The DAC will immediately open isolation switches once an event has been confirmed. Confirmed events are reported to the Solution sequence. In the case of a permanent fault, switches are opened to help isolate the fault. The DAC sends the open commands to the isolation switches to allow them to execute while the complete reconfiguration solution is being evaluated. This helps speed up the Reconfiguration sequence.

If the system determines that the event no longer exists, then the sequence returns to the Idle sequence. If the system cannot determine the nature of the event within the time limit for the Analyze sequence, the sequence returns to the Idle sequence. The Analyze sequence default time setting is 120 seconds.

4.1.1.2 FEEDER RETURN-TO-NORMAL SEQUENCE

This scheme consists of four sequences: idle, update, analyze, and reconfigure. The purpose of the Idle sequence is to verify whether a feeder is armed. If the feeder is armed, the sequence remains in the Idle mode until a return-to-normal (RTN) command is detected. The feeder will respond to an RTN command only when the feeder is armed, no abnormal conditions exist on any device in the actual or normal feeder configuration, and there are no supervisory blocks in the program. Once an RTN command is detected, the sequence transitions to the Update sequence.

In the Update sequence, an integrity poll of all connected devices is completed to ensure subsequent decisions are based on up-to-date information about the distribution network. The integrity poll also helps ensure each device is responsive. If a device is unresponsive, a communications alarm will be generated. The DAC will poll all devices in the present feeder configuration, adjacent feeder, all devices in the normal feeder configuration, and all devices in any feeder that is part of the normal configuration of the RTN feeder. The scheme will remain in the Update sequence until all related devices have responded to the integrity poll. Once this condition is satisfied, the sequence transitions to the Analyze sequence.

The Analyze sequence is executed when the system completes the Update sequence. The purpose of the Analyze sequence is to confirm the RTN command should be processed. It verifies there are no abnormal conditions present on any feeders that would be involved in the RTN operations and there are no other events detected in the scheme. Abnormal conditions are defined to include hot-line tags, nonreclose status, supervisory control disabled, or communications failures. If an abnormal condition is detected on a normal feeder configuration, the sequence will abort and return to the Idle sequence. If an RTN command is confirmed, the system identifies all normally-closed (NC) switches on the feeder that are presently open and all normally-open (NO) contacts that are presently closed. These switches make up the minimum set of switches that must be operated to return the feeder to the normal configuration.

4.1.1.3 SCHEME SOLUTION SEQUENCE

This scheme consists of three sequences: idle, analyze, and solution. This sequence is executed in response to confirmed events or confirmed RTN commands reported by the event and RTN sequences described previously.

In the Idle sequence, the system monitors for confirmed events or RTN commands reported by any feeder in the scheme. The system transitions to the Analyze sequence when one or more feeders report a confirmed event or RTN command and all feeders are in the Idle sequence.

The Analyze sequence evaluates scenarios that can be used to address outages caused by permanent faults or open-phase conditions, as well as overload conditions. The system identifies isolation, sectionalizing, and restoring switches for each confirmed event. Isolation switches are identified in the Analyze sequence and reported to the Solution sequence. Once an event has been confirmed, isolation switches must be opened to isolate un-faulted sections of the feeder from the faulted section. All closed switches downstream of a permanent fault, or open phase, are potential sectionalizing switches. Switches with a bypass or inhibit control input asserted are not considered as potential restoration switches. The system identifies all closed switching devices in the affected distribution network that can be used to sectionalize the load. The system also identifies all open switching devices that can be used to restore load. All open switches adjacent to an overloaded feeder are potential restoration switches.

Based on the settings in the DAC system, load transfer operations are selected between feeders that did not experience an event to increase the capacity available to restore stranded load sections. Each scenario is evaluated to determine its validity and relative suitability. Scenarios that involve unavailable sources, or result in permanently connecting multiple sources in parallel, are rejected. If load shedding is disabled, the system rejects all scenarios that result in load shedding.

The scenarios that are not immediately rejected are compared and the best solution is selected. The following criteria (listed in order) are used when evaluating scenarios:

1. Minimize the amount of overload above temporary limits.
2. Minimize the amount of load left de-energized.
3. Minimize the amount of overload above normal limits.
4. Minimize the maximum amount of load allowed to be restored by any one feeder that has voltage above a Level 1 threshold, but below a Level 2 threshold.
5. Minimize the total amount of load selected to be restored by feeders that have voltage above a Level 1 threshold, but below a Level 2 threshold.
6. Minimize switching operations.
7. Minimize the maximum amount of load to be restored by any one non-preferred source.
8. Minimize the total amount of load to be restored by non-preferred sources.
9. Bias the selection toward using the normal source to re-energize load if no overloads above normal limits will result.
10. Maximize the amount of margin below normal limits.

The system favors scenarios with the least number of switching operations. If a solution is found that re-energizes all the affected load and results in all components in the distribution system operating below their normal capacity limits, then the system selects this solution and does not evaluate more complex solutions that require more switching operations. If a complete solution is not found, the system will continue to evaluate more complex scenarios and select the best solution available. The best solution may be a partial restoration or even no action at all. The system will evaluate combinations of up to five sectionalizing switches. In the case of an RTN command, the RTN command sequence identifies the switches to open and close in the Analyze step and reports to the Solution sequence. These switches make up the minimum set of switches that must be operated to return the feeder to its normal configuration; however, other switches may need to be operated to ensure no part of the distribution system is left de-energized because of the RTN operations. If a complete solution cannot be found for an RTN operation, the system will abort and return to the Idle step.

Once the system has found and selected a solution that addresses the events that occurred in the system, the Reconfiguration step is executed. The solution consists of a list of switches to open and close. Isolation switches are identified during the Analyze step of the Event sequence, and these switches will be included in all scenarios evaluated by the DAC. The isolation switches will be opened immediately in the Reconfiguration step. The DAC sends the open command and waits for the status indications from each device to confirm the operations have been completed successfully.

The DAC will restore de-energized zones by closing the selected switch based on a simple set of rules. If the system is using the open-transition switching, the DAC will close the switch if the following conditions exist:

- There is no continuity from the switch to close to the switches to open that are unopened.
- There is only one source connected to one side of the switch to close.
- There is no switching operation in progress on either side of the switch to close.
- There is live voltage on at least one side of the switch to close.

If the system is set to use the closed-transition switching, the DAC will close the switch if the previous conditions exist or if the following conditions exist:

- There are two sources connected, one on each side of the switch to close, that have the same phase relationship and same SourceGroup setting.
- There are no switches to open connected on one side and one or no switches to open on the other side.

- There is no switching operation in progress on either side of the switch to close.
- There is live voltage on at least one side of the switch to close.

Once the solution has been executed, the system transitions to the Idle step. If the system cannot successfully execute the necessary actions, the sequence will fail because it exceeded the ReconfigurationTimeLimit setting. The system will return to the Idle step.

The DAC considers the effect of load when evaluating reconfiguration scenarios. The current flow is measured at various locations throughout the distribution system by IEDs, and this information is communicated to the DAC. The DAC memorizes the calculated load on all components in the distribution network. When an event is confirmed, the DAC will use the memorized load values to determine the suitability of reconfiguration scenarios.

4.1.1.4 PERMANENT FAULT CONDITION

The permanent fault detection is implemented in the "analyze" sequence of the scheme. It is based on fault current indications and lockout indications from switching devices on the feeder. The feeder is evaluated zone by zone, starting at the point farthest away from the source. Fault current indications help identify the switching devices that have experienced fault current. The fault indication farthest from the source will identify the affected zone. Once the faulted zone has been identified, the DAC will wait for a lockout indication before the fault is considered a permanent fault. This is done to allow the local reclosers and breakers to attempt to clear the fault using traditional automatic reclosing methods. If the local automatic reclosing is successful in clearing the fault, the lockout indication will not occur and the fault indications will reset. If the fault is permanent, an upstream breaker or recloser will clear the fault and go to its lockout state. If the coordination of the protection devices is successful, the device closest to the fault will clear the fault and go to lockout. This may not be the case if there is miscoordination of protection devices. In some miscoordination cases, multiple protection devices will go to lockout. To accurately detect this situation, the DAC will force an update poll to all devices on the event feeder when the first lockout indication is detected. Once the DAC has determined that a zone is affected by a permanent fault, the Event sequence will initiate the Solution sequence to find and execute an acceptable solution.

4.1.1.5 OPEN-PHASE CONDITION

Open-phase detection is implemented in the Event sequence. Open-phase detection is based on loss-of-voltage indications from switching devices on the feeder. Before the system detects an open phase, it must first see a healthy voltage level for 30 seconds. This helps to avoid erroneous open-phase detections when lines are first energized. Additionally, voltage indications must show a possible open-phase condition for a period before the Event sequence will initiate. The EventDetectTime setting is assigned during the initial setup of the DAC. The default is 10 seconds, which helps to avoid erroneous open-phase detections during switching operations. The loss of voltage on the feeder could be caused by a fault upstream of the distribution network. The automatic reclosing schemes upstream of the distribution network may be in place to attempt to clear such a fault. Once an open-phase condition has been identified, the distribution network is evaluated to determine if there are any zones downstream of the broken jumper that could be restored by a three-phase source. If an alternative feed is available to energize these zones, the DAC will open the switch downstream of the affected zone to de-energize the downstream zones and prepare them to be restored from the alternative feed. If no alternative feed is available and single-phasing of loads is permissible, the DAC will not open the switch downstream of the affected zone. Instead, the DAC will allow the downstream load to remain energized by one or two phases.

4.1.1.6 OVERLOAD CONDITION

The DAC detects overloads on a feeder if the scheme is enabled, overload detection is enabled, the feeder is armed, no abnormal conditions exist on the feeder, and there is no fault or open-phase conditions on the feeder. Measured currents are filtered by a simple low-pass filter that smooths out step changes and jitters before they are used in the overload detection logic. The overload detection logic uses the maximum of the three filtered phase currents. The logic compares the maximum current to the normal capacity and the temporary capacity limits for the associated equipment. If the maximum current is above the normal capacity, then a Level 1 overload can be detected. If the maximum current is above the temporary capacity, then a Level 2 overload can be detected. Overloads can be detected only on equipment that is neither bypassed nor out of service. The DAC will assert a warning alarm for any

feeder that has a detected overload. This alarm can be passed to a control center to inform an operator of the situation. The Event sequence does not need to be initiated until the confirmation time has nearly expired. The overload is confirmed in the Analyze step of the Event sequence if it is still present after the confirmation time has expired. Once an overload condition has been identified, the distribution network is evaluated to determine if there are alternative feeds available that can be used to alleviate the overload. When a Level 2 overload (i.e., above temporary limits) is confirmed and a load transfer solution is not available, the DAC can perform a load shed to alleviate the overload. The DAC will attempt a load shed only when a Level 2 overload has been present for a period equal to the ShedTime setting.

4.1.2 Dynamic Feeder Optimization

Dynamic feeder optimization (DFO) is the continuous monitoring and discrete control of tap-changing equipment and reactive power sources in the distribution system to improve voltage profiles and power factors in support of power system objectives such as:

- Energy conservation
- Peak power reduction
- Power factor correction or control
- Loss reduction
- Voltage profile optimization
- Reactive power support for transmission

These objectives are interrelated and depend on voltage levels and reactive power flows on the involved feeders.

The DFO system supports the power system objectives by controlling the voltage and reactive power flow on the involved feeders and station bus. The DFO system controls tap-changing devices such as load tap changers (LTCs), feeder regulators, and line regulators. It can also control reactive power sources, which can include bus capacitor banks and line capacitor banks. The capacitor control provides coarse voltage control and power factor control while the regulator tap control provides fine voltage control.

4.1.2.1 DISTRIBUTION UNIT CONTROL

A distribution unit is a collection of a station transformer, a station bus, and the connected feeders. The DFO system provides integrated critical limits, control functions, and optimization at all three levels of the distribution unit.

The critical limits define a range of acceptable voltage and power factors, and the DFO system acts to correct any excursions beyond these critical limits. The control functions include user-defined set points and dead-band values, which define a narrow range of desired voltage, power factor, and reactive power. The DFO system acts to correct excursions beyond these control limits. Optimization functions work to gain improvements in the overall performance of the distribution unit. The priority of each function varies. The critical limits are processed with a higher priority than control functions, and control functions are processed with a higher priority than optimization functions.

The DFO system provides reactive power control or power factor control at the high side of the station transformer. When the reactive power control is enabled, the DFO system acts to control the reactive power to a user-specified reactive power set point within a reactive power dead band. When power factor control is enabled, the DFO system acts to control the power factor to a user-specified power factor set point within a reactive power dead band.

The DFO system provides critical voltage limits and power factor limits, as well as power factor control at the station bus. When any control functions in the distribution unit are enabled, the DFO system acts to drive the bus voltage and power factor within user-specified high and low limits. The DFO system also avoids operations that are predicted to drive the bus voltage or power factor outside of the high or low limits. The critical limits at the station bus have a higher priority than control and optimization functions at all levels of the distribution unit. When the power factor control is enabled on the bus, the DFO system acts to control the power factor to a user-specified power factor set point within a reactive power dead band.

The DFO system provides voltage limits and power factor limits, as well as power factor control and minimum voltage control for each feeder. When the feeder functions are enabled, the DFO system acts to drive all measured voltages on the feeder within user-specified high- and low-voltage limits. Additionally, the DFO system acts to drive the power factor at the head of the feeder within high- and low-power factor limits. The DFO system also avoids operations that are predicted to drive voltage or power factor outside of the high or low limits. The DFO system acts to optimize voltage profile and reactive power flow on the feeder.

In some cases, the critical limits and the control and optimization objectives are interrelated and can be in opposition. Therefore, the objectives are prioritized to resolve any potential conflicts. The following list presents the priority of the objectives, starting with the highest priority:

1. Critical voltage limits on feeders
2. Critical power factor limits on feeders
3. Critical voltage limits on bus
4. Critical power factor limits on bus
5. Minimum voltage set point on feeders
6. Power factor or reactive power control at station transformer high side
7. Power factor control bus
8. Voltage and reactive power optimization on feeders

4.1.2.2 DFO SEQUENCE OF OPERATION

The DFO sequence of operation consists of five steps: ready, plan, select, execute, and verify.

In the ready step, the system monitors for DFO requests. A DFO request can be initiated by a critical excursion, control excursion, mode change, set-point change, preconfigured cyclic interval, or a re-evaluation request generated in the Verify step. When the DFO is enabled, a control excursion generates a DFO request when a control limit is violated in the distribution unit. A mode change at any level in the distribution unit will generate a DFO request. A change in the set point for any enabled control function in the distribution unit also generates a DFO request.

In the plan step, the system evaluates a series of possible control scenarios. Each scenario can have multiple control actions. Only the control actions that are presently available to the DFO system are considered. The maximum number of control actions to consider in a scenario is specified by the user. The voltage and reactive power impact of each scenario is predicted, and scenarios are evaluated based on the priorities of objectives previously listed. The plan may be to do nothing, do one control action, or do multiple control actions. If the plan is to do nothing, then the sequence returns to the ready step. Otherwise, the sequence progresses to the select step.

In the select step, the system evaluates each control action in the plan to determine which control action to execute first. If the plan includes control actions, then the Select step will identify one control action in the plan. The voltage and reactive power impact of each control action in the plan is predicted, and each control action is evaluated based on the priorities of objectives previously listed. Once a control action is selected, the sequence progresses to the Execute step.

In the execute step, the DFO system issues controls and monitors device feedback and system response to perform and validate the selected control action. Once the control action is executed, the sequence progresses to the Verify step.

In the verify step, the DFO system evaluates the distribution unit to determine the effectiveness of the preceding control action. Once the verification is complete, the sequence returns to the Ready step and asserts a DFO request to re-evaluate the distribution unit to update the plan for possible subsequent control actions.

4.1.2.3 AVAILABILITY OF CONTROL ACTIONS

Several conditions affect the availability of a control action to the DFO system:

- If the DFO functions on a feeder are disabled, all devices on the feeder are unavailable.
- If the DFO functions on a device are disabled, the device is unavailable.
- If control of a device is inhibited, the device is unavailable.
- If a communications failure is detected for a device, all control actions associated with the device are unavailable.
- If a capacitor has been switched an excessive number of times in the same day, the capacitor is marked unavailable for the remainder of the day (until midnight).
- If the last attempted operation of a capacitor was bad, the capacitor is marked unavailable for a user-specified period or until the capacitor function block receives a Reset command.
- If the last attempted operation of a regulator was unsuccessful, the associated set of three regulators is marked unavailable for a user-specified period or until the regulator function block receives a Reset command.
- If a regulator is at the high tap limit, additional "raise" tap operations are unavailable. Similarly, if a regulator is at the low tap limit, additional "lower" tap operations are unavailable.

4.1.2.4 REGULATOR RESPONSE

When the DFO system operates a regulator, the system monitors the regulator tap position and the regulated voltage to verify the response to the control action. The success of the operation is determined by the response of the regulated voltage. If the regulated voltage is greater than a user-defined percentage of the expected response, the operation is successful. If the regulated voltage does not reach the expected response within the user-defined response time, the operation is not successful and a warning alarm is issued. If the last three attempted operations of a regulator are unsuccessful, a failure alarm is asserted and the associated set of three regulators is marked unavailable for a user-specified period. When this time expires, the failure alarm will clear and the regulator will become available to the DFO system.

4.1.2.5 CAPACITOR RESPONSE

When the DFO system operates a capacitor, the system monitors the capacitor switch status and the feeder VAR response to verify the response to the control action. A feedback trouble alarm is generated if the expected switch status is not received within a user-specified response time. This alarm is only a warning and does not determine the success of the operation. Two user-specified percentages and a user-specified response time are used to determine the success of the operation. One user-specified percentage defines the percent of the expected VAR response, above which is considered a good response. The other percentage defines the percent of expected VAR response, below which is considered a bad response. If the capacitor has three consecutive partial operations, the operation is also considered to be a bad operation. If the last attempted operation of a capacitor was bad, then a failure alarm is asserted and the capacitor is marked unavailable for a user-specified period. Once this period expires, the failure alarm will clear and the capacitor will become available to the DFO system.

4.1.2.6 DFO AND DEVICE CONTROL MODES

The DFO system is an automatic system that issues remote control operations to end devices. Many of the end devices that participate in the DFO system also have local automatic control capabilities. When the DFO functions on a feeder are disabled, the DFO system sends a command to the end device informing it that the remote automatic system is no longer controlling the end device. The local device control can use this indication to enable local automatic control functions. The DFO system can be configured to send a periodic Watchdog command to the end devices. This Watchdog pulse can be monitored by the end device controller. If the pulse is not received for an extended period, the local device control can be set to enable local automatic control functions. Typically, device controllers will have a Remote or Local mode and an Automatic or Manual mode. In the Remote mode, the controller accepts commands from remote systems, such as a SCADA master or the DFO system. In the Local mode, the controller will not accept commands from these remote systems.

4.1.2.7 CAPACITOR CALIBRATION

The expected voltage change on a feeder in response to a capacitor switching depends on the size of the capacitor and its location on the feeder. The size of the capacitor is specified by the user; however, the location of the capacitor is not. The user provides only the relative positions of equipment on the feeder. The expected voltage response at a point on the feeder is dependent on the impedance between that point and the source. The DFO system does not require the user to provide detailed impedance data during system setup. Instead, a calibration procedure is used to estimate the reactance between each voltage measurement point on the feeder to the source.

The following calibration procedures should be performed when the feeder load is stable:

Step 1. User opens capacitor switch.

Step 2. User disables the DFO system.

Step 3. User resets the capacitor warning and failure alarms.

Step 4. User asserts the calibrate input on the capacitor function block.

Step 5. DFO system closes the capacitor switch.

Step 6. DFO system monitors the power system response.

Step 7. DFO system opens the capacitor switch.

If the capacitor operation is not successful, the DFO system asserts the capacitor fail alarm.

If the capacitor operation is successful, the DFO system asserts the capacitor calibration completed indication.

The calibrate input on the capacitor function block is deasserted by the user.

4.2 PMU-ENABLED SOLUTIONS

PMUs have been used in numerous applications such as testing, commissioning, disturbance recording, and wide-area protection and control to improve power system operations. With PMUs available in protective relays, meters and recorders, it has become easier to implement synchrophasors in diverse applications.

PMUs provide a way to analyze both small and large disturbances in a power system. PMUs provide the following three basic elements unlike the traditional measurement methods:

- Data stream rates of 1 to 60 messages per second.
- Synchronized measurements from all locations using high-accuracy timing.
- High-accuracy measurements of voltage, current, status, and alarms.

Applications for PMUs are listed in the following subsections.

4.2.1 Islanding Detection

Islanding is a condition in which a distributed generator continues to power a location even though electrical grid power from the electric utility is no longer present. The expansion of generation into the distribution system has had a specific impact on the ability to detect islanding in a portion of the system. If a section of the distribution system is supported by a single feeder with a single circuit breaker, it is a simple process to detect when the breaker is opened and then it signals the generator to disconnect from the system. However, this is not always the case. Consider a distribution network that is configured with both radial and loop systems and interconnected with multiple breakers to provide reliable service to critical loads. In such a case, it would be difficult to determine which combination of open breakers and switchgear would cause a generator on the distribution network to be islanded with nearby connected loads.

Unintentional islanding is not a desirable operating condition. If power lines remain energized when the utility interconnection is lost, this poses a risk to utility workers in the field. Islanding also causes voltage and frequency to fall outside acceptable levels, which results in power quality issues.

Wide-area communications, combined with PMU capability in relays, make it possible to detect islanding at any location (that uses distributed generation) for no extra cost. IEEE 1547 requires distributed generation to disconnect for an islanding condition in 2 seconds or less, regardless of the load generation balance. Traditional islanding detection schemes use frequency and voltage measurements at the generator. A modern system based on PMU measurements at both the generator and remote station provides better sensitivity and speed to meet the requirements of IEEE 1547. PMUs can also help by improving generator control during islanding when the generator control is required to switch from power regulating to frequency regulating before the machine goes unstable.

4.2.2 Phase Identification

Improper phase identification causes problems with load balance, fault location and targeting, metering, and other reliability issues. With service quality becoming more important to engineer and public service commissions, phase identification has become even more significant. As computerized fault location becomes more practical, and with increased inputs from multiple IEDs, it becomes both important and perhaps easier to provide phase identification. Because of the increased availability of microprocessor-based smart controls and communications, more single-phase control and monitoring are being used. Moreover, modern recloser controls offer adaptive multiphase or single-phase tripping. Proper phase commissioning is essential for correct operation of these reclosers. Correct phase identification is also important for applications involving microprocessor-based regulators and capacitor bank controls to ensure the volt/VAR optimization scheme is operating with the correct data.

With distributed IEDs, the opportunity exists to apply distributed PMUs for phase identification. Using a synchrophasor enabled meter, it is simple to either manually or automatically identify phases.

4.2.3 Load Characterization

PMUs help provide a better understanding of distribution loads and how they are impacted by changing grid conditions. PMUs can collect data from voltage regulator controls that provide timed events with power, voltage, current, frequency, and changes in power and reactive power voltage steps. Collecting these data for individual feeders will help identify potential feeders where conservation voltage reduction (CVR) can be implemented. CVR is a technique for improving the efficiency of the electrical grid by optimizing voltage of the feeder lines that run from the substation to the customer. CVR lowers the voltage at which power is delivered and yields, on average, a 1 percent energy savings for each 1 percent in voltage reduction. The high-resolution data collected by PMUs from the regulator control can help calculate the change in power that occurs coincident with the tap changes. With multiple PMUs providing information from different feeders, the additional information will help improve the load characterization of the system to assess the impact of CVR. In this way, PMUs can help in determining necessary actions for maintaining reliability of the distribution system when there are varying loads.

4.2.4 System Monitoring

PMUs strategically placed at locations in the secondary system can help provide more insight about the system and enable detection of system conditions and local voltage transients. PMUs connected to the distribution system can detect system phase shifts, frequency, and oscillations. PMUs connected closer to the load in a distribution system can provide a better understanding of the dynamics of the connected load.

4.3 HIGH-IMPEDANCE FAULT DETECTION

High-impedance faults (HIFs) are short-circuit faults with fault currents smaller than what a traditional overcurrent protective relay can detect. Common causes for an HIF are tree branches touching a phase conductor, failing or dirty insulators that cause flashovers between a phase conductor and the ground, or a downed conductor. Almost all HIFs involve the ground directly or indirectly.

HIFs are rich in harmonic and nonharmonic content. The harmonic content results from a fault that involves an arcing process. Ungrounded systems have no intentional grounding. The ground-fault current is determined by fault resistance and stray capacitances of distribution transformers. These systems offer minimum equipment thermal stress and self-extinction of ground faults when the capacitive fault current is small. However, in a large grounded system (solidly grounded or low-impedance grounded), the fault is less likely to self-extinguish because the stray capacitance can support enough fault current. Solidly grounded systems limit the risk of overvoltages during ground faults and reduce equipment cost; however, these large current grounding schemes produce large standing unbalance that flows in the same path as the ground-fault current. This makes it difficult to detect HIFs.

Staged downed conductor tests have indicated that downed conductor HIFs generate small fault currents. The HIF current of multigrounded systems depends on the surface types upon which a conductor falls. Fault current varies from 0 to less than 100 A. These faults are masked by load unbalances in solidly grounded distribution systems. Traditional ground overcurrent elements cannot detect these faults. Detection algorithms that use current characteristics other than magnitude must be used for this purpose.

The block diagram of the HIF detection method is shown in Figure 4.2.

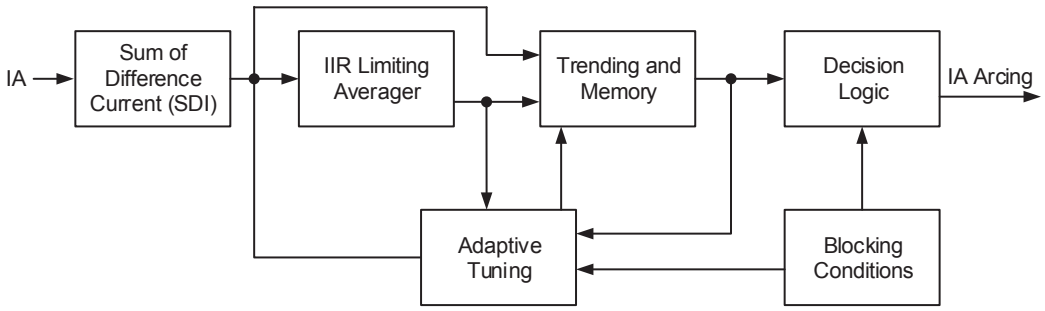


Figure 4.2: Block Diagram of HIF Detection (Nonharmonic)

The HIF detection method incorporates the following key elements:

- A quantity that reveals the HIF signatures without being affected by loads and other system operation conditions.
- A running average of the quantity that provides a stable prefault reference.
- An adaptive tuning feature that can tune out feeder ambient noise conditions.
- Logic to differentiate between an HIF condition and other system conditions such as switching operations and noisy loads.

The first function block calculates a signal quantity upon which the algorithm bases its HIF detection. This quantity is called the sum of difference current (SDI). The Infinite Impulse Response (IIR) limiting averager then establishes

a stable reference for the SDI. The trending and memory block compares the present SDI to the SDI average. It memorizes the time and ratio of the present SDI if the present SDI is greater than a set threshold for the SDI average. The decision logic uses the results from the trending and memory block to determine the existence of an HIF on the processed phase. The adaptive tuning block monitors feeder background noise during normal operating conditions and establishes a comparison threshold for the trending and memory block. This threshold is also used by the IIR limiting averager to prevent the averager input magnitude from becoming too large.

HIF detection depends on the system grounding scheme. For small-current grounding, fault detection is relatively easier because the standing unbalance comes only from line construction asymmetry and phase CT errors. However, this unbalance is normally small and modern microprocessor relays can be sensitive enough to detect most HIFs. For large current grounded systems, the detection of HIFs is more challenging because there is high standing unbalance because of single loads. Because the HIF current is less than the standing unbalance, quantities other than the fundamental value or rms value of current will be used for detection purposes. Harmonic content is usually used for HIF detection.

HIF detection technology is available in relays supported by Vendor L. As previously mentioned, these devices use both nonharmonic and odd-harmonic content for HIF detection.

4.4 FAULT LOCATION

The ability to locate and clear line faults is imperative to reduce the frequency and duration of power outages. Utilities often use the short-circuit analysis results of their distribution feeder and the measured fault current to identify possible fault locations in a feeder. This method provides good results if the fault resistance is negligible and the short-circuit analysis uses the actual system voltage during the fault.

Vendor L supports digital relays with built-in fault location capabilities. These relays accurately locate all fault types by measuring and using the phase-to-ground voltages and currents in each phase. The phasor quantities are filtered to ensure that transients do not affect the measurements. These measurements are used for determining the fault type. Knowledge of the fault type is important for accurate single-end fault locating.

The relays use the measured voltage and current in each phase to calculate the impedance. The distance to the fault is then determined using the details of the line programmed in the relay.

Fault location on distribution feeders is difficult. Traditional impedance-based fault location methods assume all feeder sections have the same impedance characteristics. However, this is not usually the case with distribution feeders that may contain sections with different conductor types and different tower configurations.

Protective relay supported by Vendor L provide differential protection and distance protection, and include the traveling-wave fault location (TWFL) feature. This relay is mainly used for transmission line applications. However, it addresses some of the challenges faced by fault location applications on distribution feeders.

The relay monitors the protected line. When a fault occurs on the line, the transient generated by the fault moves toward the relay location. The TWFL algorithm relies on the transient wave received by the relay. Once the transient is received by the relay, it is time-stamped using a high-accuracy IRIG-B signal and the information regarding the time stamp is communicated to the relay at the far terminal using a differential communications channel. Using the length of the line, the propagation velocity, and the secondary cable length of the CT, the relay can calculate the location of the fault.

The relay uses several methods for determining fault location, including:

- Traveling wave (TW)
- Multiended (ME)
- Single ended (SE)

As previously mentioned, the TWFL algorithm uses the differential communications channel to communicate information to the relay at the far terminal. For this method to be successful, a healthy differential communications channel is required.

The double-ended fault location is an impedance-based method that is used when a differential communications channel is present. Information regarding the total current is available to relays at each location and this quantity is used as a polarizing quantity to achieve results that are more accurate than the single-ended method.

The fault location method does not make use of the differential communications channel. This is an impedance-based method that uses a modified Takagi algorithm to calculate the distance to the fault using the voltage and current at the relay location.

The presence of different tower configurations, different conductor size and spacing, conductor transposition, and series capacitance should not prevent the use of traveling waves for fault location. However, the variation in electrical characteristics across the protected line could impact the propagation velocity and could lead to an error of 1 to 2 percent in the fault location distance estimation. This opens the possibility to use TWFL for fault location on distribution feeders; however, further testing is required before this option can be implemented.

4.5 DYNAMIC LINE RATING IN DISTRIBUTION CIRCUITS

Typically, the ampacity of distribution lines is set at conservative values for various seasons based on a set of assumptions such as ambient temperature, wind speed, and solar heating input. These conservative thresholds often limit the operation efficiency of the grid.

Dynamic rating is the ability to calculate the distribution line ratings based on environmental conditions. The ampacity of a conductor, in addition to the conductor type and material, heavily depends on the temperature of the conductor. One way to implement dynamic rating is to use line thermal protection.

Line thermal protection consists of monitoring the conductor temperature and generating a trip signal when the temperature becomes greater than the maximum allowed temperature for the conductor. Lines that are thermally overloaded will develop excessive sags. This can, in turn, increase the risks of faults from contact with nearby objects.

Line thermal protection is implemented by using control equations to emulate first-order heat-balance equations. The heat input to a conductor is based mainly on the heat dissipated in the conductor because of resistance, solar heat gain, and ambient temperature. Heat losses are mainly because of convection and radiation losses. An illustration of this is shown in Figure 4.3. These principles and procedures have been standardized in IEEE 738-1993, IEEE Standard for Calculating the Current-Temperature of Bare Overhead Conductors.

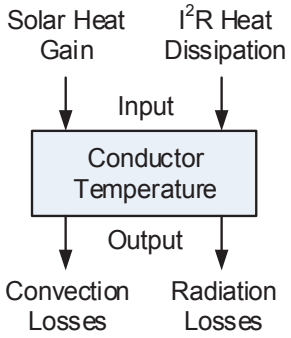


Figure 4.3: Balance Equation Schematic

The equations relate the difference between heat input and output to the heat thermal capacity of the conductor. The heat power input is calculated using the position of the conductor, day of the year, and time of the day. The protection provides an option for RTD measurements for ambient temperature. Once the equations have been programmed into the relay, the protection logic is run iteratively to calculate the conductor temperature. The logic can be programmed to alarm at a low temperature threshold and trip at a high temperature.

Research shows that line thermal protection schemes have been successfully implemented for transmission lines using Vendor L relays. However, differences in conductor types and different tower configurations may cause errors

in the thermal equation calculations. Before implementing this scheme to distribution circuits, through testing should be carried out.

4.6 BASELINE DATA

Baseline data was collected to understand the existing system characteristics for the selected distribution circuits. This data was used as reference for analysis during RTDS test runs.

1. The following list of attributes was prepared as reference for collecting baseline data. Field data was collected depending on its availability:

    a. Voltage profile

    b. Frequency

    c. Harmonics

    d. Power factor

    e. Load profile

2. Appendix B Load Profile includes the load profile data acquired over a period of 24 hours for the three selected circuits.

3. The following standards for voltage, frequency, harmonics distortion limits, and power quality indices were referred to for analysis:

    a. ANSI C84.1-2006 American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60 Hertz).

    b. IEEE 1366-2012, IEEE Guide for Electric Power Distribution Reliability Indices.

    c. IEEE 1159-2009, IEEE Recommended Practice for Monitoring Electric Power Quality.

    d. IEEE 1547-2003, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.

5 RTDS MODELING

This section describes the process involved in the test circuit data collection and conversion into RSCAD which is used for analysis and testing. It also describes the modelling assumptions made during conversion. The process followed for modelling of the RTDS load control, based on the load data available for the selected test circuits is described.

5.1 SYNERGI TO RTDS CONVERSION PROCESS

Three diverse types of distribution circuits were considered for this project, namely coastal-residential, urban, and desert-rural. The circuits were originally in the Synergi Electric software format. The original circuits were analyzed and simplified based on the requirements and scope of this project. The following assumptions or simplifications were made:

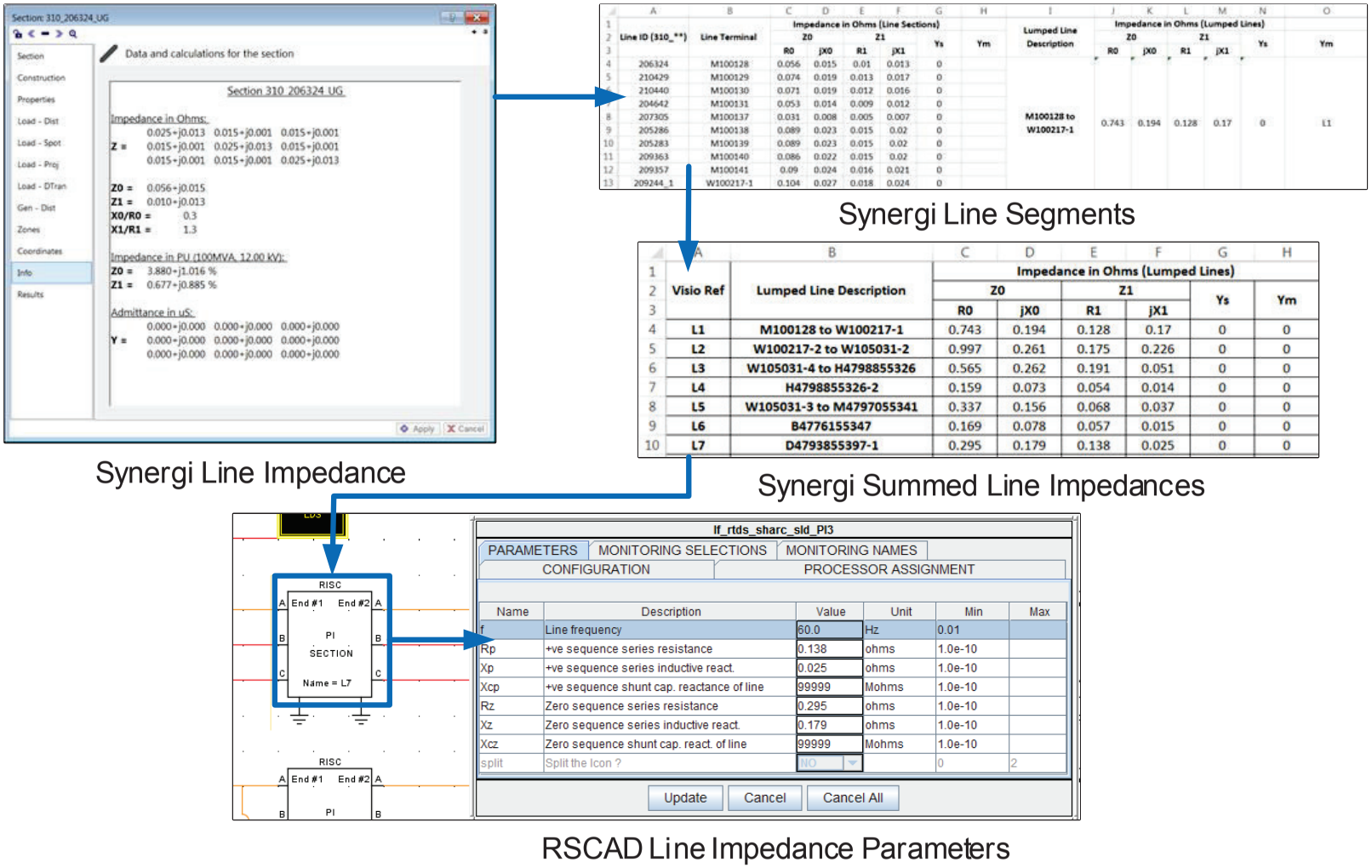
- The Synergi Electric model was converted into a 12 kV equivalent model, with the single and three phase loads and line impedances lumped.
- Fuses and switches were ignored in the 12 kV equivalent.
- The DER source was modeled as a scalable battery system.
- Harmonic sources or loads were disregarded in the 12 kV equivalent.

The simplified circuit one line were drafted using a visualization software and further translated to RSCAD, version 5.001. Refer to Appendix A for more details on the simplified circuit one line drawings. Each circuit was modeled on a single RTDS rack with a time step of less than 150 milliseconds. Field load profile data were provided by SDG&E for each circuit. The RTDS model was validated based on the field data and compared to the Synergi model for accuracy. This section explains the conversion of the Synergi data to RSCAD.

5.1.1 Line Impedance Conversion – Synergi to RSCAD

The Synergi model distribution lines were divided into multiple sections. Each section contained its own identifier and set of impedances that are represented in the upper left of Figure 5.1. The line identifier and impedances are recorded in a spreadsheet in the upper right of Figure 5.1. The distribution line segments from one intersection to the next are given a name using their respective terminal identifier from Synergi model. The impedances are summed together in Figure 5.1 (labeled “Synergi Summed Line Impedances” in the center of the figure) and given a new name (L1, L2, L3, etc.). L1 starts from the substation and turns into L2, L3, and so on, down the distribution lines. The lumped line impedances are entered in the RSCAD transmission line impedance block (PI section), as shown in the lower section of Figure 5.1. This is the last step in translating the line impedances from the Synergi model to RSCAD.

5.1.1.1 LINE IMPEDANCE CONVERSION



Visio Ref	Lumped Line Description	Z0 R0	Z0 jX0	Z1 R1	Z1 jX1	Ys	Ym
L1	M100128 to W100217-1	0.743	0.194	0.128	0.17	0	0
L2	W100217-2 to W105031-2	0.997	0.261	0.175	0.226	0	0
L3	W105031-4 to H4798855326	0.565	0.262	0.191	0.051	0	0
L4	H4798855326-2	0.159	0.073	0.054	0.014	0	0
L5	W105031-3 to M4797055341	0.337	0.156	0.068	0.037	0	0
L6	B4776155347	0.169	0.078	0.057	0.015	0	0
L7	D4793855397-1	0.295	0.179	0.138	0.025	0	0

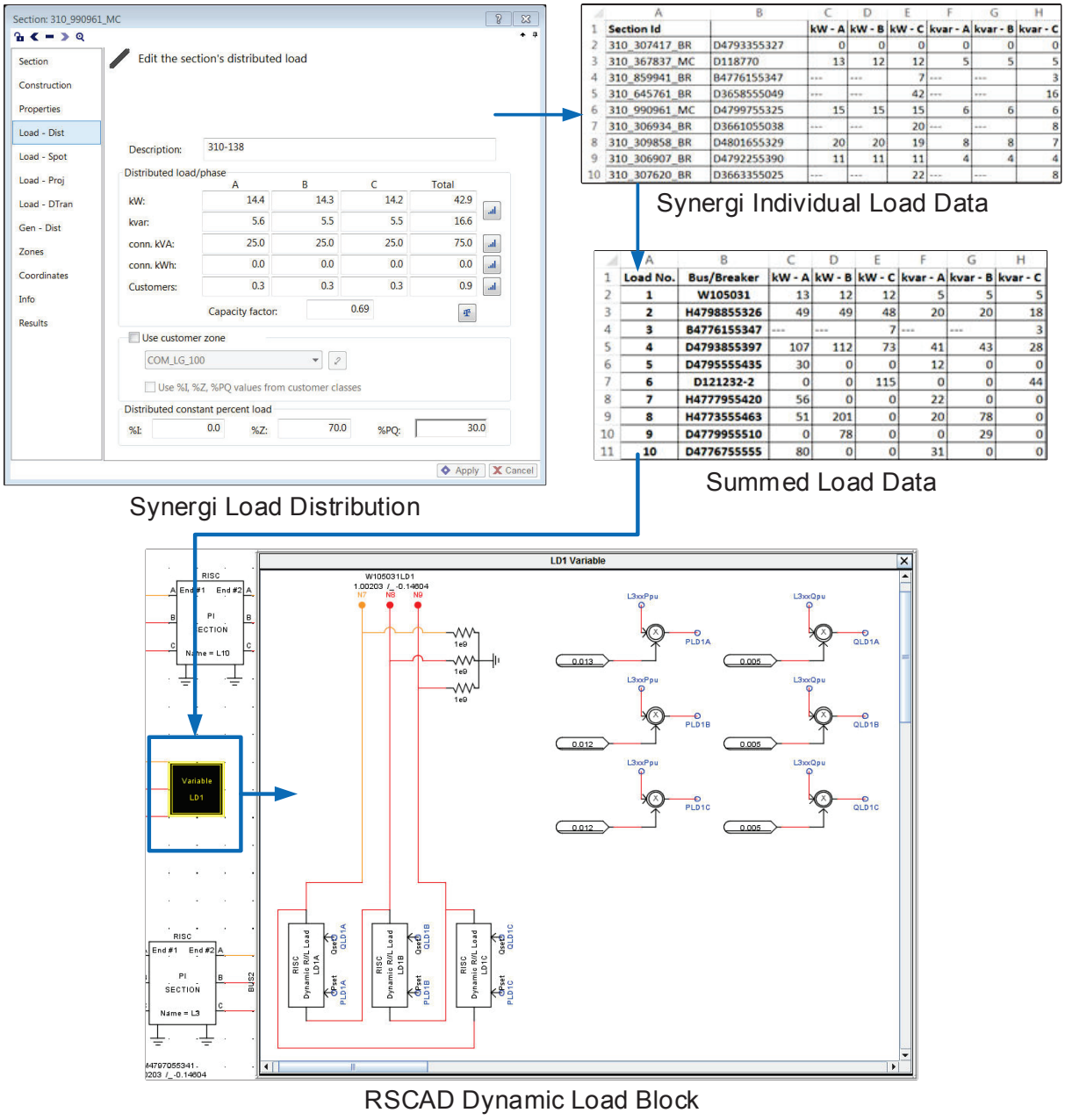
Name	Description	Value	Unit	Min	Max
f	Line frequency	60.0	Hz	0.01	
Rp	+ve sequence series resistance	0.138	ohms	1.0e-10	
Xp	+ve sequence series inductive react.	0.025	ohms	1.0e-10	
Xcp	+ve sequence shunt cap. reactance of line	99999	Mohms	1.0e-10	
Rz	Zero sequence series resistance	0.295	ohms	1.0e-10	
Xz	Zero sequence series inductive react.	0.179	ohms	1.0e-10	
Xcz	Zero sequence shunt cap. react. of line	99999	Mohms	1.0e-10	
split	Split the Icon ?	NO		0	2

Figure 5.1: Line Impedance Conversion From Synergi to RSCAD

5.1.2 Load Impedance Conversion – Synergi to RSCAD

Single-phase and three-phase loads are represented in Synergi for the test circuits. To model these loads in RSCAD, a similar process as that of the distribution line impedances was followed. The Synergi load distribution settings (upper left of Figure 5.2) were taken and recorded into a spreadsheet (upper right of Figure 5.2). This was done to each load in the system. The recorded loads were given an identifier using the designated name from Synergi and are shown in the upper right of Figure 5.2. Recorded with each load identifier are the real and reactive power values. Loads were then summed to an equivalent impedance per bus to reduce the circuit and simplify the representation that is labeled "Summed Load Data" in Figure 5.2. These data were entered in the RSCAD dynamic load block (lower part of Figure 5.2) for RTDS testing.

5.1.2.1 LOAD IMPEDANCE CONVERSION



Section Id		kW - A	kW - B	kW - C	kvar - A	kvar - B	kvar - C
310_307417_BR	D4793355327	0	0	0	0	0	0
310_367837_MC	D118770	13	12	12	5	5	5
310_859941_BR	B4776155347	---	---	7	---	---	3
310_645761_BR	D3658555049	---	---	42	---	---	16
310_990961_MC	D4799755325	15	15	15	6	6	6
310_306934_BR	D3661055038	---	---	20	---	---	8
310_309858_BR	D4801655329	20	20	19	8	8	7
310_306907_BR	D4792255390	11	11	11	4	4	4
310_307620_BR	D3663355025	---	---	22	---	---	8

Load No.	Bus/Breaker	kW - A	kW - B	kW - C	kvar - A	kvar - B	kvar - C
1	W105031	13	12	12	5	5	5
2	H4798855326	49	49	48	20	20	18
3	B4776155347	---	---	7	---	---	3
4	D4793855397	107	112	73	41	43	28
5	D4795555435	30	0	0	12	0	0
6	D121232-2	0	0	115	0	0	44
7	H4777955420	56	0	0	22	0	0
8	H4773555463	51	201	0	20	78	0
9	D4779955510	0	78	0	0	29	0
10	D4776755555	80	0	0	31	0	0

Figure 5.2: Load Impedance Conversion From Synergi to RSCAD

5.2 RTDS CONTROLLER

5.2.1 RTDS Load Impedance Controller

The RTDS can vary the load dynamically via the RunTime view or by running automated load schedulers. SDG&E provided a 24-hour load profile for the three test circuits, namely coastal-residential, urban, and desert-rural. Figure 5.3 shows the load profile of the coastal-residential test circuit. The 24-hour field profile was condensed to a 1-hour segment for lab testing. These data were recorded in a spreadsheet and then converted into a format that is compatible with RSCAD to create an automated load scheduler. Figure 5.4 shows the RSCAD load control input that can be controlled via the RunTime interface or the automated load scheduler. This selection is made via the toggle switch, LPSELECT. The RunTime interface in Figure 5.5 contains slider controls to manipulate the real and reactive power of the loads as a percentage of their maximum capacity.

5.2.1.1 LOAD IMPEDANCE PROFILE AND CONTROL

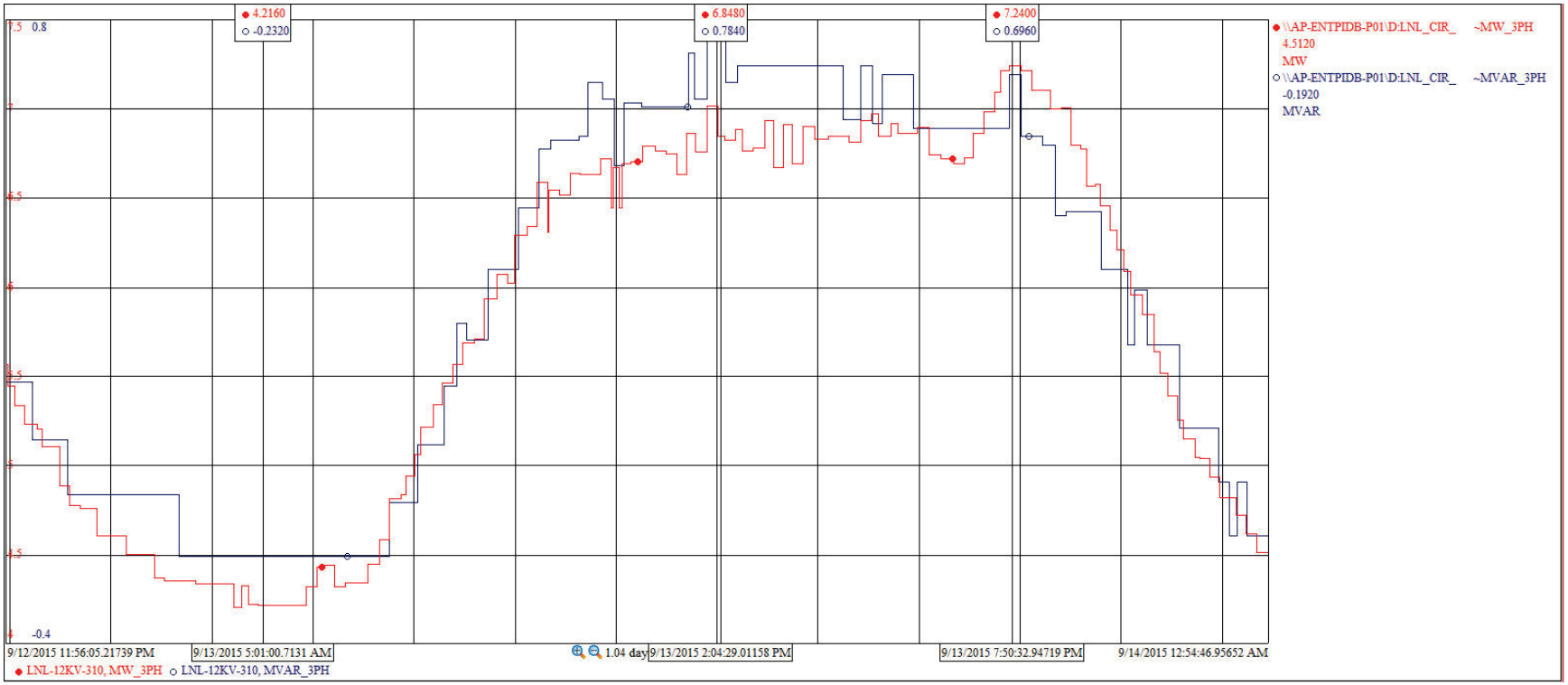


Figure 5.3: Coastal-Residential Test Circuit – 24-Hour Field Load Profile

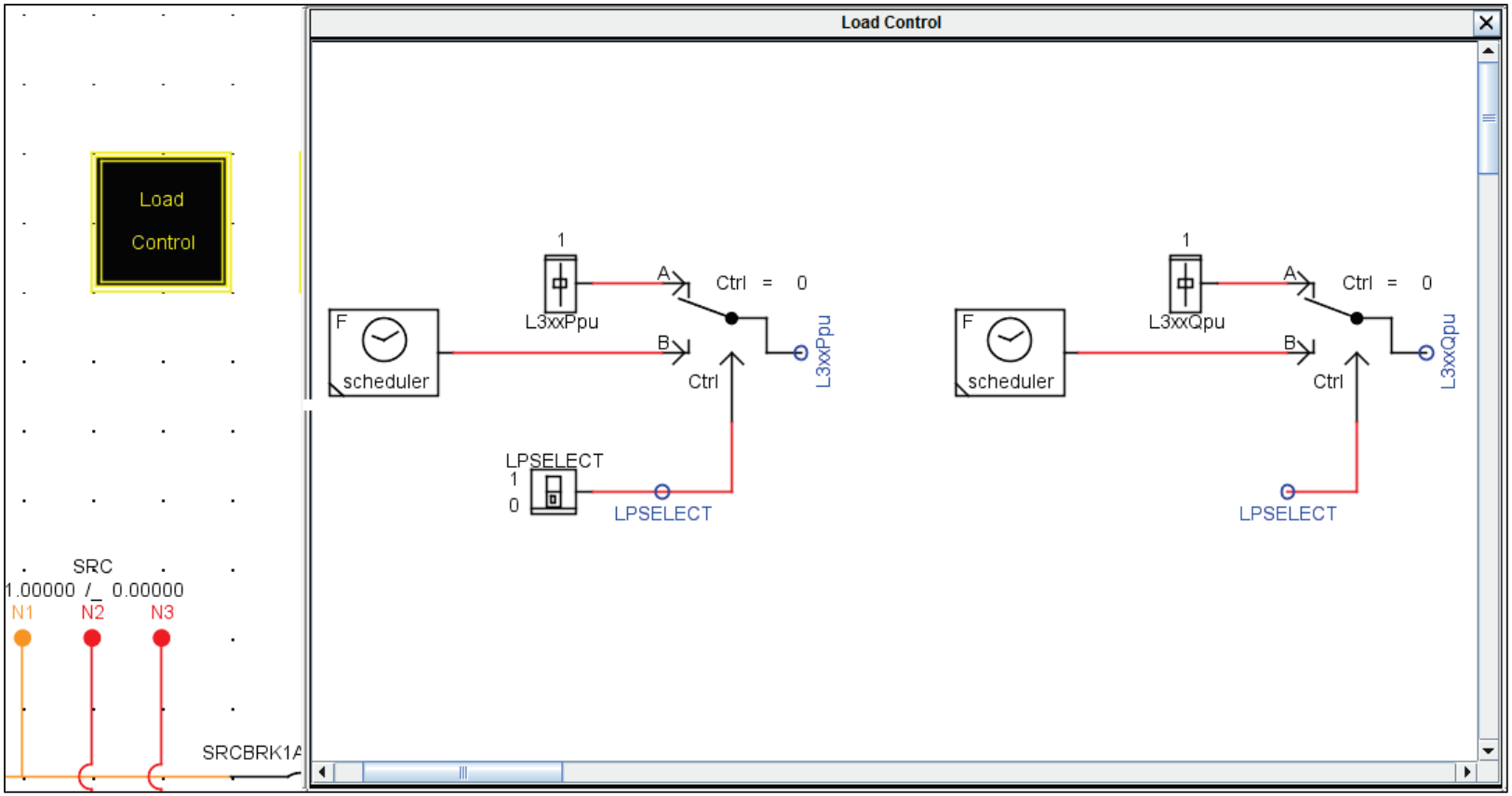


Figure 5.4: RSCAD Load Control

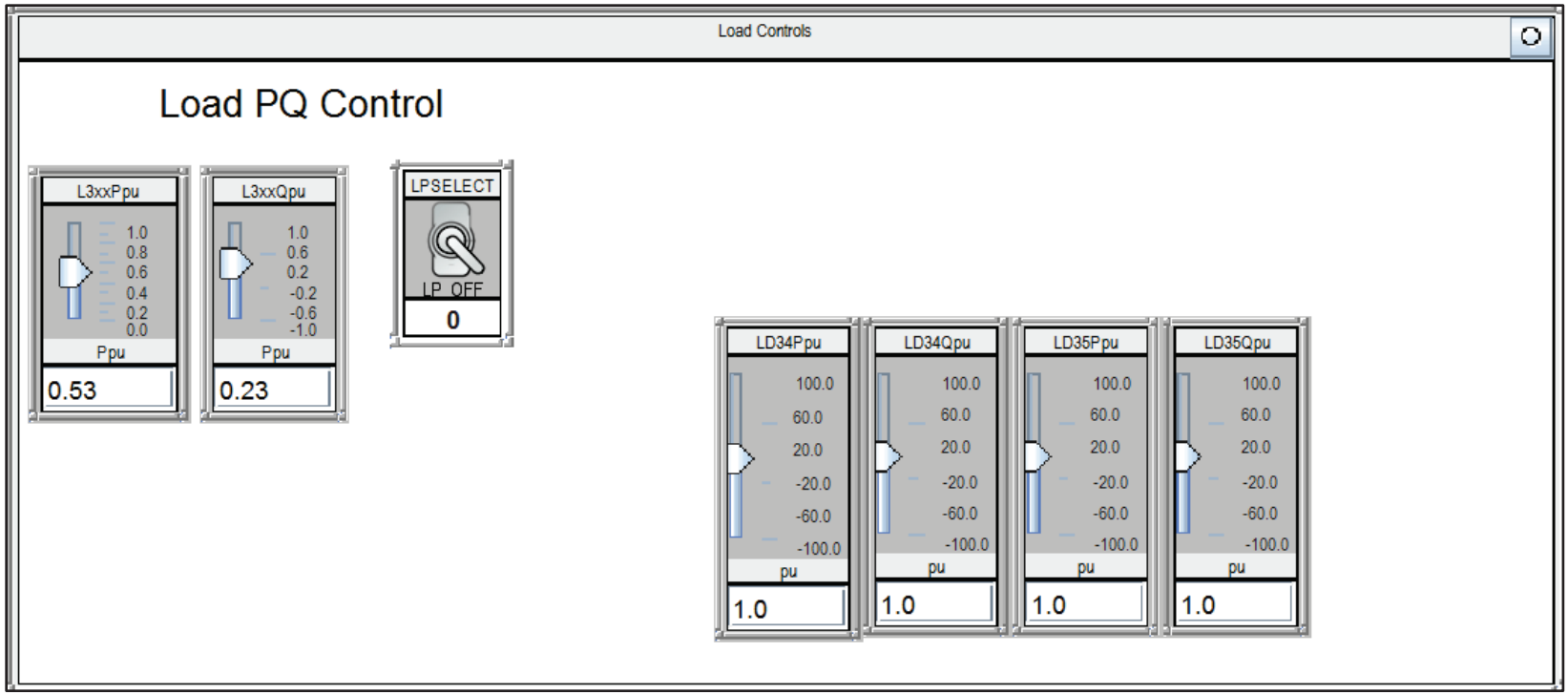


Figure 5.5: RSCAD Load Control HMI

5.3 RESULTS CAPTURE

A visualization and analysis software was used for capturing results and alarms for all test cases in this project. Phasor, analog, and digital data tags are sent from the relay under test to a data concentrator over IEEE C37.118 protocol. The data concentrator sends these tags to the visualization software where these tags are analyzed and arranged into their respective device graphs. The test results in real time are available to the user for various test scenarios. These graphs can be used for continued analysis of each test case.

RSCAD RunTime was also used to capture test results.

6 VOLTAGE REGULATOR CONTROL TESTS

This section provides the test procedure to study the existing SDG&E voltage regulator controls. The purpose of this study is to analyze the capabilities and controls of a voltage regulator as a stand-alone voltage support device in a distribution circuit. These tests would provide useful data for the development and implementation of voltage coordination scheme using multiple voltage support devices. The results from this study will also provide suggestions for improvements for optimal performance of the voltage regulators. The voltage regulator used in these tests works with a tap-changing automatic transformer to regulate distribution line voltages.

6.1 TEST SETUP

The hardware setup of the test circuit is shown in Figure 6.1. The circuit involving the voltage regulators is simulated on the RTDS and the load-side and source-side voltages are derived from the circuit. These voltages, as the low-level signals, are amplified using Vendor B amplifier and fed to the voltage regulator control. This study uses three voltage regulator controls, one for each phase.

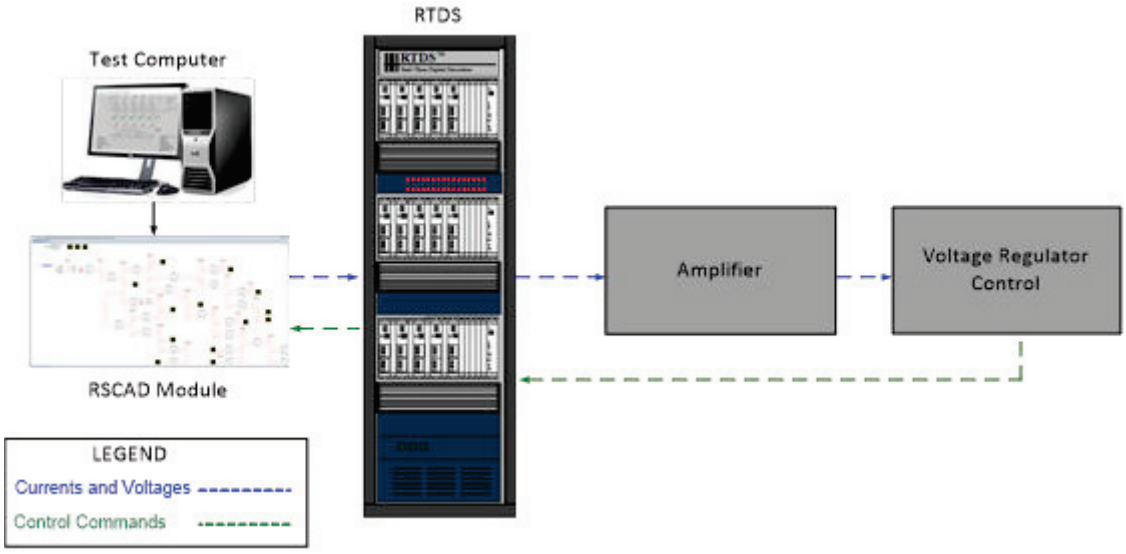


Figure 6.1: Voltage Regulator Control Test Setup

6.1.1 Voltage Regulator Control LED Definitions

The voltage regulator operation and indication light-emitting diodes (LEDs) are located on the front panel of the control. Table 6.1 lists the details for each LED. The device has 11 programmable LEDs and 11 operator-controlled pushbuttons.

Table 6.1: Voltage Regulator Operation and Indication LED Definitions

LED Name	Color	Description
NEUTRAL POSITION	Yellow	Voltage regulator is in the neutral position.
ENABLED	Green	Voltage regulator control is enabled.
ALARM	Red	Follows the state of the programmable setting ALARM.
VOLTAGE REDUCTION	Yellow	Voltage reduction in progress.
AUTO INHIBIT	Yellow	Illuminates when automatic tap changers are inhibited.
REVERSE POWER	Yellow	Reverse system power flow detected.

LED Name	Color	Description
VOLTAGE HIGH LIMIT	Red	When illuminated, the system load-side terminal voltage exceeds voltage limit setting VMAX.
HIGH BAND	Yellow	Regulated voltage is above the high-band threshold.
IN BAND	Green	Regulated voltage is between the high-band threshold and the low-band threshold.
LOW BAND	Yellow	Regulated voltage is below the low-band threshold.
VOLTAGE LOW LIMIT	Red	When illuminated, the system load-side terminal voltage is below the voltage limit setting.

6.1.2 Voltage Regulator Operator-Controlled Pushbuttons

Table 6.2 lists the possible functions of the operator-controlled pushbuttons. These pushbuttons display the desired information on the device LED screen.

Table 6.2: Voltage Regulator Operator-Controlled Pushbuttons

Pushbutton Name	Function
SETTINGS	Displays active group settings
METER	Displays fundamental metering report
OPERATION COUNT	Displays tap report
VOLTAGE LIMIT	Displays voltage limit settings
LINE DROP COMP.	Displays line drop compensation settings
HARMONICS	Displays harmonic metering report
DEMAND	Displays demand metering report
LOCAL/REMOTE	Selects LOCAL or REMOTE device operation
AUTO/MANUAL	Selects AUTO or MANUAL device operation
RAISE	Allows manual raising of tap
LOWER	Allows manual lowering of tap

6.1.3 Voltage Regulator Control I/O List

The I/O contacts designated for the voltage regulator control have been assigned based on settings received from SDG&E and the test requirements.

6.1.4 RTDS to Vendor B Amplifier Low-Level Test Interface

The RTDS simulates the power system signal and converts the digital signals to low-level analog signals that are ready to be applied to the Vendor B amplifier. The RTDS analog outputs, consisting of voltage and current outputs, are connected to the amplifier via a DB-15 cable. Figure 6.2 illustrates the analog outputs from the RTDS to the amplifier via the gigabit transceiver analog output (GTAO) card. channels 1 through 3 and channels 7 through 9 are reserved for the source-side and load-side voltages, respectively. The device can be programmed to amplify the low-level signals to the desired voltage and current levels for testing. The output of the amplifier is connected to the voltage regulator control. As illustrated in Figure 6.2, 69G1A, 69G1B, and 69G1C are the phase voltages of the load side and 69G2A, 69G2B, and 69G2C are the phase voltages of the source side of the voltage regulator C1215-69G.

The voltage regulator control digital outputs used for voltage control are given in Table 6.3.

Figure 6.3 shows the mapping for the voltage regulator digital inputs (raise, lower, and block) via the gigabit transceiver front-panel interface (GTFPI) card.

Note: ABC phase rotation is considered.

Table 6.3: Voltage Regulator Control I/O List

Output Contact	Function
OUT102	Raise Phase A
OUT103	Lower Phase A
OUT104	Block Phase A
OUT102	Raise Phase B
OUT103	Lower Phase B
OUT104	Block Phase B
OUT102	Raise Phase C
OUT103	Lower Phase C
OUT104	Block Phase C

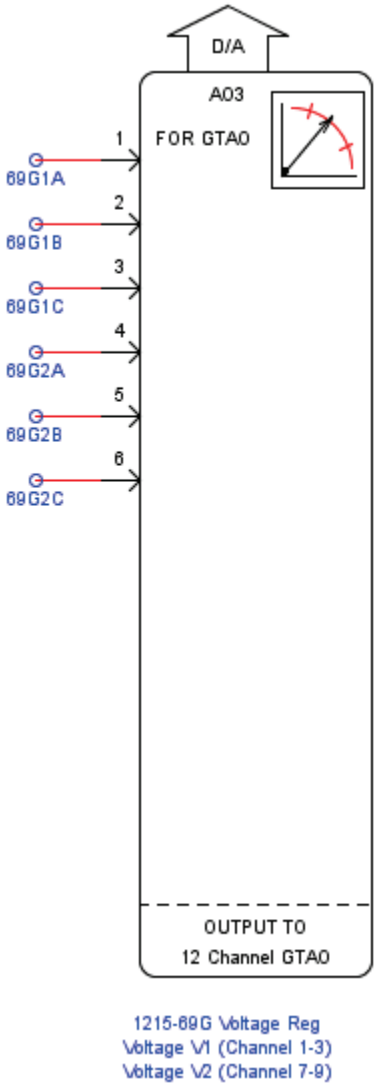


Figure 6.2: RTDS to Vendor B Amplifier Interface

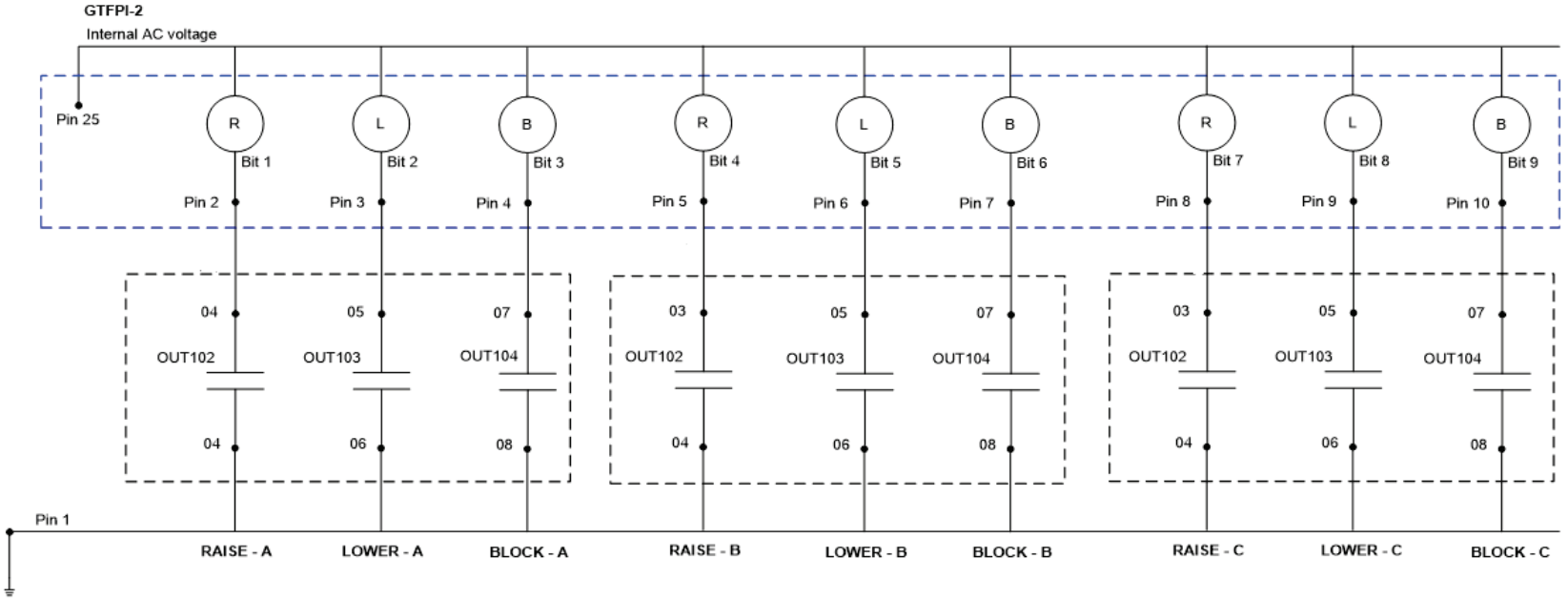


Figure 6.3: Raise, Lower, and Block Digital Input Wiring

6.1.5 Vendor B Amplifier to Voltage Regulator Control Test Interface

Figure 6.4 provides detailed information on the amplifier to the voltage regulator external test wiring. Figure 6.5 shows the internal wiring of the voltage regulator.

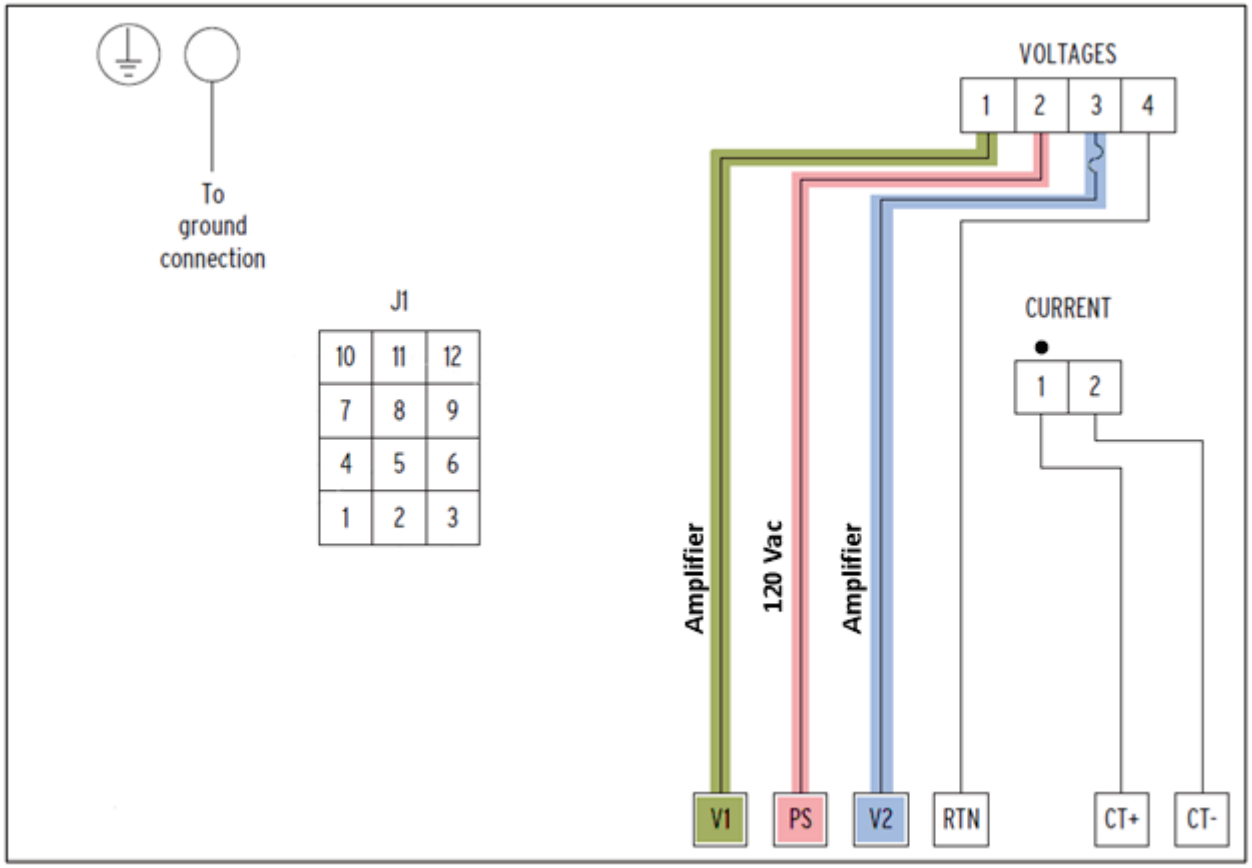


Figure 6.4: Voltage Regulator External Connection Diagram

For this testing:

- A 120 Vac power source is connected to PS.
- The load-side voltage (VL) is connected to V1.
- The source-side voltage (VS) is connected to V2.
- The secondary CT currents are connected to CT+ and CT–.
- The retrofit cable harness connector (J1) will not be used.

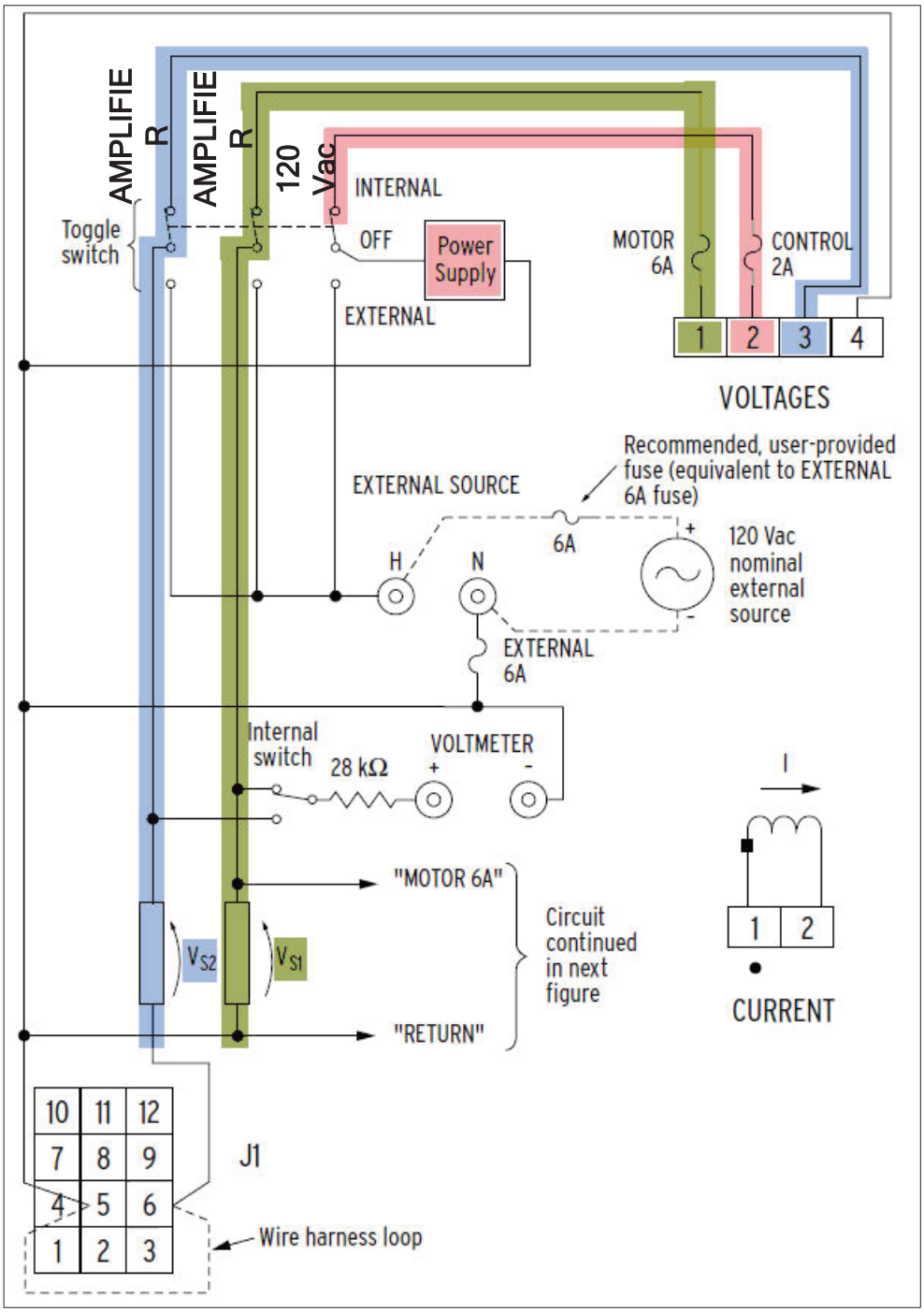


Figure 6.5: Voltage Regulator Internal Connection Diagram

To inject VS (source-side voltage) and VL (load-side voltage) from the amplifier, follow these instructions:

Step 1. Switch the control power in the front panel to Internal mode.

Step 2. Connect 120 Vac external source to V1 and G. This step will turn on the relay.

Step 3. Check to see if the relay turns on.

Step 4. Connect the voltage source from the amplifier to V1. This step will inject VL from the amplifier to the voltage regulator.

Step 5. Connect the voltage source from the amplifier to V2. This step will inject VS from the amplifier to the voltage regulator.

Step 6. Check to see if both VS and VL measurements from the relay match the amplifier voltage output.

The VS1 and VS2 generated are the variables used for the voltage regulation. VS1 corresponds to the load-side voltage and VS2 corresponds to the source-side voltage. Based on the inputs from VS1 and VS2 and the voltage range between which the voltage must be regulated, certain output contacts are triggered to raise or lower the voltage. The tap slider is shifted up or down based on the operation.

Figure 6.6 is an example case that shows the voltage profile and tap-changing positions for a voltage raise operation on a 32-tap voltage regulator unit.

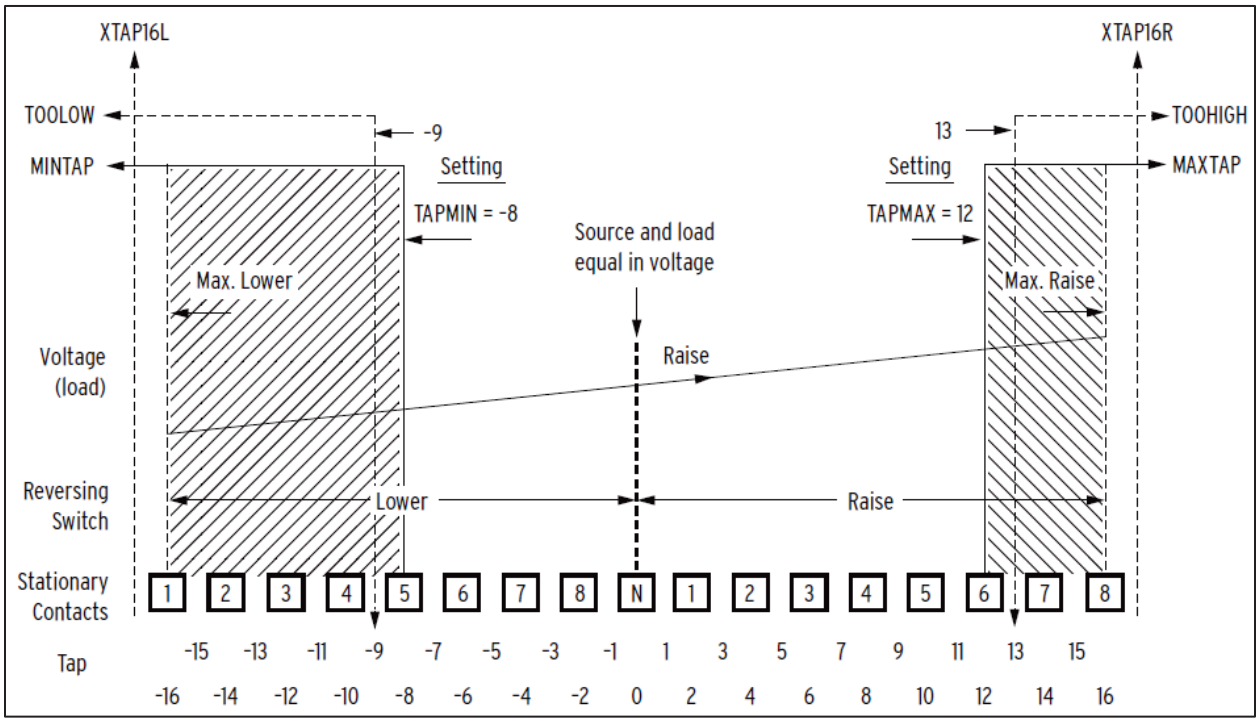


Figure 6.6: Voltage Profile Plot of a Continual Raise Operation

Notes:

- The device word bits TAPMAX and TAPMIN are the boundary tap positions for the voltage regulator control.
- The device word bit TOOLOW asserts to a logical 1 when the tap is at a TAPMIN –1 or a lower tap value.
- The device word bit TOOHIGH asserts to a logical 1 when the tap is at a TAPMAX –1 or a higher tap value.

- The device word bit XTAP16L asserts momentarily to a logical 1 when the tap value attempts to go lower than TAP = –16.
- The device word bit XTAP16R asserts momentarily to a logical 1 when the tap value attempts to go higher than TAP = 16.

6.2 OPERATING MODES

The voltage regulator control has several operating modes to accommodate different operating conditions and applications. The automatic modes of operation dictate whether the voltage regulator control will regulate voltage in the forward or reverse direction. The different modes of operation are as follows:

1. Locked Forward Mode (LOCKFWD): Power flow is expected to always be in the forward direction (normal load side).

2. Locked Reverse Mode (LOCKREC): Power flow is expected to always be in the reverse direction (normal source side).

3. Idle Reverse Mode (IDLEREV): Power flow is expected to always be in the forward direction; however, no voltage regulation should occur if the power flow is indeterminate, such as a no-load condition.

4. Bidirectional Mode (BIDIR): Power flow varies, alternatively operating in the forward and reverse directions.

5. Cogeneration Mode (COGEN): Cogeneration/independent generation unit is on the normal load side and the power flow varies, alternatively operating in the forward and reverse directions.

The voltage regulator controls in the SDG&E circuits are set to the locked forward operating mode. Depending on the operating mode, the voltage regulator generates output control commands based on the voltage it sees on the load and source side.

1. Raise Tap (RAISESV): Tap to be raised because the current tap is too low (TOOLOW asserts).

2. Lower Tap (LOWERSV): Tap to be lowered because the current tap is too high (TOOHIGH asserts).

3. Inhibit Tap (INHIBITSV): The INHIBITSV asserts when the voltage is out of band. It then deasserts and the timing to tap restarts from the beginning.

4. Block Tap (BLOCKSV): The block tap operates similar to the INHIBITSV Relay Word bit. However, when the BLOCKSV asserts, the timing to tap continues with the present timer. No tapping occurs when the timer times out (a pending tap condition exists). Then, if the voltage is still out of band when it deasserts, a tap occurs immediately for this pending tap condition.

6.3 TEST PROCEDURE

The following is the procedure carried out during the testing process:

Step 1. Connect the RTDS I/O module to the amplifier as described in Section 6.1.4.

Step 2. Connect the amplifier to the voltage regulator.

Step 3. Modify the voltage regulator control settings to reflect the tap and voltage limits, as provided by SDG&E.

Step 4. Run the RTDS model and verify accuracy of the I/O across all devices. Follow the instructions described in Section 6.1.5 for the amplifier connected to the voltage regulator control.

Step 5. Run the RTDS model on varying loads based on the load profile provided by SDG&E and observe the operation of the voltage regulator.

According to recommendations from SDG&E, the load was increased considerably to best simulate the voltage regulator operation. The modified load profile was essentially the original load profile with each load point increased to three times the actual load.

Step 6. Observe the voltage profile on the RTDS RunTime interface for each voltage regulator operation.

Step 7. Analyze each voltage regulator operation and suggest steps to improve the voltage profile, if required.

6.4 VOLTAGE REGULATOR TEST

The functional testing of the voltage regulators was performed on the desert-rural test circuit. The desert-rural circuit was chosen for these tests since it has existing voltage regulators installed. The analysis and understanding of the voltage regulator operation, as a stand-alone device for correcting the voltage profile, will aid in developing the voltage support coordination scheme using multiple devices in Section 10.

This circuit has two voltage regulator banks, as shown in Figure 6.7. For this study, the voltage regulators 1215-69G were considered because of their proximity to the source and the number of loads available on their load terminals.

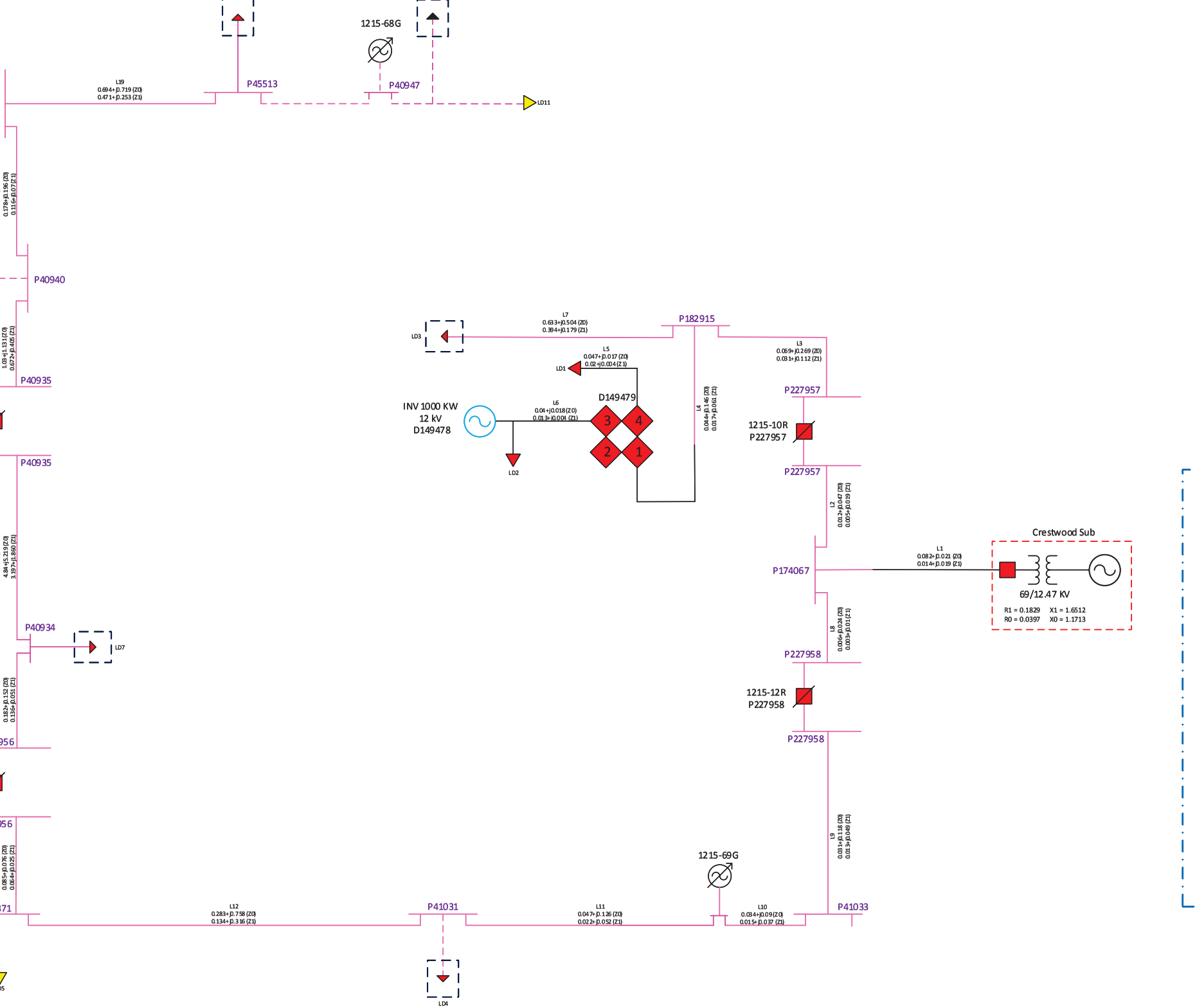


Figure 6.7: Simplified One-Line Drawing of Desert-Rural Test Circuit

6.5 VOLTAGE REGULATOR RTDS MODEL

Figure 6.8 shows the voltage regulator block and the logic for the voltage regulator, which is modeled in RSCAD.

The voltage regulator has input terminals connected to the source side and output terminals connected to the load side of the circuit. The device internal logic is shown in Figure 6.9. It consists of single-phase voltage sources connected to each phase, controlled by a regulated voltage. The voltage at the source side is sent to the externally connected voltage regulator. The voltage regulator performs the necessary calculations to determine whether a raise or a lower tap operation should be carried out. The corresponding tap operation is sent to the RTDS and based on the tap input received, the internal tap is suitably raised or lowered and fed to the single-phase voltage sources. This regulates the load voltage and ensures that the voltage stays within the specified operation band.

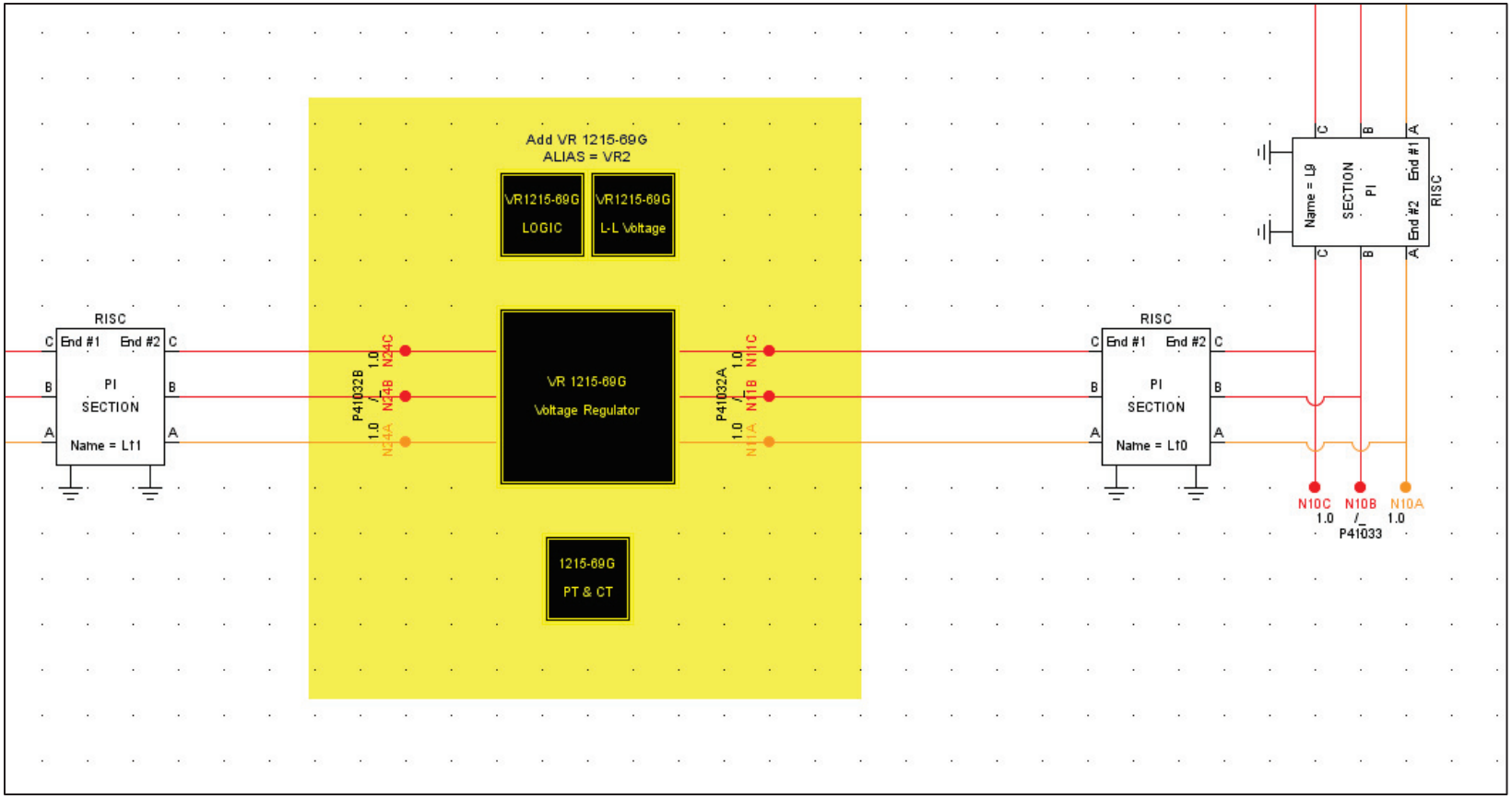


Figure 6.8: Voltage Regulator RTDS Block

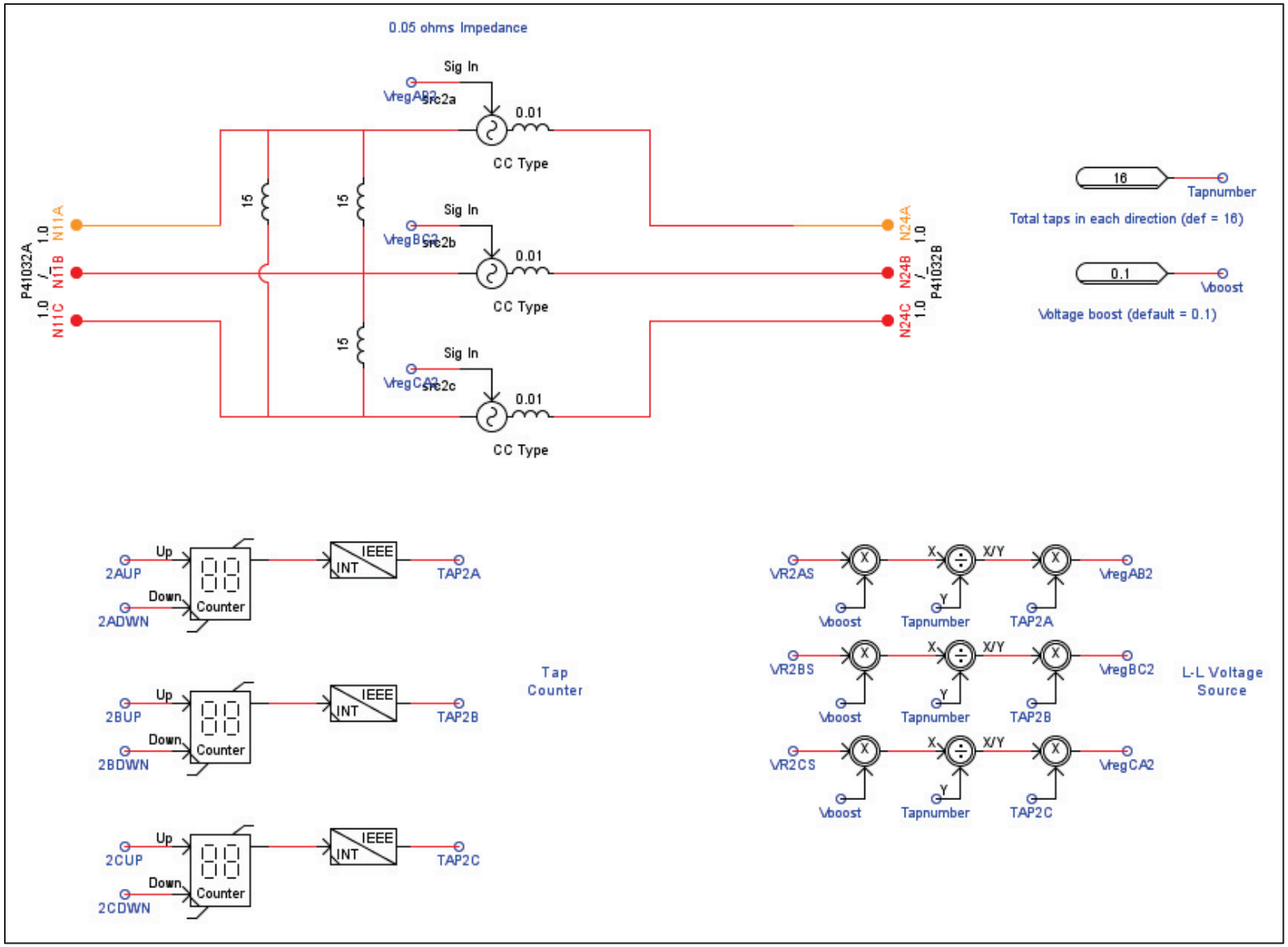


Figure 6.9: Voltage Regulator Internal Logic

6.6 VOLTAGE REGULATOR SETTINGS

The voltage regulator was set based on the standards specified by SDG&E. The following are the relevant settings that were used in the device:

CTR → 60

PTR → 1000

PT secondary voltage → 120 V

Tap changer type → COOPER

Operating mode → locked forward

Maximum tap number → 16

Minimum tap number → –16

Forward center band → 120 V

Forward bandwidth → 2 V

Forward time delay → 10 s

Maximum voltage → 130 V

Minimum voltage → 110 V

A detailed list of all voltage regulator settings is in Appendix D.

Figure 6.10 illustrates the voltage band setting for a voltage regulator. The device regulates the load-side voltage within these parameters. The device does not operate when the voltage is within the In Band voltage range. When the load voltage increases to the high-voltage band because of certain conditions such as loss of load or source fluctuations, the voltage regulator raises the tap to bring down the voltage to within the In Band voltage range. When the load voltage drops to the low-voltage band, the device raises the tap to bring the voltage within the In Band voltage range. Additionally, when the voltage goes beyond the maximum or minimum voltage limit, the device blocks all tap operations and stays idle until the voltage comes back to the device operating band. SDG&E recommends a ±5 percent voltage band over the center voltage band of 120 V. This equates to an In Band between 114 V and 126 V.

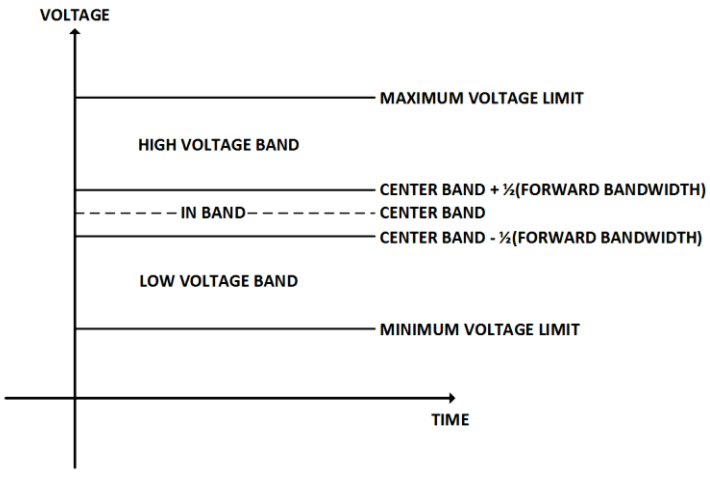


Figure 6.10: Voltage Regulator Voltage Band Setting

6.7 RTDS TEST ASSUMPTIONS

The following are the assumptions made for the RTDS voltage regulator functional tests:

- The forward bandwidth was set to 2 V (±0.8 percent) to better simulate voltage regulator operations.
- The 24-hour load profile provided by SDG&E was condensed to a 1-hour load profile for a realistic test study.

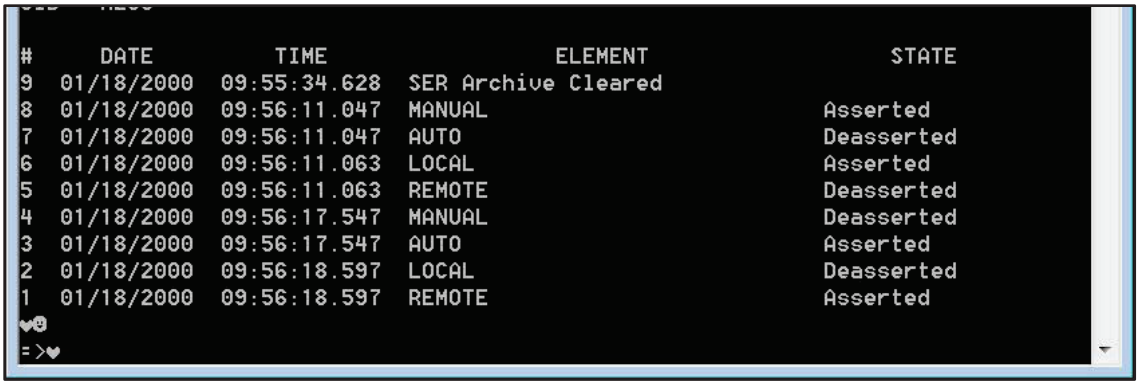
6.8 TEST SCENARIOS

6.8.1 Auto and Remote Toggle – From Local Control

Table 6.4: Auto and Remote Toggle – Local Control

Objective: Verify appropriate indication for AUTO/REMOTE operating mode.					
Specific instruction: AUTO/REMOTE toggle allowed by **AUTO** and **REMOTE** pushbutton in LOCAL mode. Carry out Test Action 1, observe corresponding results. Move on to Step 2.					
Negative test: Modes do not switch between LOCAL/MANUAL and AUTO/REMOTE.					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. Voltage regulator in MANUAL mode. **MANUAL** LED is ON.	1. Press **AUTO/MANUAL** pushbutton. 2. Press **AUTO/MANUAL** pushbutton.	1.a. **AUTO** LED – ON 1.b. **MANUAL** LED – OFF 1.c. Voltage Regulator in AUTO mode 2.a. **AUTO** LED – OFF 2.b. **MANUAL** LED – ON 2.c. Voltage regulator in MANUAL mode	1. Voltage regulator switches to AUTO mode successfully. 2. Voltage regulator switches to MANUAL mode successfully.	Y	
2. Voltage regulator in MANUAL mode. **MANUAL** LED is ON.	1. Press **REMOTE/LOCAL** pushbutton. 2. Press **REMOTE/LOCAL** pushbutton.	1.a. **REMOTE** LED – ON 1.b. **LOCAL** LED – OFF 1.c. Voltage regulator in REMOTE mode 2.a. **REMOTE** LED – OFF 2.b. **LOCAL** LED – ON 2.c. Voltage regulator in LOCAL mode	1. Voltage regulator switches to REMOTE mode successfully. 2. Voltage regulator switches to LOCAL mode successfully.	Y	
Test notes: The voltage regulator may be placed in Automatic mode when there are no lockout conditions and all three-phase voltages are healthy. Observe system voltage profile after the switching operation.					

The Sequential Events Recorder (SER) report for the Auto and Remote Toggle tests carried out as outlined in Table 6.4 is illustrated in Figure 6.11, Figure 6.12, and Figure 6.13. The voltage regulators performed switching between AUTO and REMOTE modes successfully per the test specifications.



#	DATE	TIME	ELEMENT	STATE
9	01/18/2000	09:55:34.628	SER Archive Cleared	
8	01/18/2000	09:56:11.047	MANUAL	Asserted
7	01/18/2000	09:56:11.047	AUTO	Deasserted
6	01/18/2000	09:56:11.063	LOCAL	Asserted
5	01/18/2000	09:56:11.063	REMOTE	Deasserted
4	01/18/2000	09:56:17.547	MANUAL	Deasserted
3	01/18/2000	09:56:17.547	AUTO	Asserted
2	01/18/2000	09:56:18.597	LOCAL	Deasserted
1	01/18/2000	09:56:18.597	REMOTE	Asserted

Figure 6.11: Test Scenario 3.7.1. Phase A Voltage Regulator SER



#	DATE	TIME	ELEMENT	STATE
9	01/18/2000	09:22:49.783	SER Archive Cleared	
8	01/18/2000	09:56:55.422	MANUAL	Asserted
7	01/18/2000	09:56:55.422	AUTO	Deasserted
6	01/18/2000	09:56:55.439	LOCAL	Asserted
5	01/18/2000	09:56:55.439	REMOTE	Deasserted
4	01/18/2000	09:57:00.972	MANUAL	Deasserted
3	01/18/2000	09:57:00.972	AUTO	Asserted
2	01/18/2000	09:57:02.789	LOCAL	Deasserted
1	01/18/2000	09:57:02.789	REMOTE	Asserted

Figure 6.12: Test Scenario 3.7.1. Phase B Voltage Regulator SER



#	DATE	TIME	ELEMENT	STATE
9	01/18/2000	09:23:28.909	SER Archive Cleared	
8	01/18/2000	09:57:07.263	MANUAL	Asserted
7	01/18/2000	09:57:07.263	AUTO	Deasserted
6	01/18/2000	09:57:07.280	LOCAL	Asserted
5	01/18/2000	09:57:07.280	REMOTE	Deasserted
4	01/18/2000	09:57:10.330	MANUAL	Deasserted
3	01/18/2000	09:57:10.330	AUTO	Asserted
2	01/18/2000	09:57:11.064	LOCAL	Deasserted
1	01/18/2000	09:57:11.064	REMOTE	Asserted

Figure 6.13: Test Scenario 3.7.1. Phase C Voltage Regulator SER

6.8.2 Automatic Voltage Regulation – Voltage Raise/Lower Operation

Voltage regulation is performed by the voltage regulator within its voltage band settings. The device must be set in AUTO mode for voltage regulation. The voltage regulator detects voltages that fall outside the voltage regulation band and subsequently raises or lowers tap to bring the voltage within specified limits. The voltages specified in Table 6.5 and Table 6.6 indicate the CT secondary voltages.

Table 6.5: High-Voltage Lower Tap Operation

Objective: Verify regulator lowers tap for high-voltage conditions.					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. System with nominal voltage and current conditions: VA = 120 V ∠0° VB = 120 V ∠–120° VC = 120 V ∠+120° 2. Voltage regulator in AUTO and REMOTE modes. 3. Voltage regulation enabled. 4. Initial tap setting.	1. Raise test set voltage VA = 121 V ∠0° VB = 121 V ∠–120° VC = 121 V ∠+120°	1.a. **HIGH BAND** LED blinks yellow. 1.b. Lower Tap operation initiated. 1.c. **IN BAND** LED blinks green.	The **HIGH BAND** LED turns yellow as expected. LOWER Word bit initiated by the relay resulting in tap lowering.	Y	
1. System with nominal voltage and current conditions: VA = 120 V ∠0° VB = 120 V ∠–120° VC = 120 V ∠+120° 2. Voltage regulator in AUTO and REMOTE modes. 3. Voltage regulation enabled. 4. Initial tap setting.	1. Raise test set voltage VA = 128 V ∠0° VB = 128 V ∠–120° VC = 128 V ∠+120°	1.a. **HIGH BAND** LED blinks yellow. 1.b. Lower Tap operation initiated. 1.c. Voltage verified or previous tap operation. 1.d. Next Lower Tap operation initiated after the forward tap delay. 1.e. Steps 1.c. and 1.d. repeat until load voltage is In Band. 1.f. **IN BAND** LED blinks green.	The voltage regulator operated as desired for a high band, with checks at each tap operation until the voltage was In Band.	Y	
Test notes: Voltage regulator operation is verified for each phase. Observe system voltage profile after the switching operation.					

Refer to Figure 6.14 through Figure 6.19 for combined high- and low-voltage tap operations.

Table 6.6: Low-Voltage Raise Tap Operation

Objective: Verify regulator raises tap for low-voltage conditions.					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. System with nominal voltage and current conditions: VA = 120 V ∠0° VB = 120 V ∠–120° VC = 120 V ∠+120° 2. Voltage regulator control in AUTO and REMOTE modes. 3. Voltage regulation enabled. 4. Initial tap setting.	1. Lower test set voltage VA = 119 V ∠0° VB = 119 V ∠–120° VC = 119 V ∠+120°	1.a. **LOW BAND** LED blinks yellow. 1.b. Raise Tap operation initiated. 1.c. **IN BAND** LED blinks green.	The **LOW BAND** LED turns yellow as expected. RAISE Word bit initiated by the relay resulting in tap lowering.	Y	
1. System with nominal voltage and current conditions: VA = 120 V ∠0° VB = 120 V ∠–120° VC = 120 V ∠+120° 2. Voltage regulator control in AUTO and REMOTE modes. 3. Voltage regulation enabled. 4. Initial tap setting.	1. Lower test set voltage VA = 112 V ∠0° VB = 112 V ∠–120° VC = 112 V ∠+120°	1.a. **LOW BAND** LED blinks yellow. 1.b. Raise Tap operation initiated. 1.c. Voltage verified for previous tap operation. 1.d. Next Raise Tap operation initiated after the forward tap delay. 1.e. Steps 1.c. and 1.d. repeat until load voltage is In Band. 1.f. **IN BAND** LED blinks green.	The voltage regulator operated as desired for a low band, with checks at each tap operation until the voltage was In Band.	Y	
Test notes: Voltage regulator operation is verified for each phase. Observe system voltage profile after the switching operation.					

Figure 6.14 through Figure 6.19 illustrate voltage raise and lower operations performed by the voltage regulators and their respective SER data. It was observed that with an increase in load, there was a significant voltage drop in the system. The voltage regulators detected a drop-in voltage beyond the normal operating band (In Band) and correspondingly raised the regulator tap in steps to bring back the voltage to the normal operating band. The time stamp with the voltage reading indicates the point at which the voltage is In Band. The load was not decreased, resulting in the system voltage increasing to the high-voltage band of the voltage regulator. The voltage regulators lowered the regulator tap in steps to bring the voltage back to the normal operating band.

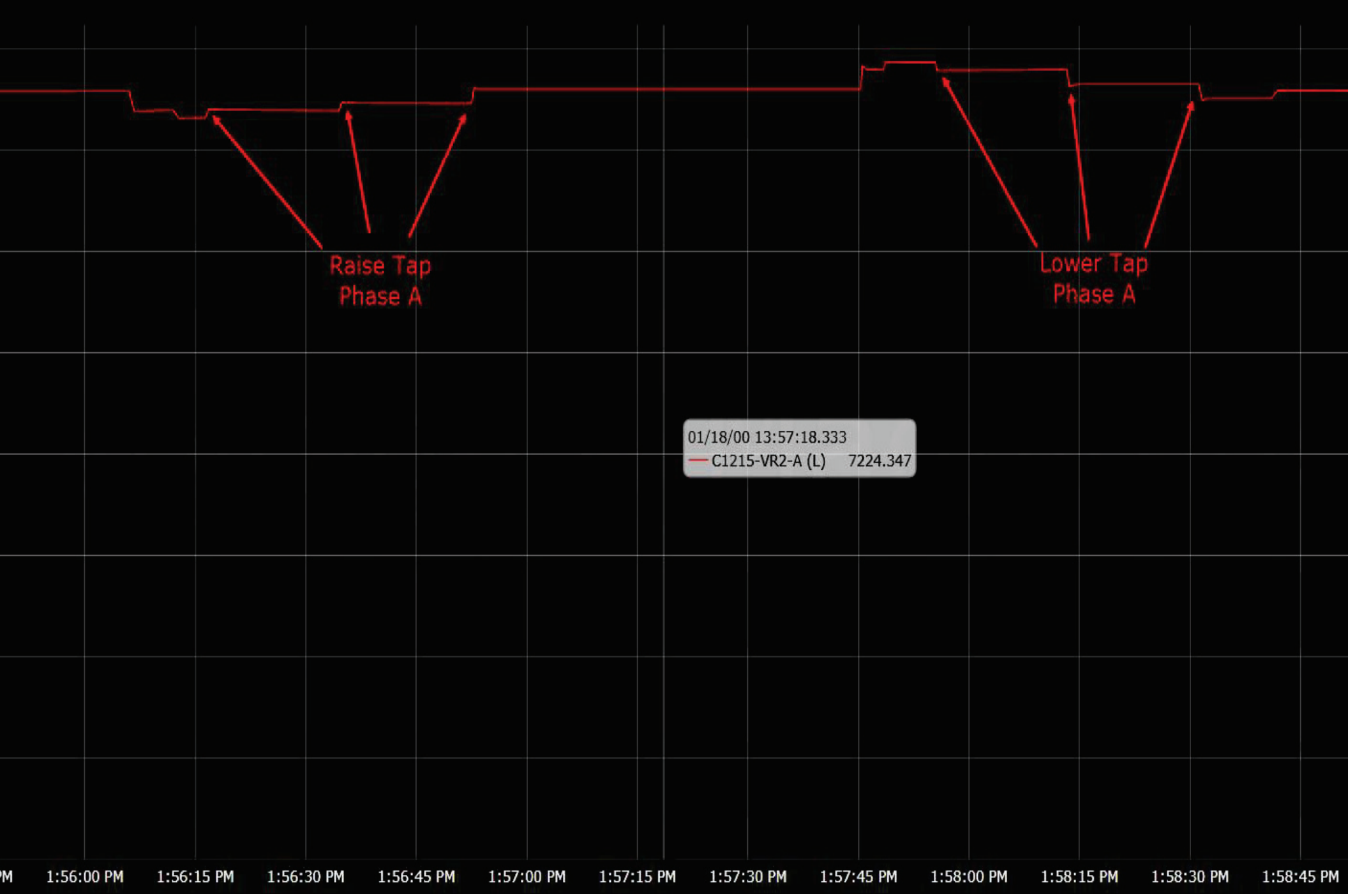
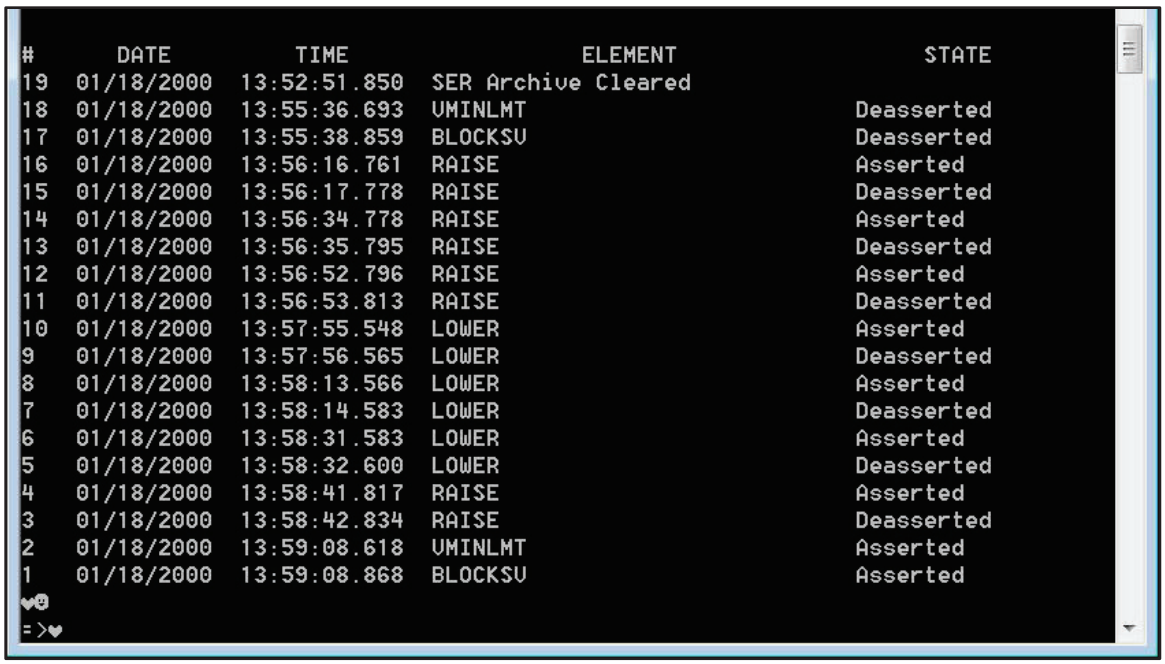


Figure 6.14: Test Scenario 3.7.2. Phase A Voltage Regulator Output Voltage Waveform



#	DATE	TIME	ELEMENT	STATE
19	01/18/2000	13:52:51.850	SER Archive Cleared	
18	01/18/2000	13:55:36.693	VMINLMT	Deasserted
17	01/18/2000	13:55:38.859	BLOCKSV	Deasserted
16	01/18/2000	13:56:16.761	RAISE	Asserted
15	01/18/2000	13:56:17.778	RAISE	Deasserted
14	01/18/2000	13:56:34.778	RAISE	Asserted
13	01/18/2000	13:56:35.795	RAISE	Deasserted
12	01/18/2000	13:56:52.796	RAISE	Asserted
11	01/18/2000	13:56:53.813	RAISE	Deasserted
10	01/18/2000	13:57:55.548	LOWER	Asserted
9	01/18/2000	13:57:56.565	LOWER	Deasserted
8	01/18/2000	13:58:13.566	LOWER	Asserted
7	01/18/2000	13:58:14.583	LOWER	Deasserted
6	01/18/2000	13:58:31.583	LOWER	Asserted
5	01/18/2000	13:58:32.600	LOWER	Deasserted
4	01/18/2000	13:58:41.817	RAISE	Asserted
3	01/18/2000	13:58:42.834	RAISE	Deasserted
2	01/18/2000	13:59:08.618	VMINLMT	Asserted
1	01/18/2000	13:59:08.868	BLOCKSV	Asserted

=>

Figure 6.15: Test Scenario 3.7.2. Phase A Voltage Regulator SER

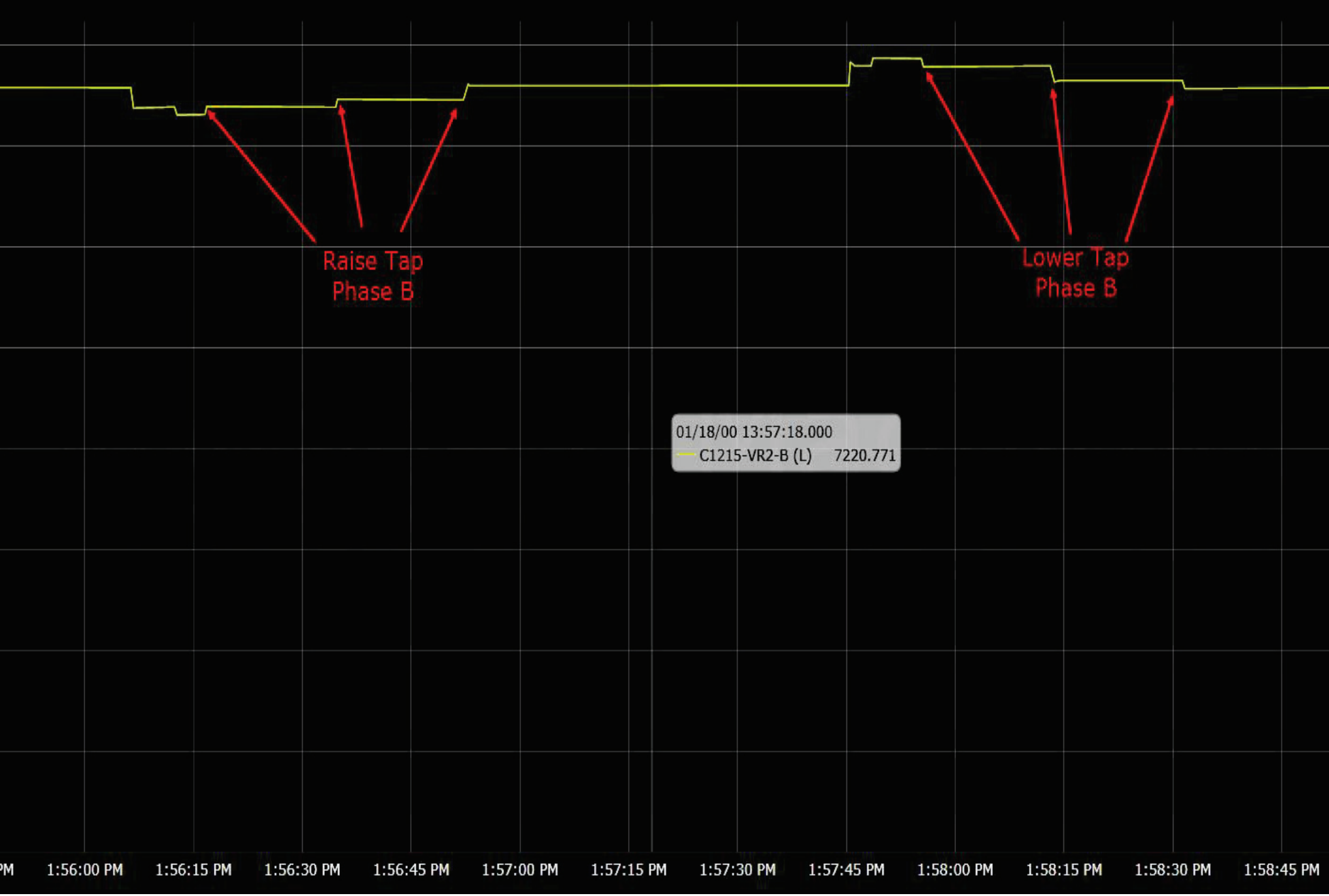
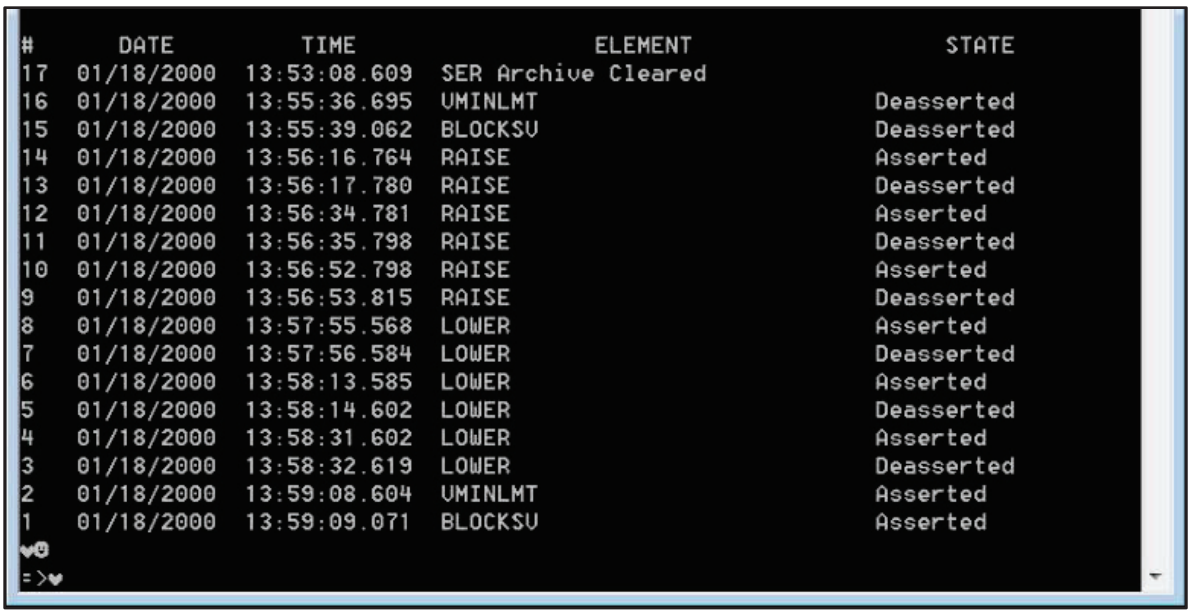


Figure 6.16: Test Scenario 3.7.2. Phase B Voltage Regulator Output Voltage Waveform



#	DATE	TIME	ELEMENT	STATE
17	01/18/2000	13:53:08.609	SER Archive Cleared	
16	01/18/2000	13:55:36.695	VMINLMT	Deasserted
15	01/18/2000	13:55:39.062	BLOCKSV	Deasserted
14	01/18/2000	13:56:16.764	RAISE	Asserted
13	01/18/2000	13:56:17.780	RAISE	Deasserted
12	01/18/2000	13:56:34.781	RAISE	Asserted
11	01/18/2000	13:56:35.798	RAISE	Deasserted
10	01/18/2000	13:56:52.798	RAISE	Asserted
9	01/18/2000	13:56:53.815	RAISE	Deasserted
8	01/18/2000	13:57:55.568	LOWER	Asserted
7	01/18/2000	13:57:56.584	LOWER	Deasserted
6	01/18/2000	13:58:13.585	LOWER	Asserted
5	01/18/2000	13:58:14.602	LOWER	Deasserted
4	01/18/2000	13:58:31.602	LOWER	Asserted
3	01/18/2000	13:58:32.619	LOWER	Deasserted
2	01/18/2000	13:59:08.604	VMINLMT	Asserted
1	01/18/2000	13:59:09.071	BLOCKSV	Asserted

Figure 6.17: Test Scenario 3.7.2. Phase B Voltage Regulator SER

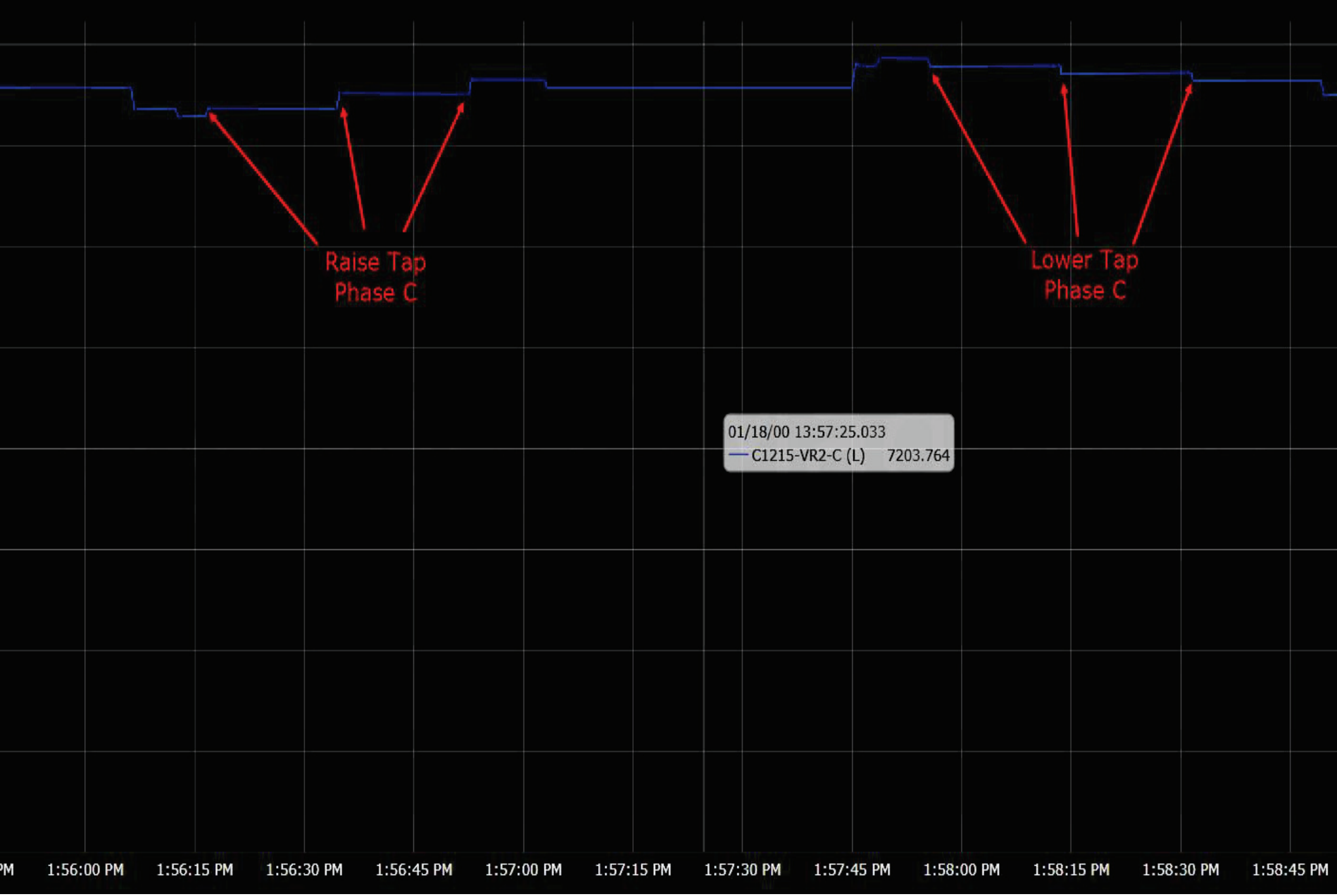
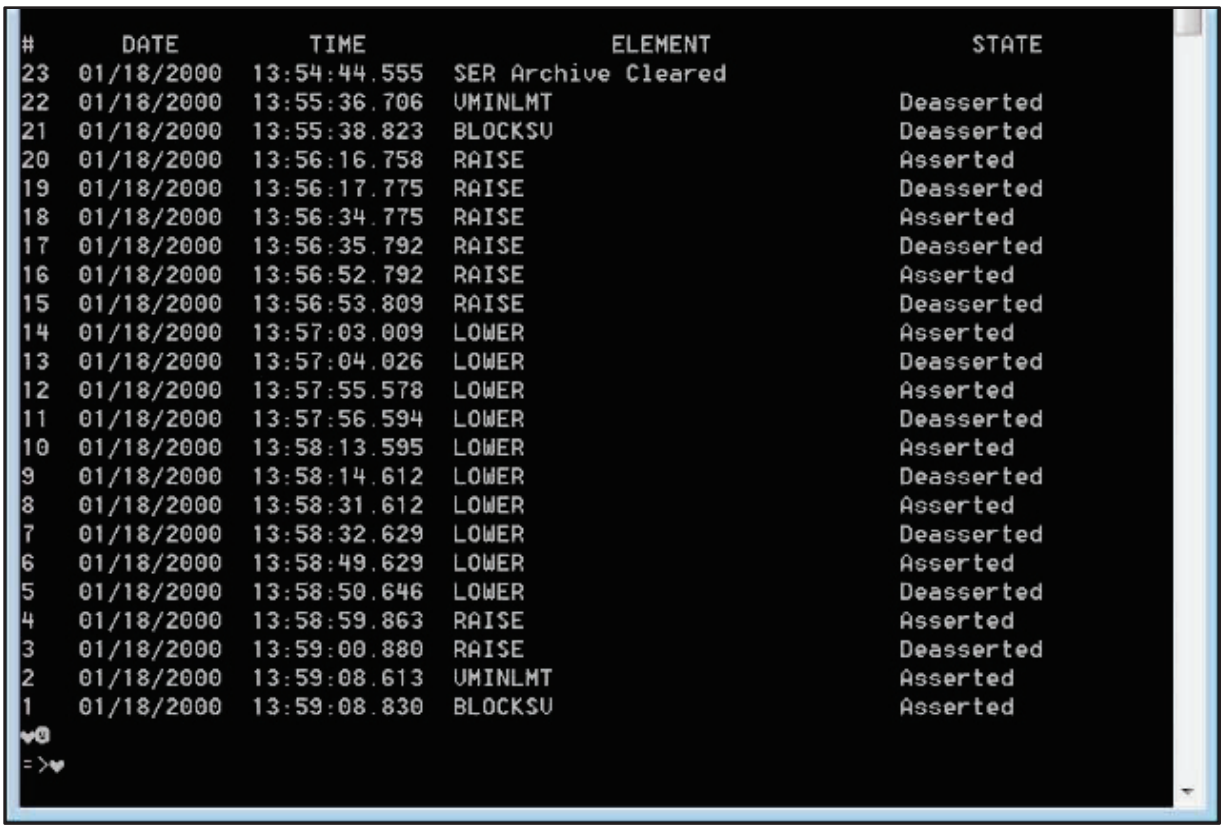


Figure 6.18: Test Scenario 3.7.2. Phase C Voltage Regulator Output Voltage Waveform



#	DATE	TIME	ELEMENT	STATE
23	01/18/2000	13:54:44.555	SER Archive Cleared	
22	01/18/2000	13:55:36.706	VMINLMT	Deasserted
21	01/18/2000	13:55:38.823	BLOCKSV	Deasserted
20	01/18/2000	13:56:16.758	RAISE	Asserted
19	01/18/2000	13:56:17.775	RAISE	Deasserted
18	01/18/2000	13:56:34.775	RAISE	Asserted
17	01/18/2000	13:56:35.792	RAISE	Deasserted
16	01/18/2000	13:56:52.792	RAISE	Asserted
15	01/18/2000	13:56:53.809	RAISE	Deasserted
14	01/18/2000	13:57:03.009	LOWER	Asserted
13	01/18/2000	13:57:04.026	LOWER	Deasserted
12	01/18/2000	13:57:55.578	LOWER	Asserted
11	01/18/2000	13:57:56.594	LOWER	Deasserted
10	01/18/2000	13:58:13.595	LOWER	Asserted
9	01/18/2000	13:58:14.612	LOWER	Deasserted
8	01/18/2000	13:58:31.612	LOWER	Asserted
7	01/18/2000	13:58:32.629	LOWER	Deasserted
6	01/18/2000	13:58:49.629	LOWER	Asserted
5	01/18/2000	13:58:50.646	LOWER	Deasserted
4	01/18/2000	13:58:59.863	RAISE	Asserted
3	01/18/2000	13:59:00.880	RAISE	Deasserted
2	01/18/2000	13:59:08.613	VMINLMT	Asserted
1	01/18/2000	13:59:08.830	BLOCKSV	Asserted

=>

Figure 6.19: Test Scenario 3.7.2. Phase C Voltage Regulator SER

6.8.3 Voltage High- and Low-Limit Scenarios – No Operation

Table 6.7 describes the voltage regulator operation during a large system voltage increase or decrease.

Table 6.7: Voltage High- and Low-Limit Operations

Objective: Verify if the regulator determines whether voltage goes beyond the minimum and maximum voltage limits.					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. System with nominal voltage and current conditions: VA = 120 V ∠0° VB = 120 V ∠–120° VC = 120 V ∠+120° 2. Voltage regulator in AUTO and REMOTE modes. 3. Voltage regulation enabled. 4. Initial tap setting.	1. Lower test set voltage VA = 108 V ∠0° VB = 108 V ∠–120° VC = 108 V ∠+120°	1.a. **VOLTAGE LOW LIMIT** LED blinks red. 1.b. Tap operation does not initiate.	**VOLTAGE LOW LIMIT** LED blinks red when the voltage goes beyond the minimum lower limit. Tap operation does not initiate.	Y	
1. System with nominal voltage and current conditions: VA = 120 V ∠0° VB = 120 V ∠–120° VC = 120 V ∠+120° 2. Voltage regulator in AUTO and REMOTE modes. 3. Voltage regulation enabled. 4. Initial tap setting.	1. Raise test set voltage VA = 132 V ∠0° VB = 132 V ∠–120° VC = 132 V ∠+120°	1.a. **VOLTAGE HIGH LIMIT** LED blinks red. 1.b. Tap operation does not initiate.	**VOLTAGE HIGH LIMIT** LED blinks red when the voltage goes beyond the maximum higher limit. Tap operation does not initiate.	Y	
Test notes: Voltage regulator operation is verified for each phase. Observe that the switching operation does not take place.					

Figure 6.20 through Figure 6.25 illustrate voltage limit operations performed by the voltage regulators and their respective SER data. The test circuit was initially run at the normal operating load. The load was drastically increased after a certain time period, resulting in a large voltage drop in the system. The voltage regulators detected the voltage dipping below the voltage low limit and subsequently issued a BLOCKSV Relay Word bit to cease all tap operations. The time stamp with its voltage reading indicates the point at which this operation takes place.

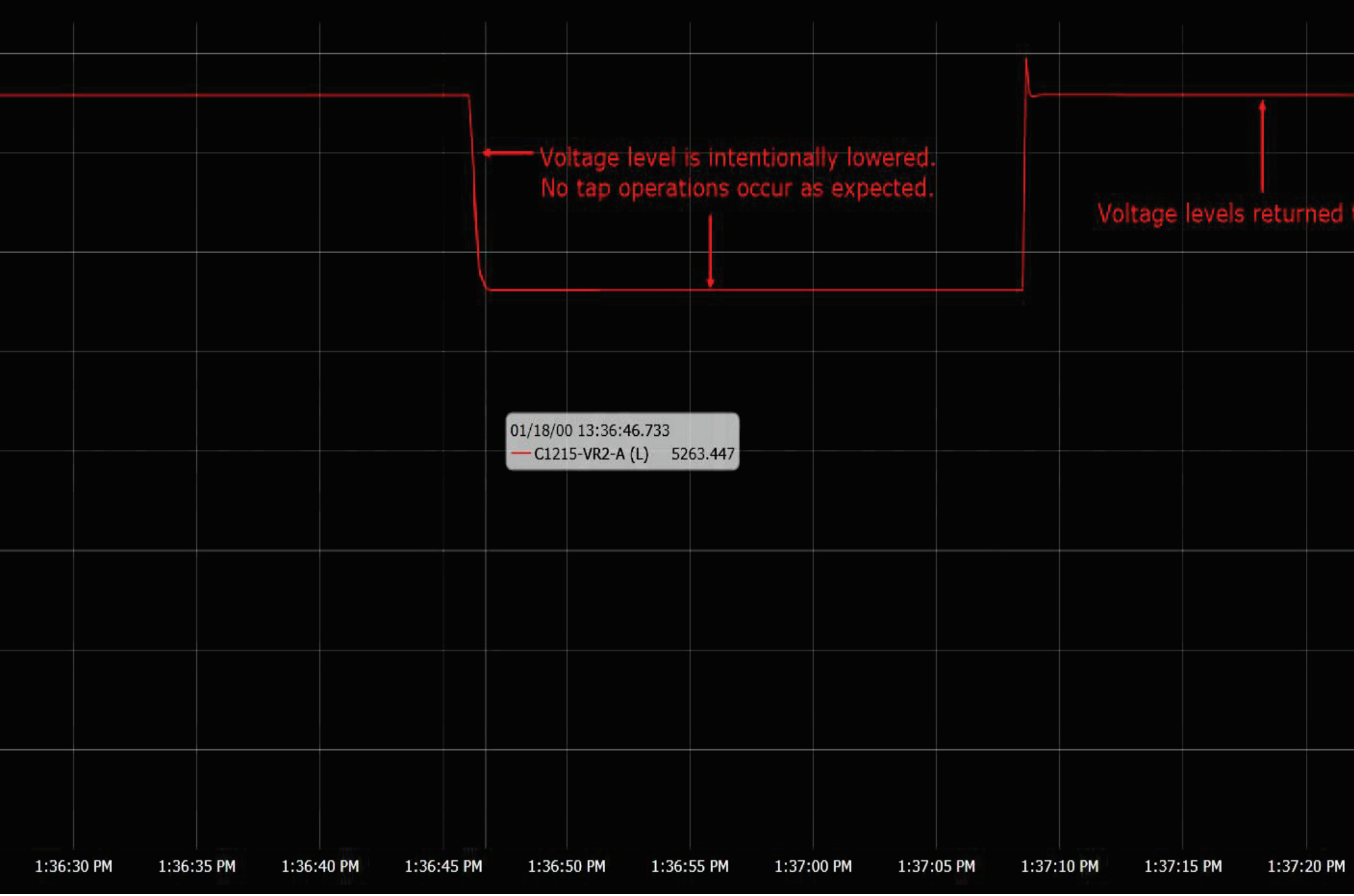
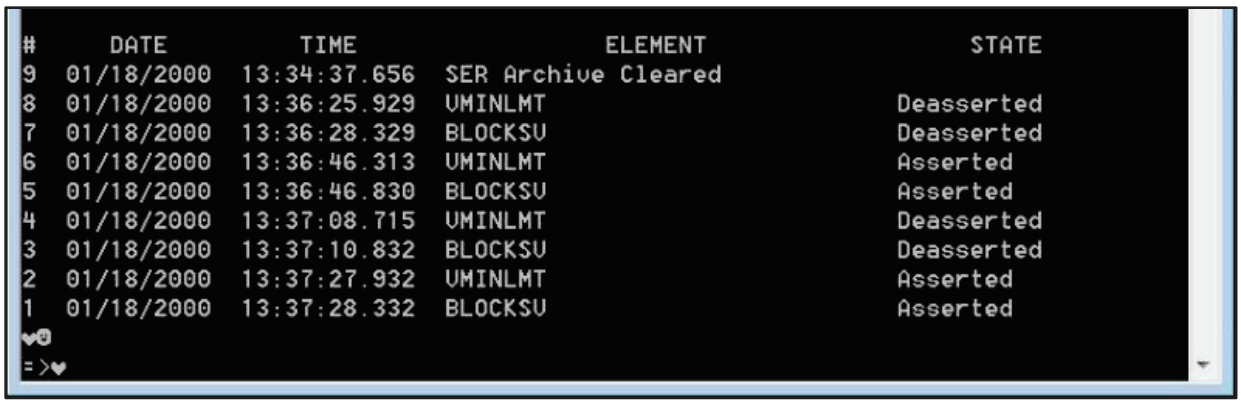


Figure 6.20: Test Scenario 3.7.3. Phase A Voltage Regulator Output Voltage Waveform



#	DATE	TIME	ELEMENT	STATE
9	01/18/2000	13:34:37.656	SER Archive Cleared	
8	01/18/2000	13:36:25.929	VMINLMT	Deasserted
7	01/18/2000	13:36:28.329	BLOCKSV	Deasserted
6	01/18/2000	13:36:46.313	VMINLMT	Asserted
5	01/18/2000	13:36:46.830	BLOCKSV	Asserted
4	01/18/2000	13:37:08.715	VMINLMT	Deasserted
3	01/18/2000	13:37:10.832	BLOCKSV	Deasserted
2	01/18/2000	13:37:27.932	VMINLMT	Asserted
1	01/18/2000	13:37:28.332	BLOCKSV	Asserted

=>

Figure 6.21: Test Scenario 3.7.3. Phase A Voltage Regulator SER

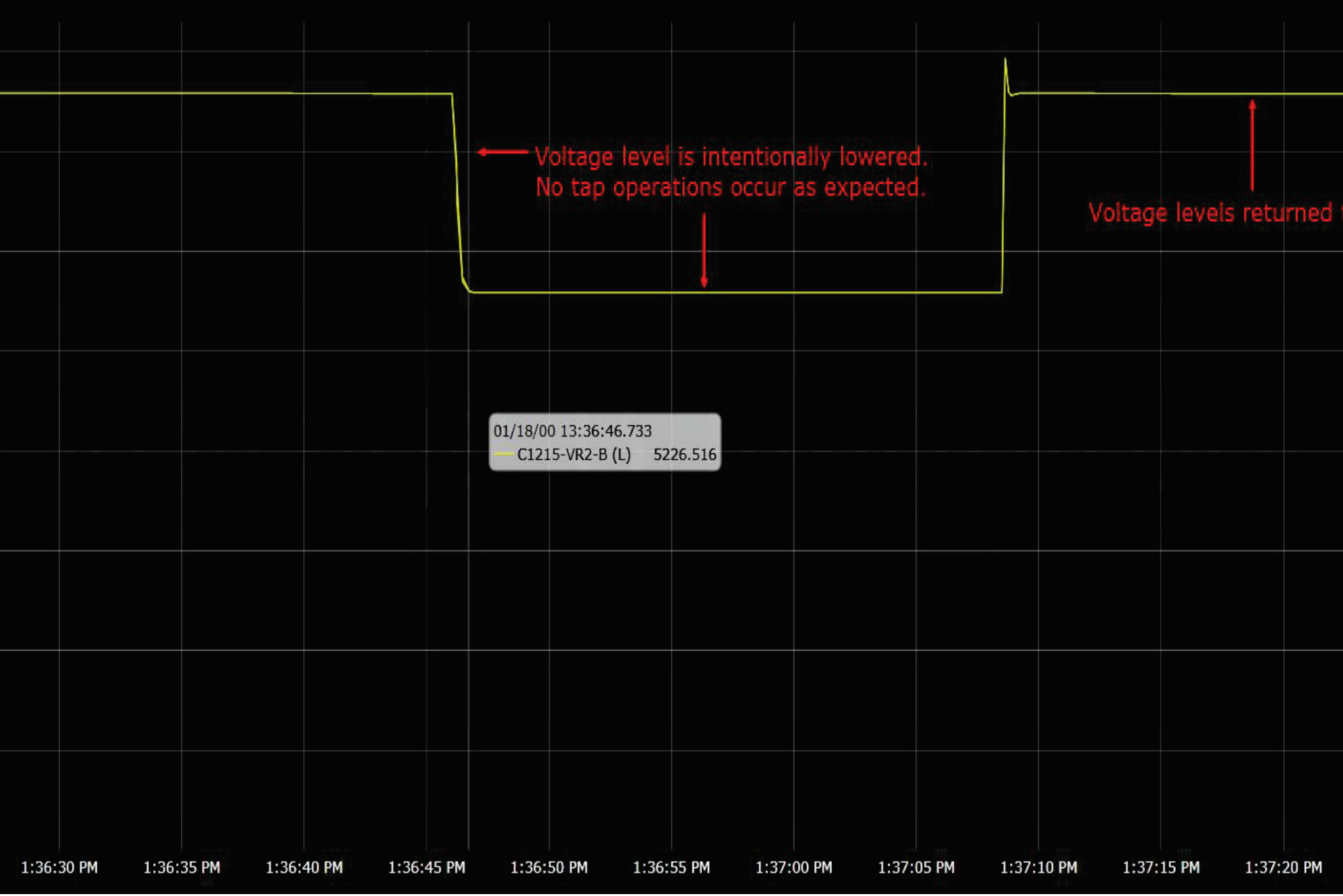
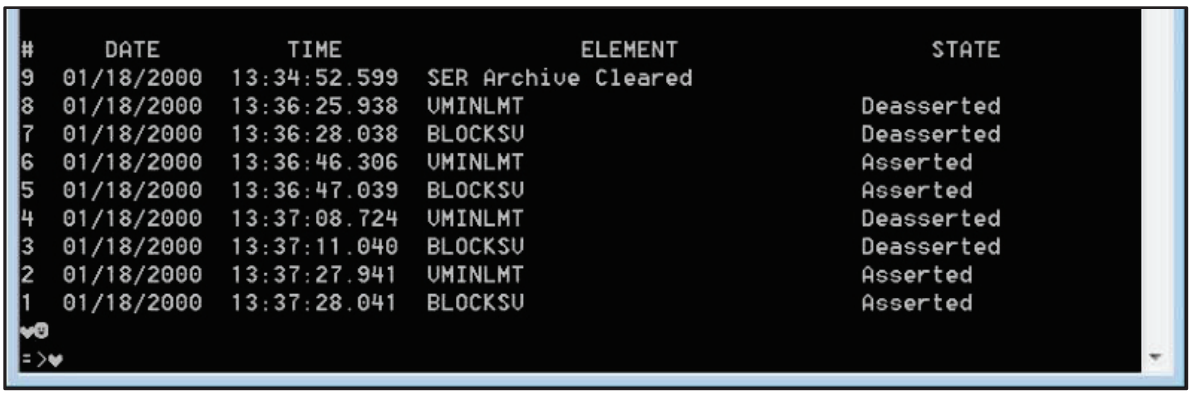


Figure 6.22: Test Scenario 3.7.3. Phase B Voltage Regulator Output Voltage Waveform



#	DATE	TIME	ELEMENT	STATE
9	01/18/2000	13:34:52.599	SER Archive Cleared	
8	01/18/2000	13:36:25.938	VMINLMT	Deasserted
7	01/18/2000	13:36:28.038	BLOCKSV	Deasserted
6	01/18/2000	13:36:46.306	VMINLMT	Asserted
5	01/18/2000	13:36:47.039	BLOCKSV	Asserted
4	01/18/2000	13:37:08.724	VMINLMT	Deasserted
3	01/18/2000	13:37:11.040	BLOCKSV	Deasserted
2	01/18/2000	13:37:27.941	VMINLMT	Asserted
1	01/18/2000	13:37:28.041	BLOCKSV	Asserted

=>

Figure 6.23: Test Scenario 3.7.3. Phase B Voltage Regulator SER

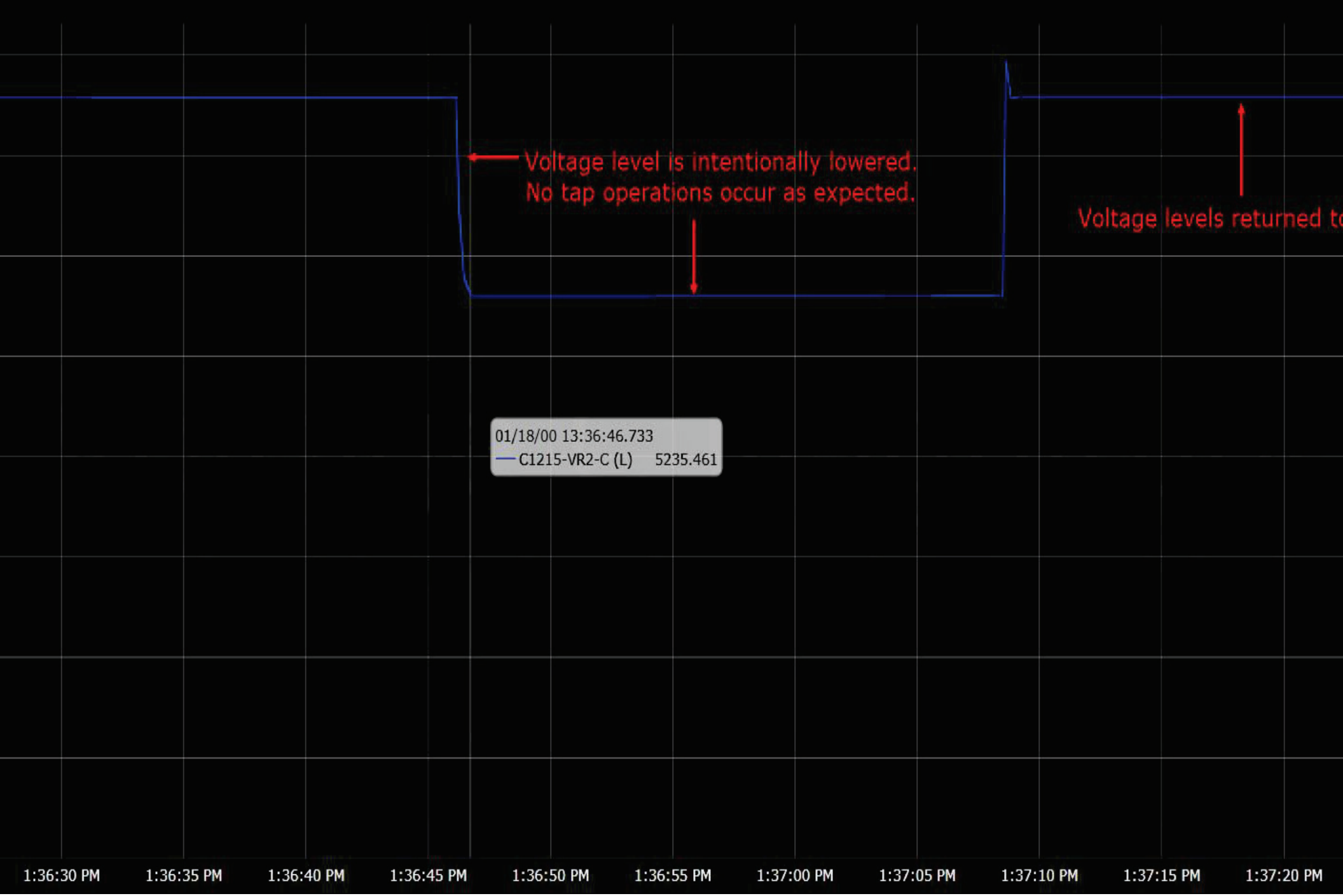
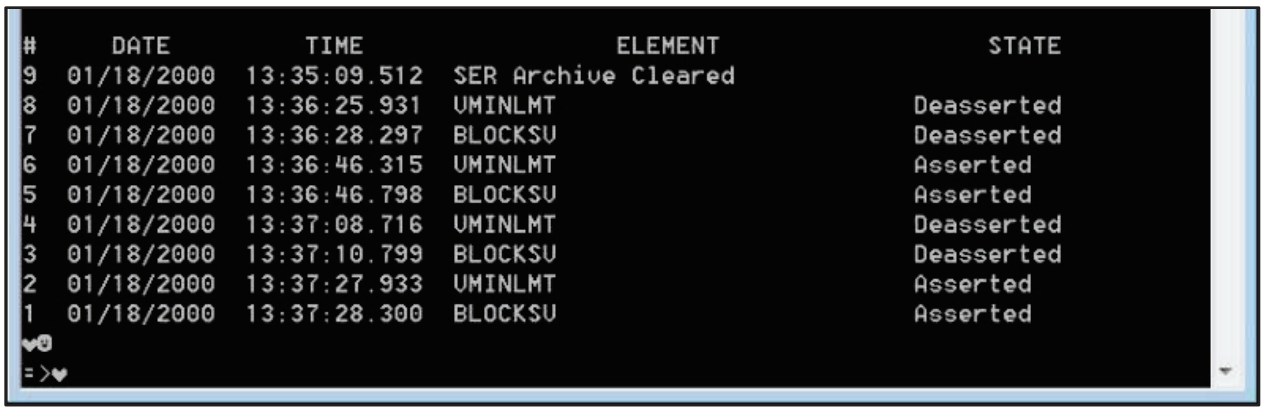


Figure 6.24: Test Scenario 3.7.3. Phase C Voltage Regulator Output Voltage Waveform



#	DATE	TIME	ELEMENT	STATE
9	01/18/2000	13:35:09.512	SER Archive Cleared	
8	01/18/2000	13:36:25.931	VMINLMT	Deasserted
7	01/18/2000	13:36:28.297	BLOCKSV	Deasserted
6	01/18/2000	13:36:46.315	VMINLMT	Asserted
5	01/18/2000	13:36:46.798	BLOCKSV	Asserted
4	01/18/2000	13:37:08.716	VMINLMT	Deasserted
3	01/18/2000	13:37:10.799	BLOCKSV	Deasserted
2	01/18/2000	13:37:27.933	VMINLMT	Asserted
1	01/18/2000	13:37:28.300	BLOCKSV	Asserted

=>

Figure 6.25: Test Scenario 3.7.3. Phase C Voltage Regulator SER

6.8.4 Load Profile Operation

Table 6.8 describes the operation of the voltage regulator during the 24-hour load profile run.

Table 6.8: Load Profile Operation

Objective: Verify the voltage regulator operation with the load profile enabled.					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. System with nominal voltage and current conditions: VA = 120 V ∠0° VB = 120 V ∠–120° VC = 120 V ∠+120° 2. Voltage regulator in AUTO and REMOTE modes. 3. Voltage regulation enabled. 4. Initial tap setting.	1. Run the RTDS model with the load scheduler ON.	1.a. **VOLTAGE LOW LIMIT** LED initially blinks red. 1.b. The voltage regulator detects the load voltage and raises or lowers the tap to bring the load voltage within the defined voltage band. 1.c. The above step repeats for each load step change.	1. The voltage regulator was observed to operate as desired, ensuring load voltage stayed within the defined voltage band for each load step.	Y	
Test notes: The voltage regulator operation is verified for each phase and for each load step change.					

The RTDS test case was run at the load profile provided by SDG&E and with a 2 V voltage regulation bandwidth. It was observed that the voltage regulators did not operate for the 24-hour load profile run. This was because the load variations do not lead to the system voltage crossing the forward bandwidth of the voltage regulators. This is illustrated for the Phase A voltage regulator in Figure 6.26 and Figure 6.27.

Based on recommendations from SDG&E, the load was increased considerably to best simulate the voltage regulator operation. The modified load profile was essentially the original load profile with each load point increased to three times the actual load. The modified load profile was run, resulting in voltage regulator operation. It was observed that the voltage regulators successfully regulated voltage at various points to bring the system voltage to within its normal operating band. Figure 6.28 through Figure 6.33 illustrate the voltage regulator operation with its corresponding SER data.

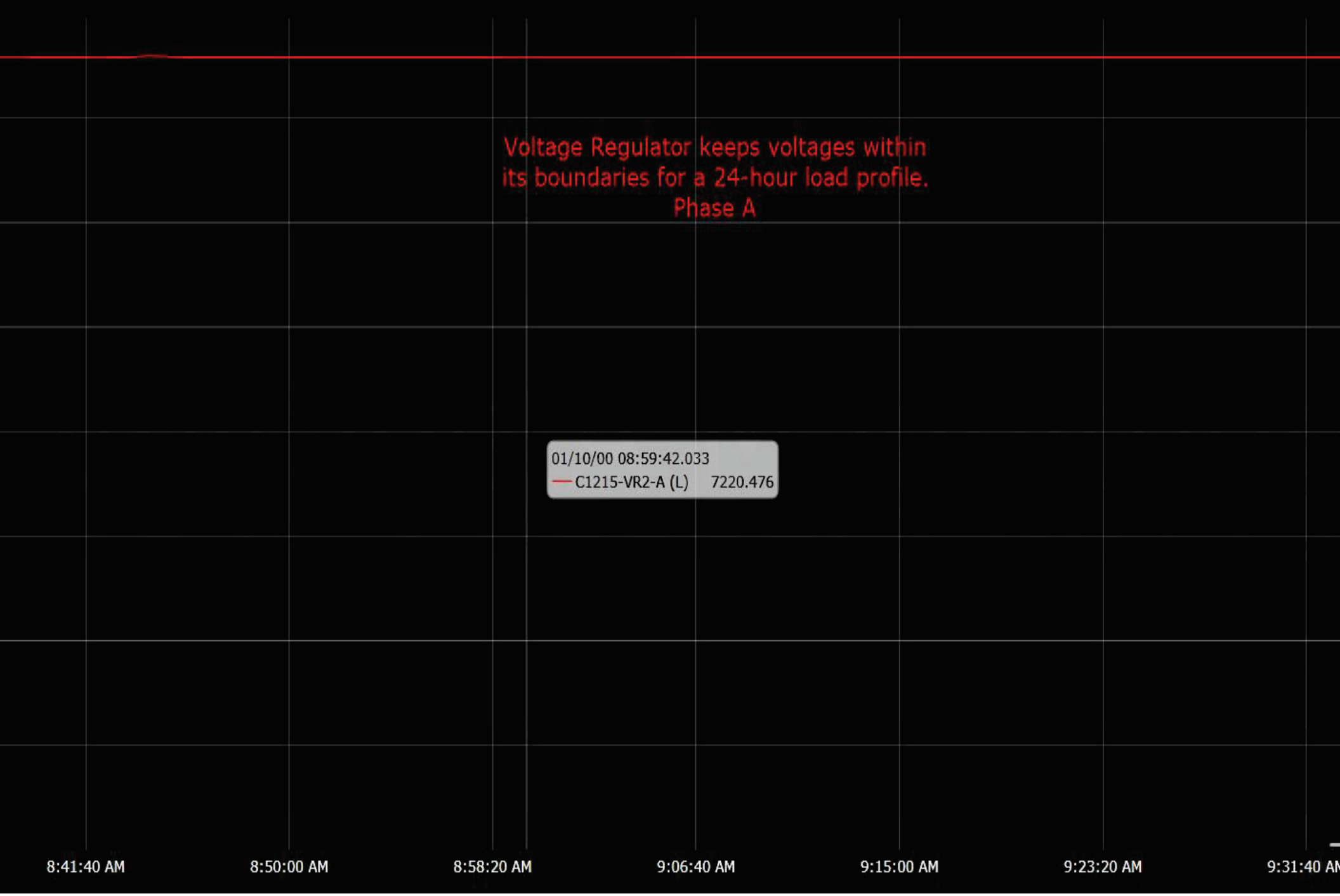


Figure 6.26: Test Scenario 3.7.4. Phase A Voltage Regulator Output Voltage Waveform – Normal Load Profile

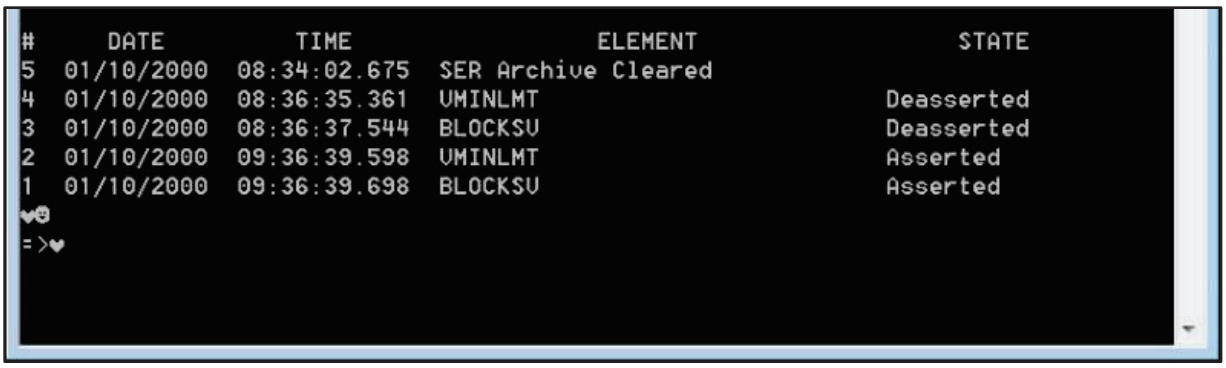


Figure 6.27: Test Scenario 3.7.4. Phase A Voltage Regulator SER – Normal Load Profile

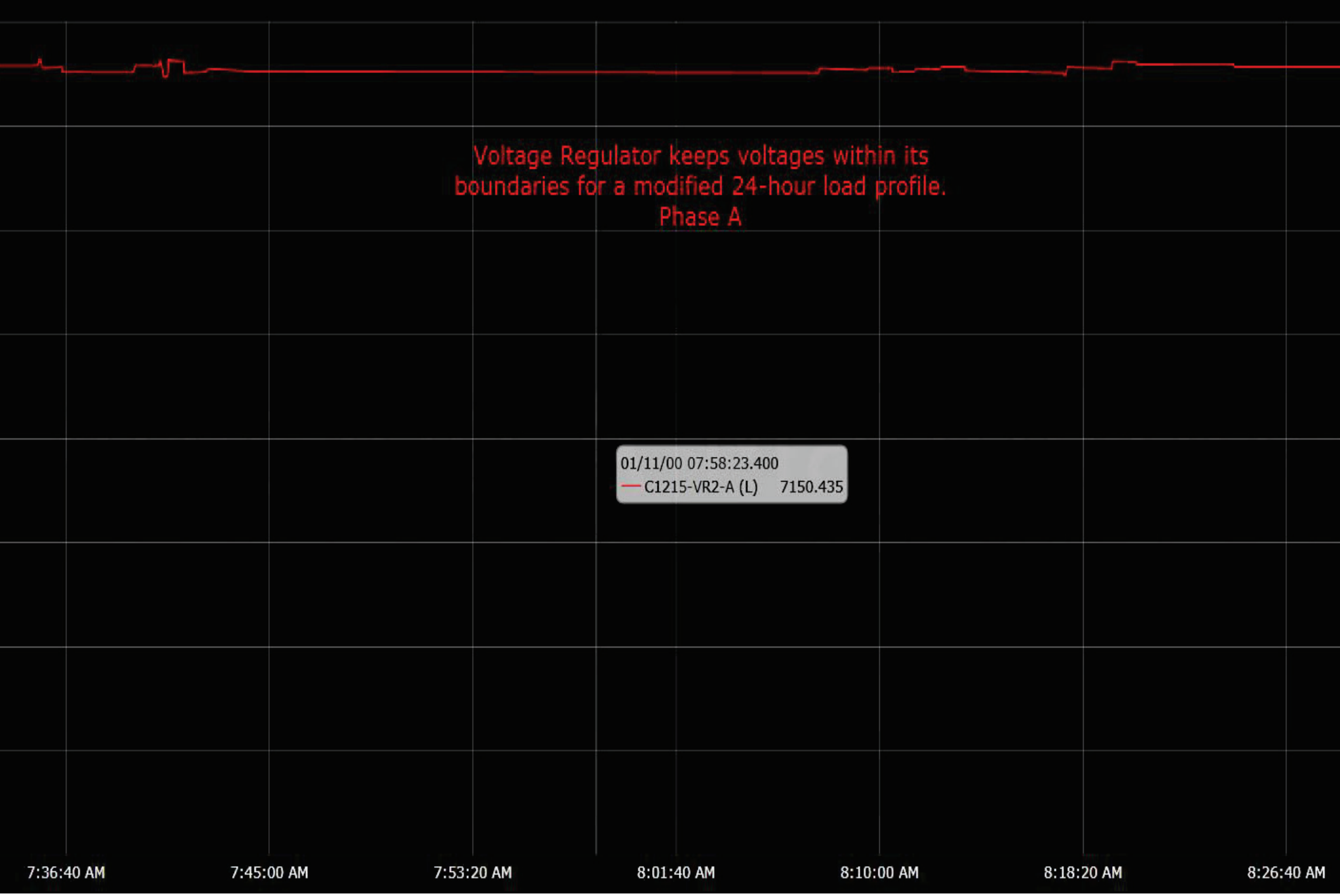
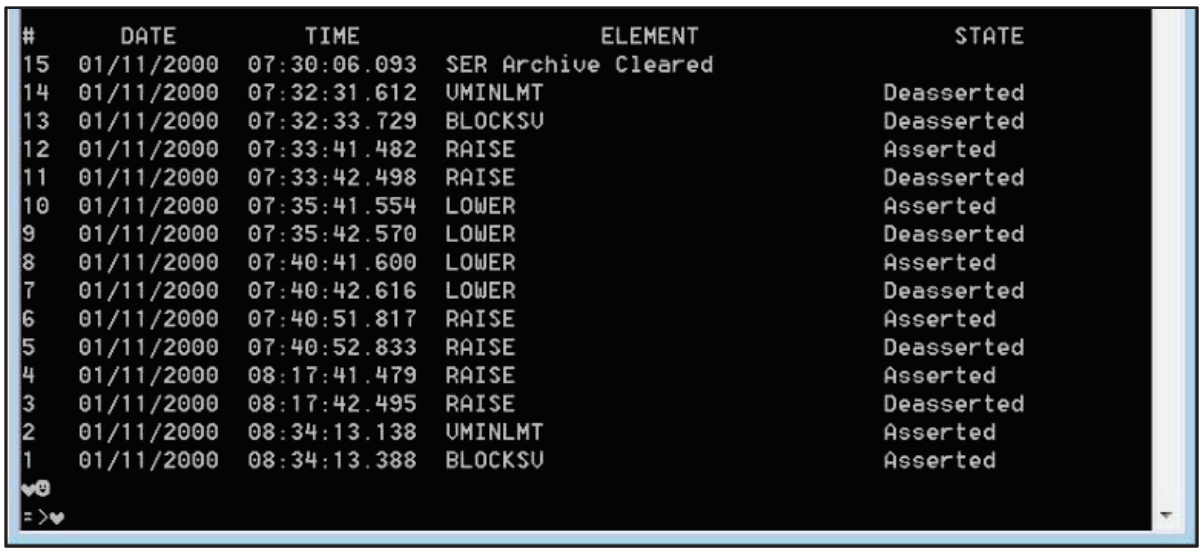


Figure 6.28: Test Scenario 3.7.4. Phase A Voltage Regulator Output Voltage Waveform – Modified Load Profile



#	DATE	TIME	ELEMENT	STATE
15	01/11/2000	07:30:06.093	SER Archive Cleared	
14	01/11/2000	07:32:31.612	VMINLMT	Deasserted
13	01/11/2000	07:32:33.729	BLOCKSV	Deasserted
12	01/11/2000	07:33:41.482	RAISE	Asserted
11	01/11/2000	07:33:42.498	RAISE	Deasserted
10	01/11/2000	07:35:41.554	LOWER	Asserted
9	01/11/2000	07:35:42.570	LOWER	Deasserted
8	01/11/2000	07:40:41.600	LOWER	Asserted
7	01/11/2000	07:40:42.616	LOWER	Deasserted
6	01/11/2000	07:40:51.817	RAISE	Asserted
5	01/11/2000	07:40:52.833	RAISE	Deasserted
4	01/11/2000	08:17:41.479	RAISE	Asserted
3	01/11/2000	08:17:42.495	RAISE	Deasserted
2	01/11/2000	08:34:13.138	VMINLMT	Asserted
1	01/11/2000	08:34:13.388	BLOCKSV	Asserted

=>

Figure 6.29: Test Scenario 3.7.4. Phase A Voltage Regulator SER – Modified Load Profile

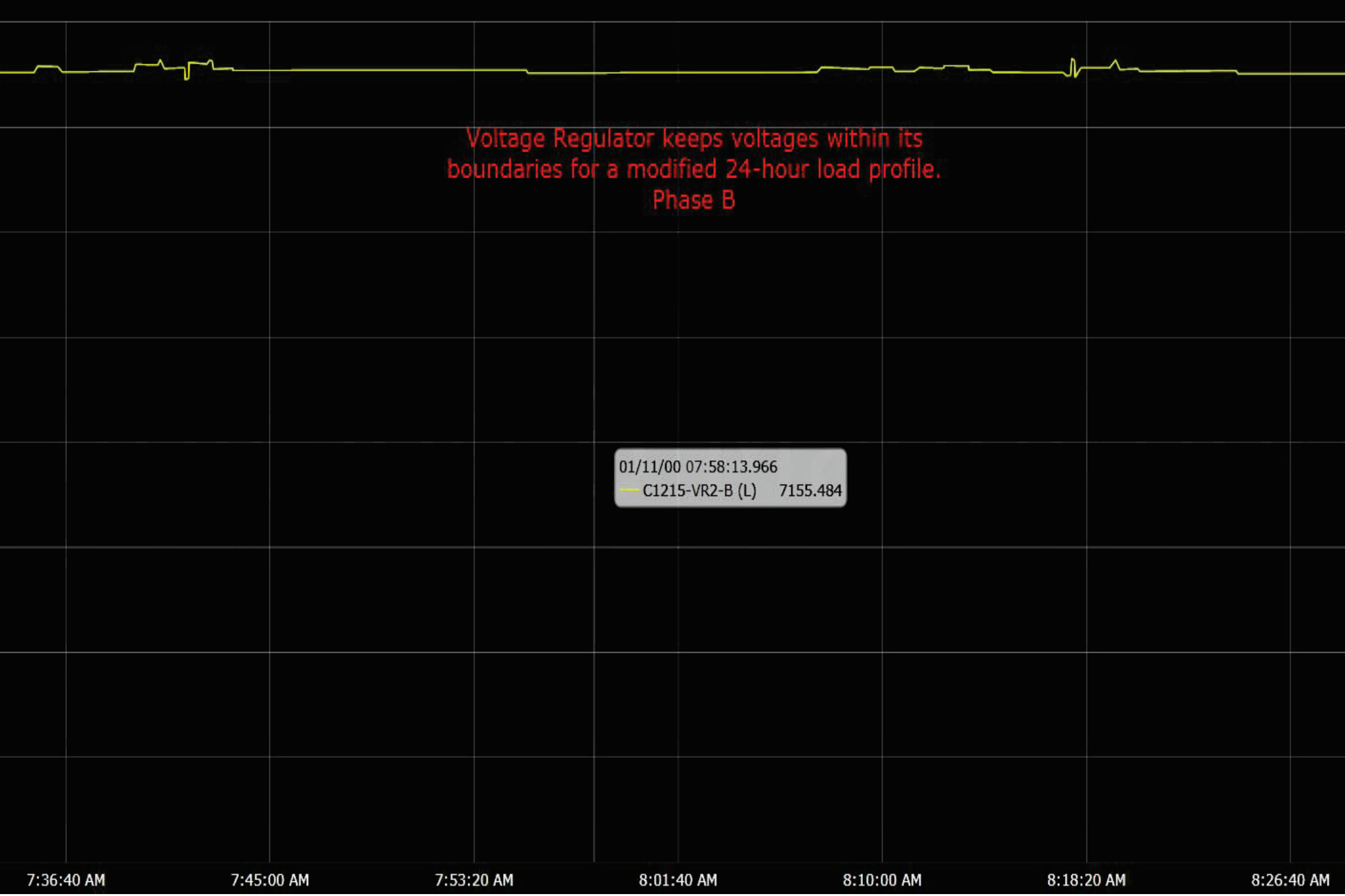
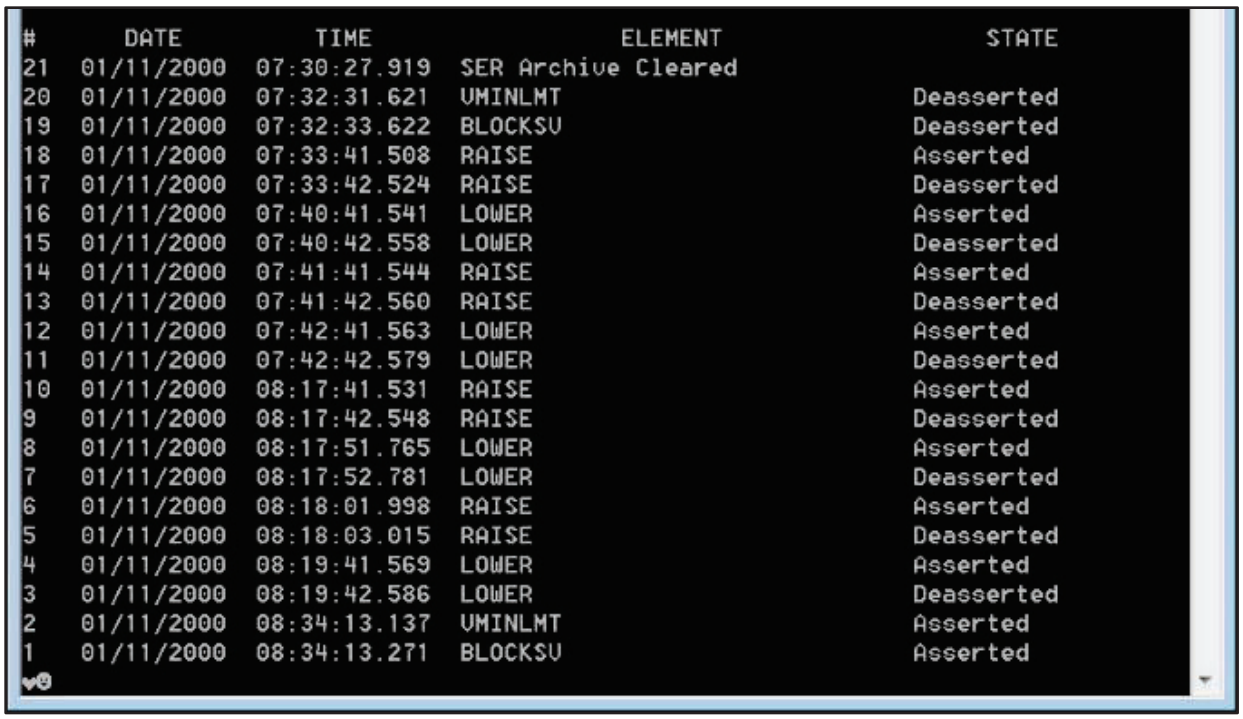


Figure 6.30: Test Scenario 3.7.4. Phase B Voltage Regulator Output Voltage Waveform – Modified Load Profile



#	DATE	TIME	ELEMENT	STATE
21	01/11/2000	07:30:27.919	SER Archive Cleared	
20	01/11/2000	07:32:31.621	VMINLMT	Deasserted
19	01/11/2000	07:32:33.622	BLOCKSV	Deasserted
18	01/11/2000	07:33:41.508	RAISE	Asserted
17	01/11/2000	07:33:42.524	RAISE	Deasserted
16	01/11/2000	07:40:41.541	LOWER	Asserted
15	01/11/2000	07:40:42.558	LOWER	Deasserted
14	01/11/2000	07:41:41.544	RAISE	Asserted
13	01/11/2000	07:41:42.560	RAISE	Deasserted
12	01/11/2000	07:42:41.563	LOWER	Asserted
11	01/11/2000	07:42:42.579	LOWER	Deasserted
10	01/11/2000	08:17:41.531	RAISE	Asserted
9	01/11/2000	08:17:42.548	RAISE	Deasserted
8	01/11/2000	08:17:51.765	LOWER	Asserted
7	01/11/2000	08:17:52.781	LOWER	Deasserted
6	01/11/2000	08:18:01.998	RAISE	Asserted
5	01/11/2000	08:18:03.015	RAISE	Deasserted
4	01/11/2000	08:19:41.569	LOWER	Asserted
3	01/11/2000	08:19:42.586	LOWER	Deasserted
2	01/11/2000	08:34:13.137	VMINLMT	Asserted
1	01/11/2000	08:34:13.271	BLOCKSV	Asserted

Figure 6.31: Test Scenario 3.7.4. Phase B Voltage Regulator SER – Modified Load Profile

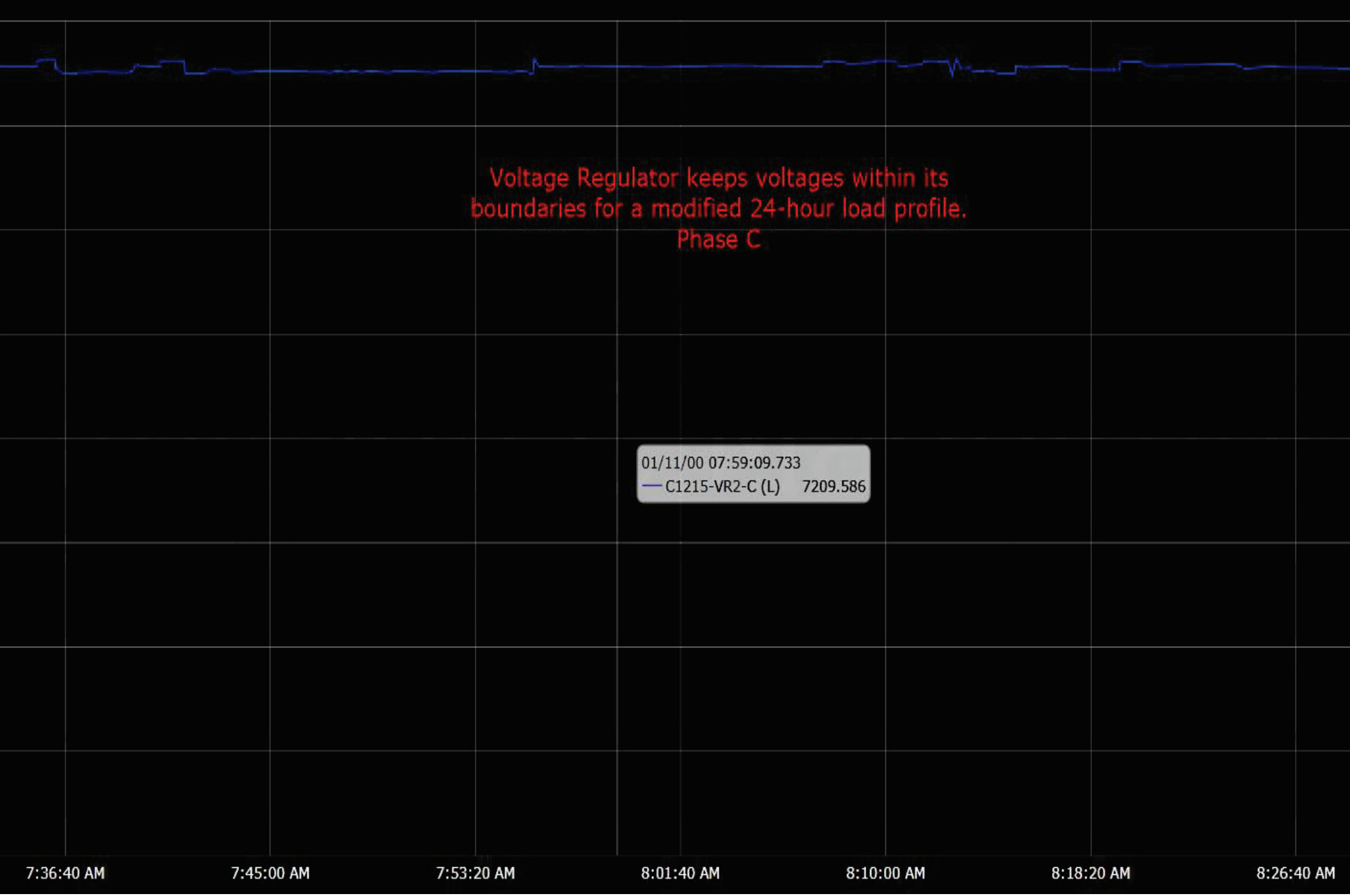
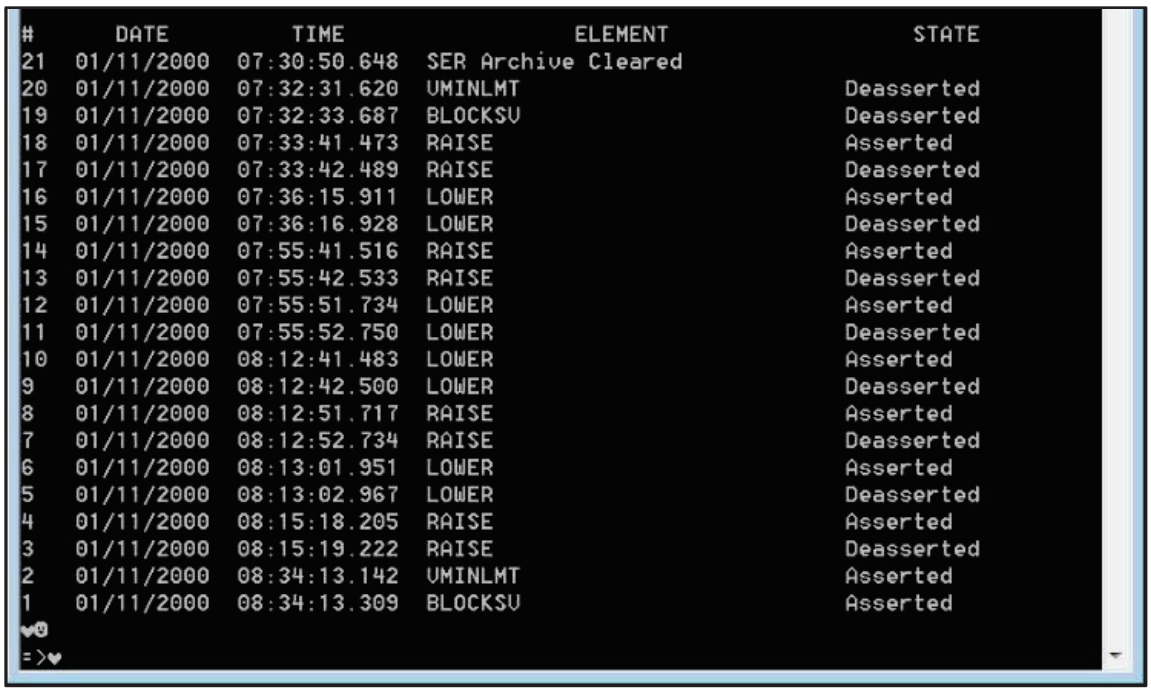


Figure 6.32: Test Scenario 3.7.4. Phase C Voltage Regulator Output Voltage Waveform – Modified Load Profile



#	DATE	TIME	ELEMENT	STATE
21	01/11/2000	07:30:50.648	SER Archive Cleared	
20	01/11/2000	07:32:31.620	VMINLMT	Deasserted
19	01/11/2000	07:32:33.687	BLOCKSV	Deasserted
18	01/11/2000	07:33:41.473	RAISE	Asserted
17	01/11/2000	07:33:42.489	RAISE	Deasserted
16	01/11/2000	07:36:15.911	LOWER	Asserted
15	01/11/2000	07:36:16.928	LOWER	Deasserted
14	01/11/2000	07:55:41.516	RAISE	Asserted
13	01/11/2000	07:55:42.533	RAISE	Deasserted
12	01/11/2000	07:55:51.734	LOWER	Asserted
11	01/11/2000	07:55:52.750	LOWER	Deasserted
10	01/11/2000	08:12:41.483	LOWER	Asserted
9	01/11/2000	08:12:42.500	LOWER	Deasserted
8	01/11/2000	08:12:51.717	RAISE	Asserted
7	01/11/2000	08:12:52.734	RAISE	Deasserted
6	01/11/2000	08:13:01.951	LOWER	Asserted
5	01/11/2000	08:13:02.967	LOWER	Deasserted
4	01/11/2000	08:15:18.205	RAISE	Asserted
3	01/11/2000	08:15:19.222	RAISE	Deasserted
2	01/11/2000	08:34:13.142	VMINLMT	Asserted
1	01/11/2000	08:34:13.309	BLOCKSV	Asserted

=>

Figure 6.33: Test Scenario 3.7.4. Phase C Voltage Regulator SER – Modified Load Profile

6.9 RECOMMENDATIONS

The recommended standard for voltage regulation as specified by SDG&E was ±5 percent, which equates to a forward bandwidth of 12 V. However, it is recommended to narrow the forward bandwidth to 2 V to allow for a better regulation. This would ensure less fluctuations in the regulated voltage and steady control over the standard voltage limits.

7 CAPACITOR BANK CONTROLLER

This section demonstrates the functions and capabilities of a capacitor bank controller. The capacitor bank controller continuously monitors the circuit parameters and switches in and out based on set criteria. The analysis and understanding of the capacitor bank controller, as a stand-alone device for correcting the voltage profile, is helpful in enhancing the voltage support coordination scheme using multiple devices described in Section 10.

This section provides the test procedure to demonstrate the various modes of operation including time of day (TOD), voltage, and KVAR for a CBC on a distribution circuit. It also provides test procedures for protection lockout functionalities. For this test, LOCAL/SUPY (supervisory) and AUTO/MANUAL modes of operation are considered. Results are recorded at the end of each test.

Tests are carried out to evaluate the best times to switch the capacitor bank in or out, based on the load and voltage profile of the modeled SDG&E test circuits.

The choice of controller does not affect the type of tests. The controller controls capacitor 131CW in the coastal-residential test circuit. The power quality meter, located downstream of 131CW at Bus P322964, is considered as a line monitor on the circuit. Refer to Appendix A for the one-line diagram of the test circuit. The coastal-residential test circuit has two capacitors: a 131CW (SCADA capacitor) and a 461CW (fixed capacitor).

7.1 TEST SETUP

This section includes details on the hardware test setup assembly in the laboratory environment.

7.1.1 I/O List

Table 7.1 shows the designated I/O contacts for the controller. The 52b contacts are used to indicate the switch status.

Table 7.1: Controller I/O List

Output Contact	Function	Input Contact	Function
OUT101	Open Phase A	IN102	52b Phase A
OUT301	Open Phase B	IN302	52b Phase B
OUT303	Open Phase C	IN304	52b Phase C
OUT102	Close Phase A	–	–
OUT302	Close Phase B	–	–
OUT304	Close Phase C	–	–

7.1.2 Front-Panel Layout

Figure 7.1 illustrates the proposed front-panel layout of the controller. The selected controller has 8 operator-controlled pushbuttons and 22 programmable LEDs.

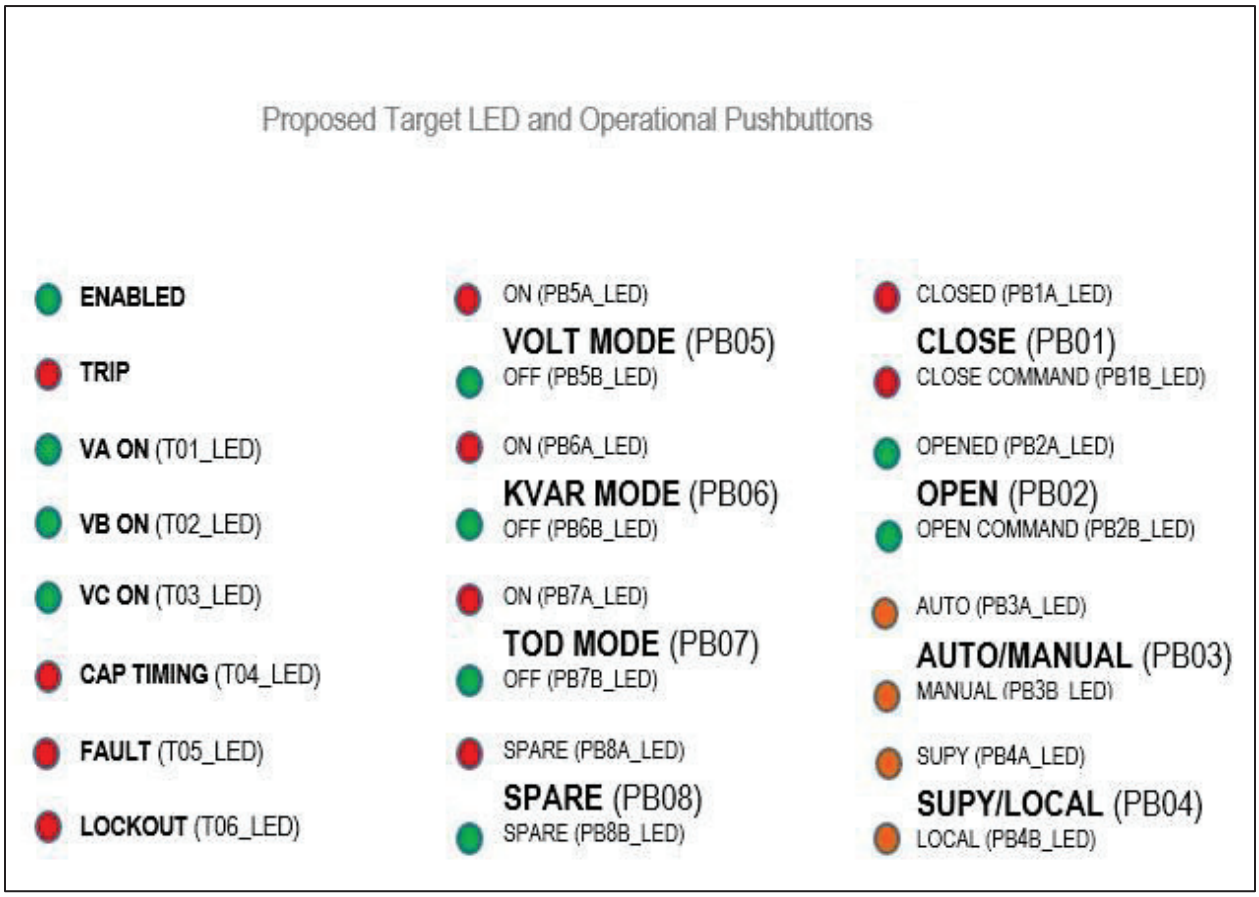


Figure 7.1: Controller Front-Panel Layout

7.1.3 Low-Level Test Interface

The controller has a low-level test interface on the four ACI/AVI current/voltage cards with both low-level voltage inputs and regular voltage inputs in Slot Z as shown in Figure 7.2. The RTDS analog outputs channel is connected to the controller via Connector J2 on Slot Z card with a ribbon cable.

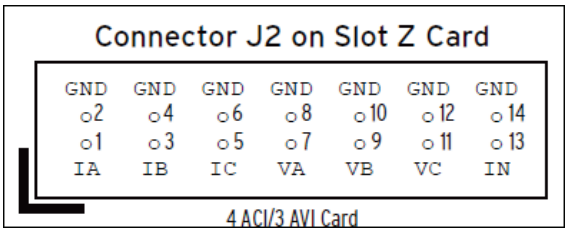


Figure 7.2: Controller Low-Level Test Interface J2

7.1.4 RTDS and Relay Interface

Figure 7.3 illustrates the interface between the RTDS and the controller/power quality meter. The controller is connected to the RTDS I/O cube such that it receives analog and digital inputs from the RTDS, and sends digital outputs or control signals to the RTDS. The power quality meter is connected to receive analog inputs from the RTDS.

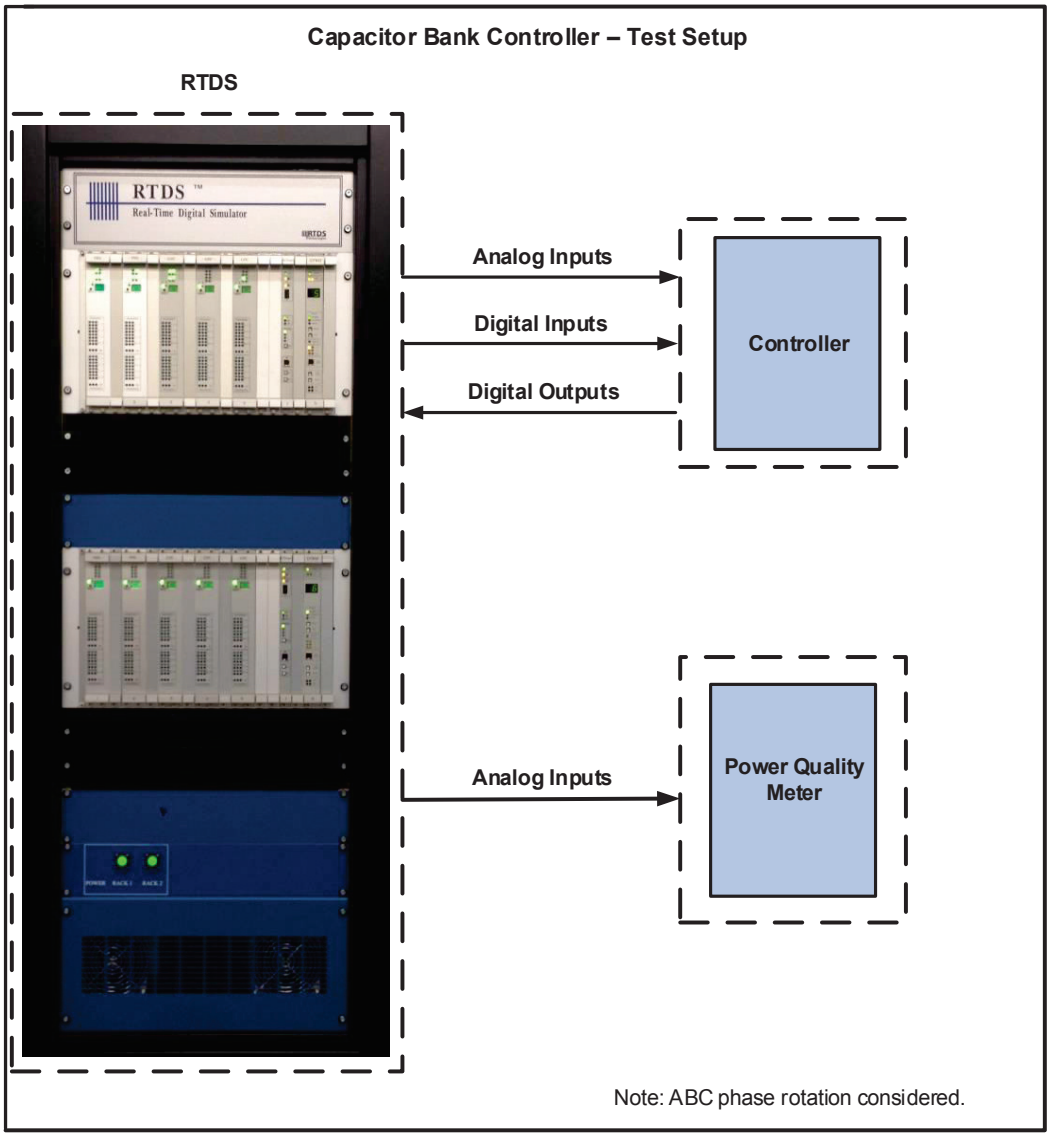


Figure 7.3: CBC – Test Setup

Figure 7.4 illustrates analog inputs from the RTDS to the controller and the power quality meter via the GTAO Cards 3 and 4, respectively.

- GTAO Card 3: Channels 7 through 9 are reserved for currents and Channels 10 through 12 are reserved for line-to-neutral voltages for the controller.
- GTAO Card 4: Channels 7 through 9 are reserved for line-to-neutral voltages for the power quality meter.

Figure 7.5 and Figure 7.6 show the mapping for digital inputs and digital outputs, respectively, via the GTFPI card.

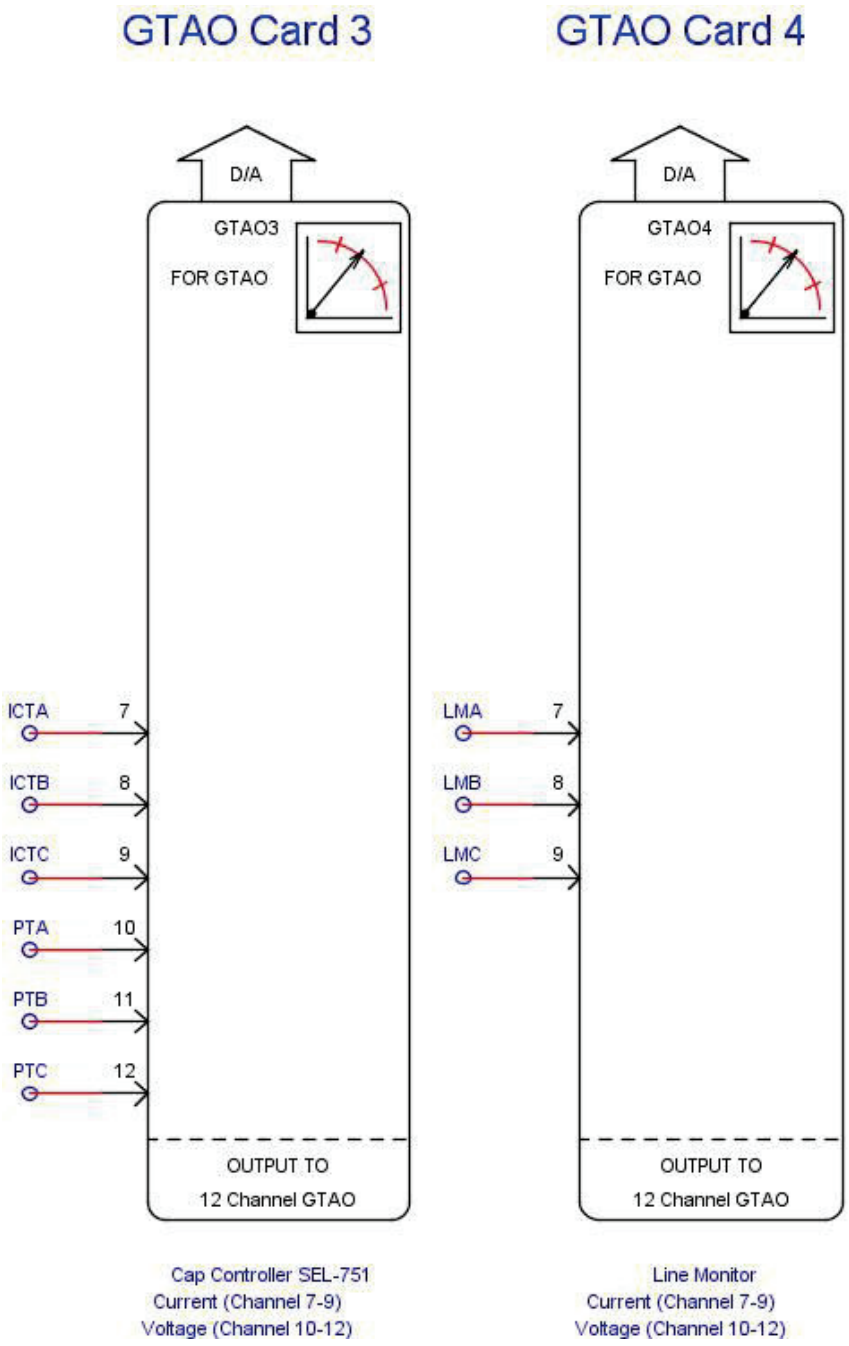


Figure 7.4: RTDS and Controller Interface – Analog Inputs

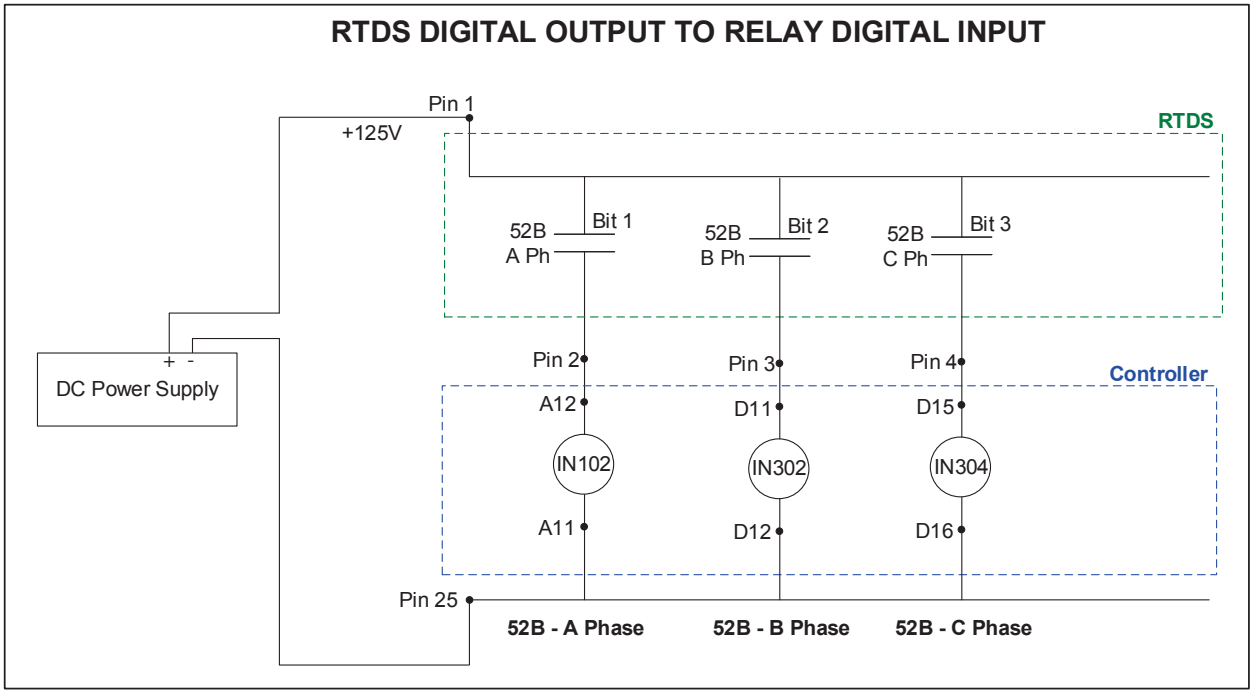


Figure 7.5: RTDS and Controller Interface – Digital Inputs

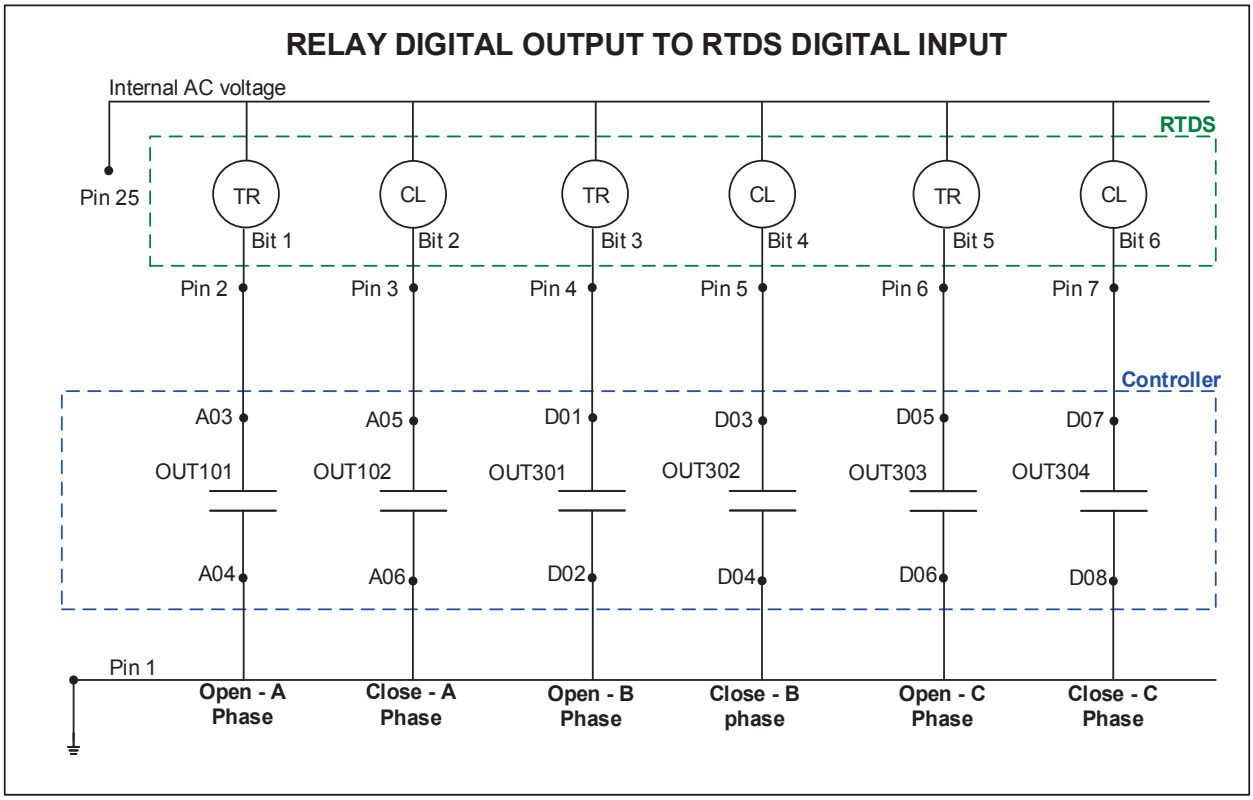


Figure 7.6: RTDS and Controller Interface – Digital Outputs

7.1.5 Tests Summary

The following tests were performed by the capacitor bank controller:

1. Modes of operations

    a. SUPY/LOCAL: SUPY refers to supervisory or remote control via SCADA. LOCAL mode refers to control via the relay front panel.

    b. AUTO/ MANUAL: AUTO refers to automatic control via various control strategies defined in the relay logic. MANUAL mode disables automatic switching operations.

    Capacitor bank switching can be carried out via:

    i. Pushbuttons when the controller is in LOCAL and MANUAL modes.

    ii. SCADA controls when the controller is in SUPY and MANUAL modes.

    iii. Voltage, KVAR, and TOD modes when the controller is in LOCAL and AUTO modes.

2. Automatic control strategies

    a. Voltage control

    When AUTO and Voltage Control modes are enabled and rms line-to-neutral voltage on all the phases is above the high-voltage threshold or below the low-voltage threshold, the controller starts timing to open or close the capacitor bank breaker. During this time, the front-panel LEDs indicate pending open or close operation. If the condition persists for 1 second (user settable), the controller initiates the capacitor bank switching.

    Voltage conditions out of the normal operating band are simulated. The voltage profile is observed post-capacitor bank switching.

    b. KVAR control

    When AUTO and KVAR Control modes are enabled, the controller operates the capacitor bank based on the measured reactive power load. Active power flow must be in the forward direction.

    When the lagging or leading reactive power exceeds the respective threshold, the controller will begin timing to operate. Refer Figure 7.7. During this time, the front-panel LEDs indicate the pending operation. If the condition persists for 1 second (user settable), the controller initiates the capacitor bank switching.

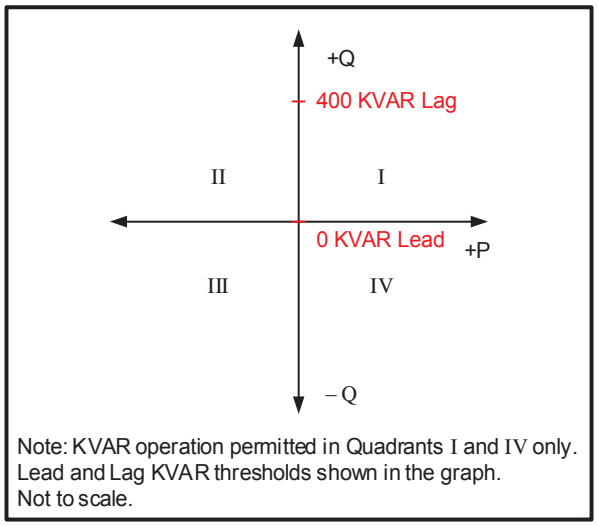


Figure 7.7: CBC KVAR Operations – Quadrants I and IV

c. TOD control

The controller provides two TOD programs: one for weekdays and one for weekends, which open and close the capacitor bank breaker based on the time of day. The controller initiates a close when the time reaches the close time setting and opens when the time reaches the open time setting.

Based on the testing carried out on the modeled SDG&E circuits, the best TOD operation setting will be evaluated.

3. Protection lockouts/alarms

a. Overvoltage lockout

If the measured voltage increases above the set threshold, the controller opens the switch and latches a lockout indication. This condition can be reset locally or remotely.

b. Voltage imbalance lockout

If the calculated voltage imbalance increases the set threshold, the controller opens the switch and latches a lockout indication. This condition can be reset locally or remotely.

c. High-current alarm

If the system current exceeds the set threshold, the controller alarms for as long as the high-current condition is present. The front-panel LED is programmed for this alarm. A high-current alarm condition does not inhibit any switching operations. It is understood that the upstream protection will arrest the high-current condition in the system.

4. Hunting lockout

The controller activates the hunting process any time the capacitor bank switch opens or closes while in AUTO mode. It remains active for the time set by the hunting time window setting. The controller counts each successive open and close operation while in AUTO mode.

When the hunting processing is active, a timer counts the minutes elapsed from the first switching operation. If the number of operations reaches the maximum allowed count, the controller latches in a hunting lockout. All automatic control ceases when a hunting lockout is latched in.

A hunting lockout latch can be reset remotely or locally.

5. Operations counter for SCADA

   The controller is programmed to count the number of open/close operations based on the following time periods. This information can be passed on to SCADA via DNP3 as analog inputs and can be used for further operational analysis.

   a. Since installation

   b. Yearly

   c. Daily

7.1.6 Analog Thresholds

Table 7.2 illustrates the thresholds used in these tests.

Table 7.2: Capacitor Bank Controller Analog Thresholds

SR. NO.	Primary	Secondary	Notes
Nominal voltage (L-N)	6.9 kV	69 V	Circuit specification
Capacitor bank size (single phase [1-ph])	400 KVAR	–	Circuit specification
PT ratio	100	–	–
CT ratio	600	–	–
Low-voltage threshold	6.55 kV	65.55 V	–5% of nominal
High-voltage threshold	7.24 kV	72.45 V	+5% of nominal
Lagging KVAR threshold (1-ph)	400 KVAR	6.67 VAR	–
Leading KVAR threshold (1-ph)	0 KVAR	0 VAR	–
Voltage imbalance threshold	–	–	3%
Overvoltage threshold	7.6 kV	76 V	+10% of nominal
High-current threshold	600 A	1 A	600 A
Hunting time window	–	–	60 min
Hunting count threshold	–	–	5 counts
TOD1 start day	–	–	2
TOD1 stop day	–	–	6
TOD1 close time	–	–	930 min (15:30:00)
TOD1 open time	–	–	300 min (05:00:00)
TOD2 start day	–	–	7
TOD2 stop day	–	–	1
TOD2 close time	–	–	930 min (15:30:00)
TOD2 open time	–	–	300 min (05:00:00)

7.2 TEST SCENARIOS AND RESULTS

Figure 7.8 is divided into three horizontal screens. The first screen shows the status of the capacitor bank controller operating modes – enabled or disabled. The second tab shows if any lockout conditions are present. The third tab shows the status of the capacitor bank breaker. If 52B is asserted, the breakers are opened, and if 52B is de-asserted, the breakers are closed. The top right-side shows "digital"- this implies that the screenshot refers to the digital results for the test under discussion. This layout is applicable to all digital test results capture in this section.

7.2.1 SUPY and LOCAL Toggle

Table 7.3: SUPY and LOCAL Toggle

Objective: Verify appropriate indication for SUPY/LOCAL operating mode.					
Specific instruction: Carry out Test Action 1, observe corresponding results. Move on to Test Action 2.					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. Controller in LOCAL mode. **LOCAL** LED is ON.	1. Press PB04. 2. Press PB04.	1.a. **SUPY** LED – ON 1.b. **LOCAL** LED – OFF 1.c. Controller in SUPY mode 2.a. **SUPY** LED – OFF 2.b. **LOCAL** LED – ON 2.c. Controller in LOCAL mode	Refer to Figure 7.8 and Figure 7.9.	Y	
Test notes: SUPY/LOCAL toggle allowed in either AUTO or MANUAL mode.					

Results/observations: Figure 7.8 shows SUPY mode is enabled because of Test Action 1 shown in Table 7.3. Figure 7.9 shows SUPY mode is disabled, which implies that LOCAL mode is enabled because of Test Action 2 shown in Table 7.3. Accurate observations were made on the relay front-panel LED.

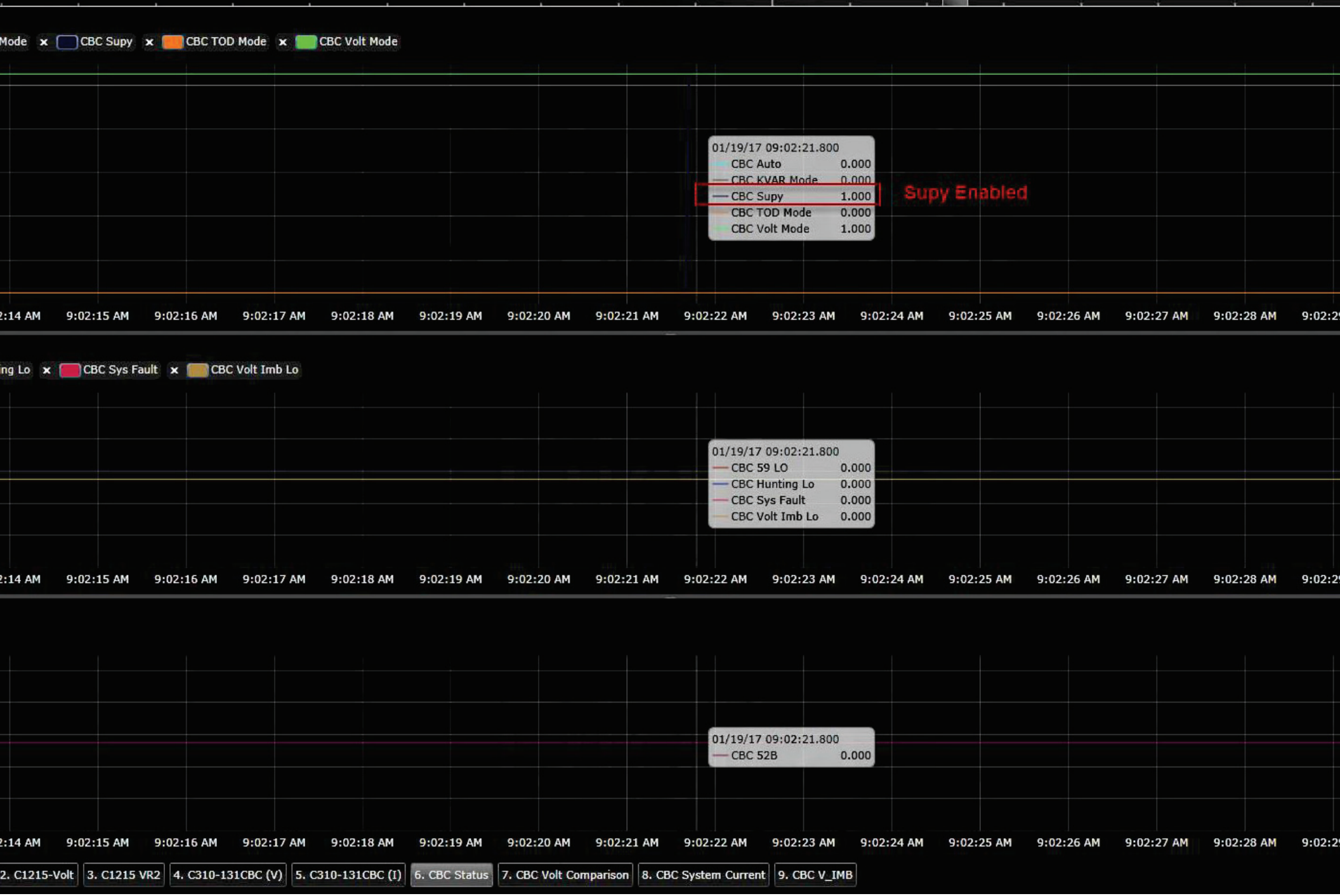


Figure 7.8: CBC SUPY Mode Enabled



Figure 7.9: CBC LOCAL Mode Enabled

7.2.2 AUTO and MANUAL Toggle – From LOCAL Control

Table 7.4: AUTO and MANUAL Toggle – LOCAL Control

Objective: Verify appropriate indication for AUTO/MANUAL operating mode.					
Specific instruction: AUTO/MANUAL toggle allowed by PB03 in LOCAL mode. Carry out Test Action 1, observe corresponding results. Move on to Test Action 2.					
Negative test: Verify modes do not toggle via remote bits when in LOCAL.					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. Controller in MANUAL mode. **MANUAL** LED is ON.	1. Press PB03. 2. Press PB03.	1.a. **AUTO** LED – ON 1.b. **MANUAL** LED – OFF 1.c. Controller in AUTO mode 2.a. **AUTO** LED – OFF 2.b. **MANUAL** LED – ON 2.c. Controller in MANUAL mode	Refer to Figure 7.10 and Figure 7.11.	Y	
Test notes: The controller may be placed in AUTO mode when there are no lockout conditions and all three-phase voltages are healthy.					

Results/observations: Figure 7.10 shows AUTO mode is enabled because of Test Action 1 shown in Table 7.4. Figure 7.11 shows AUTO mode is disabled, which implies that MANUAL mode is enabled because of Test Action 2 shown in Table 7.4. Accurate observations were made on the relay front-panel LED.

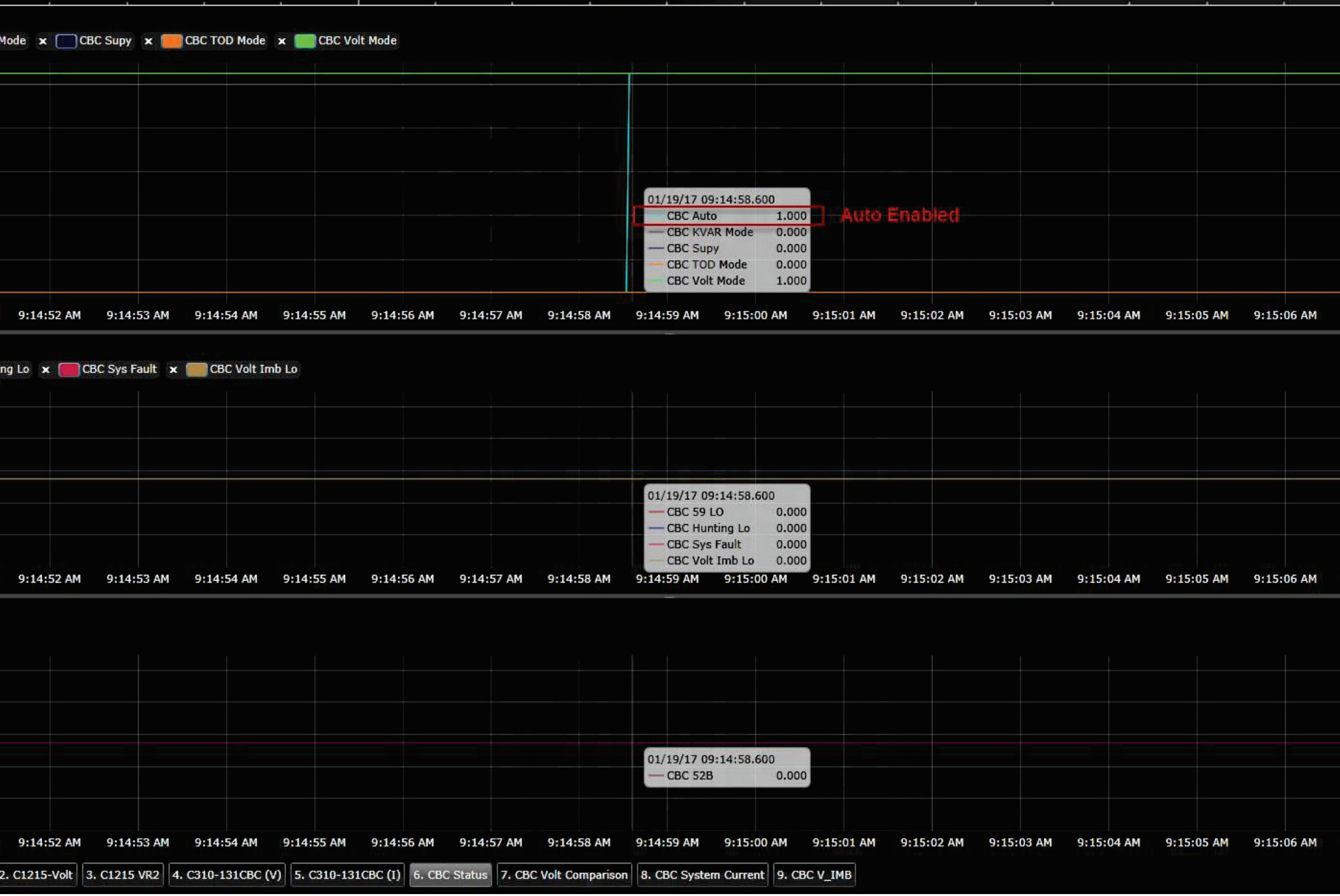


Figure 7.10: CBC AUTO Mode Enabled



Figure 7.11: CBC MANUAL Mode Enabled

7.2.3 Automatic Voltage Control Operation

When the controller is set to AUTO mode while Voltage control mode is enabled via PB05, the controller automatically opens and closes the capacitor bank to maintain the voltage between the high-voltage threshold and the low-voltage threshold. **Line-to-neutral voltages for all three phases must be outside the thresholds for valid operations.** Refer to Table 7.5 and Table 7.6 for the test procedures.

Table 7.5: High-Voltage Open Operation

Objective: Verify capacitor breaker opens for high-voltage conditions.					
Specific instruction: Ensure system is not in lockout (T06 LED).					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. System with nominal voltage and current conditions: A = 69 V ∠0° VB = 69 V ∠–120° VC = 69 V ∠+120° 2. Controller in AUTO and LOCAL mode. 3. Voltage control enabled. 4. Breaker is closed.	1. Shed the following loads to generate a high-voltage condition: LD32, LD33, LD35, LD37, LD49, LD50	1.a. Countdown timer starts for 1 s. 1.b. **OPEN COMMAND** LED blinks red. 1.c. **OPENED** LED ON after successful open operation.	Refer to Figure 7.12 and Figure 7.13.	Y	
Test notes: No operation in AUTO and SUPY mode. Observe system voltage profile after the switching operation. Refer to Appendix A for C310 circuit one-line diagram.					

Results/observations: Loads LD32, LD33, LD35, LD37, LD49, and LD50 were shed to simulate a high-voltage condition to observe the capacitor bank switching operation. It is observed that the capacitor bank controller verified if the high-voltage condition existed for a minimum of 1 second (user-settable pickup time) before switching the capacitors out. The pickup time is recommended to avoid switching operations because of momentary voltage fluctuations. Once the capacitors were switched out, the voltage was observed to be within the permitted band of ±5 percent. Refer to Figure 7.12 for the voltage profile capture. The visualization software was programmed to alarm for a high-voltage condition as shown in the right side of Figure 7.12. Figure 7.13 shows the digital status. AUTO and VOLTAGE modes were enabled for this operation. No lockout conditions were present. Capacitor bank switching is captured by the transition of the CBC 52B status from 0 to 1. Accurate observations were made on the relay front-panel LED.



Figure 7.12: CBC High-Voltage Condition



Figure 7.13: CBC High-Voltage Switching Operation

Table 7.6: Low-Voltage Close Operation

Objective: Verify capacitor breaker closes for low-voltage conditions.					
Specific instruction: Ensure system is not in lockout (T06 LED).					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. System with nominal voltage and current conditions: VA = 69 V ∠0° VB = 69 V ∠–120° VC = 69 V ∠+120° 2. Controller in AUTO and LOCAL mode. 3. Voltage control enabled. 4. Breaker is open.	1. Run load profile at 1.75 pu to simulate low-voltage conditions.	1.a. Countdown timer starts for 1 s. 1.b. **CLOSE COMMAND** LED blinks red. 1.c. **CLOSED** LED ON after successful close operation.	Refer to Figure 7.14 and Figure 7.15.	Y	
Test notes: No operation in AUTO/SUPY mode. Observe system voltage profile after the switching operation.					

Results/observations: The load profile was run at 1.75 pu to simulate a low-voltage condition to observe the capacitor bank switching operation. It is observed that the capacitor bank controller verified if the low-voltage condition existed for a minimum of 1 second (user-settable pickup time) before switching the capacitors in. The pickup time is recommended to avoid switching operations because of momentary voltage fluctuations. Once the capacitors were switched in, the voltage was observed to be within the permitted band of ±5 percent of nominal (12 kV line-to-line). Refer to Figure 7.14 for the voltage profile screen capture. The visualization software was programmed to alarm for a low-voltage condition as shown in the right side of Figure 7.14.

Figure 7.15 shows the digital status. AUTO and VOLTAGE modes were enabled for this operation. No lockout conditions were present. Capacitor bank switching is captured by the transition of the CBC 52B status from 1 to 0. Accurate observations were made on the relay front-panel LED.



Figure 7.14: CBC Low-Voltage Condition



Figure 7.15: CBC Low-Voltage Switching Operation

7.2.4 Automatic KVAR Control Operation

When the controller is set to AUTO mode while KVAR Control mode is enabled via PB06, the controller automatically opens and closes the capacitor bank to maintain the KVAR load between the lagging KVAR threshold and the leading KVAR threshold. Measured reactive power for all three phases must be outside of the thresholds for the controller to operate. Refer to Table 7.7 and Table 7.8 for the test procedures.

Table 7.7: Leading KVAR Open Operation (+P)

Objective: Verify capacitor breaker opens for leading KVAR conditions.					
Specific instruction: Ensure system is not in lockout (T06 LED).					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. System with load profile at 1 pu. 2. Controller in AUTO and LOCAL mode. 3. KVAR Control enabled. 4. Breaker is closed.	1. Run load profile at 0.1 pu to simulate lead KVAR conditions.	1.a. Countdown timer starts for 1 s. 1.b. **OPEN COMMAND** LED blinks red. 1.c. **OPENED** LED ON after successful open operation.	Refer to Figure 7.16, Figure 7.17, and Figure 7.18.	Y	
Test notes: No operation in AUTO/SUPY mode. Observe system voltage profile after switching operation.					

Results/observations: The load profile was run at 0.1 pu to simulate a lead KVAR condition to observe the capacitor bank switching operation. It is observed that the capacitor bank controller verified if the lead KVAR condition existed for a minimum of 1 second (user-settable pickup time) before switching the capacitors out. The pickup time is recommended to avoid switching operations because of momentary voltage/reactive power fluctuations. Once the capacitors were switched out, the voltage was observed to be within the permitted band of ±5 percent nominal (12 kV line-to-line). Refer to Figure 7.16 and Figure 7.17 for the PQ and voltage profile, respectively. The visualization software was programmed to alarm for a lead KVAR condition as shown in the right side of Figure 7.16.

Figure 7.18 shows the digital status. AUTO and KVAR modes were enabled for this operation. No lockout conditions were present. Capacitor bank switching is captured by the transition of the CBC 52B status from 0 to 1. Accurate observations were made on the relay front-panel LED.



Figure 7.16: CBC Lead KVAR Condition – PQ Plot



Figure 7.17: CBC Lead KVAR Condition – Voltage Plot



Figure 7.18: CBC Lead KVAR Switching Operation

Table 7.8: Lagging KVAR Close Operation (+P)

Objective: Verify capacitor breaker closes for lagging KVAR conditions.					
Specific instruction: Ensure system is not in lockout (T06 LED).					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. System with load profile at 1 pu. 2. Controller in AUTO and LOCAL mode. 3. Voltage control enabled. 4. Breaker is opened.	1. Continue to run load profile at 1 pu and observe for lag KVAR conditions.	1.a. Countdown timer starts for 1 s. 1.b. **CLOSE COMMAND** LED blinks red. 1.c. **CLOSED LED** ON after successful close operation.	Refer to Figure 7.19, Figure 7.20, and Figure 7.21.	Y	
Test notes: No operation in AUTO/SUPY mode. Observe system voltage profile after the switching operation.					

Results/observations: The load profile was run at 1 pu to simulate a lag KVAR condition to observe the capacitor bank switching operation. It is observed that the capacitor bank controller verified if the lag KVAR condition existed for a minimum of 1 second (user-settable pickup time) before switching the capacitors in. The pickup time is recommended to avoid switching operations because of momentary voltage/reactive power fluctuations. Once the capacitors were switched in, the voltage was observed to be within the permitted band of ±5 percent nominal (12 kV line-to-line). Refer to Figure 7.19 and Figure 7.20 for the PQ and voltage profiles, respectively. The visualization software was programmed to alarm for a lag KVAR condition as shown in the right side of Figure 7.21.

Figure 7.21 shows the digital status. AUTO and KVAR modes were enabled for this operation. No lockout conditions were present. Capacitor bank switching is captured by the transition of the CBC 52B status from 1 to 0. Accurate observations were made on the relay front-panel LED.



Figure 7.19: CBC Lag KVAR Condition – PQ Plot



Figure 7.20: CBC Lag KVAR Condition – Voltage Plot



Figure 7.21: CBC Lag KVAR Switching Operation

7.2.5 Time-of-Day Operation

Based on the PQ profile provided by SDG&E for the C310 circuit, the TOD close time was selected as 14:00:00 hours and the TOD open time was selected as 05:00:00 hours to maintain a smooth load profile. Refer to Figure 7.22.

When the controller is set to AUTO mode while TOD Control is enabled via PB07, the controller opens or closes the capacitor bank based on the TOD set point. Refer to Table 7.9 and Table 7.10 for the test procedures.

Table 7.9: TOD Close Operation

Objective: Verify capacitor breaker closes at TOD start time.					
Specific instruction: Ensure system is not in lockout (T06 LED).					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. System with nominal load profile. 2. Controller in AUTO and LOCAL mode. 3. TOD Control enabled. 4. Breaker is open.	1. Set time to 13:59:50.	1. The breaker should close immediately as soon as the time is 14:00:00.	Refer to Figure 7.22 and Figure 7.23.	Y	
Test notes: Observe relay SER.					

Results/observations: The model is run at nominal load for the TOD close test. The IRIG-B connection was removed for this test to change the internal clock of the controller. The time was set at 13:59:50 hours. The capacitor bank breaker closed as soon as the time turned to 14:00:00 hours.

Figure 7.23 shows the digital status. TOD mode was enabled for this operation, shown by “TODMODE” as enabled in Figure 7.23 . Capacitor bank switching is captured by CAPBRK Relay Word bit status as Closed. Accurate observations were made on the relay front-panel LED.

Recommendations: It is recommended to observe the load profile and PQ distribution over 24 hours and over different days (for example, weekends, weekdays, and different seasons) before setting up the TOD close time. Dedicated TOD programs can run in the controller for weekdays and weekends.

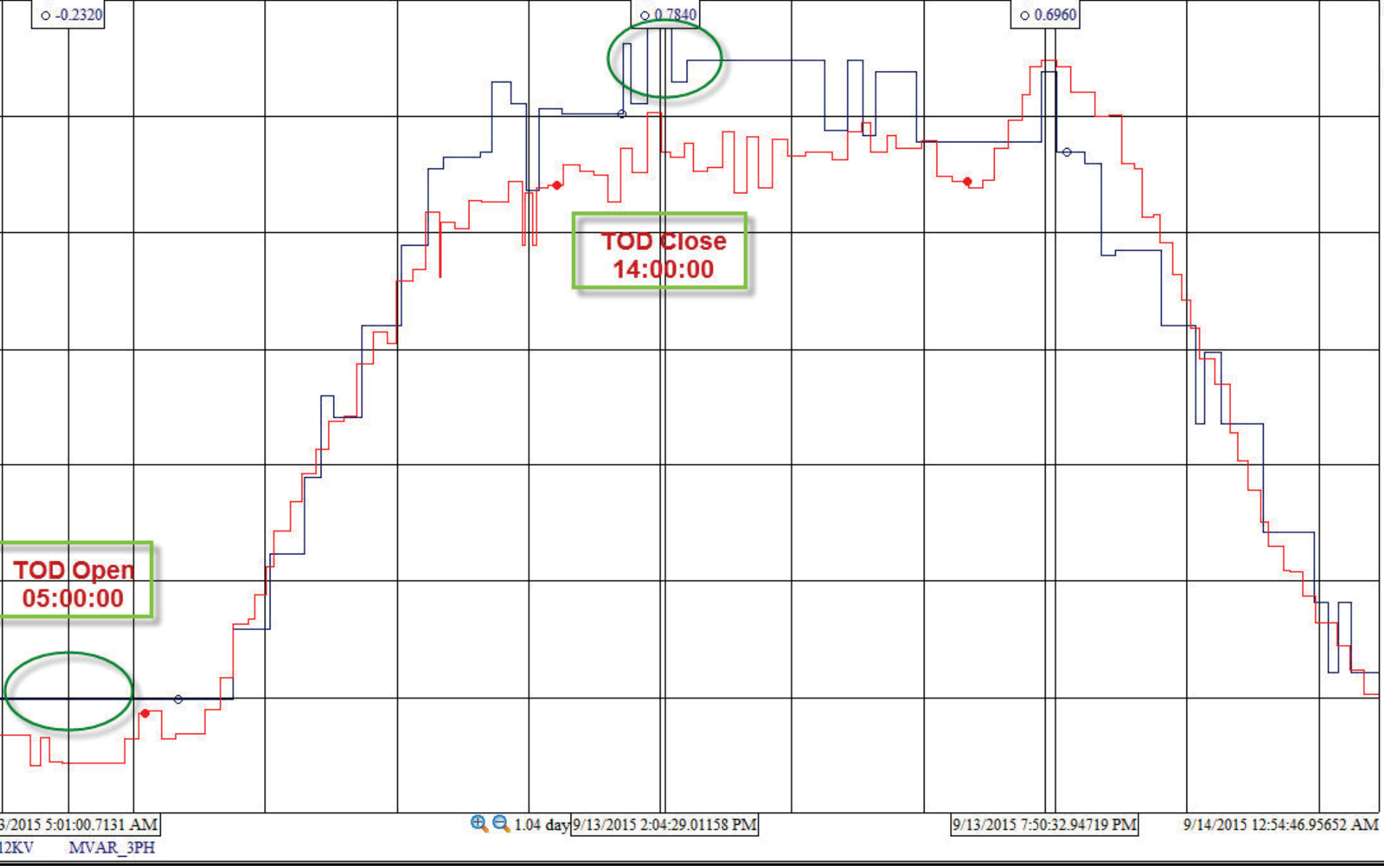


Figure 7.22: Circuit PQ Profile Over 24 Hours

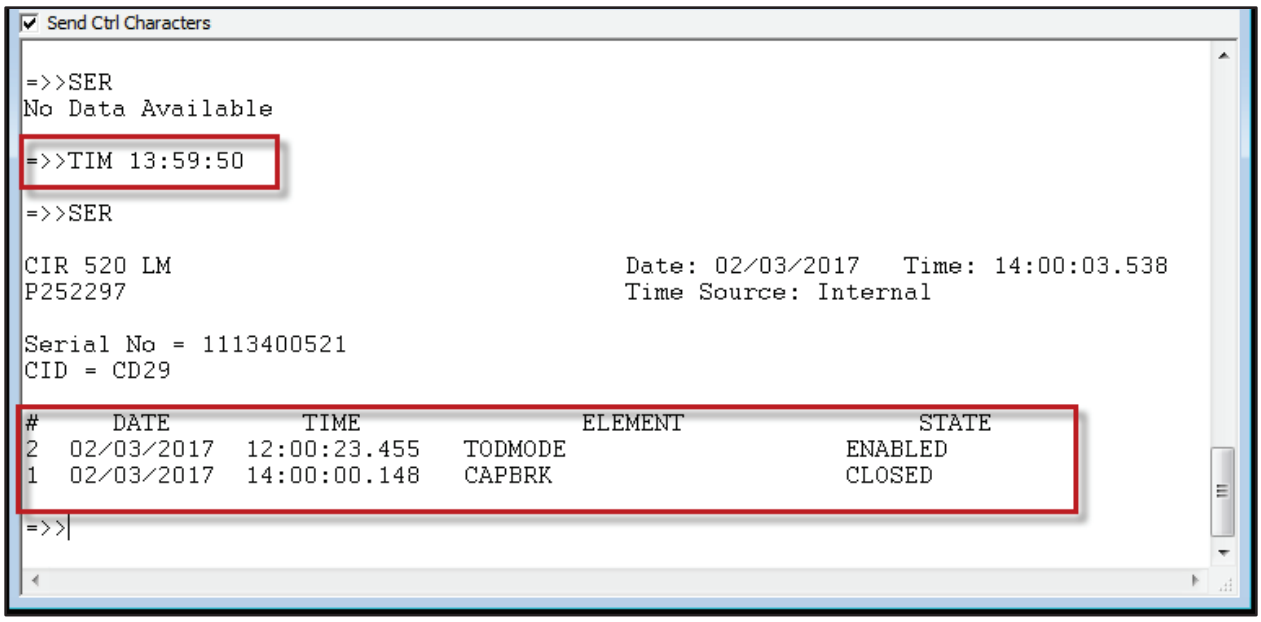


Figure 7.23: CBC TOD Close Switching Operation at 14:00:00 Hours

Table 7.10: TOD Open Operation

Objective: Verify capacitor breaker opens at TOD end time.					
Specific instruction: Ensure system is not in lockout (T06 LED).					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. System with nominal load profile. 2. Controller in AUTO and LOCAL mode. 3. TOD Control enabled. 4. Breaker is closed.	1. Set Time to 04:59:50.	1.a. The breaker should open immediately as soon as the time is 05:00:00.	Refer to Figure 7.22 and Figure 7.24.	Y	
Test notes: Observe system voltage profile after switching operation.					

Results/observations: The model is run at nominal load for the TOD open test. The IRIG-B connection was removed for this test to change the internal clock of the controller. The time was set at 04:59:50 hours. The capacitor bank breaker opened as soon as the time turned to 05:00:00 hours.

Figure 7.24 shows the digital status. The TOD mode was enabled for this operation shown by "TODMODE" as enabled in Figure 7.24 . Capacitor bank switching is captured by CAPBRK Relay Word bit status as Opened. Accurate observations were made on the relay front-panel LED.

Recommendations: It is recommended to observe the load profile and PQ distribution over 24 hours and over different days (for example, weekends, weekdays, and different seasons) before setting up the TOD open time. Dedicated TOD programs can run in the controller for weekdays and weekends.

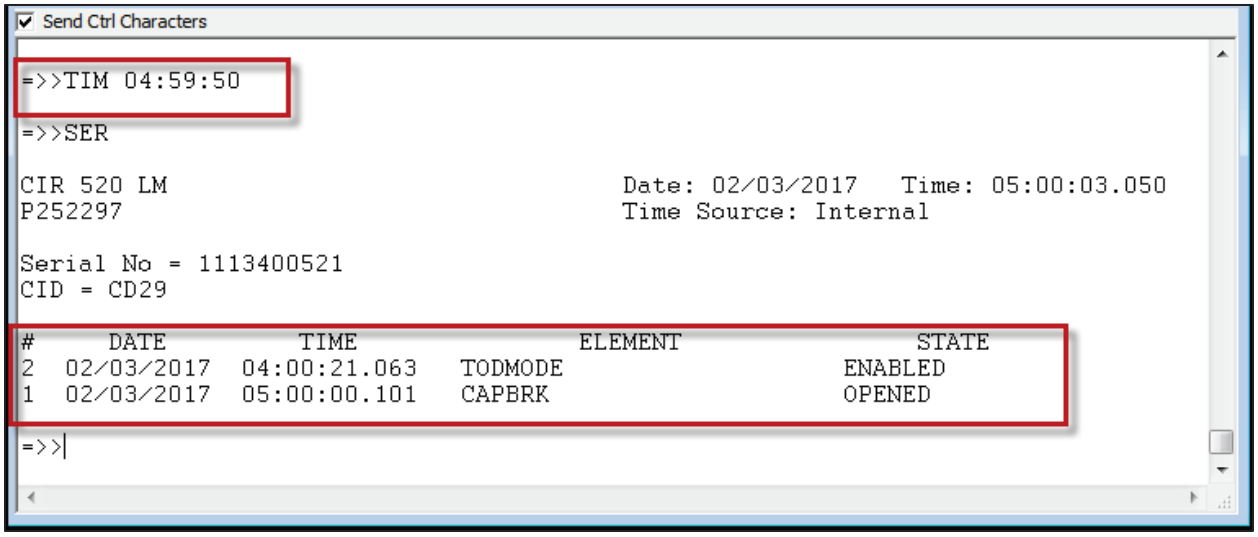


Figure 7.24: CBC TOD Open Switching Operation at 05:00:00 Hours

7.2.6 Overvoltage Lockout

Overvoltage lockout is essential for the protection of the capacitor bank. In case of an overvoltage condition, the capacitor breaker should trip and issue a lockout, thereby, preventing all automatic switching operations until the lockout is cleared by the operator. Refer to Table 7.11 for the test procedure.

Table 7.11: Overvoltage Lockout

Objective: Simulate overvoltage condition and verify capacitor breaker opens.					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. System with nominal voltage and current conditions: VA = 69 V ∠0° VB = 69 V ∠–120° VC = 69 V ∠+120° 2. Breaker closed.	1. Raise test set voltage by 12%. VA = 77 V ∠0° VB = 77 V ∠–120° VC = 77 V ∠+120°	1.a. Breaker opens. 1.b. Controller goes to lockout – LED06 ON.	Refer to Figure 7.25 and Figure 7.26.	Y	
Test notes: Overvoltage trip should be allowed in all possible combinations of operating modes because it is a protection lockout. Once a lockout is declared, all automatic operations should be inhibited.					

Results/observations: The load profile was run at 1 pu. System voltage was increased with a slider in RTDS RunTime to simulate a three-phase overvoltage condition. The controller verified if the overvoltage condition existed for a minimum of 1 second (user-settable pickup time) before switching the capacitors bank out. Refer to Figure 7.25. The visualization software was programmed to alarm for overvoltage condition as shown in the right side of Figure 7.26.

Figure 7.26 shows the digital status. The overvoltage lockout alarm is enabled. Capacitor bank switching is captured by the transition of the CBC 52B status from 0 to 1. Accurate observations were made on the relay front-panel LED.



Figure 7.25: CBC Overvoltage Condition

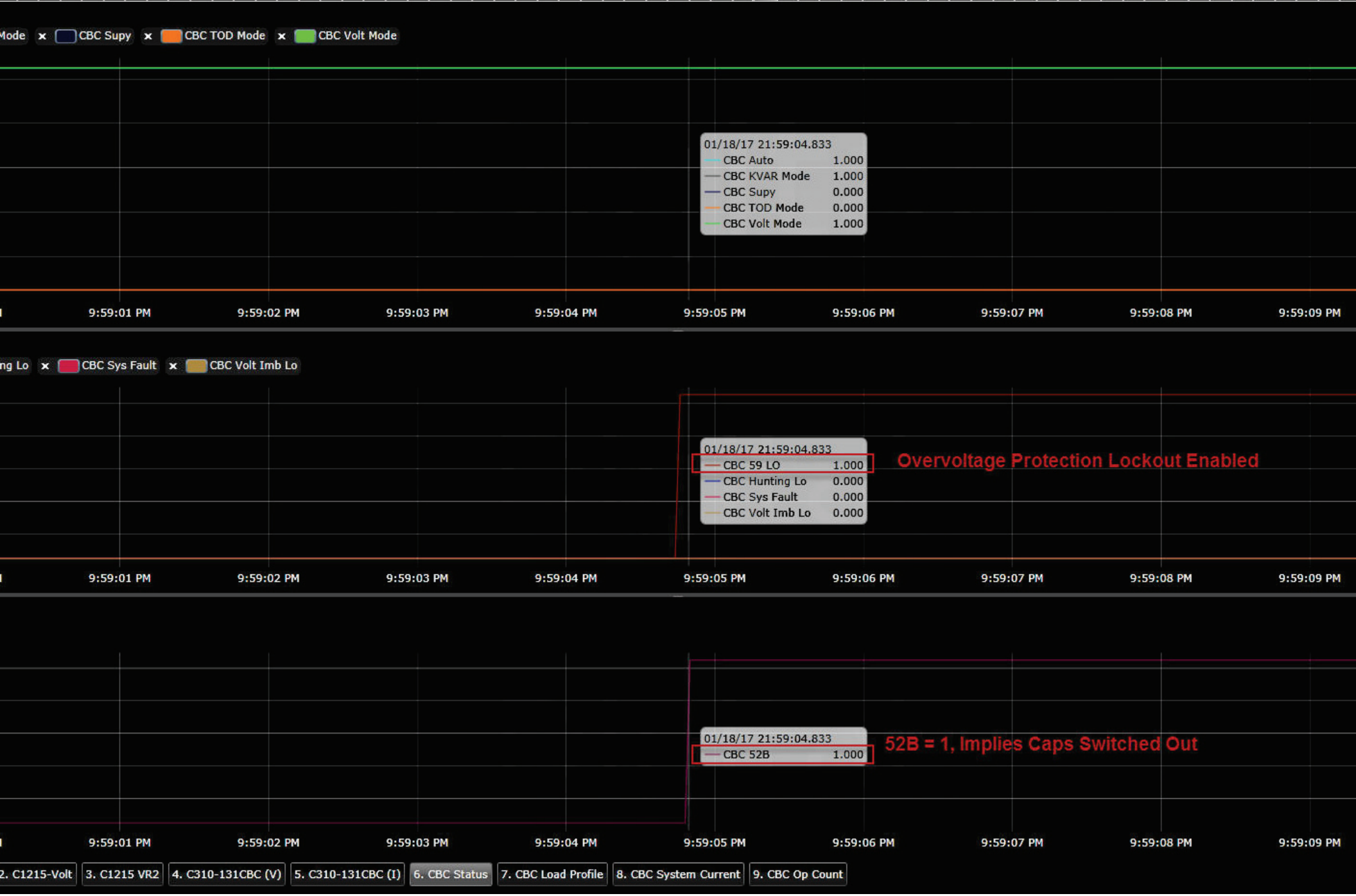


Figure 7.26: CBC Overvoltage Condition Lockout Operation

7.2.7 Voltage Imbalance Lockout

Voltage imbalance lockout is essential for the protection of the capacitor bank. In case of an imbalance condition, the capacitor breaker should trip and issue a lockout, thereby, preventing all automatic switching operations until the lockout is cleared by the operator. Refer to Table 7.12 for the test procedure.

Table 7.12: Voltage Imbalance Lockout

Objective: Simulate voltage imbalance and verify that the capacitor breaker opens.					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. System with nominal voltage and current conditions: VA = 69 V ∠0° VB = 69 V ∠–120° VC = 69 V ∠+120 2. Breaker closed.	1. Lower Phase A voltage to cause an imbalance greater than 3%.	1.a. Breaker opens. 1.b. Controller goes to lockout – LED06 ON.	Refer to Figure 7.27, Figure 7.28, and Figure 7.29.	Y	
Test notes: The voltage imbalance threshold is at 3 percent. Voltage imbalance trip should be allowed in all possible combinations of operating modes. Once lockout is declared, all automatic operations should be inhibited.					

Results/observations: The load profile was run at 1 pu. Phase A voltage was increased with a slider in RTDS RunTime to simulate a voltage imbalance condition. The controller verified if the voltage imbalance condition existed for a minimum of 1 second (user-settable pickup time) before switching the capacitors out. Refer to Figure 7.27.

Figure 7.28 captures the percentage voltage imbalance registered by the relay. The visualization software was programmed to alarm for a voltage imbalance condition as shown in the right side of Figure 7.27.

Figure 7.29 shows the digital status. Voltage imbalance lockout alarm is enabled. Capacitor bank switching is captured by the transition of the CBC 52B status from 0 to 1. Accurate observations were made on the relay front-panel LED.



Figure 7.27: CBC Voltage Imbalance Condition

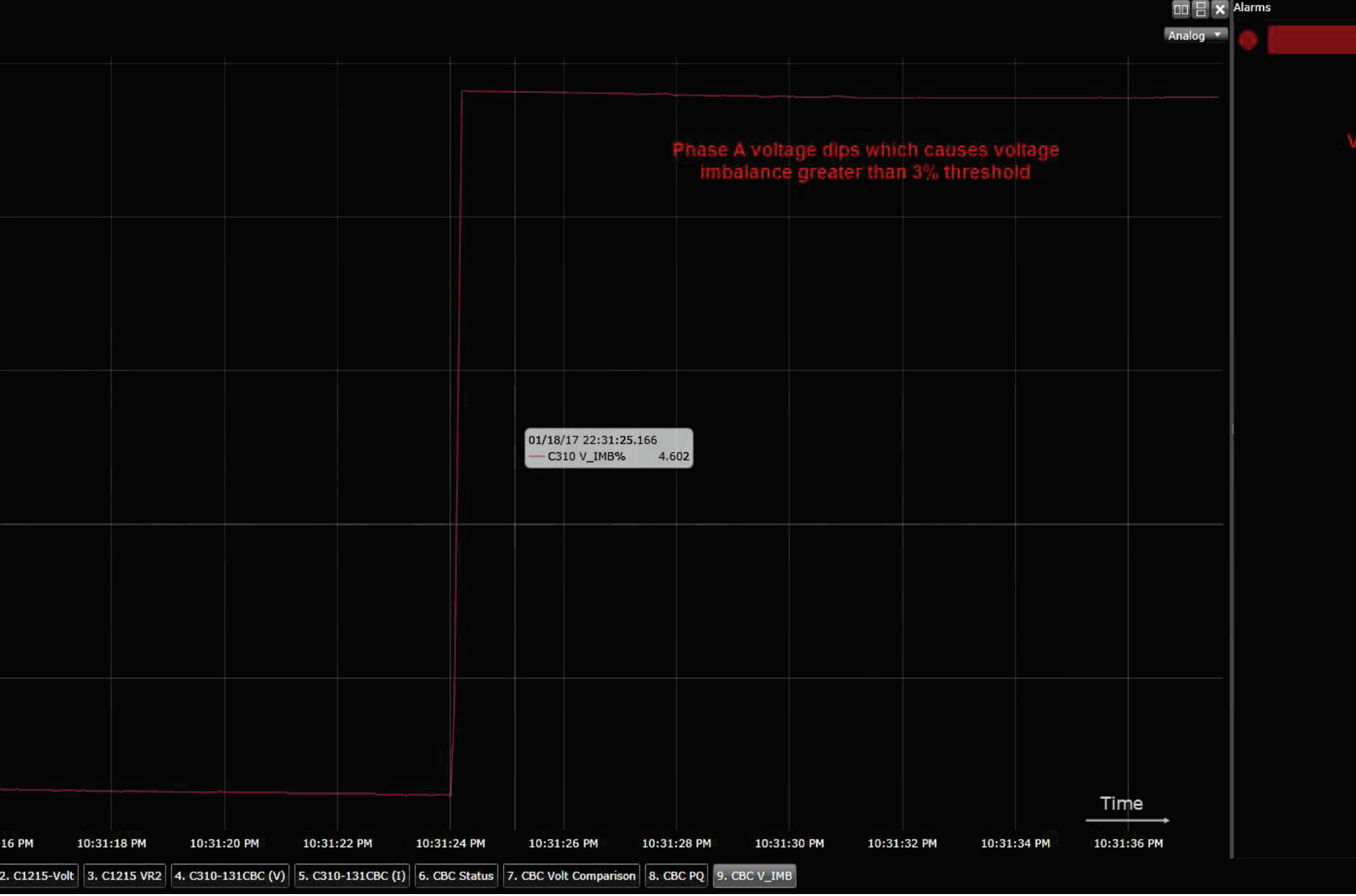


Figure 7.28: CBC Voltage Imbalance Percentage



Figure 7.29: CBC Voltage Imbalance Lockout Operation

7.2.8 High-Current Condition

The capacitor bank controller is programmed for a high-current alarm indication. If the system current exceeds the set threshold, the controller alarms as long as a high-current condition is present. A high-current condition does not cause the capacitor breaker to open or inhibit any automatic switching operations. It is understood that the upstream system protection will arrest the high-current condition in the system. Refer to Table 7.13 for the test procedure.

Table 7.13: High-Current Condition

Objective: Simulate high current and verify alarm indication.					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. Run the system with nominal voltage and current. 2. Breaker closed.	1. Raise test set current to more than 600 A primary.	1. Controller indicates high-current condition on target LED05.	Refer to Figure 7.30 and Figure 7.31.	Y	
Test notes: The high-current condition does not inhibit LOCAL or AUTO operations. LOCAL reset: Reset the fault latch by pressing the **RESET** pushbutton. Automatic reset: If the fault condition clears, the fault latches and the indication LED will clear automatically after 10 minutes.					

Results/observations: The load profile was run at 1 pu. System current was increased with the help of a slider in RTDS RunTime to simulate a high-current condition. The controller alarmed for this condition as shown in Figure 7.30.

Figure 7.31 shows the digital status. A high-current alarm is enabled. It can also be observed that the alarm automatically resets after 10 minutes provided the high-current condition is not present in the system. Accurate observations were made on the relay front-panel LED.



Figure 7.30: CBC High-Current Condition



Figure 7.31: CBC High-Current Alarm Indication and Automatic Reset

7.2.9 Hunting Lockout

When the controller is set to AUTO mode, the hunting feature inhibits further operations if a specified number of open and close operations occur within a specified time window, which is known as the hunting time window. Refer to Table 7.14 for the test procedure.

Table 7.14: Hunting Lockout

Objective: Verify hunting lockout is asserted once the counts threshold is crossed.					
Specific instruction: Ensure system is not in lockout (T06 LED).					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. System with nominal conditions. 2. Controller in AUTO mode. 3. Voltage control enabled.	1. Set hunting window = 5 min. 2. Set hunting count = 3. 3. Trigger breaker open and close operations via abnormal voltage.	1.a. Hunting lockout not asserted after the 2nd operation. 1.b. Hunting lockout asserted after the 3rd operation. 1.c. No further close/open operations are allowed. 1.d. The LCD displays Hunting Lockout.	Refer to Figure 7.32.	Y	
Test notes: The hunting window and hunting count threshold are modified to decrease the hunting time window and the hunting count for testing.					

Results/observations: Three consecutive voltage switching operations were carried out in a window of 5 minutes (as set via hunting window). The first was a high-voltage open operation, followed by a low-voltage close operation, followed by a high-voltage open operation. All three operations were captured in Figure 7.32. It can be observed that a hunting lockout is issued after the third operation because the hunting count is set to three.

Hunting lockout should prevent any further automatic operations. The alarm can be reset locally via operator controlled reset pushbutton on the relay. Options should be provided to reset this automatically after a set time or remotely via SCADA.

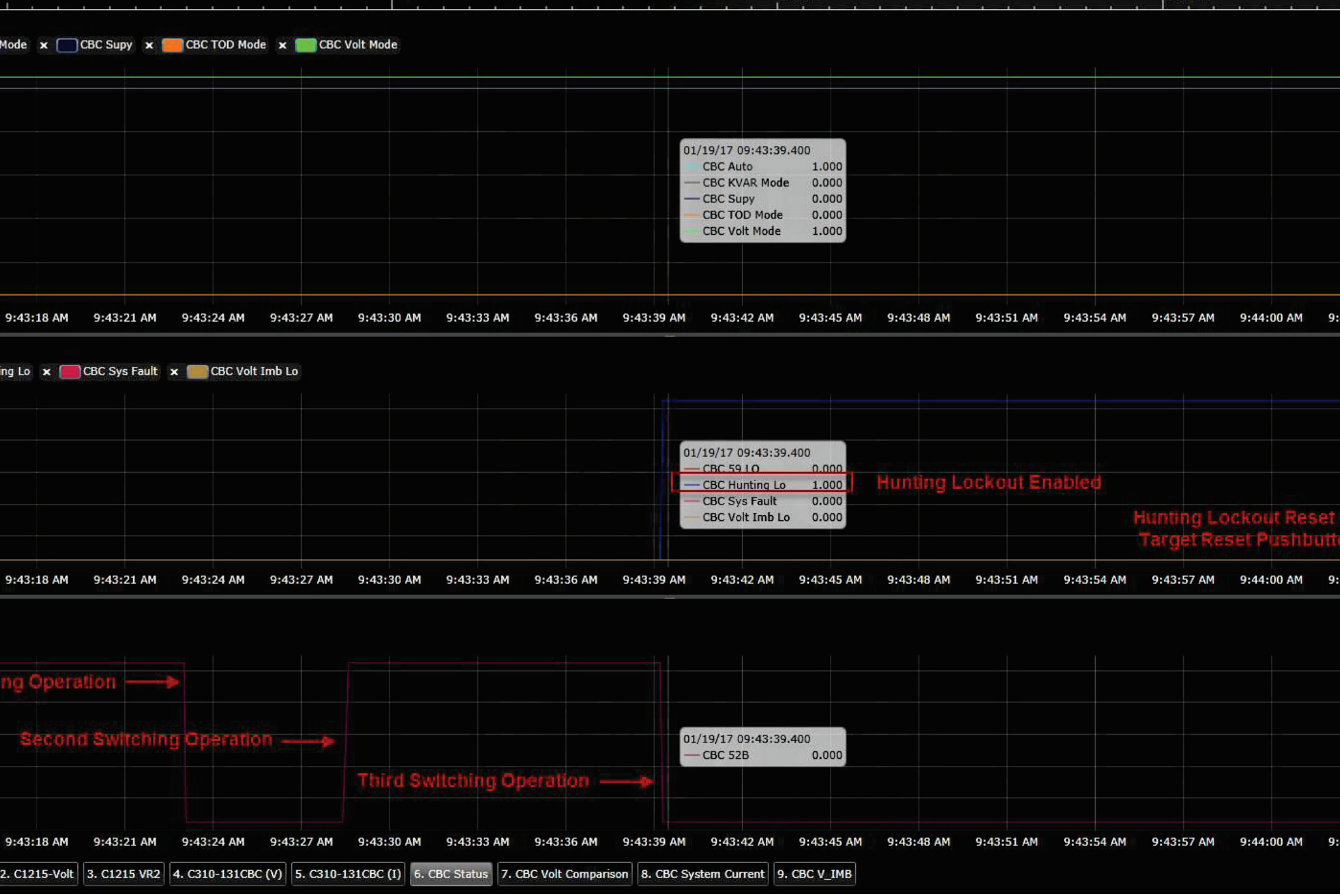


Figure 7.32: CBC Hunting Lockout

Hunting Reset: Hunting lockout can be reset as follows:

Local:

1. Ensure the controller is in LOCAL mode.
2. Press **RESET**.
3. The hunting lockout display point should clear out.

7.2.10 Operations Counters

There are three operations counters:

1. Counts since installation.
2. Yearly counts.
3. Daily counts.

Operations Counter Reset

Local Reset: Press the PB04 and **RESET** pushbuttons together for 5 seconds.

Automatic Reset: Yearly counter resets when DAYY (day of year) = 1. Daily counter resets when minutes since midnight (MINSM) = 0.

Results/observations: The controller is programmed to keep a count of the number of switching operations since installation, and on a daily and a yearly basis. This information can be vital for equipment monitoring and maintenance. Figure 7.33 shows the count registered. This can be reset locally via the **Target Reset** pushbutton on the relay.

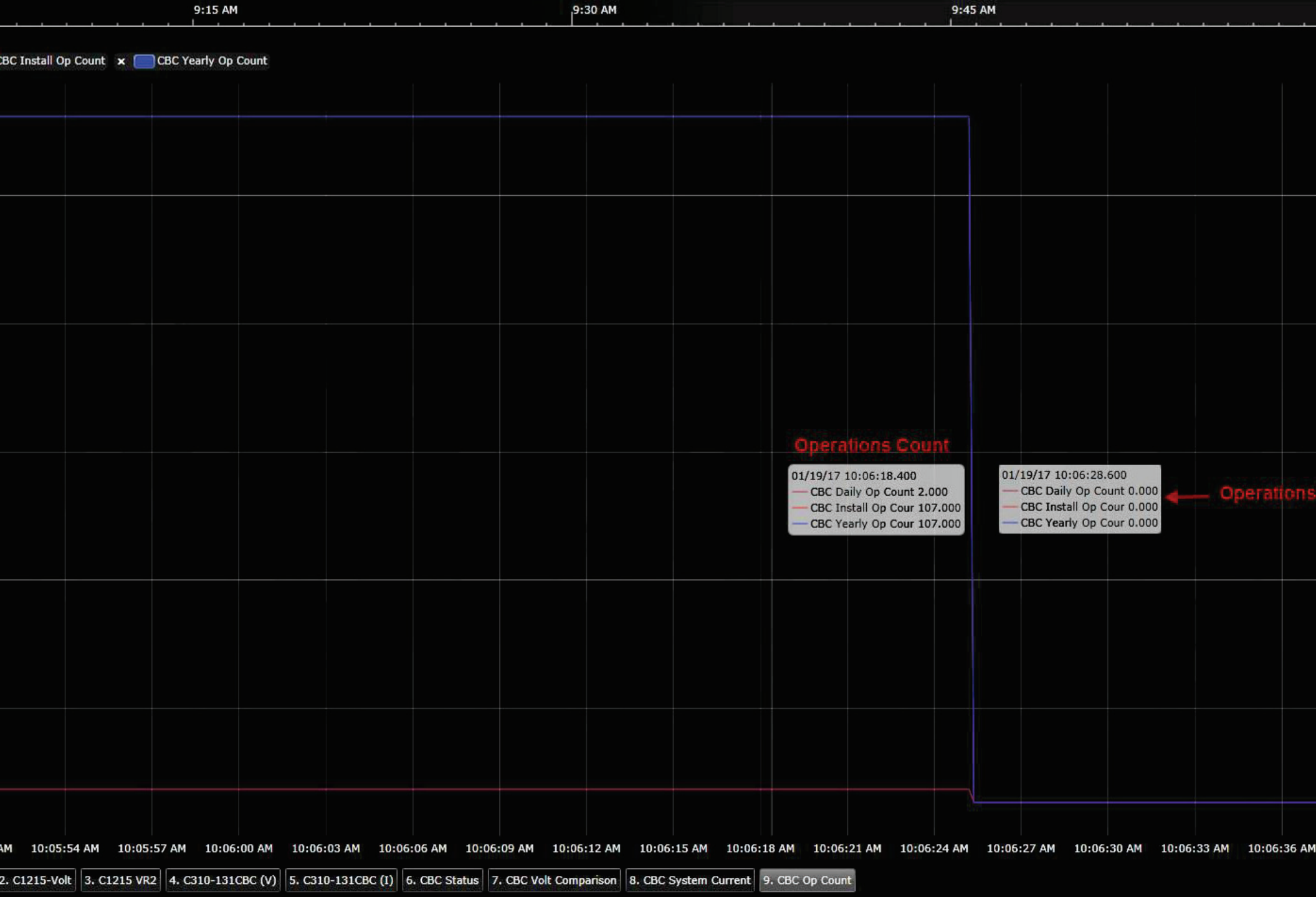


Figure 7.33: CBC Operations Counter

8 HIGH-IMPEDANCE FAULT DETECTION

High-impedance faults (HIF) are short-circuit faults with fault currents typically smaller than what traditional overcurrent relays can detect. The main causes of HIFs are tree branches touching a phase conductor, dirty insulators causing a flashover between the phase conductors and the ground, or downed conductors. Significantly small fault current values make the detection of high-impedance faults challenging. Special algorithms may be required to detect and isolate the circuit during high-impedance faults.

The Advanced Recloser Control used in this study provides the intelligence to a recloser that allows reconfiguration of a distribution system and maintenance of reliable service to as many power networks as possible in the event of a fault. In addition, the recloser control provides high-impedance fault detection and protection capabilities. The tests performed in this section demonstrate the features and functionalities available to detect high-impedance faults on distribution circuits.

Section 8.1 describes the laboratory test setup and the recloser control hardware configuration.

Section 8.2 provides an overview of HIF functionality in the recloser control.

Section 8.3 includes the procedure for testing HIFs in distribution circuits.

Section 8.4 provides a description of the HIF settings in the recloser control for laboratory testing.

Section 8.5 includes the different scenarios for testing HIFs in distribution circuits. The scenarios include faults at varying fault impedances and fault locations, and response of the high-impedance detection logic during the load profile run.

RTDS tests were carried out to study HIF detection capabilities of the recloser control at various locations of the SDG&E circuit and for faults with different fault impedances. The testing includes two scenarios. The first scenario was Auto and Remote Toggle – From Local Control (Section 8.5.1). The second scenario was HIF detection (Section 8.5.2). Refer to Figure 8.1 for a simplified one-line diagram with two fault locations. A single-line-to-ground fault with an impedance of 85 ohms and duration of 200 milliseconds is simulated for these tests.

The test results are captured using a visualization software and the sequence of events.

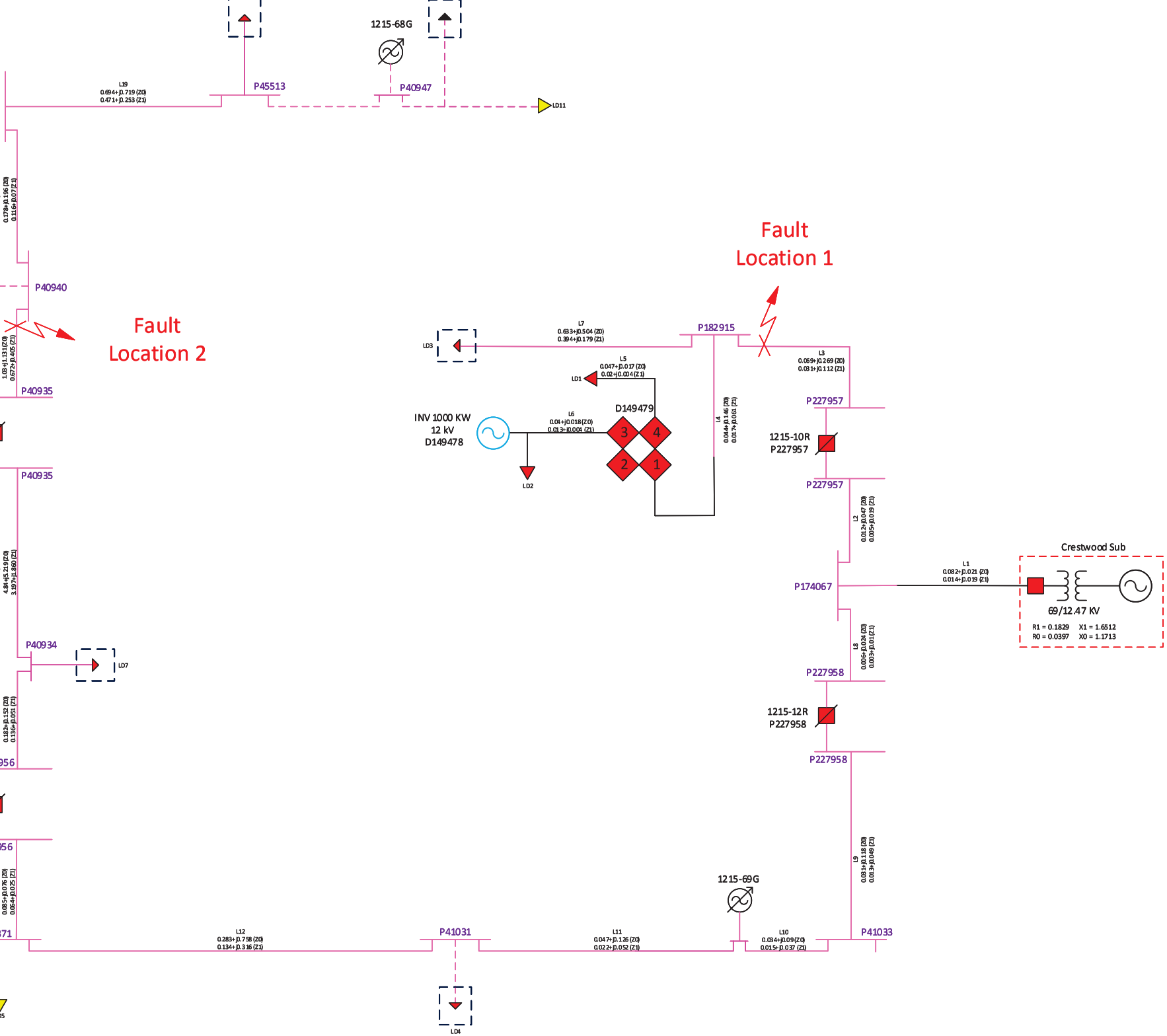


Figure 8.1: Simplified One-Line Diagram With Fault Locations

8.1 TEST SETUP

The hardware setup of the test circuit is shown in Figure 8.2. The circuit involving the recloser control is simulated on the RTDS and the recloser currents and voltages are derived from the circuit. These voltages in the low-level signal form are fed to the recloser control. The recloser control HIF logic will detect this condition and send control signals back to the RTDS to control the recloser.

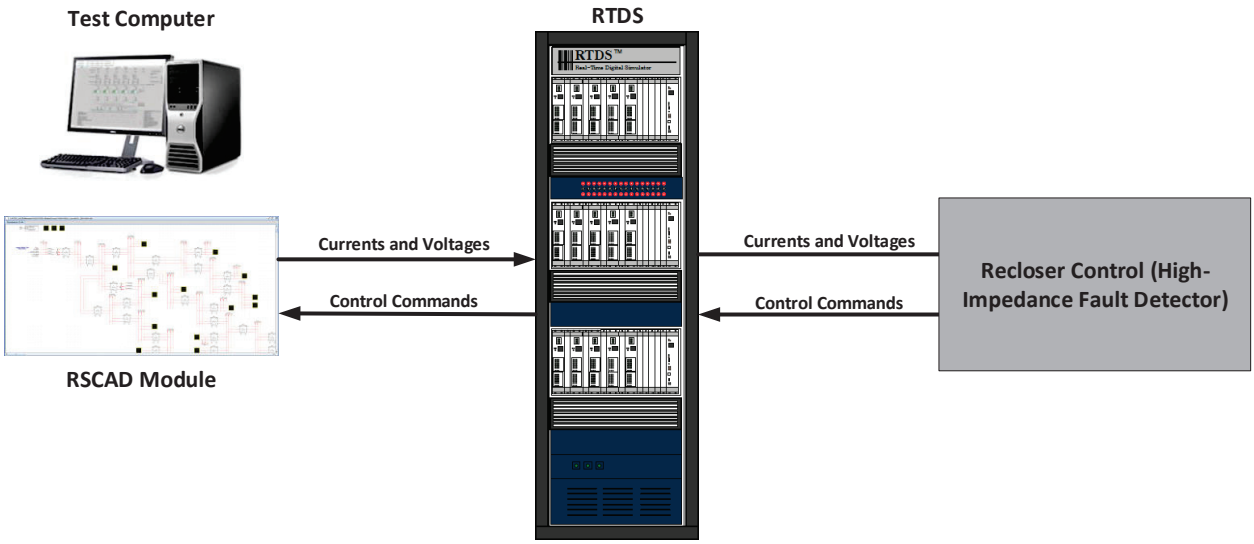


Figure 8.2: HIF Detection Test Setup

8.1.1 RTDS Interface and I/O List

Figure 8.3 illustrates the analog inputs and outputs assigned to the various channels of the RTDS GTAO card. Each of the GTAO cards represent the outputs for one recloser. For GTAO A01 (1215-10R) on the left side in Figure 8.3, Channels 1 through 3 are reserved for the A, B, and C phase currents (10RIA, 10RIB, and 10RIC, respectively). Channels 4 through 9 represent the A, B, and C voltages for the Y and Z side of the recloser (10RYA, 10RYB, 10RYC, 10RZA, 10RZB, and 10RZC, respectively). GTAO A02 (1215-32R) follows the same format.

For testing purposes, set the Relay Word bit EHIF = T (Test mode). This setting allows the HIF detection algorithm to bypass the 24-hour tuning process. For normal operation, EHIF = Y.

The recloser control indicates HIF detection through the Relay Word bits outputs detailed in Table 8.1.

Table 8.2 describes the digital outputs assignment from the recloser control to the RTDS.

Figure 8.4 shows the mapping for digital inputs and outputs, respectively, via the GTFPI card.

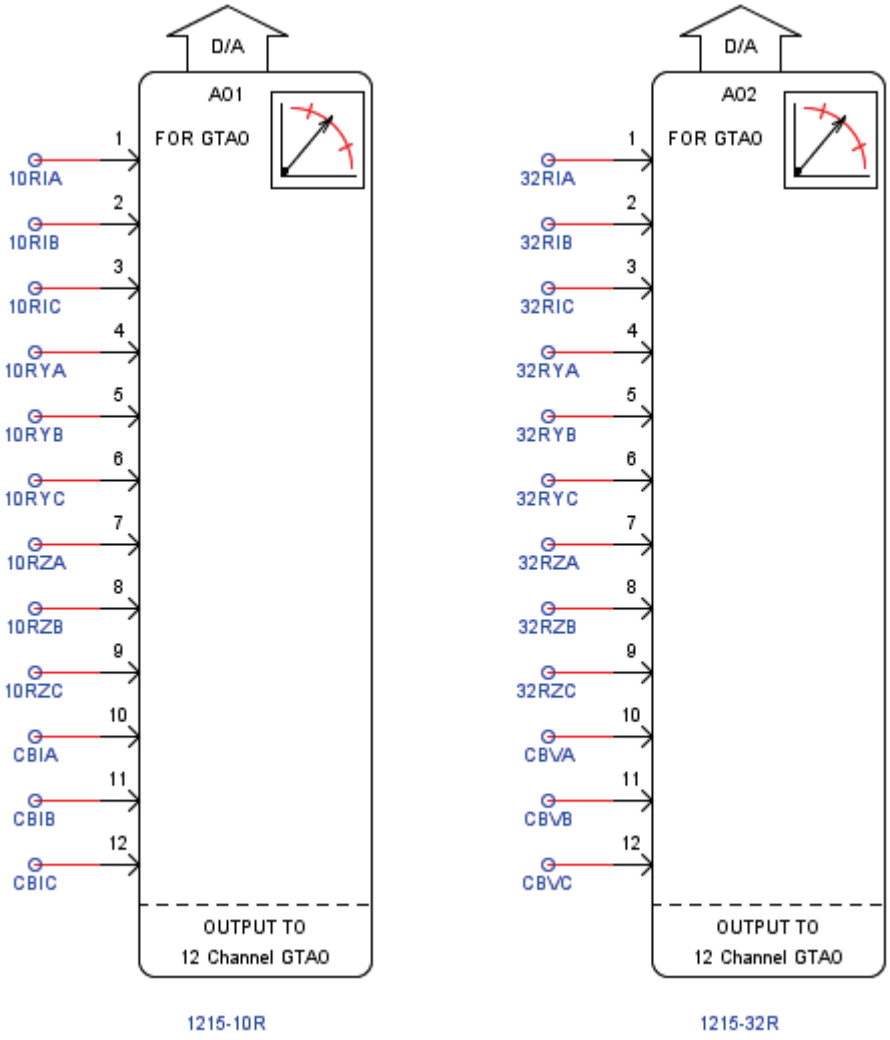


Figure 8.3: Recloser RTDS Analog Output Signals

Table 8.1: HIF Relay Word Bits

HIF Activity	Relay Word Bits
HIF SDI (nonharmonic) ALARM	HIA2_A, HIA2_B, HIA2_C
HIF SDI (nonharmonic) FAULT	HIF2_A, HIF2_B, HIF2_C
Voltage Disturbance	DVA_DIS, DVB_DIS, DVC_DIS
Disable HIF Decision Logic	DL2CLRA, DL2CLRB, DL2CLRC
Initial Tuning in Progress	ITUNE_A, ITUNE_B, ITUNE_C
Initiate Tuning Process	INI_HIF, HIFITUNE
Normal Tuning in Progress	NTUNE_A, NTUNE_B, NTUNE_C
Increase the HIF Tuning Threshold	DUPA, DUPB, DUPC
Decrease the HIF Tuning Threshold	DDNA, DDNB, DDNC
Load Reduction Detected	LRA, LRB, LRC, LR3
HIF Externally Triggered Event	HIFER
HIF Detection Mode Sensitivity	HIFMODE
HIF Event Report is being collected	HIFREC

Table 8.2: Recloser Control I/O List

Output Contact	Function
OUT101	Trip
OUT102	Close
OUT101	Trip
OUT102	Close

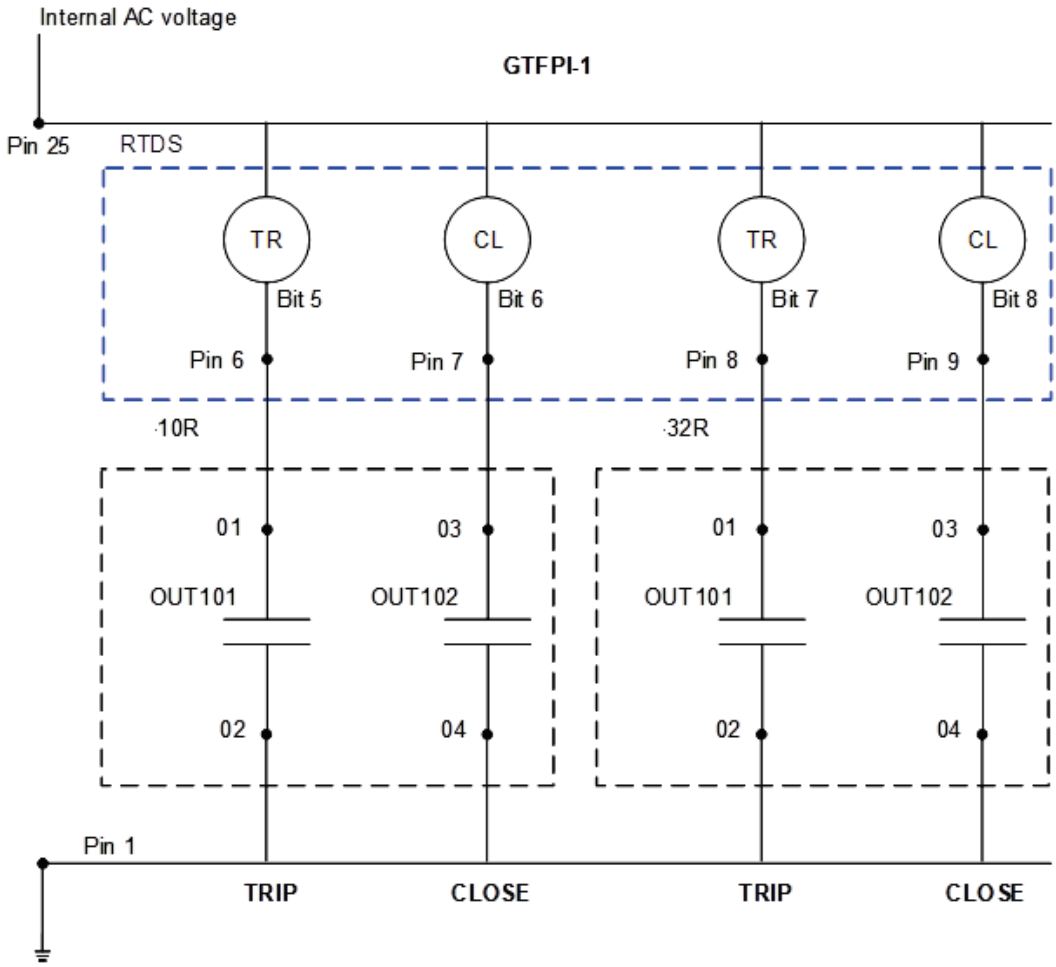


Figure 8.4: Recloser Trip and Close Digital Input Wiring

8.2 HIF OVERVIEW

HIFs are those with high resistance in the fault path. Typical causes of HIFs include trees coming into contact with overhead lines, conductors falling onto poorly conductive surfaces (asphalt, dry grass, or sand), and incipient insulation failure. Detecting HIFs on distribution systems with voltage levels below 35 kV is a challenge because the fault currents generated are below the traditional overcurrent element pickup levels. Overcurrent protection based on fundamental or rms quantities of the current is ineffective in detecting HIFs.

8.2.1 HIF Detection

The HIF detection method consists of two main algorithms:

1. HIF1 that uses the odd-harmonic content in the phase currents.
2. HIF2 that uses the interharmonics content in the phase currents.

The following are the key characteristics of the HIF detection algorithms:

- An informative quantity (e.g., the interharmonics content of the phase currents) that reveals the HIF signature without being affected by noise generated by load or switching operations on the system.

- A stable prefault reference established through an initial 24-hour tuning process and updated during normal operation.
- An adaptive tuning function that learns the margin above the reference.
- An effective decision logic to detect HIFs and discriminate HIFs from other system conditions.

The recloser control used in this test uses the HIF2 (nonharmonic) algorithm for fault detection. The block diagram describing HIF detection is shown in Figure 8.5.

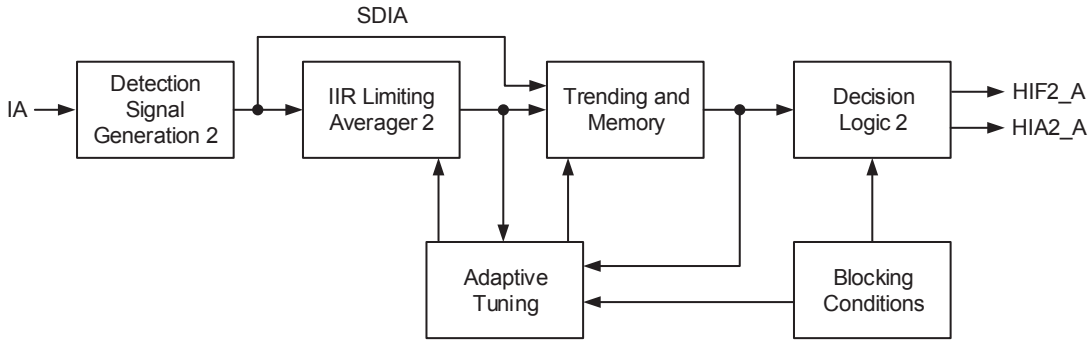


Figure 8.5: Block Diagram of HIF Detection in Recloser Control

The HIF detection element derives an SDI that represents a total nonharmonic content of the phase current to detect an HIF signature. An IIR averaging filter generates a stable reference of SDI (SDI_REF) and adapts to the ambient conditions of the feeder loads. The adaptive tuning function monitors the feeder background noise and determines the margin (d), which is used to identify HIF events. This margin also limits the input to the averager to prevent the reference from following large SDI spikes. The trending and memory function provides information to decision logic about how often (dt) and by how much (rd) SDI departs from SDI_REF, plus the learned margin d. The counting parameters are shown in Figure 8.6.

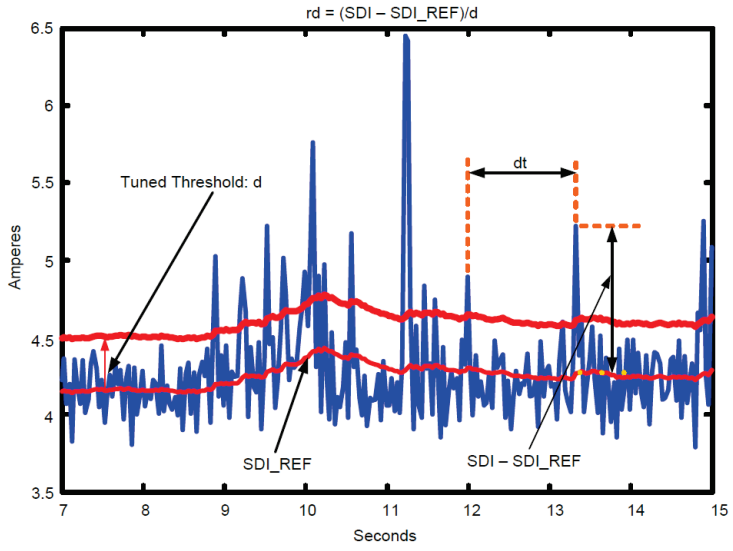


Figure 8.6: HIF2 Algorithm Counting Parameters

The decision logic uses the output from the trending and memory block to determine the existence of an HIF. It has separate counters for HIFs and alarms. Figure 8.7 shows the rd-dt plane that is divided into three regions: Fault Count, Alarm Count, and No Count. The quantity of deviation of SDI from SDI_REF is represented by rd. The

frequency of deviation of SDI from SDI_REF is represented by dt. The dt axis reflects the units of the algorithm processing rate, or the interval over which SDI accumulates.

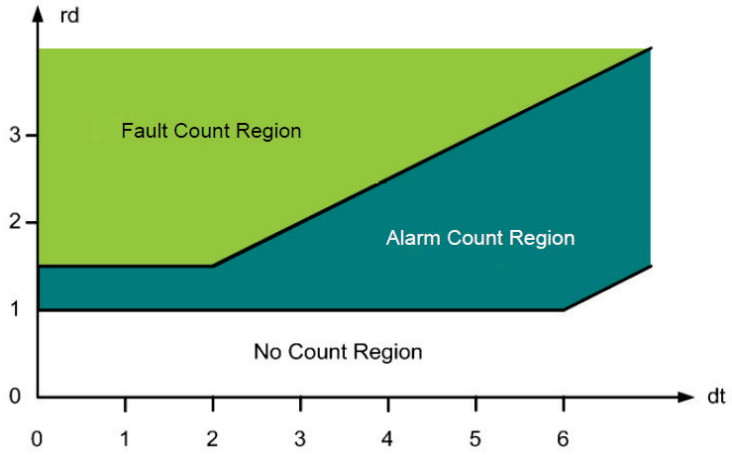


Figure 8.7: HIF2 Algorithm Counting Regions

The counting scheme used here can be correlated to a differential current operating characteristic, where rd is the operating quantity and dt is the restraint quantity. Large dt values coming from sporadic and isolated events, such as lightning or capacitor bank switching, are likely to be disregarded. Conversely, arcing events from HIFs tend to produce high SDI values occurring within a short period; therefore, the corresponding (rd, dt) pairs are more likely to be in the Fault Count region.

If the (rd, dt) pair falls within the No Count region, the algorithm generates no counts for HIFs or alarms. The No Count region accounts for system noise and disturbances generated during the normal power flow. If the pair falls in the Alarm Count region, the algorithm generates counts for alarms only. If the pair falls in the Fault Count region, the algorithm generates counts for both HIFs and alarms.

8.3 TEST PROCEDURE

The following are the steps involved in testing HIFs using the recloser control.

Step 1. Receive the settings from SDG&E for the specific recloser to be tested and load settings to the recloser control.

Step 2. Select Group 1 as the active group for testing purposes and load test settings to Group 1.

Step 3. Set the group setting, EHIF, to T.

Step 4. Set the HIF report setting, HIFLER, to 2 minutes (recommended).

Step 5. Add the HIF2 algorithm Relay Word bits to the SER.

Step 6. Depending on whether the HIF needs to trip the relay or not, set the Trip equation to contain the HIF FAULT bits or set to 0. All other tripping functions, such as switch onto fault (SOTF), are set to 0.

Step 7. Connect the three-phase voltages (V1, V2, and V3) and three-phase currents (I1, I2, and I3). Both will be sent as low-level signals to the recloser control for testing, from the RTDS to the relay via the GTAO card as shown in Figure 8.8. Channels 1 through 3 are reserved for the phase voltages and Channels 4 through 6 are reserved for phase currents. The recloser control has two sets of voltage and current inputs. Therefore, the connections must be made to the active voltage and current source windings.

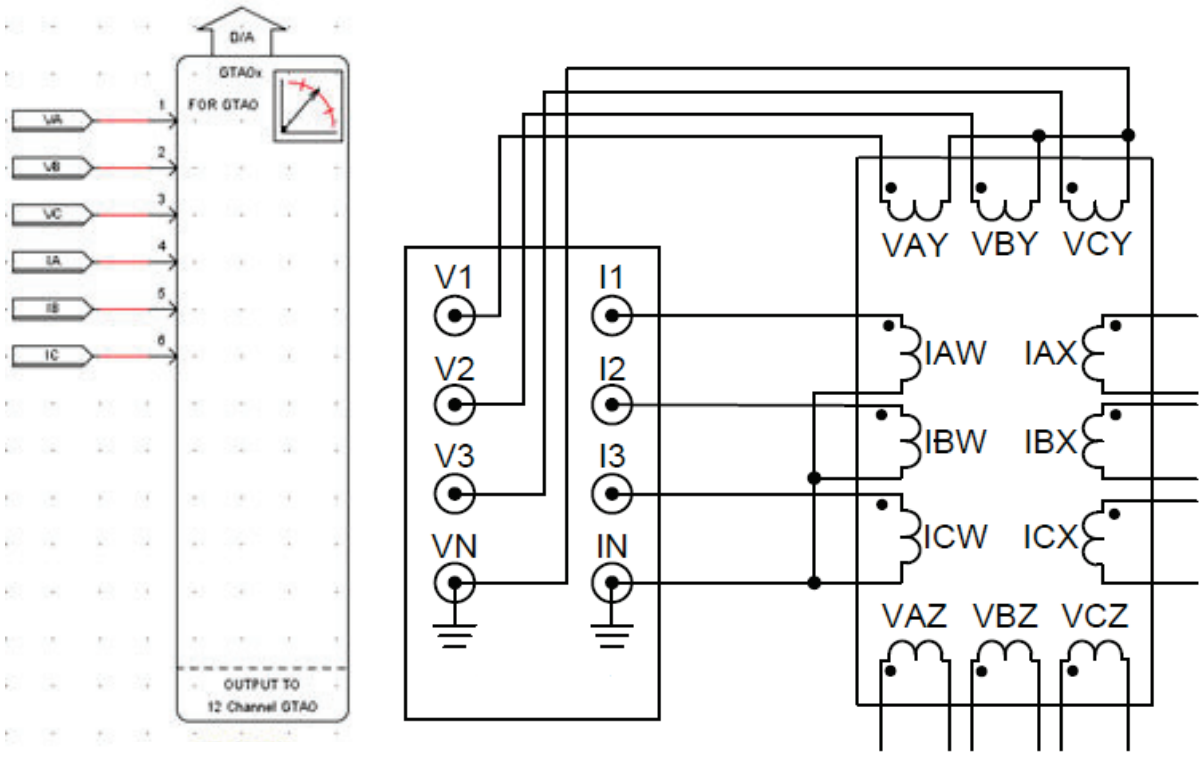


Figure 8.8: Test Setup

Step 8. Apply a balanced three-phase voltage and current. Perform a meter test (MET command) to verify the connections.

Step 9. Issue the STA C command before the start of every test to turn on the relay and reset any dropout timers and latches associated with the high-impedance algorithm.

Step 10. Issue the HIS HIF CA command to clear the HIF event history.

Step 11. Issue the SER C command to clear the SER.

Step 12. Run the test circuit on RTDS and apply high-impedance faults (different fault impedances and fault locations) to test HIF detection.

Step 13. After the test has finished, verify that the HIF2 algorithm outputs associated with the fault have picked up for the phase, or phases, under test.

Step 14. Retrieve the HIF event reports if generated during the test. Also, the RTDS RunTime plots are to be retrieved for each event.

Step 15. Analyze the SER and the event reports.

8.4 RECLOSER CONTROL SETTINGS

The recloser control was set based on the standards specified by SDG&E. The following are the important device settings pertaining to the HIF detection tests.

CTR = 1000

PTR = 266.70

Phase instantaneous overcurrent elements:

50P1P (Level 1 pickup) = 1.0 A secondary

50P1D (pickup delay) = 3.0 cycles

50P2P (Level 2 pickup) = 1.0 A secondary

50P2D (pickup delay) = 0 cycles

Ground instantaneous overcurrent elements:

50G1P (Level 1 pickup) = 1.0 A secondary

50G1D (pickup delay) = 3.0 cycles

50G2P (Level 2 pickup) = 1.0 A secondary

50G2D (pickup delay) = 0 cycles

Ground time-overcurrent elements:

51G1JP (Element J pickup) = 0.1 A secondary

51PJC (Level 1 curve) = U1

51G1JTD (time dial) = 1.0

HIF detection settings:

EHF (HIZ enable) = T (Test mode)

50GHIZP (50GHIZ overcurrent element pickup) = 0.025 A secondary

NPUDO (50GHIZ element pickup/dropoff counts) = 15

TPUDO (NPUDO time window) = 20.0 seconds

NHIZ (HIZ Counts) = 1

THIZ (NHIZ time window) = 120 seconds

The detailed settings for the recloser control were provided by SDG&E and are included in Appendix D.

50GHIZP is the ground HIF detection pickup. When the ground current, IG, is greater than 50GHIZP, element 50GHIZ asserts. When 50GHIZ asserts and deasserts in succession, the NPUDO counter starts recording and the TPUDO timer begins clocking. If the counts threshold is met (15 counts) within the TPUDO window (20 seconds), then another counter, NHIZ, begins. If NHIZ (1 count) is met within THIZ window (120 seconds), then the HIF2_A element will assert and trigger a high-impedance fault. Two counters provide additional security against nuisance tripping.

8.5 TEST SCENARIOS

8.5.1 Auto and Remote Toggle – From Local Control

Table 8.3 illustrates the Auto and Remote Toggle on the Recloser Control.

Table 8.3: Auto and Remote Toggle – Local Control

Objective: Verify appropriate indication for AUTO/REMOTE operating mode.					
Specific instruction: AUTO/REMOTE toggle allowed by **AUTO** and **REMOTE** pushbuttons in LOCAL mode. Carry out Test Action 1, observe corresponding results. Move on to Test Action 2.					
Negative test: Modes do not switch between LOCAL/MANUAL and AUTO/REMOTE.					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. Recloser control in MANUAL mode. **MANUAL** LED is ON.	1. Press **AUTO/MANUAL** pushbutton. 2. Press **AUTO/MANUAL** pushbutton.	1.a. **AUTO** LED – ON 1.b. **MANUAL** LED – OFF 1.c. Recloser control in AUTO mode 2.a. **AUTO** LED – OFF 2.b. **MANUAL** LED – ON 2.c. Recloser control in MANUAL mode.	1. Recloser control switches to AUTO mode successfully. 2. Recloser control switches to MANUAL mode successfully.	Y	
1. Recloser control in MANUAL mode. **MANUAL** LED is ON.	1. Press **REMOTE/LOCAL** pushbutton. 2. Press **REMOTE/LOCAL** pushbutton.	1.a. **REMOTE** LED – ON 1.b. **LOCAL** LED – OFF 1.c. Recloser control in REMOTE mode 2.a. **REMOTE** LED – OFF 2.b. **LOCAL** LED – ON 2.c. Recloser control in LOCAL mode	1. Recloser control switches to REMOTE mode successfully. 2. Recloser control switches to LOCAL mode successfully.	Y	
Test notes: The recloser control may be placed in Automatic mode when there are no lockout conditions and all three-phase voltages are healthy. Observe system voltage profile after switching operation.					

8.5.2 High-Impedance Fault Detection

HIF detection is performed by the recloser control based on the settings recommended by SDG&E. An HIF creates fault currents that fall well below the overcurrent pickup values; however, they persist long enough to possibly damage the system components. The recloser control detects these fault currents based on its HIF logic.

Scenario 1

Scenario 1 describes the HIZ element overcurrent pickup, as shown in Table 8.4.

Table 8.4: 50GHIZ Overcurrent Pickup Element Test

Objective: Verify the high-impedance overcurrent element (50GHIZ) picks up for HIFs.					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. System with nominal voltage and current conditions. 2. HIZ fault detection enabled.	1. Apply an HIF of 85 ohms for 200 ms close in to the recloser.	1.a. The 50GHIZ high-impedance overcurrent fault element asserts. 1.b. No other overcurrent elements assert.	The 50GHIZ element asserts as desired when the fault current crosses the element threshold.	Y	
Test notes:					

Figure 8.9, Figure 8.10, and Figure 8.11 illustrate an HIF generated close in to the recloser. Figure 8.9 is the event report of the fault as seen by the recloser control. As shown, the 50GHIZ element picks up when the fault is initiated; however, no other protection elements pick up because the fault does not cross their respective thresholds. Figure 8.10 shows that only one spike is captured because the HIF is not recurring. Figure 8.11 shows the SER for the HIF.

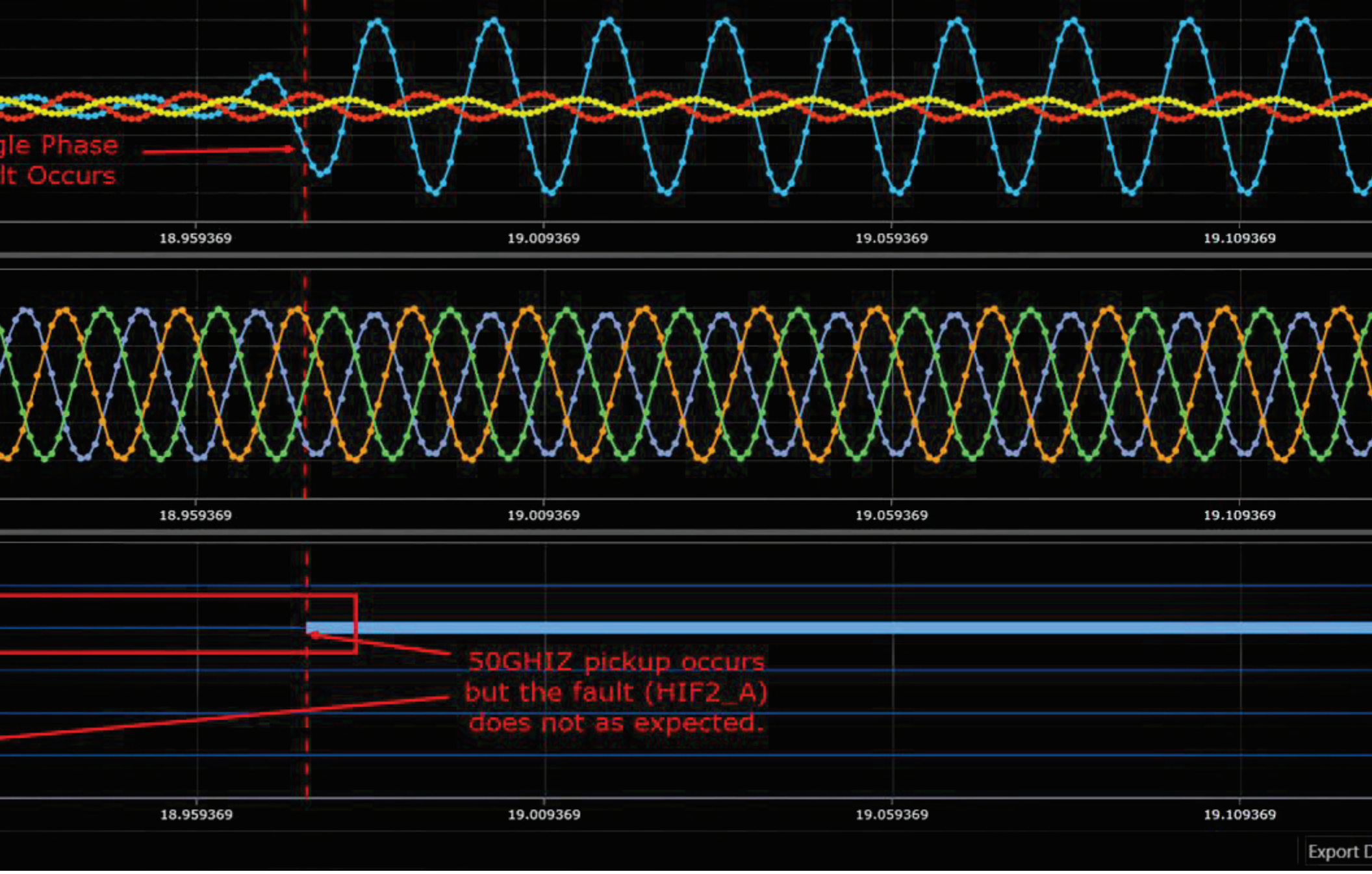


Figure 8.9: Scenario 1 – Event Report – 50GHIZ Pickup

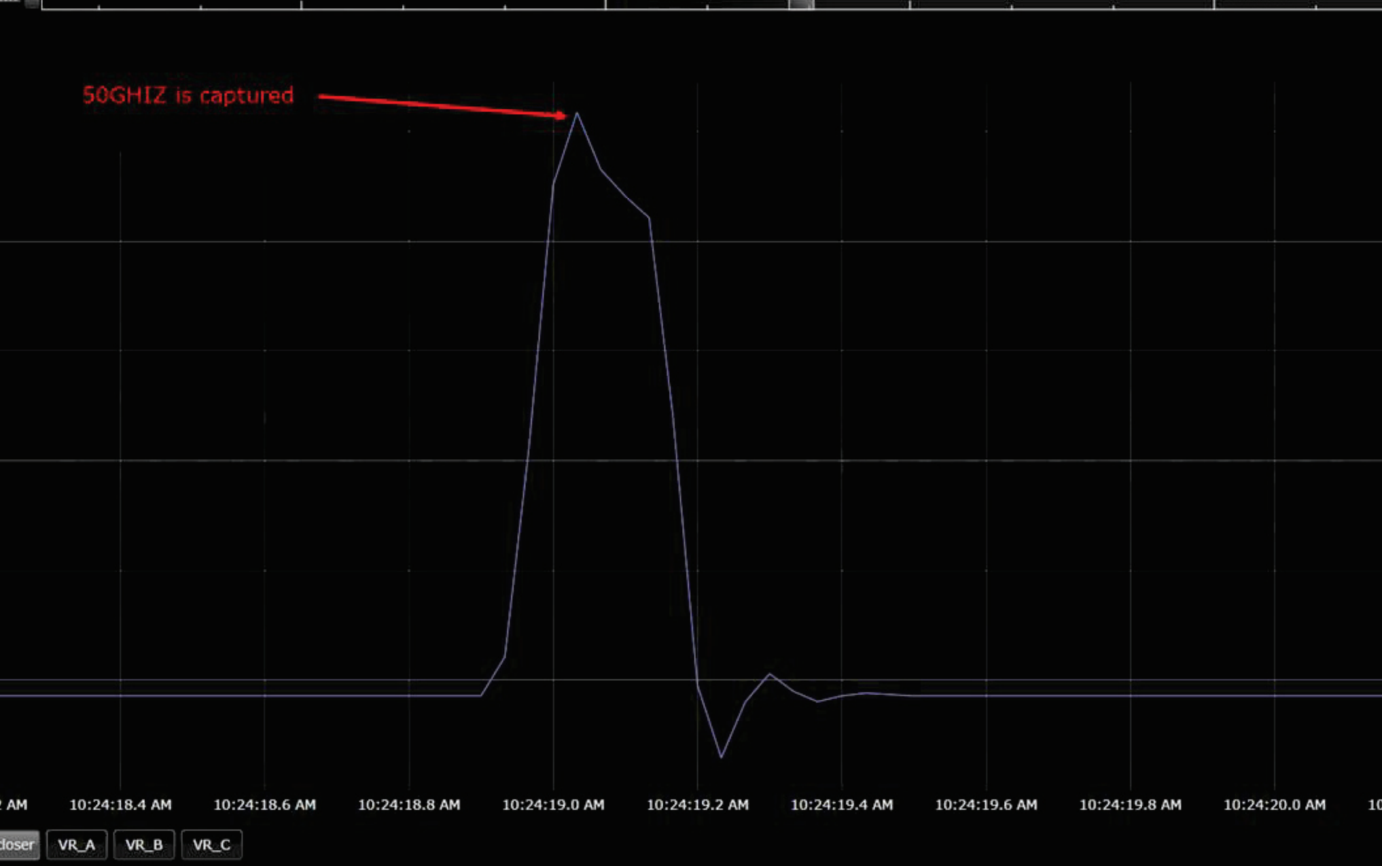


Figure 8.10: Scenario 1 – C1215-32R Current A Magnitude – Single Spike

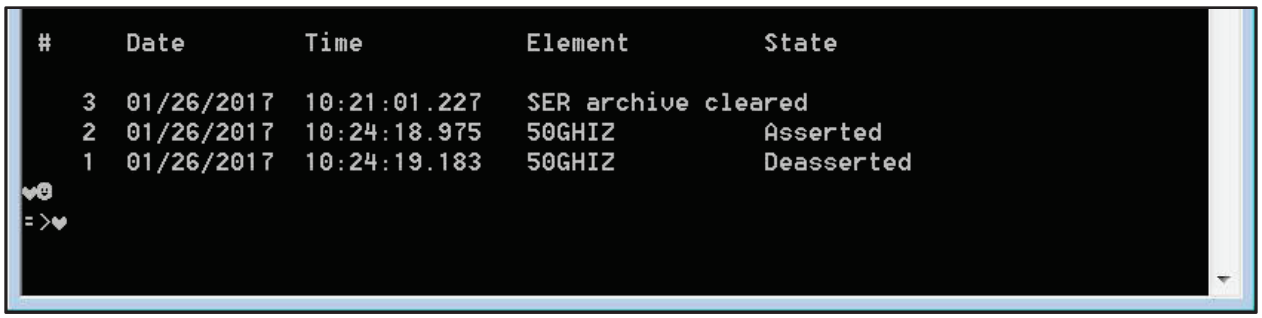


Figure 8.11: Scenario 1 – SER Report – 50GHIZ Pickup

Scenario 2

Table 8.5 illustrates a scenario where HIF is detected by the recloser.

Table 8.5: HIF Detection

Objective: Verify if recloser detects HIFs.					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. System with nominal voltage and current conditions. 2. HIZ fault detection enabled.	1. Apply an HIF of 85 ohms on the A phase that persists for a duration of 200 ms. Repeat 15 times within 20 s.	1.a. The 50GHIZ high-impedance overcurrent fault element asserts. 1.b. The A phase HIF2_A element asserts to indicate a high-impedance fault. 1.c. No other overcurrent elements assert.	The 50GHIZ element asserts. After 15 counts of the element, the HIF2_A element asserts, indicating a high-impedance fault.	Y	
Test notes:					

This test was carried out for increasing values of impedance until a point when the impedance triggered an HIF element and no other protection element. It was observed that for faults below 85 ohms, the 50G and 51G elements triggered, indicating a normal single-line-to-ground fault, which is illustrated in Scenario 4. Figure 8.12, Figure 8.13, and Figure 8.14 illustrate an HIF generated close in to the recloser. Figure 8.12 is the event report of the fault as seen by the recloser control. As shown, the 50GHIZ element picks up when the fault is initiated. The 50GHIZ element picks up and drops off for 15 counts resulting in the high-impedance fault element, HIF2_A, asserting. This indicates an HIF on the line. No other protection element asserts for this fault. Figure 8.13 shows that 15 spikes are counted within 20 seconds to meet the HIF2_A criteria. Figure 8.14 shows the SER for the HIF.

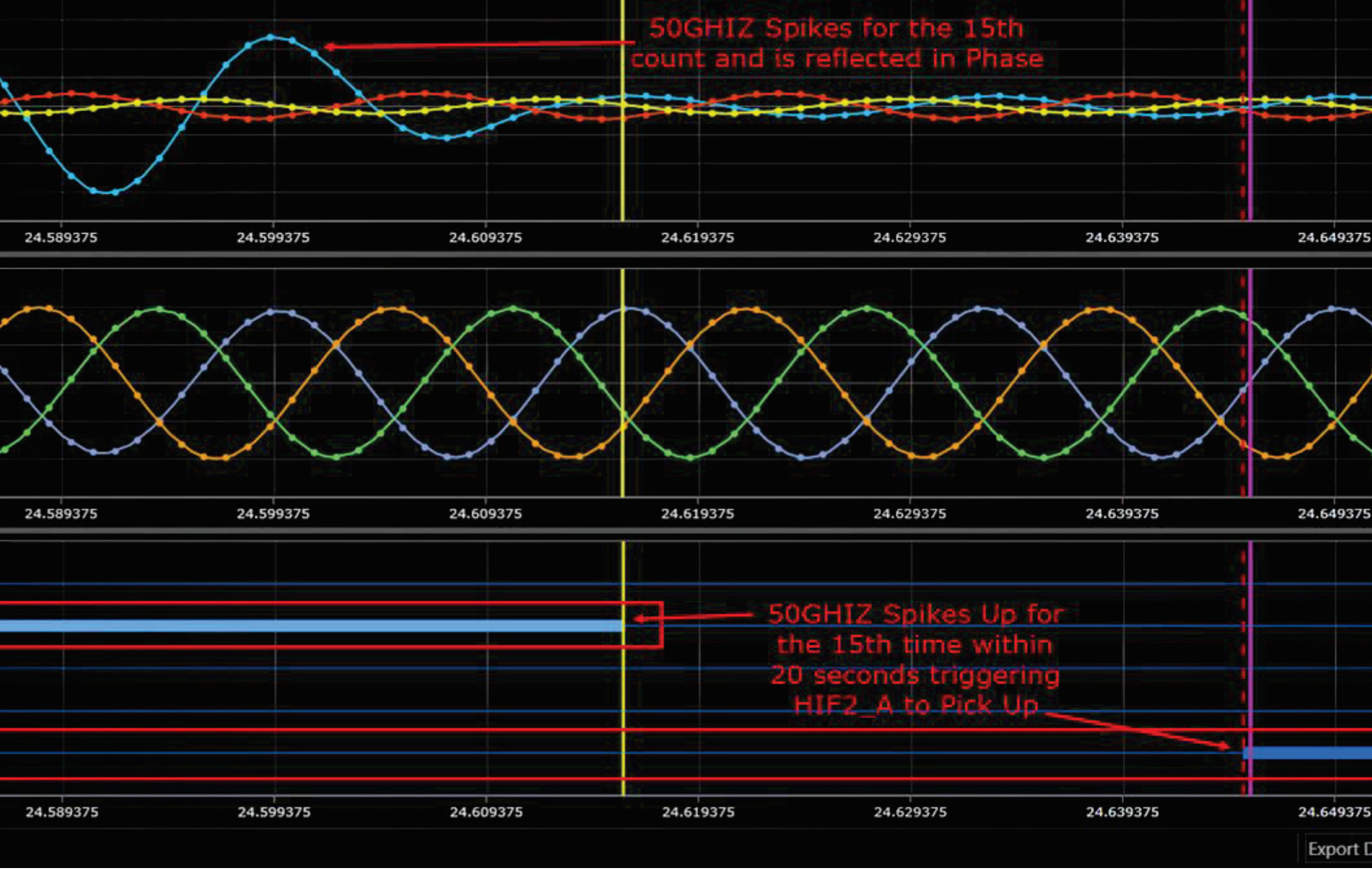


Figure 8.12: Scenario 2 – Event Report – 50GHIZ and HIF2_A Pickup

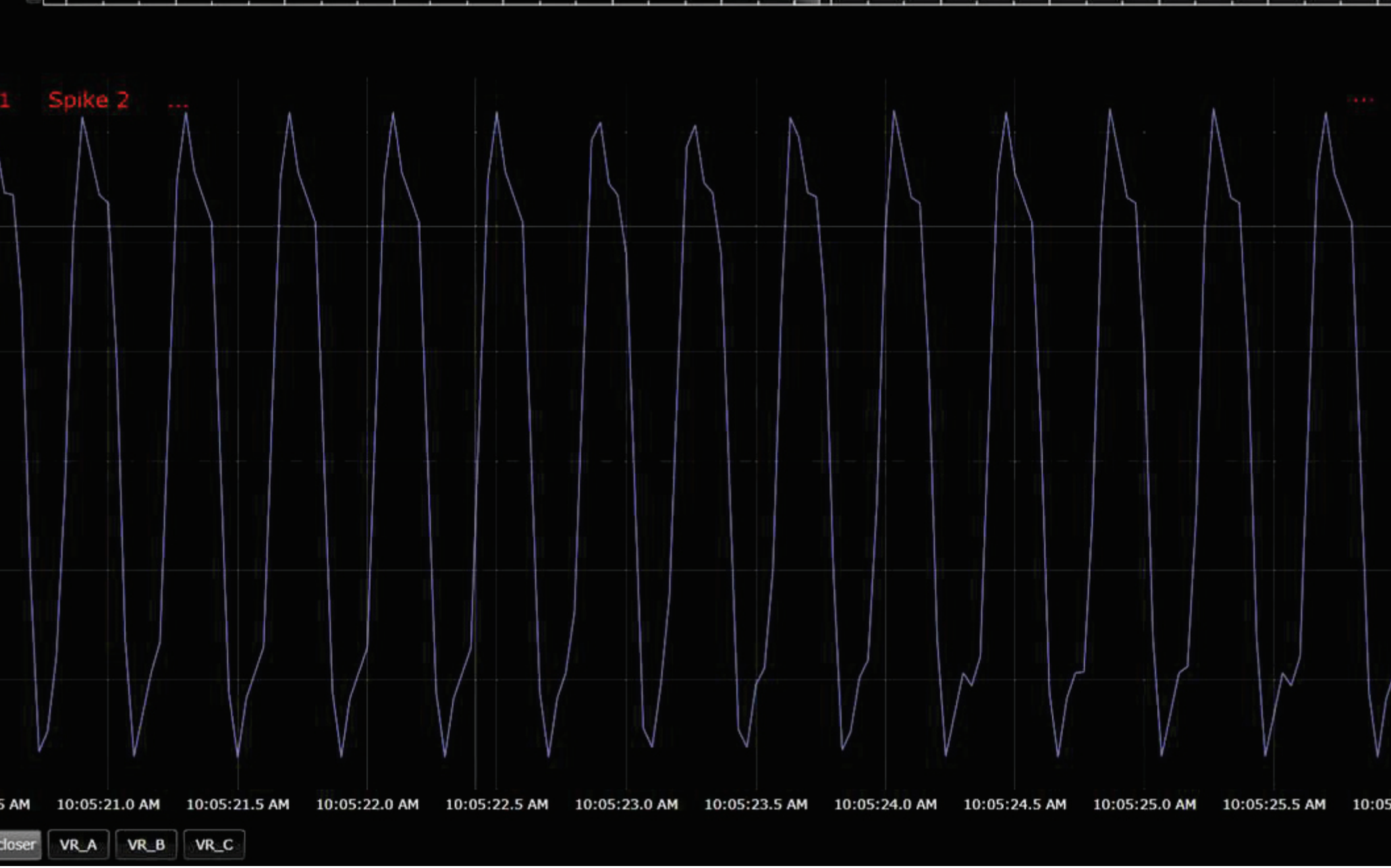
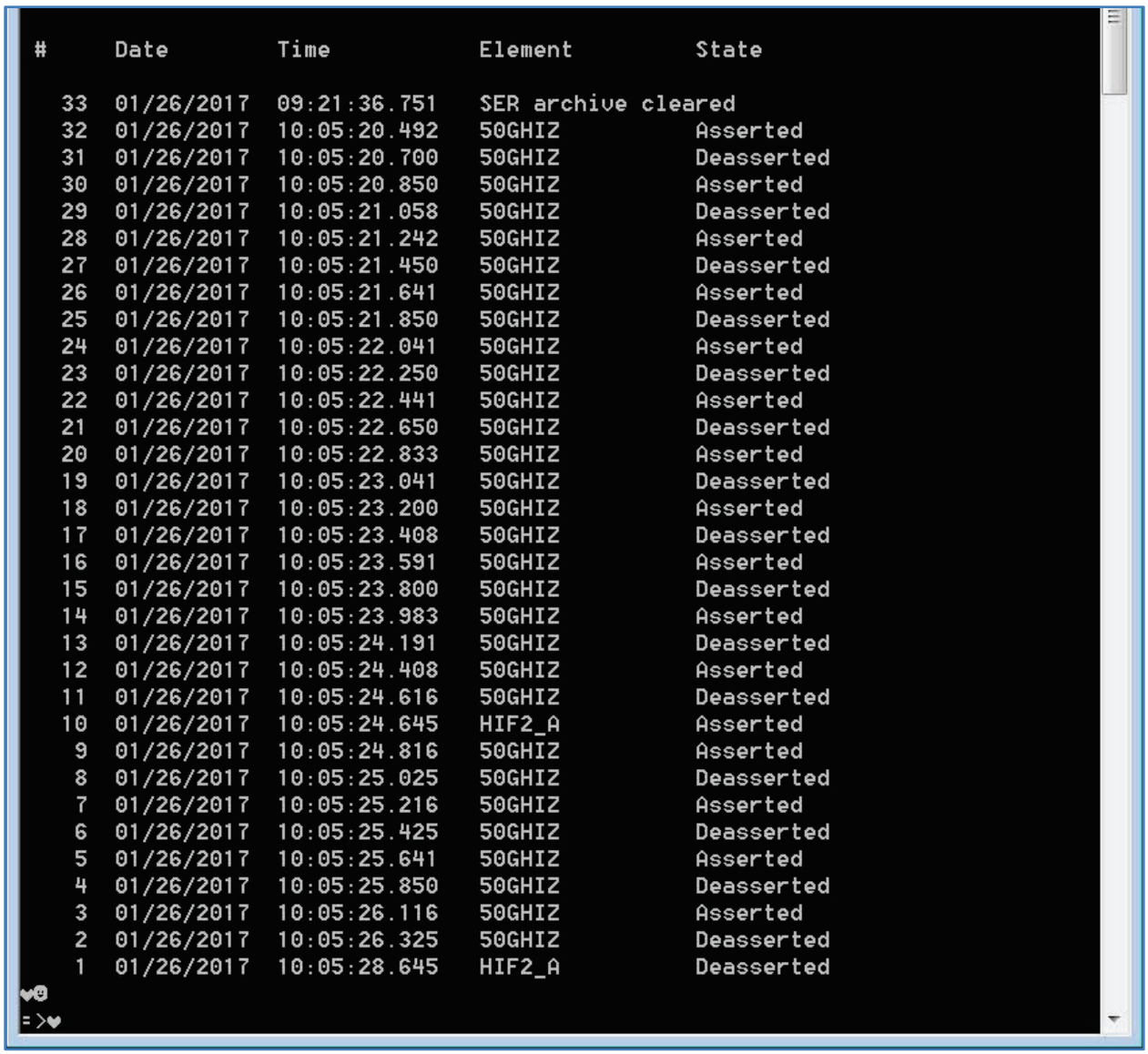


Figure 8.13: Scenario 2 – Central C1215-32R Pickup



#	Date	Time	Element	State
33	01/26/2017	09:21:36.751	SER archive cleared	
32	01/26/2017	10:05:20.492	50GHIZ	Asserted
31	01/26/2017	10:05:20.700	50GHIZ	Deasserted
30	01/26/2017	10:05:20.850	50GHIZ	Asserted
29	01/26/2017	10:05:21.058	50GHIZ	Deasserted
28	01/26/2017	10:05:21.242	50GHIZ	Asserted
27	01/26/2017	10:05:21.450	50GHIZ	Deasserted
26	01/26/2017	10:05:21.641	50GHIZ	Asserted
25	01/26/2017	10:05:21.850	50GHIZ	Deasserted
24	01/26/2017	10:05:22.041	50GHIZ	Asserted
23	01/26/2017	10:05:22.250	50GHIZ	Deasserted
22	01/26/2017	10:05:22.441	50GHIZ	Asserted
21	01/26/2017	10:05:22.650	50GHIZ	Deasserted
20	01/26/2017	10:05:22.833	50GHIZ	Asserted
19	01/26/2017	10:05:23.041	50GHIZ	Deasserted
18	01/26/2017	10:05:23.200	50GHIZ	Asserted
17	01/26/2017	10:05:23.408	50GHIZ	Deasserted
16	01/26/2017	10:05:23.591	50GHIZ	Asserted
15	01/26/2017	10:05:23.800	50GHIZ	Deasserted
14	01/26/2017	10:05:23.983	50GHIZ	Asserted
13	01/26/2017	10:05:24.191	50GHIZ	Deasserted
12	01/26/2017	10:05:24.408	50GHIZ	Asserted
11	01/26/2017	10:05:24.616	50GHIZ	Deasserted
10	01/26/2017	10:05:24.645	HIF2_A	Asserted
9	01/26/2017	10:05:24.816	50GHIZ	Asserted
8	01/26/2017	10:05:25.025	50GHIZ	Deasserted
7	01/26/2017	10:05:25.216	50GHIZ	Asserted
6	01/26/2017	10:05:25.425	50GHIZ	Deasserted
5	01/26/2017	10:05:25.641	50GHIZ	Asserted
4	01/26/2017	10:05:25.850	50GHIZ	Deasserted
3	01/26/2017	10:05:26.116	50GHIZ	Asserted
2	01/26/2017	10:05:26.325	50GHIZ	Deasserted
1	01/26/2017	10:05:28.645	HIF2_A	Deasserted

Figure 8.14: Scenario 2 – SER Report – 50GHIZ Picks Up 15 Times to Trigger HIF2_A

Scenario 3

Scenario 3 involves running the 24-hour load profile and observing the recloser operation for the duration. The test is described in Table 8.6.

Table 8.6: Recloser Response During Load Profile Operation

Objective: Verify if the recloser HIF logic operates during a normal load profile.					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. System with nominal voltage and current conditions. 2. Run the system in the normal load profile. 3. HIZ fault detection enabled.	1. Run the system in the normal load profile and observe recloser operation, if any.	1. The 50GHIZ or the HIF2_A, HIF2_B, or HIF2_C do not operate.	The 50GHIZ or the HIF elements do not operate.	Y	
Test notes:					

Figure 8.15 and Figure 8.16 illustrate the visualization software and the SER report for the duration of the normal load profile operation. As observed from the SER log in Figure 8.16, none of the HIF elements operate from the start to the end of the 24 hour load profile run. This is the desired result for a normal operation of the system.

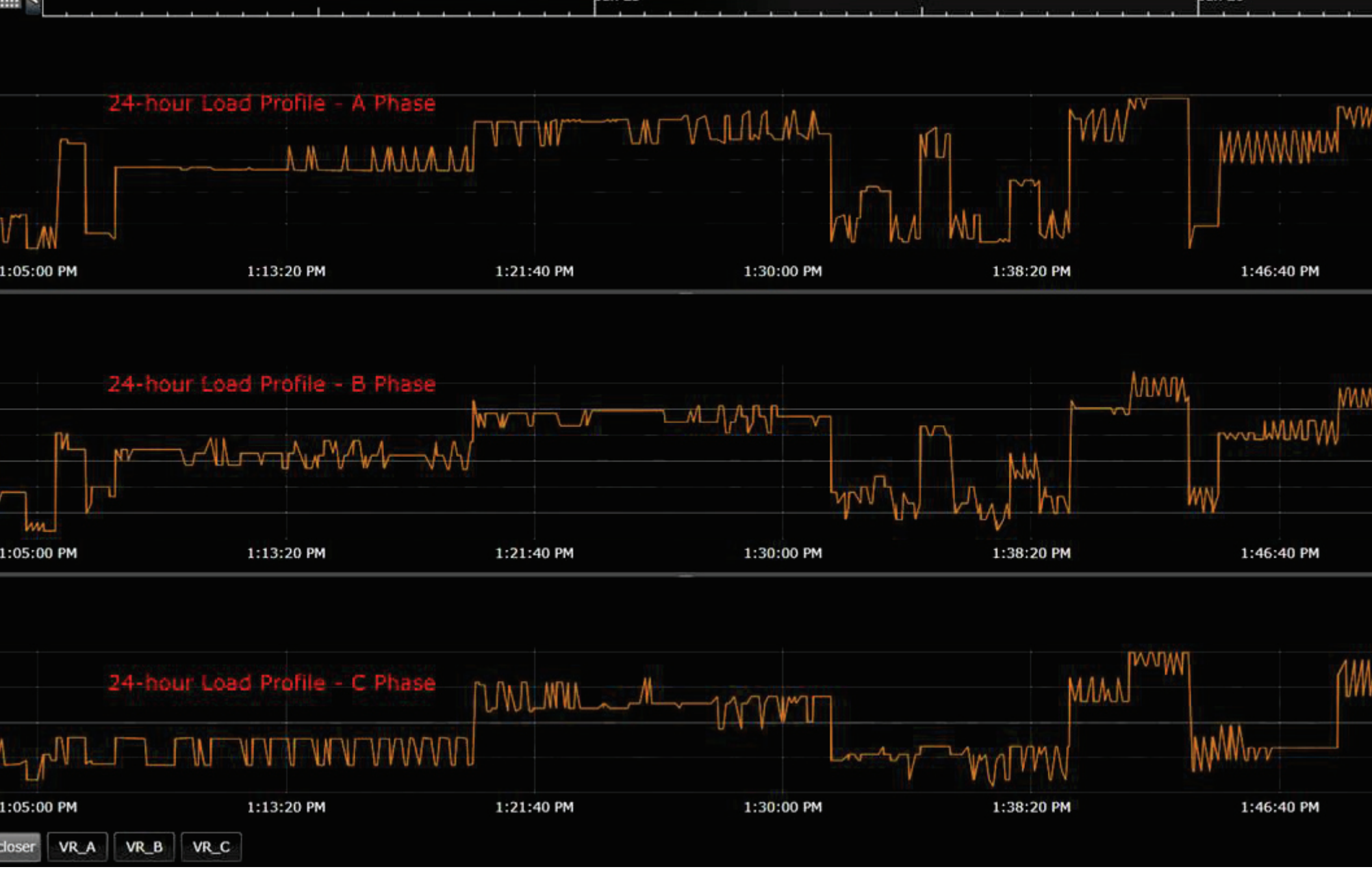


Figure 8.15: Scenario 3 – Central with 24-Hour Load Profile

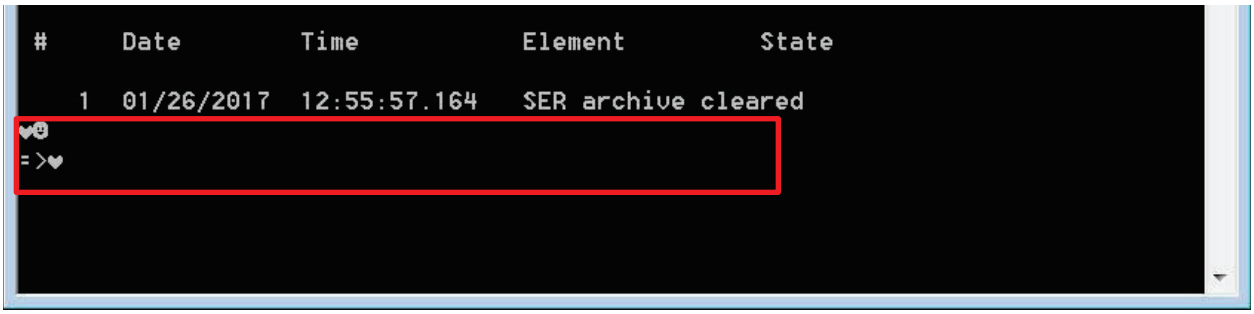


Figure 8.16: Scenario 3 – SER Shows No Pickup on a 24-Hour Load Profile Cycle as Expected

Scenario 4

Scenario 4 involves observing the recloser operation for a bolted fault. Table 8.7 describes this scenario.

Table 8.7: Recloser Operation During Bolted Fault

Objective: Verify recloser operation for a bolted fault.					
Test Initial Conditions	**Test Actions**	**Expected Results**	**Actual Results**	**Pass**	**Fail**
1. System with nominal voltage and current conditions. 2. HIZ fault detection enabled.	1. Apply a bolted fault on the A phase.	1.a. The 50 and 51 overcurrent ground elements assert, indicating a phase-to-ground fault. 1.b. The 50GHIZ asserts. 1.c. The HIF2_A element does not assert because the fault does not satisfy the spike count requirements.	1. The 50G1, 51G1 and 50P1 elements assert. 2. The 50GHIZ element asserts, but HIF2_A element does not assert.	Y	
Test notes:					

Figure 8.17, Figure 8.18, and Figure 8.19 illustrate the visualization software and the SER report for a bolted fault to assure the HIF2_A element does not pick up. The HIF2_A high-impedance fault element does not operate during the bolted fault (see elements in Figure 8.17 and Figure 8.19), which is desired.

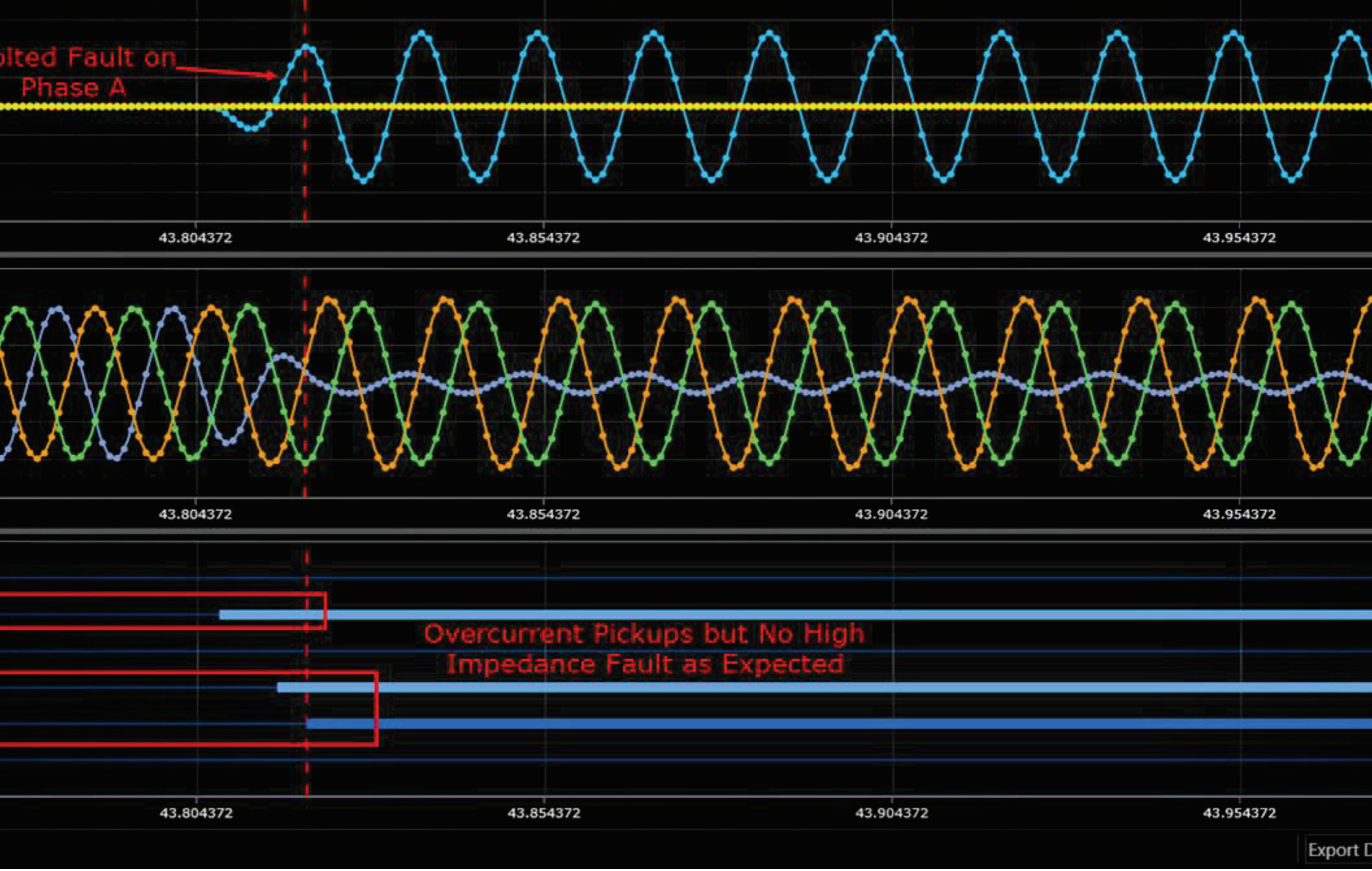


Figure 8.17: Scenario 4 – Overcurrent Protection Pickups with No HIF Pickup

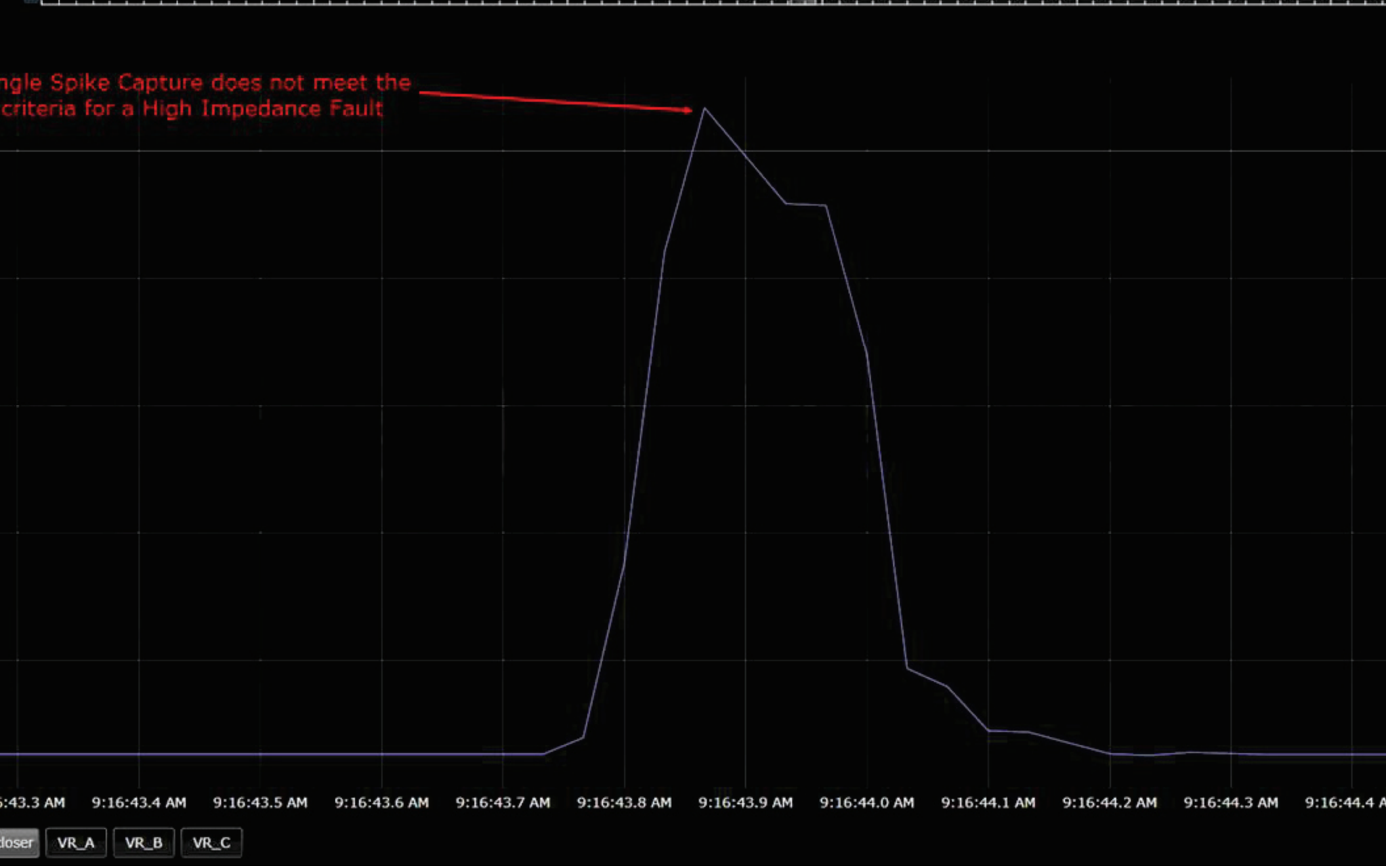


Figure 8.18: Scenario 4 – Central Single Spike Does Not Meet HIF Criteria

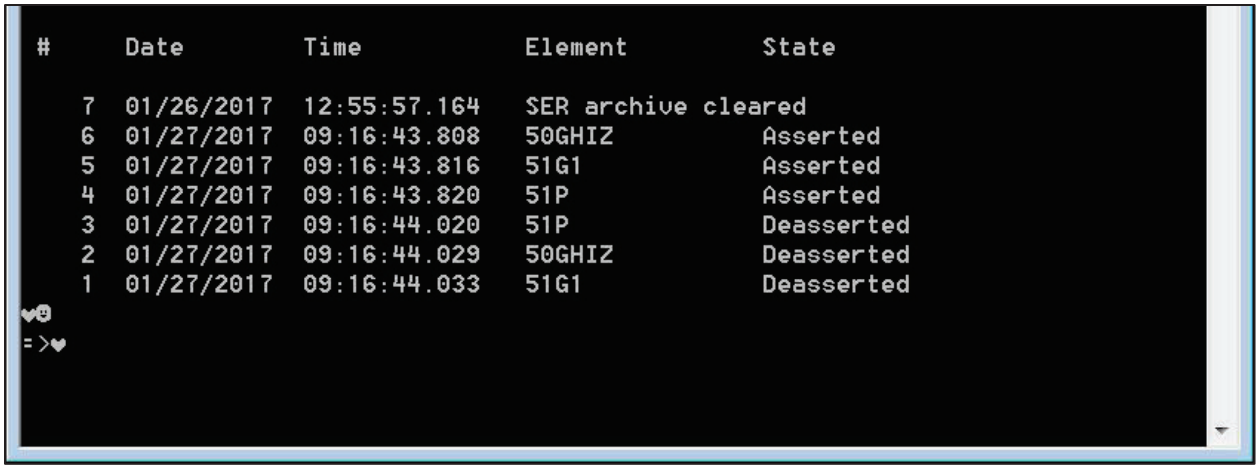


Figure 8.19: Scenario 4 – SER Shows Expected Overcurrent Pickups

8.6 RECOMMENDATION

It is recommended that SDG&E monitor the coastal-residential, urban, and desert-rural test circuits carefully for HIFs. The tests show that the high-impedance protection works as expected and can be used to indicate how the SDG&E circuits will behave in the event of an HIF. It is recommended to monitor the circuit operations closely to fine tune the HIF detection settings for each circuit. For reclosers in the field, it is recommended to look at field data and formulate HIF settings based on the circuit behavior and characteristics.

9 POWER QUALITY IN ISLANDS

The objective of this test was to define different system island configurations and observe voltage and frequency on pre- and post-islanded systems. PMUs were placed along the length of the desert-rural circuit in RSCAD to record these parameters. These tests demonstrate how synchrophasors can be applied to monitor voltage, frequency and any other relevant circuit parameters, real-time, during switching in and out of an island. The information obtained can be used to set up accurate protection and control parameters to maintain frequency and voltage in band during switching.

9.1 ISLAND CONFIGURATIONS

The desert-rural test circuit is selected for the demonstration of these tests. Three island configurations are considered for this purpose.

Island 1: This island is formed when Way 1 of the switch (D149479) is opened. Loads LD1 and LD2 are a part of the island supported by DER D149478 rated at 12 kV, 1000 kW. The rest of the circuit is supported by the utility. Refer to Figure 9.1.

Island 2: This island is formed when the normally-closed recloser 1215-10R is opened. Loads LD1, LD2, and LD3 are a part of the island supported by DER D149478 rated at 12 kV, 1000 kW. The rest of the circuit downstream of 1215-12R is supported by the utility. Refer to Figure 9.2.

Island 3: This island is formed when the substation feeder breaker is open and the utility source is unavailable. The entire test circuit is supported by DER D149478. Refer to Figure 9.3. Island 3 is considered for test demonstrations in this report.

The generation capacity of the DER may have to be adjusted via the slider in RTDS RunTime to meet the load requirement for all three island configurations. The island tests were carried out based on the 24-hour load profile for the test circuit.

Note: Refer to Table 9.1 for load distribution across the desert-rural Circuit C1215.

Table 9.1: Desert-Rural Test Circuit – Load Distribution

RTDS/Visio Reference	kW – A	kW – B	kW – C	KVAR – A	KVAR – B	KVAR – C
LD1	113	102	116	37	33	38
LD2	399	385	427	132	125	141
LD3	14	19	72	5	6	24
LD4	0	25	0	0	8	0
LD5	0	0	20	0	0	7
LD6	9	51	15	3	16	5
LD7	55	80	35	19	26	11
LD8	6	21	27	2	6	9
LD9	0	53	18	0	19	6
LD10	124	0	0	39	0	0
Total Load	720	736	730	237	239	241

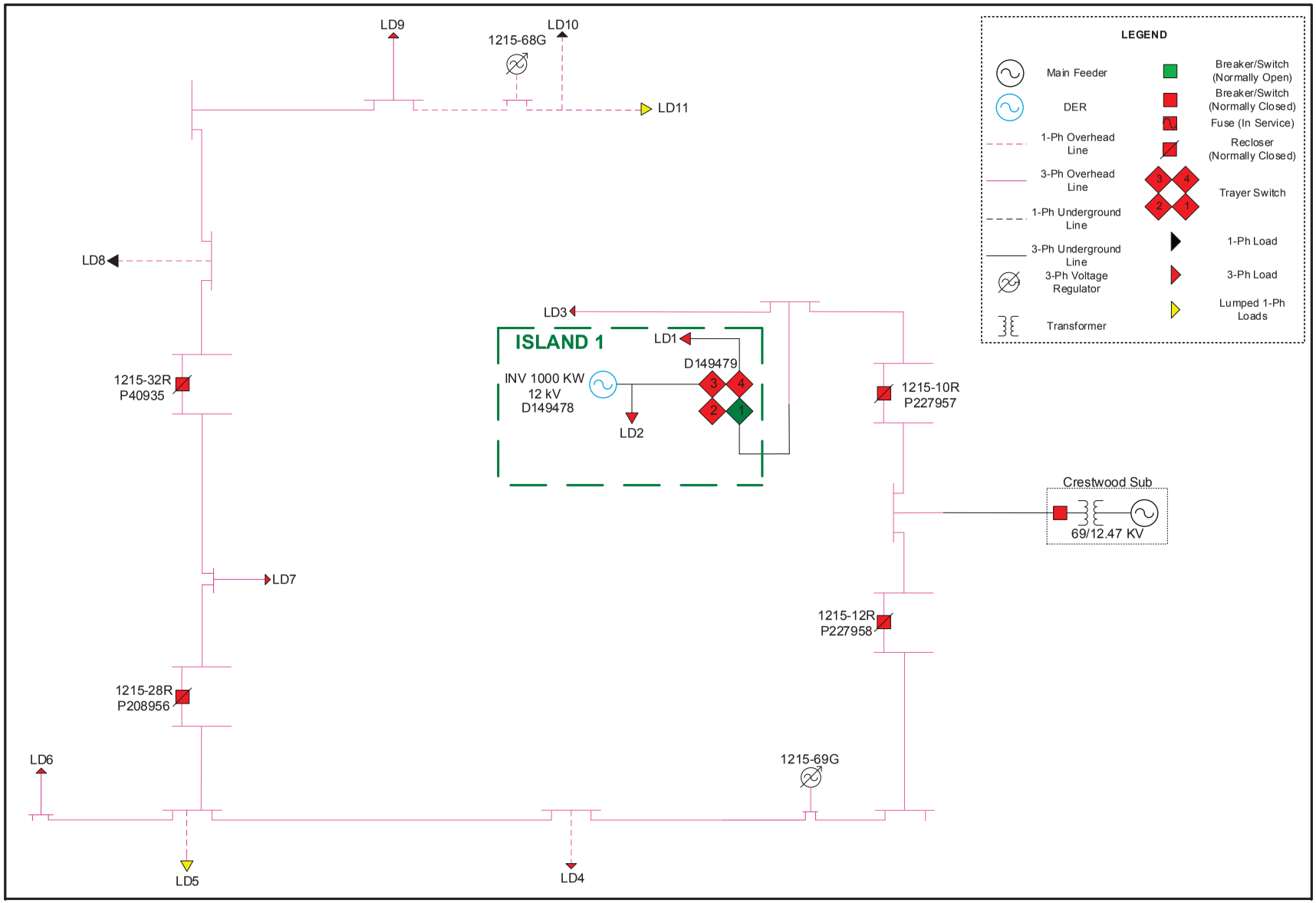


Figure 9.1: Desert-Rural Test Circuit – Island 1

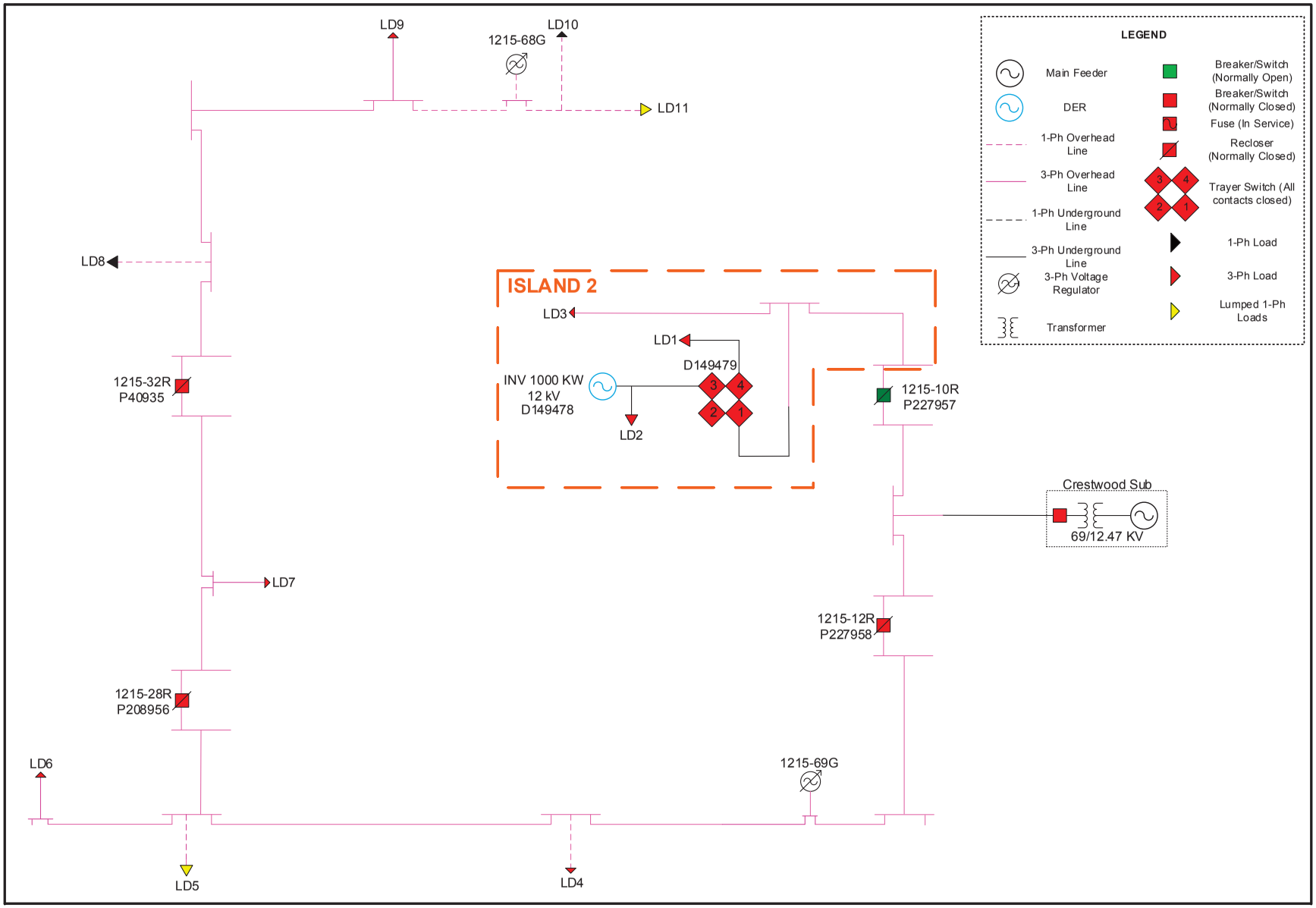


Figure 9.2: Desert-Rural Test Circuit – Island 2

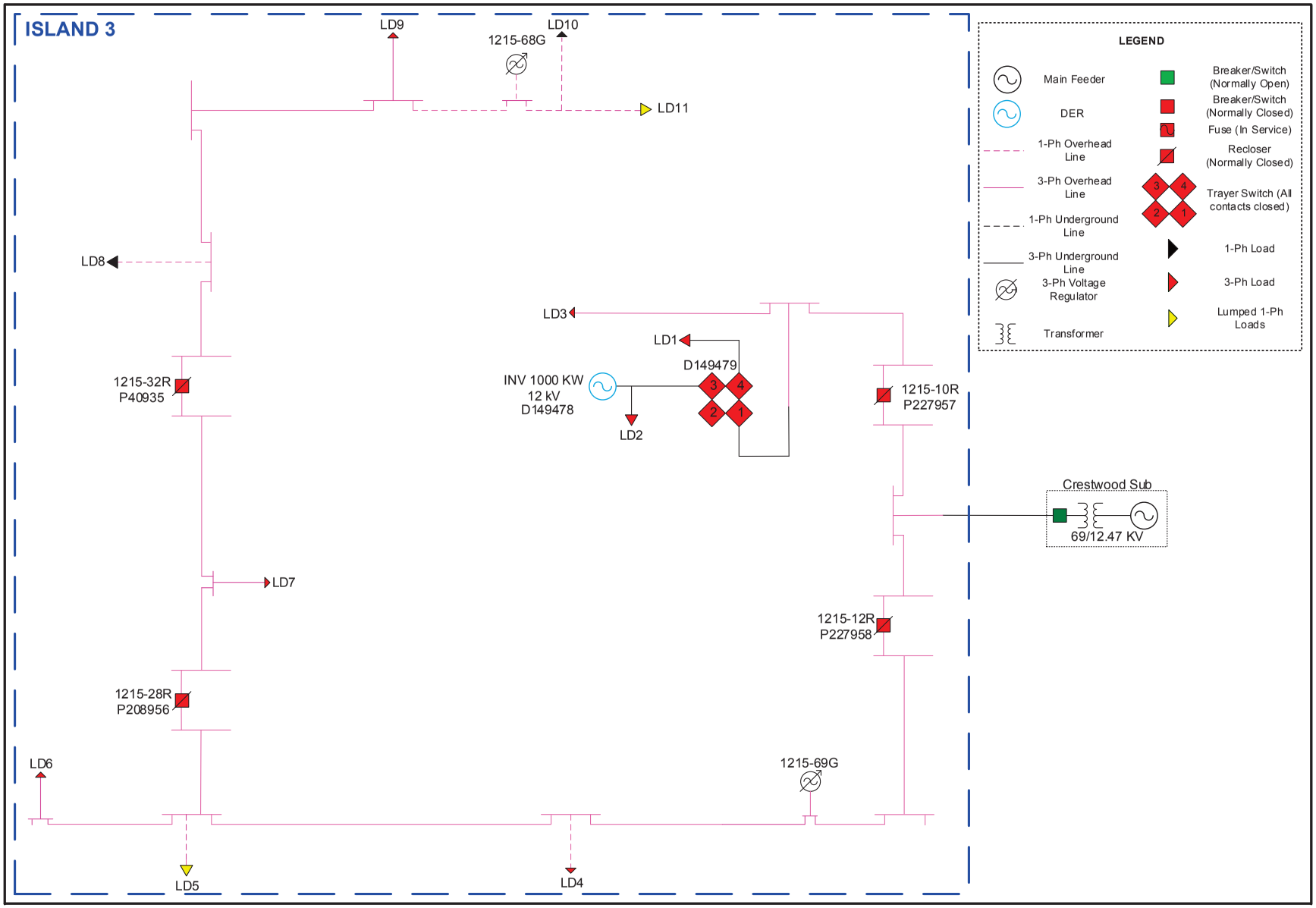


Figure 9.3: Desert-Rural Test Circuit – Island 3

9.2 TEST SETUP

9.2.1 Phasor Measurement Units

Software PMUs are modeled in RSCAD at Locations 1 through 4 for these tests. Location 5 is represented by a hardware PMU and a power quality meter to record harmonics. Refer to Figure 9.4 for more details.

The PMUs are placed such that synchrophasor data over the entire length of the circuit can be collected and analyzed.

1. Location 1: At DER to monitor the parameters at the source level. It is referred to as L1 on the visualization software results screen.

2. Location 2: At D149479 that marks the end of the circuit for Island 1 (Island 3 is studied based on the tests described in this document). It is referred to as L2 on the visualization software results screen.

3. Location 3: At Voltage Regulator 1215-69G as an intermediate point on the circuit. It is referred to as L3 on the visualization software results screen.

4. Location 4: At Recloser 1215-32R as an intermediate point on the circuit. It is referred to as L4 on the visualization software results screen.

5. Location 5: At load LD10 to collect data from the end of the circuit. It is referred to as L5 on the visualization software results screen.

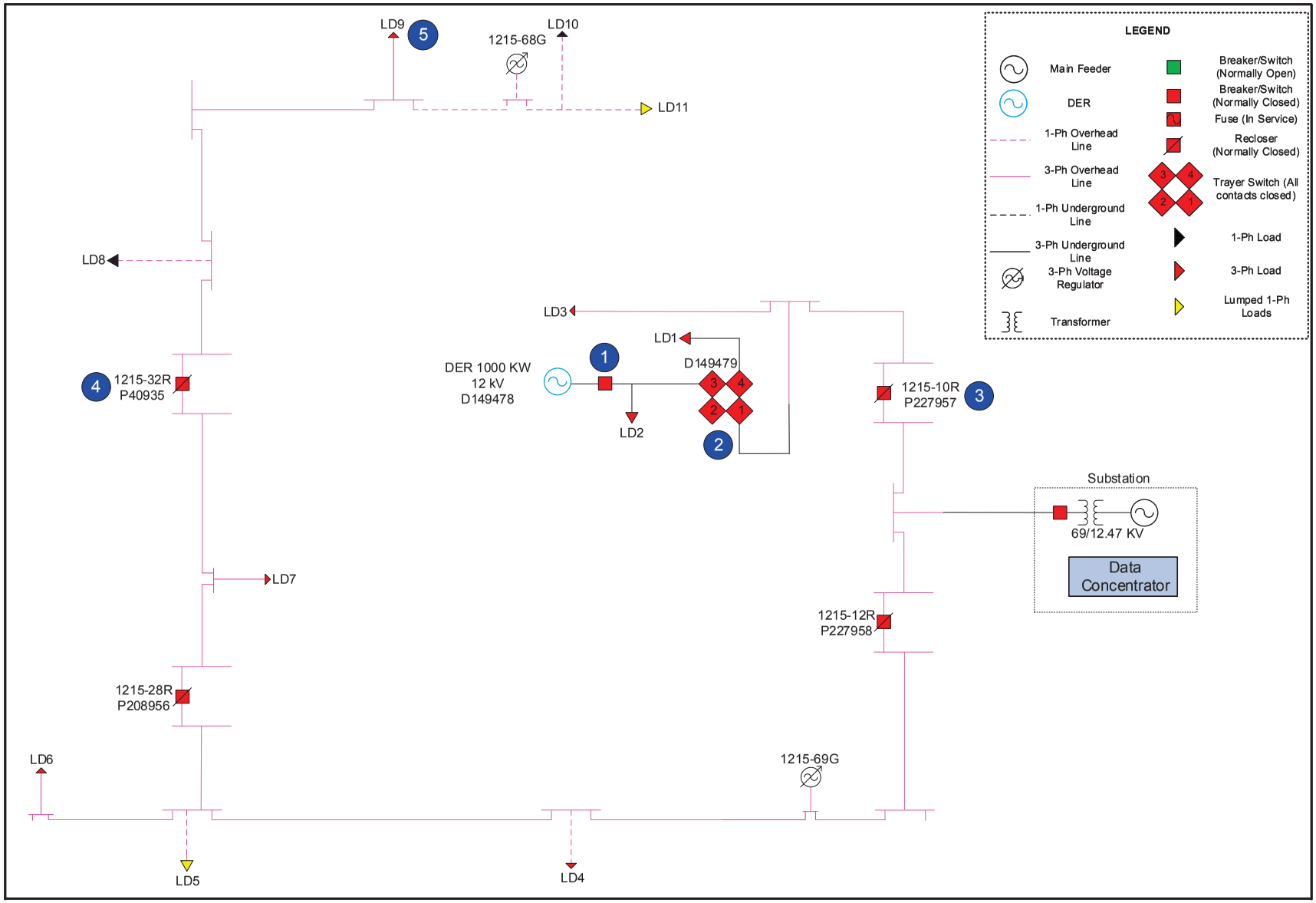


Figure 9.4: Locations of PMUs

9.2.2 RTDS and PMU Interface

Figure 9.5 illustrates the interface between the RTDS and the hardware PMU. The power quality meter is connected to the RTDS I/O cube such that it receives analog and digital inputs from the RTDS. The meter has a low-level test interface available and therefore no amplifiers are required between the RTDS and the meter for analogs.

The software PMUs are modeled in RSCAD software.

Note: ABC phase rotation is considered.

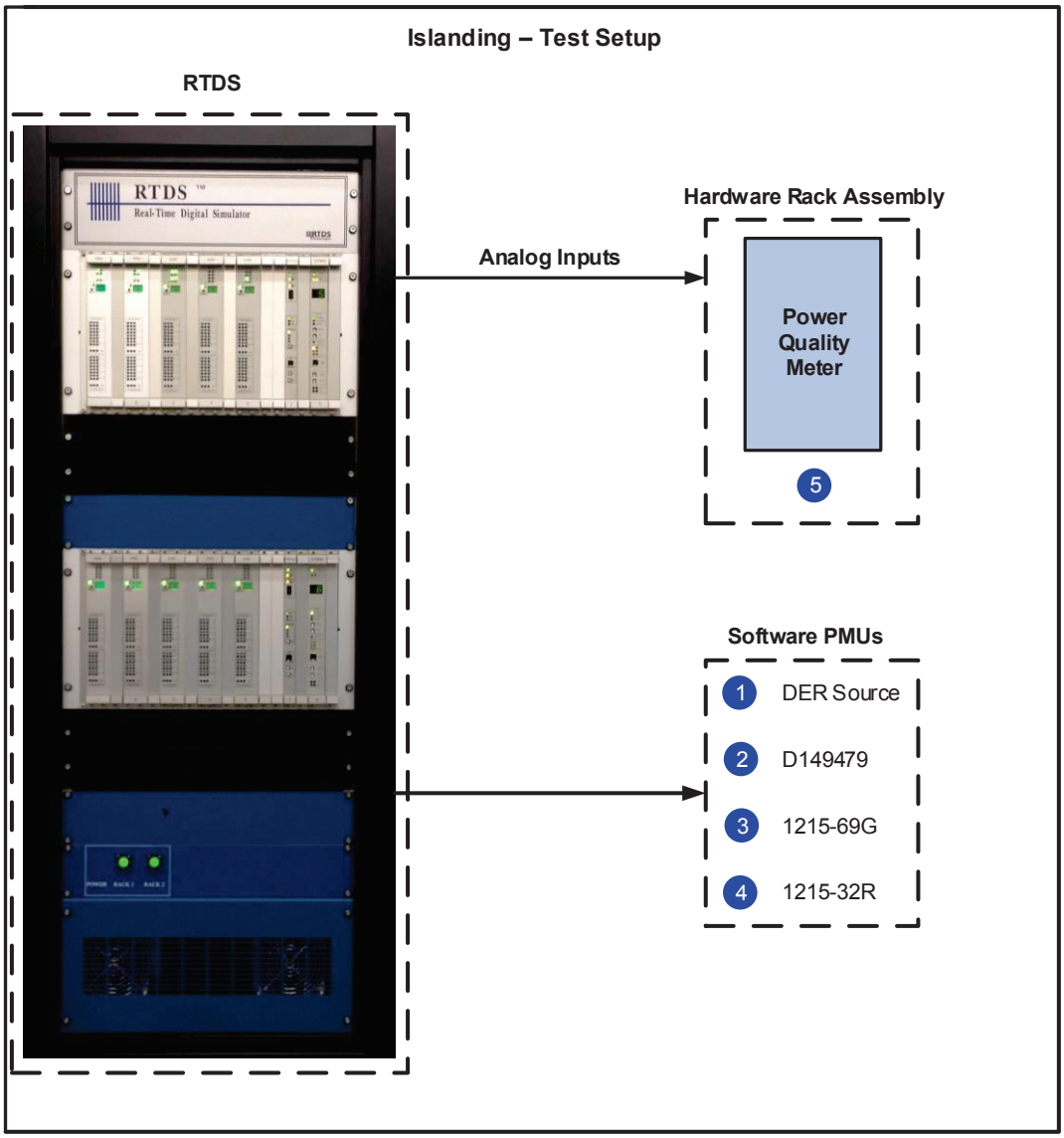


Figure 9.5: RTDS and PMUs Interface

9.2.3 PMU Communications Architecture

In addition to the PMU locations discussed in the previous section, the data concentrator is considered at the substation level. The data concentrator collects phasor, analog, and digital data over synchrophasor protocol (conforming to IEEE C37.118.1-2011) from the field PMUs.

Figure 9.6 shows the configuration required to establish successful communication between the PMUs and data concentrator over synchrophasor protocol. The PMUs and data concentrator are connected to an unmanaged Ethernet switch so that all devices are on the same network. A satellite-synchronized clock is used to provide an IRIG-B signal to all PMUs for time synchronization. A test computer to configure the PMU and the data concentrator settings is also added in the same network.

Time-aligned phasor data collected from all field PMUs is displayed collectively on one platform for further analysis using a visualization software.

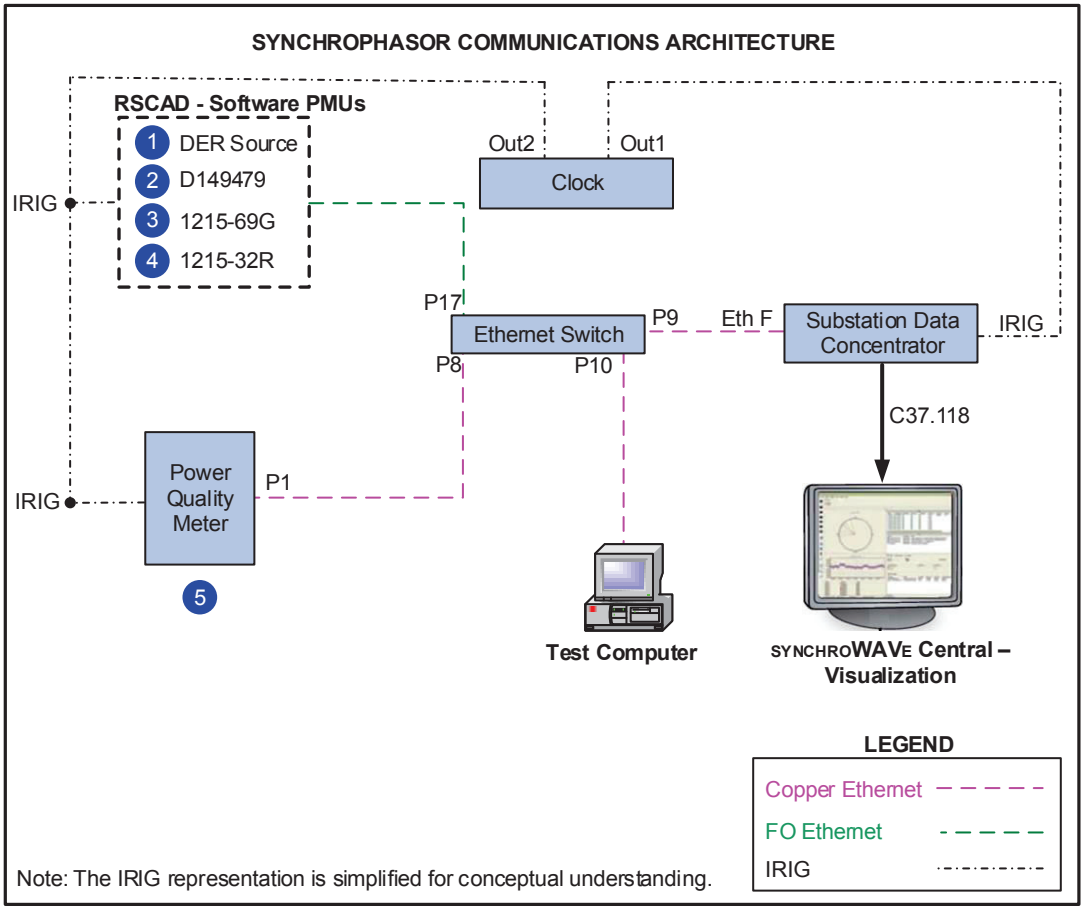


Figure 9.6: Synchrophasor Communications Architecture

9.3 TEST PROCEDURE AND RESULTS

The following tests are performed based on the island configurations discussed in Section 9.1. Test results in the form of voltage phasors and analogs are shown for visualization.

9.3.1 Test 1

Observe the voltage profile along the island and ensure it is within the allowed bands. According to ANSI C84.1-2006, American National Standard for Electric Power Systems and Equipment, the DER island system should be able to actively regulate within the agreed-upon ranges, as specified in Table 9.2 and Table 9.3.

Table 9.2: ANSI C84.1-2006 Standard Nominal System Voltages and Voltages Range – Service Voltage

Nominal Voltage (V)	Service Voltage (V)			
	Range A		Range B	
	Maximum	Minimum	Maximum	Minimum
120	126	114	127	110
240	252	228	254	220
480	504	456	508	440

Table 9.3: ANSI C84.1-2006 Standard Nominal System Voltages and Voltages Range – Utilization Voltage

Nominal Voltage (V)	Utilization Voltage (V)			
	Range A		Range B	
	Maximum	Minimum	Maximum	Minimum
120	125	110 (108)[1]	127	106 (104)[1]
240	250	220 (216)[1]	254	212 (208)[1]
480	500	440 (432)[1]	508	424 (416)[1]

[1] Not applicable to lighting loads.

In Table 9.2 and Table 9.3, Range A refers to the optimal voltage range; whereas, Range B is acceptable, however it is not optimal. In addition, the difference between minimum service and minimum utilization voltages is intended to allow for a voltage drop in the customer wiring. The NEC allows up to a 5 percent drop: up to a 3 percent drop in the main feeder and an additional less than 3 percent drop in individual branch circuits.

Notes:

1. The nominal voltage specified in Table 9.2 and Table 9.3 may need to be scaled for analysis of the 12 kV or 12.47 kV SDG&E circuits.

2. SDG&E will confirm the acceptable voltage band, based on practice.

Results/observations: Figure 9.7 shows the voltage profile at the five locations for the Island 3 scenario as discussed in Section 9.1. Momentary voltage spikes were observed at the time of switching in and out of the island. The voltage profile recovers and steady-state voltages are observed for the rest of the load profile in the island. Additional voltage monitoring and control devices are recommended to dampen these transients quickly to prevent protective relaying in the island from tripping.



Figure 9.7: Voltage Monitoring in Island 3

9.3.2 Test 2

Power quality: Observe THD for currents and voltages, if any.

According to IEEE 1547.4-2011, IEEE Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems, the DER island system should meet IEEE 519-2014 as shown in Table 9.4 and Table 9.5.

Table 9.4: IEEE 519-2014 Maximum Harmonic Current Distortion in Percent of Current

Individual Harmonic Order h (Odd Harmonics)	h < 11	11 ≤ h < 17	17 ≤ h < 23	23 ≤ h < 35	35 ≤ h	Total Demand Distortion (TDD)
Percentage (%)	4	2	1.5	0.6	0.3	5

Table 9.5: IEEE 519-2014 Maximum Harmonic Voltage Distortion in Percent

Bus Voltage V at Point of Common Coupling	Individual Harmonic (%)	THD (%)
1 kV < V > 69 kV	3	5

Note: Harmonic-related tests are not feasible in the laboratory environment because the DER and the load models do not inject harmonics in the circuit.

9.3.3 Test 3

Observe the frequency pattern before and after island formation. According to IEEE 1547.4-2011, the frequency deviation of a DER island system needs to be acceptable to all associated parties. North American power systems normally operate at 60 Hz with a tight frequency band of ± 0.05 Hz. SDG&E will confirm acceptable frequency bands, based on practice.

Results/observations: Momentary frequency spikes were observed at the time of switching in and out of the island as shown in Figure 9.8 for the Island 3 scenario. The frequency was found to be outside the band of ± 0.05 Hz for the duration of the test in the island scenario. Frequency monitoring and control devices are recommended to control the frequency when in an island scenario to ensure that it stays within the agreed-upon band. The RTDS test case does not include a frequency controller in a feedback loop to maintain the IEEE acceptable frequency band.

These tests demonstrate the application of synchrophasors to gather and analyze data, such as frequency and voltage, at different points in the distribution circuit using PMUs. The data collected over real-time provides a deeper understanding of the system dynamics. This concept can be applied in the field environment where the information obtained can be used to set up accurate protection and control parameters to maintain frequency and voltage in band during switching in and out of an island or any other scenario.

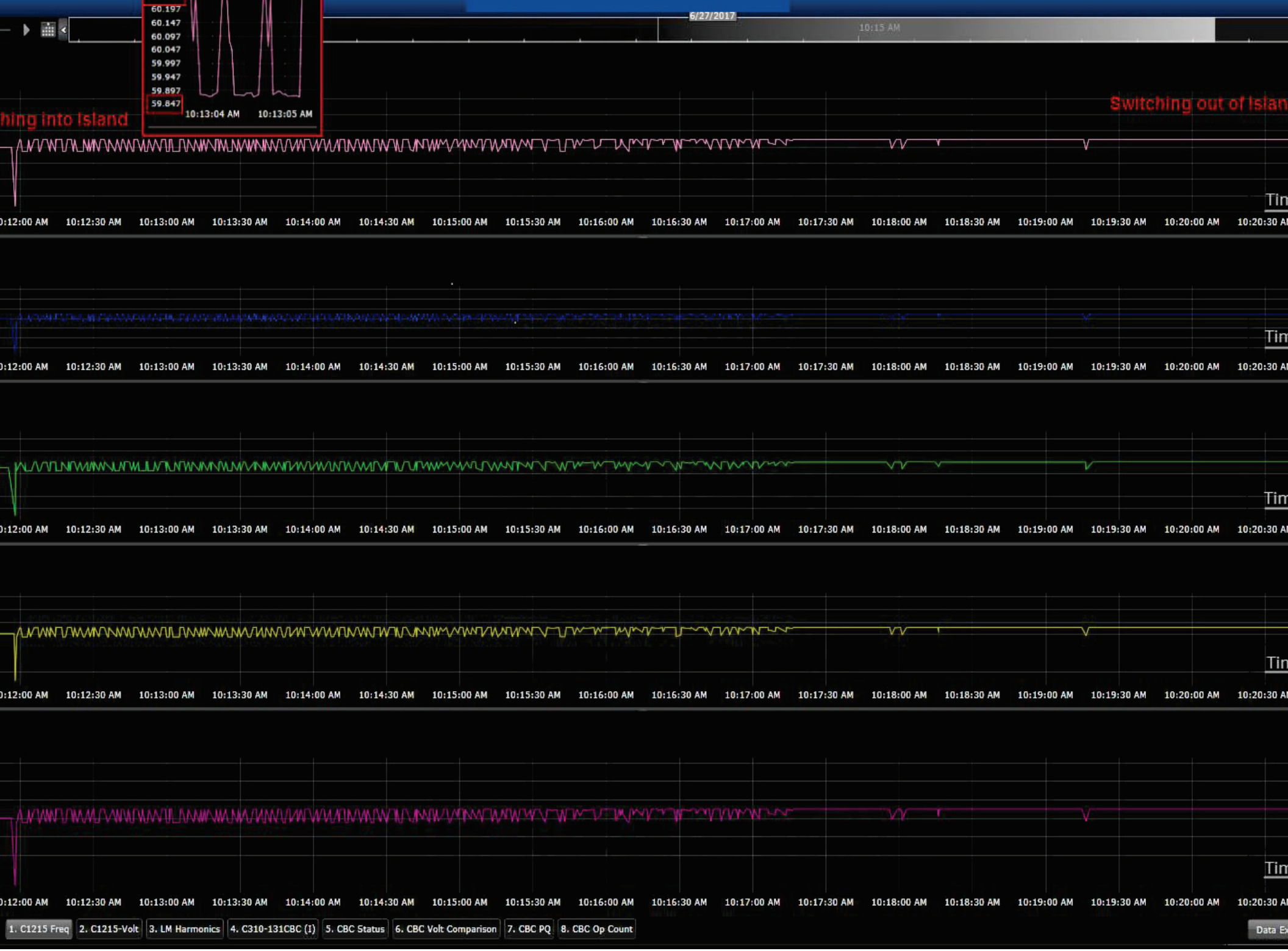


Figure 9.8: Frequency Monitoring in Island 3

10 VOLTAGE SUPPORT COODINATION TESTS

Typically, distribution circuits have a variety of voltage correction devices that regulate the voltage within the specified band. These devices operate in a stand-alone mode depending on the local voltage conditions seen by the voltage correction devices. This section demonstrates a scheme developed to control the switching of multiple voltage correction devices from a central controller.

The objective of these tests is to study the system response and interaction between a DER and a voltage regulator to regulate the voltage profile by meeting the reactive power demand of the system. The switching order of these devices is managed by the algorithm running in a central controller modeled in RSCAD software. Two operating scenarios were defined to validate the scheme. Refer to Section 10.3.1.

10.1 CIRCUIT SELECTION

The desert-rural test circuit is selected for this test. The circuit has a DER and voltage regulators which forms a basic circuit where the interaction between two varied voltage correction devices can be studied. The desert rural circuit with the DER at Position 1 and voltage regulators at Positions 2 and 3 are shown in Figure 10.1.

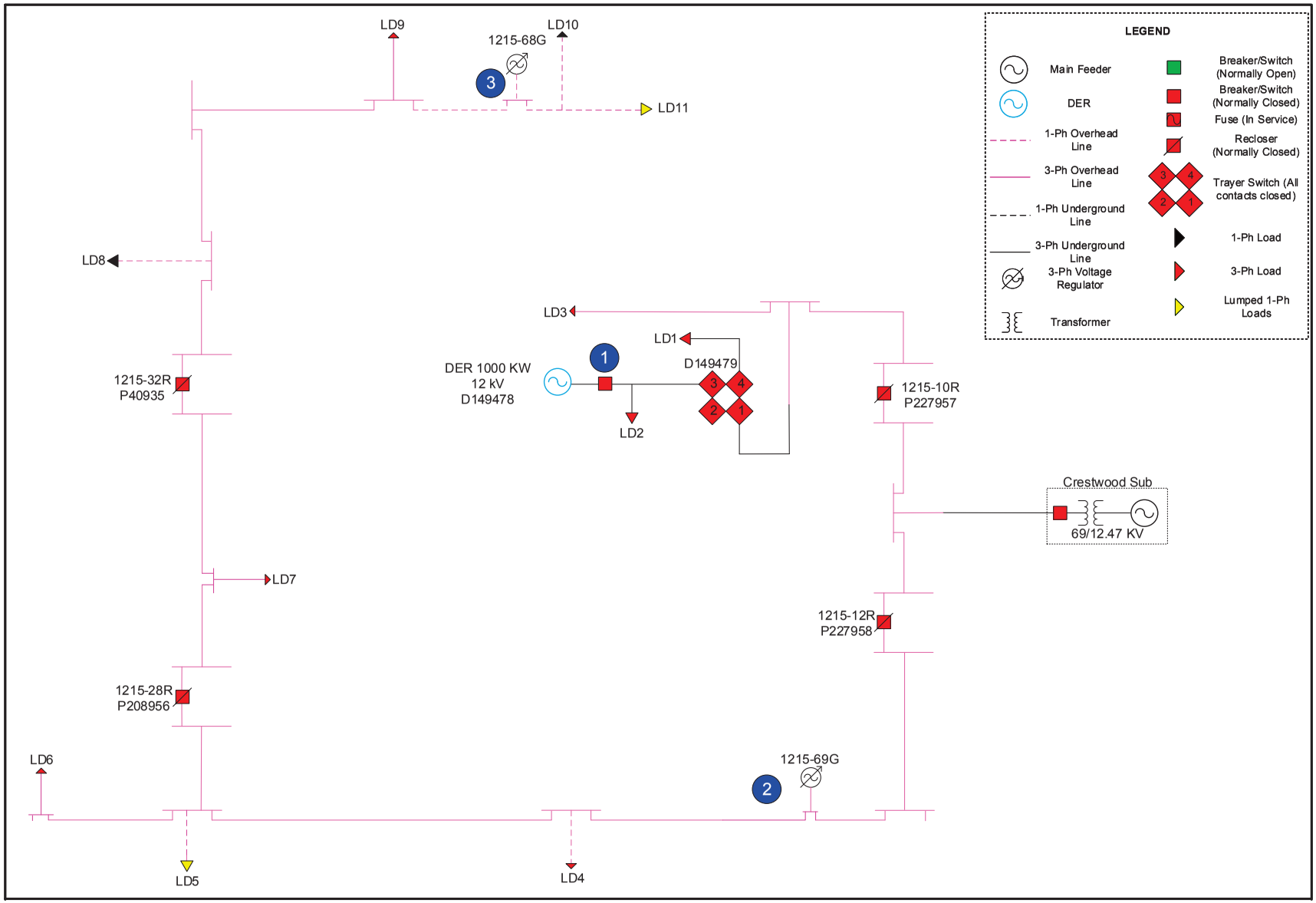


Figure 10.1: Desert-Rural Test Circuit

10.2 TEST SETUP

The desert-rural test circuit with DER and voltage regulators were modeled in RSCAD for this test. This test setup does not include hardware devices. Logic to control and coordinate the DER and voltage regulators is designed in RSCAD. All results are recorded and compiled on the RSCAD RunTime screen.

10.2.1 Distributed Energy Resource

The DER used in these tests have been updated from a scalable constant current source to a scalable battery system that can operate under Volt/VAR mode. The DER battery stacks are controlled by the DER controller. The controller operates in the dq plane with real and reactive power sliders to control the DER output.

The Volt/VAR mode provides smooth control over the reactive power output of the DER in response to the fluctuations in the bus voltage. The bus voltage reference can be set to a desired value in the controller. When the bus voltage goes below this reference, the controller boosts the reactive power output to meet the reactive power deficit of the system. Similarly, it can consume reactive power when the system voltage rises above the reference value. The volt/VAR characteristic is shown in Figure 10.2.

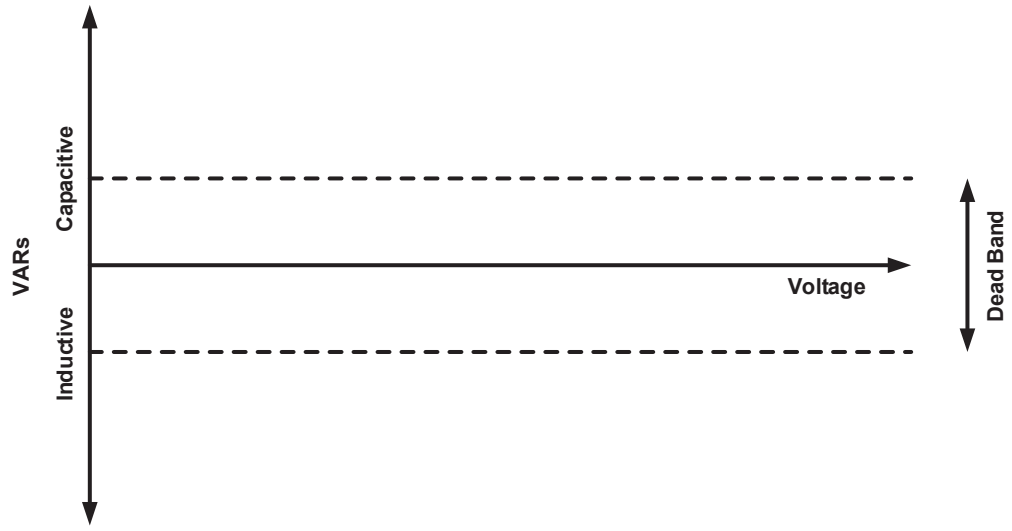


Figure 10.2: Volt/VAR Mode Operation

The DER in the Volt/VAR mode receives the system voltage and monitors the difference against a user-defined reference voltage. Based on the output from the comparator, the volt/VAR controller calculates the increment or decrement to the existing reactive power output using an integral controller. The volt/VAR controller logic is illustrated in Figure 10.3.

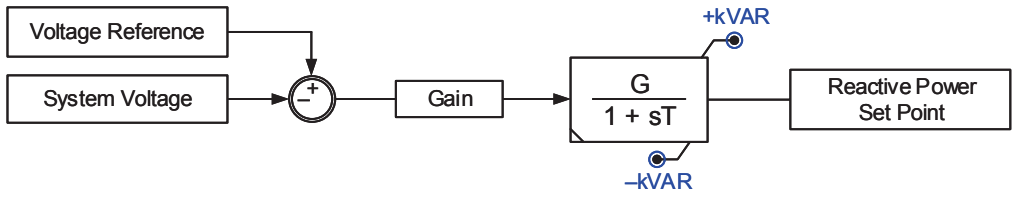


Figure 10.3: Volt/VAR Controller Logic

10.2.2 Voltage Regulator

The voltage regulator logic used in these tests is an extension of the voltage regulator logic described in Section 6.6. Additional logic was added to replicate the hardware connected to the circuit, which is the voltage regulator control. The voltage center band and bandwidth are user defined, which sets the upper and lower voltage band limits of the voltage regulator. Voltage comparators added to each phase compare the system voltage to the band limits, which helps determine whether a tap raise or lower operation must be carried out to bring the voltage in band. The intertap duration is a user-settable value. The tap raise or lower operations are contingent on which test scenario is being run, which is described in Section 10.3. The hardware functions "BLOCK" and "INHIBIT" have not been modeled because these functions are not significant to the tests being performed in this section.

10.2.3 Voltage Controller

The voltage controller block on RSCAD continuously monitors the voltage at the reference point of the circuit and switches the DER and voltage regulator on or off to maintain the voltage within the specified band setting. An out-of-band condition would trigger the DER to switch on first. A continued out-of-band condition would next trigger the voltage regulator. The DER in the Volt/VAR mode and the voltage regulator tap changes would ensure that the voltage stays within the specified center band. The device that assumes primary control of voltage correction depends on the scenario, which will be discussed later in this section.

Figure 10.4 illustrates the voltage band check of the voltage controller block. The voltage location dial allows selection of a particular point on the circuit as the reference point for voltage regulation. In this study, the voltage at the end of the line was chosen as the reference voltage. The reference voltage is verified for an in-band or out-band condition. The pickup and dropoff timer at the end of the voltage band check ensures that the voltage is in that band for a certain time interval before asserting. This is especially critical if the DER comes online and takes a few cycles to stabilize to the desired reactive power output.

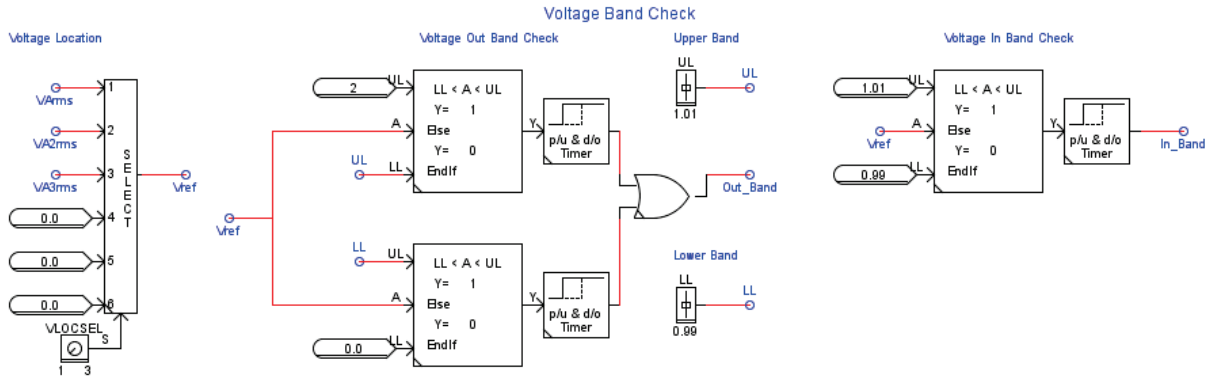


Figure 10.4: Voltage Band Check

Figure 10.5 illustrates the controller On/Off logic. The DER switches on only when the voltage has remained out of band for a certain amount of time. The voltage regulator switches on based on the scenario being run. Both the DER and the voltage regulator would switch off when the voltage comes back in band.

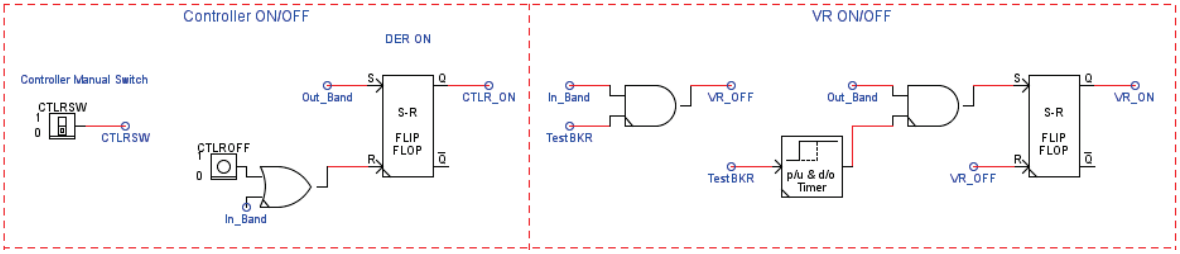


Figure 10.5: Controller On/Off Logic

Figure 10.6 illustrates the control logic for the voltage control Scenario 1. Scenario 1 involves the voltage regulator switching on after the DER has constantly been providing VARs for a prolonged period to help support system voltage. The DER, in this case, need not have achieved its maximum VAR capacity. This is particularly useful for cases in which the DER needs to be relieved from long-term voltage correction or to reduce the costs involved because of extended DER usage. In this scenario, the logic runs a check on the DER reactive power output for a specific period and triggers the voltage regulator to start raising or lowering its taps to bring the DER to an approximate zero VAR output, while at the same time ensuring that the system voltage stays in band. With each tap operation, more DER reactive power becomes available for future use. The DER remains the primary device for voltage correction for further voltage disturbances.

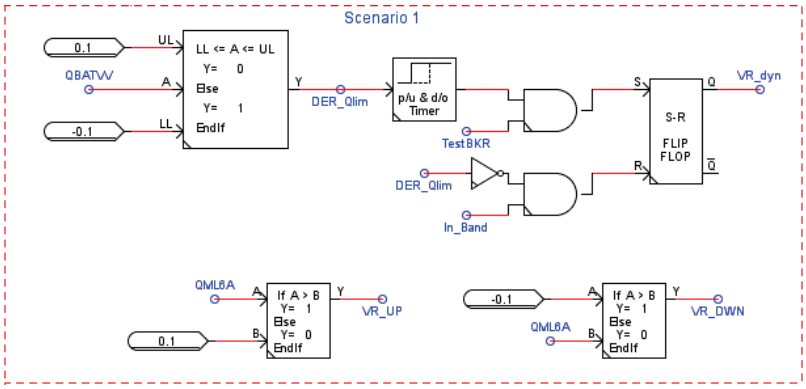


Figure 10.6: Voltage Control – Scenario 1

Scenario 2, shown in Figure 10.7, involves voltage regulator operation only if the DER is not able to support the system voltage. The system voltage going out of band would result in the DER switching on after a user-defined time interval. The DER would adjust its reactive power output to bring the system voltage in band. However, in a situation in which the DER attains it maximum VAR capability, the Scenario 2 logic would trigger the voltage regulator to come online and start raising or lowering its taps to reduce the DER output to zero, and at the same time bring system voltage in band. The voltage regulator is now the primary voltage corrector for any further voltage disturbances. The DER would only come back online when the voltage regulator has reached its maximum tap position. The DER allows for a faster and smoother voltage correction. The scenario selector selects the scenario to operate based on its input dial position.

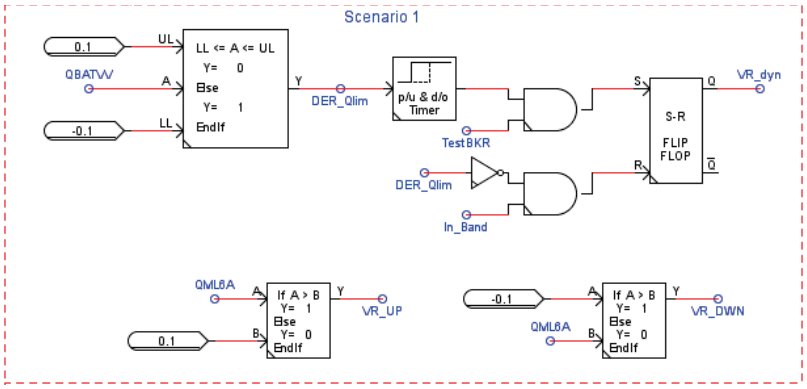


Figure 10.7: Voltage Control – Scenario 2

10.2.4 RSCAD RunTime

The RunTime screen for these tests is shown in Figure 10.8. It consists of controls for the circuit breakers and their status indicators. The controls described in Section 10.2.3 form part of the master controller. The load control has a selector switch to turn On/Off the 24-hour load profile and sliders to set the active and reactive power for the connected loads in the circuit. The inverter control sets the active and reactive power set point of the DER and includes a selector switch to toggle the Volt/VAR mode On/Off. Timers implemented in the DER logic can be controlled in the RunTime module.

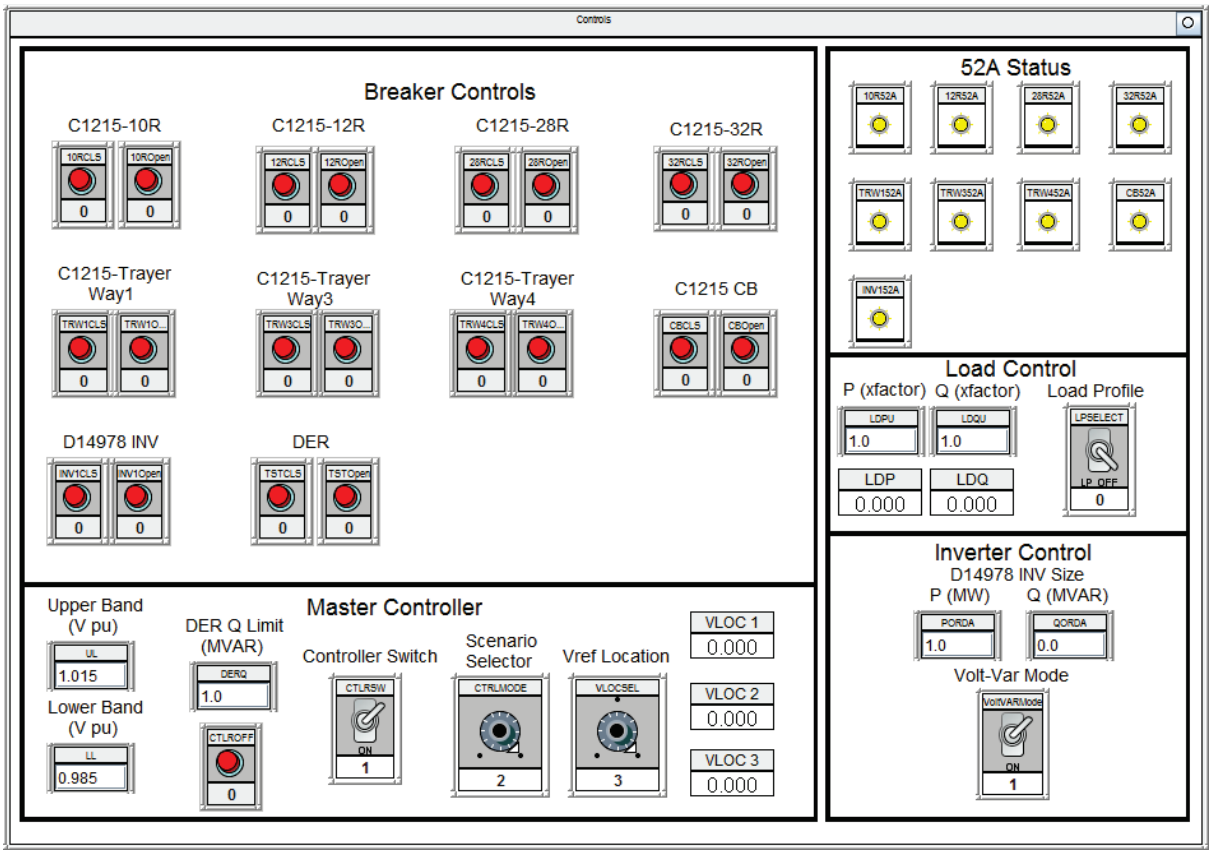


Figure 10.8: DER Test RunTime Controls

10.2.5 Hardware Implementation

The DER tests were performed on the RTDS using software models of the master controller, DER, and voltage regulator. The following are examples of devices that could be used for an actual hardware implementation of these tests. Appendix E – Proprietary Information includes a look-up table for the following devices:

- Master Controller – Device L1
- Voltage Regulator Control – Device L2
- Data Concentrator – Device L3
- DER – Device M

10.3 TEST PROCEDURE

The DER is running in parallel with the grid for these tests. The DER is set in the Volt/VAR control mode. Voltage disturbances are created in the system by switching loads in and out to vary the system voltage magnitude. Logic for controlling and coordinating the DER and the voltage regulator will be designed in RSCAD.

10.3.1 Load Switching

For this test, switch in a significant load that decreases the voltage magnitude below the set reference. Then, switch out the load in steps to bring the voltage magnitude above the set reference (see Table 10.1).

Table 10.1: Load Switching

<table>
<tr><td colspan="3">Objective: Verify that the DER and voltage regulator work together to support voltage during a step increase and decrease in load.</td></tr>
<tr><th>Test Initial Conditions</th><th>Test Actions</th><th>Observations and Results</th></tr>
<tr><td rowspan="2">1. System with nominal voltage condition.
2. Volt/VAR control mode enabled.</td><td>1. Switch in load in steps.</td><td>Scenario 1: VAR requirement is less than the VAR capacity of the DER.
1. Decrease in voltage magnitude.
2. DER increases reactive power to restore the voltage within band.
3. Although voltage already restored, the voltage regulator is triggered to respond after a user-settable delay to relieve the DER from long-term correction.
4. The voltage regulator continues to operate until the VAR output in the DER is reduced to a minimum.
5. For a further decrease in voltage, the DER acts as the primary voltage correction device.
Scenario 2: The VAR requirement is more than the VAR capacity of the DER.
1. Decrease in voltage magnitude.
2. The DER increases reactive power to maintain the voltage.
3. Study the interaction between the DER and voltage regulator. Coordinate and control these devices to support the system voltage:
a) The DER supports the system voltage until it attains the maximum rated VAR capacity.
b) A further decrease in system voltage results in the voltage regulator raising its taps after a user-settable delay, to support the voltage.
c) The voltage regulator would continue raising taps until the DER reactive power output reduces to a minimum.
d) For a further voltage decrease, the voltage regulator acts as the primary voltage correction device.</td></tr>
<tr><td>2. Switch out load in steps.</td><td>1. Increase in voltage magnitude when the loads are switched out.
2. Observe the DER and voltage regulator response for Scenario 1 and Scenario 2.</td></tr>
</table>

Figure 10.9 illustrates the timeline for the operation of scenarios 1 and 2. The side-by-side representation of these scenarios shows the difference in operation of the DER and VR based on the respective scenario.

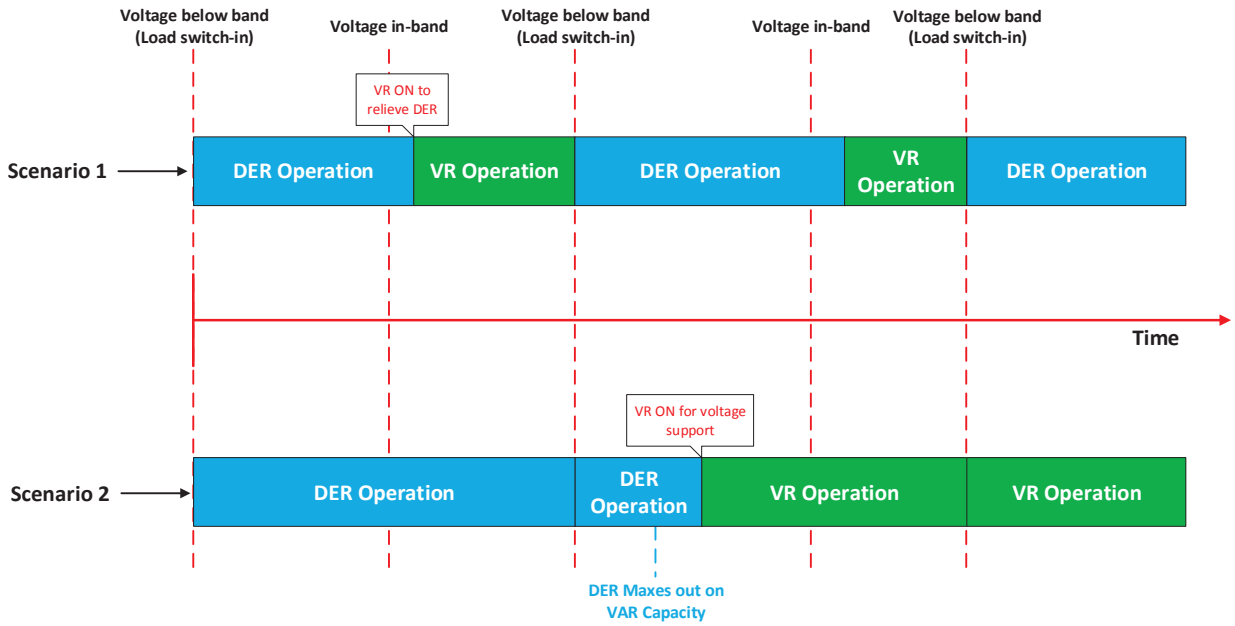


Figure 10.9: Voltage Support Coordination Scenario Operation

10.4 TEST RESULTS

10.4.1 Scenario 1

Scenario 1 was tested with the following assumptions. The system voltage is on a 12 kV base. The following set points are user defined and can be changed to values to best reflect field conditions.

Voltage upper band – 1.015 pu

Voltage lower band – 0.985 pu

DER MVAR limit – 1.0 MVAR

Voltage regulator on time delay – 10 seconds

Intertap delay – 4 seconds

Tests were carried out to validate the Scenario 1 operation with loads switched in and out in steps. To illustrate this scenario, the whole test has been broken down into eight individual events as illustrated in Figure 10.10. The following describes the circuit response and device operation during each event.

Initial Response

1. The test circuit is initially run at half the connected load capacity. The system voltage drops to below the In Band voltage setting. The DER switches on and increases the reactive power output to 0.65 MVAR to help bring the system voltage in band. The voltage controller sets the voltage regulator on standby.

2. The voltage regulator switches on after a user-defined time interval. The voltage regulator raises one tap to bring the reactive power output of the DER to zero and the system voltage in band. This ensures that the DER reactive power is made available for further voltage corrections. At the end of this event, the voltage regulator tap position is now one and the DER reactive power output is approximately zero.

Load Switch In Test

3. A large load is switched in, causing the system voltage to dip below the voltage lower limit. The DER increases its reactive power at once to help mitigate this event. The DER reactive power output attains its maximum capacity. At the end of this event, the system voltage is at 0.97 pu and DER output is at 1 MVAR.

4. Similar to Event 2, the voltage regulator starts raising taps to bring down the DER output and support the system voltage at the same time. The intertap time interval ensures that the DER and system voltage stabilizes before the next incremental tap operation.

5. At Tap 5, the DER output reduces to zero and the system voltage stays at approximately 0.998 pu.

Load Switch Out Test

6. A load-shedding event results in the system voltage rising beyond the upper limit of the In Band region. As a result, the DER reduces its reactive power output and starts absorbing reactive power to bring the voltage in band. By the end of the event, it was observed that the system voltage was at 1.01 pu with the DER at –0.84 MVAR. The voltage regulator is on standby for operation.

7. After the user-defined time interval, the voltage regulator starts reducing taps in steps to bring the DER reactive power output back to zero, while at the same time ensuring that the system voltage is brought back in band.

8. The voltage regulator has completed its tap operations, settling at Tap Position 3. The DER output is approximately zero and the system voltage is at 1 pu.

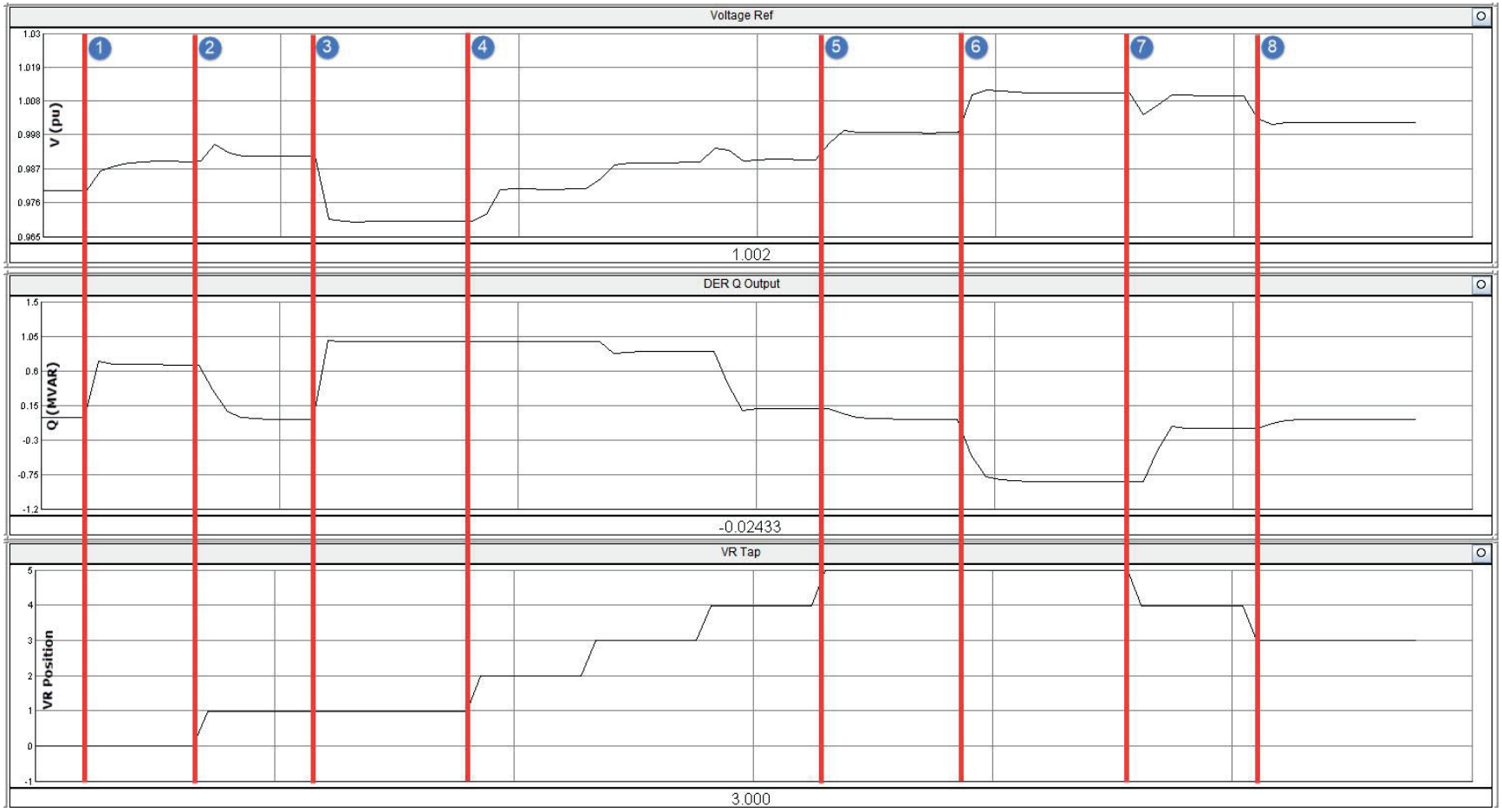


Figure 10.10: Scenario 1 RunTime Plot

10.4.2 Scenario 2

Scenario 2 was tested with the following assumptions. The system voltage is on a 12 kV base. The following set points are user defined and can be changed to values to best reflect field conditions.

Voltage upper band – 1.010 pu

Voltage lower band – 0.985 pu

DER MVAR Limit – 1.0 MVAR

Voltage regulator on time delay – 6 seconds

Intertap delay – 2 seconds

Tests were carried out to validate the Scenario 1 operation, with loads switched in and out in steps. Similar to Scenario 1, Figure 10.11 illustrates Scenario 2 with seven individual events. The following describes the circuit response and device operation during each event.

Initial Response

1. The circuit is initially run with half the connected load capacity. The DER is off, with the loads being fully supported by the utility. The system voltage falls below the lower voltage limit. The DER switches on after the specified DER switch on time, and increases its reactive power output to support the voltage to bring it in band. It was noted that the DER was able to support the system voltage before attaining its maximum VAR capacity. This event also illustrated that the volt/VAR control operates seamlessly to bring the DER reactive power output to a level that is just enough to support the system voltage. The voltage regulator remains off because the DER has not attained its maximum VAR capacity. At the end of this event, the DER reactive power output is approximately 0.66 MVAR and the system voltage is at 0.99 pu.

2. In this event, a large load is switched in to a point at which the DER would reach its maximum VAR capacity. The system voltage initially drops below the voltage lower limit, but picks up once the DER raises its reactive power output. The system voltage settles at 0.986 pu at the end of this event. The voltage regulator has not been triggered to operate.

Load Switch In Test

3. A further step increase in load results in the system voltage dropping out of band. The DER is already at its maximum VAR capacity. The voltage controller now begins to perform voltage checks to bring the voltage regulator online. The voltage regulator is now on standby to operate.

4. The voltage regulator, after a specific time interval, starts to raise its taps in steps, with each tap raise bringing the DER reactive power output down. This would continue until the DER reactive power output is close to zero and the voltage is brought in band. At the end of this test, the voltage regulator taps up to the fourth tap position, which results in a drop in the DER reactive power to zero VARs, bringing the system voltage to approximately 0.995 pu.

5. The DER has almost no reactive power output at this stage. The voltage regulator raise operation has ceased and stays at Tap Position 4.

Load Switch Out Test

6. This event illustrates the system response when loads are switched out. A step reduction in load results in the system voltage rising beyond the upper band limit, which in turn triggers the voltage regulator to lower one tap; thus, bringing the voltage in band. The DER does not operate because the voltage regulator has now assumed primary control for voltage correction. At the end of this event, the voltage regulator is at Tap Position 3 and the system voltage is at 0.99 pu.

7. Another step reduction in load results in a similar response as observed in Event 6. This illustrates that the voltage regulator is the first device to respond to a system voltage disturbance.

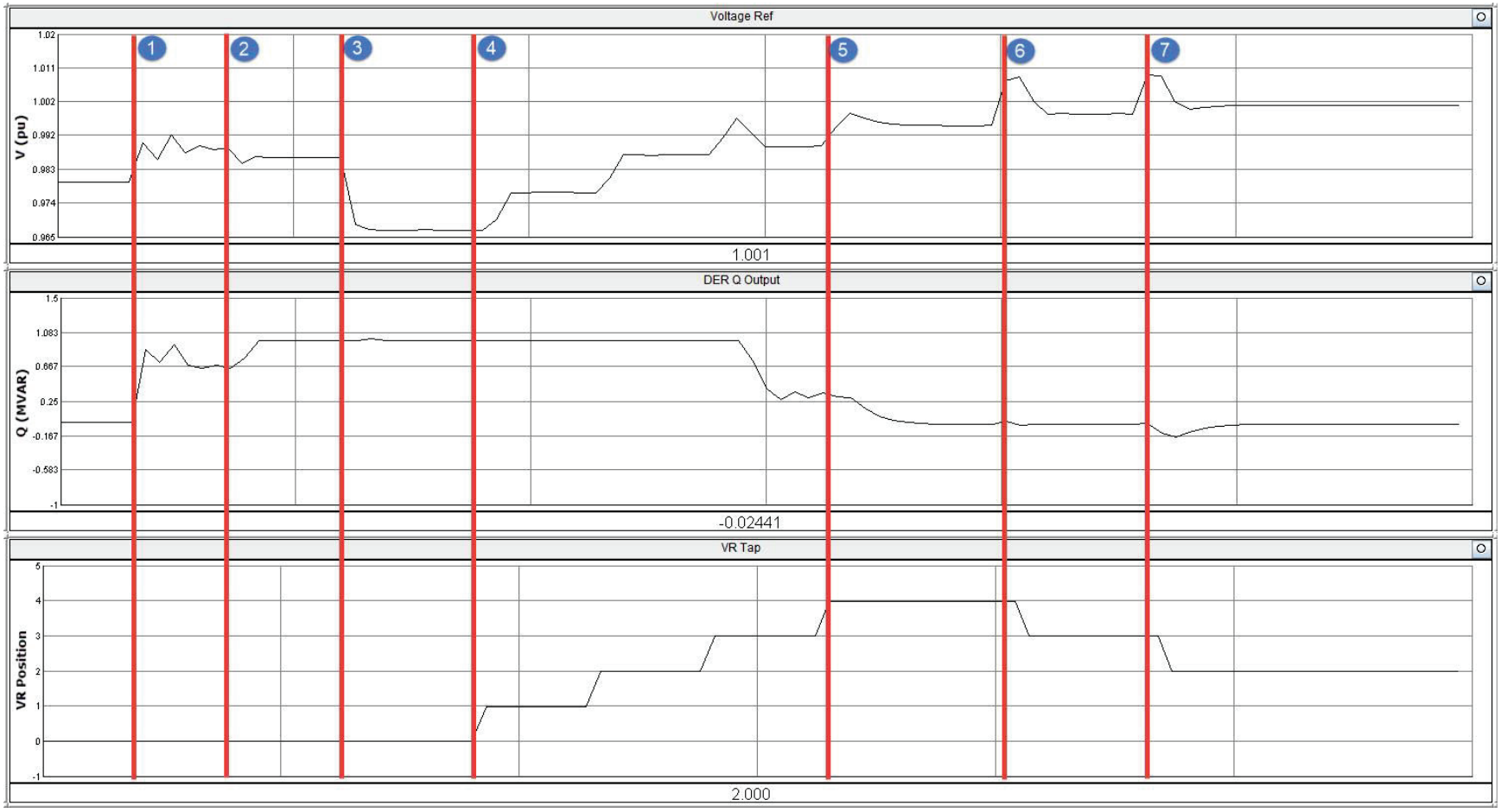


Figure 10.11: Scenario 2 RunTime Plot

11 FINDINGS

11.1 VOLTAGE COORDINATION TEST RESULTS ANALYSIS

The voltage coordination tests were carried out with two voltage correction devices, a DER and a voltage regulator, to demonstrate the implementation of a master controller to regulate system voltage in a distribution circuit. The master controller continuously monitors the voltage in the system and selectively switches the DER and voltage regulator to help mitigate a rise or drop in voltage. A tight voltage bandwidth was chosen for these tests to illustrate a successful operation of the voltage control. The controller operated seamlessly for various scenarios, providing useful information on the behavior of voltage correction devices and the coordination between them.

A DER and a voltage regulator on the selected desert-rural test circuit were found to be sufficient for voltage control. However, larger circuits may require multiple voltage correction devices such as DER, voltage regulator, and capacitor banks. These devices would be coordinated by the master controller. The voltage coordination test demonstration on the RTDS provides a good starting point for the implementation of a complex controller system for future implementations. This is further discussed in Section 12.1.

The Volt/VAR mode of the DER was observed to provide a smooth voltage correction as compared to the step-voltage correction of the voltage regulator. This can be seen in the Scenario 1 and Scenario 2 RunTime plots shown in Section 10. The scenarios tested employ the DER as the initial primary voltage correction device. It is recommended to have the DER continue as the primary voltage control device with the voltage regulator or other step-voltage controller brought in when the DER is not able to support the voltage.

The voltage regulator provides a good response to the voltage drop in the circuit and operates reliably when triggered by the master controller. However, for the desert-rural test circuit, the voltage regulator was observed to create a localized rise in voltage at its load terminals. This could be attributed to the fact that it regulates voltage in steps, with the rise or drop in voltage more pronounced at its load terminals; however, it reduces the voltage with loads downstream.

The DER tests were performed with selectable time delays on the controller operation and for the intertap delays for the voltage regulator. The time delays used in these simulations were selected to demonstrate the response of the master controller and the voltage correction devices. The intertap delay was added based on the field voltage regulator operation. For voltage regulators in the field, an intentional time delay is always included to avoid tap changer operation when the voltage excursion outside of the bandwidth is of a short duration. An example of such a case is a large motor starting on the system. The voltage level may be pulled low; however, it will be expected to recover in approximately 15 seconds. To have made a raise tap change within this short period would not significantly help in the motor starting and would require consecutive tap lowering operations after the motor came up to speed. This would also accelerate the wear of the tap changer. Consequently, an intentional delay is set at the discretion of the system operator, based on factors such as system loads, voltage regulation bandwidth, and voltage regulator response time. The software model time delay was found to respond accurately and can be adjusted to reflect the field voltage regulator settings. The time delays under discussion may need to be fine-tuned based on the industrial references and field operational practices.

11.2 VOLTAGE REGULATOR LOCATION ANALYSIS

The individual VR tests detailed in Section 6 reveal that SDG&E complies to the voltage regulation of ±5 percent, which equates to a forward bandwidth of 12 V, across the coastal-residential, urban and desert-rural circuits. However, it is recommended to narrow the forward bandwidth to allow for a better regulation. This would ensure less fluctuations in the regulated voltage and steady control over the standard voltage limits.

Section 10 includes pre-commercial voltage coordination tests that were carried out on the DER and voltage regulator on the desert-rural test circuit. The voltage regulator connected in the circuit helps regulate the voltage and bring it in band. Table 11.1 illustrates the voltage drop at various points of the circuit, with and without the voltage correction devices connected. Bus P40935A is connected to a long line section, which contains a considerable voltage drop.

Table 11.1: Desert-Rural Test Circuit Voltage Levels

Bus Name	% Line Lengths	Connected Load		Voltage Levels (pu)		
		P (MW)	Q (MVAR)	No DER	With DER	With VR
D1494793	1.65	1211	398	0.985	1.000	0.987
D1494794	1.79	331	108	0.985	1.000	0.987
D1494791	1.38	1542	506	0.985	1.000	0.987
P190655	9.14	105	35	0.985	0.999	0.987
P227957B	0.39	1647	541	0.986	0.999	0.988
CW	0.00	2186	717	0.987	1.000	0.988
P227958A	0.35	539	176	0.986	0.999	0.988
P41033	0.62	539	176	0.986	0.999	0.988
P41032A	0.93	539	176	0.986	0.999	0.987
P41032B	0.93	539	176	0.986	0.999	1.007
P41031	1.38	539	176	0.986	0.999	1.007
P190371	4.14	514	168	0.985	0.998	1.006
P208956A	5.46	419	137	0.985	0.998	1.006
P40934	8.26	419	137	0.984	0.997	1.005
P40935A	74.08	249	81	0.976	0.990	0.998
P40940	87.91	249	81	0.975	0.988	0.996
P40942	90.30	195	64	0.975	0.988	0.996
P45513	100.00	195	64	0.974	0.987	0.995
P40947	100.00	124	39	0.974	0.987	0.995

To mitigate this effect, it is recommended to add an additional voltage regulator at the midpoint of the line, at Bus P40935A. This would smooth the voltage along the long section of line and provide a better voltage regulation for the whole circuit. Moving the existing voltage regulator is not a solution because it goes beyond the area of influence of the DER. This would cause a section of the line to drop below the In Band voltage because the DER rated at 1 MW, 1 MVAR would not be able to support it.

In the pre-commercial voltage support coordination tests described in Section 10, the master controller regulated the voltage regulator taps based on the voltage at the end of the circuit. The voltage regulator tap operation is controlled by the master controller and operates to bring the voltage at the end of the circuit to within the voltage bandwidth. Voltage regulator advanced settings, such as line drop compensation and voltage limit, have not been considered for these tests. Figure 11.1 illustrates the voltage profile with the existing voltage regulator in service. There is a localized voltage rise at the load terminals of the voltage regulator. For the connected load and line length in this circuit, the voltage does not go beyond the In Band voltage range. However, for future expansion, with more loads and lines added to the circuit, the existing voltage regulator would create a localized voltage rise that could affect the loads connected near its load terminals.

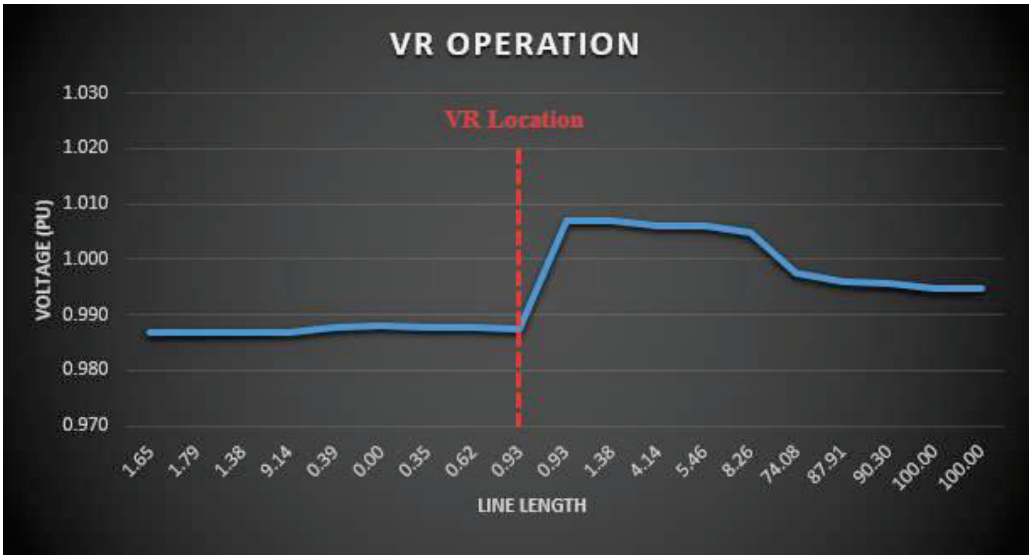


Figure 11.1: Voltage Profile With Voltage Regulator In Service

Refer to Appendix A for more information on the desert-rural test circuit one-line diagram.

For future implementation on larger circuits, it is recommended to connect multiple voltage regulators at various points of the circuit, based on the load and line impedance distribution in the circuit. The master controller would operate each voltage regulator based on the voltage drop at the next voltage regulator location, thus ensuring a much smoother profile. Voltage limit settings can be incorporated to ensure that the localized voltage drop or rise does not exceed stipulated limits.

12 RECOMMENDATIONS

The pre-commercial demonstration tests performed in this project lay the groundwork for commercial adoption of future smart circuit concepts. It is recommended that SDG&E pursue commercial adoption of some of the key concepts that were demonstrated. Specific recommendations follow in this section. Based on the findings and analysis of the demonstrations performed, recommendations on the integration and coordination of multiple voltage correction devices on a larger system, controlled by a central master controller, are described in this section. It was demonstrated via simulations that the DER and VR can be controlled interactively to provide voltage support on distribution circuits. Practical implementation and inclusion of other voltage correction devices are discussed. This section also describes certain modern solutions, such as downed conductor detection and power quality monitoring, which offers insights on how to improve existing distribution circuits.

12.1 SYSTEM VOLTAGE COORDINATION – ADVANCED CONTROL

Section 10 demonstrated the interaction and control of multiple voltage correction devices at a central level controller to maintain the system voltage within the specified band. The master controller discussed in Section 10 was designed with controls for coordinating a DER and voltage regulator for a voltage correction application. This was based on the desert-rural test circuit and provides a good insight into factors to examine for system voltage conditioning. Device factors such as real and reactive power capabilities, response time, device location, and smoothness of voltage correction play a big part in the addition to circuit parameters such as connected load and line impedances.

It is recommended to expand this concept to larger circuits that have multiple voltage correction devices such as multiple DERs, voltage regulators, and single-step or multistep capacitor controllers. Based on the results obtained from Section 10, it was observed that the DER was the first device to react to a voltage disturbance. Advanced controls can be implemented via a master controller at a central level that determine and control the switching priority of these devices based on the design philosophy. With this approach, the DER can be controlled to focus on the real power demand and devices such as voltage regulators and capacitor bank controllers can be controlled to focus on voltage correction. Other advantages of this scheme include monitoring and limiting frequent operation of any one device, which improves its lifespan and reduces frequent maintenance requirements. To achieve this scheme, it is important that these devices communicate at a central level.

Figure 12.1 illustrates the architecture envisioned to achieve the best practice recommended above. For this implementation, an automation controller capable of handling multiple communications protocols is considered as the master controller. Synchrophasor protocol based on IEEE C37.118.2-2011, IEEE Standard for Synchrophasor Data Transfer for Power Systems, is considered for data gathering from multiple field devices. IEC 61850 GOOSE protocol is considered for sending the switching controls from the master controller to the field devices.

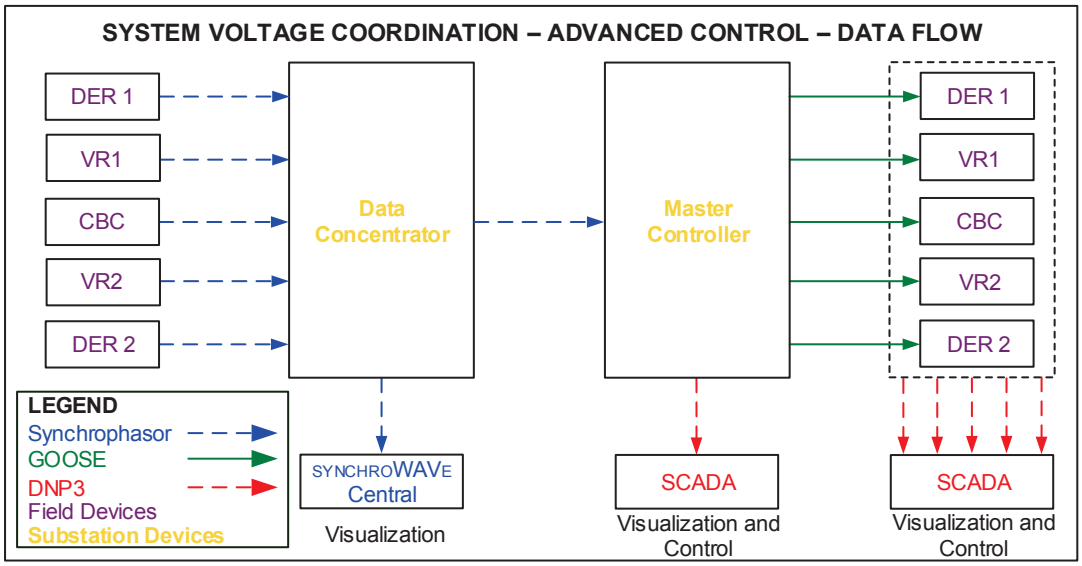


Figure 12.1: Data Flow for Advanced Control of System Voltage Coordination

Following is the description of the elements of the advanced control system illustrated in Figure 12.1:

- Field devices: DERs, voltage regulators, and capacitor bank controllers.
- Master controller: Automation controller.
- Communications protocol: Synchrophasor, IEC 61850 GOOSE, and DNP3.

The following path for data flow is recommended for this implementation:

- The field devices read currents and voltages via CTs and PTs that are wired to them.
- These data are collected and sent to the data concentrator located at a central location (possibly the substation) via synchrophasor protocol. This data stream carries the relevant phasor, analog, and digital information.
- The data concentrator collects the information and sends it over the to the master controller via synchrophasor protocol.
- The master controller uses this information in the algorithms that are specifically designed to determine the switching priority of these devices. The switching controls are sent back to the field devices via GOOSE protocol. This step closes the loop of data flow.
- For visualization, two paths are recommended:
  - Implementation of tools capable of providing instant access to real-time and historical data. This can be implemented for system-wide monitoring and analysis.
  - A traditional SCADA setup implemented via DNP3 protocol between the individual field devices and the SCADA, as well as the master controller and the SCADA.

The protocols and devices considered in this section are selected specifically for this discussion. This concept can be extended to other devices and protocols supported by various vendors. Based on the understanding and research carried out as a part of this project, it is recommended to implement the above discussed best practices to the already existing infrastructure at San Diego Gas & Electric. This is a cost-effective and efficient way to proceed with the commercial implementation of the recommended best practices.

Some of the challenges associated with implementing this concept to larger circuits include bringing together devices from multiple vendors on one platform and the communications protocols supported by them. As a step in commercial adoption, it is recommended to evaluate the selected devices and protocols, as well as the communications delays associated with the selected devices and protocols, before implementation. Refer to Section 13 for the technology transfer plan recommended for successful commercial implementation of the voltage support coordination scheme.

12.2 DOWNED CONDUCTOR DETECTION

From the pre-commercial tests performed on HIF detection, it is recommended that SDG&E monitor the coastal-residential, urban, and desert-rural test circuits carefully for HIFs. The tests showed that the high-impedance protection works as expected and can be used to indicate how the SDG&E circuits will behave in the event of an HIF. It is recommended to observe and fine-tune the HIF settings that are needed for each circuit.

With an extensive amount of overhead power lines across the country, the hazards of downed conductors cannot be overlooked. A weather-related or accidental incident can bring live conductors crashing to the ground. If still energized, these pose dangers to human and animal life and cause forest fire hazards, especially in dry regions (Figure 12.2). Utilities need to be able to quickly repair a broken line. To do so, they must be able to detect the downed conductor and its location at the earliest moment.

An HIF occurs in the event of an energized conductor making unwanted ground contact. Unfortunately, there are chances an energized broken conductor may go undetected with conventional overcurrent relays because the measured fault currents are very low. Several technologies have been developed to detect HIFs. In any scenario, the detection and isolation will take effect only after the live conductor has hit the ground and has created potential safety hazards, even if it is for a brief amount of time. Much time and effort has been dedicated by utilities and manufacturers toward developing methods for quickly detecting and isolating these faults.

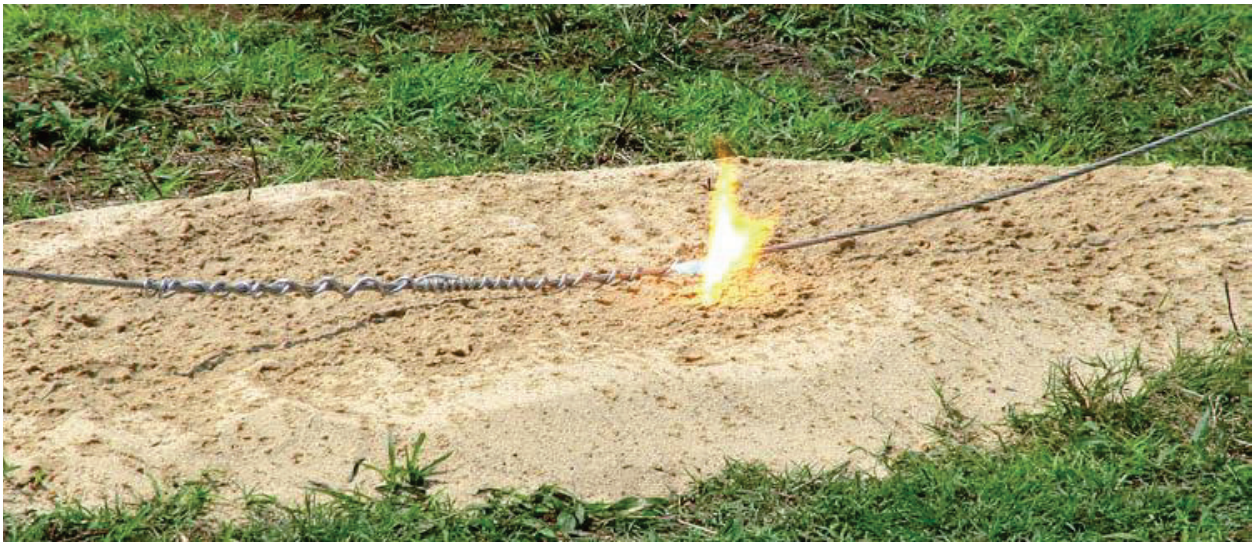


Figure 12.2: Energized Downed Conductor Causes Arcing – Potential Safety Hazard

With advancement in technology and availability of fast-speed communication, falling energized conductors can be detected and isolated before they hit the ground. Protection schemes have been developed that identify the break of a phase conductor and trip the affected section of the circuit in the small time window between the moment of the break and the time the conductor hits the ground. The result of this is that the conductor is de-energized when it hits the ground, thereby eliminating the risk of arcing or the presence of energized conductors on the ground.

The protection philosophy previously described makes use of IEDs with the ability to stream PMU data and central controllers with high-speed Ethernet radio communication. IEDs capable of synchrophasor communication and IEC 61850 GOOSE may already be present on several SDG&E distribution circuits, performing other protection and automation functionalities. The existing infrastructure can be enhanced to perform the falling energized conductor detection. Circuit IED PMUs may include substation protective relays on the breaker of the circuit, recloser controllers, capacitor bank controllers, voltage regulators, et cetera. The data from the field devices are collected by a data concentrator, which in turn transfers it to the central controller. Falling energized conductor detection algorithms are located within this central controller. Post detection, controls to isolate the affected section of the circuit are sent to the relevant field PMUs by the central controller. Synchrophasor protocol may be implemented to gain a deeper insight into the distribution system for visualization.

Figure 12.3 illustrates a conceptual distribution circuit with Source A and Source B. Once the broken conductor is detected by the central controller, PMU3 and PMU4 will trip and isolate the affected section. The loads on either side of the affected sections will continue to be supported by the two sources.

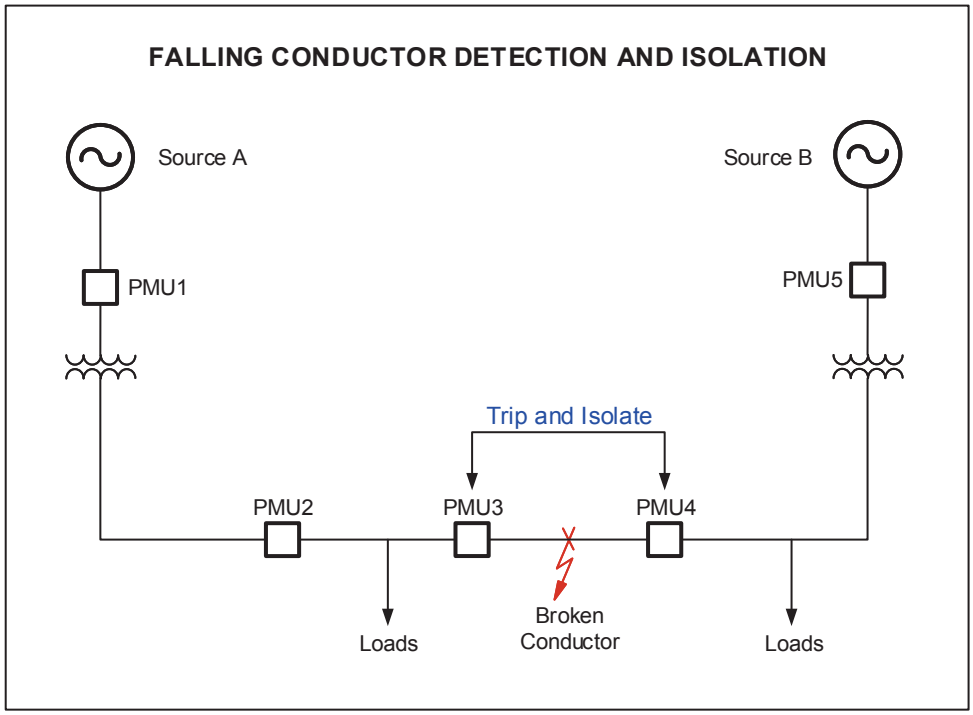


Figure 12.3: Falling Conductor Detection and Isolation

12.3 ISLAND DETECTION – VECTOR SHIFT ELEMENT

Certain feeder protection relays have the vector shift element feature that is used to detect islanding conditions of distributed generators (DGs) or loss of mains, and disconnect these DGs from the utility network under these conditions. The vector shift element is designed for applications where a DG is connected to either the utility of other main generators that require fast disconnection upon detection of an islanding condition. The element operates within 3 cycles, providing fast and reliable island detection; it operates fast enough to prevent out-of-synchronism reclosing of network feeders and thereby avoiding generator damage and any adverse effects. It is recommended that SDG&E explore commercial use of the vector shift element feature.

12.3.1 Vector Shift Element Logic

The vector shift element detection occurs when there are sudden phase variations on all three phases of the voltage waveforms. At the instance of islanding, the sudden change in load current causes a sudden change in the periods of the voltage signals. This element measures the difference in the present period duration and a reference period. This difference is then converted into degrees and compared against a user-defined setting.

Figure 12.4 describes the vector shift element logic. The element performs period calculations on each of the voltage inputs: VA, VB, and VC. The zero-crossing detector performs the period calculations. The time stamps of two consecutive positive or negative zero crossings are used to determine the period. The relay establishes a reference period for each phase using the previous 32-period measurement. The initialization period for this element requires at least 16 cycles of voltage signal to establish an accurate reference period. During the initialization period, this element does not detect an islanding condition.

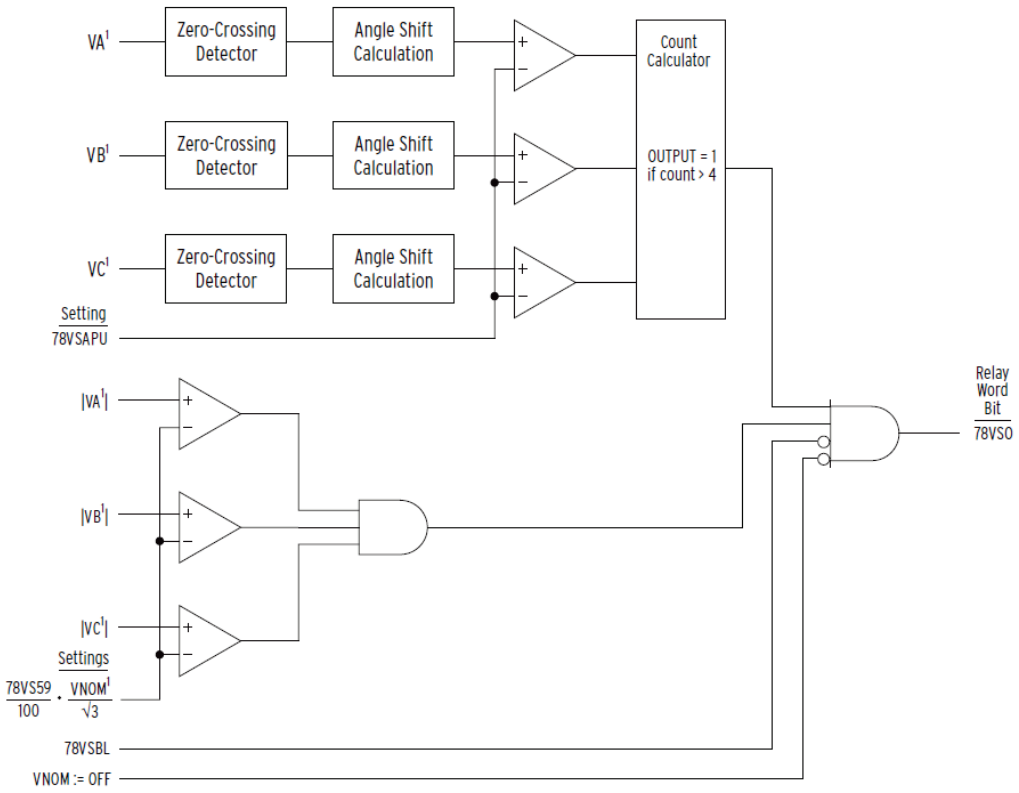


Figure 12.4: Vector Shift Element Logic

In each quarter cycle, the relay calculates the difference between the present period on each phase with the corresponding reference period. This difference is expressed in degrees to determine the angle shift and compared against the setting 78VSAPU. The count calculator increments each time the measured angle shift is greater than the threshold setting 78VSAPU. If the count exceeds four and no blocking conditions exist, the 78VSO asserts, indicating an islanding or loss-of-mains condition. The 78VS59 setting prevents false tripping under power system short-circuit conditions. The 79VSBL setting provides additional blocking conditions as required by the application used.

The vector shift element (78VS) and the fast rate-of-change-of-frequency element (81RF) can be used to detect islanding conditions. The vector shift element is designed to detect islanding at the instance of occurrence. It typically responds within 1.5 to 3 cycles after an islanding condition occurs. Conversely, the 81RF is designed to detect islanding conditions during and after the voltage shift occurs. The 81RF is used to compliment the 78VS element by providing more dependable protection.

12.4 ISLAND DETECTION – FAST RATE-OF-CHANGE-OF-FREQUENCY PROTECTION

Frequency changes occur in power systems when there is an unbalance between load and the active power generated, such as in an islanded condition. Typically, a generator control action adjusts the generated active power and restores the frequency to the nominal value. Failure of such a control action may lead to system instability unless remedial action is taken. The fast rate-of-change-of-frequency (df/dt) protection provides a fast response to islanding conditions, using the 81RF element.

Figure 12.5 shows the characteristic, based on frequency deviation from the nominal frequency (DF = FREQ – FNOM) and the rate-of-change-of-frequency (DF3C), to detect islanding conditions. The element uses a time window of 3 cycles to calculate the value of DF3C. Under steady-state conditions, the operating point is close to the origin. During islanding, the operating point typically enters Trip Region 1 or Trip Region 2 of the characteristic. The element uses the settings 81RFDFP in hertz and 81RFRP in hertz per second to configure the characteristic. It is recommended that SDG&E explore commercial use of the fast rate-of-change-of-frequency feature.

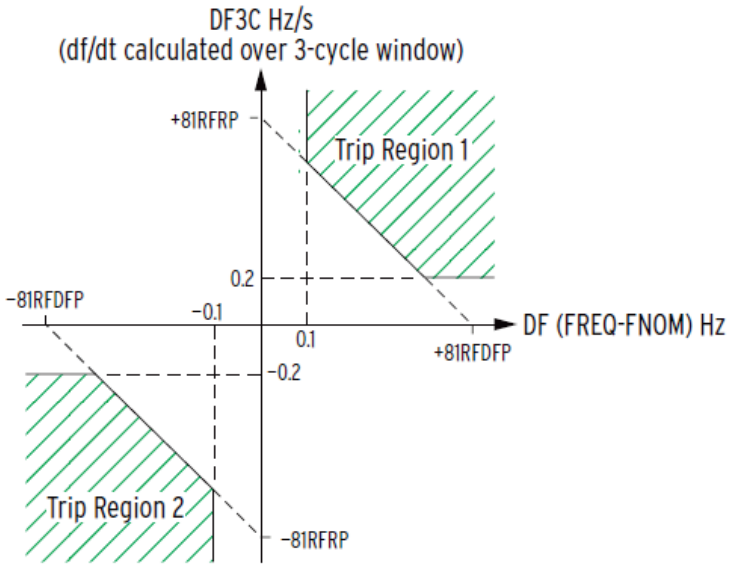


Figure 12.5: 81RF Characteristics

12.5 FAST DECOUPLING SCHEMES

Fast decoupling schemes are used to detect an island and to disconnect all loads, except the essential island loads, ensuring a stable power supply to these loads. A fast decoupling scheme makes use of the fast df/dt elements, along with synchrophasor quantities, to ensure a quick response during islanding. It is recommended that SDG&E explore commercial use of fast decoupling schemes feature.

12.5.1 Local Decoupling Protection Scheme

This decoupling scheme relies on local measurement only because the remote-end system information is not available. The following elements are enabled for this scheme:

- Df/dt
- Fast df/dt (81RF)
- Underfrequency (UF) and overfrequency (OF)
- Undervoltage (UV) and overvoltage (OV)

Figure 12.6 illustrates the decoupling curve for a case study. The under- and overfrequency elements are selected to coordinate with the generator protection at 59.5 Hz and 60.5 Hz, respectively, with a 12-cycle delay. Additional under- and overfrequency alarm elements are enabled with a 30-cycle (0.5 second) delay. In this decoupling scheme, df/dt is selected at 2.5 Hz/second with a 10-cycle delay and with a fast df/dt of 7.5 Hz/second with a –7.5 slope. This protection is found to be sensitive for weak system operating conditions, and operates accurately and faster than df/dt. This scheme adjusts the df/dt set point based on the deviation of frequency from the nominal frequency.

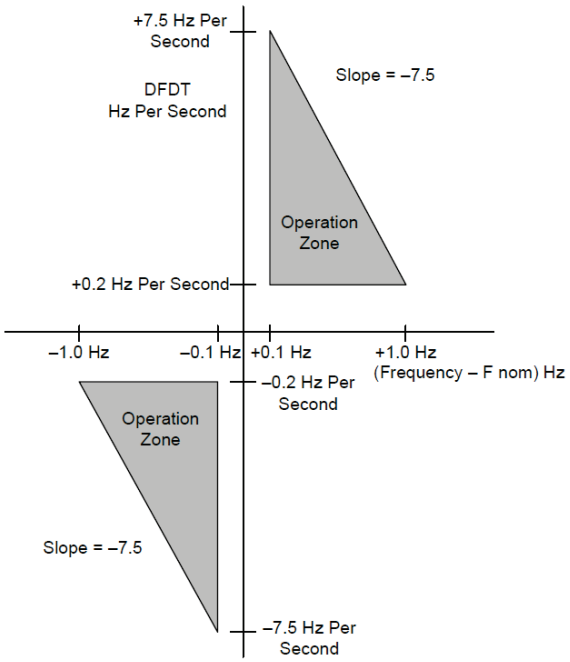


Figure 12.6: Fast df/dt Logic

12.5.2 Synchrophasor-Based Decoupling Protection

12.5.2.1 Synchrophasor Protocol

The synchrophasor protocol makes use of synchronized phasor measurements, as well as the message format to communicate data in a real-time system. A synchrophasor stream consists of synchronized measurements of voltage phasors, current phasors, and frequency with the UTC as a reference for measurement. IEEE C37.118 and IEEE C37.118a, IEEE Standard for Synchrophasor Measurements for Power Systems – Amendment 1: Modifications of Selected Performance Requirements, define the synchrophasor protocol. Synchrophasors have applications in wide-area power system monitoring and analysis. Traditional information management systems such as DNP3, Modbus, and object linking and embedding (OLE) for Process Control (OPC) communicate information back to a central station, only in magnitude measurement. These systems update every few seconds to every few minutes. These data are not time-stamped, which makes it difficult to accurately determine the system conditions. Synchrophasor measurements help overcome these shortcomings. Synchrophasors can be placed at various points in the power system, collecting critical system data and sending the data to the central station, via synchrophasors, for dynamic system analysis.

12.5.2.2 Synchrophasor-Based Decoupling Protection

The local-based protection will not operate accurately for system conditions when the load flow on the tie lines between two systems is low and the remote-end breaker opens. During this condition, because the tie line is floating, the local operating quantities such as voltage, frequency, df/dt, and fast df/dt will not see adequate change to operate. In such an operating condition, the remote substation information and breaker statuses are required to correctly determine an islanding condition. When the remote-end breaker opens, the frequency between the substation slips; however, it is not fast enough to trigger the local decoupling protection. Having synchrophasor

communication between these two substations helps detect an islanding condition and to decouple the system faster and more reliably as compared to the local, fast decoupling scheme. Synchrophasors installed at the local end and remote end continuously collect synchrophasor data and send the data to a central controller. For the condition previously discussed, when the difference in frequency between the local end and remote end goes beyond a certain set point, the controller would be able to make a quick and accurate decision on decoupling the system.

12.6 POWER QUALITY MONITORING

There are several reasons to monitor power quality. The primary is the economics behind it, especially if critical process loads are adversely affected by poor power quality. The effect on equipment and process operation can include misoperations, damage, process disruption, et cetera. In addition, equipment damage and frequent repairs both cost money and increase down time.

Power quality monitoring is a very important aspect to be considered while providing reliable power to customers. In addition to resolving equipment disruptions, data monitored and collected over time can help in developing the equipment tolerances and sensitivity. This can provide a basis for developing equipment compatibility specifications for future equipment enhancements. It is recommended that SDG&E explore expanded power quality monitoring and additional uses of the power quality data.

Recording power system monitoring data over time is equally essential for analysis and resolving disruptions. Some of the power quality attributes that can be measured and recorded include the following.

12.6.1 Voltage Sag, Swell, and Interruption

According to IEEE 1159-2009, IEEE Recommended Practice for Monitoring Electric Power Quality, voltage sag is defined as a decrease in rms voltage to between 0.1 pu and 0.9 pu for durations from 0.5 cycles and 1 minute. Voltage sags are usually associated with system faults; however, they can also be caused by switching loads, starting significantly large motors, or can be related to weather disturbances, among other issues. Short-duration voltage sags are known to cause process disruptions in various industries.

Voltage swell is defined as an increase in rms voltage above 1.1 pu for durations from 0.5 cycle to 1 minute. Swells can be caused by switching off a large load, load shedding, or switching on a large capacitor bank. An increase in voltage applied to equipment above its nominal rating may cause failure of the components, depending upon the magnitude and frequency of occurrence.

Voltage interruptions are defined as a decrease in supply voltage to less than 10 percent of nominal for a period in excess of 1 minute. These may affect electronic and lighting equipment and cause misoperation or shutdown.

12.6.2 Harmonics

Harmonics are sinusoidal voltages or currents having frequencies that are integer multiples of the frequency at which the supply system is designed to operate. Power electronics-based equipment is a major contributor of harmonics in the power systems. Harmonics injection can cause overheating of rotating equipment, transformers, and premature failure of protective devices. IEEE 519-2014, outlines typical harmonic current limits for customers and voltage limits for supply voltage. Customers and electric power providers should attempt to operate within these limits to minimize the effects of harmonic distortion on the supply and customer end of the utility.

12.6.3 Unbalance

Voltage unbalance in three-phase systems is defined as the ratio of the magnitude of the negative-sequence component to the magnitude of the positive-sequence component, expressed as a percentage. Typically, the voltage unbalance of a three-phase service is less than 3 percent. Large single-phase loads can lead to higher unbalance in the system. High-voltage unbalance can lead to power supply ripple and heating effects on distribution equipment, which in effect may shorten equipment life.

Smart meters can be employed at key locations on a distribution circuit to monitor and record the previously mentioned parameters. It would be efficient to include tools that can retrieve power quality data captured by

individual meters located in the field, at a central level. This will assist in device management and monitoring on one convenient interface, instead of several individual sites. Automatic data collection improves efficiency by eliminating the time spent in the field manually collecting data from devices.

It is recommended that data collection tools be implemented to automatically collect power systems data. These data can be viewed and organized with the help of meter report software in the form of currents, voltages, harmonics, frequency, sag, swell, and interruption trends. Interactive charts and flexible report structures help manage data easily using a single interface (refer to Figure 12.7).

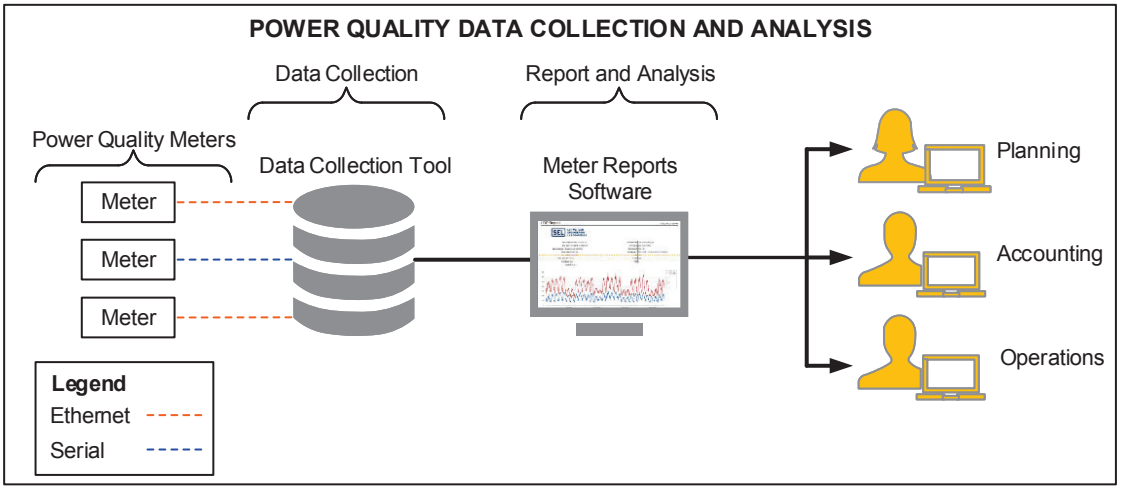


Figure 12.7: Power Quality Data Collection and Analysis

Refer to Section 9 for detailed results on power quality monitoring in the desert-rural test circuit. Circuit parameters such as voltage and frequency were observed at the time of switching in and out of an intentional island. System harmonics were not monitored because the RTDS model does not consider any source or load harmonics.

13 TECHNOLOGY TRANSFER PLAN

13.1 INTRODUCTION

The Technology Transfer Plan lists the steps for commercial adoption of the best practices discussed in this report. This plan describes the activities, equipment, and resources involved and the required coordination between diverse groups to successfully implement the best practices commercially.

13.2 PROCEDURE FOR COMMERCIAL IMPLEMENTATION

This report discusses the demonstration of the voltage support coordination scheme, including two voltage support devices and a central master controller, with the help of RTDS. The technology transfer plan bridges the gap between the laboratory demonstration of the voltage support coordination scheme and its successful commercial implementation in the field on larger distribution circuits with several voltage support devices. The design for the layout is described in the following subsections.

13.2.1 Design and Review

- *Distribution circuit selection*: This is the first step towards field implementation of the scheme. A distribution circuit will be selected based on the criteria that it includes a few voltage support devices. A simplified one-line diagram will be created to represent the voltage support devices, loads, sources, and any other information that may be relevant to the case.

  Device and communications protocols: This is a very important step because it is the design foundation of the scheme. Existing field voltage support devices will be evaluated for the features and functionalities that they offer. This will be a good time to perform any device upgrades, if required. The vendors and device recommendations for the master controller will be reviewed and finalized. The recommended communications protocols will be reviewed. Appendix E – Proprietary Information includes a list of recommended devices (Device L1, Device L2, Device L3, and Device M) for field implementation. Once the devices and communications protocols are finalized, a system architecture will be created defining the communications paths.

- *Enhancement of algorithms*: The algorithms developed in this project will be enhanced and the voltage support coordination philosophy will be reviewed to include multiple voltage support devices. This will mark the end of the design and review phase.

13.2.2 In-house Testing and Validation

- *RTDS model development and integrated testing*: The selected distribution circuit will be modeled in the RTDS. Once the algorithms are finalized, test equipment will be assembled for integrated RTDS testing. The voltage support coordination scheme will be tested in the laboratory environment. This step validates the scheme for larger distribution circuits including several voltage support devices.

- *Results, observations, and analysis*: Results and observations from the tests will be tabulated for further analysis and improvements.

13.2.3 Field Implementation and Monitoring

- *Development of test plan*: A detailed step-by-step test plan should be developed to test and commission the scheme on the live distribution circuit in future work.

- *Monitoring and training*: The field operations on live distribution circuits, as a result of the voltage support coordination scheme, should be closely monitored and verified to work as expected for a substantial period of time. Training material should be prepared and delivered to operators from the distribution planning and operations group to bring them up-to-speed with the field operations and SCADA indications.

- *Standardization*: This step includes standardizing the process of design and field implementation such that multiple distribution circuits can be enhanced efficiently with the voltage support coordination scheme.

13.3 CHALLENGES

One of the challenges associated with implementing this concept on larger distribution circuits with several voltage support devices includes bringing together devices from multiple vendors on a single platform. It is pertinent that these devices speak the same language; namely, that they have compatible communications capabilities.

Seamless coordination between different working groups within the organization or third-party vendors is essential.

13.4 RESOURCES

The implementation of the voltage support coordination scheme requires collaborated efforts between different working groups. The facility, system, and the groups within an organization and their tasks are defined below. Although each group has an assigned task, coordinated efforts and discussion between the working groups on a regular basis are essential.

- *Test facility* with advanced infrastructure to assemble the required test equipment for validation of the scheme for larger distribution circuits including several voltage support devices.
- *System protection group* to review the voltage support coordination philosophy and finalize the device selection.
- *Information technology or communications specialists* to review the communications protocols and network design.
- *Distribution planning and operations* to work in coordination with the system protection group to review the voltage support coordination philosophy and the switching order of the voltage support devices.
- *SCADA and relay technicians* to assist in installation, programing, and testing of the devices on the distribution circuits.

13.5 CONCLUSION

Based on the understanding and research carried out as a part of this project, there is a possibility of making the recommended enhancements to the existing infrastructure on San Diego Gas & Electric distribution circuits. This will be a cost-efficient way to implement the recommended best practices.

Once the voltage support coordination philosophy is defined for a couple of circuits and tested with the help of integrated RTDS testing, and the scheme is validated for larger distribution circuits with several voltage support devices, further RTDS testing for more circuits may not be required. At this point, the scheme will be standardized and minimum changes should be made from one circuit to another.

14 OVERALL PROJECT CONCLUSIONS

SDG&E's EPIC-1, Project 5, on Smart Distribution Circuit Demonstrations was successfully completed and documented in this report. Phase 1 of the project covered the evaluation and documentation of products and technologies currently available for improved distribution circuit design, system operation, and protection. Emerging distribution circuit solutions and operation practices were discussed for maintaining reliable, uninterrupted energy delivery to the customers. Phase 1 provided the required background for shortlisting the devices that were eventually used for demonstration of advanced circuit concepts through laboratory simulations.

Phase 2 of the project included selection and modeling of three diverse SDG&E distribution circuits viz., coastal-residential, urban, and desert-rural in RSCAD environment for demonstration of advanced circuit concepts. The first phase of demonstrations included testing capabilities and controls of a voltage regulator, and a capacitor bank controller as stand-alone voltage support devices in a distribution circuit. These tests provided useful data for the development of the more sophisticated voltage support coordination scheme with multiple devices. The results from the tests carried out on voltage regulator control also provide suggestions for improvements for optimal performance. The observations and results captured were analyzed and the findings from stand-alone device testing provided inputs on how to tweak the existing circuits for improved reliability and performance.

The second phase of the demonstrations included development of algorithms to enable controlled switching of multiple voltage support devices on a distribution circuit using a central controller on RTDS platform. The pre-commercial laboratory demonstrations successfully lay out the groundwork required for commercial implementation of the scheme. A technology transfer plan was created to bridge the gap between the laboratory demonstration of the voltage support coordination scheme and its successful commercial adoption in the field on larger distribution circuits with multiple voltage support devices. On larger distribution circuits with multiple voltage correction devices, system-wide voltage coordination would be required for efficient and reliable service to the customers. This implementation will also aid in improving the lifespan of various distribution equipment, as well as lower the associated maintenance costs.

Phase 3 of the project included findings and recommendations from the test demonstration in Phase 2. The recommended system architecture for commercial implementation of voltage support coordination scheme is provided.

In addition to this, certain other advanced distribution solutions are also recommended. With large distribution circuits arises the challenge of detecting, locating, and isolating HIFs caused because of downed or broken energized conductors. An energized conductor on the ground for a brief amount of time may pose as a huge safety hazard to human and animal life. Solutions for the efficient detection of broken conductors at synchrophasor speeds were discussed.

Solutions were discussed on efficient and reliable ways to detect islands in existing and future circuits. Fast decoupling schemes are particularly effective in ensuring that an island is detected in a few cycles and all loads except critical island loads are disconnected. This allows for continuous and stable power supply to these loads.

Power quality monitoring is a very important aspect to be considered while providing reliable power to customers. In addition to resolving equipment disruptions, data monitored and collected over time can help in developing the equipment tolerances and sensitivity. The various power quality attributes were discussed in detail and recommendations were provided on the implementation of a system for centralized power quality monitoring and analysis.

15 METRICS AND VALUE PROPOSITION

15.1 PROJECT METRICS

The project tracking metrics included the milestones in the project plan. Technical metrics were developed to guide the actual demonstration work. In general, the ultimate measure of success was having a benchmark future distribution circuit design concept that helps advance future distribution system development. The circuit design can assimilate a wide variety of existing and emerging device types and has a protection system that allows this assimilation to be done without compromising reliability or safety.

Also, project results were submitted as technical papers and presentations for consideration by major technical conferences and publications.

The following metrics were identified for this project:

- **Economic benefits:**
    a. Reduction in electrical losses in the transmission and distribution system.
- **Safety, Power Quality, and Reliability (Equipment, Electricity System):**
    a. Outage number, frequency and duration reductions.
    b. Public safety improvement and hazard exposure reduction.
    c. Utility worker safety improvement and hazard exposure reduction.
    d. Reduction in system harmonics.
- **Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy:**
    a. Description of the issues, project(s), and the results or outcomes.
    b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360).
    c. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360).
    d. Integration of cost-effective smart appliances and consumer devices (PU Code § 8360).
- **Effectiveness of information dissemination:**
    a. Number of information sharing forums held.
    b. Stakeholders attendance at workshops.
    c. Technology transfer.
- **Adoption of EPIC technology, strategy, and research data/results by others**
    a. Description/documentation of projects that progress deployment, such as Commission approval of utility proposals for wide spread deployment or technologies included in adopted building standards
    b. Number of technologies eligible to participate in utility energy efficiency, demand response or distributed energy resource rebate programs
    c. EPIC project results referenced in regulatory proceedings and policy reports

15.2 VALUE PROPOSITION: PRIMARY AND SECONDARY GUIDING PRINCIPLES

The value proposition is to address how the project met the EPIC principals.

Table 15.1 summarizes the specific EPIC primary and secondary principles advanced by the Smart Distribution Circuit Demonstrations Project.

Table 15.1: EPIC Primary and Secondary Guiding Principles

Primary Principals			Secondary Principals				
Reliability	Lower Costs	Safety	Loading Order	Low-Emission Vehicles / Transportation	Safe, Reliable & Affordable Energy Sources	Economic Development	Efficient Use of Ratepayers Monies
✓	✓	✓					

The Smart Distribution Circuit Demonstrations Project covers the following primary EPIC principals:

- **Reliability:** The results of this project demonstrates several scenarios and options with the possibility to improve power reliability and performance with system monitoring. Also, the observations and results captured were analyzed and the findings from stand-alone device testing provided inputs on how to tweak the existing circuits for improved reliability and performance.

- **Lower Costs:** Based on the understanding and research carried out as a part of this project, there is a possibility of making the recommended enhancements to the existing infrastructure. The implementation of some of the recommendations would aid in improving the lifespan of various distribution equipment, which in turn lowers the associated maintenance costs.

- **Safety:** As part of the recommendations, the downed conductor detection using high impedance fault (HIF). With large distribution circuits arises the challenge of detecting, locating, and isolating HIFs caused because of downed or broken energized conductors. An energized conductor on the ground for a brief amount of time may pose as a huge safety hazard to human and animal life. Solutions for the efficient detection of broken conductors at synchrophasor speeds were discussed.

16 REFERENCES

[1] S. A. Mohammed, A. G. Cerrada, M. A. Abdel-Moamen, and B. Hasanin, "Dynamic Voltage Restorer (DVR) System for Compensation of Voltage Sags, State-of-the-Art Review," International Journal of Computational Engineering Research, Vol. 3, Issue 1, January 2013.

[2] IRIG Standard 200-04, "IRIG Serial Time Code Formats," Timing Committee, Telecommunications and Timing Group, Range Commanders Council, September 2004. Available: http://jcs.mil/RCC.

[3] Cyber Sciences, Inc., "Overview of IRIG-B Time Code Standard," TN-102, May 2016. Available: www.cyber-sciences.com.

BIBILIOGRAPHY

A. Avendaño, "Testing the High-Impedance Fault Detection Element in the SEL-751 and SEL-451," SEL Application Guide 2015-10. Available https://selinc.com/literature /application-guides.

Electric Power Research Institute (EPRI), Inc., "A Consumer's Guide to Plug-In Electric Vehicles," July 2014. Available http://www.epri.com.

ANSI C84.1-2006, American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60 Hertz).

A. Polikoff, "Using Traveling Wave Fault Location in the SEL 411L-1 Relay," SEL Application Guide 2015-20. Available: https://selinc.com/literature/application-guides.

A. von Meier, D. Culler, A. McEachern, and R. Arghandeh, "Micro-Synchrophasors for Distribution Systems," proceedings of the 5th IEEE PES Innovative Smart Grid Technologies (ISGT) European 2014 Conference, Instanbul, Turkey, 2014.

C. Kriger, S. Behardien, and J. Retonda-Modiya, "A Detailed Analysis of the GOOSE Message Structure in an IEC 61850 Standard-Based Substation Automation System," International Journal of Computers, Communications & Control, Vol. 8, Issue 5, pp. 708, October 2013.

D. Hou, "High-Impedance Fault Detection – Field Tests and Dependability Analysis," proceedings of the 36th Annual Western Protective Relay Conference, Spokane, WA, October 2009.

D. Nakafuji, L. Rogers, J. Bestebreur, M. Rourke, and G. Zweigle, "Integrating Synchrophasors and Oscillography for Wide-Area Power System Analysis," proceedings of the 19th Annual Georgia Tech Fault and Disturbance Analysis Conference, Atlanta, GA, 2016.

E. Gomez-Luna, G. A. Mayor, C. Gonzalez-Garcia, and J. P. Guerra, "Current Status and Future Trends in Frequency-Response Analysis With a Transformer in Service," IEEE Transactions on Power Delivery, Volume 28, Issue 2, pp. 1024-1031, April 2013.

E. O. Schweitzer, III, A. Guzman, H. J. Altuve, and D. A. Tziouvaras, "Real-Time Synchrophasor Applications for Wide-Area Protection, Control, and Monitoring," proceedings of the 3rd International Conference on Advanced Power System Automation and Protection (APAP), Seogwipo, Jeju, South Korea, 2009.

"EVSE Cluster Analysis, Electric Vehicle Supply Equipment Support Study," prepared by WXY Architecture+Urban Design, Barretto Bay Strategies and Energetics Incorporated, December 2012.

G. Benmouyal, M. B. Bryson, and M. Palmer, "Implementing a Line Thermal Protection Element Using Programmable Logic," proceedings of the 30th Annual Western Protective Relay Conference, Spokane, WA, October 2003.

G. Hataway, B. Flerchinger, and R. Moxley, "Synchrophasors for Distribution Applications," proceedings of the Power and Energy Automation Conference, Spokane, WA, March 2013.

G. Paoletti and A. Golubev, “Partial Discharge Theory and Applications to Electrical Systems,” 1999 Annual Pulp and Paper Industry Technical Conference, Seattle, WA. June 1999.

“GRC R&D Projects for DER Applications Report,” Schweitzer Engineering Laboratories, Inc. report prepared for SDG&E 2016.

IEEE C37.118, IEEE Standard for Synchrophasor Measurements for Power Systems.

IEEE C37.118a-2014, IEEE Standard for Synchrophasor Measurements for Power Systems – Amendment 1: Modification of Selected Performance Requirements.

IEEE 519-2014, IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems.

IEEE 1159-2009, IEEE Recommended Practice for Monitoring Electric Power Quality.

IEEE 1547.4, IEEE Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems.

IEEE 1588-2008, IEEE Standard for a Precision Clock Synchronization Protocol for Networked Measurement and Control Systems.

J. Matson, “Choosing the correct Time Synchronization Protocol and incorporating the 1756-TIME module into your Application,” Rockwell Automation, Inc., Publication ENET-WP030A-EN-E, May 2013.

K. Mustafa, K. Garg, and R. Swaminathan, “Saudi Aramco Experience – Islanding Scheme for Manifa Central Processing Facility”, proceedings of the 2014 Petroleum and Chemical Industry Europe Conference, Amsterdam, The Netherlands, June 2014.

K. Zipp, “What is a Smart Solar Inverter?” Solar Power World, January 2014. Available: http://www.solarpowerworldonline.com/2014/01/smart-solar-inverter.

L. Hamrick, “Dissolved Gas Analysis for Transformers,” NETA World, Winter 2009-2010. Available: http://www.netaworld.org/.

“NTP: The Network Time Protocol,” ntp-4.2.8p10 was released on 21 March 2017, http://www.ntp.org.

RTDS Technologies Inc., RTDS Hardware Manual, Rev 00 (Date Code January 2009).

SAE International, “SAE Electric Vehicle and Plug in Hybrid Electric Vehicle Conductive Charge Coupler,” SAE J1772, February 2016. Available: http://standards.sae.org.

SEL-651R-2 Recloser Control Instruction Manual (Date Code 20160526). Available https://selinc.com.

S. T. Watt, H. Loehner, S. V. Achanta, A. Kivi, and B. Rowland, “Extending SCADA Networks Using Wireless Communications,” proceedings of the 2nd Annual PAC World Americas Conference, Raleigh, NC, September 2015.

T. D. Haskell, “Modeling and Analysis of a Dynamic Voltage Regulator,” (master’s thesis, California Polytechnic State University, May 2013. Available: http://digitalcommons. Salpoly.edu/cgi/viewcontent.cgi?article=2073&context=theses).

T. Hoevenaars, K. LeDoux, and M. Colosino, “Interpreting IEEE STD 519 and meeting its harmonics limits in VFD applications,” proceedings of the 2003 Petroleum and Chemical Industry Conference, IEEE Paper No. PCIC-2003-15.

T. M. Lebakken and D. R. Orlando, “Substation Automation and Communication Standards: IEC 61850 and DNP3,” Electric Light & Power, 2007. Available: http://www.elp.com/articles /powergrid_international.

V. Rusov and S. Zhivodernikov, “Transformer Condition Monitoring,” proceedings of the 2008 International Conference on Condition Monitoring and Diagnosis, Beijing, China, April 2008.

W. O'Brien, E. Udren, K. Garg, D. Haes, and Bala Sridharan, "Catching Falling Conductors in Midair – Detecting and Tripping Broken Distribution Circuit Conductors at Protection Speeds," proceedings of the 42nd Annual Western Protective Relay Conference, Spokane, WA, October 2015.

APPENDIX A CIRCUIT ONE-LINE DIAGRAM

The following three simplified one-line drawings are drafted in Microsoft Visio software. Each diagram represents an SDG&E circuit that was modeled in RSCAD to recreate and simulate the distribution system. Faults, high-impedance faults, and islanding are simulated in RSCAD. The circuits are:

1. Coastal-residential circuit – Figure A.1
2. Urban test circuit – Figure A.2
3. Desert-rural test circuit – Figure A.3

Note: It is recommended to print the circuit one line diagrams on a large sheet for clarity.

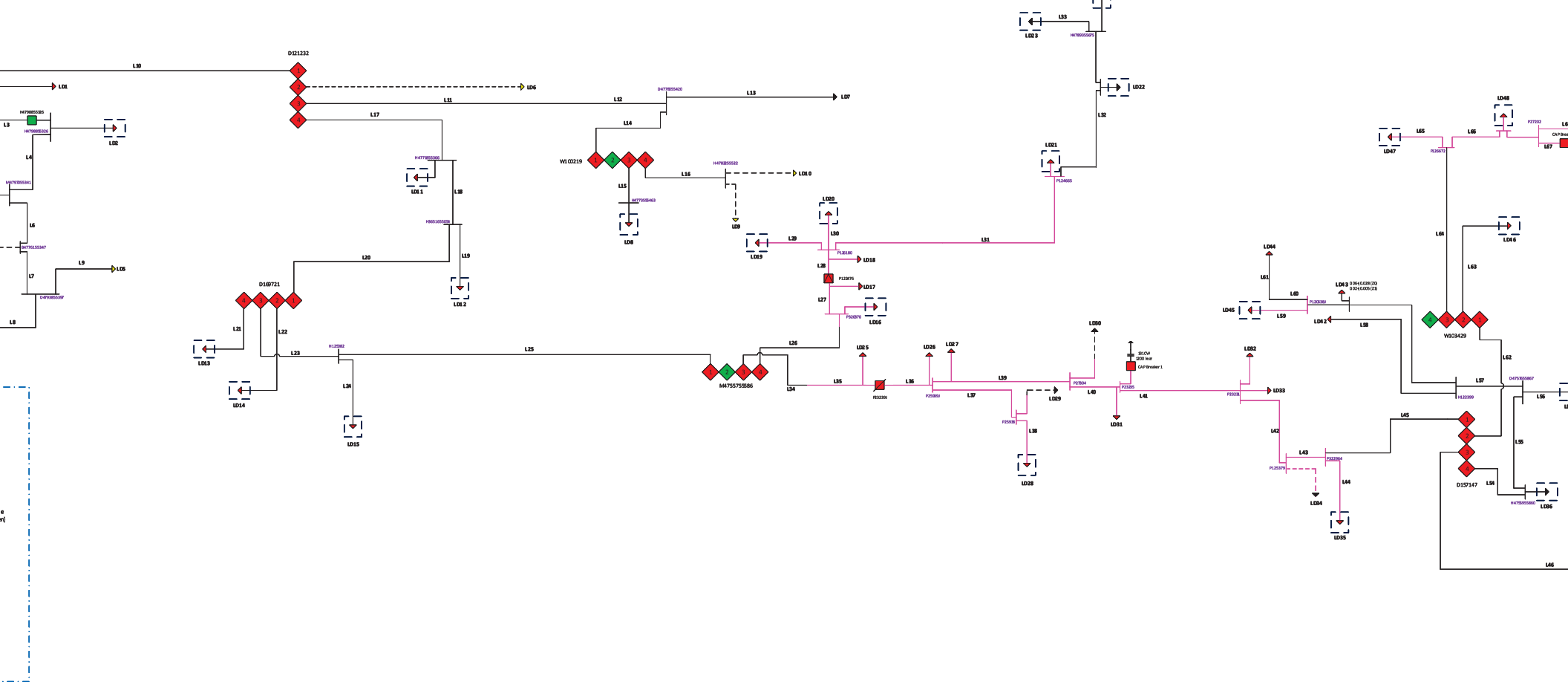


Figure A.1: Coastal-Residential Test Circuit One-Line Diagram

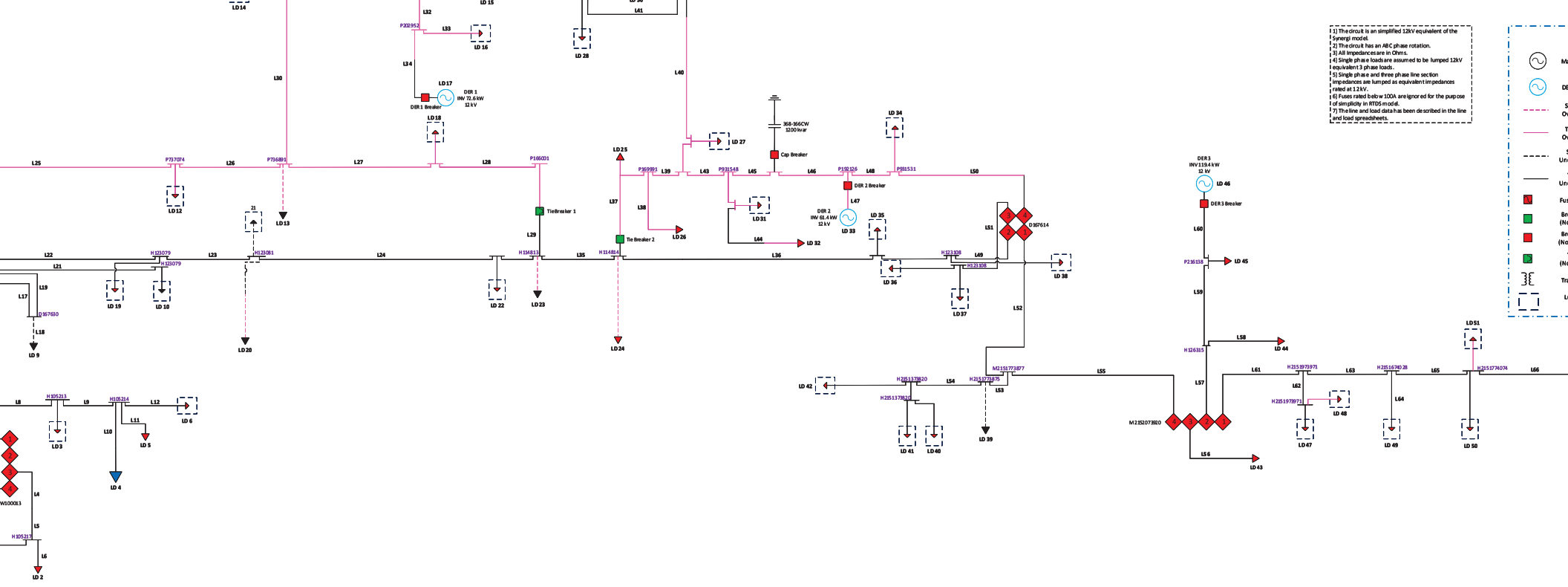


Figure A.2: Urban Test Circuit One-Line Diagram

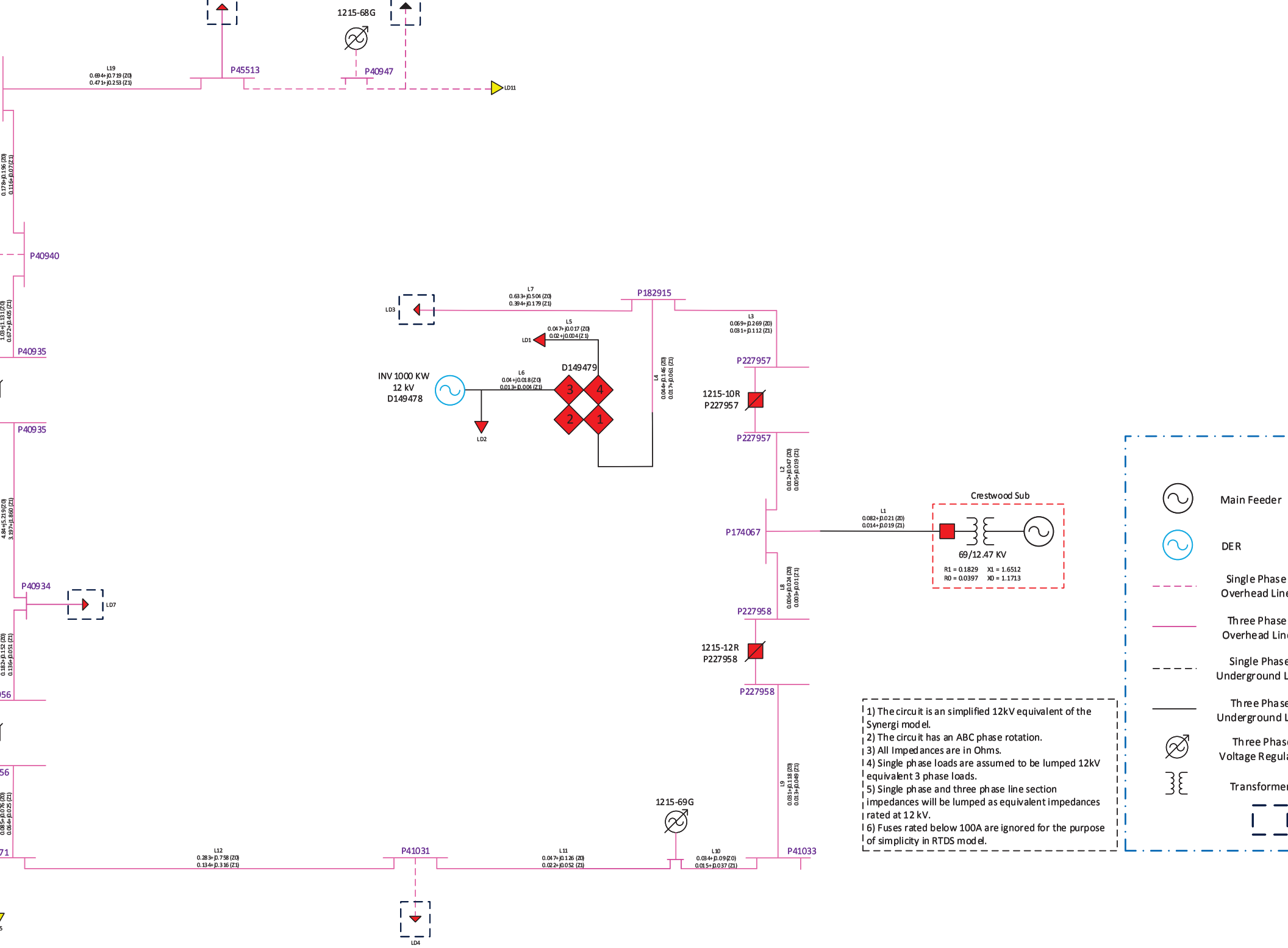


Figure A.3: Desert-Rural Test Circuit One-Line Diagram

APPENDIX B LOAD PROFILE

The following figures and tables show the actual load for a 24-hour period and the necessary slider position (in the digital simulator) required to obtain the condensed 60-minute equivalent load values. The tables are provided to show the specific slider settings necessary to get the desired real and reactive power setting output for RSCAD testing. The layout is as follows:

1. Coastal-Residential Test Circuit
    a. Figure B.1 – Actual Load Profile Over 24 Hours
    b. Figure B.2 – Actual Load
    c. Figure B.3 – Slider Position
    d. Table B.1 – Load and Slider Position Value
2. Urban Test Circuit
    a. Figure B.4 – Actual Load Profile Over 24 Hours
    b. Figure B.5 – Actual Load
    c. Figure B.6 – Slider Position
    d. Table B.2 – Load and Slider Position Value
3. Desert-Rural Test Circuit
    a. Figure B.7 – Actual Load Profile Over 24 Hours
    b. Figure B.8 – Actual Load
    c. Figure B.9 – Slider Position
    d. Table B.3 – Load and Slider Position Value

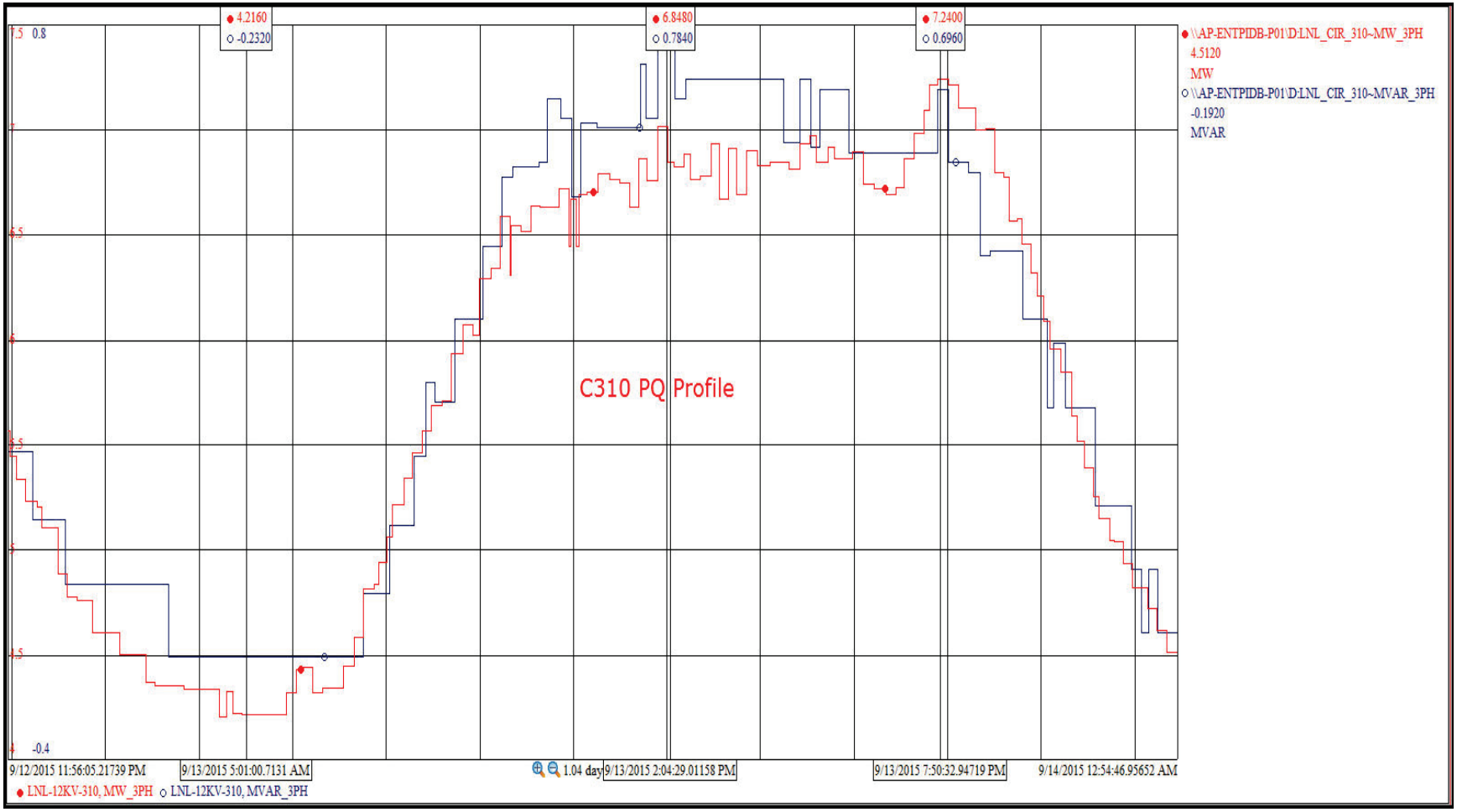


Figure B.1: Coastal-Residential Test Circuit – Actual Load Profile Over 24 Hours

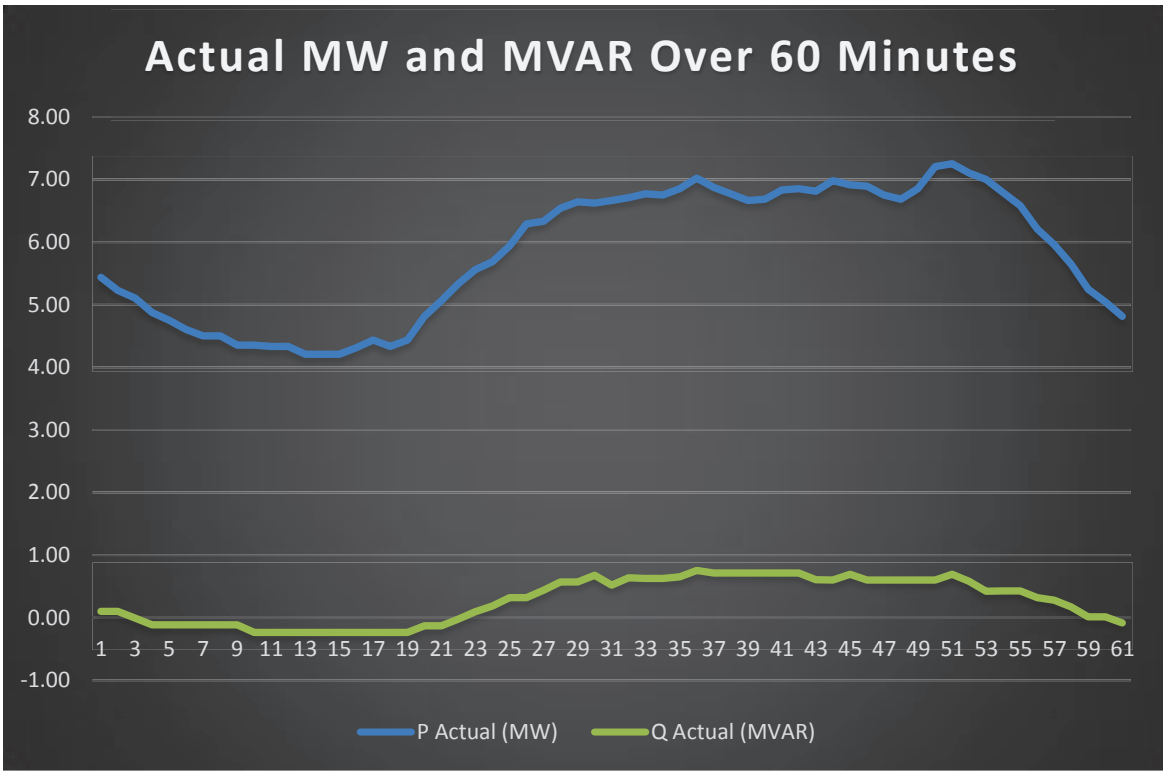


Figure B.2: Coastal-Residential Test Circuit – Actual Load Profile Over 60 Minutes

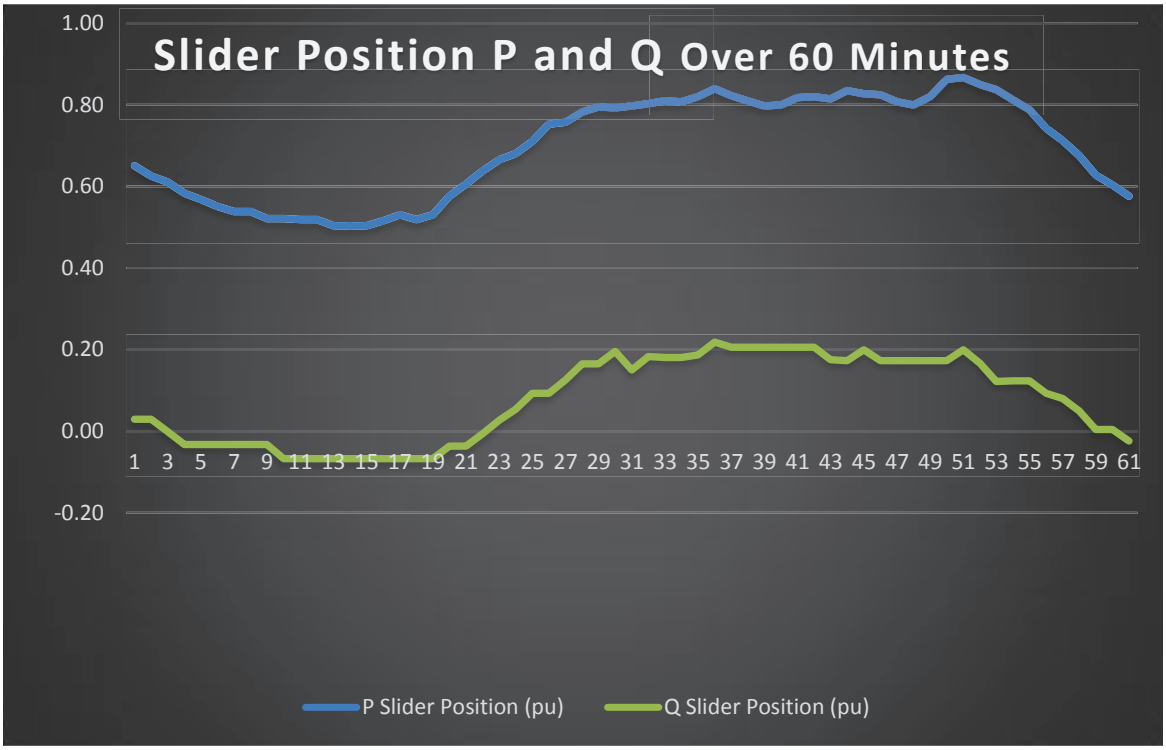


Figure B.3: Coastal-Residential Test Circuit – Slider Position Over 60 Minutes

Table 16.1: Load and Slider Position Value – Coastal-Residential Test Circuit

Time	P Actual (MW)	P Slider Position (pu)	Q Actual (MVAR)	Q Slider Position (pu)
1	5.44	0.65	0.100	0.029
2	5.23	0.63	0.100	0.029
3	5.10	0.61	–0.007	–0.002
4	4.88	0.58	–0.114	–0.033
5	4.75	0.57	–0.114	–0.033
6	4.60	0.55	–0.114	–0.033
7	4.50	0.54	–0.114	–0.033
8	4.50	0.54	–0.114	–0.033
9	4.35	0.52	–0.114	–0.033
10	4.35	0.52	–0.236	–0.068
11	4.33	0.52	–0.236	–0.068
12	4.33	0.52	–0.236	–0.068
13	4.21	0.50	–0.236	–0.068
14	4.21	0.50	–0.236	–0.068
15	4.21	0.50	–0.236	–0.068
16	4.31	0.52	–0.236	–0.068
17	4.44	0.53	–0.236	–0.068
18	4.33	0.52	–0.236	–0.068
19	4.44	0.53	–0.236	–0.068
20	4.81	0.58	–0.129	–0.037
21	5.06	0.61	–0.129	–0.037
22	5.33	0.64	–0.021	–0.006
23	5.56	0.66	0.093	0.027
24	5.69	0.68	0.186	0.053
25	5.94	0.71	0.321	0.092
26	6.29	0.75	0.321	0.092
27	6.33	0.76	0.436	0.125
28	6.54	0.78	0.571	0.164
29	6.65	0.79	0.571	0.164
30	6.63	0.79	0.679	0.195
31	6.67	0.80	0.521	0.150
32	6.71	0.80	0.636	0.183
33	6.77	0.81	0.629	0.181
34	6.75	0.81	0.629	0.181
35	6.85	0.82	0.650	0.187
36	7.02	0.84	0.757	0.218

Time	P Actual (MW)	P Slider Position (pu)	Q Actual (MVAR)	Q Slider Position (pu)
37	6.88	0.82	0.714	0.205
38	6.77	0.81	0.714	0.205
39	6.67	0.80	0.714	0.205
40	6.69	0.80	0.714	0.205
41	6.83	0.82	0.714	0.205
42	6.85	0.82	0.714	0.205
43	6.81	0.81	0.607	0.175
44	6.98	0.83	0.600	0.172
45	6.92	0.83	0.693	0.199
46	6.90	0.82	0.600	0.172
47	6.75	0.81	0.600	0.172
48	6.69	0.80	0.600	0.172
49	6.85	0.82	0.600	0.172
50	7.21	0.86	0.600	0.172
51	7.25	0.87	0.693	0.199
52	7.10	0.85	0.579	0.166
53	7.00	0.84	0.421	0.121
54	6.79	0.81	0.429	0.123
55	6.58	0.79	0.429	0.123
56	6.21	0.74	0.321	0.092
57	5.96	0.71	0.279	0.080
58	5.65	0.67	0.171	0.049
59	5.25	0.63	0.014	0.004
60	5.04	0.60	0.014	0.004
61	4.81	0.58	–0.086	–0.025

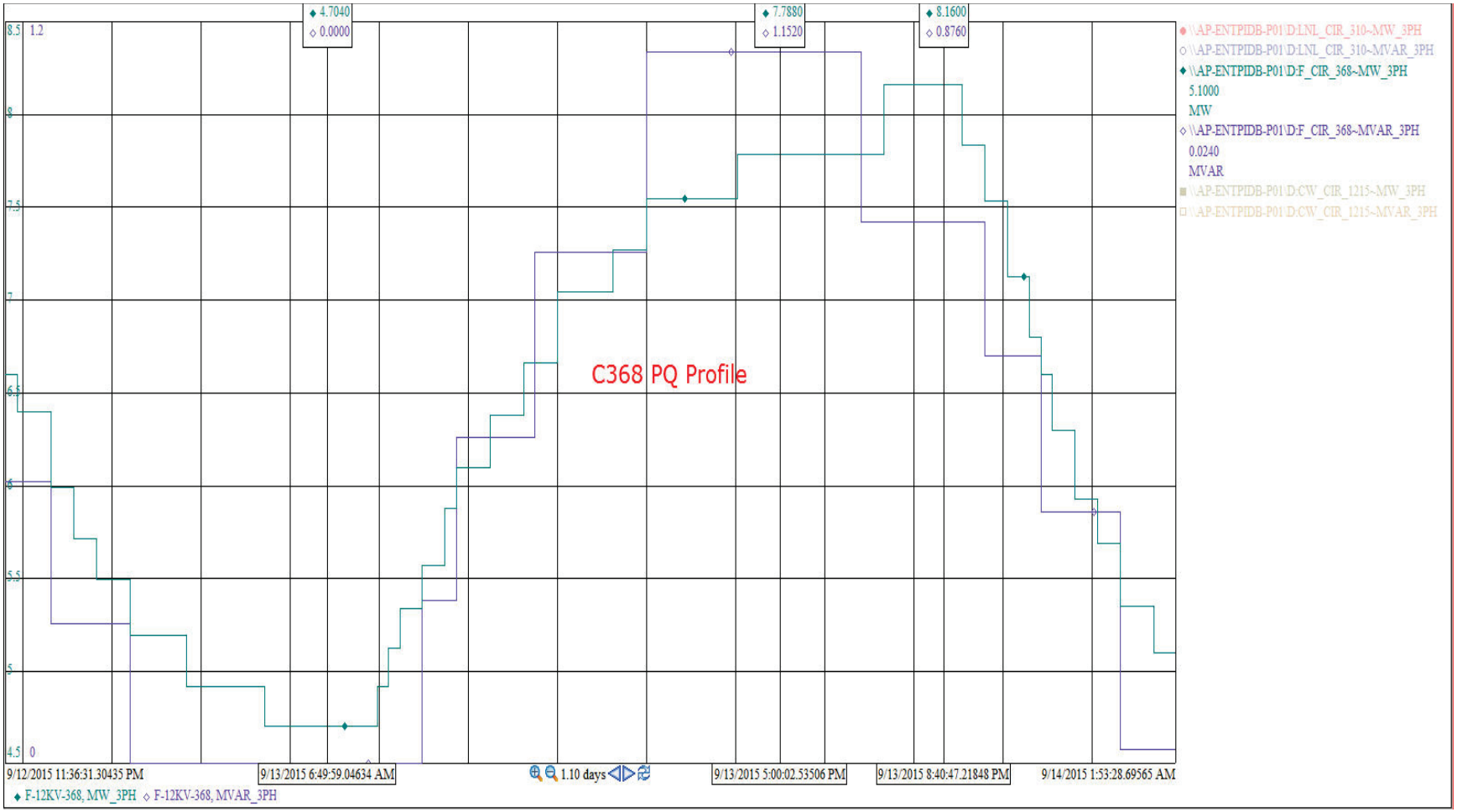


Figure B.4: Urban Test Circuit – Actual Load Profile Over 24 Hours

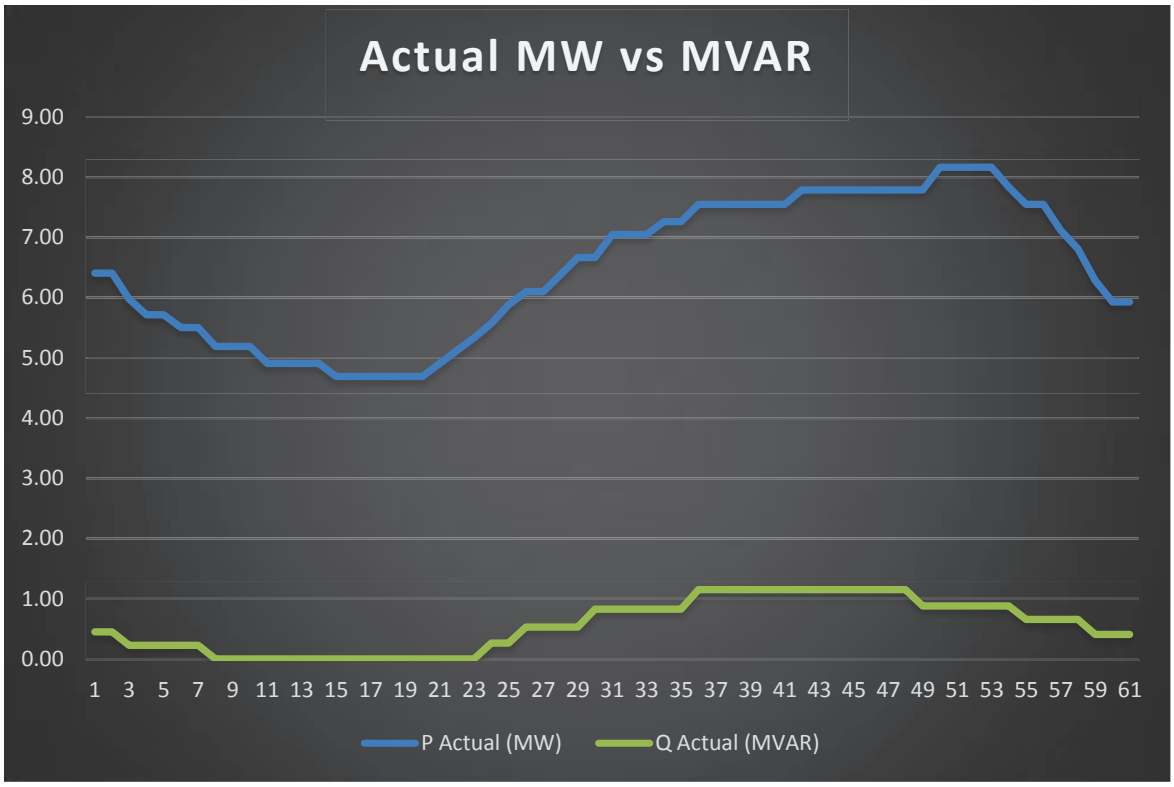


Figure B.5: Urban Test Circuit – Actual Load Profile Over 60 Minutes

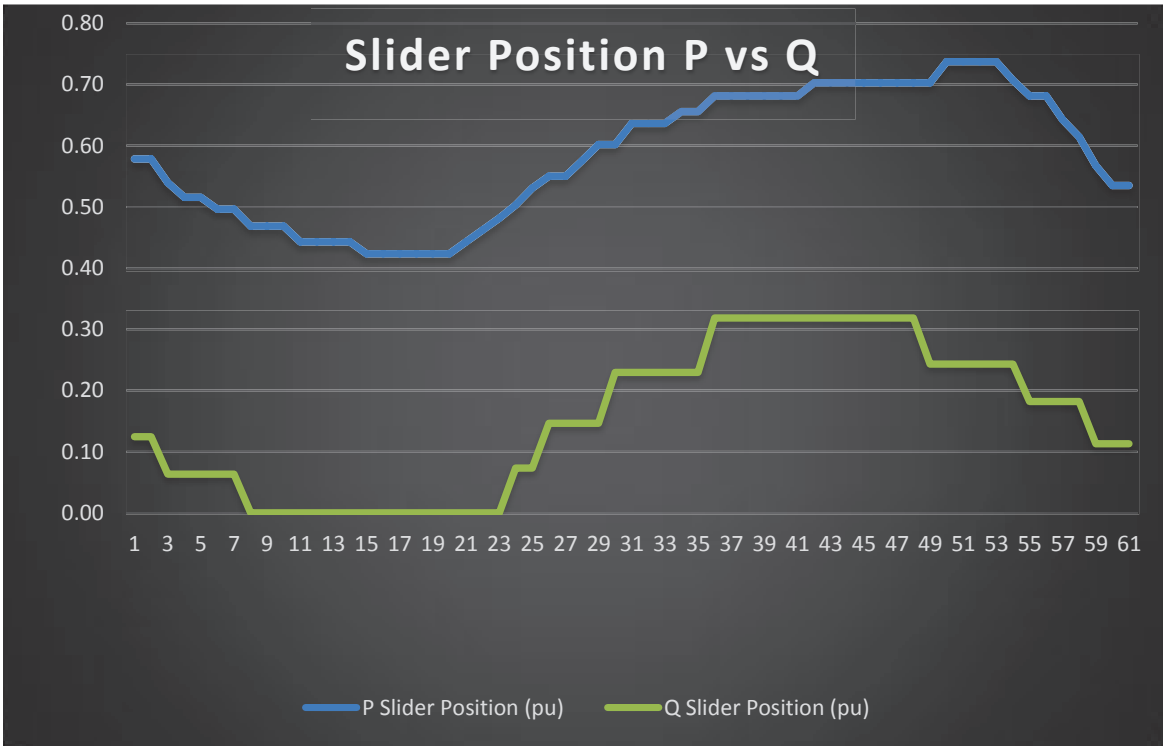


Figure B.6: Urban Test Circuit – Slider Position Over 60 Minutes

Table 16.2: Load and Slider Position Value – Urban Test Circuit

Time	P Actual (MW)	P Slider Position (pu)	Q Actual (MVAR)	Q Slider Position (pu)
1	6.40	0.58	0.450	0.125
2	6.40	0.58	0.450	0.125
3	5.98	0.54	0.229	0.063
4	5.71	0.52	0.229	0.063
5	5.71	0.52	0.229	0.063
6	5.50	0.50	0.229	0.063
7	5.50	0.50	0.229	0.063
8	5.19	0.47	0.000	0.000
9	5.19	0.47	0.000	0.000
10	5.19	0.47	0.000	0.000
11	4.90	0.44	0.000	0.000
12	4.90	0.44	0.000	0.000
13	4.90	0.44	0.000	0.000
14	4.90	0.44	0.000	0.000
15	4.69	0.42	0.000	0.000
16	4.69	0.42	0.000	0.000
17	4.69	0.42	0.000	0.000
18	4.69	0.42	0.000	0.000
19	4.69	0.42	0.000	0.000
20	4.69	0.42	0.000	0.000
21	4.90	0.44	0.000	0.000
22	5.12	0.46	0.000	0.000
23	5.33	0.48	0.000	0.000
24	5.57	0.50	0.264	0.073
25	5.88	0.53	0.264	0.073
26	6.10	0.55	0.529	0.146
27	6.10	0.55	0.529	0.146
28	6.38	0.58	0.529	0.146
29	6.67	0.60	0.529	0.146
30	6.67	0.60	0.829	0.229
31	7.05	0.64	0.829	0.229
32	7.05	0.64	0.829	0.229
33	7.05	0.64	0.829	0.229
34	7.26	0.66	0.829	0.229
35	7.26	0.66	0.829	0.229
36	7.55	0.68	1.150	0.318

Time	P Actual (MW)	P Slider Position (pu)	Q Actual (MVAR)	Q Slider Position (pu)
37	7.55	0.68	1.150	0.318
38	7.55	0.68	1.150	0.318
39	7.55	0.68	1.150	0.318
40	7.55	0.68	1.150	0.318
41	7.55	0.68	1.150	0.318
42	7.79	0.70	1.150	0.318
43	7.79	0.70	1.150	0.318
44	7.79	0.70	1.150	0.318
45	7.79	0.70	1.150	0.318
46	7.79	0.70	1.150	0.318
47	7.79	0.70	1.150	0.318
48	7.79	0.70	1.150	0.318
49	7.79	0.70	0.879	0.243
50	8.17	0.74	0.879	0.243
51	8.17	0.74	0.879	0.243
52	8.17	0.74	0.879	0.243
53	8.17	0.74	0.879	0.243
54	7.83	0.71	0.879	0.243
55	7.55	0.68	0.657	0.182
56	7.55	0.68	0.657	0.182
57	7.12	0.64	0.657	0.182
58	6.81	0.61	0.657	0.182
59	6.29	0.57	0.407	0.113
60	5.93	0.54	0.407	0.113
61	5.93	0.54	0.407	0.113

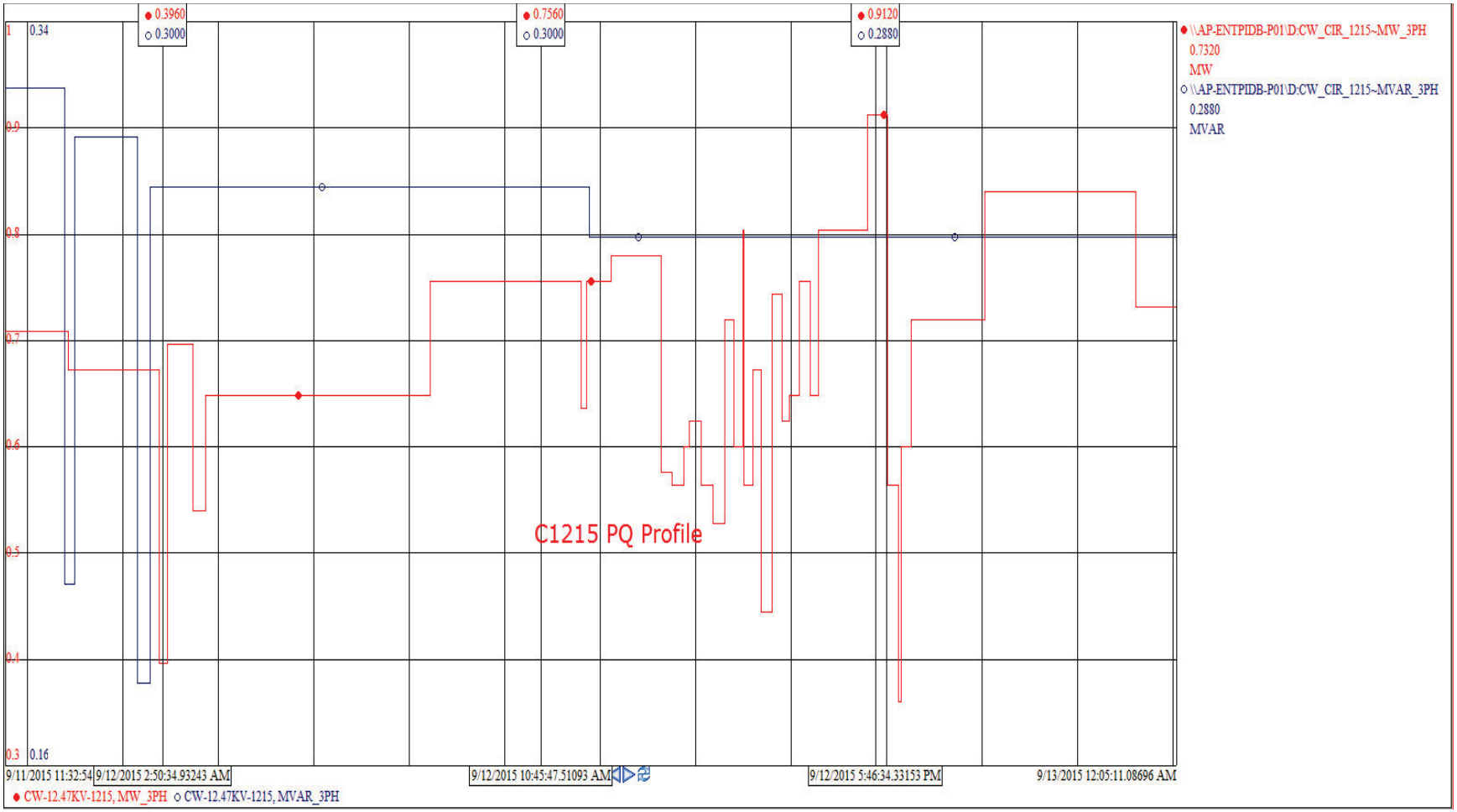


Figure B.7: Desert-Rural Test Circuit – Actual Load Profile Over 24 Hours

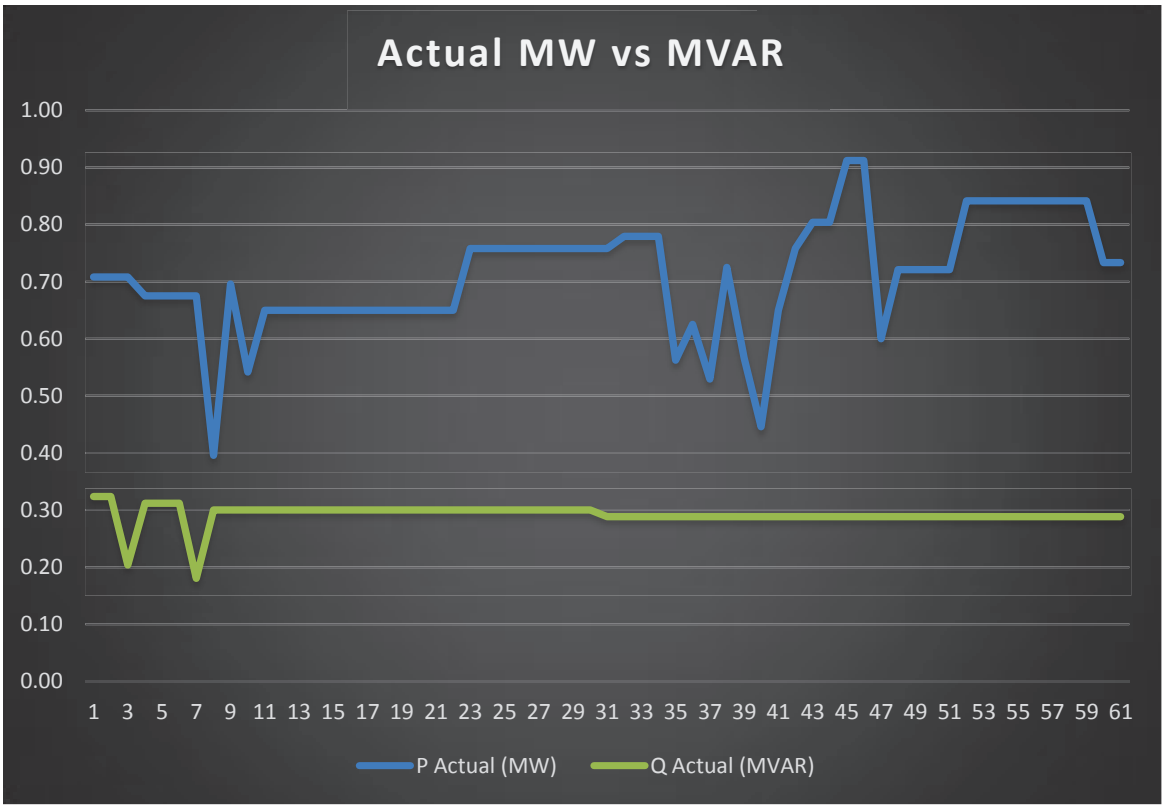


Figure B.8: Desert-Rural Test Circuit – Actual Load Profile Over 60 Minutes

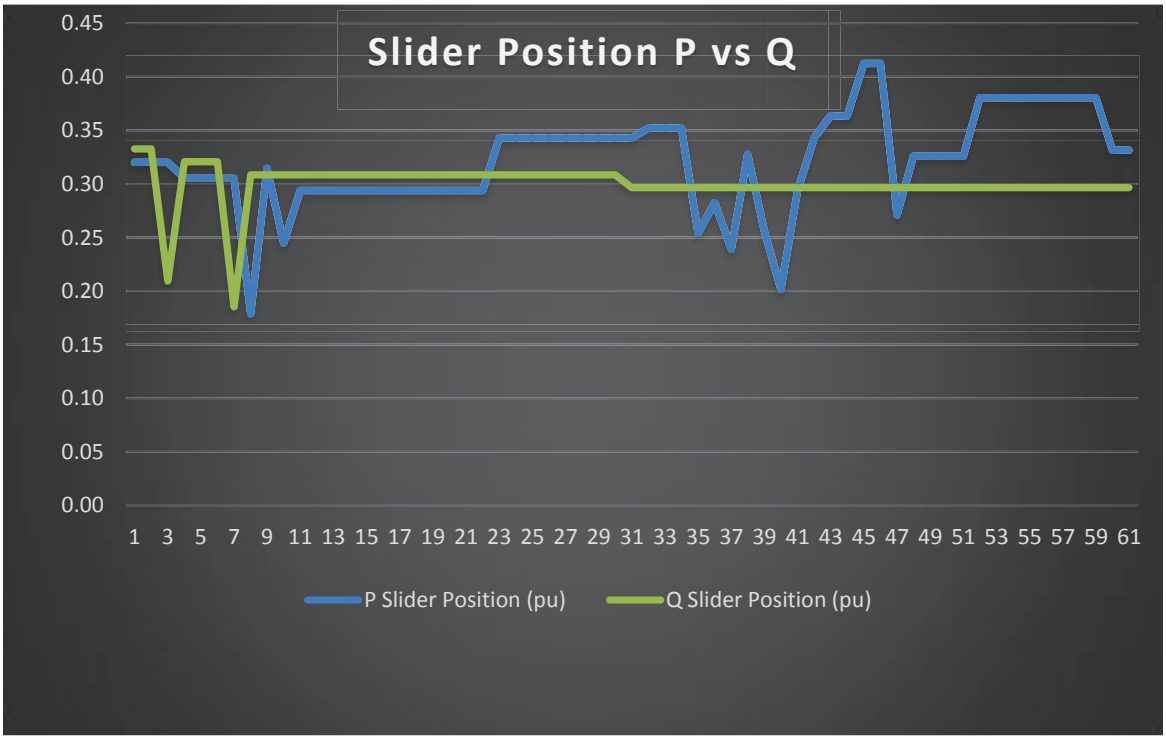


Figure B.9: Desert-Rural Test Circuit – Slider Position Over 60 Minutes

Table 16.3: Load and Slider Position Value – Desert-Rural Test Circuit

Time	P Actual (MW)	P Slider Position (pu)	Q Actual (MVAR)	Q Slider Position (pu)
1	0.71	0.32	0.324	0.333
2	0.71	0.32	0.324	0.333
3	0.71	0.32	0.204	0.210
4	0.68	0.31	0.312	0.321
5	0.68	0.31	0.312	0.321
6	0.68	0.31	0.312	0.321
7	0.68	0.31	0.180	0.185
8	0.40	0.18	0.300	0.309
9	0.70	0.31	0.300	0.309
10	0.54	0.24	0.300	0.309
11	0.65	0.29	0.300	0.309
12	0.65	0.29	0.300	0.309
13	0.65	0.29	0.300	0.309
14	0.65	0.29	0.300	0.309
15	0.65	0.29	0.300	0.309
16	0.65	0.29	0.300	0.309
17	0.65	0.29	0.300	0.309
18	0.65	0.29	0.300	0.309
19	0.65	0.29	0.300	0.309
20	0.65	0.29	0.300	0.309
21	0.65	0.29	0.300	0.309
22	0.65	0.29	0.300	0.309
23	0.76	0.34	0.300	0.309
24	0.76	0.34	0.300	0.309
25	0.76	0.34	0.300	0.309
26	0.76	0.34	0.300	0.309
27	0.76	0.34	0.300	0.309
28	0.76	0.34	0.300	0.309
29	0.76	0.34	0.300	0.309
30	0.76	0.34	0.300	0.309
31	0.76	0.34	0.289	0.296
32	0.78	0.35	0.289	0.296
33	0.78	0.35	0.289	0.296
34	0.78	0.35	0.289	0.296
35	0.56	0.25	0.289	0.296
36	0.63	0.28	0.289	0.296

Time	P Actual (MW)	P Slider Position (pu)	Q Actual (MVAR)	Q Slider Position (pu)
37	0.53	0.24	0.289	0.296
38	0.73	0.33	0.289	0.296
39	0.57	0.26	0.289	0.296
40	0.45	0.20	0.289	0.296
41	0.65	0.29	0.289	0.296
42	0.76	0.34	0.289	0.296
43	0.80	0.36	0.289	0.296
44	0.80	0.36	0.289	0.296
45	0.91	0.41	0.289	0.296
46	0.91	0.41	0.289	0.296
47	0.60	0.27	0.289	0.296
48	0.72	0.33	0.289	0.296
49	0.72	0.33	0.289	0.296
50	0.72	0.33	0.289	0.296
51	0.72	0.33	0.289	0.296
52	0.84	0.38	0.289	0.296
53	0.84	0.38	0.289	0.296
54	0.84	0.38	0.289	0.296
55	0.84	0.38	0.289	0.296
56	0.84	0.38	0.289	0.296
57	0.84	0.38	0.289	0.296
58	0.84	0.38	0.289	0.296
59	0.84	0.38	0.289	0.296
60	0.73	0.33	0.289	0.296
61	0.73	0.33	0.289	0.296

APPENDIX C VOLTAGE REGULATOR CONTROL SETTINGS

This appendix includes the settings used for the laboratory demonstration of the stand-alone voltage regulator tests described in Section 6.

Settings Calculation Sheet for the Voltage Regulator Control

kVA := kV·A pu := 1

MVA := MW j := $\sqrt{-1}$

Regulator Nameplate Data:

Set the kV to the voltage regulator rated nameplate line-neutral voltage.

Regulator Rated Voltage Line to Neutral: KV := 7.2kV

Select the polarity of the current transformer (CT) connection.

Regulator CT Winding Polarity: CTPOL := "NORM"

Set the voltage regulator primary CT nominal rating in primary amps.

Regulator Primary Current: CTPRIM := 10A

Regulator CT Ratio: CTR := 60

Set the regulator type to the tap changer manufacturer.

Regulator Type: TAPCHNGR := "COOPER"

Set the tapchanger type.

Tap Changer Type: TYPE := "B"

Select the polarity of the potential transformer (PT) PT1 connection.

PT1 Winding Polarity: PT1POL := "NORM"

Enter the primary and secondary winding information for the PT1 source.

PT1 Primary Voltage: PT1PRIM := 7.20kV

PT1 Secondary Voltage: PT1SEC := 120V

If there is a second PT connected on the source or load side of the voltage regulator, enable the second PT.

Second PT Connected: _2ND_PT := "Y"

PT2 Winding Polarity: PT2POL := "NORM"

Regulator PT2 Primary Voltage: PT2PRIM := 7.20kV

Regulator PT2 Secondary Voltage: PT2SEC := 120V

Connection Data:

Set the nominal system primary line-to-neutral voltage, and the nominal secondary voltage.

Base Primary Voltage: $BASE_{pri} := 7.2kV$

Base Secondary Voltage: $BASE_{sec} := 120V$

Set the regulator secondary connection.

Regulator Configuration: $CONFIG := "WYE"$

Set the delta configuration to be an open or closed delta.

Delta Power Type: $DELTA := "CLOSED"$

Angle By Which I Lags V: $D\_LAG := 30deg$

Angle By Which I Leads V: $D\_LEAD := 30deg$

Angle By Which I Lags V: $ISHIFT := 0deg$

Configuration Settings:

X corresponds to the specific phase - A, B or C.

Terminal Identification: $TID := "1215\text{-}68GX"$

The operation of the voltage regulator has several automatic modes to accommodate different operating conditions and applications. The modes are LOCKFWD, LOCKREV, IDLEREV, BIDIR, and COGEN. The regulator is utilized to regulate the bus voltage for forward load flow. The operation mode will be set in the locked forward mode.

Operating Mode: $OPMODE := "LOCKFWD"$

The nominal load current measured by the regulator is calculated based on the transformer MVA rating.

$MVA_{SelfCool} := 7.5MVA$ $V_{W2} := 12.47kV$ $I_{W2} := \frac{MVA_{SelfCool}}{\sqrt{3} \cdot V_{W2}}$ $I_{W2} = 347.24A$

The TAPMAX and TAPMIN settings provide a software limit switch on the regulator. The maximum allowable setting is +/- 16, which corresponds to +/- 10% voltage regulation. If +/- 8 was used, it would correspond to +/- 5% voltage regulation. With the load nominal load current well below the regular rated current, the voltage regulation can be set to achieve maximum regulation.

Maximum Software Tap Number: $TAPMAX := 16$

Minimum Software Tap Number: $TAPMIN := -16$

After the first tap, if additional tapping is needed to bring the voltage back within its normal range, the timing reverts to setting TD2 (Time Delay for Subsequent Taps).

Time Delay 2 for Subsequent Taps: TD2 := 10s

Forward Controller Settings:

There are multiple modes for resetting. The FAST time characteristic is the basic method for resetting the first-tap definite time delay. The DISC characteristic operates on the traditional induction disc relay. The DELAY mode prevents the resetting when the regulated voltage momentarily goes back in band. The DLY_FRZ characteristic freezes the timer when the regulated voltage enters the in-band region.

Forward Reset Characteristic: F_CHAR := "DISC"

Forward Center Band: F_CNBND := 120V

Forward Band Width: F_BNDWD := 2.0V

Forward Time Delay 1 for First Tap: F_TD1 := 30.0s

Forward Disc-like Reset Factor: F_DISC := 0.60

Forward Delay on Reset: F_DLYRS := 0.0

Reverse Controller Settings:

There are multiple modes for resetting. The FAST time characteristic is the basic method for resetting the first-tap definite time delay. The DISC characteristic operates on the traditional induction disc relay. The DELAY mode prevents the resetting when the regulated voltage momentarily goes back in band. The DLY_FRZ characteristic freezes the timer when the regulated voltage enters the in-band region.

The Reverse Controller Settings have been disabled since the device is on "LOCKFWD" operation.

Reverse Reset Characteristic: R_CHAR := "DISC"

Reverse Center Band: R_CNBND := 120V

Reverse Band Width: R_BNDWD := 2.0V

Reverse Time Delay 1 for First Tap: R_TD1 := 30.0s

Reverse Disc-like Reset Factor: R_DISC := 0.60

Reverse Delay on Reset: R_DLYRS := 0.0

Line Drop Compensation Settings:

The Line Drop Compensation (LDC) Settings are used when the delivery point for regulated voltage is beyond the load terminal on the voltage regulator. Line drop compensation keeps the voltage constant at the delivery point.

Enable Line Drop Compensation: ELDC := "N"

Line Drop Compensation is disabled in this study.

Forward Resistive LDC Voltage: VLDCFWR := 0.0V

Forward Reactive LDC Voltage: VLDCFWX := 0.0V

Reverse Resistive LDC Voltage: VLDCRVR := 0.0V

Reverse Reactive LDC Voltage: VLDCRVX := 0.0V

Overcurrent Settings:

Seven levels of load overcurrent elements are available. There are also two directional threshold elements which are used to determine the operational mode of the voltage regulator control. One fast operating fault overcurrent element is provided to trigger an alarm when an overcurrent fault occurs on the power system.

Load Current Levels: E50L := "1"

The load overcurrent element is set to 125% of the rated regulator current and is used to block the voltage regulator control from changing taps when asserted and does not reset the regulation timers.

Load OC Setting: $_{50L1P} := \frac{150\% \cdot CTPRIM}{CTR}$ $_{50L1P} = 0.25A$

The fault overcurrent element is set to 200% of the rated regular current and is used to block the voltage regulator control from changing taps when asserted.

Fault OC Setting: $_{50FLTP} := \frac{200\% \cdot CTPRIM}{CTR}$ $_{50FLTP} = 0.33A$

Set the forward and reverse directional thresholds.

Forward I Threshold: _50FWDP := 0.002A

Reverse I Threshold: _50REVP := 0.002A

Voltage Reduction Settings:

Voltage reduction is the deliberate lowering of the system voltage when the power demand exceeds the supply. This reduction in voltage is achieved by lowering the existing center band setting by a predefined percentage.

Voltage reduction settings are disabled in this study.

Enable Voltage Reduction: ENREDUC := "N"

Voltage Reduction Mode: VREDMOD := "PULSE, LATCH, CONTROL"

Forward VR 1 Percent: VREDFP1 := 2.0

Reverse VR 1 Percent: VREDRP1 := 2.0

VR Stage 1 Timer PU: VRSPU1 := 2.0

VR Pulse Length Pulse Mode: VRPULPU := 0.02

Set LDC to Zero for Voltage Reduction: SETLDC0 := "Y, N"

Voltage Limit Settings:

The voltage regulator control causes a voltage regulator to automatically tap to keep the regulation point voltage within its range. Setting limits attempts to prevent the voltage regulator from automatically tapping too high or too low and causing abnormally high or low voltage at the voltage regulator location.

Enable Min/Max Voltage Control: ENLIMIT := "Y"

Maximum Volts: VMAX := 130.0V

Minimum Volts: VMIN := 110.0V

Runback Settings:

Additional runback (high and low) limits will instigate automatic tapping to bring the voltage back within its normal range. These runback limits are outside the VMAX/VMIN limits based on the dead band high/low settings.

Runback settings are disabled in this study.

Enable Runback: ENRUNBK := "N"

Runback Block: RBKBLSV := "50FLT"

Runback Timer: RUNBKPU := 0.5s

Dead Band (High): DBNDH := OFF

Dead Band (Low): DBNDL := OFF

Timer Settings:

The Timers provide additional settings functionality by adding state variables that can be manipulated.

Timers: ESV := 2

Variable Input Equation: SV01 = RSEFAIL OR LWRFAIL OR XTAP16R OR XTAP16L OR OPNOCUR OR TAP_DIF

For interface error conditions

Variable Timer Pickup (seconds) SV01PU := 0

Variable Timer Dropout (seconds) SV01DO := 2.0

Variable Input Equation: SV02 = VLSI

For system low voltage, used in BLOCKSV

Variable Timer Pickup (seconds) SV02PU := 0

Variable Timer Dropout (seconds) SV02DO := 2.0

Raise/Lower Settings:

Inhibit Conditions:

INHIBSV := "50FLT"

Block Tap Operations:

BLOCKSV := "50L1 OR SV02T'

Raise Command:

RAISESV := "TOOLOW AND AUTO"

Lower Command:

LOWERSV := "TOOHIGH AND AUTO"

Output Equations:

OUT101 := "NOT ALARM"

OUT102 := "RAISE"

OUT103 := "LOWER"

OUT104 := "BLOCKSV"

APPENDIX D RECLOSER SETTINGS SHEET

This appendix documents the sample field settings provided by SDG&E for recloser controllers on the desert-rural test circuit. These settings were further modified for the high-impedance fault detection tests described in Section 8.

	PROFILE 1 NORMAL			PROFILE 2 INRUSH			PROFILE 3 FAST/SENSITIZED			PROFILE 4 SWITCH		
	1	Phase	Gnd		Phase	Gnd		Phase	Gnd		Phase	Gnd
Initial Trip Settings										All Protection Disabled		
Min Trip/Fault Ind Pick Up Amps	Enabled	150	100	Enabled	180	100	Enabled	100	25	Fault Ind	150	100
TCC for Initial, Test, & Closing Profiles		U3	U3		U3	U3		U3	U3			
Time Mult (Time Dial)		2.00	5.00		2.00	5.00		2.00	5.00			
Min TCC Response Time (sec)		0.05	0.05		0.05	0.05		0.05	0.05			
Time Adder		0	0		0	0		0	0			
Disc Reset Type (EM or DT)	E/M	calc	calc	E/M	calc	calc	E/M	calc	calc			
Low Cut-off (Amps)		N/A	N/A		N/A	N/A		N/A	N/A			
Initial Def Time-1		1300	1300		1300	1300		100	25			
Initial Def Time-1 Delay		0.050	0.050		0.050	0.050		0.050	0.050			
Initial Def Time-2		N/A	N/A		N/A	N/A		1300	1300			
Initial Def Time-2 Delay		0.000	0.000		0.000	0.000		0.000	0.000			
High Current Lockout Initial Trip	Disabled		1300	Enabled		1300	Enabled		1300			
Sensitive Earth	Enable			Enable			Enable					
TCC Minimum Trip (Amps)			20			20			20			
TCC Minimum Trip (Seconds)			2			2			2			
TCC			U1			U1			U1			
TCC Time Multiplier			15			15			15			
TCC Time Adder (Seconds)			0			0			0			
TCC Reset Time (Seconds)			120			120			120			
TCC Low Cut-off (Amps)			NA			NA			NA			
Def Time-1 Pick Up (Amps)			20			20			20			
Def Time-1 Min Trip (Seconds)			5.0			5			5			
SGF Number of Tests			0			0			0			
Reset			T/A			T/A			T/A			
SGF Spike Counting	Enable			Enable			Enable					
Number of Spikes	25			25			25					
Moving Reset Window (seconds)	40			40			40					
TCCs for Test Sequence 1 and 2												
All same as Initial Trip except:												
High Current Lockout Test 1 & 2:	Enabled		1300	Disabled			Disabled					
Testing After Intital Trip												
TCC Trips to lockout (see next line)	3			1			1					
High Current Operations to lockout	2			0			0					
Over-current Number of Tests	2			0			0					
Open Intervals (seconds)	5, 10			n/a			n/a					
Reset time (seconds)	120			n/a			n/a					
Hot Line Tag	GLOBAL			GLOBAL			GLOBAL					
TCC settings = Initial Trip EXCEPT:												
TCC		106	102									
Time Multiplier (Time Dial)		1.00	1.00									
Closing Profiles	GLOBAL			GLOBAL			GLOBAL					
Pulse 1- Test or Close	Pulse Close											
Profile1- Pulse Closing Enabled	Yes											
Pulse 2- Test or Close	Non-Pulse											
Profile2- Pulse Closing Enabled	No											
Profile Active Time (Seconds)	1											
External Lever Delay (Seconds)	2											
Sync Check Enabled	No											
TCC settings = Initial Trip EXCEPT:												
Min Trip Amps (Double Phase Amps)		300	300									
Cold Load Pick Up	GLOBAL			GLOBAL			GLOBAL					
Activate Cold Load Pick-up	Enabled											
Max Cold Load Modifier (%)	120%	180			216			120				
T1-Apply Delay (Minutes)	15											
T2-Ramp-up Delay (Minutes)	15											
T3-Ramp-down Delay (Minutes)	15											
T4-Removal Delay (Minutes)	15											

Normal Curve Setting Pick Up Times	Phase Curve Testing						Ground Curve Testing					
	Min PU	Curve	TD/Mult	200%	500%	1000%	Min PU	Curve	TD/Mult	200%	500%	1000%
Settings and ASPEN pickup times (sec):	150	U3	2.00	2.779	0.516	0.271	100	U3	5.00	6.948	1.290	0.677
Field test times (sec):												

TESTING NOTES:

	PROFILE 1 NORMAL			PROFILE 2 INRUSH			PROFILE 3 FAST/SENSITIZED			PROFILE 4 SWITCH		
	1	Phase	Gnd		Phase	Gnd		Phase	Gnd		Phase	Gnd
Initial Trip Settings										All Protection Disabled		
Min Trip/Fault Ind Pick Up Amps	Enabled	**180**	**130**	Enabled	**220**	**130**	Enabled	**100**	**30**	Fault Ind	**180**	**130**
TCC for Initial, Test, & Closing Profiles		U3	U4		U3	U4		U3	U4			
Time Mult (Time Dial)		4.30	6.30		4.30	6.30		4.30	6.30			
Min TCC Response Time (sec)		0.05	0.05		0.05	0.05		0.05	0.05			
Time Adder		0	0		0	0		0	0			
Disc Reset Type (EM or DT)	E/M	calc	calc	E/M	calc	calc	E/M	calc	calc			
Low Cut-off (Amps)		N/A	N/A		N/A	N/A		N/A	N/A			
Initial Def Time-1		1500	1500		1500	1500		100	30			
Initial Def Time-1 Delay		0.050	0.050		0.050	0.050		0.050	0.050			
Initial Def Time-2		N/A	N/A		N/A	N/A		1500	1500			
Initial Def Time-2 Delay		0.000	0.000		0.000	0.000		0.000	0.000			
High Current Lockout Initial Trip	Disabled		1500	Enabled		1500	Enabled		1500			
Sensitive Earth	Enable			Enable			Enable					
TCC Minimum Trip (Amps)			25			25			25			
TCC Minimum Trip (Seconds)			2			2			2			
TCC			U1			U1			U1			
TCC Time Multiplier			15			15			15			
TCC Time Adder (Seconds)			0			0			0			
TCC Reset Time (Seconds)			120			120			120			
TCC Low Cut-off (Amps)			NA			NA			NA			
Def Time-1 Pick Up (Amps)			25			25			25			
Def Time-1 Min Trip (Seconds)			5.0			5			5			
SGF Number of Tests			0			0			0			
Reset			T/A			T/A			T/A			
SGF Spike Counting	Enable			Enable			Enable					
Number of Spikes	25			25			25					
Moving Reset Window (seconds)	40			40			40					
TCCs for Test Sequence 1 and 2												
All same as Initial Trip except:												
High Current Lockout Test 1 & 2:	Enabled		1500	Disabled			Disabled					
Testing After Intital Trip												
TCC Trips to lockout (see next line)	3			1			1					
High Current Operations to lockout	2			0			0					
Over-current Number of Tests	2			0			0					
Open Intervals (seconds)	5, 10			n/a			n/a					
Reset time (seconds)	120			n/a			n/a					
Hot Line Tag	GLOBAL			GLOBAL			GLOBAL					
TCC settings = Initial Trip EXCEPT:												
TCC		**106**	**102**									
Time Multiplier (Time Dial)		**1.00**	**1.00**									
Closing Profiles	GLOBAL			GLOBAL			GLOBAL					
Pulse 1- Test or Close	Pulse Close											
Profile1- Pulse Closing Enabled	Yes											
Pulse 2- Test or Close	Non-Pulse											
Profile2- Pulse Closing Enabled	No											
Profile Active Time (Seconds)	1											
External Lever Delay (Seconds)	2											
Sync Check Enabled	No											
TCC settings = Initial Trip EXCEPT:												
Min Trip Amps (Double Phase Amps)		**360**	**360**									
Cold Load Pick Up	GLOBAL			GLOBAL			GLOBAL					
Activate Cold Load Pick-up	Enabled											
Max Cold Load Modifier (%)	120%	**216**			**264**			**120**				
T1-Apply Delay (Minutes)	15											
T2-Ramp-up Delay (Minutes)	15											
T3-Ramp-down Delay (Minutes)	15											
T4-Removal Delay (Minutes)	15											

Normal Curve Setting Pick Up Times	**Phase Curve Testing**						**Ground Curve Testing**					
	Min PU	Curve	TD/Mult	200%	500%	1000%	Min PU	Curve	TD/Mult	200%	500%	1000%
Settings and ASPEN pickup times (sec):	180	U3	4.30	5.975	1.109	0.583	130	U4	6.30	12.129	1.710	0.583
Field test times (sec):												

TESTING NOTES:

	PROFILE 1			PROFILE 2			PROFILE 3			PROFILE 4		
	NORMAL			INRUSH			FAST/SENSITIZED			SWITCH		
	1	Phase	Gnd		Phase	Gnd		Phase	Gnd		Phase	Gnd
Initial Trip Settings										All Protection Disabled		
Min Trip/Fault Ind Pick Up Amps	Enabled	**125**	**100**	Enabled	**150**	**100**	Enabled	**100**	**25**	Fault Ind	**125**	**100**
TCC for Initial, Test, & Closing Profiles		U3	U4		U3	U4		U3	U4			
Time Mult (Time Dial)		3.40	4.30		3.40	4.30		3.40	4.30			
Min TCC Response Time (sec)		0.05	0.05		0.05	0.05		0.05	0.05			
Time Adder		0	0		0	0		0	0			
Disc Reset Type (EM or DT)	E/M	calc	calc	E/M	calc	calc	E/M	calc	calc			
Low Cut-off (Amps)		N/A	N/A		N/A	N/A		N/A	N/A			
Initial Def Time-1		1300	1300		1300	1300		100	25			
Initial Def Time-1 Delay		0.050	0.050		0.050	0.050		0.050	0.050			
Initial Def Time-2		N/A	N/A		N/A	N/A		1300	1300			
Initial Def Time-2 Delay		0.000	0.000		0.000	0.000		0.000	0.000			
High Current Lockout Initial Trip	Disabled		1300	Enabled		1300	Enabled		1300			
Sensitive Earth	Enable			Enable			Enable					
TCC Minimum Trip (Amps)			20			20			20			
TCC Minimum Trip (Seconds)			2			2			2			
TCC			U1			U1			U1			
TCC Time Multiplier			15			15			15			
TCC Time Adder (Seconds)			0			0			0			
TCC Reset Time (Seconds)			120			120			120			
TCC Low Cut-off (Amps)			NA			NA			NA			
Def Time-1 Pick Up (Amps)			20			20			20			
Def Time-1 Min Trip (Seconds)			4.5			4.5			4.5			
SGF Number of Tests			0			0			0			
Reset			T/A			T/A			T/A			
SGF Spike Counting	Enable			Enable			Enable					
Number of Spikes	25			25			25					
Moving Reset Window (seconds)	40			40			40					
TCCs for Test Sequence 1 and 2												
All same as Initial Trip except:												
High Current Lockout Test 1 & 2:	Enabled		1300	Disabled			Disabled					
Testing After Intital Trip												
TCC Trips to lockout (see next line)	3			1			1					
High Current Operations to lockout	2			0			0					
Over-current Number of Tests	2			0			0					
Open Intervals (seconds)	5, 10			n/a			n/a					
Reset time (seconds)	120			n/a			n/a					
Hot Line Tag	GLOBAL			GLOBAL			GLOBAL					
TCC settings = Initial Trip EXCEPT:												
TCC		**106**	**102**									
Time Multiplier (Time Dial)		**1.00**	**1.00**									
Closing Profiles	GLOBAL			GLOBAL			GLOBAL					
Pulse 1- Test or Close	Pulse Close											
Profile1- Pulse Closing Enabled	Yes											
Pulse 2- Test or Close	Non-Pulse											
Profile2- Pulse Closing Enabled	No											
Profile Active Time (Seconds)	1											
External Lever Delay (Seconds)	2											
Sync Check Enabled	No											
TCC settings = Initial Trip EXCEPT:												
Min Trip Amps (Double Phase Amps)		**250**	**250**									
Cold Load Pick Up	GLOBAL			GLOBAL			GLOBAL					
Activate Cold Load Pick-up	Enabled											
Max Cold Load Modifier (%)	120%	**150**			**180**			**120**				
T1-Apply Delay (Minutes)	15											
T2-Ramp-up Delay (Minutes)	15											
T3-Ramp-down Delay (Minutes)	15											
T4-Removal Delay (Minutes)	15											

Normal Curve Setting Pick Up Times	Phase Curve Testing						Ground Curve Testing					
	Min PU	Curve	TD/Mult	200%	500%	1000%	Min PU	Curve	TD/Mult	200%	500%	1000%
Settings and ASPEN pickup times (sec):	125	U3	3.40	4.725	0.877	0.461	100	U4	4.30	8.278	1.167	0.398
Field test times (sec):												

TESTING NOTES:

	NORMAL			INRUSH RESTRAINT (CLPU TCCs)			PROFILE 3 (FAST/SENSITIZED)			SWITCH		
		Phase	Gnd		Phase	Gnd		Phase	Gnd		Phase	Gnd
Min Trip										Disabled		
Min Trip Pick Up		75	75		100	75		100	55			
Operations to lockout		3	3		1	1		1	1			
Block TCC Trips (F6 only: unblk/blk)		unblk	unblk		unblk	unblk		unblk	unblk		blk	blk
TCC1,2,3,4		151	142		151	142		151	142			
Min Response Time		0.05	0.05		0.05	0.05		0.05	0.05			
TCC Time Mult (F6only,1.0 if disabld)		0.50	0.50		0.50	0.50		0.50	0.50			
Open Intervals		5, 10,	5, 10,		5, 10,	5, 10,		5, 10,	5, 10,			
High Current Trip										Disabled		
Trip Delay, seconds		0.05	0.05		0.05	0.05		0.01	0.01			
Min Trip Pick Up (internal calc)	Enabled	1000	1000	Enabled	1000	1000	Enabled	1000	1000			
IT/PU Multiplier		13.33	13.33		10.00	13.33		10.00	18.18			
High Current Lockout										Disabled		
1st	Disabled			Enabled	1000	1000	Enabled	1000	1000			
2nd	Enabled	1000	1000	Disabled			Disabled					
3rd	Disabled			Disabled			Disabled					
Cold Load Pick Up	Enabled			Enabled			Enabled			Disabled		
Trips to lockout	2			1			1					
Activation time	20			20			20					
Open interval	2			2			2					
CLPU Min Pickup		100	75		100	75		100	75			
CLPU TCC		151	142		151	142		151	142			
Min Response Time		0.05	0.05		0.05	0.05		0.05	0.05			
CLPU TCC TimeMult (1.0 if disabld)		0.50	0.50		0.50	0.50		0.50	0.50			
High Current Lockout	Enabled			Enabled			Enabled					
HCL Threshold		1000	1000		1000	1000		1000	1000			
IT/PU Multiplier		10.00	13.33		10.00	13.33		10.00	13.33			
CLPU HCT Delay (sec)		0.050	0.050		0.050	0.050		0.050	0.050			
Disc Reset Coeff. (EM emulation)		4.00	4.00		4.00	4.00		4.00	4.00			
Sensitive Ground Fault	Enabled			Enabled			Enabled			Disabled		
Minimum Trip	50			50			50					
Trip Delay, seconds	4.0			4			4					
Open Intervals, seconds	2			2			2					
Operations to lockout	1			1			1					
Reset Delay, seconds	60			60			60					
Downed Cond Detection (DCD)	Enabled			Enabled			Enabled			Disabled		
DCD Spike Accum: Counts (N) / Sec (W)	15, 120			15, 120			15, 120					
DCD Spike Pick Up Buffer (amps)	25			25			25					
DCD IN (60HZ) Accum: Counts (N) / Sec (W)	15, 120			15, 120			15, 120					
DCD IN (60HZ) Pick Up Buffer (amps)	13			13			13					
DCD Counter Alarm (max before alarms)	5			5			5					
DCD SEF Adapt INT (min) / K(multipier)	1, 1			1, 1			1, 1					
DCD Run Accum (amps) / SEF Bolted (sec)	3, 1			3, 1			3, 1					
Low Set Trip (Form 6 only)	Disabled			Disabled			Enabled			Disabled		
Amps								100	55			
Delay, seconds								0.05	0.05			
Hot Line Tag	Enabled			Enabled			Enabled			Disabled		
Profile Min Trip (internal setting)		75	75		100	75		100	55			
Delay before trip		0.05	0.05		0.05	0.05		0.05	0.05			

Normal Curve Setting Pick Up Times	**Phase Curve Testing**						**Ground Curve Testing**					
	Min PU	Curve	TD/Mult	200%	500%	1000%	Min PU	Curve	TD/Mult	200%	500%	1000%
Settings and ASPEN pickup times (sec):	75	151	0.50	3.098	0.562	0.294	75	142	0.50	4.850	0.435	0.123
Field test times (sec):												

TESTING NOTES: **On return to service, field tech to take snapshots of Low & High harmonic screens and email to Syst Prot Eng.**

Appendix 8

EPIC-1, Project 5, Module 2: Smart Distribution Circuit Demonstrations – Pre-Commercial Demonstration of Methodologies and Tools for Energy Storage Integration into Smart Distribution Circuits



EPIC Final Report

Program	**Electric Program Investment Charge (EPIC)**
Administrator	**San Diego Gas & Electric Company**
Project Number	**EPIC-1, Project 5, Module 2**
Project Name	**Smart Distribution Circuits**
Module Name	**Pre-Commercial Demonstration of Methodologies and Tools for Energy Storage Integration into Smart Distribution Circuits**
Date	**December 31, 2017**

Attribution

This comprehensive final report documents work done in this EPIC activity.

The project team for this work included the following individuals, listed alphabetically by last name.

Internal SDG&E Staff

Laurence Abcede

Donald Balfour

Frank Goodman

Christian Henderson

Prajwal Raval

Amin Salmani

Greg Smith

Quanta Technology, LLC

David Boroughs

Shadi Chuangpishit

Farbod Farzan

Ming-chen Hsu

Farbod Jahanbakhsh

Farid Katiraei

Nikoo Kouchakipour

Ralph Masiello

Douglas Proudfoot

Victor Romero

Vahid Salehi

Chi Zhang

EXECUTIVE SUMMARY

This executive summary overviews the work performed in EPIC-1, Project 5, Module 2 on Smart Distribution Circuit Demonstrations. It is a companion to other activities in that project.

Project Objectives and Chosen Focus

The objective of EPIC-1, Project 5 was to perform pilot demonstrations of smart distribution circuit features and associated simulation work to identify best practices for integrating new and existing distribution equipment in these circuits.

Energy storage systems are key components of smart distribution circuits with variety of applications that can enhance performance and provide superior value proposition in future distribution circuits.

The chosen focus of this specific project module was on Pre-Commercial Demonstration of Methodologies and Tools for Energy Storage Integration into Smart Distribution Circuits. The work included:

- Assessing the present state of energy storage systems (ESS) at SDG&E, including assessment and design approaches utilized, application selection processes applied and final selections, as well as areas for potential enhancements.
- Identifying candidate methodologies and tools that could be used in future energy storage projects as part of distribution circuit modernization programs, based on examination of available tools and methodologies utilized by SDG&E and/or other utility practices and state-of-the-art in the industry.
- Selecting a series of use cases to evaluate ESS solutions and to perform overall economic analysis of the solution versus conventional approaches based on comparative capital costs and market benefits. The use cases included examination of the benefits of stacking applications of the ESS. The use cases were aligned with SDG&E ESS strategic planning needs.
- Demonstrating state-of-the-art methodologies and tools for structured and consistent assessment of energy storage projects, to cover both technical studies (planning and design) and business evaluation.
- Preparing a comprehensive final report, including findings, conclusions, and recommendations on which methodologies and tools should be used commercially in routine planning by SDG&E.

Key Findings

- The methods and tools discussed can significantly improve the benefit/cost analysis results when stacking of application, reliability and other benefits offered by ESS are considered.
- The process for implementing distribution ESS in the markets has multiple hurdles to overcome. Included are regulatory approval of the evaluation framework and establishing the tools and process to ensure the ESS is ready to perform its distribution system value when needed.
- Detailed ESS distribution application evaluation require time-series analysis. However, commercial tools available today do not use time-series analysis and have limitations in the

accuracy of the assessments possible when analyzing distribution system issues in conjunction with ESS applications and solutions.

- A major shortcoming of the existing tools and models is that most tools use one type of "generator" representation (typically synchronous generator model) as a proxy for an energy storage system during the discharge mode, and load models as a proxy for energy storage in a charge mode.
- Most tools focus on single application analysis such as peak shaving, generation shifting, or congestion management. None of the available tools can analyze stacking of applications and/or added value of market participation in conjunction with distribution reliability applications.
- Distribution planning software tools have limited or no capabilities in performing power flow analyses on part of a distribution circuit that is separated from the main source (substation) in an isolated (island) mode.
- The methodology for performing distribution planning studies should incorporate the addition of newly developed time-based power flow analytics and time-series load/resource data for enabling hosting capacity analysis.
- Energy storage system models that incorporate accurate characteristics of the power conversion systems, the energy storage technology, and controls with considerations for operating constraints of real world utilization need to be developed.
- ESS benefit/cost analysis that relies solely on capital upgrade deferral or renewable smoothing is unlikely to provide cost-effective applications based on current ESS costs and operation and maintenance (O&M) charges. Adding market applications, especially ancillary services, can significantly improve the economics of ESS. However, market participation will add complexity into the analysis and evaluation process. The ESS sizing and technology selection has to be also carefully examined based on the operating constraints and impact on power quality of distributions systems.
- There are multiple challenges to achieve the potential benefits of ESS deployment but all are expected to be manageable and become more mainstream as new installations and ESS applications are deployed

Key Recommendations and Next Steps

- It was recommended that analysis methodologies and ESS evaluation tools similar to the ones investigated and demonstrated in this project should be considered in assessment of future ESS projects. Incorporating a commonly applied analysis tool that can evaluate various ESS applications to quantify benefits and various value-added opportunities will significantly improve the economics of the projects and will increase benefits to ratepayers.
- It would be beneficial to utilize an integrated analytical platform and associated methodologies across various business units that are involved in ESS projects from planning to operation, to ensure that estimated benefits would be properly realized in the field and during operation.
- Further standardization of the deployment aspects (engineering and controls) and proper site integration into distribution management systems for automated control and operation should also be emphasized as next critical steps.

TABLE OF CONTENTS

EXECUTIVE SUMMARY ..... **III**

List of Acronyms and Abbreviations xiii

1 INTRODUCTION **1**

1.1 Objective 1

1.2 Issues/Problems Being Addressed 1

1.3 Project Tasks and Deliverables Produced 2

1.3.1 Phase 1 - Task 1: Team Formation and Project Plan 2

1.3.2 Phase 1 - Task 2: Procurement of Contractor Services 2

1.3.3 Phase 2 - Task 1: Evaluate baseline 2

1.3.4 Phase 2- Task 2: Identify circuits and applications 2

1.3.5 Phase 2 - Task 3: Assess available tools 3

1.3.6 Phase 2 - Task 4: Propose methodology 3

1.3.7 Phase 2 - Task 5: Implement methodology 3

1.3.8 Phase 2 - Task 6: Demonstrate methodology 3

1.3.9 Phase 2 - Task 7: Additional use cases 3

1.3.10 Phase 2 - Task 8: Final Report and Tech Transfer of Project Results 3

2 ANALYSIS AND ASSESSMENTS **4**

2.1 Task 1: Baseline Evaluation and Analysis of Energy Storage Systems Applications in Use 4

2.2 Task 2: Select Circuits and Applications 6

2.2.1 Clustering Criteria 6

2.2.2 Applications 8

2.2.3 Selecting representative circuits from the clusters for further study 13

2.3 Task 3: Assessment of Energy Storage Analysis Tools 16

2.3.1 Evaluation Methodology 16

2.3.2 Degrees of complexity 17

2.3.3 Types of tools 18

2.3.4 Tool Limitations 24

2.3.5 Stacked Applications 28

2.3.6 Storage Portfolio Determination 31

2.3.7 Vendor 12 Cost Calculation Tool 6 Assessment 31

2.3.8 Conclusions 33

2.4 Task 4: Propose methodology 35

2.5 Task 5: Implementing the methodology 38

2.5.1 Circuit upgrade deferral application 38

2.5.2 Reliability Enhancement for Customers – ESS in Microgrid Application 43
2.5.3 PV Integration Mitigation..... 47

3 SUMMARY OF THE PROJECT RESULTS..... 53

3.1 Task 6: Demonstrating the methodology 53
3.1.1 Capacity Deferral..... 53
3.1.2 Reliability Enhancement for Customers – ESS in Microgrid Application 66
3.1.3 PV Integration Mitigation..... 72
3.2 Task 7: Summary Results for Additional Use Cases 87
3.2.1 Whole Sale Market Analysis..... 88
3.2.2 Application of Energy Storage for Demand Management in Commercial Buildings 101
3.2.3 Hybrid ESS Applications for Residential and Commercial Buildings 114

4 KEY FINDINGS AND RECOMMENDATIONS 125

4.1 Findings and Recommendations Related to Assessment of Existing Applications and Tools 125
4.1.1 Gap analysis and needs..... 126
4.1.2 Deployment and operational challenges 126
4.1.3 Recommendations 127
4.2 Findings and Recommendations Related to Methodologies and Tools for Assessment of Future Projects..... 128
4.2.1 Tools and methodologies..... 128
4.2.2 Gaps in commercial tools and industry practices related to technology assessment approaches 129
4.2.3 Standardization and regulatory compliance..... 130
4.2.4 ESS Projects Responsibilities 130
4.2.5 Approach Towards Markets Participation 135
4.3 Findings and Recommendations Related to Implementation of Methodology and Tools in Assessment of Future Distribution Circuits Design Practices 135
4.3.1 Tools and assessment methodologies 136
4.3.2 Applications of other similar emerging technologies in distribution systems..... 137
4.3.3 Voltage and VAR compensation assessments 138
4.3.4 Conclusions 139

5 SUMMARY OF RECOMMENDATIONS AND NEXT STEPS..... 141

6 TECHNOLOGY/KNOWLEDGE TRANSFER FOR APPLYING THE RESULTS INTO PRACTICE .. 142

6.1 Information Sharing Forum..... 142
6.2 Particular to SDGE's internal technology transfer 142
6.3 Adaptability to other utilities and/or the broader industry..... 143

7 METRICS AND VALUE PROPOSITION 144
7.1 Metrics 144
7.2 Value Proposition 147
7.2.1 Primary Principles 147
7.2.2 Secondary Principles 148
8 REFERENCES 149
9 APPENDIX 150
9.1 Additional study results for Capacity Deferral Application 150
9.1.1 BESS sizing - Centralized Upgrade Deferral for CCUD 1 150
9.1.2 BESS sizing - Centralized Upgrade Deferral for CCUD 2 153
9.1.3 BESS sizing - Centralized Upgrade Deferral for CCUD 3 156
9.2 Additional study results for Microgrid Application 159
9.2.1 BESS sizing for CMG2 159
9.2.2 BESS sizing for CMG3 163
9.2.3 BESS sizing for CMG4 165
9.2.4 CBA for Circuit CMG2 169
9.2.5 CBA for Circuit CMG3 173
9.2.6 CBA for Circuit CMG4 174
9.3 Additional study results for PV Intermittency Application 176
9.3.1 Load profile selection and daily analysis 176
9.3.2 Flicker summary results for all circuits (table format) 178
9.4 Additional study results for wholesale market participation 189

List of Figures

Figure 1-1. Primary project tasks 2
Figure 2-1. Characterizing Storage Assessment Tools 17
Figure 2-2. ESS Tool Categorization Matrix 19
Figure 2-3. ESS Tool Categorization Matrix - populated 20
Figure 2-4. Gap in available tool set for Distribution applications 34
Figure 2-5. ESS analysis approach for system applications 35
Figure 2-6. Overview of the capacity deferral valuation process as used to evaluate sample SDG&E circuits 42
Figure 2-7. ESS sizing methodology for microgrid application 45
Figure 2-8. Sample flicker calculation curve 48
Figure 2-9. Distribution Planning Tool 4 – Python interface flowchart without the battery 49
Figure 2-10. Distribution Planning Tool 4 – Python interface flowchart with the battery 50
Figure 3-1. Location of the battery for circuit CCUD 2 54
Figure 3-2. Power Flow (Centralized Upgrade Deferral) for CCUD 2 55
Figure 3-3. Battery Output Power (Centralized Upgrade Deferral) for CCUD 2 55
Figure 3-4. Battery State of Charge (Centralized Upgrade Deferral) for CCUD 2 56
Figure 3-5. Accumulative Discharge (Centralized Upgrade Deferral) for CCUD 2 56
Figure 3-6. Battery Locations for CCUD 2 57
Figure 3-7. Power Flow (Distributed Upgrade Deferral) for CCUD 2 58
Figure 3-8. ESS1 and ESS2 Output Power (Decentralized Upgrade Deferral) for CCUD 2 59
Figure 3-9. ESS1 and ESS2 State of Charge (Distributed Upgrade Deferral) for CCUD 2 60
Figure 3-10. ESS1 and ESS2 cumulative discharge (Distributed Upgrade Deferral) for CCUD 2 61
Figure 3-11. CMG1 - Microgrid Topology 66
Figure 3-12. Required kW and kWh of ESS to support load downstream of Recloser 1 for an 8 hour outage at different times of year 67
Figure 3-13. Required kW and kWh of ESS to support load downstream of Recloser 2 for an 8 hour outage at different times of year 68
Figure 3-14. Required kW and kWh of ESS to support CMG1 circuit load for an 8 hour outage at different times of year 68
Figure 3-15. Recloser 1 and 2 - SOC constraints for 8-hr outage 70
Figure 3-16. Selected PV profile for PV impact analysis 72
Figure 3-17. Reference diagram of CPVIM 1 73
Figure 3-18. Voltage profiles at the PV, F1 and F3 location on CPVIM 1 74
Figure 3-19. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 1 at PV location 75
Figure 3-20. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 1 at the F1 location 76
Figure 3-21. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 1 at the F3 location 77
Figure 3-22. Location of the battery for CPVIM 1 78
Figure 3-23. Flicker calculation curves for CPVIM 1 at PV, F2 and F3 locations after BESS installation 79
Figure 3-24. Power Flow Comparison upstream vs. downstream of BESS for CPVIM 1 (9 hours) 80
Figure 3-25. Power Flow Comparison upstream vs. downstream of BESS for CPVIM 1 (1 hour) 80
Figure 3-26. Battery active power for CPVIM 1 81
Figure 3-27. Voltage comparison at PV, F2 and F3 locations before and after Battery Installation for CPVIM 1 82

Figure 3-28. Battery accumulative charge for CPVIM 1 83
Figure 3-29. Battery accumulative discharge for CPVIM 1 83
Figure 3-30. Maximum discharge (Real-time energy market) 84
Figure 3-31. Maximum charge (Real-time energy market) 85
Figure 3-32. Minimum discharge (Regulation market) 85
Figure 3-33. Maximum discharge (Regulation market) 85
Figure 3-34. Minimum charge (Regulation market) 86
Figure 3-35. Maximum charge (Regulation market) 86
Figure 3-36. May 21, 2016 analysis (Location A) 93
Figure 3-37. June 20 2016 analysis (Location A) 94
Figure 3-38. A day in August 2016 analysis (Location A) 95
Figure 3-39. June 23 BESS Behavior with No Charging Limits 97
Figure 3-40. BESS behavior with Charging Limits 98
Figure 3-41. June 23 BESS with Hypothetical Charging Limits 99
Figure 3-42. Single Line of Benchmark Study and its Geographical Location 102
Figure 3-43. Load Annual Demand Data 102
Figure 3-44 - Sample week simulation results for the sample case 106
Figure 3-45. Outage simulation results on October 1st 107
Figure 3-46. Net present cost of project based on PV/ESS size 111
Figure 3-47. Capacity Shortage (%) based on PV/ESS size 111
Figure 3-48. Cost Summary for Energy Resources under different cost categories 112
Figure 3-49. 30-Year Cash Flow under different cost categories 113
Figure 3-50. Flowchart of the proposed study approach for hybrid system evaluation 115
Figure 3-51. Solar radiation and temperature profiles for a selected location in the study area 117
Figure 3-52. Proposed TOU-DR2 Time of Use Hourly Schedule 118
Figure 3-53. Daily and monthly electricity rate schedules 119
Figure 3-54. Annual View of Hourly impact of using battery 120
Figure 3-55. Hourly impact of using battery 121
Figure 3-56. Flow of Annual Power to Building CB1 (Total 246,723 kWh) 121
Figure 3-57. Assumption for battery degradation model 122
Figure 4-1. Planning approach 131
Figure 4-2. RACI (Responsible-Accountable-Consulted-Informed) model 134
Figure 9-1. Location of the battery for circuit CCUD 1 150
Figure 9-2. Power Flow (Centralized Upgrade Deferral) for CCUD 1 151
Figure 9-3. Battery Output Power (Centralized Upgrade Deferral) for CCUD 1 151
Figure 9-4. Battery SOC, cumulative charge and discharge for CCUD 1 (centralized) 153
Figure 9-5. Location of the battery for circuit CCUD 2 153
Figure 9-6. Power Flow (Centralized Upgrade Deferral) for CCUD 2 154
Figure 9-7. Battery Output Power (Centralized Upgrade Deferral) for CCUD 2 154
Figure 9-8. Battery State of Charge (Centralized Upgrade Deferral) for CCUD 2 155
Figure 9-9. Accumulative Discharge (Centralized Upgrade Deferral) for CCUD 2 155
Figure 9-10. Battery Location for CCUD 3 156
Figure 9-11. Power Flow (Centralized Upgrade Deferral) for CCUD 3 157
Figure 9-12. C1202 Battery Output Power (Centralized Upgrade Deferral) for CCUD 3 157
Figure 9-13. C1202 Battery State of Charge (Centralized Upgrade Deferral) for CCUD 3 158
Figure 9-14. C1202 Accumulative Discharge (Centralized Upgrade Deferral) for CCUD 3 158
Figure 9-15. CMG2 - microgrid topology 159
Figure 9-16. Required kW and kWh of ESS to support CMG2 microgrid load for 4-hour outages 160

Figure 9-17. Required kW and kWh of ESS to support CMG2 microgrid load for 6-hour outages..... 161
Figure 9-18. Required kW and kWh of ESS to support CMG2 microgrid load for 8-hour outages..... 162
Figure 9-19. CMG3- microgrid topology 163
Figure 9-20. Required kW and kWh of ESS to Support CMG3 Microgrid Load for 4-hour Outages 164
Figure 9-21. Required kW and kWh of ESS to support CMG3 microgrid load for 6-hour outages..... 164
Figure 9-22. Required kW and kWh of ESS to support CMG3 microgrid load for 8-hour outages..... 165
Figure 9-23. CMG4 - microgrid topology 165
Figure 9-24. Required kW and kWh of ESS to support CMG4 microgrid load for 4-hour outages..... 167
Figure 9-25. Required kW and kWh of ESS to support CMG4 microgrid load for 6-hour outages..... 168
Figure 9-26. Required kW and kWh of ESS to support CMG4 microgrid load for 8-hour outages..... 169
Figure 9-27. SOC constraints for 4-hr outage (without PV) 170
Figure 9-28. SOC constraints for 4-hr outage (with PV)..... 170
Figure 9-29. SOC constraints for 6-hr outage (without PV) 171
Figure 9-30. SOC constraints for 6-hr outage (with PV)..... 171
Figure 9-31. SOC constraints for 8-hr outage (without PV) 171
Figure 9-32. SOC constraints for 8-hr outage (with PV)..... 172
Figure 9-33. CMG3- SOC constraints for 8-hr outage 174
Figure 9-34. CMG4- SOC constraints for 8-hr outage 175
Figure 9-35. Load profile for CPVIM 1..... 176
Figure 9-36. Load profile for CPVIM 2..... 176
Figure 9-37. Load profile for CPVIM 3..... 177
Figure 9-38. Load profile for CPVIM 4..... 177
Figure 9-39. Load profile for CPVIM 5..... 177
Figure 9-40. Load profile for CPVIM 6..... 178
Figure 9-41. Load profile for CPVIM 7..... 178
Figure 9-42. Reference diagram of CPVIM 4..... 181
Figure 9-43. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F1 location 182
Figure 9-44 – Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F2 location..... 183
Figure 9-45. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F6 location 184
Figure 9-46. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F7 location 185
Figure 9-47. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F8 location 186
Figure 9-48. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F9 location 187
Figure 9-49. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F10 location 188
Figure 9-50. May 21st, 2016 analysis with 20% assumption (Location A)..... 189
Figure 9-51. May 21st, 2016 analysis with 50% assumption (Location A)..... 190
Figure 9-52. May 21st, 2016 analysis with 100% assumption (Location A)..... 191
Figure 9-53. June 20th analysis for 20% assumption (Location A) 192
Figure 9-54. June 20th analysis for 50% assumption (Location A) 193
Figure 9-55. June 20th analysis for 100% assumption (Location A) 194

List of Tables

Table 2-1. ESS Applications 9
Table 2-2. Summary table of the selected circuits for the upgrade deferral application 14
Table 2-3. Summary table of the selected circuits for the microgrid application 14
Table 2-4. Summary table of the selected circuits for the PV impact mitigation application 14
Table 2-5. Observations on Tools for Valuing Storage in the Wholesale Markets 27
Table 2-6. Comparison of major capabilities of tools available for evaluating energy storage applications in distribution systems and stacked benefits 30
Table 2-7. Cost Calculation Tool 6 modeled applications with source of market price, retail rate or avoided cost [11] 32
Table 2-8. Sample of typical assumptions and parameters 43
Table 3-1. Summary table of the selected circuits for the upgrade deferral application 53
Table 3-2. Required Battery Size and Projected Capital Cost 62
Table 3-3. Annual Market Revenue ($) 62
Table 3-4. Immediate T&D Upgrades NPV Costs and Revenue Requirements (in $K) 63
Table 3-5. T&D Deferral Costs and Revenue Requirements (in $K) – Battery Disposition Scenario: Out 63
Table 3-6. T&D Deferral Costs and Revenue Requirements (in $K) – Battery Disposition Scenario: In 64
Table 3-7. Overall Benefits comparing Deferral to Immediate T&D upgrades ($K) – Battery Disposition Scenario: Out 64
Table 3-8. Overall Benefits comparing Deferral to Immediate T&D upgrades ($K) – Battery Disposition Scenario: In 64
Table 3-9. Summary table of the selected circuits for the microgrid application 66
Table 3-10. Recommended ESS sizes for CMG1 67
Table 3-11. ESS sizes for CMG1 69
Table 3-12. CMG1: ESS: 450 kW, 1,350 kWh on Recloser 1 71
Table 3-13. CMG1: ESS: 550 kW, 2,200 kWh on Recloser 2 71
Table 3-14. Summary table of the selected circuits for the PV impact mitigation application 72
Table 3-3-15. NPV Table for CPVIM 2 87
Table 3-3-16. The 10 MW BESS in the Day Ahead and Real Time Energy markets for 2016 data 90
Table 3-3-17. Evaluating the 10 MW BESS Participation in Ancillary service Markets (Regulation) for 2016 data 90
Table 3-3-18. Chart Elements 92
Table 3-3-19. The 10 MW BESS in the Day Ahead and Real Time Energy markets for 2016 data with limits imposed on hourly charging at Location B 96
Table 3-3-20. Economics with limits reduced (Location B) 98
Table 3-21. Scheduled Rates for Utility 103
Table 3-22. Demand Rates for Utility 103
Table 3-23. Feasible optimization results 108
Table 3-24. Net Present Costs under different cost categories 112
Table 3-25. Annualized Costs under different cost categories 112
Table 3-26. Project Economic Metrics (Comparing with and without ESS cases, both cases including PV) 113
Table 3-27. Representative residential and commercial buildings for the Hybrid ESS analysis 115
Table 3-28. TOU-DR2 Time of Use Rate Designations 118
Table 3-29. Commercial time of use and demand rates 119
Table 3-30. Commercial time of use and demand price 120
Table 3-31. Average Cost per kWh with Time of Use Rates and Supplementary PV and Battery 123

Table 3-32. Cost and Benefit of Solar PV 123
Table 3-33. Summary of the Hybrid ESS benefit/cost analysis 124
Table 4-1. ESS size requirements for worst case reverse power flow 138
Table 7-1. Project Metrics 144
Table 9-1. ESS size recommendations for CMG2 159
Table 9-2. Recommended ESS sizes for CMG3 163
Table 9-3. Recommended ESS sizes for CMG4 166
Table 9-4. ESS sizes for CMG2 170
Table 9-5. CMG2: 4-hr outage (ESS: 750 kW, 3000 kWh) without PV 172
Table 9-6. CMG2: 4-hr outage (ESS: 750 kW, 3000 kWh) with PV 172
Table 9-7. CMG2: 6-hr outage (ESS: 1100 kW, 4400 kWh) without PV 172
Table 9-8. CMG2: 6-hr outage (ESS: 1100 kW, 4400 kWh) with PV 173
Table 9-9. CMG2: 8-hr outage (ESS: 1400 kW, 5600 kWh) without PV 173
Table 9-10. CMG2: 8-hr outage (ESS: 1400 kW, 5600 kWh) with PV 173
Table 9-11 CMG3: ESS: 800 kW, 3200 kWh 174
Table 9-12 CMG4: ESS: 2,500 kW, 10,000 kWh 175
Table 9-13. Flicker analysis summary for circuit CPVIM 1 (Fx is the monitoring point) 179
Table 9-14. Flicker analysis summary for circuit CPVIM 2 179
Table 9-15. Flicker analysis summary for circuit CPVIM 3 179
Table 9-16. Flicker analysis summary for circuit CPVIM 4 179
Table 9-17. Flicker analysis summary for circuit CPVIM 5 179
Table 9-18. Flicker analysis summary for circuit CPVIM 6 180
Table 9-19. Flicker analysis summary for circuit CPVIM 7 180

List of Acronyms and Abbreviations

AB	Assembly Bill
AES	Advanced Energy Storage
AGC	Automatic Generation Control
AMI	Advanced metering Infrastructure
ANSI	American National Standards Institute
ASET	Automated Security Enhancement Tool
BESS	Battery Energy Storage System
BOP	Balance of Plant
CAIDI	Customer Average Interruption Duration Index
CAISO	California Independent System Operator
CAM	Computer Aided Manufacturing
CAPEX	Capital Expenditure
CCUD	Circuit for Capacity Upgrade Deferral
CC	Cycle Charging
CD	Capital Deferral only
CDA	Capacity Deferral and Arbitrage
CDAAM	Capacity Deferral, Arbitrage and Ancillary Service Market
CEC	California Energy Commission
CIS	Customer Information System
COE	Cost of Energy
CMG	Circuit for Microgrid
CPUC	California Public Utilities Commission
CPVIM	Circuit for PV Impact
DA	Day Ahead
DBE	Diverse Business Enterprise
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DNI	Direct Normal Irradiance
DOE	Department of Energy
D-SCADA	Distribution SCADA
DVC	Distributed Voltage Control
EOL	End of Line
EPIC	Electric Program Investment Charge
EPS	Electric Power System
EMTDC	Electromagnetic Transient and Direct Current
ESCT	Energy Storage Cost Template
ESP	Expedited Storage Projects

ESS	Energy Storage System
EV	Electrical Vehicle
FAT	Factory Acceptance Test
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation and Services Restoration
GHI	Global Horizontal Irradiance
GRC	General Rate Case
HA	Hour Ahead
HOMER	Hybrid Optimized Model for Electric Renewables (Software)
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent System Operator
kW	Kilowatts
kWH	Kilowatt Hour
LACC	Levelized Annual Cost of Capital
LF	Load Following
LMP	Locational Marginal Price
MIP	Mixed Integer Programming
MG	Microgrid
MVA	Mega Volt Ampere
MW	Megawatts
MWH	Megawatt Hour
NASA	National Aeronautics and Space Administration
NGR	Neutral Grounding Resistor
NODES	Network Optimized Distributed Energy Systems
NOPR	Notice of Proposed Rulemaking
NPC	Net Present Cost
NREL	National Renewable Energy Laboratory
NO	Normally Open
NPV	Net Present Value
OH	Overhead
OPEX	Operating Expense
OPF	Optimal Power Flow
PEV	Plug-in Electric Vehicle
POC	Point of Connection
PSCAD	Power System Computed Aided Design (Software)
PSLF	Positive Sequence Load Flow (Software)
PPA	Power Purchase Agreement
PV	Photovoltaic
R&D	Research and Development

RACI	Responsible-Accountable-Consulted-Informed
RFP	Request for Proposal
ROC	Rate of Charge
ROCP	Rate of Change of Active Power
ROI	Return on Investment
ROR	Rate of Return
RT	Real Time
RTP	Real Time Pricing
SAIDI	System Average Interruption Duration Index
SAM	System Advisor Model (Software)
SCADA	Supervisory Control and Data Acquisition
SCC	Short Circuit Capacity
SCUC	Security Constrained Unit Commitment
SDG&E	San Diego Gas and Electric
SOC	State Of Charge
SRE	Sempra Energy
T & D	Transmission and Distribution
TMY	Typical Meteorological Year
TOU	Time of Use
TOV	Temporary Overvoltage
UG	Underground
VAF	Vanadium Redox Flow Battery
VAR	volt-ampere reactive
VBA	Visual Basic for Applications
VOM	Variable Operation and Maintenance

1 INTRODUCTION

1.1 Objective

This project module was part of EPIC-1, Project 5 on smart distribution circuit demonstrations. The objective of EPIC-1, Project 5 was to perform pilot demonstrations of smart distribution circuit features and associated simulation work to identify best practices for integrating new and existing distribution equipment in these circuits. Simulation studies were utilized to optimize a particular circuit and the desired features in that circuit to assess their suitability for widespread commercial adoption.

The focus of the project module covered in this report was to demonstrate methodologies and tools for use in enhanced technical analysis of distribution circuits and the application of energy storage systems (ESS) to resolve identified issues. Identification of potential storage projects will be enhanced by the implementation of these tools that can more effectively model the distribution system and the complex nature of ESS value propositions. Additionally, the economics can now be evaluated by using methodology and tools that maximize the ESS value by taking into account capacity upgrade deferral opportunities and CAISO market benefits, thereby "stacking" the benefits in a financial manner. Proper stacking of ESS benefits can significantly improve the cost effectiveness analysis results.

An additional objective was to make recommendations on which methodologies and tools should be used commercially by SDG&E as best practices in its future power system planning for assimilation of ESS. Recommendations were also provided towards successful deployment of ESS. These overall results will enhance and streamline both the identification and evaluation of ESS in the distribution system.

1.2 Issues/Problems Being Addressed

With the significant growth of Distributed Energy Resources (DER) and ESS on distribution systems in California, the analytical tools for circuit modeling and analysis require further modernization. Current tools used for distribution planning have typically performed static analysis dealing with loading or voltage issues during peak periods. In recent years, some of the distribution planning analysis has transitioned to an hourly analysis. Software tools that can improve this hourly analysis to a more granular level can improve the results by more accurately finding issues and solutions as well as finding unexpected distribution problems. An example of an unexpected issue is PV caused flicker. Sometimes flicker related problems are found due to customer complaints rather than analysis. It is best for the utility and the customer if problems are effectively predicted and resolved before they occur.

The overall benefit/cost analysis process for ESS needs to be enhanced so that it becomes more thorough thus helping ESS opportunities expand. When ESS is identified as a potential solution, currently the typical evaluation will be a comparison of the traditional upgrade cost versus the cost of ESS. Software tools that can also evaluate the potential CAISO market benefits and properly sum those benefits will better demonstrate the potential value of ESS. Some of the roadblocks towards wider scale deployment of ESS is the belief by some that ESS is many years from being cost effective thus receive a low priority as compared to other day to day challenges. Demonstrating the significance of the combined value can help expedite the resolution of challenges to use storage on the distribution system and in CAISO markets.

ESS installations have many similarities to traditional electric utility infrastructure, but there are also significant differences that provide opportunities for enhancements which would help maximize their

value and avoid eventual problems. Many of those challenges are related to the integration of the processes, engineering standards, and day-to-day operations. Identifying and improving those situations will also help improve the value of ESS systems.

1.3 Project Tasks and Deliverables Produced

The project was performed in two phases. The first phase incorporated the initial preparation tasks of the project which included development of the project plan and selection of the project team and contractors. Phase 2 of the project dealt with technical parts.

The tasks included in phase 1 were:

1.3.1 Phase 1 - Task 1: Team Formation and Project Plan

The SDG&E EPIC program manager identified the technical lead for the project based on experience and technical expertise. Later, the internal project team was formed by identification of technical skills and expertise available within the organization. After forming the internal project team task to develop the project plan was given to the technical lead. The technical lead with the help of the project team wrote the project plan as per the guidance provided by the SDG&E EPIC program manager adhering to EPIC guidelines.

1.3.2 Phase 1 - Task 2: Procurement of Contractor Services

Scope of the work was identified and written for the part of the project needed to be contracted out to engineering consulting firm. Standard company practices were followed for contractor selection and procurement.

The phase 2 of the project included the following major tasks (Figure 1-1):

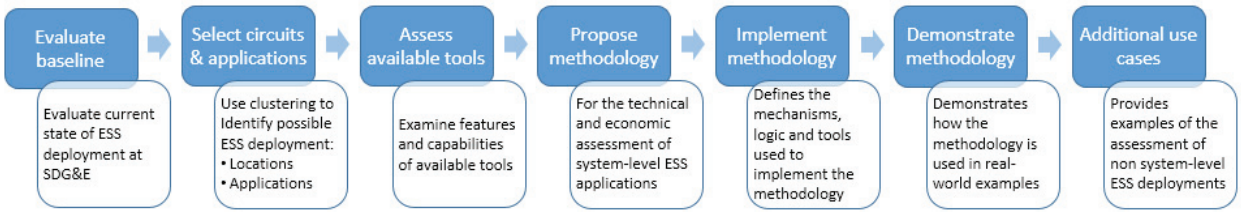


Figure 1-1. Primary project tasks

1.3.3 Phase 2 - Task 1: Evaluate baseline

This task assessed the present state of energy storage systems at SDG&E and the applications in use, as well as determination of potential areas for utilization enhancement.

1.3.4 Phase 2- Task 2: Identify circuits and applications

This task proposed a framework for identifying which distribution circuits could potentially benefit from future deployment of ESS and which applications should be considered. Using the framework, 28 feeders and 5 applications were identified and these results used in subsequent tasks to demonstrate the use of the assessment methodology developed as part of this project.

1.3.5 Phase 2 - Task 3: Assess available tools

This task assessed a number of Energy Storage Analysis tools used in the industry. The investigation covered technical analysis as well as the economics related to capital deferral and markets benefits. The results were used to select the tools used for the remainder of the project.

1.3.6 Phase 2 - Task 4: Propose methodology

This task proposed a methodology to be used to analyze the technical and economic viability of deploying ESSs on the SDG&E distribution system.

1.3.7 Phase 2 - Task 5: Implement methodology

This task provided a detailed description of the mechanics involved in applying the various steps of the methodology developed in the preceding task, for three different types of system applications.

1.3.8 Phase 2 - Task 6: Demonstrate methodology

Using some of the circuits identified in Phase 2 - Task 2, this task demonstrated how the methodology can be applied to real-world cases.

1.3.9 Phase 2 - Task 7: Additional use cases

This task analyzed three additional use cases that utilized portions of the methodology on single facility end use (non-system) related applications.

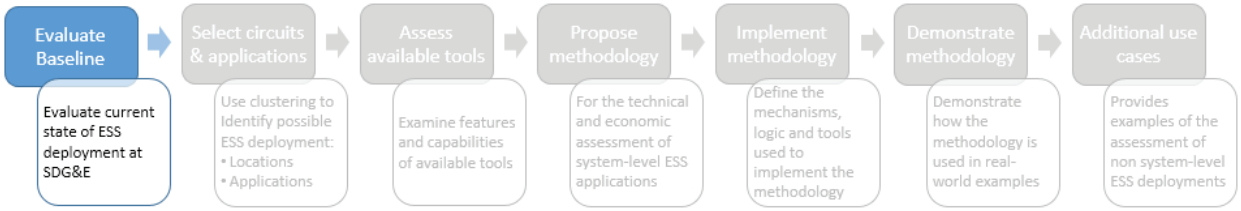
1.3.10 Phase 2 - Task 8: Final Report and Tech Transfer of Project Results

This was the final project task and included two key activities: a) Preparation of the draft and final report for the project, and b) Knowledge transfer plan and demonstration session for utilization of the methodology and tools.

2 ANALYSIS AND ASSESSMENTS

This section provides a summary of the tool evaluation performed and development of methodology to analyze ESS applications.

2.1 Task 1: Baseline Evaluation and Analysis of Energy Storage Systems Applications in Use



Early in the project, a series of brainstorming sessions were held with multiple SDG&E groups and stakeholders. Additional follow-up sessions were conducted with specific organizations who were determined to have more direct involvement and critical roles in ESS projects in the future. The sessions were used to understand the current process for ESS selection and deployments, as well as to identify their ESS related responsibilities and to discuss suggestions and opportunities to improve the process and value received from ESS. The groups interviewed included:

- Electric Generation
- Market Operations
- Advanced Technology
- Distributed Energy Resources
- Electric Distribution Operations
- Distribution Planning
- Substation Engineering
- Distributed Energy Management Systems
- Customer Generation
- Distribution Reliability
- Facilities
- Customer Services

The findings from the interviews were utilized in the assessment of the tools required and also in the development of a viable methodology comprehensive enough to address various key aspects of the ESS project life cycle.

Through June 2017, SDG&E has installed a significant amount of ESS in its service territory, primarily driven by regulatory requirements and reliability improvement needs.

There are two types of ESS connected to the distribution system:

- Seven large ESS site ranging in size from 1 MW to 30 MW, connecting to 12 kV substation buses or across the circuits.
- Community type ESS sites ranging in size from 25 kW to 200 kW.

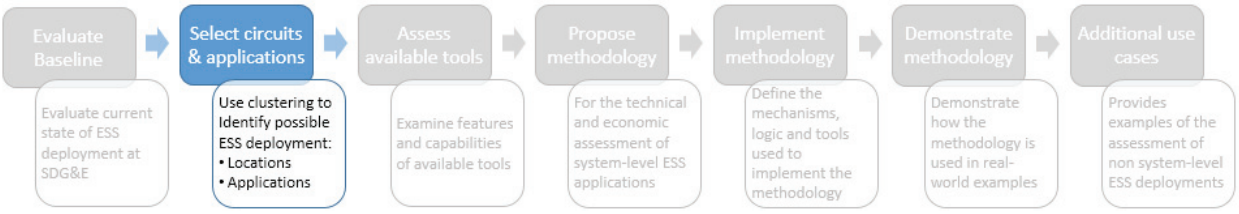
Overall SDG&E has 30+ battery systems in operation, with a combined capacity of 104 MW. This 104 MW of energy storage achieves 63% of a CPUC approved Assembly Bill (AB) 2514 requirement of 165 MW. While 104 MW of ESS is in place, SDG&E-owned storage is about 44.5 MW (43%) with most going

operational in 2017. There are two large ESS Projects in progress that will achieve the overall 165 MW requirement by adding an additional 70 MW combined ESS at two different substations.

These installations have provided excellent experience on the procurement, installation and operation of ESSs.

Besides the expected reliability benefits, much of the early deployments were implemented with expectations towards significant learnings about the technological capabilities, installation requirements, and operational opportunities towards resolving distribution system issues. The recent ESS projects were also targeted toward participation and experience with wholesale market.

2.2 Task 2: Select Circuits and Applications



The objective of this task was to develop a framework for identifying which distribution circuits could potentially benefit from future deployment of ESS, analyzing which applications should be considered and then creating a list of actual circuits to be used elsewhere in the project. It did this by:

- Identifying common parameters and characteristics that could be used as criteria to group circuits together into clusters that shared similar attributes.
- Identifying the ESS applications most suitable for use with these different clusters of distribution circuits.
- Using the framework to select a number of representative circuits that could potentially benefit from the deployment of ESS and which were used in the remainder of the project to test the concepts, tools and methodologies proposed.

The benefit of performing detailed analysis on the technical and cost/benefit implications of ESS deployment on a small representative sample of the different clusters is that it becomes a relatively simple matter to extrapolate the impacts of ESS deployment on a much larger scale.

2.2.1 Clustering Criteria

The approach to defining the criteria used to group circuits together into clusters that shared similar attributes involved two steps:

- Step 1: Identify typical distribution system issues that can be mitigated by an ESS,
- Step 2: Determine key circuit characteristics from an ESS deployment perspective

Working with distribution planning groups, the findings from each step were discussed and ultimately several representative circuits and potential sites were selected for each target application. The two steps utilized in this process is described below.

Step 1: Identify System Issues that an ESS can mitigate

System Issues that can be mitigated by the deployment of an ESS include:

- **Load management,** to flatten the profile and reduce peak load durations that can exceed thermal limits of conductors or circuit/substation apparatus (circuit breakers, switches, line reclosers, circuit ties, voltage regulation devices, transformers, etc.).
- **PV generation management**, to better correlate load and generation time locally and avoid excessive reverse power flow that can affect the operation of voltage control devices or cause power quality issues (voltage, flicker, harmonics, etc.).

- **Voltage and reactive power support**, to prevent significant over/under voltage situations due to excess generation or fast-changes beyond the regulation capability of feeder voltage control devices.
- **Intermittency and ramp rate management**, to improve firm capacity of PV systems and control ramp rate.
- **Circuit reliability enhancement,** to avoid sustained outages in areas without circuit ties and alternative solutions for supplying customers during outages caused by equipment/cable failure (with minimum time to repair of 8 to 10 hours typically), and any areas with CAIDI more than 100 minutes. This incorporates customers on radial circuits, branches and boundary areas.
- **Backup supply for mission-critical utility services and infrastructure,** such as communication towers in back-country , or utility infrastructure in Fire Prevention zones
- **Backup supply for critical customers,** such as military bases, hospitals, government buildings, data centers, etc.
- **Any others known distribution impacts of DERs**, such as protection coordination issues and unintentional islanding scenarios.

Step 2: Determine key circuit characteristics

Key circuit characteristics from an ESS deployment perspective that can be used to group the circuits and ESS sites as clusters with common characteristics and behavior, include:

- List of circuits with known voltage or power quality issues, or prone to show power quality problems, such as:
  - Circuits with customer complaints
  - Very long circuits (over 20 miles)
  - Circuits with major load center away from substations
  - Circuits with large PV/DG toward the end of line
  - Circuits that have more than 3 sets of voltage regulator on one backbone
  - Circuits with Short Circuit Capacity (SCC) less than 150 MVA at substation or less than 35 MVA at the end of line (EOL)
  - Circuits with minimum day-time load less than 1 MW (very lightly loaded)
  - Circuits with peak to minimum load ratio more than 10
  - Others relevant criteria.
- List of circuits serving critical customers such as: water treatment facilities, military/navy bases/facilities, airports, hospitals, etc.
- List of circuits with large customers (more than 3 MW peak load)
- List of distribution substations with radial supply (one major feeder)
  - Distribution substations at the end of a radial feeder with no alternative supply path
  - Substations that will be on critical operator watch list during maintenance, when they have no alternative feeder during schedule maintenance or contingency events with one feeder out (abnormal condition)
- List of circuits with existing high PV penetration (% PV rating to the circuit kV rating > 50%) – nameplate
- List of circuits approaching maximum hosting capacity for DER interconnections by limiting category:

    - Steady state voltage limit (Vpu < 0.93 or Vpu > 1.07)
    - Temporary voltage limit (TOV > 1.8 pu for more than 5 cycles)
    - Thermal limit (current > 600 A)
    - Flicker limit (ΔV > 3%)
    - High generation to minimum load ratio (Gen(rated)/L(min) > 0.75)
    - Significant change in short circuit capacity on the circuit (SSC(with DER) / SSC (without DER) > 150%)
    - Other relevant criteria
- List of circuits or substations with large load growth, approaching thermal limit in the next 2-5 years
- List of circuits suggested for re-conductoring in the next 5 years
- List of circuits known with high percentage losses or low power factor
- List of circuits with overhead conductor more than 80% of circuit length
- List of circuits with FLISR schemes activated on them (for re-configuration)
- List of circuits with no-tie to any other circuit for re-configuration
- List of boundary circuits/substation in areas with limitations in circuit extension
- List of circuits with high adoption rate of Electric Vehicles
- List of circuits on CPUC emergency load curtailment list (rotational outage list during emergency)
- List of worst performing circuits or circuits with CAIDI more than 100 minutes or CAIFI more than 0.5 (and main root-cause of outage)

2.2.2 Applications

ESS applications considered in this project fall into one of five categories:

- Wholesale
- Transmission
- Generation
- Distribution
- Behind-the-meter

And within each of these domains, there are multiple sub-domains of applications. Those storage applications which are being pursued today in commercial or pilot projects are tabulated in Table 2-1 below. There are other potential applications such as the provision of synthetic governor or inertial response and putative distribution system ancillary services that are nascent and not listed.

Table 2-1. ESS Applications

Domain	Sub-Domain	Applications
Wholesale	Energy Markets	Day Ahead Markets
		Hour Ahead Markets
		Real Time Energy
	Ancillary Service Market	Regulation
		Ramping
		Spinning Reserve
		Quick Start Reserve
		Black Start
Transmission	Congestion Relief	N-0 Congestion Relief
		N-1 Congestion Relief
	Capacity /Operability	VAR Support
Generation	Scheduling	Curtailment Management
		Self Firming
		Smoothing
	Market Participation	Time Shifting / Arbitrage
		Wholesale Products per Above
Distribution	Capacity	Upgrade Deferral
	Renewable Integration	Back Feed Prevention
		Voltage Control
		PV Smoothing (Flicker Control)
	Local Resiliency	Islanded Circuit Operation
Behind the Meter	Bill Management	Demand Charge/Peak Shaving
		Time Shifting (TOU or RTP) / arbitrage
	Reliability	Islanding / Off Grid

	Outside of project scope – non-distribution

The distribution-focused ESS applications are described in the sections that follow:

2.2.2.1 Wholesale

- Day Ahead Energy – arbitraging prices across time or time shifting energy. (called DA henceforth)
- Hour Ahead Energy – same issue, but performed as part of the hour ahead hourly energy bidding/award process instead of the Day Ahead process. (called HA henceforth)

- Real Time Energy – same issue, but performed against the intra hour dispatching process. (called RT henceforth)
- Regulation – providing regulation service and the ability to respond to 4 second AGC signals from the grid operator. (Called REG henceforth)
- Fast ramping. This is a product particular to California today although under consideration elsewhere.
- Spinning Reserve – ability to provide rapid response to the grid operator against a large generator contingency and to provide that energy for sufficient time for the grid operator. While requirements for DA, HA, RT products vary in detail from one market to another, requirements for "reliability" products such as spinning reserve are determined ultimately by NERC, note.
- Non-spin or quick start reserve – a product with slightly slower response requirements than spin which is aimed at hydroelectric and gas turbine generation, among others, than can reliably be started in minutes.
- Blackstart – Generators which normally require power from the grid in order to start can qualify as able to provide black start services with the installation of energy storage sufficient to power them through startup. This accesses a revenue stream for these units and also helps the state with maintaining black start capacity in the face of plant retirements.

2.2.2.2 Capacity Deferral

The capacity deferral application uses the storage discharging to reduce upstream circuit load where the loading is projected to exceed ratings in the near term. In other words, capacity deferral shaves peaks by discharging on peak and then to charging off peak.

Centralized model

In many circuits the circuit element affected first by load growth is the station exit cable, which may be underground. Aerial space over the station apparatus is frequently in short supply and a short underground cable to a riser pole is a typical solution. This cable often has a rating that is more restrictive than the overhead conductors, and replacing it is costly. In this instance, the battery can be located adjacent to the station and is referred to as a "centralized" capacity deferral application. Such a location can also help with capacity issues at the station transformer level when the N-1 rating after an outage of one of 2 or 3 units causes overloads at peak hours.

Decentralized model

When the ratings issues are with the overhead or underground conductors, then storage must be located along the feeder downstream of the overloaded section. Such a solution is a "distributed storage" capacity upgrade deferral application. Analyzing this application really requires a distribution load flow with a time series solution so that the effect of storage discharging and the control algorithm that each battery employs can be validated along with the sizing. It is also possible in this application to gain some additional capacity by power factor correction to unity on a time varying basis, which can be done with inverter based storage as opposed to switched capacitors.

When the BESS is far down the feeder, and on the secondary, it has the potential to relieve overloads/peak shave all along the feeder back to the station and at the station. However, the size of a BESS located on the secondary is necessarily much smaller than a BESS in the station or on the MV

feeder. Consequently, to achieve capacity deferral with such BESS it will be important to exploit multiple BESS.

Capacity deferral is only needed at peak hours – so is not used year-round. It is a natural extension to use the peak shaving year round and also to optimally discharge and recharge the battery to minimize the costs of wholesale energy as delivered to the feeder, that is, at the appropriate locational marginal price. It is also possible to estimate potential revenues from using the battery in the more lucrative ancillary markets, if and when this is allowed by state and federal regulators and by the ISO. Because capacity deferral is reducing peak loads, it "fits" or is compatible with market applications in general although regulation services are typically most valuable at peak as well so the allocation of battery capacity for regulation has to take a second position behind the mandatory peak shaving usage.

2.2.2.3 Renewables Integration

The Renewable Integration application set has three parts:

- One is to perform a form of peak shaving on the net circuit flow in the other direction, to prevent back feed or the condition where net flow from the feeder is back into the station. This may or may not be an issue for the utility, depending upon the particulars of the protection equipment.
- A second is to ensure that the absolute voltage level along the circuit is within ANSI standards. This is best accomplished by using excess capacity from the battery inverter to supply and withdraw VAR from the circuit.
- A third is to avoid flicker caused by excessive rate of change of voltage due to PV variability.

Back feed Prevention

Back feed prevention is performed similarly to capacity deferral, except that storage charging is used to increase feeder load and avoid negative load (back feed) at off peak hours when PV production is highest (i.e. weekend afternoons on moderately hot/cool days in April/May). The algorithms for managing the battery are similar to that for managing capacity deferral. Depending upon the ISO market back feed prevention may or may not be compatible with optimizing wholesale energy costs. At high PV penetration in the market, prices may be low when PV production is peaking, and back feed prevention is then compatible with optimizing market costs. But in other situations, this may not be the case. The same potential constraints with providing ancillaries exist as with other applications – there are hours where charge/discharge capabilities are limited and ancillary services offers must be limited.

Voltage Control

The control of voltage level is best done by using the battery inverter to inject/withdraw VAR at the circuit location. The control algorithm looks at the filtered circuit voltage that is being controlled (typically and best at the battery as then no communications are required) and controls the VAR output. The VAR output will impose limits on the kW charge discharge, which in turn limits the amount of capacity available for other applications. By increasing the inverter size beyond the battery power rating this capability can be provided without limiting battery usage for other applications. While it is theoretically possible to perform the same function by varying battery power output, this will interfere with other applications and might be incompatible with them. The use of the inverter and reactive output is generally preferable and less costly as well as no additional energy storage capability is

needed. To maximize the benefit, the battery should be as close to the focus of PV production or where the circuit voltages are most affected, but this only affects inverter sizing somewhat.

Because PV production may cause overvoltage for hours at a time, controlling this with battery charging would require longer duration batteries, running up the costs. Unless justified by price / time arbitrage as with capacity deferral, this is uneconomical as compared to using VAR for voltage control.

Sizing the battery for this in general requires running a time series of load and PV profiles on a distribution load flow, with an external algorithm controlling the inverters (on a 10 second time step, typically) so as to manage the absolute voltage level. The control algorithm has to be coordinated with the control algorithm that is providing flicker control as well. Less effective measures can include:

- Performing the circuit analysis at on and off peak loads and at peak and nil PV production to attempt to measure worst case voltages, and then determining the amount of VAR injection required to maintain acceptable voltage levels. This approach can work but can be in error as the worst voltages may be at the point when local PV production versus local load is maximum or some other combination. In other words, the sampling approach is not guaranteed to find the worst case. This is especially true if different circuit locations have radically different load profiles (customer types) as well as concentrations of PV.
- Attempting to estimate circuit voltage impact by considering the amount of PV production minus load and the local circuit short circuit impedance. This estimates the voltage effect of a given power injection. As with estimating PV hosting capacity, this approach has proven inaccurate in practice. Spreadsheet based approaches that use circuit length and voltage, peak load, and PV penetration to estimate battery sizing (and costs) for voltage control are therefore rough estimates only and not valid for business case much less engineering estimates.

Flicker Control (PV Smoothing)

Flicker is defined as a rate of change of voltage up or down that exceeds ANSI standards and which would cause lighting to noticeably vary. Voltage flicker is caused /aggravated by PV variability due to scattered cloudiness. The flicker phenomenon can be controlled via rapid variation of local battery charging/discharging so as to slow the rate of the combined PV/battery power injection to within limits. That is, when the PV production is dropping, the battery discharges at a rate so as to temporarily smooth the PV variation and reduce the rate of change of voltage to within limits. Because the rate of change calculation is “noisy” (i.e., Differencing voltage samples across time steps) some filtering is needed but the filter design cannot itself mask effects that must be controlled. Because the level of power charge/discharge is only as great as the PV itself, and the duration short (minutes at most) the battery size is modest. This makes this a cost-effective application when the alternative is re-conductoring to stiffen the circuit voltage response.

As with controlling voltage level, it is conceivable to develop rules of thumb instead of performing time series analysis to size the battery. And as with voltage control and PV hosting, such sampling or rule of thumb estimates will be inaccurate.

2.2.2.4 Local Resiliency – Microgrids / Islanding

There are instances when “normal” circuit N-1 measures (normally open ties to adjacent circuits) are not available or would be prohibitively expensive and so circuit sections near the end of a circuit cannot be

switched to alternate supply in the event of an upstream outage. Such instances can be found at the "edges" of a network where adjacent circuits are not convenient. When the edges are imposed by physical/geographic factors such as rivers, bodies of water, mountains/canyons, forests, etc., poor reliability at the end of the circuit may be the case and lack of an N-1 alternative aggravates the situation. Pilot projects as at Borrego Springs have demonstrated that battery storage, possibly in conjunction with local Distributed Generation, may be a viable alternative in these cases. The size of the battery is determined by the amount of load, net of DG and Demand Response, which must be carried. The energy/duration of the battery is determined by the load profile over time and the expected time to repair.

Because the battery must be available for islanded duty whenever an outage might occur, a minimum state of charge to meet the outage energy needs and restoration times must be maintained. This puts constraints on other uses for the battery. Depending upon circuit load profiles across the year and load factor, as much as 50% of battery capacity could be available for market participation on different days / at different times. Also, depending upon circumstances, at some times during the year it may make operational sense to completely restrict battery usage to islanding – as during forest fire season, during a hurricane watch, and so forth.

2.2.3 Selecting representative circuits from the clusters for further study

The clustering results and circuit/substation selected list were used to:

1. Collect data for representative circuits per cluster and evaluate information such as:
   - Historical load profiles, – at least 1 year for circuits associated with each circuit
   - Available/expected DG capacity and potential impact or possible penetration limitations
   - Site representative PV profiles (high resolution) and historical generation levels
   - Historical power quality and reliability data and/or any records of major outages or reliability issue associated with a circuit or cluster.
2. Obtain up-to-date planning model for each circuit
3. Identify load growth in the area/circuit,
4. Identify existing and expected amount (and distribution) of DERs (PVs , Wind, etc.) on each corresponding circuit,
5. Investigate circuit maps and planning models showing all critical devices, sections with thermal limits, and methods of voltage and reactive power management,
6. Examine any known circuit restrictions or operation difficulty,
7. Document any special operating procedures and circuit conditions that can affect ESS installation or operation,
8. Identify ESS applications that should be evaluated per cluster,
9. Determine the number, capacity and potential locations for ESS deployment by application categories and usage per cluster and to rank the clusters
10. Prepare a summary report on clustering criteria and methods, as well as findings from the system characterization in terms of any system impact that requires mitigation and the gaps in the measurement, monitoring and operation to support the assessments
11. Evaluate the SCADA monitoring and field connectivity for the cluster circuits.

By applying the clustering criteria, candidate circuit and substations were ranked and and/or locations for possible ESS deployment identified for each of the following application areas:

- Capacity upgrade deferral — 3 circuits
- Community microgrid applications — 4 circuits
- PV impact analysis and potential voltage issues — 8 circuits
- Whole sale market analysis — 2 locations (one at substation, one on a circuit)
- Single facility energy storage — 2 locations
- Multiple family housing — 4 locations

Table 2-2, Table 2-3, and Table 2-4 list the parameters of the shortlisted circuits for capacity upgrade deferral, community microgrids and PV Impact which were the results of identifying representative circuits and locations from the clustering analysis. The actual circuit identifiers have been replaced with generic identifiers; Circuit Capacity Upgrade Deferral (CCUD x), Circuit Microgrid (CMG x) and Circuit PV Impact (CPVIM x).

Table 2-2. Summary table of the selected circuits for the upgrade deferral application

Circuit ID	2019 forecasted load (A)	Average forecasted load growth per yr 2019 to 2021	SDG&E Ampacity (A)	Distribution Planning Tool 4 Ampacity (A)	Circuit PV Size (kW)	Number of Capacitors	Number of Voltage Regulator	10 yrs Capacity (MVA)
CCUD 1	369	3.30%	408	395	981	1	0	10.4
CCUD 2	564	1.30%	600	580	580	1	0	13.5
CCUD 3	558	1.40%	600	580	935	1	0	13.5

Table 2-3. Summary table of the selected circuits for the microgrid application

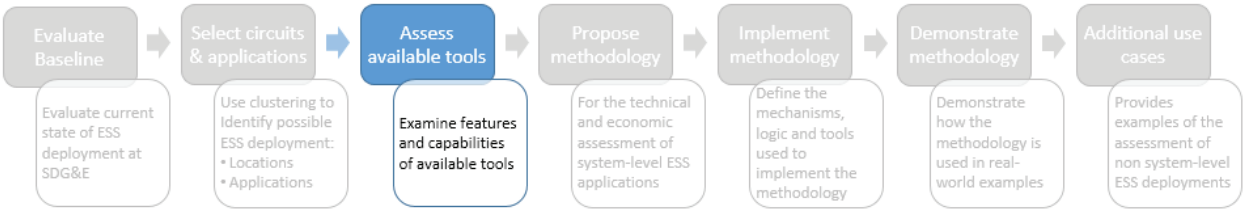
Circuit ID	# customers in MG Area	Peak load for MG [kW]	Minimum load for MG [kW]	MG Resources	# of Capacitors	# of Voltage Regulator
CMG 1	Whole circuit: 263 Recloser 1: 55 Recloser 2: 146	700	0	ESS only	1	0
CMG 2	255	712	0	ESS + PV	0	2
CMG 3	281	616	6	ESS only	0	1
CMG 4	837	2,064	0	ESS only	1	6

Table 2-4. Summary table of the selected circuits for the PV impact mitigation application

Circuit ID	PV Size (kW)	Dominant PV Type	Peak Circuit Load (A)	Minimum Day Time Circuit Load (A)	# of Capacitors	# of Voltage Regulator
CPVIM 1	8,955	Centralized	407	-5.38	5	3
CPVIM 2	7,128	Centralized	254	-5.23	2	2

Circuit ID	PV Size (kW)	Dominant PV Type	Peak Circuit Load (A)	Minimum Day Time Circuit Load (A)	# of Capacitors	# of Voltage Regulator
CPVIM 3	4,918	Distributed	470	-0.82	3	0
CPVIM 4	4,188	Distributed	479	-0.2	3	0
CPVIM 5	4,066	Distributed	454	-0.74	2	0
CPVIM 6	4,045	Distributed	467	-0.92	2	0
CPVIM 7	3,725	Distributed	490	-0.17	0	1
CPVIM 8	3,710	Distributed	501	0.9		

2.3 Task 3: Assessment of Energy Storage Analysis Tools



A list of Energy Storage Analysis tools in common use in the industry was compiled and the individual tools assessed. The results were used to select the tools utilized in the remainder of the project.

2.3.1 Evaluation Methodology

A comprehensive review of literature, publications, reports, and any information on available ESS tools and ESS assessment approaches in the public domain and/or from previous SDG&E projects was performed. Several ESS tools were identified and evaluated: such as tools developed by Vendor 12, Vendor 1, Vendor 6, and a few ESS assessment tools that are considered as integral parts of commercial planning software tools. Where information was available on proprietary tools used by consulting/ engineering companies and storage developers these were also considered.

The different tools were characterized by tool types and their intended purpose(s) itemized. A set of high level functional requirements for different purposes was developed. The focus was placed on the use of storage tools for (a) actual project design and evaluation and (b) developing a roadmap and business case for a system level portfolio of storage projects. A gap analysis against the needs of these two purposes was performed.

In addition, the task also included the investigation of any SDG&E in-house developed tools and/or any ESS analyzing tools used by major US Investor Owned Utilities such as Southern California Edison, Commonwealth Edison, Duke Energy, or others - to the extent that information was available - to facilitate selection and/or enhancement of an ESS planning and analysis tool that can support development of an ESS utilization roadmap.

For the purposes of this report, the tools were evaluated along several dimensions:

- The range of storage applications and technologies covered
- Degree of rigor in modelling and analysis
- Ease of achieving specificity to particular geographies, utilities, jurisdictions
- Ease of achieving specificity to a particular project and basing storage project design on tool results

This is shown graphically in Figure 2-1. The vertical axis, “integration and ease of use,” measures the extent to which the tool can utilize data from other analytical tools such as commercial production costing or distribution load flow software, and to how easy it is to make use of that data. The horizontal axis, range of applications addressed, characterizes which set of storage applications a tool covers. Some tools focus on a particular domain such as wholesale market benefits whereas others purport to cover all applications. The third axis, rigor, accuracy, and specificity address whether a tool will provide engineering level quantitative results for a specific storage implementation on a specific circuit or is simply a broad range of estimated benefits for a class of applications/locations.

As examples to illustrate these characterizations, the Vendor 5/6 tool, Technology Selection Tool 1, purports to cover all applications but only gives a broad range of potential benefits for each, and does not integrate with any other tools. The Vendor 12 tool Cost Calculation Tool 6 addresses multiple applications and can be made to be specific to a particular location and implementation, but it does not directly integrate with other tools and requires user effort to import relevant data from circuit analysis tools, for instance.

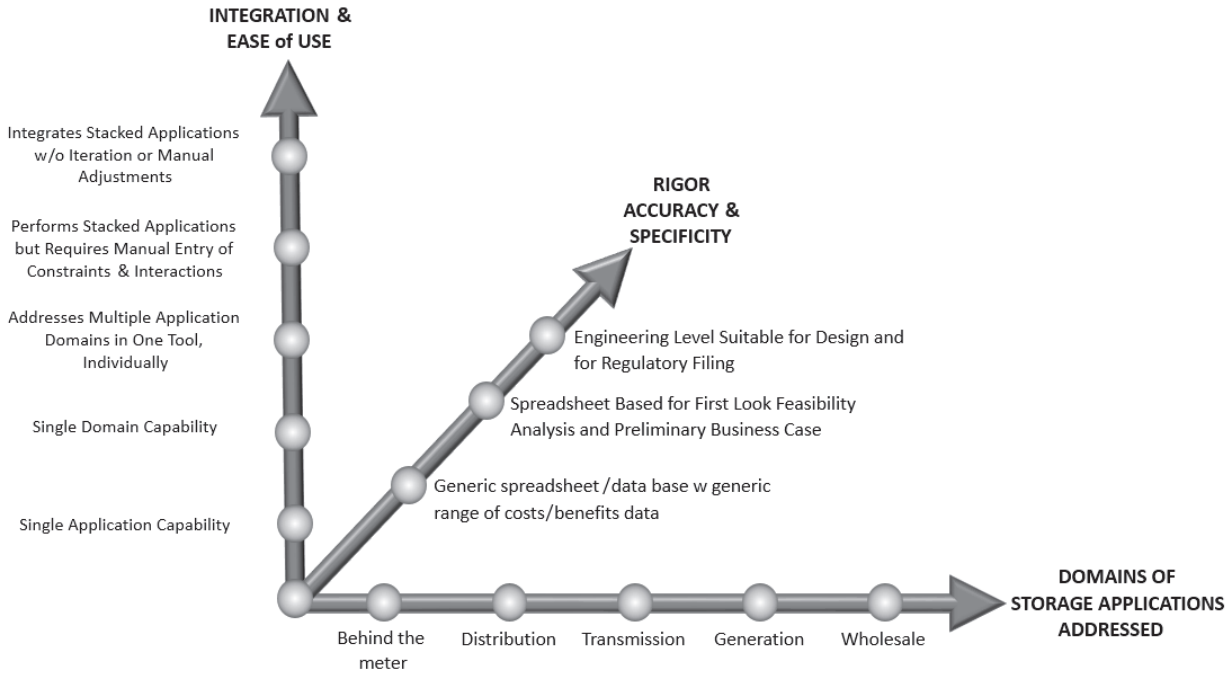


Figure 2-1. Characterizing Storage Assessment Tools

2.3.2 Degrees of complexity

In some cases, it is straightforward to estimate the "value" of a storage resource against a single application. For instance, to estimate the value of a battery that is dedicated to wholesale regulation services, it is possible to simply load historical hourly cleared regulation prices into a spreadsheet and sum the potential revenues for providing a MW of regulation up/down for a year. With a little more effort, some more complex applications can be similarly valued. For instance, the avoidance of retail demand charges can be estimated in a spreadsheet by loading the particular load profile (for a year) into a spreadsheet and computing the energy above the threshold every day, then using that to both size the battery and estimate the savings.

Other applications and combinations of applications require something more sophisticated than a simple spreadsheet. For instance, a typical question would be "determine the value of a storage asset in the wholesale markets" This requires determining how to co-optimize the use of the battery in the different energy and ancillaries markets across each day, considering the limitations on battery power rating and energy rating/duration. Doing this across an entire year may be beyond the capabilities of the embedded EXCEL SOLVER and it may be desirable to access a more capable optimization engine, perhaps in a different formulation in a tool such as Matlab.

The market applications pose one degree of difficulty in assessing the economics of a storage project. The storage costs are known, and the market prices are known so that it is only necessary to determine the best use of the storage asset and compute the market revenues from that use. In other domains, the problem is more complicated as the valuation involves comparing the cost of the storage asset to the cost of addressing the problem by other means.

For example, the distribution capacity deferral can be a straightforward task in terms of determining the size and charge/discharge profile of the battery, using a spreadsheet against the circuit load profile and rating as with the retail demand management example. Then the cost of the storage project can be estimated. However, this must be compared to the avoided cost of the deferral, and then a decision made as to how long the upgrade is deferred (which may affect the battery size if load continues to grow). The amount of conventional distribution investment needed to accommodate a given future load growth may vary widely according to the type of circuit (overhead, underground, urban underground secondary network), its voltage level, the length of the circuit, and whether there are adjacent circuits with spare capacity available. While it may be possible to estimate this avoided cost with rules of thumb, that may only be usable for a feasibility study and the actual business case will require the actual engineering design and costing to be done. Finally, the avoided cost is a regulatory asset so the details of how a given utility values regulated capital projects has to be mirrored in any analysis.

The industry uses the term “stacked applications” to refer to the case when a given storage resource is performing multiple applications across domains. Examples of this include a battery that is primarily performing a distribution application such as capacity deferral but which is also used (conceptually, today) to realize revenues from providing wholesale market ancillary services. In general, we employ the term stacked applications to refer to combinations of applications which cross domains in the taxonomy above. Distribution storage could be used to participate in a scheme for transmission congestion relief. Behind the meter storage could conceivably provide wholesale services or distribution capacity deferral. Valuing stacked applications is typically complex and few tools today do this with any pretense of analytical rigor. None do it easily from a user perspective. In order to do this accurately the tool must:

- Have a priority for which application takes precedence over others or which application imposes constraints on others. For instance, the distribution capacity deferral application takes precedence over market applications, or maintaining sufficient state of charge for an expected outage in a local resiliency application takes precedence over other applications.
- Assess the value in both domains (as in wholesale and distribution) with a degree of analytical rigor and accuracy appropriate to that domain. This means, in general, that at least two sets of tool types must be applied in an integrated way – combinations such as distribution load flow and market optimization, or optimal power flow and production costing.
- Where a tool in one domain may not currently support storage as an object or model element in the tool with any detail, some external simulation of storage may be required to gain fidelity. The means by which this can be accomplished and the user friendliness and flexibility of doing so are then key issues.

2.3.3 Types of tools

For the purposes of comparison, the different tools available in the market were categorized based on two parameters:

- Domain(s) served
- Area(s) of focus

In addition, in broad strokes, the different tools trace their lineage back to one of six areas:

- Feasibility analysis
- Technology selection
- Cost calculations
- Distribution studies
- Transmission studies
- Production costing

The combination of these attributes is shown graphically in the categorization matrix below (Figure 2-2).

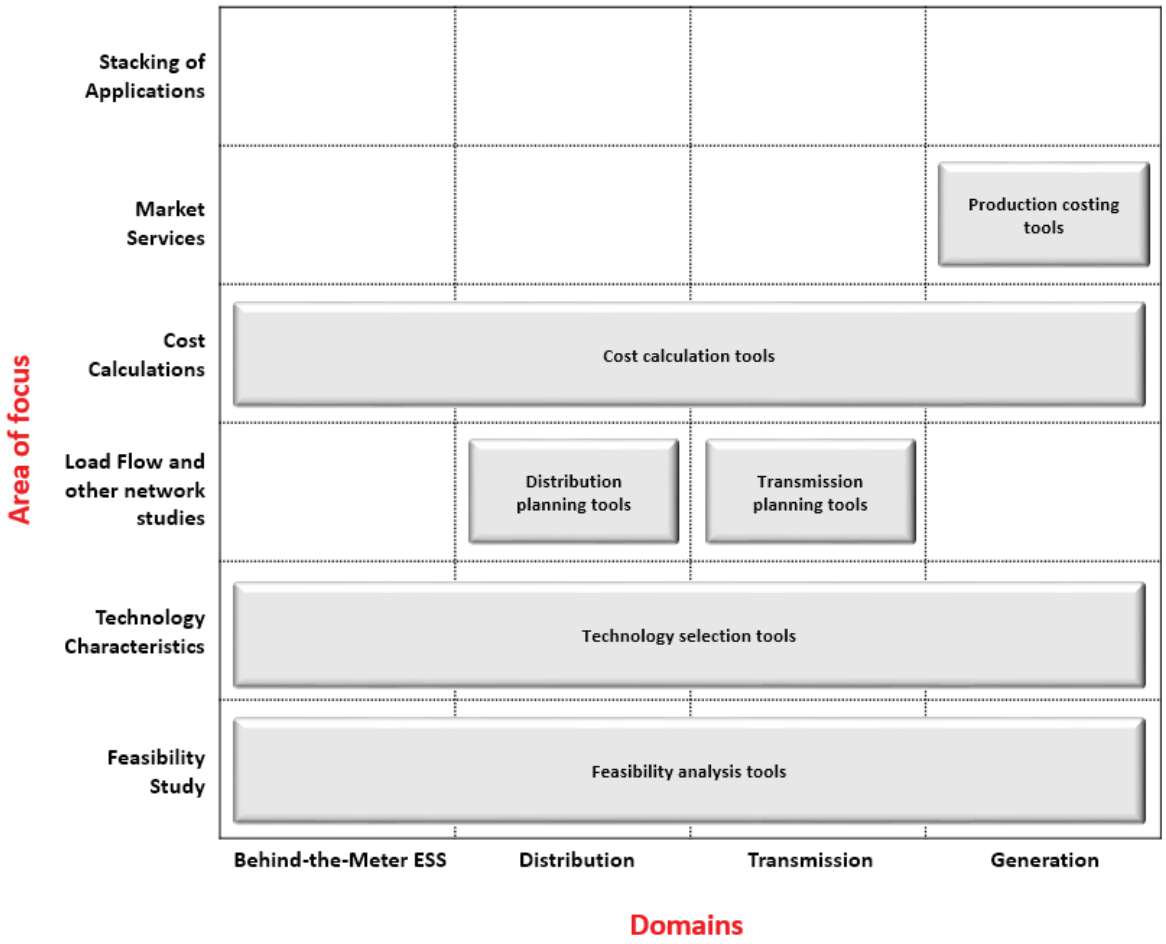


Figure 2-2. ESS Tool Categorization Matrix

One final tool characteristic is whether the tools are commercially available (marketed and sold), publicly available (available for free download and use), or custom (in use by their creators, but not available to others).

One danger of trying to compare and contrast software tools is that their features and functions are dynamic, making any comparison almost immediately stale. The populated matrix that follows (Figure

2-3) must therefore be viewed in that context. Furthermore, there are several tools that are briefly described in the sections that follow that are not shown on the matrix because they fall into the category of not available to anyone other than their creators.

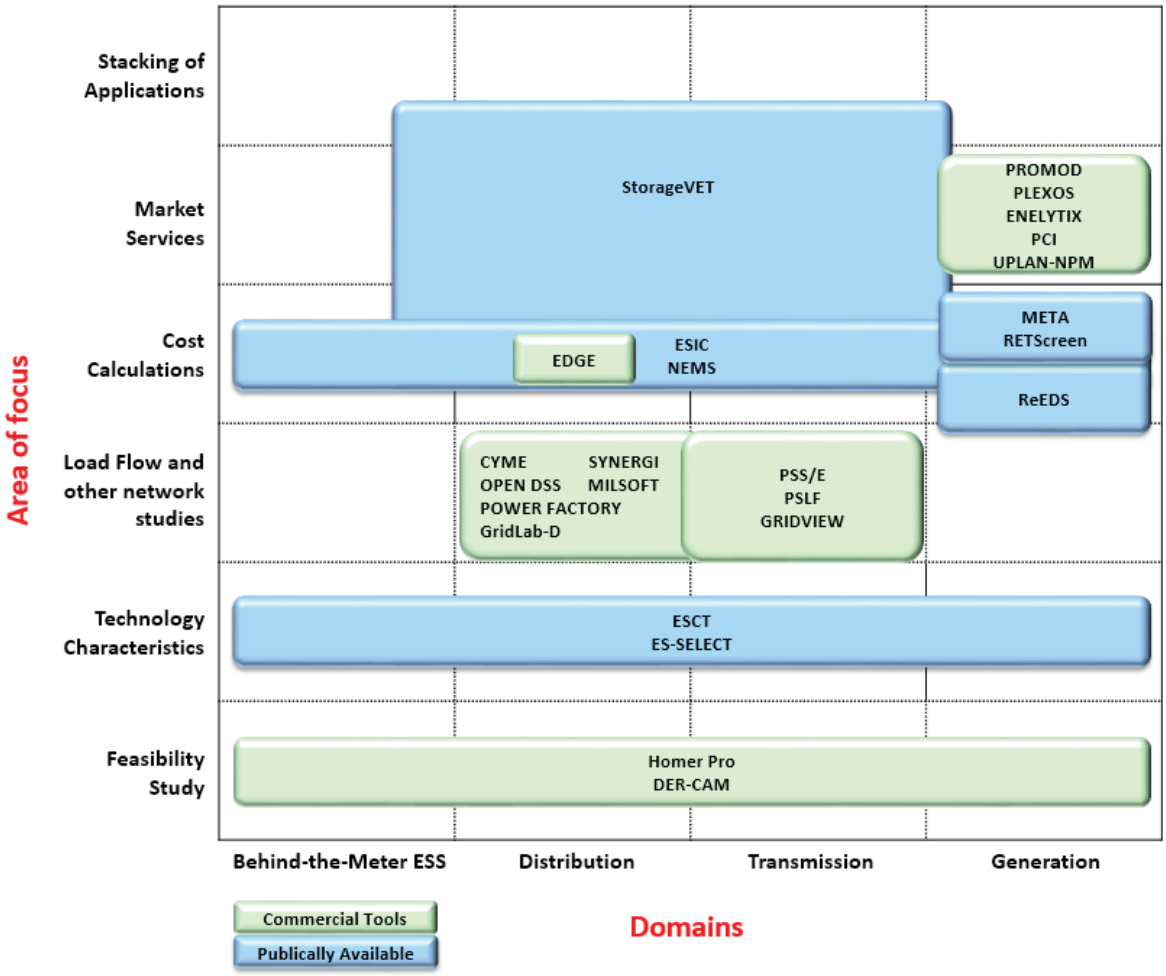


Figure 2-3. ESS Tool Categorization Matrix - populated

Since ESS is still a relatively nascent technology, the available tools that address aspects of ESS deployment have typically added these as ancillary functions to the tool's primary function and there are often trade-offs that result. These are discussed in sections that follow.

Feasibility analysis tools

Feasibility Analysis Tool 1: Feasibility Analysis Tool 1, originally developed by Vendor 1 and then enhanced and distributed by Vendor 2, is a microgrid optimization tool, which is able to model a power system's physical behavior and its life-cycle cost, which incorporates the total cost of installing and operating the system over its life span. Feasibility Analysis Tool 1 uses the total net present cost to represent the life-cycle cost of the system. The advanced storage module includes the Modified Kinetic Battery Model to represent the rate dependent losses, changes in capacity with temperature, variable depth of discharge for cycle life, and increased degradation rate at higher temperatures. With these

features, users are able to create new batteries and add them to the existing Feasibility Analysis Tool 1 battery library. It is assessed in more detail in a separate section below.

Feasibility Analysis Tool 2: Feasibility Analysis Tool 2, developed by Vendor 3, performs investment modeling and optimal modeling of DER integration for microgrids. The objective of Feasibility Analysis Tool 2 is to minimize the cost of operating on-site generation and CHP systems. Feasibility Analysis Tool 2 model determines what technologies should be adopted for DERs and how the DER should be operated based on the site load profile and market price information. Feasibility Analysis Tool 2 is capable of modeling ESS in microgrids and in its more advanced (proprietary, not publicly available) version can incorporate distribution circuits within the microgrid and can determine the sizing of DER components.

Feasibility Analysis Tool 3: Feasibility Analysis Tool 3, developed by Vendor 4, is an energy management software system used for energy efficiency and renewable energy and cogeneration project feasibility studies. This tool can perform clean energy modeling, cost, emission, financial, and sensitivity and risk analysis.

Technology selection tools

Technology Selection Tool 1: Technology Selection Tool 1 was created by Vendor 5 in collaboration with Vendor 6, licensed for public use. This tool provides a visual platform to compare energy storage technologies and their feasibility for specific applications. This tool is designed to work with the uncertainties of storage and application characteristics, costs, and benefits using Monte Carlo analysis. The output of this tool includes cumulative costs and benefits, comparison of different technologies, and feasibility scores. The tool supports 19 different energy storage technologies with 23 different applications. It is useful as a first examination of BESS possibilities. However, the performance and cost data of emerging BESS technologies change rapidly, and the data base behind Technology Selection Tool 1 is not updated as frequently as might be desired, so results have to be considered in that light. Technology Selection Tool 1 should be seen as an introduction to Energy Storage and a source of general information, but not as a tool to begin the design or financial evaluation of a project.

Technology Selection Tool 2: Technology Selection Tool 2 was developed by Vendor 7 at the request of a federal agency to identify and quantify the benefits accrued through the service provided by storage projects. This tool identifies 18 applications and their benefits categorized as economic, reliability or environmental. This tool performs cost/benefit analysis on the energy storage systems regardless of who the likely benefactor is.

Distribution planning tools

Distribution Planning Tool 1: Distribution Planning Tool 1 was developed by Vendor 8 to perform a daily or weekly unit commitment and hourly or sub-hourly dispatch, recognizing both generation and transmission impacts & market performance. Distribution Planning Tool 1 is an industry accepted simulation approach in the Western Electric Coordinating Council territory. The Distribution Planning Tool 1 analysis methodology combines generation, transmission, loads, fuels, and market economics intone integrated framework for location dependent market analysis, reliability and market performance indices.

Distribution Planning Tool 2: Distribution Planning Tool 2, developed by Vendor 9, is mostly suited for ESS technical and planning studies. This tool provides time series power flow analysis for ESS in

distribution level. Distribution Planning Tool 2 utilizes some default dispatch strategies, however requires a higher level of software for control and automation purposes.

Distribution Planning Tool 3: Distribution Planning Tool 3, developed by Vendor 10, is a power flow analysis tool that can be suited for ESS studies in distribution level for the purpose of planning and technical studies. Distribution Planning Tool 3 can be utilized to perform detailed power system studies on ESS on each node of system. The dispatch models in Distribution Planning Tool 3 can be defined by user based on the load profile of circuit under study.

Distribution Planning Tool 4: Distribution Planning Tool 4, developed by Vendor 5, is a power flow analysis tool that can be suited for ESS studies in distribution level for the purpose of planning and technical studies. Distribution Planning Tool 4 can be utilized to perform time series analysis on ESS on each node of system. Extra modules can be developed to study ESS for different applications (e.g., PV smoothing, capacity deferral, etc.)

Distribution Planning Tool 5: Distribution Planning Tool 5, developed by Vendor 11, is a power system analysis tool that can be utilized in both transmission and distribution level. The ESS study tools for this software are need to be customized and developed by the user via some pre-existing modules in software platform.

Distribution Planning Tool 6: Distribution Planning Tool 6, developed by Vendor 12, is power system simulation tool for distribution systems. This tool utilizes time series analysis and supports nearly all frequency domain analyses performed on electric utility power distribution systems. Distribution Planning Tool 6 can be suited to support the analysis of distributed generation and ESS units interconnected to distribution systems.

Distribution Planning Tool 7: Distribution Planning Tool 7, developed by Vendor 13, is a power system planning tool that can be utilized for ESS analysis in transmission level. The ESS study tools for this software are not readily available and should be customized and developed by the user through some pre-existing modules in software platform.

Transmission planning tools

Transmission Planning Tool 1: Transmission Planning Tool 1, developed by Vendor 14, is a power transmission system planning tool software that can be utilized for ESS analysis in transmission level. The ESS study tools for this software are not readily available and should be customized and developed by the user through some pre-existing modules in software platform.

Transmission Planning Tool 2: Transmission Planning Tool 2, developed by Vendor 15, is a comparable and competing product to Transmission Planning Tool 1.

Other specialty tools

Specialty tools are utilized to perform special studies that are outside of the scope of T&D planning and system protection analysis. Below are the list of specialty tools investigated.

Specialty Tool 1: Specialty Tool 1, developed by Vendor 16, is a power system electromagnetic transient simulation tool mainly designed for analyzing transients. Specialty Tool 1 utilizes Electromagnetic Transient (EMTDC) as the simulation engine which facilitates simulating time domain instantaneous

responses (electromagnetic transients) of electrical systems. Specialty Tool 1 can be utilized to study the grid integration impacts of ESS units, such as power quality issues, harmonic studies, stability analysis, transient analysis, etc.

Specialty Tool 2: Specialty Tool 2 is not shown on the graphic as it is somewhat unique in its application, although other power system dynamic tools such as Transmission Planning Tool 2 can approach some of its capabilities. Specialty Tool 2 was developed by Vendor 5 in Matlab-Simulink platform. This tool primarily targets transmission applications for ISO needs and is suited to perform frequency response and balancing energy studies of renewable and distributed energy resources and storage energy resource in 1 sec to 24 hour timeframe. It is primarily used for analyzing future system performance, designing Automatic Generation Control algorithms, and other control area problems.

Cost calculation tools

Cost Calculation Tool 1: Cost Calculation Tool 1, developed by Vendor 17, provides a comparative assessment of the economic costs of more than 40 electricity generation and delivery technologies, including conventional generation options such as thermal, renewable options including hydroelectric and wind, and emerging options such as energy storage. One of the features of Cost Calculation Tool 1 is that it allows for integration of environmental externalities, such as local pollution and greenhouse gas emissions.

Cost Calculation Tool 2: Cost Calculation Tool 2 was developed by Vendor 1. This tool is a long-term capacity-expansion model for the deployment of electric power generation technologies and transmission infrastructure. Cost Calculation Tool 2 uses a linear programming approach to minimize the capital, fuel, and operation costs of energy storage systems.

Cost Calculation Tool 3: Cost Calculation Tool 3 was developed by Vendor 18. This tool determines the optimal energy storage system characteristics using different modules such as Electricity Market Module, Electricity Capacity Planning, and Electricity Load and Demand. The objective of planning module is to minimize the total, discounted present value of the costs associated with meeting demand complying with environmental regulations. The planning module allows planners to analyze new capacity additions, construction costs, computation of avoided costs, emission banking, pollution control retrofits, and capacity requirements.

Cost Calculation Tool 4: Cost Calculation Tool 4 was developed by Vendor 12. This tool is mainly intended to perform business studies for distribution system applications in Excel platform. This tool enables utilizes and suppliers to indicate the scope for an energy storage system or project and helps buyers to clarify what they need. The main output of this tool is the total cost of ownership of energy storage system. This tool is openly available for public use.

Cost Calculation Tool 5: Cost Calculation Tool 5, developed by Vendor 19, is a MATLAB-based simulation tool designed to comprehensively assess the DER value proposition in different regulatory and utility business model environments based on a detailed assessment of the technical and operational implications. This tool utilizes Distribution Planning Tool 6 for running time series power flow simulations.

Cost Calculation Tool 6: Cost Calculation Tool 6 was developed by Vendor 12 and is mainly intended for energy storage system business studies. Cost Calculation Tool 6 has a web-based platform, performs cost/benefit analysis of energy storage projects and analyzes life degradation. Cost Calculation Tool 6

can perform electricity market analysis (suited for CAISO). Cost Calculation Tool 6 is not capable of analyzing stacked applications directly. Cost Calculation Tool 6 was developed jointly by Vendor 12 and a state energy commission with approximately $1M of funding, and is heavily tailored towards state-specific ESS applications. It is assessed in more detail in a separate section below.

Production costing tools

Production Costing Tool 1: Production Costing Tool 1 was developed by Vendor 8 to perform generation and transmission system studies. This tool performs a daily or weekly unit commitment and hourly or sub-hourly dispatch, recognizing both generation and transmission impacts at the nodal and zonal level. The output of this tool includes a detailed production cost modeling. Production Costing Tool 1 is widely used for renewable curtailment studies, for valuing a new generation project or a new transmission project. Production Costing Tool 1 has limited capabilities to model energy storage and cannot co-optimize storage charging and discharging or ancillaries' provision.

Production Costing Tool 2: Production Costing Tool 2 is a production cost model from Vendor 20. This tool is object oriented and allows the user to develop specific resource models to some extent. It is able to co-optimize storage charging and discharging (originally used for pumped hydro modelling). Regulation reserves are held in a regulation raise (and lower) reserve category and cannot contribute to energy or other ancillary services. Production Costing Tool 2 addresses the losses due to the inefficiencies of charging and discharging by adding an auxiliary load to the energy storage resource model. Production Costing Tool 2 is widely used within WECC for analyzing renewable penetration impacts, cost of additional ancillary services, and so on.

Production Costing Tool 3: Production Costing Tool 3 is a production costing simulation available from Vendor 21. It is cloud based (runs on Amazon Cloud Services) and has capabilities similar to Production Costing Tool 2.

There is a category of unit commitment tools that are used by generation market participants to determine bidding strategies. Unit Commitment Tool 1 by Vendor 22 is an example of this. These tools today do not accommodate storage as the generation owners have not as yet had to incorporate these into their operations. Large storage operators no doubt have proprietary tools but these were not accessible for evaluation.

Production Costing Tool 4: Production Costing Tool 4, by Vendor 23, simulates the electricity market using security constrained unit commitment and security constrained economic dispatch. This tool integrates the electricity market with a full transmission network model. Production Costing Tool 4 is a powerful tool to co-optimize energy and ancillary services market products and produce information on the projected hourly operation of generators, ancillary service revenue, costs, and net income. It is not known if Production Costing Tool 4 has been enhanced to incorporate ESS.

2.3.4 Tool Limitations

2.3.4.1 Using "Educational" Tools

Tools designed for "educational" purposes include tools developed by US DOE in the past decade– Technology Selection Tool 1 and Technology Selection Tool 2. These tools are Excel-based and employ an internal data base of storage technology parameters and costs, plus some parameters around the performance requirements of different applications. These tools typically provide benefits analyses with

a wide range, appropriately given the simple nature of the calculations and lack of geography/site/application specificity. As such they are useful for introducing energy storage to stakeholders and corporate management. They are relatively useless for evaluating specific projects or portfolios, and it was not the intent of the tool developers that they be used for those purposes. A weakness of this category of tool is that the internal data bases may not be current. Cost and performance data for different storage technologies may be out of date, and projected performance of laboratory/pre-commercial technologies may not have been realized. These tools typically include numerous technologies in a research and development phase which may not ever be commercially viable. Any use of these tools must include caveats about the data currency and realism issues.

Some of the Excel-based tools may be useful for evaluating initial business case feasibility before performing more rigorous analysis. But given the wide range of estimated benefits, results have to be interpreted as very rough estimates and only that.

As noted above, general high level "survey" tools are more valuable today for educational and introductory purposes than for realistic project analysis. Technology Selection Tool 1, for instance, cannot be used to evaluate a project feasibility. Technology Selection Tool 2 and Cost Calculation Tool 4 can be used to get a first estimate of a storage project's likely costs, but the currency of the data in these tools must be verified and industry surveys from Vendor 7, Vendor 24, and others will provide more up to date information.

2.3.4.2 Using planning tools

The major distribution and transmission planning tool sets either do not have storage object models or have limited capabilities in terms of using these for particular applications or for assessing sizing requirements. This is expected to change rapidly as the software companies move to incorporate storage in their capabilities. Tools that employ distribution planning load flows for storage sizing typically do so with external time series control of the storage using python, Matlab, or other coded algorithms.

In the distribution space, the tools typically found for distribution planning are Distribution Planning Tool 3, Distribution Planning Tool 4, Distribution Planning Tool 2, Distribution Planning Tool 7, and Distribution Planning Tool 6. Any can be used to evaluate samples (as in peak load, minimum load, peak PV production) with storage added as a user specified injection/withdrawal. Using these tools for storage applications in distribution this way is labor intensive.

Distribution Planning Tool 3, Distribution Planning Tool 6, and Distribution Planning Tool 4 support a Python license and this allows time series simulation with the external Python code actually simulating the storage asset and its control algorithms. Distribution Planning Tool 6 and Distribution Planning Tool 3 have been used in previous utility ESS assessments in state or utility storage roadmap and valuation projects. For this project the Python code was also ported to Distribution Planning Tool 4 so that that tool could be used. All three of these distribution planning tools will perform well for use in storage sizing and evaluation efforts, with idiosyncrasies unique to each around issues of high PV penetration. All three have PV hosting capacity analysis capabilities under development or released, note.

The effectiveness of the particular Python storage applications is therefore more a determinant of the capabilities of the tool than of the distribution load flow to which it is mated. From published work, the

Vendor 5 application performs capacity deferral. The Python code used in the project supports capacity deferral and it also supports the PV integration applications, which were demonstrated in this project.

It is normally the case that one storage resource can provide all the renewable integration applications in conjunction. In some cases, the capacity deferral application may be combined with renewable integration. However, renewable integration is very locational which may make this impractical.

Local resiliency is not a problem of analyzing the distribution circuit but is one of ensuring that the storage resource in conjunction with other energy resources is capable of meeting load within the microgrid for the duration required. This is similar to the behind the meter microgrid application and addressable with the same tool kits. Feasibility Analysis Tool 1 is widely used for this purpose; there are other tools with similar capability available from several vendors. Feasibility Analysis Tool 2 tool is another one.

There is also a stacked application for the local islanding application. The storage must be sized to carry the peak loading day for enough hours to allow business as usual repairs. This means that in off peak seasons there may be sufficient energy storage capacity to enable participation in wholesale market products so long as state of charge is sufficient for the outage energy needs.

Distribution applications are very much in a pilot/demonstration stage today and there are few examples of stacked applications in commercial operation. Uncertainty is one obstacle, lack of integrated controls for stacked applications another.

2.3.4.3 Using production costing tools

All production costing tools are set up to evaluate generation resources against these products and to co-optimize participation in the different markets. However, not all are set up to include “energy limited” resources such as storage, other than possibly pumped hydroelectric. And even if they do accommodate pumped hydroelectric, common shortcomings include easy handling of multiple storage resources or the ability to optimally schedule charging as well as discharging.

Some production costing tools are able to address the real time market explicitly or indirectly. Explicit representations reduce the time step from 1 hour to the real time market time step of 5 or 15 minutes. This produces exact results at significant increases in computer time. Others may approximate the representation to retain use of an hourly time step and then co-optimize the ability to be in the RT market as well as DA and ancillaries. None of the production costing tools represent the actual energy flow in charging or discharging in the regulation market which may be a factor for storage depending upon the details of the ISO regulation product.

The California ISO market has unique features of the regulation market that are not duplicated in other ISO markets. The production costing tools may not capture the details of these at a level that works for energy storage planning. The regulation product has separate up and down components so that a resource can be in one or the other or both. There is a special regulation product for storage where the ISO biases the setpoint in a subsequent 15 minute time step so as to “repay” the energy net charge/discharge of the prior time period. This allows a storage resource with a shorter duration (nominally 15 minutes but certainly 30 minutes) to play in this market. Today, resources in this market cannot be in the energy markets.

The problem of engineering validation of schedules derived from production costing models or other models is a different problem. Here the storage resource needs to be simulated with reasonable fidelity in a simulation appropriate to the application. For energy products this is not an issue. For regulation where system control area performance is an issue, then dynamic simulations such as Transmission Planning Tool 2 or proprietary tools such as Specialty Tool 2 or similar tools from Vendor 15 and Vendor 1 are required.

When physical validation with a dynamic simulation tool such as Transmission Planning Tool 2 or Specialty Tool 2 is required, then a day at a time is typically simulated and a means of annualization by extrapolation has to be developed if needed. More typically extreme scenarios are defined and days selected against this set of characteristics as performance, not annualized cost is the objective.

When an existing storage project has been in the wholesale markets for some time, it is straightforward to calculate the performance of the project against the theoretical best as one metric of how well the project has performed, or better said, as a metric of how well original projections compare to actual. It is also possible to assess the impact of different factors: actual vs historical prices (a major factor), project availability, accuracy of forecast prices used in daily decision making, and so on.

Production costing tools in general are able to assess generation and to some extent storage resource revenues in the wholesale markets across a range of products. All the production costing tools mentioned incorporate transmission network models and constraints (usually not AC models, note) so can model transmission N-0 and N-1 congestion and compute nodal prices. However, their network models are not suitable for distribution networks so that the tools cannot be used to assess wholesale market services revenues for distributed or behind the meter ESS. Table 2-5 presents a comparison of some features of commonly used production costing tools.

Table 2-5. Observations on Tools for Valuing Storage in the Wholesale Markets

Tool	Has Storage Object	Co-optimizes charge & discharge DA schedule	Co optimizes HA storage schedule	Co-optimizes ancillaries	Allows user object definitions (e.g., degradation, self-discharge)
Generation Management Tool (Vendor 22)	No	No	No	No	No
Production Costing Tool 1 (Vendor 8)	No	Discharge only	Discharge	With discharge	No
Production Costing Tool 3 (Vendor 21)	Yes	Yes	Yes	Yes	Unknown
Production Costing Tool 2 (Vendor 20)	Yes	Yes	Yes	Yes	Yes

2.3.4.4 Using specialty tools

There are a number of tools available that can co-optimize storage participation in the wholesale markets given a time series of hourly prices as inputs. These can be spreadsheet based, written in a

high-level language such as Matlab, or developed in a coding language such as Python. The formulation of the problem – objective function of maximizing revenues and constraints on capacity, state of charge, etc., can be written in the language of the chosen platform and then an available/native optimization "solver" package or more capable 3rd party code can be used to perform the optimal scheduling. Other "tools" may approximate this via less rigorous approaches, using averaging or other approximations, but there are multiple organizations with true optimization capabilities today. These tools typically work on an hourly resolution (only) and must ignore or approximate the Real Time market revenues.

All such "price taker" tools use historical ISO prices for market products and determine an optimal schedule against those prices. This is valid for DA prices if the storage resource can act as a passive non-participant and vary its charging and discharging on a Real Time Pricing (RTP) basis. It is not valid if the resource must be in the market as at a minimum the resource must schedule or bid the charging and then offer the charging so must determine which hours to target, as the ISOs do not co-optimize this for the storage resource. For the RT market and the ancillaries market the resource must be an active participant and must submit offers in order to be awarded product delivery at market price. Thus, the resource operator is dependent upon price forecasting tools or similar in order to develop a bidding strategy. This means that the optimal strategy developed in the storage valuation tool is a theoretical optimum which cannot be realized in practice and must be discounted to some extent.

These tools exhibit the same characteristics with regard to annualization as the production costing tools. Hourly analysis can be carried out on an 8760 basis. Sub hourly analysis may require sampling and extrapolation although some tools can perform it on an 8760 basis as well.

Vendor 12, and some consultants have developed specialized tools for assessing various storage applications at higher fidelity using engineering grade network analysis coupled with co-optimization of the ESS for wholesale market services. These include tools that use Python and/or Excel to set up and simulate ESS for capacity deferral, renewable integration, and local microgrid applications. These tools interface to Distribution Planning Tool 3, Distribution Planning Tool 6, and Distribution Planning Tool 4 to perform AC distribution network simulations and are capable of assessing stacked applications including wholesale market services.

2.3.5 Stacked Applications

Stacked Applications is the term used to describe a situation where the storage resource is used for more than one domain of applications. The normal case is one where one storage resource is used for multiple renewable integration applications, or to accesses wholesale markets in addition to its primary mitigation function projects, i.e. when the wholesale market applications and T&D applications are allowed to be performed by the same storage resource.

Generally speaking, the T&D "reliability" applications take precedence over "wholesale market participation" in that the applications that ensure safe operation of the T&D system will come first, and market operations cannot be allowed to interfere with the instantaneous requirements of the reliability application. This means that the source of the information about the T&D application must provide constraints on how much storage capacity is available for other applications on a basis that is usable by the tool being used for market valuation.

Unfortunately, market valuation tools are all based to some extent on hourly analysis (or more granular) of price time series or market simulations. This means that the T&D constraints must be similarly posed

to be useful. When the T&D sizing/valuation/validation process does not produce this data, something must be done with load profile shapes, PV shapes, and the like to approximate it.

Tools that use generic factors to reduce capacities, etc. fall into the educational class and will be essentially useless for this purpose.

Once the T&D constraints are available, the storage capacities available for market purposes must be modified on an hourly / daily basis so that the market valuation can respect the T&D application requirements.

The constraint transfer can be manual, possibly with simplifications, or automated to some degree via file transfer/upload, etc.

As of this draft, there are no tools available that completely automate this process although some approach it in terms of anticipating the need and preparing the constraint data from the T&D analysis ready for input to the market valuation analysis.

The use of different circuit analysis tools with different storage valuation tools is discussed below. The tools listed are the ones primarily used by large utilities in California. There is good body of experience on utilizing Distribution Planning Tool 3, Distribution Planning Tool 4, Distribution Planning Tool 6, and Distribution Planning Tool 5 for similar projects, and the observations are based on those experience in the context of California. It should be noted that software vendors are continuously improving the models and features of the existing tools based on the feedback and request from utilities and industry user. For that reason, the information in Table 2-6 should not be considered exhaustive and final. There are always newer versions of the tools that may provide additional features and need to be evaluates on the case by case basis.

Table 2-6. Comparison of major capabilities of tools available for evaluating energy storage applications in distribution systems and stacked benefits

	User Interface & Models			ESS Distribution Applications				ESS Market Applications			Stacking
Tools / Vendor	**Supporting External Scripts (API)**	**Open Source**	**Energy Storage Model?**	**Capacity Upgrade Deferral**	**PV Integration Impact**	**Voltage & Flicker Mitigation**	**Islanding (Microgrid)**	**Hourly Energy**	**Real Time Energy**	**Regulation**	**Application Co-Evaluation**
Distribution Planning Tool 3	YES	NO	Basic, Some controls	YES	YES	Voltage Control	No	N/A	N/A	N/A	N/A
Distribution Planning Tool 4 (Vendor 5)	YES	NO	Basic, Scheduling Charge and Discharge	Single location (using scheduling)	No	No	No	N/A	N/A	N/A	N/A
Distribution Planning Tool 6 (Vendor 12)	YES	YES	Possible[1]	Possible[1]	Possible[1]	Possible[1]	Possible[1]	N/A	N/A	N/A	N/A
Distribution Planning Tool 2 (Vendor 9)	YES	NO	Possible[1]	Possible[1]	Possible[1]	Possible[1]	Possible[1]	N/A	N/A	N/A	N/A
Distribution Planning Tool 5 (Vendor 11)	YES	NO	Possible[1]	Possible[1]	Possible[1]	Possible[1]	Possible[1]	N/A	N/A	N/A	N/A
Vendor 5 ESS	NO	NO	Explicit[2]	YES	Unknown	Voltage only	YES	YES	YES	YES	Unknown
Cost Calculation Tool 6 (Vendor 12)	NO	No, but planned	Explicit[2]	YES	NO	Voltage only	NO	YES	YES	YES	Limited
ESS-ASET	YES	Semi	Explicit[2]	YES	YES	YES	YES	YES	YES	YES	YES

1: Complex approach; User needs to develop custom model
2: Including an object model for energy storage (equations, constraints, and parameters)

2.3.6 Storage Portfolio Determination

For utilities and for state policy makers, an important question today is “how much storage do we need?” and related to that “what is a no regrets figure for storage?” Variations on this question can get to the level of “for what purpose and where” as well.

Determining the characteristics of desirable portfolios is also sometimes called a “roadmap” process that may also address the rate at which this storage is implemented, and what indicators along the way (such as PV penetration, storage costs, and energy prices) inform the process.

As of today, there is not even a widely agreed process for conducting such an exercise. Several utilities have proceeded down this path.

At the wholesale level, iterations using a production cost program are a valid way to address the question, including the question of how much is needed to integrate a specified renewable portfolio or to address how different storage portfolios will address the costs of renewable integration in terms of production costs and ensuring that sufficient reserves and system flexibility is maintained. Such an analysis would not, however, address the question of whether conventional plant revenues are sufficient and what capacity payments or equivalent might be required from that perspective.

At the transmission level, there have been as yet no studies to examine total storage portfolios for congestion management.

At the utility distribution level, there have been several such studies. These basically repeat the distribution application assessment for a circuit or station across the population of utility circuits and stations, or find a way to parameterize these results based on a sample and then extrapolate this to the entire population based on those parameters.

If these studies include stacked applications, then they are vulnerable to the wholesale market price taker problem. They use historical price time series as inputs. However, if a particular T&D utility were to deploy wholesale level storage in total (as in > 1000 MW) and all of it were doing stacked applications, then the assumption of wholesale price time series is not valid and probably optimistic, as that much storage will act to depress high prices.

2.3.7 Vendor 12 Cost Calculation Tool 6 Assessment

The Vendor 12 Cost Calculation Tool 6 tool is a major, integrated tool which can assess all the various applications described and which has been extensively customized to the California situation. As such, it merits a more in-depth discussion than most other tools considered.

This assessment is based on a review of the documentation set Vendor 12 Cost Calculation Tool 6 1.0 and the on-line cloud-based version.

Cost Calculation Tool 6 is based on the Analytical software platform. This is a heavy duty commercial simulation/optimization platform that uses EXCEL as a GUI and allows users the benefit of a variety of sophisticated and powerful optimization engines/solvers that would otherwise be expensive to access. This gives Cost Calculation Tool 6 capabilities beyond those available from EXCEL and VBA based tools

Cost Calculation Tool 6 is tailored to the California system and markets, and has incorporated CA ISO historical prices for use in valuations. This greatly facilitates use of it for storage assessments in California. As such, it is not intended for nor suitable for use in other regions when wholesale prices must be factored in. It also has pre-loaded load profiles for use in assessing various T&D applications, so is again California specific and not suitable for geographies with significantly different weather, etc.

The Cost Calculation Tool 6 modeled Services are shown in Figure ES-1 of the Vendor 12 documentation (Table 2-7):

Table 2-7. Cost Calculation Tool 6 modeled applications with source of market price, retail rate or avoided cost [11]

	CAISO Markets/ Tariff Rates	Bilateral Markets or Internal Utility Dispatch Costs	Utility Rates/ Customer-sited Applications	T&D Investment and Operations
Resource Adequacy Capacity	✓	✓		
Day Ahead Energy Time Shift	✓	✓		
Real Time Energy Dispatch	✓	✓		
Flexible Ramping Product	✓			
Frequency Regulation	✓	✓		
Spinning Reserve	✓	✓		
Non-Spinning Reserve	✓	✓		
Black Start	✓	✓		
T&D Investment Deferral				✓
Transmission Congestion Relief	✓			✓
Transmission Voltage/Reactive Power Support	✓			✓
Equipment Life Extension				✓
Losses Reduction	✓			✓
Voltage Control	✓			✓
Retail Demand Charge Reduction			✓	
Retail Energy Time Shift			✓	
Power Quality			✓	
Backup Power			✓	
Demand Response Program Participation	✓		✓	✓
PV Self-Consumption (FITC Eligibility)			✓	✓

Vendor 12 describes the following limitations of Cost Calculation Tool 6:

- It models storage as a price taker in the market and uses historical prices as given. Thus it assumes perfect foreknowledge of prices in establishing day ahead scheduling for the time series optimization. This is typical of storage (and other resources in the market) valuation approaches and is in effect state of the art. Without knowledge of what price forecasting/scheduling tool a user might have access to this is the best that could be done.

- Because it models storage as a price taker it is appropriate (only) for assessing incremental individual storage project revenues and returns in the wholesale markets. This means, by extension of this point, that Cost Calculation Tool 6 as it is – is *not* a suitable tool for assessing impacts of storage profiles on the state markets, answering questions such as "what is the no-regrets level of storage in the state?" and so on. It was not the intent of Cost Calculation Tool 6 to provide this capability. Advanced Production Costing tools such as Production Costing Tool 2 are better suited for this purpose.
- Cost Calculation Tool 6 does not model effects such as AC voltage effects. Thus in valuing storage as a VAR resource on a distribution system, it requires external inputs obtained from a distribution circuit analysis tool. This is typical of the state of the art today.
- It does not address emissions benefits. Again, this is best done via an advanced production costing tool which typically has this capability.
- The details of the co-optimization of energy and ancillaries across time are not transparent. The documentation states that some approximations are taken to avoid the creation of non-linear or integer variables in the tool. This is not surprising, as large numbers of integer variables or non-linear functions can tax the optimization. Without further work to compare Cost Calculation Tool 6 results with those of a more rigorous formulation the impact of these approximations cannot be determined. It may well be that during the tool development this was examined and determined to be unimportant.
- Cost Calculation Tool 6 does not explicitly address the distribution micro grid or local circuit resiliency application. However, use of the behind the meter backup generation capability can achieve results for this application with the correct data entries so long as circuit constraints do not enter the problem.

2.3.8 Conclusions

The state of energy storage in the electric power industry has developed rapidly and is variously at the stage of pilot projects to commercially viable businesses depending upon the application and the geography/jurisdiction. Early storage tools which were aimed at "education" and "introduction" were useful at the time but have not kept pace with the need to perform true engineering and detailed financial modelling.

As with every other technology in use in electric power, rule of thumb or simplified analyses have their place in terms of "first look" at technology viability for meeting needs or estimating market revenues. However, actual project planning and financial evaluation before proceeding cannot depend upon such approaches, and rapidly evolves to detail engineering simulations and analyses coupled with sophisticated financial analyses. A perfect example of this is the wind industry that has long relied on 8760-hour time series analysis of wind production and then state of the art production costing/security constrained unit commitment analyses of market revenues and potential curtailment as a condition of securing project finance. Energy storage is reaching similar states of sophisticated analysis rapidly for the same reasons.

Even when the storage investments are driven by grid reliability needs and will be rate based at the start, the role that market revenues can play in the economic viability of a project is crucial. Analyzing these finances requires levels of sophistication as with the wind farm example. Storage is more complicated than most technology investments in that it lends itself to stacked applications and

revenues that encompass one or more reliability applications as well as multiple sources of market revenues.

The survey of the different tools available indicated that (as shown in Figure 2-4) today the engineering tools routinely used in distribution planning have not, for the most part, accommodated storage technologies at fidelity for reliability applications, and are not at all able to address market application revenues. For this reason, a combination of storage specific application software wrapped around commercial distribution planning software is the only realistic alternative.

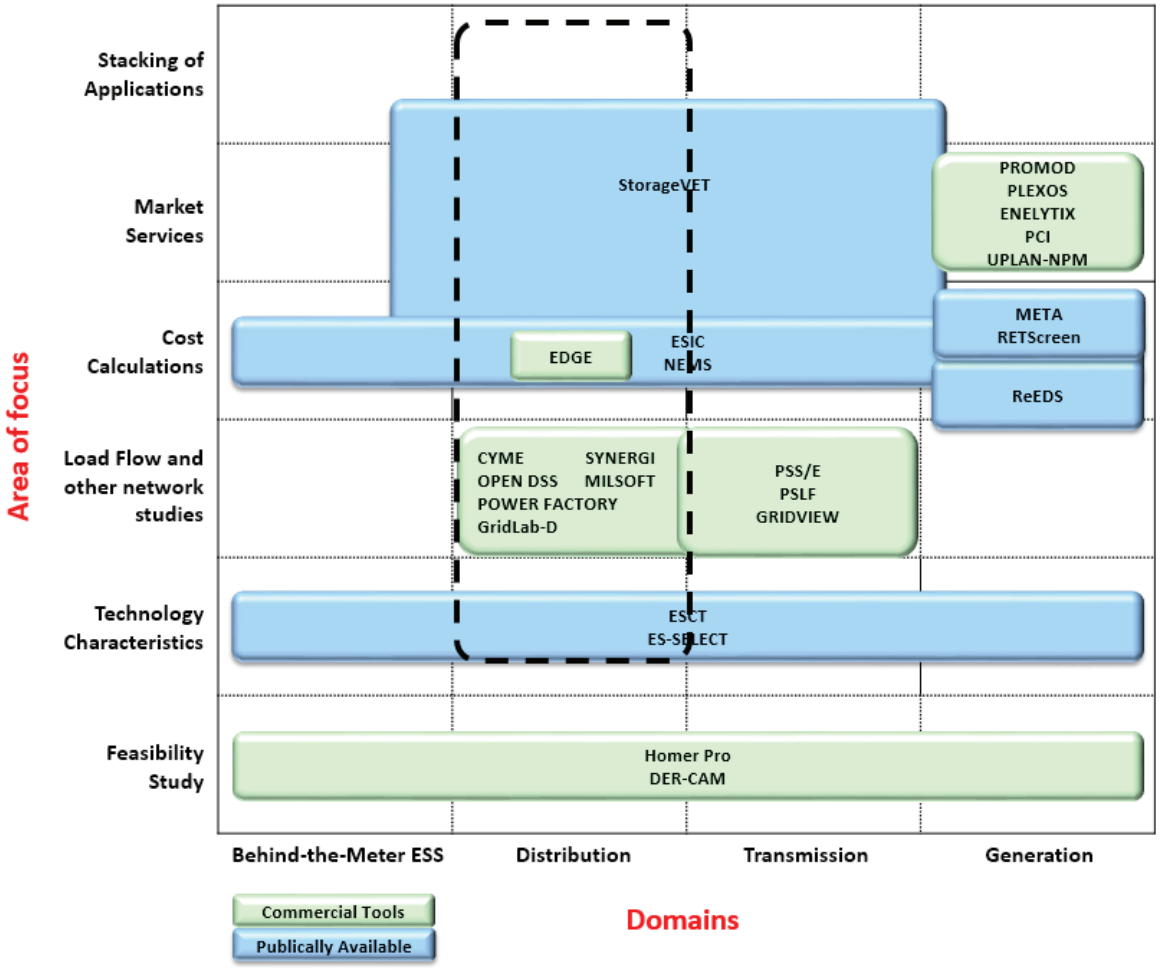
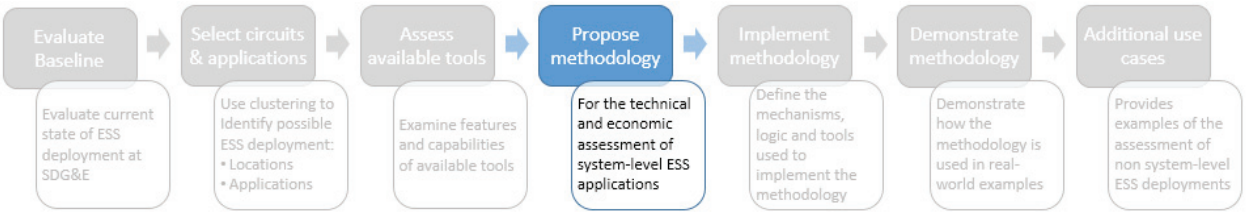


Figure 2-4. Gap in available tool set for Distribution applications

2.4 Task 4: Propose methodology

This task proposed a methodology to be used to analyze the technical and economic viability of deploying ESSs on the SDG&E distribution system.



There are two categories of applications to be considered; system applications where the ESS is deployed as a grid asset, and end-use applications where the ESS is deployed as a pure market asset or for the end-use customer specific purpose. The methodology for evaluating these two categories of applications differs. The methodology discussed in this section, and implemented and demonstrated in the next two sections, is designed for performing energy storage value evaluation for system applications. The methodology consists of the four steps shown in Figure 2-5 below.

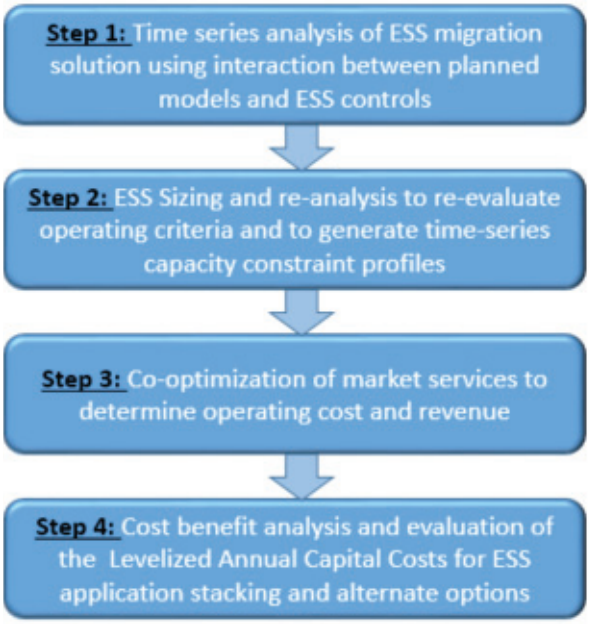


Figure 2-5. ESS analysis approach for system applications

- In Step 1, typical planning tools are used to determine the proper size and location of single or multiple energy storage units that can mitigate the specific issue addressed by that application. In the case of SDG&E, a combination of Distribution Planning Tool 4 planning model and Python coding is used to represent and analyze specific energy storage functions as part of the circuit-based power flow studies. It should be noted that similar study approach has been applied in conjunction with other planning tools (common to other IOUs in California). Distribution Planning Tool 4 is used to perform the circuit load flow at each time step. Python code simulated the BESS and its control algorithms for each application and controls the time step.

- In Step 2, the ESS size and capacity obtained from Step 1 analysis is assessed to select a realistic rating from available commercial technologies. The time series analysis of Step 1 are repeated for the final ESS size and capacity to capture the operating constraints of the BESS and to determine available capacity and/or operating conditions under which the BESS unutilized capacity or time-frame of operation can be offered for other services.
- In Step 3, once the energy storage sizes (both power and energy capacity ratings) and constraints are obtained, optimization and analysis of various applicable market participation services are performed to estimate revenue for stacking market services with distribution reliability application as primary functions. Certain operating constraints are applied to ensure energy storage system can always meet the distribution reliability application considered. For instance, circuit loading mitigation thresholds are used for capacity upgrade deferral and/or maintaining state of charge requirements at all times are applied to ensure enough capacity to serve customer loads if a planned or unplanned outage occurs. The market analysis is on an hourly basis for 8760 hours a year and factors in load growth to analyze future years.
- Step 4 focuses in cost benefit analysis and evaluation of the Net Present Value for the ESS approach versus the more conventional approach of distribution system upgrade and enhancements.

The time series analysis approach using Python/Distribution Planning Tool 4 power flow and/or circuit loading processes was developed for this project using available algorithms and control functions from similar prior studies that can produce appropriate setpoints for BESS active and reactive power contributions in an attempt to mitigate the issue under study (such as circuit overloading, or excessive reverse power flow, or steep power changes, or significant voltage problems).

For this project, a custom design mixed integer programing (MIP) based tool was used for evaluating BESS revenues in wholesale markets and for evaluating the wholesale revenues from distribution system and microgrid stacked applications. This tool was used to perform detailed evaluations of the Escondido and El Cajon BESS participation in the wholesale markets; it was also used to evaluate the stacked-application revenues for the energy storage system sized and sited for distribution reliability applications such as capacity upgrade deferral and for PV integration mitigation, as well as for the proposed microgrid (local reliability) applications. CA ISO 2016 historical data was used to perform the theoretically optimal revenue evaluations.

It is important to recognize that real world operations cannot realize 100% of the projected theoretical best case revenues; there are several reasons for this:

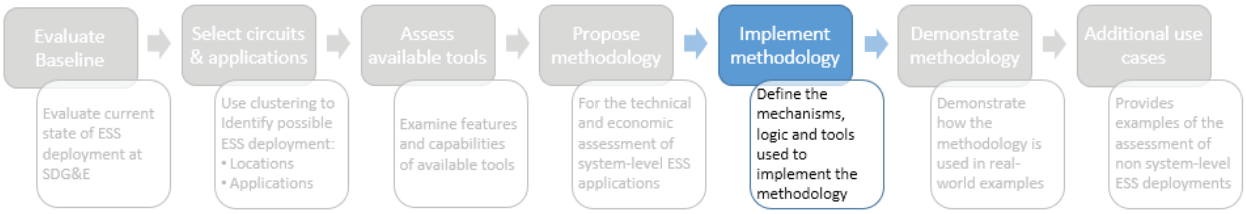
- Market prices going forward may not behave identically to historical prices. Changes in the resource mix, weather, and fuel prices as well as possible changes in market products and rules can all affect prices. Most studies nonetheless use historical prices for these analyses, although when forward gas market prices are notably different these can be factored in. Similarly, growth in renewable penetration, plant retirements, and similar trends can be factored in. This study did not include production costing analysis or future energy price forecasting. The 2016 historical prices – extracted from CAISO website - are used “as is.”
- When it is necessary to actively participate in the market by making offers, the BESS operator has to determine the price for each market product to use in submitting a bid. This requires the use of a tool such as Generation Management tools to forecast DA energy and ancillaries prices and to determine a bidding strategy, as SDG&E does today. A BESS, which is declared as a generation resource or an NGR, can participate in DA energy and ancillary markets, and in the RT market; it must make offers in order to do so. BESS located “below the take-out point” or on the distribution

system can participate passively by responding to DA energy prices – this then affects the Unaccounted for Energy account of SDG&E; the energy cost savings get passed on to SDG&E ratepayers. In order to participate in RT and ancillaries markets, distributed BESS seeking stacked applications will have to be active market participants with the same work required in developing daily bidding strategies; thus, the stacked applications revenue calculations are somewhat hypothetical today. When a rule-based bidding strategy is determined, (as might be the case for distributed storage), then this can be simulated and evaluated using the same approach as in the theoretically optimal analysis. Simulations such as these could also be used to test different rule-based strategies, ultimately including price uncertainty.

- As more energy storage systems enter the market in California, it can be expected that market prices will be impacted and that the ISO market products and rules may adapt to storage penetration.

2.5 Task 5: Implementing the methodology

This task converted the theoretical four step process proposed in the preceding task into an executable model for analysis of the three system-based ESS applications shortlisted in the section entitled Task 2: Select Circuits and Applications.



The short-listed system-based ESS applications are:

- Circuit upgrade deferral
- Reliability Enhancement for Customers by using ESS in Microgrids
- PV Integration Mitigation

The sections that follow describe how the four step methodology of performing Time Series Analysis, ESS sizing, co-optimization and cost benefit analysis are implemented for these three system applications.

2.5.1 Circuit upgrade deferral application

The circuit upgrade deferral function of ESS deals with mitigating thermal rating issues on distribution circuits and therefore deferring the distribution system upgrades for a specific period of time. Thermal limiting cases can be at: transformer bank level, circuit level, section level (further away from substation) or branch level – especially at tie-lines with limited capacity for load transfer (e.g. places where 100A tie switches were used but the load has grown beyond 100 A overtime).

The analysis is focused on estimating ESS size/capacity for providing at least 5-year capacity support and upgrade deferral for the circuit. ESS may be installed downstream of the location where upgrade is required, such as circuit head, mid-circuit and/or on a branch.

2.5.1.1 Step 1 - Perform time series analysis

Some planning related information was received from SDG&E and the rest were extracted from Distribution Planning Tool 4 models. Since the ampacity ratings from Distribution Planning Tool 4 models are lower, the project considered these numbers in capacity upgrade deferral studies in order to perform the studies for the worst case.

Based on information from SDG&E, the main cases of thermal limit issues identified for this project were at the substation level. The limiting factor is typically conductor size for the first section of the backbone that have to carry out almost the entire circuit load.

Two approaches are suggested for mitigation of thermal limits with the use of ESS:

- Centralized
- Decentralized

2.5.1.2 Step 2 - Calculate ESS sizing

The sizing calculations performed in Step 2 differ depending on the approach.

Centralized:

In this approach, a single battery energy storage system is installed close to the substation for upgrade deferral application. The battery energy storage is sized appropriately to ensure the upgrade requirements of the distribution system in a 5-year time frame will be deferred. Therefore, the following approach is applied to each potential circuit in order to size the ESS for upgrade deferral application:

1. **Size determination**: Historical load profile (2016) are used to estimate a projected load profile for a 5-year upgrade deferral analysis:
   - Considering year 2019 as the analysis start year, a projected load profile for study year (2024) is created by escalating the load growth based on the historical load profile of 2016, and the resultant maximum loading of the circuit determined.
     - Load growth % is an input provided by SDG&E per circuit identified for capacity upgrade deferral
     - If load growth % information was not available, a 0.5%-1% growth factor per year was assumed
   - The number of hours/days that there would be a violation of thermal loading of the circuit is determined
   - Based on the maximum MW thermal loading violation and also the number of hours the service required, the ESS MW size and MWh capacity per year and on 5-year basis are calculated.
2. **Size verification**: Distribution Planning Tool 4 – Python combination is used to run the circuit load flow with the battery installed close to substation. In this analysis the projected annual load profile (year 2024) is used with 15 minute resolution to verify the satisfactory performance of the ESS with specified kW and kWh sizing.

Decentralized:

In this approach, two or more energy storage systems are installed on the circuit, further away from the substation and closer to load centers. Similar to the centralized approach, the distributed approach attempts to reduce the maximum loading of the circuit below the thermal ampacity in the analysis year and therefore deferring distribution system upgrades. However, dividing the ESS and installing them at different location helps manage the distribution congestion more efficiently throughout the circuit.

The main advantage of the distributed ESS approach is to reduce the size of ESS by dividing it among multiple units, as well as enabling additional stacking applications for voltage and reactive power support on the circuits.

The sizing approach is very similar to the centralized approach,

1. **Size determination**: Historical load profile (2016) are used to estimate a projected load profile for a 5-year upgrade deferral analysis:
   - Considering year 2019 as the analysis start year, a projected load profile for study year (2024) is created by escalating the load growth based on the historical load profile of 2016 and the maximum loading of the circuit determined.
     - Load growth % was an input provided by SDG&E per circuit identified for capacity upgrade deferral
     - If load growth % information was not available, a 0.5%-1% growth factor per year was assumed
   - The number of hours/days there is a violation of thermal loading of the circuit is determined
   - Thermal limiting points (TLPs) of the circuit downstream of the substation are determined and the effect of installing multiple ESSs downstream of TLPs assessed on ESS sizing and applications.
   - The geographical map of the area is investigated to finalize the multiple ESS locations based on space availability to install the ESS.
   - Based on the aforementioned analysis, the ESS locations, MW size and MWh capacity per year on 5-year basis are determined.
2. **Size verification**: Distribution Planning Tool 4 – Python combination is used to run the circuit load flow with the multiple ESS installed downstream of the substation, close to load centers. In this analysis the projected annual load profile (year 2024) is used with 15 minute resolution to verify the satisfactory performance of the ESS with specified kW and kWh sizing and modify the kW and/or the kWh capacity of the ESS if required.

2.5.1.3 Step 3 - Co-optimization of market services

Capacity upgrade deferral only requires the use of an energy storage system (ESS) during peak months at most. The rest of the year the ESS asset is not used for this core distribution reliability function (primary application). The peak shifting effect of capacity upgrade deferral necessarily provides some savings in wholesale energy costs via time arbitrage depending upon the ratio of on peak to off peak prices; these savings flow to the ratepayers (or so it is assumed). During the period of the year when the storage asset is not required for deferral; this time arbitrage is still possible. This service results in additional ratepayer savings when the asset is assumed to be utility owned with all energy cost savings passed on to ratepayers. The ability to fully utilize the storage this way adds to the business case and economic assessment (Secondary application).

Many analyses also examine “shared applications” or “hybrid application” meaning that the storage is also used for ancillary services provision. The recent FERC NOPR (Docket No. PL17-2-000January 2017) on storage in the wholesale markets encourages the aggregation of distributed storage resources for market participation and would open the door for ancillary service provision. However, this is definitively a market function and a regulated utility in a restructured environment in general today cannot act as a market participant. In order to achieve the shared applications model, the storage asset must be “shared” on some basis between the utility (for reliability functions) and a market participant (for market functions). This implies that the full benefits of market participation for ancillary services would not necessarily flow to ratepayers, depending upon whether the utility owns the storage and “rents” it out to participants when not needed or the utility contracts for its use via a kind of PPA agreement, with a developer owning the storage and using it in the markets. The FERC NOPR would

suggest that this could change to allow regulated utilities to exploit stacked applications for the benefit of ratepayers.

This project analyzes three different variations of the hybrid application:

- Capacity Deferral Only (CD): Utility owned storage used for capacity upgrade deferral only. All arbitrage gains flow to ratepayers but when the storage is not needed for capacity deferral it sits idle. This generally justifies the smallest amount of storage and results in the weakest business case.
- Capacity Deferral and Arbitrage (CDA): Utility owned storage used for capacity upgrade deferral as a priority and for time arbitrage with "smart" charging to optimize energy wholesale costs throughout the year, with all savings passed to ratepayers. This model justifies somewhat larger storage installations and results in more feeders having storage as a viable business case.
- Capacity Deferral, Arbitrage and Ancillary service Market (CDAAM): Storage used for capacity upgrade deferral as a priority, with wholesale arbitrage and ancillary services provision (regulation and ancillaries) co-optimized as would be done by a sophisticated market participant. All economic benefits are assumed passed to ratepayers on some basis for the purposes of this roadmap. This case results in the most number of circuits justifying storage with the largest amounts of storage.

In each case, detailed technical, economic, and market operations analysis are required to understand not only whether storage is viable on a given circuit or location, but also exactly how much storage and for how long it is deployed before the circuit is upgraded.

Another important variation is the disposition of the storage after the deferral period. Many analyses assume that the storage is simply disposed of after the deferral period. This is uneconomic as the storage may have 50% or more of its useful life remaining. Here, we examines two variations:

- The storage is relocated to a new feeder (Out) for capacity upgrade deferral at the end of the deferral period (which means its remaining capital value after depreciation is transferred to a new feeder application), or
- The storage is left in place (In) and used purely for wholesale energy arbitrage. Both alternatives may result in positive business cases depending on cost of T&D upgrades, storage cost and storage market participation.

An overview of the capacity deferral valuation process as used to evaluate sample SDG&E circuits in this project is shown in Figure 2-6 below.

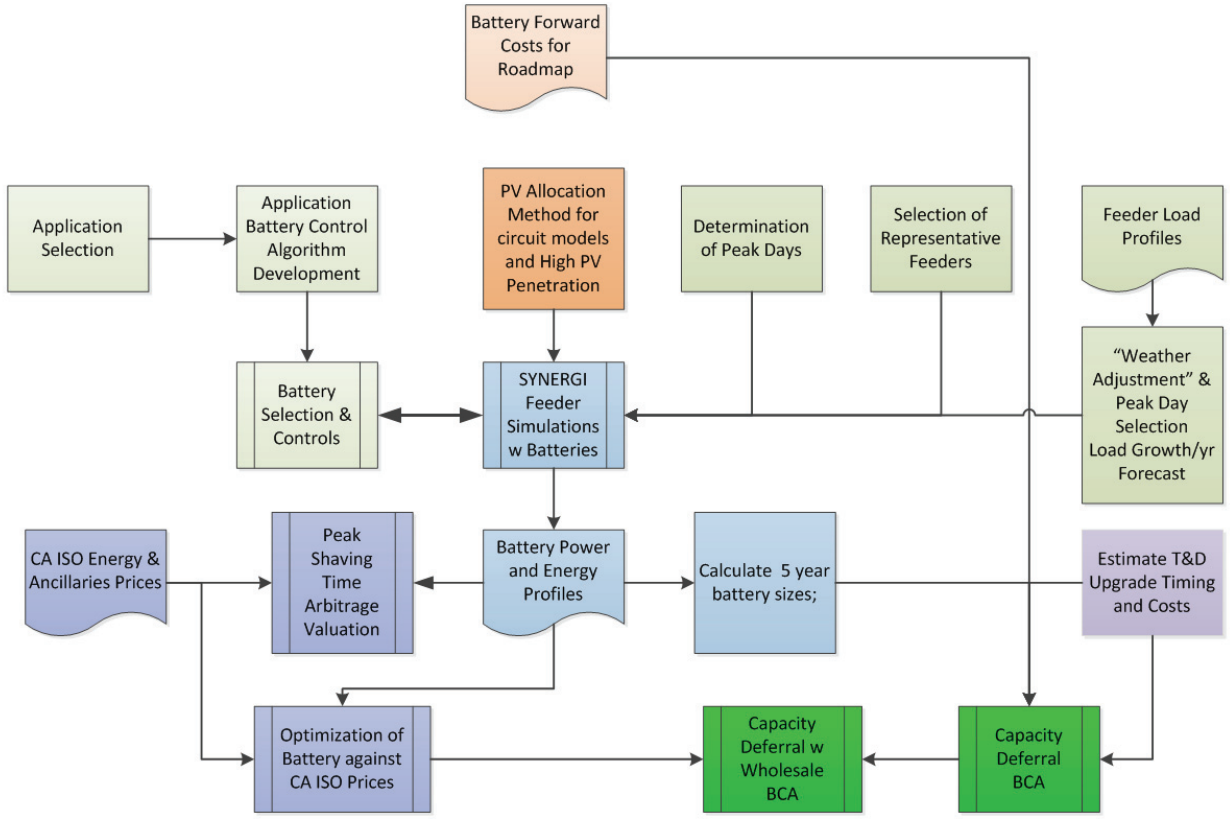


Figure 2-6. Overview of the capacity deferral valuation process as used to evaluate sample SDG&E circuits

2.5.1.4 Step 4 - Cost benefit analysis

The cost benefit analysis is accomplished by the following steps:

- What is the size of storage needed to address a given situation
- What is the cost of that storage
- What is the cost of the "traditional" distribution construction/upgrade alternative
- What is the Net Present Value of the difference in costs of the two approaches

The size of the storage has the two parameters of power capacity and energy capacity or duration – each of which influence the battery cost.

The cost of the traditional solution can be a generalization as in FERC Form 1 data on the cost of a MW of distribution capacity or can be an entry for each case.

For each circuit, the economics of T&D capacity upgrade deferral (5 year deferral) are evaluated. In this analysis it is assumed that year 0 is 2019. The "base case" is a distribution capacity upgrade in the first year (2020). It was assumed that when capacity expansion is done, the circuit will be upgraded to accommodate 10 years of load growth, and a generic cost per MW of upgrade (to cover transformer, circuit breaker, exit cable, conductor, switchgear – all in) is applied. Storage is being used as an alternative to defer upgrade for 5 years.

Battery costs in future years can originate from industry surveys, from vendor quotations, or from applications of costing tools such as the Argonne National Laboratories Bat-Pac tool[1].

The upgrade resulted in a cash cost in the year of deployment, plus an ongoing OPEX cost and financing cost to the utility. It is also assessed for ratepayer impact in terms of ongoing revenue requirement. Table 2-8 provides a sample of typical assumptions made in the model.

Table 2-8. Sample of typical assumptions and parameters

Parameter	Value	Comment
Battery MW cost $k/kW	$300	cost of inverter
Battery MWH cost $k/kWh	$200	cost of container
installation cost / kWh	$150	cost related to any work required to pick up the equipment at site and place it on the foundation, secure it on the foundation
Battery depreciation / yr	10.00%	Book Depreciation
Opex on Battery	5.0%	Service and maintenance

Each storage alternative is evaluated as follows:

- The storage is deployed instead of the T&D upgrade and the T&D upgrade delayed to the end of the deferral period (2025).
- The storage incurs cash costs for the installation (engineering, cost of battery, power converter, and balance of system, and erection), ongoing OPEX costs, and removal costs at the end of the deferral period.
- It also incurs depreciation during its deployment.
- At the end of the deployment the assumption is made that the storage will be relocated to another application and the particular feeder deferral "credited" with the depreciated value of the storage.

For each of the capacity upgrade deferral (CD), capacity upgrade deferral plus time arbitrage (CDA), and capacity upgrade deferral plus time arbitrage plus ancillary market (CDAAM) cases the economic benefits (all assumed going to ratepayers) are set against the annual costs of the storage and the ultimate T&D upgrade. These time series of costs and ratepayer benefits can then be compared to the base T&D upgrade on an ongoing and on aggregated cash flow basis.

2.5.2 Reliability Enhancement for Customers – ESS in Microgrid Application

Battery Energy Storage Systems (ESS) provide excellent opportunities to improve system reliability. Depending on the application implemented, ESS can reduce a sustained outage to a momentary outage or potentially completely avoid the momentary. ESS can provide opportunities for reliability improvement in areas where traditional upgrades are expensive, such as in areas with no circuit ties

[1] http://www.cse.anl.gov/batpac/about.html

capabilities. These can occur in rural areas or even in urban areas with limited access by other circuits. Areas with high PV penetration can also be evaluated to integrate with ESS for Microgrid applications.

For the purpose of customer-based reliability enhancement, the priority is to utilize ESS to serve the load of a selected area on the circuit during outages (islanded microgrid). In the microgrid application, ESS would be the primary source of grid-forming and supplying loads during outages. For this purpose, ESS should be equipped with appropriate control framework to provide voltage and reactive power control and frequency regulation. The area under ESS coverage (microgrid boundaries) should be bordered by reclosers or SCADA switches to isolate the area subsequent to islanding in upstream grid.

Beside from the microgrid application, the ESS can be also utilized for some secondary applications such as market participation and voltage support during normal operation. However, the utilization of ESS for these secondary applications should be limited such that there is always enough State of Charge (SOC) available in there battery to be utilized for customer support during unplanned outages.

2.5.2.1 Step 1 - Perform time series analysis

The ESS sizing was performed by time-series analyzing of maximum demand and reserve capacity (kW, KWh) required to supply customers within the designated microgrid territory during the worst case outage. Three sets of ESS sizing were identified based on evaluating worst case outage time of the year for 4-hour, 6-hour, or 8-hour durations, respectively

2.5.2.2 Step 2 - Calculate ESS sizing

The ESS sizing methodology for microgrid application is shown in Figure 2-7. As seen in this figure, the ESS sizing process is categorized into three main categories, namely:

- Identifying candidate locations for ESS installation
- Determine load allocation
- Calculate ESS sizing for candidate locations

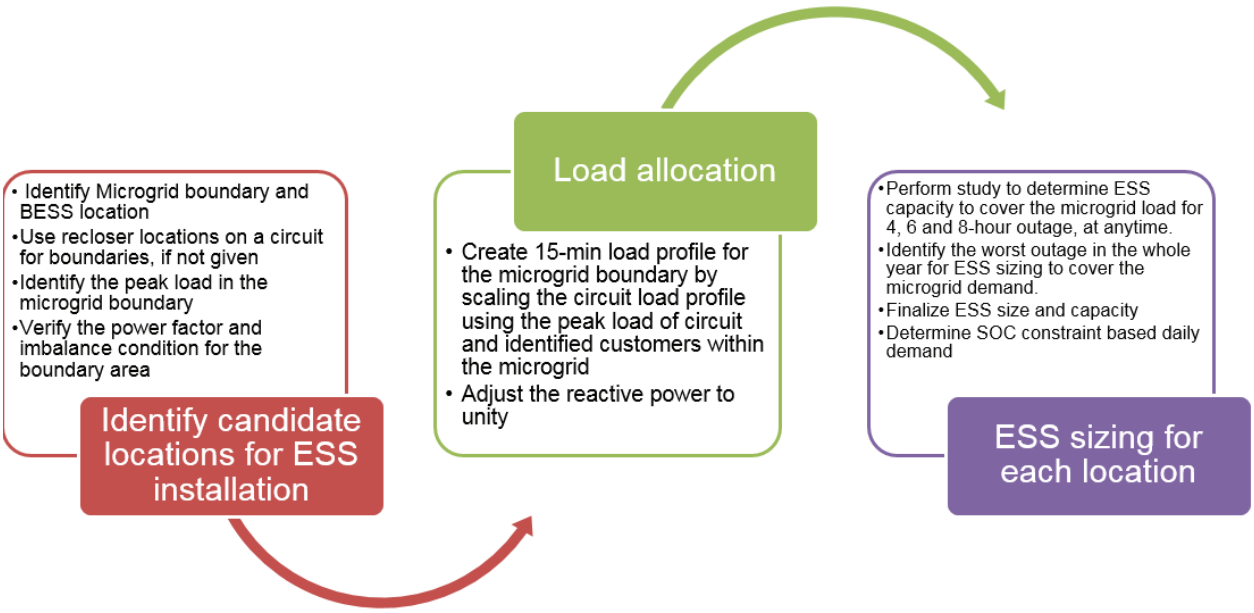


Figure 2-7. ESS sizing methodology for microgrid application

To determine the ESS size, the 15 minute load profile of circuits are utilized. The ESS size is calculated for three different outage durations, 4-hour, 6-hour, and 8-hour. The outage window is moved along the whole year starting from the first hour in January 1st of year under study to the hour 8760. The ESS is sized to cover the microgrid load during the worst outage window. It is assumed that ESS is fully charged before the outage occurs (control scheme based on initial SOC =100%). Additionally, the minimum allowable SOC of ESS is assumed to be 5%.

2.5.2.3 Step 3 - Co-optimization of market services

The objective of this study is evaluating the additional potential benefits of Battery Energy Storage Systems (ESS) by participating in CAISO wholesale and ancillary markets.

Market participation is considered as secondary application where the primary application is reliability enhancement by utilizing ESS to serve the load of a selected area – on a circuit- during outages.

In this analysis, the optimization used the DA prices for charging and the RT prices for discharging, to simulate the strategy described by SDG&E in which charging load is bid into the day ahead markets and discharging withheld from the day ahead (2016 nodal LMP prices are considered). Discharging is offered into the Real Time markets. As an additional step, the strategy of offering RegUp and RegDown services into the CAISO ancillary service markets was evaluated, again at 2016 historical prices. Each day, the optimization would co-optimize the energy and ancillary service participation across the day so as to maximize revenues subject to BESS operational constraints. Adding regulation services to the product portfolio accessible to the Escondido BESS increases revenues as would be expected.

For market participation analysis two alternatives are considered. These are

- Only participation in wholesale market, and

- Participation in both wholesale and regulation markets.

The analysis considers different outage durations and summarizes the market participation benefits for these outage scenarios. An Energy Credit is calculated for each scenario using the discharging revenues less the charging payments when only wholesale energy participation is considered. These energy credits in the wholesale and regulation case also include an estimate of the settlement of regulation revenues at RT prices. Generally, energy credits decrease as regulation capacity increases, as less battery capacity is then available for arbitrage.

In regulation market benefits calculations the mileage payment is a straight forward computation using the CA ISO 2016 historical data for up and down mileage factors and battery accuracies. The ISO data does not appear to facilitate the direct calculation of the energy credit for RegUp and RegDown energy. (The mileage factor is related to the length of the curve of AGC dispatch signals, not to the area under the curve). For purposes of this estimate, a figure of ½ of the Reg Capacity in each 15-minute period was used to estimate the RegUp and RegDown energy. This then became an increment/decrement to the BESS state of charge beginning the next 15 minute period, and was used to calculate regulation energy credits.

Annual market benefits are calculated as a summation of energy, Regulation Up and down Capacity, mileage credits less the variable O&M (VOM). Note: VOM of 0.00579 $/kWH is considered for both charging and discharging of the battery.

Utilization of ESS for some secondary applications (e.g., voltage support and market participation) should be subjected to some constraints to ensure the availability of energy required to serve the load if outage happens anytime during the day. For this purpose, the following energy constraints are calculated:

- SOC Day Long: The minimum required SOC for BESS to be armed for possible outage happening during the day.
- SOC Day End: The required BESS SOC at the end of the day.

2.5.2.4 Step 4 – Cost/benefit analysis

In order to perform cost/benefit analysis for ESS in microgrid application, the cost of alternative (wire-base) solutions were establishes as follows,

- Cost of doing nothing option: For each microgrid, the 5-year historical outage data and customer demography information were used to perform ICE Calculation to determine loss of business cost for various customers.
- For microgrid on circuits that are in boundary areas (there is no alternative path) the 20 years NPV of that cost was assigned to the business case.
- For microgrid on other circuits, cost of extending an additional circuit and/or upgrading a tie line to serve the area through an alternative path was determined. The lowest alternative option cost was assigned to the business case
- For all microgrid cases, the revenue estimate for participation in the wholesale market with capacity constraint was used as the direct revenue for the business case.

2.5.3 PV Integration Mitigation

High penetration of PV systems (both centralized and distributed) across a distribution circuit can cause significant over/under voltage conditions, visible flicker events, and possibly excessive ramping up and down. Active and reactive power produced from the PV system can have an effect on the steady-state circuit voltage (Even if the PV system does not produce reactive power, the high real power flows will induce reactive power in the circuit reactance.). Moreover, fluctuations in the PV output would cause voltage fluctuations on the circuit. BESS can be used to mitigate the aforementioned issues by controlling active and reactive power on the circuit at pre-determined locations.

The impacts of high PV penetration is highly pronounced when the feeders are lightly loaded and at the same time a large amount of PV is connected. Thus, for each of the selected circuits the day with the minimum loading in the year 2016 was chosen as the desired study day. A combination of the aforesaid chosen day and the PV profile scaled to the maximum installed PV size of the circuit provides the worst case scenario for the PV impact analysis.

2.5.3.1 Step 1 - Perform time series analysis

The system is first modelled without a BESS to produce baseline results, and then again after the BESS is deployed to verify the issues have been mitigated. The approach is as follows:

PV only, no BESS

- For selected circuits, time series analysis is performed to determine whether the existing (or expected) PV penetration level can introduce any voltage or power quality issue.
- 10 second solar radiation profiles are used for the PV production estimation.
- The existing/expected PV systems are identified in Distribution Planning Tool 4 model to incorporate variable profiles.
- 15 minute annual load profile extracted from SCADA system at the circuit head is used to perform load allocation at given steps of analysis.
- Based on resolution of load and PV profiles, 10-second time steps are used for Distribution Planning Tool 4 time series analysis. At every time step, PV system outputs are updated and a power flow is performed. At every 15 minutes, a load allocation is performed to re-assign the total circuit load (from SCADA) to the distributed and spot loads on the circuit.
- Time series analysis are performed on daily basis, and for the entire year.
- At each time step, voltage and power flow values at pre-selected metering locations on the circuit model are captured and saved in a file. The locations of interest are typically: at circuit head, at PV interconnection points, on secondary of line voltage regulators, at shunt capacitor locations, and toward the end of circuits or major branches.
- Voltage and power flow data are analyzed to determine any potential for flicker events or ramp rate issues.
- Figure 2-8 below shows an example of the flicker calculation curve for a circuit that includes a large PV system. As shown, the flicker level is above the visibility level in several instances, close to or below the irritation level (based on old GE flicker curve), or below the IEEE flicker curve; and would therefore require mitigation.

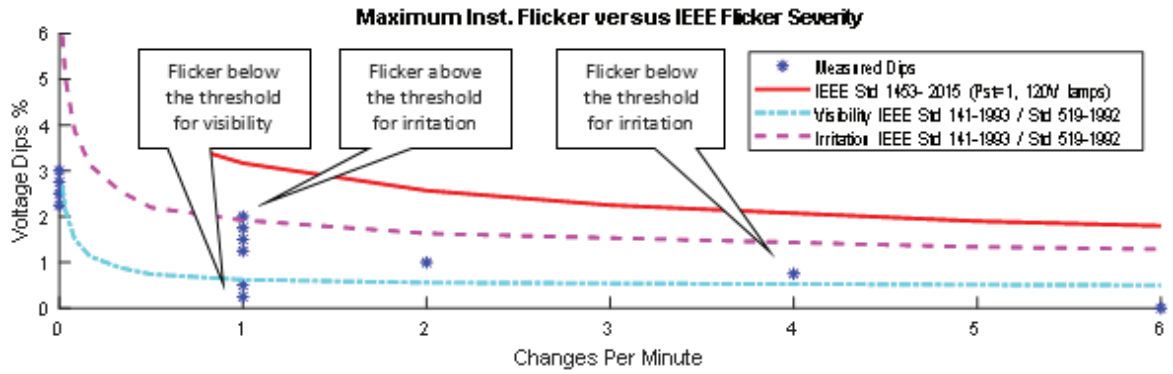


Figure 2-8. Sample flicker calculation curve

Figure 2-9 illustrates the flowchart of the Distribution Planning Tool 4 – Python interface. As shown, the first step is to input the PV and loading profiles of the chosen circuit. As it was previously mentioned, the resolution of the PV and loading profile are 10 seconds and 15 minutes, respectively. Thus, the load allocation is done every 15 minutes while the load flow analysis is done every 10 seconds and for each PV data. Moreover, it must be mentioned that in order for the load allocation function of Distribution Planning Tool 4 to work properly, all the loads and generators in the circuit must be turned off. Hence, after updating the power output of the PVs as a percentage of their corresponding ratings, the simulation time is checked to see whether 15 minutes has passed or not, if yes, all the generators and loads are turned off, the load allocation is done, and then the aforesaid generators and loads in the circuit are turned back on. Further, the load flow analysis is done and the results are stored for further analysis.

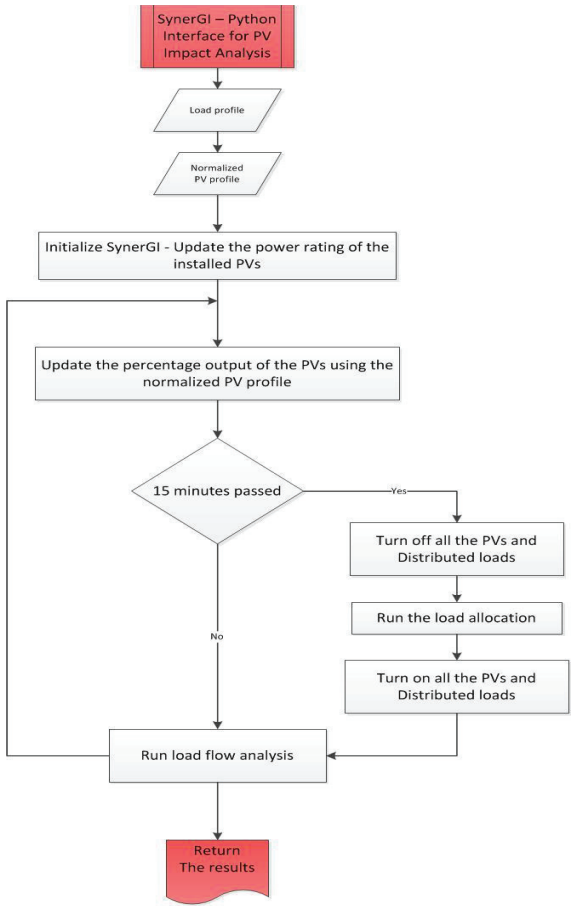


Figure 2-9. Distribution Planning Tool 4 – Python interface flowchart without the battery

PV and BESS

For the cases where a mitigation solution is required, a BESS model is incorporated in the Distribution Planning Tool 4 model close to the mitigation point. Two algorithms are used to determine BESS setpoints for active and reactive power exchange with the grid.

- In one case, (and technically when there is no ramp rate issue), voltage control function is used to determine reactive power setpoint of the BESS at every step. Time series analysis is performed to regulate voltages.
- In a case where voltage control through reactive power control is not effective and/or active power contribution from the battery is needed to manage the ramp rate below a given threshold, the BESS control function for P setpoint is also applied. The time series analyses are performed with new P and Q setpoints for the BESS.
- The new voltages and power flow values are captured and re-assessed.

The Distribution Planning Tool 4 – Python combination along with daily 15 minute load profile and PV data (10 second time steps) are used for final assessment of the PV impact mitigation with Energy Storage System (ESS) on the chosen circuits. Figure 2-10 illustrates the flowchart of the Distribution Planning Tool 4 – Python interface in presence of the battery model in Distribution Planning Tool 4. After

inputting load and PV profiles, the Distribution Planning Tool 4 model is initialized and load allocation is done (with PVs turned off) every 15 minutes. The load flow is run (with PVs turned on in the model) and the load flow results are input to the battery function. The voltage control function of the battery is called and the battery charge/discharge to control the voltage (both intermittency smoothing and voltage droop control) is calculated. Based on the battery output, the battery model parameters are set in Distribution Planning Tool 4 and the load flow will be run for the second time to capture the results with the battery performance.

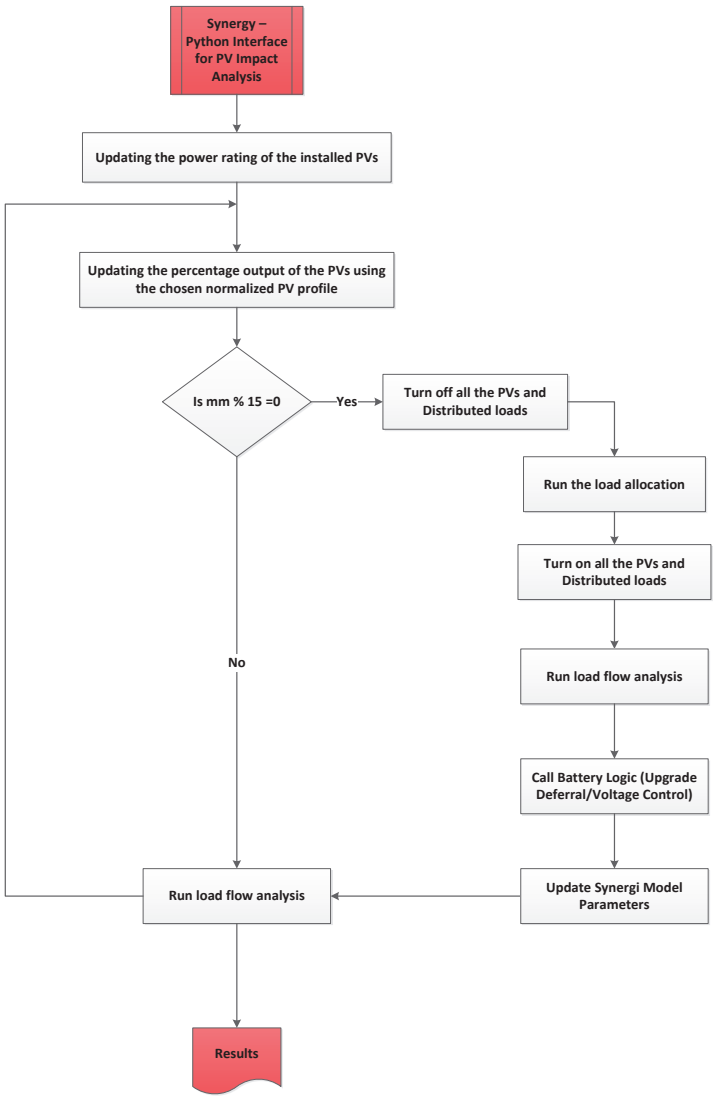


Figure 2-10. Distribution Planning Tool 4 – Python interface flowchart with the battery

2.5.3.2 Step 2 - Calculate ESS sizing

The maximum BESS P size and the maximum cumulative energy during the charge or discharge are used to calculate BESS size and capacity.

2.5.3.3 Step 3 - Co-optimization of market services

The CAISO market participation is considered as secondary application when the primary ESS application is PV smoothing. The process of calculating ESS charge/discharge constraints for CAISO frequency regulation market participation is summarized as follows:

1. First, rate of change of active power generation (RCOP) limits at the location of ESS are calculated according to the flicker limits. The flicker limits represent the maximum acceptable voltage change per minute (dVm). For example, dVm is 2.72% for one change per minute (applicable to real time market) and 1.5% for frequency regulation based on 4 second reg up and down CAISO signals. RCOP can be positive and negative depending on the impact on the voltage deviation. For example, a positive RCOP would increase the voltage at the point of connection (POC) of ESS, while a negative RCOP would decrease the voltage level at POC. To ensure that POC voltage always remain in the flicker limits (i.e. ±dVm from the nominal voltage). The maximum and minimum RCOP limits at the POC (RCOP_max and RCOP_min) are calculated using the equivalent circuit model at POC. The equivalent circuit at POC is modeled using the circuit model in Distribution Planning Tool 4.
2. The rate of change of power flow at POC is calculated using the time series analysis on the minute-by-minute load and PV profile.
3. At each time instant, the minimum ESS charge/discharge limits required for PV smoothing are calculated using the rate of change of power flow and the RCOP_max and RCOP_min calculated above. For example, if PV minus load at a specific time has a sudden ramp up that violates RCOP_max, the voltage at POC would have a sudden increase that violates (1+dVm) pu flicker limit. To avoid the violation, ESS should have a minimum charging rate. This charge rate is considered as the minimum ESS charge limit at that specific time.
4. At each time step, the maximum ESS charge/discharge limits are calculated using the rate of change of power flow, the minimum charge/discharge limits, and the RCOP_max and RCOP_min calculated above. For example, if a minimum charging limit is calculated for ESS to keep the POC voltage below (1+dVm) pu, the maximum ESS charging should be also limited to ensure that POC voltage does not fall below (1-dVm) pu.

The minimum and maximum PV smoothing charge/discharge limits for market participation are calculated for one of the SDG&E sample circuits. The market studies for this sample circuit considering the minimum and maximum PV smoothing charge/discharge limits are summarized in following sections.

2.5.3.4 Step 4 – Cost/benefit analysis

In case of PV related voltage and flicker impact mitigation, the cost of alternative (wire-based) option was calculated based on deploying localized or distributed secondary voltage control devices on all affected service transformers, using the following approach:

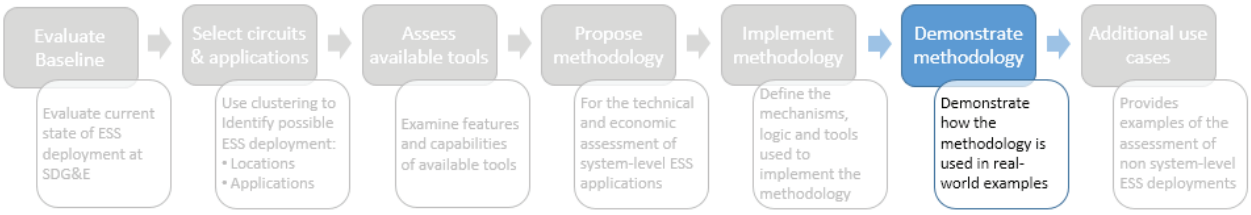
- For each circuit with PV impact, the circuit nodes affected by PV systems were identified.
- Using GIS database and circuit map, the number and size of service transformers in the affected region were determined
- Total cost of deploying secondary devices were determined by multiplying the cost of deploying each secondary device (about $15k per 50 kVA size device installed) with the number of devices required.

- Note that 50kVA is the only commercially available size. The number of devices required per service transformer need to be calculated on this basis.

3 SUMMARY OF THE PROJECT RESULTS

3.1 Task 6: Demonstrating the methodology

This task demonstrated examples of how the ESS analysis tools can be applied and how the results can be used in selection of project sizes, locations and applications as well as business case development and justification of ESS projects.



3.1.1 Capacity Deferral

The initial analysis targeted the circuits close to their thermal capacity which will be dealing with over-loading conditions in a 5-year time frame. Three circuits were identified (Table 3-1).

Table 3-1. Summary table of the selected circuits for the upgrade deferral application

Circuit ID	2019 forecasted load (A)	Average forecasted load growth per yr 2019 to 2021	SDG&E Ampacity (A)	Distribution Planning Tool 4 Ampacity (A)	Circuit PV Size (kW)	Number of Capacitors	Number of Voltage Regulator	10 yrs Capacity (MVA)
CCUD 1	369	3.30%	408	395	981	1	0	10.4
CCUD 2	564	1.30%	600	580	580	1	0	13.5
CCUD 3	558	1.40%	600	580	935	1	0	13.5

***Note**: In the sections that follow only the data for CCUD 2 are presented. However, the same analysis was performed for CCUD 1 and CCUD 3, and these data are provided in the Appendix.*

3.1.1.1 BESS Sizing

3.1.1.1.1 Study results for the centralized approach on CCUD 2

For CCUD 2, centralized deferral approach, the battery was installed at the beginning of the feeder. The battery was initially sized as 0.5 MW, 0.75 MWh (see Figure 3-1).

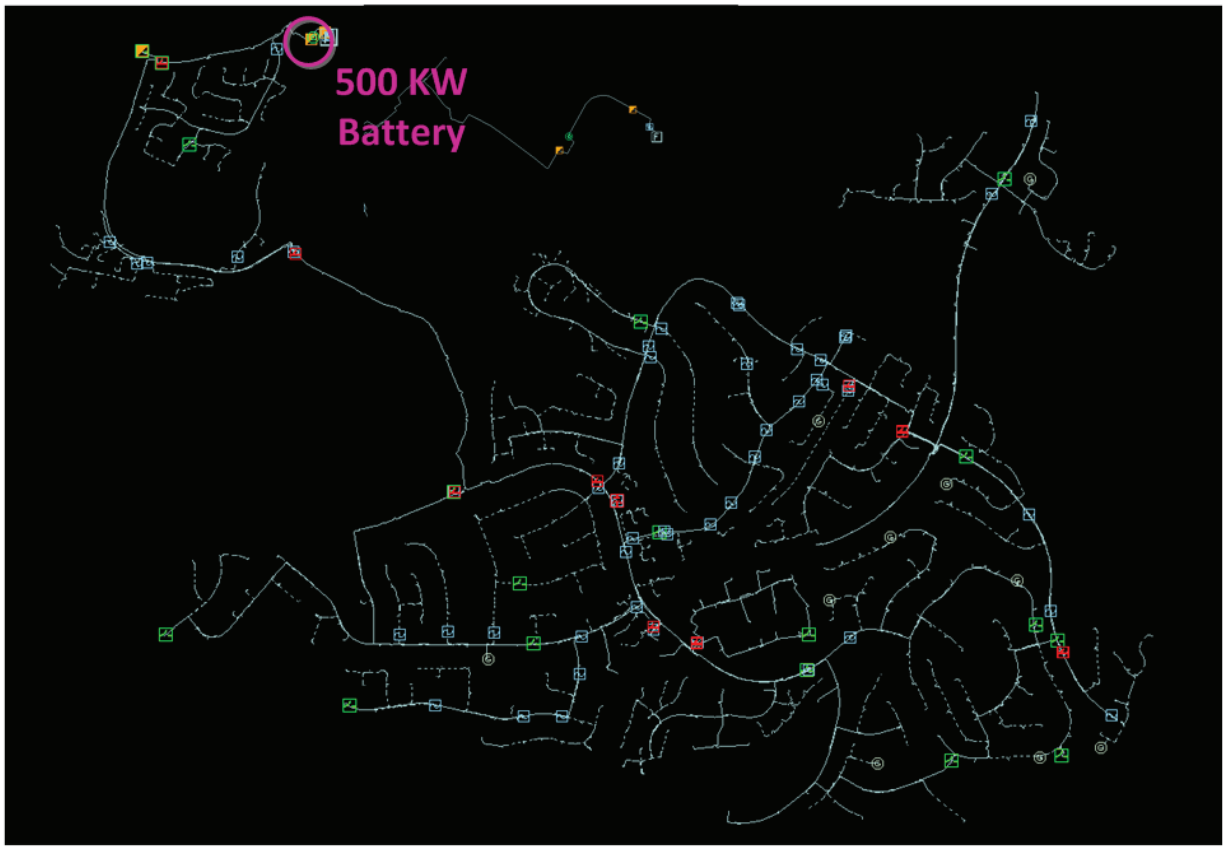


Figure 3-1. Location of the battery for circuit CCUD 2

The circuit under study has a thermal loading limit of 580 (A) determined in Distribution Planning Tool 4 model. This limit was used as the upper threshold of the circuit for peak shaving purposes. For the lower threshold zero was used to make sure that the reverse power flow is prevented. Also, the battery is scheduled to charge between 0:45 am – 5:00 am up to 95% in order to provide enough energy for discharging throughout the day.

In order to consider the worst-case scenario, the maximum peak day of year was determined for the projected (year 2024) load profile and the PV systems have been turned off during the analysis.

Figure 3-2 demonstrates the feeder power flow before and after the upgrade deferral application. The battery was charging during the scheduled charging zone up to 95% SOC and then maintained the feeder power below 12,055 kW during the day.

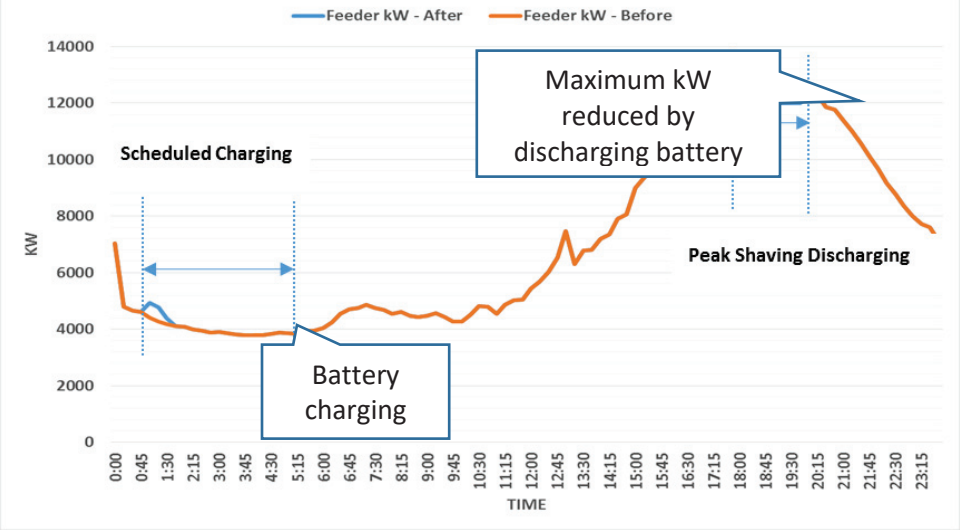


Figure 3-2. Power Flow (Centralized Upgrade Deferral) for CCUD 2

As illustrated in Figure 3-3 below, the battery charges/discharges up to the maximum rate of ~**500 kW**.

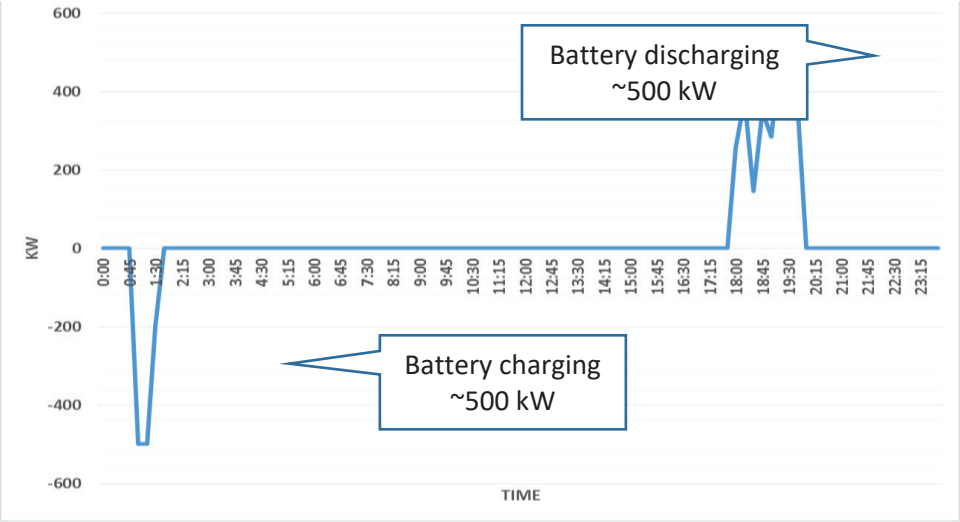


Figure 3-3. Battery Output Power (Centralized Upgrade Deferral) for CCUD 2

Figure 3-4 illustrates the battery state of charge for the day.

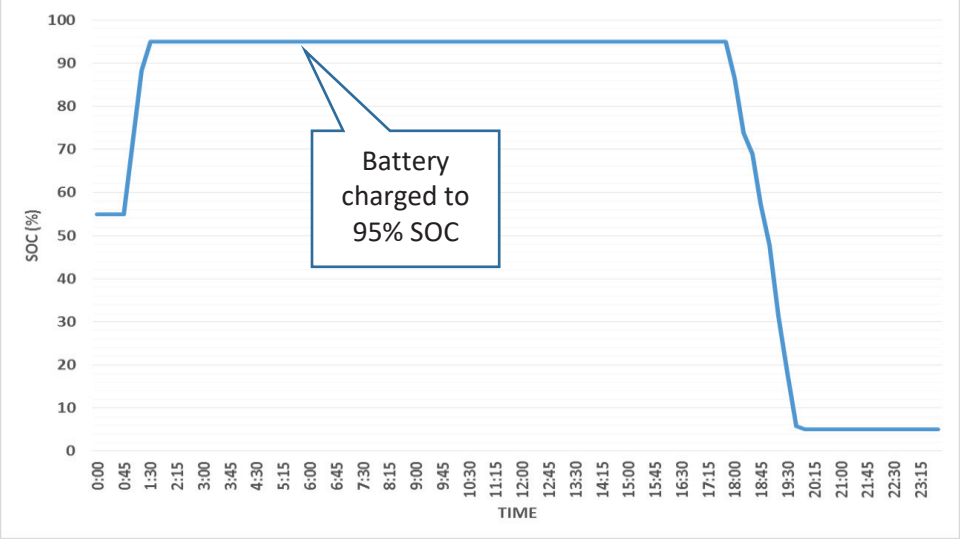


Figure 3-4. Battery State of Charge (Centralized Upgrade Deferral) for CCUD 2

The accumulative discharge of the battery by the end of the day, is almost 700 kWh (Figure 3-5) which reflects the maximum amount of energy required from the battery and justifies using a **750 kWh** battery.

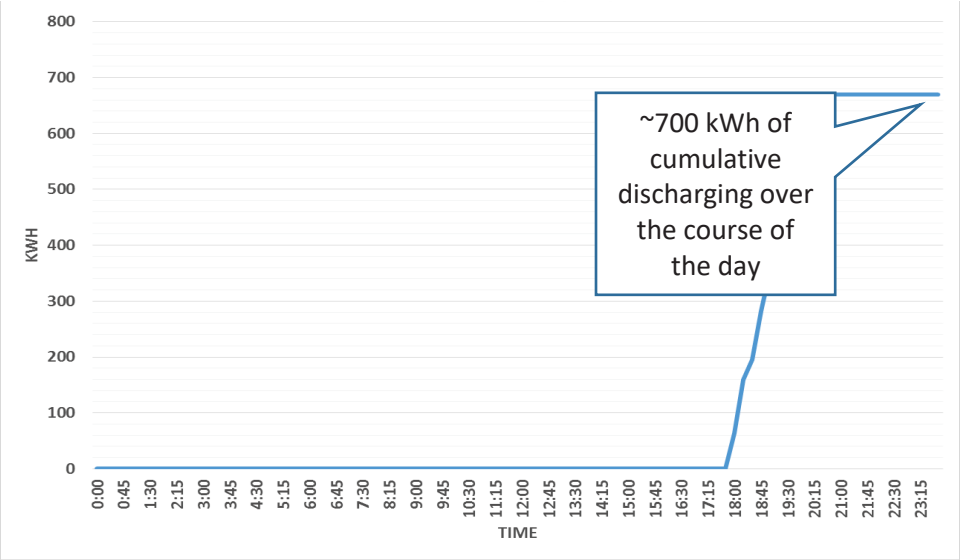


Figure 3-5. Accumulative Discharge (Centralized Upgrade Deferral) for CCUD 2

Using the analysis above, the BESS for the centralized approach was sized as **500 kW / 750 kWh**

3.1.1.2 Study results for the decentralized approach on CCUD2

For CCUD 2, distributed deferral approach, the battery was installed at two locations (see Figure 3-6) based on the thermal limiting points of the feeder as well as the space availability for battery installation. The proposed locations of two batteries have been shown in. The batteries have been initially sized as 0.4 MW, 1 MWh.

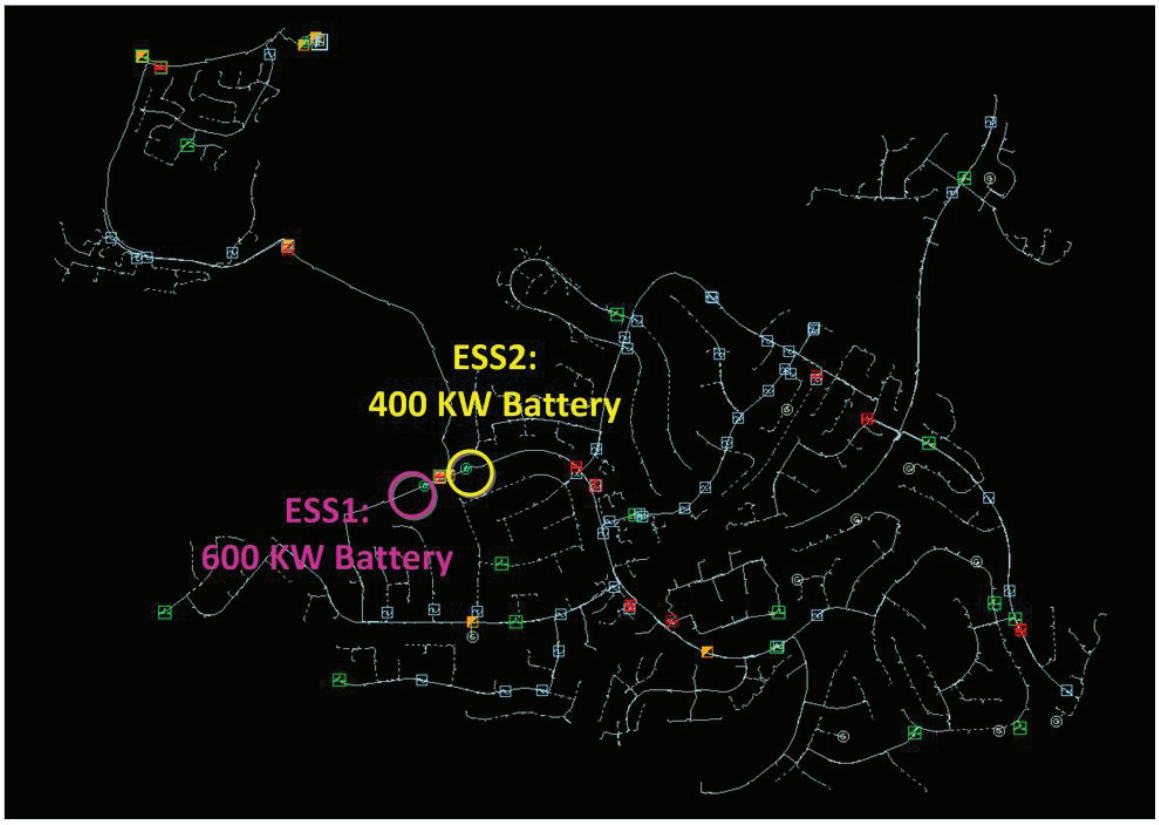


Figure 3-6. Battery Locations for CCUD 2

The circuit under study has a thermal loading limit of 580 (A) determined in Distribution Planning Tool 4 model. This limit was used as the upper threshold of the circuit for peak shaving purposes. For the lower threshold zero was used to make sure that the reverse power flow is prevented. Also, the battery is scheduled to charge between 0:45 am – 5:00 am up to 80% in order to provide enough energy for discharging throughout the day. In order to consider the worst-case scenario, the maximum peak day of year was determined for the projected (year 2024) load profile and the PV systems have been turned off during the analysis.

The excess feeder power to be provided from two batteries is divided between the batteries with respect to their kW rated ratios.

Figure 3-7 demonstrates the feeder power flow before and after the upgrade deferral application. The battery was charging during the scheduled charging zone up to 80% SOC and then maintained the feeder power below 12,055 kW during the day.

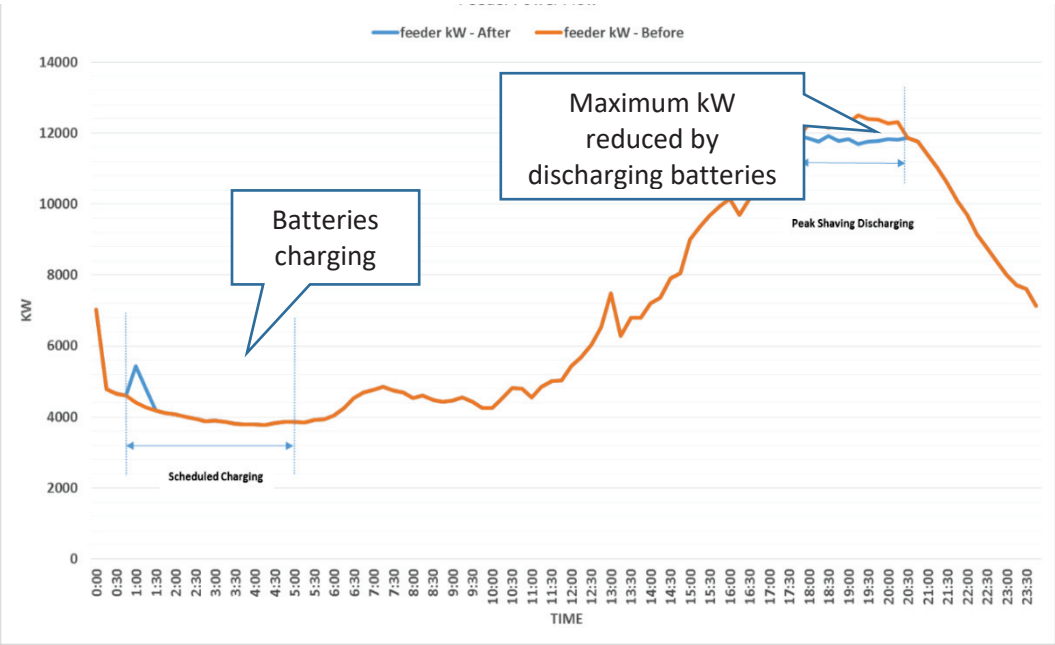


Figure 3-7. Power Flow (Distributed Upgrade Deferral) for CCUD 2

As illustrated in Figure 3-8, ESS1 and ESS2 charge/discharge up to the maximum kW rate of **600 kW and 400 kW** respectively.

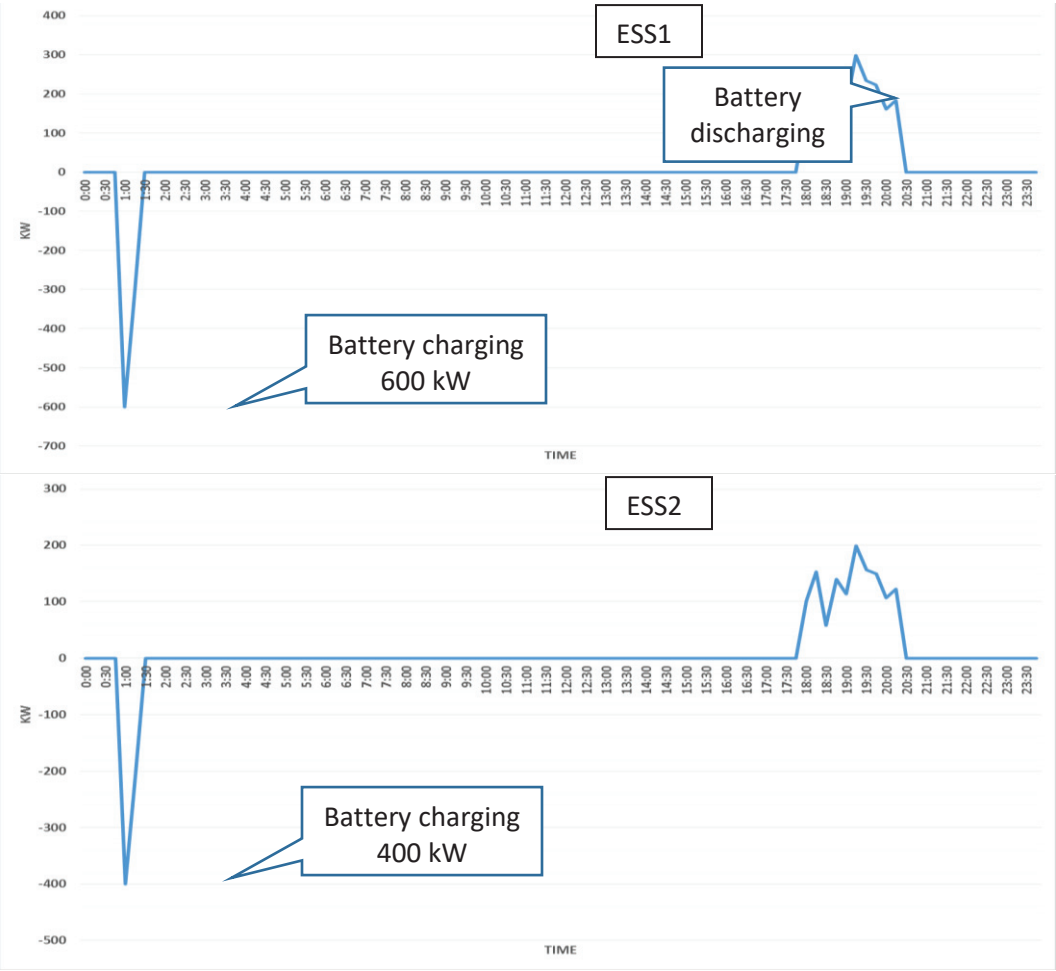


Figure 3-8. ESS1 and ESS2 Output Power (Decentralized Upgrade Deferral) for CCUD 2

Figure 3-9 illustrates the state of charge for the two BESS during the day.

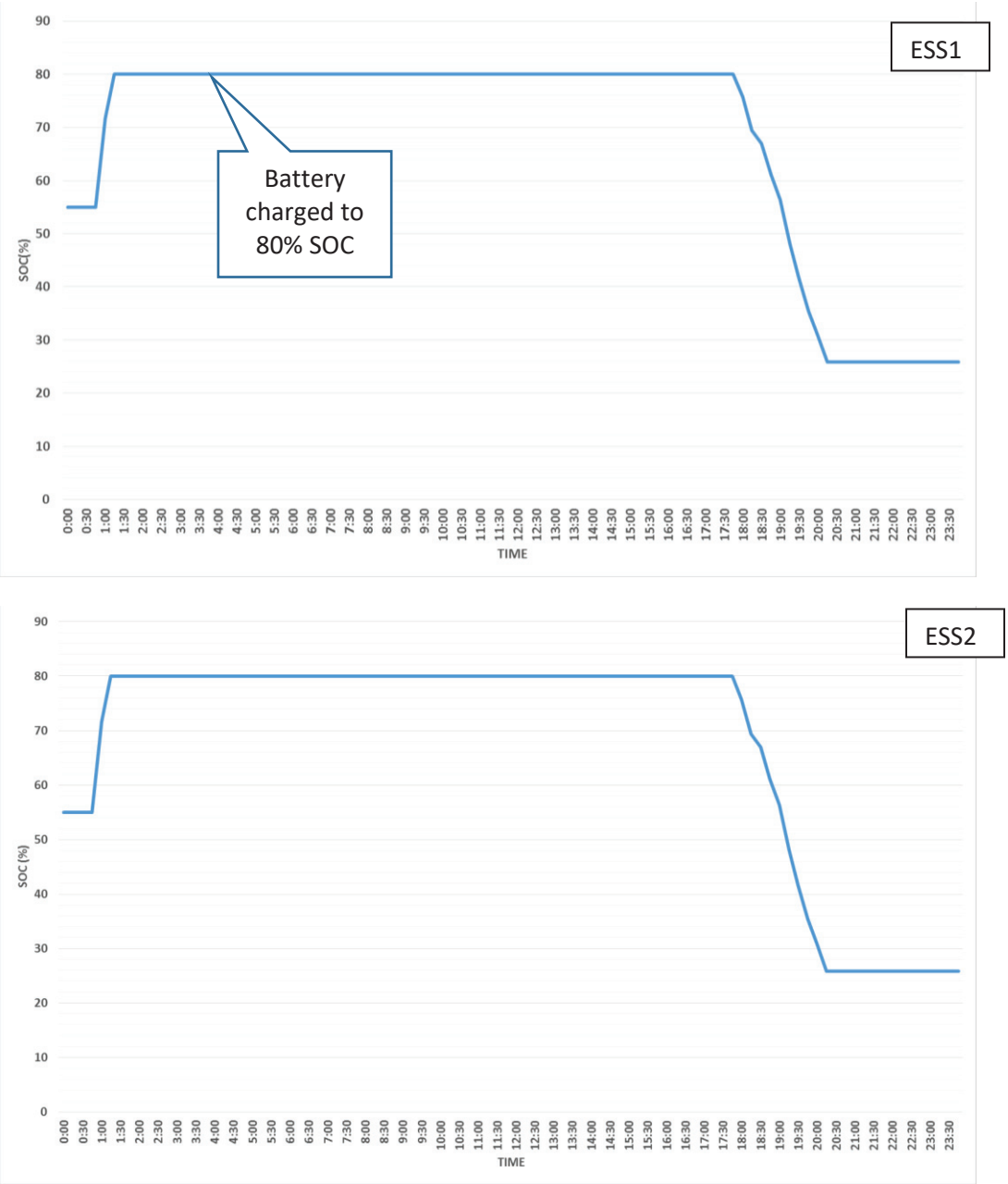


Figure 3-9. ESS1 and ESS2 State of Charge (Distributed Upgrade Deferral) for CCUD 2

The accumulative discharge of the battery by the end of the day, is almost 500 kWh for ESS1 and 320 kWh for ESS2 (Figure 3-10) which reflects the maximum amount of energy required from the battery and justifies using a one hour battery for each (**600 kWh for ESS1 and 400 kWh for ESS2**).

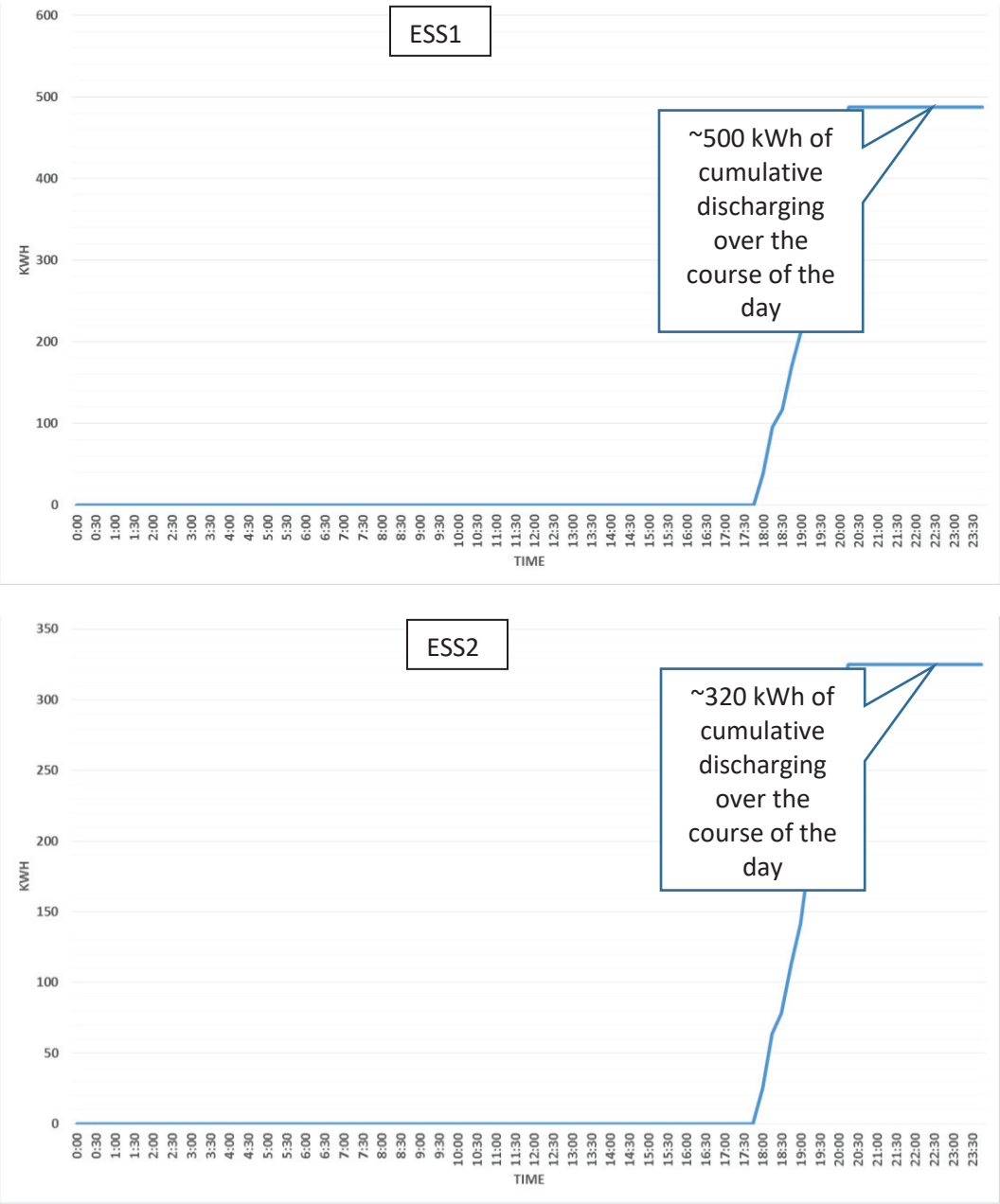


Figure 3-10. ESS1 and ESS2 cumulative discharge (Distributed Upgrade Deferral) for CCUD 2

Using the analysis above, the two BESS for the decentralized approach were sized as **600 kW / 600 kWh** and **400 kW / 400 kWh.**

3.1.1.3 Cost/benefit analysis

A mixed integer programming (MIP) optimizer formulated for optimizing storage participation in energy and ancillary service markets was used to optimize storage discharging and charging against annual load profile time series for the three circuits simulated in Distribution Planning Tool 4.

The size of the storage used for the required peak shaving in 2024 was taken from the Distribution Planning Tool 4 simulations (as shown in Table 3-2 below that tabulates both storage sizes[2] and capital costs).

Table 3-2. Required Battery Size and Projected Capital Cost

Circuit ID	Storage Power Rate (MW)	Storage Energy Capacity (MWh)	Projected Battery Cost in 2019 ($K)
CCUD 1	0.7	3.5	$1,435
CCUD 2	0.5	0.75	$413
CCUD 3	0.5	1.0	$500

The MIP algorithm then optimizes the charging and discharging for each day in the year to achieve the peak shaving goal (CD). Furthermore, MIP optimizes arbitrage benefits as a secondary application of storage in CDA case, as well as co-optimizing wholesale and ancillary market participation in CDAAM scenario.

Table 3-3 summarizes annual market benefits (revenues) for three circuits. CAISO 2016 nodal day-ahead and real-time prices as well as day-ahead regulation market prices are applied for market benefits calculation. Annual CDA and CDAAM market benefits (revenues) beyond 2024 (only for battery in) are assumed to be identical to the 2024 values, note.

Table 3-3. Annual Market Revenue ($)

Annual Market Benefits						
Circuit	Operation Strategy	2020	2021	2022	2023	2024
CCUD1	CD	$ -	$ -	$ -	$ 250	$ 838
	CDA	$ 48,742	$ 48,742	$ 48,742	$ 48,728	$ 48,330
	CDAAM	$ 115,003	$ 115,003	$ 115,003	$ 114,990	$ 114,626
CCUD2	CD	$ -	$ -	$ 0	$ 25	$ 77
	CDA	$ 26,955	$ 26,955	$ 26,953	$ 26,918	$ 26,865
	CDAAM	$ 76,302	$ 76,302	$ 76,300	$ 76,265	$ 76,213
CCUD3	CD	$ -	$ -	$ -	$ 10.19	$ 60.78
	CDA	$ 30,350.59	$ 30,350.59	$ 30,350.59	$ 30,313.12	$ 30,267.91

[2] The results for CCUD 2 were calculated in the preceding section; the results for CCUD 1 and CCUD 3 are calculated in the appendix.

	CDAAM	$ 79,060.14	$ 79,060.14	$ 79,060.14	$ 79,030.39	$ 78,986.39

Table 3-4 summarizes cost NPV and aggregated cash flows (revenue requirements) for the immediate T&D upgrades for feeders under the study. This includes annual T&D depreciation, Capex ROI, property & income taxes, and OPEX. A T&D upgrade cost of $921K/MW is assumed.

Table 3-4. Immediate T&D Upgrades NPV Costs and Revenue Requirements (in $K)

Feeder	Feeder Load Growth Rate	Peak load in 2019	Existing Feeder Rating (MW)	Immediate T&D upgrade cost NPV	Immediate T&D upgrade revenue requirements – aggregated cash flows
CCUD1	3.3%	7.5	8.2	$2,099	$4,626
CCUD2	1.3%	11.7	12.05	$2,099	$4,626
CCUD3	1.4%	11.6	12.05	$2,099	$4,626

As is illustrated, CCUD1 has the highest cost NPV for T&D upgrades. This is mainly due to the significant growth load of the circuit compared to the other two circuits, which requires greater T&D MW upgrades. All reported NPV and aggregated cash flows are calculated for a 20 year horizon.

In Table 3-5 and Table 3-6, T&D deferral NPV costs as well as revenue requirements are provided for battery "in" and "out" scenarios, respectively. This includes annual depreciation, Capex ROI, property & income taxes, and OPEX for both battery and T&D upgrades plus potential market benefits.

It should be noted that CCUD1 requires the highest T&D deferral costs mainly due to the large size of the battery and consequently highest capital investment compared to the other two circuits.

Table 3-5. T&D Deferral Costs and Revenue Requirements (in $K) – Battery Disposition Scenario: Out

Feeder	T&D Deferral cost NPV			T&D Deferral revenue requirements – aggregated cash flows		
	CD	CDA	CDAAM	CD	CDA	CDAAM
CCUD1	$2,622	$2,412	$2,126	$5,528	$5,236	$4,838
CCUD2	$1,790	$1,673	$1,460	$4,411	$4,249	$3,953
CCUD3	$1,861	$1,730	$1,520	$4,506	$4,324	$4,032

Table 3-6. T&D Deferral Costs and Revenue Requirements (in $K) – Battery Disposition Scenario: In

Feeder	T&D Deferral cost NPV			T&D Deferral revenue requirements – aggregated cash flows		
	CD	CDA	CDAAM	CD	CDA	CDAAM
CCUD1	$3,498	$3,047	$2,434	$7,673	$6,698	$5,373
CCUD2	$1,969	$1,720	$1,263	$4,890	$4,351	$3,364
CCUD3	$2,100	$1,819	$1,368	$5,129	$4,522	$3,547

In Table 3-7 and Table 3-8, summery of overall benefits are provided for battery in and out scenarios, respectively. In each table ΔNPV benefits as well as Ratepayers benefits are provided for different storage operation strategies. ΔNPV benefits are calculated as NPV costs of immediate T&D upgrades less the NPV costs of T&D deferrals. Ratepayers benefits are calculated as aggregated cash flows of immediate T&D upgrades less the aggregated cash flows of T&D deferrals.

Table 3-7. Overall Benefits comparing Deferral to Immediate T&D upgrades ($K) – Battery Disposition Scenario: Out

Feeder	ΔNPV Benefits			Ratepayers Benefits (Δ Aggregated Cash Flows)		
	CD	CDA	CDAAM	CD	CDA	CDAAM
CCUD1	**-$523**	**-$313**	**-$27**	**-$902**	**-$610**	**-$212**
CCUD2	$310	$426	$639	$215	$377	$673
CCUD3	$238	$369	$580	$120	$302	$594

Table 3-8. Overall Benefits comparing Deferral to Immediate T&D upgrades ($K) – Battery Disposition Scenario: In

Feeder	ΔNPV Benefits			Ratepayers Benefits (Δ Aggregated Cash Flows)		
	CD	CDA	CDAAM	CD	CDA	CDAAM
CCUD1	**-$1,399**	**-$948**	**-$335**	**-$3,046**	**-$2,072**	**-$746**
CCUD2	$130	$380	$836	**-$264**	$275	$1,262
CCUD3	**-$1**	$280	$731	**-$502**	$105	$1,079

Conclusions:

From the above examples, it can be observed that one of the circuits (CCUD1) is not a viable candidate for capacity deferral under any scenario, mainly because relatively large battery size requirement and significant up- front cost.

The second circuit (CCUD2) is a viable candidate for capacity deferral using a BESS under the scenarios where time arbitrage (CDA) or time arbitrage plus ancillaries (CDAA) are allowed. However, this case has also negative ratepayer benefits under a peak shaving only scenario, even though the cash flow NPV is favorable.

The third circuit studied (CCUD3) is even less favorable without the time arbitrage or ancillary service revenues.

For the two latter circuits, an assumption that the BESS may be relocated to another location in 5 years can enhance the financial outcomes. The relocation would occur after the need for capacity upgrade deferral is resolved, and the circuit finances credited with the battery residual value remaining.

The fact that the three circuits have different outcomes illustrates the need for detailed engineering and financial analysis to evaluate the real financial outcomes.

3.1.2 Reliability Enhancement for Customers – ESS in Microgrid Application

To study the microgrid application of ESS in SDG&E, four candidate circuit were selected. The information related to these circuits and the number of customers in the microgrid area are summarized in Table 3-9 below.

Table 3-9. Summary table of the selected circuits for the microgrid application

Circuit ID	# customers in MG Area	Peak load for MG [kW]	Minimum load for MG [kW]	MG Resources	# of Capacitors	# of Voltage Regulator
CMG 1	Whole circuit: 263 Recloser 1: 55 Recloser 2: 146	700	0	ESS only	1	0
CMG 2	255	712	0	ESS + PV	0	2
CMG 3	281	616	6	ESS only	0	1
CMG 4	837	2,064	0	ESS only	1	6

***Note**: In the sections that follow only the data for CMG 1 are presented. However, the same analysis was performed for CMG 2, CMG 3 and CMG 4, and these data are provided in the Appendix.*

3.1.2.1 BESS Sizing

3.1.2.1.1 Study Results for CMG 1

The microgrid studies for this circuit were conducted for two different scenarios. The microgrid topology is shown in Figure 3-11. In the first scenario, two separate microgrids were considered that could be isolated from the upstream grid through two reclosers. The ESS units were located at the location of these reclosers. In the second scenario, one ESS unit was used to support the whole circuit load during outages. This ESS unit was located at the main substation.

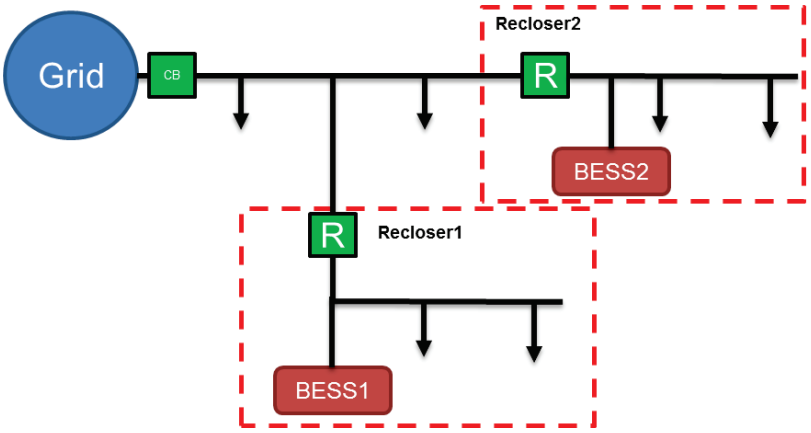


Figure 3-11. CMG1 - Microgrid Topology

The summary of recommended ESS sizes for Scenario 1 and 2 is provided in Table 3-10. These ESS sizes were recommended based on simulation results of 8-hour outages occurring any time during the year on the microgrid area. Based on the simulation results, the required size of battery (kW and kWh) for

each of the simulated 8-hour outages was determined and the ESS sized to cover the maximum required kW and kWh. The required size of ESS units for the batteries listed in Table 3-10 for different outage times are illustrated in Figure 3-12 to Figure 3-14.

Table 3-10. Recommended ESS sizes for CMG1

Scenario	ESS Location	Covered Area	Number of customers	Peak Load (kW)	Recommended ESS Size
1	Recloser 1	Branch downstream of Recloser 1	40	230	450 kW – 3 Hrs
1	Recloser 2	Branch downstream of Recloser 2	89	388	550 kW – 4 Hrs
2	CMG1 Substation	Whole circuit	164	770	1100 kW – 4 Hrs

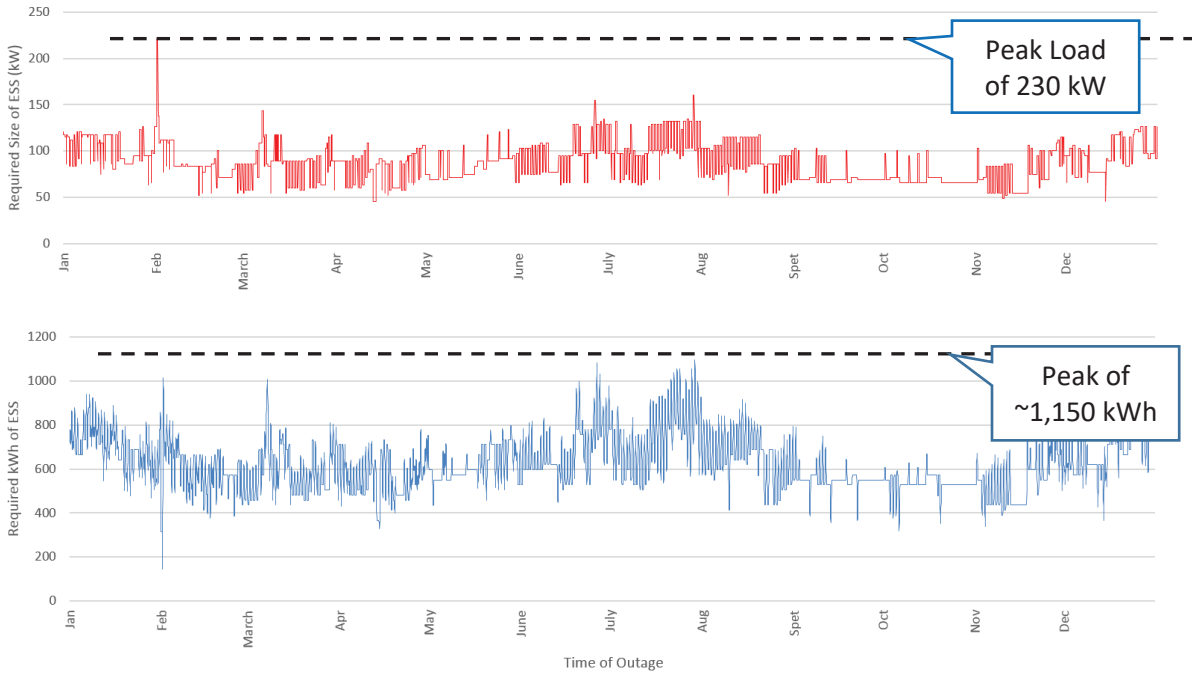


Figure 3-12. Required kW and kWh of ESS to support load downstream of Recloser 1 for an 8 hour outage at different times of year

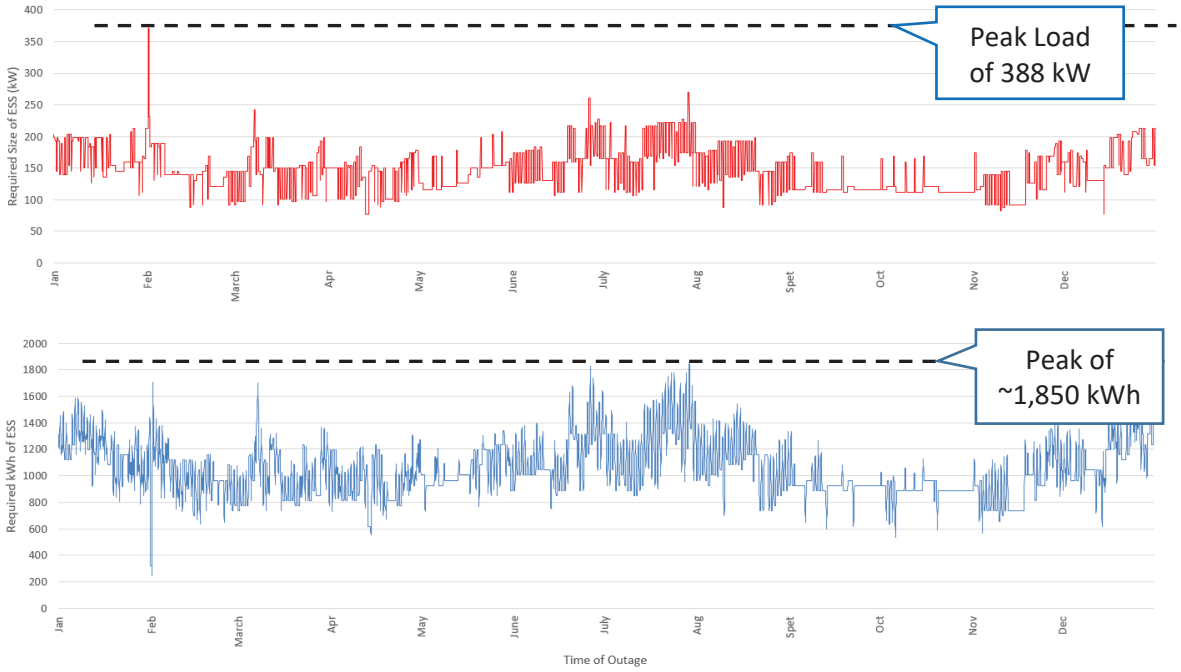


Figure 3-13. Required kW and kWh of ESS to support load downstream of Recloser 2 for an 8 hour outage at different times of year

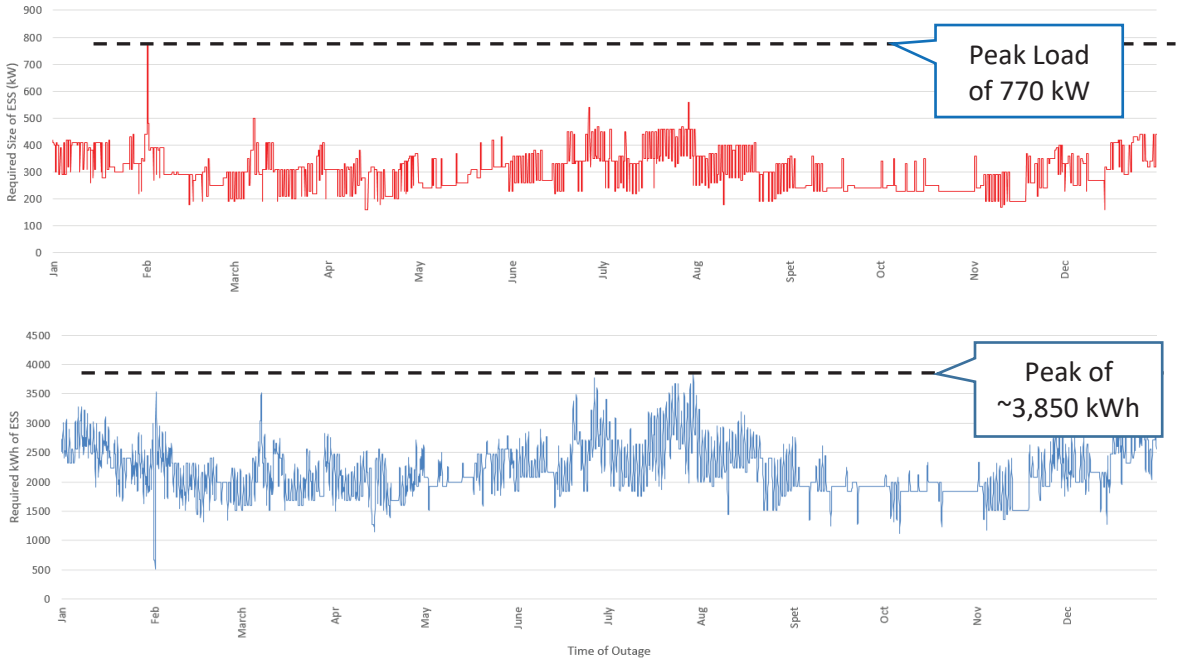


Figure 3-14. Required kW and kWh of ESS to support CMG1 circuit load for an 8 hour outage at different times of year

3.1.2.2 Cost benefit analysis

The objective of this study is evaluating the additional potential benefits of Battery Energy Storage Systems (ESS) by participating in CAISO wholesale and ancillary markets. Four microgrids, namely CMG1, CMG2, CMG3, and CMG4[3], are investigated in this analysis.

A mixed integer programming (MIP) optimizer formulated for optimizing ESS participation in energy and ancillaries markets. MIP maximizes the utilization of the excess battery capacity (based on constraints) via market participation.

3.1.2.2.1 CBA for CMG 1

Market analysis is conducted for two ESSs located on reclosers 1, and 2 and sized in a way to manage 8-hour outages as tabulated in Table 3-11 below.

Table 3-11. ESS sizes for CMG1

Reclosers	ESS Power (kW)	ESS Energy (kWh)
Recloser 1	450	1,350
Recloser 2	550	2,200

For the ESSs at the two reclosers, hourly SOC constraints are calculated via Distribution Planning Tool 4. The SOC constraints determine the total energy required to serve the load if an 8-hour outage happens anytime during the day. SOC constraints are provided in Figure 3-15 below.

[3] The results for CMG 1 were calculated in the preceding section; the results for CMG 2, CMG 3 and CMG 4 are calculated in the appendix.

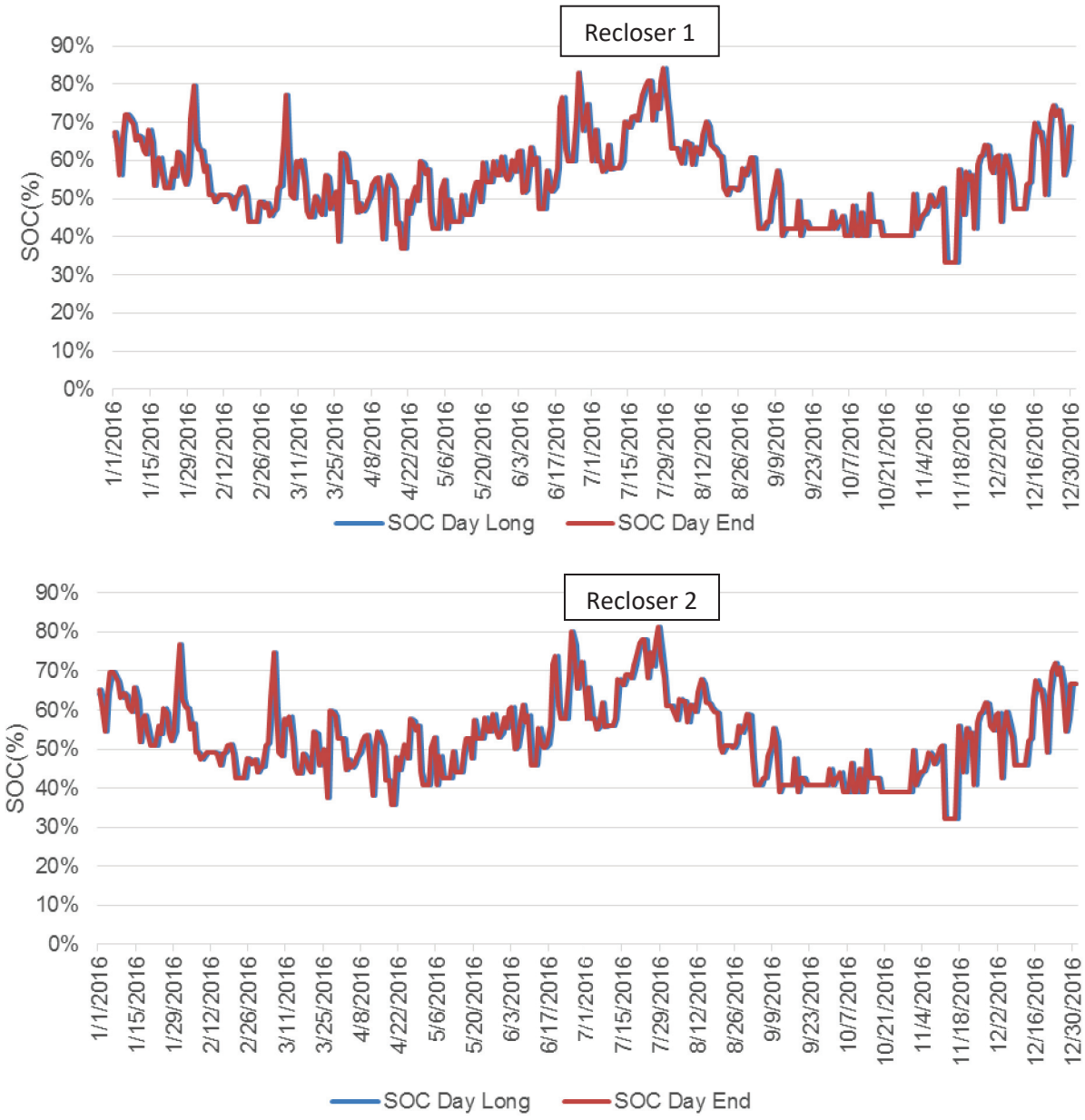


Figure 3-15. Recloser 1 and 2 - SOC constraints for 8-hr outage

Table 3-12 and Table 3-13 summarize the market participation benefits for the two ESSs. In these tables, the Energy Credit is the discharging revenues less the charging payments when only wholesale energy participation in considered. These energy credits in the regulation case include an estimate of the settlement of regulation revenues at RT prices.

In regulation market benefits calculations the mileage payment is a straight forward computation using the CA ISO 2016 historical data for up and down mileage factors and battery accuracies. Here, a figure of ½ of the Reg Capacity in each 15 minute period was used to estimate the RegUp and RegDown energy.

Annual market benefits are calculated as a summation energy, Regulation Up and down Capacity, mileage credits less the VOM. VOM of 0.00579 $/kWH is considered for both charging and discharging of the battery.

Table 3-12. CMG1: ESS: 450 kW, 1,350 kWh on Recloser 1

ESS: 450 kW, 1350 kWh on 280R	Energy Credit	Regulation Up Capacity Credit	Regulation Down Capacity Credit	Mileage UP Credit	Mileage Down Credit	VOM	Annual Market Benefits
Wholesale Energy Only	$ 26,971	$ -	$ -	$ -	$ -	$ 3,134	$ 23,837
Wholesale Energy and Ancillary	$ 24,568	$ 22,348	$ 19,563	$ 2,484	$ 4,740	$ 5,985	$ 67,720

Table 3-13. CMG1: ESS: 550 kW, 2,200 kWh on Recloser 2

ESS: 550 kW, 2200 kWh on 262R	Energy Credit	Regulation Up Capacity Credit	Regulation Down Capacity Credit	Mileage UP Credit	Mileage Down Credit	VOM	Annual Market Benefits
Wholesale Energy Only	$ 35,623	$ -	$ -	$ -	$ -	$ 4,389	$ 31,233
Wholesale Energy and Ancillary	$ 32,243	$ 27,317	$ 23,830	$ 3,068	$ 5,804	$ 7,600	$ 84,663

3.1.3 PV Integration Mitigation

To study the application of ESS to address PV Integration issues at SDG&E, eight candidate circuits were selected. The information related to these circuits is summarized in the Table 3-14 below.

Table 3-14. Summary table of the selected circuits for the PV impact mitigation application

Circuit ID	PV Size (kW)	Dominant PV Type	Peak Circuit Load (A)	Minimum Day Time Circuit Load (A)	# of Capacitors	# of Voltage Regulator
CPVIM 1	8,955	Centralized	407	-5.38	5	3
CPVIM 2	7,128	Centralized	254	-5.23	2	2
CPVIM 3	4,918	Distributed	470	-0.82	3	0
CPVIM 4	4,188	Distributed	479	-0.2	3	0
CPVIM 5	4,066	Distributed	454	-0.74	2	0
CPVIM 6	4,045	Distributed	467	-0.92	2	0
CPVIM 7	3,725	Distributed	490	-0.17	0	1
CPVIM 8	3,710	Distributed	501	0.9		

***Note**: In the sections that follow only the data for CPVIM 1 are presented. However, the same analysis was performed for CPVIM 2 to 8, and these data are provided in the Appendix*

For the ease of comparison, a single PV profile with high fluctuations was chosen and used for the PV impact analysis of all the circuits. The profile was first normalized and then scaled to the maximum installed PV size of each circuit. The normalized PV profile is shown in Figure 3-16.

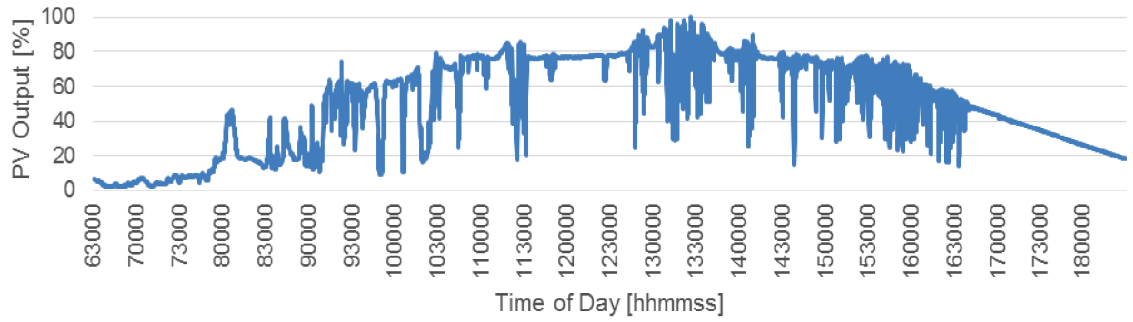


Figure 3-16. Selected PV profile for PV impact analysis

3.1.3.1 BESS Sizing

3.1.3.1.1 Study results for CPVIM 1 without BESS

Figure 3-17 presents a reference diagram of CPVIM 1.

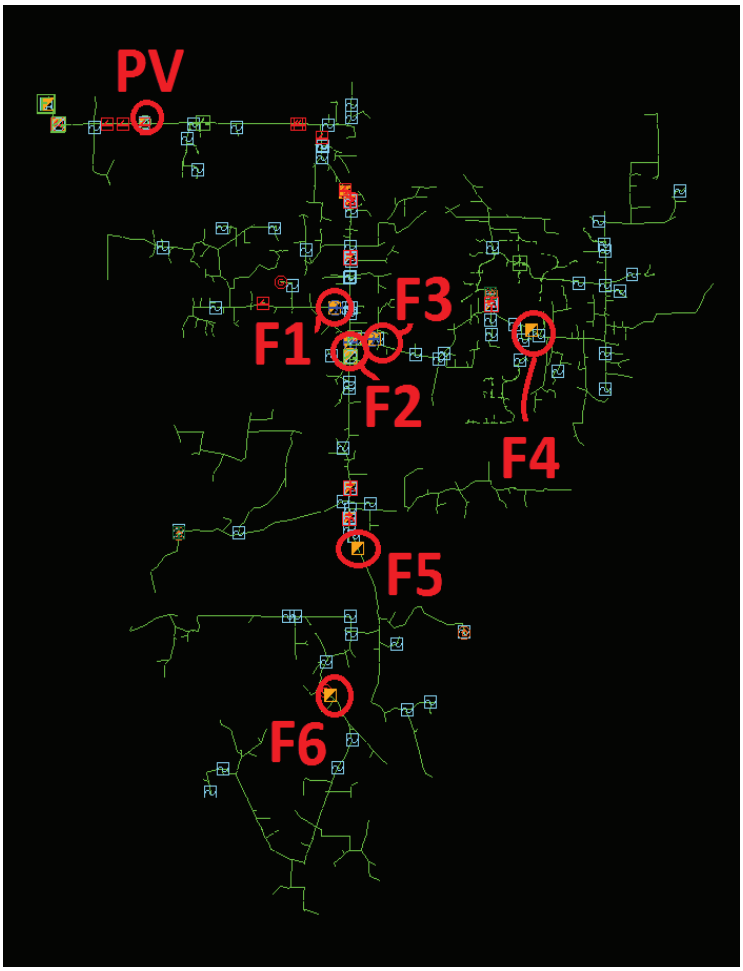


Figure 3-17. Reference diagram of CPVIM 1

Figure 3-18 below shows the phase A voltages of the meters at the locations of PV, F1, and F3 respectively. Locations F1 and F3 were selected for detailed analysis because they showed the highest incidence of flicker amongst the six locations (F1 through F6).

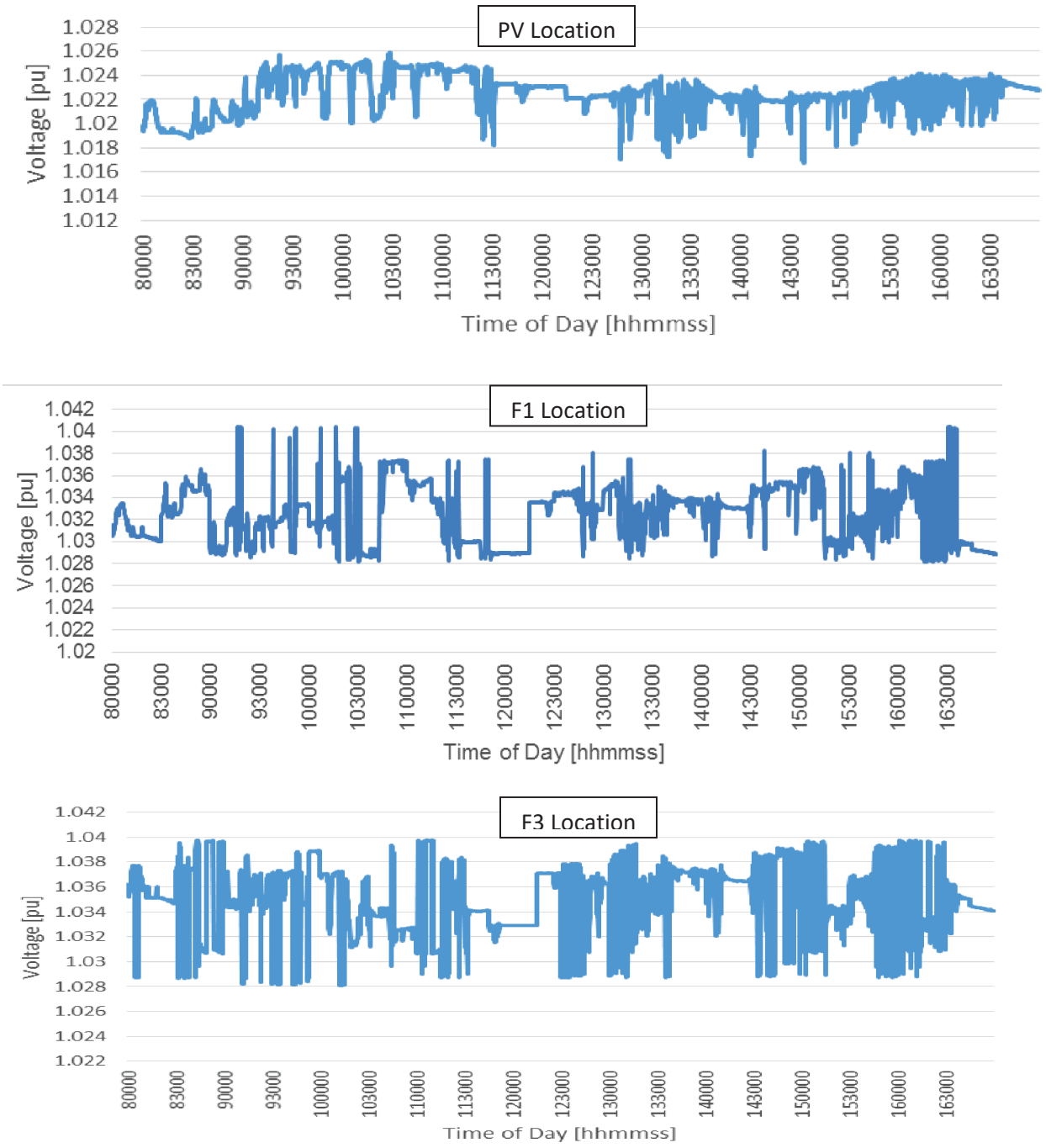


Figure 3-18. Voltage profiles at the PV, F1 and F3 location on CPVIM 1

Figure 3-19 below shows the flicker calculation curve for the meter at the PV location of CPVIM 1. As shown, the flicker level is always below the visibility level, which indicates that there is no flicker associated issues with CPVIM 1 at this location.

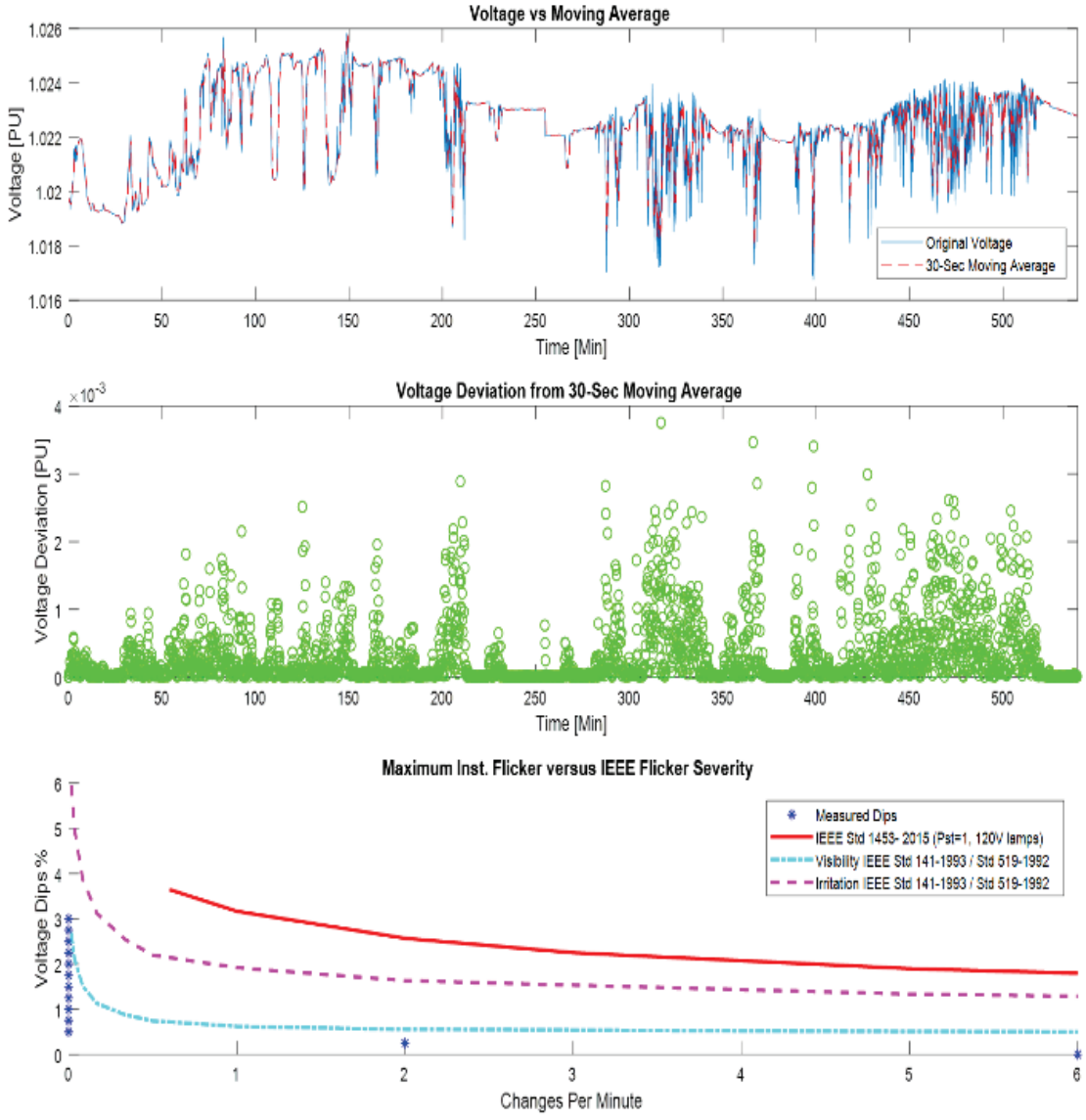


Figure 3-19. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 1 at PV location

Figure 3-20 below shows the flicker calculation curve for the meter at the PV location of CPVIM 1. As shown, the flicker level is always below the irritation level. However, there are instances when the flicker level is higher than the visibility level.

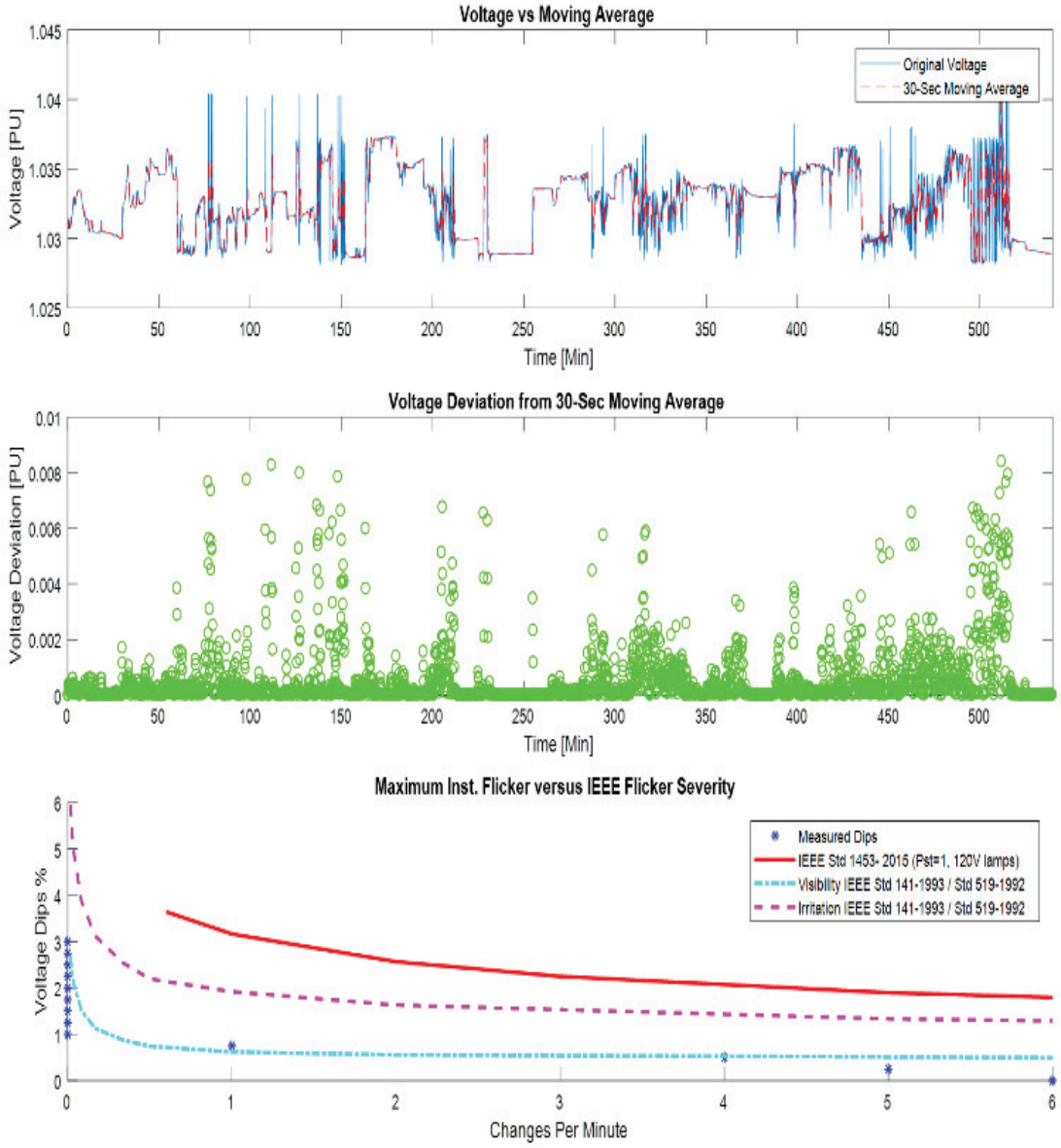


Figure 3-20. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 1 at the F1 location

Figure 3-21 below shows the flicker calculation curve for the meter at the F3 location of CPVIM 1. As with F2, the flicker level is always below the irritation level but there are instances when the flicker level is higher than the visibility level.

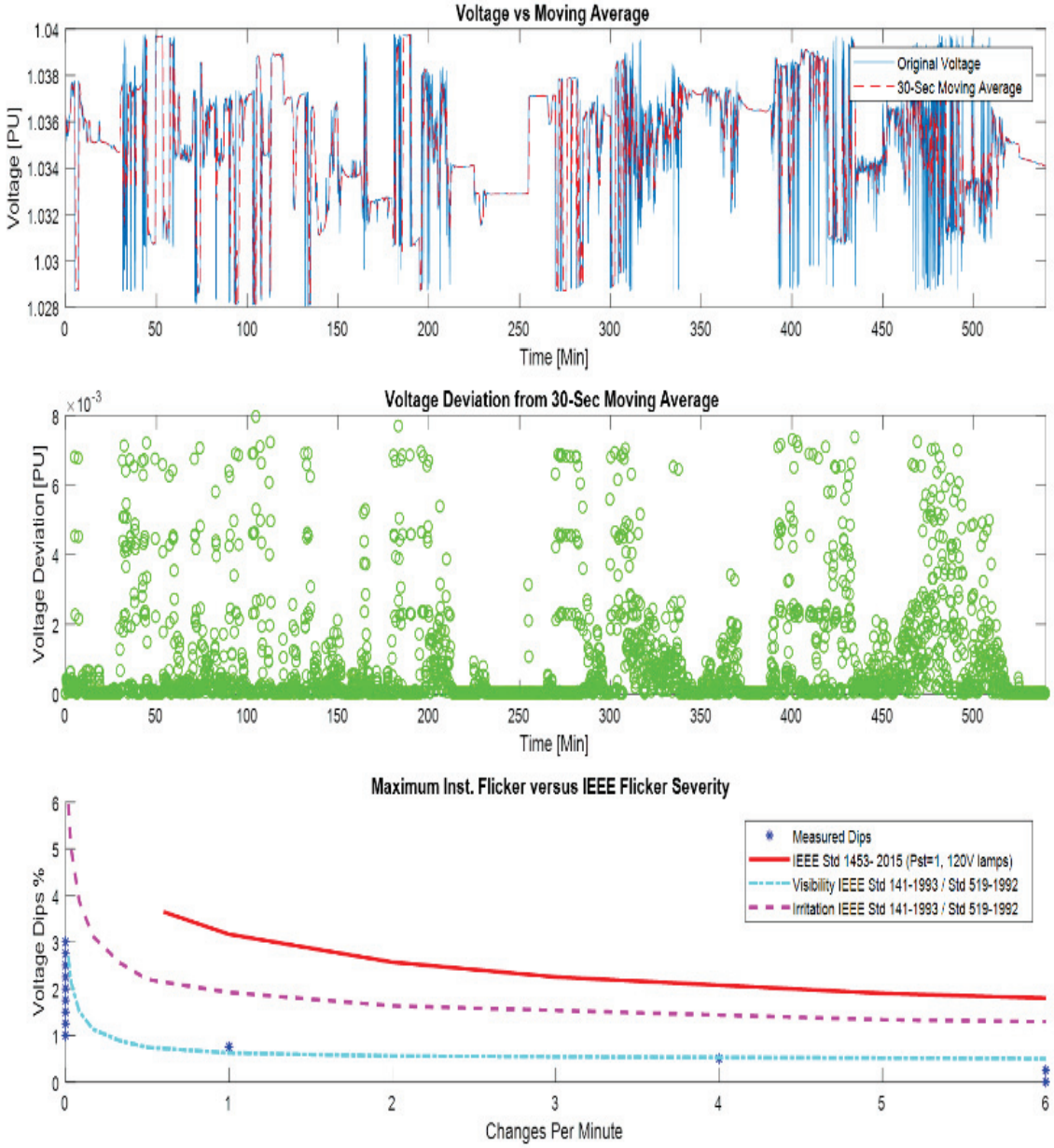


Figure 3-21. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 1 at the F3 location

3.1.3.1.2 Study results for CPVIM 1 after BESS deployment

The PV impact mitigation was evaluated for select circuits with Python-Distribution Planning Tool 4. In this case, a battery was installed at the beginning of CPVIM 1, close to the large PV location (Figure 3-22).

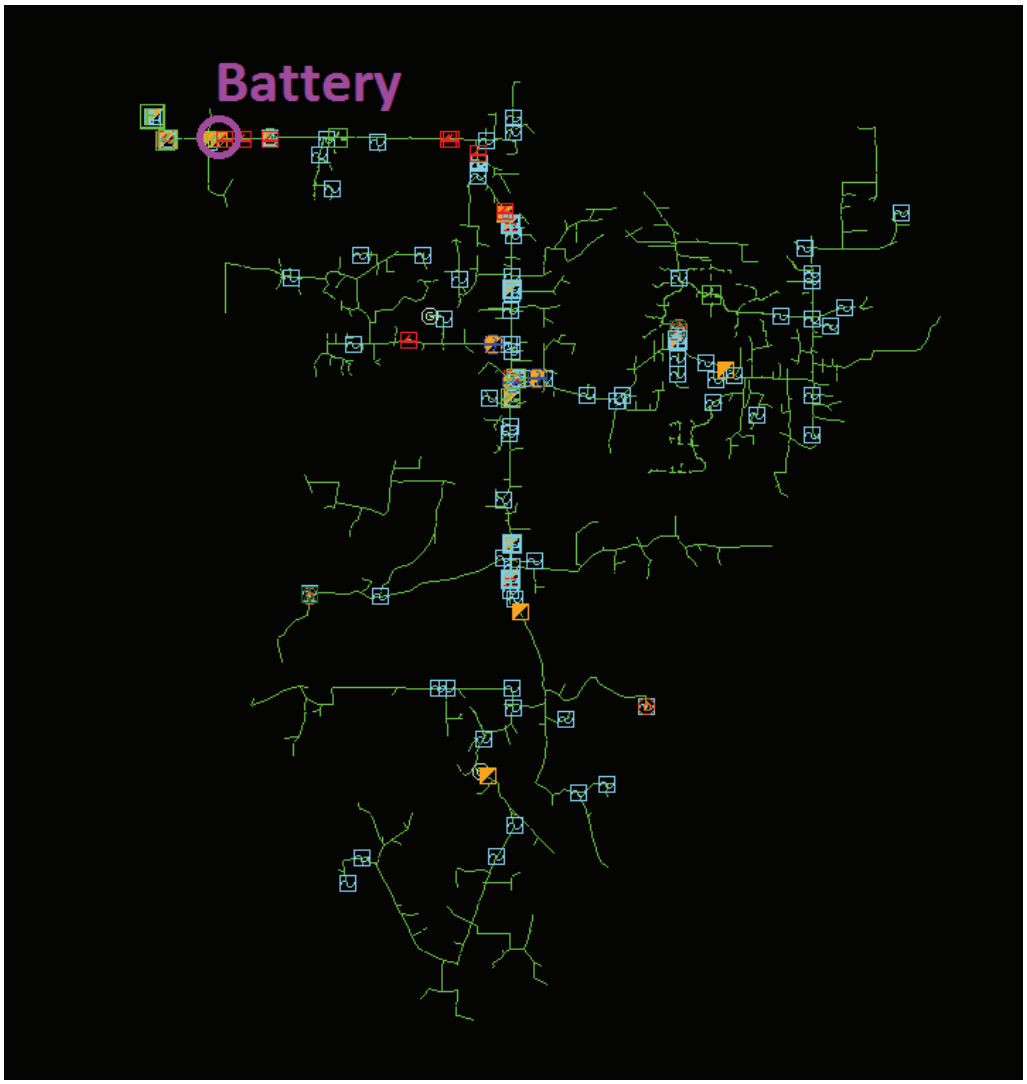


Figure 3-22. Location of the battery for CPVIM 1

A 3 MW, 6 MWh battery was initially selected and modeled in Distribution Planning Tool 4. The smoothing and voltage control logic was implemented in Python script. For PV smoothing, the battery looks at the average of power in a two minute moving average window and injects/absorbs active power to follow the average power value. This smooths out the power flow upstream of the battery. For voltage control, the logic consisting of two parts.

- Based on the voltage at a reference location (battery location in this case), the battery looks at the changes of voltage and injects/absorbs reactive power to smooth out the output voltage

and mitigates the sudden changes in the voltage. This smoothing take place based on a moving average with a one-minute time frame.

- The battery makes sure that the output voltage is within the acceptable voltage limits.

Figure 3-23 shows the flicker analysis for the three locations (PV, F2 and F3) after the BESS is deployed and in all three cases the voltage dips are now all below the limits which means that battery was able to mitigate the voltage flicker issues previously observed.

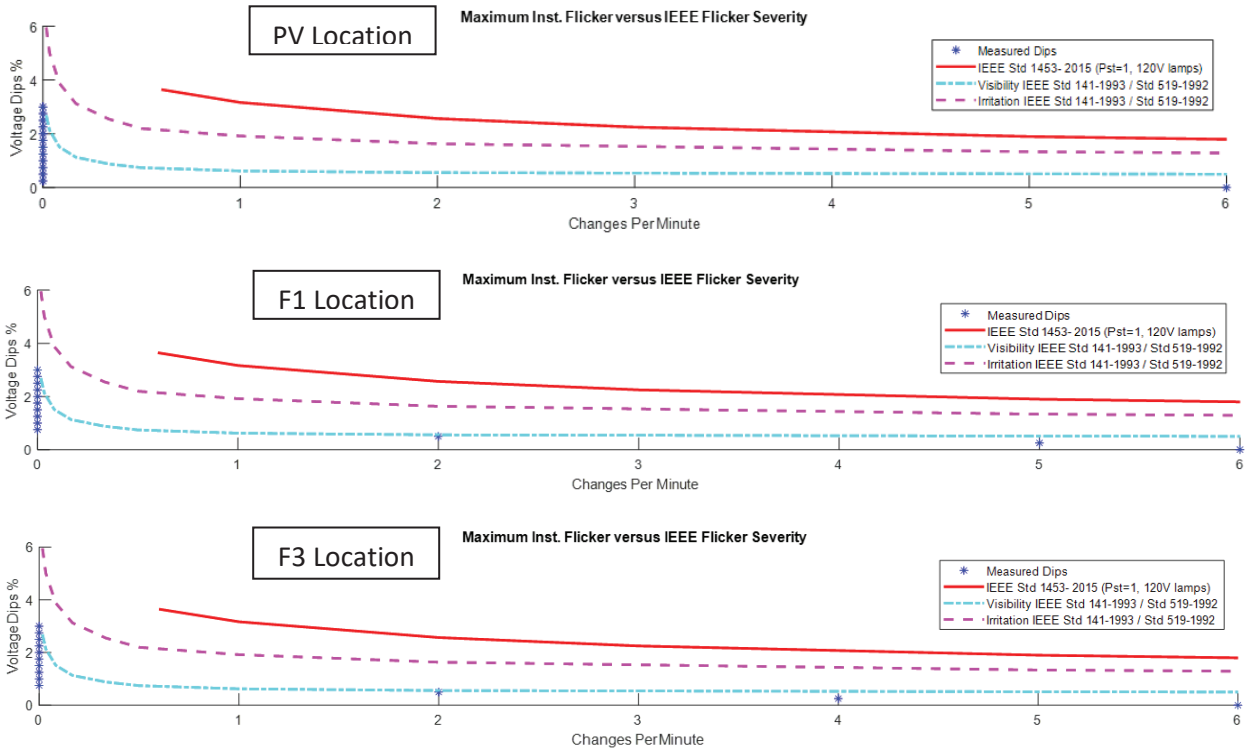


Figure 3-23. Flicker calculation curves for CPVIM 1 at PV, F2 and F3 locations after BESS installation

The results of the power smoothing are shown in Figure 3-24 where the circuit breaker power flow upstream and downstream of the BESS are compared over a nine-hour period. However, at that resolution, it is difficult to observe the impact of the BESS, so the results are repeated in Figure 3-25 over a one-hour time-frame and the ability of the BESS to smooth out the power by injecting/absorbing active power is clearly visible.

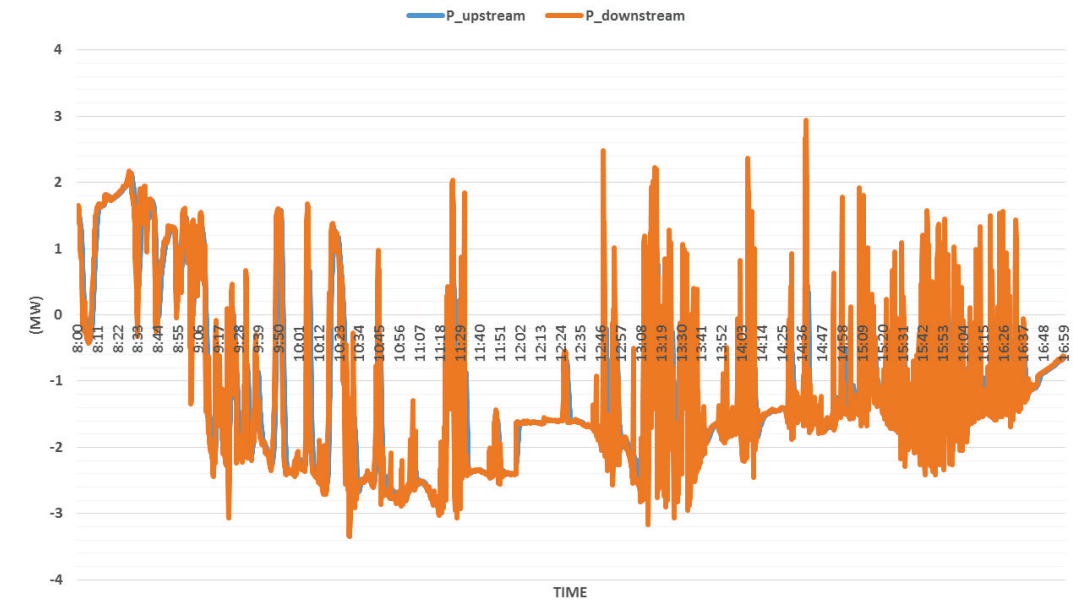


Figure 3-24. Power Flow Comparison upstream vs. downstream of BESS for CPVIM 1 (9 hours)

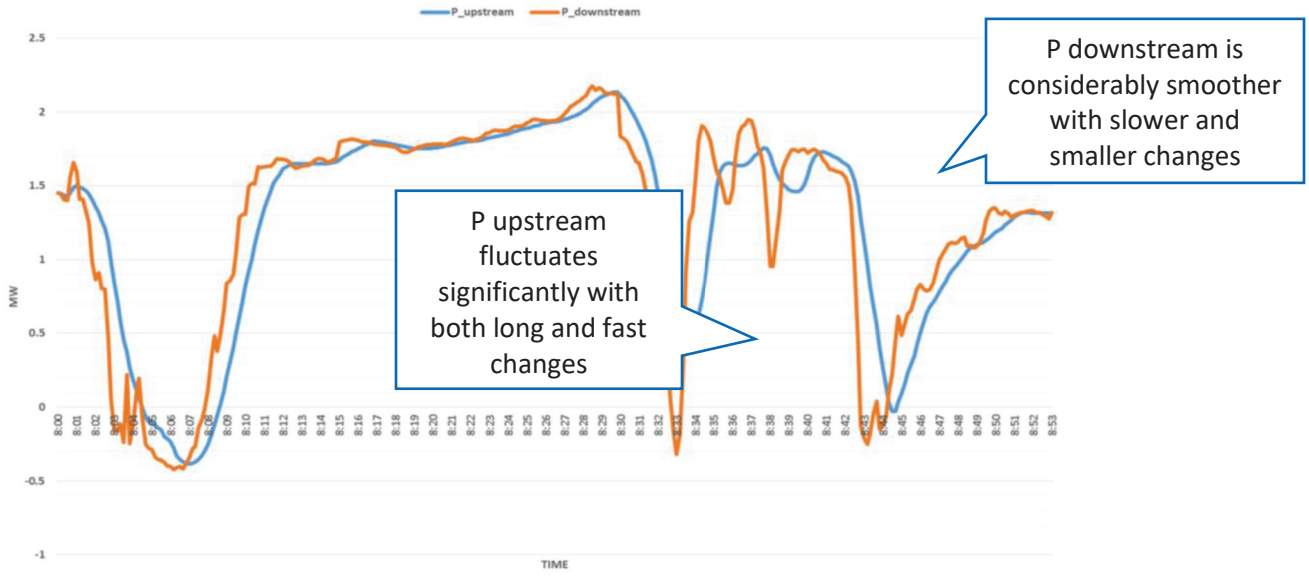


Figure 3-25. Power Flow Comparison upstream vs. downstream of BESS for CPVIM 1 (1 hour)

The battery active power output has been illustrated in Figure 3-26. As is evident, the battery kW goes up to 3,000 kW.

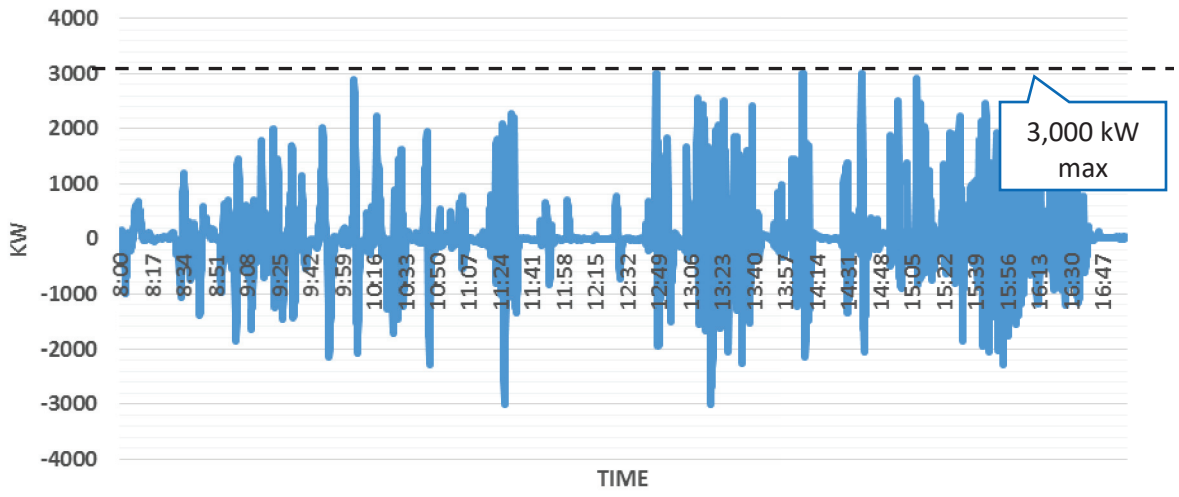


Figure 3-26. Battery active power for CPVIM 1

For voltage control, the battery looks at the voltage at the battery location and smooths out the rate of change of voltage (ROC); it also guarantees that the output voltage is within the acceptable limits. Figure 3-27 compares the voltage before and after the battery installation at the PV, F2 and F3 locations. As shown, the battery manages to reduce the voltage ROC during the sudden changes in the voltage and smooths out the output voltage by injecting/absorbing reactive power.

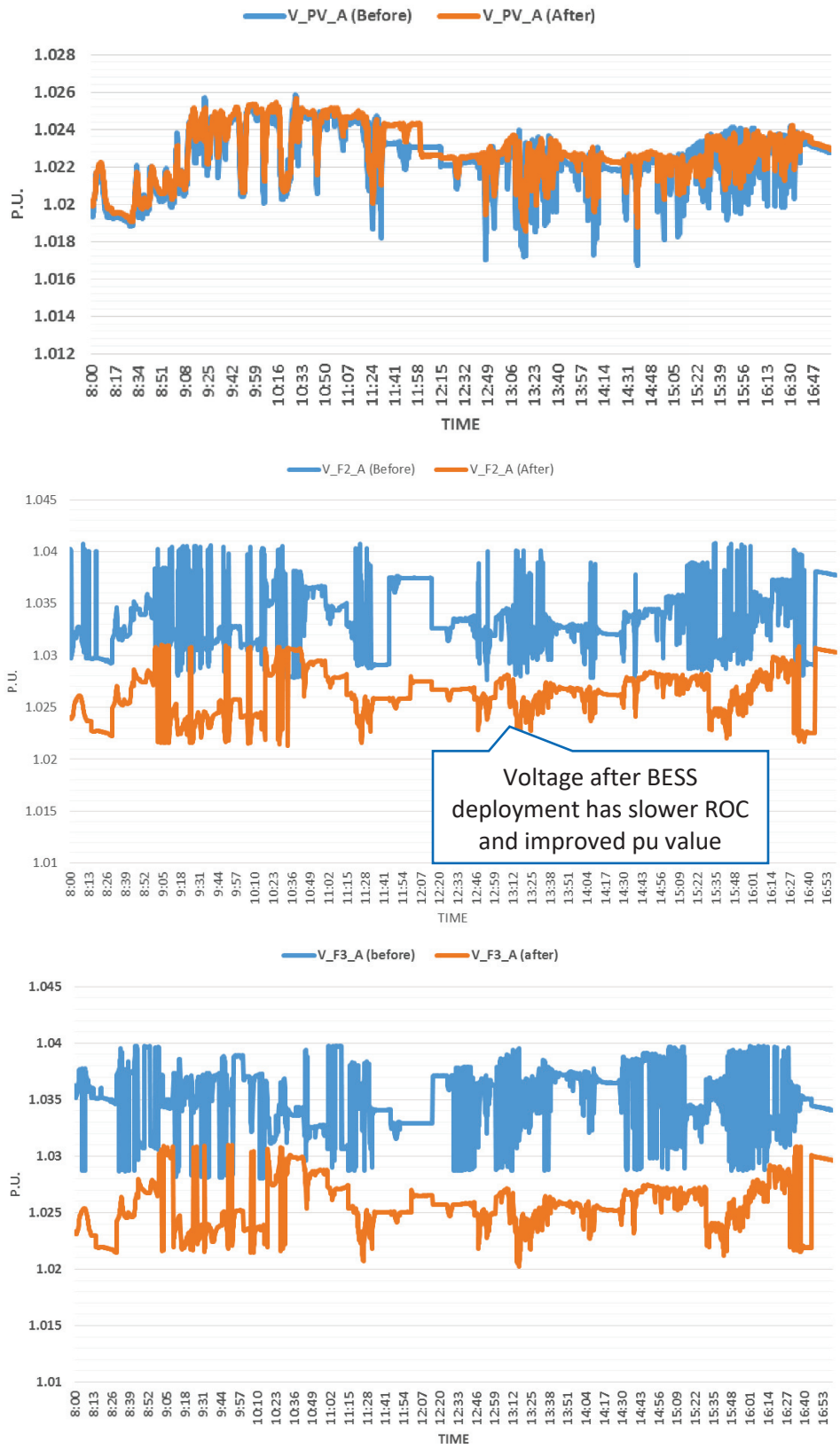


Figure 3-27. Voltage comparison at PV, F2 and F3 locations before and after Battery Installation for CPVIM 1

Finally, the accumulative charge and discharge of the battery are shown in Figure 3-28 and Figure 3-29, respectively. In general, the battery needs almost 2,000 kWh for the PV impact mitigation. Therefore, a 3,000 kW, 3,000 kWh battery would be satisfactorily performing PV smoothing application, and the remaining energy could be used for further applications.

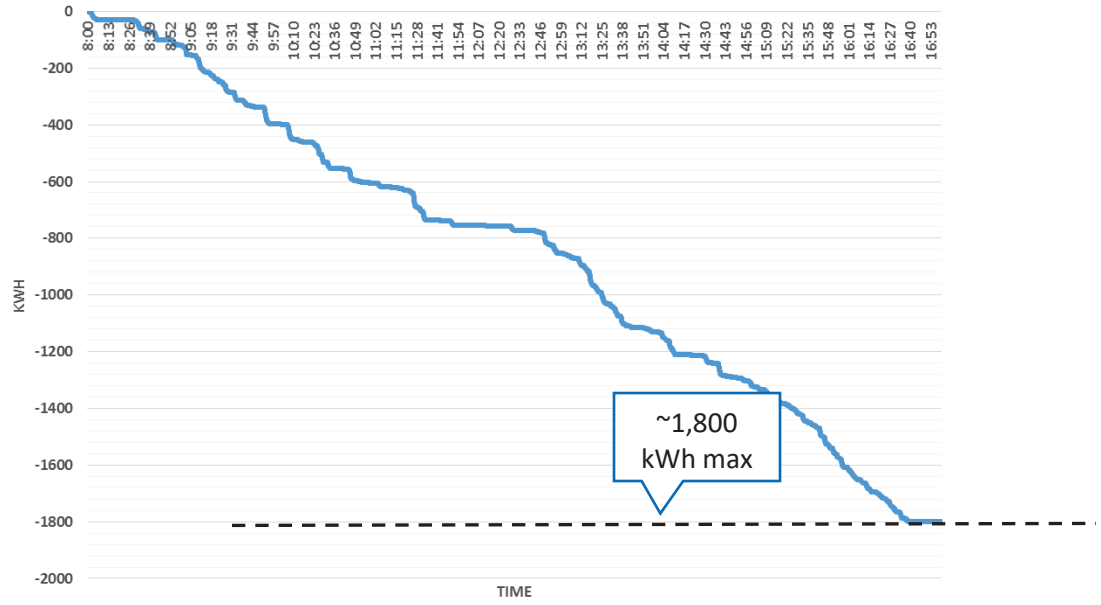


Figure 3-28. Battery accumulative charge for CPVIM 1

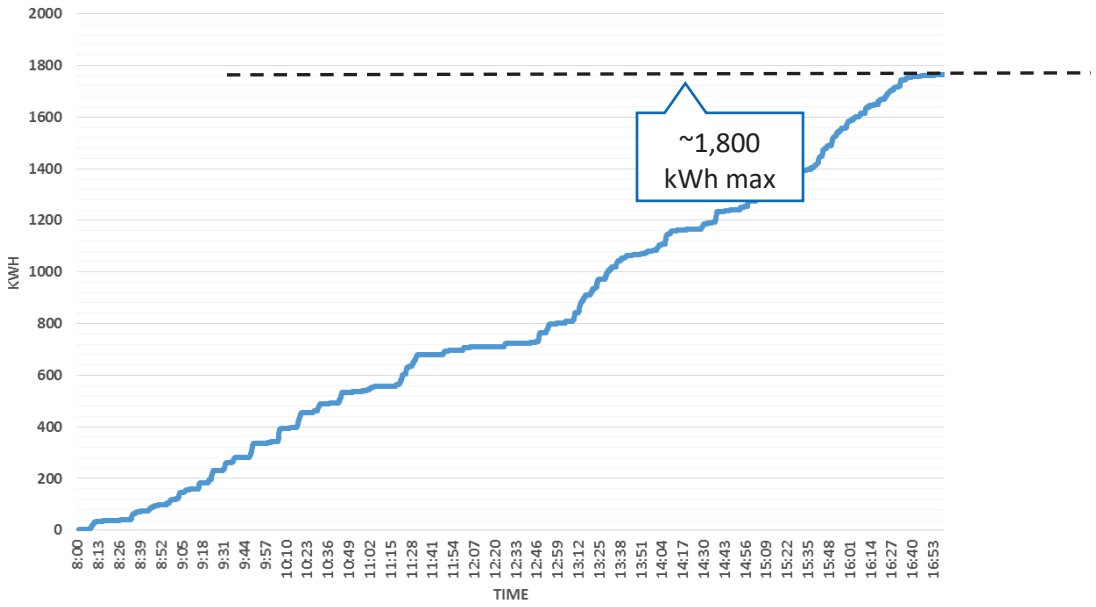


Figure 3-29. Battery accumulative discharge for CPVIM 1

3.1.3.2 Cost benefit analysis for CPVIM 2

The objective of this study is evaluating the potential benefits of Battery Energy Storage Systems (ESS) by participating in CAISO wholesale and ancillary markets. CAISO market participation is considered as secondary application where the primary ESS application is PV smoothing.

A mixed integer programming (MIP) optimizer formulated for optimizing ESS participation in energy and ancillaries markets. MIP maximizes the utilization of the excess battery capacity (based on constraints) via market participation.

In this analysis, the optimization used the DA prices for charging and the RT prices for discharging, to simulate the strategy described by SDG&E in which charging load is bid into the day ahead markets and discharging withheld from the day ahead (2016 nodal LMP prices are considered). Discharging is offered into the Real Time markets. As an additional step, the strategy of offering RegUp and RegDown services into the CA ISO ancillary service markets was evaluated, again at 2016 historical prices. Each day, the optimization would co-optimize the energy and ancillary service participation across the day so as to maximize revenues subject to BESS operational constraints. Adding regulation services to the product portfolio accessible to the BESS increases revenues as would be expected.

Market analysis was conducted for ESS sized at 2000 kW, 2000 kWh designed to smooth PV.

ESS Operation Constraints for Market Participation

According to previous section, maximum and minimum charge/discharge limits for CPVIM2 in real-time energy market and regulation market are shown in Figure 3-30 to Figure 3-35.

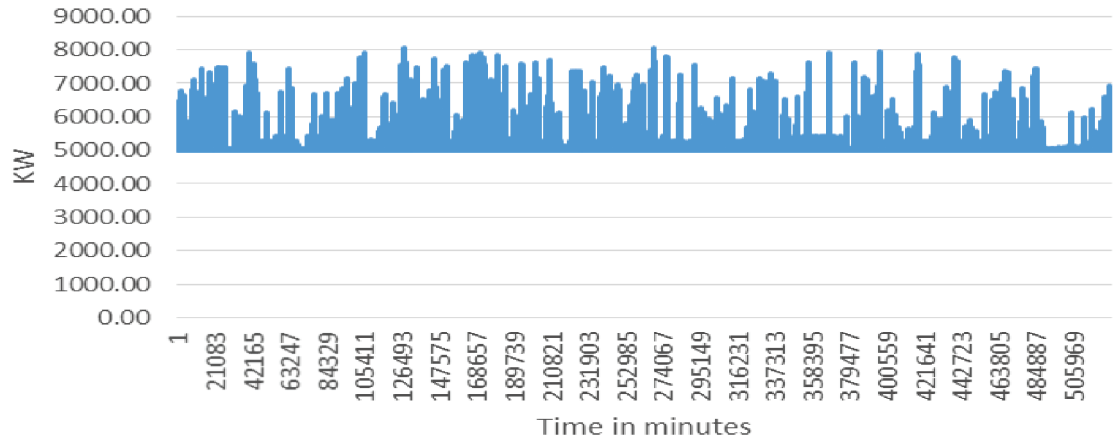


Figure 3-30. Maximum discharge (Real-time energy market)

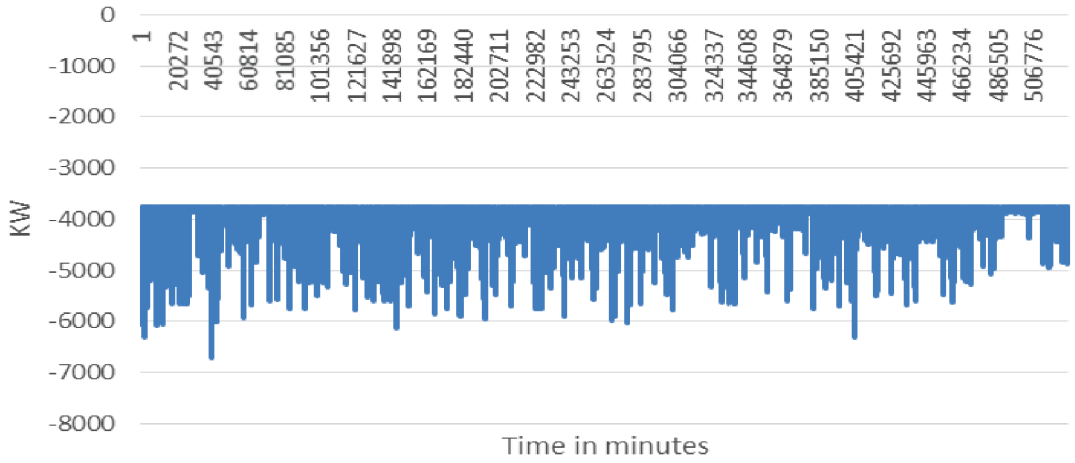


Figure 3-31. Maximum charge (Real-time energy market)

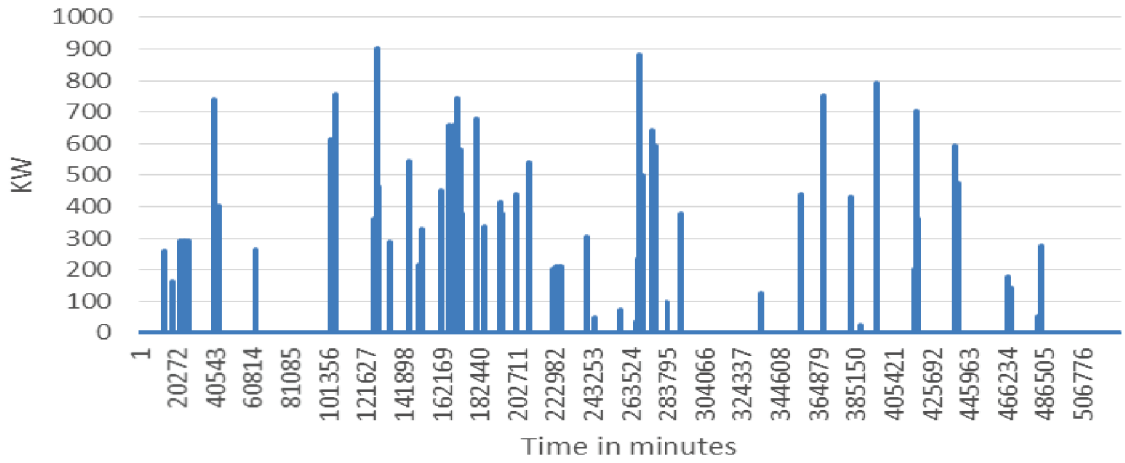


Figure 3-32. Minimum discharge (Regulation market)

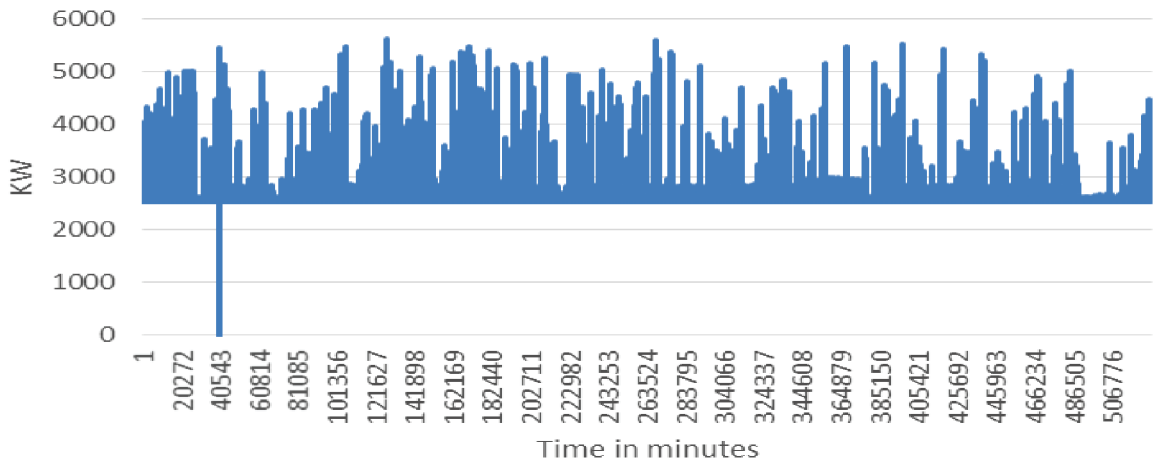


Figure 3-33. Maximum discharge (Regulation market)

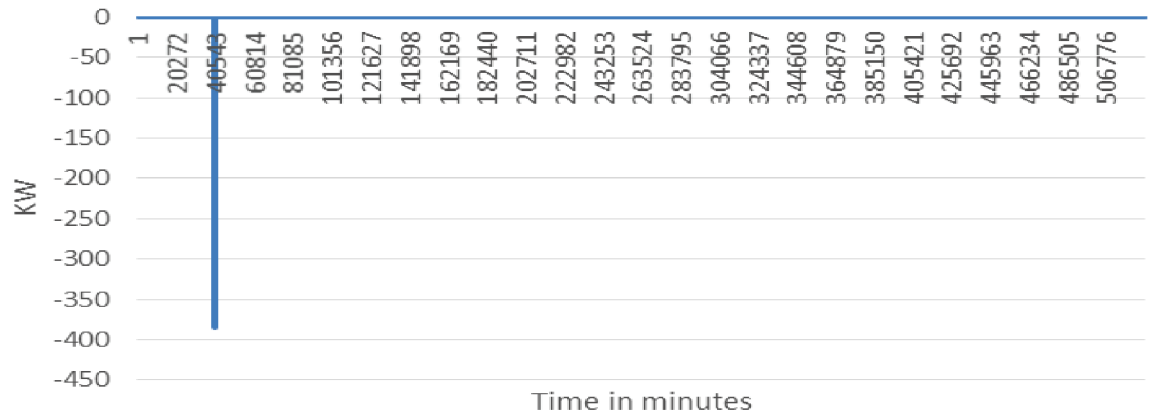


Figure 3-34. Minimum charge (Regulation market)

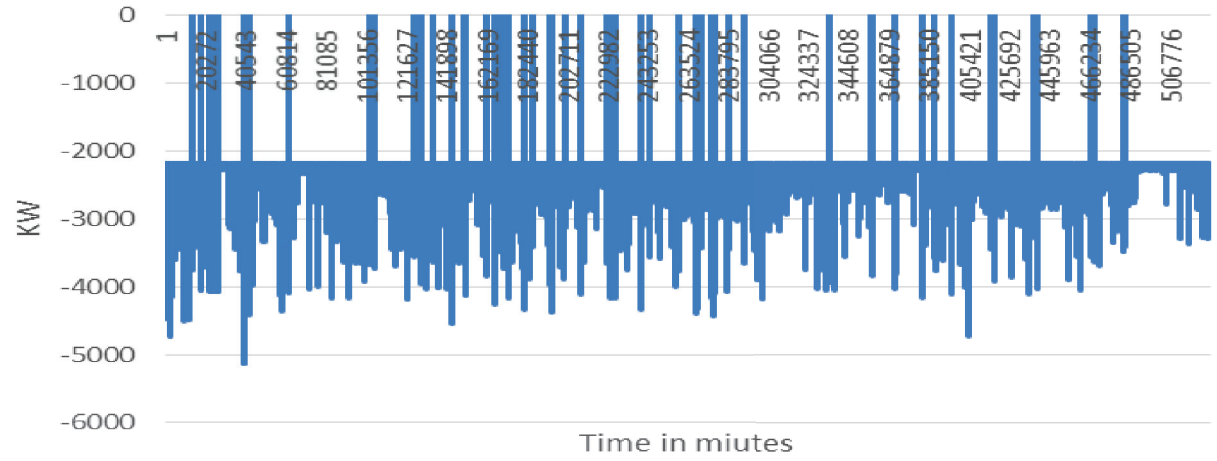


Figure 3-35. Maximum charge (Regulation market)

To create constraint profiles for market analysis, minute by minute charge and discharge limits were converted to hourly constraints. This is necessary due to hourly nature of regulation DA markets. In order to avoid violations, the most conservative approach was applied to convert minute-by-minute constraints to hourly constraints. The method was based on:

- Taking maximum of 1-minute minimum values (minimum charge/discharge) within each hour,
- Taking minimum of 1-minute maximum values (maximum allowable charge/discharge) within each hour.

It was shown that by utilizing the excess capacity of the BESS for market participation, the case resulted in a positive NPV for ESS deployment on CPVIM 2 as summarized in Table 3-3-15 below. The additional revenue was calculated by considering the operation/application constraints to ensure the primary application for the BESS (i.e. PV smoothing) was accomplished.

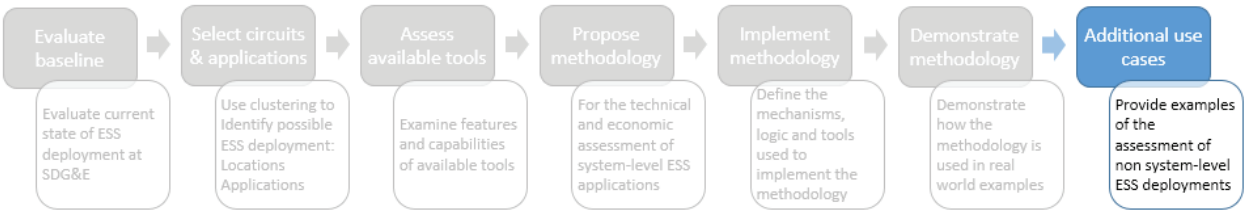
Table 3-3-15. NPV Table for CPVIM 2

Parameter	$ thousands
Battery Size	2 MW / 2 MWH
Battery Initial Cost	$1,248
Annual Depreciation	$130
Capital Return	$56
Opex	$62
Market Benefits	$230
T&D Upgrade Cost	$515
Annual Depreciation	$17
Capital Return	$23
Opex	$16
20 yr NPV of Battery vs T&D Upgrade	$1,273

Conclusions:

The use of energy storage for PV integration alone may not be financially attractive. However, by determining hourly constraints on the use of the battery to be included in regulation services, additional revenues can be obtained which make the business case viable. Note that a time base scheme for enabling regulation services will likely not produce the same benefits, as the most restrictive hourly constraint on a monthly or seasonal basis would have to be applied, which would greatly reduce revenues.

3.2 Task 7: Summary Results for Additional Use Cases



The previous sections focused on the methodology and tools for evaluating ESS deployment for system-level applications. This section examines three different uses cases for end-use applications:

- Whole sale market participation
- Demand Management in Commercial Buildings

- Hybrid Applications for Residential and Commercial Buildings

3.2.1 Whole Sale Market Analysis

For this use case a comparison of the wholesale market analysis and the potential performance of two 10 MW / 40 MWh Battery Energy Storage System (BESS) in the California ISO (CA ISO) market was performed.

Each of the two units was installed on 12 kV systems, however, one of them (Location A) was connected at substation level with a step-up transformer to 66 kV, versus the second one which was connected at circuit level, remote from the substation (Location B).

The unit at location A was connected to the sub-transmission system by a dedicated transformer, so that there were no limitations on charging/discharging power flow imposed due to other circuit/transformer loading concerns.

The evaluation for location B included limitations of the BESS charging rate due to thermal loading of the circuit and rating of the circuit at a given time of day. This resulted in varying hourly limitations on BESS charging which were additionally considered in the scheduling optimization. Because of load variation during the day and throughout different months or seasons, the load changes impose different levels of charge limitations on BESS charging on a daily basis across the year.

Neither study circuit had any significant amount of PV systems. For circuits with reasonable PV amounts, during days with high PV production, wholesale prices may be low at peak PV production hours and BESS charging might be scheduled for these hours. However, depending upon the circuit load profiles and PV penetration this may or may not coincide with peak loading. When it does, the BESS charging will be impacted and unable to fully take advantage of low prices.

After investigating available (commercial) tools for BESS market assessments, it was decided to use a proprietary storage evaluation tool from the consultant for this analysis – as one option. Another study was also suggested to compare the results with Vendor 12 Cost Calculation Tool 6 tool. The Vendor 12 Cost Calculation Tool 6 tool has identical capabilities for optimizing Day Ahead (DA), Real Time (RT), and Ancillary service revenues and can additionally factor in fast ramping services to the ISO. However, the Cost Calculation Tool 6 tool did not have the particular LMP prices for the locations of the BESS studied as pre-loaded data which would create inaccuracies at peak pricing. This report outlines the analysis and findings by using the former tool.

The theoretical best revenues obtainable against 2016 historical CAISO market prices were computed.

In the optimizations, the stated SDG&E strategy of offering charging load in the day ahead energy market and discharging energy in the Real Time market was used. The headline results from this analysis showed that the theoretical best performance against 2016 prices would be a net benefit of $725,906 for the 10 MW unit for the entire year. This net benefit is the net of receipts for discharged energy, payments for charging energy, and variable operating and maintenance costs estimated. The fixed operating cost were not included.

As a future case, the economics of the 10 MW BESS for also participating in the CA ISO ancillary service market, specifically the Regulation Up and Regulation Down markets, were assessed using the same tool and 2016 prices. If one 10MW BESS were employed to optimally charge in the Day Ahead market and

discharge in the Real Time market, the theoretical best results come to $725,906 as stated above. If the entire capacity of the BESS were to be available for regulation, a co-optimization of day ahead energy, real time energy, and regulation service across 2016 using historical prices indicates that the benefits for one 10MW BESS would be as much as $ 1,872,000. This is a theoretical best value against historical prices. However, the more than doubling of economic benefits indicates that pursuit of the ancillary service markets is well worth the effort.

3.2.1.1 Approach

This evaluation was carried out using a proprietary optimization tool previously developed by the consultant for evaluating storage projects economics. This tool methodology and mathematical formulation are developed for solution as a Mixed Integer Programming (MIP) problem. The co-optimization of storage resource participation in energy and ancillary service markets is similar to that performed by the CA ISO in its market clearing.

The baseline evaluation of the 10 MW BESS economics used 2016 CA ISO market prices for day ahead (DA), Real Time (RT), and Regulation UP (RU) and Down (RD) products. The tool computes the optimal allocation of BESS capacity to the different markets each hour, while observing constraints imposed by the BESS characteristics and capabilities. This is done for the 8760 hours of the year and the total revenues computed.

In this analysis, the optimization used the DA prices for charging and the RT prices for discharging, to simulate the strategy described by SDG&E in which charging load is bid into the day ahead markets and discharging is offered into the Real Time markets. The strategy is based on the observation that RT prices are usually higher than DA prices, sometimes significantly so.

As alternatives, strategies of offering both charging and discharging into the DA markets or alternatively offering both into the RT markets were evaluated. Results from these tended to confirm that the SDG&E strategy is valid.

As an additional step, the strategy of offering RegUp and RegDown services into the CA ISO ancillary service markets was evaluated, again at 2016 historical prices. Each day, the optimization would co-optimize the energy and ancillary service participation across the day so as to maximize revenues subject to BESS operational constraints. Adding regulation services to the product portfolio accessible to the 10 MW BESS increases revenues as would be expected.

Because the BESS has a daily limit of one deep discharge cycle, the optimization was done with various limits on the amount of the BESS capacity available for regulation. The impact of charge/discharge cycles from regulation, given the CA ISO NGR-REM protocols which manage BESS state of charge (SOC) by calculating net regulation energy in a 15 minute period and “repaying” it with Real Time energy dispatch in the next, should not be material. However, other operational issues might cause SDG&E to restrict the amount of BESS capacity available for regulation. While no operational constraints were described in the context of the 10 MW BESS in meetings with SDG&E staff, it is possible that other large BESS systems could see constraints on total regulation for reasons similar to the restrictions on charging load studied in the second part of this case study. For illustrative purposes, the analysis was carried out with, limits on maximum regulation participation of 25%, 50%, 75%, and 100%. Another reason to study limits on regulation participation is the warranty contractual limit of one deep discharge cycle per day. 100% regulation service could well violate this.

The 10 MW BESS was considered to be a NGR REM resource, meaning it participates in the energy and ancillary service markets with energy charging scheduled hourly against day ahead prices and discharge at 15 minutes scheduled duration against real time prices. Real time prices were averaged for each hour for use in hourly optimization. The ISO biases each 15 minute schedule for NGR-REM resources in the regulation service so as to "pay back" the net energy charged/discharged for regulation in the previous hour. This was factored into the simulation/optimization.

When the RT operations result in charging/discharging that varies from the DA charging schedule in the Charge DA / Discharge RT case, there is a secondary effect that the net energy for the deviation from the DA schedule will pay/be paid for the difference in the DA and RT cases. This is called the "charging DA-RT compensation" in the chart below. It is a secondary effect but not insignificant. It only occurs in this case.

The summary results of the three sets of optimizations for all of 2016 with different strategies for charging and discharging in the Day Ahead and Real Time markets are shown in the tables below.

Table 3-3-16 shows that the SG&E strategy today of charging in DA and discharging in RT provides considerable benefits over charging/discharging in the DA markets; the benefits are nearly 6 times as great. The increment to charge and discharge both in the RT markets is only 25% and it is far from clear that this increment is realizable or that the calculations are that precise. As said, this analysis validates the SDG&E strategy.

Table 3-3-16. The 10 MW BESS in the Day Ahead and Real Time Energy markets for 2016 data

Operational Strategy	Annual cost of charging	Annual revenue from discharging	Annual VOM	Charging DA-RT Compensation	Annual Benefits
Charge DA - Discharge DA	$206,744	$441,196	$114,999	$0	$119,453
Charge DA - Discharge RT	$144,706	$925,139	$85,995	$31,468	$725,906
Charge - Discharge RT	$38,924	$1,030,404	$126,792	$0	$864,688

Table 3-3-17 calculates the benefits of the 10 MW BESS participating in the Regulation market. In case there are other operational constraints that prevent the full power capacity of the BESS from being utilized, four cases where capacity was restricted to 9 MW were also analyzed.

Table 3-3-17. Evaluating the 10 MW BESS Participation in Ancillary service Markets (Regulation) for 2016 data

MW Cap avail	Reg Cap %	Energy credit (total DA and RT)	Reg Up capacity credit	Reg Down capacity credit	Mileage Up credit	Mileage Down credit	Variable O&M (VOM)	Reg Energy credit	Total Benefit
10	0	$811,901					$ 85,995		$ 725,906
10	20	$709,245	$132,323	$116,016	$15,021	$ 29,162	$112,760	$ (3,904)	$ 889,007

MW Cap avail	Reg Cap %	Energy credit (total DA and RT)	Reg Up capacity credit	Reg Down capacity credit	Mileage Up credit	Mileage Down credit	Variable O&M (VOM)	Reg Energy credit	Total Benefit
10	50	$678,755	$329,751	$289,337	$37,315	$ 72,834	$132,674	$ (10,143)	$1,275,317
10	75	$647,164	$491,787	$431,929	$55,354	$109,105	$145,081	$(16,640)	$1,590,259
10	100	$614,557	$637,215	$554,806	$73,353	$145,030	$152,580	$ (22,168)	$ 1,872,381
9	20	$646,392	$118,882	$104,288	$13,496	$ 26,210	$104,028	$ (3,472)	$ 805,239
9	50	$617,043	$296,293	$260,377	$33,408	$ 65,523	$ 120,738	$ (9,786)	$ 1,151,904
9	75	$587,405	$442,223	$388,172	$49,884	$ 98,161	$ 131,264	$ (15,115)	$ 1,434,581
9	100	$ 557,911	$573,279	$498,585	$66,147	$ 130,520	$138,045	$ (19,982)	$1,688,397

In the third column of the chart, the Energy Credit is the Discharging Revenues less the Charging Payments. Given that the charge–DA / discharge–RT strategy is simulated, the $725,906 from the first table of energy-only strategies is the baseline for comparison with the regulation simulation results once the Variable O&M (VOM) costs are deducted. These energy credits in the regulation case include an estimate of the settlement of regulation revenues at RT prices. Energy credits decrease as regulation capacity increases, as less battery capacity is then available for arbitrage.

In these calculations the mileage payment is a straight forward computation using the CA ISO 2016 historical data for up and down mileage factors and battery accuracies. The ISO data does not appear to facilitate the direct calculation of the energy credit for RegUp and RegDown energy. (The mileage factor is related to the length of the curve of AGC dispatch signals, not to the area under the curve). For purposes of this estimate, a figure of ½ of the Reg Capacity in each 15 minute period was used to estimate the RegUp and RegDown energy. This then became an increment/decrement to the BESS state of charge beginning the next 15 minute period, and was used to calculate regulation energy credits. Because the RegUp energy and RegDown energy more or less cancel each other out, based on hourly participation, the regulation energy credit is minor. As can be seen in the table, it is a small negative figure that grows as regulation capacity increases.

Because the 10 MW BESS has warranty terms stipulating a limit on daily discharge cycles, the impact of regulation service on cycling has to be considered. The mileage factor alone is insufficient to do this as it does not indicate separate measures of number of regulation cycles in a period versus size of cycles. In order to properly assess this impact a more detailed analysis would need to be done using actual CA ISO regulation instructions or a time series simulation of such at 4 second intervals. The difference in revenues are sizable and the possible impacts on battery life potentially a factor, so this analysis may be a next step prior to developing a bidding strategy for regulation services.

Overall, the results offer some obvious relationships. Making more capacity available for regulation decreases the energy credits slightly as less state of charge is allocated to DA and RT energy arbitrage –

the regulation capacity and mileage payments are greater. Regulation payments increase with added regulation capacity almost linearly.

3.2.1.2 Sample Results of Daily Scheduling

The following three examples are results obtained when limiting the regulation participation to 50% of capacity: first, the day when RegUp and RegDown prices were highest, May 21st 2016; second, the day when Day Ahead prices were highest, June 20th; and third, the day when Real Time prices were the highest, Aug. 20th.

To illustrate the complexities of these operations, consider the following sets of daily plots (Figure 3-36) of operations showing market prices, charge and discharge activities, and regulation services provision. The elements shown on the series of charts that follows are described below.

Table 3-3-18. Chart Elements

Chart Element	Description
Reg UP	BESS capacity offered to Regulation Up (KW)
Reg Down	BESS capacity offered to Regulation Down (KW)
RU CLR P	Regulation Up market clearing price ($/KW)
RD CLR P	Regulation Down market clearing price ($/KW)
RMU CLR P	Regulation Mileage Up market clearing price ($/KW)
RMD CLR P	Regulation Mileage Down market clearing price ($/KW)
DA	Day-ahead wholesale energy clearing price ($/KWh)
RT	Real-time wholesale energy clearing price ($/KWh)
Charge Down	Required Charge for Regulation Down Participation (KWh)
Discharge UP	Required Discharge for Regulation Up Participation (KWh)
Charge ENM	Charge bid in Day-ahead wholesale energy market (KWh)
Discharge ENM	Discharge offered in Real-time wholesale energy market (KWh)

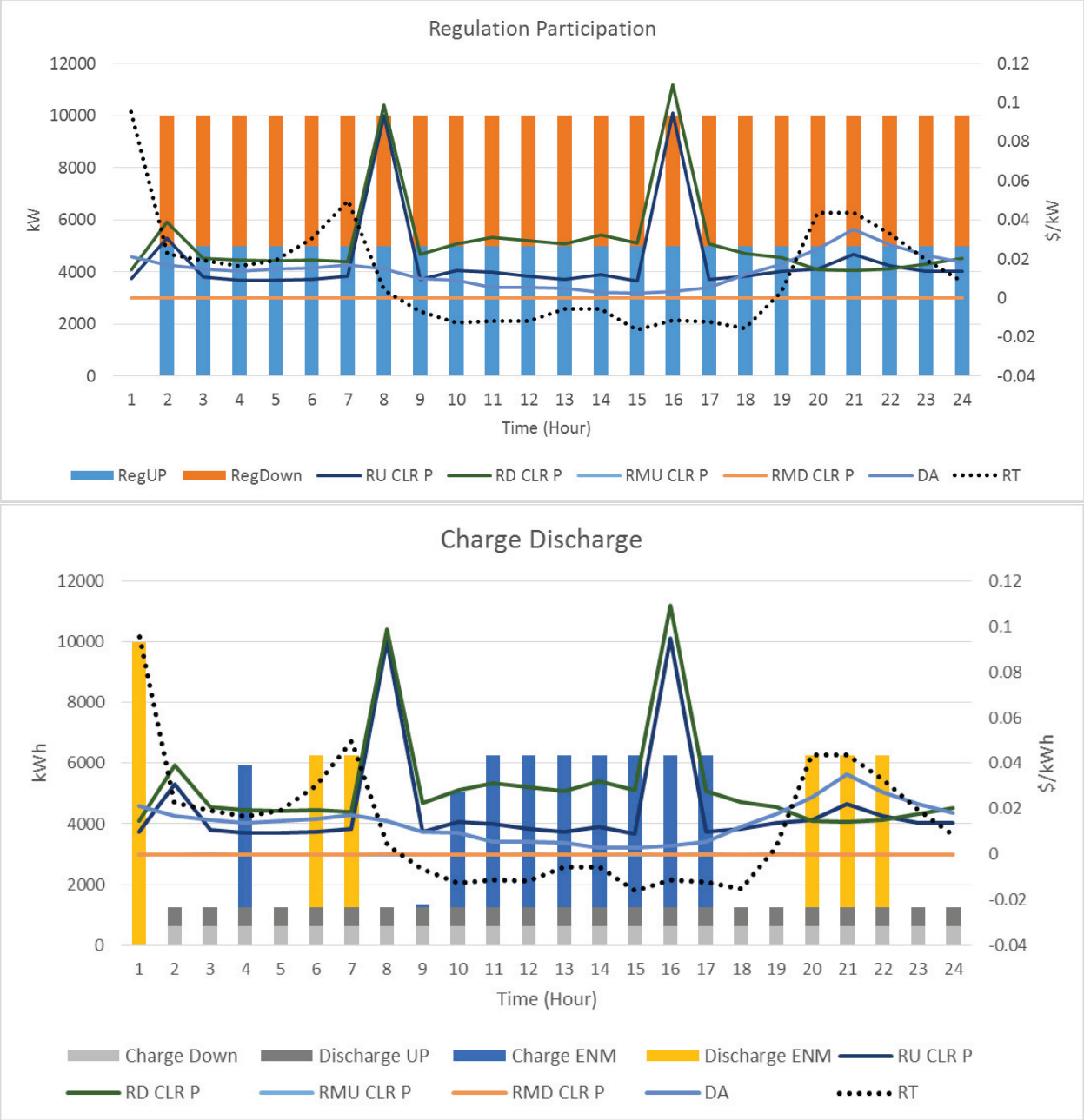


Figure 3-36. May 21, 2016 analysis (Location A)

Figure 3-36 above shows May 21 2016 simulated operation, a day with high RegUp and RegDown prices. RegUp and RegDown are sold almost continuously through the day, which limits the capacity available for charge / discharge arbitrage. Charging occurs between when DA prices are low.

By contrast, a June day with higher DA prices and spikes in RT prices shows (Figure 3-37) that the operations shift towards maximizing revenues from charge-discharge activities, following the RT prices for discharge.

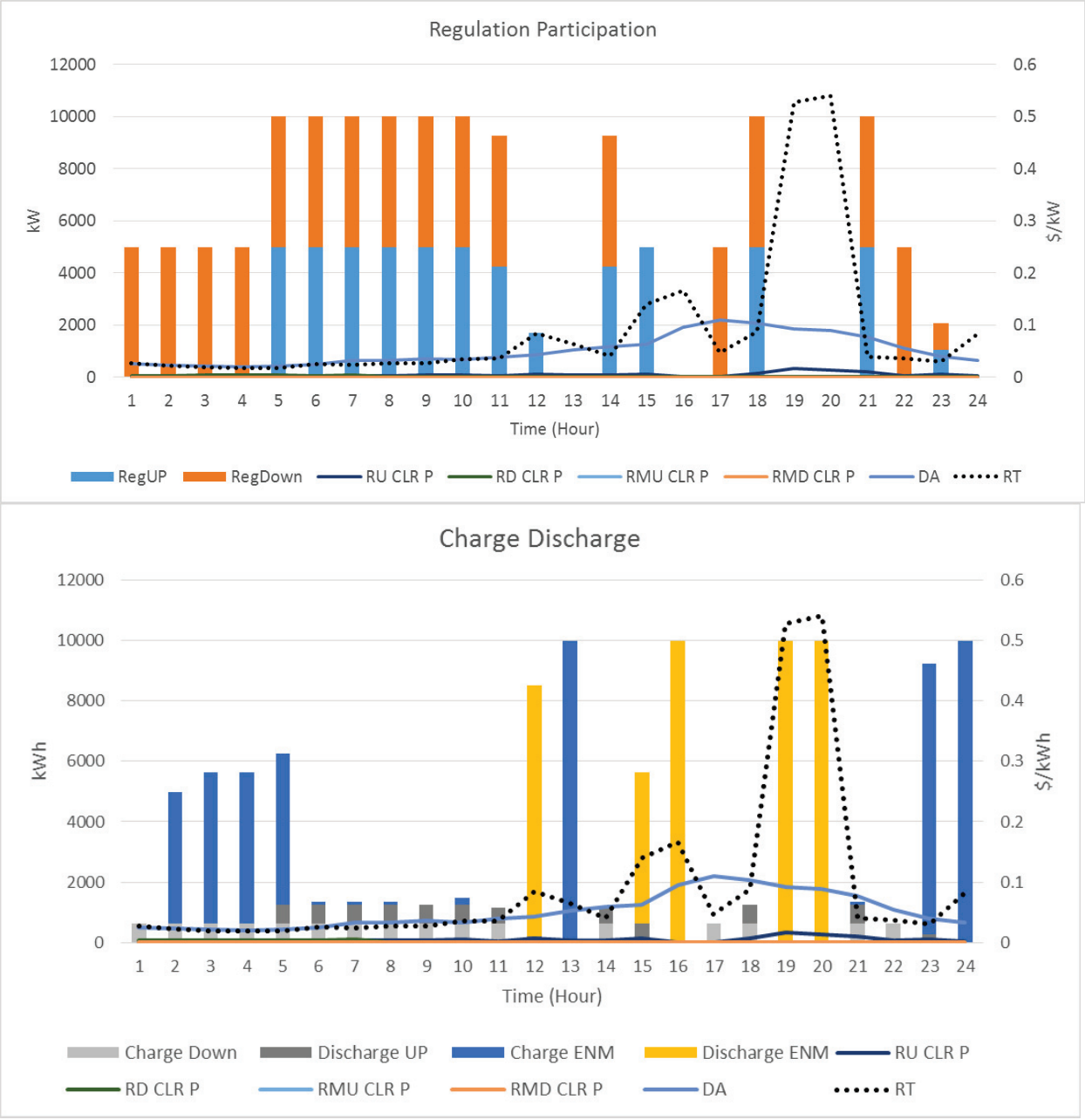


Figure 3-37. June 20 2016 analysis (Location A)

Finally, a day in August with high real time prices results in a yet different pattern (Figure 3-38):

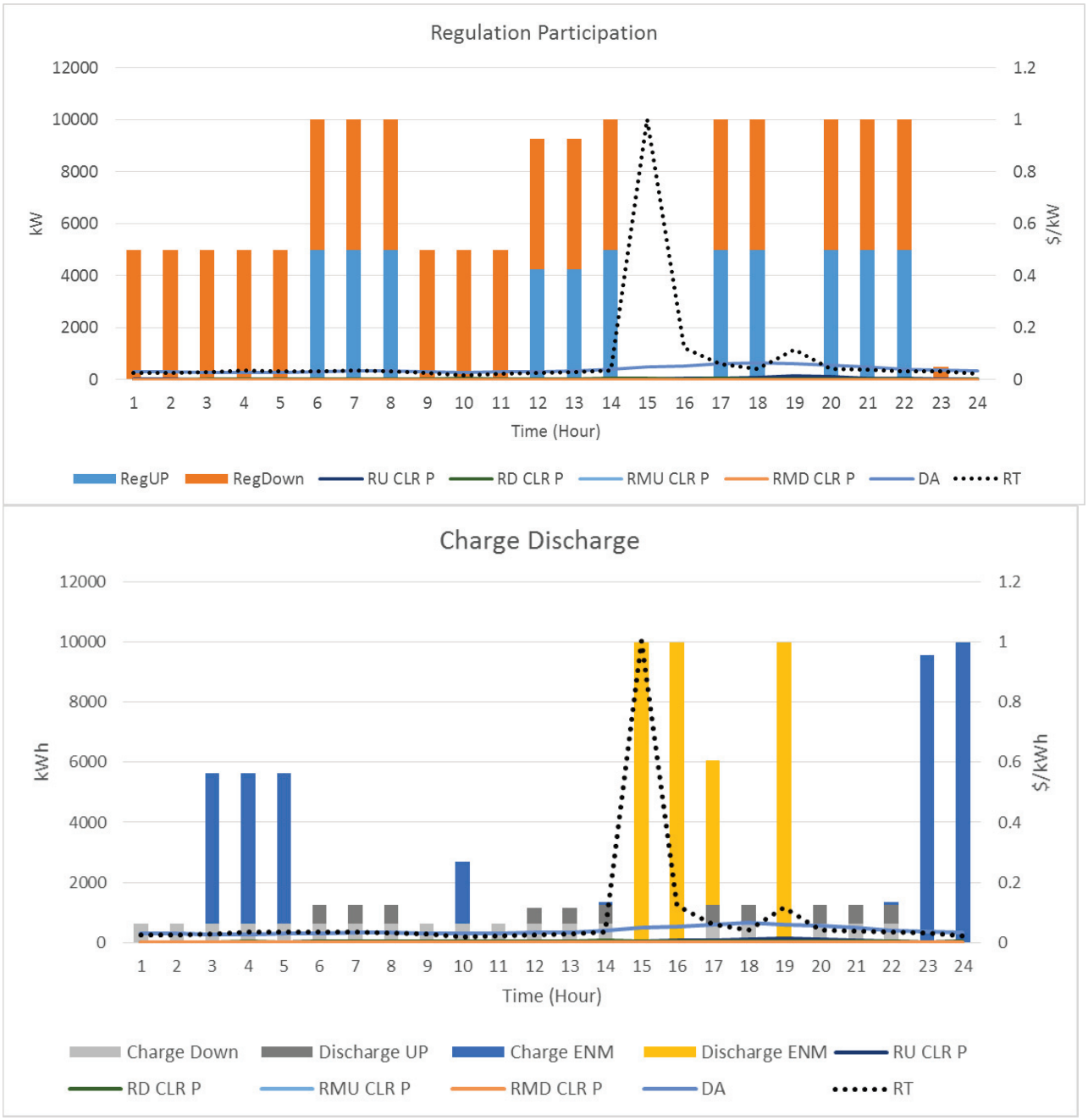


Figure 3-38. A day in August 2016 analysis (Location A)

Increasing the allowable regulation participation to 20% and 50% alters the daily pattern of participation considerably. Comparable charts to those above for different levels of regulation participation are shown in the appendix.

Similar analyses of any day in the year, with focus on aspects such as "lowest DA prices" or "highest RT prices" are possible in the tool used for this analysis. The conclusion from examining the results of the optimization of the 10 MW BESS in the energy and ancillaries markets should be that optimal scheduling is quite complex – more so than that of a conventional resource given the limited 40 MWH of energy available and the need to manage that during the day. The asymmetric nature of the CA ISO RegUp and RegDown pricing and mileage/energy usage creates additional complexities and interactions between regulation service and energy arbitrage.

Whether a tool such as Generation Management tool (Vendor 22) can effectively manage these interactions given its lack of storage representation is a question to be answered. It may be that SDG&E bidding strategy for the 10 MW Bess also needs to be informed by a detailed simulation of BESS charging and discharging as well as Generation Management tool (Vendor 22) price forecasts. The considerable additional revenues from participating in regulation service can only be realized by careful consideration of all the BESS constraints and regulation-energy interactions, so an investment in addressing these questions is worthwhile. It is also worth noting that the bulk of the large BESS in ISO markets today as merchant storage are dedicated to the regulation market where they can function as price takers without the need to anticipate DA prices. Mixing regulation, DA energy, and RT energy requires price forecasting and bidding with sophisticated strategies.

3.2.1.3 Imposing Hourly Limits on BESS charging (Location B)

As stated earlier, a second case was analyzed for the case when the BESS is connected on distribution circuits (Location B). The BESS size was kept the same (10MW / 40 MWh). This means that the total of circuit loadings and BESS charging must be within the circuit thermal limit of 600 A (12MW).

The relative size of the BESS as compared to the total circuit thermal rating and the total circuit peak loading becomes an important factor in how much the loading limits will impact BESS charging flexibility and overall market revenues.

Table 3-3-19. The 10 MW BESS in the Day Ahead and Real Time Energy markets for 2016 data with limits imposed on hourly charging at Location B

Operational Strategy	Annual cost of charging	Annual revenue of discharging	Annual VOM	Charging DA-RT Compensation	Annual Benefits
Charge DA - Discharge RT NO LIMITS	$144,706	$925,139	$85,995	$31,468	$725906
Charge DA - Discharge RT with Station Limits	$141,038	$917,865	$82,221	$31,163	$725,768

There are small differences in the charging and discharging revenues, but they net to a nearly insignificant difference in the net annual benefits. There are a number of factors at work. The limits normally will be imposed when the net load (circuit native load total – total PV production) is greatest. This tends to correlate with the periods of highest market prices, when the BESS would normally be discharging, not charging. The BESS would normally be charging when market prices are lowest, this

correlates with periods when the net load is lowest which is either after midnight or in the early afternoon when PV production is highest, and this is when market prices are lowest. The limits do not have a major impact. Another factor is that the MIP optimization may not be accurate to the 0.2% difference in net benefits that is shown in this comparison, over the 8760 hours with all the variables and constraints in the problem.

Figure 3-39 and Figure 3-40 below show the June 23 day comparing the BESS dispatch with and without the station limits imposed. With the limits, the charging level in the early hours of the day is more restrictive. This forces the total charging to take longer – to spill into later hours. But the BESS is still fully charged by the time the sun comes up and the day starts. The impact on discharging is minor.

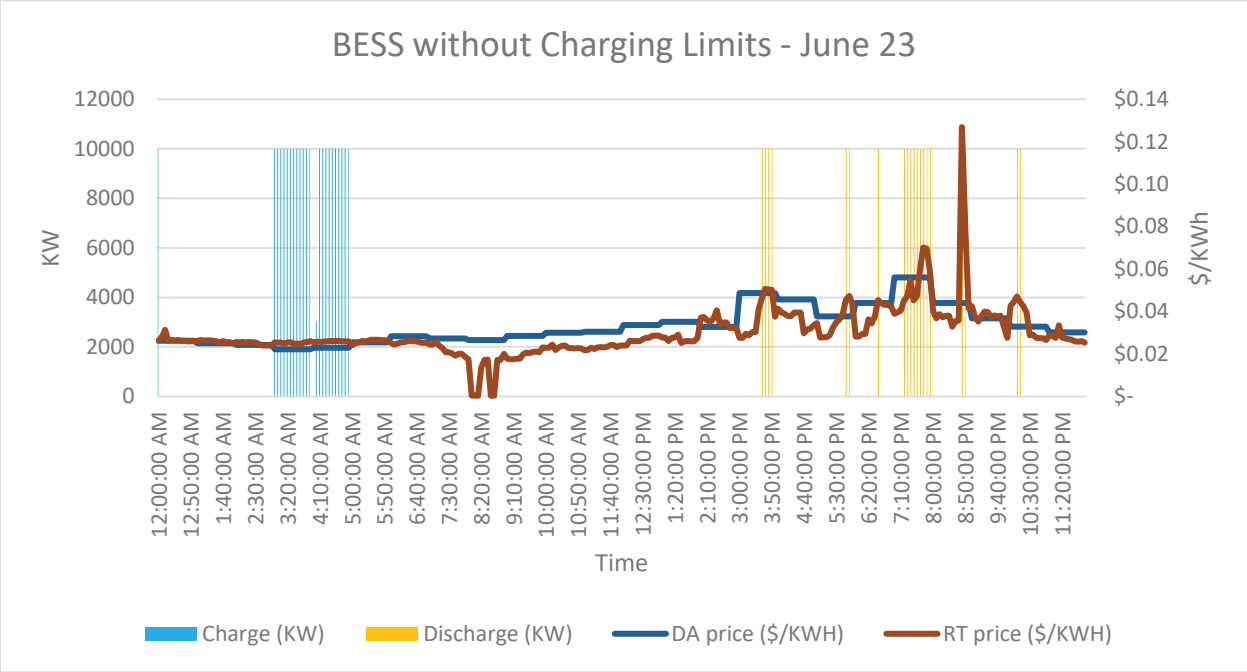


Figure 3-39. June 23 BESS Behavior with No Charging Limits

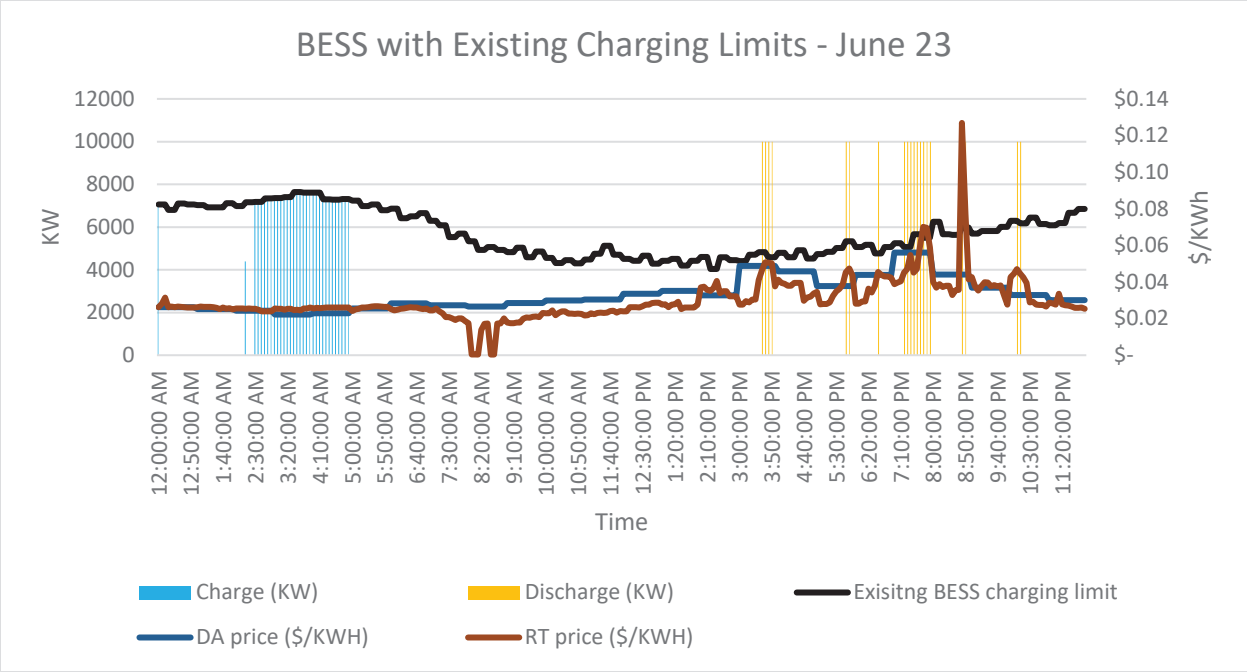


Figure 3-40. BESS behavior with Charging Limits

If the limits on charging were to be reduced to 75% of their value in the above case, then the impacts are more visible. The net benefits drop from $725,000 to $680,000 as shown in Table 3-3-20 below.

Table 3-3-20. Economics with limits reduced (Location B)

Annual cost of charging	Annual revenue of discharging	Annual VOM	Charging compensation
$ 115,367	$ 831,336	$ 55,935	$ (20,153)
Annual Benefit W/O VOM cost			$ 736,122
Annual Benefit with VOM cost			$ 680,187

Some changes are visible in the June 23 behavior as well (Figure 3-41):

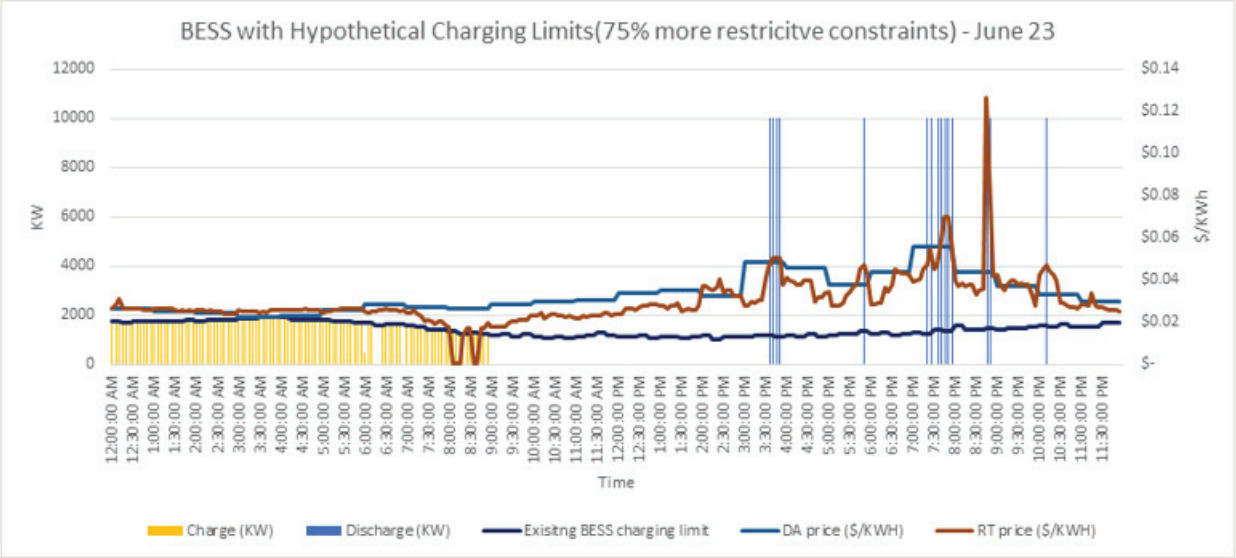


Figure 3-41. June 23 BESS with Hypothetical Charging Limits

This suggests that the cost of modifying a station configuration and providing a separate transformer for BESS interconnection should be compared to the incremental market value that can be realized by removing potential constraints. In this example, the incremental benefits are only $45,000 – how that compares to the incremental cost of bus work and a station transformer needs examination.

3.2.1.4 Shortcomings in this Analysis as a Predictor of Outcomes

It is important to recognize that real world operations cannot realize 100% of the projected best case revenues; there are several reasons for this:

- Market prices going forward in general will not behave identically to historical prices. Changes in the resource mix, weather, and fuel prices as well as possible changes in market products and rules can all affect prices. Most studies nonetheless use historical prices for these analyses, although when forward gas market prices are notably different these can be factored in. Similarly, growth in renewable penetration, plant retirements, etc., can be factored in. This study did not include production costing analysis or future energy price forecasting, and 2016 historical prices are used "as is." While production cost simulations using tools such as Production Costing Tool 1 or Production Costing Tool 2 are routinely used to simulate future hourly prices for energy and ancillaries to value new wind farms or other new resources, they are generally not used to simulate Real Time prices and valuing a BESS under hypothetical future market conditions against RT prices is a challenge.
- There may be additional operational constraints not reflected in the simulation. It would be helpful to understand those and add them to the model if possible;
- When it is necessary to actively participate in the market by making offers, the BESS operator has to determine the price for each market product to use in submitting a bid. This requires the use of a tool such as Generation Management tool (Vendor 22) to forecast DA energy and ancillaries prices and to determine a bidding strategy, as SDG&E does today. BESS which is declared as a generation resource can participate in DA energy and ancillary markets, and in the

RT market. It must make offers in order to do so. BESS located "below the take out point" or on the distribution system can participate passively by responding to DA energy prices – this then affects the Unaccounted For Energy account of SDG&E and the energy cost savings get passed on to SDG&E ratepayers. In order to participate in RT and ancillaries markets, distributed BESS seeking stacked applications will have to be active market participants with the same work required in developing daily bidding strategies. Thus the stacked applications revenue calculations are somewhat hypothetical today. When a rule based bidding strategy is determined (as might be the case for distributed storage) then this can be simulated and evaluated using the same approach as in the theoretically optimal analysis.

- As more storage enters the market in California, it can be expected that market prices will be impacted and that the ISO market products and rules may adapt to storage penetration.
- As more capacity is allocated for regulation service, the ability to achieve best case results improves. A BESS that is offering regulation service as a price taker will realize near-optimal revenues as it is not necessary to use price forecasts to determine when to schedule energy or which energy market to schedule in.

3.2.2 Application of Energy Storage for Demand Management in Commercial Buildings

The objective of this use case was to investigate application of Energy Storage Systems, ESS, for demand management in commercial building. A key assumption is that the commercial building under investigation would require energy storage to serve building load during grid outages – in a microgrid application.

Feasibility Analysis Tool 1 was used to model and optimize energy storage system along with other microgrid components. The analysis was performed by running a benchmark case using both assumed and realistic data, and by evaluating the microgrid model and the associated software tool (Feasibility Analysis Tool 1) from different technical aspects such as: input data, control settings, usability, analyzability, result generation, comparison and reporting.

3.2.2.1 General Description of Feasibility Analysis Tool 1

Feasibility Analysis Tool 1 for optimization and decision analysis for hybrid renewable microgrids including Energy Storage Systems. Feasibility Analysis Tool 1 can be utilized to size project components from a single building or household to a region both with the main grid connected and separated from it – in "islanded" mode. Feasibility Analysis Tool 1 provides solution of best reliable and more economical combination of renewable energy sources versus grid expansion option.

Feasibility Analysis Tool 1 is capable of combining multiple energy and storage sources, such as wind with solar photovoltaics and batteries and offers optimized decision analysis based on both financially and complex engineering feasibility solutions.

3.2.2.2 Approach

The approach was to find applications for, and optimize the size of, the ESS based on the demand and PV generation profile for a commercial building. During the course of this study, we also evaluated the Feasibility Analysis Tool 1 software capabilities

3.2.2.3 System parameters

Feasibility Analysis Tool 1 utilizes a wide range of data for a specific project including geographical location of project, historical time series data for weather, electrical components and economic data of project and its components, etc.

In this section, we briefly explain what is required to model a sample project including a load (building demand), grid (utility), solar photovoltaic and energy storage systems.

Figure 3-42 shows the single line of the benchmark case along with its geographical location which Feasibility Analysis Tool 1 uses to download historical data for weather including solar irradiance, wind and temperature from available resources (such as NREL or NASA).

This study was applied on a commercial building as a benchmark. The study goal was to design and size PV/ESS system components to supply demand during any grid outages, as well as optimizing the electricity bill during normal operation for more economic supply.



Figure 3-42. Single Line of Benchmark Study and its Geographical Location

3.2.2.3.1 Load Data

The building demand for an entire year (2016) was applied as a time-series data with an hour resolution to the Feasibility Analysis Tool 1 load data. The average daily kWh consumption for this load is 725 kWh/day with average annual load of 30.21 kW and peak load of 105.6 kW, which occurred at 9/26/2016 at 5 PM. Annual load profile and statistical information are shown in Figure 3-43.

For multi-year analysis, a load increase of 0.5% annually was considered for the building demand.

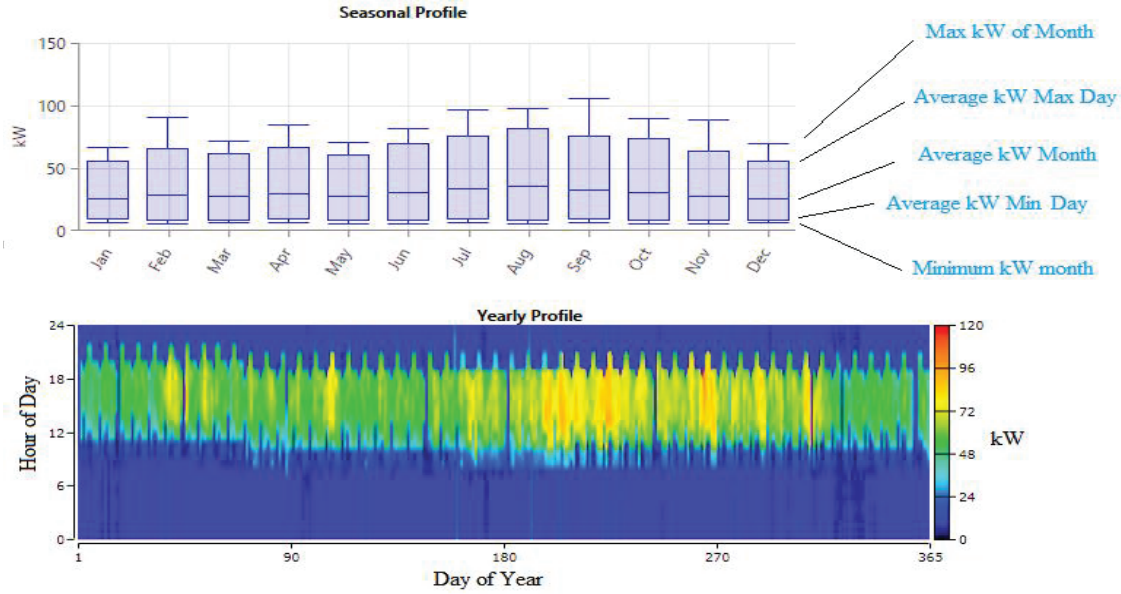


Figure 3-43. Load Annual Demand Data

3.2.2.3.2 Grid Data

The grid can utilize different rate structure (Time of Use - TOU) including Simple Rates, Real Time Rates, and Scheduled Rates. Based on the utility rate structure, the Scheduled Rates were used by defining 6 categories of TOU as shown in Table 3-21 below.

.

Table 3-21. Scheduled Rates for Utility

Rate Category	Price $/kWh	Weekday Hours	Weekends Hours	Controls applied under this rate period
Summer On-Peak	0.1276	11 AM to 6 PM	N/A	Prohibited any battery charging Prohibited any grid sales
Summer Semi-Peak	0.1178	6 AM to 11 AM 6 PM to 10 PM	N/A	Prohibited any battery charging and discharging Prohibited any grid sales
Summer Off-Peak	0.0870	10 PM to 6 AM	All Day	Prohibited any battery discharging Prohibited any grid sales
Winter On-Peak	0.1157	5 PM to 8 PM	N/A	Prohibited any battery charging Prohibited any grid sales
Winter Semi-Peak	0.1001	6 AM to 5 PM 8 PM to 10 PM	N/A	Prohibited any battery charging and discharging Prohibited any grid sales
Winter Off-Peak	0.0787	10 PM to 6 AM	All Day	Prohibited any battery discharging Prohibited any grid sales

In addition, the demand rate was defined based on the utility TOU rate as shown in Table 3-22.

Table 3-22. Demand Rates for Utility

Rate Category	Demand $/kW/month	Weekday Hours	Weekends Hours
Summer On-Peak Demand	45.64	11 AM to 6 PM	N/A
Winter On-Peak Demand	32.08	5 PM to 8 PM	N/A
Non-Coincident Demand (non-peak)	24.51	Rest	All Day

For the project lifetime (assumed 30 years), a multi-year analysis was applied by assuming the energy prices will increase 0.5% annually. No emission data was considered.

It was also assumed that the building could experience up to three outages per year with repair time of eight hours as a worst case scenario. These outage assumptions were made for demonstration purposes, the actual circuit reliability was extremely good (SAIDI < 1 minute).

Also, net purchased capacity for the building was calculated annually, considering a maximum monthly purchase capacity of 150 kW.

3.2.2.3.3 Solar Data

Solar DNI (Direct Normal Irradiance) data was captured from a local weather station and was applied to Feasibility Analysis Tool 1. It has 15 minute time resolution with 5.05 kWh/m2/day annual average. Solar GHI (Global Horizontal Irradiance) was downloaded from “National Renewable Energy Lab” resource data by Feasibility Analysis Tool 1 for the location of study. Its annual average is 5 kWh/m2/day.

3.2.2.3.4 PV/Inverter Data

The PV system was treated as a generic, roof-mount type with the following parameters:

- Capital Cost: 2300 $/kW
- Replacement Cost (after 20 years): 1750 $/kW
- Operation and Maintenance Cost: 37 $/kW
- Lifetime: 20 years
- Derating Factor: 80%
- Ground Reflectance: 20%

Other aspects for the model were: No tracking system, default slope and azimuth, and no temperature effect.

For multi-year study, PV degradation of 1% per year was considered. For optimization purpose, a search space of 0 to 100 kW with 10 kW steps was applied.

3.2.2.3.5 Energy Storage Data

The BESS was configured as follows:

- Nominal Capacity: 210 kWh, 553 Ah
- Roundtrip Efficiency: 88%
- Maximum Charge Current: 131 A
- Maximum Discharge Current: 131 A
- Capital Cost: 450 $/kWh
- Replacement Cost (after 10 years): 350 $/kWh
- Operation and Maintenance Cost: 13.5 $/kWh
- Lifetime: 10 years
- Initial State of Charge: 80%
- Minimum State of Charge: 5%

For optimization, a search space with maximum 7 battery strings was considered.

3.2.2.3.6 DC/AC Converter (Battery Charger/Discharger)

A generic model of a power converter with the following parameters was used:

- Nominal Capacity: 150 kW
- Capital Cost: 500 $/kW
- Replacement Cost: 350 $/kW
- Operation and Maintenance Cost: 15 $/kW
- Inverter Lifetime: 12 years
- Inverter Efficiency: 98%
- Rectifier Efficiency: 92%

3.2.2.3.7 Project Settings

The project lifetime was considered to be 30 years. Therefore, all the economic aspects and cost calculations were based on multi-year analysis. If the lifetime of any piece of equipment was less than 30 years, it had to be replaced.

Below are additional economic factors applied in the analysis:

- Discount Rate: 7.79%
- Inflation Rate: 2.90%
- System fixed O&M cost annual increase: 0.5%/year

3.2.2.4 Energy Storage Control Strategy

There are two control approaches in Feasibility Analysis Tool 1 for optimization of an ESS: Load Following (LF), and Cycle Charging (CC). This section provides an explanation of each approach and distinctive features of these two approaches.

3.2.2.4.1 Load Following (LF) Approach

The load following strategy is a dispatch strategy whereby whenever a generator/utility operates, it produces only enough power to meet the primary load. Charging the storage bank or serving the deferrable load are left to the renewable power sources and are lower-priority objectives in this approach. Under the load following strategy, Feasibility Analysis Tool 1 dispatches the system's controllable power sources (generators, grid, storage bank) so as to serve the primary loads at the least total cost in each time step, while satisfying the operating reserve requirement.

3.2.2.4.2 Cycle Charging (CC) Approach

The cycle charging strategy is a dispatch strategy whereby whenever a generator needs to operate to serve the primary load, it operates at full output power. Surplus electrical production goes toward the lower-priority objectives such as serving the deferrable load and charging the storage bank. When using the cycle charging strategy, Feasibility Analysis Tool 1 dispatches the controllable power sources (generators, storage bank and grid) for each time step of the simulation in a two-step process:

- Step1; selecting the optimal combination of power sources to serve the primary load, while satisfying the operating reserve requirement. To accomplish this, Feasibility Analysis Tool 1 calculates the fixed and marginal cost of each dispatchable power source. This step is identical to the load-following strategy (LF).
- Step2; Feasibility Analysis Tool 1 ramps up the output of each generator/utility in that optimal combination to its rated capacity. If a set point state of charge is applied to the cycle charging strategy, then when the storage state of charge is below the set point and the storage was not discharging in the previous time step, controller will avoid discharging the storage in this time step. A generator/utility will likely be called upon to serve the primary load and produce excess electricity to charge the storage bank. So, once the system starts charging the storage bank, it continues to do so until it reaches the set point state of charge.

For this benchmark study, the Cycle Charge approach is applicable to charge the ESS bank during the lower electricity rate hours of simulation. Therefore, this approach is recommended for this kind of ESS applications and hence we used the approach with considering a 90% State of Charge set point.

Figure 3-44 shows how the Cycle Charging approach controls ESS charging/discharging for a sample week based on the grid power price for the optimum solution. The case shown is for the weekend days of October 27th and 28th, when the electricity price is low and constant all day long; no ESS was utilized and the demand was met by shared PV and Utility powers.

During the weekdays, the utility rate structure were slightly higher during semi-peak and further on-peak hours. Therefore, ESS was discharged during those hours and was started to be charged back during off-peak hours to reach its target SOC of 90% at the end of the day.

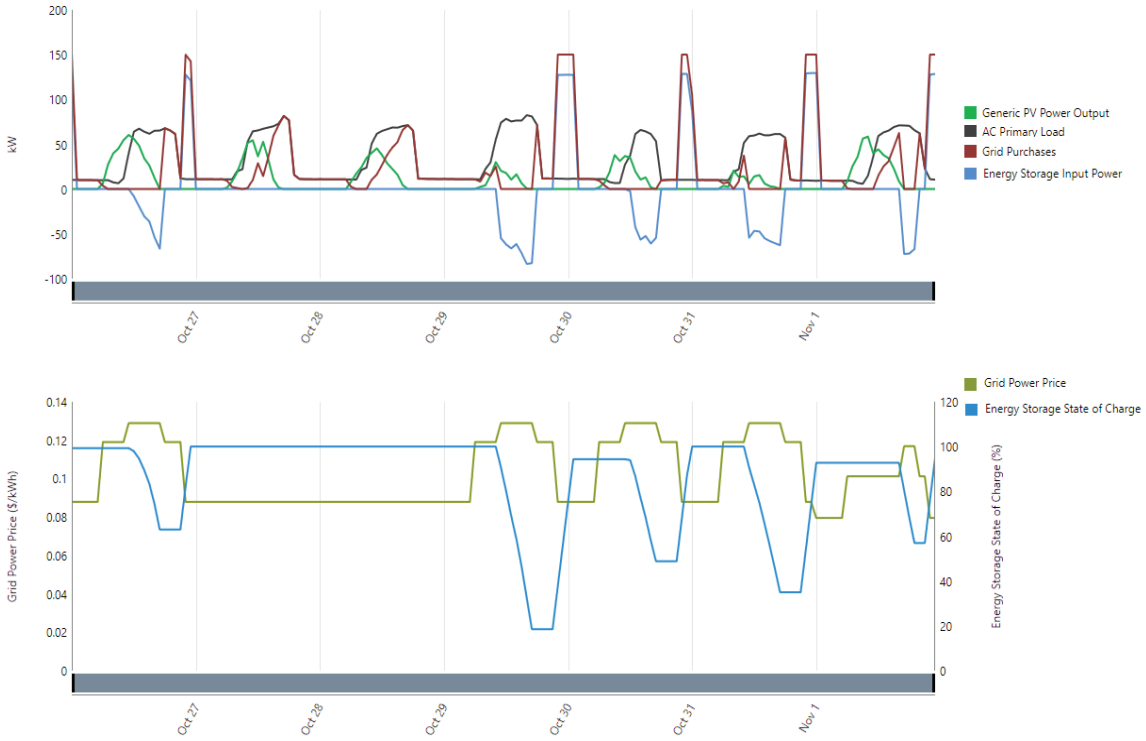


Figure 3-44 - Sample week simulation results for the sample case

Figure 3-45 shows how a simulated grid outage happening in Oct 1 is handled with both PV and ESS. The ESS is discharged deeply in the day when utility is disconnected from the building.

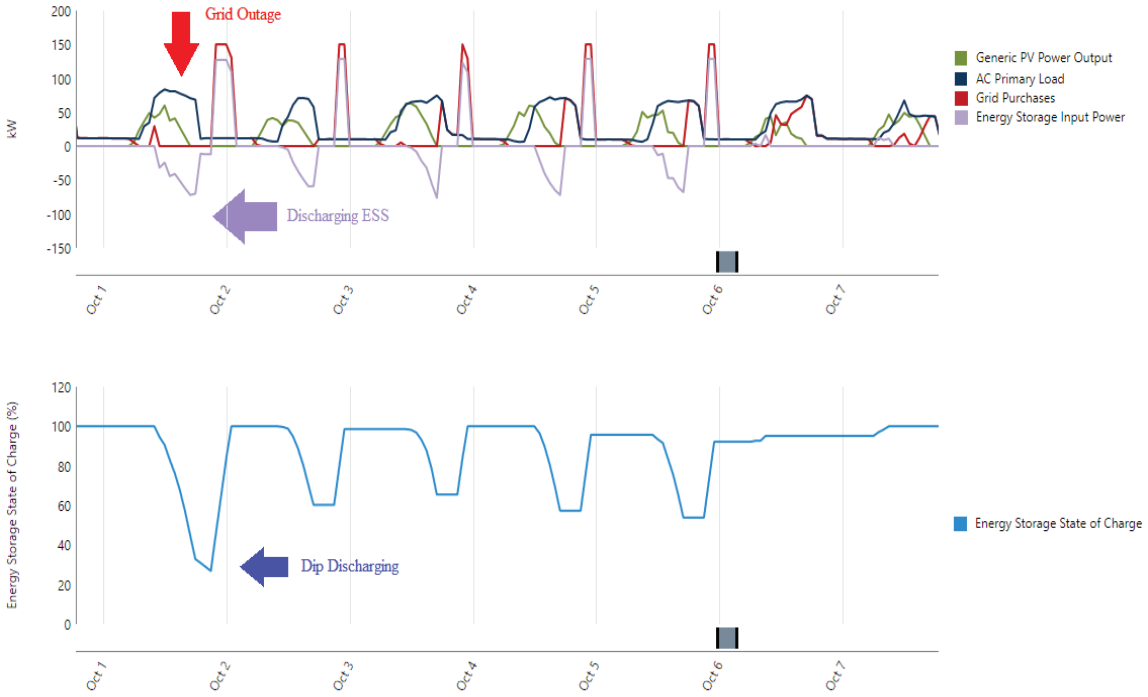


Figure 3-45. Outage simulation results on October 1st

3.2.2.5 System Sizing

Based on the preset model and data, the sizes of the PV and ESS units were evaluated for optimization. The PV system was considered to be between 0 to 100 kW with 10 kW steps. The energy storage was sized in increments of 210 kWh, with a maximum size of 7 strings (i.e. 7×210=1470 kWh).

Executing the optimization and after running both LF and CC approaches for the entire year, data was calculated for every scenario of ESS and PV size combination inside their search space.

The objective function is based on optimizing Total Net Present Cost (NPC) for the entire project life time. A solution would be provided if the least NPC as an optimized PV/ESS combination can be identified.

Table 3-23 provides the overall results for all feasible solutions which are ranked from top to bottom based on their economic value. Based on this table, the optimization solution is to utilize 70 kW of Photovoltaic along with 3×210=630 kWh of Energy Storage system. This solution has the lowest NPC of $2,156,915 and the lowest Cost of Energy (COE) of 0.479 $/kWh.

Table 3-23. Feasible optimization results

PV (kW)	ESS # Strings (×210 kWh)	AC/DC (kW)	Cost/COE ($)	Cost/NPC ($)	Cost/Operating cost ($)	Cost/Initial capital ($)	Cost/O&M ($)	System/Ren Frac (%)	PV/Capital Cost ($)	PV/Production (kWh)	ESS/Autonomy (hr)	ESS/Annual Throughput (kWh)	Grid/Energy Purchased (kWh)
70	3	150	0.479	$2,156,915	$103,526	$519,500	$87,537	23%	$161,000	106,188	18	89,589	218,434
80	3	150	0.480	$2,162,409	$102,420	$542,500	$85,615	27%	$184,000	121,358	18	84,869	208,083
60	3	150	0.481	$2,165,899	$105,549	$496,500	$90,553	19%	$138,000	91,019	18	94,513	229,630
90	3	150	0.483	$2,176,865	$101,879	$565,500	$84,618	30%	$207,000	136,528	18	80,468	198,795
50	3	150	0.486	$2,190,207	$108,540	$473,500	$94,545	15%	$115,000	75,849	18	99,581	241,587
100	3	150	0.487	$2,192,340	$101,404	$588,500	$83,549	33%	$230,000	151,698	18	76,470	190,668
40	3	150	0.498	$2,242,160	$113,279	$450,500	$100,346	11%	$92,000	60,679	18	104,604	254,296
30	4	150	0.500	$2,249,516	$109,223	$522,000	$88,821	6%	$69,000	45,509	25	114,000	269,067
20	4	150	0.501	$2,255,580	$111,061	$499,000	$91,254	0%	$46,000	30,340	25	120,478	284,080
40	4	150	0.503	$2,264,246	$108,700	$545,000	$87,872	11%	$92,000	60,679	25	107,734	254,905
50	4	150	0.505	$2,273,981	$107,862	$568,000	$86,748	15%	$115,000	75,849	25	101,827	241,825
10	4	150	0.507	$2,282,112	$114,192	$476,000	$94,956	0%	$23,000	15,170	25	127,202	300,050
100	2	150	0.507	$2,285,063	$113,241	$494,000	$102,025	33%	$230,000	151,698	12	70,620	189,752
60	4	150	0.508	$2,288,893	$107,350	$591,000	$85,909	19%	$138,000	91,019	25	96,199	229,588
90	2	150	0.510	$2,294,387	$115,285	$471,000	$104,162	31%	$207,000	136,528	12	73,640	197,519
80	2	150	0.512	$2,304,718	$117,392	$448,000	$106,389	28%	$184,000	121,358	12	76,808	206,415
50	2	150	0.512	$2,304,903	$121,766	$379,000	$111,574	16%	$115,000	75,849	12	85,564	238,220
70	4	150	0.512	$2,305,387	$106,939	$614,000	$85,189	23%	$161,000	106,188	25	90,860	218,183
70	2	150	0.512	$2,305,621	$118,903	$425,000	$108,158	24%	$161,000	106,188	12	80,008	216,313
60	2	150	0.513	$2,306,983	$120,443	$402,000	$109,870	20%	$138,000	91,019	12	82,968	226,945
30	3	150	0.515	$2,319,497	$119,622	$427,500	$107,189	6%	$69,000	45,509	18	109,715	268,017
80	4	150	0.515	$2,319,900	$106,402	$637,000	$84,237	27%	$184,000	121,358	25	85,846	207,601
	4	150	0.516	$2,324,181	$118,306	$453,000	$99,812	0%			25	133,710	316,743

PV (kW)	ESS # Strings (×210 kWh)	AC/DC (kW)	Cost/COE ($)	Cost/NPC ($)	Cost/Operating cost ($)	Cost/Initial capital ($)	Cost/O&M ($)	System/Ren Frac (%)	PV/Capital Cost ($)	PV/Production (kWh)	ESS/Autonomy (hr)	ESS/Annual Throughput (kWh)	Grid/Energy Purchased (kWh)
90	4	150	0.520	$2,340,513	$106,251	$660,000	$83,751	30%	$207,000	136,528	25	81,222	198,245
100	4	150	0.524	$2,361,348	$106,114	$683,000	$83,235	33%	$230,000	151,698	25	77,099	190,034
20	3	150	0.528	$2,378,206	$124,789	$404,500	$111,519	1%	$46,000	30,340	18	114,670	282,591
	5	150	0.538	$2,422,067	$118,520	$547,500	$94,014	0%			31	135,811	317,252
10	3	150	0.539	$2,425,303	$129,220	$381,500	$116,058	0%	$23,000	15,170	18	119,032	297,967
10	5	150	0.539	$2,429,212	$117,518	$570,500	$92,629	0%	$23,000	15,170	31	128,363	300,328
20	5	150	0.542	$2,438,818	$116,671	$593,500	$91,461	0%	$46,000	30,340	31	121,205	284,222
30	5	150	0.544	$2,449,995	$115,924	$616,500	$90,393	6%	$69,000	45,509	31	114,416	269,090
40	5	150	0.547	$2,462,503	$115,260	$639,500	$89,406	11%	$92,000	60,679	31	108,008	254,795
	3	150	0.549	$2,470,610	$133,539	$358,500	$120,248	0%			18	123,015	314,031
50	5	150	0.550	$2,476,621	$114,699	$662,500	$88,523	15%	$115,000	75,849	31	102,011	241,544
60	5	150	0.553	$2,492,061	$114,221	$685,500	$87,722	20%	$138,000	91,019	31	96,337	229,137
70	5	150	0.557	$2,508,847	$113,828	$708,500	$87,004	24%	$161,000	106,188	31	90,970	217,580
80	5	150	0.561	$2,527,018	$113,522	$731,500	$86,370	27%	$184,000	121,358	31	85,927	206,893
90	5	150	0.566	$2,547,051	$113,335	$754,500	$85,849	31%	$207,000	136,528	31	81,305	197,416
100	5	150	0.570	$2,568,900	$113,262	$777,500	$85,442	34%	$230,000	151,698	31	77,178	189,145
	6	150	0.585	$2,635,578	$126,045	$642,000	$96,717	0%			37	135,984	317,298
10	6	150	0.587	$2,643,796	$125,110	$665,000	$95,464	0%	$23,000	15,170	37	128,428	300,343
20	6	150	0.589	$2,653,393	$124,263	$688,000	$94,295	0%	$46,000	30,340	37	121,223	284,219
30	6	150	0.592	$2,664,501	$123,511	$711,000	$93,223	6%	$69,000	45,509	37	114,421	269,037
40	6	150	0.594	$2,676,927	$122,843	$734,000	$92,231	11%	$92,000	60,679	37	108,010	254,678
50	6	150	0.598	$2,690,891	$122,271	$757,000	$91,338	15%	$115,000	75,849	37	102,011	241,316
60	6	150	0.601	$2,706,139	$121,781	$780,000	$90,525	20%	$138,000	91,019	37	96,337	228,764
70	6	150	0.605	$2,722,652	$121,371	$803,000	$89,792	24%	$161,000	106,188	37	90,970	217,032

PV (kW)	ESS # Strings (×210 kWh)	AC/DC (kW)	Cost/COE ($)	Cost/NPC ($)	Cost/Operating cost ($)	Cost/Initial capital ($)	Cost/O&M ($)	System/Ren Frac (%)	PV/Capital Cost ($)	PV/Production (kWh)	ESS/Autonomy (hr)	ESS/Annual Throughput (kWh)	Grid/Energy Purchased (kWh)
80	6	150	0.609	$2,740,603	$121,052	$826,000	$89,144	28%	$184,000	121,358	37	85,964	206,211
90	6	150	0.613	$2,760,464	$120,853	$849,000	$88,612	31%	$207,000	136,528	37	81,969	196,757
100	6	150	0.618	$2,782,074	$120,765	$872,000	$88,192	34%	$230,000	151,698	37	79,791	188,829
	7	150	0.633	$2,850,158	$133,637	$736,500	$99,552	0%			43	135,996	317,299
10	7	150	0.635	$2,858,379	$132,703	$759,500	$98,299	0%	$23,000	15,170	43	128,428	300,345
20	7	150	0.637	$2,867,970	$131,855	$782,500	$97,130	0%	$46,000	30,340	43	121,223	284,214
30	7	150	0.639	$2,879,047	$131,101	$805,500	$96,056	6%	$69,000	45,509	43	114,421	269,012
40	7	150	0.642	$2,891,401	$130,428	$828,500	$95,060	11%	$92,000	60,679	43	108,010	254,603
50	7	150	0.645	$2,905,238	$129,849	$851,500	$94,158	15%	$115,000	75,849	43	102,011	241,143
60	7	150	0.648	$2,920,345	$129,350	$874,500	$93,335	20%	$138,000	91,019	43	96,337	228,479
70	7	150	0.652	$2,936,656	$128,927	$897,500	$92,590	24%	$161,000	106,188	43	90,970	216,608
80	7	150	0.656	$2,954,431	$128,596	$920,500	$91,932	28%	$184,000	121,358	43	86,550	205,815
90	7	150	0.660	$2,973,955	$128,376	$943,500	$91,380	31%	$207,000	136,528	43	84,524	196,631
100	7	150	0.665	$2,995,395	$128,278	$966,500	$90,947	34%	$230,000	151,698	43	84,354	189,057

The data tabulated above can also be shown graphically in a "heat map" which simplifies the assessment of the various options. Figure 3-46 below shows the "Total Net Present Cost" of the project based on PV size and ESS string numbers – with the dark-blue color representing the lowest cost. If the installed PV size was planned to be more than 40 kW then three battery strings (i.e. 3×210 kWh) would be a reasonable solution (see left box on the picture). But, for a wider range of PV installation, the best ESS size would be 4 battery strings (i.e. 4×210 kWh) as shown with the right box.

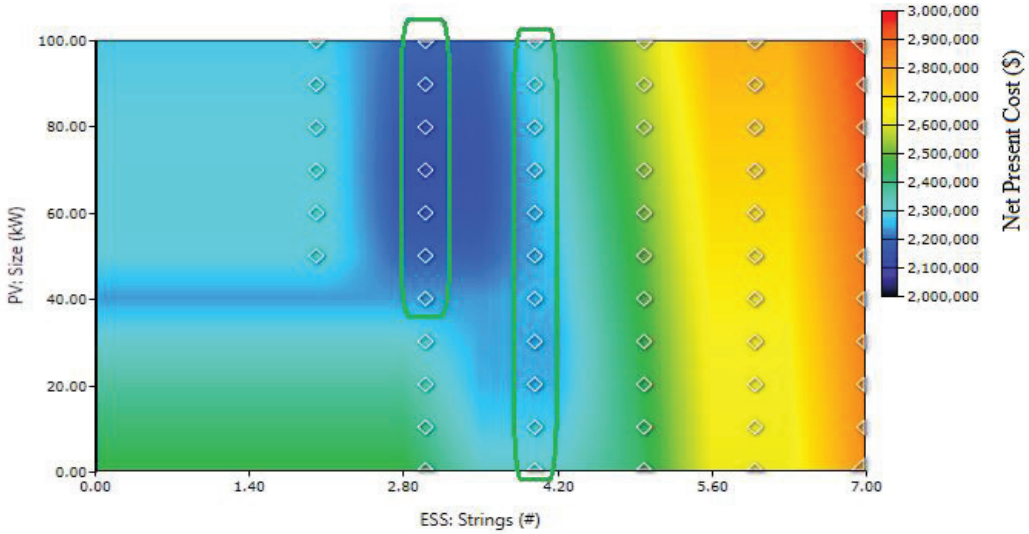


Figure 3-46. Net present cost of project based on PV/ESS size

In the Capacity Shortage percentage plot in Figure 3-47 below, the darker portion of the plot represents no capacity shortage and, hence, a feasible solution. By evaluating the plot, it is evident that at least three ESS strings are required to avoid power shortage during outages. Based on the PV size, 3 battery strings (for PV size more than 50 kW) and 4 battery strings (all PV ranges from 0 to 100 kW) would be adequate.

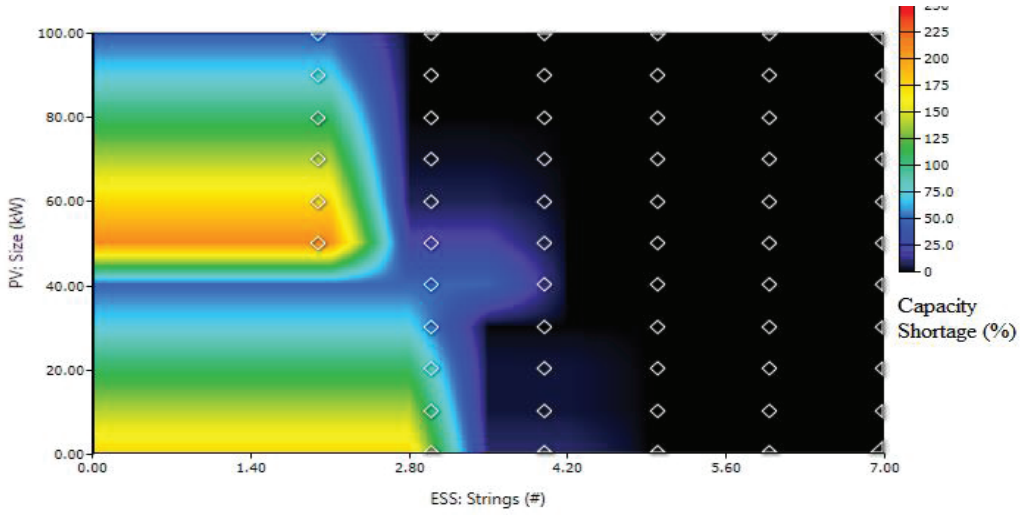


Figure 3-47. Capacity Shortage (%) based on PV/ESS size

3.2.2.6 Financial analysis

For the optimized case with PV=70 kW and ESS=3×210=630 kWh, a summary of the results are presented below. Figure 3-48 and Table 3-24 show the cost summary based on Capital, Operating, Replacement, and salvage cost as net-present values.

Table 3-25 shows the same costs annualized.

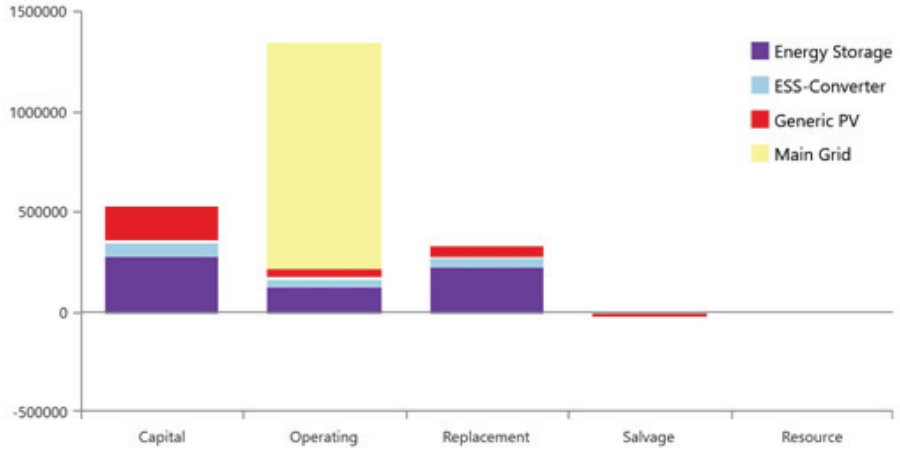


Figure 3-48. Cost Summary for Energy Resources under different cost categories

Table 3-24. Net Present Costs under different cost categories

Name	Capital	Operating	Replacement	Salvage	Resource	Total
Energy Storage	$283,500	$134,519	$225,730	$0.00	$0.00	$643,749
ESS-Converter	$75,000	$35,587	$47,303	-$6,520	$0.00	$151,370
Generic PV	$161,000	$40,965	$48,403	-$15,213	$0.00	$235,155
Grid serving	$0.00	$1.13M	$0.00	$0.00	$0.00	$1.13M
Total System	$519,500	$1.34M	$321,437	-$21,733	$0.00	$2.16M

Table 3-25. Annualized Costs under different cost categories

Name	Capital	Operating	Replacement	Salvage	Resource	Total
Energy Storage	$17,924	$8,505	$14,272	$0.00	$0.00	$40,701
ESS-Converter	$4,742	$2,250	$2,991	-$412.22	$0.00	$9,570
Generic PV	$10,179	$2,590	$3,060	-$961.85	$0.00	$14,868
Grid Serving	$0.00	$71,232	$0.00	$0.00	$0.00	$71,232
Total System	$32,846	$84,577	$20,323	-$1,374	$0.00	$136,372

Figure 3-49 show 30-years cash flow for the different cost categories.

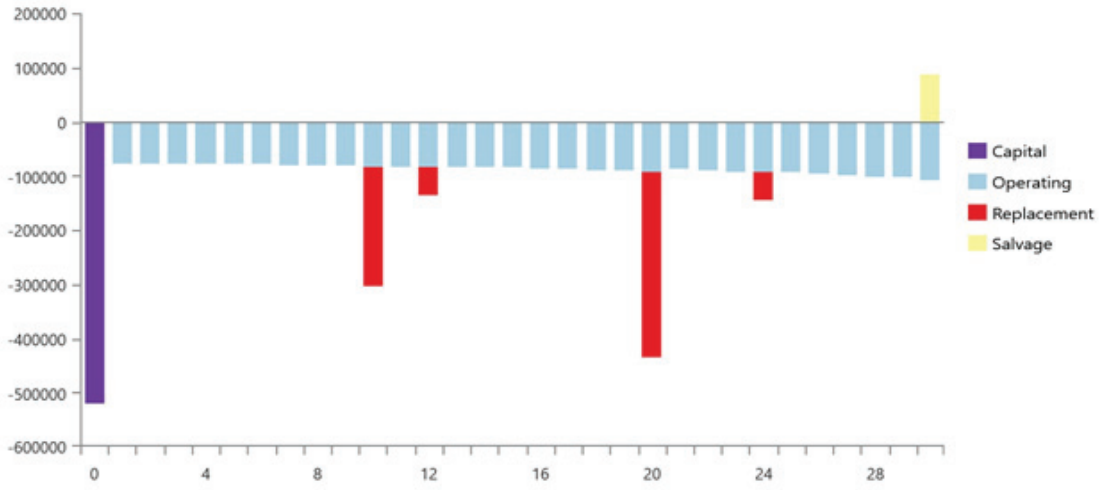


Figure 3-49. 30-Year Cash Flow under different cost categories

Utilizing the ESS system decreases the total utility bill payment from $1.612 million to $ 1.13 million in 30-years compared to the case where PV and Utility-supply are the sole resource of energy. Table 3-26 shows the project economic metrics with the payback of 5.43 years.

Table 3-26. Project Economic Metrics (Comparing with and without ESS cases, both cases including PV)

Net Present Value ($)	$313,695
Annual saving ($/yr)	$27,314
Return on investment (%)	%19
Internal rate of return (%)	%18.5
Simple payback (yr)	5.43 Year
Discounted payback (yr)	6.39 Year

3.2.2.7 Observations

The use case investigated the viability of using a hybrid system comprising of PV and ESS units to optimize electricity usage and also to serve building load during grid outages. Feasibility Analysis Tool 1 was used to generate results for a large search space incorporating mixed combination of various sizes for PV system and ESS units. The software proved adept at analyzing and optimizing both PV and ESS in a commercial building application.

Other observations include:

- Design and sizing of the PV and ESS are very sensitive to load data. The accuracy of this data and its year-to-year growth therefore plays a critical role in the optimization procedure.
- In a similar fashion, accurate weather time-series data, as well as carefully selected economic data will affect the outcome of the optimized solution.
- Grid outages require the BESS to be sized to carry the load for the duration of the outage. Feasibility Analysis Tool 1 defines outages in a random manner for the specified duration which does not always coincide with peak demand hours. It is therefore necessary to perform several sensitivity analysis to size the ESS during a worst case outage scenario with maximum load.

3.2.3 Hybrid ESS Applications for Residential and Commercial Buildings

3.2.3.1 Introduction

This use case outlines utilization of hybrid PV with battery energy storage systems in residential and commercial buildings. The objective of the use case is to investigate the economic benefit of offsetting some or all of the time of use peak energy and/or demand consumption from a battery with the intention of lowering the customer's bill to a meaningful extent. The battery would be charged using available surplus onsite PV electricity together with supplementary electricity drawn from the grid during off-peak periods. In other words, this case evaluates the merits of charging a battery using "free" solar PV power along with off peak grid-supplied power, and discharging the battery to offset higher priced energy and demand charges.

3.2.3.2 Properties Assessed

For the benchmark purpose (hypothetically), four building locations were selected as representative residential / commercial buildings for the study.

- Residential building 1 (RB1) is a multi-family building complex in Chula Vista, CA. At approximately 50,000 square foot space, the multi-family home sits on a 2.1 acre lot. From on-line information, it appears to include 5 (plus a small) buildings and maybe 60-80 apartments in total. It has 2 laundry rooms and swimming pools. There is potential to install a solar shade parking structure to generate PV. The peak annual demand for the building complex is 29.6 kW (hourly data) and the average hourly demand was 13 kW. The hybrid system evaluated for this building included 20 kW PV with a 60 kWh battery. The solar PV panels could potentially be installed on the rooftop or outdoor parking structure. This system was also evaluated using 2 potential time of use electric pricing schedules.
- Residential building 2 (RB2) is a 7,200 square foot multi-family building with 9 units in Chula Vista, CA. It has a flat roof, a peak annual demand of 14.4 kW and an average hourly demand of 4.4 kW. The hybrid system evaluated included a 10 kW rooftop solar PV system with 25 kWh of battery storage. This system was also evaluated using 2 potential time of use electric pricing schedules.
- Commercial Building 1 (CB1) is 21,000 square foot building in El Cajon, CA. It operates seven days per week, generally from mornings to late evenings and visitors are members of the general public. The building has an existing 45 kW rooftop PV system. Not factoring the contribution from the PV system, the building is estimated to have a peak annual demand of 113.5 kW and an average demand of 44.3 kW. A potential commercial sector time of use rate schedule factoring energy and demand was used for the evaluation. The hybrid system cases evaluated would use the existing PV system with 100 kWh or 150 kWh batteries.
- Commercial Building 2 (CB2) is a 25,000 square foot building in San Diego, CA. Visited by the general public, it is open seven days per week and operates from morning to early evening. The building has

a peak annual demand of 105 kW and average demand of 30.4 kW. It was evaluated for a 36 kW solar PV system with options for 90 kWh and 180 kWh battery storage capacities. A potential commercial sector time of use rate schedule factoring energy and demand was used for the evaluation.

Table 3-27 illustrates the combination of properties and systems that were assessed for the analysis.

Table 3-27. Representative residential and commercial buildings for the Hybrid ESS analysis

Address	PV Only	PV + Battery	Residential TOU-DR 2 Rate	Residential TOU-DR 3 Rate	Commercial Rate >20 kW
Residential building 1 (RB1)	✓	✓	✓	✓	
Residential Building 2 (RB2)	✓	✓	✓	✓	
Commercial building 1 (CB1)	✓	✓			✓
Commercial building 2 (CB2)	✓	✓			✓

3.2.3.3 Approach

Figure 3-50 illustrates the method used to determine the cost to benefit of adding a battery to a solar PV system for a given building. The modeling was performed using the widely available System Advisor Model (SAM) software developed by Vendor 1.

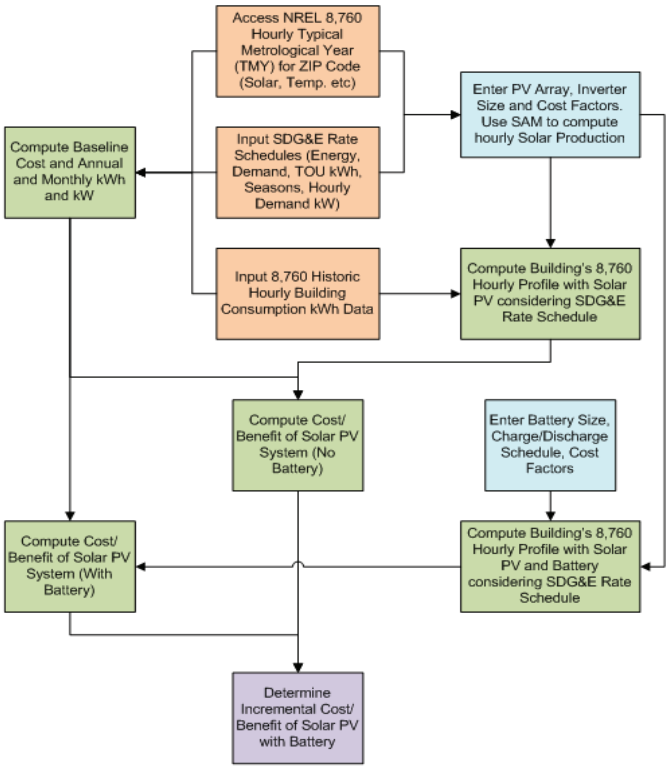


Figure 3-50. Flowchart of the proposed study approach for hybrid system evaluation

The key inputs to the SAM include:

1. 8,760 hourly historic energy consumption for the specific building,
2. The associated electricity Tariff schedule, and
3. The Typical Meteorological Year data for the building's ZIP code.

The model was used to compute the building's Baseline energy cost. Next, a solar PV Array and Inverter (building roof-top installation) were added to the model, and the cost and benefit of this system, together with the impact on the Baseline electricity bill were calculated. In the third step, a battery energy storage system was added to the model.

The battery model included the battery's degradation factors, and a schedule for charging and discharging based on the variations in the electricity prices according to the time-of-use Tariff schedule. The model was set to charge the battery using off-peak time (lowest electricity price) and PV-generated power, and to discharge to offset peak kWh and peak kW demand charges. The incremental cost and benefit of the adding the battery was then computed.

PV system sizes were selected based on performing an assessment of the available roof-top area for installing typical roof-top PV systems. The PVWatts Calculator tool from NREL[4] was used for this purpose.

Battery ESS sizing was performed according to the analysis of the historical hourly demand of the buildings and the peak load.

3.2.3.4 SAM Software

The System Advisor Model (SAM) is a performance and financial model developed by NREL. It performs hour-by-hour calculations of a power system's electric output, generating a set of 8,760 hourly values that represent the system's electricity production over a single year.

The current version of the SAM includes performance models for Photovoltaic systems together with Battery storage for photovoltaic systems.

SAM accepts inputs for the technical specifications and performance degradation associated with solar PV modules, inverters and batteries.

A variety of residential retail electricity rates and commercial retail and power purchase agreement rates can be incorporated into SAM's financial model. The financial model calculates financial metrics for various kinds of power projects based on a project's cash flows over a specified analysis period. The financial model uses the system's electrical output calculated by the performance model to calculate the series of annual cash flows.

[4] http://pvwatts.nrel.gov/

3.2.3.5 Weather Data

Figure 3-51 shows 8,760 hourly Typical Meteorological Year (TMY) data for a selected ZIP code. The SAM software uses this solar insolation and ambient temperature (among other factors) to compute the solar PV production.

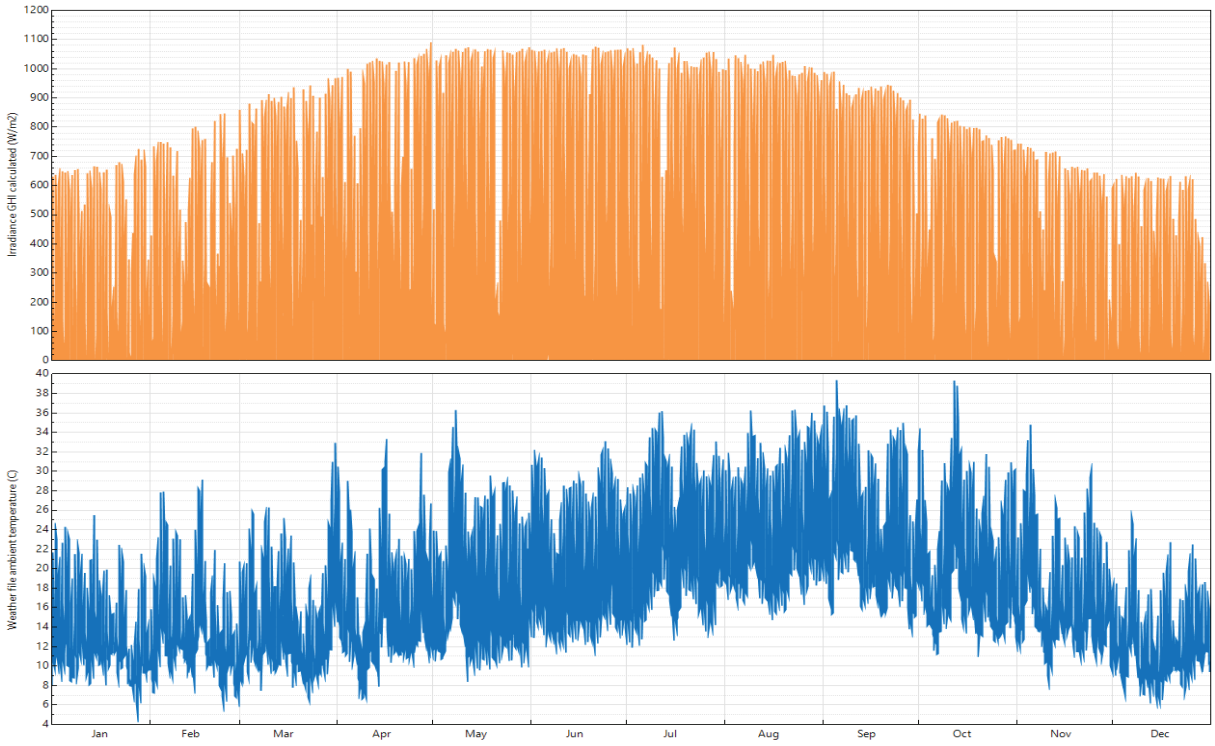


Figure 3-51. Solar radiation and temperature profiles for a selected location in the study area

3.2.3.6 Electricity Rate Data

In "Resolution E-4848. Adoption of San Diego Gas & Electric Company's residential default time-of-use pricing pilot pursuant to Decision 15- 07-001" two residential time of use rates TOU-DR2 and TOU-DR3 (referred to DR2 and DR3 in this report) were filed with the Public Utilities Commission of the State of California. [5] (Note that rates are out for decision and the analysis are only for assessment purpose).

As an example, for TOU-DR2 (see Figure 3-52) the weekday and weekend time blocks are shown. Proposed time of use rates included:

- Summer On-peak
- Summer Off-Peak
- Summer Super Off-Peak
- Winter On-peak
- Winter Off-Peak

[5] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M183/K383/183383395.PDF (Accessed 20 September 2017)

- Winter Super Off-Peak



Figure 3-52. Proposed TOU-DR2 Time of Use Hourly Schedule

This is typically for 6 time blocks illustrated by 1 to 6 in the Table 3-28.

Table 3-28. TOU-DR2 Time of Use Rate Designations

Time of Use Period for TOU-DR2	Numeric Designation in SAM Model
Summer On-peak	1
Summer Off-Peak	2
Summer Super Off-Peak	3
Winter On-peak	4
Winter Off-Peak	5
Winter Super Off-Peak	6

The SAM model accepts a numeric designator for entering time of use energy (kWh) and demand (kW) data as illustrated in Figure 3-53. In order to provide more precise instructions for the SAM model, 2 additional placeholder rates (7 and 8) were created to properly control the battery discharge hours, where rate for 8 is identical to 6 and rate for 7 is identical to 3.

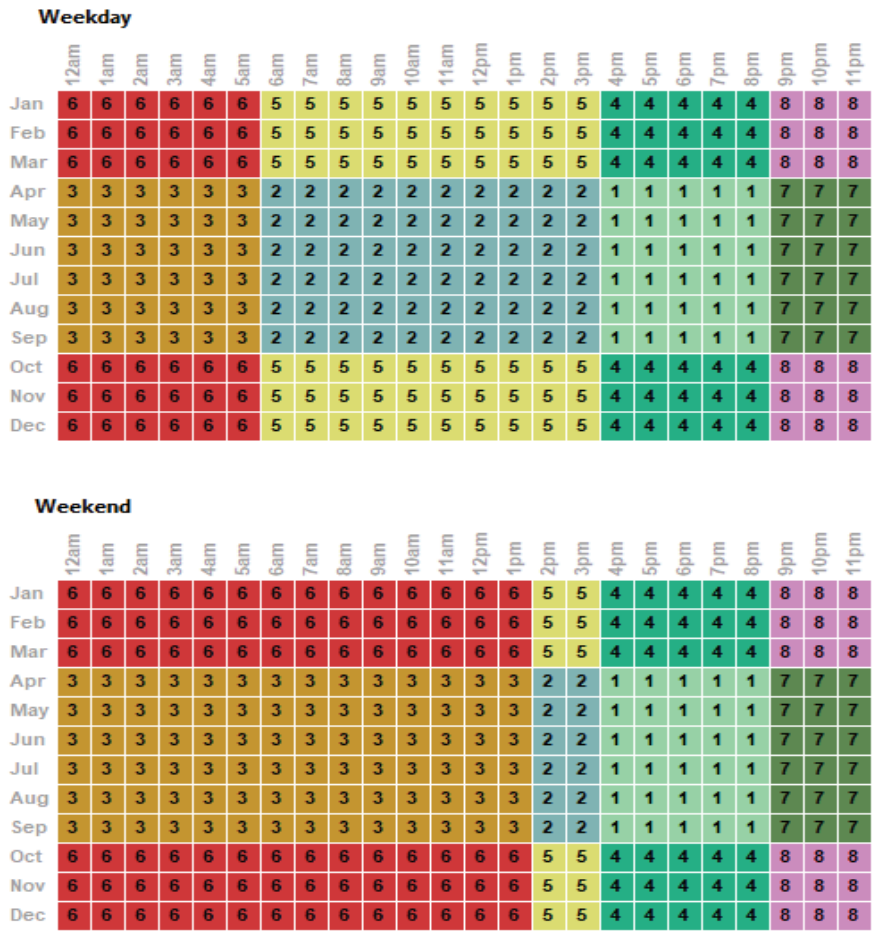


Figure 3-53. Daily and monthly electricity rate schedules

For the commercial buildings, proposed time of use rates[6] (see Table 3-29) for peak kW demand charges were input in the model, and the operating strategy was to use the battery to reduce the peak demand charges. Table 3-30 presents the commercial time of use and demand price.

Table 3-29. Commercial time of use and demand rates

Rate Category	Price $/kWh	Weekday Hours	Weekends Hours
Summer On-Peak	0.1276	11 AM to 6 PM	N/A
Summer Semi-Peak	0.1178	6 AM to 11 AM 6 PM to 10 PM	N/A
Summer Off-Peak	0.0870	10 PM to 6 AM	All Day
Winter On-Peak	0.1157	5 PM to 8 PM	N/A
Winter Semi-Peak	0.1001	6 AM to 5 PM 8 PM to 10 PM	N/A
Winter Off-Peak	0.0787	10 PM to 6 AM	All Day

[6] docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M195/K586/195586830.PDF

Table 3-30. Commercial time of use and demand price

Rate Category	Demand $/kW/month	Weekday Hours	Weekends Hours
Summer On-Peak Demand	45.64	11 AM to 6 PM	N/A
Winter On-Peak Demand	32.08	5 PM to 8 PM	N/A
Non-Coincident Demand	24.51	Rest	All Day

3.2.3.7 Battery Impact

The SAM model was set to dispatch during periods of highest energy and/or demand prices and to recharge using off-peak and/or minimum demand price electricity supplemented by the surplus power produced by the solar PV system.

Figure 3-54 shows the annual hourly impact of using the solar PV with battery combination on a sample commercial building (CB1) used for the analysis. The upper portion shows the historic hourly energy consumption of the building. The lower graph uses a different scale, and shows the charging of the battery (from lower cost hours plus available excess solar PV), and discharge of the battery during peak hours.

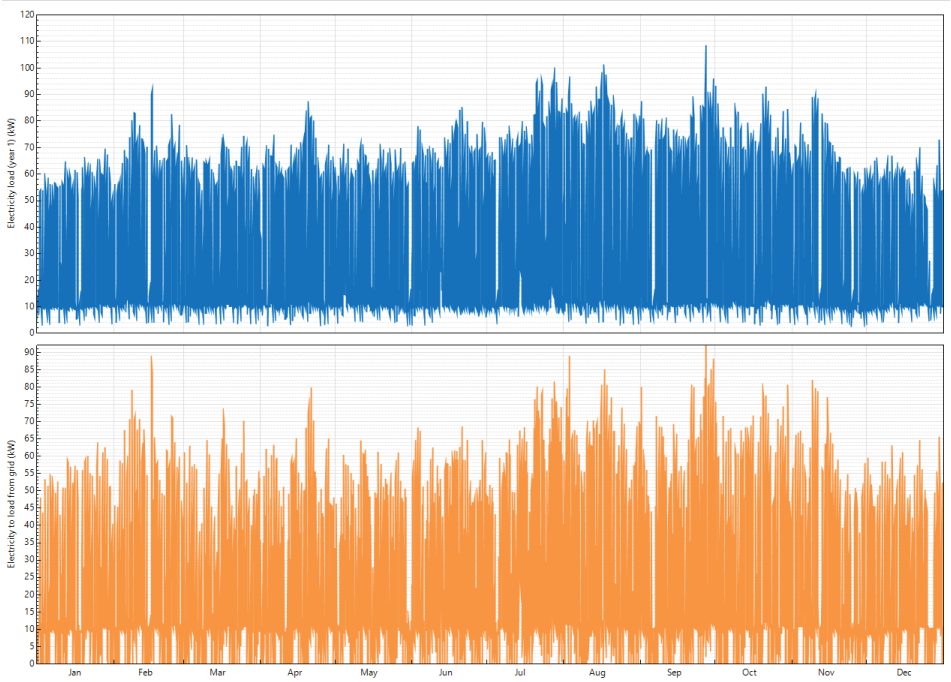


Figure 3-54. Annual View of Hourly impact of using battery

The impact of the battery can be seen in Figure 3-55 where according to the proposed Commercial time of use rates, the battery discharges during the 3 peak winter weekday hours, and recharges during the day.

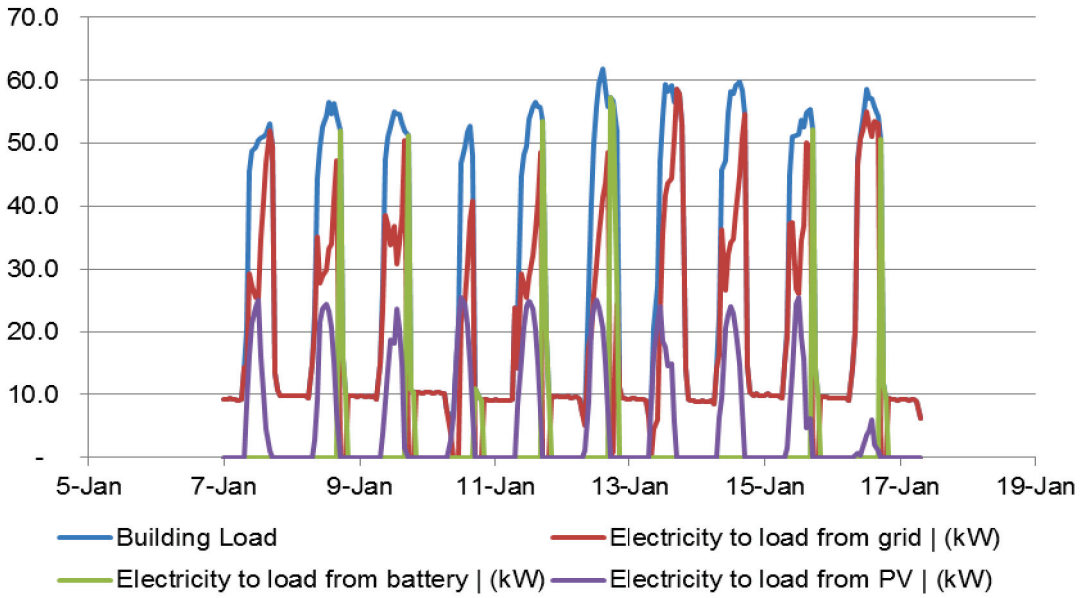


Figure 3-55. Hourly impact of using battery

Figure 3-56 shows the impact of adding a 180 kWh battery and 36 kW PV array to building CB1. The battery is charged using off peak/low demand power and surplus solar PV generated power. It can be seen that approximately 10% of the building's power consumption flows through the battery.

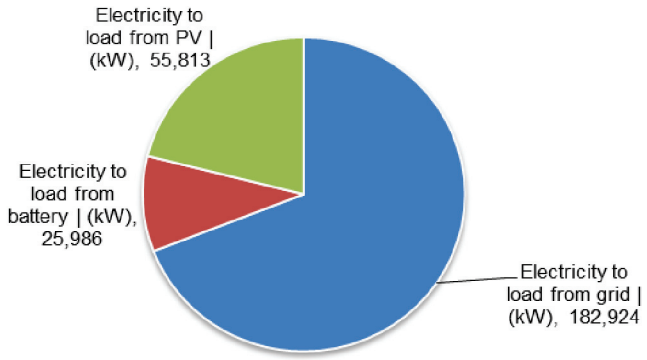


Figure 3-56. Flow of Annual Power to Building CB1 (Total 246,723 kWh)

3.2.3.8 Battery Degradation Factor

The default SAM battery degradation factors were revised to reflect actual experience with batteries of this nature and are presented in Figure 3-57.

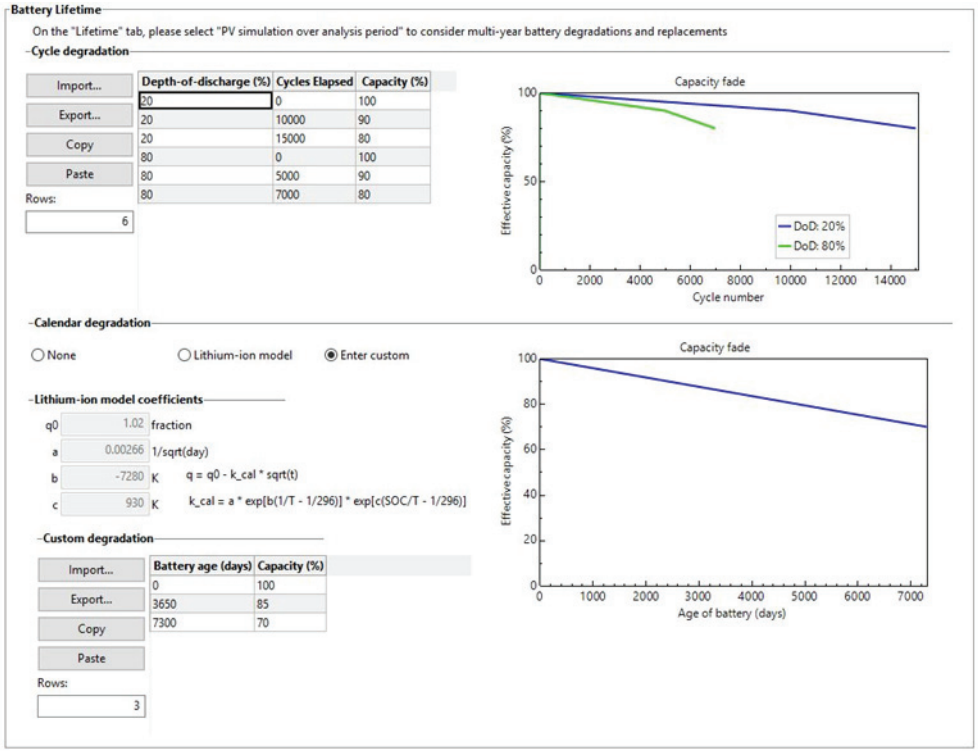


Figure 3-57. Assumption for battery degradation model

3.2.3.9 Economic Parameters Used in the SAM Model

Other economic parameters used for the model included:

- Discount Rate: 7.79%
- Inflation Rate: 2.9%
- Solar PV Modules : $0.64 per W DC
- Inverter: $0.21 per W DC
- DC to AC Ratio : From 1.15 to 1.20
- Battery Bank: $420 per kWh DC
- Balance of System: $0.36 per W DC
- Installation Labor: $0.30 per W DC
- Installer Margin and Overhead: 25%
- Permitting and Environmental Studies: $0.10 per W DC

3.2.3.10 Results Summary

Table 3-31 shows the average electricity rate per kWh expected to be paid by a customer for 100%, grid supplied, Grid supplied with Supplementary PV, and Grid supplied with PV and Battery.

- Four cases (Case 1 to Case 4) are analyzed for representative multi-family low-income residential housings in the context of rates TOU-DR2 and TOU-DR3.

- Four representative cases (Cases 5 to Case 8) incorporated commercial buildings designated as cool zones in disadvantage communities. The cases used the Commercial time of use rate but varied the battery size.

Table 3-31. Average Cost per kWh with Time of Use Rates and Supplementary PV and Battery

CASE	Applicable Rate	100% Grid Supplied ($/kWh)	Grid Supplied with PV ($/kWh)	Grid Supplied with PV and Battery ($/kWh)
Case 1 RB1	TOU-DR2	$ 0.2901	$ 0.2112	$ 0.2016
Case 2 RB1	TOU-DR3	$ 0.2939	$ 0.2149	$ 0.2095
Case 3 RB2	TOU-DR2	$ 0.2885	$ 0.2059	$ 0.1972
Case 4 RB3	TOU-DR3	$ 0.2929	$ 0.2101	$ 0.2058
Case 5 CB1	Commercial	$ 0.3413	$ 0.2952	$ 0.2789
Case 6 CB1	Commercial	$ 0.3413	$ 0.2952	$ 0.2828
Case 7 CB2	Commercial	$ 0.2926	$ 0.2461	$ 0.2446
Case 8 CB2	Commercial	$ 0.2926	$ 0.2461	$ 0.2437

Table 3-32 shows 6 cases of the cost and benefit and payback of the Solar PV systems. The first four cases are for Residential buildings RB1 and RB2 where the time of use rates are varied from TOU-DR2 and TOU-DR3. These rates have marginal impact on the solar PV simple payback which is 3.5-3.6 years. The last two cases are for buildings CB1 and CB2 and use the Commercial time of use with demand rate. The solar PV Systems are expected to have paybacks in the 4.3 to 5.2 year range.

Table 3-32. Cost and Benefit of Solar PV

Rate	PV Array Size (kW)	Study Locations (Hypothetical)	Annual Building Load kWh	Gross Electricity to Load from Grid (kWh)	Electricity to Load from PV	Electricity bill without system (year 1)	Net savings with PV Only (year 1)	PV Only Payback period
RB1 DR2	20	Chula Vista	114,279	83,592	30,687	$ 33,154	$ 9,020	3.5 years
RB1 DR3	20	Chula Vista	114,279	83,592	30,687	$ 33,589	$ 9,035	3.5 years
RB2 DR2	10	Chula Vista	47,477	35,190	12,287	$ 13,697	$ 3,921	3.6 years
RB2 DR3	10	Chula Vista	47,477	35,190	12,287	$ 13,905	$ 3,928	3.6 years
CB1 Commercial	36	San Diego	264,723	208,916	55,807	$ 90,339	$ 12,199	5.2 years
CB2 Commercial	45	El Cajon	388,696	311,690	77,005	$ 113,715	$ 18,075	4.3 years

As shown in Table 3-32, it was noted that the incremental payback for the additional battery-based hybrid ESS equipment is more than 10 years. In the case of residential customers who do not pay for peak kW demand, the cost savings are expected to be in the 1.5-3% range and the incremental payback for the battery storage is uneconomic. For commercial time of use customers with peak energy and

demand charges, the benefit of adding energy storage was between 0.5- 4.8 %. In general terms the incremental cost of adding additional battery storage greater than the expected energy and demand bill savings of avoiding peak energy at the rate schedules assessed.

Table 3-33 summarizes the results of analysis for the eight cases.

Table 3-33. Summary of the Hybrid ESS benefit/cost analysis

Case and Building	Electricity Rate Schedule	PV Array Size (kW)	Battery Size (kWh)	Location	Baseline Electric Bill (No PV or Battery)	Baseline Average Cost per kWh	Incremental Bill Savings with Battery	Percent Savings of Baseline Bill	Incremental Cost to Add Battery	Simple Payback for Battery (years)
Case 1 RB1	TOU-DR2	20	60	Chula Vista	$33,154	$0.29	$1,099	3.30%	$25,850	23.5
Case 2 RB1	TOU-DR3	20	60	Chula Vista	$33,589	$0.29	$609	1.80%	$25,850	42.4
Case 3 RB2	TOU-DR2	10	25	Chula Vista	$13,697	$0.29	$414	3.00%	$10,750	26
Case 4 RB3	TOU-DR3	10	25	Chula Vista	$13,905	$0.29	$205	1.50%	$10,750	52.4
Case 5 CB1	Commercial	36	180	San Diego	$90,339	$0.34	$4,311	4.80%	$77,551	18
Case 6 CB1	Commercial	36	90	San Diego	$90,339	$0.34	$3,278	3.60%	$38,800	11.8
Case 7 CB2	Commercial	45	150	El Cajon	$113,715	$0.29	$577	0.50%	$64,650	112
Case 8 CB2	Commercial	45	100	El Cajon	$113,715	$0.29	$919	0.80%	$43,100	46.9

3.2.3.11 Conclusions

The only way that a Hybrid ESS can be cost effective is to utilize ESS for other stacked applications such as Reliability Enhancement during grid outage situations (for scheduled utility maintenances and/or as a result of natural disasters). The added value of customer load serving during grid outages, or any possibility to aggregate smaller size ESS units and incorporate them in wholesale market applications (energy market or ancillary services) can bring in additional revenue to make the case cost effective.

It was however shown that addition of PV to each of these building can effectively reduce the electricity cost and the return on investment under either Time of Use structure (DR2 or DR3) will be tangible enough.

4 KEY FINDINGS AND RECOMMENDATIONS

This section describes findings of the project and provides a series of unique implementation considerations particular to the tools and methodologies for analysis of ESS applications. Based on the findings and observations, several recommendations are also provided to close the gap in study tools and analytical methodologies that will enhance the project planning, application selection and operation.

4.1 Findings and Recommendations Related to Assessment of Existing Applications and Tools

Utilities all have standards for distribution planning and engineering/design in place. Beginning with IEEE and ANSI standards, they develop specific practices and design approaches based on their historical practices and on the particulars of their service territory such as customer base and energy costs. The analyses and business case presentations build on these practices and are tailored to meet the needs of the local regulatory bodies as well. These standards and practices may include (but are hardly limited to):

- Philosophies on issues such as lateral fusing, employment and implementation of N-1 contingencies, including with no ties to other sources from engineering and design practices,
- Implementation of distribution automation technologies,
- Standards for monitoring and control,
- Protection setting standards,
- Design standards such as minimum levels of reserve capacity/maximum loading,
- Design standards such as normal levels of capacity upgrade to achieve,
- Selection of particular vendor products (both software tools and apparatus) to be used in design engineering.

Energy storage for utility applications in today environment will challenge all these practices.

Presently, there are no ANSI or IEEE standards that would specifically define the ESS controls and expected performance characteristics for T&D applications such as capacity upgrade deferral, distribution reliability enhancement, and/or renewable resource impact mitigation (i.e. smoothing). Available standards address type testing, device level performance and interconnection testing of ESS sites [5], [6]. New IEEE working groups, as part of IEEE 1547 and IEE 2030 family of standards are established to focus on characterization and parameterization of storage models and interaction with area electric power system (EPS). Expectation is that the new effort will aim to standardize the application definition and control aspects.

Standardization of practices in construction practices, communication infrastructure, operating practices, and safety is needed for ESS, as for all other power system infrastructure.

The software tools used in planning and design are in general not capable of optimizing storage system design and in some cases cannot analyze the effectiveness of a particular asset and design.

Some storage technologies pose life cycle risks that are difficult to assess in business cases. Degradation models are a subject of ongoing R&D.

Storage siting and local permitting are site specific and need to be addressed on a project by project basis. Federal, state, and local standards for the safe siting, installation, inspection, and maintenance of storage are being addressed across the industry.

4.1.1 Gap analysis and needs

In the production costing space there are at least two tools (Production Costing Tool 2 and Production Costing Tool 3) that can model storage adequately for annual production costing and price impact studies.

With storage as a price taker there are several tools available that can assess storage in the ISO DA, HA, RT, and ancillary markets. One of them, Cost Calculation Tool 6, is focused only on the California market, but has superior detail in the modeling of that market.

Whether the issues of integer variable creation in Cost Calculation Tool 6 and others performing product co-optimization are that significant with technologies other than Li-Ion will have to be determined over time. If the particular tool can accept alternate solvers or if the performance impacts are tolerable, additional integer variables should not be a major issue in the future. However, introducing constraints for stacked applications may make this kind of approximation more problematic.

In the distribution space, the consultant tools can analyze time series of load, PV, etc., using external Matlab or Python code and Distribution Planning Tool 6, Distribution Planning Tool 3, or Distribution Planning Tool 4. The Cost Calculation Tool 6 tool requires external distribution circuit analysis to supply it with data.

These tools can also perform stacked applications. One tool was able to demonstrate semi-automated interfaces between the circuit analysis/sizing and the market and applications cost benefits calculations. However, it is again a semi-manual process. These tools in general are suitable for the evaluation of pilot projects and for engineering a limited number of storage projects by personnel that have been trained in or exposed to the methodologies, generally in close contact with the organizations that developed them. They are not as yet suitable for general use in the T&D planning organizations by all staff.

4.1.2 Deployment and operational challenges

In order for storage projects to move from a “pilot” stage to “commercial” the planning and operations processes will have to mature and address all the process/capabilities gaps identified in previous sections. This means that tools and methodologies for planning, engineering, and operations must be coordinated across a given utility such that overall processes can be standardized, and training for all involved staff can be conducted. Additionally, the methodology for developing a business case must be communicated to and accepted by the regulatory bodies so that planning can be conducted consistent with methods and cost benefit thresholds that will meet regulatory approval.

Up till now this report has addressed evaluation methodologies and tool capabilities. Additional planning standards need to be addressed in order for any methodology to succeed. These critically revolve around (a) the question of ‘how much storage is appropriate?” and “how to manage the risks in storage deployment decisions?”

The methodologies for determining storage sizes for a given application have focused on "how much is required?" or determining a minimum size for a given application, and then for assessing stacked applications for that application and particular implementation. This is not the same as addressing "how much is appropriate?" which would take into account uncertainties in future load growth, uncertainties in energy costs, and (especially) uncertainties in storage costs and performance. The latter might well favor more flexible / modular designs capable of accepting incremental additional capacity in the future; might favor mobile storage that can be moved to a new location (at higher initial costs); and might favor "throw away" storage in some instances. None of the tools available today address this question directly; there are not published results of studies that examine more than a few dimensions of these questions. These questions are the next stage in developing planning and operational guidelines for storage.

Because storage technology is developing rapidly, there will possibly be cases of technical failures after a couple year's operations for reasons not anticipated today, and cases where newer technology is superior at lower costs, rendering plans to move older storage to a new location uneconomic. In other words there will be risks associated with a rapid adoption of new technologies. One solution has been that utilities can specify very tight and long duration warranties in order to ensure performance from manufacturers. Manufacturers may respond by pricing large amounts of additional/replacement battery pack modules as a result, greatly increasing initial costs. Different models that share risks may be more cost effective.

Methodologies to assess these risks realistically and account for them are lacking today.

4.1.3 Recommendations

Utilities should develop plans for making the transition from "pilot" or "proof of concept" status to "commercial" status with the following key steps

- Standardize the framework for calculating benefits, avoided costs, and cost benefit analysis of storage including various combinations of stacked applications.
  - Ensure that the framework adopted for a particular utility is consistent with the system engineering and design philosophy of that utility. The framework should take advantage of the state of the art in assessing storage valuation on distribution systems without venturing into R&D territory for problems as yet unaddressed (such as incorporating stochastics into valuations)
  - Obtain regulatory approval for the framework via worked examples and filings
  - The benefits methodology should be integrated with the actual procedures and tools for system operations incorporating storage so that the benefits are realizable in practice
- Identify available methodologies and tools that can perform assessments consistent with the framework, even if manual steps are necessary at the current state of tool development. The appropriate methodologies and tools should be comprehensive enough to incorporate various aspects of ESS applications and deployment environment. In addition, tools should follow and build upon existing distribution planning and operation platform (beyond a single department) to ensure sustainability in the utilization, as well as trust and support in applying them.
  - Identify gaps and forward tool development to close the gaps as part of this step. (see section on evaluation of tools)

- Acquire selected tools and arrange desirable integration steps with company data bases and existing commercial tools in use. This may involve procurements, licensing, or consulting agreements to modify existing tools in various combinations.
- Train staff in the use of the tools and embed the consideration of storage as a routine step in system planning and engineering.
- In parallel develop procedures for system operations incorporating storage and develop tool requirements for system operations. Plan operational system upgrades, procurements, and training to realize these planned tools.

4.2 Findings and Recommendations Related to Methodologies and Tools for Assessment of Future Projects

This section addresses the need to improve methodologies for assessing future projects in the short term, before new tools can be made ready. It describes how best to attack valuing storage projects on the distribution system going forward making use of tools available today. Compared to the processes used in identifying and planning projects in the period immediately after the CPUC mandate for the first year of storage deployment, it will be necessary to have a valid business case as part of planning any project and it will also be "wise" to anticipate changes in the regulatory environment and the CA ISO market rules as possible under the current FERC NOPR on distributed storage in the markets and the current CA ISO stakeholder process on DG and Distributed Storage. This section is written in the context of the evaluation of SDG&E storage projects and planning processes so generalization to other California utilities would require a mapping of their current capabilities and plans to the recommendations. This section also focuses on storage projects on the distribution system – in distribution stations or connected to distribution feeder circuits. It does not address larger storage projects that are transmission connected nor does it discuss behind the meter storage.

4.2.1 Tools and methodologies

California investor-owned utilities are required to file plans for valuing DER as well as to complete and publicize PV hosting capacity analysis on the entire distribution system. New storage projects on the distribution system should be planned in light of these requirements, and ideally storage project identification should include consideration of needs identified in the hosting capacity analysis. Near-term steps that utilities could take include:

- Using demonstrated tools that can assess distribution applications and stacked applications to screen the feeder population and identify potential storage projects to be planned in 2018-2019 against expected or possible conditions over the period 2018-2025. These applications would include:
  - Capacity deferral (station and circuit or centralized and distributed)
  - PV integration
    - Back feed prevention
    - Voltage Control
    - PV smoothing
  - Local Resiliency (distribution microgrid)
- The stacked applications should definitely include Day Ahead (hourly) energy time shifting/arbitrage and should consider Real Time energy and Ancillaries as options depending upon the outcome of the

FERC NOPR and the CA ISO stakeholder process, as these issues greatly affect potential valuations. (and also impact the costs of controls and market participation)

- This screening could be built upon the tools demonstrated and assessed during this project that already have the ability to assess distribution and stacked applications with manual integration of data and steps. The screening would be at most an annual process with updates for particular feeders / stations when conditions changes significantly.
- Given the rapid improvements in storage technology and costs, scenarios should be examined in this screening that reflect better than forecast improvements.
- Following the screening, identified circuits with potential storage applications should be examined in more detail using the methodologies demonstrated in this report to determine engineering requirements and engineering level feasibility of storage projects. In this process, combinations of distribution and stacked applications need to be examined in depth as individual applications may not have favorable cost benefit ratios where combined applications do.
- One of the largest obstacles to performing storage assessment on a given circuit is obtaining time series data for load profiles and for PV production forecast that is "clean" and without missing data and bad data. This is a general issue that affects PV hosting as well, although not the same degree (as 8760 data is not required). But this should be considered a highly desired process – to clean the data – as then all planning functions benefit.
- Another obstacle in the screening process is that detailed engineering cost estimates for avoided cost (circuit and station upgrades) may be unavailable. For initial evaluations, the utility should determine rule of thumb numbers to be used against simple categorizations of feeders (voltage level, load growth, rating vs current peak, length, etc.). Final evaluations will need detailed cost estimates.
- Agreement should be reached internally and ultimately with the CPUC on how to "derate" the estimated stacked applications benefits given the reliance on historical profiles, market prices, and perfect dispatch. This should include an assessment of how realistic projected benefits are given current operations and control room capabilities. Otherwise too optimistic a business case will be developed using unrealizable but theoretically "perfect" benefits
- Plans for DERMS applications should be reviewed in light of the planned use of storage for operations, reliability, and market benefits.
- Because the tools are not "commercial" nor at an easy to use stage, the utilities will have to consider developing a focused team within distribution planning and engineering to conduct screening and studies in this time period, possibly in conjunction with external assistance (ideally from organizations/people experienced with the tools and the problems)

4.2.2 Gaps in commercial tools and industry practices related to technology assessment approaches

Section 5.1.1 identified gaps in the capabilities of tools available today. For planning in the distribution space, the largest gap is the ease of integrating the results of time series simulations with Distribution Planning Tool 4 and external Python code with stacked applications analyses in other external tools offered by consulting firms.

Because SDG&E is standardized on the Distribution Planning Tool 4 distribution planning tool set, plans in the 2017-2019-time frame have to be built around Distribution Planning Tool 4 capabilities and short-term release plans. (Distribution Planning Tool 4 data base porting to other planning tools such as

Distribution Planning Tool 3 and Distribution Planning Tool 6 are also limited, excluding those possibilities for this purpose). Discussions with Distribution Planning Tool 4 about desired enhancements and capabilities to facilitate the integration with external scripts/applications for time series analyses and then exports to other analytical tools should be organized so that planning can be informed about Distribution Planning Tool 4 plans.

Second, the three tools capable of some degree of stacked applications benefits analysis should be examined for adaptations to the FERC NOPR and the CA ISO stakeholder process, as well perhaps as some enhancements to reflect errors in day ahead PV and market price forecasts in the optimization and benefits calculation.

4.2.3 Standardization and regulatory compliance

The CPUC should be informed about issues such as developing standards, standards gaps, and benefits assessment methodologies. While immediate regulatory objections may be unlikely, indications of possible objections might be identified in time to develop adjustments and accommodations.

Utilities should prepare a list of existing and developing standards that it will require storage proposals to comply with for use in RFPs, and revisit this periodically as standards evolve. This list should not be limited to electrical performance and interconnection but should include siting, safety, and environmental issues.

An analysis should be performed of the cost-risk-reward tradeoff between requiring strict and long-term warranties versus more relaxed terms and internal risk acceptance. RFPs may be modified to reflect multiple options for longer term warranty and maintenance agreements so that the risk-reward can be evaluated. These issues should be revisited frequently as technology and vendor terms evolve. To the maximum extent possible, procurements should drive towards standardized storage configurations, sizes, and interconnections. Procurements for higher volumes of storage at one time will result in more favorable pricing and warranty terms and this is a key factor.

4.2.4 ESS Projects Responsibilities

SDG&E ESS projects have been for both transmission system support and also for distribution system support, with both processes having differences and similarities. Recent Transmission system ESS support projects have been driven by the CPUC-directed Expedited Storage Projects (ESP) as a result of the Aliso Canyon incident. The effort was primarily managed by the Advanced Technology section including RFPs and installation contracts. These projects were identified quickly and installed amazingly well especially considering the short time frame.

ESS is relatively new to the industry and many issues continue to be resolved. It is beneficial to acknowledge the need to learn. As multiple projects move forward these lessons learned are clarified and lead to proper improved standards. For the distribution system, although the planning approach of a project is similar to traditional projects as shown in Figure 4-1, the action needed is typically unlike traditional electric utility infrastructure projects. It is important early in the process to ensure responsibilities are clear through the various stages of the project. It is best to start the collaboration early.



Figure 4-1. Planning approach

4.2.4.1 Potential Project Implementation

Distribution system identification of ESS applications would normally be done by groups responsible for circuit capacity, voltage, or reliability planning. As part of that process the size, capacity, and operational parameters would be identified and used as the project moves forward through specifications, procurement, commissioning, and operations. The planning phase is not just distribution/reliability planning but also the planning required to achieve the expected benefits. Requirements include operations controls, ESS system performance (including related metrics), communications & controls, and site requirements.

4.2.4.2 Project Evaluation- Benefit/Cost

A key challenge for ESS implementation has been the overall cost effectiveness. Current applications across the industry were at times installed as demonstration projects to learn about the overall process and economics. As ESS applications move forward, the economics have become more critical in the project applications. Economic analyses needs to determine the overall value and preliminary project approval. Besides typical capacity deferral benefits, with ESS the markets value should be included. The Market value should be integrated with the constraints to achieve the distribution system needs.

4.2.4.3 Project Approval

When traditional projects seek approval, they are normally approved based on the significance of the issue, estimated cost, the evaluation that has occurred, and available budget. For ESS projects, the approval process is similar although for large systems, regulatory approval may be required. For projects requiring regulatory approval, that may not occur until after the RFP process.

The approval process needs to include the additional evaluation towards achieving applicable regulatory ESS mandates. In addition, the methodologies and tools provided in this report can enhance the benefit cost analysis, especially the inclusion of related market benefits

4.2.4.4 Project Implementation

Procurement

The ESS Procurement process is relatively new with a much lower number of installations as compared to traditional infrastructure. The plan should be to improve and standardize the process in a similar fashion.

Technical requirements should be owned by Engineering to ensure internal oversight. In the requirements development, RFP specifications require extensive collaboration across multiple organizations. Although the categories may be similar to typical infrastructure projects, the content

would be unique to ESS. RFP categories include [7], [8]: minimum qualification requirements; system performance requirements; RFP schedule and selection criteria; RFP response requirements; scope of work; and technical specifications. Technical sub specifications include ESS performance, installation, interconnection, controls and communication, environmental, safety, commissioning, and operations.

Other issues to consider in the development of the RFP is clarity on the work to be performed to complete the installation and commissioning which includes space, physical interconnection, and communication and control integration. Maintenance requirements performed via the contract or utility need to be clarified. Once installed, the RFP must include testing to validate it meets the requirements and can perform as needed to achieve the project objective and benefits.

Installation:

Prior to installation, site considerations that require evaluation and resolution include permitting, seismic, noise, physical access, flooding, fire barriers, and spill containment. As part of the ESS installation, considerations to also include are the connection requirements to the utility grid including transformers, switches, protection system, and communications and control. The communications and control can include requirements for the ESS and the integration with the utility's control system.

New systems require extensive testing to ensure it is capable of performing as required. Testing includes factory acceptance tests (FAT), site acceptance testing as well as testing on specific pieces of equipment. Site acceptance testing is part of commissioning and overall is intended to ensure the ESS operates as required, is integrated effectively with the utility grid, the controls systems operated as required, and the system has been properly installed to maintain safety and long term performance.

4.2.4.5 ESS Operations

Since ESS installations are relatively new, operation and maintenance is another key area undergoing lessons learned as experience is gained. It is important that personnel responsible for both operations and maintenance be prepared to undertake that responsibility. Operators should have the software tools needed to facilitate monitoring ESS status as well as the information and tools needed to take action when needed- such as to use the ESS to restore load during outages. Appropriate BESS management systems applications should be required in development of operating systems that will manage DER. Clarity between requirements and constraints in support of Distribution Operations and Market Operations/Trading for the daily scheduling of BESS must be established, especially if routine distribution operations will be encountering BESS during circuit maintenance activities.

Related to maintenance requirements, the industry is still in the learning stage with much of the maintenance for large systems handled through the resultant RFP contract. Even when the maintenance is performed via the RFP contract, the utility should be knowledgeable about the required maintenance to ensure compliance. Maintenance requirements should be established and cycle inspections should be documented. Reference [9] provides the CPUC document regarding the Safety Energy Division Safety Inspection Items for Energy Storage – February 2017. Overall safety requirements related to ESS has gaps which are being addressed across the industry [10]. The gaps are largely related to the evolving nature of ESS systems.

The impact of both planned and forced maintenance on the distribution system needs to be taken into consideration. For other systems, maintenance requirements should be established and cycled inspections should be performed and documented.

4.2.4.6 RACI Matrix

Based on the results of the brainstorming sessions and the ESS project responsibilities described above, a RACI (Responsible-Accountable-Consulted-Informed) model was developed to identify the relationship between various ESS functions and organizational departments. The model is illustrated in Figure 4-2. The model was originally used to determine types of tools and methodology needed for the ESS projects and required by various departments.

Business Unit																
Regulatory Affairs	Finance/ Accounting	Safety	Environmental	Security (Physical & Cyber)	Information Technology	Advanced Technology Integration		Electric System Planning			Elec. Trans. & Dist Eng.			Electric System Operation		
Regulatory Affairs	Finance/ Accounting	Safety	Environmental	Security (Physical & Cyber)	Information Technology	Business	Technology assessment & Pilot projs. (DER)	Reliability	Electr. Distrib. Planning	Grid (transmission) Planning	Standards & Power quality	Protection & Automation Control	Substation Engineering & Design	Distribution Operation (Control Center & Field)	Transmission Operations (Control Center & Field)	Generation Operations
C	C	I	I	I	I	A/R	C	C	C	C	C	C	C	C	C	C
C	C	I	I	C	I	C	C	A/R	A/R	A/R	C	C	C	C	C	C
A/R	C	C	C	C	I	R	I	C	C	C	I	I	I	I	I	I
C	C	C	C	C	R	A/R	R	R	R	R	R	R	R	C	C	C
C	I	A/R	I	C	I	A/R	C	C	C	C	R	R	R	R	R	R
C	C	C	C	C	C	A/R	C	R	R	R	C	C	C	I	I	I
I	I	C	C	C	I	A/R	C	R	R	R	C	I	C	I	I	I
I	I	C	C	C	R	A/R	C	C	C	C	R	R	R	C	C	C
I	I	C	I	C	R	A/R	R	C	C	C	C	R	C	R	R	R
I	I	C	I	C	R	A/R	R	C	C	C	C	C	C	R	R	R
I	I	C	I	C	R	A/R	R	I	I	I	R	C	R	R	R	R
I	I	I	I	I	I	A/R	C	C	C	C	I	I	I	R	R	R
I	I	C	I	C	R	A/R	C	I	I	I	C	C	C	R	R	R
C	C	I	I	I	I	A/R	C	C	C	C	I	I	I	C	C	C

tain parts of the business function, thus the reason for multiple "R" or "A/R" assignments

)

untable-Consulted-Informed) model

4.2.5 Approach Towards Markets Participation

Market analysis was performed on potential ESS sites for projects such as capacity deferral and microgrids. That analysis has provided CD, CDA, and CDAA benefit analysis. Certainly the analysis has shown sufficient potential benefits that can significantly impact the benefit-cost justification for the ESS installation.

To achieve those benefits, multiple hurdles need to be resolved in time to maximize the market benefits when the ESS goes operational. Some of the key hurdles are:

- Regulatory
- Software Tools for Integrating Market and Distribution Benefits
- Collaboration Between Markets Operations and Distribution Operations
- Advanced Distribution Management System Enhancement

Software Tools for Integrating Market and Distribution Benefits

Market participation tools are currently available and in use. However, those tools typically do not handle distribution constraints. Those constraints result from ensuring that the ESS is readily charged to perform the discharge required for the distribution benefit. Those constraints need to be modeled on a daily basis throughout the year. The distribution constraints model must be integrated with the markets participation model for proper use of the ESS. It is recommended that a tool to perform this task be pursued.

Collaboration Between Markets Operations and Distribution Operations

Traditionally, there has been no need for collaboration between a utility's Market Operations and Electric Distribution Operations. Now, with the joint use of distribution system ESS, those two groups need to collaborate on how the ESS will be scheduled and deployed. Although the modeling tool described above can deal with scheduled charge/discharge and forecasted distribution requirements, the real world cannot be fully scheduled. The maximum ESS market benefits tend to be related to real time prices and distribution system forced outages cannot be forecasted. Distribution Operations will need to deploy the ESS as required during conditions such as forced outages, especially if the ESS is part of a microgrid. The collaboration requirements need development but should be assumed that Distribution Operations will deploy the ESS as needed but will be dependent on the real-time State of Charge (SOC). It is recommended that as the use cases for ESS are developed, this collaboration and related requirements be pursued.

4.3 Findings and Recommendations Related to Implementation of Methodology and Tools in Assessment of Future Distribution Circuits Design Practices

This section addresses recommended enhancements to project selection and design practices in the near and mid-term future, including improvements in methodologies and tools as recommended in sections 5.1 and 5.2 as well as certain other enhancements that would allow the realization of greater value from storage on the distribution system.

4.3.1 Tools and assessment methodologies

Assuming that the recommendations of section 5.2 are followed for the screening of the distribution system and the evaluation of storage benefits in detail for targeted feeders, there are then additional improvements in the detailed planning and design of particular storage projects. These are addressed in this section.

4.3.1.1 Value of time-series analysis in assessment of other technologies

This project demonstrated clearly the value of employing time series analysis of the storage resource and the control algorithms for the storage resource in conjunction with distribution circuit analysis. Whether or not this degree of rigor is applied to the business case development, it is critical to the engineering and design of the storage project. Due to PV integration, this methodology should be standardized and used for all distribution projects in future, whether or not storage is planned. It is also a superior way to assess flicker issues from PV and other problems that can arise under high DER penetration. Just as renewables have made time series analysis mandatory in assessing, planning, and operating grid scale generation resources, the same will be true for distribution level BESS in future.

Critical aspects of using the time series analysis approach to consider in future include:

- Adjusting the control algorithm and storage performance characteristics to determine the best algorithm and parameters/tuning as well as to assess the value of different levels of storage performance (rate limit, etc.). When procurement decisions for a technology type/product are being made (as in a selection of storage systems for a number of distribution projects) then the particular characteristics and algorithm can be simulated in the time series analysis as part of the evaluation. Such time series analyses are relatively new to the distribution domain but have become routine in applications such as wholesale market and grid operations, and wind farm interconnection studies. The advent of high DER penetration plus the use of some DER such as storage to facilitate DG integration and hosting capacity will demand that time series analysis become routine.

4.3.1.2 Evaluating other sizing possibilities for best cost benefits

The sizing calculations and market value assessments performed should incorporate a study of the modular sizes available closest to the values determined in the time series analysis. That is, if the time series analysis results in a 714 kW battery system the impact of using a 700 and a 750 kW system should be evaluated.

4.3.1.3 Incorporating uncertainty

The studies performed in this project used historical load profiles, PV profiles, load growth, and market prices to assess storage projects. In the future, all these variables as well as DER adoption become subject to greater uncertainty over future years. This is particularly true of PV adoption, possibly EV adoption, and possibly PV production and load profiles given the uncertainties of climate change.

A major value in energy storage systems that has not been assessed so far or published is the protection that can be provided against uncertainty, especially if the storage can easily be re-located to another location, reprogrammed for different applications, and/or resized as conditions change. Once a circuit is reconductored, for example, that cost is sunk and the decision cannot be reversed or the value of it

transferred somehow or repurposed. If load growth fails to materialize as projected, the cost may be incurred needlessly. Storage can be repurposed, resized, and relocated with only marginal costs, if plans and allowances for such are made as part of engineering design.

In other fields, the 'optionality value" of more flexible planning is recognized and factored into plans. The utility industry is not, in general, accustomed to thinking this way about projects although some generation portfolio assessments consider the optionality value in generation plant flexibility. Storage introduces the very real possibility of more flexible planning and adaptability to distribution engineering and an effort should be made to take advantage of this. The best way forward may be a subsequent EPIC or other R&D oriented project to demonstrate methodologies and benefits, or a simple first step based on probabilistic scenarios and evaluations using current approaches may be a way to explore this.

4.3.2 Applications of other similar emerging technologies in distribution systems

This study examined applications that are possible with today's technologies and for which there is a current market or perceived value. Additional new technologies/applications to consider include:

- Provision of synthetic governor response. There is a FERC NOPR which proposed to require governor response from inverter based resources, in order to compensate for decreased system primary response due to conventional generation displacement by wind and solar generation. Many respondents to the NOPR suggested making primary response a market based ancillary product as is the case in the United Kingdom. Distribution level storage could easily provide this capability with local autonomous controls for smart inverters so this should be considered in future applications. A FERC decision in late 2017 or early 2018 and a follow up CA ISO stakeholder process would bring this about sooner, not later.
- Provision of synthetic inertial response or response to rate of change of frequency. This is a current R&D topic in several DOE SHINES or NODES program projects and DOE ARPA-E projects. Smart inverters can provide this capability as well as primary governor response. If system level studies show a benefit from this, it could be a candidate for deployment in California before long.
- Continuous assessment of new storage electro-chemistries. On the one hand, Lithium Ion technology continues to improve with a focus on lowering cost, increasing energy densities, and increasing lifetime cycles. Beyond this, there are potential improvements in Vanadium-Redox Flow (VRF) technologies that could improve costs and improve cycle charge/discharge losses. This could make VRF more attractive for applications with frequent cycling duties. Other technologies that are not as commercialized (zinc air) bear monitoring because of low cost and/or intrinsic safety that facilitates siting.
- Integration of utility distribution storage roadmaps with state level planning. As storage penetrates the distribution system it will have impacts on wholesale markets and bulk power operations that can both benefit the state overall while altering the local value of storage, perhaps unfavorably. Some effects include:
    - Increased distributed storage that is performing peak shifting and energy time shifting will act to counter swings in day ahead prices due to macro-level load and renewable profiles. Decreasing this volatility will decrease the value of distributed storage market participation somewhat but also will benefit the state greatly overall. Such a macro level portfolio assessment and more integrated planning is indicated as distributed storage penetration goes. Ultimately, a way to apply some of the state level benefits to fund distributed storage or incent market participation may be desirable.

- Use of storage to manage PV interconnection will also have the effect of decreasing voltage regulation requirements due to PV volatility. An assessment of the potential impact here and the state level benefits is indicated.
- How distributed storage will impact real time energy requirements and the requirements for balancing headroom in day ahead schedules is unclear.

4.3.3 Voltage and VAR compensation assessments

As investigated and discussed in previous sections, ESS can provide reactive power compensation and voltage control. A valid question can be raised regarding the use of energy storage system for the sole purpose of voltage control on distribution systems, as compared with other technologies such as Dynamic Voltage Controller (DVC) or similar reactive power compensation devices. DVC type devices have been also introduced in the utility to manage adverse impact of high penetration of solar PV systems.

A sample case study was performed to compare the effectiveness of DVC and an ESS on the voltage control under the influence of a 2MW PV system installed toward the end of a very long radial distribution line. Based on the minimum day time loading in the area downstream of an in-line voltage regulator, on a sunny day, the reverse power flow caused by the 2 MW PV is about 0.75 MW. The significant reverse power causes the voltage to increase up to 1.08 per units, exceeding the 1.05 pu permissible threshold. Changing the voltage regulator mode to co-generation helps to resolve the voltage problem, however, because of the speed time of an electromechanical tap changer and delays built into the voltage regulator control logic, the high voltage condition will remain in effort on the circuit for a few minutes before getting resolved. In addition, fast fluctuations in PV production, due to alternating clouds, will have significant impact on the number of tap operation and maintenance life cycle.

The study determined that a 2 MVA DVC installed downstream of the voltage regulator can reduce the overvoltage conditions, however, it is less effective in mitigating the number of tap operation of the voltage regulator. The main reason has been associated with interaction of voltage regulator and DVC.

The equivalent impedance at the target location is R = 5.03 ohms, and X = 8.56 ohms (X/R = 1.7). Because of the large resistive impedance, a major part of the overvoltage is caused by voltage gain on resistive impedance during reverse power flow.

If an ESS was installed at the DVC location instead, ESS can help reduce the reverse power flow, and therefore avoid sudden change in power flow direction during intermittency. It was noted that the ESS size for the location of interest has to be 2 MW / 4 MWh, which is almost 3 times costlier than the DVC. Table 4-1 presents ESS size requirements for worst case reverse power flow.

Table 4-1. ESS size requirements for worst case reverse power flow

Day hour	10	11	12	13	14	15
*Solar irradiance [pu]	0.83	0.95	0.997	1	0.9	0.791
MWh charge per hour	0.6225	0.7125	0.74775	0.75	0.675	0.59325

Total MWh	~ 4.0					

Hence, utilizing ESS for the voltage/reactive power control application would need to be evaluated side by side with other technologies on the case by case basis. If the location of interest is highly resistive, and/or there are considerable outage scenarios, or fast flicker issues due to high level of intermittency, an ESS solution can be proposed and justified. Yet, additional stacking application for the ESS should be considered and evaluated to make the technology cost effective.

In this case, ESS should be introduced as part of a portfolio of the mitigation technologies.

4.3.4 Conclusions

The main conclusions from this project are:

- ESS applications need to be evaluated in the context of smart distribution circuits and by considering other emerging technologies that may have capabilities to achieve similar goals. An example technology examined was the use of Dynamic Voltage and Reactive Power Compensation devices versus installation of energy storage systems on circuits with high PV penetration.
- As a complimentary step in the evaluation process, standardization of the framework for calculating sizes, benefits, avoided costs, and cost benefit analysis of emerging technologies incorporating various combinations of stacked applications should be performed. The studies reported in previous sections showed that single applications would not be cost effective.
- In addition, it would be advantageous to provide planning engineers a comprehensive list of technologies and tools and their key application areas for mitigation of system impacts. Planning engineers and designers of smart distribution circuits of the future should take advantage of the state of the art in assessment and analyses tool to evaluate various possible conventional and emerging solutions.
- The benefit evaluation methodology and tools should be integrated with the actual procedures and tools for system operations incorporating emerging technologies so that the benefits are realizable in practice and after deployment in the field. This requires development of day-to-day operating procedures and guidelines for inclusion of energy storage and other emerging technologies for system operations. In addition, there should be plans in place for operational system upgrades, procurements, and training to realize full benefit of these solutions.

Some of the other key findings are listed below:

- Economic comparison of traditional infrastructure versus ESS has typically been solely based on capital, operating, and maintenance costs. Market benefits have not been included.
- The distribution planning process has used Distribution Planning Tool 4 for circuit modeling and is satisfied with its capabilities. Modeling enhancements are desirable.
- A new microgrid application is under consideration for an area in the back country
- As future ESS sites are identified, improved collaboration across organizations would improve the decision, engineering, deployment, and operations processes.
- Initial ESS sites installed years ago have had maintenance and operation challenges. Future installations need performance and maintenance requirements in contracts.

- Certain existing ESS sites are being enhanced to enable microgrid deployment during outages.
- The upcoming change in the Time of Use Rates for the On-Peak period from 11 AM -6 PM to 4 PM to 9 PM will likely increase customers' behind the meter interest in ESS.

5 SUMMARY OF RECOMMENDATIONS AND NEXT STEPS

A summary of the key recommendations from this project is given below:

- Implement tools and standardize the process for calculating benefits, avoided costs, and cost/benefit analysis of ESS,
- Improve standards and processes for co-utilization of ESS with distribution system benefits and the wholesale market. Acquire as needed regulatory approval for distribution ESS participation in the markets.
- Implement ESS control systems that can manage stacking of applications in cooperation with ESS vendors and ESS integrators.
- The ESS tools should be compatible with existing distribution planning models and study approaches to ensure on-going support and utilization by the engineers and stakeholders. Various interfacing schemes are available to add the functionalities and analysis approach to the existing software tools through APIs and drivers similar to the ones introduced and demonstrated in this project.
- Develop procedures for utilizing storage in daily system operations by acquiring and applying enhanced tools to ensure benefits are achieved.
- Communicate accountable, responsible, consulted, informed (RACI) sections' role in ESS project assessments, procurement of technologies and operation to enhance collaboration so that it can be effectively integrated with day to day business across the organization.

6 TECHNOLOGY/KNOWLEDGE TRANSFER FOR APPLYING THE RESULTS INTO PRACTICE

6.1 Information Sharing Forum

The following meetings and workshops were held to share the information with various stakeholders and the public:

- Stakeholder workshop (May 25, 2017): Over 30 people from various SDG&E departments attended the workshop
- Brainstorming sessions (May 30, 2017 to July 30, 2017): Over 10 brainstorming sessions were held with individual groups and key stakeholders within SDG&E
- IEEE PES General Meeting – panel session (July 18, 2017): Frank Goodman presented state of the ESS technology and assessment methodology at IEEE conference.
- Presentation by SDG&E to Green Team meeting (June 2017): SDG&E presentation to the Green Team members regarding the storage sites and applications
- Demonstration workshop of the tools and methodology (Oct 2017): workshop and knowledge transfer session at SDG&E on the project findings and recommendations

In addition, to further benefit the public, there are plans to submit papers and presentations for conferences and/or journals on the project results. These items, along with this comprehensive final report, will be posted on the SDG&E public website at www.sdge.com/epic.

6.2 Particular to SDGE's internal technology transfer

The results of this project were shared with the appropriate organizations within SDG&E. Key organizations included:

- Distributed Energy Resources
- Distribution Planning
- Engineering
- Advanced Technology
- Distribution Operations
- Market Operations

In addition, based on the findings and recommendations, the project team has proposed several training sessions on applications of ESS evaluation tools and utilization of the methodology targeted toward specific groups and stakeholders that will be held in upcoming months.

SDG&E is also assessing the applicability of the ESS study tools and methodologies and how best they can be integrated into existing processes to support engineering and business needs. ESS strategic taskforces are formed to further follow up and coordinate this matter among stakeholders.

6.3 Adaptability to other utilities and/or the broader industry

A key limiting factor in ESS deployment and utilization across the electric utility industry is the proper economic evaluation of ESS values. As stated previously, traditional economic evaluation has focused on the value of capital deferral. This project demonstrated the value of market participation that can enhance the business case. It also demonstrated the significant increase where ancillary services are available for participation. It is critical for the industry to expedite resolution of hurdles that limit the participation of ESS in these markets.

However, the main challenge is to have engineering tools and study methodologies that can co-analyze both distribution applications and market services. Several tools and associated analytical methodology were introduced and demonstrated in this project that can be utilized by other electric utilities to perform similar co-analysis of the stacked applications. The approach was based on enhancing existing distribution planning tools and incorporating ESS controls and market optimization as add-on analytical modules through external interfaces. This approach will ensure sustainability in use and will facilitate expedited knowledge gain and acceptance among utility engineers.

7 METRICS AND VALUE PROPOSITION

7.1 Metrics

The metrics in the Table 7-1 were identified for this project and are reference to the appropriate section.

Table 7-1. Project Metrics

List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation) – See EPIC document for reference.	Remark & Reference
1. Potential energy and cost savings	
c. Avoided procurement and generation costs	Included & verified; The demonstrated ESS investigation approach can be used to properly identify the projects and reduce the cost. For more information, refer to sections: 2.1, 2.2, 2.5, 3.2,
i. Nameplate capacity (MW) of grid-connected energy storage (target ESS size for each application)	Included & verified; The demonstrated ESS investigation approach provides methods for proper sizing ad selection of ESS locations based on the applications. For more information refer to section: 2.1
3. Economic benefits	
b. Maintain / Reduce capital costs (by proper sizing and increase in utilization factor)	Included & verified; The demonstrated method provides sizing and location selection methods to precisely select ESS and manage the capital cost. The method also target, the increase in utilization factor by combining applications with manage the maintenance cost and benefit to cost ratio. For more information refer to sections: 2.2, 2.5, 3.1, 4.2, 7.2
e. Non-energy economic benefits	The propose method utilizes the ancillary market participation that ties to Power rather than energy capacity. Grid support

List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation) – See EPIC document for reference.	Remark & Reference
	applications are also included that targets Power. For more information refer to sections: 2.2, 2.5, 3.1, 4.2, 7.2
5. Safety, Power Quality, and Reliability (Equipment, Electricity System)	
a. Outage number, frequency and duration reductions	Included & verified; Study method incorporates the assessment of grid supporting applications for outage management. Constraint calculations taps into the capacity for outage support. For more information refer to sections: 2.5, 3.1, 7.2
b. Electric system power flow congestion reduction	Included & verified; One of the ESS applications that can be assessed with the demonstrated analysis method. For more information refer to sections: 2.2, 3.1, 4.3, 7.2
c. Forecast accuracy improvement	Included & verified; Time-series analysis utilizes the forecasted load change and solar PV to reduce the error. For more information refer to sections: 2.4, 2.5, 4.3
d. Public safety improvement and hazard exposure reduction	Included & verified; One of the parameters in the assessment process is the safety consideration of the ESS. For more information refer to sections: 4.2, 7.2
f. Reduced flicker and other power quality differences	Included & verified;

List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation) – See EPIC document for reference.	Remark & Reference
	Renewable smoothing and grid support applications incorporate the flicker and power quality indices. For more information refer to sections: 2.2, 3.1, 4.3
7. Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy	
a. Description of the issues, project(s), and the results or outcomes	Included & verified; The project process flowchart deals with the standard approach and evaluation of the outcomes. For more information refer to section: 4.2
b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)	Included & verified; ESS control system requirement metrics address the safety and reliability of technology and sizing accordingly. For more information refer to sections: 4.2, 4.3
f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360)	Included and verified; Metrics were used in comparing the ESS with other smart grid technologies such as DVR. For more information, refer to sections: 4.1, 4.3
l. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)	Included and verified; Project process flowchart incorporates methodologies for streamlining the process and avoiding unnecessary costs. For more information, refer to section: 4.1
8. Effectiveness of information dissemination	
d. Number of information sharing forums held	Included and Performed;

List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation) – See EPIC document for reference.	Remark & Reference
	Multiple meetings and workshop held with stakeholders and team. For more information, refer to section: 6.1
e. Stakeholders attendance at workshops	Included and performed; Stakeholder from various departments and group related to ESS project life cycle were selected and invite to workshops. For more information, refer to sections: 2.1, 6.1
f. Technology transfer	Plan was made for knowledge transfer through open forum and conferences. For more information, refer to section: 6.2

7.2 Value Proposition

EPIC provides project funding for applied research and development, technology demonstration and deployment, and market facilitation for clean energy resources. This project has provided multiple values by supporting benefits related to improved reliability, lower costs, safety improvement, and environmental benefits. In addition, this project has provided value by demonstrating tools and methodologies that will support future ESS evaluations.

7.2.1 Primary Principles

- Improved Reliability

  PV growth on distribution circuits has resulted in the need for improved analytical tools. Circuit analysis solely based on the peak hour is not sufficient. As demonstrated in this report, higher level of time-based granularity will more effectively simulate potential problems and potential solutions. This granular predictive analysis models the circuit load and voltage, while helping to effectively determine the amount of ESS that can resolve the problem.

  The types of problems that ESS can prevent include circuit overloads, high or low voltage, voltage flicker, and outages. If overloads are not prevented, they can result in infrastructure damage or outages, or both. Voltage flicker caused by PV systems is a relatively new problem since the distribution planning process would normally prevent it when large customers or large DER are connected. However, with a high quantity of small PV systems, sudden changes caused by clouds can result in unusual voltage fluctuations especially where small conductors are involved. The legacy distribution system was not engineered and constructed with this type of

expectation. The study methodology proposed and evaluated in this project can effectively predict the issues described above thereby preventing those problems, either with ESS or other solutions.

In addition, the simulation supports the development of ESS microgrids by properly determining the ESS kW and kWh. By supplying customer load during forced or planned outages, ESS microgrids have great potential in improving reliability when properly designed and operated as described in this report. These types of applications can significantly improve circuit SAIDI.

- Lower Costs

  Opportunities are provided in this report to reduce costs to the utility and its customers.

  The improved analysis process will enable the utility to identify potential problems sufficiently in advance to pursue the most cost-effective solution.

  In addition, the integrated modeling of the capacity deferral and markets benefits allows the utility to properly compare the NPV of traditional infrastructure versus capacity deferral based on ESS applications and related market benefits.

  Ultimately, the ESS cost effectiveness is dependent on the specific use case and resultant model inputs such as required capacity upgrade cost, ESS kW/kWh/cost, load growth rate, and distribution constraints that limit market participation.

- Increased Safety

  The modeling process provided in this report improves the economics of potential ESS applications thus enhancing safety. The improved economics will help justify the application of ESS across the utility system. Providing ESS microgrids for customers such as fire stations can improve public safety by maintaining their power during outages. In addition, the current state of safety requirements, challenges, and implementation recommendations are provided in this report.

7.2.2 Secondary Principles

- Enhanced Environmental Sustainability

  ESS can reduce the need for CAISO to curtail PV generation and instead store the excess energy to utilize it when natural gas generation would otherwise be used to supply load. The economic modeling results indicate that energy storage systems can be cost effective, thus supporting additional applications.

- Efficient Use of Ratepayer Funds

  This project's enhanced analytics techniques can provide the proper evaluation for future ESS applications, including maximizing the benefits and improving the cost effectiveness. This project's tool and methodology evaluation can also help support others in their research. This research support will save future evaluators time and resources.

8 REFERENCES

[1] SDG&E Energy Storage System – 2016 Distribution Reliability/Power Quality Program Request for Proposal

[2] ESIC Energy Storage Implementation Guide- 2016

[3] California Public Utilities Commission- SED Safety Inspection Items for Energy Storage- February 2017

[4] EPRI & Sandia- Energy Storage Safety- 2016- Guidelines Developed by the Energy Storage Integration Council for Distribution-Connected Systems

[5] http://standards.ieee.org/findstds/standard/2030.3-2016.html

[6] https://smartgrid.ieee.org/resources/standards/ieee-approved-proposed-standards-related-to-smart-grid/704-p1547-8-recommended-practice-for-establishing-methods-and-procedures-that-provide-supplemental-support-for-implementation-strategies-for-expanded-use-of-ieee-standard-1547

[7] https://www.sdge.com/sites/default/files/00%20-%202016%20ESS%20RFP%20-%20Final%283%29.docx

[8] https://www.epri.com/#/pages/product/000000003002008899/

[9] https://www.epri.com/#/pages/product/000000003002008308/

[10] http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Safety/Risk_Assessment/ESS%20Inspection%20Guidelines.doc

[11] CEC report, " Validated and Transparent Energy Storage Valuation and Optimization Tool", - CEC-500-2017-016-APC, March 2017

9 APPENDIX

9.1 Additional study results for Capacity Deferral Application

9.1.1 BESS sizing - Centralized Upgrade Deferral for CCUD 1

For CCUD 1, centralized deferral approach, the battery was installed at the beginning of the feeder (Figure 9-1). The battery was initially sized as 0.7 MW, 3.5 MWh.

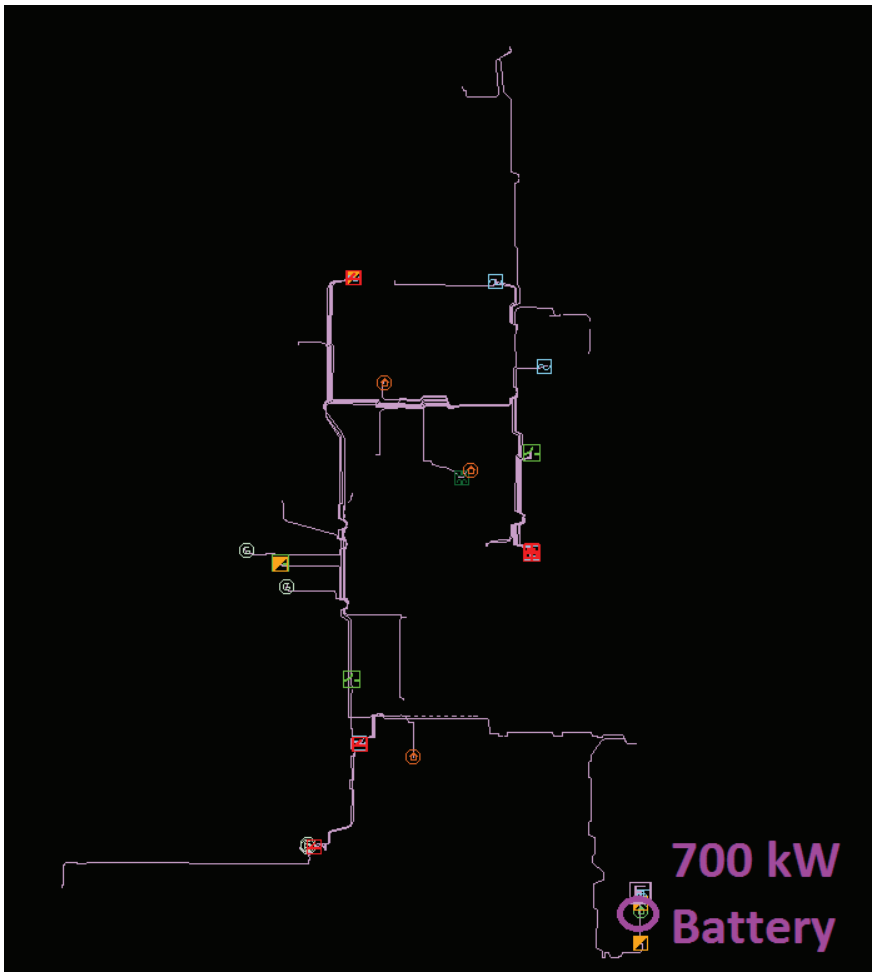


Figure 9-1. Location of the battery for circuit CCUD 1

The circuit under study has a thermal loading limit of 395 (A) determined in Distribution Planning Tool 4 model. This limit was used as the upper threshold of the circuit for peak shaving purposes. For the lower threshold zero was used to make sure that the reverse power flow is prevented. Also, the battery is scheduled to charge between 0:45 am – 5:00 am up to 95% in order to provide enough energy for discharging throughout the day.

In order to consider the worst case scenario, the maximum peak day of year was determined for the projected (year 2024) load profile and the PV systems were turned off during the analysis.

Figure 9-2 demonstrates the feeder power flow before and after the upgrade deferral application. The battery was charging during the scheduled charging zone up to 95% SOC and was then able to maintain the feeder power below 8,210 kW during the day. Figure 9-3 shows the expected power flow before and after the ESS applications.

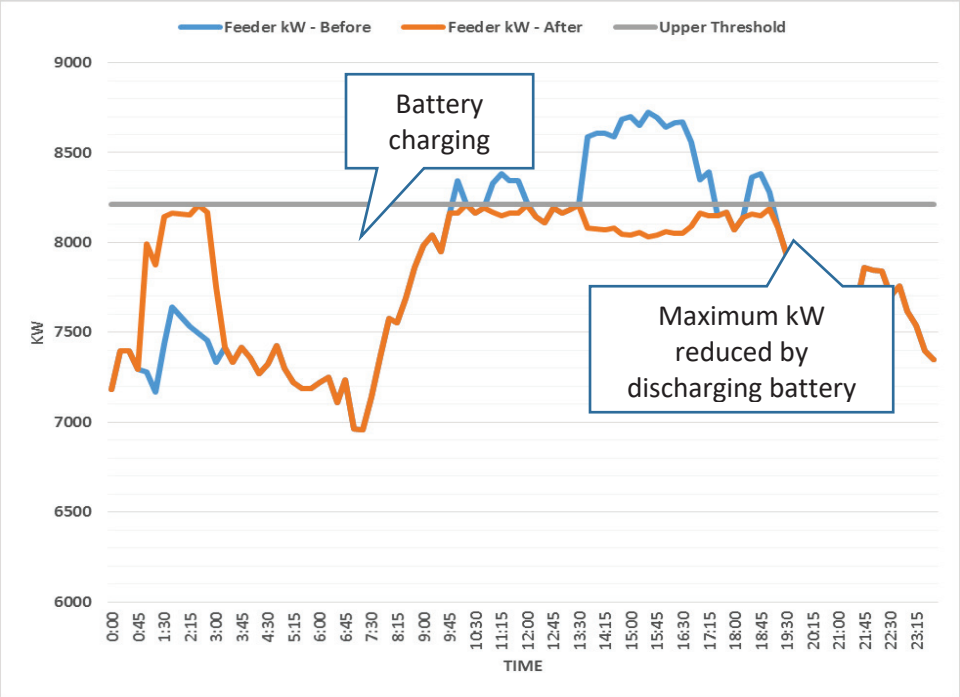


Figure 9-2. Power Flow (Centralized Upgrade Deferral) for CCUD 1

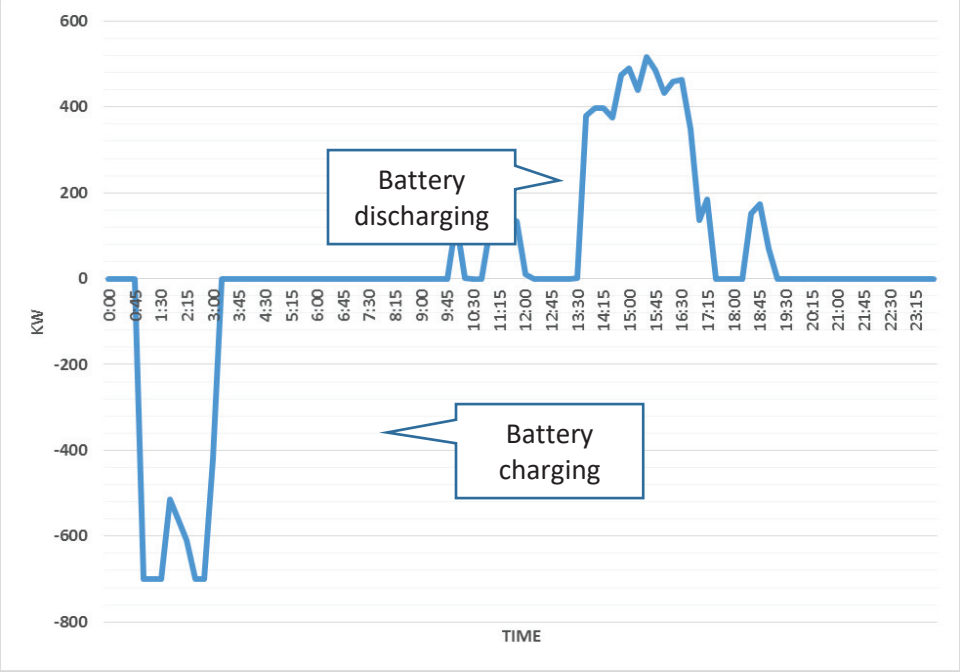


Figure 9-3. Battery Output Power (Centralized Upgrade Deferral) for CCUD 1

As illustrated in Figure 9-4, the battery charges/discharges up to the maximum rate of 700 kW. The accumulative charge of the battery by the end of the day is almost 1,400 kWh, while the discharge of the battery by the end of the day, is almost 1,800 kWh which reflects the maximum amount of energy required from the battery and justifies using a 750 kWh battery.

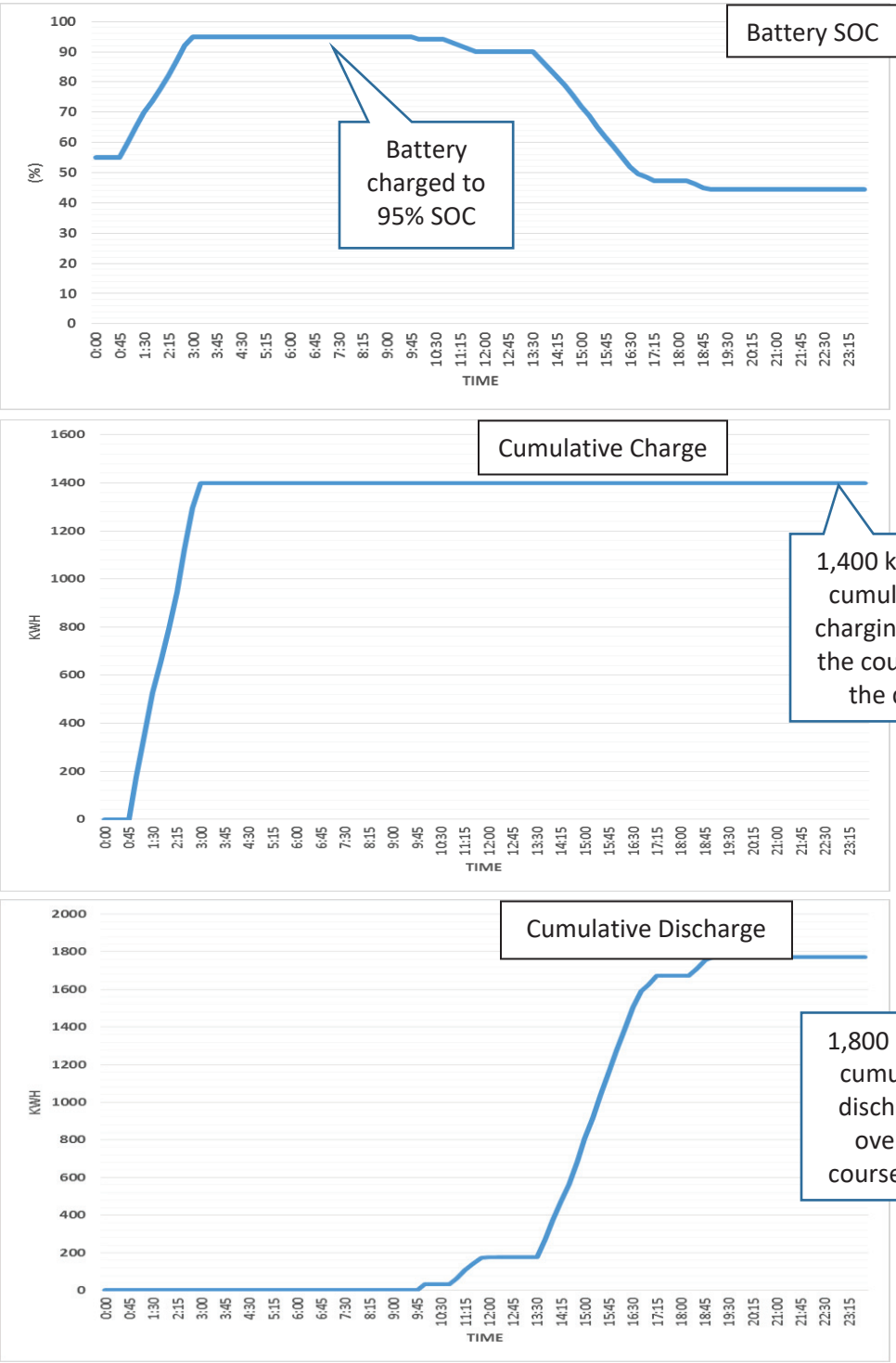


Figure 9-4. Battery SOC, cumulative charge and discharge for CCUD 1 (centralized)

9.1.2 BESS sizing - Centralized Upgrade Deferral for CCUD 2

For CCUD 2, centralized deferral approach, the battery was installed at the beginning of the feeder (Figure 9-5). The battery was initially sized as 0.5 MW, 0.75 MWh.

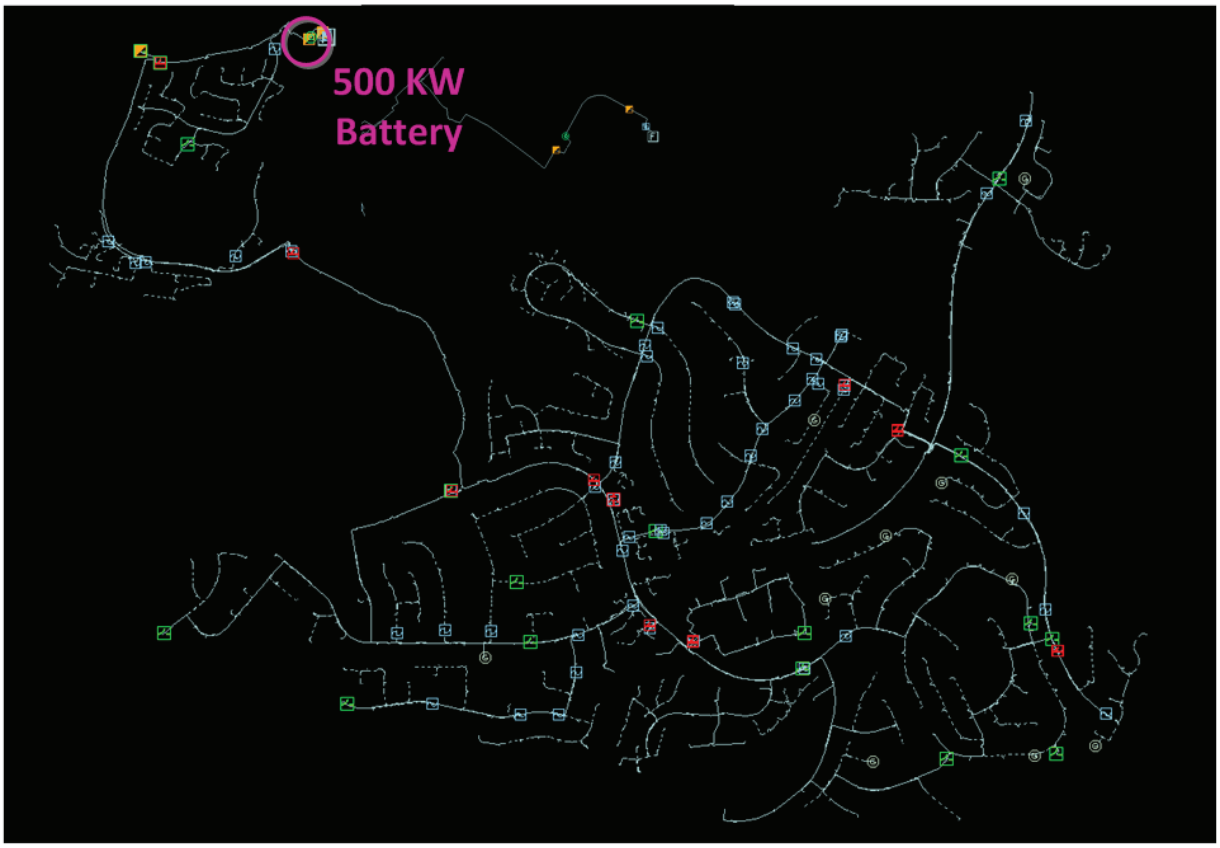


Figure 9-5. Location of the battery for circuit CCUD 2

The circuit under study has a thermal loading limit of 580 (A) determined in Distribution Planning Tool 4 model. This limit was used as the upper threshold of the circuit for peak shaving purposes. For the lower threshold zero was used to make sure that the reverse power flow is prevented. Also, the battery is scheduled to charge between 0:45 am – 5:00 am up to 95% in order to provide enough energy for discharging throughout the day.

In order to consider the worst case scenario, the maximum peak day of year was determined for the projected (year 2024) load profile and the PV systems have been turned off during the analysis.

Figure 9-6 demonstrates the feeder power flow before and after the upgrade deferral application. The battery was charging during the scheduled charging zone up to 95% SOC (Figure 9-7) and then cutting the feeder power below 12055 kW during the day. As illustrated in Figure 9-8, the battery

charge/discharge up to the maximum kW rate of 500 kW. The accumulative discharge of the battery by the end of the day, is almost 700 kWh (Figure 9-9) which reflects the maximum amount of energy required from the battery and justifies using a 750 kWh battery.

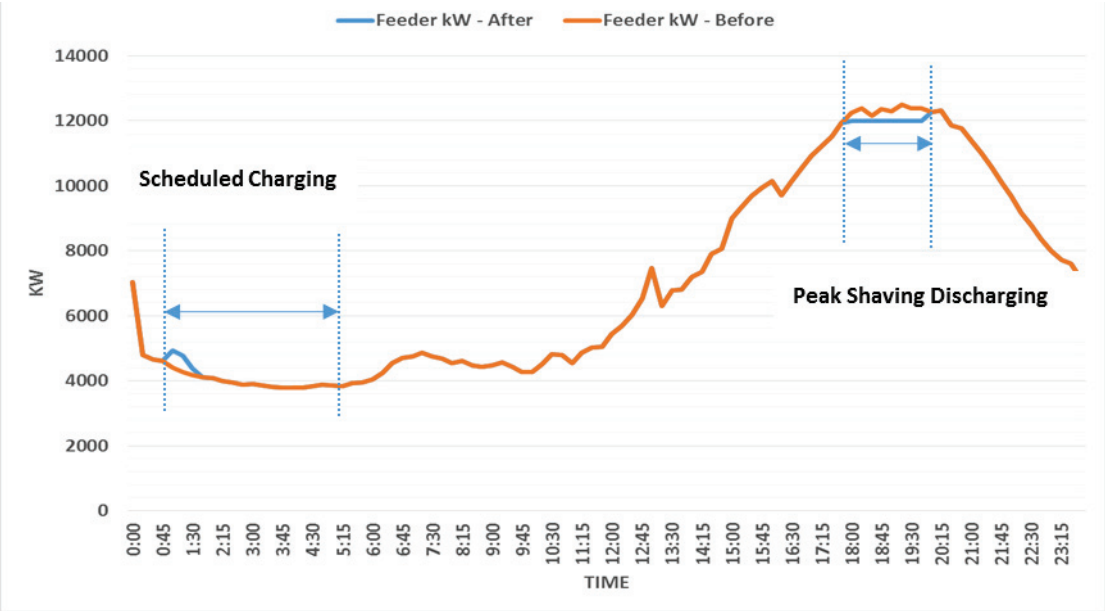


Figure 9-6. Power Flow (Centralized Upgrade Deferral) for CCUD 2

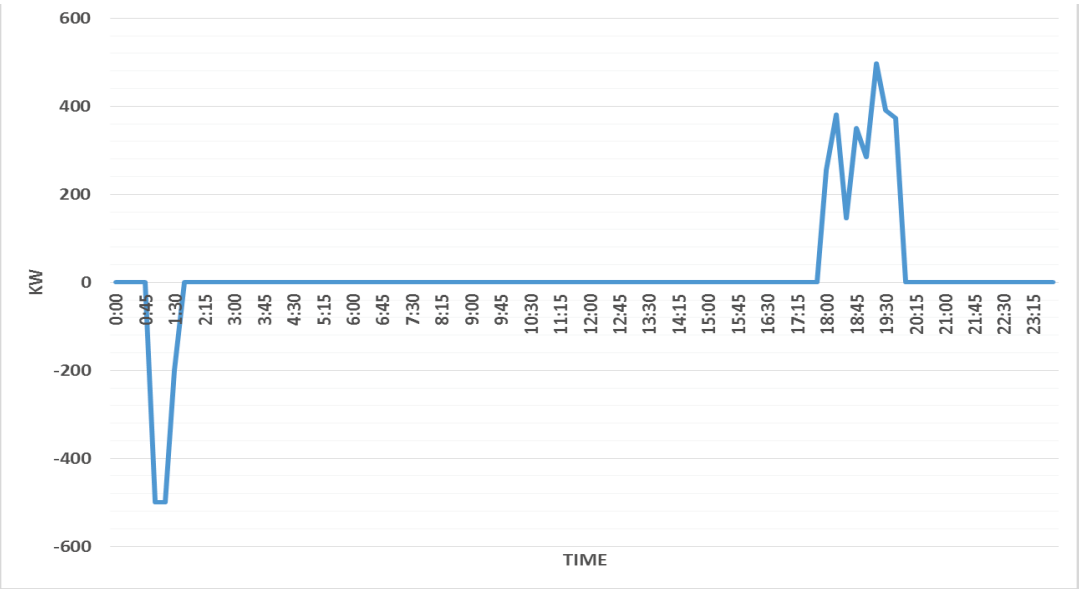


Figure 9-7. Battery Output Power (Centralized Upgrade Deferral) for CCUD 2

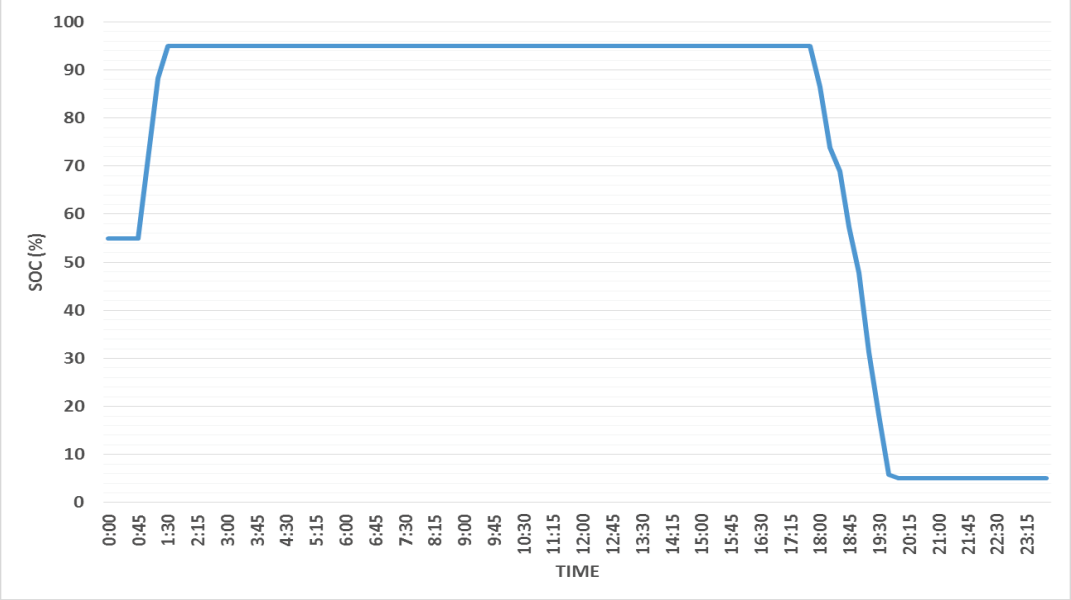


Figure 9-8. Battery State of Charge (Centralized Upgrade Deferral) for CCUD 2

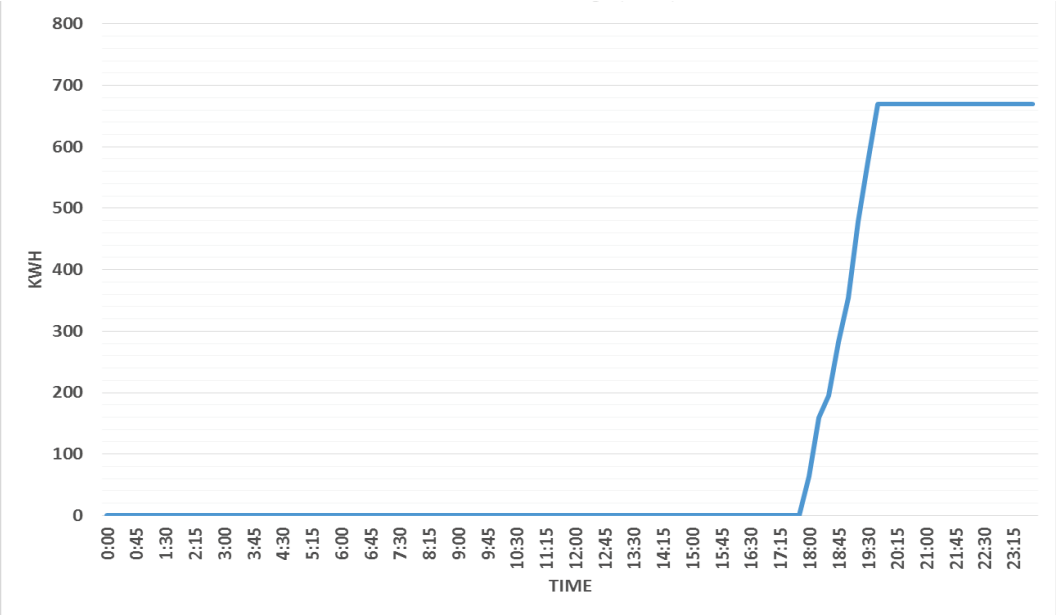


Figure 9-9. Accumulative Discharge (Centralized Upgrade Deferral) for CCUD 2

9.1.3 BESS sizing - Centralized Upgrade Deferral for CCUD 3

For CCUD 3, centralized deferral approach, the battery was installed at the beginning of the feeder (Figure 9-10). The battery was initially sized as 0.5 MW, 1 MWh.

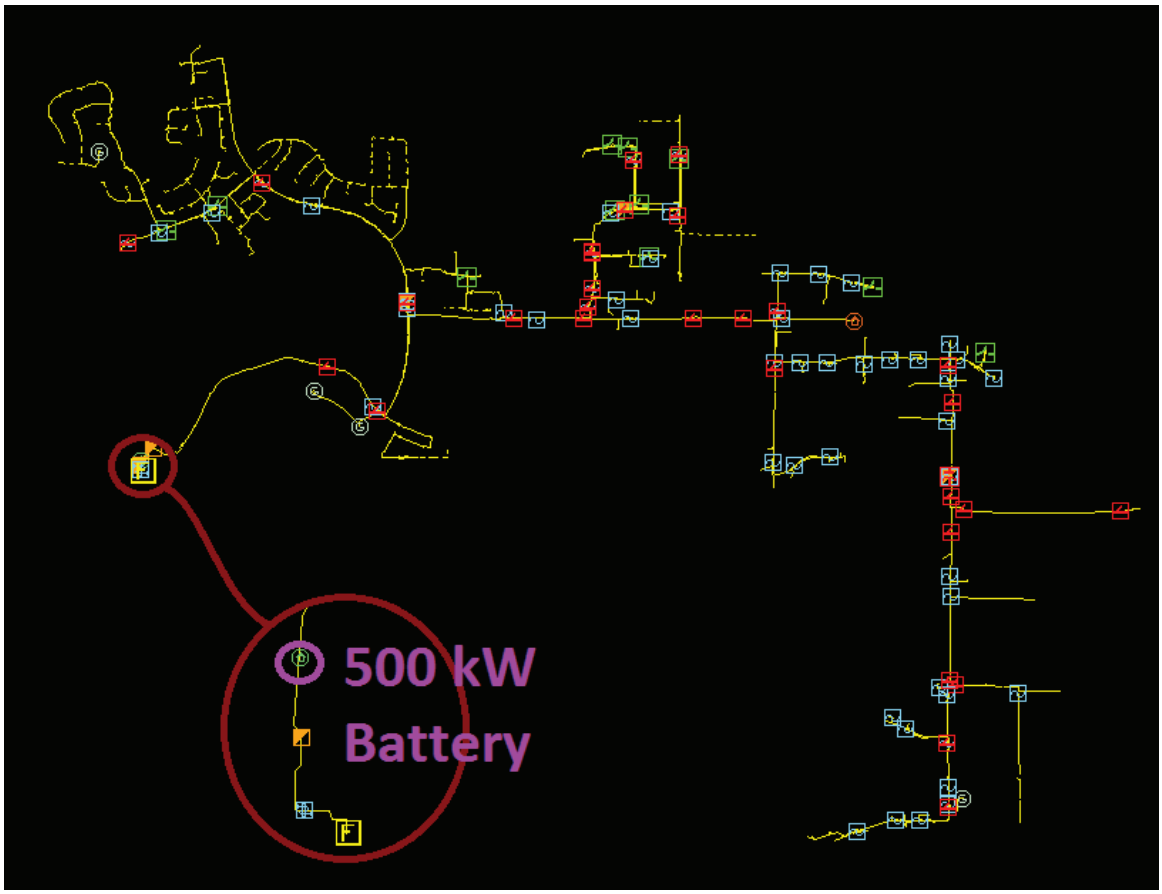


Figure 9-10. Battery Location for CCUD 3

The circuit under study has a thermal loading limit of 580 (A) determined in Distribution Planning Tool 4 model. This limit was used as the upper threshold of the circuit for peak shaving purposes. For the lower threshold zero was used to make sure that the reverse power flow is prevented. Also, the battery is schedules to charge between 0:45 am – 5:00 am up to 95% in order to provide enough energy for discharging throughout the day.

In order to consider the worst case scenario, the maximum peak day of year was determined for the projected (year 2024) load profile and the PV systems have been turned off during the analysis.

Figure 9-11 demonstrates the feeder power flow before and after the upgrade deferral application. The battery was charging during the scheduled charging zone up to 95% SOC (Figure 9-12) and then cutting the feeder power below 12055 kW during the day. As illustrated in Figure 9-13, the battery charge/discharge up to the maximum kW rate of 500 kW. The accumulative discharge of the battery by

the end of the day, is almost 800 kWh (Figure 9-14) which reflects the maximum amount of energy required from the battery and justifies using a 1000 kWh battery.

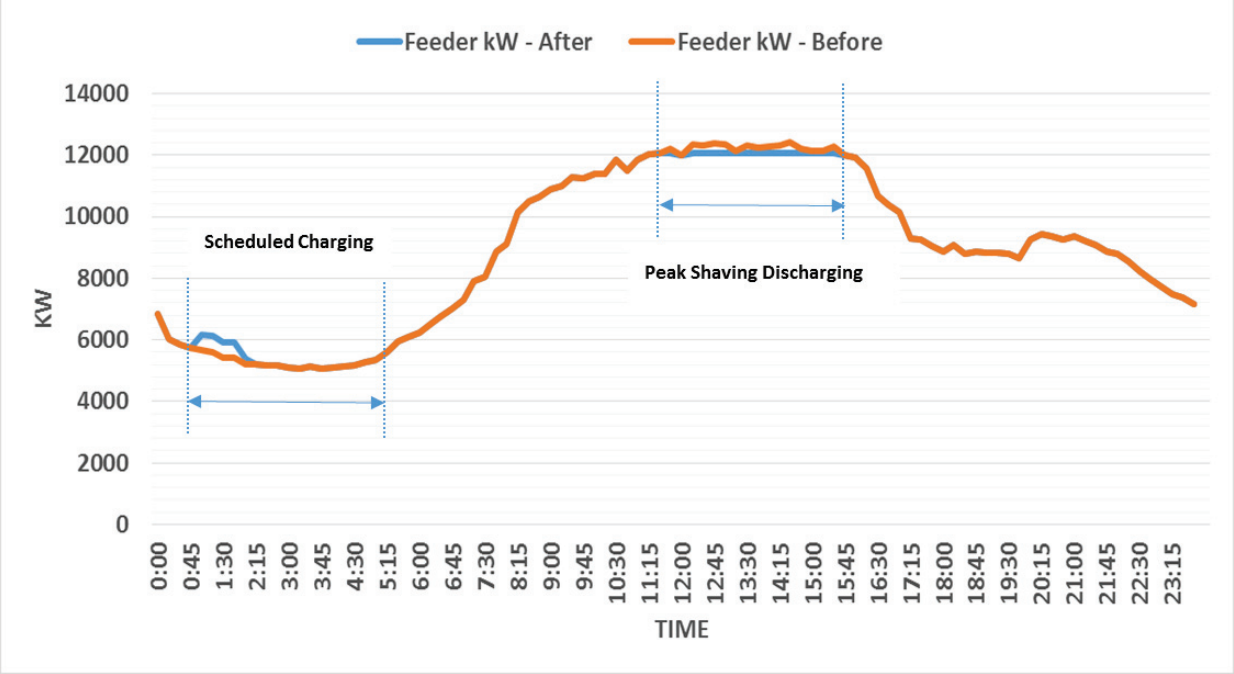


Figure 9-11. Power Flow (Centralized Upgrade Deferral) for CCUD 3

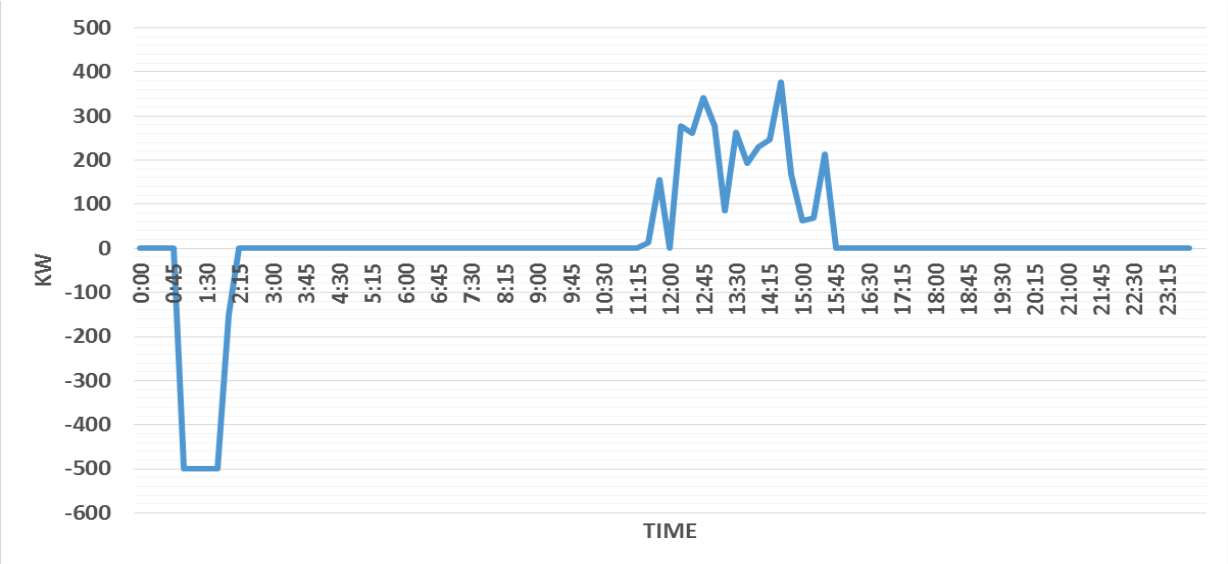


Figure 9-12. C1202 Battery Output Power (Centralized Upgrade Deferral) for CCUD 3

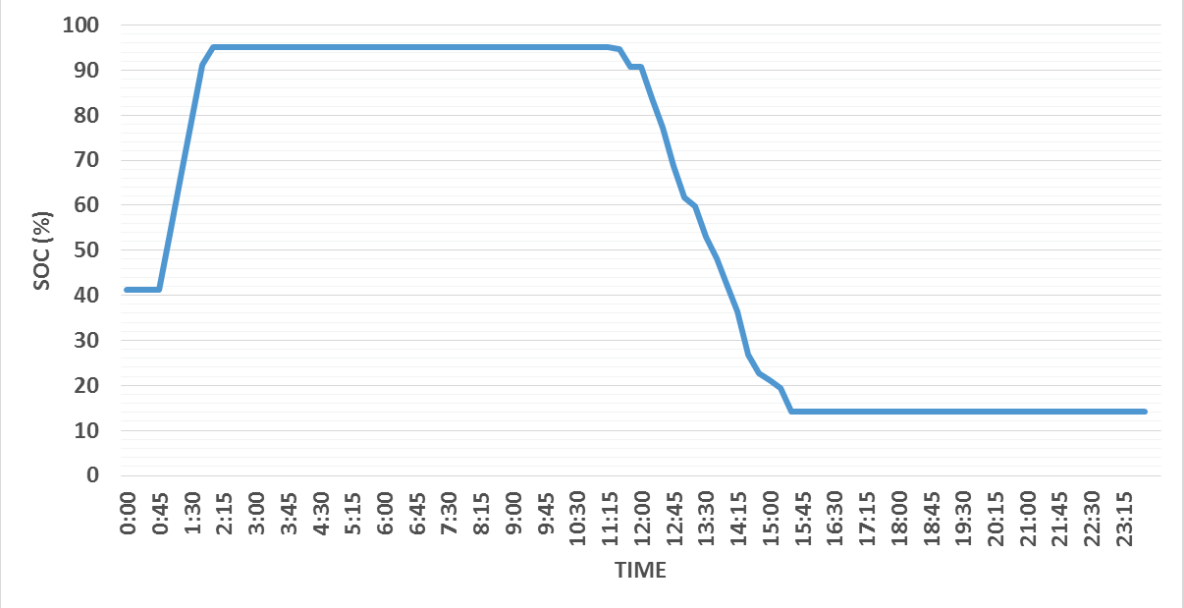


Figure 9-13. C1202 Battery State of Charge (Centralized Upgrade Deferral) for CCUD 3

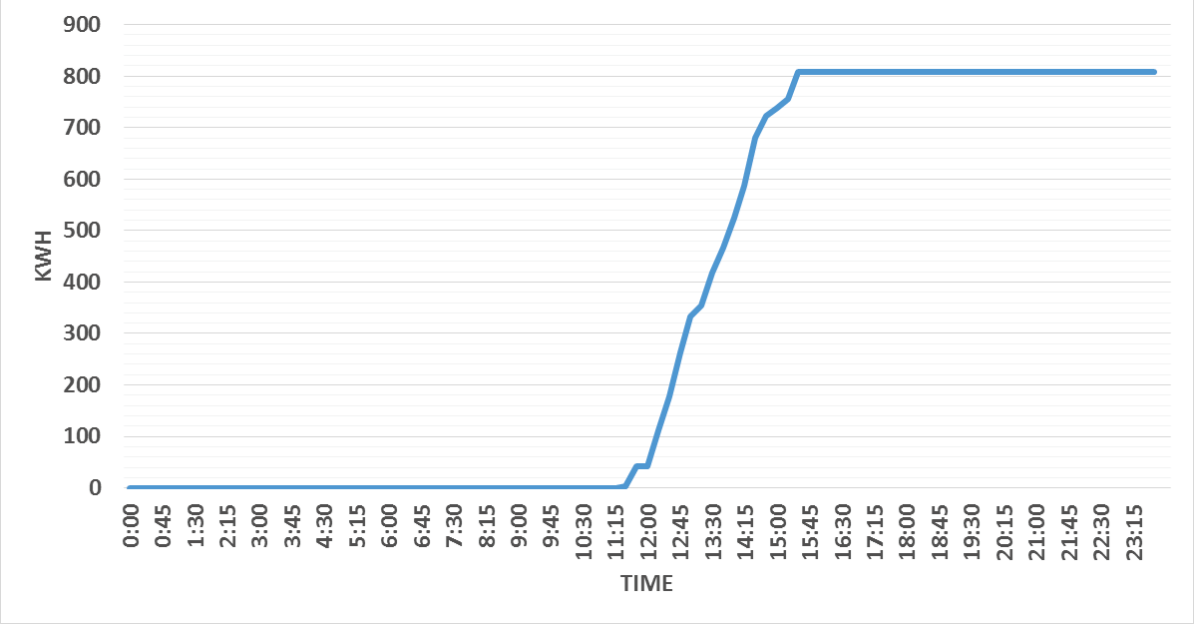


Figure 9-14. C1202 Accumulative Discharge (Centralized Upgrade Deferral) for CCUD 3

9.2 Additional study results for Microgrid Application

9.2.1 BESS sizing for CMG2

The microgrid topology and location of PV and ESS are shown in Figure 9-15.

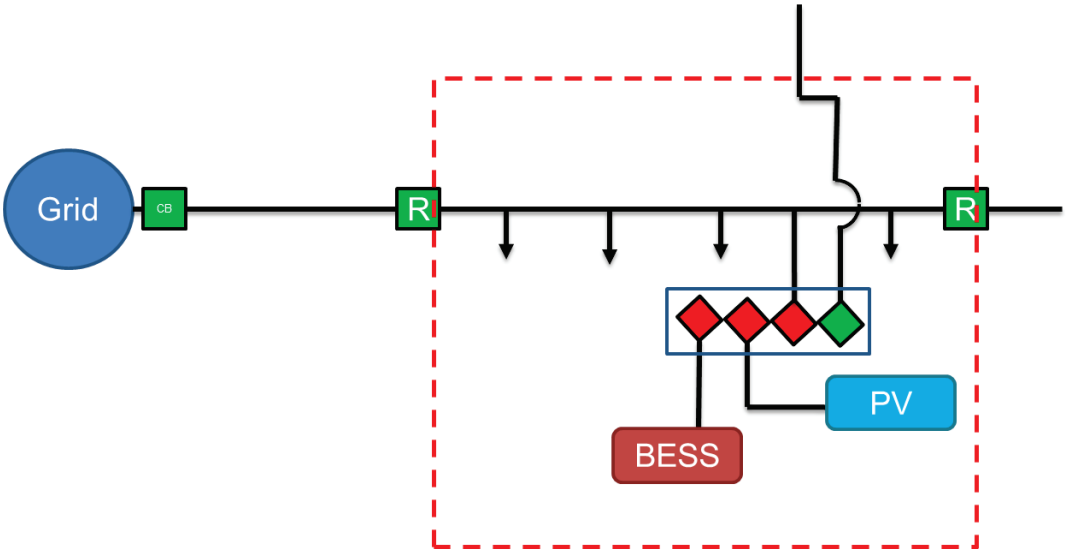


Figure 9-15. CMG2 - microgrid topology

The summary of recommended ESS sizes for is provided in Table 9-1. These ESS sizes are recommended based on simulation results of 4-hour, 6-hour, and 8-hour outages occurring any time during the year on the microgrid area. Based on the simulation results, the required size of battery (kW and kWh) for each of the simulated outages are gathered and ESS is sized to cover the maximum required kW and kWh. The required size of ESS unit for 4-hour, 6-hour, and 8-hour outages occurring at different times during 2016 are illustrated in Figure 9-16, Figure 9-17, and Figure 9-18.

Table 9-1. ESS size recommendations for CMG2

Outage Duration	Maximum Energy Required (kWh)	Peak Load (kW)	Recommended ESS Size
4 hours	2743	711	**750kW – 4.0 Hrs**
6 hours	4048	711	**1100kW – 4.0 Hrs**
8 hours	5300	711	**1400kW – 4.0 Hrs**

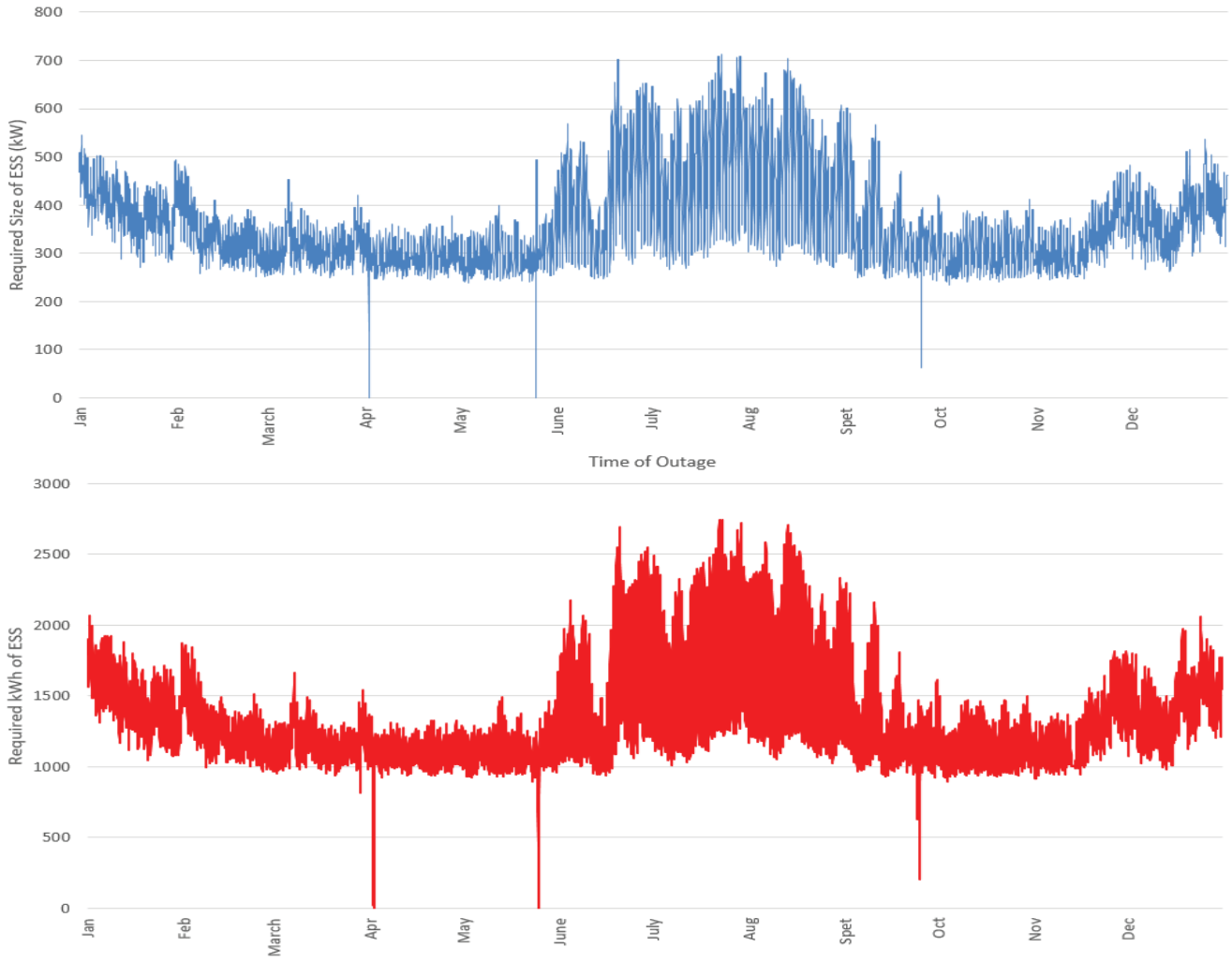


Figure 9-16. Required kW and kWh of ESS to support CMG2 microgrid load for 4-hour outages

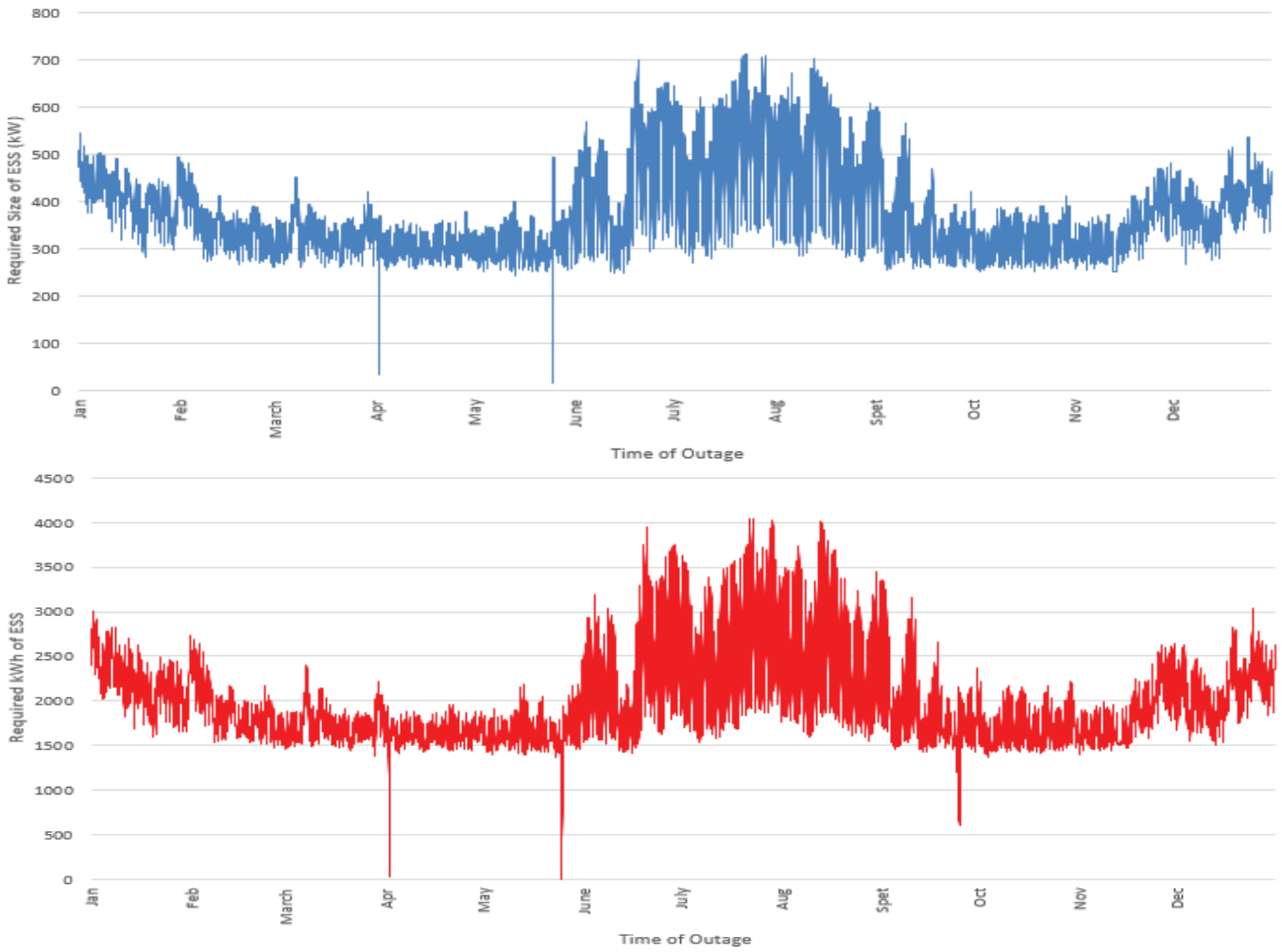


Figure 9-17. Required kW and kWh of ESS to support CMG2 microgrid load for 6-hour outages

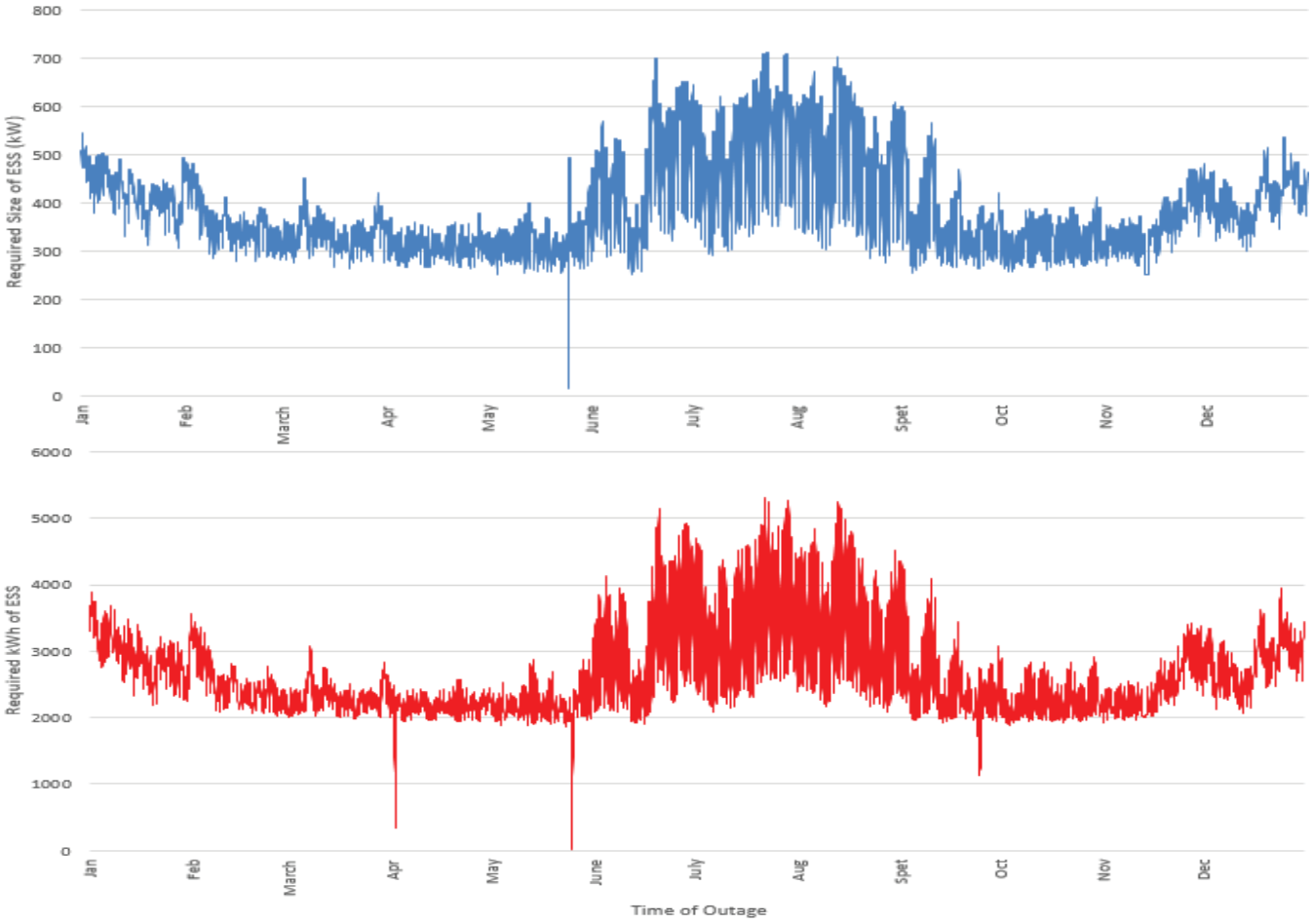


Figure 9-18. Required kW and kWh of ESS to support CMG2 microgrid load for 8-hour outages

9.2.2 BESS sizing for CMG3

The microgrid topology and location of ESS are shown in Figure 9-19. The ESS is planned to be located very close to a library as a cool zone.

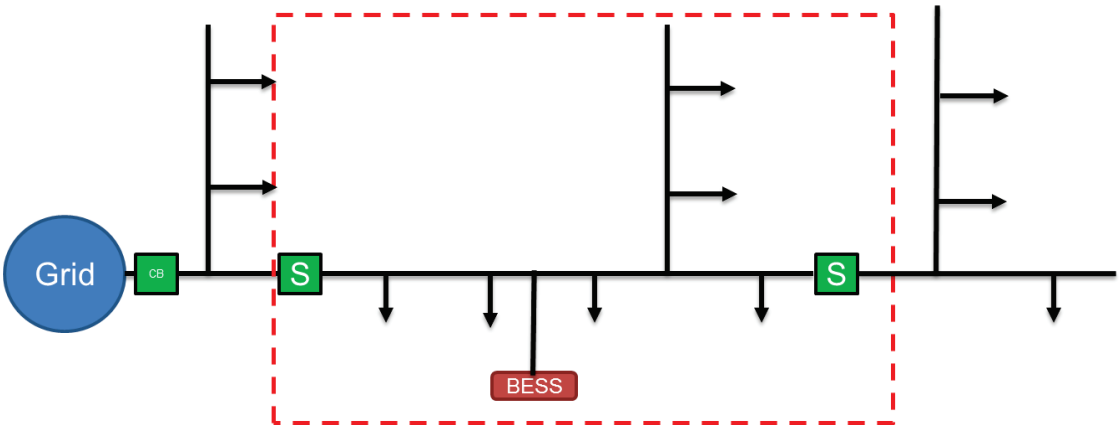


Figure 9-19. CMG3- microgrid topology

The summary of recommended ESS sizes is provided in Table 9-2. These ESS sizes are recommended based on simulation results of 4-hour, 6-hour, and 8-hour outages occurring any time during the year on the microgrid area. Based on the simulation results, the required size of battery (kW and kWh) for each of the simulated outages are gathered and ESS is sized to cover the maximum required kW and kWh. The required size of ESS unit for 4-hour, 6-hour, and 8-hour outages occurring at different times during 2016 are illustrated in Figure 9-20, Figure 9-21, and Figure 9-22.

Table 9-2. Recommended ESS sizes for CMG3

Outage Duration	Maximum Energy Required (kWh)	Peak Load (kW)	Recommended ESS Size
4 hours	2465.95 kWh	616.5kW	**800 kW – 4.0 Hrs**
6 hours	3698.93 kWh	616.5kW	**1100 kW – 4.0 Hrs**
8 hours	4931.91 kWh	616.5kW	**1400 kW – 4.0 Hrs**

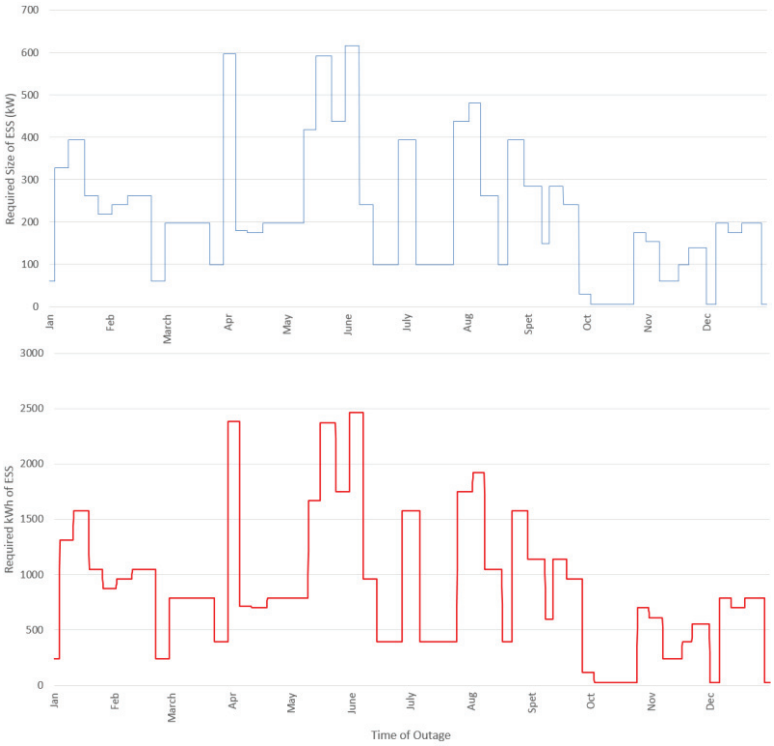


Figure 9-20. Required kW and kWh of ESS to Support CMG3 Microgrid Load for 4-hour Outages

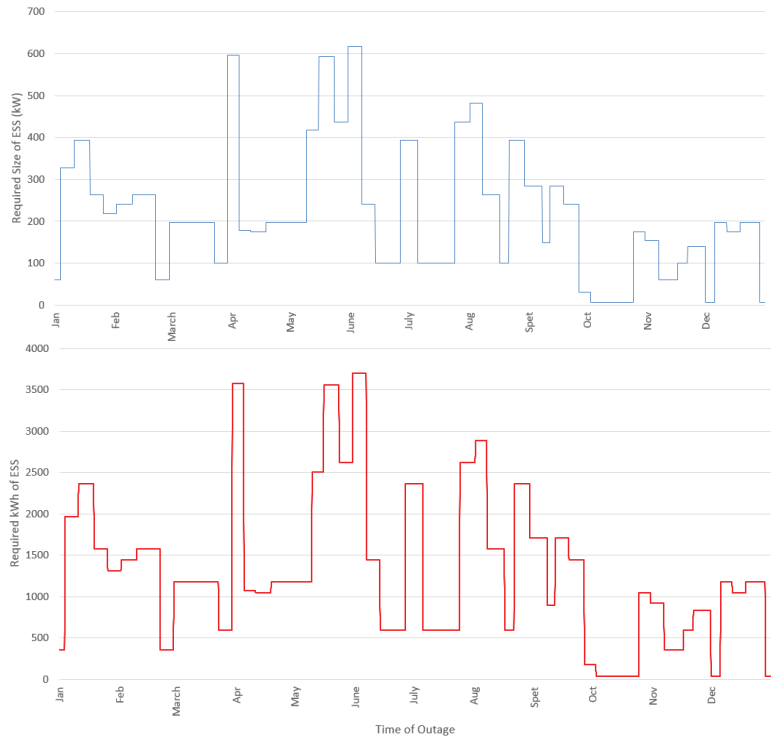


Figure 9-21. Required kW and kWh of ESS to support CMG3 microgrid load for 6-hour outages

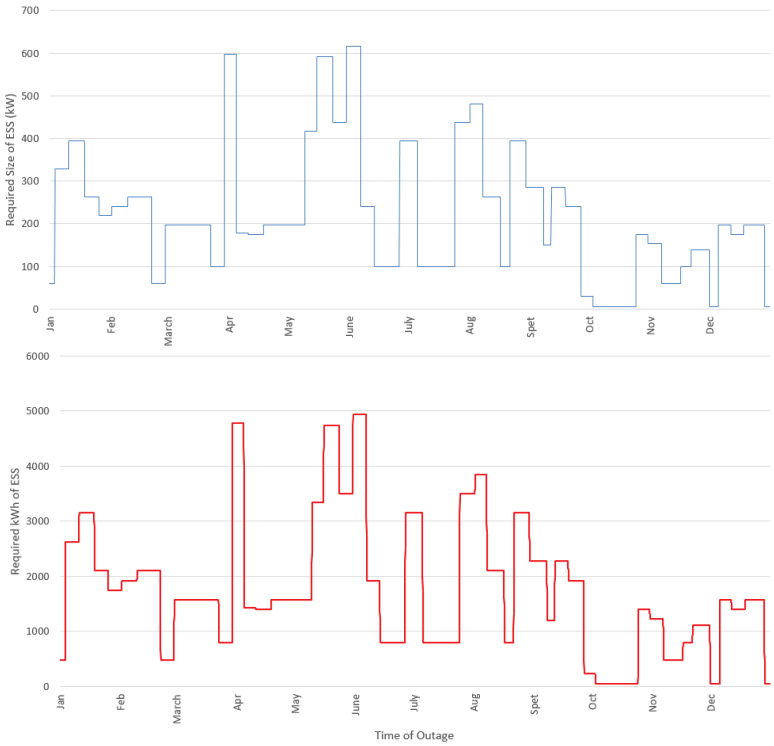


Figure 9-22. Required kW and kWh of ESS to support CMG3 microgrid load for 8-hour outages

9.2.3 BESS sizing for CMG4

The microgrid topology and location of ESS are shown in Figure 9-23. The ESS is planned to be co-located with one of the critical customers (a library) which is also utilized as a "cool zone" for the community.

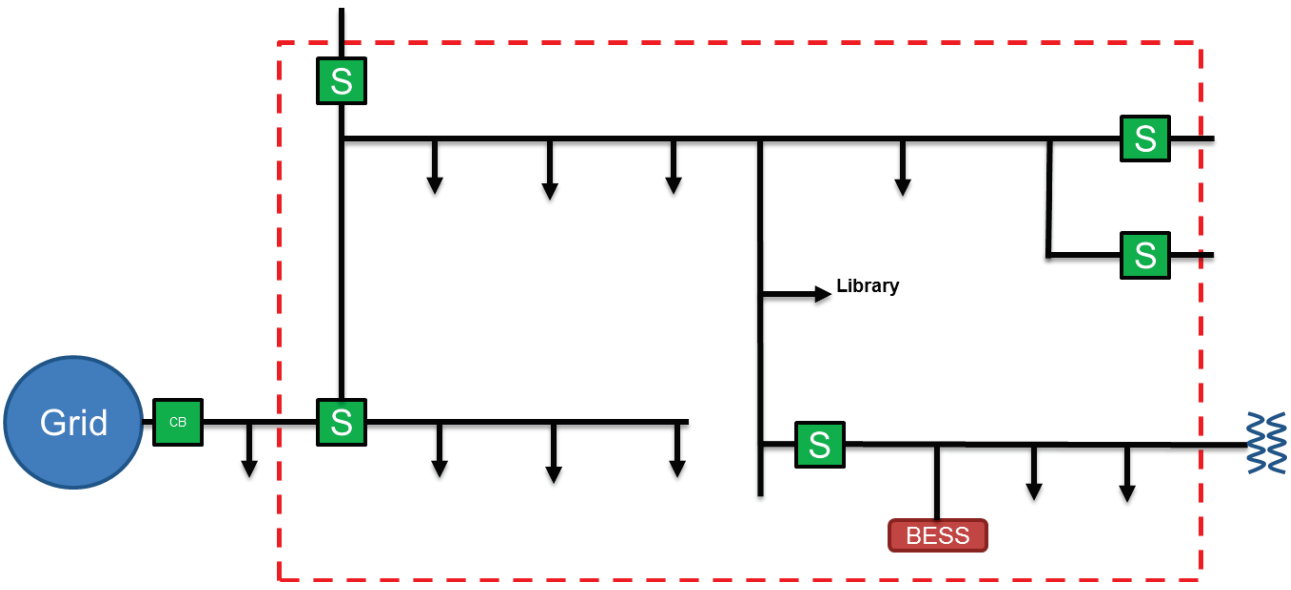


Figure 9-23. CMG4 - microgrid topology

The summary of recommended ESS sizes for is provided in Table 9-3. These ESS sizes are recommended based on simulation results of 4-hour, 6-hour, and 8-hour outages occurring any time during the year on the microgrid area. Based on the simulation results, the required size of battery (kW and kWh) for each of the simulated outages are gathered and ESS is sized to cover the maximum required kW and kWh. The required size of ESS unit for 4-hour, 6-hour, and 8-hour outages occurring at different times during 2016 are illustrated in Figure 9-24, Figure 9-25, and Figure 9-26.

Table 9-3. Recommended ESS sizes for CMG4

Outage Duration	Maximum Energy Required (kWh)	Peak Load (kW)	Recommended ESS Size
4 hours	8005.76 kWh	2063.94 kW	**2500 kW – 4.0 Hrs**
6 hours	11748 kWh	2063.94 kW	**3200 kW – 4.0 Hrs**
8 hours	15211.56 kWh	2063.94 kW	**4100 kW – 4.0 Hrs**

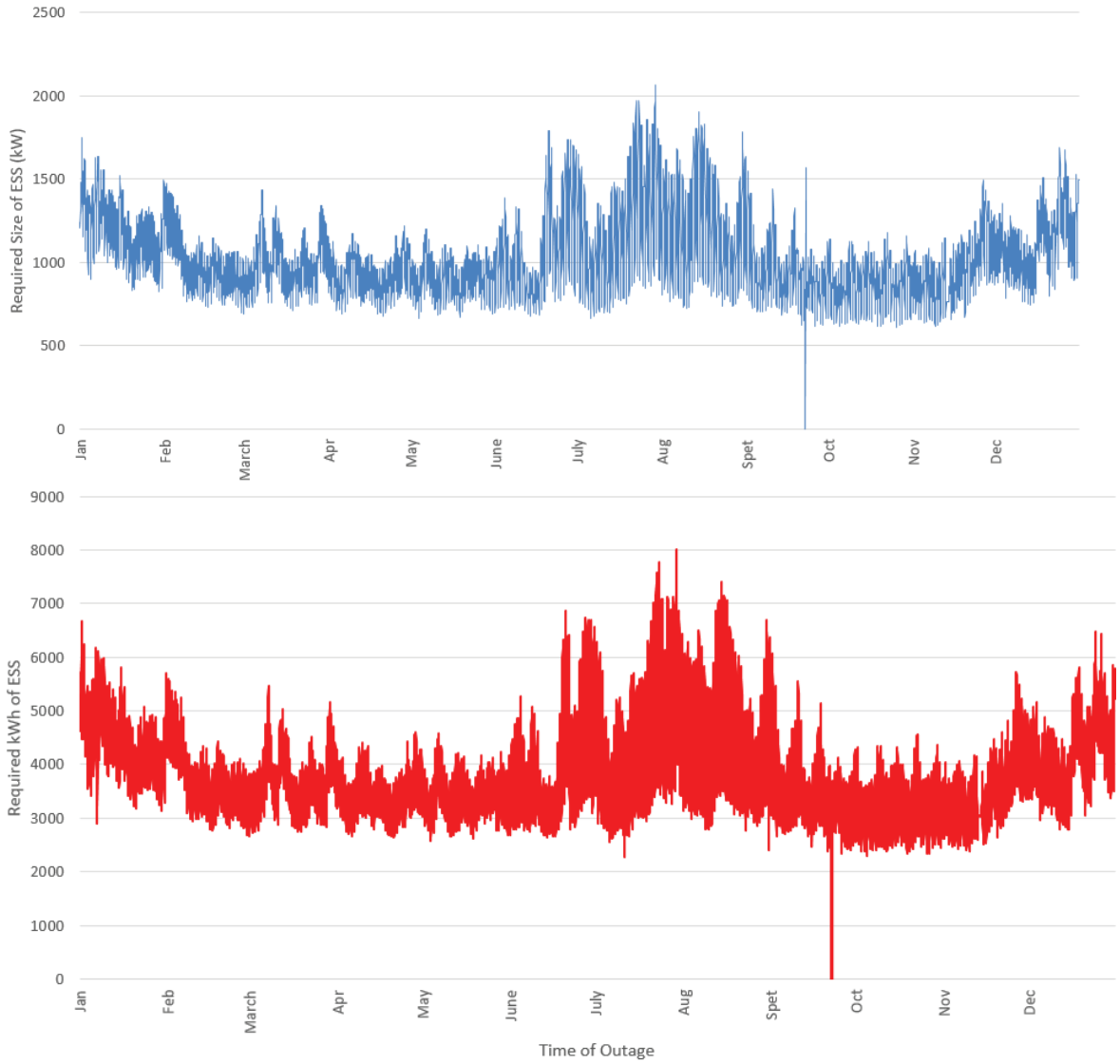


Figure 9-24. Required kW and kWh of ESS to support CMG4 microgrid load for 4-hour outages

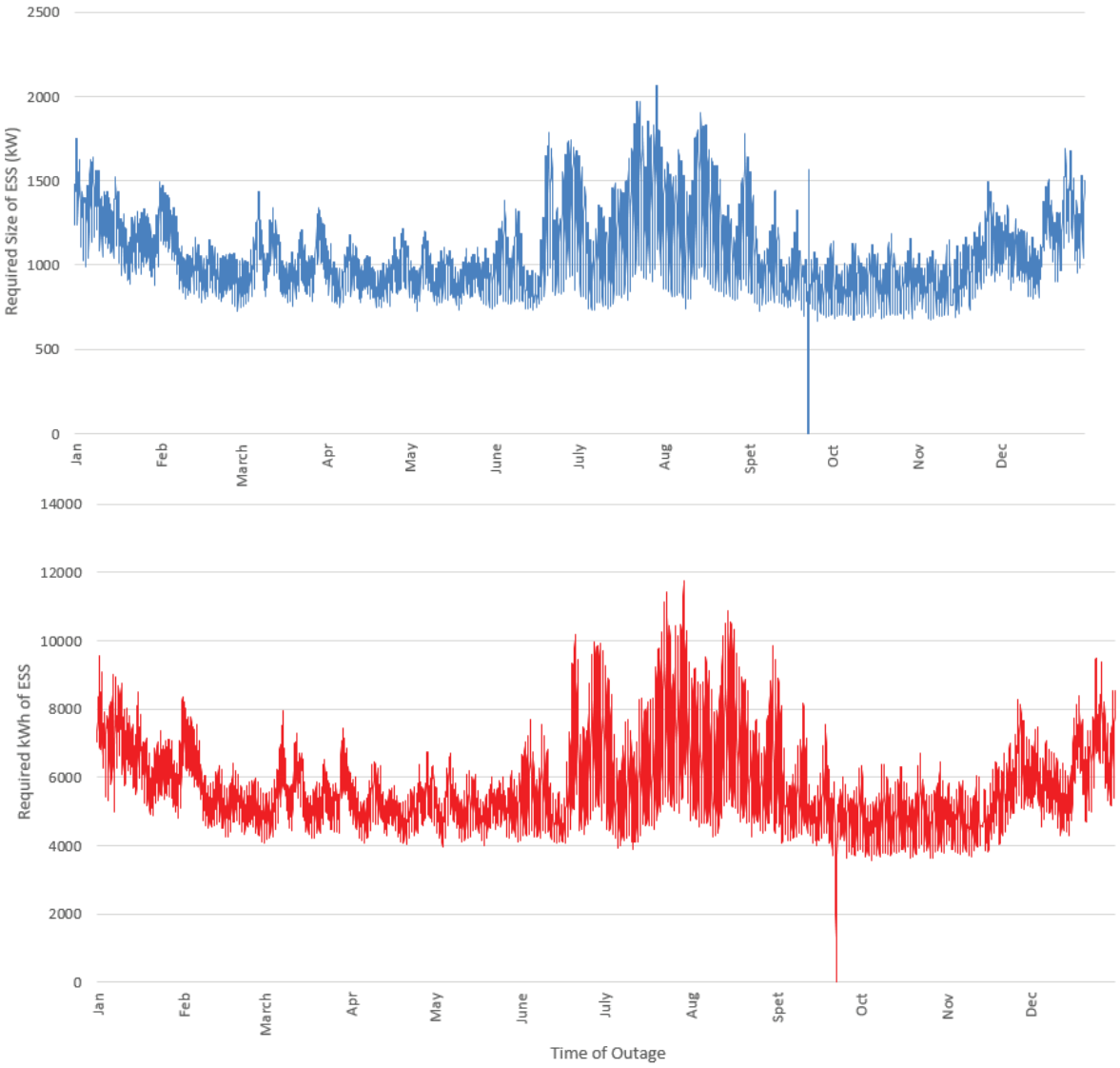


Figure 9-25. Required kW and kWh of ESS to support CMG4 microgrid load for 6-hour outages

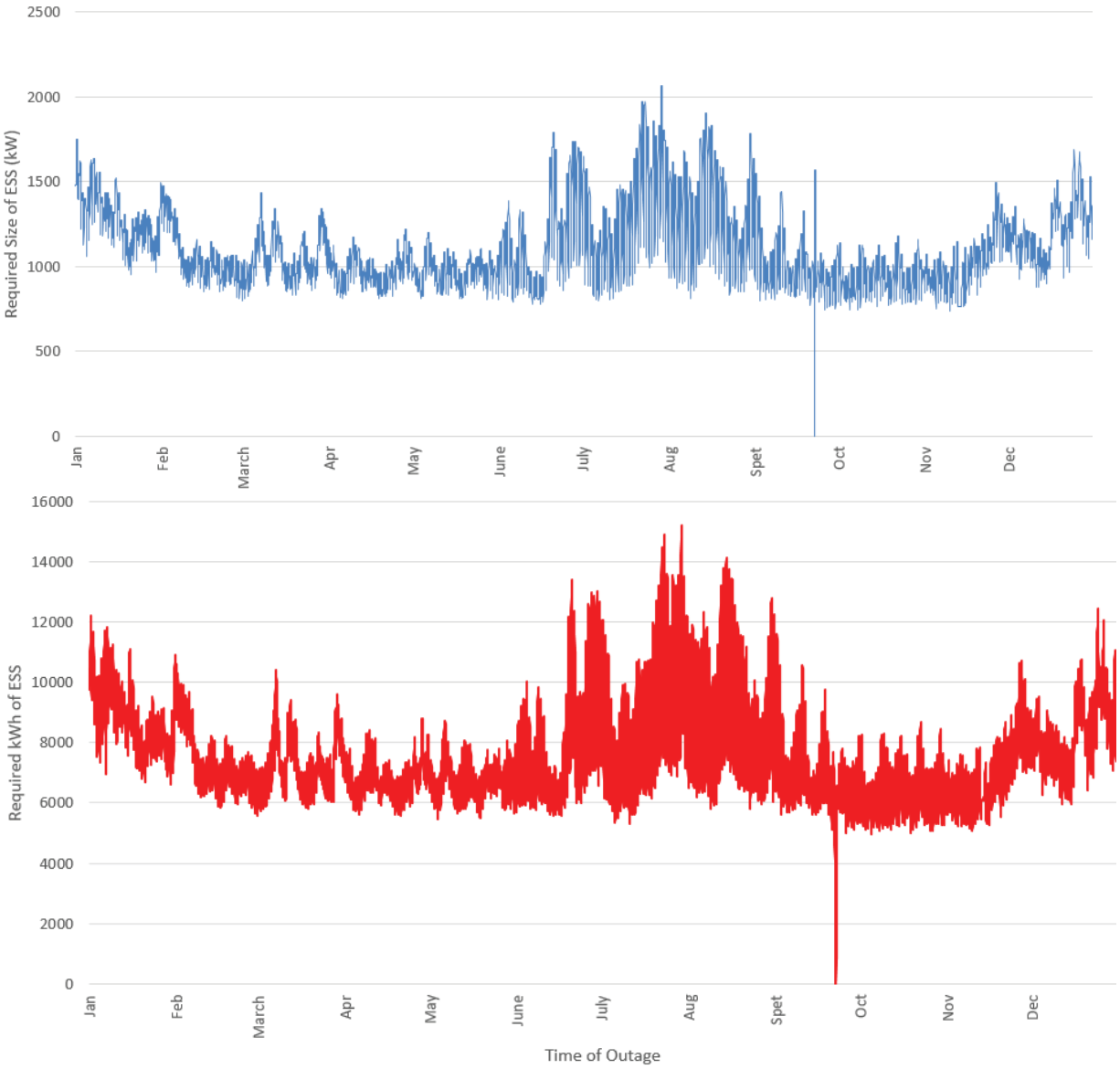


Figure 9-26. Required kW and kWh of ESS to support CMG4 microgrid load for 8-hour outages

9.2.4 CBA for Circuit CMG2

Market analysis is conducted for three ESS sizes designed to manage 4, 6, and 8 hour outages. For each scenario, two variations are considered; with and without PV. Table 9-4 summarizes ESS sizes.

Table 9-4. ESS sizes for CMG2

Outage Duration	ESS Power (kW)	ESS Energy (kWh)
4-hr	750	3,000
6-hr	1,100	4,400
8-hr	1,400	5,600

SOC constraints throughout the year for given outage scenarios are provided in Figure 9-27 to Figure 9-32. SOC constraints limit the capacity of ESS which can participate in the market as secondary application. As seen in the below figures, the SOC constraints are relatively lower in the presence of PV system. The reason is that for the outages during day time PV system can also support a portion of the microgrid load beside ESS.



Figure 9-27. SOC constraints for 4-hr outage (without PV)

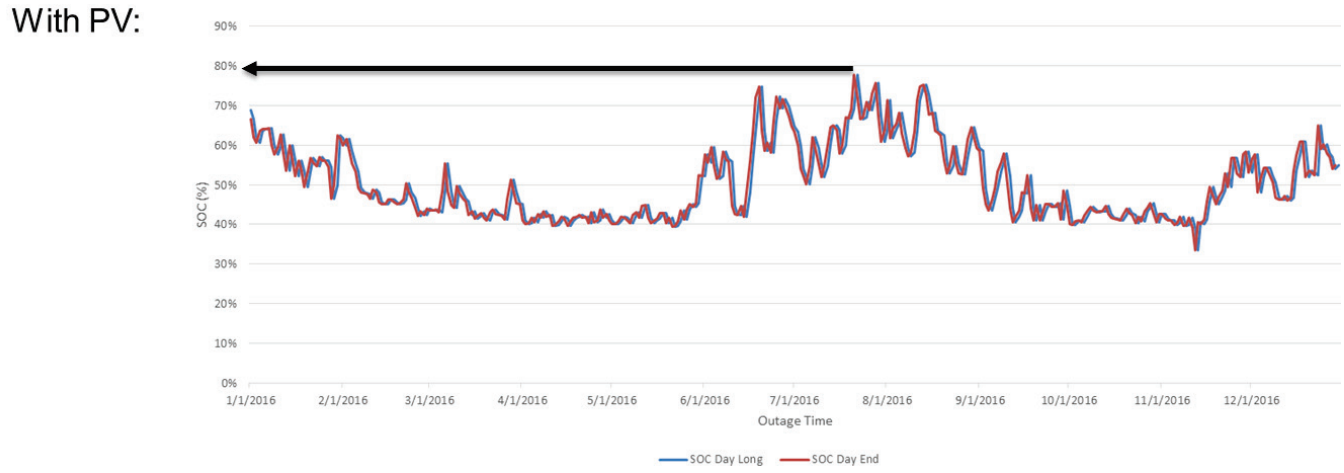


Figure 9-28. SOC constraints for 4-hr outage (with PV)

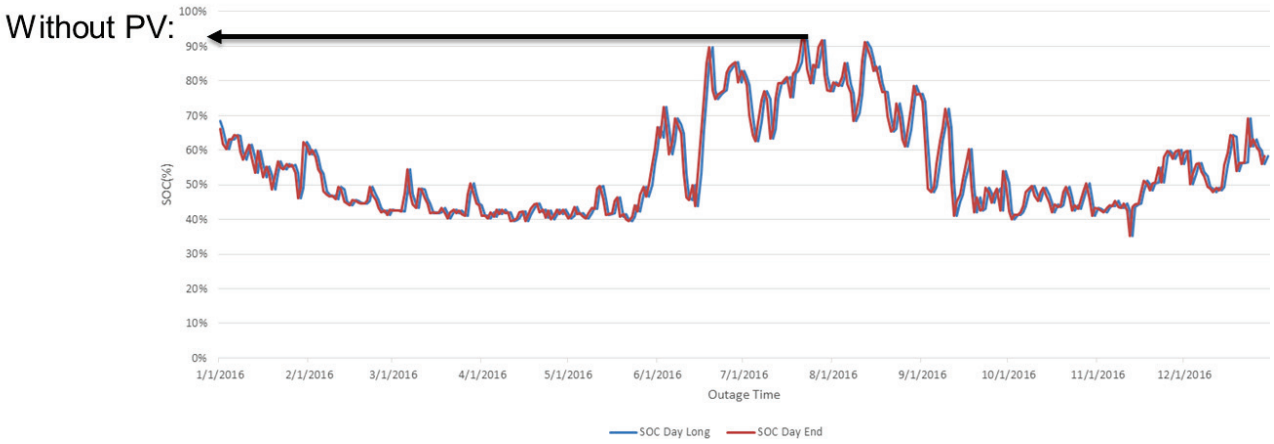


Figure 9-29. SOC constraints for 6-hr outage (without PV)

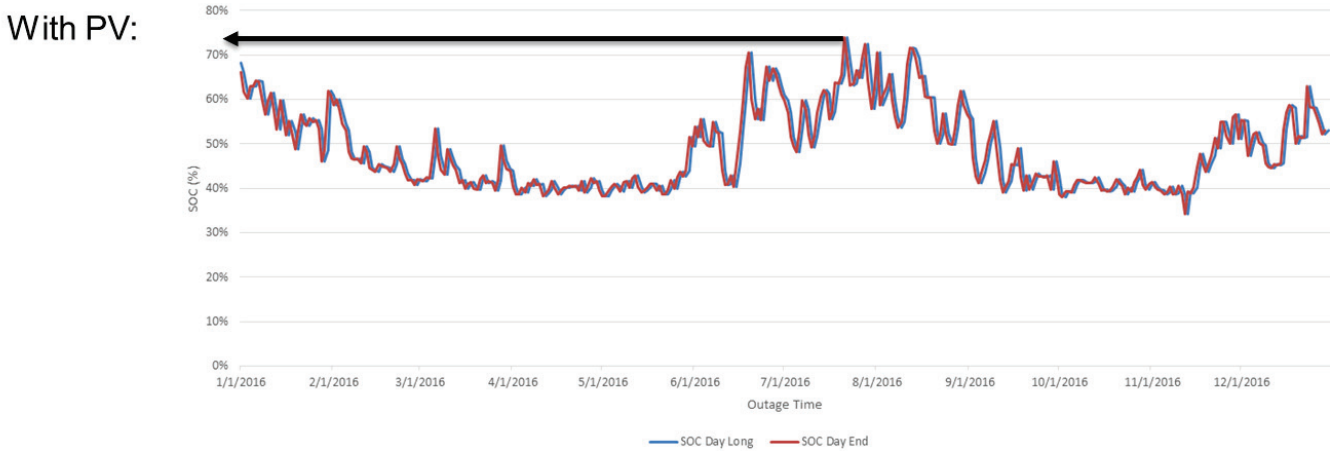


Figure 9-30. SOC constraints for 6-hr outage (with PV)

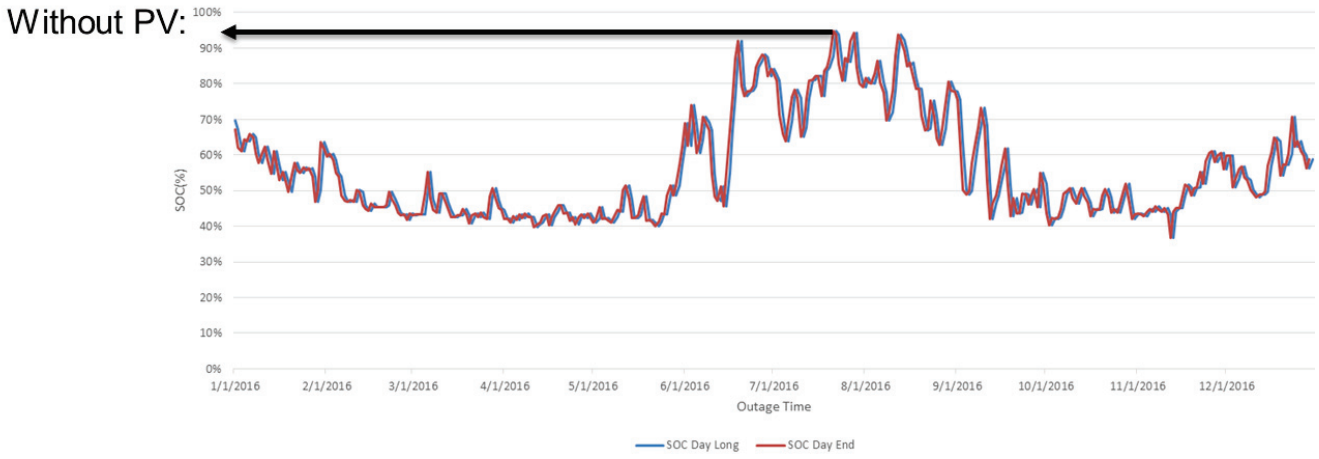


Figure 9-31. SOC constraints for 8-hr outage (without PV)

With PV:

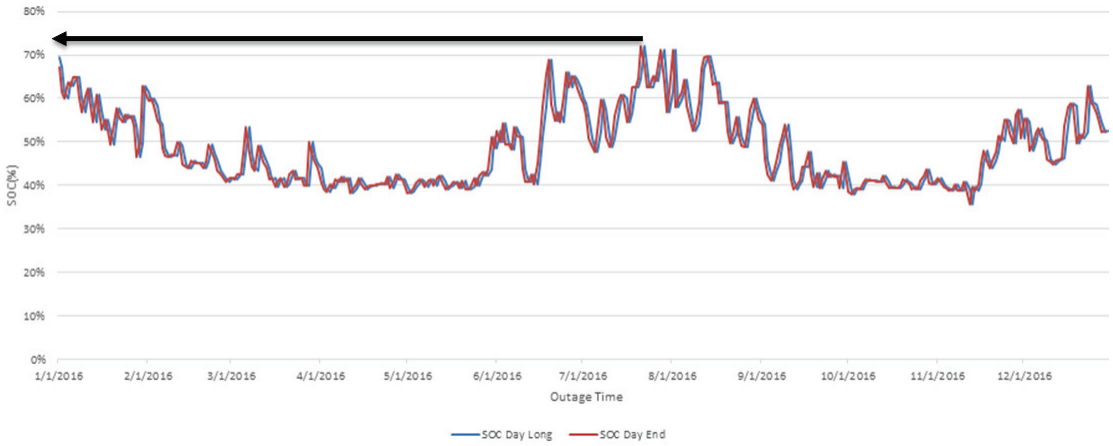


Figure 9-32. SOC constraints for 8-hr outage (with PV)

Annual market benefits are calculated as a summation of energy, Regulation Up and down Capacity, mileage credits less the variable O&M (VOM). It should be noted that VOM of 0.00579 $/kWH is considered for both charging and discharging of the battery. Table 9-5 through Table 9-10 present the results of market analysis for ESS in a microgrid.

Table 9-5. CMG2: 4-hr outage (ESS: 750 kW, 3000 kWh) without PV

4-hr outage (ESS: 750 kW, 3000 kWh) without PV	Energy Credit	Regulation Up Capacity Credit	Regulation Down Capacity Credit	Mileage UP Credit	Mileage Down Credit	VOM	Annual Market Benefits
Wholesale Energy Only	$ 41,764	$ -	$ -	$ -	$ -	$ 5,564	$ 36,200
Wholesale Energy and Ancillary	$ 37,351	$ 37,368	$ 32,557	$ 4,274	$ 8,171	$ 10,011	$ 109,710

Table 9-6. CMG2: 4-hr outage (ESS: 750 kW, 3000 kWh) with PV

4-hr outage (ESS: 750 kW, 3000 kWh) with PV	Energy Credit	Regulation Up Capacity Credit	Regulation Down Capacity Credit	Mileage UP Credit	Mileage Down Credit	VOM	Annual Market Benefits
Wholesale Energy Only	$ 45,078	$ -	$ -	$ -	$ -	$ 5,999	$ 39,078
Wholesale Energy and Ancillary	$ 40,342	$ 37,134	$ 32,506	$ 4,240	$ 8,168	$ 10,232	$ 112,158

Table 9-7. CMG2: 6-hr outage (ESS: 1100 kW, 4400 kWh) without PV

6-hr outage (ESS: 1100 kW, 4400 kWh) without PV	Energy Credit	Regulation Up Capacity Credit	Regulation Down Capacity Credit	Mileage UP Credit	Mileage Down Credit	VOM	Annual Market Benefits
Wholesale Energy Only	$ 61,275	$ -	$ -	$ -	$ -	$ 8,176	$ 53,100

Wholesale Energy and Ancillary	$ 54,793	$ 54,807	$ 47,746	$ 6,270	$ 11,983	$ 14,692	$ 160,907

Table 9-8. CMG2: 6-hr outage (ESS: 1100 kW, 4400 kWh) with PV

6-hr outage (ESS: 1100 kW, 4400 kWh) with PV	Energy Credit	Regulation Up Capacity Credit	Regulation Down Capacity Credit	Mileage UP Credit	Mileage Down Credit	VOM	Annual Market Benefits
Wholesale Energy Only	$ 66,943	$ -	$ -	$ -	$ -	$ 8,972	$ 57,970
Wholesale Energy and Ancillary	$ 59,836	$ 54,422	$ 47,650	$ 6,214	$ 11,978	$ 15,084	$ 165,017

Table 9-9. CMG2: 8-hr outage (ESS: 1400 kW, 5600 kWh) without PV

8-hr outage (ESS: 1400 kW, 5600 kWh) without PV	Energy Credit	Regulation Up Capacity Credit	Regulation Down Capacity Credit	Mileage UP Credit	Mileage Down Credit	VOM	Annual Market Benefits
Wholesale Energy Only	$ 76,595	$ -	$ -	$ -	$ -	$ 10,220	$ 66,375
Wholesale Energy and Ancillary	$ 68,489	$ 69,853	$ 60,790	$ 7,996	$ 15,253	$ 18,605	$ 203,776

Table 9-10. CMG2: 8-hr outage (ESS: 1400 kW, 5600 kWh) with PV

8-hr outage (ESS: 1400 kW, 5600 kWh) with PV	Energy Credit	Regulation Up Capacity Credit	Regulation Down Capacity Credit	Mileage UP Credit	Mileage Down Credit	VOM	Annual Market Benefits
Wholesale Energy Only	$ 85,436	$ -	$ -	$ -	$ -	$ 11,448	$ 73,988
Wholesale Energy and Ancillary	$ 76,341	$ 69,253	$ 60,646	$ 7,926	$ 15,254	$ 19,204	$ 210,215

9.2.5 CBA for Circuit CMG3

Market analysis is conducted for ESS sized at 800 kW: 3,200 kWh. ESSs is sized in a way to manage 8 hour outages. Hourly SOC constraints are calculated via Distribution Planning Tool 4. The SOC constraints determine the total energy required to serve the load if 8-hour outage happens anytime during the day. SOC constraints are provided in Figure 9-33.

Table 9-11 presents a summary of market analysis results for the ESS in the microgrid.

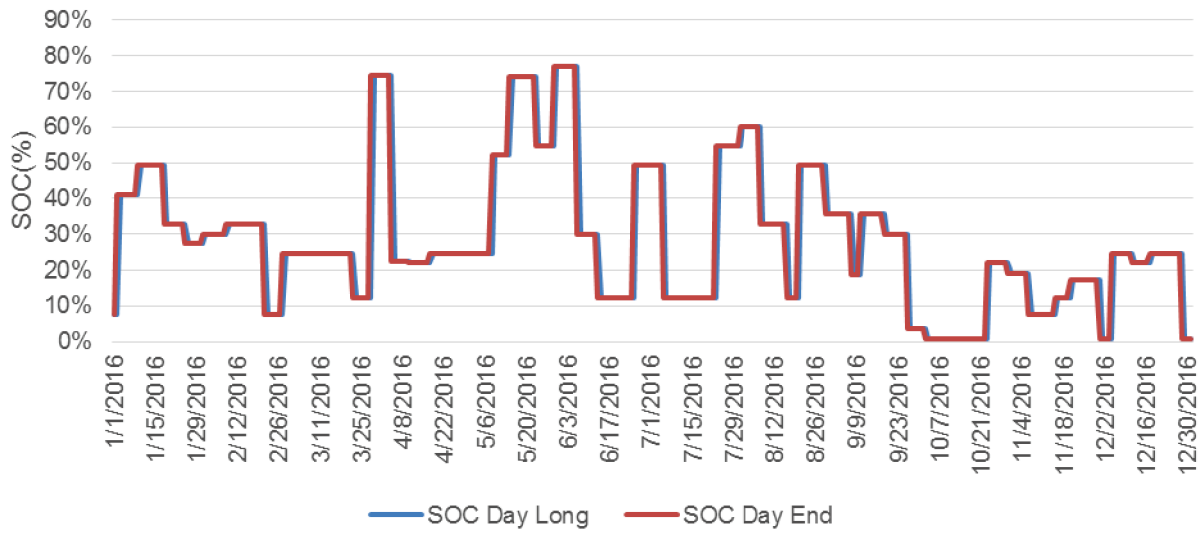


Figure 9-33. CMG3- SOC constraints for 8-hr outage

Table 9-11 CMG3: ESS: 800 kW, 3200 kWh

(ESS: 800 kW, 3200 kWh)	Energy Credit	Regulation Up Capacity Credit	Regulation Down Capacity Credit	Mileage UP Credit	Mileage Down Credit	VOM	Annual Market Benefits
Wholesale Energy Only	$ 59,965	$ -	$ -	$ -	$ -	$ 8,037	$ 51,928
Wholesale Energy and Ancillary	$ 53,337	$ 39,353	$ 34,353	$ 4,457	$ 8,734	$ 11,725	$ 128,510

9.2.6 CBA for Circuit CMG4

Market analysis is conducted for ESS sized at 2,500 kW: 10,000 kWh. ESSs is sized in a way to manage 8 hour outages. Hourly SOC constraints are calculated via Distribution Planning Tool 4. The SOC constraints determine the total energy required to serve the load if 8-hour outage happens anytime during the day. SOC constraints are provided in Figure 9-34.

Table 9-12 presents a summary of market analysis results for the ESS in the microgrid.

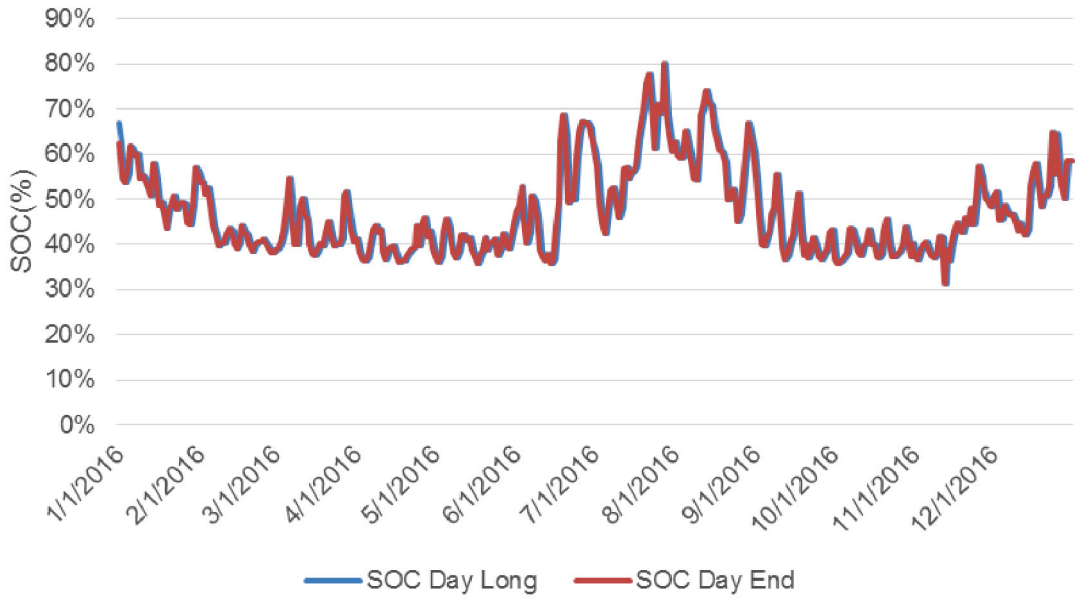


Figure 9-34. CMG4- SOC constraints for 8-hr outage

Table 9-12 CMG4: ESS: 2,500 kW, 10,000 kWh

ESS: 2500 kW, 10000 kWh	Energy Credit	Regulation Up Capacity Credit	Regulation Down Capacity Credit	Mileage UP Credit	Mileage Down Credit	VOM	Annual Market Benefits
Wholesale Energy Only	$ 173,284	$ -	$ -	$ -	$ -	$ 21,990	$ 151,294
Wholesale Energy and Ancillary	$ 155,539	$ 123,787	$ 108,026	$ 14,068	$ 27,354	$ 35,370	$ 393,405

9.3 Additional study results for PV Intermittency Application

9.3.1 Load profile selection and daily analysis

The impacts of high PV penetration is highly pronounced when the feeders are lightly loaded and at the same time a large amount of PV is connected. Thus, for each of the PV impact circuits the day with the minimum loading in the year 2016 was chosen as the desired study day. A combination of the aforesaid chosen day and the PV profile scaled to the maximum installed PV size of the circuit provides the worst case scenario for the PV impact analysis. Figure 9-35 to Figure 9-41 illustrate the load profile for the PV impact analysis circuits presented in Table 3-5.

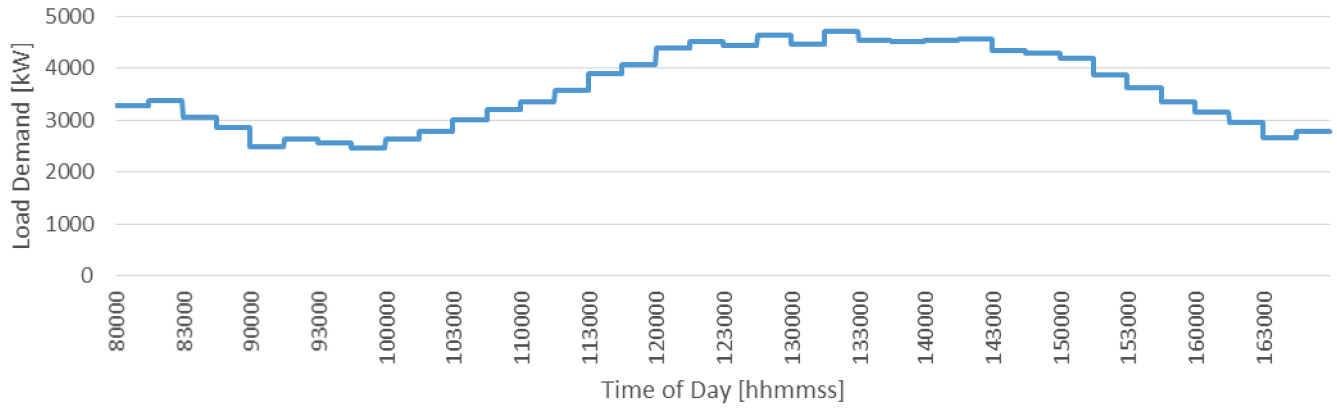


Figure 9-35. Load profile for CPVIM 1

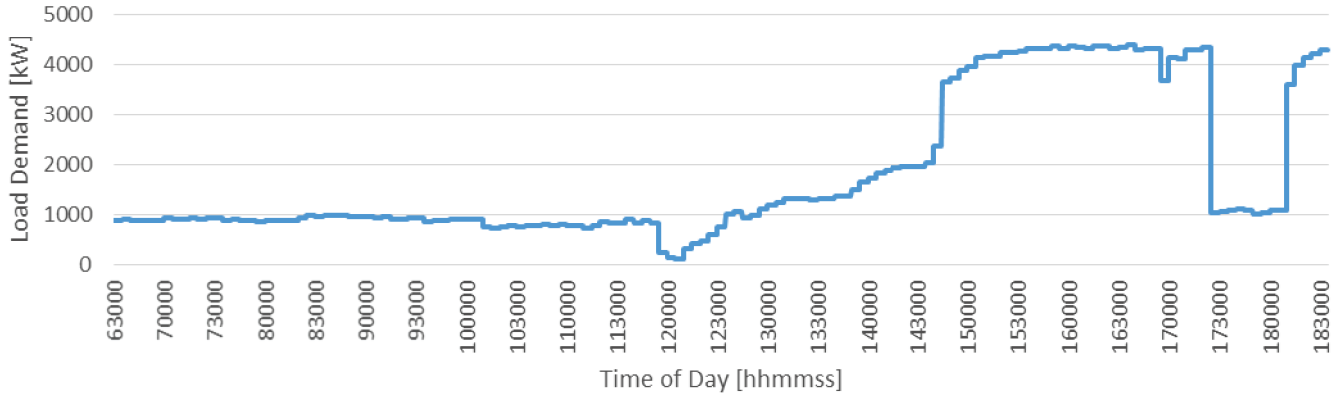


Figure 9-36. Load profile for CPVIM 2

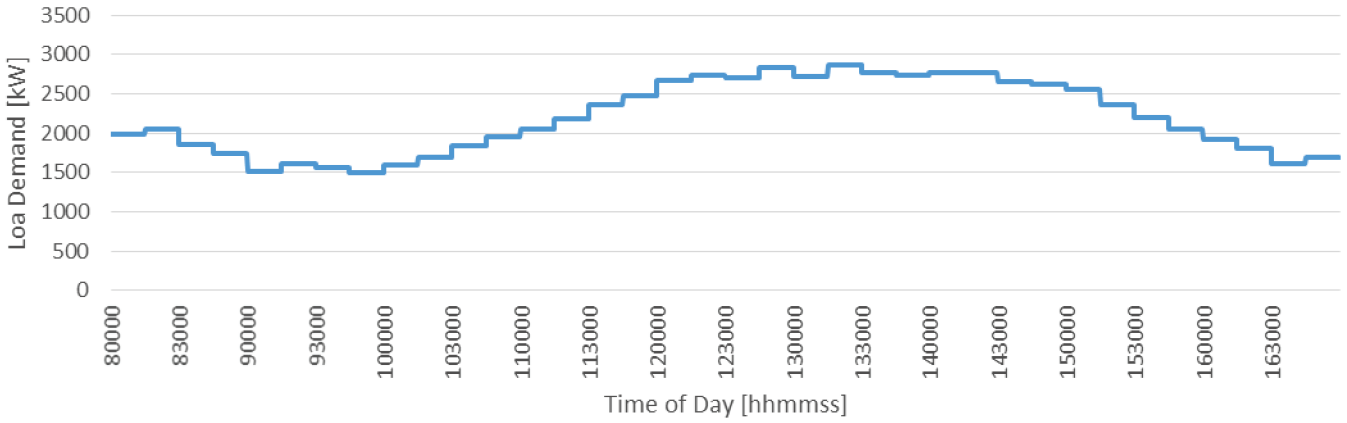


Figure 9-37. Load profile for CPVIM 3

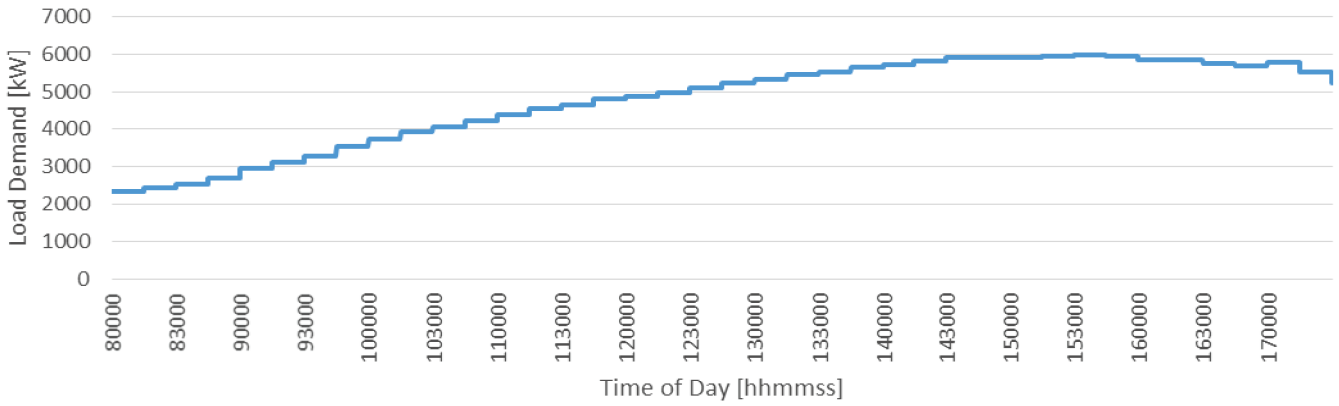


Figure 9-38. Load profile for CPVIM 4

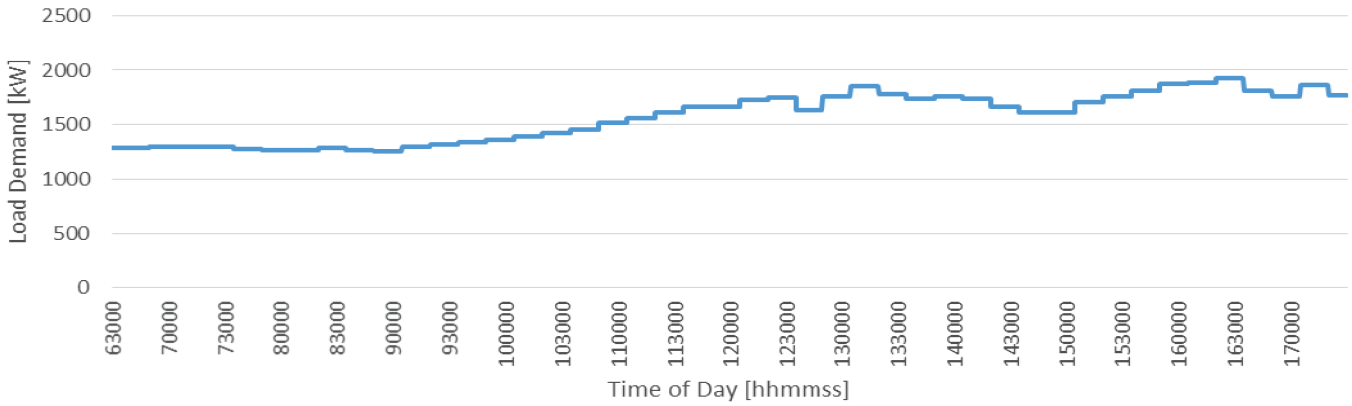


Figure 9-39. Load profile for CPVIM 5

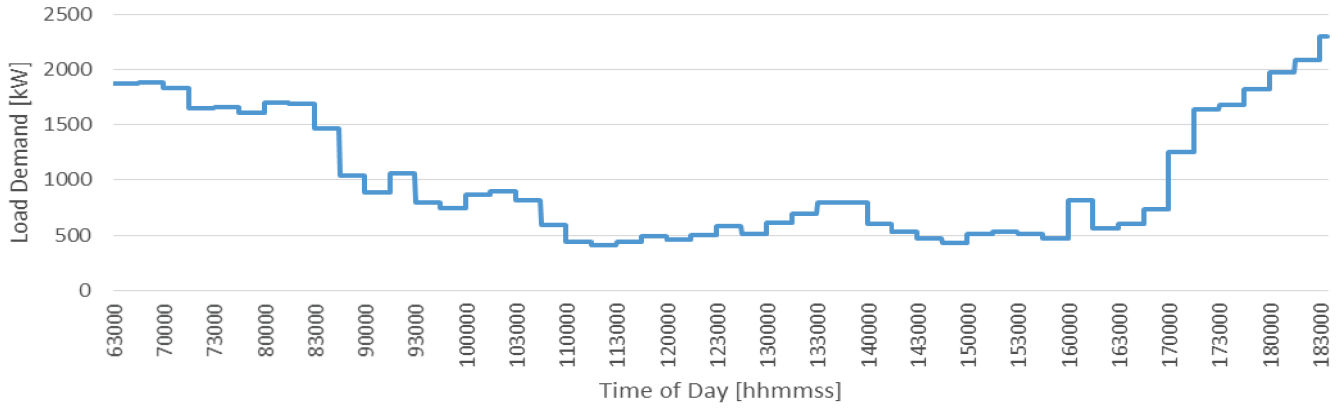


Figure 9-40. Load profile for CPVIM 6

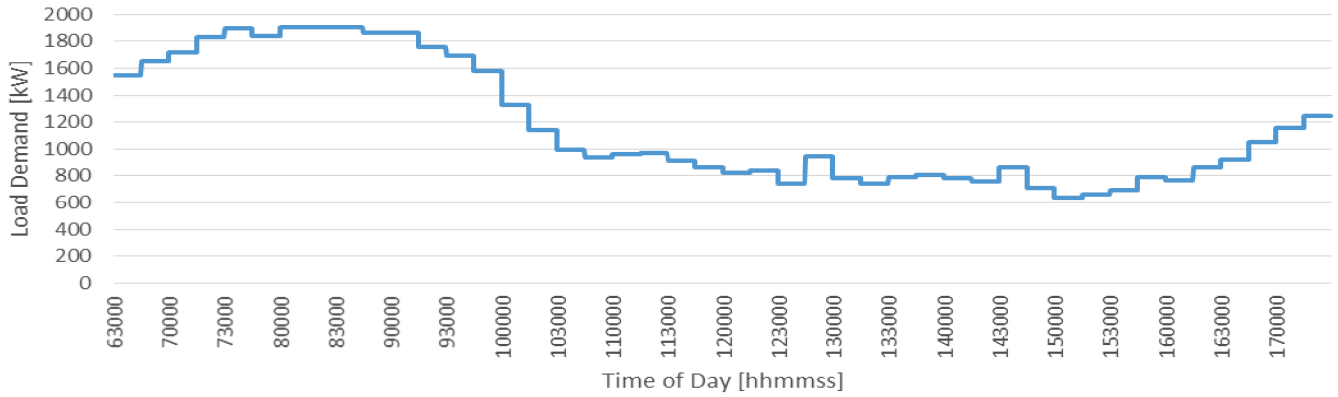


Figure 9-41. Load profile for CPVIM 7

9.3.2 Flicker summary results for all circuits (table format)

Table 9-13 to Table 9-19 illustrate the flicker analysis results of CPVIM 1, CPVIM 2, CPVIM 3, CPVIM 4, CPVIM 5, CPVIM 6, and CPVIM 7, respectively. As it can be seen from the tables, CPVIM 2, CPVIM 3, CPVIM 5, and CPVIM 7 do not have any flicker issues. CPVIM 1 and CPVIM 6 have visible voltage drops. Furthermore, CPVIM 4 has the most flicker issues associated with it, i.e., exceeding the visibility and irritation ranges.

As a result, CPVIM 1, and CPVIM 4 were chosen as the target circuits for further PV impact studies. It should be mentioned that the meters were chosen based on their locations and the availability of the measured voltage values in the model. Example locations are: PV1 (a node close to the PV1), PV2 (a node close to PV2), F1 (first measured node), F2 (second measured node), and so on. The locations that exceed each of the flicker thresholds are marked in the tables with a black triangle symbol.

Table 9-13. Flicker analysis summary for circuit CPVIM 1 (Fx is the monitoring point)

Voltage Signal	Visible Voltage Dips	Irritative Voltage Dips
V_PV1_A	-	-
V_F1_A	▲	-
V_F3_A	▲	-

Table 9-14. Flicker analysis summary for circuit CPVIM 2

Voltage Signal	Visible Voltage Dips	Irritative Voltage Dips
V_PV1_A	-	-
V_PV2_A	-	-
V_F3_A	-	-
V_F6_C	-	-

Table 9-15. Flicker analysis summary for circuit CPVIM 3

Voltage Signal	Visible Voltage Dips	Irritative Voltage Dips
V_PV1_A	-	-
V_PV2_A	-	-
V_F3_A	-	-
V_F6_C	-	-

Table 9-16. Flicker analysis summary for circuit CPVIM 4

Voltage Signal	Visible Voltage Dips	Irritative Voltage Dips
V_F2_A	▲	-
V_F6_A	▲	-
V_F7_A	▲	▲
V_F8_A	▲	▲
V_F9_A	▲	▲
V_F10_A	▲	▲

Table 9-17. Flicker analysis summary for circuit CPVIM 5

Voltage Signal	Visible Voltage Dips	Irritative Voltage Dips
V_F1_A	-	-
V_F2_A	-	-
V_F3_A	-	-
V_F6_A	-	-
V_F8_A	-	-
V_F9_A	-	-

Table 9-18. Flicker analysis summary for circuit CPVIM 6

Voltage Signal	Visible Voltage Dips	Irritative Voltage Dips
V_F1_A	-	-
V_F3_B	▲	-
V_F6_A	-	-

Table 9-19. Flicker analysis summary for circuit CPVIM 7

Voltage Signal	Visible Voltage Dips	Irritative Voltage Dips
V_F1_A	-	-
V_F2_A	-	-
V_F3_A	-	-
V_F4_B	-	-

CPVIM 4: Figure 9-42 illustrates the circuit diagram and the location of the meters used in analysis of CPVIM 4. The meters' data at the F1, F2, F6, F7, F8, F9, and F10 are analyzed to determine any potential for flicker events or ramp rate issues.

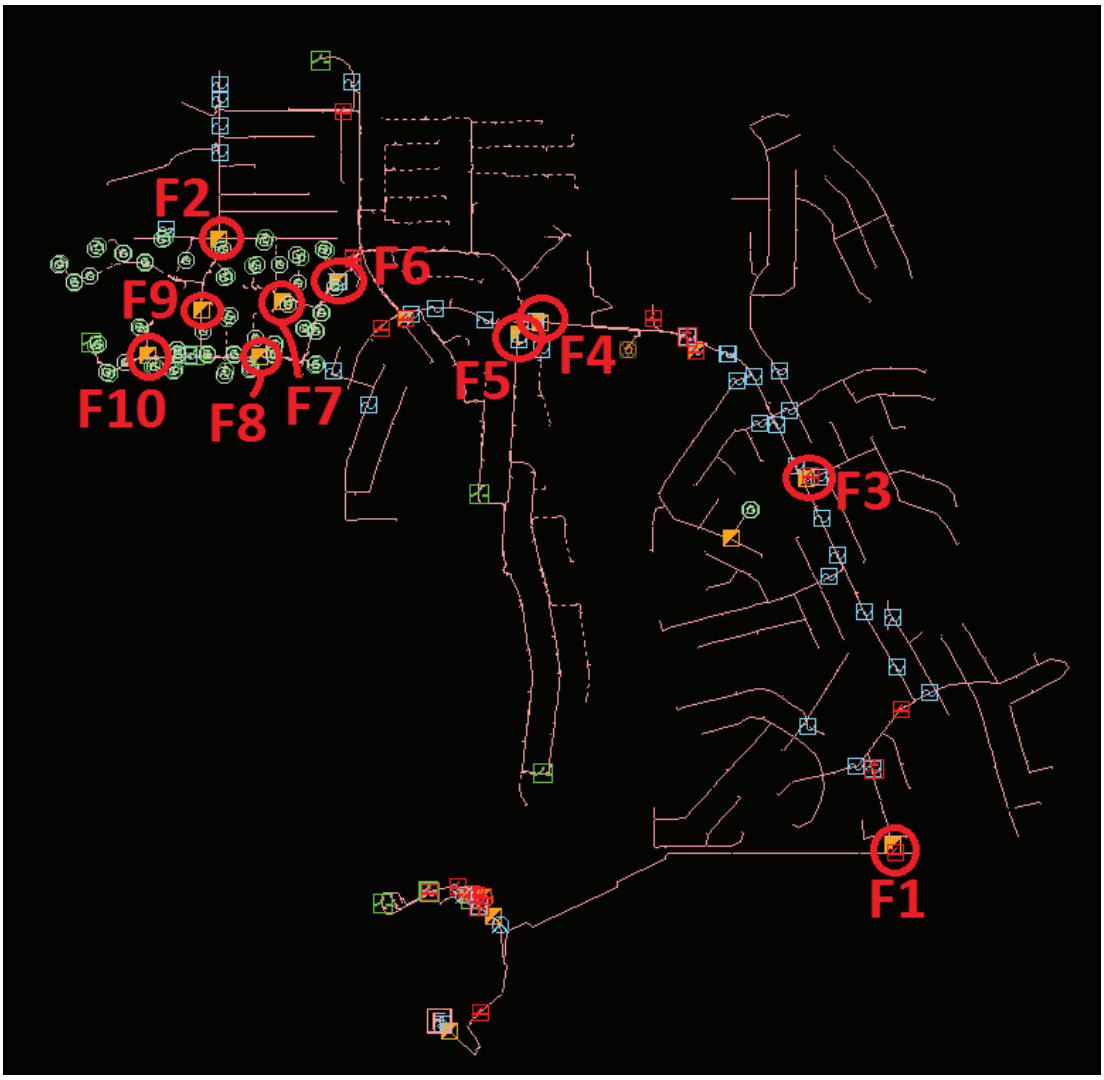


Figure 9-42. Reference diagram of CPVIM 4

Figure 9-43 below shows the flicker calculation curve for the meter at the F1 location of CPVIM 4. As can be seen from Figure 9-43, the flicker level is always below the visibility and irritation level, which indicates that there are no flicker issues at the aforementioned location.

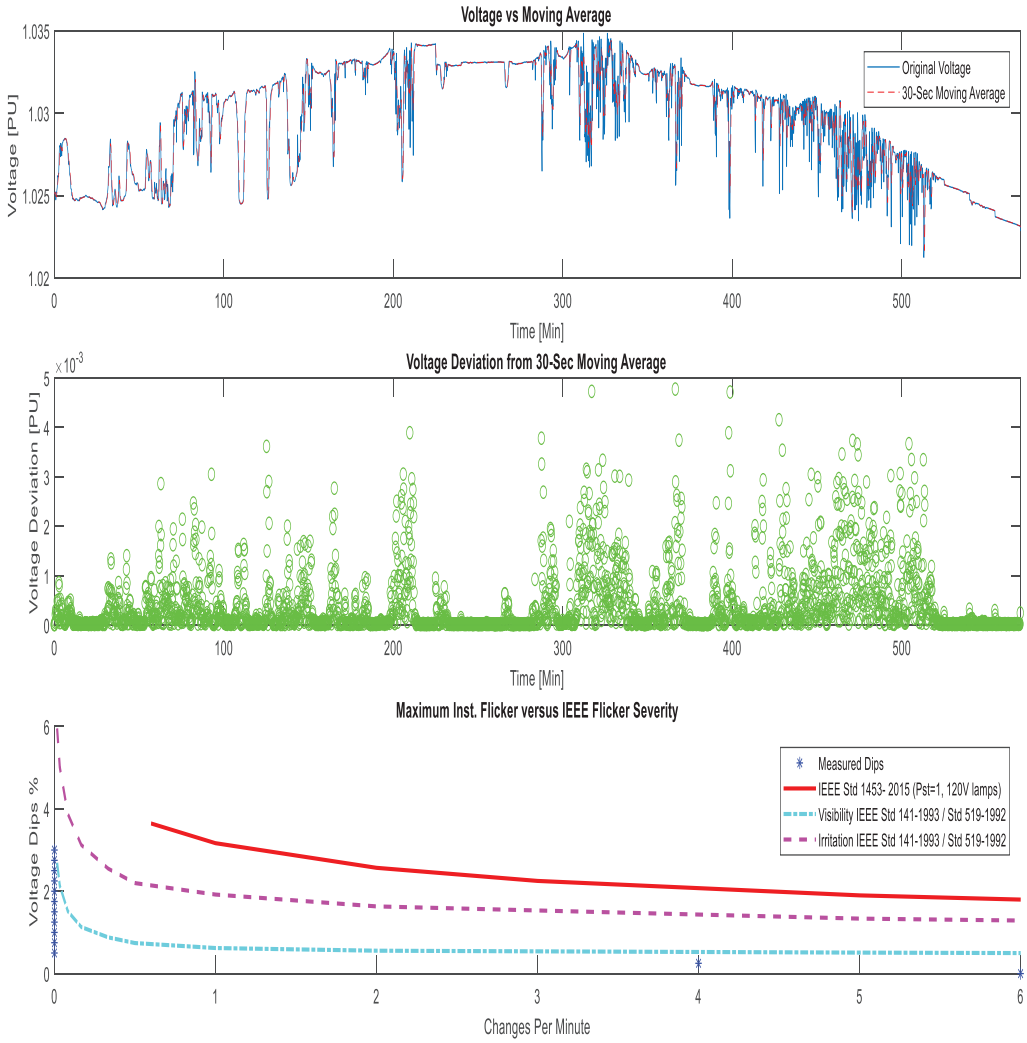


Figure 9-43. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F1 location

Figure 9-44 below shows the flicker calculation curve for the meter at the F2 location of CPVIM 4. As can be seen from, the flicker level is above the visibility level in several instances, but almost close to or below the irritation level (based on old GE flicker curve), or below the IEEE flicker curve.

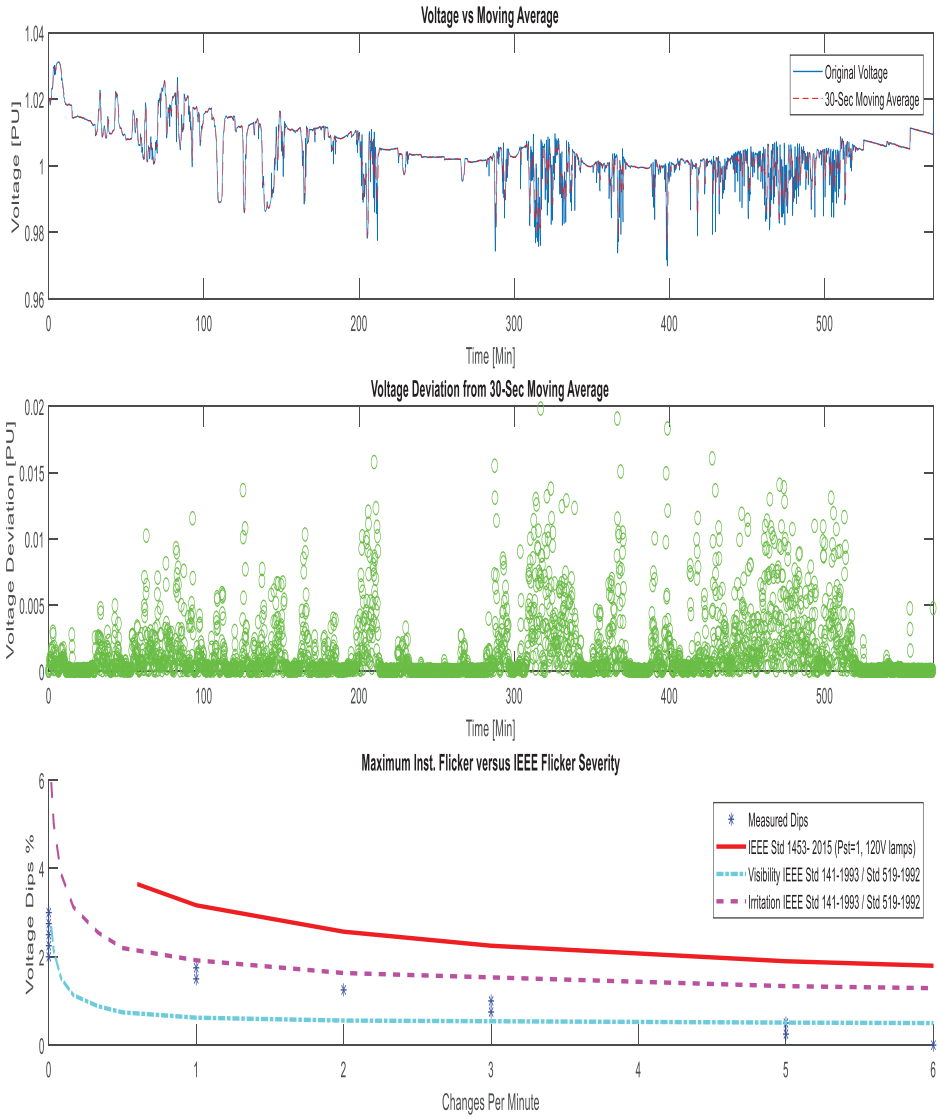


Figure 9-44 – Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F2 location

As can be seen from Figure 9-45, the flicker level is above both the visibility and the irritation level in several instances, but below the IEEE flicker curve; this indicates that the location F6 in CPVIM 4 can be an appropriate choice for installing the energy storage system.

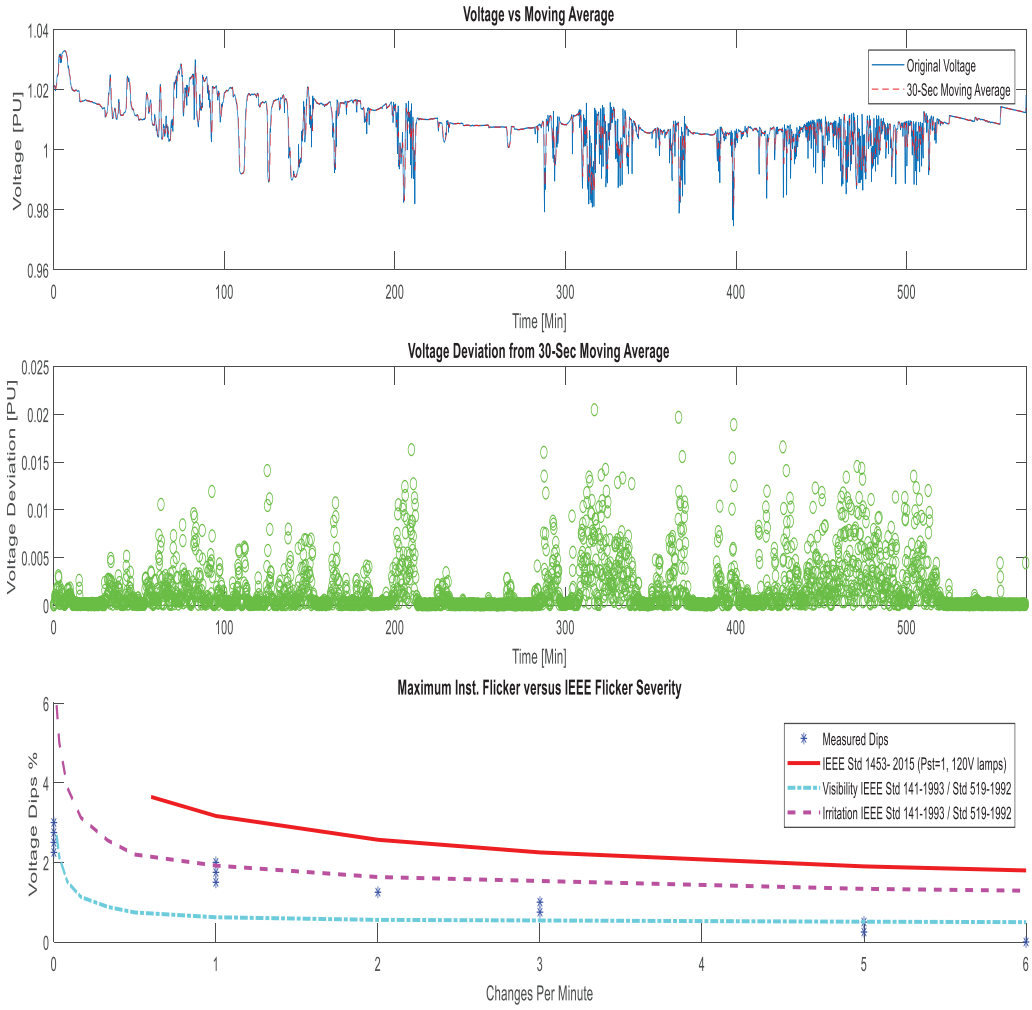


Figure 9-45. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F6 location

As can be seen from Figure 9-46, the flicker level is above both the visibility and the irritation level in several instances, but below the IEEE flicker curve; this indicates that the location F7 in CPVIM 4 can be another appropriate location choice for installing the energy storage system.

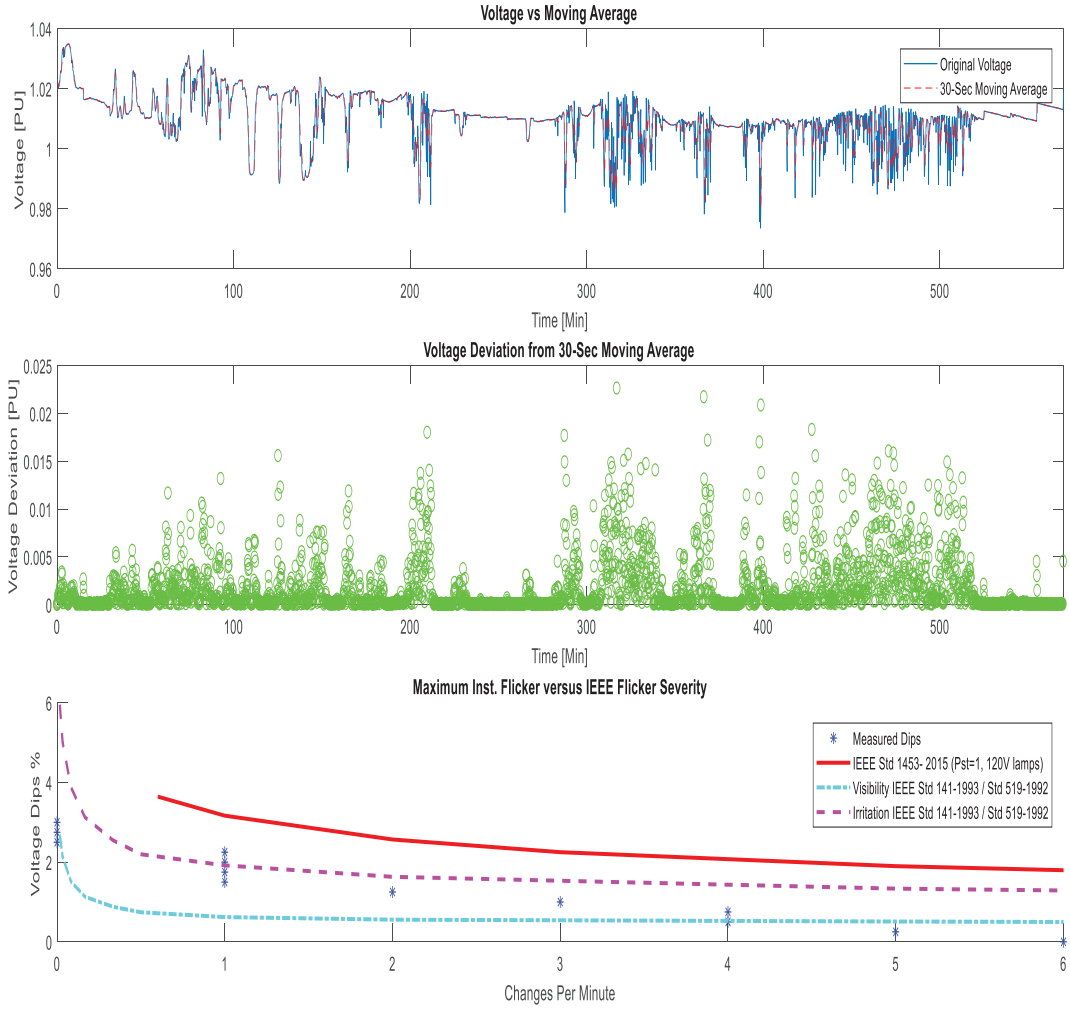


Figure 9-46. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F7 location

As can be seen from Figure 9-47, the flicker level is above both the visibility and the irritation level in several instances, but below the IEEE flicker curve; this indicates that the location F8 in CPVIM 4 can be another appropriate location choice for installing the energy storage system.

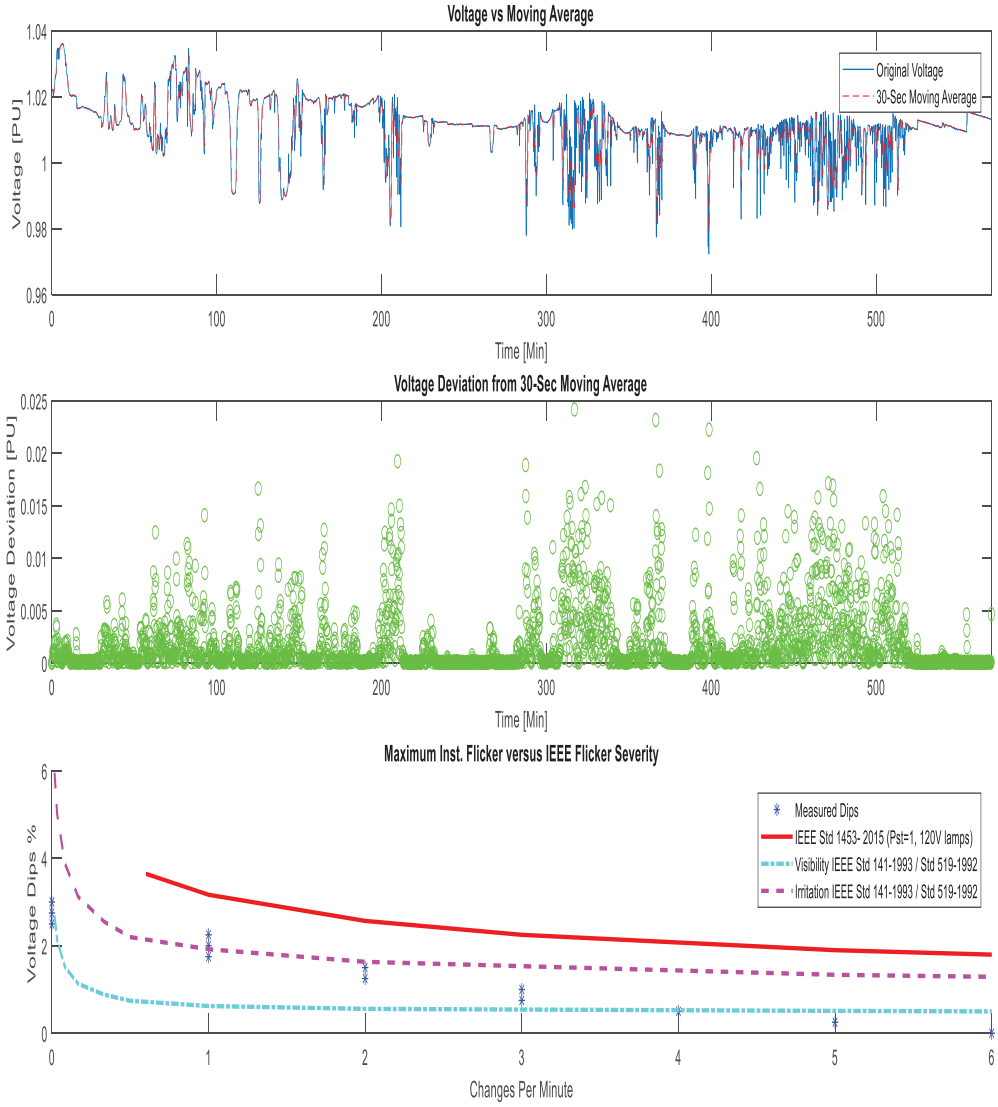


Figure 9-47. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F8 location

As can be seen from Figure 9-48, the flicker level is above both the visibility and the irritation level in several instances, but below the IEEE flicker curve; this indicates that the location F9 in CPVIM 4 can be another appropriate location choice for installing the energy storage system.

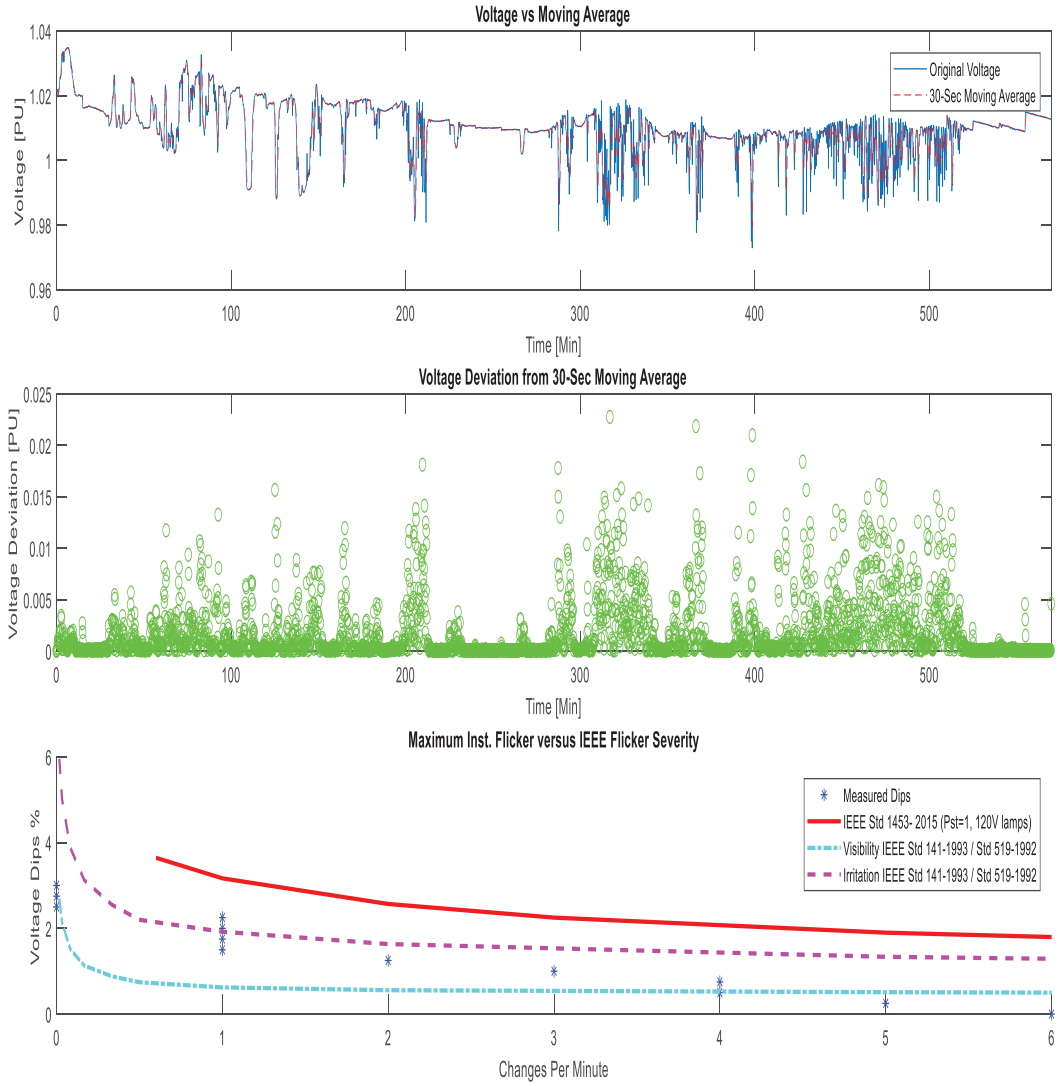


Figure 9-48. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F9 location

As can be seen from Figure 9-49, the flicker level is above both the visibility and the irritation level in several instances, but below the IEEE flicker curve; this indicates that the location F10 in CPVIM 4 can be another appropriate location choice for installing the energy storage system.

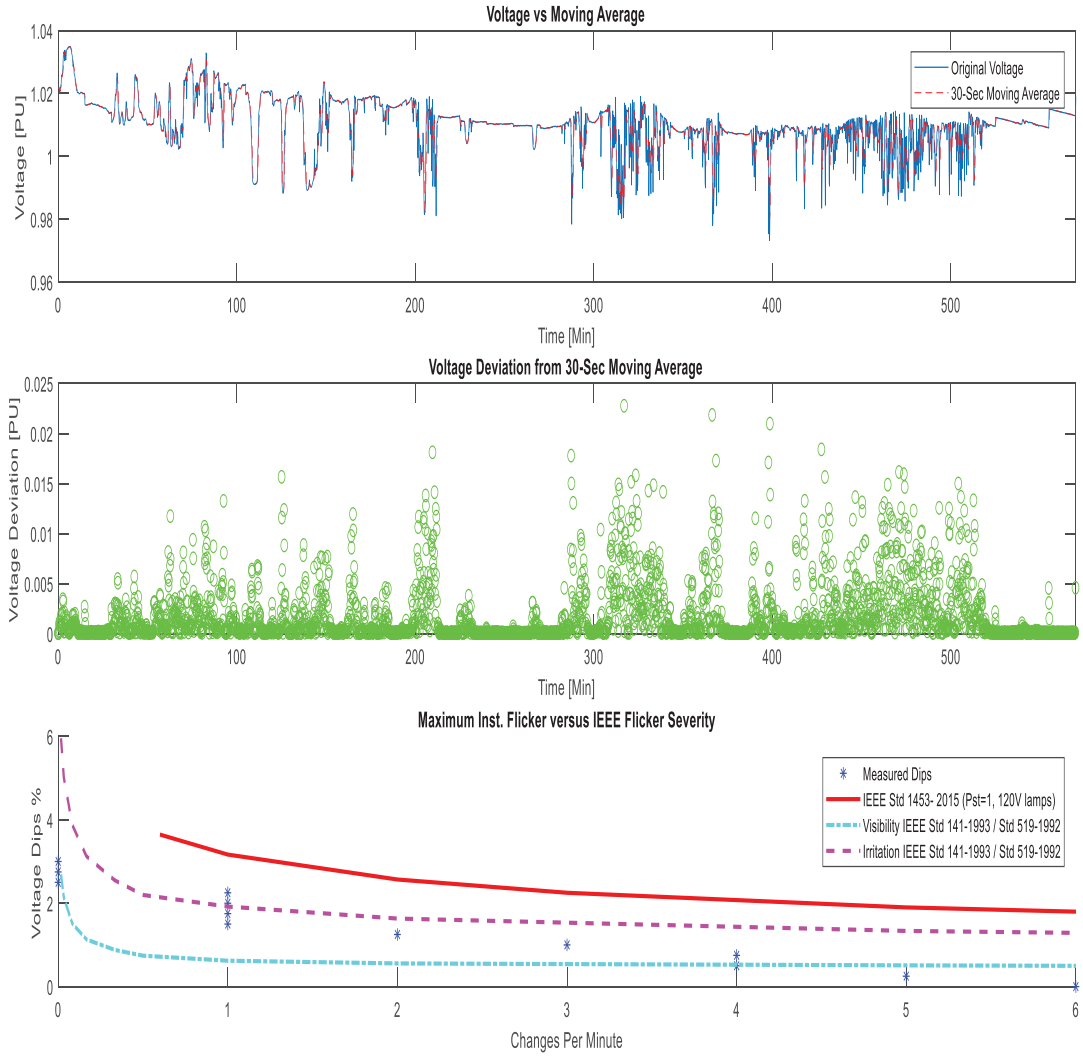


Figure 9-49. Time series data and flicker estimation and illustration with respect to permissible curves for CPVIM 4 at the F10 location

9.4 Additional study results for wholesale market participation

May 21st 2016 is the day with the highest regulation prices. We can see the change in regulation participation and charge/discharge patterns as the limit on regulation participation changes from 20% to 50% and 100% (Figure 9-50)

At 20% of capacity available for regulation:

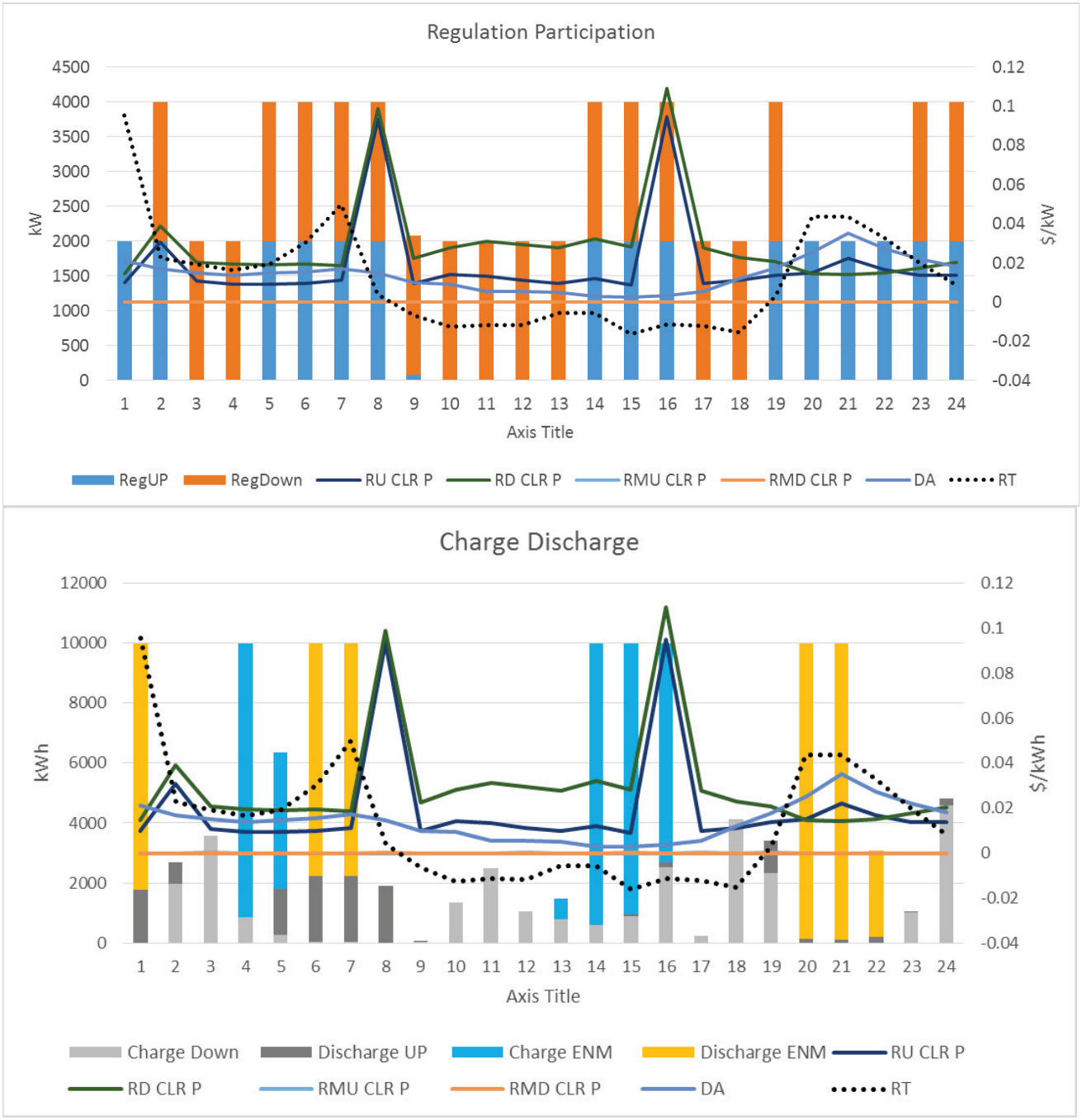


Figure 9-50. May 21st, 2016 analysis with 20% assumption (Location A)

The regulation participation is always 2 MW or 20% in the RegUp, RegDown, or both directions.

At 50% (Figure 9-51), the example results were:

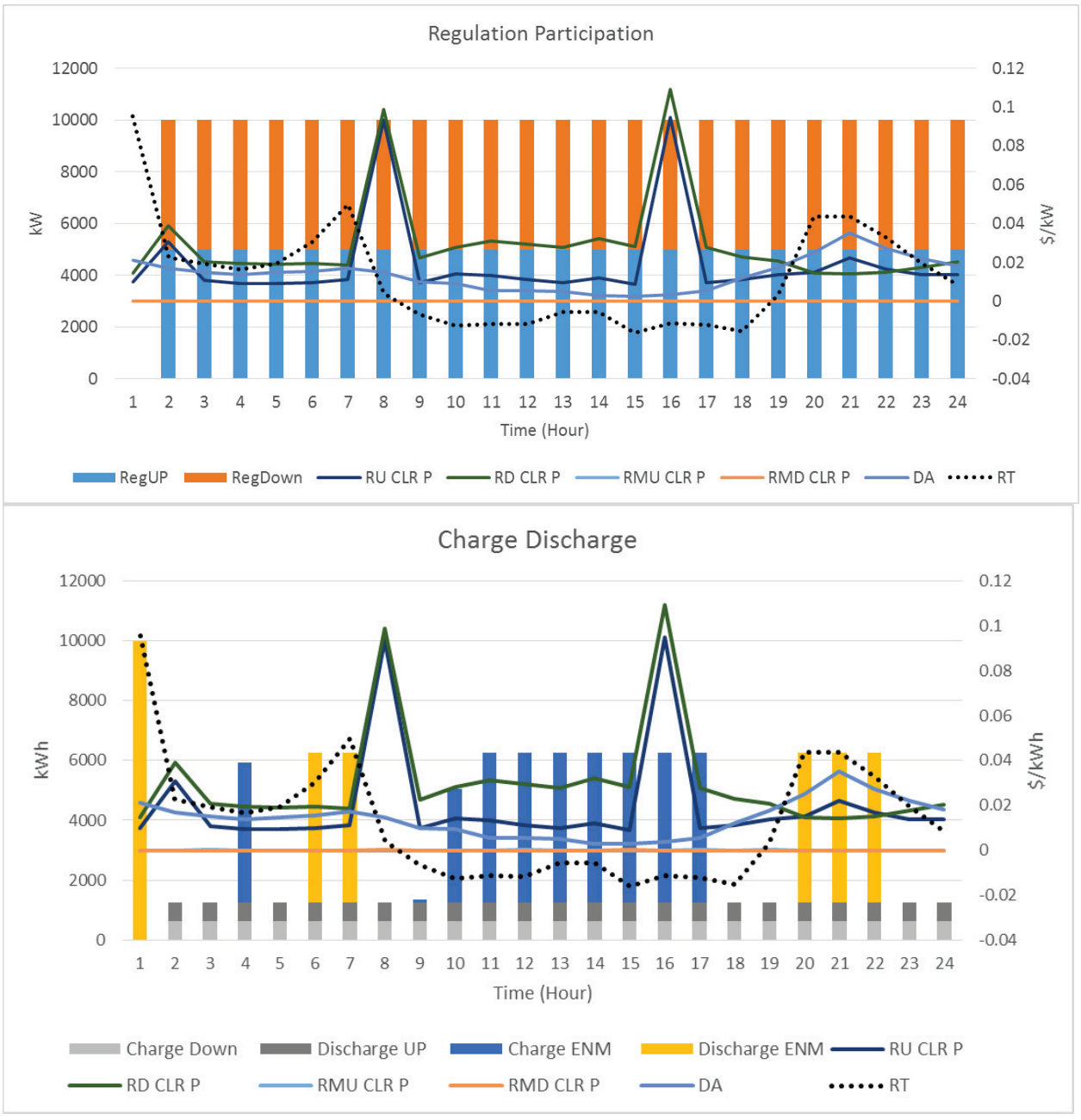


Figure 9-51. May 21st, 2016 analysis with 50% assumption (Location A)

The hourly pattern of regulation participation is nearly identical but the amount of participation is now 5 MW in every hour except hour 24 (when it is necessary to meet day ending state of charge constraints).

The pattern of energy market charging / discharging is similar on an hourly basis but the levels are different, to accommodate the charging / discharging energy for regulation.

At 100% (Figure 9-52), example results were:

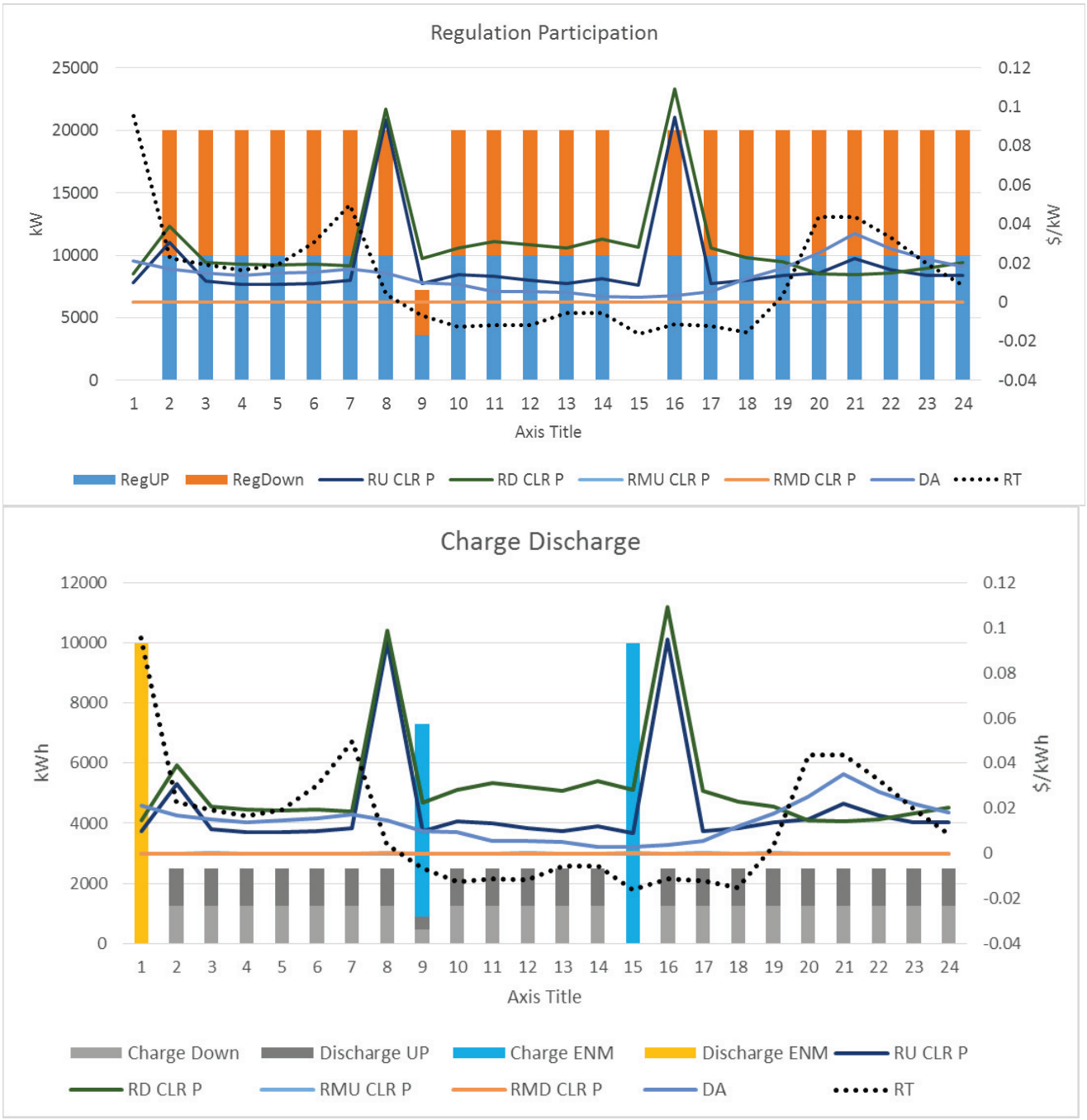


Figure 9-52. May 21st, 2016 analysis with 100% assumption (Location A)

In this case, the pattern of regulation participation has altered, and the level reaches 10 MW but not at all times. The pattern of energy market charging is quite different. The optimization is trading off regulation capacity payments against the balance of RegDown and energy market charging, and still maintaining the energy market discharging in the early evening hours when prices are highest.

If we examine the June 20th day (Figure 9-53) when DA prices are the highest, we see different behaviors:

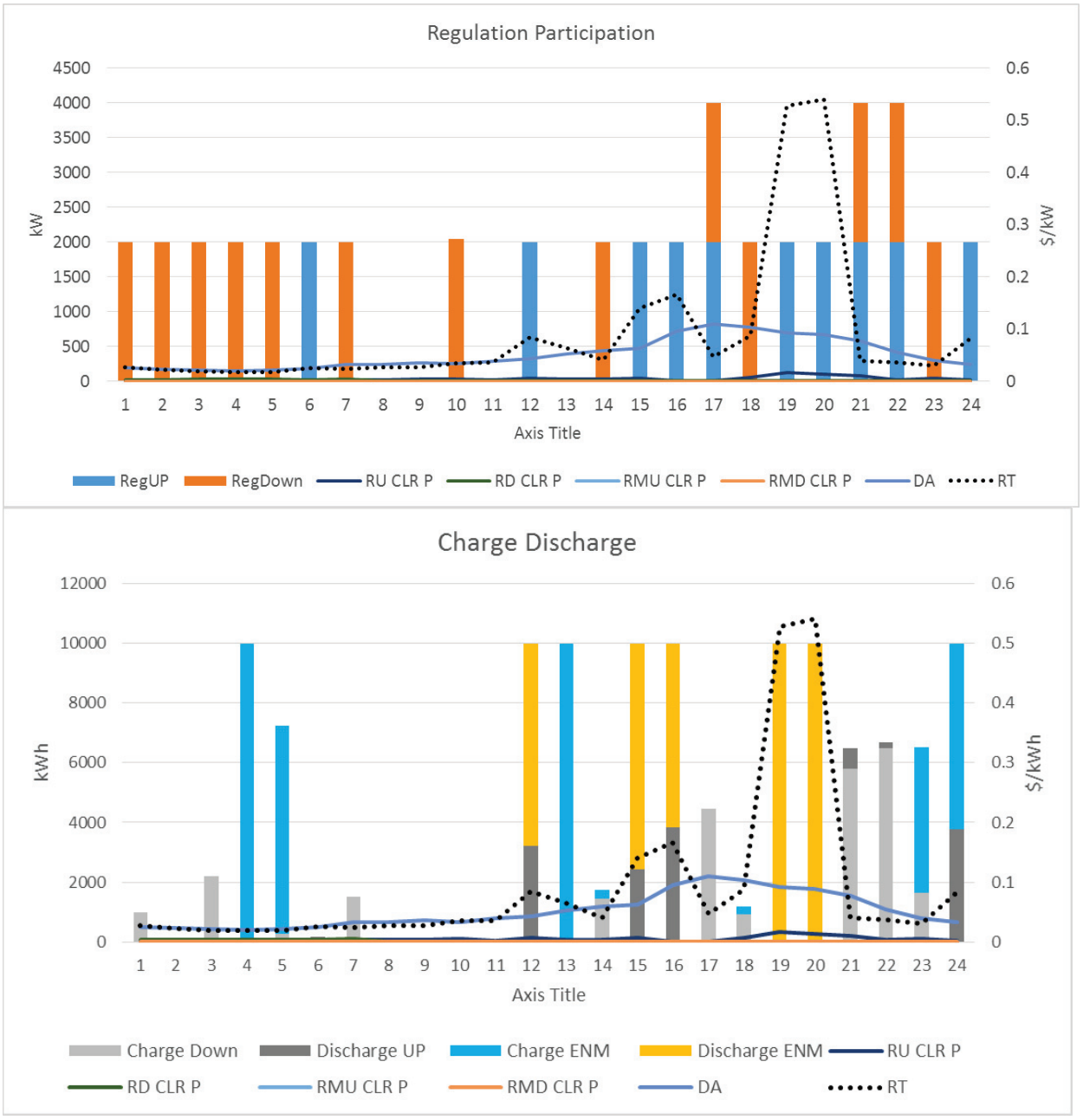


Figure 9-53. June 20th analysis for 20% assumption (Location A)

At 20% regulation capacity allowed, above, the participation in the morning is limited to RegDown. The RegUp participation and Energy discharge are focused in the afternoon when prices are highest. (Note that the RT prices, while not the highest of any day in the year, are still quite high in the early evening.)

At 50% of capacity available for regulation (Figure 9-54):

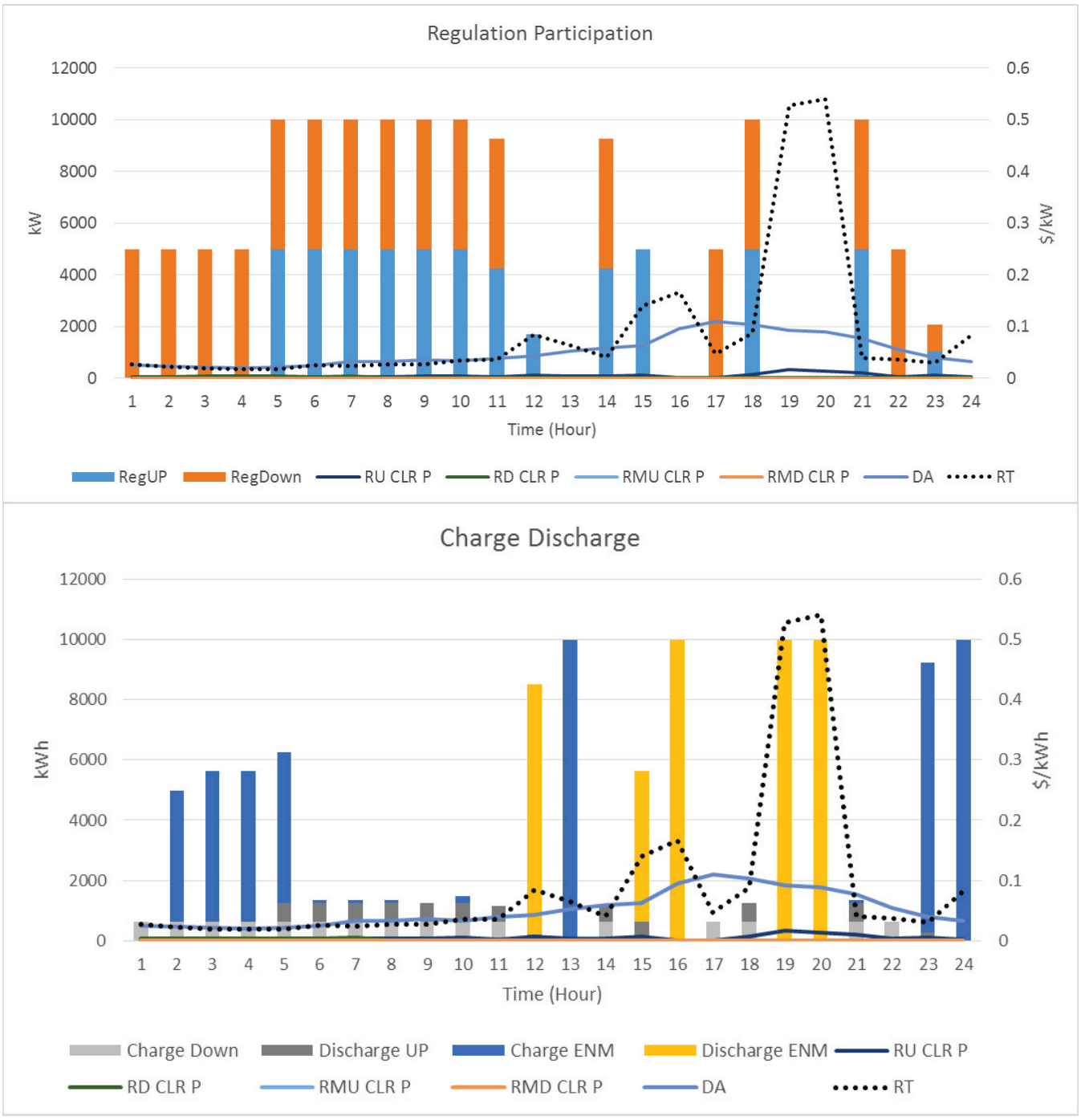


Figure 9-54. June 20th analysis for 50% assumption (Location A)

The pattern of behavior is similar to the pattern at 20% but not identical, and the RegUp / RegDown levels are usually although not always 5 MW. The energy discharge pattern is identical, but the energy charge pattern is different as the RegDown energy charging has supplied more of the charging energy needed.

At 100% (Figure 9-55), example results were:

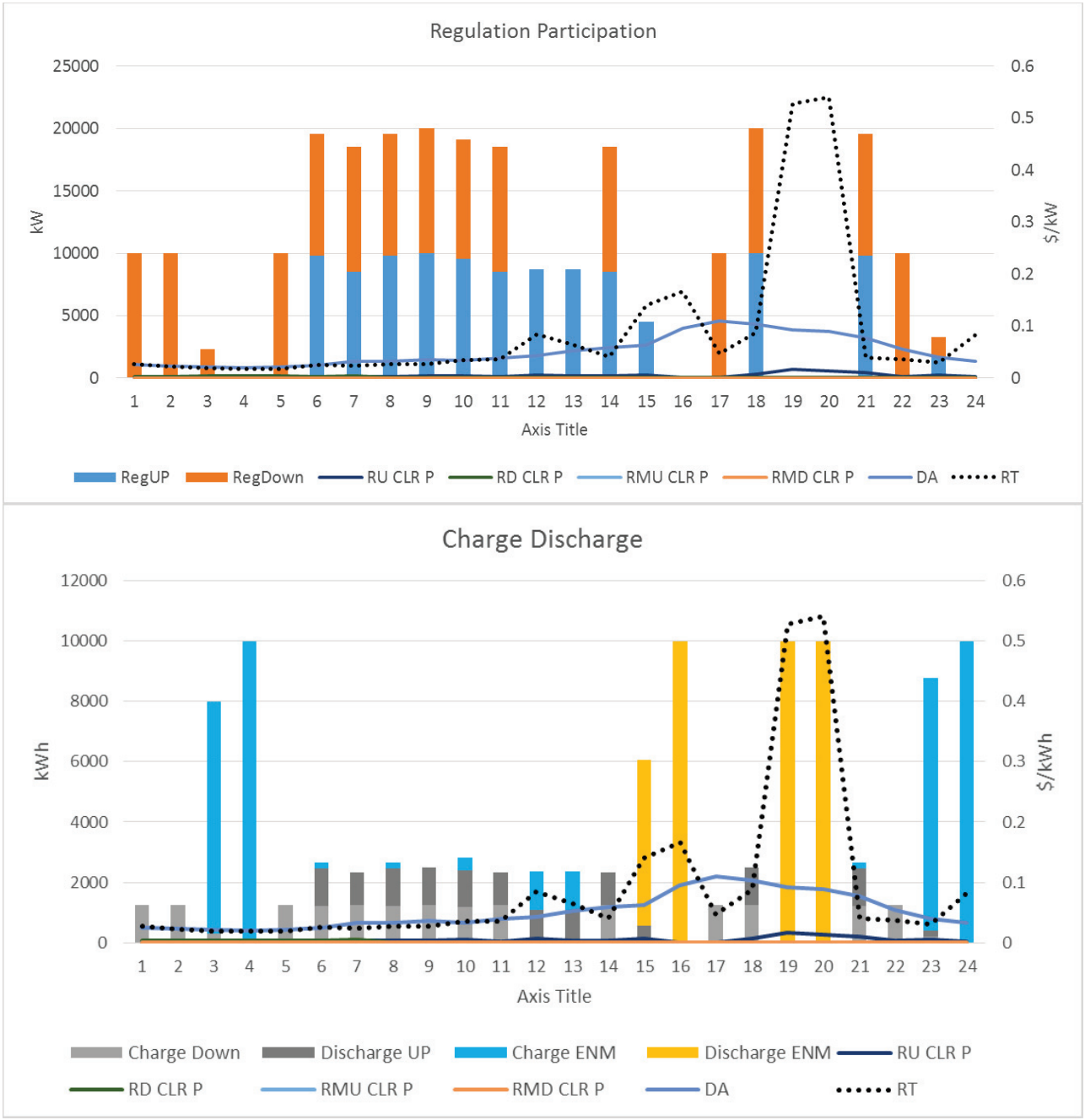


Figure 9-55. June 20th analysis for 100% assumption (Location A)

The patterns continue to evolve in the same way as from 20% to 50% but with periods of 5 MW of RegUp (but not always the 5 MW max) and energy market discharging is displaced in the afternoon hours by RegUp discharging.

Appendix 9

EPIC-2, Project 1: Modernization of Distribution System and Integration of Distributed Generation and Storage

EPIC Final Report

Program	**Electric Program Investment Charge (EPIC)**
Administrator	**San Diego Gas & Electric Company**
Project Number	**EPIC-2, Project 1**
Project Name	**Modernization of Distribution System and Integration of Distributed Generation and Storage**
Date	**December 31, 2017**

Attribution

This comprehensive final report documents the work done in Electric Program Investment Charge (EPIC) 2, Project 1. The project team that contributed to the project definition, execution, and reporting included the following individuals, listed alphabetically by last name:

San Diego Gas & Electric (SDG&E)
Hamid Daneshjoo
Frank Goodman
Molham Kayali
Zoltan Kertay
Iman Mazhari
Alfonso Orozco
Kirsten Petersen
Prajwal Raval
Marvin Zavala-Iraheta

POWER Engineers, Inc.
Matt Cabral
Jason Clack
Chris Dyer
Jared Eby
Aaron Findley
Jake Groat
Ian Higginson
John Kumm
Rick Liposchak
Chin Mou
Matt Phillips
Phil Ricker
Saurabh Shah
Samantha Strasser
Joe White

EXECUTIVE SUMMARY

This EPIC project was entitled Modernization of Distribution System and Integration of Distributed Generation and Storage and is identified as EPIC-2, Project 1 in SDG&E's EPIC-2 application approved by the California Public Utilities Commission (CPUC). The objective of the project was to demonstrate distribution system infrastructure modernization solutions, including advances in distribution system design to enable use of new technologies, such as power electronic components, new protection systems, and distributed generation and storage technologies.

The chosen priority for focus of this project was to perform a pre-commercial demonstration in a laboratory of the International Electrotechnical Commission (IEC) 61850 standard, with specific emphasis on generic object-oriented substation event (GOOSE) and sampled value (SV) messages. The demonstration work compared the results to current protective relay practice and performance. This project also examined the pros and cons of IEC 61850, investigated vendor interoperability issues, and recommendations on commercial adoption.

Summary of Key Findings and Conclusions

When compared to legacy relay systems, the test system's protective trip times were improved with IEC 61850. No degradation in fault identification performance or signal fidelity was noted with the use of SVs, and all relays were correctly restrained for out-of-zone faults. No failure to trip was noted during fault simulations when the relays properly subscribed to SV signals from the various merging units (MUs). The results demonstrated that an IEC 61850 process bus protection and control (P&C) scheme should be at least as reliable and secure, if not more so, than the existing hardwired P&C scheme. Although the initial costs of this P&C scheme may be higher, it is anticipated that the on-going costs will be reduced over a hardwired implementation, and access to corporate and other enterprise-level data will be improved.

The use of IEC 61850 SV did not impact relay performance, as compared to a direct hardwired solution, as long as the process bus networks were correctly designed and utilized managed switches for media access control (MAC) to address filtering as necessary. All use cases were able to be implemented with the IEC 61850 process bus. The technology is now at a point where it could be applied to utility protection applications, assuming careful attention to equipment selection for compatibility.

The project was focused on interoperability and protection system performance. The interoperability determination was positive. Although interoperability was not achieved with all of the devices, enough interoperability was achieved to allow for performing all of the protection test cases identified. Performance of the protection relays using an IEC 61850 P&C scheme was verified to equal or exceed the performance benchmarks set by the project team.

IEC 61850 process bus technology has progressed to the point where it may be implemented by using equipment from different manufacturers, but the user can initially expect to spend a significant amount of time configuring an application when several different manufacturers' equipment are included, mainly to get them all to communicate (subscribe) correctly. After completion of this task, relay protection settings were straightforward. The design of a fully IEC 61850 compliant substation will differ greatly from the current hardwired state of the art, which will impact design standards that may currently be in place. To ensure success, issues such as maintenance, testing, and training must

also be addressed before embarking on commercial adoption and implementation of an IEC 61850 project.

Overall, the results from this project were very promising. Compared to just a couple years ago, implementing GOOSE and manufacturing message specification (MMS) messaging was found to be much easier between relays, and between relays and MUs. SV based P&C was found to be equivalent or better than legacy solutions for the identified use cases. In addition, only a small number of SV interoperability problems were identified. It was anticipated that interoperability will greatly improve in the near term as the IEC 61850 standards, P&C equipment, and software tools mature. Interoperability will be crucial for system maintainability, ensuring that failed components may be replaced with newer equipment without comprising system operation.

Recommendations and Next Steps

The project team recommends that SDG&E continue to explore commercial adoption of IEC 61850 applications within its substations. The project findings and conclusions show that, although care is required in the selection of products, the currently available merging units and relays are sufficiently mature to support interoperability between vendors. In addition, the protection performance of the test system is equivalent to hardwired legacy P&C systems.

The project team further recommends that an SDG&E communications laboratory be developed to support future work and training. This laboratory would include the capability to mock-up future substation communications infrastructure to validate their performance before actual deployment in substations. Although this laboratory would have a focus on IEC 61850, it would also support testing of other communications technologies and standards.

With the completion of the future work items, the project team recommends that pilot projects be initiated to gain experience with IEC 61850. Potential pilot projects could include a GOOSE based 12 kilovolt (kV) capacitor control scheme using existing installed hardware, or a three breaker 69 kV P&C scheme. These pilot projects could be precursors towards development of a larger project to test the technology in an actual substation. A pilot project will serve as the basis for developing new standards for station drawings, relay settings, supervisory control and data acquisition (SCADA) and communication configurations. A substation located in close proximity to a maintenance center would be an ideal candidate for this type of pilot project because of the training opportunities it provides.

An IEC 61850 design implementation will differ greatly from current hardwired state of the art, and issues such as maintenance, testing and training, must be addressed while embarking on the first implementation of this technology.

SDG&E should make the results of this EPIC project available to the various standards bodies associated with IEC 61850 – especially IEC Technical Committee 57, Working Group 10.

The project did not explore networking architecture solutions as they were applied to substations. Network architecture, redundancy and security are essential factors in substation communications which should be considered when designing an IEC 61850 implementation. For an actual substation implementation, considerable thought should be given to network design and optimization.

TABLE OF CONTENTS

EXECUTIVE SUMMARY ..... **I**

SUMMARY OF KEY FINDINGS AND CONCLUSIONS I
RECOMMENDATIONS AND NEXT STEPS II

1. GLOSSARY **1**

2. INTRODUCTION **4**

3. IEC 61850 OVERVIEW AND ISSUES **6**

FOCUS 6
IEC 61850 6
ADVANTAGES OF IEC 61850 6
UNITED STATES ADOPTION OF IEC 61850 7
MAJOR THRUSTS OF PROJECT WORK 8
KNOWLEDGE APPLICATION 8

4. OVERVIEW OF APPROACH **9**

PRE-COMMERCIAL DEMONSTRATION 9
ADDITIONAL DEMONSTRATION AT INTEGRATED TEST FACILITY (ITF) 10
TECHNOLOGY TRANSFER ACTIVITIES DURING THE PROJECT 10
Classroom Training 10
Software Training 10
Pre-commercial Demonstration Training 10
Hands-On Training with Vendors 10

5. BASELINE ASSESSMENT **11**

6. TEST CASES **13**

TEST CASE #1 – BREAKER FAILURE PROTECTION (50BF) 13
TEST CASE #2 – LINE DIFFERENTIAL PROTECTION (87L) 14
TEST CASE #3 – LINE DISTANCE AND DIRECTIONAL OVERCURRENT PROTECTION (21 & 50/51) 14
TEST CASE #4 – HIGH VOLTAGE (HV) BUS OVERCURRENT DIFFERENTIAL PROTECTION (87B-50/51) 15
TEST CASE #5 – HV BUS RESTRAINED CURRENT DIFFERENTIAL PROTECTION (87B) 15
TEST CASE #6 – HV BUS HIGH IMPEDANCE (HIZ) DIFFERENTIAL PROTECTION (87B-HIZ) 16
TEST CASE #7 – TRANSFORMER RESTRAINED CURRENT DIFFERENTIAL PROTECTION (87T) 16
TEST CASE #8 – TRANSFORMER OVERCURRENT PROTECTION (50/51T) 17
TEST CASE #9 – 12KV BUS PARTIAL OVERCURRENT DIFFERENTIAL PROTECTION (87B-51P/G) 17
TEST CASE #10 – 12KV BUS RESTRAINED CURRENT DIFFERENTIAL PROTECTION (87B) 18
TEST CASE #11 – CAPACITOR AND REACTOR FEEDER OVERCURRENT PROTECTION (50/51) 18
TEST CASE #12 – CAPACITOR BANK UNBALANCE PROTECTION (59N) 19
TEST CASE #13 – REACTOR UNBALANCE PROTECTION (51Q) 19
TEST CASE #14 – REACTOR AND CAPACITOR BANK VAR CONTROL AUTOMATION 20
TEST CASE #15 – LINE FREQUENCY AND VOLTAGE (81, 27, AND 59) 20

7. CONCEPT OF OPERATIONS **22**

PROTECTION AND CONTROL ARCHITECTURE 22
Process Bus 22

Station Bus 23
Time Synchronization 23
Engineering and Maintenance Access 23
Information Exchanges 23
CONTROLLABLE DEVICES AND FUNCTIONAL SPECIFICATIONS 23
Capacitor and Reactor Bank Automation 23
High Side and Low Side Lockout Relays 24
Minimum Local Area Network (LAN) Communication Requirements 24
Minimum Wide Area Network (WAN) Communication Requirements 25
Cybersecurity Considerations for Switched Networks 25
OPERATIONAL REQUIREMENTS 26
8. TEST SYSTEM SPECIFICATION 28
RACK LIMITATIONS 28
ELECTRICAL 28
Voltages 28
NETWORKING 28
Fiber 29
Copper 29
Network Capabilities 31
Network Security 31
Test Set Interface 31
Network Tools 31
Station Bus 31
Process Bus 31
Process Bus #2 32
TEST SYSTEM TIME SYNCHRONIZATION 32
IEEE 1588 Precision Time Protocol (PTP) 32
Inter-Range Instrumentation Group (IRIG-B) 33
1 Pulse per Second (1PPS) 33
Simple Network Time Protocol (SNTP) 33
IEC 61850 INFORMATION TRANSFER PROTOCOLS 33
Manufacturing Message Specification (MMS) 33
Generic Object Oriented Substation Events (GOOSE) 33
Sampled Value (SV) 33
GOOSE and SV Data Flow Spreadsheet 33
Process Bus Data Flow Diagram 34
Station Bus Data Flow Diagram 34
Capacitor and Reactor Bank Automation 35
High Side (HS) and Low Side (LS) Lockout Relays 35
INTERFACES 35
Test Switches 35
DEVICE REQUIREMENTS 35
Relays 35
Process Bus Merging Units (MUs) 35
Software 36
Ethernet Switch Features 36
Time Clock 36

Breaker Simulators 36
RTDS AND COMTRADE 36
RTDS 37
RTDS Model 38
COMTRADE FILES 39
Wetting voltage 40
INTEGRATED TEST FACILITY (ITF) EVALUATION 40
9. TEST SYSTEM DESIGN 41
DESIGN PROCESS 42
MATERIAL IDENTIFICATION AND PROCUREMENT 44
PRELIMINARY DESIGN PROCESS 45
TEST SYSTEM NETWORK 49
TEST SYSTEM TIME SYNCHRONIZATION 50
IEEE 1588 PTP 51
IRIG-B 51
1PPS 52
SNTP 52
PROCESS BUS MUS 52
IEC 61850 EDITIONS 52
DATA FLOWS 64
GOOSE and Sampled Value Data Flow Spreadsheet 64
PROCESS BUS DATA FLOW DIAGRAM 71
STATION BUS DATA FLOW DIAGRAM 74
PHASE ONE INITIAL SYSTEM INTEGRATION AND CONFIGURATION 76
Vendor V2 Equipment 76
Vendor V3 Equipment 78
Vendor V6 Equipment 78
Vendor V7 Equipment 79
Test Equipment 80
Network Equipment 80
PHASE TWO SYSTEM INTEGRATION AND TESTING RESULTS 80
Vendor V3 Equipment 80
Vendor V7 Equipment 81
Vendor V6 Equipment 81
Capacitor and Reactor Bank Control System 81
Vendor V1 Equipment 81
Vendor V2 Equipment 82
PHASE THREE SYSTEM INTEGRATION AND TESTING RESULTS 82
V1M5 PDU Length Problem 84
File Import Problem into V1M8 Tool 87
Time Synchronization to the V1M5 91
Neutral Current and Voltage Calculation Problem 91
PHASE FOUR SYSTEM INTEGRATION AND TESTING RESULTS 91
Denial of Service to V2M1, V2M2, V2M3, V2M4 91
V7M2 Analog Data Set Error 92
V2M1, V2M2, V2M3, and V2M4 “Fast GOOSE” and Unsubscribing 92
V2M1 Internal Blocking 93

Miscellaneous Items 93
Distance Protection Trips 93
PHASE FIVE SYSTEM INTEGRATION AND TESTING RESULTS 94
DEVELOPED ALGORITHMS 95
Capacitor and Reactor Bank 95
Bus and Transformer "Virtual" Lockout Relays 96
INTEROPERABILITY 98

10. TEST PROCEDURES 100

TEST CASE #1 – BREAKER FAILURE PROTECTION (50BF) 100
Relay Test Setup Conditions and Requirements 100
Test Case Voltage and Current Injection from Relay Test Sets 101
TEST CASE #2 – LINE DIFFERENTIAL PROTECTION (87L) 101
Relay Test Setup Conditions and Requirements 101
Test case voltage and current injection from relay test sets 102
TEST CASE #3 – LINE DISTANCE AND DIRECTIONAL OVERCURRENT PROTECTION (21 AND 50/51) 104
Relay Test Setup Conditions and Requirements 104
Test Case Voltage and Current Injection from Relay Test Sets 104
TEST CASE #4 – HIGH VOLTAGE (HV) BUS OVERCURRENT DIFFERENTIAL PROTECTION (87B-50/51) 107
Relay Test Setup Conditions and Requirements 107
Test Case Voltage and Current Injection from Relay Test Sets 108
TEST CASE #5 – HV BUS RESTRAINED CURRENT DIFFERENTIAL PROTECTION (87B) 109
Relay Test Setup Conditions and Requirements 109
Test Case Voltage and Current Injection from Relay Test Sets 110
TEST CASE #6 – HV BUS HIGH IMPEDANCE DIFFERENTIAL PROTECTION (87B-HIZ) 111
Relay Test Setup Conditions and Requirements 111
Test Case Voltage and Current Injection from Relay Test Sets 111
TEST CASE #7 – TRANSFORMER RESTRAINED CURRENT DIFFERENTIAL PROTECTION (87T) 112
Relay Test Setup Conditions and Requirements 112
Test Case Voltage and Current Injection from Relay Test Sets 112
TEST CASE #8 – TRANSFORMER OVERCURRENT PROTECTION (50/51T) 114
Relay Test Setup Conditions and Requirements 114
Test Case Voltage and Current Injection from Relay Test Sets 115
TEST CASE #9 – 12 KV BUS PARTIAL OVERCURRENT DIFFERENTIAL PROTECTION (87B-51P/G) 117
Relay Test Setup Conditions and Requirements 117
Test Case Voltage and Current Injection from Relay Test Sets 117
TEST CASE #10 – 12 KV BUS RESTRAINED CURRENT DIFFERENTIAL PROTECTION (87B) 119
Relay Test Setup Conditions and Requirements 119
Test Case Voltage and Current Injection from Relay Test Sets 119
TEST CASE #11 – CAPACITOR AND REACTOR FEEDER OVERCURRENT PROTECTION (50/51) 120
Relay Test Setup Conditions and Requirements 120
Test Case Voltage and Current Injection from Relay Test Sets 121
TEST CASE #12 – CAPACITOR BANK UNBALANCE PROTECTION (59N) 122
Relay Test Setup Conditions and Requirements 122
Test Case Voltage and Current Injection from Relay Test Sets 122
TEST CASE #13 – REACTOR UNBALANCE PROTECTION (51Q) 123

Relay Test Setup Conditions and Requirements 123
Test Case Voltage and Current Injection from Relay Test Sets 123
Test Case Performance Tests 123
TEST CASE #14 – REACTOR AND CAPACITOR BANK VAR CONTROL AUTOMATION 123
Relay Test Setup Conditions and Requirements 123
Test Case Voltage and Current Injection from Relay Test Sets 124
TEST CASE #15 – LINE FREQUENCY AND VOLTAGE (81, 27, AND 59) 126
Relay Test Setup Conditions and Requirements 126
Test Case Voltage and Current Injection from Relay Test Sets 126

11. TEST RESULTS AND DATA ANALYSIS 129

MEASUREMENT AND VERIFICATION 129
IMPACTS ON EXISTING SUBSTATION AND TRANSMISSION PROTECTION 129
Reliability – Protection 129
Reliability – Communications 129
Speed of Operations 131
IMPACTS ON EXISTING SUBSTATION SYSTEMS AND EQUIPMENT 131
IMPACTS ON SYSTEM OPERATIONS 132
MAINTENANCE IMPACTS 132
COSTS 132
Estimate Assumptions 132
PROS AND CONS 135
Pros 135
Cons 137
MIGRATION PROCESS 137

12. KEY FINDINGS 139

IEC 61850 IMPLEMENTATION CHALLENGES 140

13. CONCLUSIONS 142

14. RECOMMENDATIONS 143

FUTURE WORK 143
Network Optimization 143
Remote Access 143
Redundancy 144
SCADA 144
SV Implementations 144

15. POST-PROJECT TECHNOLOGY TRANSFER 145

16. METRICS AND VALUE PROPOSITION:
Metrics:

METRICS AND VALUE PROPOSITION:
Metrics:

Value proposition:

REFERENCES 148

BIBLIOGRAPHY 149

APPENDICES

Appendix A - Test Case Data Flow Diagrams A-1
Appendix B - RTDS Model Diagram B-1
Appendix C - Network Layout Diagram C-1
Appendix D - 61850 Matrix D-1
Appendix E - Network IP and 61850 Dataflow Spreadsheet E-1
Appendix F - COMTRADE Graphical Analysis F-1
Appendix G - Operating Times Spreadsheet G-1
Appendix H - Observations H-1

FIGURES

Figure 1 Detail of Network Diagram 30
Figure 2 Detail of Process Bus Data Flow Diagram 34
Figure 3 Detail of RTDS Model Showing Transformer and Faults 38
Figure 4 Simplified One-line Diagram With Fault Locations Shown 40
Figure 5 Simplified Test System Diagram 41
Figure 6 DESIGN Process 42
Figure 7 Device Configuration Process 43
Figure 8 IED 61850 System GOOSE and SV Message Matrix 46
Figure 9 Defined Lockout and SCADA Devices 48
Figure 10 IEC 61850-9-2LE SV Dataset, Edition 1 53
Figure 11 IEC 61850-9-2 SV Dataset, Edition 2 54
Figure 12 Process Bus #1 Dataflow Diagram 72
Figure 13 Process Bus #2 Dataflow Diagram 73
Figure 14 Station Bus Dataflow Diagram 75
Figure 15 V1M5 Out of the Box SV Message 85
Figure 16 V1M5 SV Message after Configuration 86
Figure 17 V3M1 Relay Error on the V1M5 SV Stream 87
Figure 18 V1M8 File Import Error 88
Figure 19 V1M8 Save Error 89
Figure 20 V7M1 Data Model 90
Figure 21 V2M5 Merging Unit Data Model 90
Figure 22 V2M3 Front Panel Display Message 91
Figure 23 Analog Dataset Example 92
Figure 24 V7M1 MU “Fast Goose” Dataset 92
Figure 25 V2M4 50/51 EA138 Relay Lockout Programming 97
Figure 26 V2M4 50/51 EA138 Relay Block Close Programming 98
Figure 27 Breaker Fail Data Flow A-2
Figure 28 Line Differential Data flow A-3
Figure 29 Line Distance Data Flow A-4
Figure 30 High Side Bus Overcurrent Data Flow A-5
Figure 31 High Side Bus Differential Data Flow A-6
Figure 32 High Side Bus High-Z Data Flow A-7
Figure 33 Transformer Differential Data Flow A-8
Figure 34 Transformer Overcurrent Data Flow A-9
Figure 35 12kV Bus Partial Overcurrent Data Flow A-10
Figure 36 12kV Bus Differential Data Flow A-11
Figure 37 Cap/Reactor Bank Overcurrent Data Flow A-12
Figure 38 Capacitor Bank Unbalance Data Flow A-13
Figure 39 Reactor Bank Negative Sequence Data Flow A-14
Figure 40 Cap/Reactor Bank Automation Data Flow A-15
Figure 41 Under Frequency Data Flow A-16
Figure 42 RTDS Model B-2
Figure 43 RTDS Model HMI B-3
Figure 44 Network Layout Diagram C-2

TABLES

Table 1 Breaker Failiure 14
Table 2 Line Differential 14
Table 3 Line Distance And Directional Overcurrent 15
Table 4 Hv Bus Overcurrent Differential 15
Table 5 Hv Bus Restrained 16
Table 6 Hv Bus High Impedance Differential 16
Table 7 Transformer Restrained Current Differential 17
Table 8 Transformer Overcurrent 17
Table 9 12 Kv Bus Partial Overcurrent 18
Table 10 12 Kv Bus Restrained Current Differential 18
Table 11 Capacitor And Reactor Bank Feeder Overcurrent 19
Table 12 Capacitor Unbalance 19
Table 13 Reactor Unbalance 19
Table 14 Reactor And Capacitor Var Automation 20
Table 15 Line Frequency And Voltage 21
Table 16 Protection Device Iec 61850 Edition Matrix 58
Table 17 Merging Unit Iec 61850 Edition Matrix 60
Table 18 Merging Unit Sv – Compliance With 9-2le 62
Table 19 Protection Device Sv – Compliance With 9-2 Le 63
Table 20 Data Flow Table - Sv Control Block 65
Table 21 Data Flow Table- Sv Dataset 66
Table 22 Data Flow Table- Sv Subscribing Devices 67
Table 23 Data Flow Table - Goose Control Block 68
Table 24 Data Flow Table - Goose Dataset 69
Table 25 Data Flow Table - Goose Subscribing Devices 70
Table 26 Costs For Times No Longer Required For Legacy Design 133
Table 27 Costs For Additional Items Required For Process Bus Design 134
Table 28 Iec61850 Matrix For Protective Devices D-2
Table 29 Iec61850 Matrix For Merging Units D-3
Table 30 Process Bus #1 Data Flow Spreadsheet E-2
Table 31 Process Bus #2 Data Flow Spreadsheet E-3
Table 32 Station Bus Data Flow Spreadsheet E-4
Table 33 Relay Operating Times G-2
Table 34 Relay Operating Times Notes G-3
Table 35 Observation Log 1 ..... H-2
Table 36 Observation Log 2 ..... H-3
Table 37 Observation Log 3 ..... H-4

1. GLOSSARY

ABBREVIATION	DESCRIPTION
AC	Alternating current
ACSI	Abstract communication service interface
BFI	Breaker failure initiate
BNC	Connector type for coaxial cable
CAT5e	Category 5e Ethernet cable
CDC	Common Data Class
CID	Configured IED description
CIP	Critical infrastructure protection (when referenced with NERC i.e. NERC CIP)
COMTRADE	Common format for transient data exchange for power systems
CPU	Central processing unit
CT	Current transformer
cyc	Cycles (relating to electrical frequency)
DC	Direct current
DER	Distributed energy resource
DNP	Distributed network protocol
DOS	Denial of service (network attack)
DTT	Direct transfer trip (relay protection scheme)
ed	Edition (refers to a specific edition of the IEC 61850 standard)
ER	Event Recorder
EHV	Extra high voltage (refers to an electric system voltage typically exceeding 345,000 volts)
EPIC	Electric Program Investment Charge
FLTn	The fault location number associated with the lab testing
GOOSE	Generic object-oriented substation events (message type defined by IEC 61850)
GPS	Global positioning system
HIZ	High impedance (fault type)
HS	High side (Referring to the high voltage side of a transformer in a substation)
HSR	High-availability seamless redundancy
HV	High voltage (when referring to a substation bus)
HZ	Hertz
I/O	Input / output
ICD	IED capability description
ID	Identifier
IEC	International Electrotechnical Commission
IED	Intelligent electrical device
IEEE	Institute of Electrical and Electronics Engineers
IID	Instantiated IED Description
IP	Internet protocol
IRIG	Inter-range Instrumentation Group; refers to a time code protocol

ABBREVIATION	DESCRIPTION
ITF	Integrated Test Facility (San Diego Gas & Electric)
LAN	Local area network
LC	One of a variety of small form-factor pluggable (SFP) fiber connectors
LS	Low side (Referring to the low voltage side of a transformer in a substation)
LV	Low voltage (when referring to a substation bus)
MAC	Media access control
MM	Multimode Fiber (referencing fiber optic cable type)
MMS	Manufacturing message specification
ms	Milliseconds
MSVCB	Multicast sampled value control block
MU	Merging unit
NERC	North American Electric Reliability Corporation
P&C	Protection and control
PPS	Pulse per second
PRP	Parallel redundancy protocol
PT	Potential transformer
PTP	Precision time protocol
PUTT	Permissive under reaching transfer trip (relay protection scheme)
RJ	Registered jack (network connector as in RJ45)
RSCAD	RTDS simulator software
RTDS	Real time digital simulator for power system simulation
RTU	Remote terminal unit
SAV	Sampled analog value (a common data class in IEC 61850)
SCADA	Supervisory control and data acquisition
SCD	System configuration description
SCL	Substation configuration language
SCSM	Specific communication service mapping
SDG&E	San Diego Gas & Electric
sec	Seconds (for measurement of time)
SER	Sequential events recorder
SFP	Small form-factor pluggable (reference fiber optic transceiver)
SLG	Single line to ground (fault type)
SNTP	Simple network time protocol
SOE	Sequence of Event
ST	Straight Tip (Fiber Optic Connector)
SV	Sampled value (Message type defined by IEC 61850)
SWGR	Switchgear
TC	Technical committee within IEC
TCP	Transmission Control Protocol
UCA	Utility Communications Architecture
UCAIug	Utility Communications Architecture International Users Group

ABBREVIATION	DESCRIPTION
UFLS	Under frequency load shedding
Vac	AC voltage
VAR	Volt-ampere reactive
Vdc	DC voltage
VLAN	Virtual local area network
VxMy	A dual indexed code used to obfuscate the vendor name and model numbers of the IEDs for the project
WAN	Wide area network
Xfer	Transfer (relating to a substation transfer bus)
Xfmr	Transformer
1LG	Single phase line to ground fault
3LG	Three phase line to ground fault
3PH	Three phase (fault type)
9-2LE	IEC 61850 Section 9-2 Light Edition UCAIUG agreement on implementation of IEC 61850-9-2

2. INTRODUCTION

This project was one of three SDG&E Electric Program Investment Charge (EPIC) projects on pre-commercial demonstration of communications architecture standards for power system operations. The three projects were:

- Smart Grid Architecture Demonstrations (EPIC-1, Project 1)
    - Focus: Communications standards for integration of feeder equipment and distributed energy resources (DER) into networked automation
- Monitoring, Communication, and Control Infrastructure for Power System Modernization (EPIC-2, Project 3)
    - Focus: Open Field Message Bus
- Modernization of Distribution System and Integration of Distributed Generation and Storage (EPIC-2, Project 1)
    - Focus: IEC 61850 in Substation Network

The principal standard of interest in these three demonstrations was International Electrotechnical Commission (IEC) 61850, which is an open standard developed by industry stakeholders and promulgated through the IEC. The intent of these EPIC demonstrations was to increase the body of knowledge available to aid users in making decisions regarding their future power system communications architecture. The final reports for all three of these projects were posted on the San Diego Gas & Electric (SDG&E) EPIC website at www.sdge.com/epic. This body of work was limited in scope by funding availability in the SDG&E EPIC program, and it is acknowledged that a much larger body of work in this area is needed.

This report is the comprehensive final report for the third project listed above. The objective of the project, as stated in SDG&E's approved EPIC-2 application, was to demonstrate distribution system infrastructure modernization solutions, including advances in distribution system design to enable use of new technologies, such as power electronic components, new protection systems, distributed generation and storage technologies.

The chosen priority for focus of this project was to perform a pre-commercial demonstration in a laboratory of the International Electrotechnical Commission (IEC) 61850 standard, with specific emphasis on generic object-oriented substation event (GOOSE) and sampled value (SV) messages. The demonstration work compared the results to current protective relay practice and performance. This project also examined the pros and cons of IEC 61850, vendor interoperability issues, and recommendations on commercial adoption.

The test system for the demonstration facilitated the application of IEC 61850 to a predefined set of use cases normally found in distribution substations. Protection system performance and manufacturer interoperability observations were included.

The test system was designed to support a multi-vendor test environment. This enabled the project team to not only evaluate the protection impacts of a GOOSE and SV based P&C system, but also to evaluate the state of the industry in integrating IEC 61850 intelligent electronic devices (IEDs). The primary goals were to demonstrate a multi-vendor IEC 61850 system and determine the impact of IEC 61850 GOOSE and SV P&C messages on the identified protection use cases. Results from the demonstration were used to draw conclusions to support the recommendations.

This report includes documentation of the objective, scope, approach, test case descriptions, concept of operations, specification and design of the test system, laboratory demonstration activities, testing results, analysis, findings, conclusions, and recommendations.

3. IEC 61850 OVERVIEW AND ISSUES

Focus

The project's focus was a pre-commercial demonstration of the IEC 61850 standard as applied to a substation P&C mockup in a laboratory including:

- Specific emphasis on GOOSE and SV messages
- Study of the pros and cons of using this standard with a predefined set of use cases
- Study of vendor interoperability for some of the available IEC 61850 products
- Development of recommendations regarding commercial adoption

This project focused on IEC 61850 implementation, interoperability, control, and protection for specified use cases. Device configuration and manufacturer interpretation of the standard were key challenges in the project. The performance of the protection devices was also evaluated in order to gauge successful implementation of the standard by equipment manufacturers.

IEC 61850

IEC 61850 is an international standard. It is part of the IEC Technical Committee (TC) 57 architecture that provides an open-standard communication architecture for electric power systems. IEC 61850 is more than just a protocol; it contains methods for digitizing information and for its transfer within a substation or within the larger power system. IEC 61850 and the related TC-57 standards currently include other domains such as (but not limited to) wind power, hydroelectric plants, distribution automation, electrical mobility, electrical storage, and distributed energy resources (DER).

IEC 61850 provides a semantic model of the power system in that the model describes the meaning of its instances. This standardized model also provides organizational structure for information exchanges using various types of messaging. The main data exchange methods are MMS, GOOSE, and SV.

IEC 61850 is a large standard that contains ten parts. This standard includes, among other things, a defined set of file structures that describes device and system communications, a list of standard data objects and abstract communications services, standardized object models, a method of mapping messaging to communication methods, and a testing section to aid in verifying conformance with the standard.

Advantages of IEC 61850

A complete and comprehensive description of all of the advantages of an IEC 61850 system is beyond the scope of this section. The bibliography to this report identifies some sources of background reading material. Some of the more significant items are described below:

IEC 61850 provides standard methods of exchanging data between intelligent electronic devices (IEDs). By defining a semantic model, multi-manufacturer interoperability is possible. Not only should this ease configuration effort, but it should greatly reduce the risk that devices from different manufacturers' will not communicate.

By standardizing the communication methods and protocols, manufacturers should be able to reduce development time and costs, thus bringing lower cost products to market sooner. The standardized

file transfer method provides a structured method of exchanging configuration data between devices. This can reduce end user engineering development time and costs. It also allows for standardized end user templates that can be reused in each implementation.

One of the big advantages of IEC 61850 P&C schemes is the reduction in control wiring. Control wiring is expensive to design, install, document and modify. IEC 61850 replaces the majority of the control wiring with Ethernet cabling that allows multiple communication sessions to be supported over a single physical media. When fiber optic cabling is employed, additional advantages accrue due to its noise resistance and isolation from ground potential rise (GPR) inherent in high voltage substations.

The communications cabling employed with IEC 61850 is essentially self-monitoring due to the repetitive nature of the messages. Loss of path can be rapidly identified due to message loss. Alarms can then be initiated to resolve failures before a critical failure occurs. This facilitates continuous automatic testing and reduces effort to comply with North American Electric Reliability Corporation (NERC) PRC-005 requirements.

The IEC 61850 semantic model provides for self-descriptive capabilities. Users can browse devices prior to purchase to identify their capabilities. It simplifies design and configuration as the device capabilities are standardized, insuring consistency from manufacturer to manufacturer.

United States Adoption of IEC 61850

Adoption of IEC 61850 in the United States has been slow. There are many proposed explanations for this slow adoption. No single explanation would likely cover all the reasons. The internet provides a multitude of potential explanations for the slow adoption in the United States and the rest of North America. Some examples are:

- There is a major investment in older legacy architectures, and migration to a new architecture will be costly. A business justification is needed.
- The use of some sections of the standard is still new. While MMS and GOOSE are fairly mature, but SV is still evolving and extensive effort is required to ensure interoperability.
- The changes required to implement an IEC 61850 substation are substantial and not every end user is willing to undertake the challenge.
- IEC 61850 provides for a very different P&C scheme, which is unfamiliar to many end users and requires careful change management to succeed.
- Implementing IEC 61850 introduces Ethernet into substations. Potential NERC compliance exposure is a concern with many end users.
- Testing and maintenance will be different with a P&C scheme based on IEC 61850. Development of industry accepted processes and methodologies are still evolving.
- Introduction of the new methods and processes will take time and effort.

From the above, it appears that knowledge and familiarity with the IEC 61850 standard contribute to its limited adoption in the United States. Providing additional information on the application and implementation of the IEC 61850 standard should provide a means to improve the adoption of this technology in the United States. Interest has been growing and adoption in the United States now appears to be accelerating.

Major Thrusts of Project Work

This demonstration project had two major work thrusts. The first was to develop additional information on the interoperability of IEC 61850 GOOSE and SV products between manufacturers. The second was to demonstrate the adequacy of an IEC 61850 P&C scheme when compared to the traditional hardwired scheme.

Knowledge Application

This project demonstrated that the use of IEC 61850 enhances interoperability of multiple manufacturers' products. It also demonstrated that SV and GOOSE could provide protection system performance that was equal to or better than the tradition hardwired solution. This report provides support for these assertions and should aid prospective adopters of IEC 61850 by providing assurance that the IEC 61850 P&C scheme will not degrade protection capabilities of substations.

4. OVERVIEW OF APPROACH

Power system automation and communication technologies are improving and becoming more robust. After studying different options and based on discussion with internal stakeholders, the project team chose pre-commercial demonstration of IEC 61850 for substation protection, control, and automation as the project focus.

The project and pre-commercial demonstration were anticipated to help determine whether the utilization of IEC 61850 based systems could replace existing substation automation and protection functions without compromising characteristics such as selectivity, speed, security and reliability of present substation P&C systems. In this project, existing standards for substation protection, automation and control architecture were used as a starting point. These existing standards were mapped to the new IEC 61850 standard. Bridges between the missing links of the technology were created to provide a transition to an IEC 61850 based protection system. This project implemented test cases in the test system that tested the application of IEC 61850 GOOSE and SV to the identified use cases (breaker failure protection, line protection, bus protection, transformer protection, capacitor/reactor feeder protection, capacitor and reactor protection, and frequency deviation protection).

The use cases were then refined into test cases. Test cases provided additional details so that the performance of the test system could be evaluated for various protection scenarios. These scenarios included in-zone and out-of-zone faults for individual protection elements. In addition, test cases included various control scenarios for capacitor and reactor banks.

The test system equipment was initially installed in racks in the contractor's IEC 61850 lab. All equipment was mounted in 19" racks and connected to power sources. Communication cabling was connected to each device in accordance with Appendix C. IEDs settings were then installed and published data sets were assigned in accordance with the tables in Appendix D. IED subscriptions were also assigned per the tables in Appendix C.

Test scenarios were developed using the Real-Time Digital Simulator (RTDS) and saved as COMTRADE (common format for transient data exchange for power systems) files. These files were then re-played by the relay test sets. The relay test sets injected currents and voltages into the appropriate MUs for processing by the relays. This process enhanced repeatability of the test parameters and reduced testing times. These files were also used as inputs for the RTDS testing that was performed at the end of the project. These tests files utilized actual SDG&E simulations as developed with the RTDS.

For this project, interoperability was considered to have been achieved if the MUs and relays could accurately publish, subscribe, and respond to IEC 61850 messages within the operational time limits of the protection devices.

Pre-Commercial Demonstration

The pre-commercial demonstration was conducted while the test system was located in the contractor's IEC 61850 lab. This provided team members with the opportunity to observe the functional tests performed on each test case and verify results. Additional time was provided to explain each test case and review COMTRADE plots to verify that the team members agreed with the relay operation and timing results.

Additional Demonstration at Integrated Test Facility (ITF)

Additional tests of selected use cases were performed at SDG&E's ITF using direct signals from the RTDS simulations, as described above. This repeat of selected use case tests allowed additional stakeholders to witness testing and have a chance to discuss the results.

Technology Transfer Activities During the Project

This project investigated a multi-vendor IEC 61850 test system that utilized GOOSE, SV, and MMS. It was predominantly a technology demonstration project. Technology transfer activities were performed throughout the project. These included on-site meetings, conference calls, web based presentations, and direct face-to-face meetings. Various workshops and training classes were held as part of the pre-commercial demonstration phase of the project. System architecture, RTDS, test setup, configuring software and relay settings were examples of activities and topics which were covered during the training.

Hands-on training was provided at various times throughout the project for the project team's engineers. This training included IEC 61850 configuration and one-on-one time with relay manufacturers' technical experts while they performed troubleshooting on the test system, when it was located in the contractor's IEC 61850 lab. Additional hands-on training was provided for the project team's members who attended the pre-commercial demonstration held at the contractor's IEC 61850 lab.

Classroom Training

A four day IEC 61850 training class was provided to the project team that covered the basics of IEC 61850 (i.e. operations, theory, standard, hands-on configuration, etc.).

Software Training

All of the manufacturers' configuration software and associated licenses were provided to the project team. Training was held to review each software package and how to configure the associated manufacturer's IEC 61850 IEDs. Additionally, the review of the specific project files was done and delivered to the project team (setting files, configurations, SCL files, etc.) for future reference.

Pre-commercial Demonstration Training

Additional time was devoted to training during the pre-commercial demonstration. This allowed additional stakeholders to obtain background on the design and development of the test system.

During the pre-commercial demonstration, the protection engineers provided additional explanations and background to allow stakeholders to improve their understanding of the test cases.

Hands-On Training with Vendors

Two of the main suppliers were at the lab during the configuration effort. Stakeholders were invited to participate. Stakeholders were on-site for configuration and trouble shooting. This provided an opportunity for the stakeholders to gain additional insight into the configuration of the IEDs in the test system.

5. BASELINE ASSESSMENT

A thorough investigation into SDG&E's current standards and selected existing distribution (138/12 kV or 69/12 kV) substations was conducted to provide a baseline on the SDG&E's philosophies and practices. This provided a reference point to which the conceptual IEC 61850 substation and the IEC 61850 lab demonstrations could be compared. Creating this reference point was important for future identification of the impacts of IEC 61850 substation design and implementation as well as the performance and functionality of the substation.

Several aspects of the existing substations including standard distribution substation electrical drawing package, typical protection system architecture and preferred schemes, protection use cases, communications, time synchronization, and the local operator interfaces were examined. These were included due to the anticipated changes associated with moving toward an IEC 61850 substation.

The baseline was created from a combination of standard drawings, as-built drawings from existing sites, relay settings from existing schemes, as well as discussions with the project team.

A list of anticipated differences for a complete IEC 61850 distribution substation was compiled. Because it was not possible to foresee all potential changes, this list was intended as a starting point and was subject to change as this project progressed. During the project, the list was expanded and can be referenced below:

- **Device Changes**
  - Within the scope of the project, relays and other IEDs will be changed to IEC 61850 compliant devices with SV and GOOSE protocols
  - Merging units will be added in the substation yard with SV and GOOSE protocols
  - Additional network switches will be added to provide for separate process buses and the station bus
  - Substation battery banks may need to be enlarged to accommodate the additional direct current (DC) load associated with the MUs and network switches
  - Panel meters, annunciators, and RTUs can be selected to take advantage of the new substation communications network
- **Wiring Changes**
  - Current transformer (CT) and potential transformer (PT) wiring of substation yard devices will not go back to the control shelter. This wiring will be run to MUs and kept as close to the associated CT and PT as reasonably possible
  - Test switches will be relocated from the control shelter to the substation yard with the MUs
  - When practical, substation yard device status and alarm contacts that were wired back to the control shelter will be wired into MUs for transmission by GOOSE or MMS
  - Wiring to panel meters, annunciators, and RTUS can be reduced when these items communicate over the new substation communications network
- **Fiber Optics Cables**
  - Fiber optic cables will be run from the control shelter to each of the MUs in the substation yard
  - Fiber optic patch panels on both the MU side and the control shelter side will be necessary to facilitate testing and troubleshooting
  - Fiber optic patch cables will be required for connections between patch panels and IEDs

- **Communications Changes**
  - The station will be broken up into independent local area networks (LANs) for each station bus and process bus
  - Protection relays will require multiple Ethernet connections to the station bus and the applicable process bus
- **Documentation Changes**
  - Updates to existing standards and drawings will be required

6. TEST CASES

This project implemented test cases in the test system that tested the application of IEC 61850 GOOSE and SV to the identified use cases. These use cases were defined by the project team at the start of the project. Use cases identified were:

- Breaker failure protection
- Line protection
- Bus protection
- Transformer protection
- Capacitor/reactor feeder protection
- Capacitor and reactor protection
- Frequency deviation protection

Use cases were further refined into test cases as the project proceeded. The test cases were used to compare performance of the test system to the existing protection equipment. Drawings for each test case were included in this report as Appendix A.

- For each test case, these drawings show the general substation equipment arrangement and the applicable bus (process bus #1, process bus #2, or station bus) with the case specific IEDs highlighted
- MUs were connected to simulated instrument transformers (test set/RTDS simulation inputs) with blue solid lines that indicate the location of the simulated instrument transformers. The SV streams were shown with blue dotted lines. From the identified MUs, these lines could be traced to highlighted subscribing relays. The relays' published GOOSE messages were shown with thin black lines, which could be traced to brown "virtual buses" at each highlighted MU. The subscribing MUs' connection to the "virtual buses" was then indicated with a brown arrow
- The MUs breaker control and indication was indicated with a purple arrow. Once the MU received the applicable indication a thin black line could be traced back to another brown "virtual bus", at the subscribing relays. Another brown arrow showed the communication from the relay "virtual bus to the subscribing relay
- Red lines showed the transfer trip connection between the local and remote relays used for line protection.

Each test case is described below:

Test Case #1 – Breaker Failure Protection (50BF)

The breaker failure protection test case was intended to simulate a typical breaker failure relay application for a 69 or 138 kV breaker. The test was run with one relay set consisting of the relay receiving breaker current signals from the instrument transformers via MU and IEC 61850-9-2 process bus SV. The breaker failure relay received breaker-failure initiate (BFI) notification by GOOSE from the line protection relays, and tripped all the bus breakers if the line breaker failed to trip. Trip and indication signals were published via GOOSE messages.

TABLE 1 BREAKER FAILIURE

TEST DESCRIPTION	RELAY	COMTRADE NAME
Breaker Fail – 52A Contact	V1M2[1]	07a_Breaker Fail 52A contact Fail_V1M2_52A_BF
Breaker Fail – Current Loss	V1M2	07b_Breaker Fail No Current Drop out_V1M2_OC_BF

Test Case #2 – Line Differential Protection (87L)

The line differential protection use case was intended to simulate primary line differential protection on a 69 or 138 kV sub-transmission circuit that interconnects a typical 12 kV distribution substation to the grid. The test was run with two relay sets (A & B) each set consisted of one relay that simulated the local relay receiving signals from the instrument transformers via MU and IEC 61850-9-2 process bus SV. The second relay simulated the remote station relay, which used direct injection of secondary test signals. The local relay's trip and indication signals were published via GOOSE messages.

Because modern line differential relaying depends on continuously transmitting line terminal phase current information between relays at each end of a line, this simulation must be performed with a minimum of two relays in each set.

The primary goal of the test was to prove proper relay operation or restraint for a variety of in-zone and out-of-zone balanced and unbalanced faults, and to record the operating times for each in-zone fault for comparison to that expected for conventional relays using directly connected instrument transformers. A secondary goal was to verify that relay element performance was not impacted by the use of SV signals.

TABLE 2 LINE DIFFERENTIAL

TEST DESCRIPTION	RELAY	COMTRADE NAME
3-phase Close In Fault	V2M2	00a_Line Differential, Close In_FLT1_3PH_V2M2_87L2A
3-phase Close In Fault	V1M1	00b_Line Differential, Close In_FLT1_3PH_V1M1_87L2B
SLG Close In Fault	V2M2	00c_Line Differential, Close In_FLT1_SLG_V2M2_87L2A
SLG Close In Fault	V1M1	00d_Line Differential Close In_FLT1_SLG_V1M1_87L2B

Test Case #3 – Line Distance and Directional Overcurrent Protection (21 & 50/51)

The line impedance and directional overcurrent protection test was intended to simulate permissive under-reaching transfer-trip (PUTT) and unsupervised directional element backup protection on a 69 or 138 kV sub-transmission circuit that interconnects a typical 12 kV distribution substation to the grid. The test was run with two relay sets (A & B), with each relay receiving signals from the instrument transformers via MUs and IEC 61850-9-2 process bus SVs. Trip and indication signals were published via GOOSE messages.

Because PUTT direct-transfer-trip (DTT) signals transmitted between each line terminal were unlikely to be IEC 61850 GOOSE, and the test system was not intended to verify built-in relay DTT

[1] See appendix H for explanation of product codes

line protection logic, a remote relay was not required for this test to examine operation of the relay scheme function with IEC 61850 SV signals.

The primary goal of the test was to prove proper relay operation or restraint for a variety of in-zone and out-of-zone balanced and unbalanced faults, and to record the operating times for each in-zone fault for comparison to that expected for conventional relays using directly connected instrument transformers. A secondary goal was to verify that relay element performance was not impacted by the use of SV signals.

TABLE 3 LINE DISTANCE AND DIRECTIONAL OVERCURRENT

TEST DESCRIPTION	RELAY	COMTRADE NAME
3-phase Close In Fault	V3M1	00e_Line Distance & Directional Overcurrent_FLT1_3PH_V3M1_21-1
SLG Close In Fault	V3M1	00f_Line Distance & Directional Overcurrent_FLT1_SLG_V3M1_21-1
3-phase Remote End Fault	V2M2	01a_Line Distance & Directional Overcurrent_FLT3_3PH_V2M2_87L2A
3-phase Remote End Fault	V3M1	01b_Line Distance & Directional Overcurrent_FLT3_3PH_V3M1_21-2
SLG Remote End Fault	V2M2	01c_Line Distance & Directional Overcurrent_FLT3_SLG_V2M2_87L2A
SLG Remote End fault	V3M1	01d_Line Distance & Directional Overcurrent_FLT3_SLG_V3M1_21-2

Test Case #4 – High Voltage (HV) Bus Overcurrent Differential Protection (87B-50/51)

The HV bus overcurrent differential protection test was intended to simulate the operation of the HV bus differential zone bounded by breakers for bus faults. Over-current differential protection was the primary form of protection for 12 kV distribution substation HV buses, so the simulation test for this form of protection was run with two different manufacturers' relay sets (A & B). The test was run with the relays receiving signals from the instrument transformers via MUs publishing IEC 61850-9-2 process bus SVs. Trip and indication signals were published via GOOSE messages.

The primary goal of the test was to prove proper relay operation or restraint for HV bus faults, and to record the operating times for each fault for comparison to that expected for conventional relays using directly connected instrument transformers. A secondary goal was to verify that relay element performance was not impacted by the use of SV signals.

TABLE 4 HV BUS OVERCURRENT DIFFERENTIAL

TEST DESCRIPTION	RELAY	COMTRADE NAME
3-phase HV Bus Fault	V2M1	02a_HV Bus Overcurrent Differential_FLT4_3PH_V2M1_5051EA138
SLG HV Bus Fault	V2M1	02f_HV Bus Overcurrent Differential_FLT4_SLG_V2M1_5051EA138

Test Case #5 – HV Bus Restrained Current Differential Protection (87B)

HV bus restrained current differential protection test was intended to simulate the operation of a high voltage bus differential zone bounded by breakers bus faults using a restrained current differential element. The test was run with the relay receiving signals from the instrument transformers via MUs publishing IEC 61850-9-2 process bus SVs. Trip and indication signals were published via GOOSE messages.

One relay set was assigned to perform both this protection use case and overcurrent differential protection as this use case was not currently applied to typical distribution substations.

The primary goal of the test was to prove proper relay operation or restraint for HV bus faults, and to record the operating times for each fault for comparison to that expected for conventional relays using directly connected instrument transformers. A secondary goal was to verify that relay element performance was not impacted by the use of SV signals.

TABLE 5 HV BUS RESTRAINED

TEST DESCRIPTION	RELAY	COMTRADE NAME
3-phase HV Bus Restrained Current Differential	V1M3	02c_HV Bus Restrained Current Differential_FLT4_3PH_V1M3_5051EB138
SLG HV Bus Restrained Current Differential	V1M3	02d_HV Bus Restrained Current Differential_FLT4_SLG_V1M3_5051EB138

Test case #6 – HV Bus High Impedance (HIZ) Differential Protection (87B-HIZ)

The HV bus high-impedance differential protection test case was intended to simulate the operation of a high voltage bus differential zone bounded by breakers for bus faults. The test was run with the relay receiving signals from a summation of breaker current transformers via a resistor-divider assembly that drives a dedicated MU publishing IEC 61850-9-2 process bus SVs. Trip and indication signals were published via GOOSE messages.

One relay was assigned to perform both this protection use case and overcurrent differential protection as this use case was not currently applied to typical distribution substations.

The primary goal of the test was to prove proper relay operation or restraint for HV bus faults, and to record the operating times for each fault for comparison to that expected for conventional relays using directly connected instrument transformers. A secondary goal was to verify that relay element performance was not impacted by the use of SV signals.

TABLE 6 HV BUS HIGH IMPEDANCE DIFFERENTIAL

TEST DESCRIPTION	RELAY	COMTRADE NAME
3-phase Hi-Z Bus Fault	V2M4	02b_HV Bus Hi-Z Differential_FLT4_3PH_V2M4_5051EA138_HIZ
SLG Hi-Z Bus Fault	V2M4	02e_HV Bus Hi-Z Differential_FLT4_SLG_V2M4_5051EA138_HIZ

Test case #7 – Transformer Restrained Current Differential Protection (87T)

The transformer restrained current differential protection test was intended to simulate the operation of the transformer differential zone bounded by breakers for internal transformer and associated interconnecting bus faults using a restraint overcurrent differential element. The test was run with two different manufacturers' relay sets (A & B) with each relay receiving signals from the instrument transformers via MUs publishing IEC 61850-9-2 process bus SVs. Trip and indication signals were published via GOOSE messages.

The primary goal of the test was to prove proper relay operation or restraint for transformer faults, and to record the operating times for each fault for comparison to that expected for conventional relays using directly connected instrument transformers. A secondary goal was to verify that relay element performance was not impacted by the use of SV signals.

TABLE 7 TRANSFORMER RESTRAINED CURRENT DIFFERENTIAL

TEST DESCRIPTION	RELAY	COMTRADE NAME
3-phase Transformer In-Zone Fault	V2M3	06a_Transformer Restrained Current Differential_FLT8_3PH_V2M3_87T41A
3-phase Transformer In-Zone Fault	V1M3	06b_Transformer Restrained Current Differential_FLT8_3PH_V1M3_87T41B
3-phase Transformer Restrained Current Differential	V2M3	06c_Transformer Restrained Current Differential_FLT8_3PH_V2M1_5051_7A
3-phase Transformer Restrained Current Differential	V1M3	06d_Transformer Restrained Current Differential_FLT8_3PH_V1M3_5051_7B
SLG Transformer In-Zone Fault	V1M3	06e_Transformer Restrained Current Differential_FLT8_SLG_V1M3_87T41B

Test Case #8 – Transformer Overcurrent Protection (50/51T)

The transformer over current protection test was intended to simulate backup overcurrent protection operation for fault in a distribution transformer or interconnected bus. The test was run with two overcurrent relay sets (A & B), and two restrained current differential relay sets (C & D) with backup overcurrent elements, each receiving signals from the instrument transformer via MUs and IEC 61850-9-2 process bus SVs. Trip and indication signals were published via GOOSE messages.

The primary goal of the test was to prove proper overcurrent relay operation for 3LG and 1LG transformer or associated bus faults, and to record the operating times for each fault for comparison to that expected for conventional relays using directly connected instrument transformers. A secondary goal was to verify that relay element performance was not impacted by the use of SV signals.

TABLE 8 TRANSFORMER OVERCURRENT

TEST DESCRIPTION	RELAY	COMTRADE NAME
SLG Transformer Fault	V2M3	06f_Transformer Ovecurrent_FLT8_SLG_V2M3_87T41A
3-phase Transformer Fault	V1M4	06g_Transformer Overcurrent_FLT8_3PH_V1M4_5051_7A
SLG Transformer Fault	V1M4	06h_Transformer Overcurrent_FLT8_SLG_V1M4_5051_7B

Test Case #9 – 12kV Bus Partial Overcurrent Differential Protection (87B-51P/G)

The 12 kV bus overcurrent differential protection test was intended to simulate the operation of the bus differential zone bounded by breakers for bus faults. Overcurrent differential protection was the primary form of protection for distribution substation buses. The test was run with two different manufacturers' relay sets (A & B), with each relay receiving signals from the instrument transformers via MU publishing IEC 61850-9-2 process bus SVs. Trip and indication signals were published via GOOSE messages.

The primary goal of the test was to prove proper relay operation or restraint for 12 kV bus faults, and to record the operating times for each fault for comparison to that expected for conventional relays using directly connected instrument transformers. A secondary goal was to verify that relay element performance was not impacted by the use of SV signals.

TABLE 9 12 KV BUS PARTIAL OVERCURRENT

TEST DESCRIPTION	RELAY	COMTRADE NAME
3-phase 12kV Bus Fault	V2M1	04a_12kV Partial Bus Overcurrent Differential_FLT6_3PH_V2M1_5051BT_4041A
3-phase 12kV Bus Fault	V1M4	04b_12kV Partial Bus Overcurrent Differential_FLT6_3PH_V1M4_5051BT_4041B
SLG 12kV Bus Fault	V2M1	04c_12kV Partial Bus Overcurrent Differential_FLT6_SLG_V2M1_5051BT_4041A
SLG 12kV Bus Fault	V1M4	04d_12kV Partial Bus Overcurrent Differential_FLT6_SLG_V1M4_5051BT_4041B

Test Case #10 – 12kV Bus Restrained Current Differential Protection (87B)

The 12 kV bus restrained current differential protection test was intended to simulate the operation of the bus differential zone bounded by breakers for bus faults using a restrained current differential element and subscriptions to a maximum of six SV streams. The simulation test was run with the relay receiving signals from the instrument transformers via MUs publishing IEC 61850-9-2 process bus SVs. Trip and indication signals were published via GOOSE messages.

Only one relay set (Mfg. /Model V2M3) was assigned to perform this protection use case as it was the only one capable of subscribing to six SV streams. This 12 kV bus overall wrap has not been applied to distribution substations yet, so the settings will not match those in existing substations.

The primary goal of the test was to prove proper relay operation or restraint for low voltage (LV) bus faults, and to record the operating times for each fault for comparison to that expected for conventional relays using directly connected instrument transformers. A secondary goal was to verify that relay element performance was not impacted by the use of SV signals.

TABLE 10 12 KV BUS RESTRAINED CURRENT DIFFERENTIAL

TEST DESCRIPTION	RELAY	COMTRADE NAME
3-phase 12kV Bus Restrained Current Differential	V2M3	05a_12kV Bus Restrained Current Differential_FLT7_3PH_V2M3_87_1241A
SLG 12kV Bus Restrained Current Differential	V2M3	05b_12kV Bus Restrained Current Differential_FLT7_SLG_V2M3_87_1241A

Test Case #11 – Capacitor and Reactor Feeder Overcurrent Protection (50/51)

The reactive branch over current protection test was intended to simulate a fault on a capacitor/reactor feeder in a typical 12 kV distribution substation. The test was run with two relay sets (A & B), with each relay receiving signals from the instrument transformers via a MU and IEC 61850-9-2 process bus SVs. Trip and indication signals were published via GOOSE messages.

The primary goal of the test was to prove proper relay operation for faults on the feeder connecting the reactive components to the 12 kV bus, and to record the operating times for each fault for comparison to that expected for conventional relays using directly connected instrument transformers. A secondary goal was to verify that relay element performance was not impacted by the use of SV signals.

TABLE 11 CAPACITOR AND REACTOR BANK FEEDER OVERCURRENT

TEST DESCRIPTION	RELAY	COMTRADE NAME
3-phase 12kV Feeder Fault	V2M1	03a_Cap&Reactor Feeder Overcurrent_FLT5_3PH_V2M1_5051_17A
3-phase 12kV Feeder Fault	V1M4	03b_Cap&Reactor Feeder Overcurrent_FLT5_3PH_V1M4_5051_17B
SLG 12kV Feeder Fault	V2M1	03c_Cap&Reactor Feeder Overcurrent_FLT5_SLG_V2M1_5051_17A
SLG 12kV Feeder Fault	V1M4	03d_Cap&Reactor Feeder Overcurrent_FLT5_SLG_V1M4_5051_17B

Test Case #12 – Capacitor Bank Unbalance Protection (59N)

Capacitor bank protection has two specific use cases: feeder fault protection (see test case above) which protects for a flash-over or equipment internal short-circuit, and unbalance protection that was intended to take the bank off line if too many individual capacitor unit fuses blow. This test was intended to simulate the protective relay response to abnormal bank 3V0 voltage due to excessive imbalance. The test was run with only one relay set that matches those currently installed in typical 12 kV distribution substations, but with IEC 61850 GOOSE messaging used to trip all capacitor bank breakers and perform a lockout function to prevent the automatic Volt-Amperes Reactive (VAR) controls from bringing them back on line (the existing cap banks use a hardwired mechanical lockout relay to perform this function).

The primary goal of the test was to prove proper relay GOOSE signaling and logic operation after a trip for imbalance.

TABLE 12 CAPACITOR UNBALANCE

TEST DESCRIPTION	RELAY	COMTRADE NAME
Cap Unbalance	V3M2	Cap 59S Trip and Lockout

Test Case #13 – Reactor Unbalance Protection (51Q)

Reactor bank protection has two specific use cases: feeder fault protection (see “feeder over-current” test case above) which protects for a flash-over or equipment internal short-circuit, and unbalance protection that was intended to take the bank off line if the reactor(s) have significant standing turn-to-turn faults. This test was intended to simulate the protective relay response to abnormal bank negative-sequence current (3I2) due to excessive bank imbalance from one or more turn-to-turn faults. The test was run with only one relay set that matches those currently installed in typical 12 kV distribution substations, but with IEC 61850 GOOSE messaging used to trip all reactor bank breakers and perform a lockout function to prevent the automatic VAR controls from bringing them back on line (the existing reactor banks use a hardwired mechanical lockout relay to perform this function).

The primary goal of the test was to prove proper relay GOOSE signaling and logic operation after a trip for imbalance.

TABLE 13 REACTOR UNBALANCE

TEST DESCRIPTION	RELAY	COMTRADE NAME
Reactor Unbalance	V3M2	Reactor 51Q Trip and Lockout

Test Case #14 – Reactor and Capacitor Bank VAR Control Automation

Reactor and capacitor bank VAR Control Automation use case was intended to simulate the addition and subtraction of capacitor and reactor elements based on VAR flow in and out of the distribution step-down transformer as measured at the transformer high side (HS) connection.

This VAR control demonstration was accomplished by using the 50/51T over-current relay to measure the VAR flow and then transmit this information, in engineering units, via GOOSE analog values to the two automation controllers where the decision making logic was implemented.

All analog and discrete GOOSE messaging was carried over the station bus. Bank unbalance and feeder protection trips to the automation controllers were also handled by GOOSE messaging (see Test cases #12 and 13 above).

The simulation test was run with an automation relay that matched those currently installed in SDG&E substations so as to reuse the existing logic settings, but with IEC 61850 GOOSE messaging and logic changes incorporated as described above. The simulation test was run with one overcurrent transformer overcurrent relay (V3M1) receiving signals from the instrument transformers via a MU and IEC 61850-9-2 process bus SVs. Trip and indication signals were published via GOOSE messages.

The primary goal of the test was to prove proper relay GOOSE signaling and logic operation.

TABLE 14 REACTOR AND CAPACITOR VAR AUTOMATION

TEST DESCRIPTION	RELAY	COMTRADE NAME
Cap and Reactor Bank Automation	V3M2 V3M4	Cap & Reactor Bank Unbalance Protection and VAR Automation Test Records

Test Case #15 – Line Frequency and Voltage (81, 27, and 59)

Line frequency and voltage protection test cases were intended to simulate protective relay response to abnormal voltages (27/59) or frequency (81O/U) on a 69 or 138 kV sub-transmission circuit that interconnects a typical 12 kV distribution substation to the grid. The simulation test was run with two relay sets (A & B), with each relay receiving signals from the instrument transformers via MU and IEC 61850-9-2 process bus SV. Trip and indication signals were published via GOOSE messages.

Current sub-transmission line protection practice does not make use of 27, 59 or 81 tripping elements, but the interconnected distribution substations do use under-frequency (81U) as part of a regional under-frequency load-shed (UFLS) scheme incorporated into dedicated UFLS relays located in each distribution substation. Because IEC 61850 GOOSE messaging across the station bus provides great flexibility in how a UFLS scheme may be implemented, it was reasonable that this scheme could be incorporated into the backup distance line relays, for example, with GOOSE messages transmitted over the station bus network used to trip individual 12 kV feeder breakers; IEC 61850 would also allow a multi-level UFLS scheme to be implemented without much difficulty.

The primary goal of the test was to prove proper relay operation during sustained transmission system voltage or frequency deviations, and verify that relay element performance was not impacted by the use of SV signals.

TABLE 15 LINE FREQUENCY AND VOLTAGE

TEST DESCRIPTION	RELAY	COMTRADE NAME
Under Frequency	V2M2	08a_UnderFreq_V2M2_87L2A
Under Frequency	V3M1	08b_UnderFreq_V3M1_21-2
Under Voltage	V2M2	09a_UnderVolt_V2M2_87L2A
Under Voltage	V3M1	09b_UnderVolt_V3M1_21-2
Over Voltage	V2M2	09c_OverVolt_V2M2_87L2A
Over Voltage	V3M1	09d_OverVolt_V3M1_21-2

7. CONCEPT OF OPERATIONS

The operation of an IEC 61850 substation requires a shift from conventional substation design methods in how the protective relays acquire analog instrument transformer current and voltage signals necessary to detect faults, and the control circuits to breakers, auxiliary relays, alarm annunciators and SCADA. Typically conventional substations performed all this with copper wires that were routed from the substation yard, or within the control shelter, where they connect directly to the various P&C equipment.

The IEC 61850 substation with process bus digitally delivers these digitized current and voltage signals ("Sampled Values" or SV) via digital communications cabling. It delivers these digital signals by wiring the substation yard instrument transformers to MUs located in the high voltage equipment control cabinets in the substation yard. The MUs broadcast the continuous SV signals onto an IEC 61850 communication network called a process bus. The control shelter protection relays subscribe to the appropriate process bus signals and perform their protective functions based on the SV signals. The relays substitute the remotely generated measurements for signals that were previously locally generated analog measurements. These measurements are represented in instrument transformer primary units of volts and amps (engineering units) which facilitate easy use by a multitude of P&C equipment without special programming or decoding.

An IEC 61850 protection system operates much differently than in a conventional substation. Besides the MUs, networking equipment must also be leveraged to create at least one process bus and a station bus. These communication buses allow SV and GOOSE messages to be transmitted to and from the merging units and relays. High accuracy time synchronization also becomes critical so that the devices using these digitized analog signals can verify that the messages are valid, and properly align them with other SV signals before performing protection calculations.

With these changes to the operation of the substation, aspects of the protection system become more flexible and can be re-programmed as needed without the need to modify existing wiring and infrastructure. Lockout relay functions can be implemented in logic within the relays. Transfer trips, breaker fail initiates, and interlocks can be shared between devices over the network without any physical wires, and at far higher speed.

With these advances, substation networking sub-systems become critical to the operation of the protective system. Accurate synchronized time distribution becomes a very crucial consideration. Without it, devices cannot be sure that the data has reached them within an appropriate timeframe.

Thus communication becomes critical because the transmission and reception of messages relies upon the communication cables, Ethernet switches, and time sources. Battery banks likewise may also become larger due to the increased number of IEDs and data switches in the substation.

Protection and Control Architecture

The proposed architecture for a typical 69/12 kV substation with a process bus using SV to transmit ampere and voltage measurements from MUs to relays was examined here. This section also described the use of GOOSE to transmit status, control, and analog values from MUs to relays, from relays to MUs, and from relays to programmable automation controllers.

Process Bus

The process bus was used to transmit SV data from the MUs that digitize the analog signals and publish the data to relays that subscribe to the signals. The process bus also transmitted GOOSE

messages containing status, control, and analog data from MUs to relays, from relays to MUs, and from relays to programmable automation controllers.

Multiple process buses were recommended to manage traffic and minimize disruption in the event of a network failure or compromise. The design of this project includes three process bus switches. Due to the required number of ports, process bus #1 had two switches in a single bus and provided message transport on the 138 kV side of the transformer. Process bus #2 had one switch and provided message transport for the 12 kV side of the transformer. They were arranged so that a failure of one process bus will not compromise the overlapping protection of the high side or low-side bus.

Due to vendor implementation variations, several relay models required two connections to the process bus. These manufacturers may change this in future models so that only one connection to the process bus would be needed.

Station Bus

The station bus was the main substation network that provided the information connectivity between substation systems and other remotely located systems. For this test system, the station bus used IEC 61850, GOOSE and various configuration and diagnostic protocols. The station bus also provided engineering access to the various protection equipment and test sets for monitoring, control, and configuration.

Due to the required number of ports, the station bus contained two switches in a single bus. This arrangement minimized network hardware, but did not provide for system redundancy. A thorough review of the redundancy requirements should be made before an actual substation deployment is designed.

Time Synchronization

The design included a global positioning system (GPS) clock. In an actual substation two clocks would be necessary and arranged so that the overlapping protection of the HS or Low Side (LS) bus would not be comprised in the event of a single time source failure.

Engineering and Maintenance Access

The project did not explore remote access for engineering and maintenance. Internal policies and NERC's Critical Infrastructure Protection (CIP) requirements would need to be reviewed in order to determine the level of protection required and the preferred method of achieving this capability.

Information Exchanges

Information exchanges and data flows would be similar to those used in the test system.

Controllable Devices and Functional Specifications

This section covers the controllable devices and algorithms developed to realize the automation logic.

Capacitor and Reactor Bank Automation

Capacitor and reactor bank VAR Control Automation utilized GOOSE analog and digital messaging. This allowed for the addition and subtraction of capacitor and/or reactor elements based on VAR flow in/out of the distribution step-down transformer, as measured on the transformer high side connection. This was accomplished by using the 50/51T relay to measure the VAR flow and then transmit this information via GOOSE to the two automation controllers where the decision-making logic was installed. To prevent adding capacitors when reactors are on line and vice versa, interlocking was

performed between the standalone reactor and capacitor bank automation controllers by GOOSE messages. The imbalance relays were used to perform a lockout function when appropriate.

High Side and Low Side Lockout Relays

The lockout relays reproduced the functions of a traditional hardwired lockout relay scheme. To emulate lockout relay functions, a virtual lockout-relaying scheme was developed using latching variables and close blocking logic within the protection relays.

Minimum Local Area Network (LAN) Communication Requirements

The minimum LAN communication requirements for a substation deployment would be dependent upon the size and criticality of the substation. Larger substations would contain many more devices and thus require a higher bandwidth LAN and possibly higher reliability requirements. Network segregation is one way to manage traffic and improve reliability.

Additional requirements for an IEC 61850 process bus substation include:

- At a minimum, substation LANs should support 10/100/1000Base-TX, 100Base-FX multimode fiber (MM), and 1000Base-SX MM. This enabled Ethernet links to end devices at 100Base-FX or 100Base-TX. It also supported 1000Base-SX between Ethernet switches. Providing 10/100/1000Base-TX ports simplified local engineering and technician access to the network. The availability of gigabit switches is especially important for process bus implementation, due to the high bandwidth requirements with SV.
- A high port density on Ethernet switches reduces the number of switches in a substation and lowers costs.
- Managed switches supported virtual local area networks (VLANs) and media access control (MAC) filtering, and provided on-board monitoring of the network.
- Network devices that supported port level VLANs and priority configuration are required. Both GOOSE and SV used VLAN and priority in their message headers. Support for these features increased design flexibility.
- A wide range of media support is required. Typically, most network connections in an IEC 61850 system would use fiber and the connection types will be ether straight tip (ST) or LC. Engineering access or station bus devices required Registered Jack (RJ) 45 copper connections, so the switch needed a number of options available to adapt to project requirements.
- The network must contain devices that are Institute of Electrical and Electronics Engineers (IEEE) 1588 compliant. Devices may need to assume a boundary or transparent clock role to successfully deliver IEEE 1588 Precision Time Protocol (PTP) Power Profile messages to end devices or other switches.
- Network devices should have a wide range of power supply options. This reduces inventory and minimizes confusion with multiple power supply voltages.
    - At a minimum, switches should support DC supply voltages. The network will be part of the P&C scheme; therefore, DC supplies will increase reliability.
    - Network devices with redundant power supplies provide another option for increasing the reliability of the network. Network devices with one alternating current (AC) and one DC supply are available and can provide additional redundancy in the event of an AC outage or DC failure.

Minimum Wide Area Network (WAN) Communication Requirements

The minimum WAN communications requirements for an IEC 61850 substation using GOOSE and SV are unchanged from that of a typical substation. IEC 61850 process bus traffic does not typically extend beyond the substation itself. This allows the existing WAN communication infrastructure to remain in place until other requirements mandate a change.

Cybersecurity Considerations for Switched Networks

The following items apply to Ethernet networks in general and are not specific to IEC 61850 implementations. The following discussion provides recommended practices.

Good design practice includes cybersecurity that starts at the design phase of any communications network. The following elements associated with the Ethernet switch configuration and operation, follow National Institute of Standards and Technology (NIST) SP 800-82r2 guidance for designing a communications network with cybersecurity as a major component of the design and architecture. Compliance with these recommendations should be the bare minimum requirements in a substation deployment.

Network Segmentation and Segregation

Logical segmentation of communication networks provides effective risk management by establishing domains of authority, trust, or function. Managing data flow between domains allows more effective control of overall network traffic and provides points of isolation in the case of an incident. Segregating a substation control network in multiple process bus and station bus segments provides this isolation.

The implementation of IEEE 802.1Q VLANs provides the ability to logically segregate traffic between predefined ports on switches. This reduces the traffic on any segment so only required traffic is present. Although VLANs are an effective method to segregate traffic, they should not be used for security.

Disabling unused ports is a simple way to reduce the attack surface in a network. NERC CIP-007-6 R1 has requirements for high and medium impact bulk electric systems (BES) Cyber Systems that can be deployed on most networks. Once a port is disabled, traffic cannot pass. This is a low cost option to enhance security.

MAC Address Security

In general, Ethernet switches have the option to provide MAC address security, or port security, for each physical Ethernet interface. The MAC address for the connected device is entered into the switch configuration and prevents different devices from using the Ethernet ports on the switch. This option helps maintain a consistent configuration management baseline and reduces the chances of a malicious device being connected to the network. There are ways to "spoof" MAC addresses, so the protection is not assured, but the risk reduction associated with malicious devices and the benefits to configuration management are attractive.

For substation deployment, using port security on those ports dedicated to permanent devices and leaving the laptop ports open from MAC address security, but authenticated using IEEE 802.1X authentication is one way to enhance security.

Device Passwords

All device passwords, including special passwords for field service technicians, are recommended to be changed from the factory default passwords. These default passwords are well known and easily

obtained by hackers. Replacement passwords should use a minimum of the criteria as defined in NERC CIP-007-6 R5.5 (listed below) or the maximum supported by the device.

- 5.5.1. Password length that is, at least, the lesser of eight characters or the maximum length supported by the Cyber Asset; and

- 5.5.2. Minimum password complexity that is the lesser of three or more different types of characters (e.g., uppercase alphabetic, lowercase alphabetic, numeric, non-alphanumeric) or the maximum complexity supported by the Cyber Asset.

The passwords are recommended to be changed on a periodic cycle, such as every 15 calendar months.

Devices with multi-level passwords provide increased resistance to password attacks and require sequential access before the configuration level is reached. This provides an additional recommended level of security.

Monitoring and Logging

Monitoring and logging activities are imperative to understanding the current state of the communications network, validating that the system is operating as intended, and ensuring that no policy violations or cybersecurity incidents have hindered the operation of the system. Network security monitoring is valuable to characterize the normal state of the substation communications network and can provide indications of compromised systems when signature-based technologies fail.

For substation deployment, it is recommended to use on-board logging and monitoring for project troubleshooting that can be easily configured to send logs and events to a centralized logging and monitoring server once in production.

Operational Requirements

In conclusion, an IEC 61850 substation will have additional operational requirements compared to current, conventional SDG&E substations. These additional requirements were critical to the proper functionality of the substation protection system, and thus were critical to system safety and reliability. These requirements reach into many areas of the substation and affect all protection use cases. This includes virtual lockouts since the functionality for these virtual devices resides in the protection relays themselves. LAN topology and operation was affected in order to support the protection functions of the system. The communication system was not greatly affected; however, in areas of the WAN and engineering access, the necessary studies will be required.

The changes in how the IEC 61850 substation is expected to operate include:

- Time synchronization
- Communications
- Battery sizing

Time synchronization is critical to protective functions since the validity of data streams is dependent upon the merging units being synchronized to the time source. Without synchronization, the relays will not properly receive the SV streams and GOOSE messages to which they subscribe.

Communication networks are critical and entail many different aspects. Without the proper communication networks, relays cannot receive the data they need to detect faults or to send trip

commands. The communication system includes Ethernet cables, fiber optic cables, and networking equipment, all of which must be operational and designed with the specific tasks in mind in order to maintain good communications.

An IEC 61850 substation will likely require a larger battery/DC system than a traditional substation. This is due to the addition of MUs and other IEDs)which must be powered at all times so that they can send and receive SV and GOOSE messages as required for protective functions.

As a final note, this design places potential Cyber Assets in the substation yard and therefore, they may be subject to operational requirements of NERC critical infrastructure protection (CIP) regulations.

8. TEST SYSTEM SPECIFICATION

The system specification summarized each use case and defined the architecture, layout, and interface requirements for the test system. The testing phase of the project was split into two separate phases. For the first phase, the equipment was tested in the contractor's lab using both conventional and IEC 61850 enabled test sets. The first phase also included the pre-commercial demonstration, which was performed while the equipment was in the contractor's lab. After a successful pre-commercial demonstration of each test case, the equipment was shipped to the ITF where it was interfaced with the RTDS. Select test cases were then tested a second time using the RTDS to drive the merging units.

Rack Limitations

Excluding the test sets, all of the project's equipment was to be mounted in equipment racks. The test system was designed to limit the number of equipment racks as much as possible. The test system was initially mounted at the contractor's lab in four-post racks. This mounting arrangement required six racks to hold all of the equipment.

In order to accommodate relocation of the test system to the ITF, the space to be occupied by the equipment had to comply with the available rack space. The ITF's Power Systems/RTDS Lab had only three racks available for project demonstrations. The additional racks would need to be located in the ITF's DER Lab.

With the above limitations in mind, the test system was constructed with three racks of protective devices and networking equipment that would ultimately located in the DER Lab. The remaining three racks would be would be located in the Power Systems/RTDS Lab and contain MUs, test switches, and breaker simulators.

Electrical

Testing was performed in a lab environment so electrical power limits, available bus voltages, and voltage drop constraints were observed. Each rack was equipped with two AC power outlet strips. The AC load for any rack was limited to 10 amperes. The DC load available was limited by the size of the DC power supplies. The DC power supplies were sized to provide a maximum of 1,000 watts to be shared between three racks in the ITF Lab.

Voltages

As much as possible, the test system strived to duplicate the equipment voltages in a typical utility substation. To this end, the DC voltage level was constrained to 125 Vdc (DC Voltage) when practical. 120 Vac (AC Voltage) was available in both the ITF and the contractor's lab. Supplemental sources were available to provide additional voltage levels when needed. Since the test system was installed in adjacent racks, wiring runs were inherently short and line currents were small. For this reason, voltage drop calculations were not performed.

Networking

The equipment and design for the test system network and time synchronization provided a flexible infrastructure to support functions for an IEC 61850 environment. The design provided various network medium connection options and different methods for time synchronization that were referenced in the IEC 61850 standard to support the various equipment used in this test system. The test system infrastructure also demonstrated fiber solutions, which were required between equipment located in a substation yard and in a substation control shelter via the process bus or station bus.

Figure 1 shows a portion of the test system network and time synchronization connection diagram. The intent of this diagram was to show various equipment capabilities and provide a means for documenting the different use case scenario configurations. The full diagram can be viewed in Appendix C.

Fiber

To emulate a substation to the greatest extent possible, multi-mode fiber cables were used. These typically would extend from the control shelter to substation yard equipment.

Copper

The station bus, monitoring and configuration cabling installed for the protection relays, was primarily copper category 5 Ethernet (CAT5e) cable.

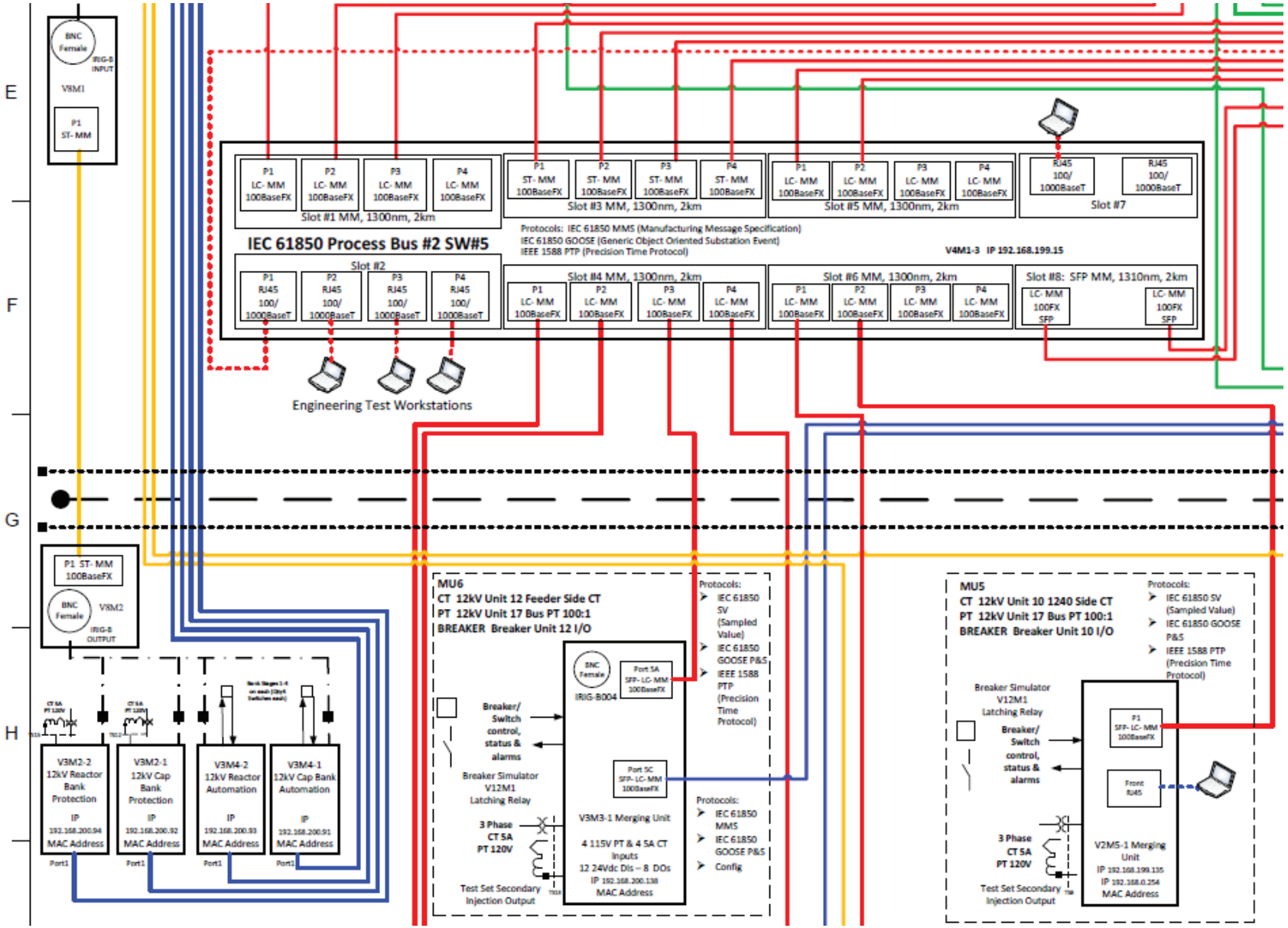


FIGURE 1 DETAIL OF NETWORK DIAGRAM

Network Capabilities

The network was designed to provide 100 megabit fast Ethernet to each end device. Communications between switches supported Ethernet at a speed of one gigabit. Due to the traffic volume associated with an IEC 61850 implementation, the network supported MAC address filtering, priority configuration, and port level VLANs. Each of these items was enabled and configured as required to ensure timely packet delivery.

Network Security

The test system's three networks were isolated, having no remote connectivity to other networks. The network equipment selected for this project was supplied with security features that can be enabled if necessary.

Test Set Interface

Manufacturers' test sets had their Ethernet configuration ports connected to the station bus for engineering programming access. The Ethernet port, on the test set with SV capability, was temporarily connected to one of the two process bus networks depending on the use case test scenario testing with SV messages. The station bus interface was used for configuration and monitoring of the test sets. All test sets were assigned a connection point into the system networks.

Network Tools

The following network tools were used as applicable to monitor the test system environment:

- Freeware network protocol analyzer
- Network monitor using IEC 61850 MMS
- Various manufacturer configuration and event viewing software
- Manufacturer built-in web clients

Station Bus

The station bus was the main substation network that provided the information connectivity between different process buses, substation systems, and other corporate/enterprise-level systems. For this test system, the station bus used IEC 61850, GOOSE, and various configuration and diagnostic protocols. It also provided engineering access to the various protection equipment and test sets for monitoring, control, and configuration. In addition, this network was connected to an IEEE 1588 PTP master clock to provide time synchronization to supporting devices.

Process Bus

The process bus networks were isolated from the station bus. The primary purpose of this network was to transfer information between the equipment MUs and devices requiring the information.

Process Bus #1

Process bus #1 used two managed switches, configured in a star architecture. It supported IEEE 1588 PTP Power Profile, using an isolated connection to the global positioning system (GPS) clock. This process bus integrated all of the equipment required to demonstrate the use cases for the HS of the transformer and transformer protection. The HS test cases were:

- Test Case #1 – Breaker Failure Protection (50BF)
- Test Case #2 – Line Differential Protection (87L)
- Test Case #3 – Line Distance and Directional Overcurrent Protection (21 & 50/51)

- Test Case #4 – High Voltage (HV) Bus Overcurrent Differential Protection (87B-50/51)
- Test Case #5 – HV Bus Restrained Current Differential Protection (87B)
- Test Case #6 – HV Bus High Impedance Differential Protection (87B-HIZ)
- Test Case #7 – Transformer Restrained Current Differential Protection (87T)
- Test Case #8 – Transformer Overcurrent Protection (50/51T)
- Test Case #15 – Line Frequency and Voltage (81, 27, and 59)

Process Bus #2

Process bus #2 uses a single managed switch. It supported IEEE 1588 PTP Power Profile, using an isolated connection to the GPS clock. This process bus integrated all of the equipment required to demonstrate the use cases for the LS of the transformer. The LS test cases were:

- Test Case #9 – 12kV Bus Partial Overcurrent Differential Protection (87B-51P/G)
- Test Case #10 – 12kV Bus Restrained Current Differential Protection (87B)
- Test Case #11 – Capacitor and Reactor Feeder Overcurrent Protection (50/51)
- Test Case #12 – Capacitor Bank Unbalance Protection (59N)
- Test Case #13 – Reactor Unbalance Protection (51Q)
- Test Case #14 – Reactor and Capacitor Bank VAR Control Automation

Test System Time Synchronization

The synchronization of all devices to a single clock was important in determining performance using time stamps and the use of SV. For the MUs and their subscribers, synchronized time was a critical component for publishing and subscribing SV messages. Each end required the same time synchronization in order to interpret the SV within the same time reference. This test system was designed to provide a number of time synchronization options that meet the IEC 61850 requirements.

There were four different methods for time synchronization represented in the IEC 61850 standard that were implemented in this test system: IEEE 1588 PTP; inter-range instrumentation group (IRIG)-B; simple network time protocol (SNTP); and 1 pulse per second (1PPS). The selected PTP GPS clock was anticipated to perform all test system time synchronization. This clock provided four independent network connections that provided PTP and SNTP while leaving the various networks isolated from each other. It also provided eight programmable 1PPS and IRIG-B outputs. These different time source options provided support for the varied manufacturer offerings for time synchronization.

Some devices required fiber optic inputs or it might have been desired that other devices utilize a fiber link from the GPS clock (to better model a substation with fiber connected devices in the yard). This test system used two different manufacturer's solutions to perform this conversion. The first solution covered equipment that had hardwired inputs on both ends, but required a fiber optic interface. This interface was used to time synchronize the reactor and capacitor bank P&C devices. The second interface converted coax to fiber for devices with fiber optic time input from the clock, which has a hardwired BNC connection.

IEEE 1588 Precision Time Protocol (PTP)

The selected clock provided master PTP clock interfaces for all of its network interfaces. The clock also supported an IEEE 1588 PC37.238/D16. *IEEE Draft Standard Profile for Use of IEEE 1588 Precision Time Protocol in Power System Applications* mode of operation. The connections between the clock and the network switches, that support PTP delivery to the end device, were shown in the Test Bed Network and Time Synch Diagram included in Appendix C. This test system used the IEEE

PC37.238 power profile for PTP. The selected switches also needed to be IEEE 1588 compliant. A boundary or transparent clock role was assumed by the switch to successfully deliver IEEE 1588 PTP Power Profile messages to end devices or other switches.

Inter-Range Instrumentation Group (IRIG-B)

Not all devices supported PTP, but they supported IRIG-B. The test system had an IRIG-B un-modulated (DC level shift) bus to provide a time source to these units. The test sets were specified with the IRIG-B input modules to synchronize events and provide time synchronization for SV messages. The test system utilized IRIGB-004, which has the year information encoded in the message.

1 Pulse per Second (1PPS)

Some MUs required 1PPS. The IEC 61850 user group's implementation standard for IEC 61850-9-2 Edition 1, known as IEC 61850-9-2LE, Utility Communications Architecture (UCA) International Users Group *Implementation Guideline for Digital Interface to Instrument Transformers Using IEC 61850-9-2*, specifies using 1PPS for MU time synchronization. The test system included fiber optic transmission equipment for this signal to provide a fiber interface to the MUs. Using this fiber optic interface mimicked field implementation requirements that place MUs in the substation yard.

Simple Network Time Protocol (SNTP)

There would be two uses for the SNTP method of time synchronization. The first was to time synchronize the V2M6 MU. This device only has the option to use SNTP for time synchronization. The second use was for relays V2M1, V2M2, V2M3, and V2M4. These relays required 1PPS inputs for SV messages. In order to maintain a synchronized time, the station bus interface was connected to the clocks SNTP server.

IEC 61850 Information Transfer Protocols

One of the main goals of the project was the reduction in substation P&C wiring. To accomplish this, IEC 61850 protocols were utilized whenever possible.

Manufacturing Message Specification (MMS)

The test system utilized MMS for non-time sensitive communications between individual relays and between relays and other IEDs, such as programmable automation controllers.

Generic Object Oriented Substation Events (GOOSE)

The test system utilized GOOSE messages for time sensitive communications from MUs to relays, between relays. This included messages to operate the breaker simulators and provide status changes to the appropriate relays.

In addition, the test system utilized GOOSE messages to provide volt-ampere reactive (VAR) data from the simulated HS bus to the reactive automation controllers.

Sampled Value (SV)

The test system utilized SV for ampere and voltage measurement communications between merging units and relays.

GOOSE and SV Data Flow Spreadsheet

A spreadsheet was developed to identify the message requirements with publishers and subscribers for both SV and GOOSE messages. Control block parameters were developed during this stage. Both GOOSE and SV messages require the identification of data sets. Each GOOSE message services a

specific purpose in the system operation; therefore, the datasets were different from each other. The IEC 61850-9-2LE document was used to fix the SV datasets so all of these datasets looked the same.

Process Bus Data Flow Diagram

For each process bus, data flow diagrams were developed to show the GOOSE and SV data flows. These diagrams document data flows to and from the devices, and the devices' relationship to the substation equipment. A portion of the data flow diagram can be seen in Figure 2. The complete diagrams can be viewed in Figure 12, Figure 13, and Figure 14.

Additional information on the multicast MAC address was included to allow rapid identification of the data flow in a device configuration file or stiffing the network. SV message addresses always start with 01-0C-CD-04 and GOOSE with 01-0C-CD-01, leaving the remaining two octets available for configuration.

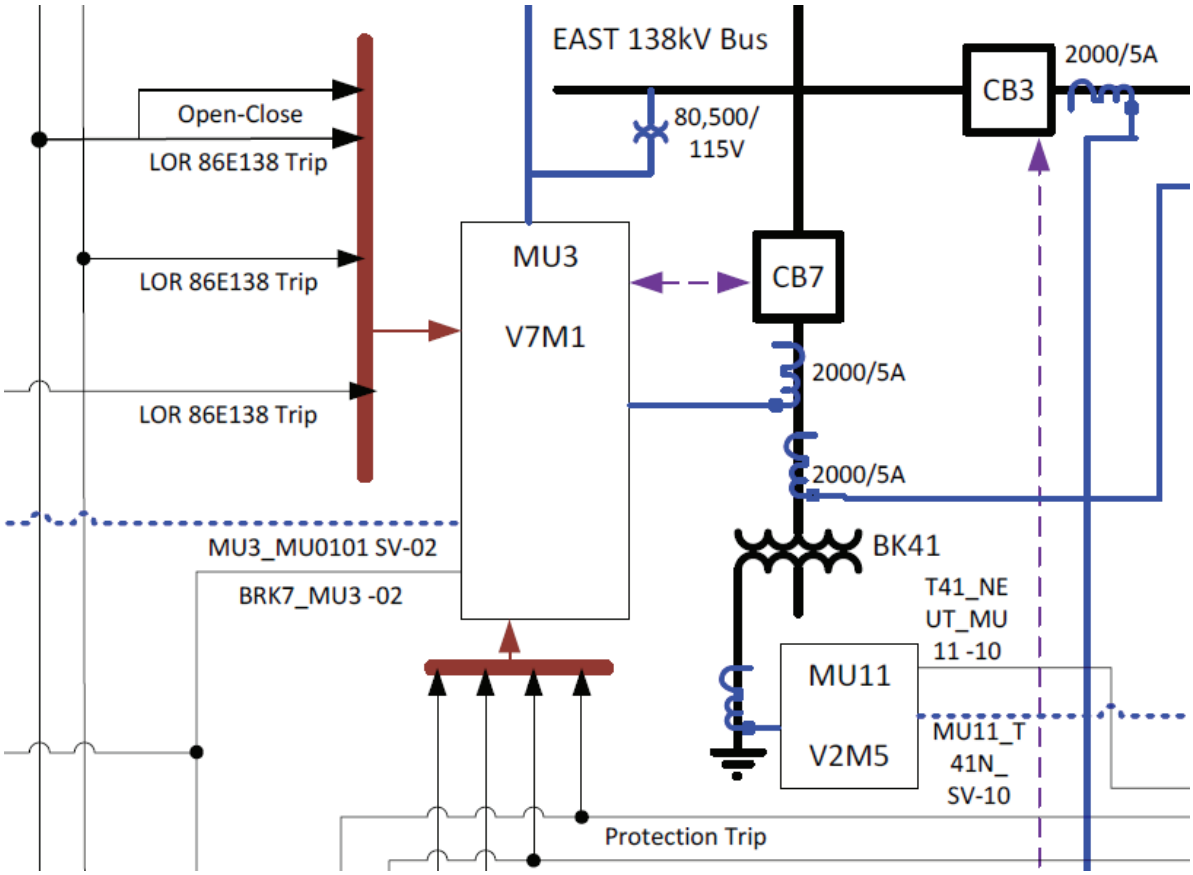


FIGURE 2 DETAIL OF PROCESS BUS DATA FLOW DIAGRAM

Station Bus Data Flow Diagram

For the station bus, a data flow diagram was developed to show the GOOSE and SV data flows. These diagrams documented data flows to and from the devices, and the devices' relationship to the substation equipment.

The only function used for the station bus was reactor and capacitor bank control. With the additional flexibility of GOOSE messaging, the same equipment and control philosophy that was currently used in the typical reactive control systems was used. A HS relay published the required analog measurement data to the controllers using GOOSE messaging. GOOSE messaging was also used to exchange information between the reactive bank protection equipment controllers.

Capacitor and Reactor Bank Automation

Reactor and capacitor bank VAR Control Automation utilized GOOSE analog and digital messaging. This allowed addition and subtraction of capacitor and/or reactor elements based on VAR flow in/out of the distribution step-down transformer as measured on the transformer HS connection. This was accomplished by using the 50/51T relay to measure the VAR flow and then transmit this information via GOOSE to the two automation controllers where the decision-making logic was configured. To prevent adding capacitors when reactors were on line and vice versa, interlocking was performed between the standalone reactor and capacitor bank automation controllers by GOOSE messages. The imbalance relays were then used to perform a lockout function when appropriate.

High Side (HS) and Low Side (LS) Lockout Relays

The lockout relays reproduced the functions of a traditional hardwired lockout relay scheme. To emulate lockout relay functions, a virtual lockout-relaying scheme was be developed using latching variables and close blocking logic within the protection relays. A detailed description of the lockout relay logic can be found in the Test System Design section.

Interfaces

Test Switches

Each MU was provided with a test switch to enable efficient connection from the test set to the MU. Test switches accommodated in-service test plugs to minimize re-wiring of the test set leads. Test switches also limited personnel exposure to energized parts. Test blocks at each MU simulated a real field installation and provide simplified test set connectivity to the MUs secondary current and voltage inputs.

IEDs were supplied with fiber ports whenever possible. When available, IEDs were supplied with at least one copper port. This simplified connection to laptops and other test/monitoring devices.

Device requirements

Relays

The protection equipment had at least one connection to the process bus and at least one connection to the station bus. All information to and from the substation equipment such as a CT, PT, circuit breaker, etc., came through the process bus interface. The station bus interface was used for GOOSE information exchange between process bus bays, SCADA MMS communication, and other uses. The test system used protection relays from three different manufacturers.

Process Bus Merging Units (MUs)

MUs were connected to the process bus and served as the interface to the substation equipment such as a CTs, PTs, circuit breaker, etc. These MUs provided the hardwired connection for the CT, PT, inputs, and output signaling that was digitized over the process bus using IEC 61850 SV and GOOSE. IEDs that subscribed to this information through their process bus connection also had an independent Ethernet connection to the station bus in order to move the required data between bays, substation level systems or corporate/enterprise level systems. These IEDs also published GOOSE messages,

which were subscribed to by the MUs to issue trip, close or other control operations to the equipment. The test system used merging units from five different manufacturers.

Software

Each IED was supplied with all of the software needed to configure and trouble shoot its performance.

Ethernet Switch Features

The Ethernet network switches supported the following features:

- Given the expectation for advanced networking features, all switches were managed. Managed switches allowed for other applications such as security features, MAC filtering, monitoring, etc.
- Support for port level VLANs, multi-cast filtering, and priority configuration was required. Both GOOSE and SV uses VLAN and priority in their message headers.
- The switches supported a wide range of media and provide a high port density.
- Most of the network connections used fiber and the connection types were either straight tip (ST) or LC. There were requirements for engineering access or station bus devices that also required RJ45 connections so the switch must have a number of options available to adapt to the project requirements.
- Gigabit switches were important, especially for the process buses, due to the high bandwidth requirements for SV.
- Each switch was IEEE 1588 compliant and was able to assume a boundary or transparent clock role to successfully deliver IEEE 1588 PTP Power Profile messages to end devices or other switches.

Time Clock

There were a wide range of options for receiving time synchronization information. A GPS clock that can provide all four time synchronization methods listed in the IEC 61850 standard; PTP, Inter-range Instrumentation Group, 1PPS and SNTP was required. Due to limitations of the manufacturers' equipment all four methods were ultimately implemented. This clock also maintained network isolation between each of the process buses and the station bus.

Breaker Simulators

The test system had a means of simulating the circuit breaker operation control and feedback interface with the MUs. Dual coil latching relays ("ice cube" relays) fulfilled this requirement. The dual coils allowed for both a trip and close control connection and one of two Form C contacts provided the position feedback to both the MU and RTDS. Another advantage of these relays was that the contact operation and release time was approximately 25 milliseconds, which was fairly close to the operating times for most circuit breakers.

RTDS and COMTRADE

The necessary RTDS model was developed to allow the RTDS to be utilized during testing. An RTDS was used to develop COMTRADE files that could be used for all testing.

RTDS

The RTDS allowed real-time modeling of power system apparatus including generators, transformers, transmission lines and power system controls. The RTDS was a combination of specially designed parallel processing hardware and customized software with detailed, efficient algorithms for representing power system apparatus.

Closed looped testing of protection systems was achieved by interfacing the analog outputs representing real-time currents and voltages from the power system to the analog inputs on the protection system. The outputs from the protection system were connected to the RTDS to provide control, such as circuit breaker tripping and closing, and to monitor the internal elements in the protection system. In addition, digital statuses, such as circuit breaker position were routed back to the protection system digital inputs. Through these connections, the RTDS and the protection system operated as if connected to an actual power system with all of the dynamics and control actions that typically occur.

The power system components were configured in a graphical user interface program. The detailed apparatus models, controls, and input / output (I/O) configuration tools were all included in the interface program. A detailed model was created that included transmission lines, ideal sources, series capacitors, generators, transformers, circuit breakers, and instrument transformers. The apparatus models were very detailed and provide an accurate representation of the power system response. Figure 3 shows a portion of the model.

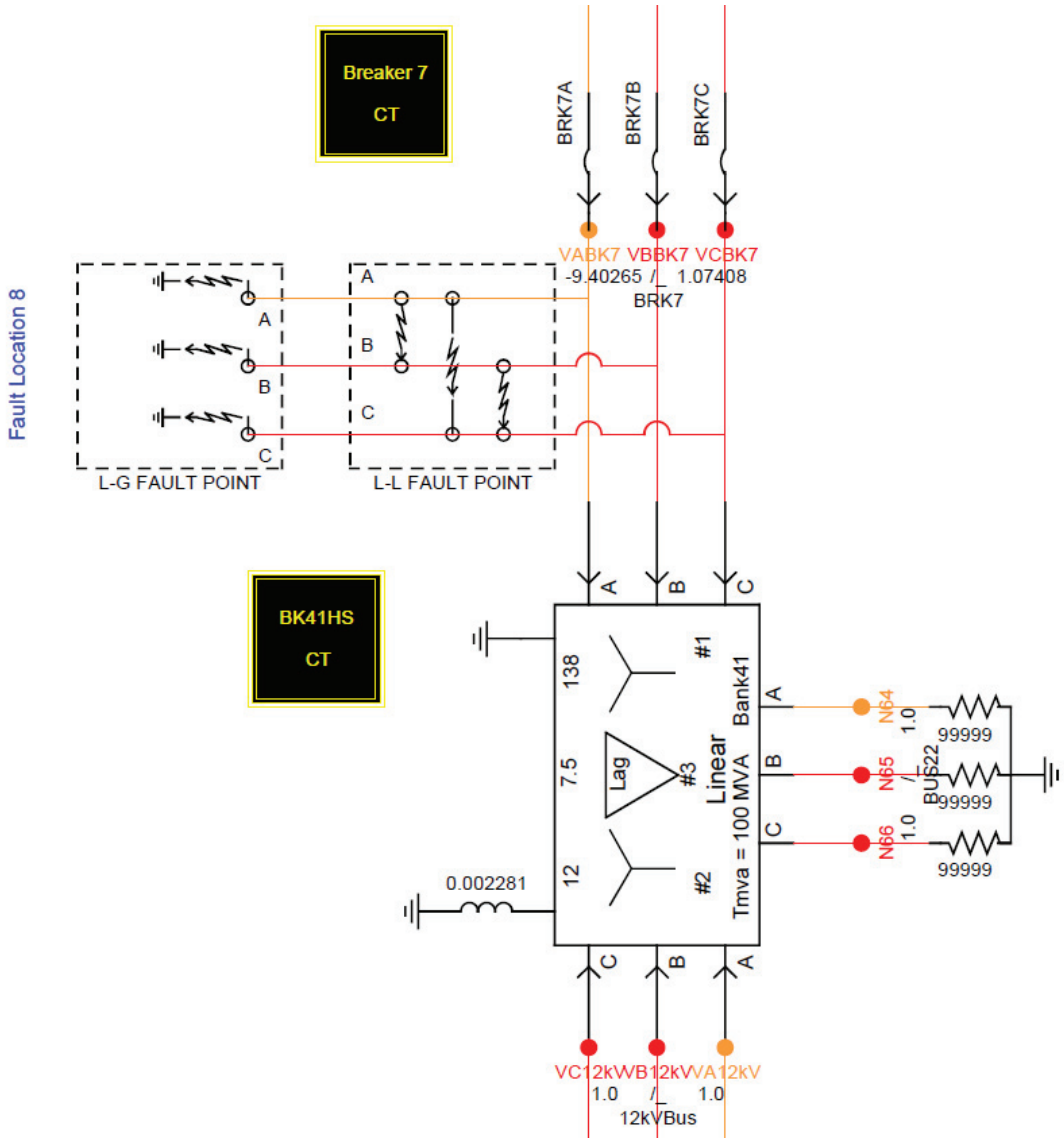


FIGURE 3 DETAIL OF RTDS MODEL SHOWING TRANSFORMER AND FAULTS

The analog waveforms and relay responses that were captured via the RTDS were in a COMTRADE format. The COMTRADE file included all the current and voltages that were being measured by the protection system and the state of the circuit breakers via output contacts from the protection system to the RTDS.

The simulation was run using a 50-microsecond time step (20 kilohertz sample rate). The COMTRADE files were captured at a 2,500 hertz sample rate, which provides 0.4 millisecond resolution of the relay response and changes in the state of the model.

RTDS Model

A power system model was developed using the data supplied. The data included detailed information on the transmission lines, protection, circuit breakers, and transformer characteristics. All transmission lines were modeled using the parameters detailed in the circuit model provided. The

system model was loosely based on an existing substation and included one 138 kV bus, one transmission line, one transformer bank, a 12 kV bus, a 12 kV capacitor bank, and a 12 kV reactor bank.

Equivalent source impedances were calculated at each bus using the Network Boundary Equivalent function in the protection database provided. An additional transmission line was included to represent the equivalent transfer impedance between the two substations due to the interconnected nature of the surrounding system. The sources at each bus were modeled as ideal sources. This baseline model allowed modifications, during testing, to accommodate frequency deviation test, voltage deviation tests, and simulation of alternate source impedances.

COMTRADE FILES

The RTDS system produces low-level analog signals that can be output to an external device under test. In order to get true secondary currents and voltages (5 A or 120 V) an amplifier was required. For testing at the contractor's lab, the results of each RTDS simulation was saved in the COMTRADE format and downloaded into a relay test set, then output to the merging units at secondary current and voltage levels.

Balanced and unbalanced faults were simulated at eight different fault locations (FLTn). For each fault location the current through all 138 kV and 12 kV breakers in the simulation, as well as the 138 kV and 12 kV potentials were saved in COMTRADE format. This arrangement allowed the test sets to output any current, voltage, or combination of the two to all merging units that were under test. A detail of the RTDS model showing the transformer and faults can be seen in Figure 4. The full diagram depicting the complete system and the specific location of each fault (FLT1, FLT2, etc.) is in Appendix B.

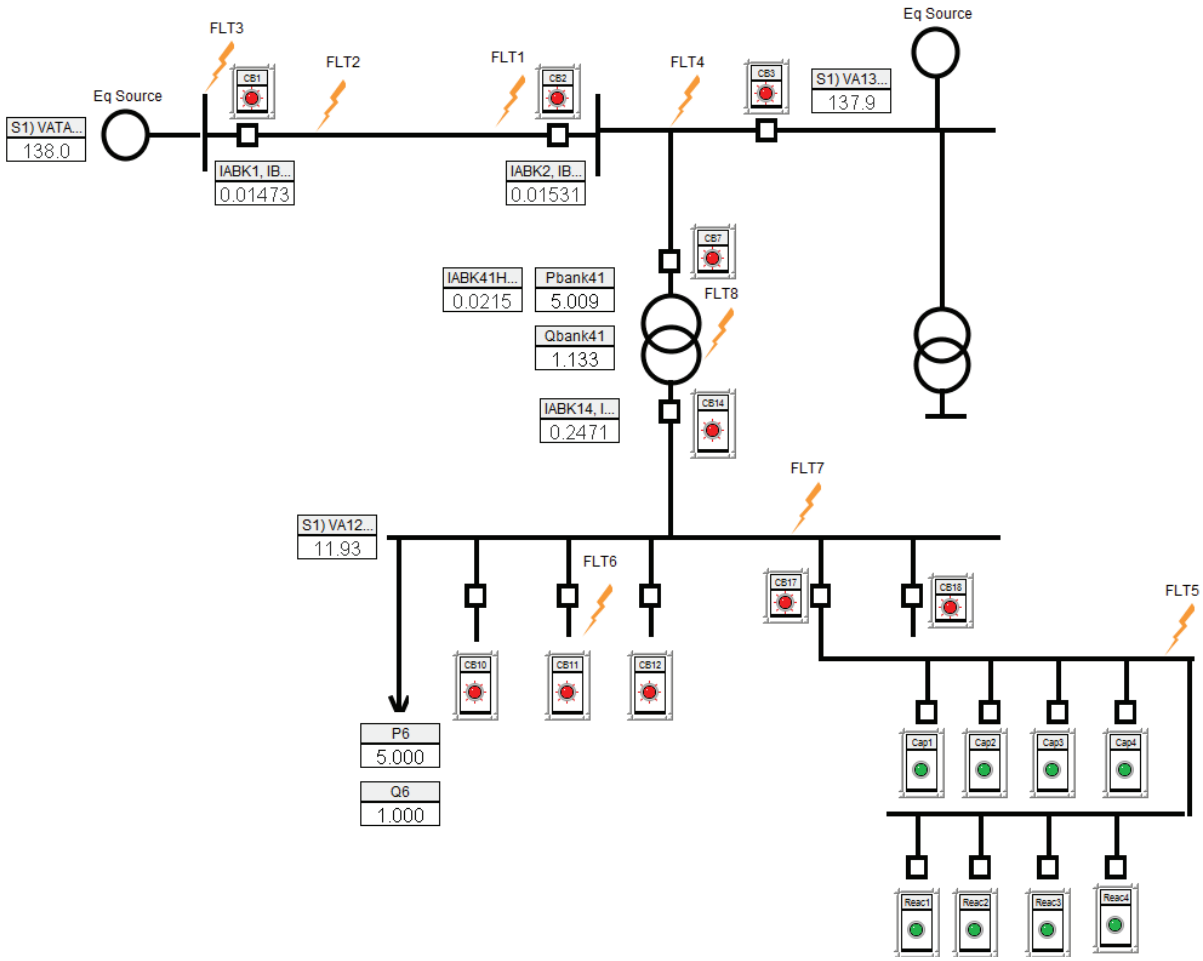


FIGURE 4 SIMPLIFIED ONE-LINE DIAGRAM WITH FAULT LOCATIONS SHOWN

For each protective device under test, analog signals representing in zone and out of zone faults, were injected into the appropriate merging units. The system response was documented to verify that each merging unit was publishing the correct sampled value stream and that the protective devices received and acted on the sampled values as expected.

Wetting voltage

Test system racks were designed so that the breaker simulators could provide the RTDS with simulated breaker position information. The wetting voltage for the RTDS was 5 Vdc (DC Voltage). One set of output contacts from each breaker simulator was available to be connected to an RTDS digital input module. These connections were performed just prior to the demonstration at the ITF.

Integrated Test Facility (ITF) Evaluation

An ITF evaluation was performed as part of this project. The evaluation identified the equipment available at SDG&E's ITF that was necessary to perform the required testing and any material or equipment that would require procurement to perform the testing. The project team acquired the material and equipment to accommodate the test system's racks that were located in the two separate labs.

9. TEST SYSTEM DESIGN

The test system was designed to allow testing of the required study use cases using either relay test sets or RTDS low-level signal amplifiers. Test sets were used at the consultant's lab and the amplifiers were used at ITF with the RTDS. The test system was designed with test switches so that either the test sets or the amplifiers could be used to inject secondary amps and voltage simulation signals into the merging units of the test system. Breaker simulation was provided by latching relays with Form C contacts. The breaker simulator relays provided status indication to the merging units and to the RTDS. Figure 5, below, is a simplified illustration of the test system configuration showing the simulated substation yard and control shelter.

The test system was designed with one station bus and two process buses. One process bus represented the devices on the 138 kV bus and the second represented the equipment on the 12 kV bus. This supported concurrent testing of both buses. Protection relays were connected to both the station bus and the process bus associated with the relay's protective function. Time synchronization was provided by a GPS referenced clock to ensure all the system IEDs were operating from the same time source. This clock provided time synchronization via four protocols: Precision time protocol (PTP, IEEE 1588), IRIG-B, 1PPS, and SNTP. These four time-code options were required to support the varying requirements of the IEDs in the test system.

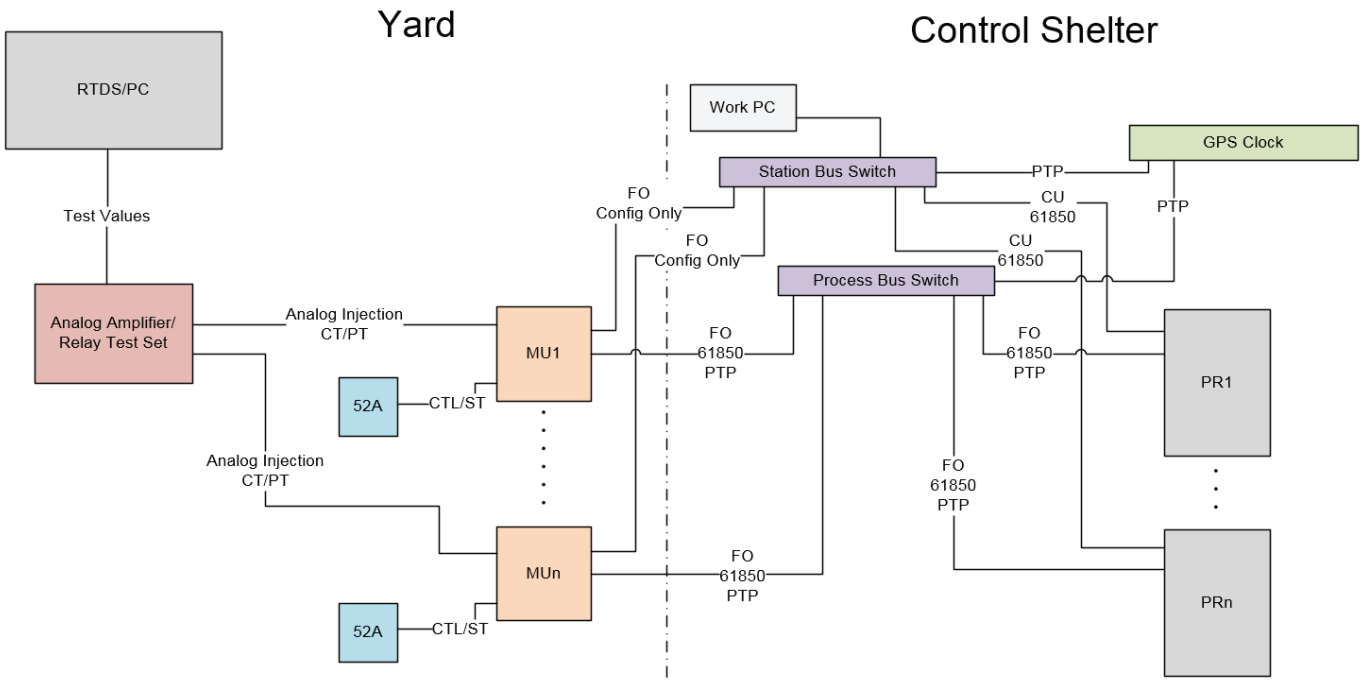


FIGURE 5 SIMPLIFIED TEST SYSTEM DIAGRAM

For the simplest breaker trip scenario, SV traffic from an MU was published to the process bus where a relay subscribes to the SV stream. This relay applies the numerical data to its built-in protection algorithms and when applicable, it publishes a trip message via GOOSE to the process bus. The MU subscribes to this message and when a trip GOOSE message was received, it closes an output contact. A breaker simulator relay coil wired to the MU operates when the output contact closes. When the breaker simulator relay contact, which was wired to an MU digital input, opens a status change (52A)

was provided to a digital input on the MU. In response to the 52A status change, the MU publishes a GOOSE message to the process bus. The relay subscribes to this breaker status message and performs any configured response such as lighting LEDs, tagging event reports or recording disturbance reports. Further detailed information was included in the attached appendices.

Design process

The design process is summarized in Figure 6 shown below. From the baseline information, the protection and test environment requirements were determined. Using the single line diagrams, from the identified substation, the CTs, PTs, and breakers required to implement the test cases were determined.

The next step was to determine the functional requirements of the equipment and place them within the single line of the substation. The functional requirements also included breaker simulators, test set injection points, and consideration for space requirements within the two labs.

With the functional requirements identified, the data requirements for each piece of equipment, for both the data source and data destination, were reviewed. This established the general functional equipment and the general data flows for the GOOSE and SV messaging.

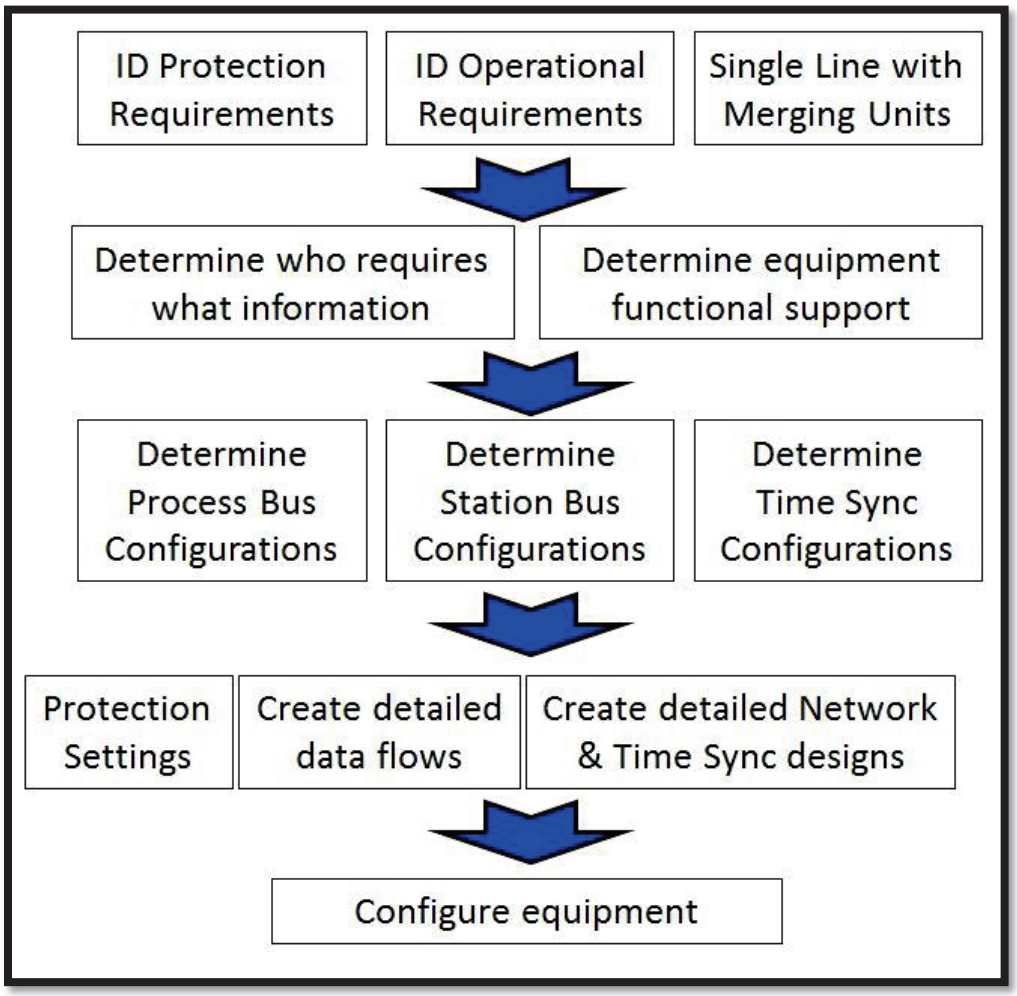


FIGURE 6 DESIGN PROCESS

The next phase was to design the infrastructure to support the IEC 61850 system. Using the information provided by the data flows, it was determined that the test system needed two independent process buses. The independent process buses limited the SV traffic to approximately six SV streams per bus leaving sufficient network bandwidth for GOOSE, PTP, and other configuration and diagnostic software tools. Separate process buses also provided separation of the HS bus test cases from the LS bus test cases, which allowed for concurrent testing of test cases on each process bus.

The single station bus created a communications path between all the protection devices, which left the two process buses isolated from any other networks. The station bus network allowed for GOOSE data exchange between all protection relays and connectivity for device and test set configuration.

The next phase of the design created the protection settings and detailed information for the GOOSE and SV control blocks and data sets. All intelligent components of the system required time synchronization to provide accurate event time stamps and support the time synchronization requirement for SV messages. Knowing that there was a variety of implementation schemes for receiving time synchronization information, a GPS clock that provided the four time synchronization methods listed in the IEC 61850 standard: PTP, IRIG-B, 1PPS and SNTP was specified. The last step was to take all of the design information and configure the equipment. Figure 7 shows a summary of the steps required to complete this phase of the design.

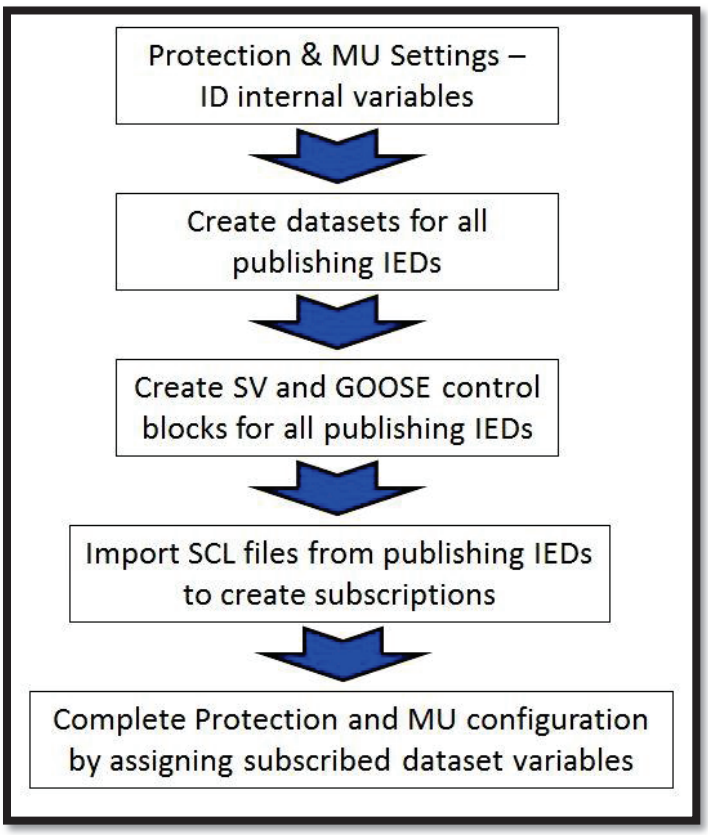


FIGURE 7 DEVICE CONFIGURATION PROCESS

The first step in this process was to determine which internal device data points were used for each functional data exchange. For each of these internal data points, there was an IEC 61850 substation configuration language (SCL), logical node data attribute was assigned for transporting GOOSE messages. For SV messages, all of the manufacturers claimed to support the IEC 61850-9-2LE implementation which, if true, would fix the SV data set. This information was then entered into the detailed data flow tables which were used for configuring the data sets in the test system equipment.

After the data sets were created, the detailed data flow tables were used to create the GOOSE and SV control blocks. Within these control blocks the multicast MAC address, AppID and GOOSE - SV identification (ID) were assigned. At this stage, all published GOOSE and SV messages could be configured.

The next step was to configure all of the required subscriptions. To do this each manufacturer's configuration software tool outputted a device IEC 61850 IED (intelligent electrical device) capability description (ICD), instantiated IED description (IID), configured IED description (CID), or system configuration description (SCD) file. These files contained all the available data set GOOSE and SV information for a device to subscribe to them. The files were then imported into the manufacturer configuration software tool where the subscribing device and specific data points within the message data set were linked to the devices internal points. Once this was done all of the "virtual wires", published messages, and subscription messages, were completed. Information exchanges were then linked from merging units to protection relays and from protection relay to protection relay.

The last step was to configure the devices using this information to fulfill its primary role as defined in the test cases. The following sections explain in greater detail for each of the major phases of the design process.

Material Identification and Procurement

Running in parallel to the design process, and using key information from it, was the equipment vendor selection process. Due to the project's aggressive schedule, manufacturers with significant presence in the United Sates were investigated. In addition, compliance with the following guidelines was required:

- All potential products were required to use a non-proprietary implementation of IEC 61850 MMS, GOOSE, and SV.
- Interoperability, with other manufacturers' products, was a requirement.
- All potential products were required to be commercially available during the project.

The project team identified four relay and merging unit manufacturers. A third party MU manufacturer was also identified. Requests for Information were then developed and in-person interviews with the four identified relay manufacturers were conducted. The interviews included a manufacturer presentation and time for questions and answers. The project team worked with the manufacturers to identify the necessary products and develop the required part numbers.

In order to investigate interoperability, the project required a minimum of two manufacturers for each use case whenever possible. Discussions with the manufacturers were required to identify the necessary relays, merging units, GPS clock, switches and ancillary equipment/materials. The information obtained from these efforts was used to guide the part number development.

Before relay test set procurement could begin, the project team determined the capabilities at the ITF and the available features from the manufacturers. Since the tests would inject currents and voltages from a traditional relay test set and the ITF testing would utilize an RTDS, a single SV test set was determined to be sufficient. At the end of the process, the use of rental test sets was identified to minimize costs. The total number of test sets was determined to allow concurrent testing of several of the use cases described above.

Procurement of the materials and test sets was a joint effort between the project team parties. All purchased materials and equipment were shipped to the contractor's office.

Preliminary Design Process

The preliminary design focused on the requirements to perform the test cases listed in the Test Cases section of this document. Using the single line prints for the identified substation specific protection devices, CTs, PTs and circuits were selected for the tests. The identified substation did not deploy backup protection schemes, but for the purpose of including multiple manufacturers in the testing, backup schemes were deployed. A means of simulating circuit breaker operation control and feedback interface with the MU was also required. Dual coil latching relays ("ice cube" relays) fulfilled this requirement. The dual coils allowed for both a trip and close control connection and the two form C contacts provided position feedback to both the MU and RTDS. The contact operation and release time of 25 milliseconds (ms) was fairly close to the operating times for most circuit breakers. Test blocks at each MU to both simulate a real field installation and provide easy test set connectivity to the MUs secondary current and voltage inputs were included.

From the baseline, methods for implementing the use cases and their protection requirements were known. The goal was to implement test cases using IEC 61850 and some of its supporting standards. To do this every CT and PT required a MU to replace the traditional CT and PT wiring with published IEC 61850 SV messages. Each circuit breaker required supervision from a MU. From the baseline study the data requirements for each of the protection relays and which breakers they would trip during a protection event were known.

In order to provide a clearer picture of all the publication and subscription requirements between devices and MUs the spreadsheet in Appendix D was created. Figure 8 shows the structure of the matrix. The left hand side lists the protection relays at the top followed by the merging units at the bottom. Along the top were the CT and PT equipment followed by the circuit breakers required to provide the protection relays with the information and controls needed to perform their operations. The matrix identified which MU was connected to which CT and PT. It also identified which MU provided the trip/close controls and position feedback for each of the various circuit breakers. Finally for each of the protection relays the matrix identified what CT and PT information they required and which circuit breakers they needed to control.

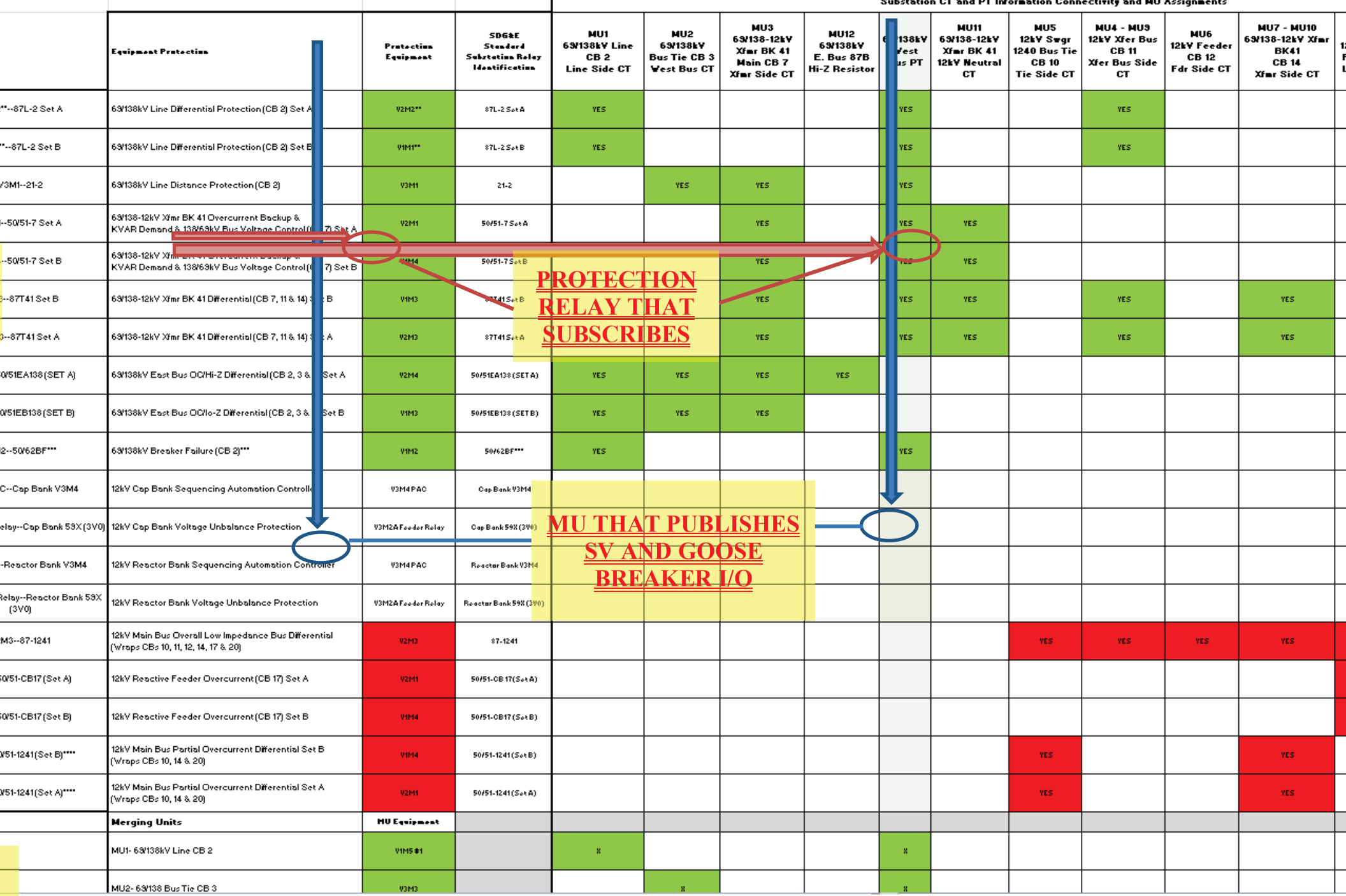


FIGURE 8 IED 61850 SYSTEM GOOSE AND SV MESSAGE MATRIX

Once the matrix was completed, the subscriptions for each protection relay from each of the MUs for published SV and GOOSE messages were available. These data flows provided the protection relays with the secondary current and voltage samples needed to perform their protection functions and status indication of the circuit breakers' position. Working in reverse this matrix also defined which MUs needed to subscribe to the published GOOSE messages from the protection relays, which execute the trip actions. Additionally the matrix provided a clear overview of the data flow segregation between devices such that the network traffic could be isolated into separate process buses. Two process buses were identified and color coded in the matrix using GREEN for process bus #1 and RED for process bus #2.

One of the testing goals was to digitize the test case implementation including lock out relays. With the matrix completed, identification of which protection relays initiate the lock out and which of the protection relays house the digital lock out logic could be determined. Once the lock out logic within this relay was set, the only means to reset it was through a physical interface with the relay's front panel pushbuttons.

The use cases did not include any SCADA operations, but in order to demonstrate the lock out operation one protection relay, that would be the SCADA control interface for the circuit breakers within a process bus, was selected. This logic required additional data flows (published data and subscriptions) for initiating lock outs and blocking circuit breaker close commands.

Figure 9 shows the lock out and SCADA supervisory device information added to the matrix. Using the base line information, identified substation single line, and the data flows developed from the MU matrix, there was enough information to develop a preliminary design. This design included a network diagram, data flow tables and protection criteria.

PROTECTION RELAY THAT DRIVES THE LOCK OUT

PROTECTION RELAY THAT IS THE LOCK OUT

	Equipment Protection	Protection Equipment	SDG&E Standard Substation Relay Identification	Lockouts and SCADA Contro		
Set B	69/138-12kV Xfmr BK 41 Differential (CB 7, 11 & 14) Set B	V1M3	87T41 Set B	LOR 86T41		
Set A	69/138-12kV Xfmr BK 41 Differential (CB 7, 11 & 14) Set A	V2M3	87T41 Set A	LOR 86T41	86T41 Master LOR Relay	
38 (SET A)	69/138kV East Bus OC/Hi-Z Differential (CB 2, 3 & 7) Set A	V2M4	50/51EA138 (SET A)	LOR 86E138	86E138 Master LOR Relay	SCAD
38 (SET B)	69/138kV East Bus OC/Io-Z Differential (CB 2, 3 & 7) Set B	V1M3	50/51EB138 (SET B)	LOR 86E138		
BF***	69/138kV Breaker Failure (CB 2)***	V1M2	50/62BF***	LOR 86E138		
ank V3M4	12kV Cap Bank Sequencing Automation Controller	V3M4 PAC	Cap Bank V3M4			
Bank 59X (3V0)	12kV Cap Bank Voltage Unbalance Protection	V3M2A Feeder Relay	Cap Bank 59X (3V0)	LOR 59X CAP	59XCAP Master LOR Relay	
Bank V3M4	12kV Reactor Bank Sequencing Automation Controller	V3M4 PAC	Reactor Bank V3M4			
tor Bank 59X (3V0)	12kV Reactor Bank Voltage Unbalance Protection	V3M2A Feeder Relay	Reactor Bank 59X (3V0)	LOR 59X REAC	59XREAC Master LOR Relay	
241	12kV Main Bus Overall Low Impedance Bus Differential (Wraps CBs 10, 11, 12, 14, 17 & 20)	V2M3	87-1241	LOR 86B1241	86B1241 Master LOR Relay	SC 10,1

PROTECTIO THAT SERVE SCADA INTE

Test System Network

The equipment and design for the test system network and time synchronization provided a flexible infrastructure to support functions for an IEC 61850 environment. The design provided various network medium connection options and different methods for time synchronization per the IEC 61850 standard to support the various equipment used in this test system. Specifically, the test system infrastructure must demonstrate fiber solutions, which will be required between equipment located in the substation yard and substation control shelter via the process bus.

There were many different manufacturers that could provide equipment and fulfill the requirements for this test system. Manufacturer selection included previous experience with the product, discussion with product manufacturers, providing a multi-vendor test environment, and the products' specifications to meet the requirements for the test system.

The diagram shown in Appendix C was the test system network and time synchronization connection diagram. The intent of this diagram was to show the various equipment capabilities and provide a means for documenting the different use case scenario configurations.

Each network port used in this test system was assigned an IP address that was associated with the network to which it was connected. Some of these ports were required for testing and some were required for point to point connection for access. In some cases the network connection ports did not support transmission control protocol (TCP) /IP. These ports only provided a, non-routable, layer 2 MAC interface for GOOSE and SV messaging.

There were some devices that did not support both GOOSE and SV messages on the same port. These devices had two separate network connections to the process bus.

Station Bus

The station bus was the main substation network that provided the information connectivity between different process buses, substation systems and enterprise systems. For this test system the station bus used IEC 61850, GOOSE and various configuration and diagnostic protocols. It also provided engineering access to the various protection equipment and test sets for monitoring, control and configuration. In addition, this network was connected to an IEEE 1588 PTP master clock to provide time synchronization to supporting devices.

The station bus was the communications conduit for device-to-device GOOSE messages allowing for the transfer of information between isolated process bus networks. IEC 61850 MMS was used to access SCADA, configuration and health information from the various devices. It was also used to test the system supervisory control close blocking by the digital lockouts.

Managed switches made up the station bus. These switches had a mixture of copper RJ45 and multimode fiber connections to accommodate the different manufacturer connectivity options. All network traffic used virtual local area network #1.

Process Bus

Each process bus was designed as a separate network that was isolated from the station bus and the other process bus network. The primary purpose of this network was to transfer information between the equipment MUs and devices requiring the information. MUs typically had only a single process bus interface vs. protection relays that had independent process bus and station bus interfaces. Some manufacturers' protection relays provided independent process bus interfaces, with one only

supporting SV messages and the other only supporting GOOSE. Other manufacturers' MUs provided independent station bus interfaces.

The test system used both IEC 61850 SV and IEC 61850 GOOSE protocols. The process buses were also connected to an IEEE 1588 PTP master clock to provide time synchronization to supporting devices. The test system equipment had fiber optic options to emulate real world solutions that would be deployed in the field. The network diagram indicated the demarcation between the substation yard equipment and the substation control shelter equipment with a dashed line. All communications paths crossing this line used fiber optics, which would be the communications medium of choice for process bus connectivity.

There were two independent process bus networks designed into the test system to accommodate different test case scenarios divided between the high side and low side of the transformer. Each process bus had at least four engineering access ports to be used for monitoring and device configuration. The network and its equipment were designed to allow concurrent test case testing on both process bus #1 and #2. All network traffic used virtual local area network #1.

Process Bus #1

Process bus #1 used two managed switches. It was configured in a star design without using high-availability seamless redundancy (HSR) or parallel redundancy protocol (PRP). This process bus integrated all of the equipment required to demonstrate the test cases for the high side of the transformer and transformer protection. It supported IEEE 1588 PTP Power Profile, using an isolated connection to the GPS clock.

Some of the devices connected to the network did not manage all the SV and GOOSE traffic. When some devices dropped packets due to a central processing unit (CPU) overload condition, static MAC filtering on some of the ports was deployed. This solved problems and relieved the affected device of the additional burden on parsing all the messages.

Process Bus #2

Process bus #2 was a single managed switch. It was configured in a star design without using HSR or PRP. It supported IEEE 1588 PTP Power Profile, with an isolated connection to the GPS clock. This process bus integrated all of the equipment required to demonstrate the test cases for the low side of the transformer.

To prevent the same dropped packet problem, seen on process bus #1, static MAC filtering, as used on process bus #1, was deployed.

Test Set Interface

Each test set was connected via Ethernet to the station bus for engineering programming access. The SV capable test set's Ethernet port was temporarily connected to one of the two process bus networks, depending on the SV message needs of the test case scenario. The station bus interface was used for configuration and monitoring of the test sets. All test sets were assigned a connection point into the system networks.

Test System Time Synchronization

All devices were time synchronized to a single clock to allow verification of performance using time stamps and the use of SV. For the MUs and their subscribers, synchronized time was a critical component for publishing and subscribing SV messages. Each end required the same time synchronization in order to interpret the SV within the same time reference. This test system was designed to provide a number of time synchronization options that met the IEC 61850 requirements.

The selected clock supported four independent network connections to provide PTP and SNTP while leaving the various networks isolated from each other. It also provided eight programmable 1PPS and IRIG-B outputs. These different time source options provided support for the varied manufacturer offerings for time synchronization.

In order to maintain the test system's scheme for fiber optic cabling between the MU racks and switch/relay racks, fiber was required. Some devices, however only provided support for copper time signals. When a device required a fiber optic input, or the device required a fiber link directly from the GPS Clock, the test system used two different manufacturer solutions to perform this conversion. The first solution covered equipment on both ends that had hardwired inputs but required fiber optic cabling between the clock and the end device. V8M1 and V8M2 were used to support the copper inputs and provide a fiber channel between the two sets of racks. This interface was used to time synchronize the reactor and capacitor bank P&C devices. The second interface covered devices that required fiber optic time input from the clock's copper output. A V8M1 fiber convertor was used for this interface.

IEEE 1588 PTP

The PTP connections included the connections between the clock and the network switches to support PTP delivery to the end device. This test system used the IEEE PC37.238 power profile for PTP. The following PTP configuration parameters were used:

V3M5 Clock:

- The clock identification was 10
- Power Profile (Layer 2)
- 1 step
- Station bus domain 0, process bus #1 domain 1 and process bus #2 domain 2

Ethernet Switches:

- Power Profile (Layer 2)
- 1 step
- Domain as the network requires
- Transparent Clock
- All ports enabled
- MAC filtering enabled as required per port

The following equipment was configured to use PTP:

- V3M1 and V3M3
- V7M1
- V6M1
- V1M1, V1M2, V1M3, V1M4
- V2M5
- All network Ethernet switches

IRIG-B

For the devices that did not support PTP but supported IRIG-B, the test system used an IRIG-B unmodulated (DC level shift) signal to provide a time source. In addition, the relay test sets were specified with the IRIG-B input modules to synchronize events and provide time synchronization for the V10M1's SV messages. IRIG-B-004 was used to include the year information in the message.

The following equipment was configured to use IRIG-B:

- All test sets
- V1M5 MU
- V2M2 remote station protection relay

1PPS

For relays and MUs that required 1PPS, the test system included fiber optic transmission equipment to provide a fiber interface to the devices in the simulated substation yard.

The following equipment was configured to use fiber optic 1PPS:

- V2M1, V2M2, V2M3

SNTP

There were two uses for this method of time synchronization. The first was to time synchronize the V2M6 MU. This device only supported SNTP for time synchronization. The second use was for the V2M1, V2M2, V2M3, and V2M4 process bus connected protection relays. These relays required 1PPS inputs for SV messages.

The following equipment was configured to use SNTP:

- V2M1, V2M2, V2M3, and V2M4 process bus connected protection relays
- V2M6 MU

Process bus MUs

MUs were connected to each process bus and served as the interface to the analog substation equipment such as CTs, PTs, circuit breakers, etc. These MUs provided the hardwired connection for the instrument transformer inputs and output signaling that was digitized over the process bus using IEC 61850 SV and GOOSE. These IEDs also published GOOSE messages which were subscribed to by the MUs to issue trip, close or other control operations to the equipment. The test system used merging units from five different manufactures.

IEC 61850 Editions

With the multi-vendor environment there were varied implementations of the IEC 61850 part editions. A base edition to design the system around and determine if there were any compatibility issues between the manufacturers was required. During testing and despite claims on the device support of IEC 61850-9-2 LE Editions 1 or 2, there were implementation differences from the LE document. In some cases this caused an incompatibility problem between SV publishers and subscribers. The following summarizes some of these differences identified.

The SV dataset in LE was fixed and used the data model from IEC 61850-7-4 ed1. In Figure 10 the dataset name “PhsMeas1” and the order of the logical nodes, data objects and attributes follow the LE document, current ABCN followed by voltage ABCN. The prefix was built using the substation section of the SCL, identifying both the sensor and the phase.

The logical node data objects used the common data class (CDC) SAV. The LE document defined a fixed scaling for the “SVClscaleFactor” and “sVC.offset” attributes.

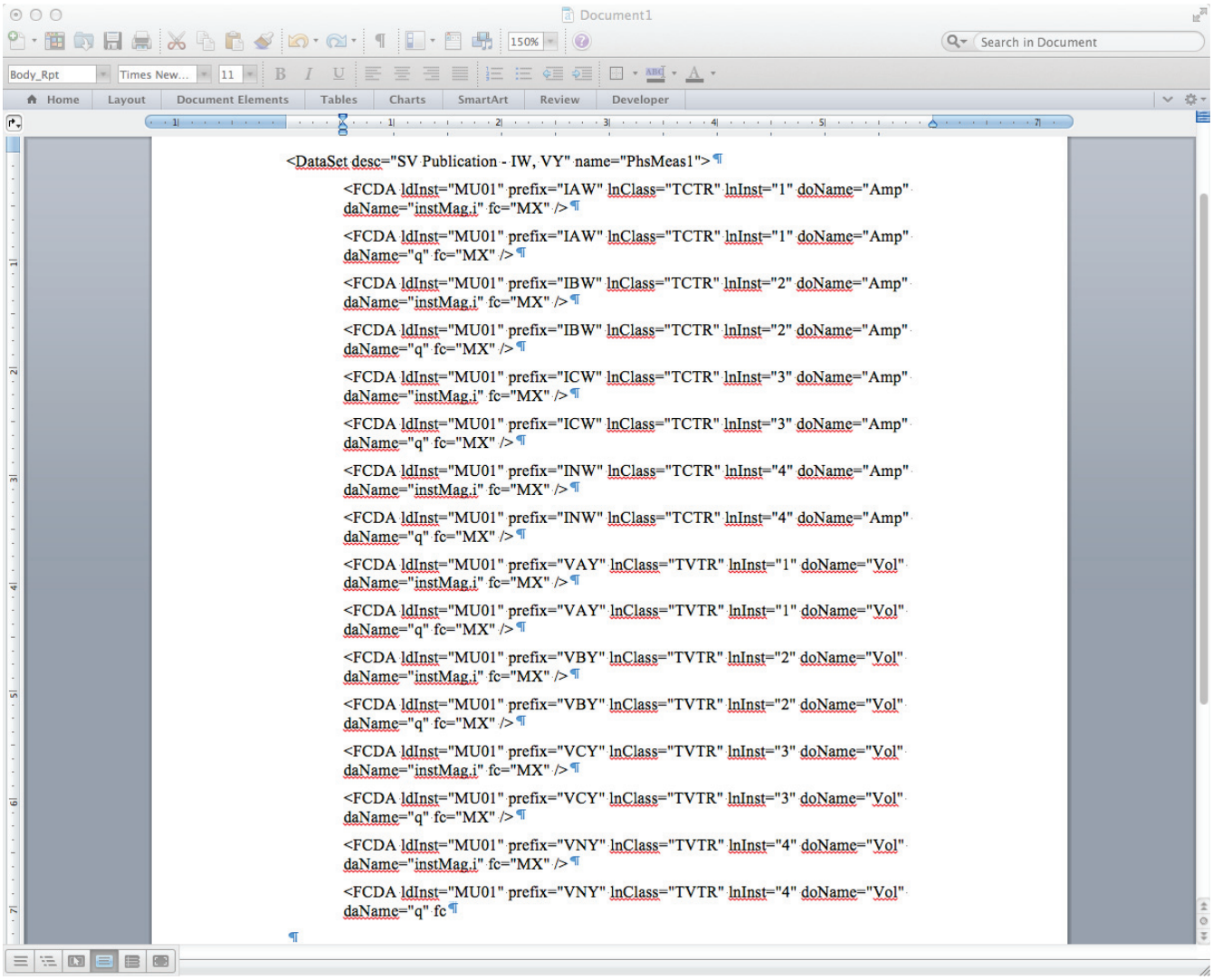


FIGURE 10 IEC 61850-9-2LE SV DATASET, EDITION 1

In edition 2, the “doName” was changed for the logical nodes as follows

- “TVTR” was changed to “TCTR”
- ”Amp” was changed to “AmpSv”
- “Vol” was changed to “VolSv”

Figure 11 shows the model for a different LE merging unit, which has the order and dataset naming correct but has implemented the edition 2 changes to the model.

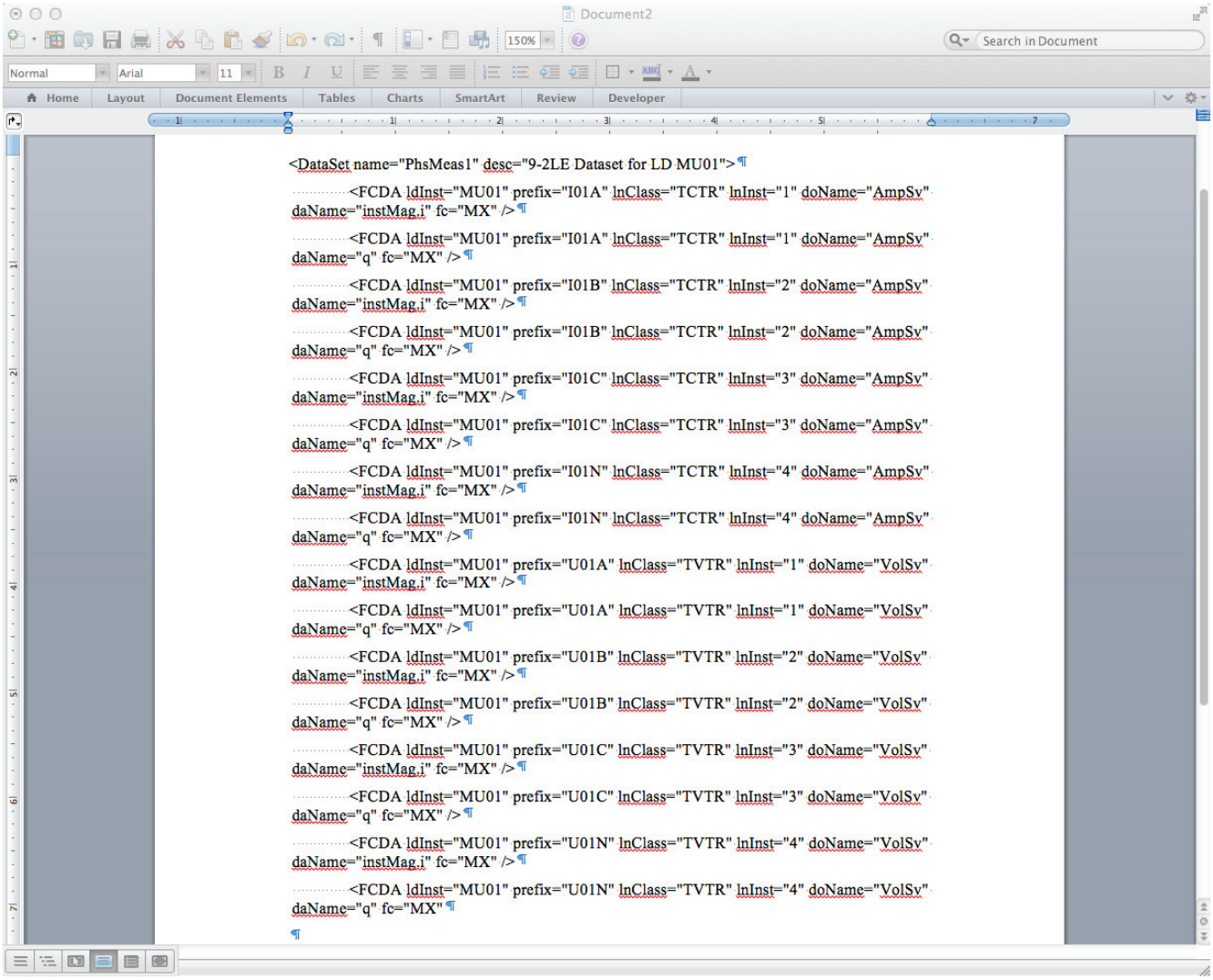


FIGURE 11 IEC 61850-9-2 SV DATASET, EDITION 2

Some of the merging units which were set to publish the LE streams sent the edition 2 model vs. the edition 1 model. Examples of this included:

- Clock source in LE was to be 1PPS but most devices did not accept 1PPS taking in its place either or both were IRIG-B or IEEE 1588. There were a number of LE publishers and subscribers which only used IRIG-B or IEEE 1588 for time synchronization.

- The SV control block in all cases matched the edition 1 requirements for LE. Some manufacturers allowed the users to select and de-select control block options to provide additional support for edition 2 SV streams. The multicast sampled value control block (MSVCB) for edition 1 had the following structure (taken from IEC 61850-7-4 Edition 1 2004-04):

    MsvCBNam ObjectName
    MsvCBRef ObjectReference
    SvEna Boolean
    MsvID Visible-string
    DatSet ObjectReference
    ConfRev Integer
    SmpRate Integer
    OptFlds
        refresh-time Boolean
        sample synchronized Boolean
        sample-rate Boolean

The LE document fixed the value for some of these fields. For the protection profile which was used in testing, the SmpRate should be 80; OptFlds: refresh-time could be true or false; sample-synchronized should be true; and sample-rate should be false. The svID and dataset naming conventions were defined.

The SV message buffer was also defined in the LE document but some differences in implementation were identified. The edition 1 message buffer format, minus the header format, was structured as follows (taken from IEC 61850-7-4 Edition 1 2004-04):

- MsvID or UsvID - Should be a system-wide unique identification.
- DatSet- ObjectReference datset OPTIONAL. The value was from the MSVCB.
- SmpCnt- Will be incremented each time a new sampling value was taken. The counter shall be set to zero if the sampling was synchronized by clock signal (SmpSynch = TRUE) and the synchronizing signal occurs. When sync pulses were used to synchronize merging units, the counter shall be set to zero with every sync pulse. The value 0 shall be given to the data set where the sampling of the primary current coincides with the sync pulse.
- ConfRev- The value was from the MSVCB.
- RefrTm contains the refresh time of the SV buffer. OPTIONAL
- SmpSynch- BOOLEAN value, TRUE = SV are synchronized by a clock signal. FALSE = SV are not synchronized.
- SmpRate- The value was from the MSVCB.
- Sample [1..n] Type depends on the common data class defined in IEC 61850-7-3.

The LE document also defined the message buffer format as having the svID, smpCnt, confRev, smpSynch and the data (samples). The OPTIONAL DatSet and RefrTm were not included. The LE stated that as long as the merging unit was time synchronized the “SmpSynch” should be set to TRUE (Boolean). The SmpCnt should behave as specified in IEC 61850-7-2 Edition 1.

In edition 2, there were a few changes to both the MSVCB format and attribute definitions. The following lists these changes:

The "OptFlds" changed as follows:

OptFlds

"refresh-time" was the same

"sample" synchronized was now ignored and kept to ensure backwards compatibility

"sample-rate" was the same

"data-set" was added

"security" was added

"SmpMod" was added in order to identify the method of sampling.

There were a few changes in edition 2 to both the SV message buffer format and attribute definitions. The following lists these changes:

The "SmpSynch" has changed from Boolean to INT8U and the definitions of the values changed as follows:

0= SV are not synchronized by an external clock signal.
1 = SV are synchronized by a clock signal from an unspecified local area clock.
2 = SV are synchronized by a global area clock signal (time traceable).
5 to 254 = SV are synchronized by a clock signal from a local area clock identified by this value
3; 4; 255 = Reserved values – Do not use.

The "SmpMod" data object was added to communicate the method of synchronization taken from the MSVCB.

The biggest impact identified was that most venders claiming to have an LE edition of the SV stream went ahead and implemented the edition 2 definition for the "SmpSynch." This meant that a merging unit that was time synchronized and following the LE document would set this value to TRUE. A SV subscriber using the edition 2 definition would interpret the value of TRUE to a numerical 1 meaning that it was not synchronized. This was identified on one of the test system's merging units.

- The use of GOOSE messaging between editions did not presented a problem. The only changes made in edition 2 were to change the test field to a simulation field. Since this was not used in testing, the edition 1 and 2 devices functioned with both messages. Half of the merging units only implemented edition 2 GOOSE along with some of the protection relays. The exception was the V3M4 which only supported edition 1. No problems were identified in implementing GOOSE solutions for the test system but due to every device except the V3M4 supporting edition 2 we chose to create our projects based on edition 2.
- SCL file schemes and structures changed in edition 2. Some manufacturer's configuration tools accepted both edition 1 and 2 files while others required the user to declare the edition at the start of a project and only accept that edition's files. From the matrix the team determined that all of the software tools would accept edition 2 files verses edition 1 files. This was also a factor in the decision to create the project as an edition 2 project.

TABLE 16 and Table 17 show a summary of the project's edition 1 LE and edition 2 support for SV, GOOSE and configuration system SCL files between the various manufacturer equipment and software tools. These matrices summarized the manufacturer support for each edition based on the

option codes selected at the time of purchase. Options may be available to revise the assessments, in these figures, but the listed results were specific to the products selected for this project. In many cases the manufacturers support exceeded the requirements of the specific edition even when strict compliance was not identified.

TABLE 16 PROTECTION DEVICE IEC 61850 EDITION MATRIX

			IEC 61850 Edition 2			IEC 61850 Edition 1			Configuration Tool		
Protection Description	Protection Equipment	Standard Substation Relay Identification	61850-8-1: GOOSE	61850-9-2: SV	SCL Files	61850-8-1: GOOSE	61850-9-2 LE: SV	SCL Files	Accepts both editions (1 & 2) within the same project?	Will use 9-2 LE using both editions?	Input file types
69/138kV Line Differential Protection (CB 2) Set B	V1M1**	87L-2 Set B	YES	NO	YES: .SCD, .ICD, .IID	YES	YES	YES: .SCD, .ICD, .IID	NO	YES	.SCD, .ICD, .IID
69/138kV Line Distance Protection (CB 2)	V3M1	21-2	YES	NO	YES: .CID	NO	YES	YES: .CID	YES	YES	.ICD, .CID
69/138-12kV Xfmr BK 41 Overcurrent Backup &	V2M1	50/51-7 Set A	YES	NO	YES: .CID, .ICD, .IID	NO	YES	YES: .CID, .ICD	NO	YES	.SCD, .ICD, .IID, .CID
69/138-12kV Xfmr BK 41 Overcurrent Backup & KVAR Demand & 138/69kV Bus Voltage Control (CB 7) Set B	V1M4	50/51-7 Set B	YES	NO	YES: .SCD, .ICD, .IID	YES	YES	YES: .SCD, .ICD, .IID	NO	YES	.SCD, .ICD, .IID
69/138-12kV Xfmr BK 41 Differential (CB 7, 11 & 14) Set B	V1M3	87T41 Set B	YES	NO	YES: .SCD, .ICD, .IID	YES	YES	YES: .SCD, .ICD, .IID	NO	YES	.SCD, .ICD, .IID
69/138-12kV Xfmr BK 41 Differential (CB 7, 11 & 14) Set A	V2M3	87T41 Set A	YES	NO	YES: .CID, .ICD, .IID	NO	YES	YES: .CID, .ICD	NO	YES	.SCD, .ICD, .IID, .CID
69/138kV East Bus OC/Hi-Z Differential (CB 2, 3 & 7) Set A	V2M4	50/51EA138 (SET A)	YES	NO	YES: .CID, .ICD, .IID	NO	YES	YES: .CID, .ICD	NO	YES	.SCD, .ICD, .IID, .CID
69/138kV East Bus OC/Io-Z Differential (CB 2, 3 & 7) Set B	V1M6	50/51EB138 (SET B)	YES	NO	YES: .SCD, .ICD, .IID	YES	YES	YES: .SCD, .ICD, .IID	NO	YES	.SCD, .ICD, .IID
69/138kV Breaker Failure (CB 2)***	V1M2	50/62BF***	YES	NO	YES: .SCD, .ICD, .IID	YES	YES	YES: .SCD, .ICD, .IID	NO	YES	.SCD, .ICD, .IID
12kV Cap Bank Sequencing Automation Controller	V3M4	Cap Bank V3M4	NO	N/A	NO	YES	N/A	YES: .CID - MANUAL CHANGE TO .ICD	YES	N/A	.ICD, .CID
12kV Cap Bank Voltage Unbalance Protection	V3M2	Cap Bank 59X (3V0)	YES	N/A	YES: .CID - MANUAL CHANGE TO .ICD	YES	N/A	YES: .CID - MANUAL CHANGE TO .ICD	YES	N/A	.ICD, .CID
12kV Reactor Bank Sequencing Automation Controller	V3M4	Reactor Bank V3M4	NO	N/A	NO	YES	N/A	YES: .CID - MANUAL CHANGE TO .ICD	YES	N/A	.ICD, .CID
12kV Reactor Bank Voltage Unbalance Protection	V3M2	Reactor Bank 59X (3V0)	YES	N/A	YES: .CID	YES	N/A	YES: .CID	YES	N/A	.ICD, .CID
12kV Main Bus Overall Low Impedance Bus Differential (Wraps CBs 10, 11, 12, 14, 17 & 20)	V2M3	87-1241	YES	NO	YES: .CID, .ICD, .IID	NO	YES	YES: .CID, .ICD	NO	YES	.SCD, .ICD, .IID, .CID
12kV Reactive Feeder Overcurrent (CB 17) Set A	V2M1	50/51-CB (Set A)	YES	NO	YES: .CID, .ICD, .IID	NO	YES	YES: .CID, .ICD	NO	YES	.SCD, .ICD, .IID, .CID
12kV Reactive Feeder Overcurrent (CB 17) Set B	V1M4	50/51-CB (Set B)	YES	NO	YES: .SCD, .ICD, .IID	YES	YES	YES: .SCD, .ICD, .IID	NO	YES	.SCD, .ICD, .IID
12kV Main Bus Partial Overcurrent Differential Set B (Wraps CBs 10, 14 & 20)****	V1M4	50/51-1241 (Set B)****	YES	NO	YES: .SCD, .ICD, .IID	YES	YES	YES: .SCD, .ICD, .IID	NO	YES	.SCD, .ICD, .IID
12kV Main Bus Partial Overcurrent Differential Set A (Wraps CBs 10, 14 & 20)****	V2M1	50/51-1241 (Set A)****	YES	NO	YES: .CID, .ICD, .IID	NO	YES	YES: .CID, .ICD	NO	YES	.SCD, .ICD, .IID, .CID

TABLE 17 MERGING UNIT IEC 61850 EDITION MATRIX

			IEC 61850 Edition 2			IEC 61850 Edition 1			Configuration Tool		
Merging Units	MU Equipment	Standard Substation Relay Identification	61850-8-1: GOOSE	61850-9-2: SV	SCL Files	61850-8-1: GOOSE	61850-9-2 LE: SV	SCL Files	Will accept both editions (1 & 2) within the same project?	Will use 9-2 LE using both editions?	Input file types
MU1- 69/138kV Line CB 2	V1M5 #1		YES	NO	YES: .SCD, .ICD, .IID	YES	YES	YES: .SCD, .ICD, .IID	NO	YES	.SCD, .ICD, .IID
MU2- 69/138 Bus Tie CB 3	V3M3		YES	NO	YES: .CID - MANUAL CHANGE TO .ICD	NO	YES	YES: .CID	YES	YES	.ICD, .CID
MU3- 69/138-12kV Xfmr BK 41 CB 7	V7M1 #1 CKT 1		YES	YES	YES: .CID	NO	YES	YES: .CID	YES	YES	.ICD, .CID
MU4- 12kV Xfer Bus CB 11	V7M1 #1 CKT 2		YES	YES	YES: .CID	NO	YES	YES: .CID	YES	YES	.ICD, .CID
MU5- 12kV Swgr 1240 Bus Tie CB 10	V2M5		YES	NO	YES: .CID, .ICD, .IID	YES	YES	YES: .CID, .ICD	NO	YES	.SCD, .ICD, .IID, .CID
MU6- 12kV Feeder CB 12	V3M3		YES	NO	YES: .CID - MANUAL CHANGE TO .ICD	NO	YES	YES: .CID	YES	YES	.ICD, .CID
MU7- 69/138-12kV Xfmr BK41 CB 14	V2M5		YES	NO	YES: .CID, .ICD, .IID	YES	YES	YES: .CID, .ICD	NO	YES	.SCD, .ICD, .IID, .CID
MU8a- 12kV Reactive Feeder CB 17	V2M6		YES	N/A	YES: .CID, .ICD, .IID	YES	N/A	YES: .CID, .ICD	NO	YES	.SCD, .ICD, .IID, .CID
MU8b- 12kV Reactive Feeder CB 17	V6M1		YES	YES		NO	YES		N/A	YES	.icd
MU9- 12kV Xfer Bus CB 11	V7M1 #2 CKT 1		YES	YES	YES: .CID	NO	YES	YES: .CID	YES	YES	.ICD, .CID
MU10- 69/138-12kV Xfmr BK41 CB 14	V7M1 #2 CKT 2		YES	YES	YES: .CID	NO	YES	YES: .CID	YES	YES	.ICD, .CID
MU11- 69/138-12kV Xfmr BK 41 12kV Neutral CT	V2M5		YES	NO	YES: .CID, .ICD, .IID	YES	YES	YES: .CID, .ICD	NO	YES	.SCD, .ICD, .IID, .CID
MU12- 69/138kV E. Bus 87B Hi-Z Resistor	V3M3		YES	NO	YES: .CID - MANUAL CHANGE TO .ICD	NO	YES	YES: .CID	YES	YES	.ICD, .CID
MU13- 12kV Swgr 1242 Bus Tie CB 20	V1M5 #2		YES	NO	YES: .SCD, .ICD, .IID	YES	YES	YES: .SCD, .ICD, .IID	NO	YES	.SCD, .ICD, .IID

These tables indicated that the manufacturers mostly supported edition 2 along with SV LE. Based on this the project planned to use the edition 2 project files. As the project proceeded and more details on the manufacturers' SV LE implementations were identified, it was determined that none of the manufacturers strictly followed the LE implementation guide. This led to some potential interoperability concerns. In order to determine the IEC 61850 edition for the project to use, a comparison was performed for each manufacturer's IEDs using a strict interpretation of the requirements from the LE implementation guide. With the "No-Any" entry, the items so identified could be configured to become compliant. and Table 19 show the LE agreement implementation items on the left and to the right the tables show how the manufacturers implemented them.

Most of the manufacturers had moved to implement edition 2 features while attempting to maintain the LE compliance which was based on edition 1. Some manufacturers strictly enforced some of the items and made changes in others in order to accommodate both edition 1 and 2. The use of the SmpSynch field in the SV message buffering and the AppID were the two most noticeable items. As stated above, the SmpSynch definition and data type were changed in edition 2 and one merging unit that strictly used the LE implementation for this field would not communicate with a protection device that strictly used the IEC 61850 edition 2 implementation.

In many cases the manufacturers have added support for features in excess of the LE implementation guide. For this case, the table showed a response such as "NO-any." In these cases, the manufacturers were not strictly compliant with the LE implementation guide. However, the manufacturers' products could support the requirement due to enhanced configurability that was added to their products. The "No-Any" entry, indicates that items so identified could be configured to become compliant.

	LPHD	YES	YES	YES	YES	YES
	InnATCTR1	YES	YES	YES	YES	YES
	InnBTCTR2	YES	YES	YES	YES	YES
	InnCTCTR3	YES	YES	YES	YES	YES
	InnNTCTR4	YES	YES	YES	YES	YES
	UnnATVTR1	YES	YES	YES	YES	YES
	UnnBTVTR2	YES	YES	YES	YES	YES
	UnnCTVTR3	YES	YES	YES	YES	YES
	UnnNTVTR4	YES	YES	YES	YES	YES
Logical Nodes data	As defined in IEC 61850-7-4 & 7-3 ed1	NO- Uses ed2	YES	NO	NO- Uses ed1	NO- Uses ed2
DataSet	xxxxMUnn/LLN0$PhsMeas1	NO- ed2	YES	YES	NO- ed2	NO- ed2
DS MemberRef	InnATCTR1.Amp	NO- ed2	YES	YES	NO- ed2	NO- ed2
	InnBTCTR2.Amp	NO- ed2	YES	YES	NO- ed2	NO- ed2
	InnCTCTR3.Amp	NO- ed2	YES	YES	NO- ed2	NO- ed2
	InnNTCTR4.Amp	NO- ed2	YES	YES	NO- ed2	NO- ed2
	UnnATVTR1.Vol	NO- ed2	YES	YES	NO- ed2	NO- ed2
	UnnBTVTR2.Vol	NO- ed2	YES	YES	NO- ed2	NO- ed2
	UnnCTVTR3.Vol	NO- ed2	YES	YES	NO- ed2	NO- ed2
	UnnNTVTR4.Vol	NO- ed2	YES	YES	NO- ed2	NO- ed2
DS MemberRef Data Order	Ordered as shown above	YES	YES	YES	YES	YES
SAV Common data Class	instMag.i: INT32	YES	YES	YES	YES	YES
	sVC.scaleFactor: FLOAT32- .001 for current and .01 for voltage	YES	YES	YES	YES	YES
	sVC.offset: FLOAT33- Always 0	YES	NO- any	YES	YES	YES
Multicast Sampled Value Control Block (MSVCB) Name	xxxxMUnn/LLN0$MSVCB01	NO- any	YES	NO- any	YES	YES
-NoASDU	1	YES	YES	YES	YES	YES
- OptFlds- security	FALSE	YES	YES	YES	YES	YES
- OptFlds- data-set	FALSE	YES	YES	YES	YES	YES
MsvID	xxxxMUnn01	NO- any	YES	NO- any	NO- any	NO- any
SmpRate	80	YES	YES	YES	YES	YES
OptFlds- refresh-time	TRUE/FALSE	YES	YES	YES	YES	YES
- sample-synchronized	TRUE	YES	YES	YES	YES	YES
- sample-rate	FALSE	YES	YES	YES	YES	YES
Clock Source	1PPS +/-1µsec accuracy optical input	YES	NO IEEE 1588	NO IEEE 1588 & IRIG-B	NO IRIG-B	YES
Nominal frequency	50 or 60 Hz	YES	YES	YES	YES	YES
Physical Layer	100BaseFX ST or MT-RJ or 100BaseTX RJ-45	NO LC	NO LC	NO LC	NO LC	NO LC
AppID	Shall always be 0x4000	NO- any	NO- any	NO- any	NO- any	NO- any
Quality IEC 61850-7-3 extended	attribute "derived" BOOLEAN	YES	NO	YES	YES	NO
Message Buffer-	Shall behave as specified in					

Logical Nodes	LLNO	N/A	N/A	N/A
	LPHD	N/A	N/A	N/A
	InnATCTR1	N/A	N/A	N/A
	InnBTCTR2	N/A	N/A	N/A
	InnCTCTR3	N/A	N/A	N/A
	InnNTCTR4	N/A	N/A	N/A
	UnnATVTR1	N/A	N/A	N/A
	UnnBTVTR2	N/A	N/A	N/A
	UnnCTVTR3	N/A	N/A	N/A
	UnnNTVTR4	N/A	N/A	N/A
Logical Nodes data	As defined in IEC 61850-7-4 & 7-3 ed1	N/A	N/A	N/A
DataSet	xxxxMUnn/LLN0$PhsMeas1	N/A	N/A	N/A
DS MemberRef	InnATCTR1.Amp	N/A	N/A	N/A
	InnBTCTR2.Amp	N/A	N/A	N/A
	InnCTCTR3.Amp	N/A	N/A	N/A
	InnNTCTR4.Amp	N/A	N/A	N/A
	UnnATVTR1.Vol	N/A	N/A	N/A
	UnnBTVTR2.Vol	N/A	N/A	N/A
	UnnCTVTR3.Vol	N/A	N/A	N/A
	UnnNTVTR4.Vol	N/A	N/A	N/A
DS MemberRef Data Order	Ordered as shown above			
SAV Common data Class	instMag.i: INT32	N/A	N/A	N/A
	sVC.scaleFactor: FLOAT32- .001 for current and .01 for voltage	N/A	N/A	N/A
	sVC.offset: FLOAT33- Always 0	N/A	N/A	N/A
Multicast Sampled Value Control Block (MSVCB) Name	xxxxMUnn/LLN0$MSVCB01	N/A	N/A	N/A
-NoASDU	1	N/A	N/A	N/A
- OptFlds- security	FALSE	N/A	N/A	N/A
- OptFlds- data-set	FALSE	N/A	N/A	N/A
MsvID	xxxxMUnn01	N/A	N/A	N/A
SmpRate	80	N/A	N/A	N/A
OptFlds- refresh-time	TRUE/FALSE	N/A	N/A	N/A
- sample-synchronized	TRUE	N/A	N/A	N/A
- sample-rate	FALSE	N/A	N/A	N/A
Clock Source	1PPS +/-1µsec accuracy optical input	YES (Strict)	NO IEEE 1588 & IRIG-B	NO (IEEE 1588)
Nominal frequency	50 or 60 Hz	YES	YES	YES
Physical Layer	100BaseFX ST or MT-RJ or 100BaseTX RJ-45	YES	NO LC	NO LC
AppID	Shall always be 0x4000	YES- must be 0x4000	NO- Does not matter	NO- Does not matter
Quality IEC 61850-7-3 extended	attribute "derived" BOOLEAN	N/A	N/A	N/A
Message Buffer- SmpSynch	Shall behave as specified in IEC 61850-7-2 ed1			

Data Flows

GOOSE and Sampled Value Data Flow Spreadsheet

The documents shown in Appendix E contain the data flow information for process bus #1, process bus #2, and the station bus. Each SV and GOOSE message required a multicast MAC addresses, AppIDs, and message IDs. This spreadsheet was created to identify the message requirements and to establish the publishers and subscribers.

The following figures (Table 20, Table 21, Table 22, Table 23, Table 24, and Table 25) provide a sample of the information contained in this appendix. The purpose of these figures was to orientate the reader on their use and structure. The reader should reference the attached appendices for up to date information on the data flows.

TABLE 20 DATA FLOW TABLE - SV CONTROL BLOCK

	Process Bus #1 Sampled Value (SV) Messages											
IEDname	**Publishing IED**	**Measurement and Control points**	**Voltage**	**Current**	**MAC Address**	**VLAN ID**	**VLAN-PRIORITY**	**App ID (hex)**	**SmpRate (sample/ cycle)**	**MsvID**	**Dataset Name**	**Dataset index 1**
MU1_CB2	MU1- 69/138kV Line CB 2_V1M5 #1	69/138kV Line CB 2 Line Side CT, west bud PT and CB2 I/O	115V - 700 ratio	5A - 400 ratio	01-0C-CD-04-00-00	1	4	0x4000	80	MU1_CB2_V1M5	PhsMeas1	PhA_Amps. instMag.i
MU2_CB3_V3M3	MU2- 69/138 Bus Tie CB 3_V3M3	69/138kV Bus Tie CB 3 West Bus CT, west bus PT and CB3 I/O	115V - 700 ratio	5A - 400 ratio	01-0C-CD-04-00-01	1	4	0x4000	80	MU2_CB3_V3	PhsMeas1	PhA_Amps. instMag.i
MU3_4_CB7_11_V7M1	MU3- 69/138-12kV Xfmr BK 41 CB 7 _V7M1 #1 CKT 1	69/138-12kV Xfmr BK 41 Main CB 7 Xfmr Side CT, 12kV Swgr 1241 Unit 17 Bus PT 100:1and CB7 I/O	115V - 700 ratio	5A - 400 ratio	01-0C-CD-04-00-02	1	4	0x4000	80	MU3_MU0101	PhsMeas1	PhA_Amps. instMag.i
MU3_4_CB7_11_V7M1	MU4- 12kV Xfer Bus CB 11_V7M1 #1 CKT 2	12kV Xfer Bus CB 11, 12kV Swgr 1241 Unit 17 Bus PT 100:1, CB Unit 11 I/O	120V - 100 ratio	5A - 400 ratio	01-0C-CD-04-00-03	1	4	0x4000	80	MU4_MU0201	PhsMeas1	PhA_Amps. instMag.i
MU7_CB14_V2M5	MU7- 69/138-12kV Xfmr BK41 CB 14_V2M5	69/138-12kV Xfmr BK41 CB 14 Xfmr Side CT, 2kV Swgr 1241 Unit 17 Bus PT 100:1, CB Unit 14 I/O	115V - 700 ratio	5A - 400 ratio	01-0C-CD-04-00-06	1	4	0x4000	80	MU7_CB14_V2	PhsMeas1	PhA_Amps. instMag.i
MU11_T41NEU_V2M5	MU11- 69/138-12kV Xfmr BK 41 12kV Neutral CT_V2M5	69/138-12kV Xfmr BK 41 12kV Neutral CT, no I/O	120V - 100 ratio	5A - 400 ratio	01-0C-CD-04-00-10	1	4	0x4000	80	MU11_T41N_V2	PhsMeas1	PhA_Amps. instMag.i
MU12_HIZ_V3M3	MU12- 69/138kV E. Bus 87B Hi-Z Resistor_V3M3	69/138kV E. Bus 87B Hi-Z Resistor, no I/O	115V - 700 ratio	5A - 400 ratio	01-0C-CD-04-00-11	1	4	0x4000	80	MU12_HIZ_V3	PhsMeas1	PhA_Amps. instMag.i

Table 20 shows the information required to program the SV control block parameter in the merging units. This table documents the first section of the data flow document for SV messages.

One would determine the required SV settings for a particular device by starting in Table 20 (in the leftmost column of any row) and reading across the table through Table 21 and Table 22. This information would be input into the IEDs as required. The large format version of the full table in Appendix E would normally be used to identify the SV data for entry into the devices. GOOSE data would be similarly identified in Table 23, Table 24, and Table 25.

TABLE 21 DATA FLOW TABLE- SV DATASET

							SV Control Block and referenced dataset information						
SmpRate (sample/ cycle)	MsvID	Dataset Name	Dataset index 1	Dataset index 2	Dataset index 3	Dataset index 4	Dataset index 5	Dataset index 6	Dataset index 7	Dataset index 8	Dataset index 9	Dataset index 10	D
80	MU1_CB2_V1M5	PhsMeas1	PhA_Amps. instMag.i	PhA_Amps.q	PhB_Amps. instMag.i	PhB_Amps.q	PhC_Amps. instMag.i	PhC_Amps.q	NEUT Amps. instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	V
80	MU2_CB3_V3	PhsMeas1	PhA_Amps. instMag.i	PhA_Amps.q	PhB_Amps. instMag.i	PhB_Amps.q	PhC_Amps. instMag.i	PhC_Amps.q	NEUT Amps. instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	V
80	MU3_MU0101	PhsMeas1	PhA_Amps. instMag.i	PhA_Amps.q	PhB_Amps. instMag.i	PhB_Amps.q	PhC_Amps. instMag.i	PhC_Amps.q	NEUT Amps. instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	V
80	MU4_MU0201	PhsMeas1	PhA_Amps. instMag.i	PhA_Amps.q	PhB_Amps. instMag.i	PhB_Amps.q	PhC_Amps. instMag.i	PhC_Amps.q	NEUT Amps. instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	V
80	MU7_CB14_V2	PhsMeas1	PhA_Amps. instMag.i	PhA_Amps.q	PhB_Amps. instMag.i	PhB_Amps.q	PhC_Amps. instMag.i	PhC_Amps.q	NEUT Amps. instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	V
80	MU11_T41N_V2	PhsMeas1	PhA_Amps. instMag.i	PhA_Amps.q	PhB_Amps. instMag.i	PhB_Amps.q	PhC_Amps. instMag.i	PhC_Amps.q	NEUT Amps. instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	V
80	MU12_HIZ_V3	PhsMeas1	PhA_Amps. instMag.i	PhA_Amps.q	PhB_Amps. instMag.i	PhB_Amps.q	PhC_Amps. instMag.i	PhC_Amps.q	NEUT Amps. instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	V

Table 21 shows the dataset contents and is located to the right of the columns shown in Table 20. The IEC 61850-9-2LE document fixed the SV dataset so all of these datasets were identical.

TABLE 22 DATA FLOW TABLE- SV SUBSCRIBING DEVICES

	Subscribing IEDs									
ıdex 16	V2M2**--87L-2 Set A	V1M1**--87L-2 Set B	V3M1--21-2	V2M1--50/51-7 Set A	V1M4--50/51-7 Set B	V1M3--87T41 Set B	V2M3--87T41 Set A	V2M4-50/51EA138 (SET A)	V1M3--50/51EB138 (SET B)	V1M2--50/62BF
:s-Vol.q	YES	YES						YES	YES	YES
:s-Vol.q			YES (IW & VY)					YES	YES	
:s-Vol.q			YES (IX & VZ)	YES	YES	YES	YES	YES	YES	
:s-Vol.q	YES	YES				YES	YES			
:s-Vol.q						YES	YES			
:s-Vol.q				YES	YES	YES	YES			
:s-Vol.q								YES		

Further to the right, in Table 21one encounters the last section, which was shown in Table 22. This section indicated which devices subscribed to the various SV messages.

TABLE 23 DATA FLOW TABLE - GOOSE CONTROL BLOCK

Summary Use	IEDname	Publishing IED	Measurement and Control points, etc.	MAC Address	VLAN ID	VLAN-PRIORITY	App ID (hex)	Min Trime (ms)	Heatbeat Rate, Max time (ms)	Control Block Name and GoID	Dataset Name	Datase
Breaker Position	MU1_CB2	MU1- 69/138kV Line CB 2_V1M5 #1	CT TL138XX Breaker 2 Line Side CT; PT 138kV West Bus PT; Breaker 2 I/O	01-0C-CD-01-00-00	1	4	0x0000	4	500	BRK2_MU1	CB2_52A	GGIO1. stVal (5
Breaker Position	MU2_CB3_V3M3	MU2- 69/138 Bus Tie CB 3_V3M3	CT Bus Tie Breaker 3 West Bus CT PT 138kV West Bus PT BREAKER 3 I/O	01-0C-CD-01-00-01	1	4	0x0001	4	1000	BRK3_MU2	CB3_52A	ANN.I 14,Ind (Input
Breaker Position	MU3_MU4 CB7_11_V7M1	MU3- 69/138-12kV Xfmr BK 41 CB 7 _V7M1 #1 CKT 1	CT Breaker 7 BK 41 Transformer Side CT PT 12kV Unit 17 Bus PT 100:1 BREAKER 7 I/O	01-0C-CD-01-00-02	1	4	0x0002	20	1000	BRK7_MU3	MU3_STATUS	CTRL/E IO1.In (CB7
Breaker Position	MU3_MU4 CB7_11_V7M1	MU4- 12kV Xfer Bus CB 11_V7M1 #1 CKT 2	CT 12kV Unit 11 Trans Bus Side CT PT 12kV Unit 17 Bus PT 100:1 BREAKER Unit 11 I/O	01-0C-CD-01-00-03	1	4	0x0003	20	500	BRK11_MU4	MU4_STATUS	CTRL/E IO1.In (CB1
Breaker Position	MU3_MU4 CB7_11_V7M1	MU3 & MU4 CB7 & CB 11-1_V7M1 #1&2	ALL STATUS INPUTS	01-0C-CD-01-00-39	1	4	0x0027	1	1000	MU3_MU4_FASTGOOSE _FIXED	DigInput	CTRL/E IO1.In (CB7

Table 23 showed the GOOSE messages which were arranged similarly to the SV messages. This first section contained all the GOOSE control block parameters required to program the devices.

TABLE 24 DATA FLOW TABLE - GOOSE DATASET

GOOSE Control Block and referenced dataset information														
Control Block Name and GoID	Dataset Name	Dataset index 1	Dataset index 2	Dataset index 3	Dataset index 4	Dataset index 5	Dataset index 6	Dataset index 7	Dataset index 8	Dataset index 9	Dataset index 10	Dataset index 11	Dataset index 12	Da
BRK2_MU1	CB2_52A	GGIO1.SPCS01.stVal (Input 1-52a)	GGIO1.SPCS01.q (Input 1-52a)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	
BRK3_MU2	CB3_52A	ANN.IN2GGIO14,Ind01.stVal (Input 1- 52a)	ANN.IN2GGIO14,Ind01.q (Input 1- 52a)	ANN.IN2GGIO14,Ind02.stVal (VT Fuse Fail A)	ANN.IN2GGIO14,Ind02.q (VT Fuse Fail A)	ANN.IN2GGIO14,Ind03.stVal (VT Fuse Fail B)	ANN.IN2GGIO14,Ind03.q (VT Fuse Fail B)	ANN.IN2GGIO14,Ind04.stVal (VT Fuse Fail C)	ANN.IN2GGIO14,Ind04.q (VT Fuse Fail C)	-----	-----	-----	-----	
BRK7_MU3	MU3_STATUS	CTRL/BININGGIO1.Ind1.stVal (CB7 52A)	CTRL/BININGGIO1.Ind1.q (CB7 52A)	CTRL/BININGGIO1.Ind2.stVal	CTRL/BININGGIO1.Ind2.q	CTRL/BININGGIO1.Ind3.stVal (CB7 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind3.q (CB7 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind4.stVal (CB7 1241 UNIT 17 PT PHB FUSE)	CTRL/BININGGIO1.Ind4.q (CB7 1241 UNIT 17 PT PHB FUSE)	CTRL/BININGGIO1.Ind5.stVal (CB7 1241 UNIT 17 PT PHC FUSE)	CTRL/BININGGIO1.Ind5.q (CB7 1241 UNIT 17 PT PHC FUSE)	CTRL/BININGGIO1.Ind6stVal (CB7 1241 UNIT 17 PT NEU FUSE)	CTRL/BININGGIO1.Ind6.q (CB7 1241 UNIT 17 PT NEU FUSE)	
BRK11_MU4	MU4_STATUS	CTRL/BININGGIO1.Ind7.stVal (CB11 52A)	CTRL/BININGGIO1.Ind7.q (CB11 52A)	CTRL/BININGGIO1.Ind8.stVal	CTRL/BININGGIO1.Ind8.q	CTRL/BININGGIO1.Ind9stVal (CB11 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind9.q (CB11 1241 UNIT 11 PT PHA FUSE)	CTRL/BININGGIO1.Ind10.stVal (CB11 1241 UNIT 11 PT PHB FUSE)	CTRL/BININGGIO1.Ind10.q (CB11 1241 UNIT 11 PT PHB FUSE)	CTRL/BININGGIO1.Ind11.stVal (CB11 1241 UNIT 11 PT PHC FUSE)	CTRL/BININGGIO1.Ind11.q (CB11 1241 UNIT 11 PT PHC FUSE)	CTRL/BININGGIO1.Ind12stVal (CB11 1241 UNIT 11 PT NEU FUSE)	CTRL/BININGGIO1.Ind12.q (CB11 1241 UNIT 11 PT PNEU FUSE)	
MU3_MU4_FASTGOOSE_FIXED	DigInput	CTRL/BININGGIO1.Ind1.stVal (CB7 52A)	CTRL/BININGGIO1.Ind2.stVal	CTRL/BININGGIO1.Ind3.stVal (CB7 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind4.stVal (CB7 1241 UNIT 17 PT PHB FUSE)	CTRL/BININGGIO1.Ind5.stVal (CB7 1241 UNIT 17 PT PHC FUSE)	CTRL/BININGGIO1.Ind6stVal (CB7 1241 UNIT 17 PT NEU FUSE)	CTRL/BININGGIO1.Ind7.stVal (CB11 52A)	CTRL/BININGGIO1.Ind8.stVal	CTRL/BININGGIO1.Ind9stVal (CB11 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind10.stVal (CB11 1241 UNIT 11 PT PHB FUSE)	CTRL/BININGGIO1.Ind11.stVal (CB11 1241 UNIT 11 PT PHC FUSE)	CTRL/BININGGIO1.Ind12stVal (CB11 1241 UNIT 11 PT NEU FUSE)	

Table 24 shows the dataset contents that were located to the right of the columns shown in Table 23. Each GOOSE message served a specific purpose in the system operation and therefore the datasets were different from each other.

TABLE 25 DATA FLOW TABLE - GOOSE SUBSCRIBING DEVICES

	Subscribing IEDs										Subscribing Merging Units						
ndex	V2M2**--87L-2 Set A	V1M1**--87L-2 Set B	V3M1--21-2	V2M1--50/51-7 Set A	V1M4--50/51-7 Set B	V1M3--87T41 Set B	V2M3--87T41 Set A	V2M4-50/51EA138 (SET A)	V1M3--50/51EB138 (SET B)	V1M2--50/62BF	MU1- 69/138kV Line CB 2_V1M5 #1	MU2- 69/138 Bus Tie CB 3_V3M3	MU3- 69/138-12kV Xfmr BK 41 CB 7 _V7M1 #1 CKT 1	MU4- 12kV Xfer Bus CB 11_V7M1 #1 CKT 2	MU7- 69/138-12kV Xfmr BK41 CB 14_V2M5	MU11- 69/138-12kV Xfmr BK 41 12kV Neutral CT_ V2M5	MU12- 69/138kV E. Bus 87B Hi-Z Resistor_V3M3
	YES	YES	YES					YES	YES	YES							
								YES	YES	YES							
				YES	YES		YES	YES	YES	YES							
				YES	YES		YES										
				YES	YES		YES										
				YES	YES		YES										

Further to the right in Table 24, one encounters the last section, which was shown in Table 25. This section indicated which devices subscribe to the various GOOSE messages.

Process Bus Data Flow Diagram

Figure 12 and Figure 13 show the data flow diagrams for process bus #1 and process bus #2, respectively. The data flow diagrams provide a graphic representation of the data flow tables presented in the previous section. The diagrams show all the GOOSE and SV data flows for each process bus to and from each device connected to the process bus and the device's relationship to the substation equipment. The diagram was intended to provide an understanding of the purpose of the data flow and provides information to link it to the data flow spreadsheet.

Additional information on the multicast MAC address was useful for quickly identifying the data flow in a device configuration file or to analyze captured traffic on the network. SV message addresses always start with 01-0C-CD-04 and GOOSE with 01-0C-CD-01 leaving the remaining two octets available for configuration. For this project, the fifth octet was not used and set to 00, so, for simplicity; the diagram only displays the value for the last octet. The octets used hex numbers but in order to make the messages easier to identify, the MAC address were sequentially increased so as to appear to be using base 10 numbers. As an example, the addresses jumped from 01-0C-CD-01-09 to 01-0C-CD-01-10 without using A, B, C, D, E or F in the last hex space.

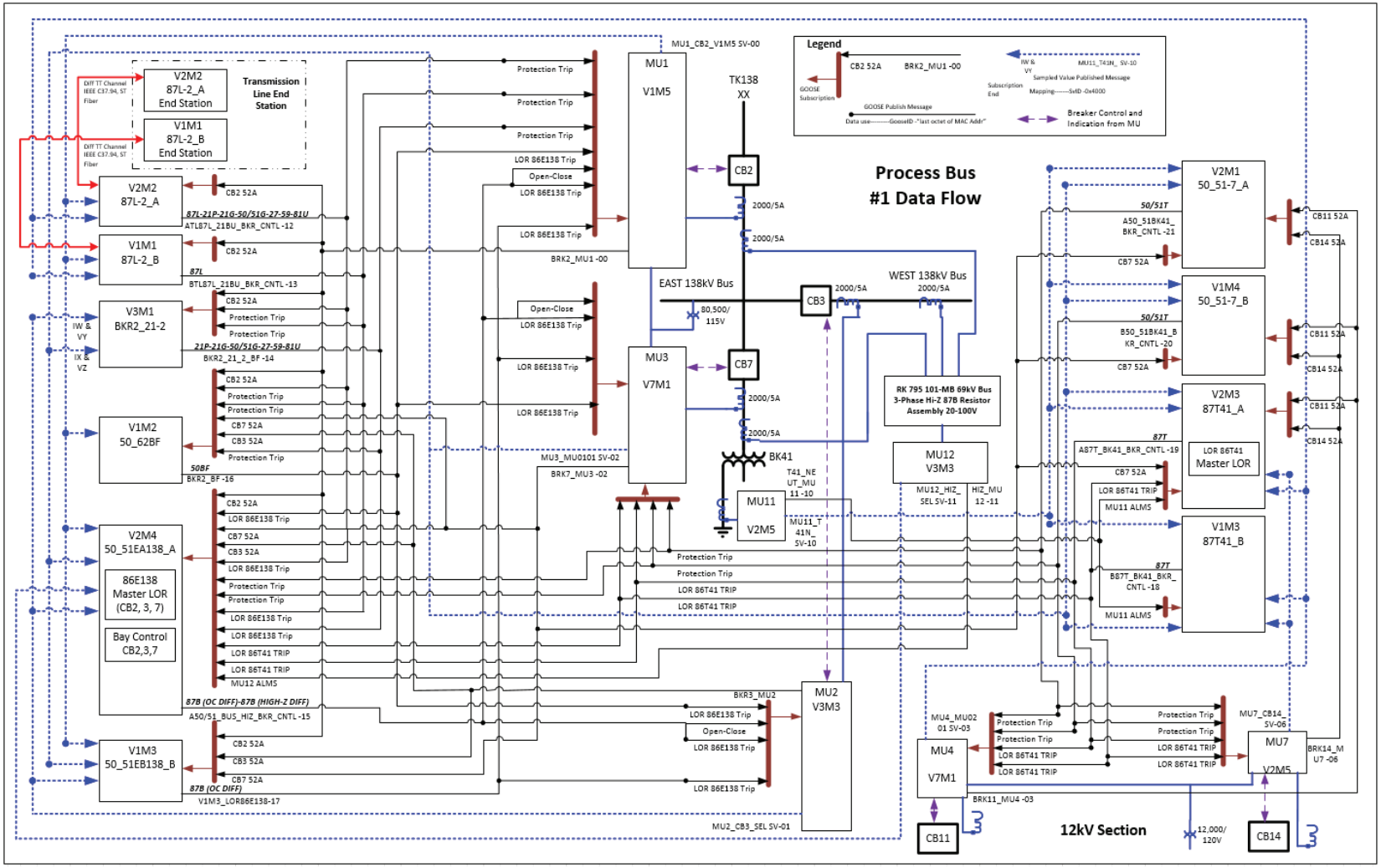


FIGURE 12 PROCESS BUS #1 DATAFLOW DIAGRAM

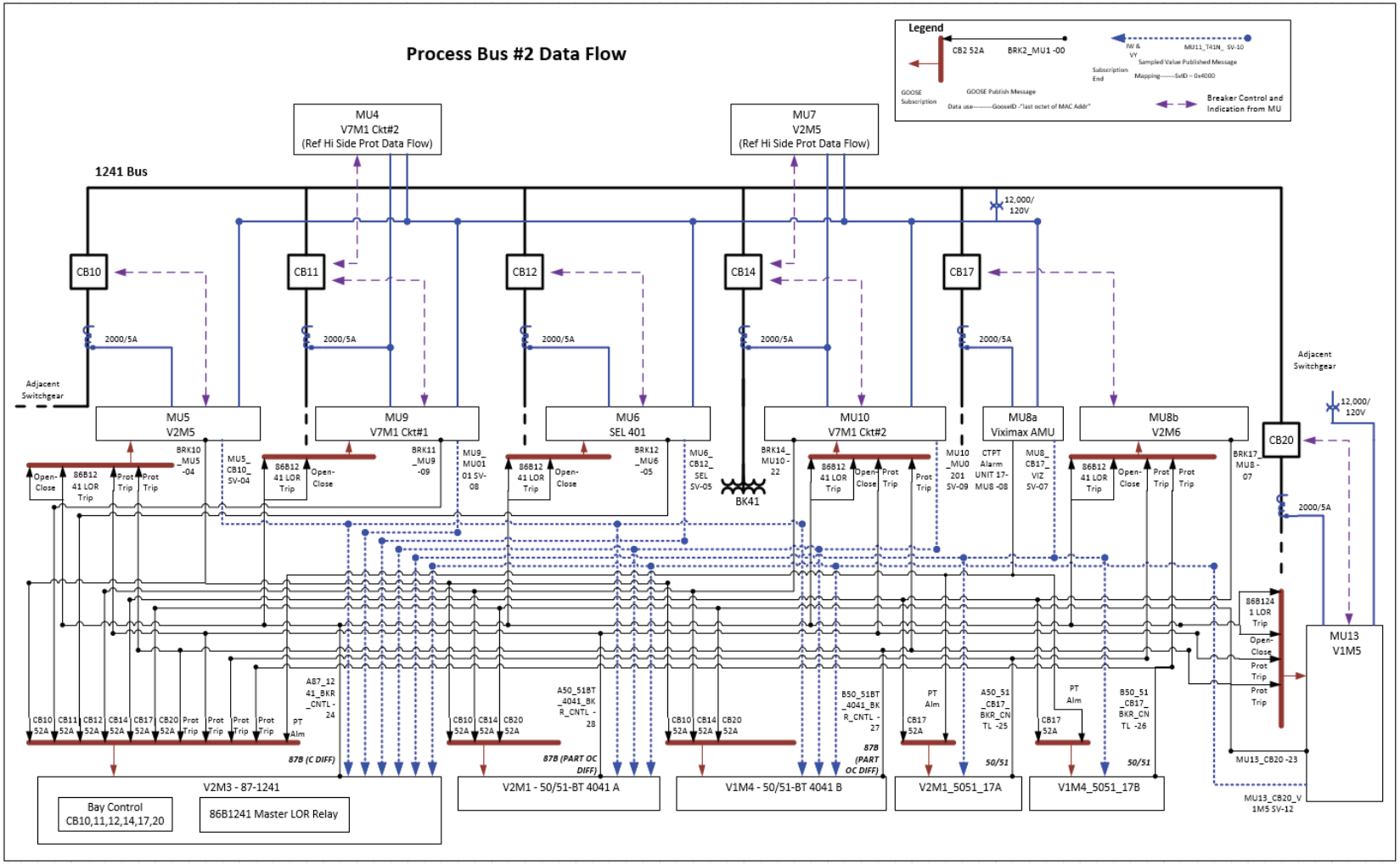


FIGURE 13 PROCESS BUS #2 DATAFLOW DIAGRAM

Station Bus Data Flow Diagram

Figure 14 shows the data flow diagram for the station bus. This data flow diagram provided a graphic representation of the data flow tables presented in the previous section. The diagram showed all the GOOSE data flows for the station bus to and from the devices and the device's relationship to the substation equipment. The diagram was intended to provide an understanding of the purpose of the data flow and provided information to link it to the data flow spreadsheet.

The only function using the station bus was the reactor and capacitor bank control. This was the same equipment and control philosophy as was currently used in the project team's systems with the added flexibility of GOOSE messaging. The V3M1 published the required analog measurement data to the V3M4 controllers using GOOSE messaging. GOOSE messaging was also used to exchange information for the bank protection equipment which included the V3M2 protection relays and the V3M4 controllers.

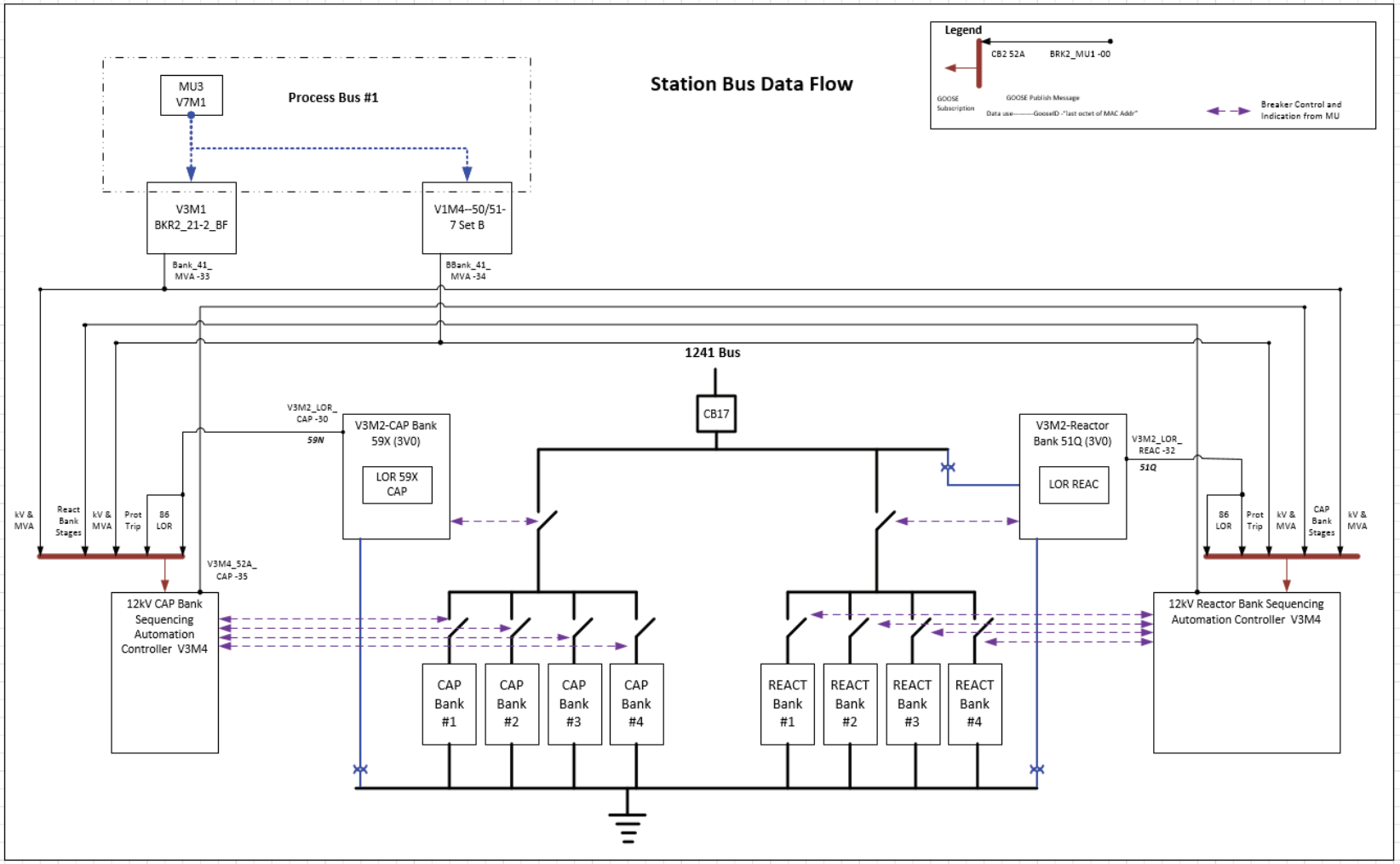


FIGURE 14 STATION BUS DATAFLOW DIAGRAM

Phase One Initial System Integration and Configuration

Throughout this project, a product code was assigned to each product. These codes were used to obfuscate the manufacturer identity and model numbers of the products utilized in the test system. This code was described in Appendix H.

This section covers the integration of the test system components. At this point in the process, Vendor V1's equipment had just arrived and was not included in the initial system check out. The goal of the first phase of the testing was to determine if the equipment would support the critical GOOSE and SV operations.

Vendor V2 Equipment

Vendor V2 sent two engineers to provide support during the three day testing exercise. In summary, the vendor's representatives were not able to get their protection relays to subscribe to any of the four vendor merging units: Vendors V1, V3, V6, or V7. The following summarizes the integration and results with the V2M1 relay:

- This protection relay successfully published and subscribed to the V2M6 I/O merging unit MU8B_CB17_V2M6. The breaker simulator was successfully tripped and closed.
- This protection relay successfully published and subscribed to the V2M5 merging unit MU5_CB10_V2M5. The breaker simulator was successfully tripped and closed.
    - This manufacturer's equipment attempted to subscribe to a SV stream using their V2M1 protection relay from their V2M5 merging unit's SV stream, but was not successful. Many different configuration changes and system reconfigurations were done in order to attempt to solve the problem. The following summarizes these attempts:
    - Validate that the V2M5 was synchronized to the PTP GPS Clock, which was confirmed. Change the IRIG-B time input into the V2M1 protection relay from IEEE 1588 PTP to a direct 1PPS signal and validate it was time synchronized. This did not make a difference.
    - The vendor used their SV sniffing tool to determine that the V2M5 was publishing a validate stream. No problems were detected.
    - The vendor suggested that the AB and CD network connections could not be on the same subnet IP address. Both were required to be connected to the process bus because this vendor only supports SV from one port and GOOSE from the other. This configuration was changed without resolution.
    - The network sniffing tool was using to determine that the correct SV control block parameters were being transmitted. The correct control block was being sent but the time sync indication from the V2M5 indicated it was in local time, not using an external source.
    - This vendor made many configuration changes to include multicast MAC addresses, AppIDs, datasets, etc. This did not make a difference.
    - This vendor checked to verify that the license on the device supported the IEC 61850 functions. They found the licenses were correct.

    - This vendor requested a direct fiber point to point connection with their V2M5 merging unit to eliminate the existing process bus network. This was done with no change noted.

- The V3M1 could not subscribe to the V2M5 merging unit either. The error on the V3M1 was a time sync error. All other merging units presented a value of 2, meaning global time traceable synchronization in the "smpSynch" field but the V2M5 had a value of 1, meaning local time. A subscriber will not use the stream if it has lost global time but it was confirmed that the V2M5 was synchronized to the PTP clock. The problem may be in IEC 61850 edition implementation. IEC 61850-9-2 Edition 1 specified the "smpSynch" as a Boolean value with "0" meaning no time sync and "1" meaning good time sync. IEC 61850-9-2 Edition 2 specified the "smpSynch" as:
    - 0= SV are not synchronized by an external clock signal.
    - 1= SV are synchronized by a clock signal from an unspecified local area clock.
    - 2= SV are synchronized by a global area clock signal (time traceable).
    - 5 to 254= SV are synchronized by a clock signal from a local area clock identified by this value.
    - 3;4;255= Reserved values – Do not use.
- The IEC 61850-9-2LE document was based on edition 1 but most vendors have mixed edition implementations focusing only on the dataset, sample rate, and naming conventions from the LE document. The network sniffing tool SV decoder was using the edition 2 definitions of the "smpSynch" but it was postulated that the V2M5 may be using the edition 1 definition. This was thought to be why the V3M1 would not use the V2M5 SV stream, if it used the edition 2 definition (that the time synchronization was bad when in reality it was good).
    - The vendor attempted to subscribe using their V2M1 protection relay to the other vendor merging unit streams but each failed like the V2M5.
- The V6M1 CID file would import into the this vendor's configuration software but when the IEC 61850 component of the software was opened and then closed, it wrote over the MAC address, AppIDs for both the GOOSE and SV control blocks. The software reset the values to the first allowable values. This vendor agreed to investigate this behavior.
- This vendor's merging units MU5 and MU11 were configured and tested for proper SV publishing. Both had the local time sync indication in the stream.

This vendor had a system working at their corporate office, which they were using to compare settings and system configuration to the project's test system setup. It was based on this working system that this vendor requested the various changes to the project's test system in an attempt to get their equipment to work with the V2M5 SV stream. None of the changes worked, nor did the vendor's equipment work on the other vendor's merging units that were working in the system.

The plan was to ship the V2M5 and V2M1 IEDs back to the factory so that the vendor could work on them at their factory. Their current working system was being used for another customer and could not be shipped at the time. This vendor's field engineers planned to return to implement their findings.

Vendor V3 Equipment

The team tested the V3M3 merging units and the V3M1 protection relay. The following summarizes the results of the integration.

- The team configured the V3M3 MU12_HIZ_V3M3 merging unit and determined that it was publishing the proper GOOSE and SV messages.
- This relay was able to successfully subscribe to the SV stream using the V3M1 relay's WY metering points. Preliminary checks using the test set software, V3M3 and V3M1 metering functions showed that the streams were being transmitted and received correctly with no errors.
- These devices controlled and received feedback using GOOSE to and from the V3M3 MU12_HIZ_V3M3 merging unit and V3M3 with a test bit. (The MU12_HIZ_V3M3 merging unit did not have a connected breaker simulator in the test system).
- A second SV stream in the V3M3 using the XZ metering points from the V2M5 MU5 merging unit was configured. This first produced a configuration revision mismatch error which was corrected and then produced a time sync error which was covered in the Vendor V2 section.
- Configuration of the MU8A_CB17_V6M1 merging unit was attempted, but a CID file schema error in the V3M6 software appeared when attempts to load the new CID file, into the relay, were made. The V6M1 file loaded correctly in the V3M6 software and allowed the data object to map into the V3M3 but the file would not load into the device. The investigation was covered in the Vendor V6 section, and a successful download was achieved.
- Configuration of the V7M1 MU9_10_CB11_14_V7M1 merging unit SV stream into the XZ metering points was attempted but it was unsuccessful.
- The V3M3 MU12_HIZ_V3M3 merging unit stream was then removed from the WY metering points and mapped only the V7M1 MU9_10_CB11_14_V7M1 merging unit SV stream. This worked with no problems.
- The V7M1 MU9_10_CB11_14_V7M1 merging unit stream was then removed from the WY metering points and mapped only the MU8A_CB17_V7M1 merging unit SV stream. This change worked with no problems and avoided the V7M1 CID file problem with the V3M6 software by using the V3M7 software. The V3M7 SV setting overrode the V3M6 settings and did not require the import of an IEC 61850 information exchange file.
- An attempt to add a second stream using the V3M3 MU12_HIZ_V3M3 merging unit to the XZ metering points was made but this did not work.
- Vendor V3 merging units MU12, MU6 and MU2 were configured and tested for proper SV and GOOSE publishing.

This problem was reported to the vendor.

Vendor V6 Equipment

There was only one V6M1 merging unit in the test system. The V6M1 did not have any control and was only used as a SV merging unit. The following observations were from the integration of the V6M1:

- The V6M1 was configured and it was determined that the correct GOOSE and SV published messages were being sent out onto the process bus.
- The V6M2 configuration software did not export an IEC 61850 ICD or CID file. The manufacturer provided a XML template, which required manual input of the proper information from the configuration files into a XML file. Problems arose with both the V2M8 and V3M6 software when using this file. These problems prevented testing of the GOOSE and SV message subscriptions. After a number of attempts to correct the file it was determined that the template provided had too many problems to fix. The V7M1's working CID file was then modified to match the V6M1. This effort succeeded and the file was successful with other third party device configuration tools.
- The V3M1 successfully subscribed to the 8A_CB17_V6M1 merging unit by using the V3M7 vs. the V3M6 software which removed the CID file problem.
- The V6M1 time source was changed to PTP from the IRIG-B connection. This change freed up the fiber connected IRIG-B that provided time to the V3M2 capacitor and reactor bank relays. The fiber converter was determined to be unable to drive all five units.
- After the time source change MU8A_CB_V6M1 was once again subscribed to the V3M3 relay to make sure there was still good time sync for the stream. Everything worked fine.

Vendor V7 Equipment

The V7M1 merging units were received just as the testing started but they were still installed and prepared in time for this integration effort. The following were observations from the effort:

- The first unit that was powered-up would not publish any GOOSE or SV messages. It was then configured as the MU3_4_CB7_11_V7M1 merging unit. The equipment successfully took the configuration and all diagnostics and logs showed no errors but the unit was still not publishing any messages. It was determined that the unit did have the latest firmware. The manufacturer was contacted, they sent the same firmware, and suggested that the unit be re-flashed. The manufacturer's suggestions were deployed but the results were unchanged, leaving the equipment in the same state.
- The second unit was then powered-up. This unit did publish GOOSE and SV streams. It was then reconfigured to match the MU9_10_CB11_14_V7M1 settings in steps, checking after each download that the unit was still publishing. Eventually the unit was fully configured with the exception of the Ethernet ports IP addresses. These addresses were left at the default values.
- It was determined that the SV stream was correct and the V3M1 protection relay was able to subscribe to it.
- Given that the MU9_10_CB11_14_V7M1 unit worked using the default IP addresses the configuration of the MU3_4_CB7_11_V7M1 merging unit was changed back to the default IP addresses. The unit then successfully published GOOSE and SV messages.
- If the SVid name was put in as per the project documents, but the stream could not be read without errors. Once the name was shorten by four characters, the streams worked properly with the subscribers. All four V7M1 unit SVid names were changed.
- All four of Vendor V7 merging units MU3, MU4, MU9 and MU10 were configured and tested successfully for proper SV publishing.

Test Equipment

The team was able to configure the relay test sets to use the IRIG-B interface in order to run time synchronized tests. The team was able to run a COMTRADE file play back through the relay test sets and capture the secondary injection results. When compared, these results matched the expected results and it was determined that the test system was working properly.

Network Equipment

The test system network equipment and configuration performance exceeded the requirements for this test system. During the initial testing, up to nine SV streams ran over a single process bus along with IEEE-1588 PTP, 10 active GOOSE messages, and configuration access. There were no performance issues noted and no delay in configuration and monitoring access over the network.

Phase Two System Integration and Testing Results

This section covered the second phase integration and initial testing. The phase one testing identified problems with V2M1, V2M2, V3M3, and V2M4 relays when subscribing to any merging unit including the V2M5. It was also determined that the V2M5 SV stream could not be subscribed to by the V3M1 even though it could subscribe to the remaining three models of merging units. In order to perform this testing a number of devices were removed from their specified network interface. For this testing these devices were returned back to their assigned networks.

There was also a problem with the V3M3 not subscribing to a second SV stream.

Vendor V3 Equipment

The following observations on this vendor's equipment:

- Concerning the problem with the second V3M1 stream not working, all the files and configurations were gathered and sent to the manufacturer. The manufacturer followed-up by telephone and the situation was discussed. The manufacturer did not see any reason for the lack of errors and the relay still indicated that it was subscribed to the stream. The following was determined:
    - The V3M1 was configured for both PTP and IRIG-B to allow for consideration of redundancy options. It was assumed that the PTP would be the dominant source over IRIG-B but what the V3M1 always defaults to the IRIG-B source. The manufacturer suggested that the IRIG-B was disconnected and the relay was reconfigured to use PTP. Upon completion, the second SV stream started working. The manufacturer later informed the team that there was an additional IRIG-B setting to configure. Under the global settings, time and date management, there was an IRIG-B setting. When this was set to "none" the V3M1, for the purposes of the SV timing, considered itself to be under "local" time even though it had an IRIG-B input. Setting this to the "C37.118" setting changed its use of the IRIG-B signal to global time (C37.118 is the standard for Synchro phasor Measurements for Power Systems). The manufacturer used this to tie into the SV subscriptions for time synchronization. Verification showed that the V3M1 time source switched to IRIG-B. The status of the metering values for the first and second SV streams was then confirmed. Once changed to "C37.118" and re-connected to the IRIG-B signal, both SV subscriptions performed successfully with two streams using both PTP and IRIG-B.
    - It was identified that V3M1 did not have error indication when a stream was dropped. Only the "COM SV" command showed the status of the streams, but it required manual checking.

- This unit had a time differential field which was unused if locally synced but if global sync was in place it indicated a time value. Global sync was required when using more than one SV stream.

- The V3M1 sent both 3-phase voltage and MVA metering values to both V3M4s. It required both the voltage from MU1 and the current from MU3 in order to calculate these metering values. Since MU1 was not operating yet, to test this GOOSE interface MU3's voltage was temporarily directed to VY and it's current to IX. MU3 would normally be mapped to VZ and IX.
- Using the test set injection into MU3 and the metering calculation in the V3M1 it was determined that the M3V4s were receiving the correct voltage and MVA values via GOOSE.
- Because of Vendor V2's strict requirement to have the AppID set to 4000 for all SV messages, V3M1 subscriptions were re-tested and no problems were identified.

Vendor V7 Equipment

The following changes were made to the V7M1 units:

- MU9_MU10 was temporarily placed on process bus #1 for testing. This relocation required a change to the PTP domain to one from two. The PTP setting was then changed back to two and the fiber connection moved to process bus #2. Checks were then performed to make sure the PTP was synced up properly.

Vendor V6 Equipment

The following changes were made to the V6M1:

- V6M1 was temporarily placed on process bus #1 for testing, which required a change to the PTP domain to one from two. The PTP setting was then changed back to two and the fiber connection moved to process bus #2. Checks were then performed to make sure the PTP was synced up properly.

Capacitor and Reactor Bank Control System

The capacitor and reactor bank control system were each consisted of a V3M2 protection relay and a V3M4 automation controller. The concept was for the V3M2 to provide protection and the V3M4 to provide the logic that controls the insertion and removal of the capacitor or reactor bank stages. The V3M4 received the bus voltage and MVA metering data from both the V3M1-21-2 and V1M4-50/51-7 Set B protection relays. During this phase of the testing Vendor V1 relays were not available but V3M1 was running with two streams. The V3M3 units were fully configured and tested in the lab using one of the data streams from the V3M1. The test used both the secondary injection test sets to inject current and voltage into the merging units subscribed to by the V3M1. These values, through logic calculations, were then passed to the V3M4 using GOOSE messaging.

The team found and corrected a number of problems with the logic, and in the end was able to demonstrate that changes made at the test set correctly controlled the proper number of capacitor and reactor banks.

Vendor V1 Equipment

The remaining Vendor V1 equipment arrived and the team worked on assembly and installation into the racks. This work was in preparation for Vendor V1's scheduled site visit.

- The installation for the V1M5s was completed. While working on the Vendor V2 solution it was identified that V1M5 was also streaming on process bus #1. Its AppID was 4000 and MAC address was 00 which was the proper configuration for MU1. A fifth stream was added to the V2M3 87T41 but it would not subscribe to the stream. Using the manufacturer's SV browser it was determined that the stream was set for 50 hertz which caused the stream to be dropped.
- The SymSync field indicated a value of 1 "local" with an IRIG-B signal on the time signal fiber input. The unit would not accept a 1PPS signal without the unit configuration tools on-site. This would be accomplished with Vendor V1's engineers.

Vendor V2 Equipment

This manufacturer found a working solution and returned the shipped equipment back to the lab. The manufacturer also sent an engineering team to report on the problems found from their team's investigation and what needed to be changed in order to get their equipment running in the test system. The following summarizes the meeting and re-test results:

- The manufacturer found two problems, the first was that the V2M1, V2M2, V2M3, and V2M4 protection relays strictly adhered to the LE document stating that only an AppID of 4000 could be used. The device rejected any SV stream that did not have an AppID of 4000. This was the only setting that was not changed during the manufacturer's first three day on-site testing.
- The V2M1, V2M2, V2M3, and V2M4 relays will accept both IRIG-B (hardwired input) and 1PPS (fiber input). The device however, required 1PPS when SV stream synchronization was required per the LE document. This was attempted during the manufacturer's first visit but since the AppID was not set to 4000, the SV subscriptions did not work.
- Once the AppID for the V2M5 MU11 merging units and both of the V7M1 MU3 and MU4 were changed to 4000, SV subscriptions were successful. To confirm a different relay, V2M3 87T41 Set A, was used to perform the tests. This relay successfully subscribed to all three streams with no errors. Injection of currents and voltages into all three merging units and showed that the metering functions on the V2M3 87T41 Set A were accurately indicating the correct metering values.

Phase three system integration and testing results

The primary purpose for this testing session was to work with the Vendor V1 engineer to get the Vendor V1 equipment and software working within the test system. The following summarized the findings:

- MU1 V1M5 was configured per the data flow diagram. The following items were identified:
    - The V1M5 did not support 1PPS on the time source fiber input, only IRIG-B. It did not support IEEE 1588 either, so the IRIG-B fiber signal was used.
    - No configuration parameter was available to tell the MU to calculate the In and Vn values when there was no connection available. The LE document states this and adds a "derived" bit to the quality for the value. This parameter existed on all the other merging units and they all reported "derived" on the In and Vn. The V1M5 did not.
    - With the unit's web page interface, it was seen that the unit was successfully time syncing to the IRIG-B signal.

- These next two points indicate that the unit had fully switched from publishing an SV LE message to an edition 2 SV message.
    - The network sniffer could not parse out the SV message using the LE decoder. It was suspected that when the unit was configured for edition 2, it used an edition 2 message buffer not an edition 1 based LE message buffer. This put additional fields in the message that the network sniffer could not decode.
    - The "SymSync" field was no longer BOOLEAN as the fault published message indicated. It published an edition 2 value of "2" global.
- Attempts to subscribe to the MU1 stream from the V3M1 relay were unsuccessful. The PDU length error indicated by the V3M1 was the same error type shown in the network traffic capture, which indicated that the SV message had the addition edition 2 fields. The additional edition 2 fields could not be processed by the V3M1 relay.

- The V2M2 87L set A relay was then subscribed to the MU1 stream and had no problems. The SV stream values and synchronization were successful.

The V1M5 merging unit, unlike all the others, completely changed its mode of operation when the unit was configured as edition 1 or edition 2. For full SV LE compatibility one must configure the unit as edition 1. As configured in edition 2 the MU published edition 2 message buffer with the additional fields that were non-LE. It also changed how it published the SymSync field from the BOOLEAN edition 1 definition to the INT edition 2 definitions. The current overwhelming system support was for edition 2 having vendors offer edition 2 GOOSE and files while still using SV LE based on edition 1. Having the V1M5 being one or the other presented a problem when integrating it into the system. The following captures some of the high level problems:

- If one left the V1M5 at edition 2:
    - The V3M1 would not subscribe to the V1M5 SV stream. This was due to the way that V3M1 examined the SV message and finding an additional field that it cannot understand. The V3M1 dropped the stream at this point.
    - The V2M1, V2M2, V2M3, and V2M4 relays would subscribe to the V1M5 SV stream. They reacted differently by not analyzing the entire message and accepting it even though it had an additional field.
    - The Vendor V1 relays would subscribe to the V1M5.
    - All IEC 61850 files were in edition 2 format and transferred between the various vendor tools. Both V2M8 and V1M9 tools only accepted the edition files for eth project edition in use at the time, which was edition 2.
- If one changed the V1M5 MU back to edition 1:
    - The IEC 61850 file format for the V1M5 MU would need to be modified to look like an edition 2 file in order to use it in both the V2M8 and V1M9 configuration tools.
    - The V3M1 would still not be able to subscribe to the SV stream. By changing the MU configuration to edition 1 the SymSync field would change to BOOLEAN which would publish a true "1" value for good time synchronization per the edition 1 and LE documents. The V3M1 only interpreted this field as edition 2, which meant that the V3M1 thought that the MU was only locally time synchronized with no global synchronization. With this indication it would not synchronize with multiple SV

streams. This situation would be similar to the V2M5 which published a SymSync in edition 1. The V3M1 would not be able to subscribe to either of these merging units.

With both cases still resulting in no communications with the V3M3 and both allowing for good SV communications with both the Vendor V1 and Vendor V2 relays, the best course of action was to keep the project in edition 2. A solution must be found to test the V3M1 without using the V1M5 or V2M5 merging units.

V1M5 PDU Length Problem

Out of the box, V1M5 published SV messages which could be subscribed to by the V2M1, V2M2, V2M3, V2M4, and V3M1 relays. The SV messages were found to be configured as 50 Hz and would not work in the relays but a good SV subscription was established. The default factory settings were IEC 61850-9-2 edition 1, 50 Hz. It was also noted that the "SymSync" field in the SV message buffer followed the ed1 BOOLEAN definition.

Figure 15 shows a network capture of the SV message from the V1M5 without any configuration changes. The team was able to successfully subscribe to this SV stream less the 50 Hz problem.

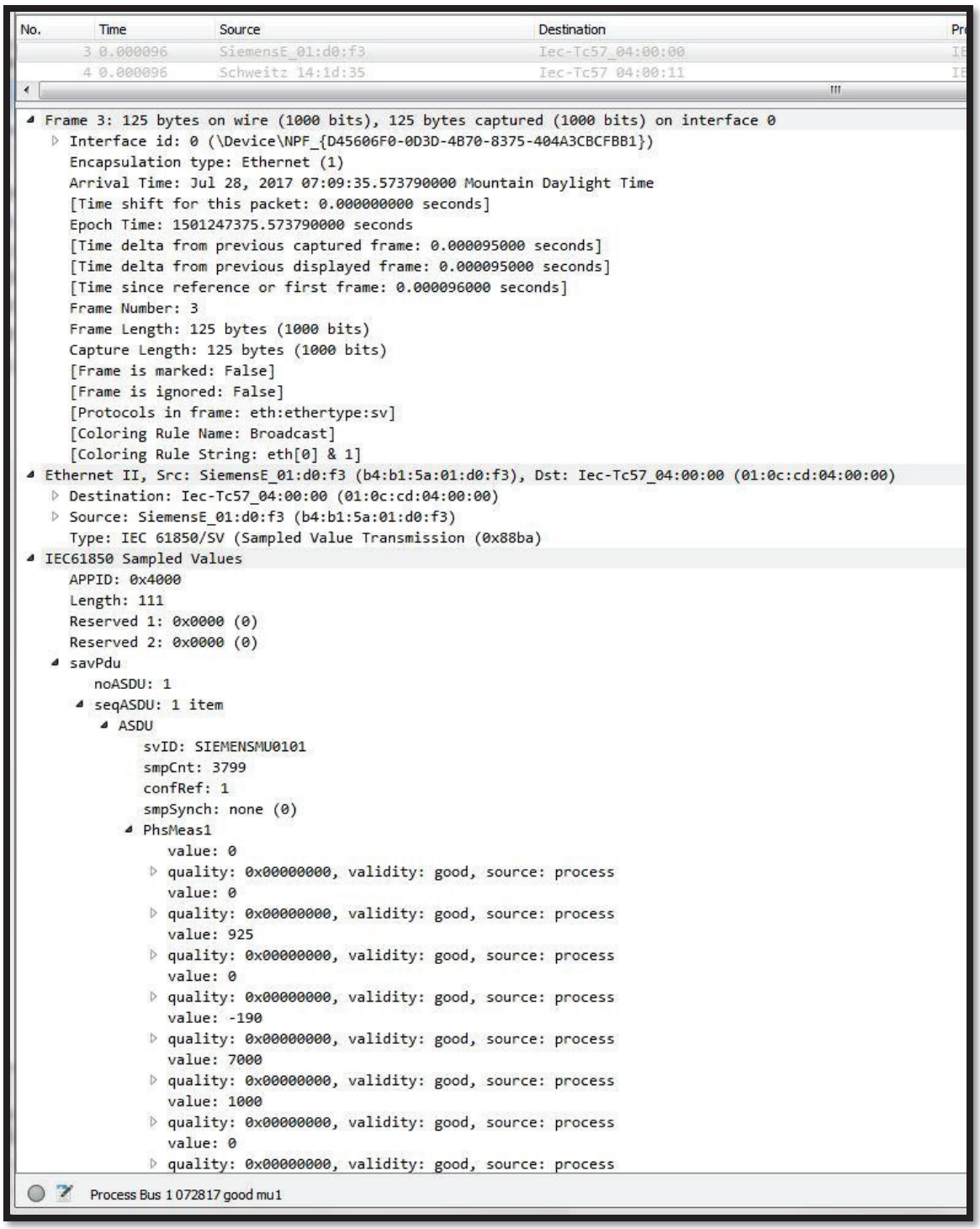


FIGURE 15 V1M5 OUT OF THE BOX SV MESSAGE

After the V1M5 was configured and set for IEC 61850 Edition 2, the behavior changed. The network analyzer picked up an error on the PDU length and the "SymSync" field started behaving like the edition 2 definitions which was expected (see Figure 16).

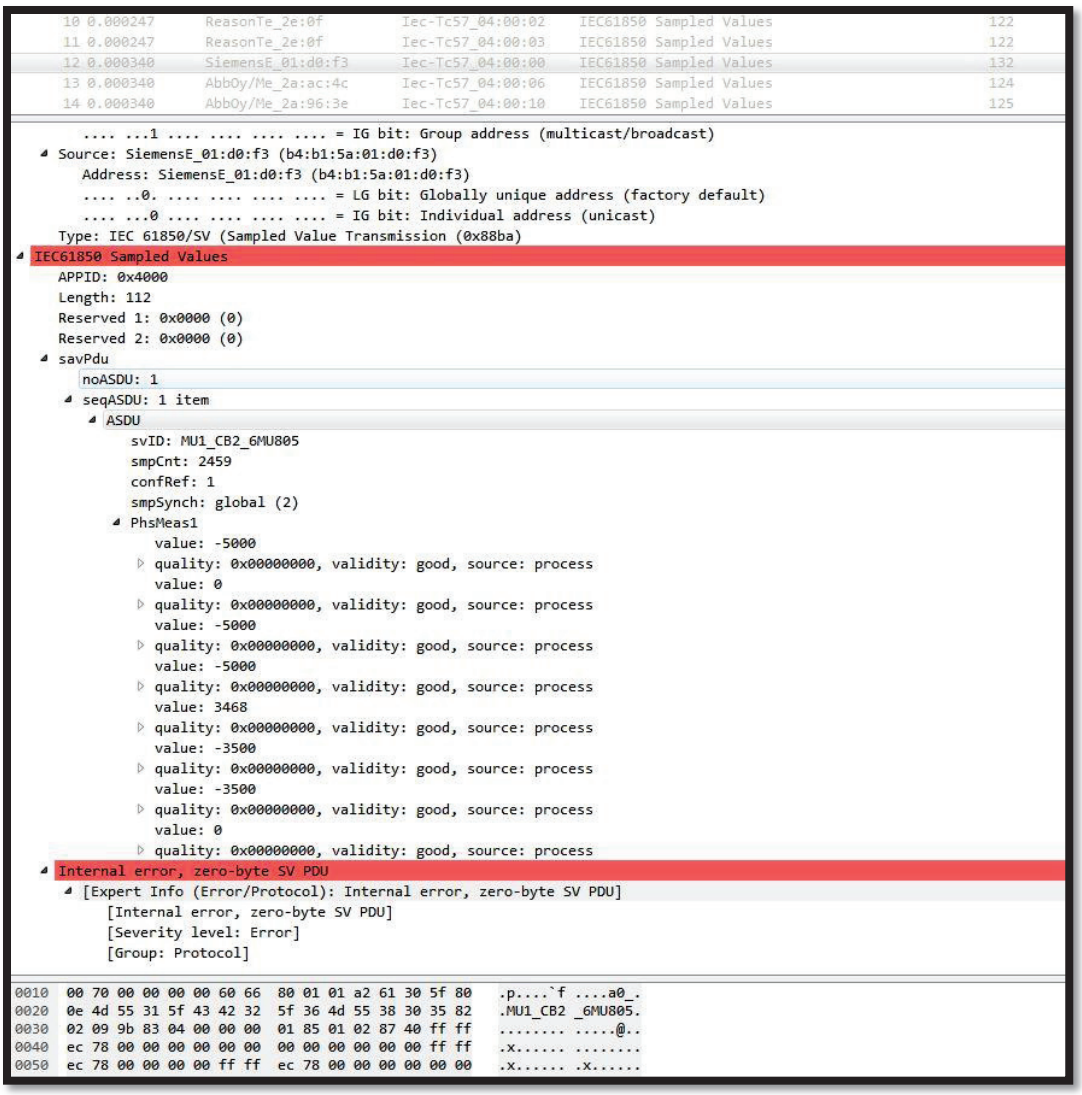


FIGURE 16 V1M5 SV MESSAGE AFTER CONFIGURATION

The PDU length error was unexpected. The V3M1 relay also detected this problem and would no longer subscribe to the SV stream. Figure 17 showed that it too found a PDU length problem.

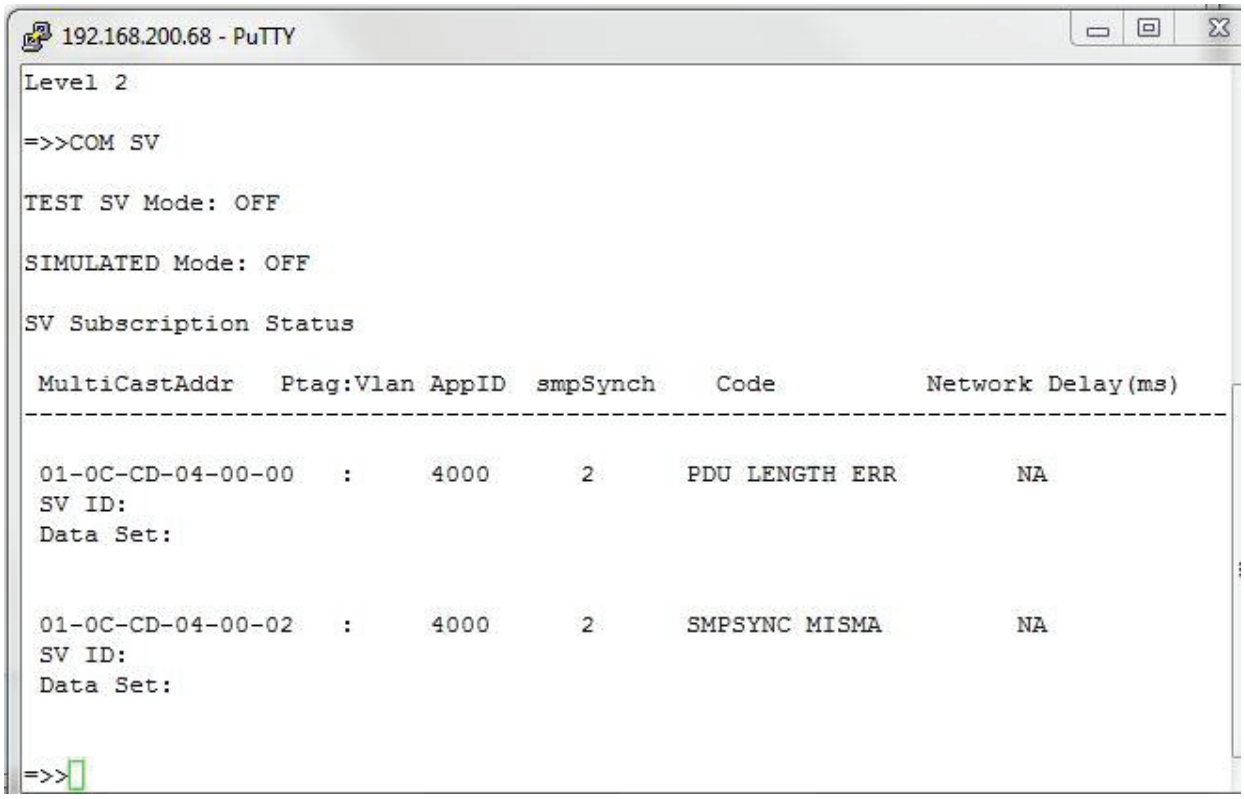


FIGURE 17 V3M1 RELAY ERROR ON THE V1M5 SV STREAM

Explanations were needed for why the V1M5 SV message and behavior differed between setting the unit up as an edition 1 device vs. an edition 2 device. An explanation on why there was a PDU Length error after configuring the merging unit to edition 2 vs. the default configuration SV message was requested.

File Import Problem into V1M8 Tool

The next set of testing was to have Vendor V1 relays subscribe to the other vendor merging units. The following documented the results:

- The V7M1 merging unit was configured into the V1M8 configuration tool. The IEC 61850 CID file generated by the V7M1 tool imported correctly into the V1M8 tool. The V7M1 SV streams were successfully subscribed from both MU3 and MU4 to a Vendor V1 relay.
- The team attempted to import the CID file for the V2M5 MU but ran into an import error showing some missing information. The V1M9 software wanted to see the attributes for "SmpRate," "RigVal" and "ClipVal" from the CID file. If these fields were not in the file, the V1M8 software filled in a zero value and created an error. Once this missing setting error was created, the V1M8 file could not be saved and there was no way to manually enter the require data fields.

The same problem was found when attempting to add the V3M3 and V6M1 merging unit CID files. Vendor V1relays must be able to subscribe to SV and GOOSE messages from the V2M5, V3M3, and V6M1 merging units to complete our planned protection testing schemes. Currently Vendor V1 relays can only subscribe to the V7M1 and V1M5 merging units.

Figure 18 is a view of the V1M8 software used to program the Vendor V2 SVs. The SMV-ID showed MU13 was a V1M5 merging unit and the MU5 was a V2M5 merging unit. When importing, MU5 errors were received with the zeroed data fields.

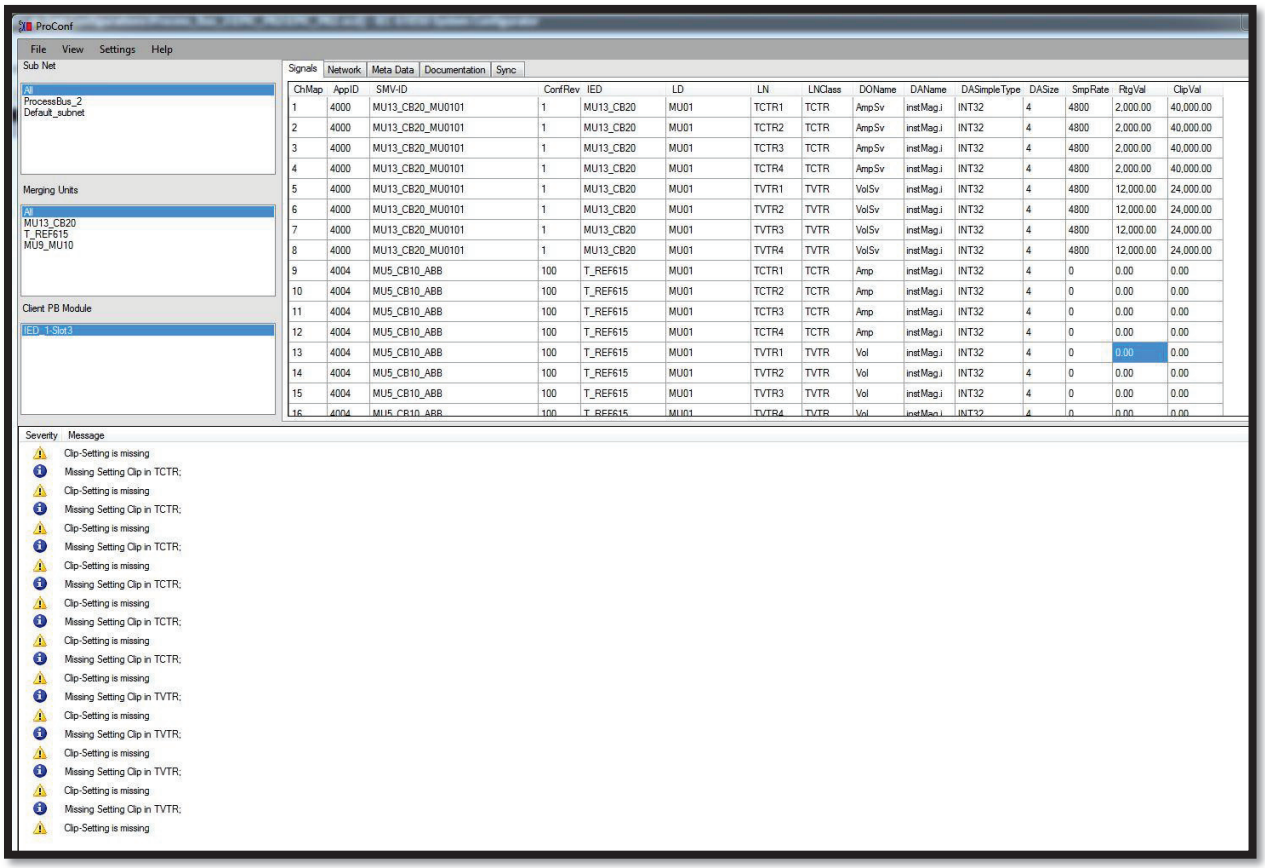


FIGURE 18 V1M8 FILE IMPORT ERROR

The data attribute "smpRate" found in the Measured Value (MV) common data class was an optional field in the standard. The standard also defined the value of the "smpRate" as the number of samples per nominal period. Only in the case of direct current systems was the value represented as the number of samples per second. The V1M8 software required this optional field and converted the value to a sample per second value. The software was also looking for the system frequency value, "HzRtg" within the TVTR and TCTR logical nodes which was also an optional field in the CID file.

The "RtgVal" could not be directly found in the standard but could only be associated with the "VRtg" data object found in the TVTR Voltage transformer logical node. This data object provided the rated voltage and was also an optional settings data object in the standard. The program looked at "VRtg" Data object found in the TCTR voltage transformer logical node. This data object provided the rated current and was also an optional settings data object in the standard.

The "ClipVal" could not be directly found in the standard but could only be associated with "maxVal" data attribute found in the ASG analogue setting common data case which was assigned to the "ARtg" data object in both the TVTR and TCTR logical nodes. This field, too, was optional. Figure 19 showed the error generated after importing V2M5 to a working file using both V1M5 and V7M1.

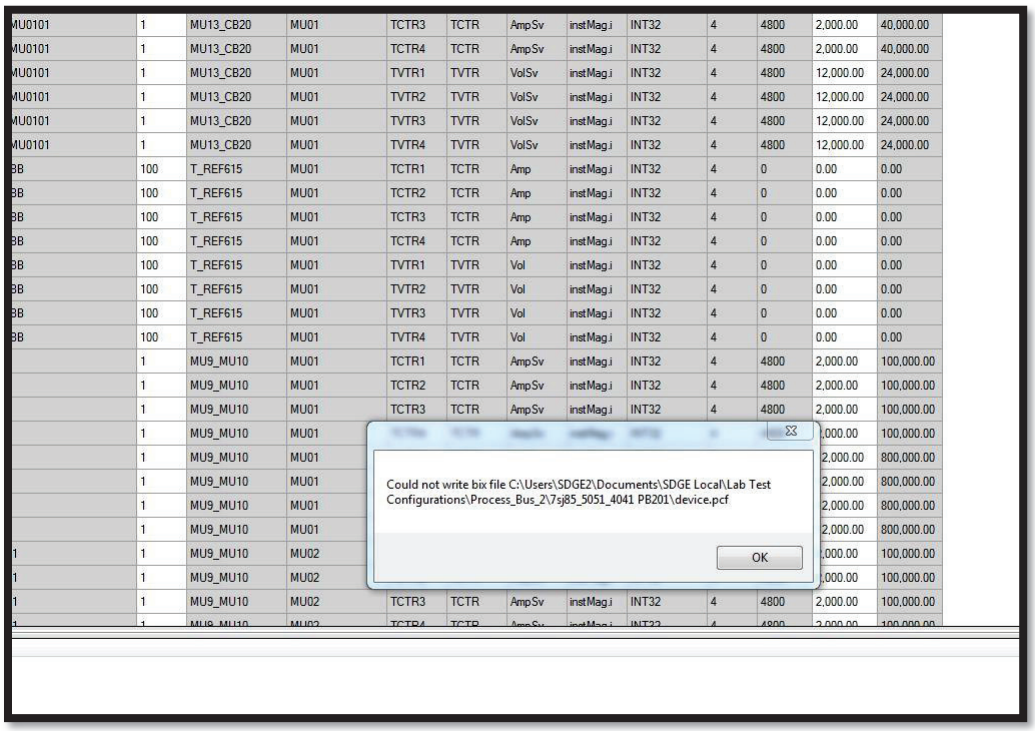


FIGURE 19 V1M8 SAVE ERROR

Figure 20 showed that the V7M1 merging unit provided these optional IEC 61850 data fields.

MU3_MU4 • Data Model • MU01 • U01ATVTR1

LN U01ATVTR1 Voltage transformer

Name		Description	Value
DO Beh		Behaviour	
DO VolSv		Voltage (sampled value)	
DO VRtg		Rated voltage	12000 V
DA setMag	[SP]	The value of an analogue setting or set point	12000 V
DA units	[CF]	Units of the attribute(s) representing the value of the data	V
DA minVal	[CF]	Defines together with maxVal the setting range for ctlVal (CDC INC, BSC, ISC), setVal (CDC IN...	1 V
DA maxVal	[CF]	Defines together with minVal the setting range for ctlVal (CDC INC, BSC, ISC), setVal (CDC IN...	1000000 V
DA stepSize	[CF]	Defines the step between individual values that ctlVal (CDC INC, APC, BAC), setVal (CDC ING)...	1 V
DO HzRtg		Rated frequency	60 Hz
DA setMag	[SP]	The value of an analogue setting or set point	60 Hz
DA units	[CF]	Units of the attribute(s) representing the value of the data	Hz
DA minVal	[CF]	Defines together with maxVal the setting range for ctlVal (CDC INC, BSC, ISC), setVal (CDC IN...	50 Hz
DA maxVal	[CF]	Defines together with minVal the setting range for ctlVal (CDC INC, BSC, ISC), setVal (CDC IN...	60 Hz
DA stepSize	[CF]	Defines the step between individual values that ctlVal (CDC INC, APC, BAC), setVal (CDC ING)...	10 Hz
DO Rat		Winding ratio of an instrument transformer/transducer	100
DA setMag	[SP]	The value of an analogue setting or set point	100
DA f	[SP]	Floating point value	100
DA minVal	[CF]	Defines together with maxVal the setting range for ctlVal (CDC INC, BSC, ISC), setVal (CDC IN...	1
DA maxVal	[CF]	Defines together with minVal the setting range for ctlVal (CDC INC, BSC, ISC), setVal (CDC IN...	10000
DA stepSize	[CF]	Defines the step between individual values that ctlVal (CDC INC, APC, BAC), setVal (CDC ING)...	0.1
DO FuFail		TVTR fuse failure	
DA stVal	[ST]	Status value of the data	

FIGURE 20 V7M1 DATA MODEL

Figure 21 showed the V2M5 data model for the TCTR logical node having no optional data fields. The V3M3 and V6M2 merging units also only had the mandatory data fields required by the standard.

REF615_MU7 • Data Model • MU01 • I01ATCTR1

LN I01ATCTR1 Current transformer

Name		Description	Value
DO Mod		Mode	on
DO Beh		Behaviour	on
DO NamPlt		Name plate	
DO Amp		Current of a non-three-phase circuit	
DA instMag	[MX]	Magnitude of the instantaneous value of a measured value	
DA i	[MX]	Integer value	
DA q	[MX]	Quality of the attribute(s) representing the value of the data	
DA sVC	[CF]	Scaled value configuration	
DA scaleFactor	[CF]		0.001
DA offset	[CF]		

FIGURE 21 V2M5 MERGING UNIT DATA MODEL

The V1M8 software tool, which was required to program the Vendor V2 SVs, required that the vendor implement optional IEC 61850 data fields within their merging units. A solution must be found by the vendor to fix this problem.

Time Synchronization to the V1M5

The V1M5 documentation and configuration tools used the terms PPS and IRIG-B interchangeably. The time synchronization configuration only listed IRIG-B but did reference PPS in other locations. It was determined that the unit will only synchronize if IRIG-B was connected to the unit's fiber time source input. The unit would not time synchronize if the output from the GPS clock was 1PPS.

Neutral Current and Voltage Calculation Problem

The Utility Communications Architecture's Implementation Guideline for Digital Interface to Instrument Transformers using IEC 61850-9-2, known as IEC 61850-9-2LE, stated that if the neutral current and/or voltage were not measured the merging unit must calculate these values as a sum of the phase values. The document then required an additional indication in the quality field to show that the values were "derived." This was resolved in Phase Five below.

Phase Four System Integration and Testing Results

The primary purpose for this testing session was to work with the Vendor V2 engineer to get the manufacturer's equipment and software working within the test system. The findings follow.

Denial of Service to V2M1, V2M2, V2M3, V2M4

Discovered issue with intermittent receipt of GOOSE messages by Vendor V2 relays, particularly the V2M3 (87T41A) relay. The team contacted the factory representative with relay front panel screenshots (Figure 22), a network traffic capture, and exported the device settings files in order to troubleshoot the problem.

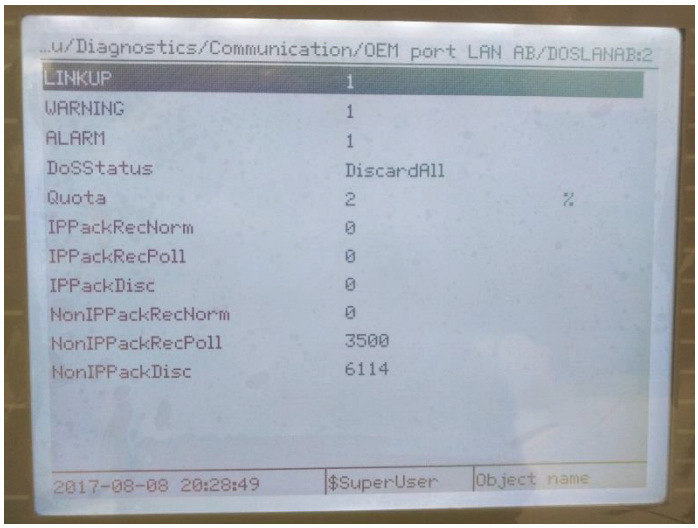


FIGURE 22 V2M3 FRONT PANEL DISPLAY MESSAGE

After contact and discussions with the factory, the intermittent GOOSE message receipt issue was traced to the denial of service (DOS) logic built-in to the relay Ethernet ports. A denial of service situation typically exists when the network traffic exceeds the CPU's ability to process it. The large amount of GOOSE and SV traffic was causing the built-in DOS protection to activate, blocking the receipt of GOOSE messages by the relays.

The DOS issue was corrected by setting up MAC address filtering on the process bus #1 and process bus #2. No further intermittent receipt of GOOSE messages was detected.

V7M2 Analog Data Set Error

Identified V7M2 MU configuration software bug, where one could not import CID file from V3M3 relay. The bug caused all of the available GOOSE datasets to "disappear" from the V7M2 software, rendering them inaccessible.

After contact with the manufacturer, it was determined that the bug was due to the analog GOOSE dataset present in the V3M3 CID. V7M1 MUs could not process CID files which contain analog GOOSE datasets.

```
</DataSet>
<DataSet desc="Transformer Bank 41 MVA data" name="Bank_41_MVA">
  <FCDA ldInst="MET" prefix="MET" lnClass="MMXU" lnInst="1" doName="PhV" daName="phsA.instCVal.mag.f" fc="MX" />
  <FCDA ldInst="MET" prefix="MET" lnClass="MMXU" lnInst="1" doName="PhV" daName="phsA.q" fc="MX" />
  <FCDA ldInst="MET" prefix="MET" lnClass="MMXU" lnInst="1" doName="PhV" daName="phsB.instCVal.mag.f" fc="MX" />
  <FCDA ldInst="MET" prefix="MET" lnClass="MMXU" lnInst="1" doName="PhV" daName="phsB.q" fc="MX" />
  <FCDA ldInst="MET" prefix="MET" lnClass="MMXU" lnInst="1" doName="PhV" daName="phsC.instCVal.mag.f" fc="MX" />
  <FCDA ldInst="MET" prefix="MET" lnClass="MMXU" lnInst="1" doName="PhV" daName="phsC.q" fc="MX" />
  <FCDA ldInst="ANN" prefix="PMV" lnClass="GGIO" lnInst="3" doName="AnIn01" daName="instMag.f" fc="MX" />
  <FCDA ldInst="ANN" prefix="PMV" lnClass="GGIO" lnInst="3" doName="AnIn01" daName="q" fc="MX" />
  <FCDA ldInst="ANN" prefix="PMV" lnClass="GGIO" lnInst="3" doName="AnIn02" daName="instMag.f" fc="MX" />
  <FCDA ldInst="ANN" prefix="PMV" lnClass="GGIO" lnInst="3" doName="AnIn02" daName="q" fc="MX" />
  <FCDA ldInst="ANN" prefix="PMV" lnClass="GGIO" lnInst="3" doName="AnIn03" daName="instMag.f" fc="MX" />
  <FCDA ldInst="ANN" prefix="PMV" lnClass="GGIO" lnInst="3" doName="AnIn03" daName="q" fc="MX" />
```

FIGURE 23 ANALOG DATASET EXAMPLE

Figure 23 is the analog dataset from the V3M3 CID file which the V7M2 software could not import. This was not a "problem" with the CID (this was a valid GOOSE analog dataset) the problem was that the V7M2 software could not import analog GOOSE datasets.

V2M1, V2M2, V2M3, and V2M4 "Fast GOOSE" and Unsubscribing

V2M1, V2M2, V2M3, and V2M4 relay issue with V7M1 MU and its "Fast GOOSE" dataset subscription, which caused issues with the V2M1, V2M2, V2M3, and V2M4 ability to subscribe to other datasets from V7M1.

Removing the "Fast GOOSE" subscription from the V2M1, V2M2, V2M3, and V2M4 relays corrected the issue (see Figure 24).

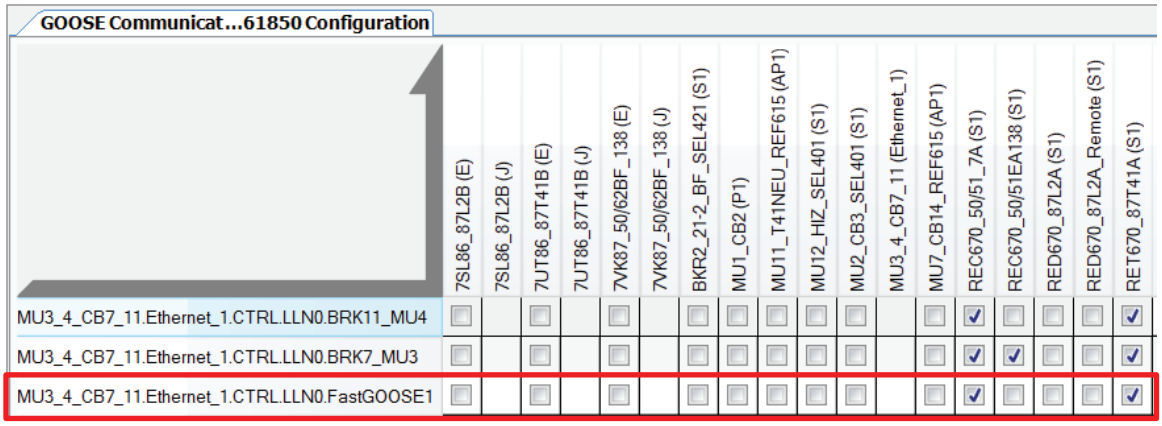


FIGURE 24 V7M1 MU "FAST GOOSE" DATASET

A software bug was identified V2M8 that prevented publishers unsubscribing from some V7M1 MU datasets. After unsubscribing, saving the V2M8 file, and reopening it, all V7M1 datasets were automatically re-subscribed.

The issue was resolved by deleting the V7M1 MU device from the V2M8 software, re-importing the device CID file, and subscribing to only the desired V7M1 GOOSE datasets.

V2M1 Internal Blocking

When a simulated three phase 12 kV bus fault was injected into the V2M1 87-1241A relay, the relay did not respond correctly. While troubleshooting the Vendor V2 relay, it was discovered that all protective functions were receiving an internal blocking signal.

The issue was resolved when one of the MUs affiliated with the V2M1 87-1241A was found to have an incorrect SV AppId value (x4005 instead of x4000). After changing the AppId to x4000, all internal protection blocks were removed.

Miscellaneous Items

- Corrected an issue with duplicate GOOSE dataset MAC addresses for the "MU2_CB3_V3M3" device on the process bus #1 network.
- Found an issue in the GOOSE control block for the V2M1 (5051_EA138) HIZ 138 kV bus differential relay. V2M8 software would overwrite the GOOSE control block information (App ID, MAC address, etc.) with default values, which caused problems with the GOOSE messaging.
    - Issue was deemed to be the result of the internal dataset processing by the software. Corrected issue by deleting and re-creating the GOOSE control block from scratch.
- MU3_CB7: no status/control being displayed on the front of the V2M1 EA138 relay
    - Issue was solved by updating the MU3_CB7 programming to verify that the published GOOSE dataset contained the correct attributes, then re-importing the MU3_CB7 "CID" file into the V2M7 software.
- MU1_CB2: no status received on the V2M1, V2M2, V2M3, and V2M4 relays. Control to MU was active from V2M2 87L2A, but not from V2M1 EA138.
    - Issue was solved during Vendor V1's second site visit as described in Phase Five below.
    - MU13_CB20: receiving breaker status indications, but unable to send controls to MU from V2M1, V2M2, V2M3, and V2M4 relays.
        - Issue was solved by using the same process as described above.

Distance Protection Trips

- At fault location 1, line differential and zone distance trips were issued by Vendor V1 relays, but the distance element protection did not pick-up in V2M1, V2M2, V2M3, and V2M4 relays.
- At fault location 2, Both Vendor V2 and Vendor V1 relays tripped on line differential for a remote three phase fault.
- Vendor V2 and Vendor V1 relays did not trip for a remote SLG fault. The COMTRADE fault waveforms did not look correct upon inspection.

- Both Vendor V2 and Vendor V1 relays tripped on line differential for remote line-line fault.
- V2M2 87L protection for fault locations 1 through 3. Noted that V2M2 distance protection would pick-up for close-in faults, but not remote faults.
    - Distance elements were having issues detecting both phase and ground faults using the simulated COMTRADE files.
    - Issue partially resolved by increasing the local source strength in the RTDS model.
    - Issue with phase distance elements was resolved by adjusting the pickups to values of secondary ohms (the manufacturer had previously indicated that the values should be in primary ohms).
    - Issue with ground distance elements was resolved by disconnecting the neutral current "IN" portion SV DataStream, received from the MU1_CB2_V1M5, from the internal programming in the V2M1, V2M2, V2M3, and V2M4 relays. The V1M5 MU was not transmitting a neutral/residual current value to the V2M1, V2M2, V2M3, and V2M4 relays, hence the neutral/residual current channel was being continuously written to a value of "0." Disconnecting the neutral current "IN" data stream, in the project file and reapplying it to the relays, allowed the V2M1, V2M2, V2M3, and V2M4 relays to internally calculate residual ground currents from the measured phase currents, resulting in correct distance element operation.
- V1M5 MUs were still unable to receive single point controls issued by the various Vendor V2 relays. Contacted both manufacturers, but still waiting on feedback. V1M5 MUs appear to only be controllable by the "SMPPTRC" tripping block (present in the V2M1 87L2A relay, which was the only device configured to control the V1M5 MU).

Phase Five System Integration and Testing Results

The primary purpose for this testing session was to work with the Vendor V1 engineer to resolve the outstanding configuration issues and get this manufacturer's equipment and software working within the test system. The following summarized the findings:

- Single-point TRIP/CLOSE commands sent to V1M5 MUs from the V2M1, V2M2, V3M3, and V2M4 relays were non-functional. Vendor V1 began by troubleshooting the issue with V1M5 MUs not receiving single-point commands correctly. The factory representative spent several hours troubleshooting the V1M5 MUs using a network traffic analyzer and the MUs online diagnostic tools. No errors were found in the relay or MU configurations, the V1M5 MUs simply could not interpret the published datasets
    - Final resolution: issue was related to problems in the headers of the ".ICD" files exported from the V2M8 software. Corrected the issue by manually modifying the ".CID" files exported from the V2M8 software into ".ICD" files, which were imported into the V1M9 software. Previously, ".ICD" files created directly from the V2M8 software had been used to attempt to set up the GOOSE subscriptions.
- The 138 kV breaker failure protection (V1M2 relay) was non-functional.

  Troubleshooting the 138 kV breaker failure protection (V1M2) involved verification that the breaker failure initiated and the breaker status were being received correctly via GOOSE. No issues were found in the existing programming.
    - Final resolution: The factory representative adjusted some of the breaker failure set points and the breaker failure protection was tested and found to work correctly.

Developed Algorithms

Two algorithms were developed during the test design phase. They were the reactive bank automation and the bus lockout function. These algorithms did not previously exist and were developed specifically for this project. These functions were essential to certain protection schemes and while legacy devices may have these functions included, they were easily configured in the test devices due to the versatile nature of IEC 61850 GOOSE messaging.

Capacitor and Reactor Bank

Capacitor and reactor bank VAR control automation was a specific use case that demonstrated the power of GOOSE analog and digital messaging and can eliminate the point-to-point digital signaling currently used in existing distribution substation applications.

This use case included two VAR automation controllers, a transformer overcurrent relay (50/51T), and two reactive bank imbalance protection relays. It was important to note that the automation controllers' options were anticipated to be the same as the current standard part number with the addition of the IEC 61850 GOOSE option. This similarity allowed the majority of the existing logic settings to be reused.

The 50/51T relay provided both of the automation controllers with analog GOOSE messages representing the transformer VAR demand measured at the high side of the terminal. This facilitated addition and subtraction of capacitor/reactor elements to minimize transformer VAR demand, and in turn regulate bus voltage. This scheme was designed to allow up to two 50/51T relays to transmit the GOOSE analog VAR values to the automation controllers. Automatic throw-over logic was included to switch between the sources to prevent relay failure or maintenance from disturbing the automatic reactance control scheme.

One automation controller was dedicated to controlling the capacitor bank stages, while the second was dedicated to the reactor bank. The logic to evaluate VARs outside the threshold was located in the automation controllers.

To maintain the interlock functionality, both automation controllers exchanged their respective stage statuses with each other using station bus GOOSE messages. Thus the capacitor bank automation controller possessed information on the transformer high side VARs as well as the reactor stage statuses. Likewise, the reactor bank automation controller possessed information on the transformer HS VARs as well as the capacitor stage statuses. Both automation controllers utilized this information to decide when to open and close stages while ensuring that the two banks would not "fight each other". This simple scheme inhibited the capacitor bank logic until all of the reactor bank "step" switches were open, and did the same for the reactor bank logic.

Remote monitoring and control of the banks by SCADA could be done utilizing the same station bus connection, eliminating the existing discrete status and control wiring to the SCADA RTU. GOOSE messaging also provided bank unbalance and feeder protection trips to the automation controllers so as to trip all step-switches open and lockout operation for maintenance troubleshooting.

A numerical relay, with GOOSE messaging, was included which replaced the existing capacitor bank electromechanical voltage unbalance relay. This relay implemented a software lockout scheme as opposed to the electromechanical lockout in the standard design. A second numerical relay performed the equivalent unbalance protection function for the reactor bank using a negative sequence overcurrent element. When either relay detected an imbalance condition, it latched a lockout in the relay. This condition was continuously sent by GOOSE to the associated bank

automation controller until the lockout was reset. Upon receipt of a GOOSE status that the lockout asserted, the associated automation controller tripped all four stages and the main breaker and blocked closing of until the lockout condition was cleared. A programmed "Lockout Reset" pushbutton on each bank imbalance protection relay cleared the lockout condition.

Bus and Transformer "Virtual" Lockout Relays

These lockout relays programmed in the test system were designed to reproduce the functions of a traditional hardwired bus lockout relay scheme. In a traditional hardwired lockout relay scheme, copper wiring was used to transmit trip and block close signals from a centralized electromechanical lockout to the breakers associated with a particular zone of protection. Commercially available lockout relays provided the flexibility to trip and block close multiple breaker units, initiated by one or several protective relay trips. To emulate lockout relay functions in the test system, a virtual lockout-relaying scheme was implemented using latching variables, close blocking logic and GOOSE messaging in the test system protection relays. Other than the reactive bank lockout functions described above, three virtual lockout relays were simulated in the test system:

- 138 kV bus differential lockout (86-EA138)
- 138/12 kV transformer differential lockout (86-T41A)
- 12 kV bus differential lockout (86-1241A)

The development of the virtual lockout relays for the test system involved three main steps: selecting protective devices to house each virtual lockout relay, programming the virtual lockout relay schemes, and establishing GOOSE subscriptions to implement trip and block close functionality.

- **Protective device selection**
  Three protective devices were selected, one to house each of the virtual lockout relays described above. All virtual lockout logic was implemented using V2M3 and V2M4 relays. These relays were selected to house the virtual lockout relay schemes because these devices were the earliest available for test system development. To simplify the scheme, pushbutton close commands were programmed only in the relays designed to house the virtual lockout relay schemes.

  - The V2M4 50/51 EA138 relay was selected to house the 138 kV bus differential virtual lockout relay 86-EA138. This relay provided close pushbutton functionality for all 138 kV circuit breakers, as well as a virtual lockout relay reset pushbutton.

  - The V2M3 87T41A relay was selected to house the 138/12 kV transformer differential virtual lockout relay 86-T41A. This relay provided close pushbutton functionality only for its 12 kV low-side main breaker, as well as a virtual lockout relay reset pushbutton.

  - The V2M3-1241A relay was selected to house the 12 kV bus differential virtual lockout relay 86-1241A. This relay provided close pushbutton functionality for all 12 kV circuit breakers, as well as a virtual lockout relay reset pushbutton.

Virtual Lockout Relay Programming

Each virtual lockout followed a similar programming approach. A set of trip initiate conditions for each virtual lockout were used to control a latch variable within the relays. An example of the

lockout logic for the V2M1 50/51 EA138 relay was included in Figure 25 below. For this example, the lockout trip conditions resulted from the following:

- Assertion of any high-impedance bus differential protection condition
- Assertion of a phase low-impedance bus differential protection condition
- Assertion of a ground low-impedance bus differential protection condition

These protection trips controlled a lockout latch variable, resettable only by front panel pushbutton.

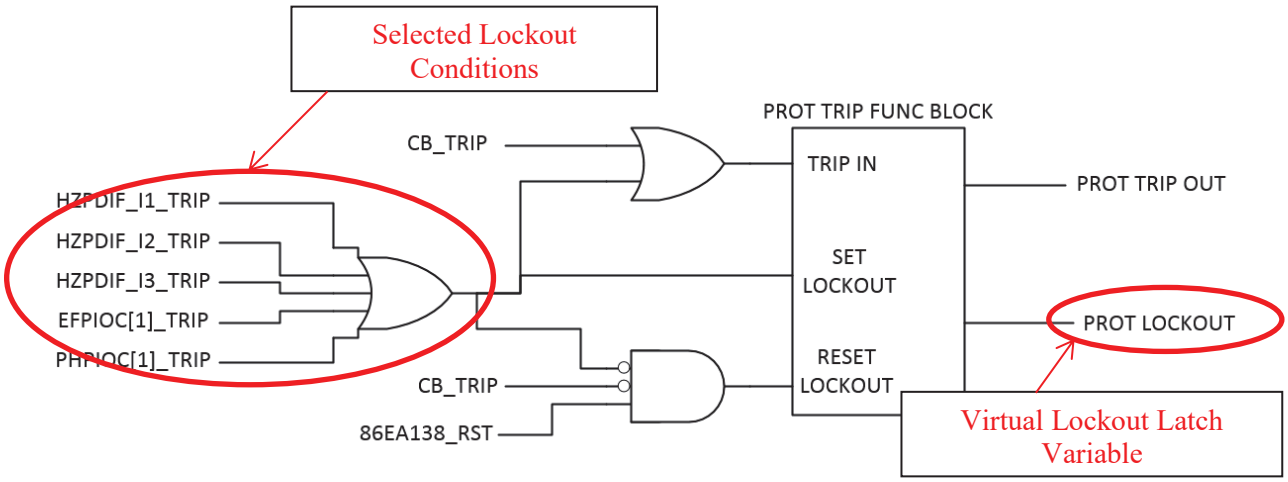


FIGURE 25 V2M4 50/51 EA138 RELAY LOCKOUT PROGRAMMING

GOOSE Implementation of Virtual Lockout Trip and Block Close Functionality

The virtual lockout latch variables tripped and blocked close for all associated breakers participating in the lockout scheme. Virtual lockout latch variables were converted to GOOSE messages by the protective relay and transmitted over the process bus as part of the GOOSE dataset. Block close conditions were compiled for each breaker as required for the application. These block close conditions included:

- The virtual lockout latch variables
- All local protection relay trips
- Any adjacent protection relay trips

Examples of the virtual lockout trip and block close functionality routed via GOOSE messages were provided in Figure 26 below for the V2M1 50/51 EA138 relay. In the example, the 138 kV bus differential virtual lockout latch variable was used to block close for all associated breakers.

An external virtual lockout latch variable was transmitted via GOOSE from the V2M3 87T41A relay to the V2M3 50/51 EA138 relay to block close conditions for only the transformer primary breaker. Front panel pushbutton close commands from the V2M1 50/51 EA138 relay were blocked until all of the associated block close conditions were eliminated.

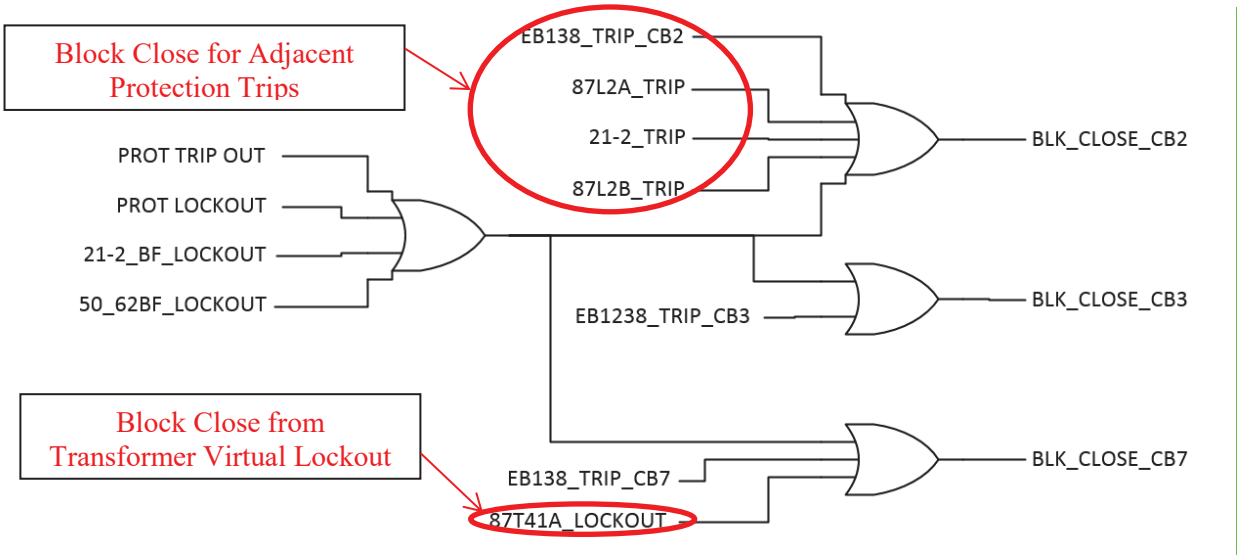


FIGURE 26 V2M4 50/51 EA138 RELAY BLOCK CLOSE PROGRAMMING

Interoperability

Investigation into interoperability was the most challenging experience when designing the test system. Although the Utility Communications Architecture International Users Group (UCAIug) issued an implementation guide in 2006, the recent advent of edition 2 created interoperability issues as the manufacturers migrated to the revised standard.

It was noted that even though manufacturers claimed support for IEC 61850-9-2LE (Light Edition) in both edition 1 or 2, there were differences from the LE document. It appeared that manufacturers picked what they determined were the important aspects of the LE document and only implemented those in their edition 2 products. In some cases this caused an incompatibility problem between SV publishers and subscribers.

Most of the manufacturers moved to implement edition 2 features while attempting to maintain the LE compliance with edition 1. Some manufacturers strictly enforced some of the items and made changes in others in order to accommodate both edition 1 and 2. The use of the SmpSynch field in the SV message buffering and the SV AppID were the two most noticeable items. The SmpSynch definition and data type was changed in edition 2. One merging unit strictly used the LE implementation for this field and it did not work with a protection device that strictly used the IEC 61850 Edition 2 implementation.

The use of GOOSE messaging between editions did not present a problem, and the ease in setting up relay logic for these signals with the current manufacturer software was greatly improved over experiences from just a few years ago. Configuration software included function blocks, directly tied to the IEC 61850 configurations, which could be re-used to quickly build relay logic functions. The only modification made in edition 2 was to change the “test field” to a “simulation field”. This field was not utilized in the test system. For the test system, edition 1 and 2 devices could function with both message types. It was determined that half the merging units had only implemented edition 2 GOOSE along with some of the protection relays. The exception was the capacitor and reactor automation controllers which only supported edition 1 GOOSE. There were no problems in implementing GOOSE solutions for the test system but since every other device supported edition 2, the projects was based on edition 2.

SCL file schemes and structures changed in edition 2. Some manufacturers' configuration tools accepted both edition 1 and 2 files while others required that the edition be declared at the start of a project and would then only accepts files from the declared edition. From the matrices, in TABLE 16 and Table 17, it was determined that all of the software tools would accept edition 2 files versus edition 1 files, which greatly impacted the decision to create the project as an edition 2 project.

10. TEST PROCEDURES

The demonstration plan was developed to ensure that each test case and its associated tests were performed and documented. Test case plan development was based on traditional relay testing plans. For each test case, a description of the case was included to describe the test configuration and success criteria. Test set-up conditions described the relays under test and the protection functions to be evaluated.

The source of the relay settings is then described and the relevant portion of the RTDS model is indicated. This section 10 also describes how the trip and close signals were transmitted. Finally, the test case performance tests are described with individual actions for each step. Captured wave forms, digital point statuses and contact operations are illustrated using COMTRADE plots and a graphical event analyzer. These files illustrate the raw data that was used to populate the results within the plan. Also included is a summary of all the operating times for each fault simulation.

Each test case was carefully designed to emulate real world scenarios. Here the configuration and setup of individual test cases were examined in detail. Relay protection settings and system voltage and current characteristics were explained. Finally, the raw performance data resulting from the simulation by the test set, which was extracted from the protection relays, was analyzed. These files were included in Appendix F.

Performance tests demonstrate proper operation of the test bed setup and relay settings, and record performance result data for the test cases. Tripping of circuit breakers was simulated by latching relays connected to MU digital outputs. Critical timing and observed element operation was recorded and included in Appendix G.

Test Case #1 – Breaker Failure Protection (50BF)

Relay Test Setup Conditions and Requirements

1. The test was performed on one manufacturer's high-performance breaker-failure numerical relay.
    a. The selected relay evaluated was:
        i. Mfg./Model V1M2 breaker failure/control relay
2. Backup line distance (21) and directional overcurrent protection (50/51) element performance was evaluated in a separate test case test from breaker failure so as to produce distinct results for the protection test case analysis.
3. Distance and directional overcurrent element settings matched those installed in the identified substation relays as much as possible.
4. For pre-commercial demonstration, an RTDS model of the identified substation, using equivalents to represent the system beyond the remote substation buses, was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current and voltage playback signals were connected to the appropriate MUs and relay analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
5. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU1 (69/138 kV line CB 2)
    a. Mfg./Model V1M5
    b. CTR= 400T
    c. PTR= 700T (W. bus)

50BF Performance Tests (Mfg./Model V1M2)

1. Simulate a 3LG fault close-in to the breaker by COMTRADE playback injection with CB 2 breaker current not dropping out and record the following:
    a. Download event record from each relay
    b. Fault Initiation Time: 6:10:7.110 PM**
    c. 50BF Relay Fault Recorder Initiation Time: 6:10:7.116 PM
    d. 50BF GOOSE BFI Received Time: 6:10:7.116 PM (50BF element pickup)
    e. Relay 50BF Trip Time: 6:10:7.496 PM
    f. CB 2 52a Open Detected Time: 6:10:7.561 PM
    g. CB 7 52a Open Detected Time: 6:10:7.550 PM
    h. CB 3 52a Open Detected Time: 6:10:7.547 PM
    i. Comments: 62BF set @ 0.417s (25 cycles)

2. Simulate a 3LG fault close-in to the breaker by COMTRADE playback injection with CB 2 breaker 52a status contact not dropping out and record the following:
    a. Download event record from each relay
    b. Fault Initiation Time: 6:19:01.110 PM
    c. 50BF Relay Fault Initiation Time: 6:19:01.116 PM
    d. 50BF GOOSE BFI Received Time: 6:19:01.116 PM (50BF element pickup)
    e. Relay 50BF Trip Initiation Time: 6:19:01.496 PM
    f. CB 2 52a Open Detected Time: 6:19:01.561 PM
    g. CB 7 52a Open Detected Time: 6:19:01.550 PM
    h. CB 3 52a Open Detected Time: 6:19:01.547 PM
    i. Comments: 62BF set @ 0.417s (25 cycles)

**Note: All times listed in the report were in GMT, which was the master simulations test-system setting.

Test Case #2 – Line Differential Protection (87L)

Relay Test Setup Conditions and Requirements

1. The tests were performed on two different manufacturers' high-performance numerical line differential relays that also incorporated backup impedance and directional overcurrent tripping elements. The selected relays to be evaluated were:
    a. Set A – Mfg./Model V2M2
    b. Set B – Mfg./Model V1M1

2. Backup line distance (21) and directional overcurrent protection (50/51) element performance was evaluated in a separate test case test from line differential (87L) so as to produce distinct results for protection test case analysis.

3. Differential protection communications was via an industry standard IEEE C37.94, 64 kB channel that connected the local and remote simulation relays via a multi-mode (MM) fiber-optic jumper. As the communications channel effect on relaying performance was not under

study, a direct fiber-optic connection without multiplex or transmission delay was assumed for the test.

4. Differential element settings matched those installed in the identified substation relays as much as possible.
5. For pre-commercial demonstration, an RTDS model of the identified substation, using equivalents to represent the system beyond the remote substation buses, was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current and voltage playback signals were connected to the appropriate MUs and relay analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
6. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test case voltage and current injection from relay test sets

1. MU1 69/138 kV Line CB 2) for local relays
    a. Mfg./Model V1M5
    b. CTR= 400T
    c. PTR= 700T (W. bus)

2. Direct connection to Set A and B remote relays

Set A 87L Performance Tests (Mfg./Model V2M2)

1. Simulate a 3LG fault behind the local 87L Set A by COMTRADE playback injection and record the following:
    a. Local Relay 87L Element Restrained? (Yes/No): Yes
    b. Local Relay 87L Element Restrained? (Yes/No): Yes
    c. Comments: None – proper operation, no event records triggered in local relay

2. Simulate a 1LG fault behind the local 87L Set A by COMTRADE playback injection and record the following:
    a. Local Relay 87L Element Restrained? (Yes/No): Yes
    b. Local Relay 87L Element Restrained? (Yes/No): Yes
    c. Comments: None – proper operation, no event records triggered in local relay

3. Simulate a 3LG fault close-in to the local 87L Set A by COMTRADE playback injection and record the following:
    a. Download event records from the relays at each line end
    b. Fault Initiation Time: 9:52:00.532 PM
    c. Local Relay 87L Trip Initiation Time: 9:52:00.543 PM
    d. Remote Relay 87L Trip Initiation Time: 9:52:00.543 PM
    e. Local Relay 52a Open Detected Time: 9:52:00.565 PM
    f. Comments: True sub-cycle relay operation

4. Simulate a 1LG fault close-in to the local 87L Set A by COMTRADE playback injection and record the following:
    a. Download event records from the relays at each line end

b. Fault Initiation Time: 10:14:30.534 PM
c. Local Relay 87L Trip Initiation Time: 10:14:30.549 PM
d. Remote Relay 87L Trip Initiation Time: 10:14:30.545 PM
e. Local Relay 52a Open Detected Time: 10:14:30.565 PM
f. Comments: True sub-cycle relay operation

5. Simulate a 3LG fault behind the remote 87L Set A by COMTRADE playback injection and record the following:
   a. Local Relay 87L Element Restrained? (Yes/No): Yes
   b. Local Relay 87L Element Restrained? (Yes/No): Yes
   c. Comments: None – proper operation, event triggered by overreaching distance protection

6. Simulate a 1LG fault behind the remote 87L Set A by COMTRADE playback injection and record the following:
   a. Local Relay 87L Element Restrained? (Yes/No): Yes
   b. Local Relay 87L Element Restrained? (Yes/No): Yes
   c. Comments: None – proper operation, event triggered by overreaching distance protection

Set B 87L Performance Tests (Mfg./Model V1M1)

1. Simulate a 3LG fault behind the local 87L Set A by COMTRADE playback injection and record the following:
   a. Local Relay 87L Element Restrained? (Yes/No): Yes
   b. Local Relay 87L Element Restrained? (Yes/No): Yes
   c. Comments: None – proper operation, no event records triggered in local relay

2. Simulate a 1LG fault behind the local 87L Set A by COMTRADE playback injection and record the following:
   a. Local Relay 87L Element Restrained? (Yes/No): Yes
   b. Local Relay 87L Element Restrained? (Yes/No): Yes
   c. Comments: None – proper operation, no event records triggered in local relay

3. Simulate a 3LG fault close-in to the local 87L Set A by COMTRADE playback injection and record the following:
   a. Download event records from the relays at each line end
   b. Fault Initiation Time: 7:05:00.492 PM
   c. Local Relay 87L Trip Initiation Time: 7:05:00.517 PM
   d. Remote Relay 87L Trip Initiation Time: 7:05:00.519 PM
   e. Local Relay 52a Open Detected Time: 7:05:00.567 PM
   f. Comments: 1.4 cycle relay operation – this was slow for a high-end 87L relay

4. Simulate a 1LG fault close-in to the local 87L Set A by COMTRADE playback injection and record the following:
   a. Download event records from the relays at each line end
   b. Fault Initiation Time: 6:55:30.492 PM
   c. Local Relay 87L Trip Initiation Time: 6:55:30.515 PM
   d. Remote Relay 87L Trip Initiation Time: 6:55:30.523 PM
   e. Local Relay 52a Open Detected Time: 6:55:30.569 PM

f. Comments: 1.4 cycle relay operation - this was slow for a high-end 87L relay

5. Simulate a 3LG fault behind the remote 87L Set A by COMTRADE playback injection and record the following:
   a. Local Relay 87L Element Restrained? (Yes/No): Yes
   b. Local Relay 87L Element Restrained? (Yes/No): Yes
   c. Comments: None – proper operation, no event records triggered in local relay

6. Simulate a 1LG fault behind the remote 87L Set A by COMTRADE playback injection and record the following:
   a. Local Relay 87L Element Restrained? (Yes/No): Yes
   b. Local Relay 87L Element Restrained? (Yes/No): Yes
   c. Comments: None – proper operation, no event records triggered in local relay

Test Case #3 – Line Distance and Directional Overcurrent Protection (21 and 50/51)

Relay Test Setup Conditions and Requirements

1. The tests were performed on two different manufacturers' high-performance numerical line differential relays that also incorporate backup impedance and directional overcurrent tripping elements. The selected relays to be evaluated were:

   a. Set A - Mfg./Model V2M2
   b. Set B – Mfg./Model V3M1

2. Line distance (21) and directional overcurrent protection (50/51) element performance was evaluated in a separate test case test from line differential (87L) so as to produce distinct results for protection test case analysis.

3. Distance and directional overcurrent element settings matched those installed in the identified substation relays as much as possible.

4. For pre-commercial demonstration, an RTDS model of the identified substation, using equivalents to represent the electric system beyond the remote substation buses was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current and voltage playback signals were connected to the appropriate MU analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.

5. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU1 (69/138 kV Line CB 2) for Set A
   a. Mfg./Model V1M5
   b. CTR= 400T
   c. PTR= 700T (W. bus)

2. MU2 (69/138 kV Tie CB 3) for Set B
   a. Mfg./Model V3M3

b. CTR= 400T
c. PTR= 700T (W. bus)

3. MU3 (69/138 kV BK41 CB 7) for Set B
   a. Mfg./Model V7M1
   b. CTR= 400T
   c. PTR= 700T (W. bus)

Set A (21, 50, 51) Performance Tests (Mfg./Model V2M2)

1. Simulate a 3LG fault behind the breaker by COMTRADE playback injection and record the following:
   a. Relay Zone 1, 2, and 3 Forward 21P Elements Restrained? (Yes/No): Yes
   b. Comments: None – proper operation, no event records triggered in relay

2. Simulate a 1LG fault behind the breaker by COMTRADE playback injection and record the following:
   a. Relay Zone 1 and 2 Forward 21G Elements Restrained? (Yes/No): Yes
   b. Relay Zone 1 Forward 50G and 51G Elements Restrained? (Yes/No): Yes
   c. Comments: None – proper operation, no event records triggered in relay

3. Simulate a 3LG fault close-in to the breaker by COMTRADE playback injection and record the following:
   a. Download event record from the relay (the previous 87L test may be re-used)
   b. Fault Initiation Time: 9:52:00.532 PM
   c. Relay Fault Initiation Time: 9:52:00.532 PM
   d. Relay Zone 1 Forward 21P Trip Initiation Time: 9:52:00.542 PM
   e. Relay Zone 2 and 3 Forward 21P Element Pickup? (Yes/No) : Yes
   f. Local Relay 52a Open Detected Time: 9:52:00.576 PM
   g. Comments: True sub-cycle relay operation

4. Simulate a 1LG fault close-in to the breaker by COMTRADE playback injection and record the following:
   a. Download event record from the relay (the previous 87L test may be re-used)
   b. Fault Initiation Time: 10:14:30.534 PM
   c. Relay Fault Initiation Time: 10:14:30.534 PM
   d. Relay Zone 1 Forward 21G Element Trip Initiation Time: 10:14:30.542 PM
   e. Relay Zone 2 Forward 21G Element Pickup? (Yes/No): Yes
   f. Relay Zone 1 Forward 50G Element Trip Initiation Time: 10:14:30.549 PM
   g. Relay Forward 51G Element Pickup? (Yes/No): Yes
   h. Relay 52a Open Detected Time: 10:14:30.562 PM
   i. Comments: True sub-cycle relay operation

5. Simulate a 3LG fault at the remote bus by COMTRADE playback injection and record the following:
   a. Download event record from the relay (the previous 87L test may be re-used)
   b. Fault Initiation Time: 8:05:30.495 PM
   c. Relay Zone 2 and 3 21P Pickup Time: 8:05:30.563 PM
   d. Relay Zone 1 Forward 21P Element Restrained? (Yes/No): Yes
   e. Relay Zone 2 Forward 21P Trip Initiation Time: 8:05:30.766 PM
   f. Relay Zone 3 Forward 21P Trip Initiation Time: 8:05:31.063 PM

g. Relay 52a Open Detected Time: 8:05:30.787 PM
h. Comments: Relay detected high SIR and switched in automatic SIR filtering – this filtering added about 55ms of extra delay to the 21P-2 element operation as compared to the Set B performance for the same fault. The actual network in this location has this actual condition as confirmed with the provided circuit model, so the relay acted appropriately to improve security. 21P-2 delay was 200ms and 21P-3 delay was 500ms.

6. Simulate a 1LG fault at the remote bus by COMTRADE playback injection and record the following:
   a. Download event record from the relay (the previous 87L test may be re-used)
   b. Fault Initiation Time: 11:59:40.500 PM
   c. Relay Zone 2 and 3 21G Pickup Time: 11:59:40.518 PM
   d. Relay Zone 1 Forward 21G Element Restrained? (Yes/No): Yes
   e. Relay Zone 2 Forward 21G Trip Initiation Time: 11:59:40.721 PM
   f. Relay Zone 3 Forward 21G Trip Initiation Time: 11:59:41.021 PM
   g. Relay Zone 1 Forward 50G Element Restrained (Yes/No): Yes
   h. Relay Forward 51G Element Trip Initiation Time: No Operation
   i. Relay 52a Open Detected Time: 11:59:40.744 PM
   j. Comments: Relay's ground directional overcurrent element was not able to detect the 1LG fault due to marginal ground source behind relay, and almost equal magnitude currents in the un-faulted phases at almost the same phase angle (-89°) as the faulted phase due to nearby isolated ground sources which probably lowered the negative-sequence polarizing voltage – this behavior was not a process bus issue but a simulation corner case. The actual network in this location has this actual condition as confirmed with the provided circuit model, and demonstrates that numerical relay settings should always incorporate alternate fault detecting elements.

Set B 21, 50 and 51 Performance Tests (Mfg./Model V3M1):

1. Simulate a 3LG fault behind the breaker by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Relay Zone 1, 2, and 3 Forward 21P Elements Restrained? (Yes/No): Yes
   c. Comments: None – proper operation, no event records triggered in relay.

2. Simulate a 1LG fault behind the breaker by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Relay Zone 1 and 2 Forward 21G Elements Restrained? (Yes/No): Yes
   c. Relay Zone 1 Forward 50G and 51G Elements Restrained? (Yes/No): Yes
   d. Comments: None – proper operation, no event records triggered in relay.

3. Simulate a 3LG fault close-in to the breaker by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Fault Initiation Time: 14:43:08.470***
   c. Relay Fault Initiation Time: 14:43:08.470
   d. Relay Zone 1 Forward 21P Trip Initiation Time: 14:43:08.473
   e. Relay Zone 2 and 3 Forward 21P Element Pickup? (Yes/No) : Yes

f. Local Relay 52a Open Detected Time: 14:43:08.496
g. Comments: Timing from SER report.

***Note: Some relays reported time using a 24 hour format. To simplify comparison between this section and the files in Appendix F, the 24 hour time format was utilized here to match the files in Appendix F.

4. Simulate a 1LG fault close-in to the breaker by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Fault Initiation Time: 16:58:19.511
   c. Relay Fault Initiation Time: 16:58:19.511
   d. Relay Zone 1 Forward 21G Element Trip Initiation Time: 16:58:19.515
   e. Relay Zone 2 Forward 21G Element Pickup? (Yes/No): Yes
   f. Relay Zone 1 Forward 67G1 Element Trip Initiation Time: 16:58:19.518
   g. Relay Forward 51G Element Pickup? (Yes/No): Yes
   h. Relay 52a Open Detected Time: 16:58:19.543
   i. Comments: 67G1 pickup slower than Z1G due to unique phasor situation described above.

5. Simulate a 3LG fault at the remote bus by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Fault Initiation Time: 3:28:13.466 PM
   c. Relay Zone 2 21P Pickup Time: 3:28:13.478 PM
   d. Relay Zone 1 Forward 21P Element Restrained? (Yes/No): Yes
   e. Relay Zone 2 Forward 21P Trip Initiation Time: 3:28:13.680 PM
   f. Relay 52a Open Detected Time: 3:28:13.703 PM
   g. Comments: Sub-cycle relay 21P operation; Zone 2 timer set for 200 ms delay. This relay's performance was very impressive.

6. Simulate a 1LG fault at the remote bus by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Fault Initiation Time: 5:25:09.503 PM
   c. Relay Zone 2 21G Pickup Time: 5:25:09.515 PM
   d. Relay Zone 1 Forward 21G Element Restrained? (Yes/No): Yes
   e. Relay Zone 2 Forward 21G Trip Initiation Time: 5:25:09.714 PM
   f. Relay Zone 1 Forward 50G Element Restrained (Yes/No): Yes
   g. Relay Forward 51G Element Trip Initiation Time: 5:25:09.626 PM
   h. Relay 52a Open Detected Time: 5:25:09.651 PM
   i. Comments: This relay's ground directional overcurrent element had no difficulty detecting the remote bus ground fault unlike Set A. Sub-cycle relay 21G operation; Zone 2 timer set for 200 ms delay. This relay's performance was very impressive.

Test Case #4 – High Voltage (HV) Bus Overcurrent Differential Protection (87B-50/51)

Relay Test Setup Conditions and Requirements

1. The selected relays to be evaluated were:

a. Set A - Mfg./Model V2M1
b. Set B - Mfg./Model V1M3

2. Overcurrent differential element settings matched those installed in the identified substation relays as much as possible.

3. For pre-commercial demonstration, an RTDS model of the identified substation, using equivalents to represent the electric system beyond the remote substation buses was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current and voltage playback signals were connected to the appropriate MU analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.

4. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU1 (69/138 kV Line CB 2)
   a. Mfg./Model V1M5
   b. CTR= 400T
   c. PTR= 700T (W. bus)

2. MU2 (69/138 kV Tie CB 3)
   a. Mfg./Model V3M3
   b. CTR= 400T
   c. PTR= 700T (W. bus)

3. MU3 (69/138 kV BK41 CB 7)
   a. Mfg./Model V7M1
   b. CTR= 400T
   c. PTR= 700T (W. bus)

Set A 87B-50/51 Overcurrent Differential Performance Tests (Mfg./Model V2M1)

1. Simulate a close-in 3LG fault on the transmission line by COMTRADE playback injection and record the following:
   a. Relay 87B-50/51 Restrained? (Yes/No): Yes
   b. Comments: None – proper relay operation

2. Simulate a close-in 1LG fault on the transmission line by COMTRADE playback injection and record the following:
   a. Relay 87B-50/51 Restrained? (Yes/No): Yes
   b. Comments: None – proper relay operation

3. Simulate a 3LG fault on the HV bus by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Fault Initiation Time: 2:55:00.495 PM
   c. Relay Fault Initiation Time: 2:55:00.500 PM

d. Relay 87B-50P Trip Initiation Time: 2:55:00.500 PM
e. Relay Longest 52a Open Detected Time: 2:55:00.528 PM
f. Comments: Excellent sub-cycle operation.

4. Simulate a 1LG fault on the HV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 3:34:11.504 PM
    c. Relay Fault Initiation Time: 3:34:11.509 PM
    d. Relay 87B-50/51Trip Initiation Time: 3:34:11.509 PM
    e. Relay Longest 52a Open Detected Time: 3:34:11.535 PM
    f. Comments: Excellent sub-cycle operation.

Set B 87B-50/51 Overcurrent Differential Performance Tests (Mfg./Model V1M3)

1. Simulate a 3LG fault on the transmission line by COMTRADE playback injection and record the following:
    a. Relay 87B-50/51 Restrained? (Yes/No): Yes
    b. Comments: None – proper relay operation.

2. Simulate an SLG fault on the transmission line by COMTRADE playback injection and record the following:
    a. Relay Differential Overcurrent Restrained? (Yes/No): Yes
    b. Comments: None – proper relay operation.

3. Simulate a 3LG fault on the HV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 3:55:00.500 PM
    c. Relay Fault Initiation Time: 3:55:00.504 PM
    d. Relay 87B-50P Trip Initiation Time: 3:55:00.504 PM
    e. Relay 52a Open Detected Time: 3:55:00.534 PM
    f. Comments: Excellent sub-cycle operation.

4. Simulate an SLG fault on the HV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 4:10:00.495 PM
    c. Relay Fault Initiation Time: 4:10:00.503 PM
    d. Relay 87B-50G Trip Initiation Time: 4:10:00.503 PM
    e. Relay 52a Open Detected Time: 4:10:00.533 PM
    f. Comments: Excellent sub-cycle operation.

Test Case #5 – HV Bus Restrained Current Differential Protection (87B)

Relay Test Setup Conditions and Requirements

1. The selected relay to be evaluated were:
    a. Mfg./Model V1M3

2. Existing distribution substations and standards did not use overcurrent differential protection for this application, so settings did not match those installed in the identified substation relays; typical industry standard settings were applied.
3. For pre-commercial demonstration, an RTDS model of the identified substation using, equivalents to represent the electric system beyond the remote substation buses was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current and voltage playback signals were connected to the appropriate MU analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
4. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU1 (69/138 kV Line CB 2)
    a. Mfg./Model V1M5
    b. CTR= 400T
    c. PTR= 700T (W. bus)

2. MU2 (69/138 kV Tie CB 3)
    a. Mfg./Model V3M3
    b. CTR= 400T
    c. PTR= 700T (W. bus)

3. MU3 (69/138 kV BK41 CB 7)
    a. Mfg./Model V7M1
    b. CTR= 400T
    c. PTR= 700T (W. bus)

87B Restrained Current Differential Performance Tests (Mfg./Model V1M3)

1. Simulate a close-in 3LG fault on the transmission line by COMTRADE playback injection and record the following:
    a. Relay Differential Overcurrent Restrained? (Yes/No): Yes
    b. Comments: None – proper relay operation.

2. Simulate a close-in 1LG fault on the transmission line by COMTRADE playback injection and record the following:
    a. Relay Differential Overcurrent Restrained? (Yes/No): Yes
    b. Comments: None – proper relay operation.

3. Simulate a 3LG fault on the HV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 3:55:00.500 PM
    c. Relay Fault Initiation Time: 3:55:00.504 PM
    d. Relay 87B Trip Initiation Time: 3:55:00.504 PM

e. Relay 52a Open Detected Time: 3:55:00.534 PM
f. Comments: Excellent sub-cycle operation.

4. Simulate a 1LG fault on the HV bus by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Fault Initiation Time: 4:10:00.495 PM
   c. Relay Fault Initiation Time: 4:10:00.503 PM
   d. Relay Trip Initiation Time: 4:10:00.503 PM
   e. Relay 52a Open Detected Time: 4:10:00.533 PM
   f. Comments: Excellent sub-cycle operation.

Test Case #6 – HV Bus High Impedance Differential Protection (87B-HIZ)

Relay Test Setup Conditions and Requirements

1. The selected relay to be evaluated was:
   a. Mfg./Model V2M4
2. Existing distribution substations and standards did not use high-impedance differential protection for this application, so settings do not match those installed in the identified substation relays; typical industry standard settings were applied.
3. For pre-commercial demonstration, an RTDS model of the identified substation, using equivalents to represent the system beyond the remote substation buses was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current signals from the breakers bounding the differential zone were summed together in the model and the output of this summation was connected to the MU analog input. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
4. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU12 (69/138 kV Line CB 2, CB3, CB7 summed externally in a High Impedance (HIZ) resistor assembly made by Mfg. V2)
   a. Mfg./Model V3M3
   b. CTR= Special Setting based on chosen resistor setting – see relay settings documentation
   c. PTR= 700T (W. bus)

87B-HIZ High Impedance Bus Differential Performance Tests (Mfg./Model V2M4)

1. Simulate a 3LG fault on the transmission line by COMTRADE playback injection and record the following:
   a. Relay 87B-HIZ Restrained? (Yes/No): Yes
   b. Comments: Test simulated by direct MU current injection from F6150e as resistor assembly was not available.

2. Simulate a 1LG fault on the transmission line by COMTRADE playback injection and record the following:
    a. Relay 87B-HIZ Restrained? (Yes/No): Yes
    b. Comments: Test simulated by direct MU current injection from F6150e as resistor assembly was not available.

3. Simulate a 3LG fault on the HV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 3:35:24.653 PM
    c. Relay Fault Initiation Time: 3:35:24.656 PM
    d. Relay 87B-HIZ Trip Initiation Time: 3:35:24.656 PM
    e. Relay 52a Open Detected Time: 3:35:24.680 PM
    f. Comments: Test simulated by direct MU current injection from F6150e as resistor assembly was not available; relay sub-cycle performance.

4. Simulate a 1LG fault on the HV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 3:36:42.554 PM
    c. Relay Fault Initiation Time: 3:36:42.557 PM
    d. Relay 87B-HIZ Trip Initiation Time: 3:36:42.557 PM
    e. Relay 52a Open Detected Time: 3:36:42.581 PM
    f. Comments: Test simulated by direct MU current injection from F6150e as resistor assembly was not available; relay sub-cycle performance.

Test Case #7 – Transformer Restrained Current Differential Protection (87T)

Relay Test Setup Conditions and Requirements

1. The selected relays to be evaluated were:
    a. Set A – Mfg./Model V2M3
    b. Set B – Mfg./Model V1M3

2. Transformer restrained differential current element settings matched those installed in the identified substation relays as much as possible.

3. For pre-commercial demonstration, an RTDS model of the identified substation, using equivalents to represent the electric system beyond the remote substation buses was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current and voltage playback signals were connected to the appropriate MU analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.

4. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU3 (69/138 kV BK41 CB 7)

a. Mfg./Model V7M1
b. CTR= 400T
c. PTR= 700T (W. bus)

2. MU4 (12 kV BK41 CB 11)
   a. Mfg./Model V7M1
   b. CTR= 400T
   c. PTR= 100T (12 kV bus)

3. MU7 (12 kV BK41 CB 14)
   a. Mfg./Model V2M5
   b. CTR= 400T
   c. PTR= 100T (12 kV bus)

Set A 87T Transformer Restrained Overcurrent Diff. Performance Tests (Mfg./Model V2M3)

1. Simulate a 3LG fault on the high voltage bus by COMTRADE playback injection and record the following:
   a. Relay Differential Overcurrent Restrained? (Yes/No): Yes
   b. Comments: No operation for out of zone fault.

2. Simulate a 1LG fault on the high voltage bus by COMTRADE playback injection and record the following:
   a. Relay Differential Overcurrent Restrained? (Yes/No): Yes
   b. Comments: No operation for out of zone fault.

3. Simulate a 3LG fault in the transformer zone by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Fault Initiation Time: 8:23:30.488 PM
   c. Relay Fault Pickup Time: 8:23:30.488 PM
   d. Relay 50P Trip Initiation Time: 8:23:30.496 PM
   e. Relay 87U Trip Initiation Time: 8:23:30.505 PM
   f. Relay 87R Trip Initiation Time: 8:23:30.515 PM
   g. Relay Longest 52a Open Detected Time: 8:23:30.516 PM
   h. Comments: Excellent operation.

4. Simulate a 1LG fault in the transformer zone by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Fault Initiation Time: 9:00:30.494 PM
   c. Relay Fault Pickup Time: 9:00:30.494 PM
   d. Relay 50G Trip Initiation Time: 9:00:30.503 PM
   e. Relay 87R Trip Initiation Time: 9:00:30.519 PM
   f. Relay Longest 52a Open Detected Time: 9:00:30.523 PM
   g. Comments: Excellent operation.

Set B 87T Transformer Restrained Overcurrent Diff. Performance Tests (Mfg./Model V1M3)

1. Simulate a 3LG fault on the high voltage bus by COMTRADE playback injection and record the following:
    a. Relay Differential Overcurrent Restrained? (Yes/No): Yes
    b. Comments: No operation for out of zone fault.

2. Simulate a 1LG fault on the high voltage bus by COMTRADE playback injection and record the following:
    a. Relay Differential Overcurrent Restrained? (Yes/No): Yes
    b. Comments: No operation for out of zone fault.

3. Simulate a 3LG fault in the transformer zone by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 9:23:30.468 PM
    c. Relay Fault Pickup Time: 9:23:30.518 PM
    h. Relay 50P Trip Initiation Time: **No Operation
    i. Relay 87U Trip Initiation Time: **No Operation
    d. Relay 87R Trip Initiation Time: **No Operation
    e. Relay Longest 52a Open Detected Time: N/A
    f. Comments: **Relay restrained due to "Bad Quality" data target for the MU7 Data Stream. This was a possible ICD/CID configuration issue with the process bus communications module.

4. Simulate a 1LG fault in the transformer zone by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 10:00:30.470 PM
    c. Relay Fault Pickup Time: 10:00:30.520 PM
    j. Relay 50G Trip Initiation Time: **No Operation
    d. Relay 87R Trip Initiation Time: **No Operation
    e. Relay Longest 52a Open Detected Time N/A
    f. Comments: **Relay restrained due to "Bad Quality" data target for the MU7 Data Stream. This was a possible CID/ICD configuration issue with the process bus communications module.

Test Case #8 – Transformer Overcurrent Protection (50/51T)

Relay Test Setup Conditions and Requirements

1. The tests were performed on four relays from two different manufacturers of high-performance numerical overcurrent relays. The selected relays to be evaluated were:
    a. Set A – Mfg./Model V2M4
    b. Set B – Mfg./Model V1M4
    c. Set C – Mfg./Model V2M3
    d. Set D – Mfg./Model V1M3
2. Overcurrent element settings matched those installed in the identified substation relays as much as possible.

3. For pre-commercial demonstration, an RTDS model of the identified substation, using equivalents to represent the electric system beyond the remote substation buses was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current playback signals were connected to the appropriate MU analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
4. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU3 (69/138 kV BK41 CB 7)
    a. Mfg./Model V7M1
    b. CTR= 400T
    c. PTR= 700T (W. bus)

2. MU11 (BK41 Neutral)
    a. Mfg./Model V2M5
    b. CTR= 600T
    c. PTR= Not Used

Set A (50/51) Performance Tests (Mfg./Model V2M4)

1. Simulate a transformer 3LG fault by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Event Initiation Time: 8:23:30.488 PM
    c. Relay 50P Trip Initiation Time: 8:23:30.498 PM
    d. Relay 52a Open Detected Time: 8:23:30.508 PM
    e. Comments: Excellent sub-cycle operation.

2. Simulate a transformer 1LG fault by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Event Initiation Time: 9:00:30.494 PM
    c. Relay 50N Trip Initiation Time: 9:00:30.504 PM
    d. Relay Open Detected Time: 9:00:30.514 PM
    e. Comments: Excellent sub-cycle operation.

Set B (50/51) Performance Tests (Mfg./Model V1M4)

1. Simulate a transformer 3LG fault by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Event Initiation Time: 9:23:30.492 PM
    c. Relay 50P Trip Initiation Time: 9:23:30.502 PM
    d. Relay Longest 52a Open Detected Time: 9:23:30.512 PM

e. Comments: Excellent sub-cycle operation.

2. Simulate a transformer 1LG fault by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Event Initiation Time: 10:00:30.505 PM
    c. Relay 50N Trip Initiation Time: 10:00:30.516 PM
    d. Relay Longest 52a Open Detected Time: 10:00:30.528 PM
    e. Comments: Excellent sub-cycle operation.

Set C (50/51) Performance Tests (Mfg./Model V2M3)

1. Simulate a transformer 3LG fault by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Event Initiation Time: 8:23:30.488 PM
    c. Relay 50P Trip Initiation Time: 8:23:30.496 PM
    d. Relay 52a Open Detected Time: 8:23:30.516 PM
    e. Comments: Excellent Operation.

2. Simulate a transformer 1LG fault by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Event Initiation Time: 9:00:30.494 PM
    c. Relay 50N Trip Initiation Time: 9:00:30.503 PM
    d. Relay 52a Open Detected Time: 9:00:30.519 PM
    e. Comments: Excellent Operation.

Set D (50/51) Performance Tests (Mfg./Model V1M3)

1. Simulate a transformer 3LG fault by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Event Initiation Time: 9:23:30.488 PM
    c. Relay 50P Trip Initiation Time: **No Operation
    d. Relay Longest 52a Open Detected Time: N/A
    e. Comments: **Relay restrained due to "Bad Quality" data target for the MU7 Data Stream. This was a possible ICD/CID configuration issue with the process bus communications module.

2. Simulate a transformer 1LG fault by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Event Initiation Time: 10:00:30.470 PM
    c. Relay 50N Trip Initiation Time: **No Operation
    d. Relay Longest 52a Open Detected Time: N/A
    e. Comments: **Relay restrained due to "Bad Quality" data target for the MU7 Data Stream. This was a possible CID/ICD configuration issue with the process bus communications module.

Test Case #9 – 12 kV Bus Partial Overcurrent Differential Protection (87B-51P/G)

Relay Test Setup Conditions and Requirements

1. The selected relays to be evaluated were:
    a. Set A – Mfg./Model V2M4
    b. Set B – Mfg./Model V1M4
2. Differential overcurrent element settings matched those installed in the identified substation relays as much as possible.
3. For pre-commercial demonstration, an RTDS model of the identified substation, using equivalents to represent the system beyond the remote substation) buses, was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current and voltage playback signals were connected to the appropriate MU analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
4. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU5 (12 kV Tie CB 10)
    a. Mfg./Model V2M5
    b. CTR= 400T
    c. PTR= 100T (12 kV bus)

2. MU10 (12 kV BK41 CB 14)
    a. Mfg./Model V7M1
    b. CTR= 400T
    c. PTR= 100T (12 kV bus)

3. MU13 (12 kV Tie CB 20)
    a. Mfg./Model V1M5
    b. CTR= 400T
    c. PTR= 100T (12 kV bus)

Set A 87B-50/51 Overcurrent Differential Performance Tests (Mfg./Model V2M4)

1. Simulate 3LG fault in the transformer by COMTRADE playback injection and record the following:
    a. Relay 87B-51 Restrained? (Yes/No): Yes
    b. Comments: No operation for out of zone fault, no event reports generated.

2. Simulate an SLG fault in the transformer by COMTRADE playback injection and record the following:
    a. Relay 87B-51 Restrained? (Yes/No): Yes
    b. Comments: No operation for out of zone fault, no event reports generated.

3. Simulate a 3LG fault on the 12 kV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 2:51:00.203 PM
    c. Relay Fault Pickup Time: 2:51:00.207 PM
    d. Relay 87B-51P Trip Initiation Time: 2:51:01.541 PM
    e. Relay Longest 52a Open Detected Time: 2:51:01.569 PM
    f. Relay 51 element operated with the expected time delay? (Yes/No): Yes
    g. Comments: 87B-51P Element has inverse-time delay.

4. Simulate an SLG fault on the 12 kV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 3:14:09.501 PM
    c. Relay Fault Pickup Time: 3:14:09.506 PM
    d. Relay 87B-51P/G Trip Initiation Time: 3:14:11.206 PM
    e. Relay Longest 52a Open Detected Time: 3:14:11.229 PM
    f. Relay 51 element operated with the expected time delay? (Yes/No): Yes
    g. Comments: 87B-51P/G Elements have inverse-time delay.

Set B 87B-50/51 Overcurrent Differential Performance Tests (Mfg./Model V1M4)

1. Simulate 3LG fault in the transformer by COMTRADE playback injection and record the following:
    a. Relay 87B-51 Restrained? (Yes/No): Yes
    b. Comments: No operation for out of zone fault, no event reports generated.

2. Simulate an SLG fault in the transformer by COMTRADE playback injection and record the following:
    a. Relay 87B-51 Restrained? (Yes/No): Yes
    b. Comments: No operation for out of zone fault, no event reports generated.

3. Simulate a 3LG fault on the 12 kV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 7:52:30.536 PM
    c. Relay Fault Pickup Time: 7:52:30.541 PM
    d. Relay 87B-51P Trip Initiation Time: 7:52:31.893 PM
    e. Relay Longest 52a Open Detected Time: 7:52:31.906 PM
    f. Relay 51 element operated with the expected time delay? (Yes/No): Yes
    g. Comments: 87B-51P Element has inverse-time delay.

4. Simulate an SLG fault on the 12 kV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 4:14:09.502 PM
    c. Relay Fault Pickup Time: 4:14:09.508 PM
    d. Relay 87B-51P/G Trip Initiation Time: 4:14:11.218 PM
    e. Relay Longest 52a Open Detected Time: 4:14:11.236 PM
    f. Relay 51 element operated with the expected time delay? (Yes/No): Yes

g. Comments: 87B-51P/G Elements have inverse-time delay.

Test Case #10 – 12 kV Bus Restrained Current Differential Protection (87B)

Relay Test Setup Conditions and Requirements

1. The selected relay to be evaluated was:
    a. Mfg./Model V2M3
2. The typical existing distribution substations do not currently use restrained overcurrent differential protection for this application, although it was shown on the standard drawings, so settings did not match those installed in the identified substation relays.
3. For pre-commercial demonstration, an RTDS model of the identified substation, using equivalents to represent the system beyond the remote substation buses, was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current and voltage playback signals were connected to the appropriate MU analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
4. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU5 (12 kV Tie CB 10)
    a. Mfg./Model V2M5
    b. CTR= 400T
    c. PTR= 100T (12 kV bus)

2. MU6 (12 kV Feeder CB 12)
    a. Mfg./Model V3M3
    b. CTR= 240T
    c. PTR= 100T (12 kV bus)

3. MU8 (12 kV Cap Feeder CB 17)
    a. Mfg./Model V6M1 and Mfg./Model V2M6
    b. CTR= 240T
    c. PTR= 100T (12 kV bus)

4. MU9 (12 kV Transfer Bus CB 11)
    a. Mfg./Model V7M1
    b. CTR= 400T
    c. PTR= 100T (12 kV bus)

5. MU10 (12 kV BK41 CB 14)
    a. Mfg./Model V7M1
    b. CTR= 400T
    c. PTR= 100T (12 kV bus)

6. MU13 (12 kV Tie CB 20)
    a. Mfg./Model V1M5
    b. CTR= 400T
    c. PTR= 100T (12 kV bus)

87B Restrained Current Differential Performance Tests (V2M3)

1. Simulate a 3LG fault on the Cap/Reactor feeder by COMTRADE playback injection and record the following:
    a. Relay 87B Trip Restrained? (Yes/No): Yes
    b. Comments: No operation for out of zone fault, no event reports generated.

2. Simulate a close-in SLG fault on the Cap/Reactor feeder by COMTRADE playback injection and record the following:
    a. Relay 87B Trip Restrained? (Yes/No): Yes
    b. Comments: No operation for out of zone fault, no event reports generated.

3. Simulate a 3LG fault on the LV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 9:41:39.080 PM
    c. Relay Fault Pickup Time: 9:41:39.093 PM
    d. Relay 87B Trip Initiation Time: 9:41:39.101 PM
    e. Relay Longest 52a Open Detected Time: 9:41:39.136 PM
    f. Comments: Excellent Hi-Speed Operation – 3.4 cycles fault application to clear.

4. Simulate an SLG fault on the LV bus by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 10:03:34.081 PM
    c. Relay Fault Initiation Time: 10:03:34.100 PM
    d. Relay 87B Trip Initiation Time: 10:03:34.094 PM
    e. Relay Longest 52a Open Detected Time: 10:03:34.132 PM
    f. Comments: Excellent Hi-Speed Operation– 3.1 cycles fault application to clear.

Test Case #11 – Capacitor and Reactor Feeder Overcurrent Protection (50/51)

Relay Test Setup Conditions and Requirements

1. The tests were performed on two different manufacturers' high-performance numerical feeder relays that incorporated non-directional overcurrent tripping elements. The selected relays to be evaluated were:
    a. Set A – Mfg./Model V2M4
    b. Set B – Mfg./Model V1M4
2. Overcurrent element settings matched those installed in the identified substation relays as much as possible.
3. For pre-commercial demonstration, an RTDS model of the identified substation, using equivalents to represent the system beyond the remote substation buses, was used to generate COMTRADE data files for each line node for playback by relay test sets. The secondary current playback signals were connected to the appropriate MU analog inputs. Results for this test are included in Appendix F with the file names described in Section 6.

4. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU8 (12 kV CB17)
    a. Mfg./Model V6M1 and Mfg./Model V2M6
    b. CTR= 240T
    c. PTR= 100T (12 kV bus)

Set A (50/51) Performance Tests (Mfg./Model V2M4)

1. Simulate a 12 kV feeder 3LG fault downstream of Breaker 17 by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 3:34:11.454 PM
    c. Relay Fault Pickup Time: 3:34:11.504 PM
    d. Relay Trip Initiation Time: 3:34:11.508 PM
    e. Relay 52a Open Detected Time: 3:34:11.528 PM
    f. Relay Element Tripped: 50P
    g. Comments: Feeder too short for 51P operation.

2. Simulate a 12 kV feeder 1LG fault downstream of Breaker 17 by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 8:10:00.488 PM
    c. Relay Fault Pickup Time: 8:10:00.538 PM
    d. Relay Trip Initiation Time: 8:10:00.543 PM
    e. Relay 52a Open Detected Time: 8:10:00.572 PM
    f. Relay Element Tripped: 50P and 50G
    g. Comments: Feeder too short for 51P/G operation.

Set B (50/51) Performance Tests (Mfg./Model V1M4)

1. Simulate a 12 kV feeder 3LG fault downstream of Breaker 17 by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 4:34:11.498 PM
    c. Relay Fault Pickup Time: 4:34:11.506 PM
    d. Relay Trip Initiation Time: 4:34:11.515 PM
    e. Relay 52a Open Detected Time: 4:34:11.545 PM
    f. Relay Element Tripped: 50P
    g. Comments: Feeder too short for 51P operation.

2. Simulate a 12 kV feeder 1LG fault downstream of Breaker 17 by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Fault Initiation Time: 4:39:41.080 PM

c. Relay Fault Pickup Time: 4:39:41.088 PM
d. Relay Trip Initiation Time: 4:39:41.089 PM
e. Relay 52a Open Detected Time: 4:39:41.112 PM
f. Relay Element Tripped: 50P and 50G
g. Comments: Feeder too short for 51P/G operation.

Test Case #12 – Capacitor Bank Unbalance Protection (59N)

Relay Test Setup Conditions and Requirements

1. The test was performed on one manufacturer's high-performance numerical feeder relay that incorporated zero-sequence over-voltage elements (59N). The selected relay to be evaluated was:
    a. Mfg./Model V3M2
2. $3V_0$ overvoltage element settings matched those installed in the identified substation relays as much as possible.
3. For pre-commercial demonstration testing, a static test plan was developed for the relay test set. The secondary voltage signal was directly connected to the relays analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
4. Trip and close signals to the breakers were via GOOSE messages to the capacitor bank automation controller, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

Merging units were not used for this simulation test as it was unlikely that the factory-built capacitor bank would ever use merging units and compatible relays since the wiring was all factory installed and the assembly shipped as one pre-assembled unit to the job site.

59N Performance Tests (Mfg./Model V3M2)

Simulate a capacitor bank $3V_0$ over-voltage condition by relay voltage injection and record the following:

1. Download sequential events recorder (SER) and event recorder (ER) from the protective relay and associated reactor and capacitor bank automation controllers for the tests
2. Event Initiation Time: 16:08:46.024
3. Relay Trip Time: 16.08.46.528
4. Relay 59N element operated with the expected time delay? (Yes/No): Yes
5. Relay 59N element tripped and locked out all capacitor breakers? (Yes/No): Yes
6. Capacitor automation controller cannot operate locked-out breakers? (Yes/No): Yes
7. Comments: 0.5 Sec 59N element definite-time delay.

Test Case #13 – Reactor Unbalance Protection (51Q)

Relay Test Setup Conditions and Requirements

1. The test was performed on one manufacturer's high-performance numerical feeder relay that incorporated negative-sequence ($3I_2$) overcurrent elements (59Q). The selected relay to be evaluated was:
    a. Mfg./Model V3M2
2. $3I_2$ overcurrent element settings matched those installed in the identified substation relays as much as possible.
3. For pre-commercial demonstration testing, a static test plan was developed for the relay test set. The secondary current signals were directly connected to the relays analog inputs. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
4. Trip and close signals to the breakers were via GOOSE messages to the reactor bank automation controller, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

Merging units were not used for this simulation test as it was unlikely that the factory-built reactor bank would ever use merging units and compatible relays since the wiring was all factory installed and the assembly shipped as one pre-assembled unit to the job site.

Test Case Performance Tests

Test case performance tests were intended to demonstrate proper operation of the test bed setup and relay settings, and to record performance result data for the study test cases. Tripping of circuit breakers was simulated by latching relays connected to MU digital outputs. Critical timing and observed element operation was recorded.

51Q Performance Tests (Mfg./Model V3M2)

Simulate a reactor bank $3I_2$ overcurrent condition by relay current injection and record the following:

1. Download SER and ER from the protective relay and associated reactor and capacitor bank automation controllers for the tests
2. Event Initiation Time: 15:36:35.014
3. Relay Trip Time: 15:36:35.735
4. Relay 51Q element operated with the expected time delay? (Yes/No): Yes
5. Relay 51Q element tripped and locked out all reactor breakers? (Yes/No): Yes
6. Reactor automation controller cannot operate locked-out breakers? (Yes/No): Yes
7. Comments: 51Q Element has inverse-time delay.

Test Case #14 – Reactor and Capacitor Bank VAR Control Automation

Relay Test Setup Conditions and Requirements

1. The test was performed with two automation controllers that match the existing installations, and incorporate both GOOSE digital and analog signaling. The selected automation relay to be evaluated was:

a. Mfg./Model V3M4

2. The test was performed using one manufacturer's high-performance numerical overcurrent relay to measure and signal VAR flow data via GOOSE analogs. This relay was used to line impedance and overcurrent protection (see Line Distance and Directional Overcurrent Test Case above), but was mapped to MU3 which was transformer primary breaker CB7. The selected relay to be used was:

    a. Mfg./Model V3M1

3. Automation controller logic settings matched those installed in the most recent capacitor and reactor bank installations as much as possible.

4. For pre-commercial demonstration testing, a static test plan was developed for the relay test set because RTDS simulation files would be too large for the relay test sets for what was a slow operating control function (switching in/out reactors and capacitors would never be performed quickly in regulatory control applications to avoid voltage instability and excess wear on the breakers). The secondary current and voltage simulation signals from the test set were connected to the appropriate MU analog inputs. SER results for this test are included in Appendix F with the file names described in Section 6.

5. Trip and close signals to the breakers were via GOOSE messages to the reactor bank automation controller, and the breakers were simulated by latching relays. Programmable pushbuttons and targets on the protective relays and automation controllers were configured to simulate manual trip and close logic to represent panel mounted control switches and panel status lamps for the breakers.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU3 (69/138 kV BK41 CB 7)
    a. Mfg./Model V7M1
    b. CTR= 400T
    c. PTR= 700T (W. bus)

Capacitor and Reactor Bank Automation Performance Tests (Mfg./Model V3M1 and V3M4)

1. Starting from a reset position with the 51Q and 51N relay lockouts reset, and no capacitor or reactor bank simulated breakers closed, apply a VAR flow into the transformer above the threshold switching point (+1.8 MVAR):
    a. Did capacitor bank controller add a cap within the expected time delay? (Yes/No): Yes
    b. Did reactor bank controller add operate? (Yes/No): No
    c. Did proper breaker status indicators indicate? (Yes/No): Yes
    d. Can additional cap steps be added if VAR flow was maintained above threshold for programmed delay time? (Yes/No): Yes
    e. Comments: Delays set faster than actual installations to speed lab demonstration.

2. Starting from the last capacitor step added state, apply a VAR flow out the transformer above the threshold switching point (-1.8 MVAR):
    a. Did capacitor bank controller remove a cap within the expected time delay? (Yes/No):Yes
    b. Did reactor bank controller add operate? (Yes/No): No
    c. Did proper breaker status indicators indicate? (Yes/No): Yes
    d. Can additional cap steps be removed if VAR flow was maintained above threshold for programmed delay time? (Yes/No): Yes
    e. Comments: Delays set faster than actual installations to speed lab demonstration.

3. Continuing with the capacitor step removal action keep applying a VAR flow out the transformer above the threshold switching point (-1.8 MVAR):
    a. Did capacitor bank controller remove all caps within the expected time delay? (Yes/No):Yes
    b. Did reactor bank controller start adding reactor steps after the capacitor breakers were all opened and with the expected delay time? (Yes/No): Yes
    c. Did proper breaker status indicators indicate? (Yes/No): Yes
    d. Can additional reactor steps be added if VAR flow was maintained above threshold for programmed delay time? (Yes/No): Yes
    e. Can the reactor bank controller add all the reactance steps in the specified time delay period, one at a time? (Yes/No): Yes
    f. Comments: Delays set faster than actual installations to speed lab demonstration.

4. Apply a VAR flow into the transformer above the threshold switching point (+1.8 MVAR):
    a. Will the reactor bank controller remove all reactance steps within the expected time delay until the capacitor and reactor were back at the original starting point of no reactance correction applied? (Yes/No): Yes
    b. Comments: Delays set faster than actual installations to speed lab demonstration.

5. Demonstrate manual cap and reactor bank operation:
    a. Will each controller manually add and subtract reactance steps under pushbutton command? (Yes/No): Yes
    b. Will the reactor bank controller block adding capacitor steps while any reactor step breakers were closed? (Yes/No): Yes
    c. Will the capacitor bank controller block adding reactor steps while any capacitor step breakers were closed? (Yes/No): Yes
    d. Comments: Delays set faster than actual installations to speed lab demonstration.

6. Download SER from each bank controller that records the actions above for the project test record.

Test Case #15 – Line Frequency and Voltage (81, 27, and 59)

Relay Test Setup Conditions and Requirements

1. The tests were performed on two different manufacturers' high-performance numerical line relays that incorporated under/over voltage and frequency elements. The selected relays to be evaluated were:
    a. Set A - Mfg./Model V2M2
    b. Set B – Mfg./Model V3M1
2. Voltage (27/59) and frequency (81) protection element performance were evaluated in a separate test case test from line differential (87L), distance (21), and overcurrent (50/51) test cases due to the typical time delay used with these protective elements
3. For pre-commercial demonstration testing, simulation of 27, 59 and 81U events were performed by use of a relay test set with pre-programmed static test plan. Because relay elements used for tripping on voltage or frequency were delayed far longer than fault protection elements, an RTDS simulation generated COMTRADE file was too large to use for playback testing. COMTRADE results for this test are included in Appendix F with the file names described in Section 6.
4. Trip and close signals to the breakers were via GOOSE messages to the appropriate MUs, and the breakers were simulated by latching relays. Programmable pushbuttons on the protective relays were configured to simulate manual trip and close logic to represent panel mounted control switches.

Test Case Voltage and Current Injection from Relay Test Sets

1. MU1 (69/138 kV Line CB 2) for Set A
    a. Mfg./Model V1M5
    b. CTR= 400T
    c. PTR= 700T (W. bus)

2. MU2 (69/138 kV Tie CB 3) for Set B
    a. Mfg./Model V3M3
    b. CTR= 400T
    c. PTR= 700T (W. bus)

3. MU3 (69/138 kV BK41 CB 7) for Set B
    a. Mfg./Model V7M1
    b. CTR= 400T
    c. PTR= 700T (W. bus)

Set A (27, 59, 81U) Performance Tests (Mfg./Model V2M2)

1. Simulate a 138 kV under-voltage condition by COMTRADE playback injection and record the following:
    a. Download event record from the relay
    b. Event Initiation Time: 4:33:20.002
    c. Relay Pickup Time: 4:33:20.014
    d. Relay 27 Trip Initiation Time: 4:33:21.017

e. Relay 27 Elements operated with the expected time delay? (Yes/No): Yes
f. Relay recorded the correct voltage magnitude? (Yes/No): Yes
g. Comments: 1.0 sec. programmed element delay.

2. Simulate a 138 kV over-voltage condition by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Event Initiation Time: 4:30:50.994
   c. Relay Pickup Time: 4:30:50.014
   d. Relay 59 Trip Initiation Time: 4:30:51.017
   e. Relay 59 Elements operated with the expected time delay? (Yes/No): Yes
   f. Relay recorded the correct voltage magnitude? (Yes/No): Yes
   g. Comments: 1.0 sec. programmed element delay.

3. Simulate a 138 kV under-frequency condition by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Event Initiation Time: 8:33:35.944
   c. Relay Pickup Time: 8:33:36.144
   d. Relay 81U Trip Initiation Time: 8:33:36.644
   e. Relay 81U Elements operated with the expected time delay? (Yes/No): Yes
   f. Relay recorded the correct system frequency? (Yes/No): Yes
   g. Comments: 0.5 sec. programmed element delay.

Set B (27, 59, 81U) Performance Tests (Mfg./Model V3M1)

1. Simulate a 138 kV under-voltage condition by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Event Initiation Time: 10:27:26.981 AM
   c. Element Pickup Time: 10:27:27.017 AM
   d. Relay 27 Trip Initiation Time: 10:27:27.184 AM
   e. Relay 27 Elements operated with the expected time delay? (Yes/No): Yes
   f. Relay recorded the correct voltage magnitude? (Yes/No): Yes
   g. Comments: 10 cycle (166.7ms) programmed element delay.

2. Simulate a 138 kV over-voltage condition by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Event Initiation Time: 10:04:30.980 AM
   c. Element Pickup Time: 10:04:31.016 AM
   d. Relay 59 Trip Initiation Time: 10:04:31.183 AM
   e. Relay 59 Elements operated with the expected time delay? (Yes/No): Yes
   f. Relay recorded the correct voltage magnitude? (Yes/No): Yes
   g. Comments: 10 cycle (166.7ms) programmed element delay.

3. Simulate a 138 kV under-frequency condition by COMTRADE playback injection and record the following:
   a. Download event record from the relay
   b. Event Initiation Time: 10:57:35.542 AM

c. Element Pickup Time: 10:57:35.559 AM
d. Relay 81U Trip Initiation Time: 10:57:36.059 AM
e. Relay 81U Elements operated with the expected time delay? (Yes/No): Yes
f. Relay recorded the correct system frequency? (Yes/No): Yes
g. Comments: 0.5 sec. programmed element delay.

11. TEST RESULTS AND DATA ANALYSIS

The analysis of test results and data and the methodology for the development of findings are discussed below. After the testing was completed, each of the items identified in the test plan were reviewed and assigned to an engineer for analysis.

Measurement and Verification

The project team provided metrics for the performance of their traditional hardwired protective relay system. The primary measurement of interest was the protection system operation time. This time was measured from the initiation of the fault condition until the relay received status that the breaker simulator had operated. These values were used to compare the performance of the IEC 61850 protection and control schemes, identified in the use cases, to the traditional P&C schemes. This information was readily obtained from the relay event recorders and COMTRADE waveform capture capabilities in the relays. See Appendix F for COMTRADE graphical analysis.

Interoperability was more subjective. In general, the interoperability requirements were met if any two devices could communicate via GOOSE and SV. The fact that the test system was able to simulate all the use cases was evidence that interoperability was achieved.

Impacts on Existing Substation and Transmission Protection

The main protection concerns that were identified in this project were speed and reliability. The following items address these concerns.

Reliability – Protection

Protection with IEC 61850 SV performs no differently than a hardwired instrument transformer application of protection relays. The real differences were in how the instrument transformer signals reached the relays and were mapped to the protective elements within the relays themselves.

As far as performance under faulted conditions, simulations performed as part of the study showed that there was little if any impact by going to fully digital CT and PT analog data streams supplied by MUs. Modern numerical relay manufacturers already perform analog to digital conversion at sampling rates equal to those used in MUs. Whether the relay operates with locally produced digitized analog data, or from a remote MU, makes little difference to the protection performance. The potential for a slight additional delay in transmission and reception of remote SV signals does exist, but it could be minimized with good process bus design methodology to avoid any possibility of excessive data latency due to packet collisions.

In this study, relay performance observed during testing far exceeded any requirements that would be expected for application in a distribution substation interconnected to a sub-transmission system. This finding was in line with expectations of replacing existing devices with new devices that have the same or better functionality.

Reliability – Communications

This section considers the reliability of the baseline system vs. the SV and GOOSE implementation for the transportation of CT/PT measurements and binary interlock signals. Reviewing how analog CT/PT and binary signals currently get to the protection relays using the base case system design, one finds the following major components:

- Substation equipment providing the signal source:
    - CT and PT measurement apparatus
    - Breaker and disconnect switch auxiliary (AUX) position contacts

    - Breaker and disconnect switch trip and close coils inputs
- Signal transport:
    - Hardwired point-to-point signal cables
    - Terminal blocks at various locations in the signal path
    - At least one test switch for test signal injection and trip circuit blocking at each protective relay
- Protection relays:
    - CT and PT inputs and signal conditioning circuits
    - Binary inputs and signal conditioning circuits

Using IEC 61850 changes some of the major components and adds additional ones as follows:

- Substation equipment providing the signal source:
    - CT and PT measurement apparatus
    - Breaker and disconnect switch AUX position contacts
    - Breaker and disconnect switch trip and close coils inputs
    - IEC 61850 source merging unit with:
        - CT and PT inputs and signal conditioning circuits
        - Binary inputs and signal conditioning circuits
        - Network Interface Controller
        - At least one test switch for test signal injection and trip circuit blocking
- Signal transport:
    - Fiber optic cable
    - Process bus Ethernet network switch(es)
        - NOTE: Using a process bus HSR network eliminates the network switch(es)
- Protection relays:
    - Network Interface Controller

- IEC 61850 adds an additional IED at the signal source while moving the inputs and signal conditioning circuits from the protection relay to the field installed merging unit. Given that fully tested hardwired installations are generally very reliable, reliability might be reduced by having a single merging unit provide the information to multiple protection relays. However, IEC 61850 does not eliminate the standard practice for overlapping zones of protection for backup failure, and with its additional features, it provides continuous on-line monitoring and alarming for signal failures that a typical hardwired P&C system does not. The IEC 61850 method may add a single point of failure with the merging unit, but with proper design, the potential loss of reliability could be mitigated.

- The multiple copper wires handling individual signals were replaced by a single fiber optic cable, which interfaced at the merging unit, process bus Ethernet network switch, and the protection relay with a single network interface controller on each end of the fiber optic cables that comprise this path. However, including signal path redundancy to an IEC 61850 system was very easy and fairly cost effective, and all equipment used in this study all had this capability.

- The base system did not depend on an accurate GPS sourced time synchronization that an IEC 61850 solution requires.

- Having a test switch at each merging unit could have an increased possibility of test contacts being left open or placed in the wrong position due to its location in the field equipment. This problem also existed with the base system, but the base system did not have the

capability to monitor and alarm failure of these signals continuously like an IEC 61850 system.

The IEC 61850 method can be just as reliable, if not more reliable, than a hardwired protection system, but it does introduce additional single points of failure, which need to be mitigated. The IEC 61850 solution provides many built-in redundancy options such as dual merging units, network redundancy using PRP and/or HSR and the flexibility of adding additional protection relays to improve reliability.

Speed of Operations

One interesting finding of protection performance identified during this study, which was not caused by the application of IEC 61850 SV, was a 1-5 ms penalty in protection element operating times that were observed when test results from application specific and software-defined relays were compared. Software defined or "universal" relays were marginally slower to operate when presented with the same fault simulation as the application specific relays and when the same protection elements were compared. Because software defined relays could be configured in a multitude of ways with a large set of potential protection elements to choose from, the task of optimizing protection operating times was made more difficult for the relay design engineer.

For most protection applications, other than at extra high voltage (EHV) or where grid stability would be a concern, the observed difference in operating times would make little if any practical difference and the flexibility of a software defined relay may be of great advantage. Software defined relays do impose a greater time requirement upon the protection engineer to configure and set them, which should be considered before deciding to apply them; better configuration software tools going forward will alleviate this issue.

Impacts on Existing Substation Systems and Equipment

The main substation and equipment impacts associated with an IEC 61850 implementation were the need for IEC 61850 capable protective relays, requirements for additional equipment to be installed in the field, and impacts to control building equipment.

The protective relays that SDG&E currently uses do not have IEC 61850 capabilities or if they do, the capabilities are limited to GOOSE and MMS. Based on currently available IEC 61850 compatible devices, SDG&E would need to adopt different manufacturers and relay types into their substation standards to implement IEC 61850 with process bus functionality.

Additional equipment would need to be installed in the substation yard for an IEC 61850 application that utilizes sampled values. Merging units need to be installed in the yard equipment cabinets which will also require CT/PT test switches, a fiber optic patch panel, DC power, and an AC source for test equipment. Additionally, breaker control switches, local/remote switches, and other types of control switches may need to be moved from the control shelter to the equipment cabinets or duplicated in the equipment control cabinets for use when testing. Either the yard equipment control enclosures need to be sized to accommodate this additional equipment or separate stand-alone enclosures would be required to house the new equipment.

For the control shelter, additional communication equipment such as Ethernet switches must be installed for the IEC 61850 system. Depending on how equipment was located within the racks, this may require additional rack space. Typically additional rack space could be made available when moving from a hardwired solution to an IEC 61850 solution, so this available space would be utilized

for the additional Ethernet switches. A larger battery system in the control shelter was also anticipated due to the additional DC load from Ethernet switches and merging units.

Impacts on System Operations

If the IEC 61850 system was limited to within the substation and if properly integrated with the SCADA equipment, there should be little apparent change from a system operations perspective. The main impact to system operations would be any changes made to the location of control switches within the substation. Operational procedures may need to be updated if control switches were moved from the control shelter to the equipment cabinets. Even with an IEC 61850 implementation, there should still be breaker control capability in the control shelter whether it is physical control switches or programmable push buttons on the protective relays.

Maintenance Impacts

The biggest impact from a maintenance perspective will be protective relay testing. If merging units were installed in the substation yard, relay technicians would need to set up test equipment at that location. Test switches for these MUs would be in the equipment cabinets as well.

If additional test switches were desired in the control shelter, for isolation of protective relays from trip circuits and close circuits, they would need to be added. During testing relay technicians would need to put the protective relays in a "test mode" which will communicate to other protective relays to not take action based on received GOOSE messages for trip and close commands.

Costs

The project team performed a cost comparison between the traditional P&C scheme and one using IEC 61850 GOOSE and SV. This estimate calculated the installed costs of the items that would no longer be required with the process bus design and compared that to the costs for the additional equipment with one possible process bus design.

Estimate Assumptions

- This estimate only included the installation costs for the difference between the legacy design and the process bus design
- The estimate assumed that MUs were located in the substation yard high-voltage equipment control enclosures, with relays in the control shelter
- The estimate assumed that 12 kV relays and MUs were located in factory constructed metal-clad breaker assemblies
- Wiring between MUs/relays and equipment terminal blocks remains so these costs were excluded from the estimate
- Test switches will be required in the field equipment but these were already a part of the legacy design so there was no additional material included for these
- Each field wiring run was assumed to start at the field equipment and was run to the Control Shelter and terminated. An additional run of cable was required to connect from the marshalling cabinets/incoming terminal blocks to the panels in the control shelter
- Labor and control cable costs were obtained from the project team
- Current quotes were obtained for legacy IEDs
- Prices on other miscellaneous items were obtained from previous projects

- Impacts to ancillary systems were not studied (Arc Flash, DC bus short circuit interrupting capability, etc.)
- Costs of the process bus IEDs were those obtained during the material acquisition phase for the test system
- Improvements in Engineering efficiency were not tabulated since they were anticipated to be highly dependent on each utility's level of IEC 61850 experience and how each utility allocates its workforce
- These costs were based on one possible design. This design could be optimized to reduce these costs

The costs for the items that would no longer be required for the legacy design were calculated. They were shown in Table 26. These costs would reduce the substation overall cost.

TABLE 26 COSTS FOR TIMES NO LONGER REQUIRED FOR LEGACY DESIGN

QUANTITY	DEVICE TYPE	DESCRIPTION/ DETAILS	COST EACH DELIVERED TO SDG&E	EXTENDED PRICE
7	Meter		1,725.00	12,075.00
6	Ethernet Switch		2,623.00	15,738.00
2	GPS Clock		1,700.00	3,400.00
2	Relay		5,418.00	10,836.00
2	Relay		13,530.00	27,060.00
10	Relay		4,193.00	41,930.00
2	Relay		6,685.00	13,370.00
1	Relay		6,115.00	6,115.00
1	Relay		5,800.00	5,800.00
8	Relay		3,917.00	31,336.00
2	Relay		8,435.00	16,870.00
2	Automation Controller		2,700.00	5,400.00
2	Serial Cable	40 feet	41.92	83.84
1	Serial Cable	7 feet	32.00	32.00
1	Serial Cable	3 feet	21.00	21.00
1	Serial Cable	10 feet	12.06	12.06
1	Serial Cable	7 feet	11.00	11.00
1	Serial Cable	15 feet	14.71	14.71
1	Serial Cable	30 feet	22.66	22.66
1	Serial Cable	5 feet	28.00	28.00
37	Control Cable	1,305 feet	0.74	965.70
14	Control Cable	480 feet	1.42	681.60
7	Control Cable	320 feet	2.77	886.40
11	Control Cable	1,090 feet	1.10	352.00
17	Control Cable	1,910 feet	1.80	576.00
5	Control Cable	550 feet	3.27	1,046.40

QUANTITY	DEVICE TYPE	DESCRIPTION/ DETAILS	COST EACH DELIVERED TO SDG&E	EXTENDED PRICE
20	Control Cable	4,000 feet	2.00	640.00
7	Control Cable	1,400 feet	3.69	1,180.80
89	Terminal Blocks	12 position	31.01	2,759.89
32	Shorting blocks	12 position	44.20	1,414.40
4,048	Terminal Lugs	Ring tongue	0.61	2,469.28
4,048	Labels	Package of 200	29.65	600.12
60	Battery	Cells, 365AH	490.35	29,421.00
1	Charger	Charger	4,431.00	4,431.00
1	Battery Rack	High seismic rated 2 tier	3,003.00	3,003.00
659	Labor	Install labor	83.68 $/hr.	55,145.12
			Total	**237,579.86**

The costs for the additional items that would be required with the process bus design were then calculated. They were shown in Table 27. These costs add to the cost of the overall substation.

TABLE 27 COSTS FOR ADDITIONAL ITEMS REQUIRED FOR PROCESS BUS DESIGN

QUANTITY	DEVICE TYPE	VENDOR CODE	COST EACH DELIVERED TO SDG&E	EXTENDED PRICE
7	Panel meter	N/A	350.00	2,450.00
2	GPS Clock	V3M5	4,970.00	9,940.00
8	Ethernet Switch	V4M1	9,388.00	75,104.00
21	MU	V3M3	5,695.00	119,595.00
11	Relay	V3M1	9,170.00	100,870.00
2	Automation Controller	V3M4	2,700.00	5,400.00
2	Relay	V3M2	2,835.00	5,670.00
13	Relay	V2M1	11,825.00	153,725.00
2	Relay	V2M2	11,488.00	22,976.00
3	Relay	V2M3	12,970.00	38,910.00
4	Fiber Plant	N/A	389.60	1,558.40
60	Battery	N/A	832.65	49,959.00
1	Charger	N/A	6,704.25	6,704.25
2	Battery Rack	N/A	3,093.30	6,186.60
			Total	**599,048.25**

The reader can see that the process bus initial installation costs are significantly greater than the costs estimated for the legacy design. Initial material costs are a primary driver for this cost increase. Some of the reasons for this cost increase are listed below:

- All SV relay and merging units are early generation equipment. The manufacturers are currently charging a premium for these relays as the technology is implemented in their most capable numerical relays
- The addition of IEC 61850 protocols to relays currently increases cost
- SV requires MUs to be installed in all the equipment, in the substation yard, that is associated with the process bus
- Process bus adds a significant amount of DC load to the amount allocated for P&C. This is due to the additional Ethernet equipment and MUs. In this estimate the P&C load increased by approximately 170%. This increase in load required a larger DC plant to supply the load.

Despite the increase in initial material costs, it was anticipated that process bus material costs will reduce as adoption rates increase and the equipment becomes more common. But even with a significant decrease in material costs, IEC 61850 requires additional P&C infrastructure to support the equipment for a process bus implementation. This will likely remain a cost increase when compared to the legacy design.

The labor costs associated with the process bus implementation were reduced significantly. This was primarily due to the reduction in wiring. However, this cost reduction was not as significant as the increase in material costs.

Future savings were anticipated to offset these costs as the engineering effort was reduced by leveraging utility specific standards and templates which were less complex. Substation apparatus could be specified to include factory installation of MUs, further driving down costs. Current industry estimates suggest that IEC 61850 with process bus can reduce engineering time by as much as 75%. In addition, future substation additions and changes will require significantly less effort and cost as much of the new work would be implemented in software.

Finally, IEC 61850 prepares the utility for a digital future that will support features and applications that are only starting to become available. These could include additional diagnostic features and self-test capabilities.

Taking the long view, it would be conceivable that relays will only be available from manufacturers with IEC 61850 features and no hardwired connections in the next 15-20 years, much like what has occurred with the transition to numerical relays from electromechanical and static models. This technology transition was driven not only by improved features and capabilities, but the semiconductor manufacturing industry's tendency to continue to shorten the production lifespan of critical components.

Pros and Cons

Like any new endeavor, migrating to an IEC 61850 process bus P&C scheme includes benefits and drawbacks. This section identifies some of these items.

Pros

Wiring

A very significant advantage to IEC 61850 was reduction in hard wired control circuits and its attendant complexity. All of this complexity gets moved to configuring the protective relays and IEC 61850 communications between devices. Obviously, this saves on wiring, terminating, labeling, and reduces the chances of wiring errors. It also reduces fabrication time and expense for protection

panels and reduces construction and testing time at the substation. With the reduction in field wiring, the required time in the field for installation and testing of protection panels could be reduced from weeks to days.

CT Performance

One big advantage with SV protection was that current and potential signals were transmitted across the process bus network in primary engineering units, allowing maximum CT and PT ratios to be used without compromising accuracy or impacting signal fidelity and internal protective relay setting limitations. This has an obvious advantage with impedance relaying, where protection settings developed in secondary units were dependent on the instrument transformer connected ratios, where CTs were frequently tapped down to bring the maximum secondary impedance within the relay's fixed setting range. Because of a multi-ratio CT's poorer electromagnetic performance (saturation) at lower ratios, avoiding reduced taps was a great advantage. With the move towards SV, future relays could be set in primary units, eliminating a major issue in existing protection methodology.

Semantic Model

IEC 61850 provides a semantic model for standardized structured data exchanges between devices. This allows for standard object model names. Thus the data becomes visible without configuration, which enables self-description of the IEDs. An IEC 61850 protocol browser can be used to view the capabilities of an IEC 61850 device even before the device was placed in service at the substation. The schema also allows the configuration files to be standardized into IEC 61850 file types. These file types can be used to support configuration and engineering efforts.

GOOSE

By its nature high speed GOOSE messages were ideal for relay to relay and relay to MU message transfer. It allowed for supervision of the link due to its periodic retransmission properties. Studies of GOOSE timing have identified that it typically performs far faster than hardwired I/O, which was limited by the time to close electromechanical contacts. Within the industry, GOOSE was currently fairly mature and a GOOSE application would be an ideal candidate for an early implementations. Currently, the IEC 61850 standard development teams were working on an implementation of GOOSE for substation to substation control communication.

Sampled Values

SV messages separate the sampling of analog values from their calculation and metering. They allow analog values to be measured one time and shared among applications. Not only does this reduce wiring effort and time, it also allows for consistent high quality data with a minimum of infrastructure and the time to verify calibration during routine maintenance.

Engineering Effort

Engineers will be able to test protective system development in a basic lab environment while developing settings before they were deployed in an actual substation. This will reduce schedule pressure and errors. It will also allow P&C schemes to be developed as standard templates which will significantly reduce future deployment time and improve quality.

Interoperability

One of the most significant goals of the IEC 61850 Standard was interoperability. If consistently implemented, it would allow IEDs from different manufacturers to communicate, exchange data, and make use of the information. It would simplify the design, construction, implementation, commissioning, testing, and maintenance of P&C systems in substations. Allowing users to select any manufacturer's device, apply it with any other manufacturer's device, and be assured that the devices would interoperate would be an enormous benefit to the industry and all users.

Lockout relays

At the request of the project team, lockout relay functionality was implemented within certain relays. This allowed the project team to better visualize the way that a "digital" lockout scheme would perform. While this was not a unique benefit associated with an IEC 61850 P&C scheme, it does demonstrate the capability of advanced numerical relays. The adoption of this type of lockout relaying would eliminate traditional hardwired lockout relays, cumbersome wiring and simplify the NERC PRC-005 testing.

Cons

Limited Interoperability at this Time

The drawbacks to IEC 61850 for the project team included limitations of the current industry technology across manufacturers, the need for modifications to current standards and practices, and the required training of personnel for the large technology shift. The results of this study showed that not all relay manufacturers support sampled values in a completely interoperable manner. Some manufacturers' relays were also much easier to learn and configure than others – an important consideration during the selectin process. Furthermore, interoperability across relay manufacturers was inconsistent. This study found that IEC 61850 SV technologies were still developing in the industry and further development was needed for consistent interoperability between relay manufacturers.

Migration Process

This EPIC-2, Project 1 served as a technology demonstration and feasibility study. In this case, adopting IEC 61850 process bus appears feasible. The next step in the process would be to determine a precise list of the exact functions and features of IEC 61850 that SDG&E would like to adopt. This list should include those functions and features that were beyond the scope of this project.

SDG&E now has the opportunity to evaluate their current standards and determine how they can be modified to accommodate future technologies like IEC 61850. This could include:

- Provisioning future rack/panel space to accommodate the additional communication equipment that will be required in the control shelter
- Increasing the size of control cabinets in transformer, breakers, and other equipment so that the addition of merging units and associated equipment may be easily installed
- Verification that a standard control shelter size can accommodate the larger battery system required for an IEC 61850 application
- Development of a training program around IEC 61850 to cover the technology itself, testing, and operations
- Identification and implementation of small pilot applications, to develop experience with IEC 61850. Implementation of the capacitor/reactor automation logic would be a very achievable project that would allow SDG&E to gain valuable experience in a low risk manner
- Development of a larger pilot project to test the technology in full substation implementation. This pilot project should serve as the basis for developing new standards for station drawings, relay settings, SCADA, and communication configurations. A small substation located in close proximity to a maintenance center would be an ideal candidate for this type of pilot project

- The relays in SDG&E's standards do not currently have IEC 61850 process bus capabilities. This means that new standard drawing packages, relay configurations, and define new equipment standards for IEC 61850 applications will need to be created. The project team may even have to switch to different protection philosophies and suppliers when implementing IEC 61850. An example was the high-impedance bus differential relay applied on some transmission buses. This application would still require a significant amount of CT wiring, in the field to a central summing point, for conversion of the analog signals into an MU readable signal
- Currently IEC 61850 is not used extensively in SDG&E's substations. Adoption of IEC 61850 will mean new technology for the protection and substation design engineers to learn and develop expertise around. Furthermore, field support personnel, such as operators and relay technicians, will also experience the technology change. For operations, testing, procedures will have to be modified to fit the new technology. As an example, when MUs were installed in field devices for SV and GOOSE, some testing will need to be performed at the breakers and transformers located in the substation yard, instead of in the air-conditioned control shelter.

12. KEY FINDINGS

Based on a review of the pre-commercial demonstration test results and execution of the test system design and relay settings/IEC 61850 configurations, the following key findings were developed:

- Multi-vendor interoperability is not universal for the products tested in this project. Because these initial integration efforts were significant, future implementations should benefit from these experiences.
- Use of IEC 61850 SV did not impact relay performance, as compared to a direct hardwired solution, as long as the process bus network was correctly designed and utilizes managed switches for MAC address filtering as necessary.
    - Other than the obvious wiring and data communications advantages that IEC 61850 GOOSE and SV have over conventional hardwired relay installations, protection settings and schemes did not change with an IEC 61850 process bus installation, as basic protection concepts did not change.
- All SV based test cases evaluated were able to be implemented with IEC 61850 process bus. The technology evaluated was at a point where it could be applied to utility protection applications, assuming careful attention to equipment selection for compatibility.
- GOOSE messages successfully replaced traditional hard wire status and control wiring in the project. Analog values that were embedded within GOOSE data sets, successfully controlled a reactive automation application.
- IEC 61850 process bus compatible relays and merging units were still so new that the manufacturers' technical sales representatives were only generally familiar with application and configuration. One should expect to initially spend a considerable amount of engineering time on resolving IEC 61850 process bus configuration issues and locating manufacturer staff that will be able to provide the required engineering support.
- Manufacturers have not coalesced around fully interoperable SV options; IEC 61850-9LE still has a large potential for differences that allows manufacturers' equipment to meet the standard, yet not work with each other without a large amount of end-user effort.
- IEC 61850 GOOSE/MMS messaging was stable with good interoperability between different manufacturers' equipment. Configuration tools were fairly easy to learn and use.
- Relay manufacturers' documentation, as far as implementing an SV application, was lacking and many critical items can be expected to be discovered only by extensive communication with the manufacturers to learn unpublished information and facts.
- SV compatible relays require the capability to subscribe to at least six SV channels, with the ability to internally map the various voltage and amperage signals to the proper protection elements without limitations, if the technology was to maximize its potential to replace hardwired equipment. The overcurrent bus differential use case proved this fact.
- MUs should support, at a minimum, a built-in SER for GOOSE I/O troubleshooting. Built-in capability to implement basic Boolean logic and an ER would be very desirable features too. Some of the test system MUs supported Boolean logic, an ER, and a time stamped SER.
- MUs should integrate analog inputs with digital inputs and outputs into a small panel mounted enclosure for easy field installation in yard apparatus such as transformers and circuit breakers. Only two manufacturers' MUs evaluated in this study were close to meeting this requirement.

- Only one manufacturer's MU used in the study was easily interfaced with all three manufacturers relays evaluated in the study. MUs generally worked very well with relays built by the same manufacturer.
- Manufacturers' relay and MU configuration software packages were still a "work in progress." One major relay manufacture's software evaluated was found to be very difficult to work with, with multiple non-integrated applications, which required direct assistance by the manufacturer's staff to complete the configuration tasks. This level of complexity would not be acceptable in an implementation environment. Other relay manufacturers' software packages were fairly user friendly and intuitive. The majority of the issues encountered during configuration were eventually resolved with assistance from the manufacturers' support staff.
- Ethernet switches necessary to integrate all the parts of an IEC 61850 SV substation have a power demand significantly higher than the relays and MUs themselves, which could impact station battery sizing and should not be ignored.
- The network and time synchronization system proposed for the test system provided a broad range of support to cover the various vendors' networking and time synchronization interfaces. It also provided the quantities and types of equipment to simulate the required process bus architectures and fiber implementation that would occur in a real substation installation.
- The initial material costs of a substation designed with IEC 61850 GOOSE and SV P&C was calculated to be greater than the initial material costs of a traditional P&C substation.
- Some manufacturers' relays require different ports for SV and GOOSE signals intended for the same process bus connection. This was a disadvantage that must be rectified in future models because it impacts the ability to connect the relays to both the station and process buses, provide a port for dedicated maintenance access.
- The results support this project's EPIC value proposition in that the P&C scheme evaluated was anticipated to be at least as reliable, if not more so, than the existing legacy P&C scheme. Although the initial costs of a P&C scheme as described in this project may be higher, it was anticipated that the on-going costs will be reduced.
- The project's goals to investigate interoperability and determine protection system performance were achieved:
    - The interoperability determination was successful. Although interoperability was not universally achieved for all of the devices, enough interoperability was achieved to allow for testing of all of the protection use cases identified in the project scope.
    - Performance of the protection relays using an IEC 61850 P&C scheme were verified to equal or exceed the performance requirements set by the project team.

IEC 61850 Implementation Challenges

Transitioning protection design philosophy from using direct CT/PT and I/O connections to each protection relay to using IEC 61850 GOOSE and SV still presents many challenges.

The first challenge would be to design the infrastructure that would serve as the signal transport medium, replacing the hardwired copper cable. Process bus design and equipment assignment was an important first step which drove parts of the network equipment specification. The manufacturers had different limitations on how the equipment could interface with the process bus which introduced network complexity and interoperability issues. Another important component required by IEC

61850 SV was time synchronization. A mix of time synchronization requirements was identified from the various manufacturers included in this project, which covered the entire list of methods called out in the standard. The test system design team found a GPS clock source that could support all of these time source types and provide network isolation between the various networks.

With the release of edition 2, for many of the IEC 61850 parts, new challenges arose in determining which edition to use for the project. In a single manufacturer solution this would generally not be a problem but with a multi-manufacturer project, it was vital that all of the manufacturers function together under the same SCL model, SV and GOOSE edition. A further challenge in choosing the edition was that most manufacturers were still only providing SV using the UCA International Users Group (UCAIug), "IMPLEMENTATION GUIDELINE FOR DIGITAL INTERFACE TO INSTRUMENT TRANSFORMERS USING IEC 61850-9-2" (LE) which is based on IEC 61850-9-2 Edition 1. A mix of implementations with both edition 1 and edition 2 functions were identified and that added an additional degree of difficulty for the test system implementation.

Another challenge was providing the correct SCL file type and edition necessary to import into other manufacturers' configuration tools. The manufacturers had limitations in their configuration tools for exporting the SCL file type, edition, and providing optional information that was required by other manufacturer configuration tools. In some cases, manual modifications to the SCL files, to allow proper information exchanges, was required. There were numerous character length limitations for the various GOOSE and SV parameter settings which, when exceeded did not produce any errors within the configuration tool. These problems could only be found with the identification of an unrelated problem and working backwards to determine the cause, including application of a network analysis tool. The lack of built-in error checking in the configuration tools required significant additional testing to determine the root cause of problems. Some confusion was identified with one manufacturer's tools, where separate software packages were used for each type of configuration task. In some cases it was not clear how to link the information between the software packages. Appendix H contains a list of observations identified during configuration and testing. This list was anticipated to provide assistance to the engineers responsible for device configuration in future projects.

Protection and merging unit electrical and protection settings were very similar to what was required for the base systems. Some of the protection relays still had some setting requirements around CT and PT ratios, which seemed redundant given that the merging units provided primary values for the samples. This and other settings such as the reference SV stream were different from what the protection engineers were used to but once done, the settings were the same as they have done before.

Testing was another challenge. The development of new procedures to ensure the infrastructure was working correctly was followed by the execution of the protection scheme testing. Good documentation was the key to success and much effort was expended to develop proper dataflow tables and diagrams to communicate all the virtual wiring, GOOSE, and SV used in the system between the various members of the system configuration team. These documents along with the networking and time synchronization diagrams provided the base information to create the testing procedures, and will be crucial when performing actual implementations.

All IEC 61850 implementations challenges were easily solved during the initial equipment selection process and design. Like the traditional design methods, determine the equipment to use, identify which IEC 61850 functions to implement, and determine how the user can work out solutions. Once complete the challenges associated with the first project will be minimized.

13. CONCLUSIONS

Upon review of the demonstration findings, the following conclusions are made:

- The results of this project were very encouraging. SV based P&C were found to be equivalent or better than the legacy hardwired solutions for the use cases identified. IEC 61850 did not degrade and in some cases improved protection, control and automation schemes.
- SV messages were more flexible than the existing traditional hardwired P&C system.
- GOOSE messages were more flexible and faster than the existing traditional hardwired P&C system.
- IEC 61850 SV and GOOSE increased P&C system flexibility and provided opportunities for new P&C schemes due to digitization of the system.
- Although not yet universal, substantial SV interoperability was identified. It was anticipated that interoperability will only improve with time.
- The interoperability results of this project should be of interest to all potential users of SV. The project findings should assist manufacturers with their SV implementations so as to improve interoperability. These results should also assist adopters of IEC 61850 with the selection and evaluation of future manufacturer product offerings.
- Once the team was sufficiently experienced with the products' configuration details configuration time decreased. Configuration templates would be especially valuable in this regard.
- The project provided opportunities to learn more about IEC 61850's limitations, capabilities and vendors' interoperability.

14. RECOMMENDATIONS

The project team recommends that SDG&E continue to explore commercial adoption of IEC 61850 applications within its substations. The project findings and conclusions show that, although care is required in the selection of products, the currently available merging units and relays are sufficiently mature to support interoperability between vendors. In addition, the protection performance of the test system is equivalent to hardwired legacy P&C systems.

The project team further recommends that an SDG&E communications laboratory be developed to support future work and training. This laboratory would include a capability to mock-up future substation communications infrastructure to validate their performance before actual deployment in substations. Although this laboratory would have a focus on IEC 61850, it would also support testing of other communications technologies and standards.

With the completion of the future work items, discussed in the next section, the project team recommends that pilot projects be initiated to gain experience with IEC 61850. Potential pilot projects could include a GOOSE based 12 kilovolt (kV) capacitor control scheme using existing installed hardware, or a three breaker 69 kV P&C scheme. These pilot projects could be precursors towards development of a larger project to test the technology in an actual substation. A pilot project will serve as the basis for developing new standards for station drawings, relay settings, SCADA and communication configurations. A substation located in close proximity to a maintenance center would be an ideal candidate for this type of pilot project because of the training opportunities it provides.

An IEC 61850 design implementation will differ greatly from current hardwired state of the art, and issues such as maintenance, testing and training, must be addressed while embarking on the first implementation of this technology.

SDG&E should make the results of this EPIC project available to the various standards bodies associated with IEC 61850 – especially IEC Technical Committee 57, Working Group 10.

Future work

The following future work items represent valuable next-step options in the adoption of a full IEC 61850 substation. These items would allow the user to gain valuable experience with the IEC 61850 standard. Each item was sized such that a small team of two to three subject matter experts could be identified and assembled to research and develop the necessary components in a relatively short period of time.

Network Optimization

In accordance with the project team's direction, the test system network design was the minimal necessary to complete the testing. Although basic multi-cast filtering was configured, configuration items did not include advanced networking features or optimization. For an actual substation implementation consideration should be given to additional network design and optimization. Suggested items of particular interest may include VLANs, priorities, and multi-cast filtering.

Remote Access

In accordance with the project team's direction, remote access was not explored. It was understood that the project team was investigating this capability as part of a separate project. Internal policies and NERC CIP requirements would need to be investigated in order to determine the level of protection required and the preferred method of achieving this capability.

Redundancy

Redundancy was a broad topic that covers many disciplines. It can include protection design, local network design, and WAN design. Currently the project team has a protection philosophy that provides a degree of redundancy. This philosophy could be combined with local networking to achieve the degree of redundancy necessary to meet the project team's requirements. Combining the protection redundancy requirements with network redundancy could yield synergies and provide significant benefits.

SCADA

The project's scope did not include exploration of metering, data acquisition, or local annunciation. Each of these items presents an opportunity to combine with the IEC 61850 P&C developed in this project to enhance the current design and lower costs.

- Individual panel meters were a standard of the current substation design. The relays included in this project included large LCD screens, which could be used to display local metering. Another option could include stand-alone displays that were connected to serial ports on the relays. Other options could be explored to balance features and costs.
- A station data concentrator, RTU, or gateway that supports GOOSE messages and/or MMS would enable the project team to further reduce station wiring. Multiple products were currently available that support this solution. An engineering study and lab test of these products would enable the project team to identify an acceptable product.
- Similarly, the current use of panel annunciators could be modified to eliminate the serial communications driven annunciators. GOOSE messaging was a potential opportunity to further reduce wiring within the substation.

SV Implementations

This project utilized IEC 61850-9-2, Edition 2 for SV. Many interoperability issues arose from inconsistent design choices between manufacturers concerning the edition 2 implementations. IEC published standard 61869-9 in 2016. This standard provides guidance on the digital interface for instrument transformers. It would be worthwhile to investigate products that have implemented this standard to determine if interoperability would be improved.

15. POST-PROJECT TECHNOLOGY TRANSFER

The project team will submit presentations and papers to major conferences and/or journals. These submissions include, but are not limited to, the annual EPIC Symposium.

The availability of this report on the SDG&E EPIC website https://www.sdge.com/epic will be widely announced.

A PowerPoint presentation will be developed and used to aid in engaging the stakeholder groups within SDG&E. This presentation will also aid in coordination with external stakeholders in IEC 61850.

16.METRICS AND VALUE PROPOSITION:

Metrics:

The following metrics were identified for this project. Given the proof of concept nature of this EPIC project, these metrics are forward looking to prospective adoption of IEC 61850 standards.

The main protection concerns that were identified in this project were speed and reliability. The following items address these concerns.

Potential energy and cost savings

Due to saving on the engineering efforts of the design process using IEC 61850 equipment, which can be reflected to the price of energy for ratepayer.

The main saving comes from the integrated engineering tools that makes it easier to design the substation and test the equipment before deployment, which is hard to achieve now and its is time consuming using the current legacy systems.

Economic benefits

Maintain/Reduce operations and maintenance costs

IEC 61850 digital equipment allows easier maintenance and debugging of the equipment using advanced embedded software tools.

The labor costs associated with the process bus implementation were reduced significantly. This was primarily due to the reduction in wiring.

Improvements in system operation efficiencies and adding automation features

Operation efficiency can be improved using IEC 61850 equipment especially with the new peer-to-peer communication feature, which allows major improvements of operations, and more equipment can be monitored and operated to reduce the cause of outages and improve the efficiency. This also allow more automation in the substation and things like triggering CAP banks and Voltage regulators can be improved.

Value proposition:

The purpose of EPIC funding is to support investments in R&D projects that benefit the electricity customers of SDG&E, PG&E, and SCE. The primary principles of EPIC are to invest in technologies and approaches that provide benefits to electric ratepayers by promoting greater reliability, lower costs, and increased safety. As discussed and summarized below, this project met all three of the EPIC primary principles: reliability, lower cost, and safety, and two of the EPIC secondary principles were applied.

Primary principles

- **Reliability:**
  The new equipment performed all the protection schemes in current substations with a faster initiation time and more operation capabilities.

The new digital system allows easy add and integration of a new equipment without a need of running new wires every time a new IED is added to the network

- **Lower cost:**
  Although the current equipment cost for the new merging units is higher nevertheless, the long run cost is lower due to saving on engineering efforts and design time and reducing the labor cost for wiring in addition to the added operating features.

- **Safety:**
  Reducing the number of wiring reduces the cause of fire due to a short in wires or a failure since the substation racks uses fiber optic.

  Due to peer-to-peer communication feature now you can disconnect lines in case of a failure automatically which avoid the human delay that can cause damage to the network and the grid.

Secondary principles

- **Safe, Reliable & Affordable Energy Sources:**
  As mentioned earlier with peer-to-peer communication, utility networks can perform new safety features that is not available in the current substations which makes it safter and more reliable.

- **Efficient Use of Ratepayers Monies:**
  Saving money in distribution due to the new technologies and features would result in lower distribution and maintenance cost and that can be reflected to the ratepayers energy cost. This can be accomplished using the new engineering tools that comes with IEC 61850 new equipment and the new peer to peer communication without a need to run many cables between equipment in the substation.

Primary Principals			Secondary Principals				
Reliability	Lower Costs	Safety	Loading Order	Low-Emission Vehicles / Transportation	Safe, Reliable & Affordable Energy Sources	Economic Development	Efficient Use of Ratepayers Monies
✓	✓	✓			✓		✓

REFERENCES

[1] IEC. (2016, 04). IEC 61869-9 ed 1. *Instrument transformers –Part 9: Digital interface for instrument transformers*. IEC.

BIBLIOGRAPHY

Group, R. C.-T. (2004). IRIG Standard 200-04. *IRIG SERIAL TIME CODE FORMATS*. Range Commanders Council-Telecommunications and Timing Group.

IEC. (2003, 08). IEC/TS 61850-2 ed 1. *Communication networks and systems- Part 2: Glossary*.

IEC. (2009, 12). IEC 61850-6 ed 2. *Communication networks and systems for power utility automation – Part 6:Configuration description language for communication in electrical substations related to IEDs*. IEC.

IEC. (2010, 08). IEC 61850-7-2 ed 2. *Communication networks and systems for power utility automation –Part 7-2: Basic information and communication structure – Abstract communication service interface (ACSI), 2*. IEC.

IEC. (2010, 12). IEC 61850-7-3 ed 2. *Communication networks and systems for power utility automation –Part 7-3: Basic communication structure – Common data classes, 2*. IEC.

IEC. (2010, 03). IEC 61850-7-4 ed 2. *Communication networks and systems for power utility automation –Part 7-4: Basic communication structure – Compatible logical node classes and data object classes, 2*. IEC.

IEC. (2010, 03). IEC/TR 61850-90-1 ed 1. *Communication networks and systems for power utility automation –Part 90-1: Use of IEC 61850 for the communication between substations*. IEC.

IEC. (2011, 04). IEC 61850-4 ed 2. *Communication networks and systems for power utility automation –Part 4: System and project management*. IEC.

IEC. (2011, 07). IEC 61850-7-1 ed 2. *Communication networks and systems for power utility automation –Part 7-1: Basic communication structure – Principles and models*. IEC.

IEC. (2011, 06). IEC 61850-8-1 ed 2. *Communication networks and systems for power utility automation –Part 8-1: Specific communication service mapping (SCSM) – Mappings to MMS (ISO 9506-1 and ISO 9506-2) and to ISO/IEC 8802-3, 2*. IEC.

IEC. (2011, 09). IEC 61850-9-2 ed 2. *Communication networks and systems for power utility automation –Part 9-2: Specific communication service mapping (SCSM) – Sampled values over ISO/IEC 8802-3*. IEC.

IEC. (2012, 12). IEC 61850-10 ed 2. *Communication networks and systems for power utility automation – Part 10: Conformance testing(Edition 2)*. IEC.

IEC. (2012, 05). IEC/TR 61850-90-5 ed 1. *Communication networks and systems for power utility automation –Part 90-5: Use of IEC 61850 to transmit synchrophasor information according to IEEE C37.118*. IEC.

IEC. (2013). IEC 61131-3. *Programmable controllers - Part 3: Programming languages* . IEC.

IEC. (2013, 12). IEC 61850-3 ed 2.0. *Communication networks and systems for power utility automation –Part 3: General requirements*. IEC.

IEC. (2013, 01). IEC 61850-5 ed 2. *Communication networks and systems for power utility automation –Part 5: Communication requirements for functions and device models*. IEC.

IEC. (2013, 03). IEC/TR 61850-1 ed 2. *Communication networks and systems for power utility automation –Part 1: Introduction and overview*. IEC.

IEC. (2013, 08). IEC/TR 61850-90-4 ed 1. *Communication networks and systems for power utility automation –Part 90-4: Network engineering guidelines*. IEC.

IEC. (2015, 03). IEC 62271-3 ed 2. *High-voltage switchgear and controlgear –Part 3: Digital interfaces based on IEC 61850*. IEC.

IEC. (2015, 06). IEC PAS 61850-9-3 ed 1. *Communication networks and systems for power utility automation –Part 9-3: Precision time protocol profile for power utility automation*. IEC.

IEC. (2016, 04). IEC 61869-9 ed 1. *Instrument transformers –Part 9: Digital interface for instrument transformers*. IEC.

IEC. (2016, 02). IEC TR 61850-90-2 ed 1. *Communication networks and systems for power utility automation –Part 90-2: Using IEC 61850 for communication between substations and control centres*. IEC.

IEC. (2016, 05). IEC TR 61850-90-3 ed 1. *Communication networks and systems for power utility automation –Part 90-3: Using IEC 61850 for condition monitoring diagnosis and analysis*. IEC.

IEC. 61869-9: Instrument transformers - Part 9: Digital interface for instrument transformers

IEC. 62439-3: Clause 4 Parallel Redundancy Protocol (PRP) and Clause 6 High-availability Seamless Redundancy (HSR) Protocol.

IEEE. (2006). IEEE 1613. *Approved Draft IEEE Standard Environmental and Testing Requirements for Communications Networking Devices in Electric Power Substations*. IEEE.

IEEE. (2007). IEEE 1686-2007. *IEEE Standard for Intelligent Electronic Devices Cyber Security Capabilities*. IEEE.

IEEE. (2011). IEEE C37.118. *Standard for Synchrophasor Measurements for Power Systems*. IEEE.

IEEE. (2012). IEEE Std 1815-2012. *IEEE Standard for Electric Power Systems Communications-Distributed Network Protocol (DNP3)* . IEEE.

IEEE. (2013). IEEE 1686-2013. *IEEE Standard for Intelligent Electronic Devices Cyber Security Capabilities*. IEEE.

IEEE. (2013, 01). IEEE Std C37.94 - IEC 62843. *Standard for N times 64 kilobit per second optical fiber interfaces between*. IEEE.

IEEE. (2015). IEEE 1588 PC37.238/D16. *IEEE Draft Standard Profile for Use of IEEE 1588 Precision Time Protocol in Power System Applications*. IEEE.

IEEE. (2015). IEEE 1815.1-2015. *IEEE Approved Draft Standard for Exchanging Information between Networks Implementing IEC 61850 and IEEE Std 1815(TM) (Distributed Network Protocol - DNP3) - Corrigendum 1* . IEEE.

IEEE. (2016, 08). IEEE PC37.238. *IEEE Draft Standard Profile for Use of IEEE 1588 Precision Time Protocol in Power System Applications*. IEEE.

IEEE. 802.1Q IEEE Standard for Local and metropolitan area networks—Bridges and Bridged Networks

NERC. “NERC CIP-007-6 R5.5”

NIST. “NIST SP 800-82r2, Guide to Industrial Control Systems (ICS) Security”, File Name: NIST.SP.800-82r2, last modified May 2015.

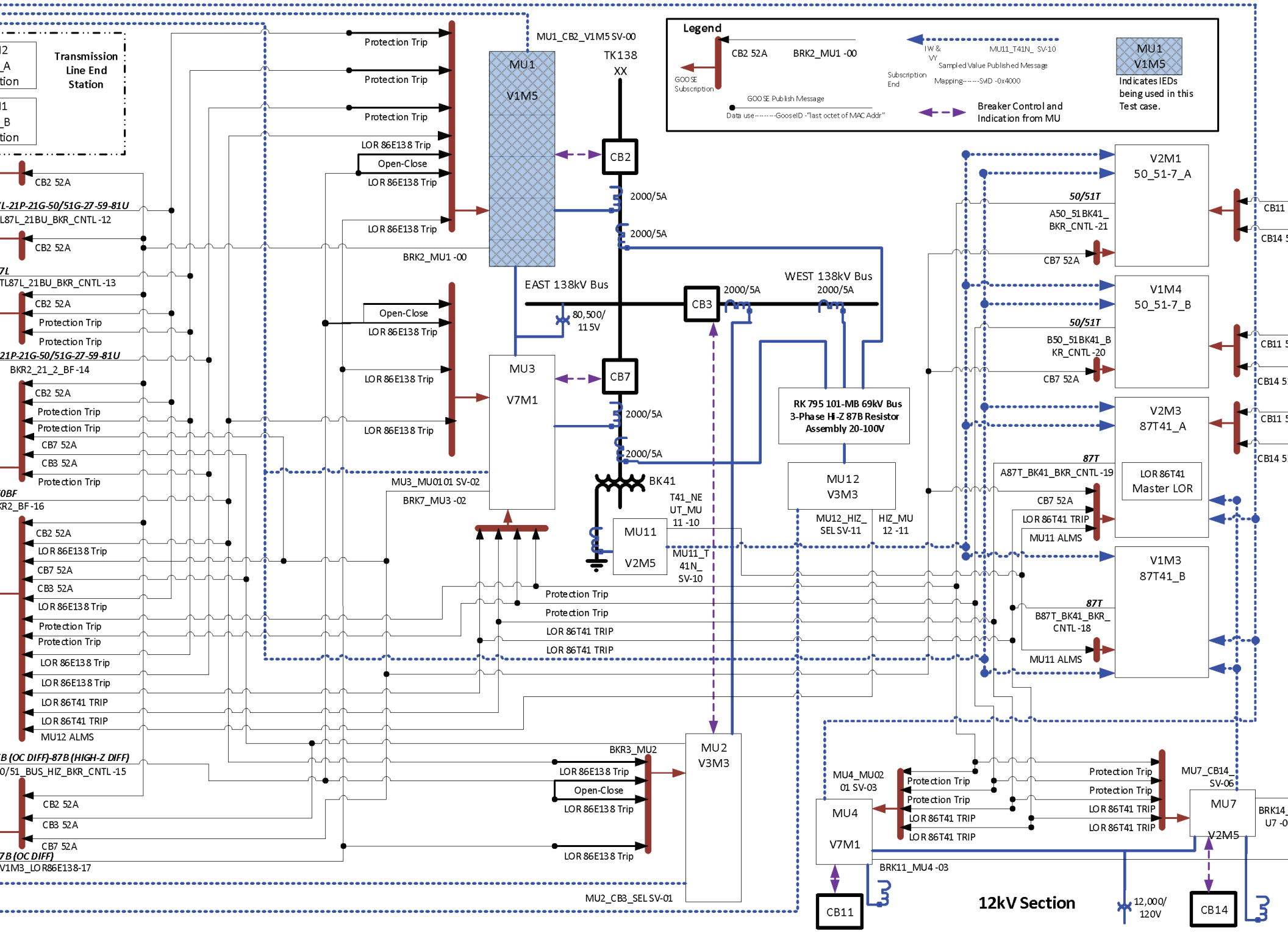
Organization, M. (2012, 04). Modbus. *MODBUS APPLICATION PROTOCOL SPECIFICATION V1.1b3*. Modbus Organization.

UCA International Users Group. “IMPLEMENTATION GUIDELINE FOR DIGITAL INTERFACE TO INSTRUMENT TRANSFORMERS USING IEC 61850-9-2”, File Name: DigIF_spec_9-2LE_R2-1_040707-CB, Modification Index: R2-1, 2004-07-07, Last Modified 2011-03-14.

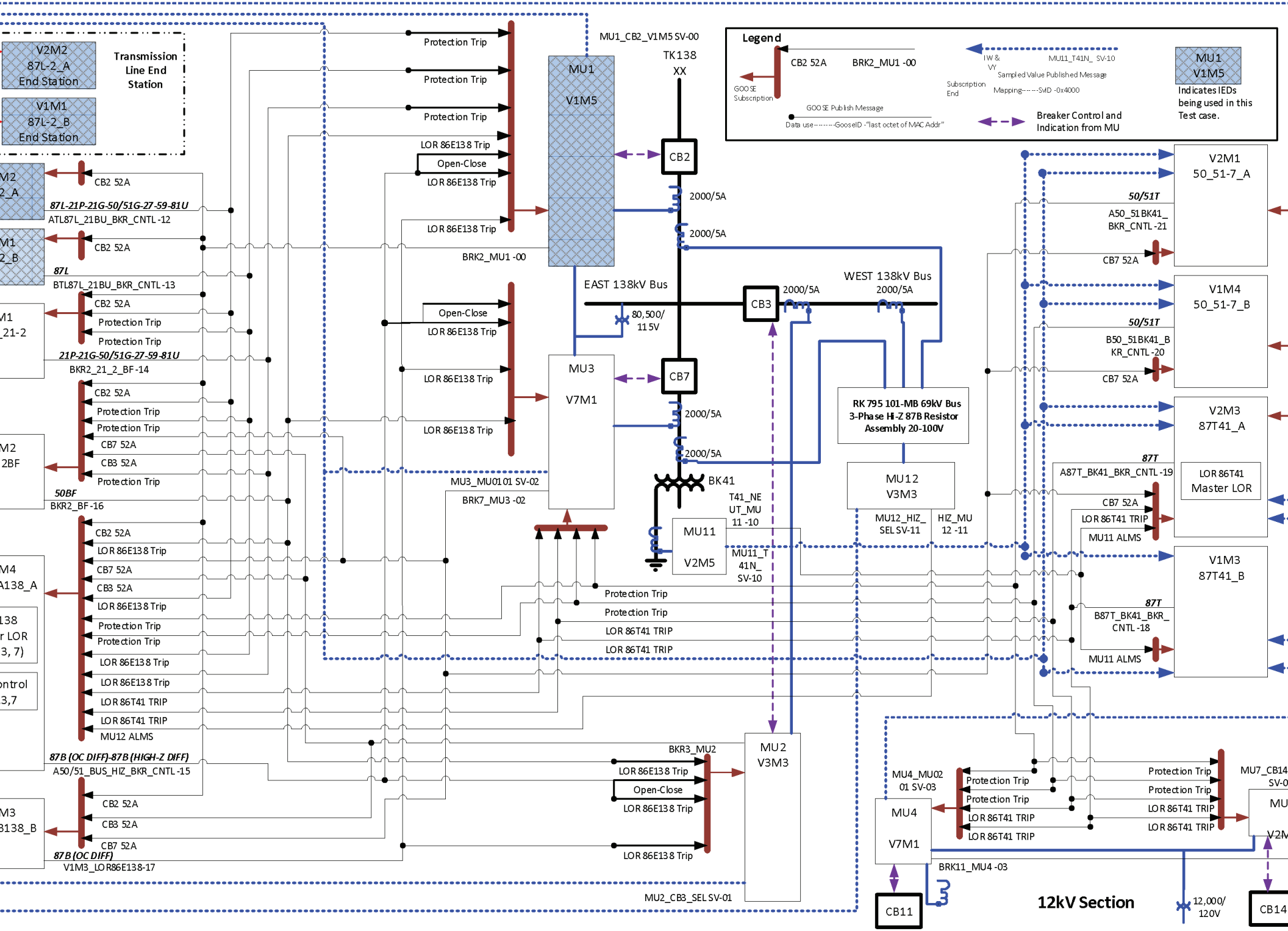
APPENDIX A - TEST CASE DATA FLOW DIAGRAMS

The test case data flow diagrams contained in this appendix illustrate the flow of information and which relays and merging units are associated with the case. Use cases that deal with particular conditions, such as the phases of a fault, are not illustrated. Even though the diagram shows all merging units and relays, only the merging units and protection relays which were included in the test are shaded with a blue background and gray cross-hatches. IEC 61850 SV messages are indicated with dotted blue lines. GOOSE messages are indicated with solid black lines. SV and GOOSE message names are indicated near the transmitting device. Arrows on SV and GOOSE messages indicate a device was subscribing to that message.

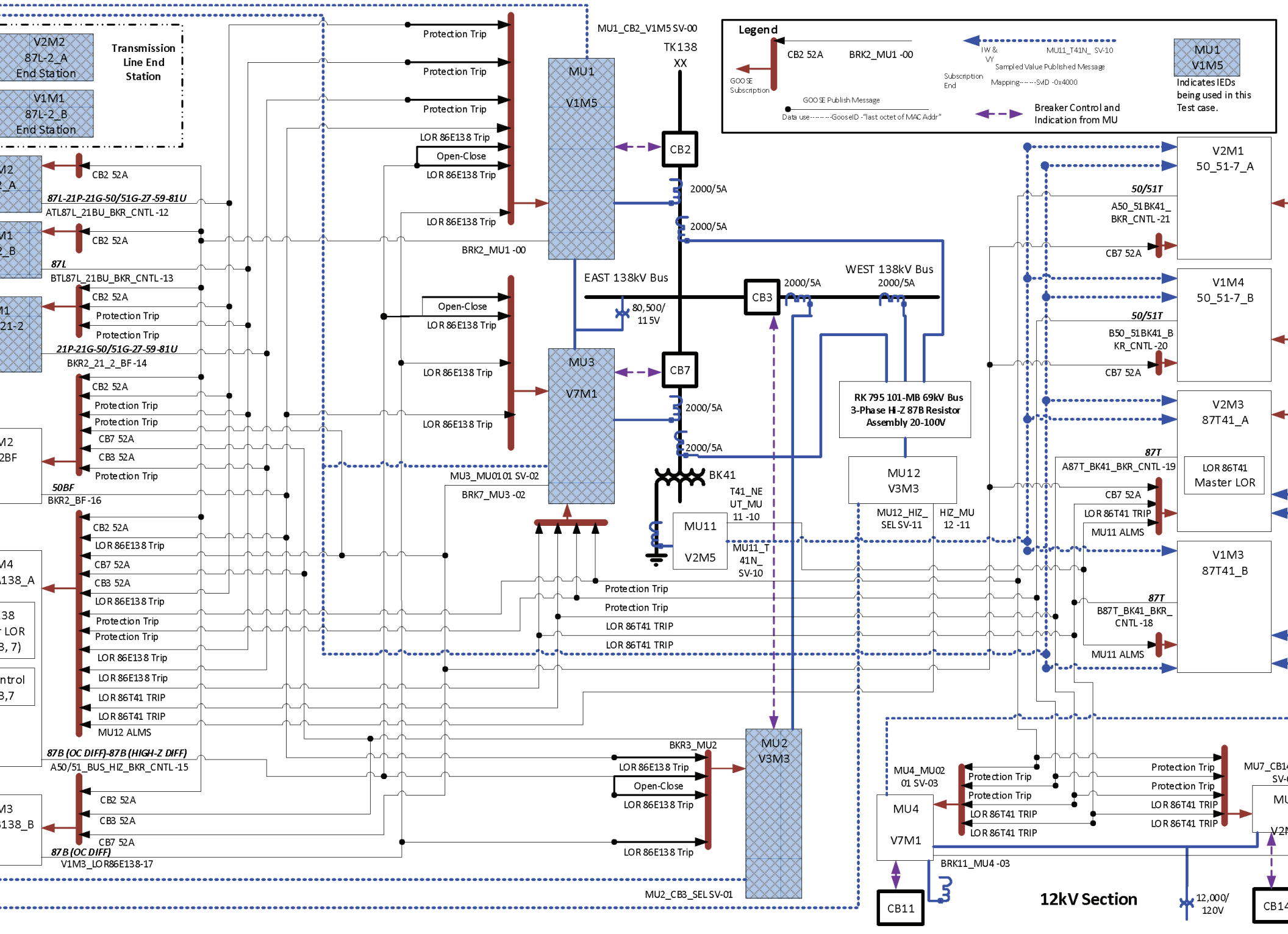
Process Bus #1 Data Flow Test Case 1: Breaker Fail



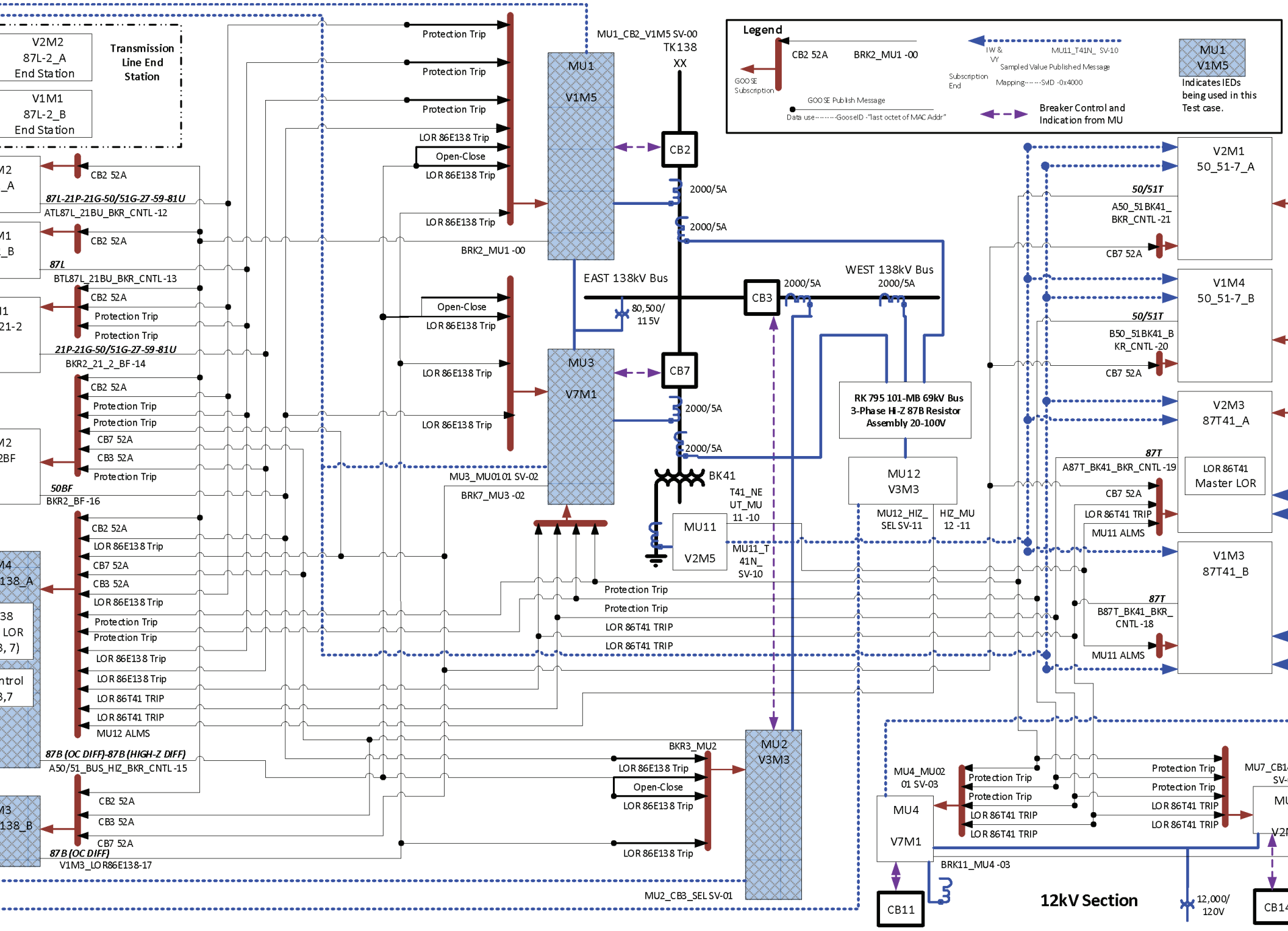
Process Bus #1 Data Flow — Test Case2: Line Diff



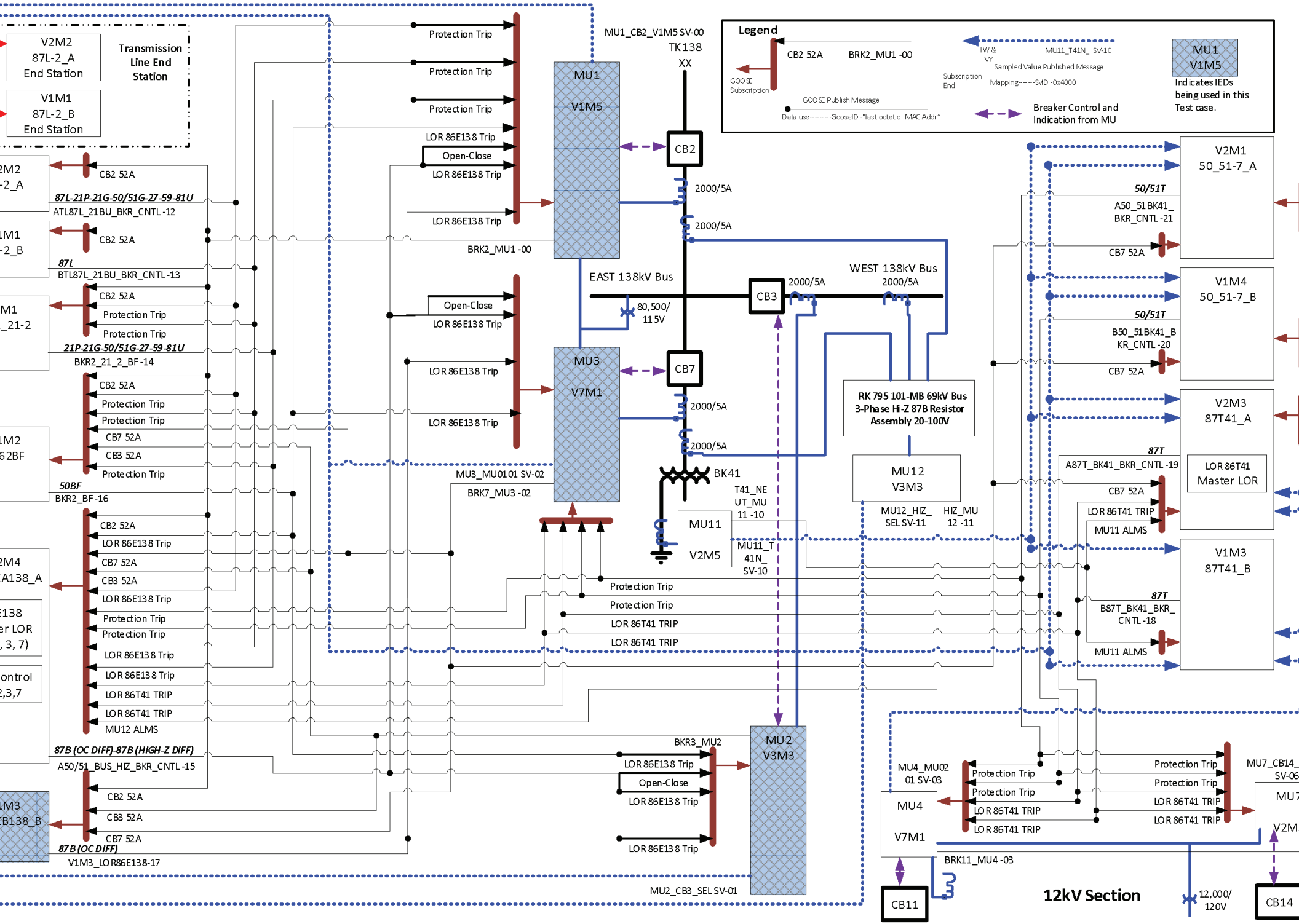
Process Bus #1 Data Flow Test Case 3: Line Distance



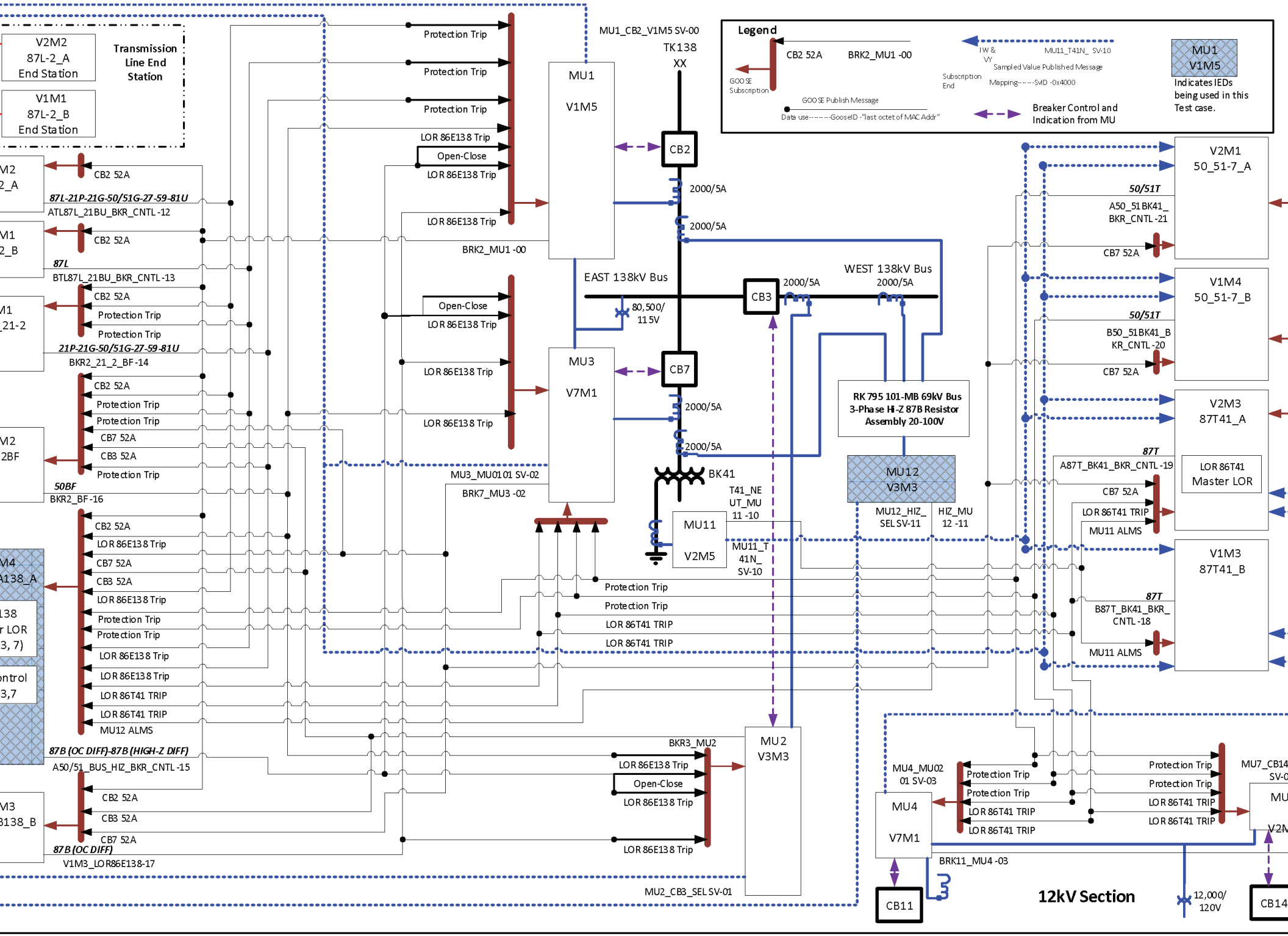
Process Bus #1 Data Flow Test Case 4: HS Bus OC



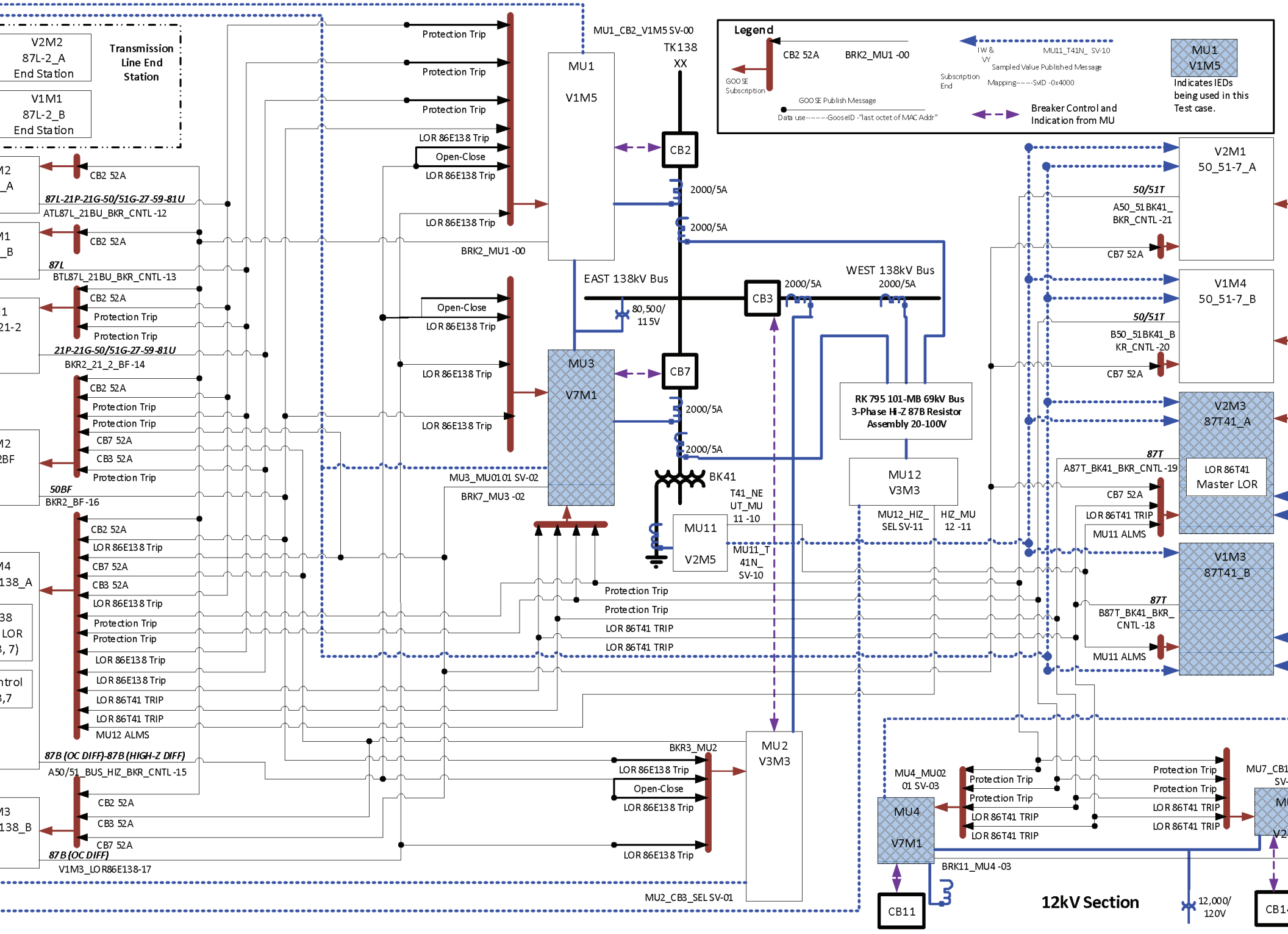
Process Bus #1 Data Flow — Test Case 5:HS Bus Diff



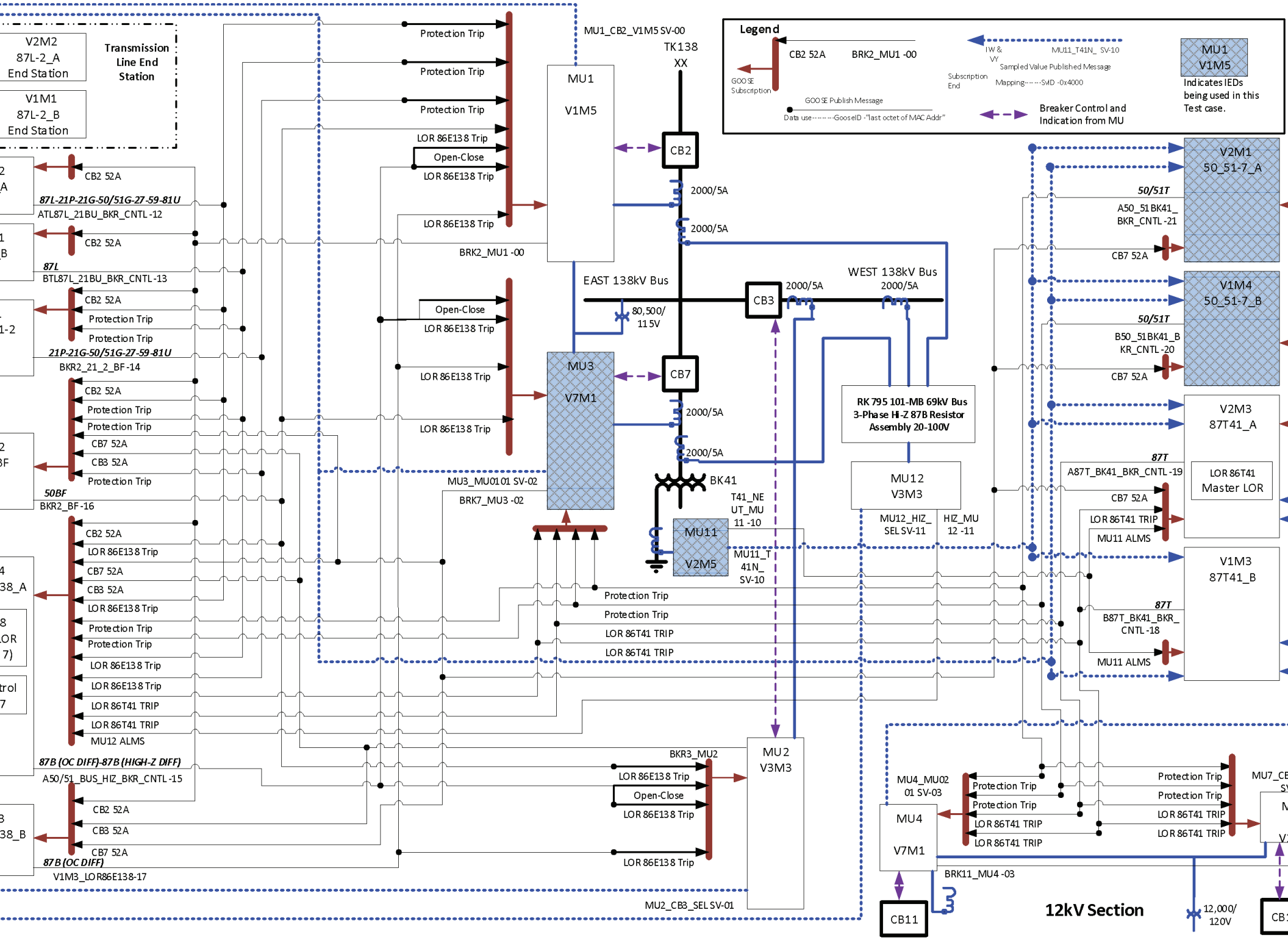
Process Bus #1 Data Flow Test Case 6: HS Bus High-Z



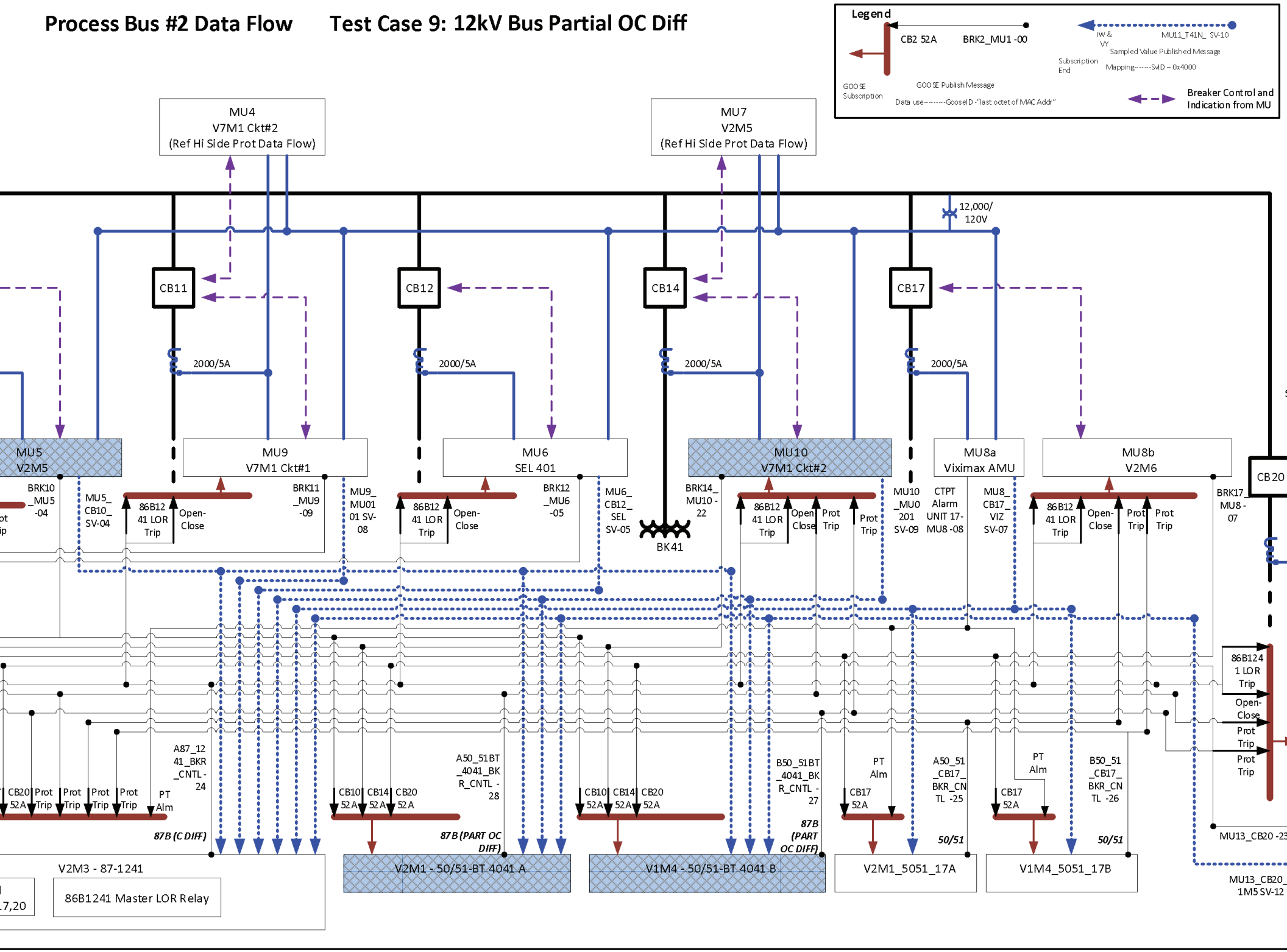
Process Bus #1 Data Flow — Test Case 7: Transformer Diff



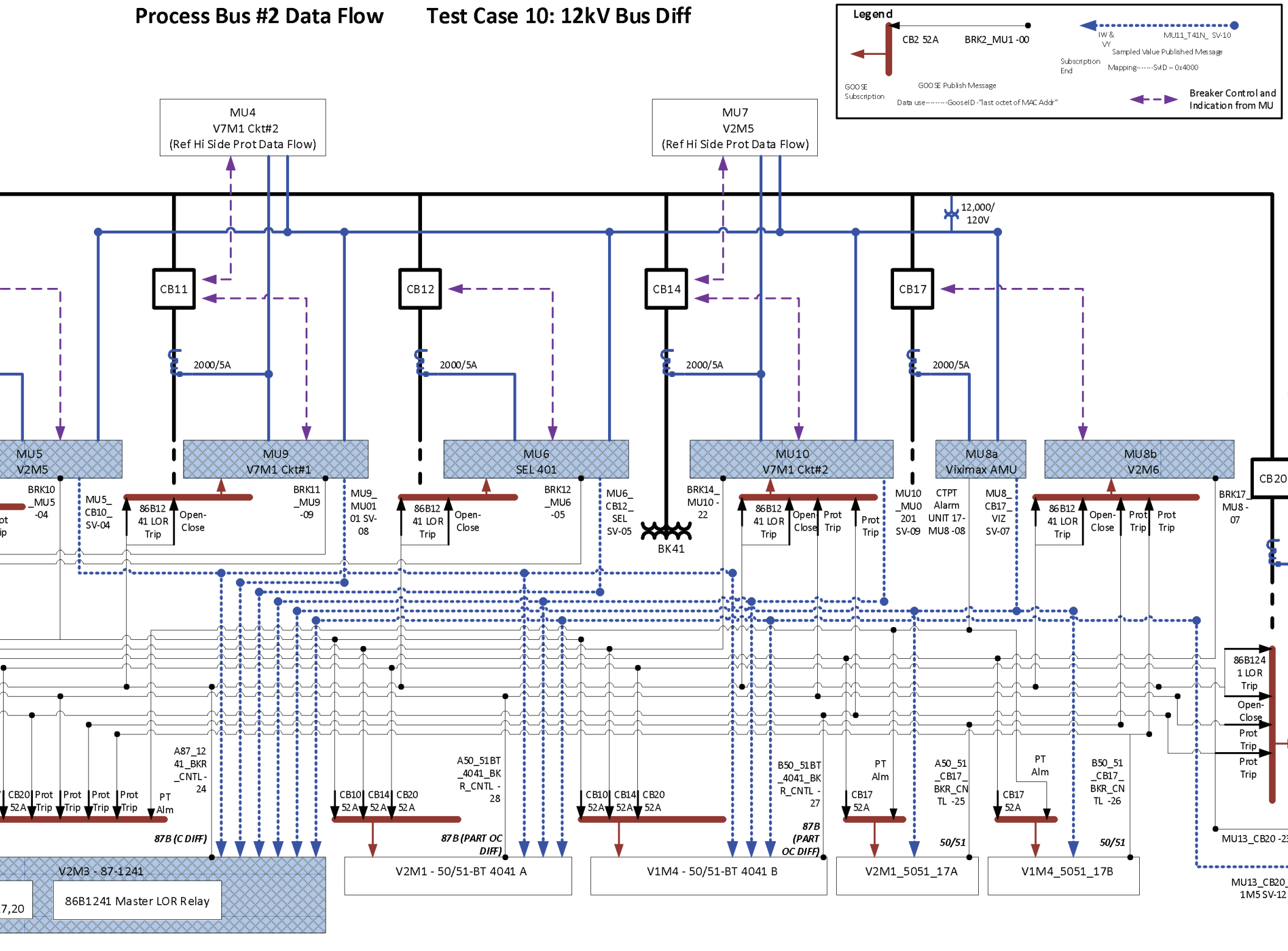
Process Bus #1 Data Flow — Test Case 8: Transformer OC



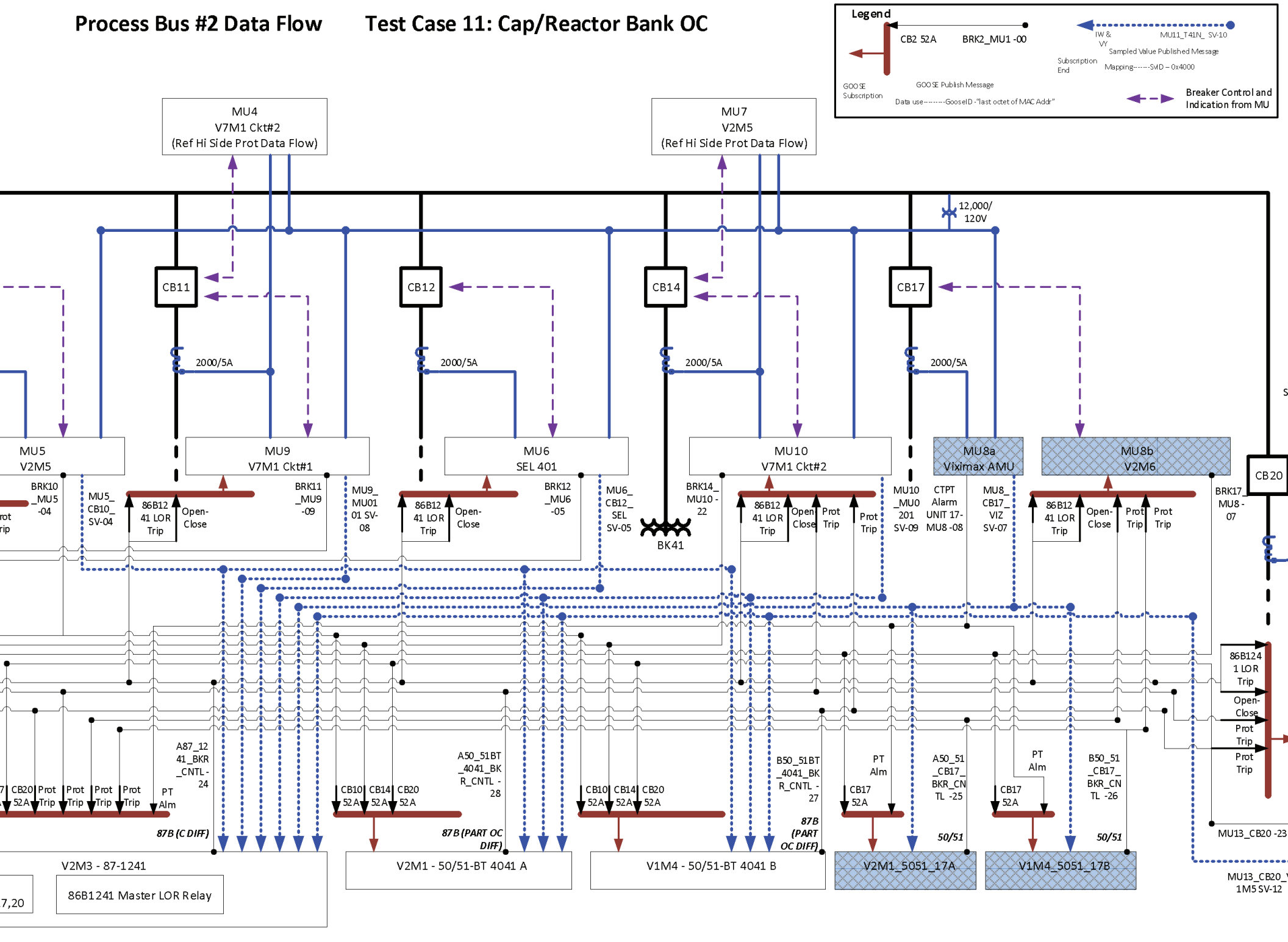
Process Bus #2 Data Flow Test Case 9: 12kV Bus Partial OC Diff



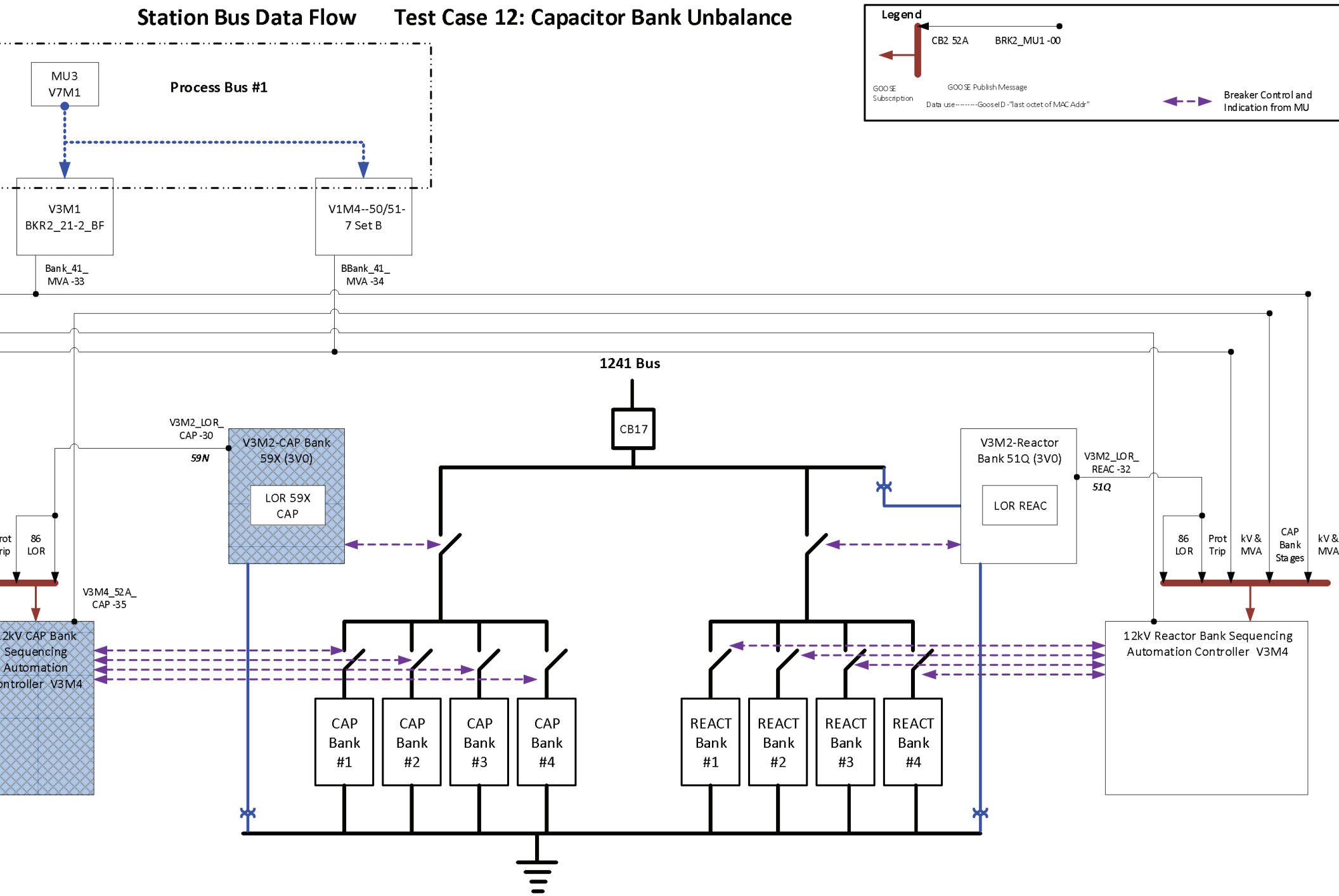
Process Bus #2 Data Flow Test Case 10: 12kV Bus Diff



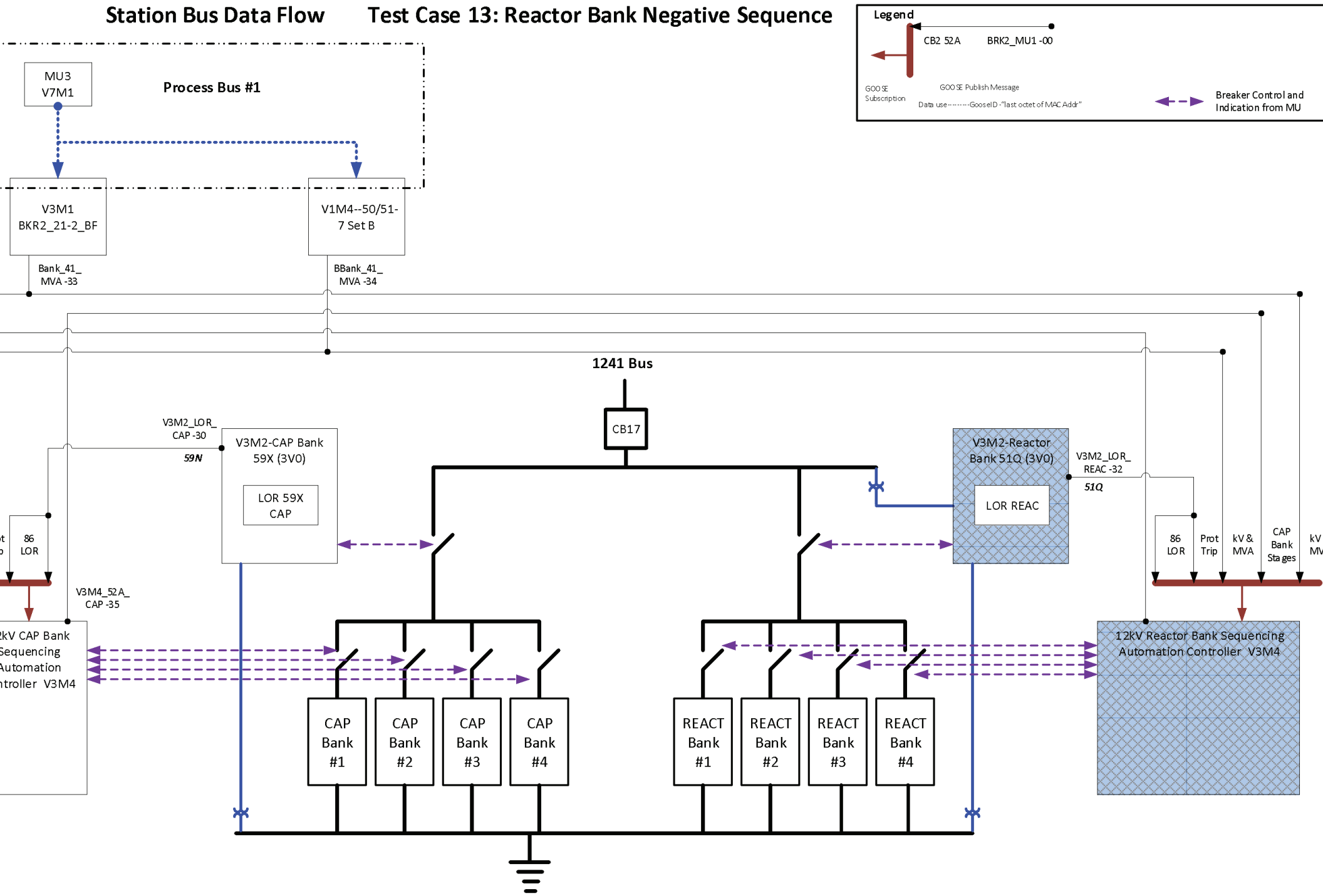
Process Bus #2 Data Flow Test Case 11: Cap/Reactor Bank OC



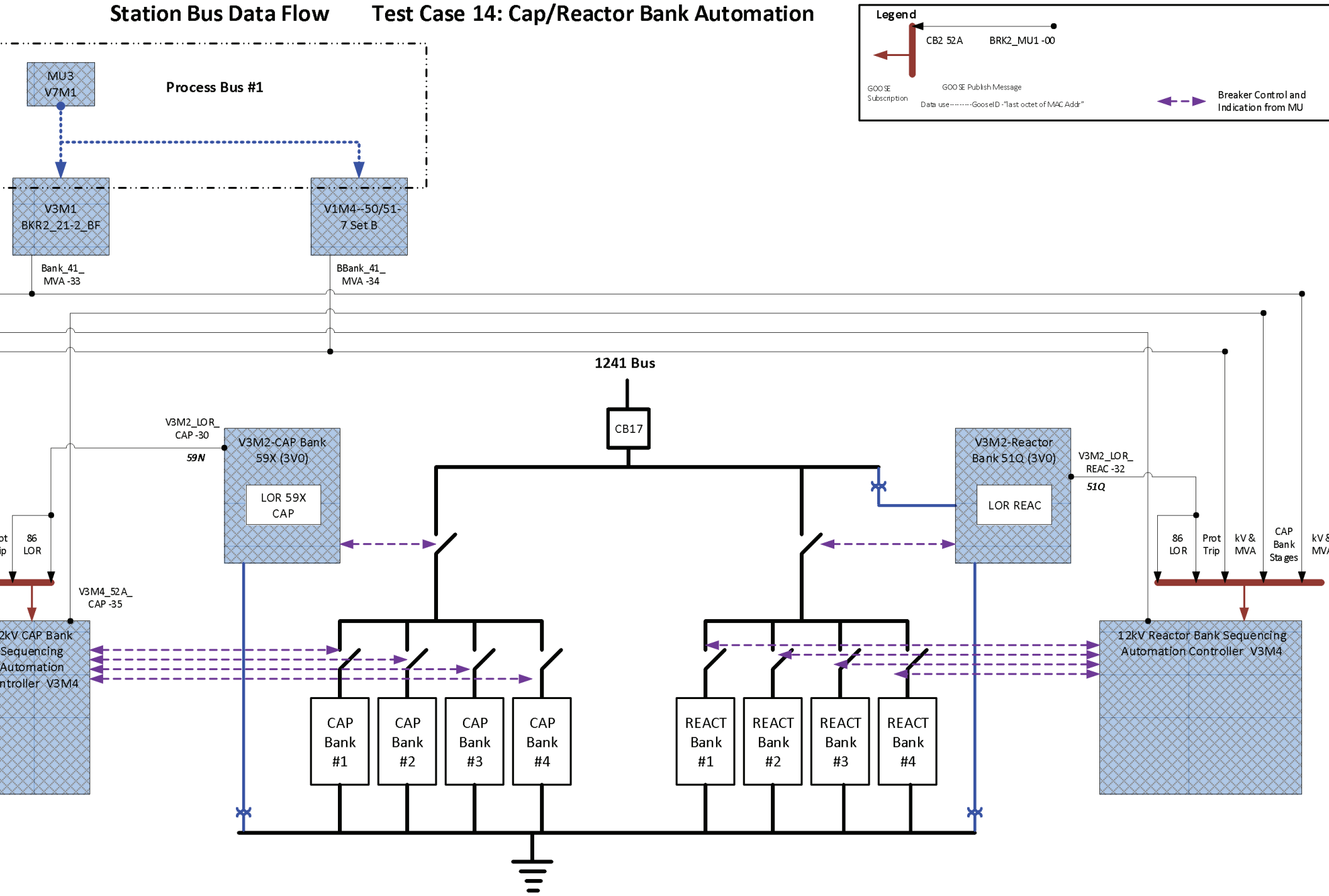
Station Bus Data Flow Test Case 12: Capacitor Bank Unbalance



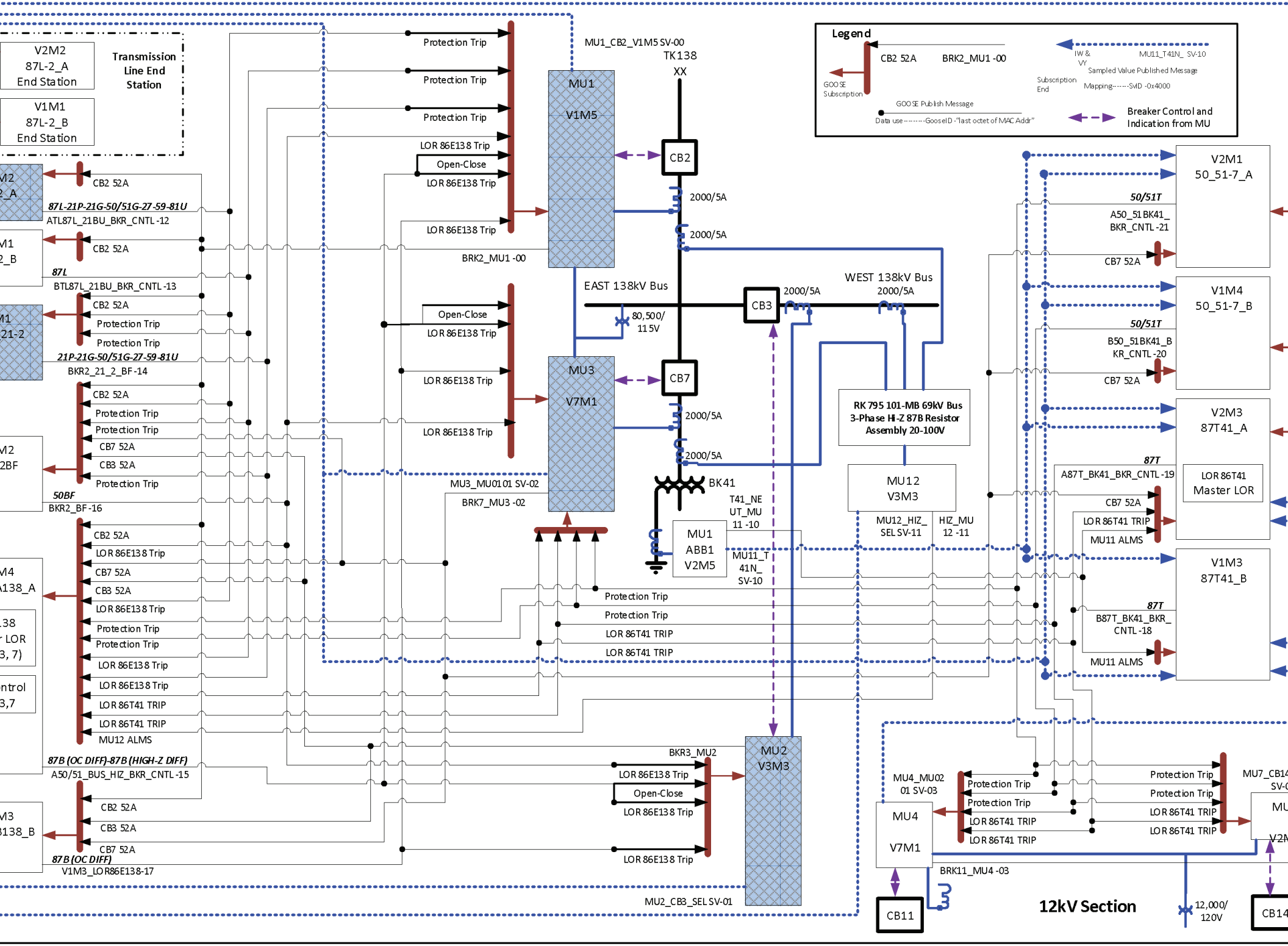
Station Bus Data Flow Test Case 13: Reactor Bank Negative Sequence



Station Bus Data Flow Test Case 14: Cap/Reactor Bank Automation



Process Bus #1 Data Flow Test Case 15: Under Frequency



APPENDIX B - RTDS MODEL DIAGRAM

This Appendix B shows the full system model which was used in the RTDS to develop the test parameters and characteristics for each use case. The model in Figure 42 includes all the breakers, capacitors, reactors, transformers and transmission lines in the test system. This diagram also shows the locations of each fault.

Figure 43 shows the RTDS interface. It allowed the display of the controls for each fault as well as breaker status and test results.

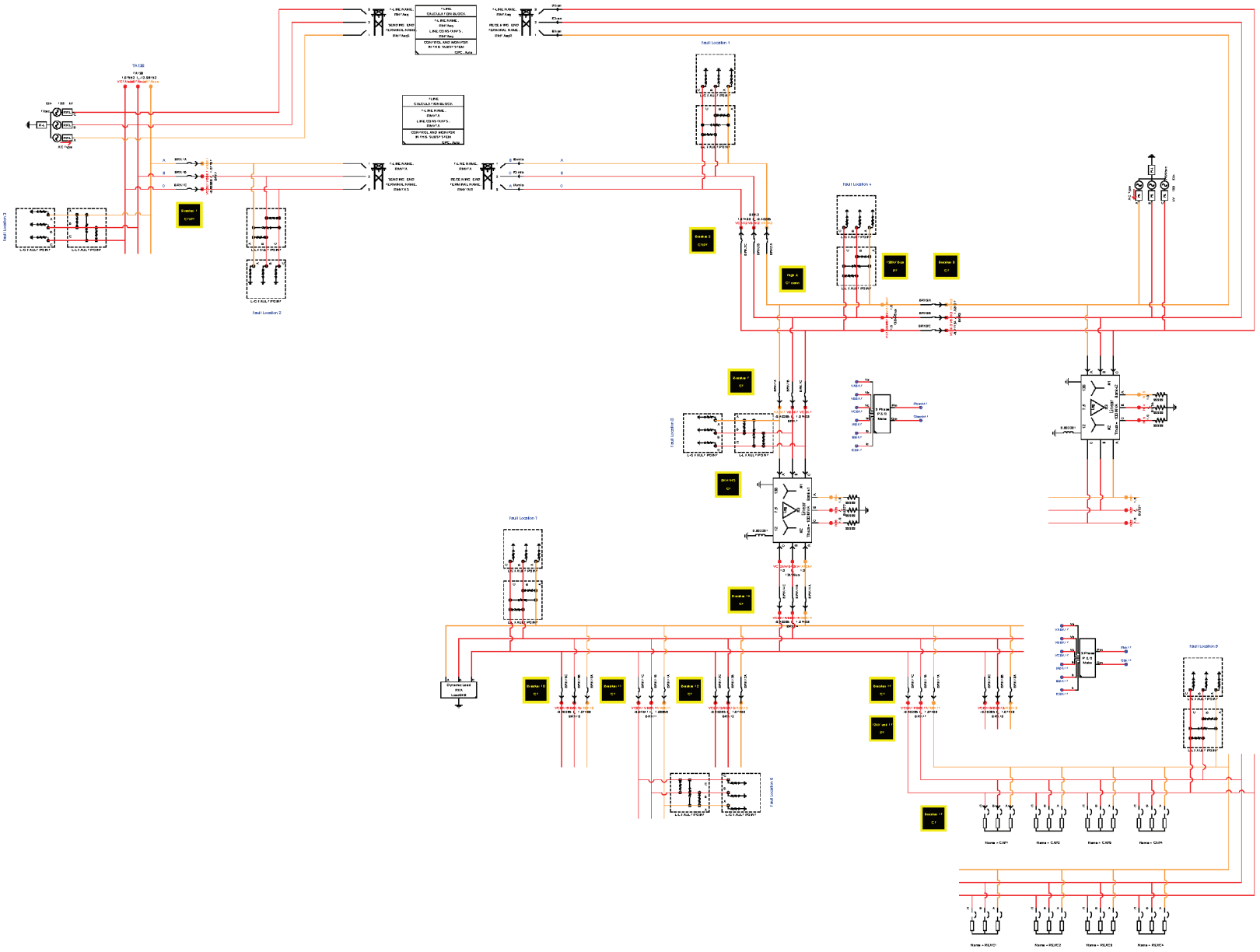


FIGURE 42 RTDS MODEL

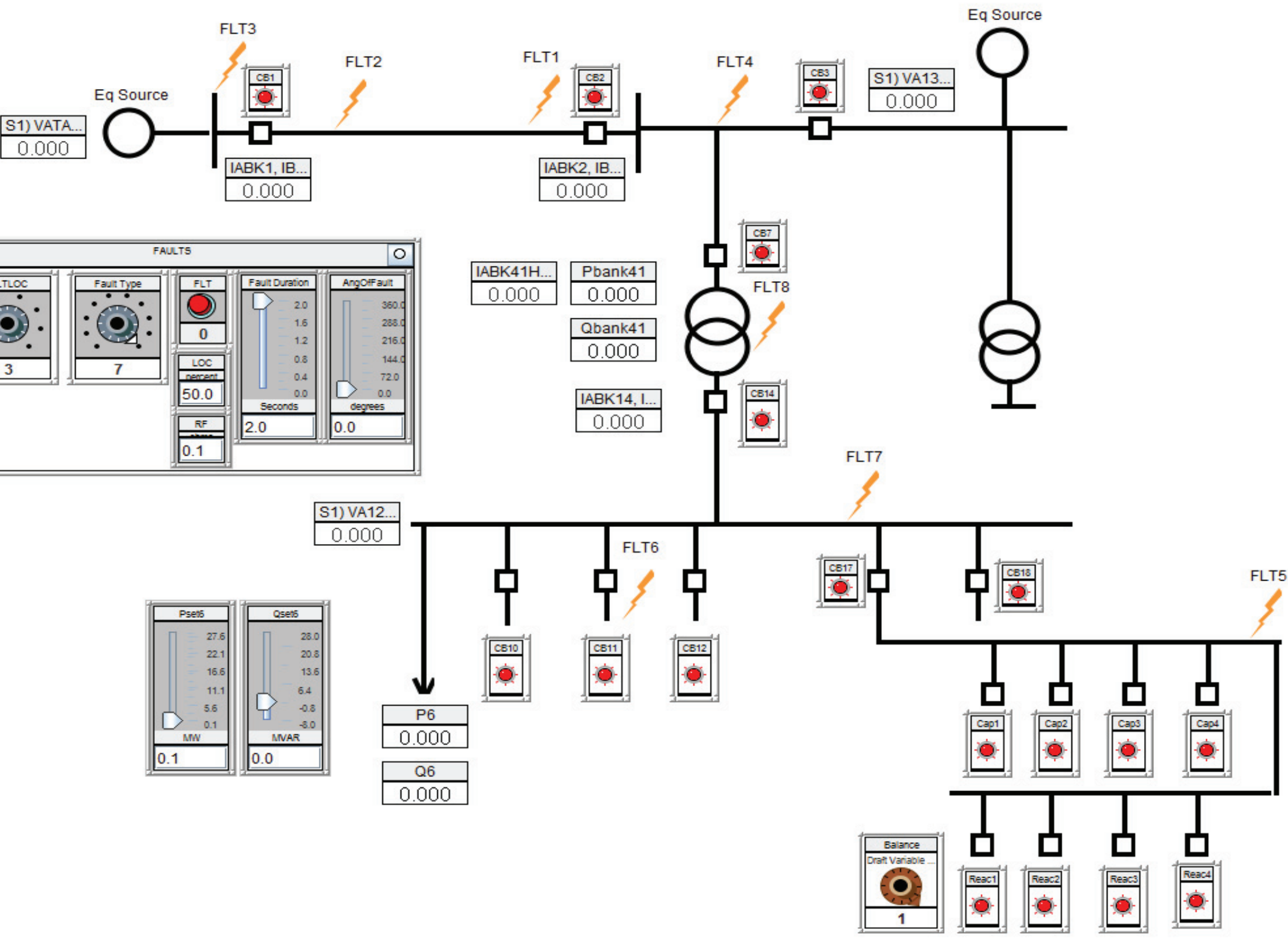
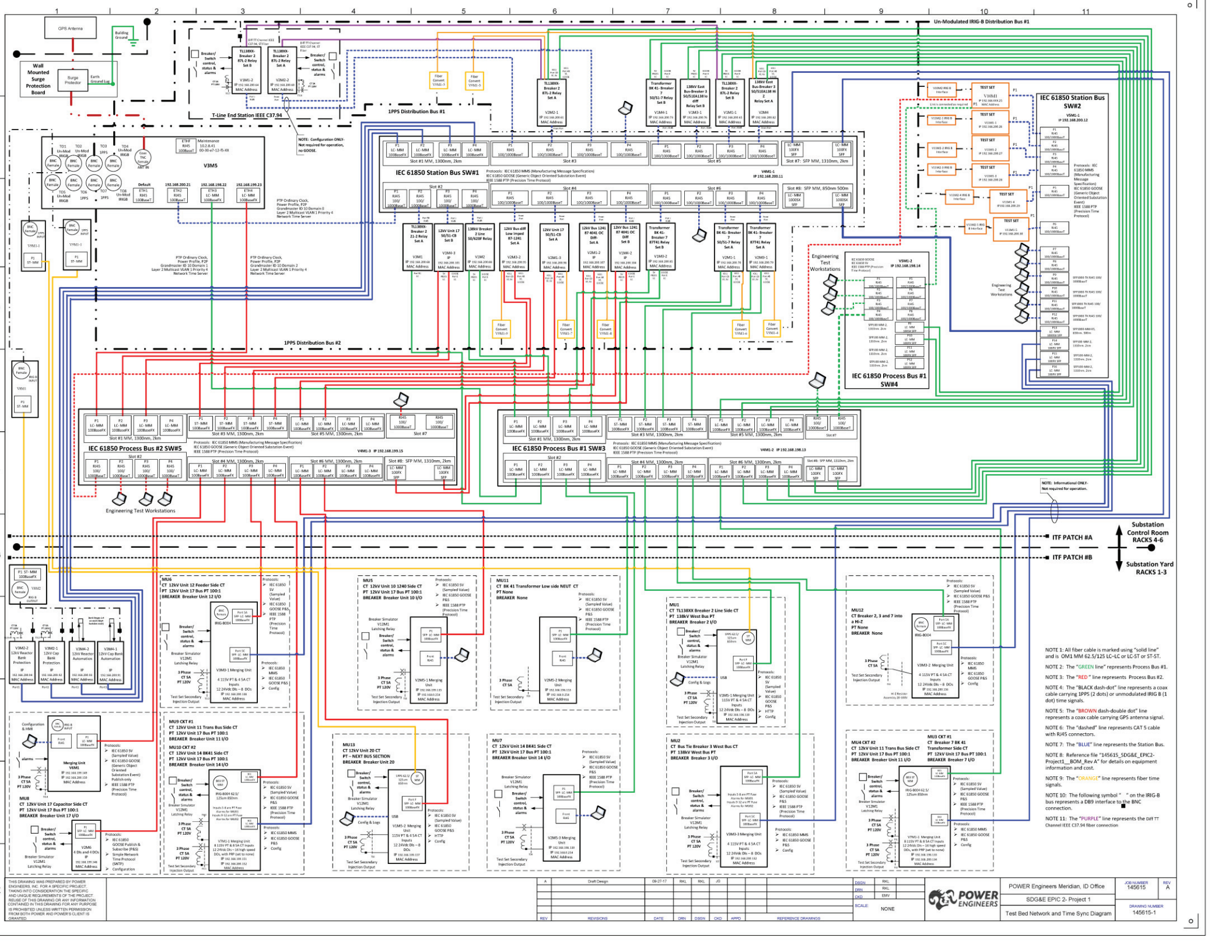


FIGURE 43 RTDS MODEL HMI

APPENDIX C - NETWORK LAYOUT DIAGRAM

The network layout diagram identifies the network connections for each device included in the test system. The diagram includes protection relays, merging units, Ethernet switches and the GPS time clock. In this diagram, the isolated process bus and station bus connections are laid out. These connections are indicated with colored lines to easily and quickly distinguish the networks. Blue lines indicate station bus connections, green lines are bus #1 and red is for process bus #2. The diagram indicates GPS time signals with yellow lines. Also shown in this diagram are the CT/PT sensors and breakers associated with particular merging units. The diagram indicates the physical separation of the substation control shelter and the substation yard with a thick dashed line near the middle of the image.


GPS Antenna
Building Ground
Wall Mounted Surge Protection Board
Surge Protector
Earth Ground Lug
T-Line End Station IEEE C37.94
Un-Modulated IRIG-B Distribution Bus #1
1PPS Distribution Bus #1
1PPS Distribution Bus #2
V3M5
IEC 61850 Station Bus SW#1
IEC 61850 Station Bus SW#2
IEC 61850 Process Bus #1 SW#3
IEC 61850 Process Bus #1 SW#4
IEC 61850 Process Bus #2 SW#5
Engineering Test Workstations
ITF PATCH #A
ITF PATCH #B
Substation Control Room RACKS 4-6
Substation Yard RACKS 1-3
MU6
MU5
MU11
MU12
MU2
MU3 CKT #1
MU4 CKT #2
MU8
MU5 CKT #1
MU10 CKT #2
MU13
MU7
NOTE 1: All fiber cable is marked using "solid line" and is OM1 MM 62.5/125 LC-LC or LC-ST or ST-ST.
NOTE 2: The "GREEN" line" represents Process Bus #1.
NOTE 3: The "RED " line represents Process Bus #2.
NOTE 4: The "BLACK dash-dot" line represents a coax cable carrying 1PPS (2 dots) or unmodulated IRIG B (1 dot) time signals.
NOTE 5: The "BROWN dash-double dot" line represents a coax cable carrying GPS antenna signal.
NOTE 6: The "dashed" line represents CAT 5 cable with RJ45 connectors.
NOTE 7: The "BLUE" line represents the Station Bus.
NOTE 8: Reference file "145615_SDG&E_EPIC2-Project1__BOM_Rev A" for details on equipment information and cost.
NOTE 9: The "ORANGE" line represents fiber time signals.
NOTE 10: The following symbol " " on the IRIG-B bus represents a DB9 interface to the BNC connection.
NOTE 11: The "PURPLE" line represents the Diff TT Channel IEEE C37.94 fiber connection
THIS DRAWING WAS PREPARED BY POWER ENGINEERS, INC. FOR A SPECIFIC PROJECT, TAKING INTO CONSIDERATION THE SPECIFIC AND UNIQUE REQUIREMENTS OF THE PROJECT. REUSE OF THIS DRAWING OR ANY INFORMATION CONTAINED IN THIS DRAWING FOR ANY PURPOSE IS PROHIBITED UNLESS WRITTEN PERMISSION FROM BOTH POWER AND POWER'S CLIENT IS GRANTED
A Draft Design 09-27-17 RKL RKL JO
REV REVISIONS DATE DRN DSGN CKD APPD REFERENCE DRAWINGS
DSGN RKL
DRN RKL
CKD EMV
SCALE: NONE
POWER ENGINEERS
POWER Engineers Meridian, ID Office
SDG&E EPIC 2- Project 1
Test Bed Network and Time Sync Diagram
JOB NUMBER 145615
REV A
DRAWING NUMBER 145615-1

APPENDIX D - IEC61850 MATRIX

This appendix contains the IEC 61850 matrices. The matrix in Table 28 describes the IEDs which were used in the HS and LS use cases. HS cases are indicated with red shading and LS with green shading. This matrix was also used to explain the protection function nomenclature for each protection relay and shows the relay identifiers. In any given row, the control and lock out functions are associated with the relays in that row.

In Table 29, merging units are described with their functional position in the test system. HS cases are indicated with red shading and LS with green shading.

2kV Xfmr BK 41 al (CB 7, 11 & 14) Set _87T41 Set A	V2M3-87T41 Set A	69/138-12kV Xfmr BK 41 Differential (CB 7, 11 & 14) Set A	V2M3	87T41 Set A	LOR 86T41	86T41 Master LOR Relay
East Bus OC/Hi-Z al (CB 2, 3 & 7) Set _50/51EA138 (SET A)	V2M4-50/51EA138 (SET A)	69/138kV East Bus OC/Hi-Z Differential (CB 2, 3 & 7) Set A	V2M4	50/51EA138 (SET A)	LOR 86E138	86E138 Master LOR Relay
East Bus OC/lo-Z al (CB 2, 3 & 7) Set _50/51EB138 (SET B)	V1M3-50/51EB138 (SET B)	69/138kV East Bus OC/lo-Z Differential (CB 2, 3 & 7) Set B	V1M3	50/51EB138 (SET B)	LOR 86E138	---
Breaker Failure (CB M2_50/62BF***	V1M2-50/62BF***	69/138kV Breaker Failure (CB 2)***	V1M2	50/62BF***	LOR 86E138	---
p Bank Sequencing on Controller_V3M4 p Bank V3M4	V3M4 PAC-Cap Bank V3M4	12kV Cap Bank Sequencing Automation Controller	V3M4 PAC	Cap Bank V3M4	---	---
p Bank Voltage e Protection_V3M2 elay_Cap Bank 59X	V3M2 Feeder Relay-Cap Bank 59X (3V0)	12kV Cap Bank Voltage Unbalance Protection	V3M2A Feeder Relay	Cap Bank 59X (3V0)	LOR 59X CAP	59XCAP Master LOR Relay
actor Bank Sequencing on Controller_V3M4 actor Bank V3M4	V3M4 PAC-Reactor Bank V3M4	12kV Reactor Bank Sequencing Automation Controller	V3M4 PAC	Reactor Bank V3M4	---	---
actor Bank Voltage e Protection_V3M2 elay_Reactor Bank 59X	V3M2 Feeder Relay-Reactor Bank 59X (3V0)	12kV Reactor Bank Voltage Unbalance Protection	V3M2A Feeder Relay	Reactor Bank 59X (3V0)	LOR 59X REAC	59XREAC Master LOR Relay
n Bus Overall Low ce Bus Differential Bs 10, 11, 12, 14, 17 & 3_87-1241	V2M3-87-1241	12kV Main Bus Overall Low Impedance Bus Differential (Wraps CBs 10, 11, 12, 14, 17 & 20)	V2M3	87-1241	LOR 86B1241	86B1241 Master LOR Relay
active Feeder ent (CB 17) Set _50/51-CB (Set A)	V2M1-50/51-CB17 (Set A)	12kV Reactive Feeder Overcurrent (CB 17) Set A	V2M1	50/51-CB 17(Set A)	---	---
active Feeder ent (CB 17) Set _50/51-CB (Set B)	V1M4-50/51-CB17 (Set B)	12kV Reactive Feeder Overcurrent (CB 17) Set B	V1M4	50/51-CB17 (Set B)	---	---
n Bus Partial ent Differential Set B Bs 10, 14 & 1M4_50/51-1241 (Set	V1M4-50/51-1241 (Set B)****	12kV Main Bus Partial Overcurrent Differential Set B (Wraps CBs 10, 14 & 20)	V1M4	50/51-1241 (Set B)	---	---
n Bus Partial ent Differential Set A Bs 10, 14 & 2M1_50/51-1241 (Set	V2M1-50/51-1241 (Set A)****	12kV Main Bus Partial Overcurrent Differential Set A (Wraps CBs 10, 14 & 20)	V2M1	50/51-1241 (Set A)	---	---

Process Bus 1 High Side Use Cases

Process Bus 2 Low Side Use Cases

U3- 69/138-12kV Xfmr BK 41 CB 7 _V7M1 #1 CKT 1	MU3- 69/138-12kV Xfmr BK 41 CB 7	V7M1 #1 CKT 1
U4- 12kV Xfer Bus CB 11_V7M1 #1 CKT 2	MU4- 12kV Xfer Bus CB 11	V7M1 #1 CKT 2
U5- 12kV Swgr 1240 Bus Tie CB 10_V2M5	MU5- 12kV Swgr 1240 Bus Tie CB 10	V2M5
U6- 12kV Feeder CB 12_V3M3	MU6- 12kV Feeder CB 12	V3M3
U7- 69/138-12kV Xfmr BK41 CB 14_V2M5	MU7- 69/138-12kV Xfmr BK41 CB 14	V2M5
U8a- 12kV Reactive Feeder CB 17_V2M6	MU8a- 12kV Reactive Feeder CB 17	V2M6
U8b- 12kV Reactive Feeder CB 17_V6M1	MU8b- 12kV Reactive Feeder CB 17	V6M1
U9- 12kV Xfer Bus CB 11 _V7M1 #2 CKT 1	MU9- 12kV Xfer Bus CB 11	V7M1 #2 CKT 1
U10- 69/138-12kV Xfmr BK41 CB 14_V7M1 #2 CKT 2	MU10- 69/138-12kV Xfmr BK41 CB 14	V7M1 #2 CKT 2
U11- 69/138-12kV Xfmr BK 41 12kV Neutral CT_V2M5	MU11- 69/138-12kV Xfmr BK 41 12kV Neutral CT	V2M5
U12- 69/138kV E. Bus 87B Hi-Z Resistor_V3M3	MU12- 69/138kV E. Bus 87B Hi-Z Resistor	V3M3
U13- 12kV Swgr 1242 Bus Tie CB 20_V1M5 #2	MU13- 12kV Swgr 1242 Bus Tie CB 20	V1M5 #2
	Process Bus 1 High Side Use Cases	
	Process Bus 2 Low Side Use Cases	

APPENDIX E - IEC61850 DATA FLOW SPREADSHEETS

Appendix E contains the IEC61850 dataflow spreadsheets. Analogous to a wiring schematic, this spreadsheet details each message being used in the test system. Because the messages could become numerous and unwieldy, the spreadsheet is necessarily large. For each network bus, the spreadsheet is divided into two sections; one for SV messages and one for GOOSE messages. Publishing IEDs are listed along the far left column, and subscribing IEDs are listed along the top. Details of each message are listed in the middle.

This spreadsheet provides details about each IED, such as system functional position, CT/PT ratios, measurement and control points. SV and GOOSE control blocks are detailed with the broadcast MAC address, VLAN ID, VLAN priority, Application ID (APP ID) and message ID. Each index of the message is then detailed moving across the spreadsheet from left to right. The IEC 61850 standard defines sampled values message structure, and as such, these messages were identical. GOOSE messages were configured specifically for their individual purpose. Logic nodes, logical devices, data objects and data attributes are all defined in this spreadsheet. In the subscribing IEDs section of the spreadsheet, to the far right, subscribers to certain messages are indicated by a 'Yes' in the cell. If a device is not subscribing to a message, that cell was grayed out. The data flow tables are further described in Section 9.

TABLE 30 PROCESS BUS #1 DATA FLOW SPREADSHEET

SV Control Block and referenced dataset information

	MAC Address	VLAN ID	VLAN-PRIORITY	App ID (hex)	SmpRate (sample/cycle)	MsvID	Dataset Name	Dataset Index 1	Dataset Index 2	Dataset Index 3	Dataset Index 4	Dataset Index 5	Dataset Index 6	Dataset Index 7	Dataset Index 8	Dataset Index 9	Dataset Index 10	Dataset Index 11	Dataset Index 12	Dataset Index 13	Dataset Index 14	Dataset Index 15	Dataset Index 16	Dataset Index 14	Dataset Index 15	Dataset Index 16	Dataset Index 16
o	01-0C-CD-04-00-00	1	4	0x4000	80	MU1_CB2_V IM5	PhsMeas1	PhA_Amps.instMag.i	PhA_Amps.q	PhB_Amps.instMag.i	PhB_Amps.q	PhC_Amps.instMag.i	PhC_Amps.q	NEUT Amps.instMag.i	NEUT Amps.q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	NEUT Volts-Vol.q
o	01-0C-CD-04-00-01	1	4	0x4000	80	MU2_CB3_V 3	PhsMeas1	PhA_Amps.instMag.i	PhA_Amps.q	PhB_Amps.instMag.i	PhB_Amps.q	PhC_Amps.instMag.i	PhC_Amps.q	NEUT Amps.instMag.i	NEUT Amps.q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	NEUT Volts-Vol.q
o	01-0C-CD-04-00-02	1	4	0x4000	80	MU3_MU0101	PhsMeas1	PhA_Amps.instMag.i	PhA_Amps.q	PhB_Amps.instMag.i	PhB_Amps.q	PhC_Amps.instMag.i	PhC_Amps.q	NEUT Amps.instMag.i	NEUT Amps.q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	NEUT Volts-Vol.q
o	01-0C-CD-04-00-03	1	4	0x4000	80	MU4_MU0201	PhsMeas1	PhA_Amps.instMag.i	PhA_Amps.q	PhB_Amps.instMag.i	PhB_Amps.q	PhC_Amps.instMag.i	PhC_Amps.q	NEUT Amps.instMag.i	NEUT Amps.q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	NEUT Volts-Vol.q
o	01-0C-CD-04-00-06	1	4	0x4000	80	MU7_CB14_V2	PhsMeas1	PhA_Amps.instMag.i	PhA_Amps.q	PhB_Amps.instMag.i	PhB_Amps.q	PhC_Amps.instMag.i	PhC_Amps.q	NEUT Amps.instMag.i	NEUT Amps.q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	NEUT Volts-Vol.q
o	01-0C-CD-04-00-10	1	4	0x4000	80	MU11_T41N_V2	PhsMeas1	PhA_Amps.instMag.i	PhA_Amps.q	PhB_Amps.instMag.i	PhB_Amps.q	PhC_Amps.instMag.i	PhC_Amps.q	NEUT Amps.instMag.i	NEUT Amps.q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	NEUT Volts-Vol.q
o	01-0C-CD-04-00-11	1	4	0x4000	80	MU12_HIZ_V3	PhsMeas1	PhA_Amps.instMag.i	PhA_Amps.q	PhB_Amps.instMag.i	PhB_Amps.q	PhC_Amps.instMag.i	PhC_Amps.q	NEUT Amps.instMag.i	NEUT Amps.q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	NEUT Volts-Vol.q

Subscribing IEDs

Dataset Index 16	V2M2**--87L-2 Set A	V1M1**--87L-2 Set B	V3M1--21-2	V2M1--50/51-7 Set A	V1M4--50/51-7 Set B	V1M3--87T41 Set B	V2M3--87T41 Set A	V2M4-50/51EA138(SET A)
NEUT Volts-Vol.q	YES	YES						YES
NEUT Volts-Vol.q			YES (IW & VY)					YES
NEUT Volts-Vol.q			YES (IX & VZ)	YES	YES	YES	YES	YES
NEUT Volts-Vol.q	YES	YES				YES	YES	
NEUT Volts-Vol.q						YES	YES	
NEUT Volts-Vol.q				YES	YES	YES	YES	
NEUT Volts-Vol.q			YES (IV & VX)					YES

GOOSE Control Block and referenced dataset information

s	VLAN ID	VLAN-PRIORITY	App ID (hex)	Min Trime (ms)	Heatbeat Rate, Max time (ms)	Control Block Name and GoID	Dataset Name	Dataset Index 1	Dataset Index 2	Dataset Index 3	Dataset Index 4	Dataset Index 5	Dataset Index 6	Dataset Index 7	Dataset Index 8	Dataset Index 9	Dataset Index 10	Dataset Index 11	Dataset Index 12	Dataset Index 13	Dataset Index 14	Dataset Index 15	Dataset Index 16	Dataset Index 17
0-00	1	4	0x0000	4	500	BRK2_MU1	CB2_52A	GGIO1.SPCS01.stVal (Input 1-52a)	GGIO1.SPCS01.q (Input 1-52a)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
0-01	1	4	0x0001	4	1000	BRK3_MU2	CB3_52A	ANN.IN2GGIO14.Ind01.stVal (Input 1- 52a)	ANN.IN2GGIO14.Ind01.q (Input 1- 52a)	ANN.IN2GGIO14.Ind02.stVal (VT Fuse Fail A)	ANN.IN2GGIO14.Ind02.q (VT Fuse Fail A)	ANN.IN2GGIO14.Ind03.stVal (VT Fuse Fail B)	ANN.IN2GGIO14.Ind03.q (VT Fuse Fail B)	ANN.IN2GGIO14.Ind04.stVal (VT Fuse Fail C)	ANN.IN2GGIO14.Ind04.q (VT Fuse Fail C)	-----	-----	-----	-----	-----	-----	-----	-----	-----
0-02	1	4	0x0002	20	1000	BRK7_MU3	MU3_STATUS	CTRL/BININGGIO1.Ind1.stVal (CB7 52A)	CTRL/BININGGIO1.Ind1.q (CB7 52A)	CTRL/BININGGIO1.Ind2.stVal	CTRL/BININGGIO1.Ind2.q	CTRL/BININGGIO1.Ind3.stVal (CB7 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind3.q (CB7 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind4.stVal (CB7 1241 UNIT 17 PT PHB FUSE)	CTRL/BININGGIO1.Ind4.q (CB7 1241 UNIT 17 PT PHB FUSE)	CTRL/BININGGIO1.Ind5.stVal (CB7 1241 UNIT 17 PT PHC FUSE)	CTRL/BININGGIO1.Ind5.q (CB7 1241 UNIT 17 PT PHC FUSE)	CTRL/BININGGIO1.Ind6stVal (CB7 1241 UNIT 17 PT NEU FUSE)	CTRL/BININGGIO1.Ind6.q (CB7 1241 UNIT 17 PT NEU FUSE)	-----	-----	-----	-----	-----
0-03	1	4	0x0003	20	500	BRK11_MU4	MU4_STATUS	CTRL/BININGGIO1.Ind7.stVal (CB11 52A)	CTRL/BININGGIO1.Ind7.q (CB11 52A)	CTRL/BININGGIO1.Ind8.stVal	CTRL/BININGGIO1.Ind8.q	CTRL/BININGGIO1.Ind9.stVal (CB11 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind9.q (CB11 1241 UNIT 11 PT PHA FUSE)	CTRL/BININGGIO1.Ind10.stVal (CB11 1241 UNIT 11 PT PHB FUSE)	CTRL/BININGGIO1.Ind10.q (CB11 1241 UNIT 11 PT PHB FUSE)	CTRL/BININGGIO1.Ind11.stVal (CB11 1241 UNIT 11 PT PHC FUSE)	CTRL/BININGGIO1.Ind11.q (CB11 1241 UNIT 11 PT PHC FUSE)	CTRL/BININGGIO1.Ind12stVal (CB11 1241 UNIT 11 PT NEU FUSE)	CTRL/BININGGIO1.Ind12.q (CB11 1241 UNIT 11 PT PNEU FUSE)	-----	-----	-----	-----	-----
0-39	1	4	0x0027	1	1000	MU3_MU4_FASTGOOSE_FIXED	DigInput	CTRL/BININGGIO1.Ind1.stVal (CB7 52A)	CTRL/BININGGIO1. Ind2.stVal	CTRL/BININGGIO1.Ind3.stVal (CB7 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind4.stVal (CB7 1241 UNIT 17 PT PHB FUSE)	CTRL/BININGGIO1.Ind5. stVal (CB7 1241 UNIT 17 PT PHC FUSE)	CTRL/BININGGIO1.Ind6stVal (CB7 1241 UNIT 17 PT NEU FUSE)	CTRL/BININGGIO1.Ind7.stVal (CB11 52A)	CTRL/BININGGIO1.Ind8.stVal	CTRL/BININGGIO1.Ind9stVal (CB11 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind10.stVal (CB11 1241 UNIT 11 PT PHB FUSE)	CTRL/BININGGIO1.Ind11.stVal (CB11 1241 UNIT 11 PT PHC FUSE)	CTRL/BININGGIO1.Ind12stVal (CB11 1241 UNIT 11 PT NEU FUSE)	-----	-----	-----	-----	-----
0-06	1	4	0x0006	4	500	BRK14_MU7	CB14_52A	MVGAPC1.Ind1.stVal (CB 14 52A)	MVGAPC1.Ind1.q (CB 14 52A)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
0-10	1	4	0x000A	4	10000	T41_NEUT_MU11	ALARM	LLN0.Health.stVal (internal alarm)	LLN0.Health.q (internal alarm)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
0-11	1	4	0x000B	4	500	HIZ_MU12	HIZ_AL	ANN.PLTGGIO2.Ind01.stVal (alarm point, PB1 toggles)	ANN.PLTGGIO2.Ind01.q (Alarm point, PB1 toggles)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
0-12	1	4	0x000C	4	500	ATL87L_21BU_BKR_CNTL	TRIP	CTRL/SMPPTRC1.Op.general (Trip CB 2)	CTRL/SMPPTRC1.Op.q (Trip CB 2)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
0-13	1	4	0x000D	4	500	BTL87L_21BU_BKR_CNTL	DataSet	LPHD0.SPS1.stVal (Trip CB 2)	LPHD0.SPS1.q (Trip CB 2)	LPHD0.SPS2.stVal (FUTURE)	LPHD0.SPS2.q (FUTURE)	LPHD0.SPS.stVal (FUTURE)	LPHD0.SPS.q (FUTURE)	-----	-----	-----	-----	-----	-----	-----	-----	-----
0-14	1	4	0x000E	4	500	BKR2_21_2_BF	TRIP_BF	PRO.TRPPTRC1.Tr.general (21 Trip CB 2)	PRO.TRPPTRC1.Tr.q (21 Trip CB 2)	PRO.BFR1RBRF1.Opln.q (FUTURE)	PRO.BFR1RBRF1.Opln.t (FUTURE)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
0-21	1	4	0x0015	4	500	A50_51BK41_BKR_CNTL	TRIP	MON/SP16GAPC1.Ind1.stVal (Trip CB 7)	MON/SP16GAPC1.Ind1.q (Trip CB 7)	MON/SP16GAPC1.Ind2.stVal (Trip CB Unit 11)	MON/SP16GAPC1. Ind2.q (Trip CB Unit 11)	MON/SP16GAPC1.Ind3.stVal (Trip CB Unit 14)	MON/SP16GAPC1.Ind 3.q (Trip CB Unit 14)	-----	-----	-----	-----	-----	-----	-----	-----	-----
0-20	1	4	0x0014	4	500	B50_51BK41_BKR_CNTL	DataSet	.stVal (Trip CB 7)	.q (Trip CB 7)	stVal (Trip CB Unit 11)	.q (Trip CB Unit 11)	.stVal (Trip CB Unit 14)	.q (Trip CB Unit 14)	-----	-----	-----	-----	-----	-----	-----	-----	-----
0-18	1	4	0x0012	4	500	B87T_BK41_BKR_CNTL	DataSet	.stVal (Trip CB 7)	.q (Trip CB 7)	stVal (Trip CB Unit 11)	.q (Trip CB Unit 11)	.stVal (Trip CB Unit 14)	.q (Trip CB Unit 14)	-----	-----	-----	-----	-----	-----	-----	-----	-----
0-19	1	4	0x0013	4	500	A87T_BK41_BKR_CNTL	TRIP	MON/SP16GAPC1.Ind1.stVal (Trip CB 7)	MON/SP16GAPC1.Ind1.q (Trip CB 7)	MON/SP16GAPC1.Ind2.stVal (Trip CB Unit 11)	MON/SP16GAPC1. Ind2.q (Trip CB Unit 11)	MON/SP16GAPC1.Ind3.stVal (Trip CB Unit 14)	MON/SP16GAPC1.Ind 3.q (Trip CB Unit 14)	-----	-----	-----	-----	-----	-----	-----	-----	-----
0-15	1	4	0x000F	4	500	A50/51_BUS_HIZ_BKR_CNTL	TRIP_CLS	MON/SP16GAPC1.Ind1.stVal (Open CB 2)	MON/SP16GAPC1.Ind1.q (Open CB 2)	MON/SP16GAPC1.Ind2.stVal (Close CB 2)	MON/SP16GAPC1. Ind2.q (Close CB 2)	MON/SP16GAPC1.Ind3.stVal (Open CB Unit 7)	MON/SP16GAPC1.Ind 3.q (Open CB Unit 7)	MON/SP16GAPC1.Ind4.stVal (Close CB Unit 7)	MON/SP16GAPC1.Ind4.q (Close CB Unit 7)	MON/SP16GAPC1.Ind5. stVal (Open CB Unit 3)	MON/SP16GAPC1.Ind5.q (Open CB Unit 3)	MON/SP16GAPC1.Ind6.stVal (Close CB Unit 3)	MON/SP16GAPC1. Ind6.q (Close CB Unit 3)	MON/SP16GAPC1.Ind7.stVal (LOR86E138 Trip 2,3,7)	MON/SP16GAPC1.Ind7.q (LOR86E138 Trip 2, 3 7)	MON/SP16GAPC1.Ind8.stVal (LOR86E138 Trip 2,3,7)#2	MON/SP16GAPC1.Ind8.q (LOR86E138 Trip 2,3,7) #2	-----
0-17	1	4	0x0011	4	500	V1MB_LOR86E138	DataSet	.stVal (CB3 Pro Trip)	.q ((CB3 Pro Trip)	stVal (LOR86E138 Trip 2,3,7)	.q (LOR86E138 Trip 2,3,7)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
0-16	1	4	0x0010	4	500	BKR2__BF	DataSet	RBRF1.OpEx.general (LOR86E138 BF Trip 2,3, 7)	RBRF1.OpEx.q (LOR86E138 BF Trip 2,3,7)	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----

Subscribing IEDs

Dataset Index 17	V2M2**--87L-2 Set A	V1M1**--87L-2 Set B	V3M1--21-2	V2M1--50/51-7 Set A	V1M4--50/51-7 Set B	V1M3--87T41 Set B	V2M3--87T41 Set A	V2M4-50/51EA138 (SET A)	V1M3--50/51EB138 (SET B)	V0M2--50/62BF	MU3--69/138kV Line CB 2_V1M5 #1
-----	YES	YES	YES					YES	YES	YES	
-----								YES	YES	YES	
-----				YES	YES		YES	YES	YES	YES	
-----				YES	YES		YES				
-----				YES	YES		YES				
-----						YES					
-----			YES					YES		YES	YES (TRIP Output #1)
-----			YES					YES		YES	YES (TRIP Output #1)
-----								YES		YES	YES (TRIP Output #1)
-----								YES			
-----						YES		YES (Block CB7 Close)			
-----								YES (Block CB7 Close)			
-----											YES (TRIP Output #1, Close Output #2)
-----								YES			YES (TRIP Output #1)
-----								YES			YES (TRIP Output #1)

TABLE 9 PROCESS BUS #2 DATA FLOW SPREADSHEET

SV Control Block and referenced dataset information																							Subscribing IEDs				
ent	MAC Address	VLAN ID	VLAN-PRIORITY	App ID (hex)	SmpRate	MsvID (Note 1) xxxxMUnn01	Dataset Name	Dataset index 1	Dataset index 2	Dataset index 3	Dataset index 4	Dataset index 5	Dataset index 6	Dataset index 7	Dataset index 8	Dataset index 9	Dataset index 10	Dataset index 11	Dataset index 12	Dataset index 13	Dataset index 14	Dataset index 15	Dataset index 16	V2MB - 87-1241 A	V2M1 - 50/51-CB17 (CAPS) A	V1M4 - 50/51-CB17 (CAPS) B	V1M4 - 50/51-BT4041 B	V2M1 - 50/51-BT4041 A
D ratio	01-0C-CD-04-00-04	1	4	0x4000	80	MU5_CB10_V2	PhsMeas1	PhA_Amps.instMag.i	PhA_Amps.q	PhB_Amps.instMag.i	PhB_Amps.q	PhC_Amps.instMag.i	PhC_Amps.q	NEUT Amps.instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	YES			YES	YES
D ratio	01-0C-CD-04-00-05	1	4	0x4000	80	MU6_CB12_V3	PhsMeas1	PhA_Amps.instMag.i	PhA_Amps.q	PhB_Amps.instMag.i	PhB_Amps.q	PhC_Amps.instMag.i	PhC_Amps. q	NEUT Amps.instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	YES				
D ratio	01-0C-CD-04-00-07	1	4	0x4000	80	MU8_CB17_V6	PhsMeas1	PhA_Amps.instMag.i	PhA_Amps.q	PhB_Amps.instMag.i	PhB_Amps.q	PhC_Amps.instMag.i	PhC_Amps. q	NEUT Amps.instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	YES	YES	YES		
D ratio	01-0C-CD-04-00-08	1	4	0x4000	80	MU9_MU0101	PhsMeas1	PhA_Amps.instMag.i	PhA_Amps.q	PhB_Amps.instMag.i	PhB_Amps.q	PhC_Amps.instMag.i	PhC_Amps. q	NEUT Amps.instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	YES				
D ratio	01-0C-CD-04-00-09	1	4	0x4000	80	MU10_MU0201	PhsMeas1	PhA_Amps.instMag.i	PhA_Amps.q	PhB_Amps.instMag.i	PhB_Amps.q	PhC_Amps.instMag.i	PhC_Amps. q	NEUT Amps.instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	YES			YES	YES
D ratio	01-0C-CD-04-00-12	1	4	0x4000	80	MU13_CB20_V3M5	PhsMeas1	PhA_Amps.instMag.i	PhA_Amps.q	PhB_Amps.instMag.i	PhB_Amps.q	PhC_Amps.instMag.i	PhC_Amps. q	NEUT Amps.instMag.i	NEUT Amps. q	PhA Volts-Vol.instMag.i	PhA Volts-Vol.q	PhB Volts-Vol.instMag.i	PhB Volts-Vol.q	PhC Volts-Vol.instMag.i	PhC Volts-Vol.q	NEUT Volts-Vol.instMag.i	NEUT Volts-Vol.q	YES			YES	YES

GOOSE Control Block and referenced dataset information																															Subscribing IEDs			
ddress	VLAN ID	VLAN-PRIORITY	App ID (hex)	Min Time (ms)	Heatbeat Rate, Max time (ms)	Control Block Name and GoID	Dataset Name	Dataset index 1	Dataset index 2	Dataset index 3	Dataset index 4	Dataset index 5	Dataset index 6	Dataset index 7	Dataset index 8	Dataset index 9	Dataset index 10	Dataset index 11	Dataset index 12	Dataset index 13	Dataset index 14	Dataset index 15	Dataset index 16	Dataset index 17	Dataset index 18	Dataset index 19	Dataset index 20	Dataset index 21	Dataset index 22	Dataset index 23	Dataset index 24	Dataset index 25	V2MB - 87-1241 A	V2M1 - 50/51-CB (CAPS) A	V1M4 - 50/51-CB (CAPS) B	V1M4 - 50/51-BT 4041 B
-01-00-04	1	4	0x0004	4	500	BRK10_MU5	CB10_52A	MVGAPC1.SPCSO1.stVal (Input 1- CB 10 52a)	MVGAPC1.SPCSO1.q (Input 1- CB 10 52a)	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	YES			YES
-01-00-05	1	4	0x0005	4	500	BRK12_MU6	BKR12_MU6	ANN.IN2GGIO14_Ind01.stVal (Input 1- 52a)	ANN.IN2GGIO14_Ind01.q (Input 1- 52a)	ANN.IN2GGIO14_Ind02.stVal (VT Fuse Fail A)	ANN.IN2GGIO14_Ind02.q (VT Fuse Fail A)	ANN.IN2GGIO14_Ind03.stVal (VT Fuse Fail B)	ANN.IN2GGIO14_Ind03.q (VT Fuse Fail B)	ANN.IN2GGIO14_Ind04.stVal (VT Fuse Fail C)	ANN.IN2GGIO14_Ind04.q (VT Fuse Fail C)	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	YES			
-01-00-07	1	4	0x0007	4	500	BRK17_MU8	CB17_52A	SCMLGGIO1.Ind1.stVal (Input 1- CB17 52a)	SCMLGGIO 1.Ind1.q (Input 1- CB17 52a)	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	YES	YES	YES	
-01-00-08	1	4	0x0008	10	500	CTPT Alarm UNIT 17-MU8	gcb01	GGIO 1.Ind1.stVal (internal alarm)	GGIO 1.Ind1.q (internal alarm)	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	YES	YES	YES	
-01-00-09	1	4	0x0009	20	500	BRK11_MU9	BKR11_MU9	CTRL/BININGGIO 1.Ind1.stVal (CB11 52A)	CTRL/BININGGIO1.Ind1.q (CB11 52A)	CTRL/BININGGIO1.Ind2.stVal	CTRL/BININGGIO 1. Ind2.q	CTRL/BININGGIO1.Ind3.stVal (CB11 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind3.q (CB11 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind4.stVal (CB11 1241 UNIT 17 PT PHB FUSE)	CTRL/ BININGGIO1.Ind4.q (CB 11 1241 UNIT 17 PT PHB FUSE)	CTRL/BININGGIO1.Ind5.stVal (CB11 1241 UNIT 17 PT PHC FUSE)	CTRL/BININGGIO 1. Ind5.q (CB11 1241 UNIT 17 PT PHC FUSE)	CTRL/BININGGIO 1.Ind6stVal (CB11 1241 UNIT 17 PT NEU FUSE)	CTRL/BININGGIO1.Ind6.q (CB7 1241 UNIT 17 PT NEU FUSE)	----	----	----	----	----	----	----	----	----	----	----	----	----	YES			
-01-00-22	1	4	0x0016	20	500	BRK14_MU10	BKR14_MU10	CTRL/BININGGIO 1.Ind7.stVal (CB14 52A)	CTRL/ BININGGIO1.Ind7.q (CB14 52A)	CTRL/BININGGIO1.Ind8.stVal	CTRL/BININGGIO 1. Ind8.q	CTRL/BININGGIO 1.Ind9stVal (CB14 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind9.q (CB14 1241 UNIT 11 PT PHA FUSE)	CTRL/BININGGIO 1.Ind10.stVal (CB14 1241 UNIT 11 PT PHB FUSE)	CTRL/ BININGGIO1.Ind10.q (CB 14 1241 UNIT 11 PT PHB FUSE)	CTRL/BININGGIO 1.Ind11.stVal (CB14 1241 UNIT 11 PT PHC FUSE)	CTRL/BININGGIO 1.Ind11.q (CB14 1241 UNIT 11 PT PHC FUSE)	CTRL/BININGGIO1.Ind12stVal (CB 14 1241 UNIT 11 PT NEU FUSE)	CTRL/BININGGIO1.Ind12.q (CB14 1241 UNIT 11 PT PNEU FUSE)	----	----	----	----	----	----	----	----	----	----	----	----	----	YES			YES
-01-00-40	1	4	0x0028	1	500	gooseID	DigInput	CTRL/BININGGIO 1.Ind1.stVal (CB11 52A)	CTRL/BININGGIO1.Ind2.stVal	CTRL/BININGGIO1.Ind3.stVal (CB11 1241 UNIT 17 PT PHA FUSE)	CTRL/BININGGIO1.Ind4.stVal (CB11 1241 UNIT 17 PT PHB FUSE)	CTRL/BININGGIO1.Ind5.stVal (CB11 1241 UNIT 17 PT PHC FUSE)	CTRL/BININGGIO1.Ind6stVal (CB11 1241 UNIT 17 PT NEU FUSE)	CTRL/BININGGIO1.Ind7.stVal (CB14 52A)	CTRL/BININGGIO1.Ind8.stVal	CTRL/BININGGIO1.Ind9.stVal (CB14 1241 UNIT 17 P T PHA FUSE)	CTRL/BININGGIO1.Ind10.q stVal (CB14 1241 UNIT 11 PT PHB FUSE)	CTRL/BININGGIO1.Ind11.stVal (CB 14 1241 UNIT 11 PT PHC FUSE)	CTRL/BININGGIO1.Ind12stVal (CB141241 UNIT 11 PT NEU FUSE)	----	----	----	----	----	----	----	----	----	----	----	----	----	YES			YES
-01-00-23	1	4	0x0017	4	500	Control_DataSet / MU13_CB20	DataSet	GGIO.SPCSO1.stVal (Input 1- CB20 52a)	GGIO. SPCSO1.q (Input 1- CB20 52a)	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	YES			YES
-04-00-24	1	4	0x0018	4	500	A87_1241_BKR_CNTL	TRIP_CLS	MON/SP16GAPC1.Ind1.stVal (Trip BRK Unit 10)	MON/SP16GAPC1.Ind1.q (Trip BRK Unit 10)	MON/SP16GAPC1.Ind2.stVal (Close BRK Unit 10)	MON/ SP 16GAPC1.Ind2.q (Close BRK Unit 10)	MON/SP 16GAPC1.Ind3.stVal (Trip BRK Unit 12)	MON/SP16GAPC1.Ind3.q (Trip BRK Unit 12)	MON/SP16GAPC1.Ind4.stVal (Close BRK Unit 12)	MON/SP16GAPC1.Ind4.q (Close BRK Unit 12)	MON/SP16GAPC1.Ind5.stVal (Trip BRK Unit 17)	MON/SP 16GAPC1.Ind5.q (Trip BRK Unit 17)	MON/SP16GAPC1.Ind6 stVal (Close BRK Unit 17)	MON/SP16GAPC1.Ind6.q (Trip BRK Unit 17)	MON/SP16GAPC1.Ind7.stVal (Trip BRK Unit 11)	MON/SP16GAPC1.Ind7.q (Trip BRK Unit 11)	MON/SP16GAPC1.Ind8.stVal (Close BRK Unit 11)	MON/SP 16GAPC1.Ind8.q (Close BRK Unit 11)	MON/SP16GAPC1.Ind9 stVal (Trip BRK Unit 14)	MON/SP16GAPC1.Ind9.q (Trip BRK Unit 14)	MON/SP16GAPC1.Ind10.stVal (Close BRK Unit 14)	MON/SP16GAPC1.Ind10.q (Close BRK Unit 14)	MON/SP16GAPC1.Ind11.stVal (Trip BRK Unit 20)	MON/SP16GAPC1.Ind11.q (Trip BRK Unit 20)	MON/SP16GAPC1.Ind12.stVal (Close BRK Unit 20)	MON/ SP16GAPC1.Ind12.q (Close BRK Unit 20)	----				
-01-00-25	1	4	0x0019	4	500	A50_51_CB17_BKR_CNTL	TRIP	CTRL/SMPPTRC1.Op. general (Trip BRK Unit 17)	CTRL/ SMPPTRC1.Op.q (Trip BRK Unit 17)	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	YES			
-01-00-26	1	4	0x001A	4	500	B50_51_CB17_BKR_CNTL	DataSet	.stVal (Trip BRK Unit 17)	.q (Trip BRK Unit 17)	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	YES			
-01-00-27	1	4	0x001B	4	500	B50_51BT_4041_BKR_CNTL	DataSet	.stVal (Trip BRK Unit 10)	.q (Trip BRK Unit 10)	.stVal (Trip BRK Unit 14)	.q (Trip BRK Unit 14)	.stVal (Trip BRK Unit 20)	.q (Trip BRK Unit 20)	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	YES			
-0-00-28	1	4	0x001C	4	500	A50_51BT_4041_BKR_CNTL	TRIP	MON/SP16GAPC1.Ind1.stVal (Trip BRK Unit 10)	MON/SP16GAPC1.Ind1.q (Trip BRK Unit 10)	MON/SP16GAPC1.Ind2.stVal (Trip BRK Unit 14)	MON/SP 16GAPC1.Ind2.q (Trip BRK Unit 14)	MON/SP 16GAPC1.Ind3.stVal (Trip BRK Unit 20)	MON/SP16GAPC1.Ind3.q (Trip BRK Unit 20)	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	----	YES			

TABLE 32 STATION BUS DATA FLOW SPREADSHEET

GOOSE Control Block and referenced dataset information																				
Trime (ms)	Heatbeat Rate, Max time (ms)	Control Block Name and GoID	Dataset Name	Dataset index 1	Dataset index 2	Dataset index 3	Dataset index 4	Dataset index 5	Dataset index 6	Dataset index 7	Dataset index 8	Dataset index 9	Dataset index 10	Dataset index 11	Dataset index 12	Dataset index 13	Dataset index 14	Dataset index 15	Dataset index 16	12kV Cap Ba Sequencing Automation Controller_ PAC__Cap B V3M4
100	500	V3M2_LOR_CAP	Cap_LOR_Trip	ANN.LTGGIO5.Ind13.stVal (Trip CAP BANK- used for blocking)	ANN.LTGGIO5.Ind13.q (Trip CAP BANK used for blocking)	ANN.SVGGIO4.Ind06.stVal (MASTER STAGES 1-4 OPEN CMD TO V3M4)	ANN.SVGGIO4.Ind06.q (MASTER STAGES 1-4 OPEN CMD TO V3M4)	ANN.SVGGIO4.Ind07.stVal (MASTER STAGES 1-4 CLOSE CMD TO V3M4)	ANN.SVGGIO4.Ind07.q (MASTER STAGES 1-4 CLOSE CMD TO V3M4)	PRO.QTPTOC7.Op.general (51QT Trip CAP BANK)	PRO.QTPTOC7.Op.q (51QT Trip CAP BANK)	----	----	----	----	----	----	----	----	YE
100	500	V3M2_LOR_REAC	Reac_LOR_Trip	ANN.LTGGIO5.Ind13.stVal (Trip REAC BANK- used for blocking)	ANN.LTGGIO5.Ind13.q (Trip REAC BANK- used for blocking)	ANN.SVGGIO3.Ind06.stVal (MASTER STAGES 1-4 OPEN CMD TO V3M4)	ANN.SVGGIO3.Ind06.q (MASTER STAGES 1-4 OPEN CMD TO V3M4)	ANN.SVGGIO3.Ind07.stVal (MASTER STAGES 1-4 CLOSE CMD TO V3M4)	ANN.SVGGIO3.Ind07.q (MASTER STAGES 1-4 CLOSE CMD TO V3M4)	PRO.QTPTOC7.Op.general (51QT Trip CAP BANK)	PRO.QTPTOC7.Op.q (51QT Trip CAP BANK)	----	----	----	----	----	----	----	----	
100	500	V3M4_52A_CAP	Cap_Stage_Stat	ANN/INCGGIO13.Ind1.stVal (Stage 1 open/close)	ANN/INCGGIO13.Ind1.q (Stage 1 open/close)	ANN/INCGGIO13.Ind2.stVal (Stage 2 open/close)	ANN/INCGGIO13.Ind2.q (Stage 2 open/close)	ANN/INCGGIO13.Ind3.stVal (Stage 3 open/close)	ANN/INCGGIO13.Ind3.q (Stage 3 open/close)	ANN/INCGGIO13.Ind4.stVal (Stage 4 open/close)	ANN/INCGGIO13.Ind4.q (Stage 4 open/close)	----	----	----	----	----	----	----	----	
100	500	V3M4_52A_REAC	ReacT_Stage_Stat	ANN/INCGGIO13.Ind1.stVal (Stage 1 open/close)	ANN/INCGGIO13.Ind1.q (Stage 1 open/close)	ANN/INCGGIO13.Ind2.stVal (Stage 2 open/close)	ANN/INCGGIO13.Ind2.q (Stage 2 open/close)	ANN/INCGGIO13.Ind3.stVal (Stage 3 open/close)	ANN/INCGGIO13.Ind3.q (Stage 3 open/close)	ANN/INCGGIO13.Ind4.stVal (Stage 4 open/close)	ANN/INCGGIO13.Ind4.q (Stage 4 open/close)	----	----	----	----	----	----	----	----	YE
100	500	A_Cap_Reac_Met	Bank_41_MVA	MET.METMMXU1.PhV.phsA.instCVal.mag.f (69kV bus voltage Phase A)	MET.METMMXU1.PhV.phsA.q (69kV bus voltage Phase A)	MET.METMMXU1.PhV.phsB.instCVal.mag.f (69kV bus voltage Phase B)	MET.METMMXU1.PhV.phsB.q (69kV bus voltage Phase B)	MET.METMMXU1.PhV.phsC.instCVal.mag.f (69kV bus voltage Phase C)	MET.METMMXU1.PhV.phsC.q (69kV bus voltage Phase C)	ANN.PMVGGIO3.AnIn01.mag.f (Bank 41 A phs MVA)	ANN.PMVGGIO3.AnIn01.q (Bank 41 A phs MVA)	ANN.PMVGGIO3.AnIn02.mag.f (Bank 41 B phs MVA)	ANN.PMVGGIO3.AnIn02.q (Bank 41 B phs MVA)	ANN.PMVGGIO3.AnIn03.mag.f (Bank 41 C phs MVA)	ANN.PMVGGIO3.AnIn03.q (Bank 41 C phs MVA)	----	----	----	----	YE
100	500	B_Cap_Reactor_Metering		.f (69kV bus voltage Phase A)	.q (69kV bus voltage Phase A)	.f (69kV bus voltage Phase B)	.q (69kV bus voltage Phase B)	.f (69kV bus voltage Phase C)	.q (69kV bus voltage Phase C)	.f (KVAR Phase A)	.q (KVAR Phase A)	.f (KVAR Phase B)	.q (KVAR Phase B)	.f (KVAR Phase C)	.q (KVAR Phase C)	----	----	----	----	YE

APPENDIX F - COMTRADE GRAPHICAL ANALYSIS

Appendix F contains the raw COMTRADE file data for each of the fault cases analyzed. Information is divided into analog signals (voltage, current, frequency, etc.) and digital signals (protection element pickup/operate, 52A breaker statuses, etc.) for each relay. Analog signals utilized custom naming where appropriate to identify the channels, whereas digital signals utilized the naming assigned by a given protective relay.

For each case, the fault inception point is marked with a vertical orange line. A vertical blue line denotes the operate time of a protection element or a corresponding 52A dropout time, as appropriate for the fault analyzed. Appendix G contains timing data and additional analysis of the COMTRADE data presented.

Note: some relays produce more digital signals than in use for the given application, or reported no activity on particular digital signal channels. Blank digital element plots were left in the dataset to demonstrate non-operation of protective elements for a given fault scenario.

Note to Reader: Due to its size and format of the graphics, the content of Appendix F is provided in a separate PDF file and is not included in this MS Word document.

APPENDIX G - OPERATING TIMES SPREADSHEET

Appendix G contains the timing information extracted from the raw COMTRADE file data presented in Appendix F. The tables list each fault location analyzed, the fault type, and operate times related to the protective elements under investigation (pickup, trip, and 52A dropout). All timings reported were based on normalizing the fault initiation to a time of zero milli-seconds. Total operate times and the round-trip 52A dropout time conveyed through the network are presented in milli-seconds and cycles (cyc). Relays associated with several circuit breakers (e.g., the 12 kV bus differential relay) have multiple 52A dropout times listed, with corresponding notes that indicate which simulated circuit breaker corresponds to the 52A dropout time reported.

For each fault location, notes are included to discuss the test performed and results obtained. These notes correlate to the faults listed in the table, as well as documented in the raw COMTRADE plots in Appendix F.

Note: results related to the capacitor/reactor automation testing were reported in Appendix F.

TABLE 33 RELAY OPERATING TIMES

	Fault Time (ms)	Pickup (ms)	Trip (ms)	52A Dropout (ms)	52A Dropout (ms)	52A Dropout (ms)	52A Dropout (ms)	52A Dropout (ms)	52A Dropout (ms)	Pickup Time (ms)	Pickup Time (cyc)	Trip Time (ms)	Trip Time (cyc)	52A Dropout Time (ms)	52A Dropout Time (ms)	52A Dropout Time (ms)	52A Dropout Time (ms)	52A Dropout Time (ms)	52A D Ti (m
	0	23	23	50.7	-	-	-	-	-	23	1.38	23	1.38	27.7	-	-	-	-	
te)	0	25	25	-	-	-	-	-	-	25	1.5	25	1.5	-	-	-	-	-	
	0	10.8	13.3	33.3	-	-	-	-	-	10.8	0.648	13.3	0.798	20	-	-	-	-	
te)	0	10.8	14.2	-	-	-	-	-	-	10.8	0.648	14.2	0.852	-	-	-	-	-	
	0	10	10	33.3	-	-	-	-	-	10	0.6	10	0.6	23.3	-	-	-	-	
	0	23	23	54	-	-	-	-	-	23	1.38	23	1.38	31	-	-	-	-	
te)	0	25.8	30.8	53.8	-	-	-	-	-	25.8	1.548	30.8	1.848	23	-	-	-	-	
	0	15	25	30.8	-	-	-	-	-	15	0.9	25	1.5	5.8	-	-	-	-	
te)	0	10.8	20.8	30.8	-	-	-	-	-	10.8	0.648	20.8	1.248	10	-	-	-	-	
	0	15.8	523.3	30.8	-	-	-	-	-	15.8	0.948	523.3	31.398	-492.5	-	-	-	-	
te)	0	10.8	15.8	-	-	-	-	-	-	10.8	0.648	15.8	0.948	-	-	-	-	-	
	0	9.1	9.1	29.1	-	-	-	-	-	9.1	0.546	9.1	0.546	20	-	-	-	-	
	0	4.2	4.2	29.2	-	-	-	-	-	4.2	0.252	4.2	0.252	25	-	-	-	-	
	0	8.4	108.4	29.2	-	-	-	-	-	8.4	0.504	108.4	6.504	-79.2	-	-	-	-	
	0	68.3	271.7	291.7	-	-	-	-	-	68.3	4.098	271.7	16.302	20	-	-	-	-	
	0	12.5	212.5	237.5	-	-	-	-	-	12.5	0.75	212.5	12.75	25	-	-	-	-	
	0	17.5	220.8	244.2	-	-	-	-	-	17.5	1.05	220.8	13.248	23.4	-	-	-	-	
	0	12.5	212.5	150	-	-	-	-	-	12.5	0.75	212.5	12.75	-62.5	-	-	-	-	
	0	12.5	125	150	-	-	-	-	-	12.5	0.75	125	7.5	25	-	-	-	-	
	0	2.2	9	-	-	-	-	-	-	2.2	0.132	9	0.54	-	-	-	-	-	
	0	5	5	32.5	21.7	19.2	-	-	-	5	0.3	5	0.3	27.5	16.7	14.2	-	-	
	0	0	7.5	-	-	-	-	-	-	0	0	7.5	0.45	-	-	-	-	-	
	0	4.2	4.2	30.8	20.8	17.5	-	-	-	4.2	0.252	4.2	0.252	26.6	16.6	13.3	-	-	
	0	3.3	3.3	26.7	20	17.5	-	-	-	3.3	0.198	3.3	0.198	23.4	16.7	14.2	-	-	
	0	3.3	3.3	27.2	20.5	17.2	-	-	-	3.3	0.198	3.3	0.198	23.9	17.2	13.9	-	-	
	0	0.8	9.5	-	-	-	-	-	-	0.8	0.048	9.5	0.57	-	-	-	-	-	
	0	5	8.3	28.3	-	-	-	-	-	5	0.3	8.3	0.498	20	-	-	-	-	
	0	9.5	9.5	-	-	-	-	-	-	9.5	0.57	9.5	0.57	-	-	-	-	-	
	0	15.9	15.9	39.2	-	-	-	-	-	15.9	0.954	15.9	0.954	23.3	-	-	-	-	
	0	5	1352	-	-	-	-	-	-	5	0.3	1352	81.12	-	-	-	-	-	
	0	3.4	1338.4	1358.4	1351.7	1365	-	-	-	3.4	0.204	1338.4	80.304	20	13.3	26.6	-	-	
f)	0	5.7	1714.7	-	-	-	-	-	-	5.7	0.342	1714.7	102.882	-	-	-	-	-	
f)	0	5	1700.9	1720.9	1714.2	1727.5	-	-	-	5	0.3	1700.9	102.054	20	13.3	26.6	-	-	
	0	13	13.9	33.9	30.5	30.5	30.5	53.9	50.5	13	0.78	13.9	0.834	20	16.6	16.6	16.6	40	
	0	14.1	14.9	34.9	31.6	31.6	31.6	51.6	44.9	14.1	0.846	14.9	0.894	20	16.7	16.7	16.7	36.7	
	0	7.5	7.5	18.3	18.3	27.5	-	-	-	7.5	0.45	7.5	0.45	10.8	10.8	20	-	-	
	0	16.7	16.7	18.3	18.3	27.5	-	-	-	16.7	1.002	16.7	1.002	1.6	1.6	10.8	-	-	
	0	27.5	27.5	18.3	18.3	27.5	-	-	-	27.5	1.65	27.5	1.65	-9.2	-9.2	0	-	-	
	0	27.8	105.8	-	-	-	-	-	-	27.8	1.668	105.8	6.348	-	-	-	-	-	
	0	10	10	20	-	-	-	-	-	10	0.6	10	0.6	10	-	-	-	-	
	0	4.3	6.5	-	-	-	-	-	-	4.3	0.258	6.5	0.39	-	-	-	-	-	
	0	9.2	9.2	19.2	19.2	29.2	-	-	-	9.2	0.552	9.2	0.552	10	10	20	-	-	
	0	25.8	25.8	19.2	19.2	29.2	-	-	-	25.8	1.548	25.8	1.548	-6.6	-6.6	3.4	-	-	
	0	1063.7	1063.7	-	-	-	-	-	-	1063.7	63.822	1063.7	63.822	-	-	-	-	-	
	0	10	10	20	-	-	-	-	-	10	0.6	10	0.6	10	-	-	-	-	
	0	11	13	-	-	-	-	-	-	11	0.66	13	0.78	-	-	-	-	-	
	0	11.7	1023.3	1030	-	-	-	-	-	11.7	0.702	1023.3	61.398	6.7	-	-	-	-	
	0	25	191.7	220.9	-	-	-	-	-	25	1.5	191.7	11.502	29.2	-	-	-	-	
	0	14.2	1016.7	1040.8	-	-	-	-	-	14.2	0.852	1016.7	61.002	24.1	-	-	-	-	
	0	12.5	179.2	204.2	-	-	-	-	-	12.5	0.75	179.2	10.752	25	-	-	-	-	
	0	146.5	654.8	674.8	-	-	-	-	-	146.5	8.79	654.8	39.288	20	-	-	-	-	
	0	500	670.8	-	-	-	-	-	-	500	30	670.8	40.248	-	-	-	-	-	
	0	37.1	417.1	-	-	-	-	-	-	37.1	2.226	417.1	25.026	-	-	-	-	-	

TABLE 34 RELAY OPERATING TIMES NOTES

ment Tested	Test Results	Testing Notes
87L	Success	87L protection tripped for close-in, in-zone 3PH fault.
87L	Success	87L protection tripped for close-in, in-zone 3PH fault.
87L	Success	87L protection tripped for close-in, in-zone 3PH fault.
87L	Success	87L protection tripped for close-in, in-zone 3PH fault.
21P	Success	21P protection tripped for close-in 3PH fault in the forward direction.
87L	Success	87L protection tripped for close-in, in-zone SLG fault.
87L	Success	87L protection tripped for close-in, in-zone SLG fault.
87L	Success	87L protection tripped for close-in, in-zone SLG fault.
87L	Success	87L protection tripped for close-in, in-zone SLG fault.
87L	Success	87L protection tripped for close-in, in-zone SLG fault. Inverse time delayed element: Pickup = 180 A primary, Curve Type = ANSI Very Inverse, Time Dial = 1.0
87L	Success	87L protection tripped for close-in, in-zone SLG fault.
21G	Success	21G protection tripped for close-in SLG fault in the forward direction.
21G	Success	21G protection tripped for close-in SLG fault in the forward direction.
51G	Success	51G protection timed-out and tripped for a close-in SLG fault in the forward direction. Inverse time delayed element: Pickup = 180 A primary, Curve Type = ANSI Very Inverse, Time Dial = 1.0
L / 21P	Success	87L protection properly restrained for out-of-zone fault. Overreaching 21P protection tripped for remote 3PH fault in the forward direction. Definite Time Delay = 200 ms. Pickup time delayed by ~(
L / 21P	Success	87L protection properly restrained for out-of-zone fault. Overreaching 21P protection tripped for remote 3PH fault in the forward direction. Definite Time Delay = 200 ms.
L / 21G	Success	87L protection properly restrained for out-of-zone fault. Overreaching 21G protection tripped for remote SLG fault in the forward direction. Definite Time Delay = 200 ms.
L / 21G	Success	87L protection properly restrained for out-of-zone fault. Overreaching 21G protection tripped for remote SLG fault in the forward direction. Definite Time Delay = 200 ms.
51G	Success	51G protection timed-out and tripped for a remote SLG fault in the forward direction. Inverse time delayed element: Pickup = 180 A primary, Curve Type = ANSI Very Inverse, Time Dial = 1.0
(138 kV)	Success	87B protection tripped for in-zone 138 kV 3PH fault.
(138 kV)	Success	87B protection tripped for in-zone 138 kV 3PH fault.
(138 kV)	Success	87B protection tripped for in-zone 138 kV SLG fault.
(138 kV)	Success	87B protection tripped for in-zone 138 kV SLG fault.
(138 kV)	Success	87B HIZ protection tripped for in-zone 138 kV 3PH fault.
(138 kV)	Success	87B HIZ protection tripped for in-zone 138 kV SLG fault.
kV feeder)	Success	50P protection tripped for a downstream 12 kV feeder 3PH fault.
kV feeder)	Success	50P protection tripped for a downstream 12 kV feeder 3PH fault.
kV feeder)	Success	50G protection tripped for a downstream 12 kV feeder SLG fault.
kV feeder)	Success	50G protection tripped for a downstream 12 kV feeder SLG fault.
/ partial diff)	Success	51P protection pickup, time-out, and trip for a downstream 12 kV transfer bus 3PH fault. Inverse time delayed element: Pickup = 2400 A primary, Curve Type = ANSI Very Inverse, Time Dial = 1.0
/ partial diff)	Success	51P protection pickup, time-out, and trip for a downstream 12 kV transfer bus 3PH fault. Inverse time delayed element: Pickup = 2400 A primary, Curve Type = ANSI Very Inverse, Time Dial = 1.0
/ partial diff)	Success	51G protection pickup, time-out, and trip for a downstream 12 kV transfer bus SLG fault. Inverse time delayed element: Pickup = 500 A primary, Curve Type = ANSI Very Inverse, Time Dial = 6.5
/ partial diff)	Success	51G protection pickup, time-out, and trip for a downstream 12 kV transfer bus SLG fault. Inverse time delayed element: Pickup = 500 A primary, Curve Type = ANSI Very Inverse, Time Dial = 6.5
(12 kV)	Success	87B protection tripped for in-zone 12 kV 3PH fault.
(12 kV)	Success	87B protection tripped for in-zone 12 kV SLG fault.
kV XFMR OC)	Success	50P transformer 138 kV overcurrent protection tripped for a transformer internal 3PH fault.
rained XFMR diff)	Success	87U (unrestrained) transformer differential protection tripped for a transformer internal 3PH fault.
ained XFMR diff)	Success	87R (restrained) transformer differential detected and tripped for a transformer internal 3PH fault.
FMR diff)	Partial Success	Transformer differential detected internal 3PH fault on all phases but did not trip. Sampled Values received from MU were reported by the relay as "bad quality," which blocks differential operatio
kV XFMR OC)	Success	50P transformer 138 kV overcurrent protection tripped for a transformer internal 3PH fault.
kV XFMR OC)	Success	50P transformer 138 kV overcurrent protection tripped for a transformer internal 3PH fault.
kV XFMR OC)	Success	50G transformer 138 kV overcurrent protection tripped for a transformer internal SLG fault.
ained XFMR diff)	Success	87R (restrained) transformer differential detected and tripped for a transformer internal SLG fault.
FMR diff)	Partial Success	Transformer differential detected internal SLG fault on the correct phase but did not trip. Sampled Values received from MU were reported by the relay as "bad quality," which blocks differential o
kV XFMR OC)	Success	50G transformer 138 kV overcurrent protection tripped for a transformer internal SLG fault.
kV XFMR OC)	Success	50G transformer 138 kV overcurrent protection tripped for a transformer internal SLG fault.
8 kV OV)	Success	59 protection pickup, time-out, and trip for a 138 kV overvoltage condition. Definite Time Delay = 1000 ms.
8 kV OV)	Success	59 protection pickup, time-out, and trip for a 138 kV overvoltage condition. Definite Time Delay = 167 ms.
38 kV UV)	Success	27 protection pickup, time-out, and trip for a 138 kV overvoltage condition. Definite Time Delay = 1000 ms.
38 kV UV)	Success	27 protection pickup, time-out, and trip for a 138 kV overvoltage condition. Definite Time Delay = 167 ms.
38 kV UF)	Success	81 underfrequency protection pickup, time-out, and trip for a 138 kV overvoltage condition. Definite Time Delay = 500 ms.
38 kV UF)	Success	81 underfrequency pickup, time-out, and trip for a 138 kV overvoltage condition. Definite Time Delay = 500 ms.
Fail - Position)	Success	Breaker failure test with breaker position blocked in the close position to test the position-based breaker failure scheme. Breaker failure successfully declared and adjacent breakers tripped. Re-t
Fail - Current)	Success	Breaker failure test with breaker position included but continuous current to test the current-based breaker failure scheme. Breaker failure successfully declared and adjacent breakers tripped. R

APPENDIX H – OBSERVATION LOG

Appendix H contains a log of observations regarding specific equipment which were gathered during the process of the project. These observations recorded issues encountered by the project team that required resolution during the course of the project. Observations included physical limitations such time sync connections as well as software and firmware issues that had to be addressed for proper operation. The figures show the date that each observation was made and a detailed description of the observation. Due to the number of entries, the data was divided into three tables.

To remain impartial, it was necessary to avoid disclosing vendor and model information. A product code was developed to obfuscate the vendor name and model numbers of the IEDs for the project. The first character was the letter “V”, which indicated that the next character would reference a vendor. The second character was a numerical index that represented a specific vendor. The third character was the letter “M”, which indicated that the next character would reference a product model. The fourth character was another numerical index that represented a specific vendor’s product model.

8/29/2017	V2M3 V2M4	Event list and disturbance list must be cleared individually
4/27/2017	V2M1 V2M2 V2M3	Relays selected port for SV protocol will not support any other protocol. This requires an additional process bus connection for GOOSE communications.
4/27/2017	V2M1 V2M2 V2M3	Relays will only support a single port for GOOSE messages. This means that the station bus connection cannot use GOOSE messages
8/28/2017	V2M1 V2M2 V2M3 V2M4	Relays will block all relay actions if any SV stream fails
7/26/2017	V2M1 V2M2 V2M3 V2M4	Relays require optical 1PPS time signal to subscribe to SVs. The IRIGB connection will not work for SV. This requires a SNTP connection in addition to the 1PPS connection to provide real time to the relay.
7/26/2017	V2M1 V2M2 V2M3 V2M4	Relays require SV App ID = 0x4000 for all SV subscriptions. The relay will reject any SV message that does not have this App ID.
7/22/2017	V2M1 V2M2 V2M3 V2M4	Software would overwrite RCB values to first available good value if invalid data was input. No other configuration tool error was indicated. The user must notices that the value had not changed.
8/4/2017	V2	When the user creates the project in the configuration tool the IEC 61850 edition must be declared. The tool will only accept SCL files created using that edition schema, you can not mix editions.
4/27/2017	V2M1 V2M2 V2M3 V2M4	Front port supports MMS and Config when using GOOSE for the process bus port.
7/21/2017	V2M5	Relay uses the SV "smpSynch" from edition 1 only. This is a problem when other subscribers products use the edition 2 definition for the "smpSynch". When this occurs the subscriber interrpets the SV message as not being globally time synced and will not use the stream.
7/11/2017	V2M6	Adjacent module connector pins interfer with din rail bracket end clamp
4/27/2017	V2M7	Only available with 24 Vdc power supply
4/27/2017	V2M1 V2M2 V2M3 V2M4	Relays have thermal limts that prevent side by side mounting on 19" rack
8/31/2017	V2M1 V2M2 V2M3 V2M4	6 Pushbuttons require 2 pushes. One to "wake" the relay & a second to activate function.
6/6/2017	V2	Software, v2.8 - SSL error upon loading for some PCs
9/7/2017	V2	Software will overwrite calculated neutral values with a zero even if MU does not have neutral value inputs, if link is connected in software
8/10/2017	V7M1	MU Configuraion software does not display CIDs from V3 or V1, so import cannot be performed when GOOSE message has analog values in data set
8/30/2017	V7M1	MU does not support event records
7/3/2017	V7M1	MU does not have hardware for high speed tripping yet, but provided catalog number for it during procurement stage.
7/17/2017	V7M1	MU has a 10 character limit on the SVid field. The configuation tool does not provide an error check allowing you to exceed this limit. When exceeded the SV message publishes but is corrupted.

7/12/2017	V4M1	Switches run warm and may need additioanl spacing between adjacent units on a single rack. Manual recommends 1RU above each one.
3/14/2017	V4M1	Switches with 4.3.2x firmware, use strong ciphers and responsiveness was slow. They are shipped using 2048 bit key slowing down the web configurtion interface to a 20 to 30 second response. This was changed to 128bit key via the console port interface which created a fast but still secure web interface.
7/28/2017	V3M4	Unit only supports IEC 61850 edition 1. All SCL files are in editon 1 format and cannot be imported into the V1 or V2 configuration tools.
8/4/2017	V3M1	Relay can not subscribe to V1 or V2 MUs due to the SV "smpSynch" definition missmatch.
7/28/2017	V3M1	Relay defaults to IRIG when given a choice of time protocols. So if IEEE1588 PTP is configured the IRIGB must be dis-connected from the relay. When using PTP the "IRIG B configuration parameter" must be set to "C37.118" for the SV to sync to the PTP source.
7/28/2017	V3M1	Relay does not have an error indication for loss of SV stream
7/18/2017	V3M1	Relay must use PTP in order to subscribe to multiple SV streams
7/18/2017	V3M1	Relay can subscribe to a max of 6 SV streams but relay only provides internal variables to map 2 SV streams.
7/18/2017	V3M1	Relay can only provide metering data for one SV stream.
7/18/2017	V3M1	Relay would only subscribe to SV from the V6 when V3M6 was used because the manual SCL file would not properly import into the configuration tool.
4/11/2017	V3M3	MUs are 19" wide only and have a very large foot print.
9/1/2017	V3M5 V3M6	V3M7 and V3m6 can both be used to configure the V3 relays SV subscriptions. The V3M7 settings will always override the V3M6 settings which leads to confusion during the configuration process.
9/1/2017	V3M1 V3M3	Recommends PTP for SV
9/7/2017	V3M1	Relay displays primary values on display independent of PTR values in relay
9/1/2017	V3M1 V3M3	Time domain of relays must match MU.
9/1/2017	V3M1 V3M3	Relay will reset time source if time domain is changed
7/11/2017	V1M3	Relay has limited clearance to IRIG DB9 connector
8/4/2017		When the user creates the project in the configuration tool the IEC 61850 edition must be declared. The tool will only accept SCL files created using that edition schema, you can not
7/19/2017	V1	IEDs requires 3 different software packages to configure. V1M6, V1M7, & V1M8)
7/11/2017	V1	Invoices are printed on paper that approximates 8x12 instead of 8.5x11
8/4/2017	V1M5	MU can either be strictly Edition 1 or strictly Edition 2. LE is not supported in Edition 2.
8/4/2017	V1M5	MU cannot derive In and Vn from phase quantities per the LE document
8/4/2017	V1M5	MU in Edition 1 requires manual change to CID file so that the file can be used in an edition 2 project.
8/4/2017	V1M1 V1M2 V1M3 V1M4	Relays only support IRIGB fiber input, not 1PPS
8/4/2017	V1M5	MU publishes SV streams with a PRP header even when PRP is not configured. We had to change a separate non-PRP related NIC configuration parameter to stop the the unit from adding the PRP header. The V3M1 would not accept streams with the PRP header.

		V2M3, V2M4.
4/10/2017	V1M1 V1M2 V1M3 V1M4	Process bus module is limited to 3 SV stream subscriptions
4/10/2017	V1M1 V1M2 V1M3 V1M4	Process bus requires a "add-on" expansion module
7/11/2017	V1M1 V1M2 V1M3 V1M4	Relay mounting brackets are not plates. Instead they are custom drilled rails. Filler plates are available to close off open space in a 19" rack
9/7/2017	V1M1	Remote 7SL86 did not time synch via IRIGB. PTP was required.
9/6/2017	V1M1	7SL86 requires PTP="on" and PPS="off"
8/7/2017	V1M1 V1M2 V1M3 V1M4	Relays do not come with transceiver in service ports of process bus module
7/11/2017	V1M1 V1M2	Relays do not ship with process bus module assembled. User must assemble relay to its process bus module prior to installation
	V6M1	Does not support GOOSE subscriptions.
	V6M1	IEC 61850 template was manually edited using SEL CID as a model. The configuration tool does not export an SCL file.
	V6M1	MU does not support event records
	V6M1	Only supports Modbus for control of output contacts
	V6M1	Provided IEC 61850 CID template that was missing necessary blocks to allow for import into other devices. We had to use another vendors file as a go by.
7/18/2017	V6M1	The configuration tool does not export an SCL file; ICD, CID, or IID files.
9/3/2017	V6M1	"Color identidfier for selected phase" is in hexadecimal
6/16/2017	All	Every vendor had some mixed variation of edition 1 and 2 implementation.
8/9/2017	V2M1 V2M2 V2M3 V2M4	ZZZ MAC filtering of GOOSE is required in switches due to network traffic volume. V2M1, V2M2, V2M3, & V2M4 identified network traffic as a "DOS" condition
8/30/2017	All	ZZZ MUs with differential relaying when set up to reference voltage vector require voltage input
9/5/2017	V2M2	Relay picks up slowly for remote faults when SIR is high. High SIR filter needs additional investigatation.
9/5/2017	V2M1 V2M2 V2M3 V2M4	Relay logic requires multiple logic gates to achieve desired function and this causes 2-3 ms delays in tripping. Delay is dependant on number and type of logic gates. This is most noticable with high speed tripping applications.
9/6/2017	V1M1	Relay interpreted valid data stream with bad quality even though other relays using the same stream operated succsessfully.

Appendix 10

EPIC-2, Project 2: Data Analytics in Support of Advanced Planning and System Operations

EPIC Final Report

Program	**Electric Program Investment Charge (EPIC)**
Administrator	**San Diego Gas & Electric Company**
Project Number	**EPIC-2, Project 2**
Project Name	**Data Analytics in Support of Advanced Planning and System Operations**
Date	**December 31, 2017**

Attribution

This comprehensive final report documents the work done in EPIC-2, Project 2. The project team that contributed to the project definition, execution, and reporting included the following individuals, listed alphabetically by last name.

SDG&E

Daly, Tim
Flamenbaum, Robert
Gooch, Michael
Goodman, Frank
Hobbib, Tom
Katmale, Hilal
Mariano, Gabe
Mariano, Lori
Oldham, Yvette
Poole, Kayla
Shiffman, Nadav
Surbey, Chris
Thiemsuwan, Jade
Wu, Henry

Sparta Consulting

Bhandari, Akshit
Bhatt, Rathin
Boddikuri, SaiPradeep
Jain, Anjali
Madhathisheril, Abhay
Sahu, Vipul
Shaik, Samir
Sharma, Rahul
Sharma, Rohit
Sreedhar, Ramanadham
Stacklin, Alan

Thoughtspot, Inc

LeKodak, Eric
Rutledge, Elijah
Spencer, Tyler
Weaver, Nathan

Executive Summary

Using advances in machine learning, and taking advantage of the existing Hadoop Data Lake, EPIC-2, Project 2 on Data Analytics in Support of Advanced Planning and System Operations delivered on three main objectives: (1) integrated several data sources for ongoing ingestion, (2) built preliminary predictive models for major electric distribution asset management use cases, and (3) provided visualizations using Microsoft Power Business Intelligence (BI) Dashboards to provide insight into the health of various assets on the grid. The project laid the groundwork for further model development and refinement.

SDG&E's asset management strategies for electric distribution widely focus on time-tested methods of both qualitative and quantitative prioritization. Per industry and company standard practices, engineers regularly utilize comprehensive models to estimate operational and financial benefits of upgrading select equipment to improve system reliability. Although these models, which concentrate on improving reliability metrics like System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), have proven effective over several years of operation, SDG&E is actively pursuing alternative ways to model engineering data utilizing predictive analytics.

Incorporating predictive analytics into daily asset planning and operations practices could be expected to enhance the overall risk management model for SDG&E's electric infrastructure by improving the organization's understanding of equipment failure triggers and their likelihood to occur, thus catalyzing prudent identification of root causes and effective long-term risk mitigations and controls. Through several years of sensor evolution and mass deployment, such as advanced metering infrastructure (AMI), distribution Supervisory Control and Data Acquisition (SCADA), and other intelligent electronic devices (IEDs), SDG&E has realized a substantial data set that can be used for asset planning and improved operational insights. Managing and exploiting this "Big Data" to achieve the ideal predictive analytics is a work in progress and is best explored via demonstrating high-value use cases that may augment and improve SDG&E's business operations.

Four use cases were initially chosen to demonstrate the viability of predictive failures:

1. Underground Electric Distribution Cable,
2. 600-amp Tee Connectors,
3. Padmount Service Transformers, and
4. Overhead Distribution Wire Failures (i.e. Wire Down).

Underground electric distribution cable and padmount service transformers were chosen based on the belief that there was a relatively large amount of data available and those assets form a large part of the asset base in the field. The 600-amp tee connector and overhead distribution wire failure use cases were not expected to have extensive amounts and available data; however the failures had such significant consequences that predicting failures could have a valuable operational benefit to the company.

The models that were developed, initially intended for a logistics planning purpose, ended up also providing value from an electric operations perspective. As the models predicted devices with high probability of failure, they could consequently be used to influence prioritization for preventative maintenance and other capital development planning. For example, predicting cable failures may enable the company to get an earlier start on planning various logistics for proactive replacements. Hedging time for design, engineering, permitting, other internal/external reviews, and preventing forced outages may result in saved operational costs and improved public safety.

Table of Contents

1 Project Description ____ *8*

1.1 Objective ____ 8

1.2 Issue/Problem Being Addressed ____ 8

1.3 Project Description, Tasks, and Deliverables Produced ____ 10

2 Demonstration Results ____ *19*

2.1 Data Ingestion into Data Lake ____ 19

2.2 Data Modeling ____ 33

2.3 Visualizing Predictive Analytics Use Cases ____ 36

3 Project Outcome ____ *55*

3.1 Key Findings ____ 55

3.2 Lessons Learned ____ 55

3.3 Recommendations and Next Steps ____ 56

4 Technology Transfer Plan ____ *58*

4.1 SDG&E Technology Transfer Plans ____ 58

4.2 Adaptability to Other Utilities and Industry ____ 58

5 Metrics and Value Proposition ____ *59*

5.1 Metrics ____ 59

5.2 Value Proposition ____ 59

Figures and Tables

Figure 1: Tenets for Predictive and Prescriptive Analytics ____ 9
Figure 2: Process Workflow ____ 24
Figure 3: As-Is Data Architecture ____ 25
Figure 4: As-Is Data Architecture – Detailed View ____ 26
Figure 5: Data Architecture Vision ____ 27
Figure 6: Future Vision - Data Lake Architecture ____ 28
Figure 7: Receiver Operating Curve (ROC) ____ 34
Figure 8: Visualization Dashboard ____ 38
Figure 9: High Level Dashboard – Initial Forecast for the first year for all districts ____ 41
Figure 10: Forecast for first year for a sample district ____ 42
Figure 11: Forecast for first year for a sample substation ____ 43

Figure 12: Forecast for third year for a sample circuit ____ 44
Figure 13: Forecast for a chosen Slicer value – 0.90 to 0.95 for all districts for a 3-year forecast period ____ 45
Figure 14: Forecasts for sample high risk circuit at equipment category level for 5-year forecast period ____ 46
Figure 15: Forecast for a sample high-risk circuit at individual equipment level for Tees at 853 Circuit ____ 47
Figure 16: Forecasts for fourth year for a sample substation with slicer value ranging from 0.80 to 1.0 ____ 48
Figure 17: Monthly District Outages for 2017 ____ 50
Figure 18: Top Conductors by Outages ____ 51
Figure 19: Monthly Outages for the Last 3 Years ____ 52
Figure 20: Total number of outages by cause category ____ 53
Figure 21: Outages Pinboard ____ 54

Table 1: EPIC2 Project 2 Pre-Commercial Demonstration - Phased Approach..... 10
Table 2: Data Sources Used for Ingestion 21
Table 3: Data Ingestion Requirements..... 30
Table 4: Data Ingestion Use Cases 31
Table 5: Data Visualization Requirements 36

List of Acronyms and Abbreviations

AMI	Automated Metering Infrastructure
BI	Business Intelligence
CPUC	California Public Utilities Commission
CS	Composite Score
DBE	Diverse Business Enterprise
EDW	Engineering Data Warehouse
EFR	Equipment Failure Report
EPIC	Electric Program Investment Charge
GIS	Geographic Information System
HDFS	Hadoop Distributed File System
IED	Intelligent Electronic Devices
ISO	International Standards Organization
ML	Machine Learning
NMS	Network Management System
ODBC	Open Database Connectivity
ORC	Optimized Row Columnar
PF	Probability of Failure
RFP	Request for Proposal
ROC	Receiver Operating Curve
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition System
SDG&E	San Diego Gas and Electric
SOW	Statement of Work
SQL	Standard Query Language
UI	User Interface

1 Project Description

1.1 Objective

The objectives of the pre-commercial demonstration of EPIC-2, Project 2 on Data Analytics in Support of Advanced Planning and System Operations were:

- To address the "data tsunami" associated with widespread system monitoring and use of controllable devices in the power system to help create better data management.
- To demonstrate solutions for the data management issues and challenges that accompany the extensive amount of real-time and stored data being archived from field devices.
- To identify the data mining procedures and the data-archiving methods, utilizing this data to improve power system operations.
- To document solutions that are deemed to be best practices for use in improving the data management systems that support power system operations.

The project results were expected to benefit SDG&E and other utilities, most of which are dealing with the same issues.

1.2 Issue/Problem Being Addressed

The advent of new power system technology and applications such as synchrophasors, advanced meters, and other sensors has dramatically increased the level of data collection. These new assets and the traditional aging assets require utilities to find more effective and efficient ways to monitor and maintain these assets, with high degree of availability and reliability. The final objective for traditional or next generation asset management is to help reduce, minimize or optimize asset lifecycle costs across all phases from asset investment planning, design, installation & commissioning, operation and maintenance through decommissioning and disposal/replacement. Preventive maintenance prescriptions from manufacturers do not necessarily help avoid asset failures. Avoiding unexpected outages, managing asset risk, and maintaining assets before failure strikes are important goal for utility asset managers. This ultimately helps improve customer satisfaction.

These challenges present a unique opportunity to explore predictive and prescriptive analytics to extend the life of the assets and increase predictability in performance and health of the assets, thereby helping in planning and prioritizing maintenance activities. The emerging technology of prescriptive analytics goes beyond descriptive and predictive models by recommending multiple courses of action and showing the likely outcome of each selection. Prescriptive analytics requires a predictive model with two additional components: actionable data and a feedback system that tracks the outcome produced by the action taken.

This EPIC project demonstrated predictive analytics for distribution asset management. The four tenets of asset management (as shown in Figure 1) include:

- Asset Property
- Prediction

- Prescription
- Pick (option to choose from)

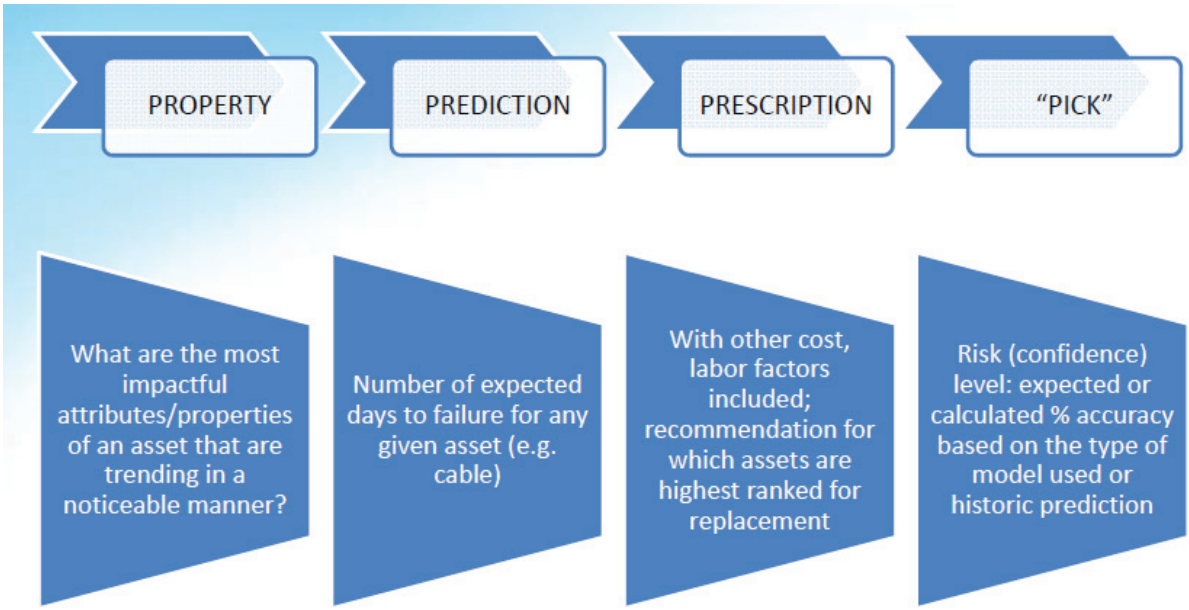


Figure 1: Tenets for Predictive and Prescriptive Analytics

SDG&E's asset management strategies for electric distribution widely focus on time-tested methods of both qualitative and quantitative prioritization. Per industry and company standard practices, engineers regularly utilize comprehensive models to estimate operational and financial benefits of upgrading select equipment to improve system reliability. Although these models, which concentrate on improving reliability metrics like System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI),, have proven effective over several years of operation, SDG&E is actively pursuing alternative ways to model engineering data utilizing predictive analytics. Incorporating predictive analytics into daily asset planning and operations practices could be expected to enhance the overall risk management model for SDG&E's electric infrastructure by improving the organization's understanding of equipment failure triggers and their likelihood to occur, thus catalyzing prudent identification of root causes and effective long-term risk mitigations and controls. Through several years of sensor evolution and mass deployment, such as advanced metering infrastructure (AMI), distribution Supervisory Control and Data Acquisition (SCADA), and other intelligent electronic devices (IEDs), SDG&E has realized a substantial data set that can be used for asset planning and improved operational insights. Managing and exploiting this "Big Data" to achieve the ideal predictive analytics is a work in progress and is best explored via demonstrating high-value use cases that may augment and improve SDG&E's business operations.

1.3 Project Description, Tasks, and Deliverables Produced

The project plan was organized into three phases. Phases consisted of sub-tasks, each of which has a report documenting the activities and results. Table 1 presents the phased approach that was developed during the project.

Table 1: EPIC2 Project 2 Pre-Commercial Demonstration - Phased Approach

Phase	Task
Phase 1 – SDG&E Internal Project Work Prior to contractor procurement	Task #1 - Development of Project Plan
	Task #2 - RFP Development
	Task #3 - RFP Release, Proposal Evaluation, and Vendor Selection
	Task #4 - Contracting, Procurement, Resourcing, and Kick-Off
Phase 2 – Project Development Activities	Task #5 – Data Ingestion Into Data Lake
	Task #6 – Advanced Data Analytics
	Task #7 – Visualization and Data Presentment
Phase 3 – SDG&E Internal Project Work prior to project conclusion	Task #8 – Comprehensive Final Report
	Task #9 – Technology Transfer

1.3.1 Phase 1 – SDG&E Internal Project Work Prior to Contractor Procurement

Task 1 – Development of Project Plan

Objective – Develop detailed work plan for the project.

Approach – The project team met with internal stakeholders to conduct a review of existing architecture for the data lake—Hadoop Distributed File System (HDFS). A future state vision for the integration of various data sources into the data lake was developed. Use cases were identified based on the requirements of the business units for asset management. The project plan identified staffing requirements for the project, both internal and contracted, with definition of needed skills. Required tools and other resources were also identified.

Output – Project work plan including technical scope definition, schedule, budget, and staffing requirements was developed.

Task 2 – Request for Proposal (RFP) Development

Objective - Develop RFP for competitive procurement of contractor services for the requisite phases of the technical scope.

Approach – An RFP was developed for the contracted portion of the work that contained the following sections:

- Brief Project Background
- Statement of Project Objective
- Scope of Work
- Approach
- List of Deliverables
- Expectations for Tech Transfer Plan
- Project Schedule
- Selection Criteria
- Solicitation Schedule
- Encouragement for Bids with Diverse Business Enterprise (DBE) Participation

The RFP was sent to multiple recipients. The proposals expected from the respondents included (at a minimum):

- Meeting the requirements of the RFP (being responsive)
- Proposed technical approach for performing the work
- Data Architecture
- Test plan for Visualization
- Findings and recommendations, based on the results
- Tech transfer plan for use of project results
- Reporting to SDG&E
- Conformance with the requirements of related CPUC EPIC decisions

The selection criteria (at a minimum) addressed the responsiveness of the bidder to the RFP requirements, elaboration on technical approach, cost, bidder experience and company qualifications, DBE participation, team structure, management plan, qualifications of individual team members, proposed schedule, cost, and acceptance of SDG&E Terms and Conditions. Bidders were encouraged to include DBE companies in their project team.

Output – RFP document was developed for release to recipients.

Task 3 – RFP Release, Proposal Evaluation, and Vendor Selection

Objective - Release RFP to external recipients, evaluate proposals received and shortlist prime contractor.

Approach - Worked with SDG&E supply management to release the RFP and manage the contractor selection. Obtained bidder responses from supply management and organized for stakeholders review during the evaluation process. Received proposal submittals were be validated, a proposal review team was established and a proposal review schedule was developed. Developed detailed evaluation criteria that evaluated the technical and financial response from the bidders. Scoring criteria incorporated an individual scoring sheet and a consolidated scoring workbook will be developed. Formed an internal proposal and project review panel of SDG&E subject matter experts from stakeholder groups to use the project

results. Subsequent to developing the evaluation criteria, responses were sent to the review panel for review and scoring. Two review panel meetings were conducted to review the scores and discuss the proposals. During the evaluation process the scoring matrix was populated to get a clear picture of strength of the bidders' proposals. Proposals were reviewed along with the scoring approaches and scoring criteria. Follow up technical questions were developed for clarification from bidders. The proposals were evaluated to assess proposer's assumptions on SDG&E team activities and identify project risks. Evaluation workshops were conducted for bidders who meet the criteria to be vetted further, and necessary discussions on the technical aspects of the statement of work (SOW) and other terms and conditions were conducted that culminated in the selection of a vendor.

Output – Vendor selection including proposal evaluation matrix, scoring matrix and identification of the selected vendor.

Task 4 – Contracting and Procurement

Objective – Procurement of selected contractor services under contract with Supply Management.

Approach - Engaged with the selected contractor in contract discussions to finalize the scope of work, schedule and budget for the project deliverables. The following documents were developed and finalized as part of the contracts package:

- Detailed scope of work
- Detailed project schedule
- Detailed Project Budget
- Professional services agreement

Output – Prime contractor agreement was finalized between SDG&E and the contractor.

1.3.2 Phase 2 – Project Development Activities

This section describes the project development activities that were undertaken by the project team that included SDG&E resources and the prime contractor resources. The project undertook a demonstration to integrate multiple data sources into the data lake (a Hadoop Distributed File System (HDFS)), develop algorithms to perform predictive analytics, and create visualizations for stakeholder engagement

Task 5 – Data Ingestion into Data Lake

Task 5 involved the following sub-tasks that were undertaken to ingest data from multiple data sources into the data lake.

Task 5a – Data Ingestion Requirements Elicitation and Design

Objective - Develop requirements and design the ingestion of data from various data sources into the data lake.

Approach - This task involved the development of detailed requirements for data ingestion into the data lake. A current state diagram was developed to describe the existing data architecture. A data architecture vision was also developed to describe the future state that is anticipated for the data architecture. Multiple use cases were discussed to fit the business stakeholder requirements within SDG&E. From the list of use cases, four cases were developed in detail to meet various operational and analytical scenario requirements. The following activities were undertaken as part of this task:

- Detailed requirements development for the data lake architecture and ingestion
- Development of a requirement traceability matrix
- Development of detailed use cases
- Development of functional and technical design specifications for the pre-commercial demonstration system
- Development of pre-commercial demonstration system test plan and test cases.

Output – Detailed requirements and design for the pre-commercial demonstration system

Task 5b – Pre-Commercial Demonstration System Development and Unit Testing

Objective - Design and build the pre-commercial demonstration system and conduct unit testing.

Approach - Upon completion of the requirements specification document, the design and build of the pre-commercial demonstration system was undertaken. The design/build process included the typical application development activities such as:

- Development of source code of the application
- Review the code to ensure accuracy, completeness and perform quality audit
- Development of test cases
- Testing the system
- Generation of test unit logs

Output – Pre-commercial system development of the system to ingest data into the data lake.

Task 5c – Pre-Commercial Demonstration System Integration and Testing

Objective - Undertake integration and user acceptance testing of the pre-commercial demonstration system.

Approach – Testing was undertaken to test the application functionality with data from the data lake. The system test case document was used to perform testing. The testing evaluated the performance of the test system, and generated logs for documenting the test results. The user acceptance testing was performed by the project team to test the application using the system test case document. Testing was undertaken in SDG&E environment.

Output – Integration and testing of the pre-commercial demonstration system.

Task 6 – Advanced Data Analytics

Task 6 involved the following sub-tasks that were undertaken to analyze data from the data lake. Data analysis involved the use of machine learning techniques to develop test data models.

Task 6a – Data Exploration

Objective - Perform data exploration to understand the main characteristics of the dataset, to aid in model development

Approach - This task included data exploration and discovery of different data sets to perform detailed analysis of asset failures. During this task the datasets for various use cases were analyzed to understand which features to include, identify missing observations and make general hypotheses that the available data might support. Exploration of the data helped answer these questions. Some of the variables that were considered when evaluating data for the use cases include:

- Amount of data to be managed (data volume)
- Rate of data generation or change (data velocity)
- Types of data to be managed (data variety)
- Number of data sources and data relationships, and the quality of the data (data complexity)
- Types and complexity of the analytic processing (output complexity)
- Analytic application response time requirements (output agility)
- Makeup of the total analytic visualization

To create predictive models on SDG&E's electric assets, the project team acquired a complete list of assets currently installed in the system to serve as the population data set, and a valid list of assets that had failed. The electric Geographic Information System (GIS) database served as the population data set and the EFR and System Average Interruption Duration Index (SAIDIDAT) data sets served as the failed asset data sets. There were a number of issues encountered when trying to create the analytics data set from the source data, but they all stemmed from the fact that these data sets were maintained in separate databases by different groups. For example, the GIS database is maintained by the Electric GIS Services group which is an enterprise entity that serves data to the entire company. The Equipment Failure Report (EFR) on the other hand is maintained by Electric Engineering and serves to gather data on asset failure from an engineering perspective. Similarly, the SAIDIDAT data tracks outages which is related to asset failure, however the emphasis is on reliability reporting rather than engineering. Because these data sets were not built in a singular data warehouse, joining the data together proved problematic. For instance, for cable failure there is no facility id in GIS, EFR, or SAIDIDAT to create a clean join on. Instead a combination of circuit, upstream structure, and downstream structure was used. In each of these data sets, the field names for the respective fields were different and required research for intelligently joining the data together. Likewise, because these data sets are maintained by different groups for different reasons, the fields did not match up perfectly and required extensive data cleaning prior to using it in the machine learning algorithms. For instance, in the EFR table, the column, CABLE_UG_CONDUCTOR_TYPE_NAME, concatenates conductor size and type together separated by a space. In GIS, the conductor size and conductor type fields are maintained as

separate fields. In order to use this data as a variable in the analytics data set, the fields either need to be separated in the EFR or concatenated in GIS.

In addition to joining data together, the condition of some the data required us to throw away valuable data. There were instances where the EFR tracked fields that were blank in GIS, such as in the case of manufacturer and manufactured date. Whereas we had valuable information for manufacturers and manufacture dates in the EFR that would greatly aid in the process of predicting failures, this data needed to be excluded from the ADS because the data was missing from the assets we were predicting on. In this case it would've been beneficial to have been more flexible in our analytics approach. An alternative approach could include development of a linear or non-linear regression model for asset failure, instead of predicting time to failure for each asset.

In summary, data exploration and data cleaning constituted the vast majority of the time spent on the algorithm development. The addition of the data lake will help in that all of the data needed for an analytics project will be in one place, but vast manipulation of the data and research will still be needed in order to tie failed asset data sets to population data sets.

Output – Data exploration on the various data sources from the data lake.

Task 6b – Model Construction

Objective - Develop a predictive model to forecast asset failures

Approach - During this task a predictive/prescriptive model that uses data explored from Task #6a was used and probable outcomes were forecasted. A model is made up of a number of predictors, which act as variables that may influence outcomes. Once data was collected for relevant predictors, a predictive model was formulated. The model used statistical and machine learning techniques, and was constructed primarily in Spark. As additional data was available, the model was validated or revised.

Once a final analytics data set was created, the process of fine tuning the models commenced. This involved using a variety of different machine learning algorithms, such as logistic regression and random forests. Refining parameters like start, stop and cross validation helped to increase the predictive power of the model.

Output – Predictive model development to forecast asset failures

Task 6c – Model Testing

Objective - Test the analytical model developed in Task 6b

Approach - Model testing and validation is the process of assessing the performance of the data model against real data. It is important to validate the data by understanding its quality and characteristic prior to deploying in a production environment. Various approaches for assessing the quality and characteristics of a data mining model were utilized:

- Use of various measures of statistical validity to determine problems in the data or in the model.
- Separating the data into training and testing sets to test the accuracy of predictions.
- SDG&E business stakeholders review of the results of the data mining model to determine whether the discovered patterns have meaning in the targeted use case scenario.

Some additional tools for testing and validating the data model included:

- Filtering models to train and test different combinations of the same source data.
- Measuring lift and gain - A lift chart is a method of visualizing the improvement that one gets from using a data mining model, when compared to random guessing.
- Performing cross-validation of data sets
- Generating classification matrices - These charts sort good and bad guesses into a table so that one can quickly and easily gauge how accurately the model predicts the target value.
- Creating scatter plots to assess the fit of a regression formula.
- Creating profit charts that associate financial gain or costs with the use of a mining model, so that you can assess the value of the recommendations

One of the most useful forms of model validation was in the presentation to stakeholders and subject matter experts. During the creation of the transformer failure model, a Receiver Operating Curve (ROC) curve in the high 90's was achieved. For the data science team, this was great news, however when the model was presented to the engineering staff, logical flaws were found that could not be seen with any statistical model validation technique. AMI data was used to get a sense of the downstream load that on a circuit where a transformer failed, but the engineering staff insisted that load plays a minor part in the failure of a transformer and subsequently the load data was excluded from the model.

Task 7 – Visualization and Data Presentment

Task 7 involved the following sub-tasks that were undertaken to develop visual screens for presenting data analysis results from Task 6.

Task 7a – Requirements Elicitation and Design

Objective - Requirements Elicitation and Design for Visualization and Data Presentment

Approach - This task involved detailed requirements gathering develop visualizations (user interface) to visualize the output of algorithms developed in Task 6. The following activities were undertaken in this task:

- Detailed requirements and specification for visualization
- Development of requirement traceability matrix
- Development of functional and technical design specification for visualization

- Creation visualization (UX/UI) prototype
- Development of visualization test plan and test cases

The project team also utilized sophisticated visualization tools such as Power Business Intelligence (BI) and Thoughtspot to understand and visualize the data in multiple layers.

Output – Visualization and data presentment requirements

Task 7b – Pre-Commercial Demonstration System Visualization and Unit Testing

Objective - Design and build the pre-commercial demonstration system for visualization and data presentment, and conduct unit testing.

Approach - Upon completion of the requirements specification document, the design and build of the pre-commercial demonstration system was undertaken. The design/build process included the typical application development activities such as:

- Development of source code of the application
- Review the code to ensure accuracy, completeness and perform quality audit
- Development of test cases
- Testing the system
- Generation of test unit logs

Output – Pre-commercial system development of the visualization system for data presentment of the results of data analytics.

Task 7c – Pre-Commercial Demonstration System Integration and Testing

Objective - Undertake integration and user acceptance testing of the pre-commercial demonstration system for visualization and data presentment.

Approach – Testing was undertaken to test the visualization application functionality. The system test case document was used to perform testing. The testing evaluated the performance of the test system, and generated logs for documenting the test results. The user acceptance testing was performed by the project team to test the application using the system test case document. Testing was undertaken in SDG&E environment.

To expose the Hadoop data in an efficient manner, the ThoughtSpot application was evaluated as a self-service analytics and visualization tool. This application is similar to other BI tools, such as Business Objects, but has the flexibility to allow for ad-hoc queries and also provides the ability to associate synonyms with column headers, which allows people who are not familiar with the data model to access data efficiently.

Output – Integration and testing of the pre-commercial demonstration system for visualization and presentment of the results of data analysis.

1.3.3 Phase 3 – SDG&E Internal Work Prior to Project Conclusion

Task 8 – Comprehensive Final Report

Objective – Develop comprehensive final report

Approach - The comprehensive final report was developed as per an outline developed by the project team. The report was prepared as a draft for review and comment by the internal stakeholders and a final version based on comments on the draft.

Output – Comprehensive final report as presented in this document.

Task 9 – Technology Transfer

Objective – Develop technology transfer plan to share results with all stakeholders.

Approach – A technology transfer plan was developed to share the results with SDG&E stakeholders and with other stakeholders in the industry that would benefit from this pre-commercial demonstration

Output – Technology transfer plan as documented in Section 4 of this report.

2 Demonstration Results

2.1 Data Ingestion into Data Lake

As part of this pre-commercial demonstration, seven data sources were ingested into the Hadoop Data Lake. The sources were:

- Equipment Failure Reports (EFR) from Engineering Data Warehouse (EDW)
- Enterprise GIS – Electric Distribution (4/12 kV)
- Outage Data from Network Management System (NMS)
- SAIDIDAT – Reliability Database
- SAP(Systems, Applications & Products in Data Processing) Project Management – Maintenance & Inspection and Work Order Data
- OSIsoft PI Historian – Electric Distribution SCADA
- Power Quality – High Fidelity Event Waveform Data

These data sources were used to demonstrate the viability of failure prediction for the following equipment types:

- Underground Electric Distribution Cable – Use Case 1
- Underground Electric Distribution 600-amp Tee Connectors – Use Case 2
- Padmount Service Transformers – Use Case 3
- Overhead Distribution Wire Failures (i.e. Wire Down) – Use Case 4

Integrations for different data sources and various layers of the Hadoop Distributed File System were created for purposes of ingesting various source data into the Hadoop Data Lake in support of implementing data analytics algorithms to forecast and prescribe distribution asset failures.

Some key benefits of using a platform like Hadoop are as follows:

- It is best suited framework for batch processing
- Open Source platform for data storage and analytics which provides significant cost savings
- It scales it out for raw infinite data and is used in commodity hardware
- Hadoop/Hive processing performance can improve with execution engine like Tez and Spark
- It provides tight integration with Analytical model like Spark and Hive

Key lessons learned from this research that require follow up:

- Algorithm outputs were limited by data inputs. While the statement can naturally be true without further explanation, the vision of this research was that a system could be created to amplify the input data into undiscovered actionable insights. The theory has not necessarily proven false, however the set of use cases that this research was oriented to accommodate did not as a whole satisfy the business needs. That is, no comprehensive system was achieved in which an engineer or asset manager could see all four use cases

on a unified screen and develop short and long term asset maintenance or upgrade plans. While such a dashboard was delivered successfully, the analytics did not yield the expected level of confidence to put into immediate production. SDG&E will need to further improve the necessary data inputs in order to achieve favorable predictive data sets.

- Centralization of disparate data systems is important for the modernization of engineering analytics in the electric utility, however conventional concepts of dashboarding and data visualization were not outgrown in the initial process. The Hadoop system has not yet become a well-known querying system for non-IT professionals, therefore simplified tools for getting out what was put in are a necessity in order for the business to more quickly yield value. These visualization tools need to be flexible, fast, and oriented in such a way that the user can understand where data is coming from for on-the-fly validation.
- (ODBC) connecter available with Visualization tools (like Olikview, Tableau, Power BI etc.)
- It is well suited for structure, semi-structured and unstructured data storage
- Enables working on very large files and is tolerant to hardware and software failures.
- It is used as a tool for pre-processing and aggregation of very detailed data and preferred with for cold data analysis (Historical data)
- Hadoop framework support Cloud and on-Premise deployment

2.1.1 Data Sources

Table 2 below lists the data sources within SDG&E environment that were used to ingest data into the data lake:

Table 2: Data Sources Used for Ingestion

S no.	Data Source	Database Type	# of Tables	Ingestion Process
1a	EFR and DAF (EDW)	SQL Server	2	Sqoop Job
1b	Downstream data (EDW)	SQL Server	6	Sqoop Job
2	OSI PI	Oracle	6	Sqoop Job
3	NMS (Focalpoint)	Oracle	8 Views	Sqoop Job
4a	GIS Elec	Oracle	1033	Sqoop Job
4b	GIS Land	Oracle	299	Sqoop Job
5a	SAP Hana Enterprise (M&I)	SAP HANA	3 Views	Sqoop Job
5b	Infraction Data	SAP HANA	1 View	Sqoop Job
6	SAIDI-DAT (Reliability)	Access	1	Flat file
7	Power Quality Data	SQL Server	41	Sqoop Job

(1) Equipment Failure Reports from Engineering Data Warehouse

This data source was used to provide information about failed assets to inform the training data set. To properly model the probabilities of failure, we needed to include analogous examples of both failed and non-failed assets so the data that was available for failed assets provided a major constraint on what data could ultimately be included in the model. The EFR was an inconsistent data source, providing very good, granular data about Underground Electric Distribution Cable, but scarce data about Padmount Service Transformers, 600-amp Tee Connectors, and Overhead Distribution Wire. Therefore, the EFR was used primarily to provide a failed population for the Underground Electric Distribution Cable use case.

(2) High resolution voltage data from OSI PI

The data from OSI PI was brought in to provide information about how much 'wear and tear' a given asset was undergoing. However, initial efforts to integrate this data in simple ways proved unhelpful, and such data were ultimately not used in the modeling process.

Another attempt to integrate the data was to perform Machine Learning (ML)-based feature detection. By feeding the data through a neural network or other model that could distinguish between failed assets and unfailed assets, the model could generate a measure of risk based purely on voltage data, which would then be integrated with other sources of data to provide an overall analysis.

Unfortunately, the processing power required to provide such an analysis over the entire life of an asset was outside the scope of this project. After conversations with subject matter experts it was determined that basing such analysis on shorter periods of time in an asset's life would either not track to our understanding of the physical systems, and thus be likely to over fit, or would not be useful for the timeframe our models were targeting. If we were to build models based on shorter periods of time, they would predict failure but it may be too late for asset managers and operational groups to replace assets prior to failure. These models may be useful for other areas of the company, and future projects may be able to develop and deploy these models.

(3) Outage data from the NMS System

The use of outage data from the NMS system was initially conceived as a method to capture the effects of outages on circuits, with the understanding that devices that experienced more outages (i.e. subjected to more fault current) were more likely to fail sooner. The outage data also provided a vital source of failed devices for the Padmount Service Transformers, 600-amp Tee Connectors, and Overhead Distribution Wire, especially where EFR records were not available for the failed devices.

Since GIS does not currently track failed equipment at any given structure (i.e. only the current, replacement asset data is available), there were significant difficulties in integrating the various GIS attributes to the failed asset examples. Accordingly, the model was built using Circuit and Substation information as a proxy for other information that was not available. Given that Circuits and Substations were already included as information sources, including outage information would not have noticeably increased the predictive power of the algorithm, as outage information could only be integrated at the circuit level given the constraints the existing datasets have. Since outage information would only be aggregated at the circuit level, it would not provide more information than just using existing circuit information. It would, however, produce a model that was more robust to overfitting, and was therefore more likely to hold up in the future. It also would provide a model that was more explanatory, as it could highlight why some circuits had higher probabilities of failure than others. This is identified as an area for further development, beyond the scope of this project.

(4) GIS Data from the Enterprise GIS System

This data source was used to provide information about active electric assets to inform the training data set. GIS was also used to estimate data about older, failed assets, where that information was deemed important but was not available through various systems. GIS provides

a full map of the assets currently installed, including geolocation, certain connectivity information, material types, vintage/age, among several other attributes across several hundred tables.

Unfortunately, there was limited historical data available about assets that have been replaced, only keeping the service orders of such assets attached to the structures they used to inhabit. For example, a pad-mounted transformer failed and was replaced with a new one, however the existing concrete pad was left unchanged .It was possible to gather some data using these service reports, but the content contained in the reports were not consistent and did not include all the information that the GIS system had about existing assets.

(5) Maintenance Data from the Enterprise SAP system

The Maintenance Data was initially included to provide further information about whether certain assets were visibly decayed or in worse condition when inspectors had visited the site, either for routine maintenance or while conducting maintenance on other assets at the same site. However, upon looking through the data, we quickly reached the conclusion that most inspections were conducted on a scheduled basis, and so any discrepancies that were noted during said inspections would be remedied, leaving very few instances of assets in the field with unresolved inspection issues.

Furthermore, much of the data that resided in the Maintenance records was freeform text, thus integrating the data would require the use of natural language processing techniques that were out of the scope of this project. Due to the above reasons, the maintenance data was not included in the final model, but this is an area for further refinement of the models.

(6) Reliability Information from SAIDIdat

The SAIDI information was intended to aid the decision makers in understanding the impacts various asset failures had on system reliability, and to help predict how future asset failures might impact reliability. The data is manually calculated based on the output from NMS and is almost identical to the outage data from NMS/OMS for predictive purposes, however, and was therefore not used to create models.

(7) Power Quality - High Fidelity Event Waveform Data

Power Quality data is exclusively captured at select substation bus locations and is knowingly often distant, electrically, from the source of equipment failures on electric distribution circuits. Data is monitored on an ongoing basis, however high fidelity data monitoring is triggered when a preconfigured voltage or frequency deviation threshold is met. This data is generally useful when investigating forensic details about an outage or disturbance event, however for purposes of these asset failure analytics does not provide substantially more information than the SAIDI-DAT outage data. Furthermore, this data was not used to create the predictive data models

2.1.2 Process Workflow

Figure 2 below describes the process workflow used to ingest data from the various data sources into the data lake used in this pre-commercial demonstration. As seen in the image below, data from the source databases is extracted on a periodic basis and sent to a landing zone where it exists in a raw state. From the landing zone, the data is archived and then sent to the preparation zone where the data is cleansed and validated. From the preparation zone, the data enters the enterprise data layer where the model output data formatted and stored. The Spark Model uses data from the enterprise data layer for analysis. The Spark Model results are then sent back to the enterprise data layer where it is consumed by the Business Intelligence (BI) Visualization Layer.

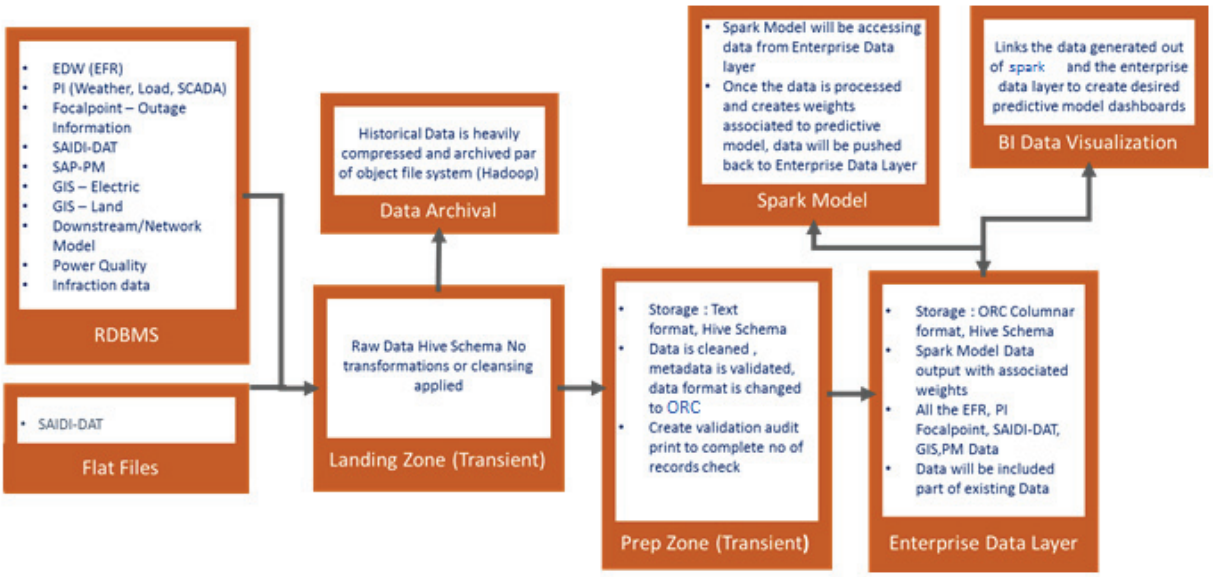


Figure 2: Process Workflow

2.1.3 As-Is Application Architecture

SDG&E's existing data architecture is shown in Figure 3 and Figure 4 below.



Figure 3: As-Is Data Architecture

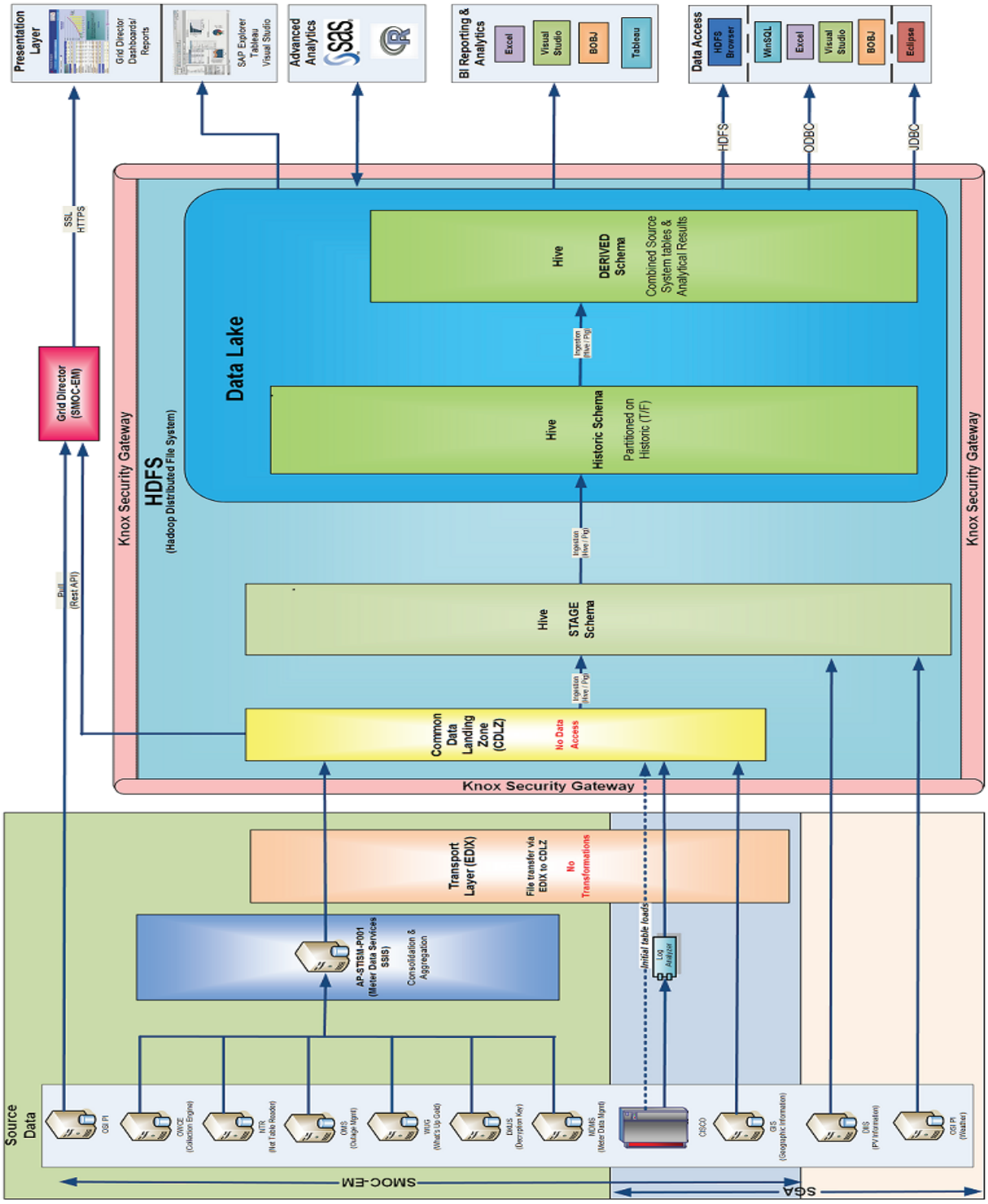


Figure 4: As-Is Data Architecture – Detailed View

2.1.4 Data Architecture Vision

The vision for the pre-commercial demonstration of the data lake functionality is shown in Figure 5 and Figure 6 below.

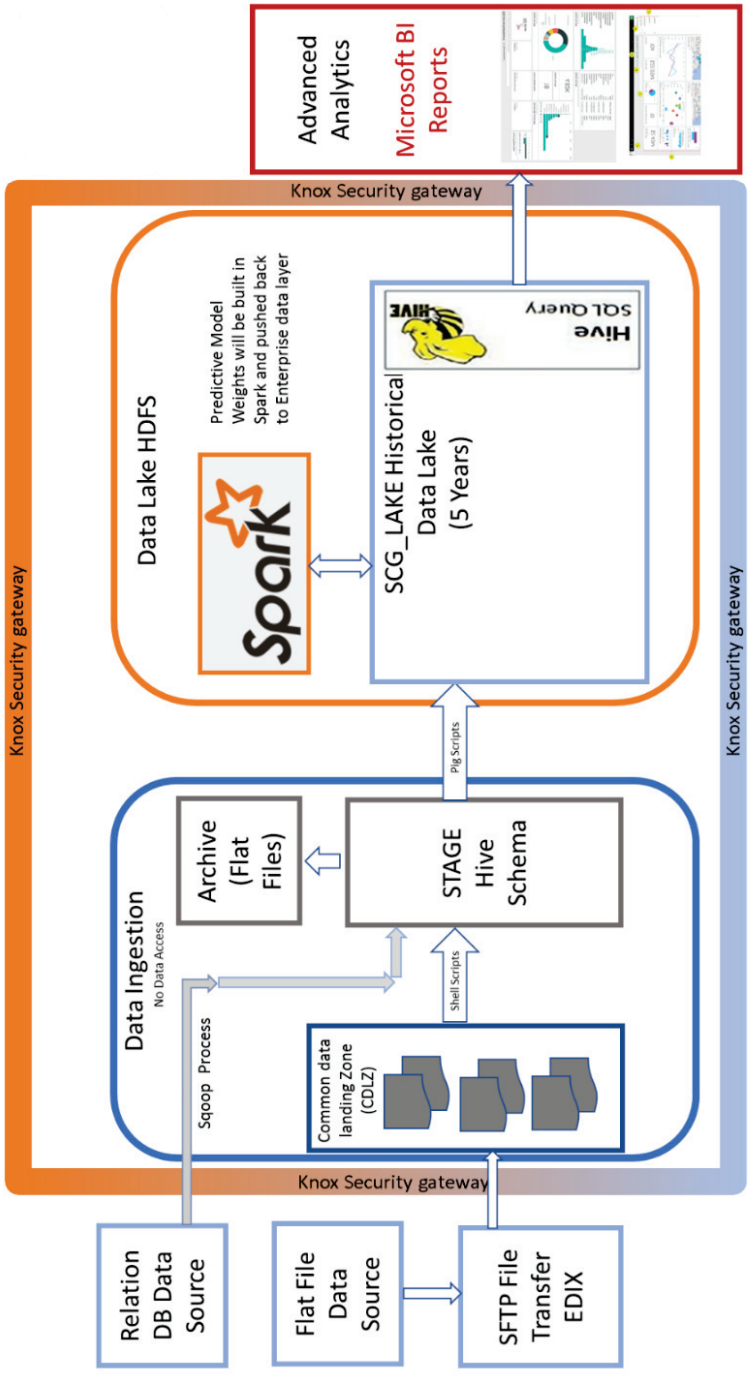


Figure 5: Data Architecture Vision

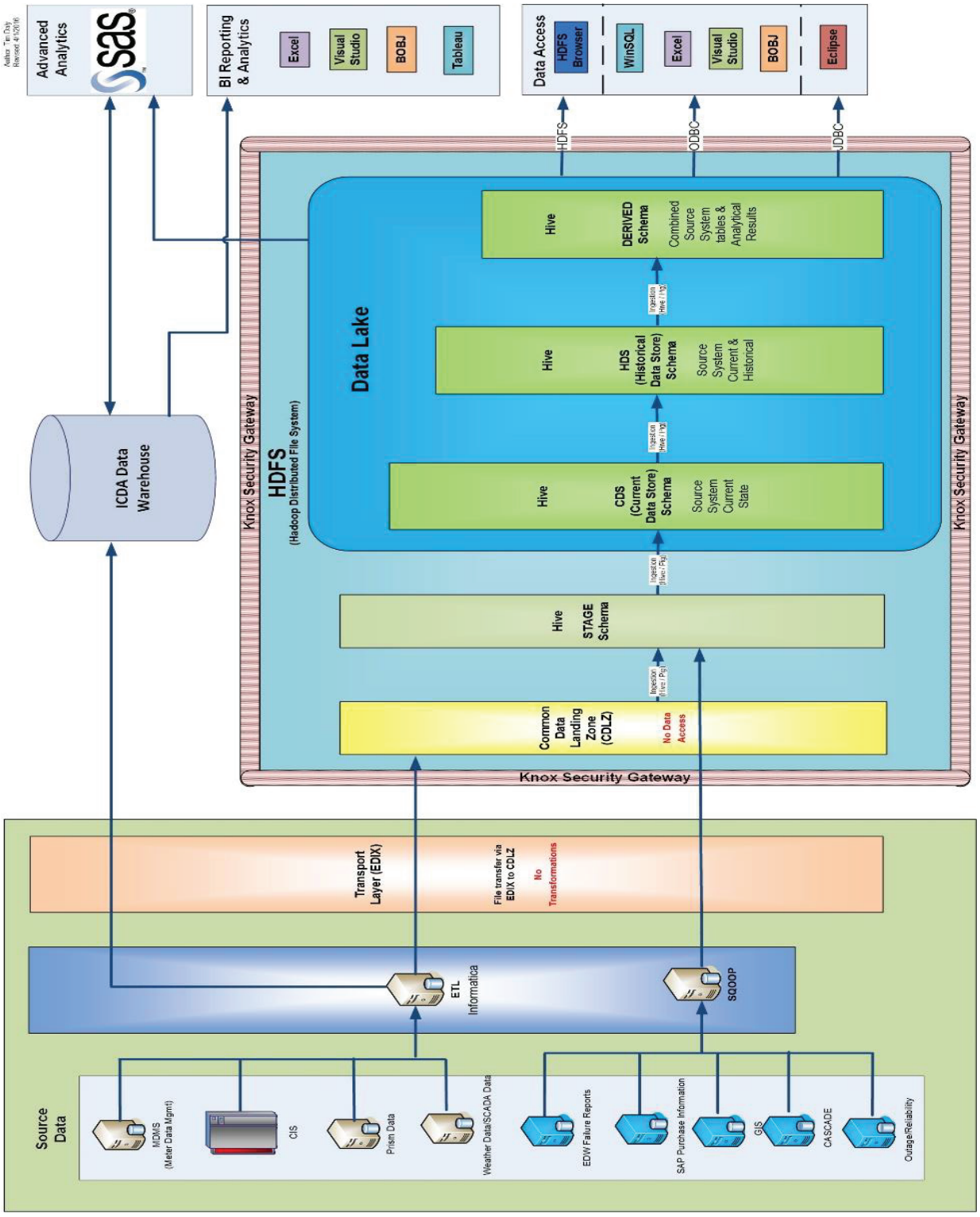


Figure 6: Future Vision - Data Lake Architecture

2.1.5 Data Lake - System Environment

The data lake eco-system consists of the following components:

- **Hadoop** - Hadoop is an open source, Java-based programming framework that supports the processing and storage of extremely large data sets in a distributed computing environment
  Reference - http://hadoop.apache.org/
- **Hadoop Distributed File System (HDFS)** - A special purpose file system designed to provide high-throughput access to data in a highly distributed environment
  Reference – http://hadoop.apache.org/docs/r1.2.1/hdfs_design.html
- **Hive -** A tool for creating higher level SQL-like queries using Hive Query Language (HQL), the tool's native language, that can be compiled into sequences of Map-Reduce programs
  Reference - https://hive.apache.org/
- **Pig -** A platform for creating higher level data flow programs that can be compiled into sequences of Map-Reduce programs, using Pig Latin, the platform's native language
  Reference - https://pig.apache.org/
- **Sqoop** - A tool designed for efficiently transferring bulk data between Apache Hadoop and structured data stores such as relational databases.
  Reference - http://sqoop.apache.org
- Apache **ORC -** Apache ORC is an optimized row columnar (ORC) file format provides a highly efficient way to store Hive data. It was designed to overcome limitations of the other Hive file formats. Using ORC files improves performance when Hive is reading, writing, and processing data.
  Reference - https://orc.apache.org/
- **Oozie Scheduler**- Oozie is a workflow scheduler system to manage Apache Hadoop jobs.
  Reference - http://oozie.apache.org

2.1.6 Data Ingestion - High Level Business Requirements

Based on the future state vision described in Figure 6 above, ten (10) data sources were identified for ingesting data into the data lake. Data from these data sources was identified to perform analytics to determine predictions and prescriptions regarding electric distribution failures. Table 3 below presents a consolidated view of the requirements that were defined for ingesting data from the data sources into the data lake.

Table 3: Data Ingestion Requirements

Sr. No.	Requirement ID	Requirement Statement
1	SRf_1	The user would like to have **EFR and DAF data** available in Hadoop Data Lake to perform analytics
2	SRf_2	The user would like to have **OSI PI data** available in Hadoop Data Lake to perform analytics
3	SRf_3	The user would like to have **Outage and restoration (Focalpoint) steps data** available in Hadoop Data Lake to perform analytics
4	SRf_4	The user would like to have **GIS ELEC data** available in Hadoop Data Lake to perform analytics
5	SRf_5	The user would like to have **GIS LAND data** available in Hadoop Data Lake to perform analytics
6	SRf_6	The user would like to have **SAP HANA Enterprise – M&I data** available in Hadoop Data Lake to perform analytics
7	SRf_7	The user would like to have **SAIDI data** available in Hadoop Data Lake to perform analytics
8	SRf_8	The user would like to have **Downstream/Network Model data** available in Hadoop Data Lake to perform analytics
9	SRf_9	The user would like to have **Power Quality data** available in Hadoop Data Lake to perform analytics
10	SRf_10	The user would like to have **Infraction data** available in Hadoop Data Lake to perform analytics

2.1.7 Data Ingestion – Use Cases

The identified use cases for the data sources mentioned above for analytics to be performed by are described in Table 4 below:

Table 4: Data Ingestion Use Cases

Sr. No.	Use Cases
Use Case 1	**Underground Electric Distribution Cable Failures**: Perform analytics and visualizations to determine predictions and prescriptions regarding electric distribution underground cable failures. Seek to proactively identify trends in underground cable failures regarding geographic region, weather conditions, age of the equipment, asset health, asset utilization (e.g. measured and derived load patterns), asset types (e.g. cable gauge, manufacturer, insulation type), installation and maintenance history, and other related attributes. Visualize a high-level operating risk* (e.g. reliability exposure, maintenance/inspection prioritization) prioritization to inform business action plans. *prescribed replacements may be prioritized by length and type of cable, type of underground structure, prospectively impacted customer counts, etc.
Use Case 2	**600-Amp Tee Connector Failures**: Perform analytics and visualizations to determine predictions and prescriptions regarding electric distribution 600-amp tee failures. Seek to proactively identify trends in 600-amp tee failures regarding geographic region, age of the equipment, weather conditions, asset health, asset utilization (e.g. measured and derived load patterns), asset types (e.g. cable gauge, manufacturer), installation and maintenance history, and other related attributes. Visualize a high-level operating risk* (e.g. reliability exposure, maintenance/inspection prioritization) prioritization to inform business action plans. *suggested derived metrics may include potential customer outage exposure (repair time, volume of customers), potential repair costs, failure trends by structure type, failures trends by derived structure state (e.g. flooded, contaminated, dry), etc.
Use Case 3	**Padmount Service Transformer**: Perform analytics and visualizations to determine predictions and prescriptions regarding electric distribution transformer failures. Seek to proactively identify trends in overhead and underground transformer failures regarding geographic region, weather conditions, asset health, age of the equipment, asset utilization (e.g. measured and derived load patterns), asset types (e.g. rating, manufacturer), installation and maintenance history, and other related attributes. Visualize a high-level operating risk* (e.g. maintenance)

	prioritization to inform business action plans. *standard KVA ratings of transformers can often be up to 150% of nameplate – develop metrics to rank transformers by overloading pattern (e.g. consistently overloaded vs. intermittently overloaded) based on data such as AMI
Use Case 4	**Overhead Distribution Wire Failures (Wire Down):** Perform analytics and visualizations to determine predictions and prescriptions regarding electric distribution wire down events (asset failures causing wires to fall to the ground). Seek to proactively identify trends in wire down causes regarding geographic region, weather conditions, asset health, asset utilization (e.g. measured and derived load patterns), asset types (e.g. wire gauge, metal type), installation and maintenance history, and other related attributes. Visualize a high-level (e.g. by operating district, substation, circuit, etc.) safety risk* prioritization to inform business action plans. *suggested derived metrics may include projected wire down counts per circuit based on failures, projected exposure for public contact, state of energization, etc.

2.2 Data Modeling

This section describes the data modeling process undertaken by the project team to create analytic models for equipment failure prediction

2.2.1 Model Design

Initial Design: Days to Failure

Based on initial scope resulting from coordination between SDG&E's Information Technology and Electric Distribution Engineering stakeholders, the initial model was slated to predict how many days a given asset would last, with an adjustable confidence interval that would provide the logistics planners the ability to be well-stocked in case of significant model error. The advantage of this approach was that it allowed the model to predict relatively far into the future, allowing logistics planners to put together both relatively short term (1 year), and long term (10 year) plans. A major disadvantage of this approach was the difficulty in integrating non-failed assets into the model, since a non-failed asset had not yet failed, so the notion of days to failure was not applicable.

The first use case that models were built for was underground electric distribution cable. The primary reason for this was the vast amount of data recorded in the Equipment Failure Report database was for failed cables, which allowed for rapid model development, to see how viable the models were to begin with. Initially, the model proved relatively correlated with days to failure (R^2 of 0.60), but the error was enormous, with a relative mean square error of 62%. It was clear that further refinement of the data was required.

After some research into best practices from other fields, a new approach was attempted. The data set was rebuilt, to include data from both failed and unfailed cables. Instead of predicting days to failure, the model predicted whether a given cable failed. To retain the advanced forecasting capabilities, a new attribute was added, 'days in operation', which measured how long a cable had been in operation. In this way, the models could still project out multiple time periods in the future. The new model was much more successful, with a misclassification rate of only 7%, and a receiver operating curve (ROC) area of 0.97.

After generating this model, our attention turned to the other three use cases. As detailed above in the data sources section, there were numerous issues getting more data for the other asset types, as the information in the equipment failure reports was scant, and the other data did not distinguish beyond the circuit level. The models for the other asset types were trained on data sets using only substation, circuit, and days in operation. Further, there were numerous issues with developing days in operation for failed assets, as service orders for failed assets were not consistently available and there was significant error in the development.

Due to the above issues, the models for the other assets had an average misclassification rate of 31% and an average ROC area of 0.75

2.2.2 Model Evaluation

The process of evaluating a model is relatively involved. There are many metrics that can be used to evaluate different model types. As the models developed for this project were Binary Classification models, the evaluation metrics for these model types will be discussed below.

Kappa Statistic

Kappa Statistic is similar to Pearson's Correlation Coefficient (R). It is a measure of how well a model sorts data into the correct classes, considering how the dataset is distributed. It is calculated thusly:

$$\kappa \equiv \frac{p_0 - p_e}{1 - p_e} = 1 - \frac{1 - P_m}{1 - P_e}$$

where P_m is the model's correct classification rate, and P_e is the expected classification rate of a random model (if the data is distributed 95-5, for example, P_e would be 95). For the models, the best Kappa statistic generated was 0.85

ROC Area

The Receiver Operating Curve (ROC) area is a measure of the area under a Receiver Operating Curve. The ROC Curve is a measure of how well the model classifies various types of data, both with high confidence and low confidence. The ROC area represents the probability that if two instances were selected, one positive and one negative, the one with the higher score is the positive instance. The best ROC Area generated was 0.97. The curve for that model is illustrated in

Figure 7 below:

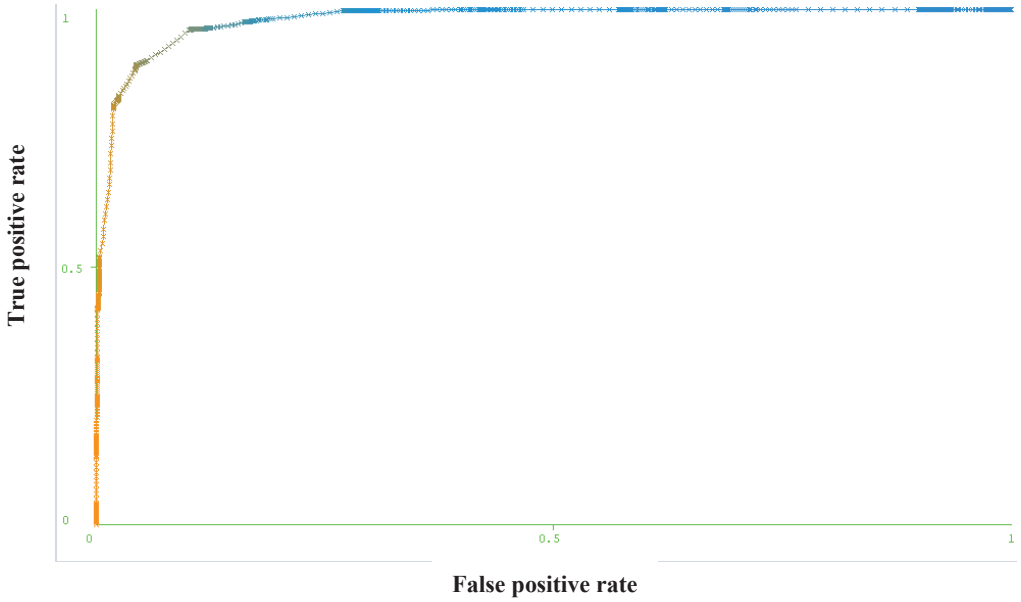


Figure 7: Receiver Operating Curve (ROC)

Misclassification Rate

Misclassification Rate is a measure of how frequently a model generates the wrong label for a given instance. It is essentially how often the model is 'wrong', either way. The best misclassification rate generated was 7%

Confusion Matrix

The Confusion Matrix is a table that shows how often each type of classification occurs: True Positive, True Negative, False Positive, and False Negative. It is useful for understanding the weaknesses of a given model. The best confusion matrix generated is presented below:

	Classified Y	**Classified N**	
Actual Y	37,114.53	1,568.67	38,683.2
Actual N	4,130.33	35,384.67	39,515
	41,244.86	36,953.34	

$$\textbf{Accuracy} = \frac{TP + TN}{total} = \frac{37{,}114.53 + 35{,}384.67}{78{,}197.97} = \mathbf{92.71}\%$$

$$\textbf{Misclassification Rate} = \frac{FP + FN}{total} = \frac{4{,}130.33 + 1{,}568.67}{78{,}197.97} = \mathbf{7.29}\%$$

2.3 Visualizing Predictive Analytics Use Cases

The forecasted data from the models was visualized on Power BI dashboards to predict and prescribe electric distribution failures for specific forecasted time period. All requirements below are for the four use cases (four equipment types) on four different dashboards i.e. each use case with its own dashboard unless stated otherwise. Table 5 below describes the high level requirements for the five dashboards that were created for this demonstration project.

Table 5: Data Visualization Requirements

Sr. No.	Requirement ID	Requirement Statement
1	SRf_11	The user would like to have **Heat Map** to see all the forecasted failures for a selected forecast period (+1 year, +2 year, etc.) to check the highest severity areas.
2	SRf_12	The user would like to have **Tree Map** to showcase the count of electric assets starting from all and use the sliders to narrow the results based on risk measure range.
3	SRf_13	The user would like to have **Bar Graph** which would be common between four different dashboards to showcase Top 10 Circuits with the average of risk measure for each of the four use cases for a selected forecast period (+1 year, +2 year, etc.)
4	SRf_14	The user would like to have a **Line Graph** to compare the forecasted failure of the asset type for the entire forecasting period
5	SRf_15	The user would like to have **a Table** to display the entire base table in descending order by the risk measure for a selected forecast period (+1 year, +2 year, etc.)
6	SRf_16	The user would like to have frequency tables (type, count/average) for the four-different equipment's highlighted in Phase 2 along with their associated attributes for a selected forecast period (+1 year, +2 year, etc.)

The fifth dashboard is different from the other four as it displays the top forecasted circuit failures by forecasted failure probability and composite score and the data from all the equipment's will be utilized.

2.3.1 Selection of Microsoft PowerBI

Over recent years of SDG&E's experience creating ad-hoc dashboards using Microsoft Power BI's visualization platform, SDG&E has become familiar with the tool and its capabilities. SDG&E therefore chose this toolset to demonstrate the results of this EPIC project so as not to introduce new variables and challenges attributed to adopting a new front-end tool. This decision aimed to allow end users of the to better focus on the business intelligence gained from the analytical models. In the event future enhancements would be desired by users, SDG&E's existing software development staff would also be best equipped to provide immediate support.

2.3.2 Dashboard Design

The overall layout of the project dashboard is unique to the specific use cases explored in this EPIC project. However, when collocated and compared with other SDG&E dashboards created in PowerBI, the widgets are easily adopted by the users and their ease of use is commonly favorable to achieve relatively quick insights. Figure 8 below presents a high-level summary of the visualization dashboard that was created for this project.



Figure 8: Visualization Dashboard

Note: The above figure does not depict any actual data or analytical results and is provided for illustrative purposes only.

The dashboards were designed to display the highest levels of information and options near the top of the window and the lowest levels on the bottom. Pictured top-left, the highest level of data selection is represented by the Risk Metric: Composite Score (CS) or Probability of Failure (FP). The Probability of Failure, configurable by the adjacent "slider" widget, allows the user to focus the geographic representation of assets based on the desired range of failure probabilities. Engineers may consider viewing the "top quartile" of probable failures in order to plan their near-term reliability improvement projects, however being weary that a probability that is "100%" may indicate a failure so imminent that more immediate operational action could also be necessary.

The Composite Score incorporates both probabilistic figures and consequential figures associated with electric assets. The notion of a composite score, which will be further explored in the future, aims to provide a prescriptive analytic, weighing enterprise consequences and benefits in one score combined with probabilistic measures (i.e. risk). Pictured top-right, the Forecast Periods (1-10 Years Out) were chosen as simple increments to model the chosen risk metric. Though the model is capable of calculating failure probabilities on a daily basis (i.e. Days in Operation described previously), the Years were chosen for its ease of use in the dashboard and also to emphasize the point that the failure probabilities do not often change significantly over a period shorter than a year at a time. Pictured center-left, the GIS map displays the assets that meet the selected criteria.

Color scales based on magnitude of the chosen Risk Metric can be customized and are shown from light green to solid black, indicating a low value to a high value, respectively. Illustrated bottom-left, the tile trees are automatically sorted by magnitude, as indicated by the size of the tile. Also included in the tile is a numeric value indicating the count of assets that meet the selected criteria. The tile tree is perhaps one of the most powerful tools on this dashboard as it can be further analyzed and sorted using Drill Down menus. For example, a user can select a desired operating District, which would then cause the map to zoom to the general area of the district. The user can then see that the tile tree automatically sorts the asset groupings by substation. The user can further drill down by circuit, then by individual asset (e.g. span of cable). With each drill down, each adjacent widget stays in synchronism by updating their respective values.

The only standalone widget that is independent from other actions chosen on this dashboard is the Top 10 widget. This widget consistently shows data reflecting all asset use cases and provides an overall ranking of asset risks for the four use cases explored in this project. Users can customize visualization settings to see any number of circuits, however 10 were chosen by default for simplicity. Each of the circuits in the Top 10 widget can be further drilled down to identify which use case (e.g. cable, tees, transformers, or wires down) contributed most to the overall risk score. Lastly, users can export the raw data table to an Excel spreadsheet using the widget pictured on the bottom-right in order to easily perform additional data processing and manipulation.

2.3.3 Additional Dashboards

This section provides additional set of dashboards that were created as part of this EPIC project. The figures shown below do not depict actual data or analytical results and are provided for illustrative purposes to demonstrate the visualization equipment failure predictive analysis. The project team created multiple versions of dashboards as part of this pre-commercial demonstrate to evaluate which type of dashboards might be suitable for the relevant stakeholder in the company.



Figure 9: High Level Dashboard – Initial Forecast for the first year for all districts

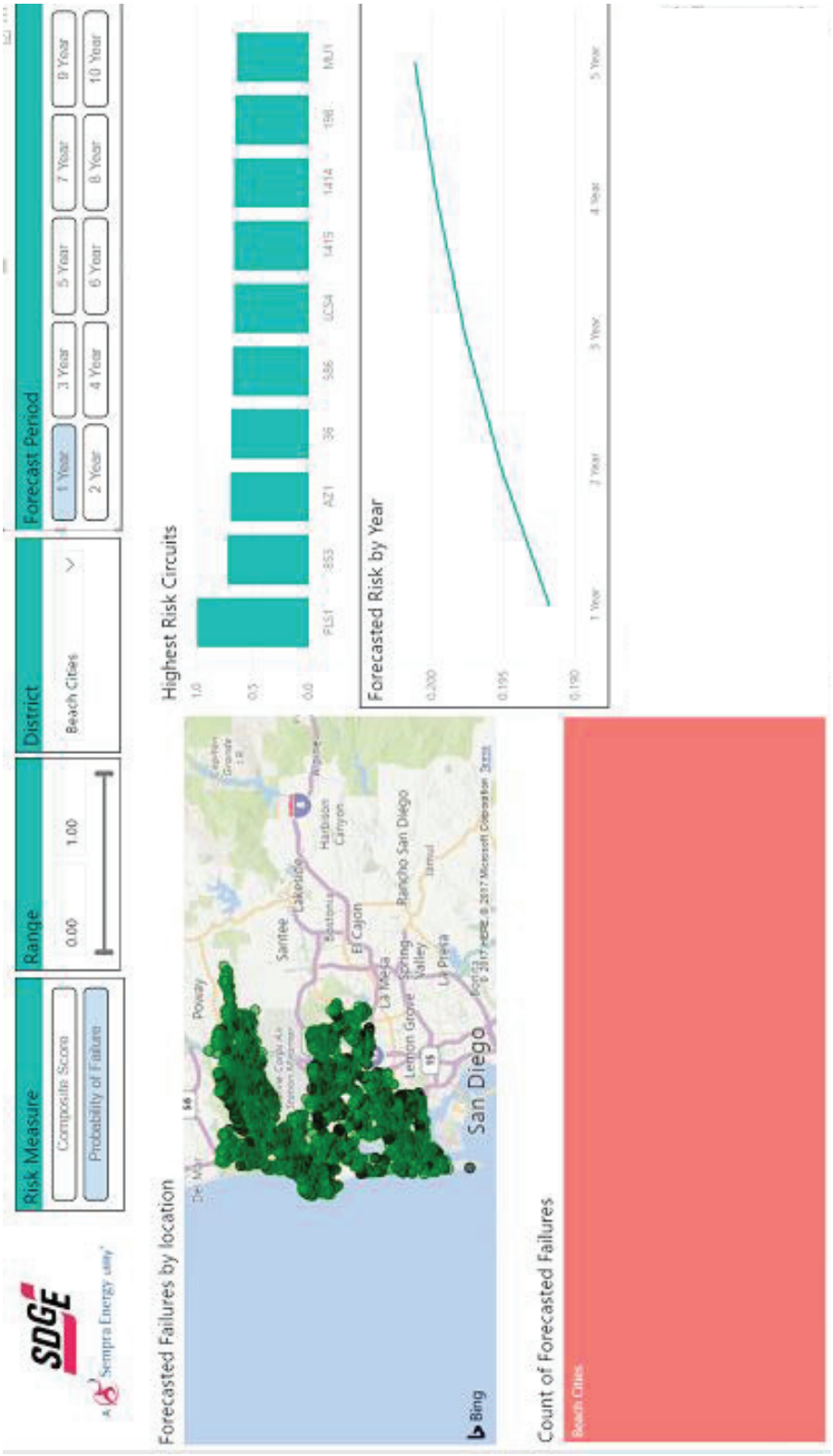


Figure 10: Forecast for first year for a sample district



Figure 11: Forecast for first year for a sample substation

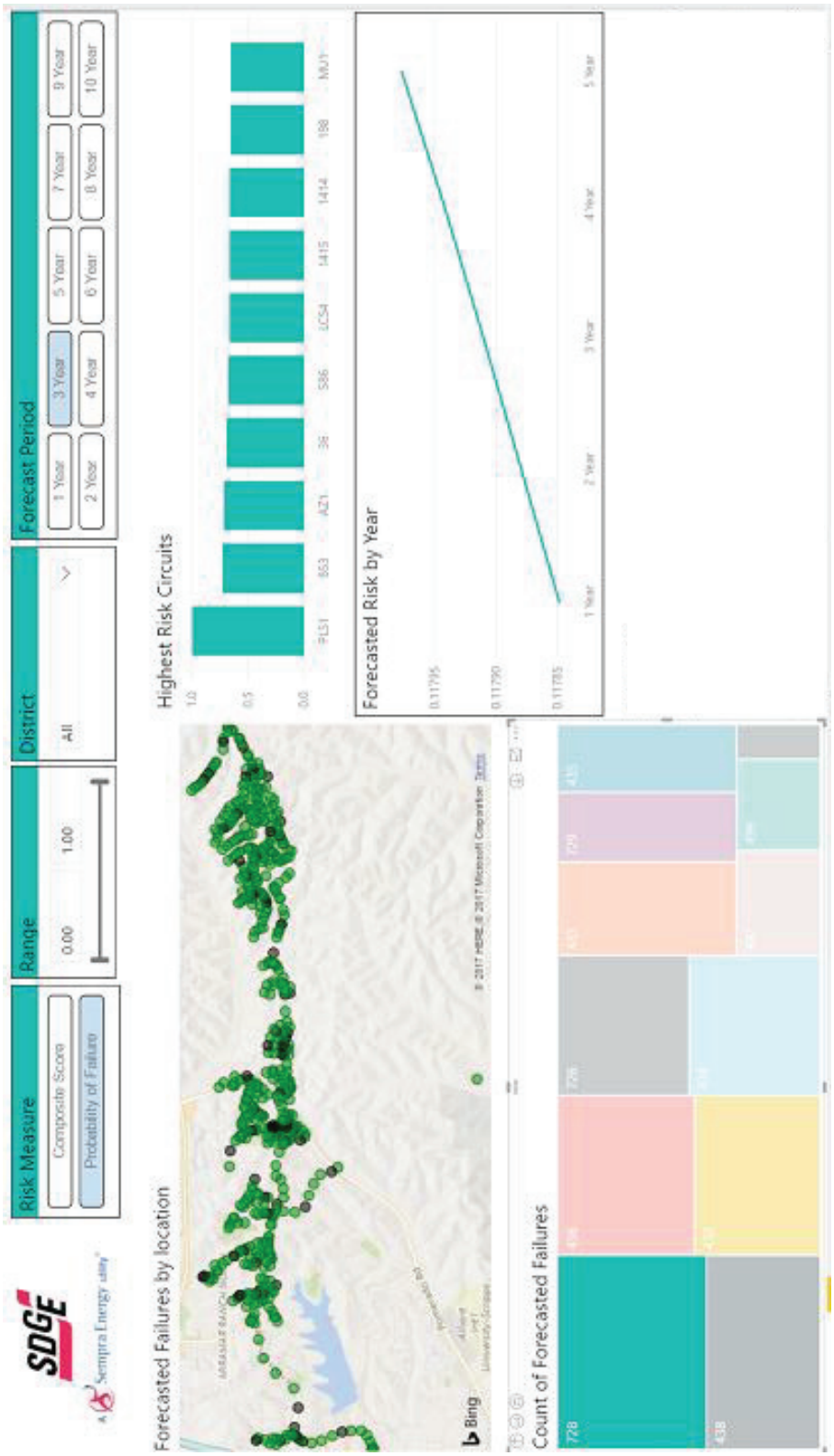


Figure 12: Forecast for third year for a sample circuit



Figure 13: Forecast for a chosen Slicer value – 0.90 to 0.95 for all districts for a 3-year forecast period

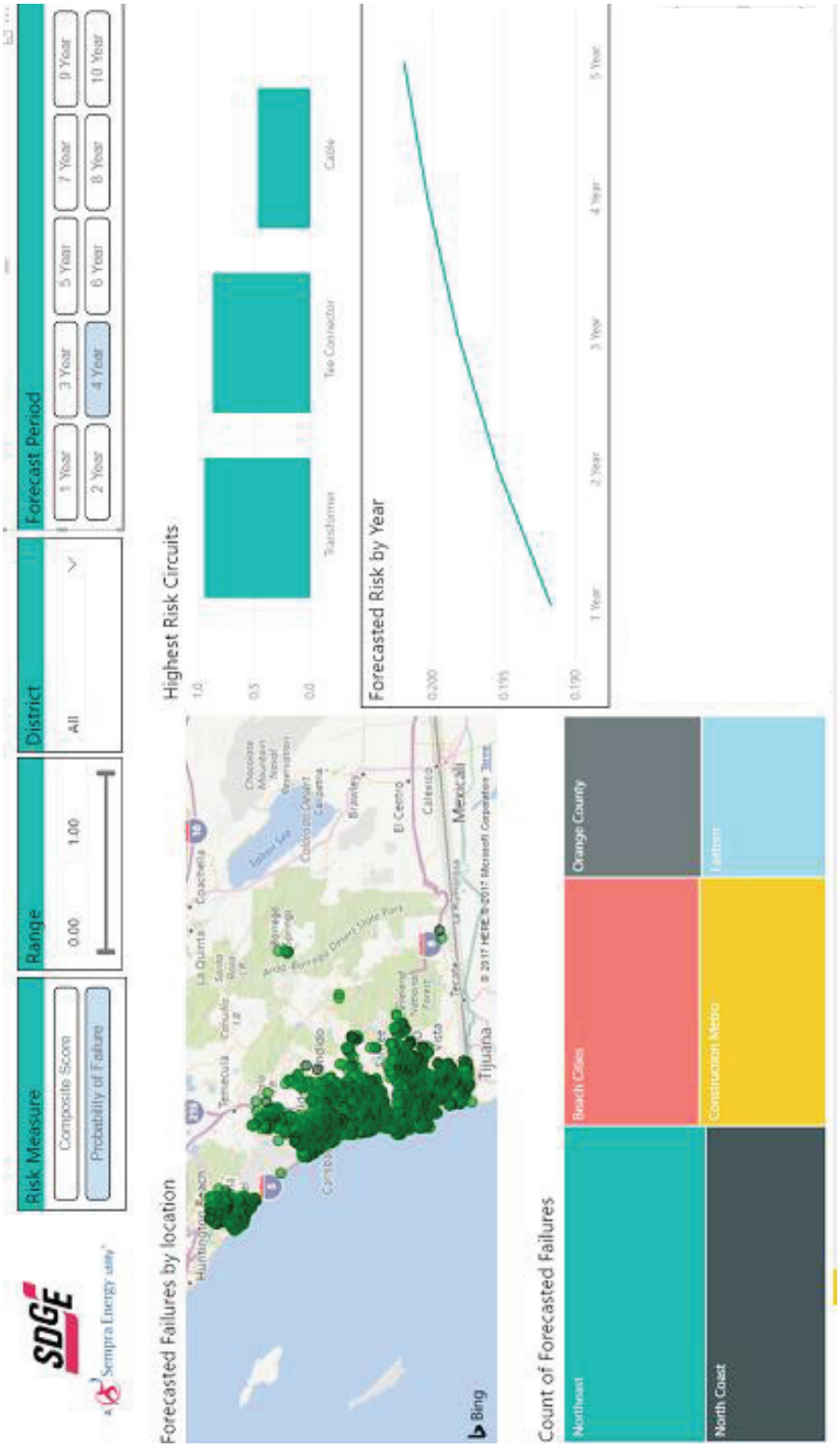


Figure 14: Forecasts for sample high risk circuit at equipment category level for 5-year forecast period

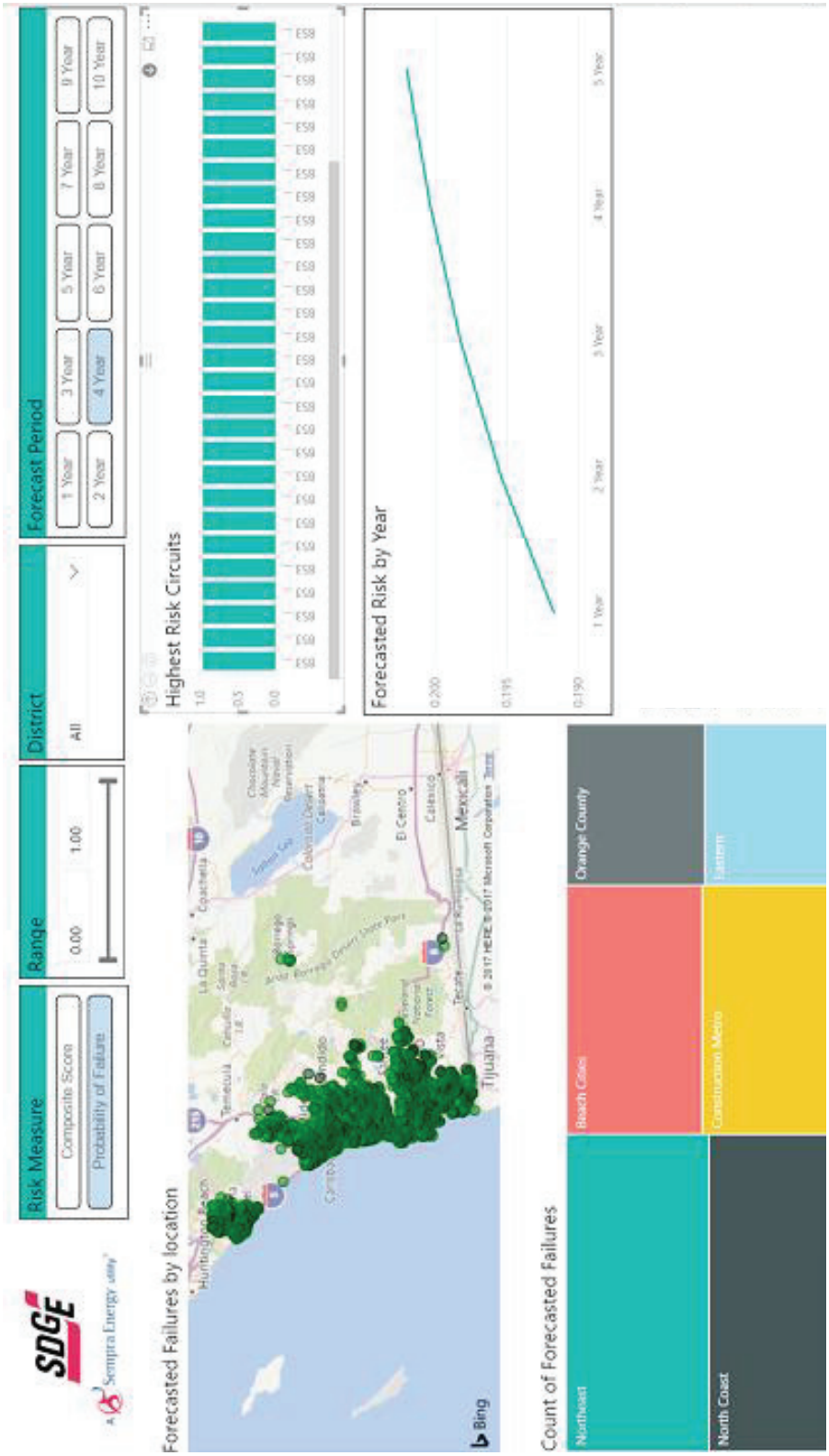


Figure 15: Forecast for a sample high-risk circuit at individual equipment level for Tees at 853 Circuit

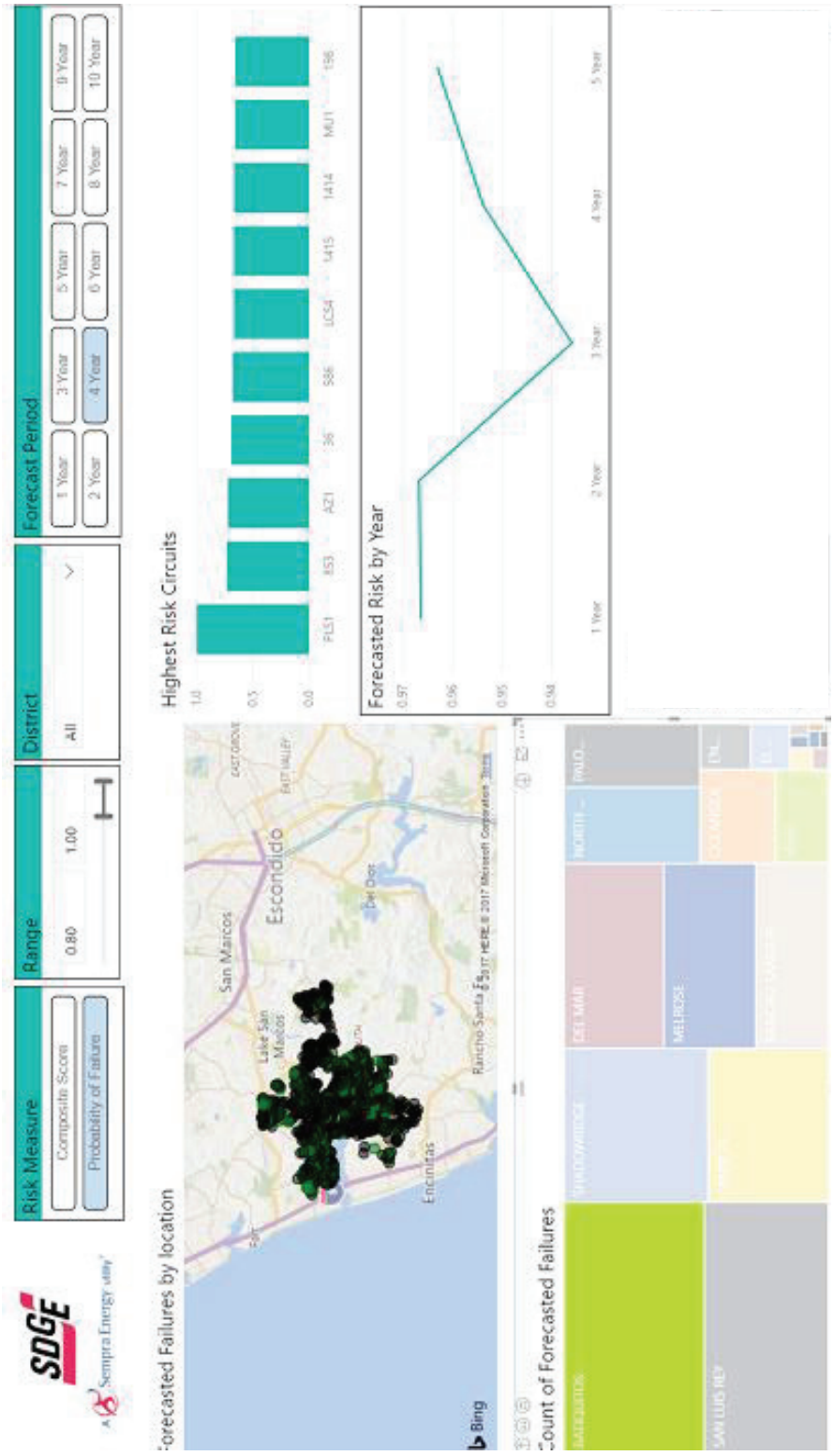


Figure 16: Forecasts for fourth year for a sample substation with slicer value ranging from 0.80 to 1.0

2.3.4 Enhanced Visualization Tool

In order to expose the Hadoop environment to more users, a self-service analytics/query tool was sought. The tool is able to allow end-users to run complex queries on the disparate data sets without having to use SQL scripting. It puts the complexity of database joins and aggregations behind the scenes and allows for data queries and reporting using business language. It requires extensive overhead to build the semantic layer that knits the disparate data sets together, however, once created; the user experience is fast and reliable. The only limit to the tool's capabilities is our ability to implement it as an Enterprise application. While the initial implementation requires extensive support from many groups, subsequent support after rollout is anticipated to be minimal and requires just one business analyst to maintain the application. The tool's usage is expected to grow in leaps and bounds as more departments are exposed to its capabilities.

The area of analysis was limited to conductor data (overhead and underground), providing self-service access to the following data set:

- Conductor meta data
- Infractions
- Outages

The objective of this analysis was to discover:

- The top 5 most reliable assets based on cumulative outages and infractions.
- The top 5 most unreliable assets based on cumulative outages and infractions.

Data Model – The project team utilized the sample data model created as part of this EPIC project and loaded source data into the in-memory cache of the product. The first step was to create a schema to allow conductor GIS tables to be loaded into the system, but also evaluate the data model to ensure outages and infraction data was properly modeled to conductor info. The net result was a simplified data model that was created.

Data Extract & Refresh - Data was loaded from a extract from GIS source system (flat files) and then loaded into the appliances in-memory cache. This data extract and load approach could be scripted for frequent data refreshes (daily) to integrated into existing ETL tools utilized by the SDG&E team. For this initial use case, information was brought in from for the last five years (2012 to 2017). The entire data set comprised 0.3GB of data. The same information comprising this data set could be extracted from the SDG&E Hadoop data lake, extracted as flat files, and refreshed on a periodic basis.

Enhanced Visualization Results - With the outages worksheet based on multiple conductor tables in the data model, the project team proved that all of the following searches were easily possible. A pinboard (dashboard) of results from these searches was created to showcase the capabilities to the end user. Searches and initial pinboard creation was completed within 30 minutes, further proof that SDG&E can save analyst time in developing customer solutions to answer questions related to conductor outages.

When performing searches using the Outages Worksheet, a "best fit" visualization is automatically presented by the appliance. Meaning if a set of measures and dimensions are included in the search, the appliance automatically displays a column chart, line chart, scatter plot, geo map, or "best visualization" to represent that search. The user could further refine these visualizations or pick from a library of other visualization types.

Data can also be represented in a tabular format, allowing SDG&E personnel to copy, filter, or extract to Excel data from the search. These features give users the flexibility to utilize this data as needed, plus construct their own pinboards of saved results.

Some of the searches performed (and the corresponding typed search in the appliance) and results included:

i. Figure 17 below presents the monthly number of outages that were analyzed for the six districts in 2017.

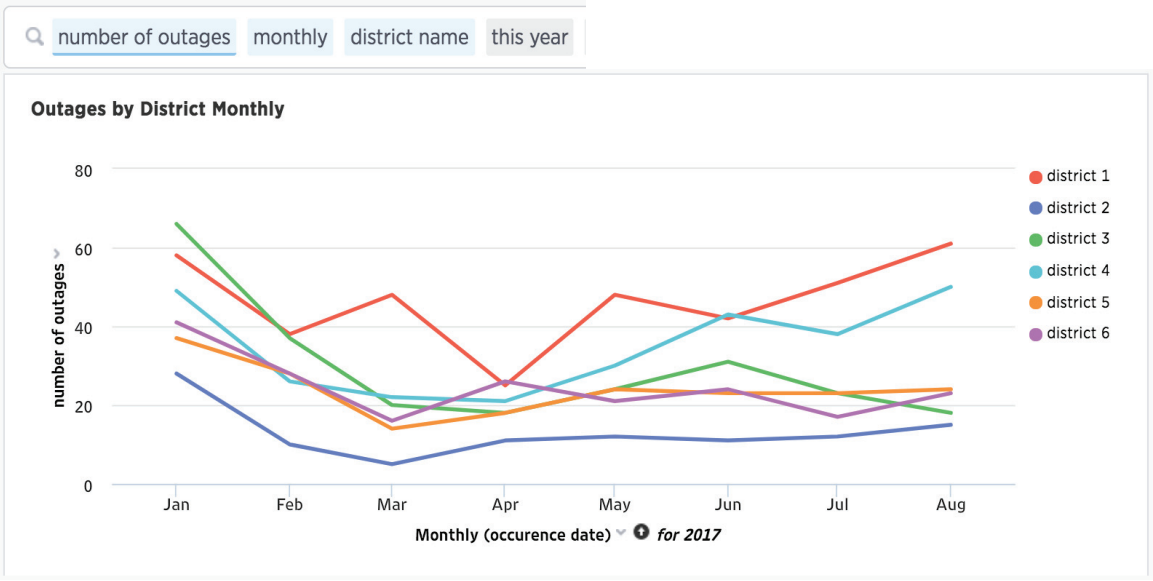


Figure 17: Monthly District Outages for 2017

ii. Figure 18 identifies the top 10 conductors (unreliable) vs the number of outages that were analyzed in the tool.

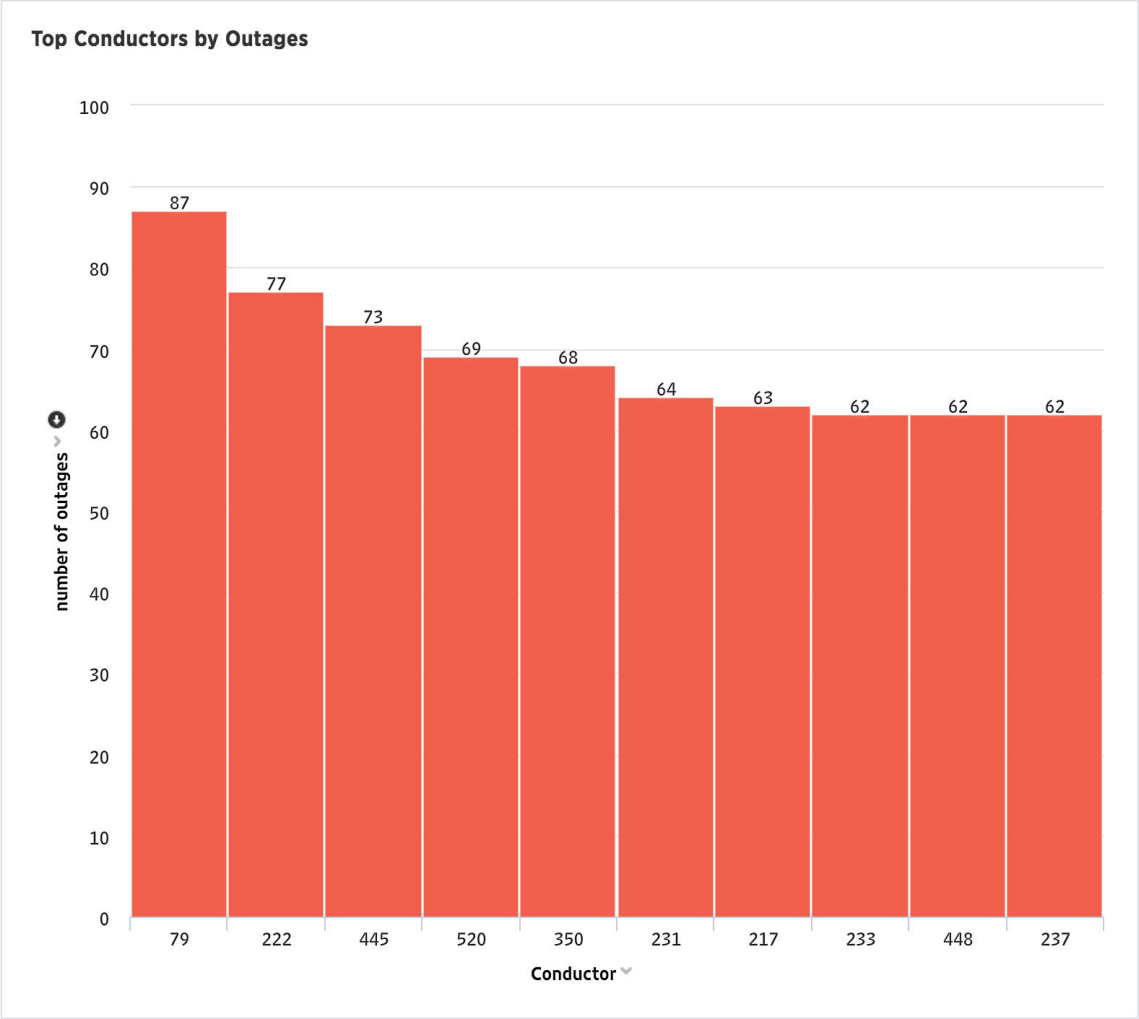


Figure 18: Top Conductors by Outages

iii. Figure 19 presents the number and trend of monthly outages over the last three years.

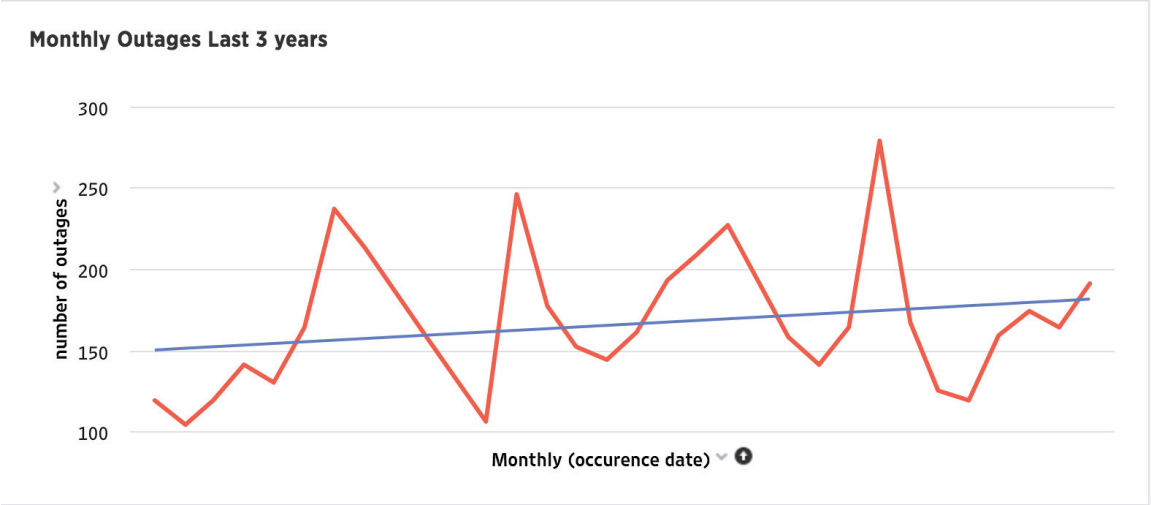


Figure 19: Monthly Outages for the Last 3 Years

iv. Total number of outages by cause category: Figure 20 presents the number of outages by the cause attributed to the outage.

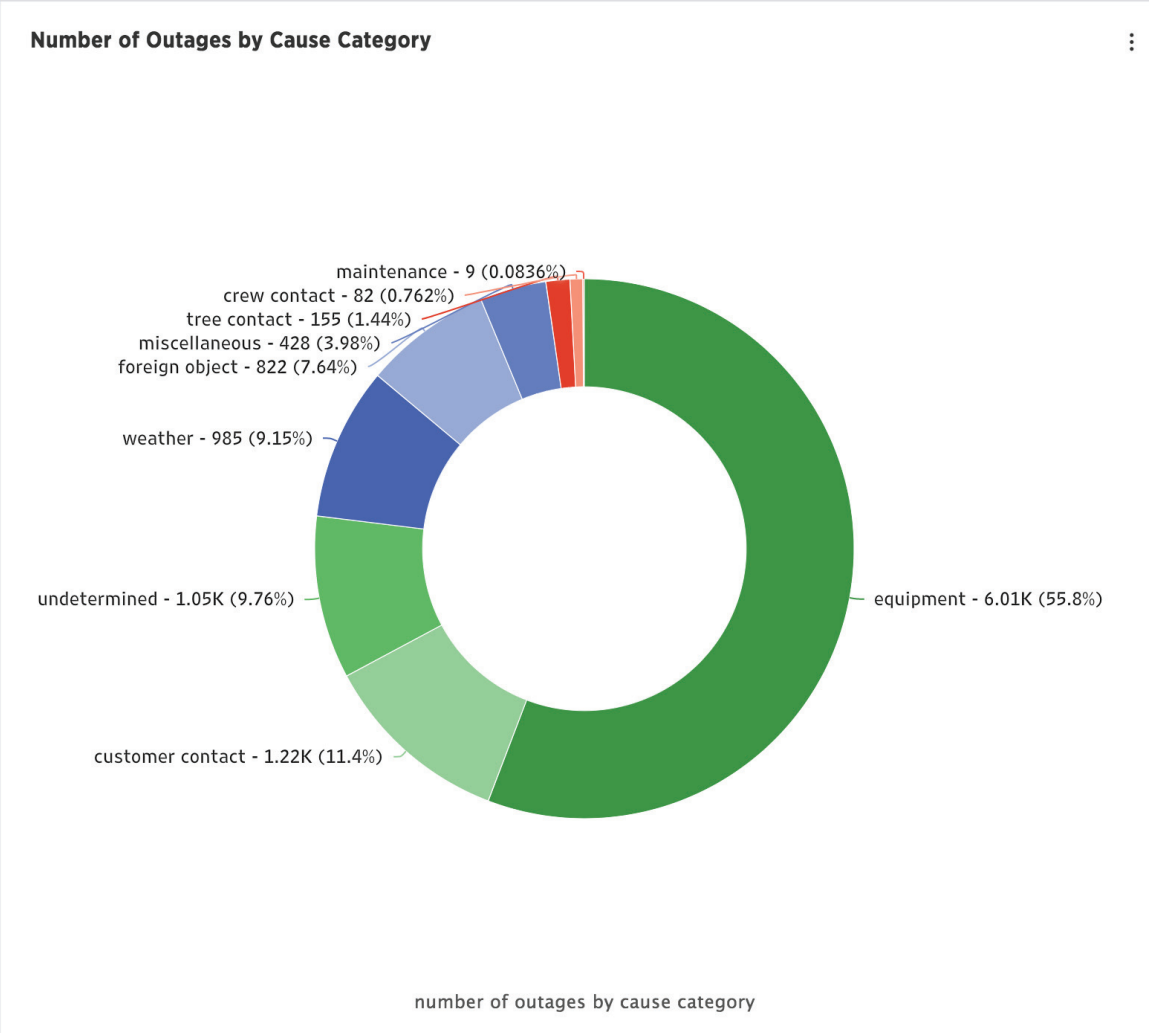


Figure 20: Total number of outages by cause category

The portion of the individual items pinned to the outages dashboard is show in Figure 21 below.

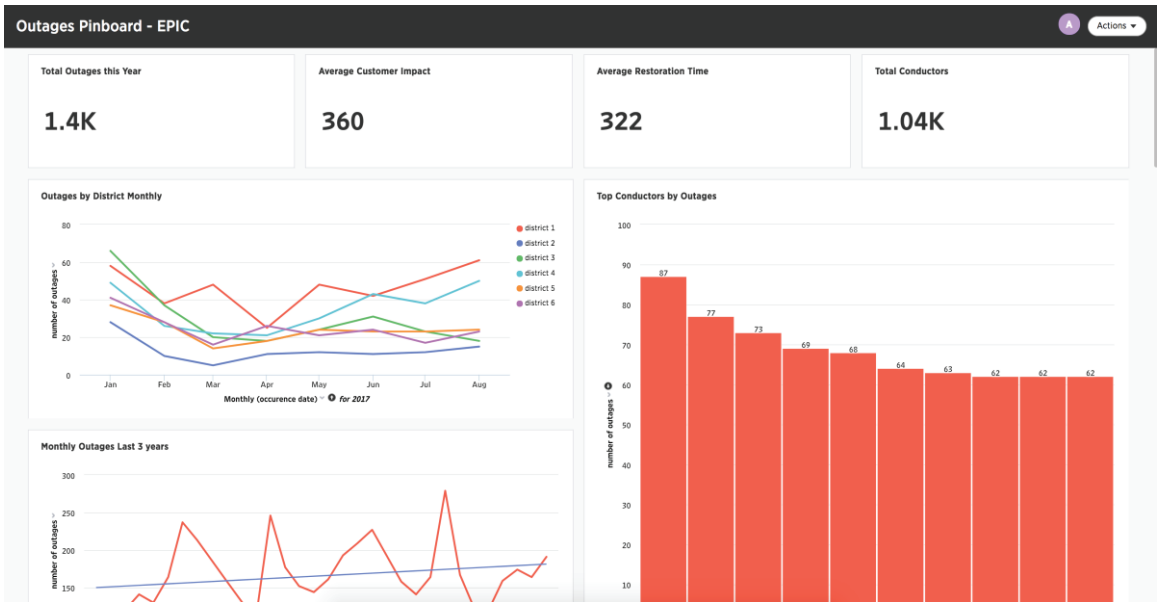


Figure 21: Outages Pinboard

Users can further interact with this pinboard by adding filters, making a copy for their personal use, scheduling the pinboard content to be sent via e-mail distribution, or export as PDF.

3 Project Outcome

3.1 Key Findings

The use of advance data analytics to analyze large amounts of data ingested into the data lake will benefit utility stakeholders to quickly identify assets that require immediate to near term attention, thereby helping in predicting asset life and developing efficient asset management strategies. The use of visualizations that were demonstrated using the tools in this project allows engineers of all levels of experience and familiarity with assets to explore and test data pertaining to the selected use cases. Prior to this development, engineers often needed to have prior knowledge of where certain data attributes exist in the data system (e.g., latitude/longitude from GIS, outage record from SAIDIDAT, or work order data from SAP). Once identifying the data location, engineers then needed to work alongside data querying experts such as business systems analysts to produce queries. These business processes often required continued repetition and refinement and often resulted in dissatisfaction with final results or limited insights delivered. These new visualizations in some cases provide the results of SDG&E's first set of predictive analytics for select use cases, highlighted by the unique capability to forecast several years out. Though the forecast period extends to 10 years, the benefits of these predictive models should ideally be realized in the 3-5 year asset planning cycle, if the models could be integrated into business practices. SDG&E realizes models such as these are the beginning of such modified business practices and aims to continue to learn from and build upon these findings.

3.2 Lessons Learned

During conceptualization of this project, SDG&E asset management professionals sought out to demonstrate machine learning algorithms, prescriptive analytics, and full exploitation of complexed datasets across the enterprise. Through collaborations between SDG&E business leads, SDG&E IT, and external technology consultants, SDG&E gained an overall improved understanding of the principle logistics of predictive algorithm development. These lessons included realizations of the need for improved data quality at the input level, consolidation of data sources, reduced duplication, and continued talent development in the areas of data science. The scarcity of historic failure data was identified as a key reason for asset analytics needing further development prior to being widely operationalized. On the contrary, in areas where historical failure data was collected consistently for several decades, the analytic results became more meaningful and easily validated through anecdotal experience.

Although the visualizations provide valuable and quick insights for general asset failure risks, SDG&E engineers desired the ability to advance their querying speed. Further customizing these predictive algorithms and extracting data from the data lake requires advanced skills with data querying, which are scarce among the business organization. To further take advantage of consolidated data views, SDG&E was interested in exploring search-driven analytics. The ideal search technology would allow the user to enter any asset information (e.g. stock number, circuit

ID, device type) and quickly learn the most relevant information pertaining to data trends. complex data indexing and querying may be required to achieve this vision. The project team leveraged existing visualization tools to evaluate search technology and conceptualize the advanced data analytics results for individual use cases

Key lessons learned from this EPIC project that require follow up:

- Algorithm outputs were limited by data inputs. While the statement can naturally be true without further explanation, the vision of this research was that a system could be created to amplify the input data into undiscovered actionable insights. The theory has not necessarily proven false, however the set of use cases that this research was oriented to accommodate did not as a whole satisfy the business needs. That is, no comprehensive system was achieved in which an engineer or asset manager could see all four use cases on a unified screen and develop short and long term asset maintenance or upgrade plans. While such a dashboard was delivered successfully, the analytics did not yield the expected level of confidence to put into immediate production. SDG&E will need to further improve the necessary data inputs in order to achieve favorable predictive data sets.
- Centralization of disparate data systems is important for the modernization of engineering analytics in the electric utility, however conventional concepts of dashboarding and data visualization were not outgrown in the initial process. The Hadoop system has not yet become a well-known querying system for non-IT professionals, therefore simplified tools for getting out what was put in are a necessity in order for the business to more quickly yield value. These visualization tools need to be flexible, fast, and oriented in such a way that the user can understand where data is coming from for on-the-fly validation.

3.3 Recommendations and Next Steps

It is recommended that SDG&E and other utility stakeholders commercially adopt and implement advance data analytics techniques for effective asset management. The stakeholders have the option to implement tools that were used in this project, or implement tools that best meet their implementation criteria. The use of data lake as a means to store large amounts of data from disparate data sources will allow multiple stakeholders within the utility to access various datasets for their individual use cases. The project team recommends various internal stakeholders seek to improve the overall usefulness of data across the enterprise with a particular focus on electric transmission, distribution, and substation assets. Some key recommendations include:

- Explore and implement data quality improvement plans, including modernizing data collection processes in the field and technology adoption to enable next generation foresight.
- Further explore sensor deployment strategies, focusing on high-value data that can be further analyzed through business intelligence.

- Enable personnel and systems to incorporate failure and other data into machine learning algorithms, whether crude or advanced in nature.

Track and prioritize operational and engineering use cases that are good candidates for the Hadoop system's capabilities

It is recommended that utility engineers and other asset managers further test the analytic and visualizations tools utilized for this demonstration and learn how to spot opportunities for developing machine learning algorithms that have statistical significance and significant impact to the business from a reliability improvement or risk reduction perspective. While Hadoop operationalization is fairly new at SDG&E, all stakeholders engaged in this endeavor should make note of the system's opportunities and obstacles in order to decide if the tool fits the current and future business needs.

4 Technology Transfer Plan

4.1 SDG&E Technology Transfer Plans

A primary benefit of the EPIC program is the technology and knowledge sharing that occurs both internally within SDG&E and across the industry. To facilitate this knowledge sharing, SDG&E will share the results of this project by announcing the availability of this report to industry stakeholders on its EPIC website, by submitting papers to technical journals and conferences, and by presentations in EPIC and other industry workshops and forums. The final results will also be presented to internal stakeholders at SDG&E to assist in prospective adoption.

4.2 Adaptability to Other Utilities and Industry

During the course of this research program, SDG&E engaged other utilities to gain real-time feedback and share results of this project at industry events. Other utilities confirmed the validity of the use cases chosen and also provided some hypotheses as to what factors were of most significance in their own findings. The results of the analytics from this EPIC project showed that data quality was of utmost importance and that ongoing feedback loops for this data will be critical to the future of analytics for these assets. These analytics are generally adaptable to other utilities, however only at a high level. The use cases focused on infrastructure failures that had common failure modes – e.g. small wire breakages, unjacketed cable failures in residential applications, underground feeder connections with threaded terminations, etc. While the causes of these failures are similar across utilities, the environmental triggers and factors that lead to these causes may often differ. San Diego has many unique land regions – salt concentrated coastal areas, areas of high winds, mostly sunny conditions with acute rainfall, etc. These lead to respective infrastructure failures due to corrosion, accelerated aging, and periodic tests of infrastructure resilience.

Analytics vendors have often viewed SDG&E's rich history of underground cable data as a fruitful tool for harvesting on analytics proving grounds. A common trend among these analytics vendors is that more data attributes collected for a longer period of time for all assets, whether minor or major in nature, could be useful for future forensic analyses. These data points are most crucial at the start and at the end of asset life, therefore good utility practices need to continue to focus on managing these data points accurately and consistently wherever possible. Utilities must also continue to collect maintenance and inspection data and marry them together with geospatial data to ensure asset history can be trended properly during its lifespan.

5 Metrics and Value Proposition

5.1 Metrics

The following metrics were identified for this project and evaluated during the course of the pre-commercial demonstration. These metrics are not exhaustive given the pre-commercial demonstration approach for this project.

Safety, Power Quality, and Reliability (Equipment, Electricity System) – The use of machine learning and advanced data analytics can help stakeholders predict the failure of equipment based on current and historical operational data and other data. The following sub-factors could be analyzed with advanced data analytics:

- Number of outages, frequency and duration reductions
- Forecast accuracy improvement
- Public safety improvement
- Utility worker safety improvement

Economic Benefits – Advanced data analytics can provide significant economic benefits by helping the identification of failing or aging equipment, before they fail, thereby reducing operational expenditures and planning capital expenditures effectively. The following sub-factors could be affected with advanced data analytics:

- Maintain/reduce operations and maintenance costs
- Maintain/reduce capital costs
- Improvement in system operation efficiencies

The list of metrics can be expanded on as utilities and other stakeholders adopt data analytics technologies in support of advanced planning and system operations.

5.2 Value Proposition

The purpose of EPIC funding is to support investments in R&D projects that benefit the electricity customers of SDG&E, PG&E, and SCE. The primary principles of EPIC are to invest in technologies and approaches that provide benefits to electric ratepayers by promoting greater reliability, lower costs, and increased safety. This EPIC project contributes to these primary and secondary principles in the following ways:

- Reliability – The use of advance analytics to predict equipment failure into daily asset planning and operations practices increases reliability and enhances the overall risk management model for the electric infrastructure.
- Safety – Preventive maintenance prescriptions using advanced analytics on vast amount of historical equipment and operating data would help enhance safety by avoiding unexpected outages, maintaining assets before catastrophic failures, and managing overall asset risk profile.

[End of Report]

Appendix 11

EPIC-2, Project 3: Monitoring, Communication and Control Infrastructure for Power System Modernization

EPIC Final Report

Program	**Electric Program Investment Charge (EPIC)**
Administrator	**San Diego Gas & Electric Company**
Project Number	**EPIC-2, Project 3**
Project Name	**Monitoring, Communication and Control Infrastructure for Power System Modernization**
Date	**December 31, 2017**

Attribution

This comprehensive final report documents the work done in this EPIC project.

The project team for this work included the following individuals, listed alphabetically by last name.

SDG&E

Atef, Kahveh
Espinoza, Mike
Exon, Jamie
Goodman, Frank
Katmale, Hilal
Kayali, Molham
Mashhoun, Marc
Salmani, Amin
Smith, Greg
Thant, Aung

GE

Adamiak, Mark
Cough, Randy
Flynn, Byron
Henehan, Nathan
Patel, Mrunal
Seiser, Matt
Sharif-Askary, Jamshid
Simpson, Robby
Smith, Justin
Tatum, Deb
Wang, Xiaofeng
Wester, Craig

Executive Summary

The objective of EPIC-2, Project 3 (Monitoring, Communications, and Control Infrastructure for Power System Modernization) was to demonstrate advanced monitoring, communication, and control infrastructure needed to operate an increasingly complex power system infrastructure. The chosen project focus was a demonstration of Open Field Message Bus (OpenFMB) with respect to San Diego Gas & Electric's (SDG&E) existing architecture and vision for the future. The project included assembly of a test system to demonstrate OpenFMB in a controlled environment within SDG&E's laboratory. This test system was used to execute specific use cases developed as part of this project, leading to a number of test results. Finally, these test results were analyzed to generate a number of findings and recommendations.

This project was one of three SDG&E EPIC projects on pre-commercial demonstration of communications standards for power system operations. The three projects were:

- Smart Grid Architecture Demonstrations
  - Focus: Communications standards for integration of feeder equipment and DER into networked automation
- Monitoring, Communication, and Control Infrastructure for Power System Modernization
  - Focus: Open Field Message Bus
- Modernization of Distribution System and Integration of Distributed Generation and Storage
  - Focus: IEC 61850 in substation network

The principal standard of interest in these three demonstrations was IEC 61850, which is an open standard developed by industry stakeholders and promulgated through the International Electrotechnical Commission. The intent of these EPIC demonstrations is to increase the body of knowledge available to aid users in making decisions regarding their future power system communications architecture. The final reports for all three of these projects are posted on the SDG&E EPIC website at www.sdge.com/epic

OpenFMB is an effort coordinated by the Smart Grid Interoperability Panel (SGIP) and standardized by the North American Energy Standards Board (NAESB). OpenFMB consists of a framework and reference architecture comprised of a variety of existing standards to enable a publish/subscribe smart grid field message bus. OpenFMB is designed to enable distributed intelligence, with peer-to-peer communication, as well as ease integration by extending the life of field assets through the use of adapters to legacy protocols.

The test system consisted of several controllable utility distribution system devices networked to mimic two feeders on SDG&E's production distribution network. These devices were networked using differing network technologies designed to reproduce field conditions. The project also demonstrated communications interoperability among different vendor products through the use of adapters which converted those products' legacy communications technologies to OpenFMB.

The OpenFMB network then used multiple communications protocols, including MQTT, DDS, and R-GOOSE, to accomplish the 13 use cases developed for this project. Finally, the demonstration system was subjected to a number of test cases to verify its correct operation and validate the use cases.

During the testing of the demonstration system, results were captured using a variety of methods such as network packet captures, oscillography, and sequence of events. These results were then analyzed to develop a number of findings and recommendations. As a result of this demonstration, it was found that OpenFMB is not yet a standard for peer-to-peer interoperability. Gaps and options in OpenFMB's definitions are hindrances to achieving interoperability. For the purposes of this project, many of these aspects were defined to create a complete demonstration system. However, further work on unambiguous definitions in the standard would aid its potential commercialization. Such definitions would provide guidance and confidence to vendors considering integration of OpenFMB into their products and, subsequently, would provide market confidence in OpenFMB.

It was also found that OpenFMB allows use of peer-to-peer communication, rather than traditional hierarchical communication between devices and the utility back office found in most currently deployed distribution systems, and the autonomy of distributed intelligence unlocks the potential for new use cases, such as distributed Volt/VAr control. Another potential use case that could drive adoption of OpenFMB would be the use of adapters on existing assets with limited communication capabilities to integrate them into a distributed intelligence network. An example is distributed energy resources (DER) that typically use Modbus for local communications via serial links, but are not capable of networked communication.

In conclusion, this project successfully demonstrated a complete OpenFMB network. The test system demonstrated the power of distributed intelligence as well as the architectural flexibility provided by adapters. While it was found that work remains to further define and mature the OpenFMB standard, it was also found that OpenFMB clearly shows promise as a framework in addressing the objective of this project. It is recommended that work be continued to further define the OpenFMB standard so that it can be successfully utilized in future utility distribution system projects and deployments.

Table of Contents

Executive Summary i

Table of Contents i

Appendices iii

List of Figures iv

List of Tables v

List of Acronyms vi

1 Introduction 1

1.1 Project Objective 1

1.2 Issue/Problem Being Addressed 2

1.3 Project Approach 3

1.3.1 Phase 1 – SDG&E Internal Work Prior to Contractor Procurement 4

1.3.2 Phase 2 – Project Development Activities 7

1.3.3 Phase 3 – SDG&E Internal Project Work Prior to Project Conclusion 8

2 OpenFMB Pre-Commercial Demonstration System 10

2.1 OpenFMB Overview 10

2.2 Publish/Subscribe Protocols 10

2.2.1 'Broker' and 'brokerless' approaches 11

2.2.2 OpenFMB and Multiple Protocols 11

2.3 Test System 14

2.4 Summary of Use Cases 33

2.5 System Tests 38

2.6 Data Collection 42

3 Overall Project Results 43

3.1 Technical Results and Findings 43

3.2 Overall Recommendations 45

4 Technology Transfer Plan 46

4.1 Technology Transfer Plan 46

4.2 Adaptability to Utilities and Industry 46
4.2.1 Potential OpenFMB Reference Architecture 46
4.2.2 Dynamic Subscriptions within OpenFMB 49
5 Metrics and Value Proposition 51
5.1 Metrics 51
5.2 Value Proposition 51

Appendices

Appendix A. Use Cases 1

Appendix B. Test Cases 71

List of Figures

Figure 1 - SDG&E Feeder A 15
Figure 2 - SDG&E Feeder B 16
Figure 3 - Demonstration Architecture 17
Figure 4 - Test System, Rack 1 20
Figure 5 - Test System, Rack 2 21
Figure 6 - Test System, Rack 3 22
Figure 7 - Demonstration Communications Architecture 24
Figure 8 - High-Level Network Concept 25
Figure 9 - Feeder A Substation Network 26
Figure 10 - Feeder A Remote Devices 28
Figure 11 - Feeder B Substation Network 29
Figure 12 - Feeder B Remote Devices 31
Figure 13 - OpenFMB Node Architecture 49

List of Tables

Table 1 – EPIC-2, Project 3 Pre-Commercial Demonstration – Phased Approach 4

Table 2 - Devices and Simulators Used in Test System 18

Table 3 - Summary of Use Cases 33

Table 4 - System Tests 38

List of Acronyms

ADMS	Advanced Distribution Management System
AMQP	Advanced Message Queuing Protocol
ANSI	American National Standards Institute
CIM	Common Information Model
CoAP	Constrained Application Protocol
CPUC	California Public Utilities Commission
DDS	Data Distribution Service
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DNP	Distributed Network Protocol
EPIC	Electric Program Investment Charge
ESB	Enterprise Service Bus
FAT	Factory Acceptance Testing
FERC	Federal Energy Regulatory Commission
FTP	File Transfer Protocol
GB	Gigabyte
GE	General Electric
GHz	Gigahertz
GOOSE	Generic Object-Oriented Substation Event
HMI	Human-machine Interface
HTTP	Hypertext Transfer Protocol
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IoT	Internet of Things
IOU	Investor Owned Utility
IP	Internet Protocol
ISO	International Organization for Standardization
IT	Information Technology
ITF	Integrated Test Facility
Kbps	Kilobits per second
kW	Kilowatt
LAN	Local Area Network
MB	Megabyte
Mbps	Megabits per second
MHz	Megahertz
MQTT	Message Queue Telemetry Transport
NAESB	North American Energy Standards Board
NERC	North American Energy Reliability Corporation
NIST	National Institute of Standards and Technology
OASIS	Organization for the Advancement of Structured Information Standards
OMG	Object Management Group
OPC UA	OPC Unified Architecture
OpenFMB	Open Field Message Bus

PMU	Phasor Measurement Unit
PV	Photovoltaic
R-GOOSE	Routable-Generic Object Oriented Substation Event
RAM	Random Access Memory
RMQ	Retail Market Quadrant
RTDS	Real Time Digital Simulator
RTU	Remote Terminal Unit
SAT	Site Acceptance Testing
SCADA	Supervisory Control and Data Acquisition
SDG&E	San Diego Gas and Electric
SDO	Standards Developing Organization
SEPA	Smart Electric Power Alliance
SGIP	Smart Grid Interoperability Panel
TCP/IP	Transmission Control Protocol/Internet Protocol
TLS	Transport Layer Security
UDP	User Datagram Protocol
UML	Unified Modeling Language
WAN	Wide Area Network
XML	Extensible Markup Language
XSD	XML Schema Definition

1 Introduction

1.1 Project Objective

The objective of the pre-commercial demonstration of EPIC-2, Project 3 (Monitoring, Communications, and Control Infrastructure for Power System Modernization) was to demonstrate advanced monitoring, communication, and control infrastructure needed to operate an increasingly complex ("smarter") power system infrastructure.

This project was one of three SDG&E EPIC projects on pre-commercial demonstration of communications standards for power system operations. The three projects were:

- Smart Grid Architecture Demonstrations
  - Focus: Communications standards for integration of feeder equipment and DER into networked automation
- Monitoring, Communication, and Control Infrastructure for Power System Modernization
  - Focus: Open Field Message Bus
- Modernization of Distribution System and Integration of Distributed Generation and Storage
  - Focus: IEC 61850 in substation network

The principal standard of interest in these three demonstrations was IEC 61850, which is an open standard developed by industry stakeholders and promulgated through the International Electrotechnical Commission. The intent of these EPIC demonstrations is to increase the body of knowledge available to aid users in making decisions regarding their future power system communications architecture. The final reports for all three of these projects are posted on the SDG&E EPIC website at www.sdge.com/epic

EPIC-2, Project 3 sought to address the following problems:

- Interoperability issues and challenges
- Peer-to-peer communication thus enabling distributed applications and avoiding brittle centralized command and associated latencies
- Integration challenges with using multi-protocol conversions
- Benefits and challenges with distributed intelligence

The project's chosen specific focus was to:

- Demonstrate and evaluate the Open Field Message Bus (OpenFMB) framework within SDG&E's existing architecture and its vision for the future operations of its distribution system.
- Demonstrate and evaluate the use of OpenFMB in the monitoring and control of a distribution network.

- Development of a test system (pre-commercial demonstration as per EPIC guidelines) to evaluate and demonstrate OpenFMB in a controlled environment within SDG&E's laboratory.
- Demonstrate the capabilities of an OpenFMB field messaging bus architecture and how a control portal along with an optimizer can be deployed on the OpenFMB network and can enable the communication and visualization of network diagrams, display and monitoring of field devices with measurement and status values.
- Demonstrate and document the use of the OpenFMB architecture to validate the pre-defined use cases.
- Demonstrate the salient features of OpenFMB such as:
  - Distributed intelligent devices and the opportunity to manage grids locally, in a manner suitable to local needs and conditions.
  - Demonstrate OpenFMB framework with field devices such as relays, reclosers, capacitors, switches, inverters and other devices that communicate to each other and take intelligent actions locally.
- Provide recommendations regarding the future use of OpenFMB and prospective next steps, based on the demonstration results and metrics.

1.2 Issue/Problem Being Addressed

The modern electric power system will be designed for two-way power flow in distribution circuits, in contrast to the traditional value chain of one way power flow from large generation systems through the transmission and distribution systems to the load. New intelligent devices that support varied functionality and features are being deployed along the transmission system, within substations, along the distribution feeders, and behind the meter at customer premises. These devices use various alternative information models and communication protocols, many of which are proprietary in nature. This inhibits devices from communicating peer-to-peer with other devices in the field, thereby hindering interoperability and making it difficult to exchange data and information for local intelligence and decision making. Additionally, distributed sources of energy are injecting power into the utility distribution system, which require new devices capable of handling the power flow. This has resulted in the traditional centralized control systems evolving into a more hierarchical model that leverages the traditional centralized control and the added distributed control.

To enable this evolving model, a new framework for monitoring, communication and control infrastructure is required. The Smart Grid Interoperability Panel (SGIP) and North American Energy Standards Board (NAESB) have been developing an open standard for utility field device interoperability. Open Field Message Bus (OpenFMB) is a specification for non-proprietary and standards-based field message bus to enable various power system field devices to interoperate. OpenFMB is intended to be used by the stakeholder community of utilities and vendors to develop the technical requirements on field devices that enable them to communicate directly with each other via a field message bus as well as with centralized data centers as they do today,

without a significant increase in the integration cost or complexity. It is a framework for utilities to securely access field data and share it between all devices and systems. OpenFMB leverages proven internet protocols (IP) for improved interoperability and situational awareness. Adoption of IP-enabled technology can be scalable to support existing power system infrastructure

1.3 Project Approach

The project plan was organized into three phases:

- Phase 1 – SDG&E Internal Project Work Prior to contractor procurement that includes
  - Task #1 - Development of Project Plan
  - Task #2 – RFP Development
  - Task #3 - RFP Release, Proposal Evaluation, and Vendor Selection
  - Task #4 - Contracting, Procurement, Resourcing, and Kick-Off
- Phase 2 – Project Development Activities
  - Task #5 – Evaluate OpenFMB Framework within SDG&E Architecture
  - Task #6 – Develop Pre-Commercial Demonstration System for Testing in ITF (Integrated Test Facility)
  - Task #7 – Pre-Commercial, Demonstration, and Analysis
- Phase 3 – SDG&E Internal Project Work prior to project conclusion
  - Task #8 – Finalize Project Report for External Release
  - Task #9 – Technology Transfer Plan

Phases consisted of sub-tasks, each of which has a report documenting the activities and results. Table *1* presents the phased approach used in the pre-commercial demonstration activities.

Table 1 – EPIC-2, Project 3 Pre-Commercial Demonstration – Phased Approach

Phase	Task
Phase 1 – SDG&E Internal Project Work Prior to contractor procurement	Task #1 - Development of Project Plan
	Task #2 - RFP Development
	Task #3 - RFP Release, Proposal Evaluation, and Vendor Selection
	Task #4 - Contracting, Procurement, Resourcing, and Kick-Off
Phase 2 – Project Development Activities	Task #5 – Evaluate OpenFMB Framework within SDG&E Architecture
	Task #6 – Develop Pre-Commercial Demonstration System for Testing in ITF
	Task #7 – Pre-Commercial Demonstration, and Analysis
Phase 3 – SDG&E Internal Project Work prior to project conclusion	Task #8 – Comprehensive Final Report
	Task #9 – Technology Transfer

1.3.1 Phase 1 – SDG&E Internal Work Prior to Contractor Procurement

Task 1 – Development of Project Plan

Objective – Develop detailed work plan for the project.

Approach – The project team met with internal stakeholders to conduct a review of existing systems for monitoring, communication and control of the power system and the plans for ongoing development of these systems. Following activities were reviewed with the stakeholders:

- OpEx2020 vision and Vision 2030
- Projects ongoing under EPIC-1
- Advanced Distribution Management System
- Distributed Energy Resource Management System

The project team identified conceptual, functional and system requirements for the pre-commercial demonstration project. These requirements were identified by reviewing SDG&E's existing plans and high-level use cases to identify key systems and their interactions for key modes of operation. The project plan identified staffing requirements for the project, both

internal and contracted, with definition of needed skills. Required equipment and other resources were also identified.

Output – Project work plan including technical scope definition, schedule, budget, and staffing requirements was developed.

Task 2 – RFP Development

Objective - Develop RFP for competitive procurement of contractor services for the requisite phases of the technical scope.

Approach – An RFP was developed for the contracted portion of the work, the contained the following sections:

- Brief Project Background
- Statement of Project Objective
- Scope of Work
- Approach
- List of Deliverables
- Expectations for Tech Transfer Plan
- Project Schedule
- Selection Criteria
- Solicitation Schedule
- Encouragement for Bids with DBE Participation

The RFP was sent to multiple recipients. The proposals expected from the respondents included (at a minimum):

- Meeting the requirements of the RFP (being responsive)
- Proposed technical approach for performing the work
- Concept of operations and system architecture
- System infrastructure specifications
- Test plan for testing at SDG&E facilities
- Measurement, verification and analysis of data
- Findings and recommendations, based on the results
- Tech transfer plan for use of project results
- Reporting to SDG&E
- Conformance with CPUC EPIC Decision 12-05-037 and other relevant EPIC decisions

The selection criteria (at a minimum) addressed the responsiveness of the bidder to the RFP requirements, elaboration on technical approach, cost, bidder experience and company qualifications, DBE participation, team structure, management plan, qualifications of individual team members, proposed schedule, cost, and acceptance of SDG&E Terms and Conditions. Bidders were encouraged to include DBE companies in their project team.

Output – RFP document was developed for release to recipients.

Task 3 – RFP Release, Proposal Evaluation, and Vendor Selection

Objective - Release RFP to external recipients, evaluate proposals received and shortlist prime contractor.

Approach - Worked with SDG&E supply management to release the RFP and manage the contractor selection. Obtained bidder responses from supply management and organized for stakeholders review during the evaluation process. Received proposal submittals were be validated, a proposal review team was established and a proposal review schedule was developed. Developed detailed evaluation criteria that evaluated the technical and financial response from the bidders. Scoring criteria incorporated an individual scoring sheet and a consolidated scoring workbook will be developed. Formed an internal proposal and project review panel of SDG&E subject matter experts from stakeholder groups to use the project results. Subsequent to developing the evaluation criteria, responses were sent to the review panel for review and scoring. Two review panel meetings were conducted to review the scores and discuss the proposals. During the evaluation process the scoring matrix was populated to get a clear picture of strength of the bidders' proposals. Proposals were reviewed along with the scoring approaches and scoring criteria. Follow up technical questions were developed for clarification from bidders. The proposals were evaluated to assess proposer's assumptions on SDG&E team activities and identify project risks. Evaluation workshops were conducted for bidders who meet the criteria to be vetted further, and necessary discussions on the technical aspects of the SOW and other terms and conditions were conducted that culminated in the selection of a vendor.

Output – Vendor selection including proposal evaluation matrix, scoring matrix and identification of the selected vendor.

Task 4 – Contracting and Procurement

Objective – Procurement of selected contractor services under contract with Supply Management.

Approach - Engaged with the selected contractor in contract discussions to finalize the scope of work, schedule and budget for the project deliverables. The following documents were developed and finalized as part of the contracts package:

- Detailed scope of work
- Detailed project schedule
- Detailed Project Budget
- Professional services agreement

Output – Prime contractor agreement was finalized with SDG&E supply management and the contractor.

1.3.2 Phase 2 – Project Development Activities

This section describes the project development activities that were undertaken by the project team that included SDG&E resources and the prime contractor resources. The project undertook an evaluation and demonstration of the OpenFMB specification within the context of SDG&E's existing architecture and vision for the future of its grid operations. The project also undertook a pre-commercial demonstration to evaluate and demonstrate OpenFMB in a controlled environment within SDG&E's laboratory. The pre-commercial test system was also used to demonstrate specific use cases developed as part of the project.

Task 5 – Evaluate OpenFMB Framework within SDG&E Architecture

Objective – Evaluate OpenFMB Framework within SDG&E Architecture

Approach - In this task, the OpenFMB framework was evaluated with respect to SDG&E's specific architecture. This phase the development of reference architecture, demonstration architecture, use cases and associated test cases. The reference architecture described how OpenFMB could be incorporated into SDG&E's production environment and is further detailed in Section 3.2.1. This reference architecture followed the approach detailed in NAESB RMQ.26 and specifically detailed a logical architecture and a node architecture. In addition, it was shown how OpenFMB could be incorporated into SDG&E's specific production environment, in the near term and long term.

The demonstration architecture describes the specific implementation of the project's OpenFMB test system and is further detailed in Section 2.3. This demonstration architecture is a subset of the overall project reference architecture and was used to create the test system. The power system equipment selected represented a range of vendors, device types, and native protocols (e.g., DNP3, Modbus), as shown in Table 2.

The use cases developed were created to demonstrate the use of OpenFMB in a variety of field scenarios. These use cases included both non-functional requirements and also addressed known business needs. The use cases were then used to create the needed data profiles for communicating between the various devices. Test cases were also created in conjunction with the use cases to verify their correct operation and to better understand the operation and usefulness of OpenFMB.

Output – OpenFMB Framework within SDG&E Architecture for pre-commercial demonstration

Task 6 – Develop Pre-Commercial Demonstration System for Testing in ITF

Objective - Design and develop pre-commercial test system incorporating the OpenFMB demonstration architecture for testing at the ITF.

Approach - In this task, a test system was designed and developed for demonstration at SDG&E's ITF, leveraging existing products. This test system realized the demonstration architecture developed in the first phase and was used to implement the use cases developed.

Adaptors were configured to interface with the various equipment in their native communication protocols (e.g., DNP3, Modbus). These adaptors converted the data into the format described by the data profiles and then sent the data over MQTT or DDS.

The test system devices were also interfaced with a power system simulator. This simulator was configured to mimic actual power system conditions and the test system was realized on a simulation of two actual SDG&E feeders. The simulator was also used during testing to simulate anomalous conditions in the power system, thus exercising the use cases. A detailed communications infrastructure was designed and developed to demonstrate a variety of communications technologies and inter-networking. The various adaptors were then integrated into the communications infrastructure to realize a field message bus.

Output – Development and integration of pre-commercial demonstration system for testing at the ITF.

Task 7 – Pre-Commercial Demonstration, and Analysis

Objective - Conduct demonstrations for the pre-commercial test system at the ITF, and analyze the results

Approach – In this task, the pre-commercial system underwent testing at the contractor's facility prior to installation at SDG&E's ITF. This initial demonstration provided opportunity for feedback and further refinement of the test system and culminated in FAT. Subsequently, the test system was integrated into SDG&E's ITF. This installation included integration with the onsite power system simulator and placement into the facility. Once installed, the test system was exercised using the previously developed test cases for pre-commercial demonstration. Data was collected during the demonstration, including network packet captures and oscillography. This data formed the basis of the findings and recommendations presented in Task 8 (this report).

Output – Pre-commercial demonstration and analysis of the OpenFMB test system

1.3.3 Phase 3 – SDG&E Internal Project Work Prior to Project Conclusion

Task 8 – Comprehensive Final Report

Objective – Develop comprehensive final report

Approach - Develop a comprehensive final report based on the CPUC EPIC Final Report guideline developed by the three IOUs. The report presented in this document follows the outline developed by the IOUs to share the results of the project undertaken.

Output – Comprehensive final report as presented in this document.

Task 9 – Technology Transfer

Objective – Develop technology transfer plan to share results with all stakeholders.

Approach – A technology transfer plan was developed to share the results with SDG&E stakeholders and with other stakeholders in the industry that would benefit from this pre-commercial demonstration

Output – Technology transfer plan as documented in Section 4 of this report.

2 OpenFMB Pre-Commercial Demonstration System

2.1 OpenFMB Overview

OpenFMB is an IoT framework designed and supported by SEPA (formerly SGIP) and standardized in NAESB as NAESB RMQ.26. OpenFMB is focused on providing an open field message bus framework using well-known and widely-adopted standards and industry-standard semantics as well as a reference architecture and common approach to development. Interfacing to other existing standards is accomplished through the use of adapters. OpenFMB is focused on field device interoperability and enabling secure, peer-to-peer communication through a publish/subscribe model, often without the need to communicate with central office head-end systems.

2.2 Publish/Subscribe Protocols

One of the requirements for OpenFMB is that it uses publish/subscribe or "pub/sub" protocols. That's a foundational element of OpenFMB that differentiates it from frameworks for handling field device messaging. Pub/sub generally describes a messaging pattern. It is an alternative to other messaging patterns such as the client-server model, e.g., used for Hypertext Transfer Protocol (HTTP) or File Transfer Protocol (FTP) technology. In that model, a client specifically requests information from or sends information to a server. This is a more "tightly coupled" relationship, in that the client knows precisely which server to communicate with and, typically, the server knows which client is trying to communicate.

In the pub/sub model, publishers have data that is published out often through what is referred to as a "topic." For example, if the publisher is a smart thermostat, the topic might be temperature. Authorized subscribers subscribe to that topic and thus they can pull temperature data. In that arrangement, the publisher and subscriber are more loosely coupled than in the client-server approach, because subscribers don't necessarily know the publishers and vice versa. One publisher could push out a topic to a large number of subscribers. Subscribers, in turn, could receive just one topic from one thermometer or it could subscribe to any number of topics from any number of publishers.

Mutual "awareness," if you will, is possible, but not required as it is in the client-server model. The key is that a subscriber is more focused on the topic than on the node it is talking to. All traffic in the pub/sub approach is subject to security protocols and publishers only publish and subscribers only receive topics for which they are authorized. Security protections are in place.

The thinking behind OpenFMB is that the pub/sub model should be a more effective model than client/server for multiple devices in a field network to communicate with one another. But it is important to note that this debate is not settled. Some see advantages to the client-server model in field device networks. But SGIP and NAESB have chosen to use the pub/sub model in the OpenFMB guide they've approved for field device networks.

2.2.1 'Broker' and 'brokerless' approaches

A further distinction with the OpenFMB's use of pub/sub should be noted. Some OpenFMB protocols use "brokers" while others are "brokerless," while some are able to do both.

A broker may be thought of as a node or device that serves as a middleman in pub/sub communications. In broker scenario, when a publisher publishes a topic it goes to a broker, which then queues it up for, and delivers to, authorized subscribers. Subscribers seeking to pull topics from publishers first go to the broker to subscribe, which pulls data from publisher. The broker is a single node or device that manages traffic between publishers and subscribers.

The role of the broker has pros and cons. Among the benefits that supporters cite is the broker's role in security enforcement, which means that that function is not distributed among publishers and subscribers. The broker performs easier routing of topics and makes discovery by either publisher or subscriber an easier task because two nodes have only one place to send topics or from which to receive topics. That means publishing and subscribing nodes need less programming code.

In a brokerless environment, all publishers are responsible for sending the appropriate data to all authorized subscribers. That means the publisher must "know" which subscribers are authorized and their addresses. Subscribers need to be able to find publishers and subscribe to them – that's the "discovery" process. That can become quite complex in a large network or a network with routers in them. It can become difficult for publishers and subscribers to find one another and it can be difficult to then manage publisher-subscriber connections, security conditions and so forth. The benefit of the brokerless arrangement is that there's no single point of failure. If a broker is used, it can fail or be overwhelmed by network congestion

2.2.2 OpenFMB and Multiple Protocols

OpenFMB, as written, provides a guide that identified (3) three choices for protocols, which provides flexibility for implementation. The three protocols, however, do not work together. With standards, there's always a trade-off: flexibility vs. interoperability. Three choices reflect flexibility. But those choices don't work together, so there's an interoperability issue between systems that make different protocol choices.

The OpenFMB guidance calls out three protocols for potential use: MQTT, DDS and AMQP. If one OpenFMB implementation uses MQTT, for ex., and another uses DDS, they won't talk to each other. But in a specific application, one choice can be explored for its efficacy.

If the application needs fast, real-time data, e.g., with a synchrophasor, DDS might be the choice. If the application calls for a wider, distributed network of devices, the best choice might be MQTT. Each has pros and cons. That's why the authors of this report refer to OpenFMB as an "integration framework." OpenFMB today is not fully defined, it's more of an approach to integrating new devices in the field and avoid stranded assets. In the vernacular, OpenFMB is a sort of "grab bag," loose framework that requires choices of protocols. One cannot implement two OpenFMB devices and assume that they will interoperate.

That's just at the protocol layer. At the application layer, OpenFMB does not yet strictly define all messages. When OpenFMB is implemented, the nature of messages must be defined as well. So trade-offs exist at the application layer as well. Therefore, aspects of OpenFMB remain undefined for now. If one utility uses OpenFMB for a new purpose, e.g., synchrophasors, one utility might define it one way, and another utility might define it another way. And the two systems would not interoperate and communicate. So interoperability gaps remain, depending on how OpenFMB is implemented. OpenFMB is more a process for how users can define messages rather defining them itself.

This undefined aspect of OpenFMB makes it difficult for it to reach commercial availability, because if Vendor A's messages are defined one way and Vendor B's messages are defined in another way, the two will not interoperate and communicate. Thus there's still a lot of "option-ality" to OpenFMB, thus at this point it remains more a guide than an interoperable standard. (In the parlance of the IEEE Standards Association, e.g., OpenFMB would be called a guide, not a standard.)

MQTT: one of two protocols explored in this project

MQTT or Message Queue Telemetry Transport, was first defined by IBM but is now the standard used both in OASIS, the Organization for the Advancement of Structured Information Standards and in ISO/IEC, the International Organization for Standardization/International Electrotechnical Commission. MQTT is one of two protocols used in the demonstration project. MQTT defines the application layer protocol that runs on top of TCP/IP. So it is built on Internet technologies. For security, it uses Transport Layer Security (TLS), another Internet standard. Like http, MQTT runs on TCP/IP, and uses TLS for security.

MQTT's primary design is aimed at being "lightweight," i.e., targeted at IoT-type applications that favor small, inexpensive devices. It is designed to be lightweight both in terms of implementation – it uses minimal coding and, therefore, programming effort – as well as requiring low bandwidth from network resources. So it's fast and lightweight, which also means it has few features. That's thought of as its main advantage. Its disadvantage, according to some, is that it uses a broker and, therefore, it has a single point of failure.

DDS: the other protocol explored in this demo

DDS stands for data distribution service. It is another pub/sub protocol allowed under OpenFMB, and is one of the two protocols tested in the demonstration project. In terms of history and status, it has had mainly military applications, e.g., in equipment communicating with one another aboard submarines. Today DDS is an OMG – Object Management Group – standard. (OMG is an international, open membership, not-for-profit technology standards consortium.) At this point, DDS has a handful of implementations or use cases and is not as widely adopted as MQTT or AMQP (Advanced Message Queueing Protocol, described in the next section). There's active interest in DDS' potential, but it's fair to say that DDS is more in its infancy than other protocols identified under OpenFMB.

DDS is brokerless, in contrast to MQTT. That's viewed as one of its key advantages, i.e., it has no single point of failure. But that means paying attention to routing, discovery, etc., which affects scalability. One would not use DDS for a field network of thousands or millions of devices, thus it is not IoT friendly because it has a high overhead of programming. It is referred to as a "data-centric" protocol, meaning how a programmer would approach using it. Like other pub/sub protocols, the programmer doesn't think about the devices that are talking to each other, rather, the focus is on the nature of the data being published or subscribed to.

DDS does not run on TCP/IP. It can run on IP, but it has its own technology above IP. It doesn't use TCP, it doesn't use TLS – the traditional Internet protocols. For security it has its own, referred to as "DDS security." In a sense, DDS lives in its own world. It has a constituency as well as detractors.

Among its advantages is that it is brokerless, therefore faster. Again, no single point of failure. In the power utility world, where applications demand that lots of data is exchanged in real-time, or closed-loop control is needed (e.g., sample-value type data or synchophasors), DDS might be a candidate – those applications are its sweet spot. The corollary to the speed and lack of a single point of failure in brokerless protocols is, again, that discovery and security functions must be programmed into all the field devices communicating directly with one another. Also, without a broker, lots of pub/sub devices and their exchanges can overwhelm the network.

AMQP: not tested in this demo

The third protocol defined under the OpenFMB guidance is AMQP, or Advanced Message Queueing Protocol. It is built on TCP/IP and and it uses TLS for security – typical Internet protocols. AMQP is OASIS and ISO/IEC compliant standard. AMQP and MQTT are very similar: both are built on typical Internet protocols, are OASIS and ISO/IEC standards and both use brokers. The generally accepted difference between the two is that AMQP is richer, in that it provides more functionality. AMQP, for instance, can use both a pub/sub and a client-server communication approach. However, that added functionality comes at a cost. It is more complex, requires more programming and code and, therefore, is more difficult to implement. In sum, AMQP is richer and MQTT is more lightweight.

R-GOOSE Overview (Additional protocol reviewed in the project)

The Generic Object Oriented Substation Event (GOOSE) is a transport profile for IEC 61850. This profile was developed with the specific goal of performance in mind. As such, GOOSE only operates via Layer 2 addressing and supports multicast and quality of service. However, in the course of identifying new use cases for the IEC 61850 standard, the issue of transmitting data from one publisher to multiple subscribers in a network drove the development of routable multicast messages now known as Routable GOOSE (R-GOOSE). The primary additions being the use of routable IP addressing and a complete security profile.

2.3 Test System

The test system developed for this project was designed to meet the project's objectives and demonstrate the range of benefits of OpenFMB. This test system was designed to mimic two feeders on SDG&E's production distribution network, shown in Figure 1 and Figure 2. Figure 3 then illustrates the architecture of the test system, designed to mimic those two feeders, as described in more detail below.

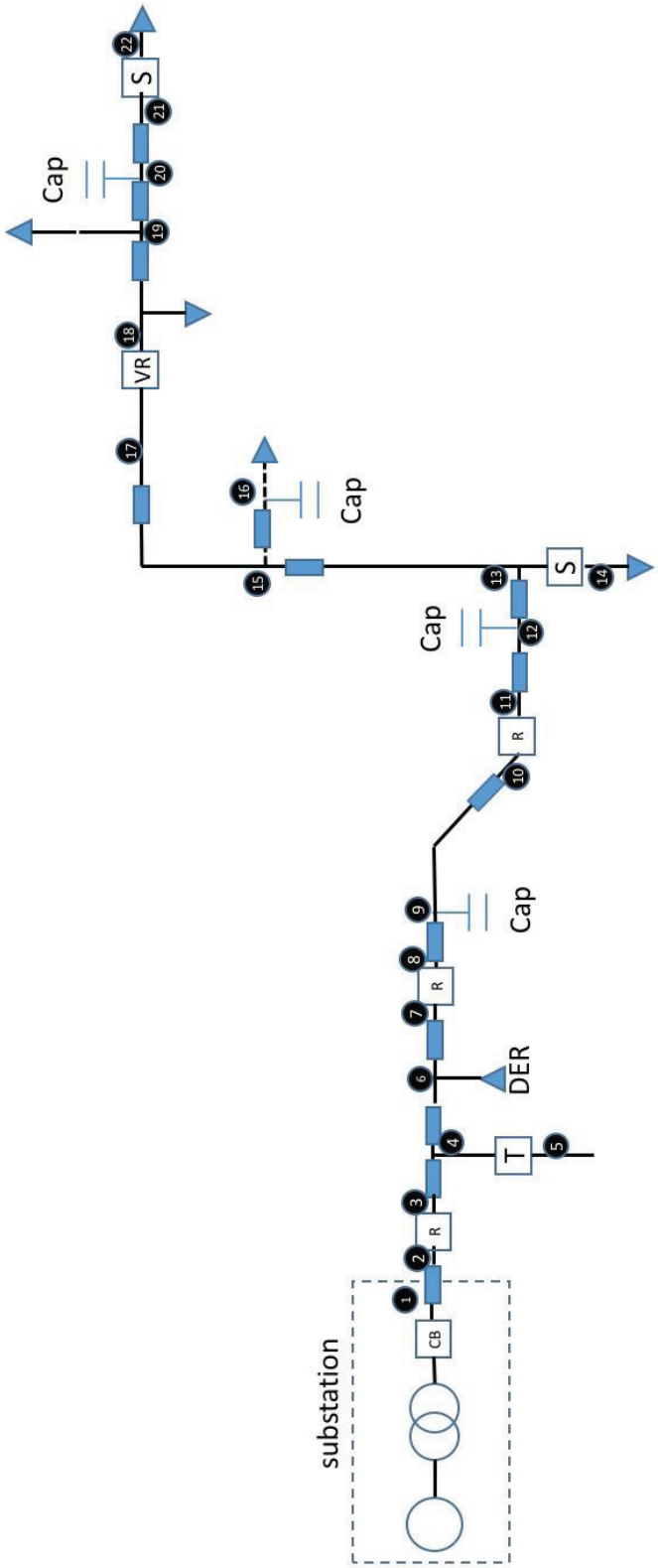


Figure 1 - SDG&E Feeder A

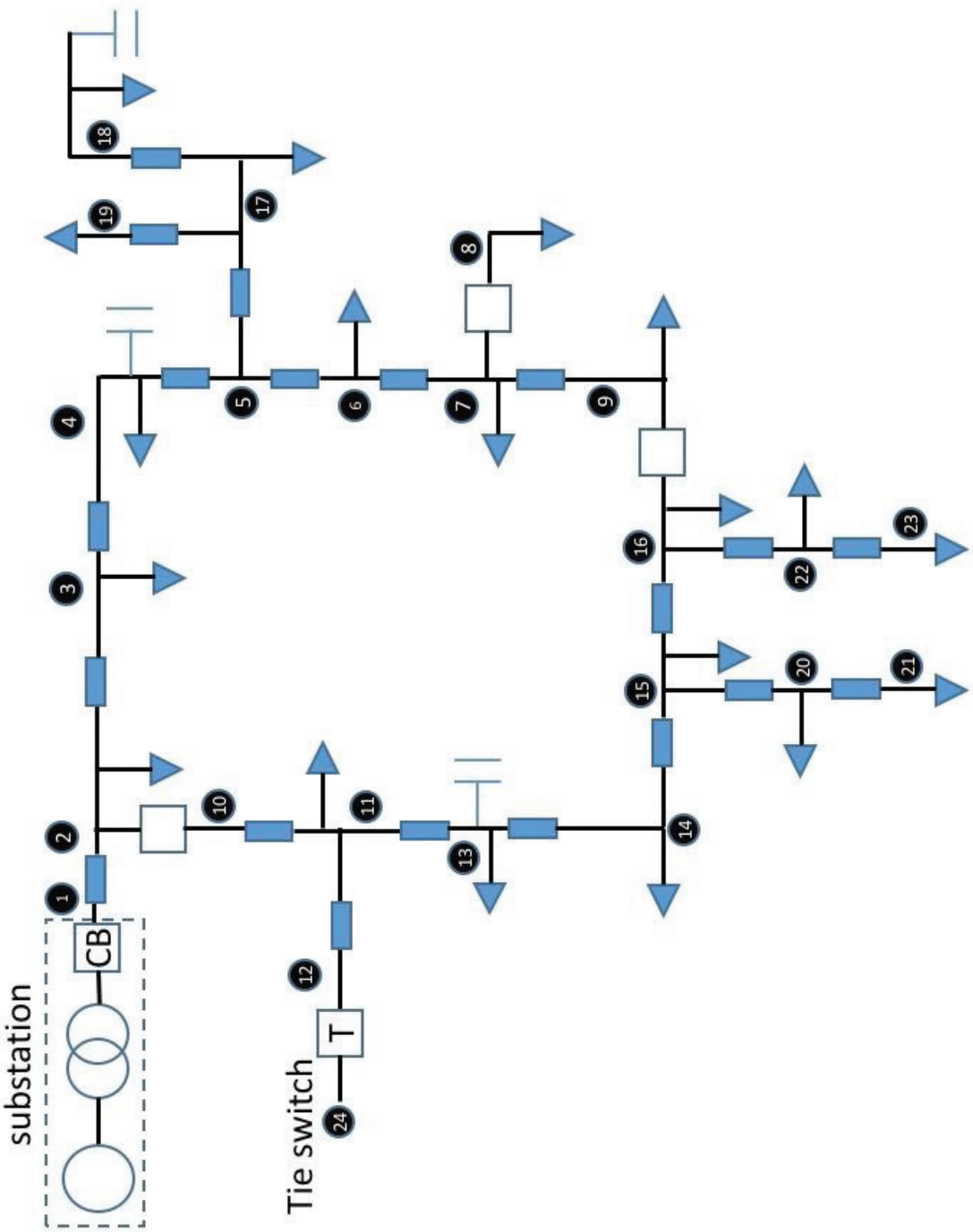


Figure 2 - SDG&E Feeder B

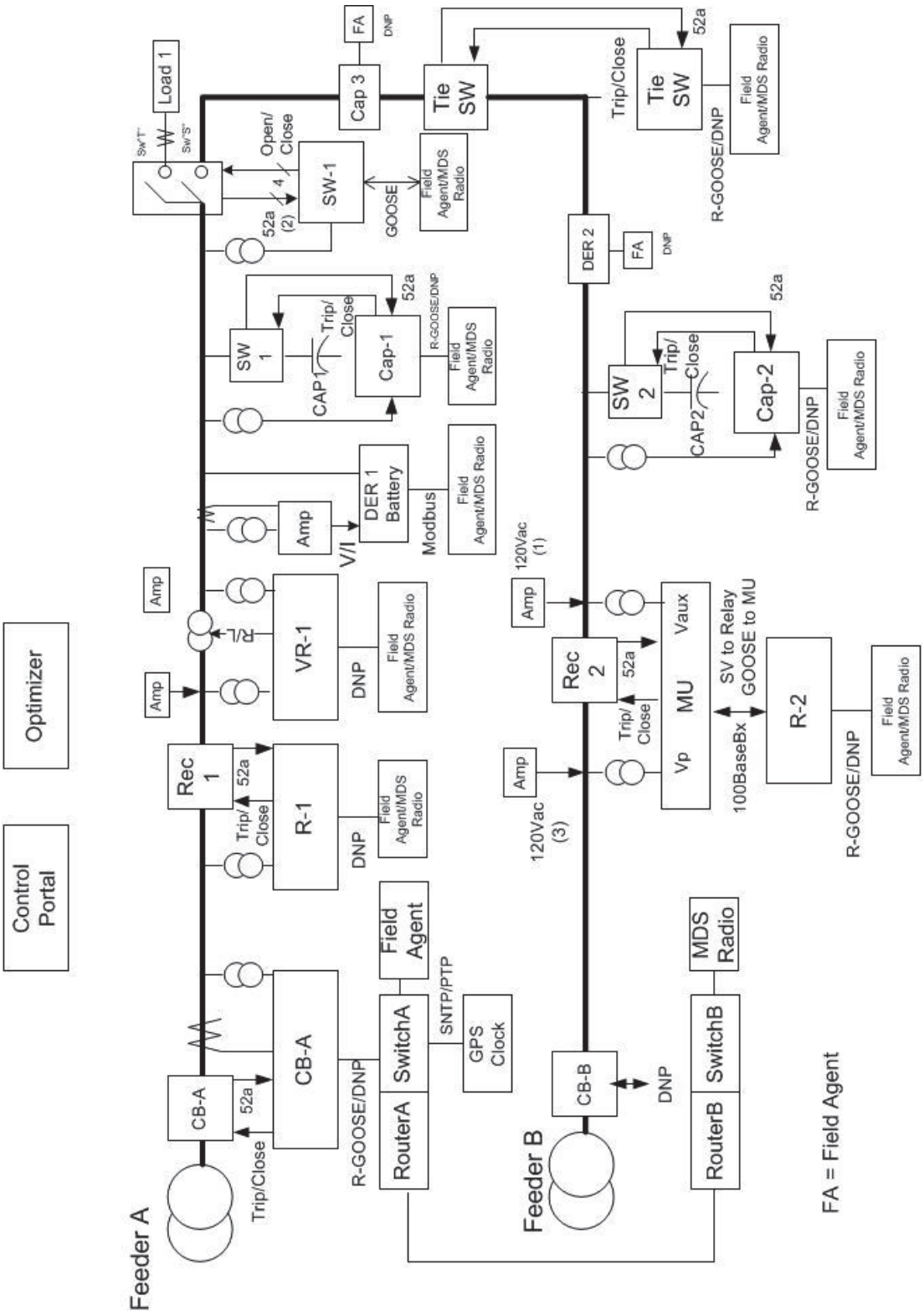


Figure 3 - Demonstration Architecture

A number of devices and simulators were used in the creation of the test system. These devices were selected to demonstrate interoperability amongst devices from a variety of manufacturers, each requiring an OpenFMB adapter to translate from their legacy communications technology to OpenFMB. These devices and simulators are listed in Table 2. Figure 4, Figure 5, and Figure 6 show the developed test system on racks, including labels for each device. These racks were then installed in the SDG&E ITF.

Table 2 - Devices and Simulators Used in Test System

Device Type	***Device Role***	***Device Description***
Control Portal	System, application	Application that provides a User Interface to visualize the circuit network, display measurement values and provide limited control capability for network devices.
Optimizer	System, application	Application which optimizes the resources included in the Vol/Var Use Cases. Optimization is accomplished using defined business rules.
Field Agent	device	Field agent software and hardware device that communicates with the "edge" field devices. The Field Agents includes Ethernet communications capability. FA nodes are connected to each Field Device and connected to the OpenFMB.
Breaker Relay	device	The Breaker Relay feeder protection system provides feeder protection, control, monitoring, and metering in an integrated package. Communicates via R-GOOSE and DNP.
Capacitor	device	The Capacitor Relay provides protection functions designed specifically to protect shunt capacitor banks. Protocols: R-GOOSE and DNP
Tie Switch	device	The controller system is a device designed to act as Tie Switch to demonstrate Use Cases. Protocol: R-GOOSE and DNP
Recloser Relay	device	The Recloser Control offers protection and communications capabilities for Automatic Network Reconfiguration in the event of a fault. Recloser-A with DNP protocol.
Voltage Regulator	device	The Voltage Regulator Controller to optimize System Voltage and control system voltage with DNP protocol.
Switch (2 position)	device	The load simulation relay provides three-phase restraint current inputs. 2 Position Switch with DNP protocol
DER / Battery Inverter	device	Inverter that connects battery to the VVC System. Assumed to be capable of operation as a rectifier. Controllable up in range zero to current maximum capability of battery. Uses Modbus protocol.
Flexible Load	device	Controllable load to simulate Critical customer loads; both shedable and non-shedable components.

Device Type	*Device Role*	*Device Description*
RTDS	System, application	Power system simulation software
Router Subnet A and B	Communication Device	Routes network traffic from Subnet A to Subnet B and vice-versa
900 MHz Radios	Communication Device	Long-range 900MHz radio access points. Configured to bridge Ethernet data over the radio link to the feeder remotes. Configured for 500kbps raw over-the-air data rate. Also configured to be a Wi-Fi access point for computer connections to the OFMB test rack.
Time Server	Server	Time server for the entire rack (both Feeder A and Feeder B). SNTP and PTP server.
Computer	Computer HW	R-GOOSE to OPC Adaptor (Windows Server)
HMI Display	System, application	Traditional HMI for Grid Devices
DER Inverter	Device	Energy Storage System device technology

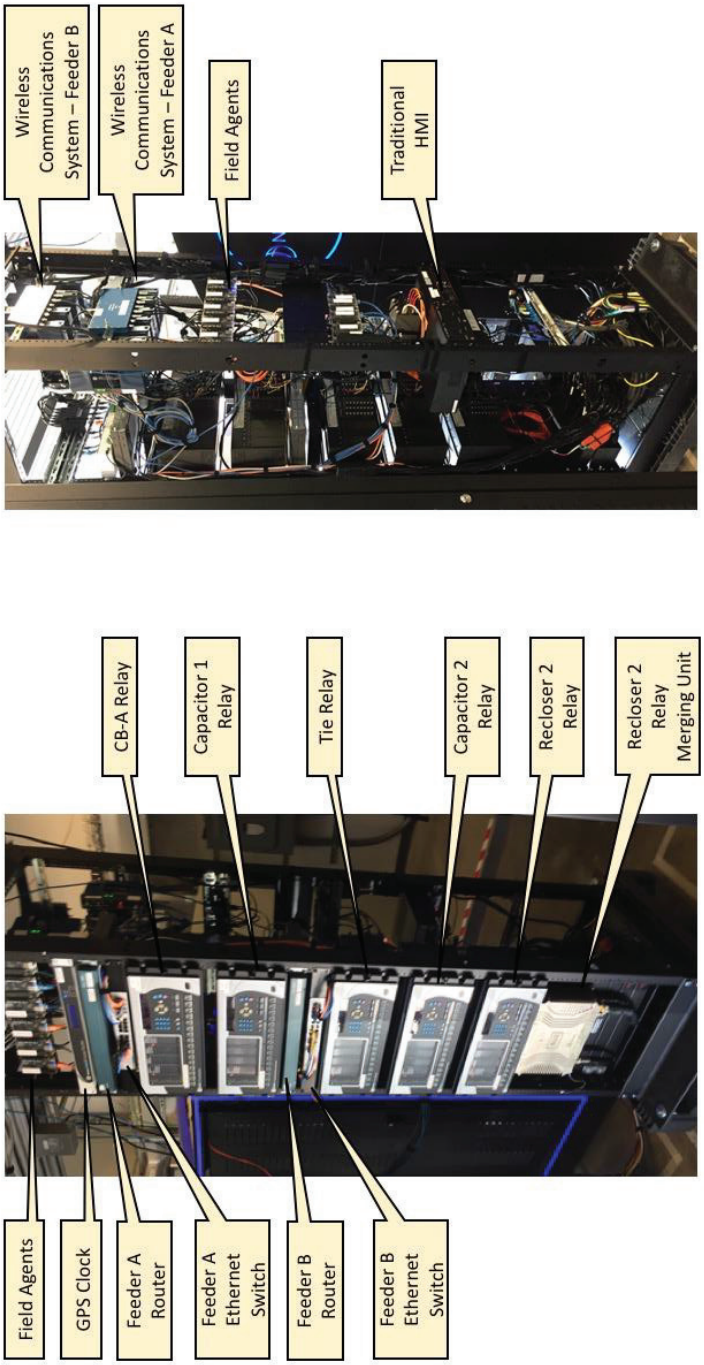
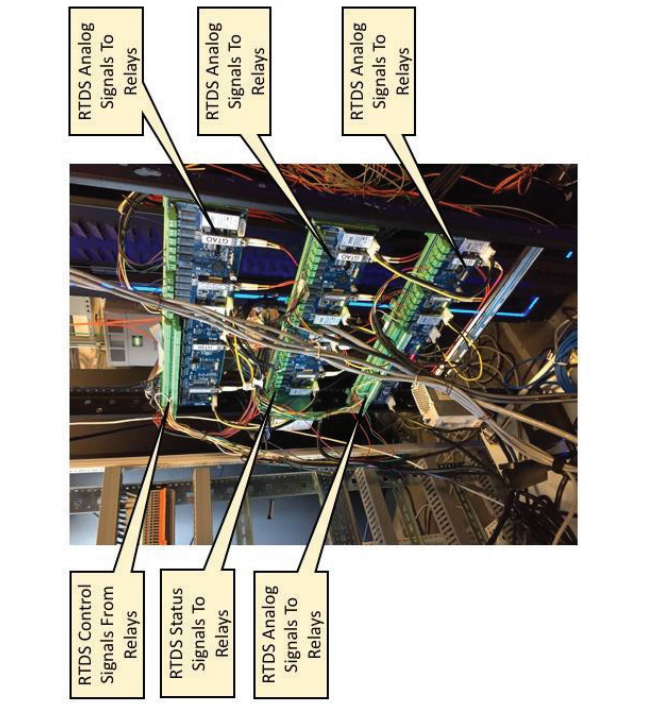


Figure 4 - Test System, Rack 1



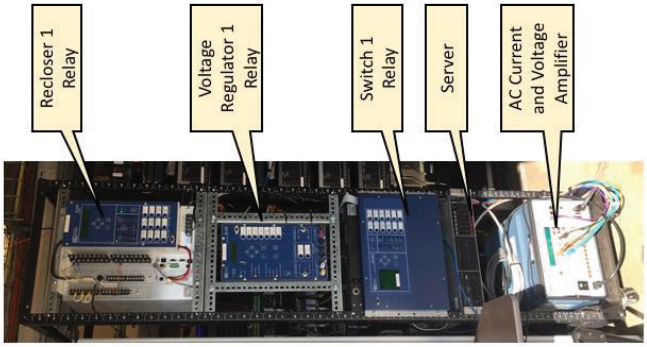


Figure 5 - Test System, Rack 2



Figure 6 - Test System, Rack 3

These devices were networked in such a way to mimic their location on two different feeders, “Feeder A” and “Feeder B,” using different networking technologies to mimic a realistic network design. The overall design of the communications is shown in Figure 7.

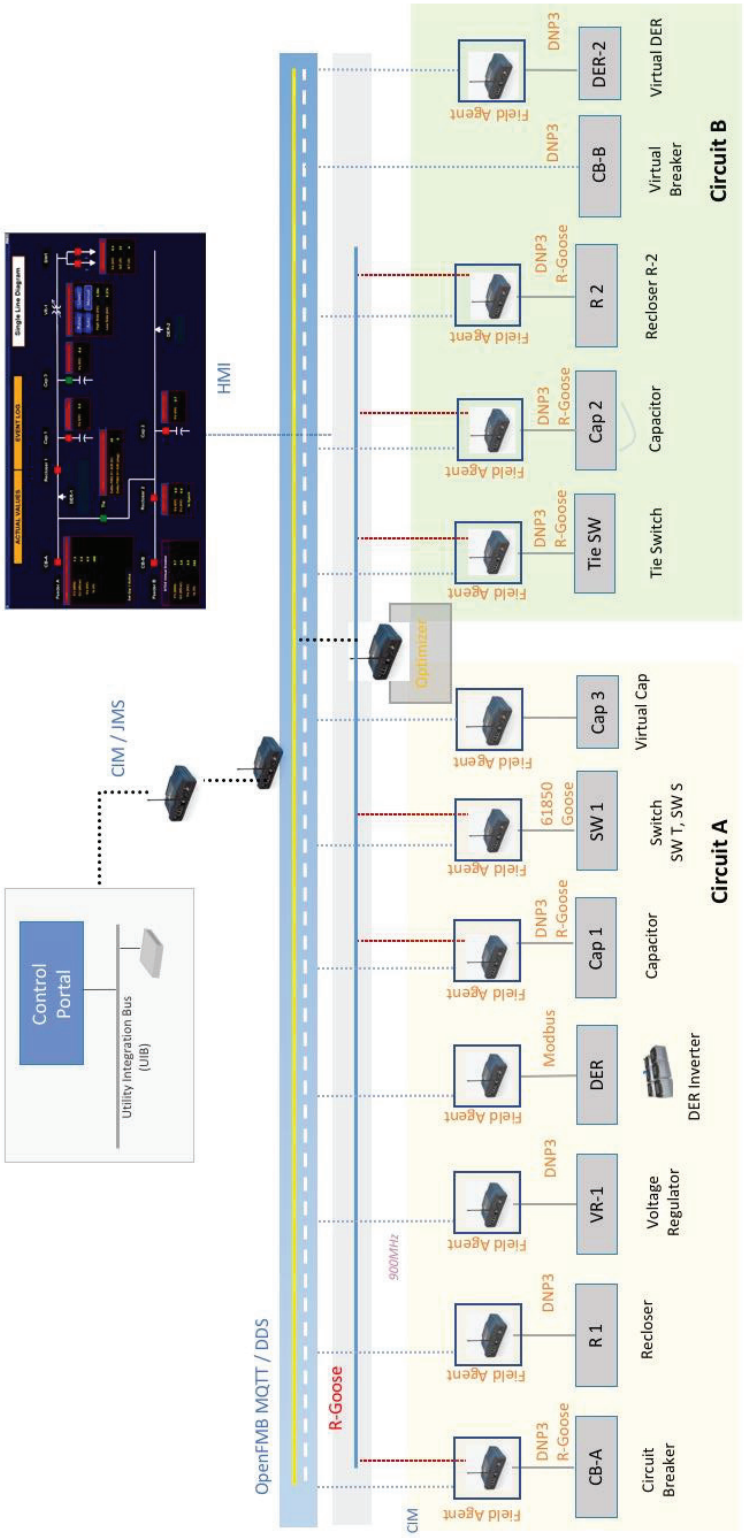


Figure 7 - Demonstration Communications Architecture

"Substation Devices" are connected via Ethernet cables to the Router/Switch for each feeder. These devices experience high speed networking connections between each other (10/100/1000Mbps). "Remote Devices" are connected via the 900MHz radio network. These devices in the real world would be located up to 10 miles from the substation and therefore, need long range wireless to communicate. Each feeder has a 900MHz radio access point and therefore the devices on that feeder share the 500kbps link.

The networking is such that Feeder A and Feeder B are in two different subnets, but connected by routers. That is, the two feeders are connected at Layer3. The OpenFMB rack IP addressing scheme is as follows (the actual IP addresses have been redacted throughout this report and replaced with 'x'):

- Feeder A is in the xxx.xxx.42.x subnet
- Feeder B is in the xxx.xxx.43.x subnet

For connecting computers and tablets to run tests and/or troubleshoot, the OpenFMB rack contains a Wi-Fi Access Point and DHCP Server for ease of use.

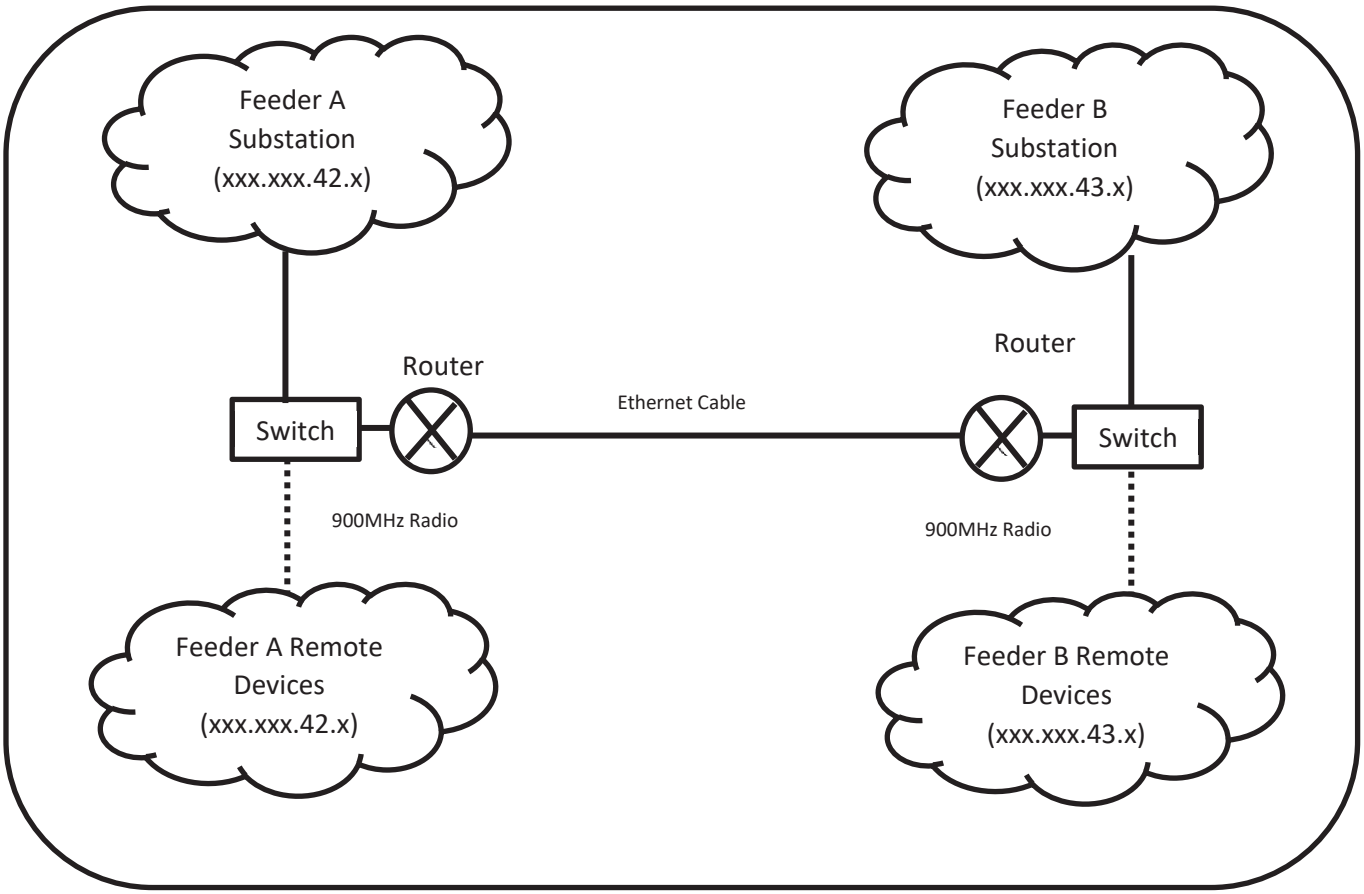


Figure 8 - High-Level Network Concept

As shown in Figure 8, the test system network is designed to connect every device in two feeders. The devices and computers in the substation are connected via high-speed Ethernet over copper cable. The remote devices of each feeder are connected via a high-power/long range radio link. The two feeders are connected to each other through 2 routers. In this way, the test system network is comprised of four major sub-sections:

1) Feeder A Substation Sub-Network

2) Feeder A Remote Devices Sub-Network

3) Feeder B Substation Sub-Network

4) Feeder B Remote Devices Sub-Network

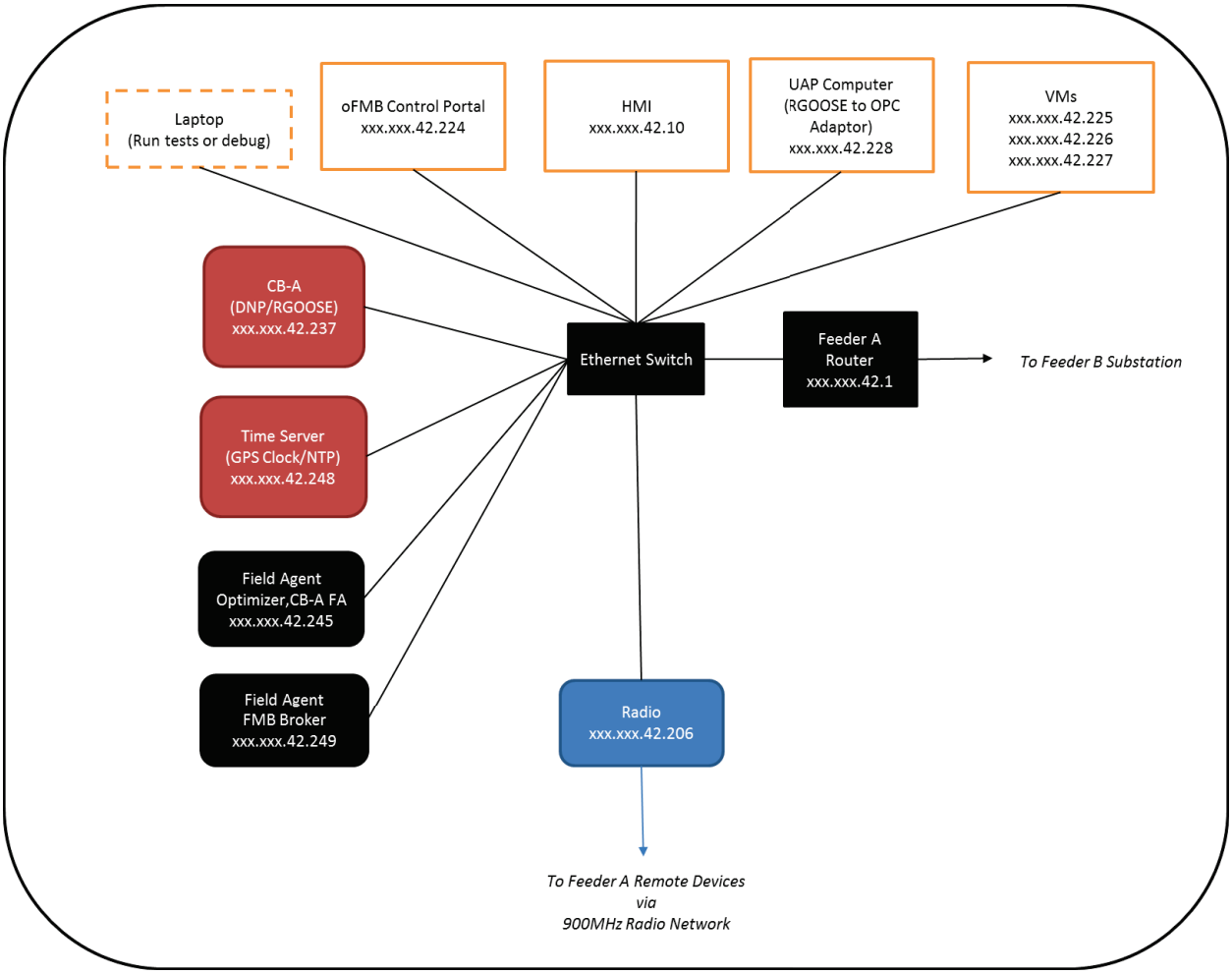


Figure 9 - Feeder A Substation Network

As shown in Figure 9, the "Feeder A Substation" portion of the network contains devices that would normally be connected in an electrical substation or be connected by a high-speed network connection to the substation. The Feeder A substation contains both devices and computers. Everything in this subnet is connected through the use of an Ethernet switch using copper cables

(Cat5/6). In this way, all devices communicate using IP (Internet Protocol) over 10/100/1000BaseT Ethernet.

There are several computers and virtual machines (VMs) connected to this part of the network. The OpenFMB Control Portal provides visualization of the FMB data. The HMI machine talks legacy protocols and shows the user details regarding the devices further down Feeder A. The UAP machine provides RGOOSE to OPC translation. An engineer's laptop can be connected to the switch to provide troubleshooting access or to run tests.

A time server that acts as a NTP server for the entire network is in this portion of the network. Devices learn date and time of day from this device. This ensures all devices in the network share the same time of day, which is important for correlating logs and published data. The circuit breaker controller (CB-A) is also connected to this portion of the network.

There are two field agents at the substation of Feeder A. In general, field agents can be loaded with different applications to provide intelligence and data translation at the edge of the network. In this case, we have two field agents configured to provide very specific functionality. One field agent functions as the optimizer for the feeder. The other field agent acts as the Field Message Bus Broker ("FMB Broker"). The FMB Broker routes messages to/from other field agents in the network. This function is how field agents can participate in different FMB topics (logical data streams).

There are two devices in the Feeder A Substation network that act to route data to other parts of the network. The Feeder A Router connects Feeder A to Feeder B so that the two feeders can send data back and forth. This router must be capable of routing both unicast and multicast IP traffic. The Radio Access Point (AP) connects wirelessly to other radios further down the feeder. The Radio AP creates a point-to-multipoint (star) network that connects all the remote radios. In this way, every remote radio transmits directly with the AP while the AP maintains multiple connections – one to each remote radio. The radio signals in the test network are carried by RF cables with fixed attenuation. In the real world, these signals would travel through antennas and then over-the-air for large distances (1-10 miles) to connect the remote devices of feeder A to the substation of feeder A.

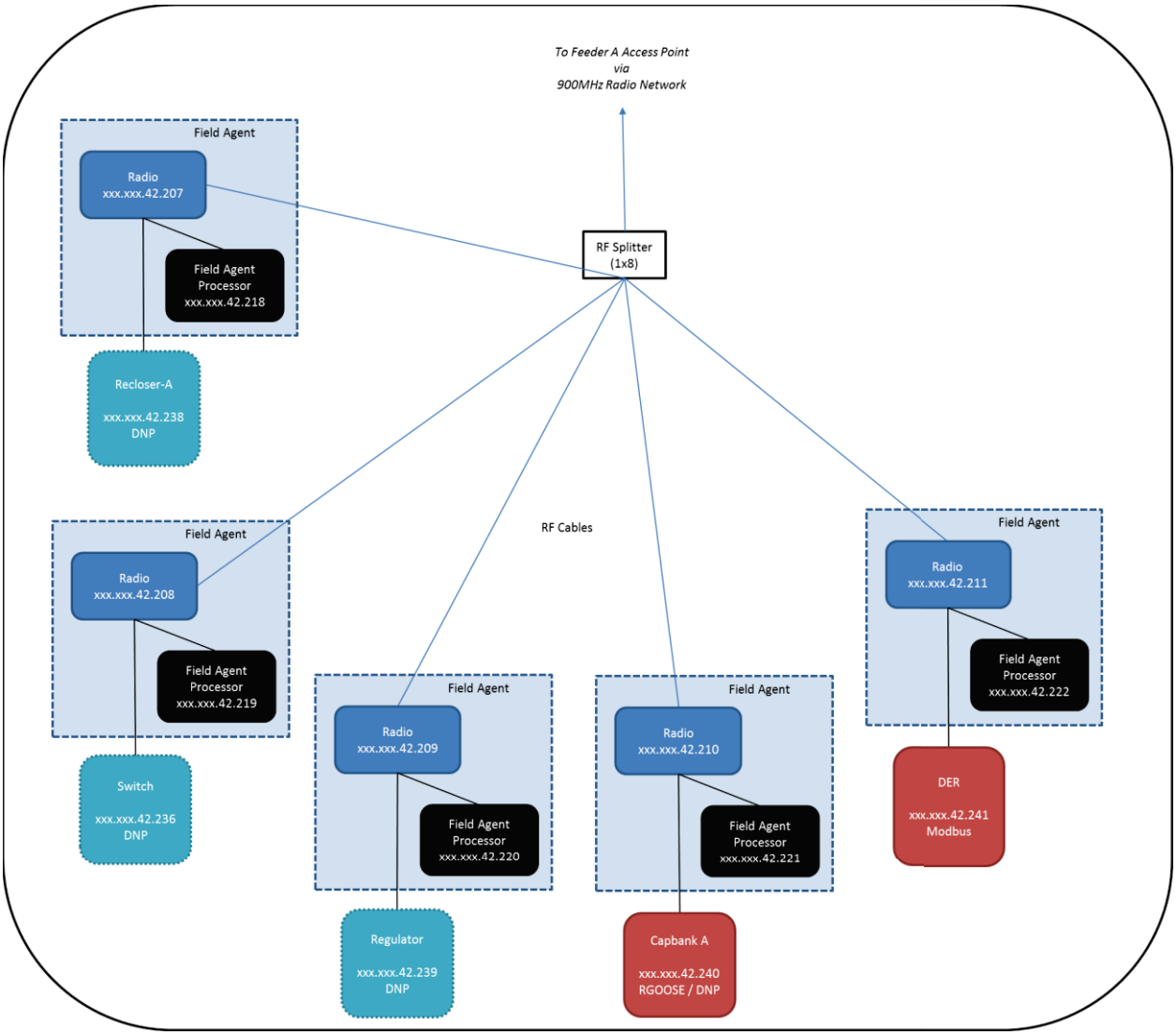


Figure 10 - Feeder A Remote Devices

As shown in Figure 10, there are a number of remote devices connected to Feeder A, along with their respective field agents.

Each controllable utility distribution system device is connected to the network using a wireless field agent. The wireless field agent contains a high-power/long range radio to connect remote devices that may be miles away from the substation. The field agent also has copper Ethernet and serial ports to physically connect to the electrical grid remote devices. Each field agent can run different field message bus protocols (MQTT, DDS, RGOOSE transport, etc.). The field agents are also capable of being loaded with different applications to implement edge features and device protocol translation (Modbus, DNP3, etc.) Therefore, we can connect different types of devices talking different protocols to the same network.

This OpenFMB test network contains various utility distribution system devices. We have the following in Feeder A:

1) Recloser controller running DNP3 ("Recloser-A")

2) 4 Position Switch controller running DNP3 ("Switch")

3) Regulator running DNP3 ("Regulator")

4) Capacitor Bank Controller running RGOOSE and DNP3 ("Capbank A")

5) Battery Inverter running Modbus ("DER")

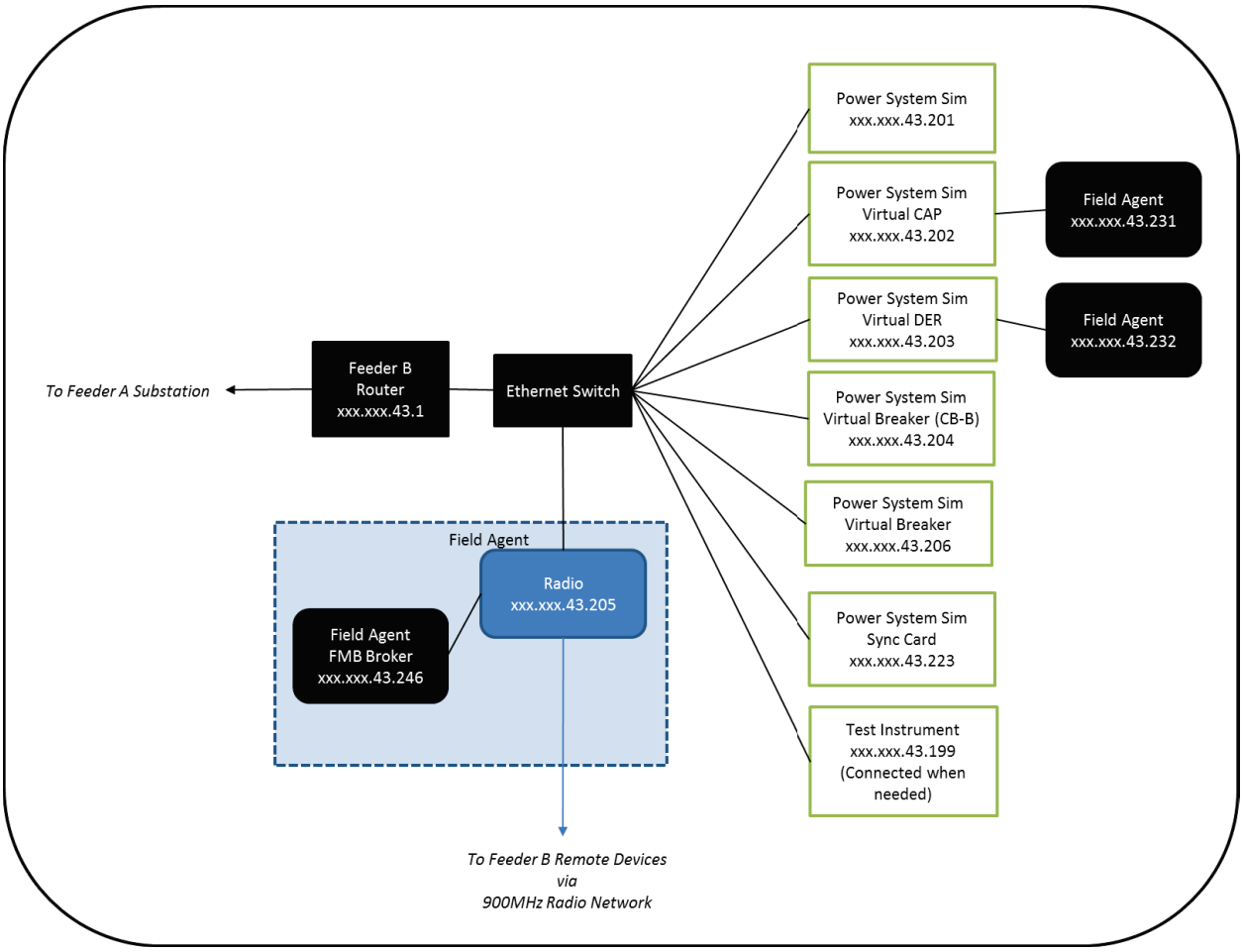


Figure 11 - Feeder B Substation Network

As shown in Figure 11, the "Feeder B Substation" portion of the network contains devices that would normally be connected in an electrical substation or be connected by a high-speed network connection to the substation. The Feeder B substation contains both devices and computers. Everything in this subnet is connected through the use of an Ethernet switch using copper cables (Cat5/6). So, in this way, all devices communicate using IP (Internet Protocol) over 10/100/1000BaseT Ethernet.

An electrical grid simulation system is connected to the network at the Feeder B Substation level. The simulation system is comprised of both physical and virtual network elements. The main simulator hardware and its synchronization card are physical devices at this level. The simulation

system is also configured for a number of virtual devices. These include a virtual capacitor controller, a virtual DER controller, and two virtual breaker controllers.

There are three field agents at the substation of Feeder A. In general, field agents can be loaded with different applications to provide intelligence and data translation at the edge of the network. One field agent acts as the Field Message Bus Broker ("FMB Broker"). The FMB Broker routes messages to/from other field agents in the network. This function is how field agents can participate in different FMB topics (logical data streams). The other two field agents provide data translation and control for the virtual CAP and the virtual DER.

There are two devices in the Feeder A Substation network that act to route data to other parts of the network. The Feeder B Router connects Feeder B to Feeder A so that the two feeders can send data back and forth. This router must be capable of routing both unicast and multicast IP traffic. The Radio Access Point (AP) connects wirelessly to other radios further down the feeder. The Radio AP creates a point-to-multipoint (star) network that connects all the remote radios. In this way, every remote radio transmits directly with the AP while the AP maintains multiple connections – one to each remote radio. The radio signals in the test network are carried by RF cables with fixed attenuation. In the real world, these signals would travel through antennas and then over-the-air for large distances (1-10 miles) to connect the remote devices of feeder B to the substation of feeder B.

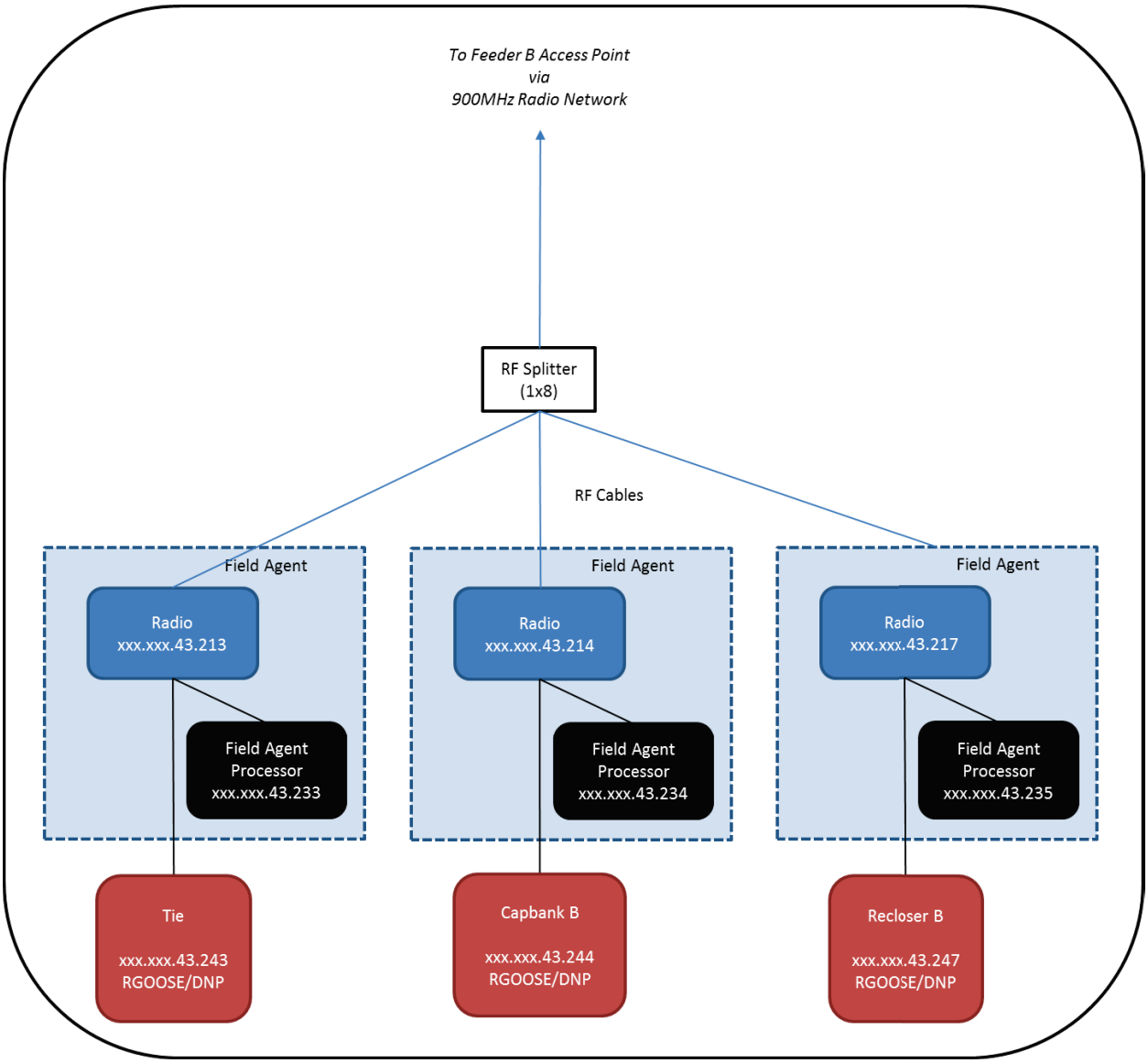


Figure 12 - Feeder B Remote Devices

As shown in Figure 12, there are a number of remote devices connected to Feeder B, along with their respective field agents.

Each controllable utility distribution system device is connected to the network using a wireless field agent. The wireless field agent contains a high-power/long range radio to connect remote devices that may be miles away from the substation. The field agent also has copper Ethernet and serial ports to physically connect to the electrical grid remote devices. Each field agent can run different field message bus protocols (MQTT, DDS, RGOOSE transport, etc.). The field agents are also capable of being loaded with different applications to implement edge features and device protocol translation (Modbus, DNP3, etc.) Therefore, we can connect different types of devices talking different protocols to the same network.

This OpenFMB test network contains various utility distribution system devices. We have the following in Feeder B:

1) Tie controller running RGOOSE and DNP3 ("Tie")

2) Capacitor Bank Controller running RGOOSE and DNP3 ("Capbank B")

3) Recloser controller running DNP3 ("Recloser B")

2.4 Summary of Use Cases

Table 3 shows the use cases that were developed for demonstration on the test system. For more details of the use cases, see 0.

Table 3 - Summary of Use Cases

Use Case 1a: OpenFMB Connection to Vendor B Devices and Virtual DER / Cap Bank	
Objective:	The objective was to demonstrate the use of OpenFMB to communicate from a Control Portal to a field device showing status (measurement values) and control (change status).
Description:	An operation of Recloser 1 (Open/Close) and Voltage measurements was made through OpenFMB messaging to the VENDOR B RECLOSER 1. The control and status of the 2-feeder switch was demonstrated from the Control Portal through OpenFMB to the VENDOR B Switch. The control and status of the Virtual DER and Virtual Cap Bank were also exercised.
Use Case 2a: Var Control	
Objective:	The objective was to evaluate R-GOOSE as an alternative pub/sub protocol under the OpenFMB standard / framework.
Description:	An operation of Recloser 1 (Open/Close) and Voltage measurements was made through OpenFMB messaging to the VENDOR B RECLOSER 1. The control and status of the 2-feeder switch was demonstrated from the Control Portal through OpenFMB to the VENDOR B Switch. The control and status of the Virtual DER and Virtual Cap Bank were also exercised.
Use Case 2b: Man-in-the-Middle Augmented Voltage/Var Control	
Objective:	The objective was to demonstrate manual control and operation using OpenFMB.
Description:	Capacitor 1 was closed. When, after closing Capacitor 1, the var level was set above the setting threshold in the VENDOR A CB-A, an OpenFMB alarm of "over VAR" was issued by the VENDOR A CB-A relay. This alarm was received by the Control Portal and indicated. The operator then placed VR1 in auto mode.
Use Case 2c: Peer-to-Peer Voltage/Var Control	
Objective:	The objective of Use Case 2c was to demonstrate automated control or operation using OpenFMB.
Description:	Capacitor 1 was closed. When, after closing Capacitor 1, the var level was set above the setting threshold in the VENDOR A CB-A, an alarm of "over VAR" was issued by the VENDOR A CB-A. This alarm was received by the Optimizer and the Optimizer then placed VR 1 Voltage Regulator in auto mode via an DNP OpenFMB command.
Use Case 2d: Voltage Override	
Objective:	The objective of Use Case 2d was to demonstrate the communication of the rejection of manual control and subsequent automatic response based on prevailing local condition using OpenFMB.

Description:	The Control Portal sent a close command to VENDOR A CAPBANK 1. As the voltage on VENDOR A CAPBANK 1 was set using the simulator to be too high, VENDOR A CAPBANK 1 refused the CLOSE control and sent a message to the VENDOR A CB-A indicating refusal to execute the requested close action. An OpenFMB message was issued indicating such from VENDOR A CB-A and was displayed on the Control Portal. Detection of Over-Voltage was also transmitted to the Optimizer which then cause VR1 to change to auto mode.
Use Case 3a: Inter-network Var Control	
Objective:	The objective of this use case was to demonstrate the inter-network communication capability of OpenFMB.
Description:	Building on Use Cases 2a, b, c, and d, an OpenFMB command was issued from the Control Portal to open Recloser 2 and then close the TIE switch. The status of Recloser 2 and Tie Breaker were monitored by the Recloser 2 and Tie Switch, respectively. This information was then sent inter-network via R-GOOSE to VENDOR A CB-A. The var load on the feeder was then increased above the setting threshold. The VENDOR A CB-A then made a determination to close Capacitor 2 for additional var support.
Use Case 3b: Peer-to-Peer Volt/Var Control	
Objective:	The objective of this use case was to demonstrate the peer-to-peer communication capability of OpenFMB to achieve progressive var support.
Description:	The var load on the feeder was increased above the setting threshold. VENDOR A CB-A then issued a signal (High Var) to the Optimizer that additional var support was needed. Upon receipt of the High Var message, the Optimizer then switched the Voltage Regulator to manual mode.
Use Case 4a: DER Active Power Control	
Objective:	The objective of this use case was to demonstrate the ability of OpenFMB to bridge Modbus communication, and to demonstrate the interoperation of traditional IED's and DER using OpenFMB.
Description:	A start command was sent from the Control Portal to the DER. An OpenFMB command to change the Power level was issued. In addition to changing the Var/Power order, a command was issued to change between operational modes from Voltage Droop regulation mode to Volt/Watt Mode regulation mode. A heartbeat signal was removed by disconnecting the DER from the network and the response of the inverter was noted. After removing the heartbeat, communication was reestablished and a reset command was issued to DER. Breaker A was opened and the response of the DER was recorded.
Use Case 5a: DER on-line / off-line	
Objective:	The objective of this use case was to demonstrate the use of R-GOOSE to improve system performance by communicating breaker status to a DER and thereby over-riding autonomous DER control functions.
Description:	A button push on VENDOR A CB-A was used to open CB-A. Upon detection of CB-A open, CB-A sent a command to VENDOR A CAPBANK 1. VENDOR A CAPBANK 1 operated an output contact to take the DER off-line.

Use Case 6a: Enhanced Automatic Feeder re-deployment	
Objective:	The objective of this use case was to demonstrate the mapping of data from GOOSE messages into OpenFMB as well as complex inter-device communication.
Description:	Using the HMI, CB-B was tripped. Vendor A CB-A Phase A current was then set to pass its pre-programmed threshold. As a result, Vendor A CB-A set its "Healthy Feeder" based on the threshold conditions, enabling auto re-deployment. As R-2 was monitoring the "Healthy Feeder" status, it issues a trip command to open R-2. R-2 then sends a command to close T-1 via R-GOOSE. Finally, Vendor A CB-A detected that T1 closed and changed its setting group and visualized via the HMI.
Use Case 7a: Automatic Feeder Re-Close	
Objective:	The objective of this use case was to demonstrate circuit re-configuration back to normal operating condition.
Description:	CB-B was closed by the HMI, placing voltage on the Breaker side of Recloser 2. Voltage was then detected on both sides of Recloser 2 and the phase angle of the voltage across the recloser was less than 30 degrees (as measured by R-2). As a result, Recloser 2 sent an open command to T-1. VENDOR A CB-A identified T-1 opened and changed back to the setting group 1.
Use Case 8a: Sample Value Test Cases (documentation only)	
Objective:	The objective of this use case was to demonstrate the high-speed transmission of sample values to further develop communication requirements for OpenFMB.
Description:	The measurement and transmission of voltage and current values from field equipment are known as sample values (SV). SV typically require high sample rates in the range of 3,000 to 96,000 samples per second. Additionally, the device creating the samples (known as the Merging Unit) can be located several kilometers away. IEC 61850 introduced the concept of sample values as a digital interface to optical current and voltage sensors as well as application-specific circumstances where remote location of voltage and current sensors is required/desirable. The IEC 61850 standard addresses issues such as data synchronization and phase correction. Given the high bandwidth and low latency constraints of such data, further study of its applicability to OpenFMB is needed.
Use Case 8b: Synchrophasors via R-GOOSE	
Objective:	The objective of this use case was to demonstrate the use of pub/sub technologies to transmit high speed data (e.g. synchrophasors) via routable R-GOOSE and evaluate the incorporation into OpenFMB standards.
Description:	Synchrophasors (V1 Magnitude and Angle) were mapped into Generic Analog 61850 data objects in VENDOR A CB-A and Recloser 2 and then included in R-GOOSE messages. R-GOOSE reception by T-1 was monitored by changing the source voltage angle and magnitude between Feeder A and Feeder B.
Use Case 9a: Dynamic Subscription (documentation only)	
Objective:	The objective of this use case was to identify the requirement for dynamic subscription for all messaging protocols for incorporation into OpenFMB

	standards.
Description:	In the scenario, when Feeder A and Feeder B are separated, there is no need to share messages between them. Once the T-1 is closed, it becomes desirable for the devices on Feeder A to be able to "subscribe" to information from devices on the "extended" line. For that purpose, it should be noted that Dynamic Subscription becomes a need in this test case. Additionally, the definition of the data objects from the newly subscribed devices may be needed, especially if there have been setting changes in any of the newly-subscribed devices.
Use Case 10a: End-to-End Security (documentation only)	
Objective:	The objective of this use case was to identify the requirement for end-to-end security in OpenFMB standards.
Description:	When communicating device-to-device in the field, end-to-end secure communications are required. End-to-end security should be developed that addresses authentication, authorization, access control, confidentiality, integrity, non-repudiation, availability, and accountability.
Use Case 11a: File transfer	
Objective:	The objective of this use case is to demonstrate file transfer using OpenFMB.
Description:	To demonstrate the transfer of a settings file, a file was transferred from the Administration Node to a Field Agent (OpenFMB Adapter). This file was of a size representative of a settings file, ~10 KB. It should be noted that settings files may also be unique to each OpenFMB node.
Use Case 11b: Firmware	
Objective:	The objective of this use case was to document or demonstrate firmware transfer.
Description:	To demonstrate the transfer of a firmware image, a file was transferred from the Administration Node to a Field Agent (OpenFMB Adapter). This file was of a size representative of a firmware image, ~10 MB. It should be noted that firmware images have various security characteristics that may be unique to each firmware instance, such as manufacturer signing. Firmware images may also be unique to each OpenFMB node.
Use Case 11c: Provisioning (documentation only)	
Objective:	The objective of this use case was to document the requirement to provision field devices using OpenFMB.
Description:	To set up an OpenFMB network, the secure provisioning of OpenFMB nodes is critical. Each OpenFMB node has to have its security credentials verified with the Administration Node. Various settings also need to be communicated relating to both the node's network and the node's application functionality. Initial subscriptions to other OpenFMB nodes also need to be created.
Use Case 12a: File transfer	
Objective:	The objective of this use case was to demonstrate file transfer using OpenFMB.
Description:	File transfer from an Administration Node to other nodes through OpenFMB (MQTT) was demonstrated. Currently, OpenFMB does not specifically define

	file transfer. In the future, OpenFMB may choose to use another protocol better suited for file transfer (e.g., SFTP) as pub/sub protocols are not typically used for large, point-to-point, file transfers. Further, individual settings and firmware are likely not to be broadcast as security images; configuration and other aspects are likely to be unique to each node. (Note: Refer to Use Case 11a for further information on file transfer.)
13a OpenFMB using DDS	
Objective:	The objective of this use case was to demonstrate OpenFMB using DDS
Description:	To demonstrate OpenFMB using DDS, the Tie SW is set as the one of the DDS nodes. The Tie SW gets the data (measurement value) from DNP3 adaptor and publishes the data on the DDS virtual FMB. Then another DDS node subscribes to the data. When the data is received, the data is published in the Audit Log.

2.5 System Tests

Table 4 summarizes the tests run on the demonstration system to verify the use cases. The complete test case document, including specific results, is provided in Appendix B.

Table 4 - System Tests

Use Case	Test Case Step	Description
1a: OpenFMB Connection to Vendor B Devices and Virtual DER / Cap Bank	1	Start control portal.
	2	Start field agents.
	3	Insert ALL Vendor A devices • CB-A, Recloser 2, Tie SW, Cap 1, Cap 2
	4	Monitor measurement values on R1.
	5	Control portal sends R1 Open command.
	6	Monitor measurement values on SW (Vendor B Switch).
	7	Control portal sends SW Open command.
	8	Monitor measurement values on Virtual DER.
	9	Control portal exercises range of DER commands: • Reset • Set voltage source inverter – PQ Mode • Set for Voltage / Watt mode of operation • Initial real power set point • Initial reactive power set point
	10	Monitor measurement values on Virtual Cap Bank.
	11	Control portal sends control values to Virtual Cap Bank.
2a: Var Control	1	Start control portal.
	2	Start field agents / optimizer.
	3	Measure the vars at the breaker Feeder A (Vendor A CB-A).
	4	Change vars in the RTDS model to exceed a set point.
	5	Send R-GOOSE message from Vendor A CB-A to Vendor A Cap Bank 1 to close capacitor Vendor A Cap Bank 1.
	6	Sent R-GOOSE message received by Vendor A Cap Bank 1 capacitor.
	7	Measure the vars at the breaker Feeder A (Vendor A CB-A).
2b: Man-in-the-Middle Augmented Voltage/Var Control	1	Measure the vars at the breaker Feeder A (Vendor A CB-A).
	2	Change vars in the RTDS model to exceed a set point if needed.
	3	Vendor A CB-A sends an alarm of "Over VAR."
	4	Control portal receives alarm.
	5	Operator places VR1 in Auto mode.
2c: Peer-to-Peer Voltage/Var Control	1	Measure the vars at the breaker Feeder A (Vendor A CB-A).
	2	Change vars to exceed a set point.
	3	Vendor A CB-A sends an alarm of "Over VAR."
	4	Control portal and optimizer receive alarm.

Use Case	Test Case Step	Description
	5	Optimizer sends command to VR1 to switch to Manual mode.
	6	VR1 regulates to a previously issued set point in Manual mode.
	7	Measure the vars at the breaker Feeder A (Vendor A CB-A).
2d: Voltage Override	1	Monitor voltage on Cap 1 Vendor A Cap Bank 1.
	2	RTDS simulates an increase in voltage (high voltage) on Cap 1 Vendor A Cap Bank 1.
	3	Control portal sends close command to Vendor A Cap Bank 1.
	4	Cap 1 Vendor A Cap Bank 1 refuses the close control.
	5	Cap 1 Vendor A Cap Bank 1 sends message to CB-A indicating refusal.
	6	CB-A sends message “Over-Voltage” to optimizer.
	7	Optimizer sends message to VR1 to change to Auto mode.
	8	VR1 receives Auto mode command.
3a: Inter-network Var Control	1	Start control portal.
	2	Start field agents.
	3	Control portal sends Open command to R2.
	4	Control portal sends Close command to T1.
	5	R2 monitors device status.
	6	T1 monitors device status.
	7	Var load on the feeder is increased above the setting threshold.
	8	Vendor A CB-A monitors network and determines to close Cap 2.
	9	Vendor A CB-A closes Cap 2 (R-GOOSE).
	10	Control portal displays measurement values.
3b: Peer-to-Peer Volt/Var Control	1	Var load on the feeder is increased above the setting threshold.
	2	Vendor A CB-A monitors network and determines var is above threshold.
	3	Vendor A CB-A issues a signal (High Var) to optimizer for var support.
	4	Optimizer receives message.
	5	Optimizer sends command to VR1 to switch to Manual mode.
	6	Control portal displays measurement values.
4a: DER Active Power Control	1	Start control portal.
	2	Start field agents.
	3	Operator issues a start command via the control portal.

Use Case	Test Case Step	Description
	4	Operator issues an enable set point command.
	5	Operator issues Real Power setpoint
	6	Operator issues Reactive Power setpoint
	7	DER mode changed to Volt / Watts mode.
	8	DER mode changed to Volt / Vars mode.
	9	Test engineer removes Ethernet connection to DER.
	10	Test engineer reconnects Ethernet connection to DER.
	11	Operator issues reset command to DER via control portal.
	12	Operator opens Breaker A.
5a: DER Online / Offline	1	Pushbutton command on Vendor A CB-A to open CB-A.
	2	Vendor A CB-A de-energizes Feeder A.
	3	Upon detection of Breaker A open, Vendor A CB-A sends a command to Vendor A Cap Bank 1.
	4	Vendor A Cap Bank 1 operates an output contact to take the DER offline.
	5	DER operates and goes offline.
6a: Enhanced Automatic Feeder Re-Deployment	1	Start control portal.
	2	Start field agents.
	3	Test engineer trips CB-B from HMI.
	4	Vendor A Phase A Current < Threshold then the Healthy Circuit status issued
	5	Vendor A CB-A sets “Healthy Feeder event” based on threshold conditions.
	6	Vendor A CB-A auto re-deployment enabled (phase A current ≤ threshold).
	7	R2 monitors “Healthy Feeder A” voltage status.
	8	R2 issues trip command open R2.
	9	R2 sends command to close T1
	10	Vendor A CB-A detects T1 closed and changes settings group.
	11	Vendor CB-A Phase A Current > Threshold then the “Load Shed status issued
	12	Vendor A CB-A sends “Load Shed” DNP point via OpenFMB to OPC UA (UAP) to SW T
	13	Vendor A CB-A Phase A Voltage ≤ Threshold then the Healthy Circuit status issued
	14	Vendor A CB-A Commands Circuit A reconfiguration
	15	Vendor A CB-A detects Tie-Breaker T1 closed, change setting group
7a: Automatic Feeder Re-Close	1	Start control portal.
	2	Start field agents.

Use Case	Test Case Step	Description
	3	Close CB-B.
	4	Measure voltage (high and load side) of R2.
	5	Measure phase angle of R2. Note: RTDS can be used to adjust phase angle.
	6	Close R2.
	7	R2 sends Open command to T1.
	8	Vendor A CB-A monitors T1 is open and changes back to the original settings group (1).
	9	Control portal displays measurement values.
	10	Close CB-B.
	11	Measure voltage (high and load side) of R2.
	12	Measure phase angle of R2. Note: RTDS can be used to adjust phase angle.
	13	Close R2, R2 fails to close
8a: Sample Value		*Documentation Only*
8b: Synchrophasors via R-GOOSE	1	Vendor A CB-A and R2 send synchrophasor data.
	2	Change source voltage angle and magnitude between Feeder 1 and Feeder 2.
9a: Dynamic Subscription		*Documentation Only*
10a: End-to-End Security		*Documentation Only*
11a: File Transfer	1	Start control portal.
	2	Start optimizer.
	3	Control portal sends message to Vendor A CB-A optimizer.
11b: Firmware		*Documentation Only*
11c: Provisioning		*Documentation Only*
12a: Operational Data File Transfer using OpenFMB		*Documentation Only (See 11a)*
13a OpenFMB using DDS	1	Set Vendor A Tie SW as one of the DDS nodes
	2	Vendor A Tie SW (Node 1) receives data (DNP3 adaptor) and publishes data via DDS OpenFMB
	3	Node 2 subscribes to data from Node 1 (View Audit Log)

2.6 Data Collection

During testing, data was collected from the demonstration system in a variety of ways including network packet captures, oscillography, and sequence of events. This data was then analyzed to create the findings and recommendations given later in this report. Additionally, this data was used in the various test cases to confirm correct operation and validation of the functionality. Detailed use case descriptions are presented in Appendix A and detailed results of test cases are presented in Appendix B.

3 Overall Project Results

3.1 Technical Results and Findings

Many aspects of OpenFMB remain undefined. As each implementation of OpenFMB may define those aspects differently, there are likely interoperability issues between different OpenFMB implementations. For the purposes of this project, those aspects that had to be defined to create a fully functioning demonstration system included:

- Provisioning of devices
- Management services (e.g., time synchronization)
- Security
- Data profiles (e.g., OpenFMB says to use CIM, but without needed precision)
- Configuration
- Standardized adapters for data translation between protocols

Similarly, OpenFMB's optionality allows the use of multiple protocols, such as those tested during this project (i.e., MQTT, DDS). Currently, OpenFMB allows each implementation to select which protocols they believe best for their circumstances. However, as each implementation of OpenFMB may choose to use different protocols, there are, once again, likely to be interoperability issues between different OpenFMB implementations. Although this project tested multiple protocols, a production deployment would likely need to constrain itself to a single protocol for a given circumstance.

Each protocol tested in this project uses a multicast approach to discovery and the transfer of data, which resulted in a level of data traffic that adversely affected network performance, increasing latency and packet loss. In a real-world production system, the network would need to be designed to take that multicast traffic into account. A production deployment would also likely need to constrain itself to a single protocol for a given network.

This project's test system also used different networking technologies, including Ethernet and 900 MHz radio, which saw degraded system performance when multicast traffic was routed between those technologies. This degraded performance was a result of several factors including saturation of the network bandwidth and the inefficiencies of multicast traffic with radio technologies (where there is often not a channel dedicated to multicast traffic but rather multicast traffic must be repeated for each connected device).

In light of potential data traffic congestion, message prioritization, such as Quality of Service, is needed for OpenFMB so that critical messages are not impeded by, for instance, less urgent file transfers. Existing, legacy client/server and/or master/slave devices have limits on the number of other devices to which they can communicate, making them unfit for peer-to-peer uses. This points to the strengths of OpenFMB and R-GOOSE publish/subscribe messaging approaches; they are designed for peer-to-peer communication.

The OpenFMB payloads, the format for data being exchanged, used in this project proved inefficient and needs further exploration to improve efficiencies. Currently, the OpenFMB standard is silent on payload formats and further work is needed to determine or define optimally efficient payloads, such as payload compression and/or more efficient formats.

The use of deadbands to report exceptions in the recording of analog information from various devices in the network needs fine-tuning to take network constraints into account and limit exception reports. While this is not unique to OpenFMB, any use of OpenFMB in the future should take this need into account. Currently, configuring adapters and mapping is difficult, particularly when standards have optionality. The commercialization of OpenFMB-related systems would have to facilitate the mapping and integration of existing devices, particularly when multiple protocols and vendor implementations are involved. Standardization of mapping (e.g., a file format) would be useful. Such a standardized mapping could then be used during the configuration of a given adapter.

The use of adapters for protocol translation introduces additional latency. The availability of native OpenFMB devices that preclude the need for adapters could eliminate adapter-related latency. Such latency may prove detrimental in certain use cases such as closed-loop control, sample value data, and synchro phasor communication.

To achieve reliability in data transfer, each protocol uses different mechanisms. For example, MQTT uses TCP with acknowledgements; R-GOOSE uses message repeat. Further study may reveal the pros and cons of the various reliability mechanisms and their impact on overall communication system performance.

OpenFMB works today through the use of adapters, which allows access to all devices in a unified manner and could be useful to avoid stranded assets, integrate existing assets into IoT and enable peer-to-peer communication. This project was thus enabled to tie together a variety of devices produced by several vendors using different standards (e.g., IEC 61850, DNP3, Modbus). As noted, the benefits of adapters are constrained by the additional latency they produce.

By using adapters, OpenFMB provides all devices with a common data model. This makes it possible for utilities to use applications that aren’t necessarily tailored to a specific technology. Utilities are freed to use best-of-breed applications because there is a common application interface available.

Further study of the pros and cons of using a broker would be useful, as well as determining its role and placement in specific network and security-related designs. (MQTT uses a broker. DDS and R-GOOSE do not.)

Lastly, an additional finding of this project was the need for dynamic subscriptions and mechanisms to support their configuration. The dynamic subscription approach should be explored for use with OpenFMB as well as other technologies.

3.2 Overall Recommendations

As a result of this demonstration, it was found that OpenFMB is not yet a standard for peer-to-peer interoperability. Gaps and options in OpenFMB's definitions, as described above, are hindrances to achieving interoperability. Further work on unambiguous definitions in the standard would aid its potential use and commercialization.

OpenFMB and its use of adapters could allow access to all devices in a unified way, protecting legacy investments and unlocking new potential in devices with limited communications capabilities, such as DER that typically use Modbus for local communication only.

OpenFMB allows peer-to-peer communication, rather than traditional hierarchical communication between devices and the utility back office found in most currently deployed distribution systems, and the autonomy of distributed intelligence unlocks the potential for new OpenFMB use cases, such as distributed Volt/VAr control.

The implementation of OpenFMB in a larger, production system will require a careful network design that takes resulting data traffic and bandwidth needs into consideration. This network design will also need to take into account application requirements to better understand each application's latency needs and capabilities.

IEC 61850 using R-GOOSE is a potentially useful alternative or addition to OpenFMB and SDG&E may wish to investigate the use of IEC 61850 using R-GOOSE further. The use of IEC 61850 with R-GOOSE could still benefit from many of the features of OpenFMB such as the use of adapters and the focus on distributed intelligence.

OpenFMB clearly shows promise as a framework for peer-to-peer communication and distributed intelligence. Further, the use of adapters in OpenFMB could help to avoid costly device replacement and extend the uses of existing devices. However, work does remain to further define and mature the OpenFMB standard as it is not yet ready for commercial adoption. It is recommended that work be continued to further define the OpenFMB standard so that it can be successfully utilized in future utility distribution system projects and deployments.

4 Technology Transfer Plan

4.1 Technology Transfer Plan

A primary benefit of the EPIC program is the technology and knowledge sharing that occurs both internally within SDG&E and across the industry. To facilitate this knowledge sharing, SDG&E will share the results of this project by announcing the availability of this report to industry stakeholders on its EPIC website, by submitting papers to technical journals and conferences, and by presentations in EPIC and other industry workshops and forums. SDG&E will also make presentations on project results to internal stakeholder groups within the company.

4.2 Adaptability to Utilities and Industry

Many aspects of OpenFMB are yet to be defined, as noted above, and the OpenFMB working group should strive to address each of these gaps to develop a truly interoperable standard. Without this further definition, there are likely to be non-interoperable implementations of OpenFMB. Further work on the OpenFMB standard is needed to provide the industry with unambiguous definitions and direction on which protocol (MQTT, DDS, AMQP) is optimal for specific circumstances or when one should be selected over another.

Currently, the OpenFMB standard is silent on payload formats and further work is needed to determine or define optimally efficient payloads. Using R-GOOSE as an additional protocol for OpenFMB is worthy of further evaluation. The industry stakeholders headed by the OpenFMB working group might consider R-GOOSE as a protocol choice, much like MQTT or DDS. In this project, proof-of-concept rules were created for orchestrating the peer-to-peer communication, which were dynamically created and deployed. Further development, including user-friendly tools, is needed to achieve production quality. A number of standards activities are evaluating dynamic rules or policies. The project recommends that the OpenFMB working group undertake this evaluation.

4.2.1 Potential OpenFMB Reference Architecture

The following section summarizes current state of the architecture to aid future OpenFMB standard development. Requirements and recommendations for this reference architecture are sourced from the NAESB RMQ.26 standard as well as potential future enhancements to the OpenFMB standard.

An OpenFMB reference architecture describes the following components:

- OpenFMB Logical Architecture
    - Operational (Data Path) Logical Architecture
    - Management Services Logical Architecture
    - Cross-Cutting Services Logical Architecture
- Node Architecture
    - Representative Hardware and Software Configurations

OpenFMB Logical Architecture

An OpenFMB operational logical architecture is related to the data path or flow of information during normal business operations. The operational logical architecture is composed of three components: application/adapter, interface, and middleware. Adapters should be developed and available for all protocols currently used by SDG&E field devices: DNP3, Modbus, IEC 61850, R-GOOSE, and ANSI C12.19. Applications and application profiles should be defined and included for all desired OpenFMB functionality (e.g., volt/var optimization, Distributed Energy Resource (DER) optimization, microgrid isolation/reconnecting).

Currently, NAESB RMQ.26 does not define specific application profiles beyond demonstration profiles or a specific canonical model. GE has developed a specific canonical model for OpenFMB that can be used to create an SDG&E canonical model and needed application profiles. In the future, this canonical model and any application profiles could be contributed back to the OpenFMB standard. In addition, as the OpenFMB standard and IEC CIM evolve, the canonical model can easily be extended or replaced due to the cleanly layered design of OpenFMB. Either a full XSD for the application profiles or only the portions relevant to the given nodes should be included for SDG&E's canonical model. Message topics should be defined and utilized for SDG&E's needs and canonical model. Based on our evaluation, one or more publish-subscribe protocols should be selected from among: MQTT, DDS, and AMQP to comprise the middleware.

Management Services Logical Architecture

An OpenFMB management services logical architecture is related to the monitoring, auditing, alerting, and updating of OpenFMB nodes. The management services layer should be flexible and allow the inclusion of additional management services plug-ins after deployment of an OpenFMB node. Updates and rollbacks of updates, as well as their timing, should be supported on all OpenFMB nodes. The updates may apply to the entire operating system or to individual components such as OpenFMB applications, adapters, and management services plug-ins.

Auditing of OpenFMB nodes should be supported. Such auditing should provide clear logging of pertinent data as well as accurate timestamps. Pertinent data should include network transfers, computing resource usage (e.g., Central Processing Unit (CPU), Random Access Memory (RAM), storage), and any installations, updates, or rollbacks. In addition to logging, data of a critical nature should be sent via an alert to an administration node.

Cross-Cutting Services Logical Architecture

An OpenFMB cross-cutting services logical architecture consists of those components which apply to both the operational logical architecture and the management services logical architecture, such as security. Security services should be based on open, standardized services appropriate for the chosen middleware (e.g., MQTT) and following the principles of defense in

depth. These security services should provide mechanisms for authentication, authorization, confidentiality, non-repudiation, integrity, and auditing.

In addition, physical security, based both on the OpenFMB node hardware as well as physical placement, as well as software isolation (e.g., virtualization, containers), should be considered. Data stored (at rest) should also be held in a confidential manner (e.g., encrypted) if necessary.

Credentials should be pre-placed in OpenFMB nodes to allow for proper authentication and authorization of an administration node and any other nodes for which "out-of-the-box" communication may be necessary. The procedures for loading these credentials vary amongst deployments and may require additional action from network owners, network operators or device manufacturers. Other OpenFMB nodes may be authenticated and authorized based on policies distributed by an administration node. QoS (quality of service) should be supported on OpenFMB nodes. Further, in the presence of hardware or communications degradation, these QoS mechanisms should be used to best utilize the degraded system.

Node Architecture

Given that SDG&E already has many deployed assets that communicate using a variety of protocols, and given that dedicated OpenFMB equipment is not readily available in the market, the proposed node architecture below heavily makes use of adapters. If, in the future, native OpenFMB nodes are available, those may be more cost effective than the below approach for new assets.

For hardware, it is recommended to use a standalone device connected to each existing field asset or, should field assets be in close proximity, a standalone device may be used for multiple existing field assets. Such a device must have sufficient speed in its CPU, sufficient room in its RAM, and storage resources to implement the desired software. In our experience, we would suggest a minimum of a 1 GHz ARM processor, 512 MB of RAM, and 4 GB of storage. This device should also be capable of utilizing a variety of communications options based on previous selections by SDG&E.

For software, it is recommended to use Docker containers running atop the Linux operating system. Containerization is proving more and more popular and is more lightweight than virtual machines. Each existing device connected to the hardware would have its own container, thus isolating each OpenFMB virtual node. These containers would then have access to adapters for each legacy protocol desired (e.g., DNP3, Modbus) as well as one or more middleware protocols (e.g., DDS, MQTT, AMQP) selected based on results of our testing. The containers would also contain applications for base OpenFMB communications as well as any new applications (e.g., peer-to-peer communication). These new applications are thus easily extensible for any new OpenFMB use cases without affecting the existing devices.

This node architecture is shown in Figure 13.

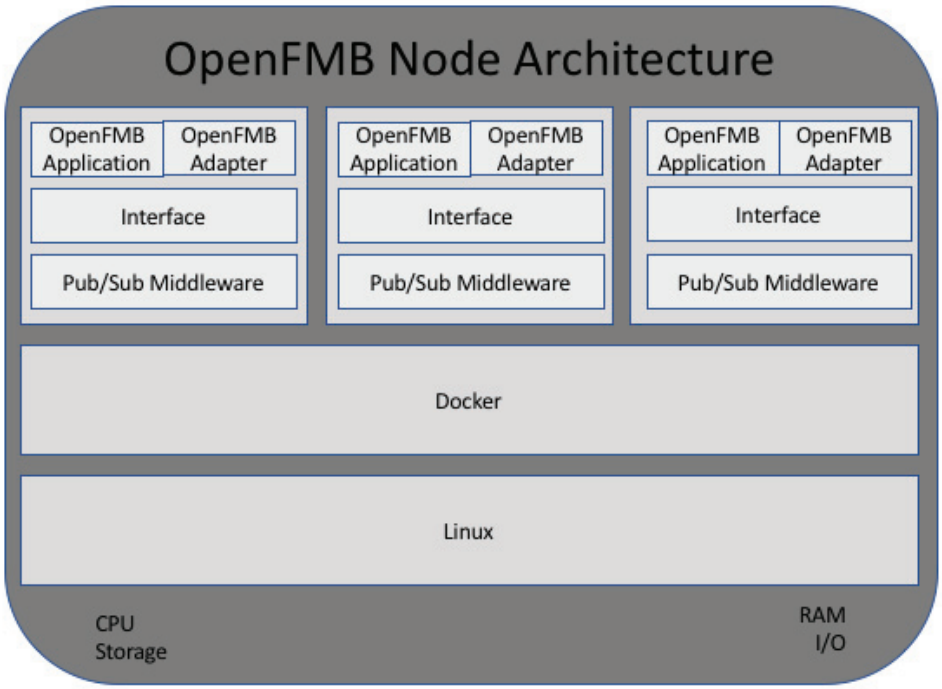


Figure 13 - OpenFMB Node Architecture

4.2.2 Dynamic Subscriptions within OpenFMB

Dynamic subscription is a finding discovered during the course of this demonstration that could be an area of future study, both for OpenFMB and for other pub/sub standards and frameworks. In pub/sub protocols, the receiver of information must subscribe to receive a published message. In the course of developing the use cases for this project, it became apparent that continuous subscription to a message is not always needed or desirable and will consume bandwidth. As such, the concept of dynamic subscription was proposed. In this scenario, a subscriber may release itself from receiving a particular message. When events on the power system dictate, the subscriber can reinitiate the subscription.

As an example, consider a device on Feeder A. In normal operating conditions, this device would likely subscribe to messages from other devices on Feeder A. However, should an event cause Feeder A to be connected electrically with Feeder B, the device may now wish to subscribe to messages from other devices on Feeder B. We have referred to this need to change subscriptions "on-the-fly" as dynamic subscription. At the application layer, the device would need to have the ability to both recognize the change in electrical network topology as well as to know which new devices and messages it would need to subscribe.

While such a capability could potentially be pre-programmed into the device or communicated from a central location, we believe further study could unlock new distributed mechanisms for these changes. It is likely a distributed mechanism would be preferable, in the event that communications to a central location is also impacted by the event as well as to avoid the latencies required to communicate to a central location during such an event. The most

efficacious design of a dynamic subscription approach has yet to be explored, but could become the focus of a follow-on demonstration project.

5 Metrics and Value Proposition

5.1 Metrics

The following metrics were identified for this project and evaluated during the course of the pre-commercial demonstration. These metrics are not exhaustive given the pre-commercial demonstration approach for this project.

Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy

- Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (PU Code § 8360)
    - The EPIC project demonstrated the potential value of OpenFMB in addressing interoperability issues that exist in the electric system today, with multiple vendor technologies/systems unable to interface or interact with each other in a seamless manner. OpenFMB could provide a framework that enables the coexistence of traditional IEDs or devices that operate in a centralized manner with new IEDs or devices (especially DERs) that have the capability to operate in a decentralized manner.
- Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360)
    - This EPIC project established a potential OpenFMB framework that could be implemented in the secondary layer that sits between the enterprise layer in a utility control center, and the primary layer that sits on multiple devices or equipment in the field. Next generation of IEDs or DERs may provide the necessary communication technology and application framework that enable peer to peer communication between devices and routes the information through the OpenFMB framework to disparate systems in the backend.

Safety, Power Quality, and Reliability (Equipment, Electricity System)

The use of OpenFMB framework to deploy decentralized applications could enable interoperability and improve information sharing between field devices and backend systems. The following sub-factors could be enhanced with the use of OpenFMB:

- Reduction in outage numbers, frequency, and duration.
- Reduction in system harmonics
- Increase in the number if nodes in the power system at monitoring points
- Public safety improvement and hazard exposure reduction

5.2 Value Proposition

The purpose of EPIC funding is to support investments in R&D projects that benefit the electricity customers of SDG&E, PG&E, and SCE. The primary principles of EPIC are to invest in technologies and approaches that provide benefits to electric ratepayers by promoting greater

reliability, lower costs, and increased safety. This EPIC project contributes to these primary and secondary principles in the following ways:

- Reliability – The use of OpenFMB to address interoperability challenges may provide greater reliability through potential improvements in distribution system operations through automated peer to peer volt/var control, DER management, or enhanced automatic feeder redeployment.
- Lower Costs – Utilizing OpenFMB as a framework for deploying multiple technologies has the potential to lower costs for integration of devices and applications that can help utilities operate their electric infrastructure efficiently and in a cost effective manner.

Appendix A. Use Cases

Use Case Contents

2. Reference Architecture 6

2.1 Reference Architecture – Figure 1 6

2.2 Reference Architecture – Figure 1 Device Names 7

3. Actors 8

3.1 Use Case Actors 8

4. General Triggering Events, Preconditions, Assumptions 10

4.1 Use Case Triggering Event, Preconditions, Assumptions 10

5. Use Case 1a - OpenFMB Connection to Relays & Virtual DER / Cap Bank 12

5.1 Use Case Description - UC 1a OpenFMB Connection to Relays & Virtual DER / Cap Bank 12

5.2 Use Case Diagram - UC 1a OpenFMB Connection to Relays & Virtual DER / Cap Bank 13

5.3 Use Case Diagram - UC 1a OpenFMB Connection to Relays & Virtual DER / Cap Bank 14

5.4 Pre-Conditions - UC 1a OpenFMB Connection to Relays & Virtual DER / Cap Bank 15

6. Use Case 2a - Var Control 16

6.1 Use Case Description – UC 2a Var Control 16

6.2 Use Case Diagram - UC 2a Var Control 17

6.3 Use Case Diagram - UC 2a Var Control 18

6.4 Use Case Pre-Conditions – UC 2a Var Control 19

7. Use Case 2b Man-in-the-Middle Augmented Voltage/Var Control 20

7.1 Use Case Description – UC 2b Man-in-the-Middle Augmented Voltage/Var Control 20

7.2 Use Case Diagram – UC 2b Man-in-the-Middle Augmented Voltage/Var Control 21

7.3 Use Case Diagram – UC 2b Man-in-the-Middle Augmented Voltage/Var Control 22

7.4 Use Case Pre-Conditions – UC 2b Man-in-the-Middle Augmented Voltage/Var Control 23

8. Use Case 2c – Peer-to-Peer Voltage/Var Control 24

8.1 Use Case Description – UC 2c Peer-to-Peer Voltage/Var Control 24

8.2 Use Case Diagram – UC 2c Peer-to-Peer Voltage/Var Control 25
8.3 Use Case Diagram – UC 2c Peer-to-Peer Voltage/Var Control 26
8.4 Use Case Pre-Conditions – UC 2c Peer-to-Peer Voltage/Var Control 27
9. Use Case 2d – Voltage Override 28
9.1 Use Case Description – UC 2d Voltage Override 28
9.2 Use Case Diagram – UC 2d Voltage Override 29
9.3 Use Case Diagram – UC 2d Voltage Override 30
9.4 Use Case Pre-Conditions – UC 2d Voltage Override 31
10. Use Case 3a – Inter-network Var Control 32
10.1 Use Case Description – UC 3a Inter-network Var Control 32
10.2 Use Case Diagram – UC 3a Inter-network Var Control 33
10.3 Use Case Diagram – UC 3a Inter-network Var Control 34
10.4 Use Case Pre-Conditions – UC 3a Inter-network Var Control 35
11. Use Case 3b – Peer-to-Peer Volt/Var Control 36
11.1 Use Case Description – UC 3b Peer-to-Peer Volt/Var Control 36
11.2 Use Case Diagram – UC 3b Peer-to-Peer Volt/Var Control 37
11.3 Use Case Diagram – UC 3b Peer-to-Peer Volt/Var Control 38
11.4 Use Case Pre-Conditions – UC 3b Peer-to-Peer Volt/Var Control 39
12. Use Case 4a – DER Active Power Control 40
12.1 Use Case Description – UC 4a DER Active Power Control 40
12.2 Use Case Diagram – UC 4a DER Active Power Control 41
12.3 Use Case Diagram – UC 4a DER Active Power Control 42
12.4 Use Case Pre-Conditions – UC 4a DER Active Power Control 43
13. Use Case 5a – DER on Line / off-line 44
13.1 Use Case Description – UC 5a DER on Line / off-line 44
13.2 Use Case Diagram – UC 5a DER on Line / off-line 45
13.3 Use Case Diagram – UC 5a DER on Line / off-line 46
13.4 Use Case Pre-Conditions – UC 5a DER on Line / off-line 47
14. Use Case 6a – Enhanced Automatic Feeder re-deployment 48

14.1 Use Case Description – UC 6a Enhanced Automatic Feeder re-deployment 48
14.2 Use Case Diagram – UC 6a Enhanced Automatic Feeder re-deployment 49
14.3 Use Case Diagram – UC 6a Enhanced Automatic Feeder re-deployment 50
14.4 Use Case Pre-Conditions – UC 6a Enhanced Automatic Feeder re-deployment 51
15. Use Case 7a – Automatic Feeder Re-Close 52
15.1 Use Case Description – UC 7a Automatic Feeder Re-Close 52
15.2 Use Case Diagram – UC 7a Automatic Feeder Re-Close 53
15.3 Use Case Diagram – UC 7a Automatic Feeder Re-Close (Use Case Diagram & Data Flow Summary redacted due to IP confidentiality concerns). 54
15.4 Use Case Pre-Conditions – UC 7a Automatic Feeder Re-Close 55
16. Use Case 8a – Sample Value Use Cases (Documentation only) 56
16.1 Use Case Description – UC 8a Sample Value Use Cases (Documentation only) 56
17. Use Case 8b – Synchrophasors via R-Goose 57
17.1 Use Case Description – UC 8b Synchrophasors via R-Goose 57
17.2 Use Case Diagram – UC 8b Synchrophasors via R-Goose 58
17.3 Use Case Diagram – UC 8b Synchrophasors via R-Goose 59
17.4 Use Case Pre-Conditions – UC 8b Synchrophasors via R-Goose 60
18. Use Case 9a – Dynamic Subscription (Documentation Only) 61
18.1 Use Case Description – UC 9a Dynamic Subscription (Documentation) 61
19. Use Case 10a – End-to-End Security (Documentation Only) 62
19.1 Use Case Description – UC 10 End-to-End Security (Documentation) 62
20. Use Case 11a – Administration of Devices using OpenFMB 63
20.1 Use Case Description – UC 11a File transfer 63
20.2 Use Case Diagram – UC 11a File transfer 64
20.3 Use Case Diagram – UC 11a File transfer 65
20.4 Use Case Pre-Conditions – UC 11a File transfer 66
20.5 Use Case Description – UC 11b Firmware 67
20.6 Use Case Description – UC 11c Provisioning (Documentation Only) 68
21. Use Case 12a – Operational Data File transfer using OpenFMB 69

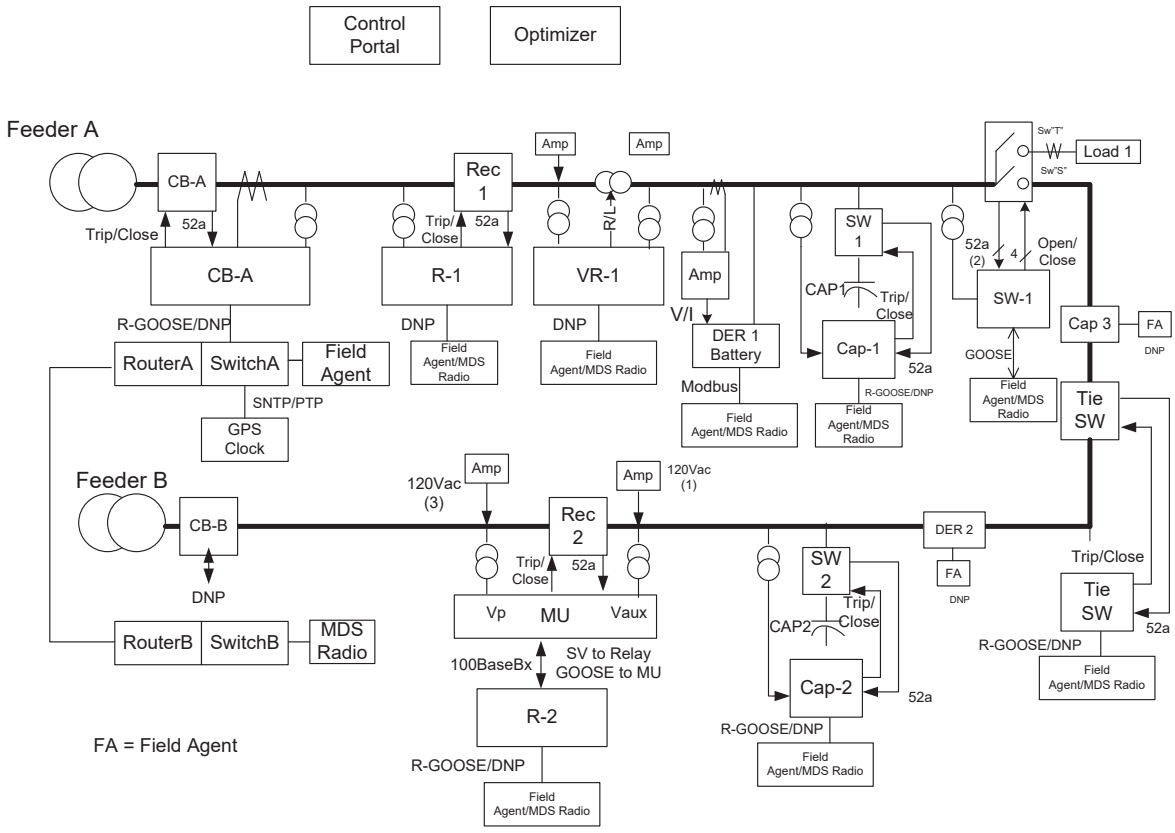
21.1 Use Case Description – UC 12a Operational Data File transfer using OpenFMB 69
22. Use Case 13a – OpenFMB using DDS 70
22.1 Use Case Description – UC 13a OpenFMB using DDS 70

1. Introduction

The purpose of this appendix is to specify system requirements including the non-functional scenarios and user stories for the OpenFMB which focuses on the application components and the data exchange necessary to perform the analysis. The requirements are intended to specify the functional and non-functional requirements for the OpenFMB configuration and to be the pre-requisite to the Use plan documents. The Use Cases have been developed to demonstrate the use of messaging to optimize distribution system performance.

2. Reference Architecture

2.1 Reference Architecture – Figure 1



2.2 Reference Architecture – Figure 1 Device Names

Note: Device Names and abbreviations

Device Description	*Device Abb.*
Vendor A - Circuit Breaker A	CB-A
Vendor A - Capacitor 1	Cap 1
Vendor A - Capacitor 2	Cap 2
Vendor A - Tie Switch	Tie SW
Vendor A - Recloser 2	R-2
Vendor A - Virtual Capacitor 3	Cap 3
Vendor A - Virtual DER	Der 2
Vendor B Recloser 1	R-1
Vendor B Voltage Regulator	VR-1
Vendor B Load Switch	SW-1
Vendor C DER	DER 1
Vendor B Circuit Breaker B	CB-B

3. Actors

3.1 Use Case Actors

Actor Name *see Actor List*	*Actor Type* *see Actor List*	*Actor Description* *see Actor List*	*Further info*
OpenFMB	System, application	System framework and reference architecture for distributed intelligent nodes interacting with each other through loosely coupled, peer -to-peer messaging for field devices and systems along the electric value chain.	Real
Control Portal	System, application	Application that provides a User Interface to visualize the circuit network, display measurement values and provide limited control capability for network devices.	Real
Network Diagram	System, application, data	Network Diagrams SDG&E provided circuits C411 and C387. The Circuits will be displayed on the Control Portal.	Real
Optimizer	System, application	Application which optimizes the resources included in the Vol/Var Use Cases. Optimization is done using based on defined business rules.	Simulated
Field Agent	device	Field agent SW & HW device that will communicate with the "edge", field devices. The Field Agents includes Radio, Communication, FA nodes are connected to each Field Device and connected to the OpenFMB.	Real
Operator	person	Operator of the Use Case scripts. This actor is required for Use Case operations as the Use system is not fully autonomous.	Real
Breaker Relay	device	The Breaker Relay feeder protection system provides feeder protection, control, monitoring and metering in an integrated package.	Real

Actor Name *see Actor List*	*Actor Type* *see Actor List*	*Actor Description* *see Actor List*	*Further info*
Capacitor Relay	device	The Capacitor Relay provides protection functions designed specifically to protect shunt capacitor banks.	Real
Tie Switch Relay	device	The controller system is a device designed to act as Tie Switch to demonstrate Use Cases.	Real
Recloser Relay	device	The Advanced Recloser Control offers protection and communications capabilities for Automatic Network Reconfiguration in the event of a fault.	Real
Voltage Regulator Relay	device	The Voltage Regulator Controller to optimize System Voltage and control system voltage.	Real
Load Relay	device	The load simulation relay provides three-phase restraint current inputs.	Real
PMU	device	Highly accurate measuring device for System electrical measure, time tags, and frequency synchronization.	Real
Battery Inverter	device	Inverter that connects battery to the VVC System. Assumed to be capable of operation as a rectifier. Controllable up in range zero to current maximum capability of solar panel.	Real
Flexible Load	device	Controllable load to simulate Critical customer loads; both load shed and non-load shed components.	Simulated
Communication	device	Interconnection of devices and systems using 900mhz and WIFI.	Real
RTDS	System, application	Power system simulation software	Simulator

4. General Triggering Events, Preconditions, Assumptions

4.1 Use Case Triggering Event, Preconditions, Assumptions

Actor/System/Information/Contract	*Triggering Event*	*Pre-conditions*	*Assumption*
Operator	Optional human operator. May observe operations of Use Case demonstrations and provide Operator inputs as required	Operator trained in use of the system	
Optimizer	There is a control simulator for managing control commands to the distribution grid. The controls are based on Use Case Using steps.	Distribution Network (2 Circuits) are imported into the Control Portal	Interaction with the Control Portal and Optimizer during Using of OpenFMB
Control Portal	Control Portal provides the visualization, monitoring and display. Measurement and Control values trigger changes the display	Control Portal is preconfigured and the distribution network circuits have been imported into the application.	
Devices (Relays)	Relay events are defined in the Use Cases. Defined events sends and receives messages via GOOSE, R-GOOSE or OpenFMB messages.	Relays are preconfigured and are connected to the distribution and communication network	Device Relays are pre-wired and connected to the networks.
Distribution Network	Distribution Network with 2 circuits connected with a tie switch have been preconfigured along with all network devices	Distribution Network (2 Circuits) have full connectivity from Circuit Breaker to network devices defined in the Use Case	Network model is provided in CIM/RFD
Messaging Protocols	MQTT, DDS, GOOSE, R-GOOSE messaging protocols.	Machine to Machine preconfigured with MQTT, DDS, GOOSE, R-GOOSE	
Communication	Communication network along with Field Agents	Communication Network is preconfigured with 2	Radio equipment and communication network

Network	have been configured. Send & receive messages can be triggered from the relays, Control Portal or Optimizer.	separate networks. Each circuit preconfigure with a separate communication network.	is preconfigured and has the ability to ping all devices on the network

5. Use Case 1a - OpenFMB Connection to Relays & Virtual DER / Cap Bank

5.1 Use Case Description - UC 1a OpenFMB Connection to Relays & Virtual DER / Cap Bank

UC 1a: OpenFMB Connection to Relays and Virtual DER / Cap Bank

Objective:

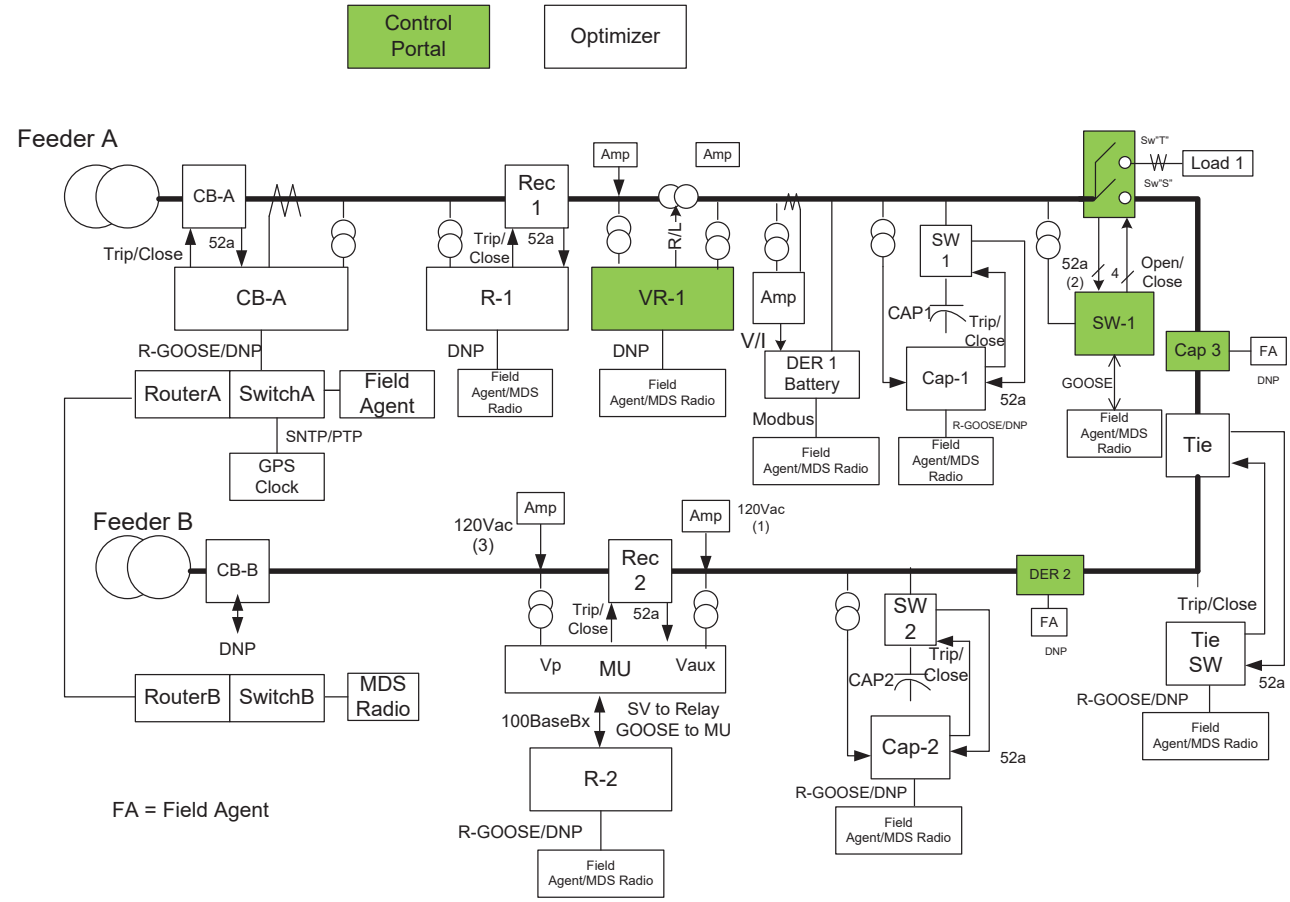
- Demonstrate the use of OpenFMB to communicate from a Control Portal to a field device showing:
  - Status – measurement values
  - Control – change status

Description:

- Operation of Recloser 1 (R-1) (Open/Close) and Voltage measurements are to be made through OpenFMB messaging to the Recloser 1 (R-1) relay.
- Control and status of Switch 1 SW-1 are to be demonstrated from the Control Portal through OpenFMB to the Switch (SW-1).
- Control and Status of the Virtual DER (DER 2)
- Control and Status of the Virtual Cap Bank (Cap 3)

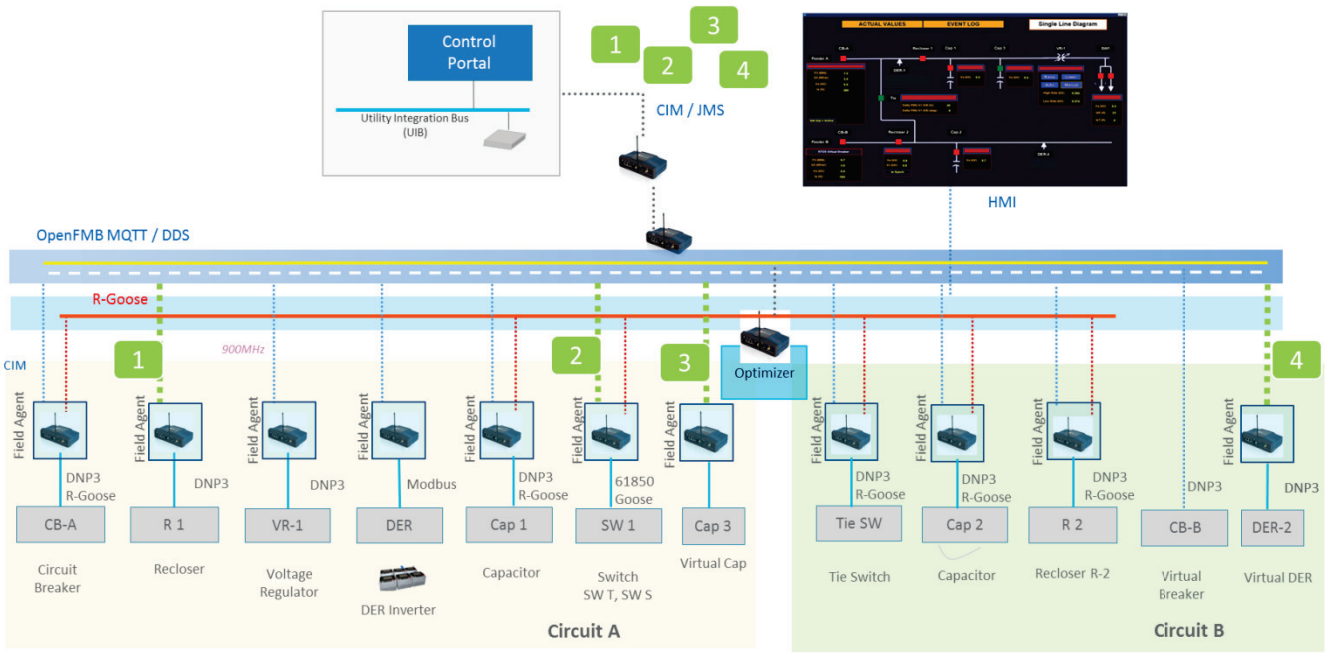
5.2 Use Case Diagram - UC 1a OpenFMB Connection to Relays & Virtual DER / Cap Bank

Logical and IO Diagram



Oct 16, 2017

5.3 Use Case Diagram - UC 1a OpenFMB Connection to Relays & Virtual DER / Cap Bank



Data Flow	*Data Flow Summary*	*Protocol*
1.	Control Portal (CP) → Field Agent → RECLOSER 1 (R-1)	CP →OpenFMB(MQTT) → DNP → RECLOSER 1 (R-1)
2.	Control Portal (CP) → Field Agent → Switch (SW-1)	CP →OpenFMB(MQTT) → DNP → Switch (SW-1)
3.	Control Portal (CP) → Field Agent → Virtual DER (DER 2)	CP →OpenFMB(MQTT) → DNP → Virtual DER (DER 2)
4.	Control Portal (CP) → Field Agent → Virtual Cap Bank (Cap 3)	CP →OpenFMB(MQTT) → DNP → Virtual Cap Bank (Cap 3)

5.4 Pre-Conditions - UC 1a OpenFMB Connection to Relays & Virtual DER / Cap Bank

Pre-Conditions	***Description***
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	RTDS is Active
7.	Network Model with Switchable Devices (2 Circuits)
8.	Tie Switch is Open
9.	Cap 1 is Open
10.	Cap 2 is Open
11.	R-1 is Closed
12.	VR-1 is Auto Mode
13.	SW-1 is Closed (2 positions)
14.	CB-A is Closed
15.	CB-B is Closed
16.	On Power-up of the Virtual DER and Field Agent, the following registers shall be WRITTEN as part of initialization OR via the Control Portal: 40007 – 2 – RESET 40008 – 2 – Set Voltage Source Inverter – PQ Mode 40101 – 256 – Set for Voltage / Watt mode of operation 40009 – 100 – Initial Real Power Set Point 40010 – 50 – Initial Reactive Power Set Point

6. Use Case 2a - Var Control

6.1 Use Case Description – UC 2a Var Control

UC 2a: Var Control

Objective:

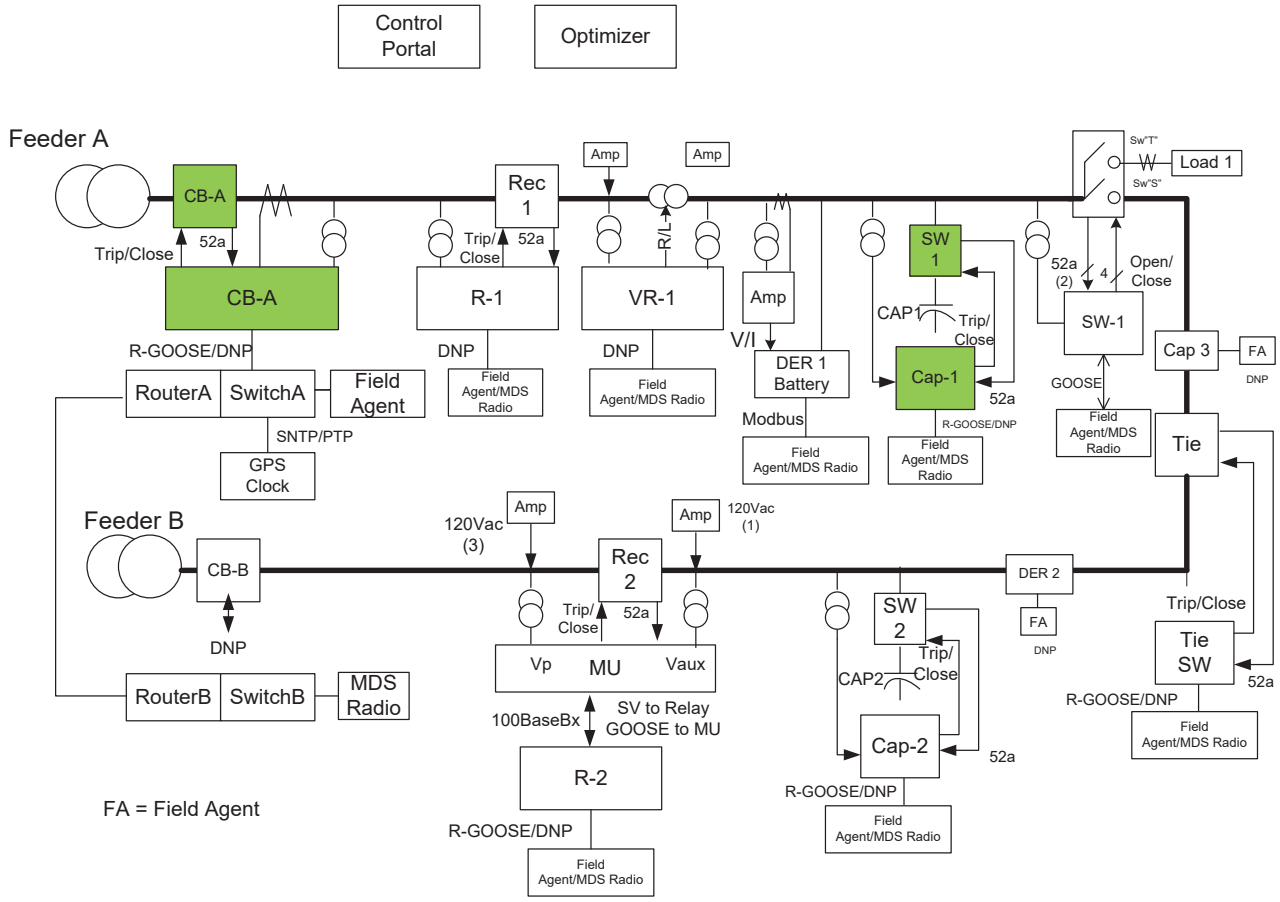
- Evaluate R-GOOSE as an alternative Pub-Sub protocol under the OpenFMB standard / framework.

Description:

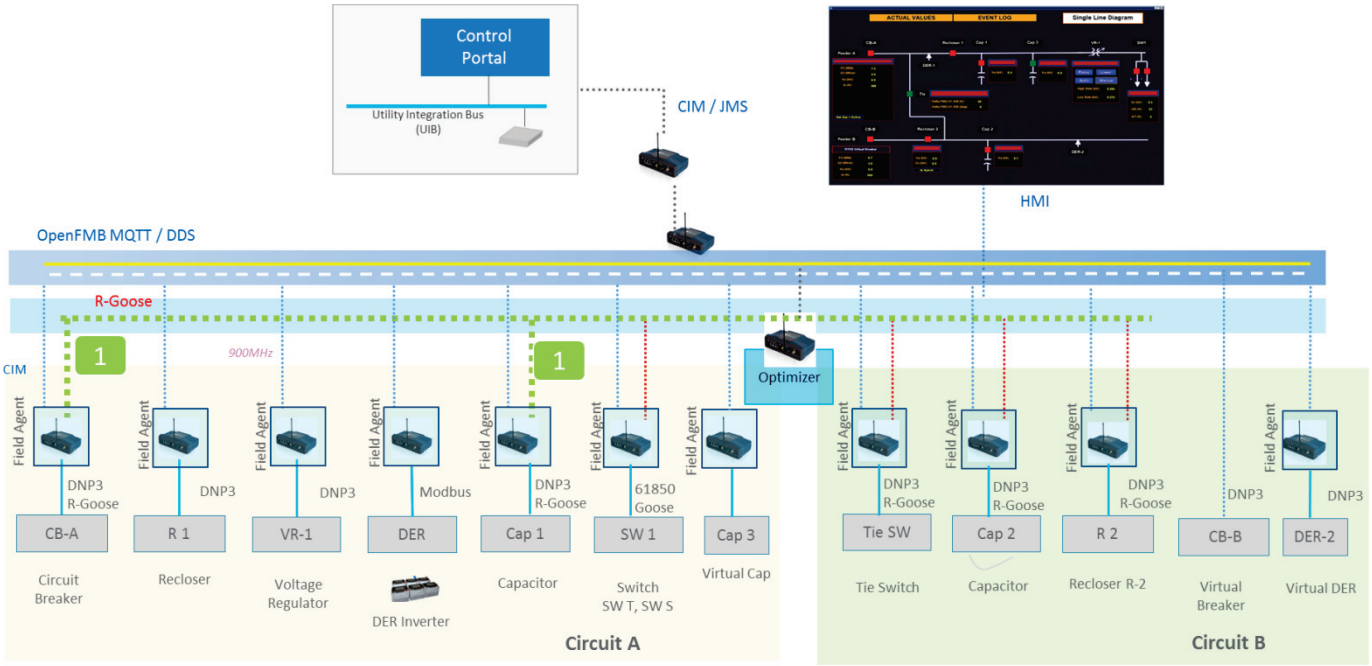
- Create a 2-line power system (Line A and Line B) with communicable devices on different networks on each line. Measure the Vars at the breaker end of Feeder A (CB-A).
- When the Vars exceed a set-point, send a R-GOOSE message from CB-A to Cap 1 to cut-in the capacitor at that location.
- Close Capacitor Cap 1

6.2 Use Case Diagram - UC 2a Var Control

Logical and IO Diagram



6.3 Use Case Diagram - UC 2a Var Control



Data Flow	*Data Flow Summary*	*Protocol*
1.	CB-A → CAP 1	CB-A → R-GOOSE → CAP 1

6.4 Use Case Pre-Conditions – UC 2a Var Control

Pre-Conditions	***Description***
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	RTDS is Active
7.	Network Model with Switchable Devices (2 Circuits)
8.	Tie Switch is Open
9.	Cap 1 is Open
10.	Cap 2 is Open
11.	R-1 is Closed
12.	VR-1 is Auto Mode
13.	SW-1 is Closed (2 positions)
14.	CB-A is Closed
15.	CB-B is Closed

7. Use Case 2b Man-in-the-Middle Augmented Voltage/Var Control

7.1 Use Case Description – UC 2b Man-in-the-Middle Augmented Voltage/Var Control

UC 2b Man-in-the-Middle Augmented Voltage/Var Control

Objective:

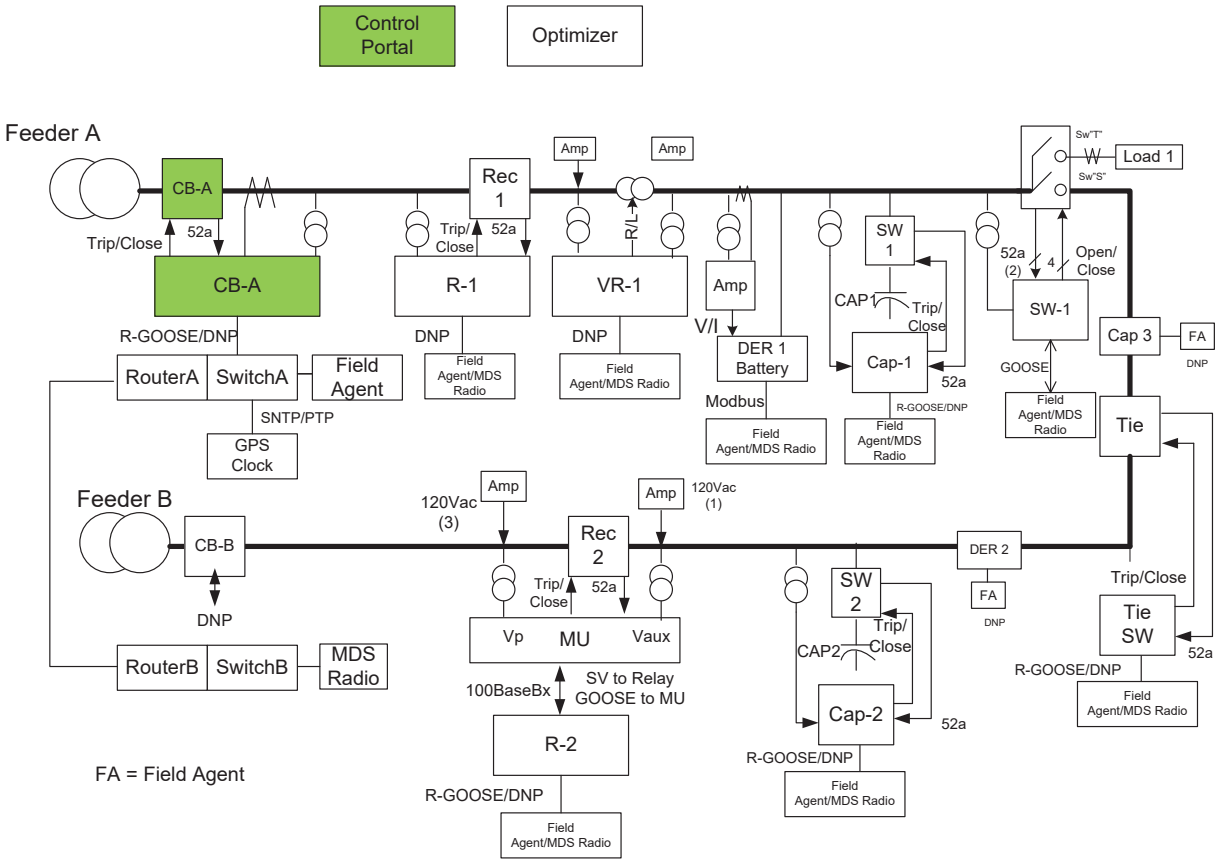
- Demonstrate manual control and operation using OpenFMB

Description:

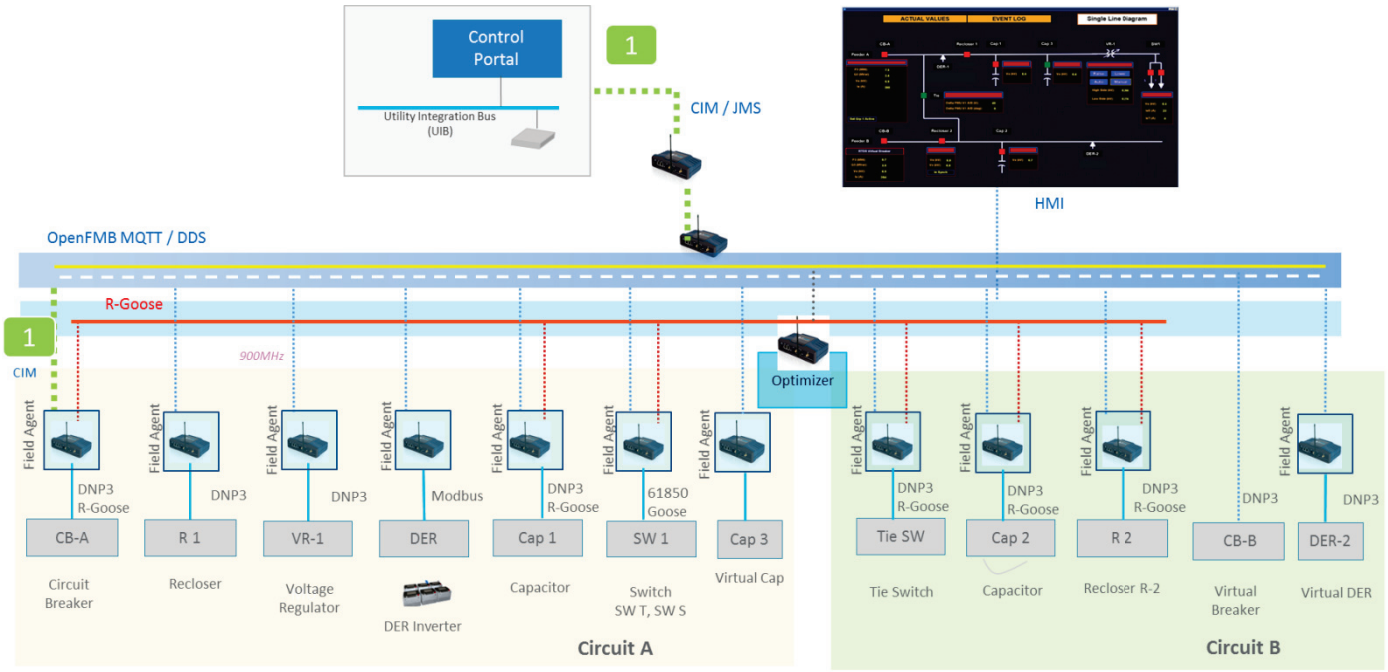
- If, after closing Capacitor 1, the var level is still above the setting threshold in the CB-A, a OpenFMB alarm of "over VAR" will be issued by the CB-A relay.
- This alarm is to be received by the Control Portal and indicated.
- Pre-condition VR-1 is in manual mode.

7.2 Use Case Diagram – UC 2b Man-in-the-Middle Augmented Voltage/Var Control

Logical and IO Diagram



7.3 Use Case Diagram – UC 2b Man-in-the-Middle Augmented Voltage/Var Control



Data Flow	*Data Flow Summary*	*Protocol*
1.	CB-A → Field Agent →Control Portal (CP)	CB-A → DNP → OpenFMB(MQTT) → CP

7.4 Use Case Pre-Conditions – UC 2b Man-in-the-Middle Augmented Voltage/Var Control

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	RTDS is Active
7.	Network Model with Switchable Devices (2 Circuits)
8.	Tie Switch is Open
9.	Cap 1 is Closed
10.	Cap 2 is Open
11.	R-1 is Closed
12.	VR-1 is Manual Mode (not a normal operating state)
13.	SW-1 is Closed (2 positions)
14.	CB-A is Closed
15.	CB-B is Closed

8. Use Case 2c – Peer-to-Peer Voltage/Var Control

8.1 Use Case Description – UC 2c Peer-to-Peer Voltage/Var Control

UC 2c Peer-to-Peer Voltage/Var Control

Objective:

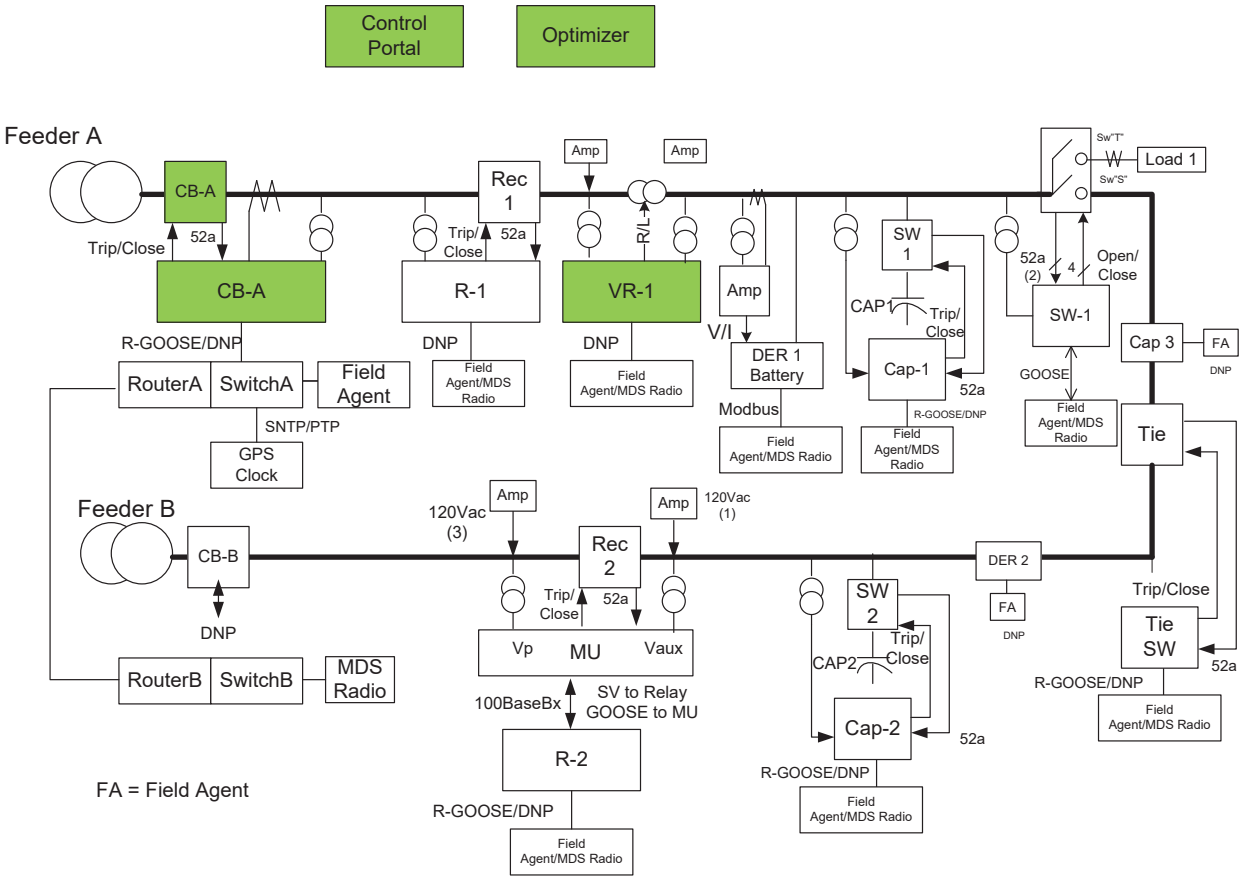
- Demonstrate automated control or operation using OpenFMB

Description:

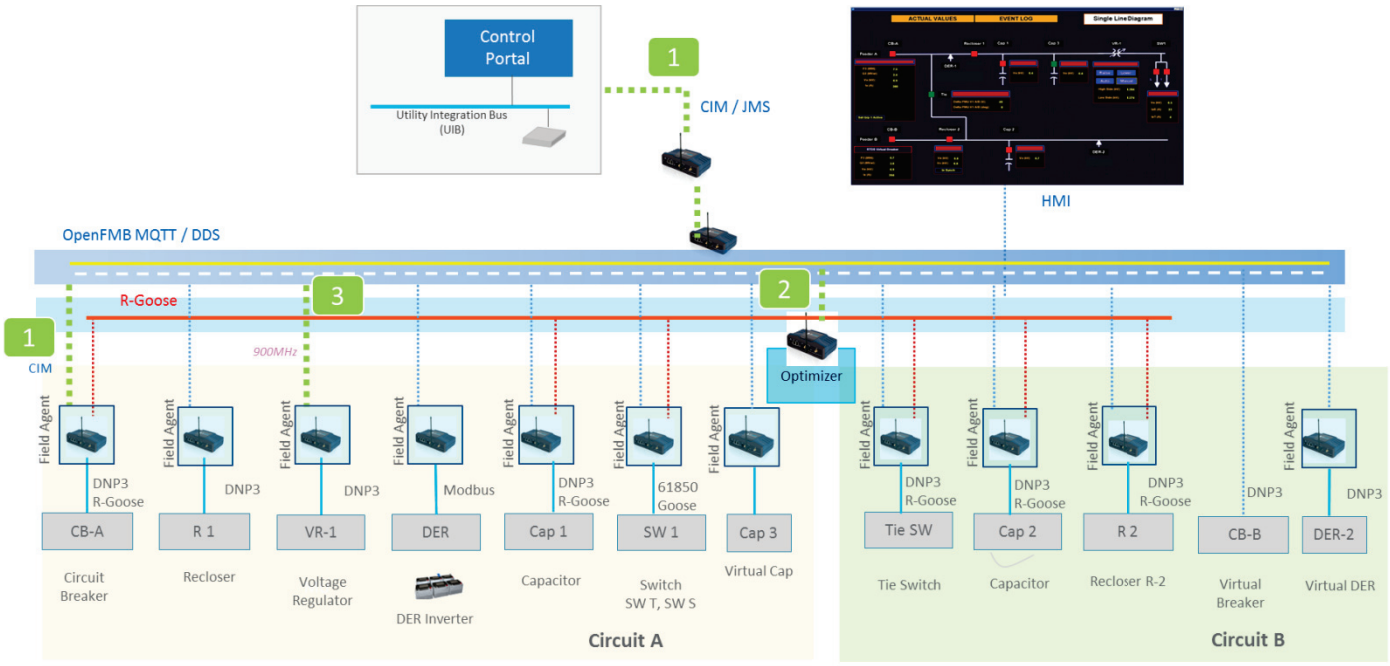
- If, after closing Capacitor 1, the var level is still above the setting threshold in the CB-A, an alarm of "over VAR" will be issued by the CB-A.
- This alarm is to be received by the Optimizer and the Optimizer then places VR-1 Voltage Regulator in auto mode via an OpenFMB command.
- Pre-Condition VR-1 manual mode
- Pre-Condition Cap 1 is closed
- RTDS raises VAR loading prior to start of test

8.2 Use Case Diagram – UC 2c Peer-to-Peer Voltage/Var Control

Logical and IO Diagram



8.3 Use Case Diagram – UC 2c Peer-to-Peer Voltage/Var Control



Data Flow	*Data Flow Summary*	*Protocol*
1.	CB-A → Field Agent →Control Portal (CP)	CB-A → DNP → OpenFMB(MQTT) → CP
2.	CB-A → Field Agent →Optimizer	CB-A → DNP "over VAR "→ Field Agent (CIM) → OpenFMB(MQTT) → "over VAR" alarm Optimizer
3.	Optimizer → CIM → OpenFMB(MQTT) → VR-1	Optimizer → CIM → OpenFMB(MQTT) → Field Agent (CIM) → DNP → VR-1 (Auto Mode)

8.4 Use Case Pre-Conditions – UC 2c Peer-to-Peer Voltage/Var Control

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	RTDS is Active
7.	Network Model with Switchable Devices (2 Circuits)
8.	Tie Switch is Open
9.	Cap 1 is Closed
10.	Cap 2 is Open
11.	R-1 is Closed
12.	VR-1 is manual Mode
13.	SW-1 is Closed (2 positions)
14.	Control Portal displays measurement values
15.	CB-A is Closed
16.	CB-B is Closed
17.	RTDS lowers the VAR loading below threshold

9. Use Case 2d – Voltage Override

9.1 Use Case Description – UC 2d Voltage Override

UC 2d Voltage Override

Objective:

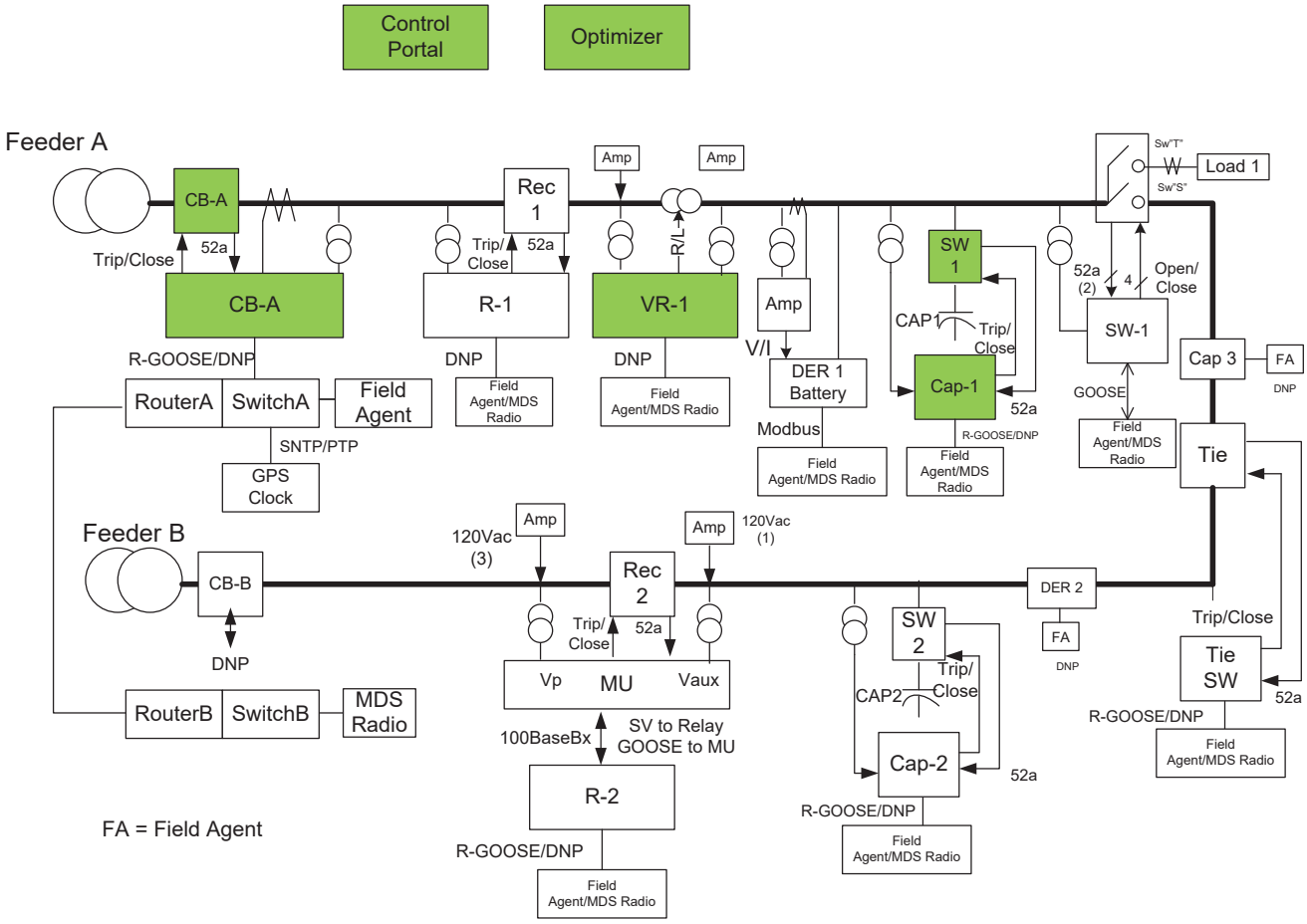
- Demonstrate the communication of the rejection of manual control and subsequent automatic response based on prevailing local condition using OpenFMB.

Description:

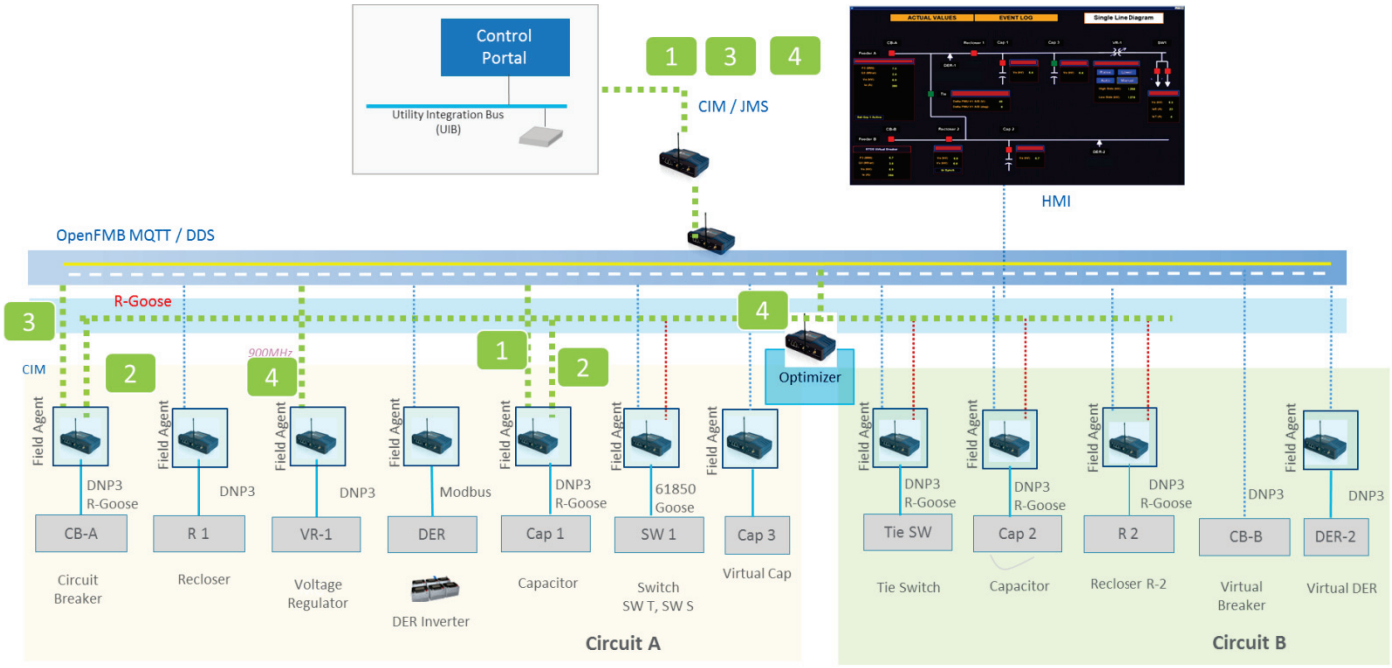
- Control Portal sends a close command to CAP 1
- If the voltage on CAP 1 is too high, CAP 1 refuse the CLOSE control and send a message to the CB-A indicating refusal of the Cap 1 devices to execute the requested close action.
- An OpenFMB message is issued indicating such from CB-A and is to be displayed on the Control Portal.
- Detection of Over-Voltage shall be transmitted to the Optimizer which will then enable the Voltage Regulator.
- Pre-condition: Voltage Regulator (VR-1) Manual Mode & high voltage (circuit A) through RTDS
- Post-condition: Voltage Regulator (VR-1) turned to Automatic Mode

9.2 Use Case Diagram – UC 2d Voltage Override

Logical and IO Diagram



9.3 Use Case Diagram – UC 2d Voltage Override



Data Flow	*Data Flow Summary*	*Protocol*
1.	Control Portal (CP) → OpenFMB(MQTT) → Field Agent → CAP 1	CP → CIM/JMS → OpenFMB(MQTT) → Field Agent (CIM) → DNP → CAP 1 (Close)
2.	CAP 1 → CB-A	CAP 1 → R-GOOSE → CB-A
3.	CB-A → Refuse Close → Control Portal (CP)	CB-A → DNP → Field Agent (CIM) → OpenFMB(MQTT) → CIM/JMS → CP
4.	Control Portal (CP) → Optimizer → VR-1	CP → CIM/JMS → OpenFMB(MQTT) → Optimizer → OpenFMB(MQTT) → Field Agent (CIM) → DNP → VR-1 (Auto Mode)

9.4 Use Case Pre-Conditions – UC 2d Voltage Override

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	RTDS is Active
7.	Network Model with Switchable Devices (2 Circuits)
8.	Tie Switch is Open
9.	Cap 1 is Open
10.	Cap 2 is Open
11.	R-1 is Closed
12.	VR-1 is Manual Mode
13.	SW-1 is Closed (2 positions)
14.	Control Portal displays measurement values
15.	CB-A is Closed
16.	CB-B is Closed
17.	RTDS voltage needs to raise to 1.6 PU

10. Use Case 3a – Inter-network Var Control

10.1 Use Case Description – UC 3a Inter-network Var Control

UC 3a Inter-network Var Control

Objective:

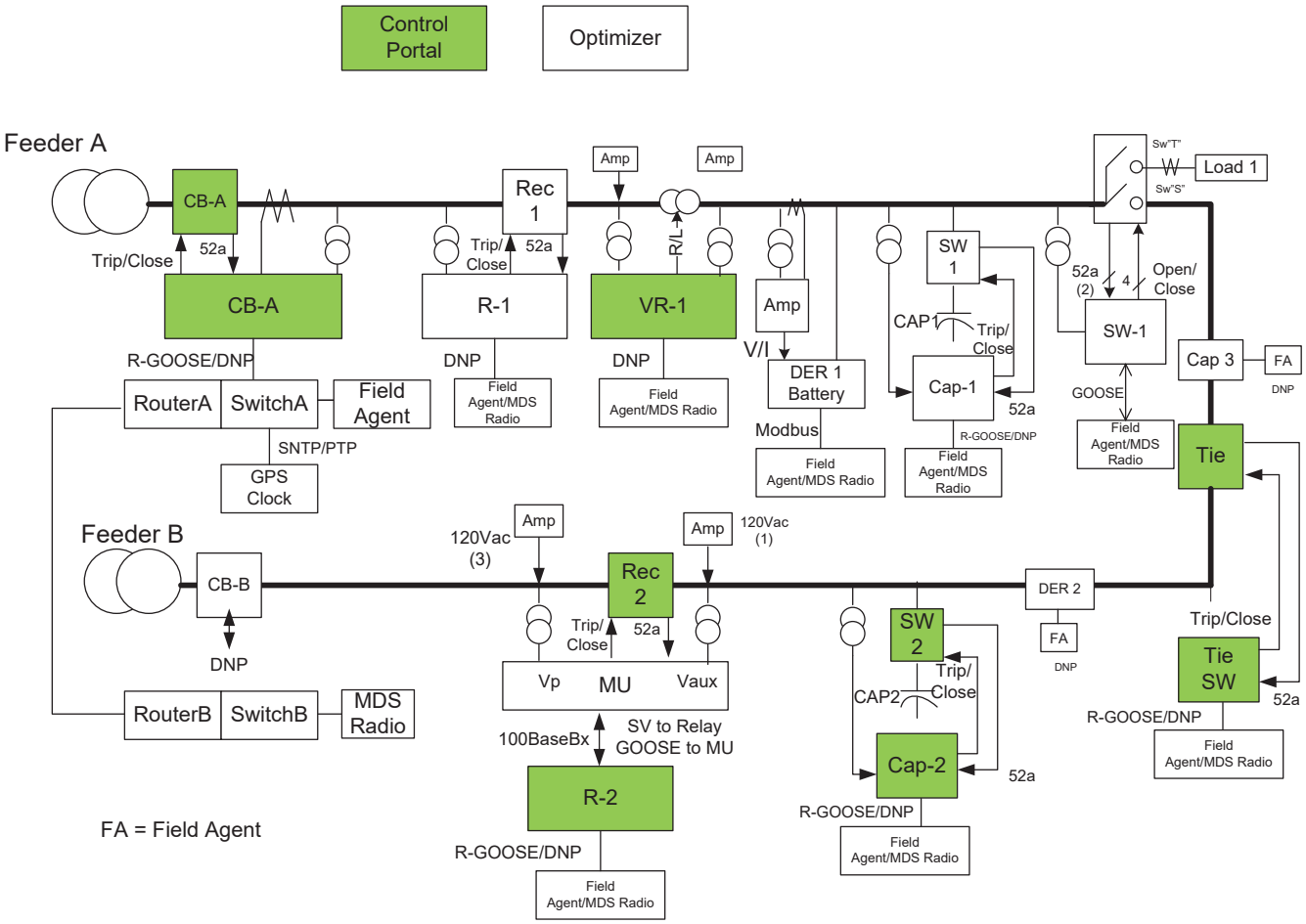
- Demonstrate Inter-network communication capability of OpenFMB

Description:

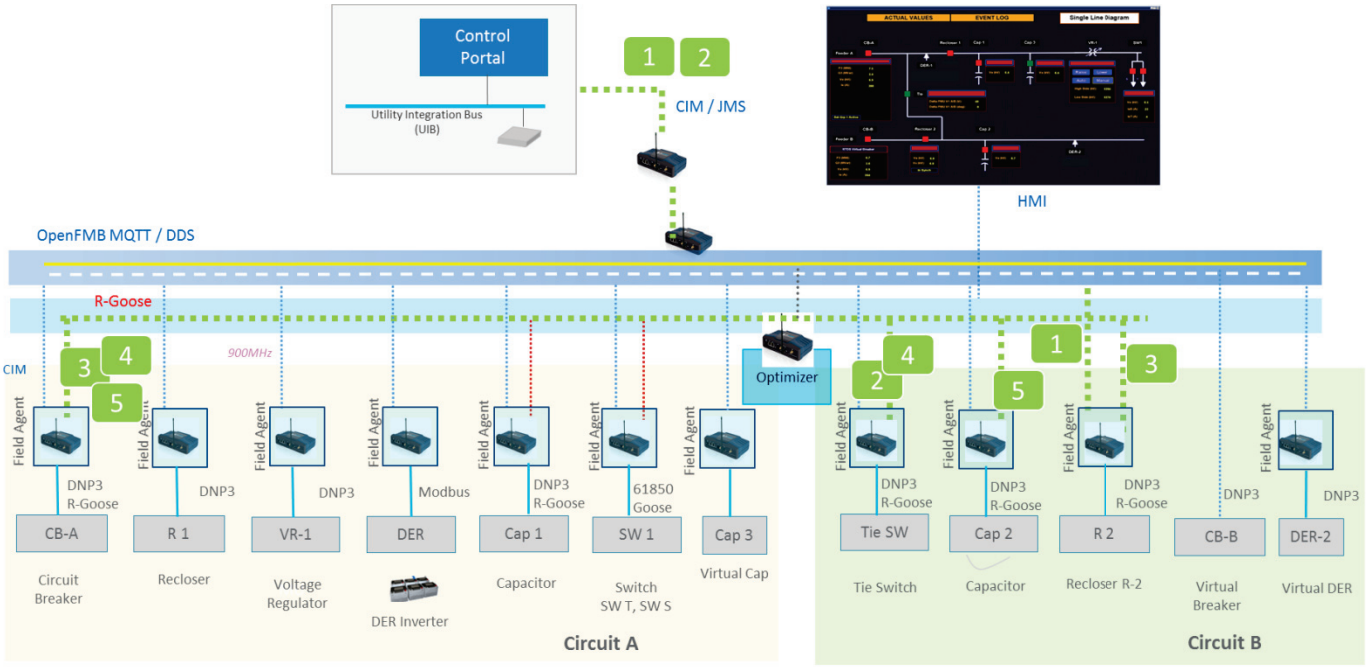
- Building on Test Case 2a, b, c, d.
- Using OpenFMB issues command from the Control Portal to open Recloser 2 R-2 and then close the TIE switch (Tie SW).
- The status of Recloser 2 and Tie Breaker are monitored by the R-2 and Tie SW relays respectively.
- This information is then sent – internetwork via R-GOOSE to CB-A.
- Var load on the feeder is then increased above the setting threshold.
- The CB-A then makes a determination to close Capacitor 2 for additional var support.
- Pre-condition: Capacitor Bank 1 is CLOSED and the Voltage Regulator (VR-1) is manual mode.
- Pre-condition: CB-B is open

10.2 Use Case Diagram – UC 3a Inter-network Var Control

Logical and IO Diagram



10.3 Use Case Diagram – UC 3a Inter-network Var Control



Data Flow	*Data Flow Summary*	*Protocol*
1.	Control Portal (CP) → OpenFMB(MQTT) → Field Agent → R-2	CP → CIM/JMS → OpenFMB(MQTT) → Field Agent (CIM) → DNP → R-2 (Open)
2.	Control Portal (CP) → OpenFMB(MQTT) → Field Agent → c	CP → CIM/JMS → OpenFMB(MQTT) → Field Agent (CIM) → DNP → Tie SW (Close)
3.	R-2 → CB-A	R-2 → R-GOOSE → CB-A (Status Change)
4.	Tie SW → CB-A	Tie SW → R-GOOSE → CB-A (Status Change)
5.	CB-A → CAP 2	CB-A → R-GOOSE → CAP 2 (Close)

10.4 Use Case Pre-Conditions – UC 3a Inter-network Var Control

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	Network Model with Switchable Devices (2 Circuits)
7.	Tie Switch is Open
8.	Cap 1 is Close
9.	Cap 2 is Open
10.	R-1 is Closed
11.	VR-1 is manual
12.	SW-1 is Closed (all 2 positions)
13.	Control Portal displays measurement values
14.	R-2 is Closed
15.	CB-B is Open

11. Use Case 3b – Peer-to-Peer Volt/Var Control

11.1 Use Case Description – UC 3b Peer-to-Peer Volt/Var Control

UC 3b Peer-to-Peer Volt/Var Control

Objective:

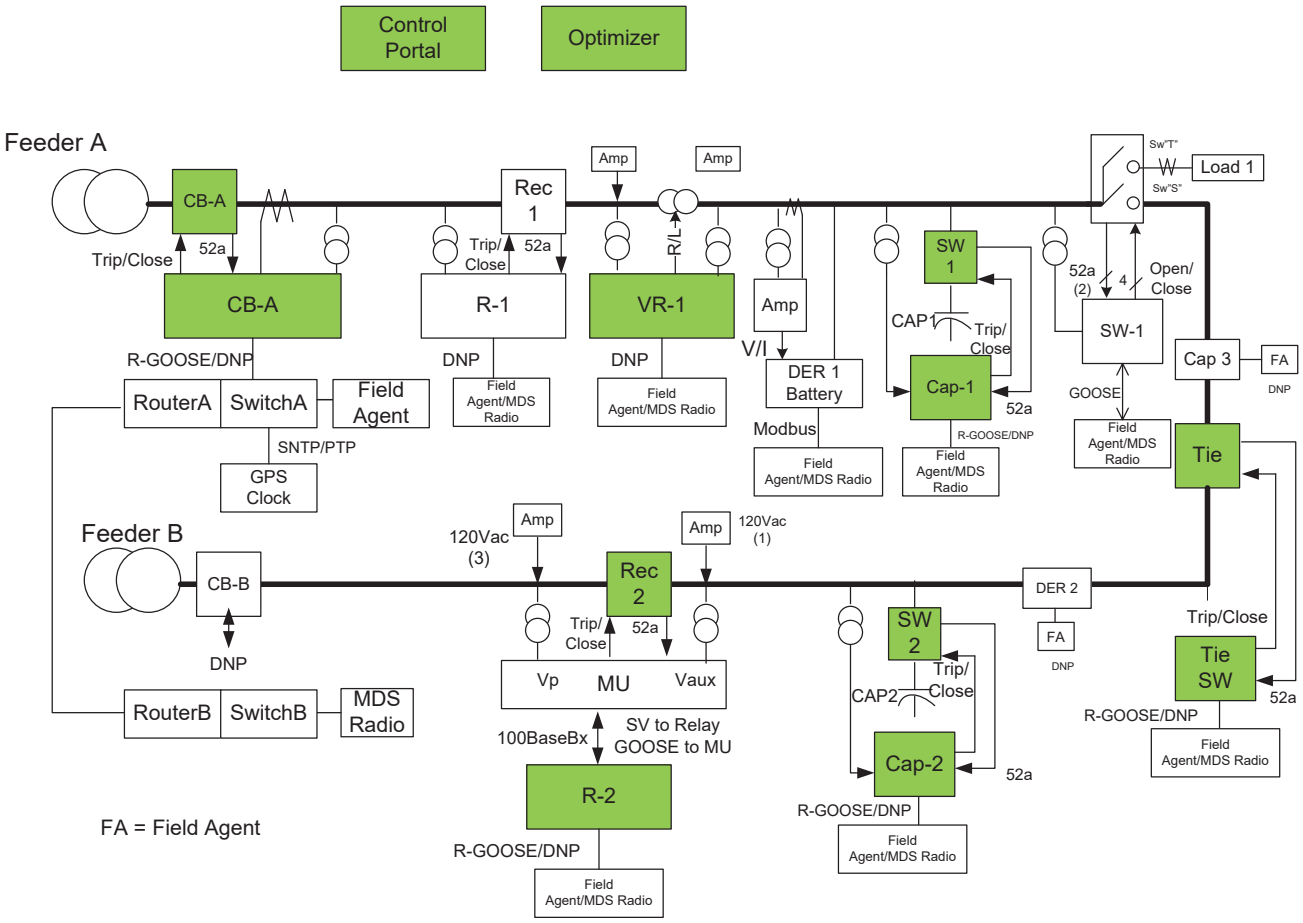
- Demonstrate Peer-to-Peer communication capability of OpenFMB to achieve progressive Var support.

Description:

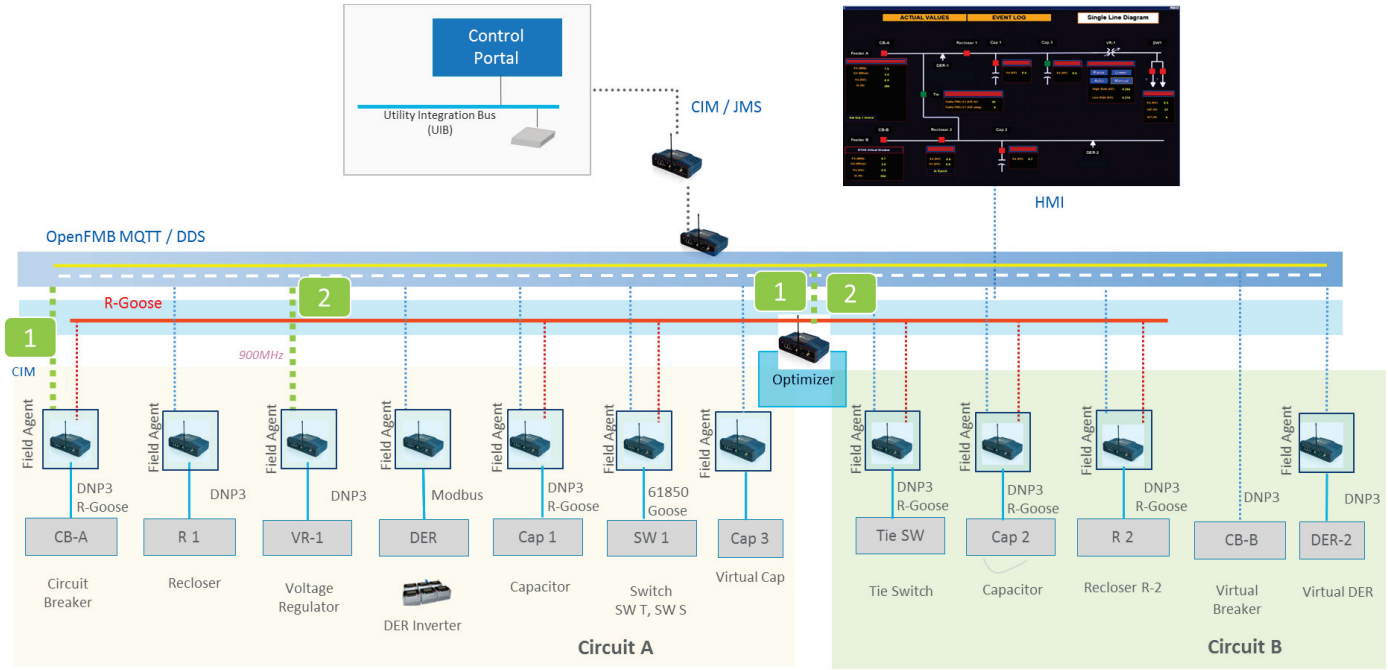
- Given that Capacitor 1 is closed AND the Tie SW is closed AND Capacitor Bank 2 is closed.
- The var load on the line is then further increased above the setting threshold.
- The CB-A then issues a signal (High Var) to the Optimizer that additional var support is needed.
- Upon receipt of a High Var message, the Optimizer will then switch the Voltage Regulator (VR-1) to manual mode.
- Pre-Condition: Voltage Regulator (VR-1) is in Auto mode

11.2 Use Case Diagram – UC 3b Peer-to-Peer Volt/Var Control

Logical and IO Diagram



11.3 Use Case Diagram – UC 3b Peer-to-Peer Volt/Var Control



Data Flow	*Data Flow Summary*	*Protocol*
1.	CB-A → Optimizer	CB-A → DNP → Field Agent (CIM) → OpenFMB(MQTT) → Optimizer
2.	Optimizer → VR-1	Optimizer → OpenFMB(MQTT) → Field Agent → DNP → VR-1 (Manual Mode)

11.4 Use Case Pre-Conditions – UC 3b Peer-to-Peer Volt/Var Control

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	RTDS is Active
7.	Network Model with Switchable Devices (2 Circuits)
8.	Tie Switch (Tie SW) is Closed
9.	Cap 1 is Close
10.	Cap 2 is Close
11.	R-1 is Closed
12.	VR-1 is Auto
13.	SW-1 is Closed
14.	Control Portal displays measurement values
15.	R-2 is Closed

12. Use Case 4a – DER Active Power Control

12.1 Use Case Description – UC 4a DER Active Power Control

UC 4a DER Active Power Control

Objective:

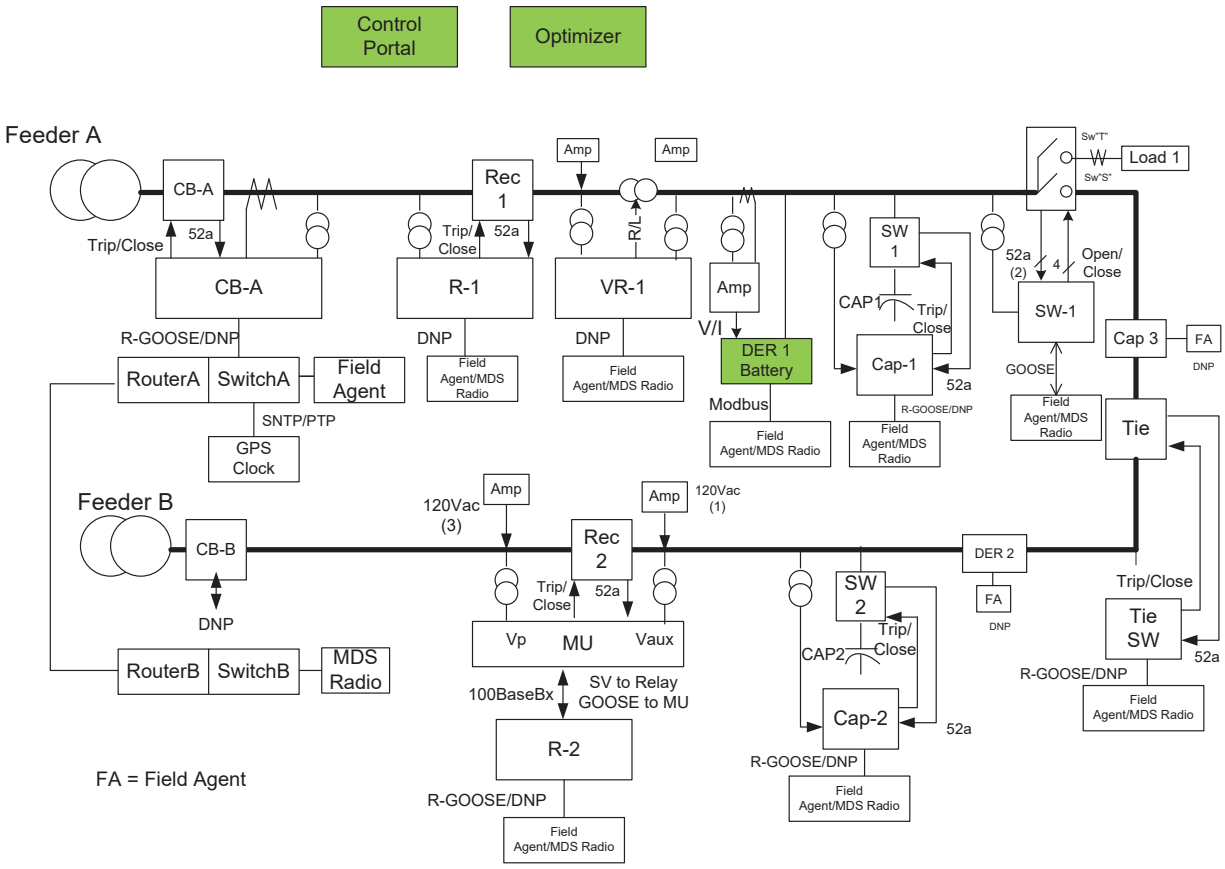
- Demonstrate the capability of OpenFMB using Modbus communication
- Demonstrate the interoperation of traditional IED's and DER using OpenFMB

Description:

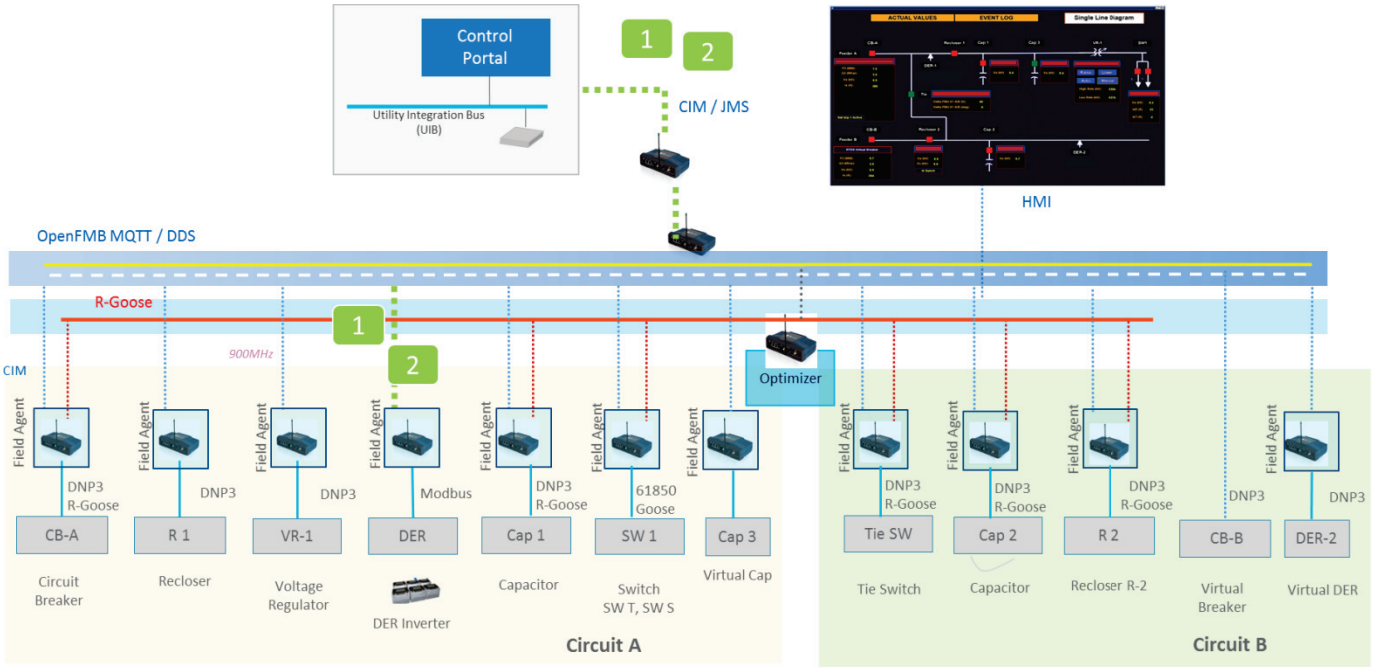
- The DER 1 inverter is to be connected into the RTDS with appropriate digital interface.
- A start command will be sent from the Control Portal to DER 1
- Operator to issue enable set point command. Enter value in the Heartbeat field
- Operator issues Real Power setpoint. Enter value in Active Power field
- Operator issues Reactive Power setpoint. Enter value in Reactive Power field
- Operator issues new High-Level Control Mode – Voltage Droop Reg. (Volts/Watts). Enter value in VoltControlMode field
- Operator issues new High Level Control Mode – Voltage Droop Reg. (Volts/Vars). Enter value in VoltControlMode field
- Test Engineer removes Ethernet connection to DER 1
- Test Engineer to re-connect Ethernet
- Operator issues reset command to DER 1 via Control Portal
- Operator to Open Breaker A and the response of the DER 1 will be recorded.

12.2 Use Case Diagram – UC 4a DER Active Power Control

Logical and IO Diagram



12.3 Use Case Diagram – UC 4a DER Active Power Control



Data Flow	*Data Flow Summary*	*Protocol*
1.	Control Portal → DER 1	Control Portal → OpenFMB(MQTT) → Field Agent → Modbus → DER 1 Inverter → Enable Start
2.	Control Portal → DER 1	Control Portal → OpenFMB(MQTT) → Field Agent → Modbus → DER 1 Inverter → Enable Joint Power/Reactive Power Set-point change
3.	Control Portal → DER 1	Control Portal → OpenFMB(MQTT) → Field Agent → Modbus → DER 1 Inverter → change Modes
4.	Control Portal → DER 1	Control Portal → OpenFMB(MQTT) → Field Agent → Modbus → DER 1 Inverter → Reset command
5.	Control Portal → DER 1	Control Portal → OpenFMB(MQTT) → Field Agent → Modbus → DER 1 Inverter → Enable Stop

12.4 Use Case Pre-Conditions – UC 4a DER Active Power Control

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	Network Model with Switchable Devices (2 Circuits)
7.	Tie Switch (TIE SW) is Open
8.	Cap 1 is Close
9.	Cap 2 is Close
10.	R-1 is Closed
11.	VR-1 is Auto
12.	SW-1 is Closed (2 positions)
13.	Control Portal displays measurement values
14.	R-2 is Closed
15.	DER inverter or Simulator has heartbeat
16.	On Power-up of the DER 1 and Field Agent, the following registers shall be WRITTEN as part of initialization via the Control Portal: 40003 – 2 – START (Enter 1 CP Switch Position) 40007 – 2 – RESET 40008 – 2 – Set Voltage Source Inverter – PQ Mode 40009 – 100 – Initial Real Power Set Point 40101 – 256 – Set for Voltage / Watt mode of operation 40010 – 50 – Initial Reactive Power Set Point

13. Use Case 5a – DER on Line / off-line

13.1 Use Case Description – UC 5a DER on Line / off-line

UC 5a DER on Line / off-line

Objective:

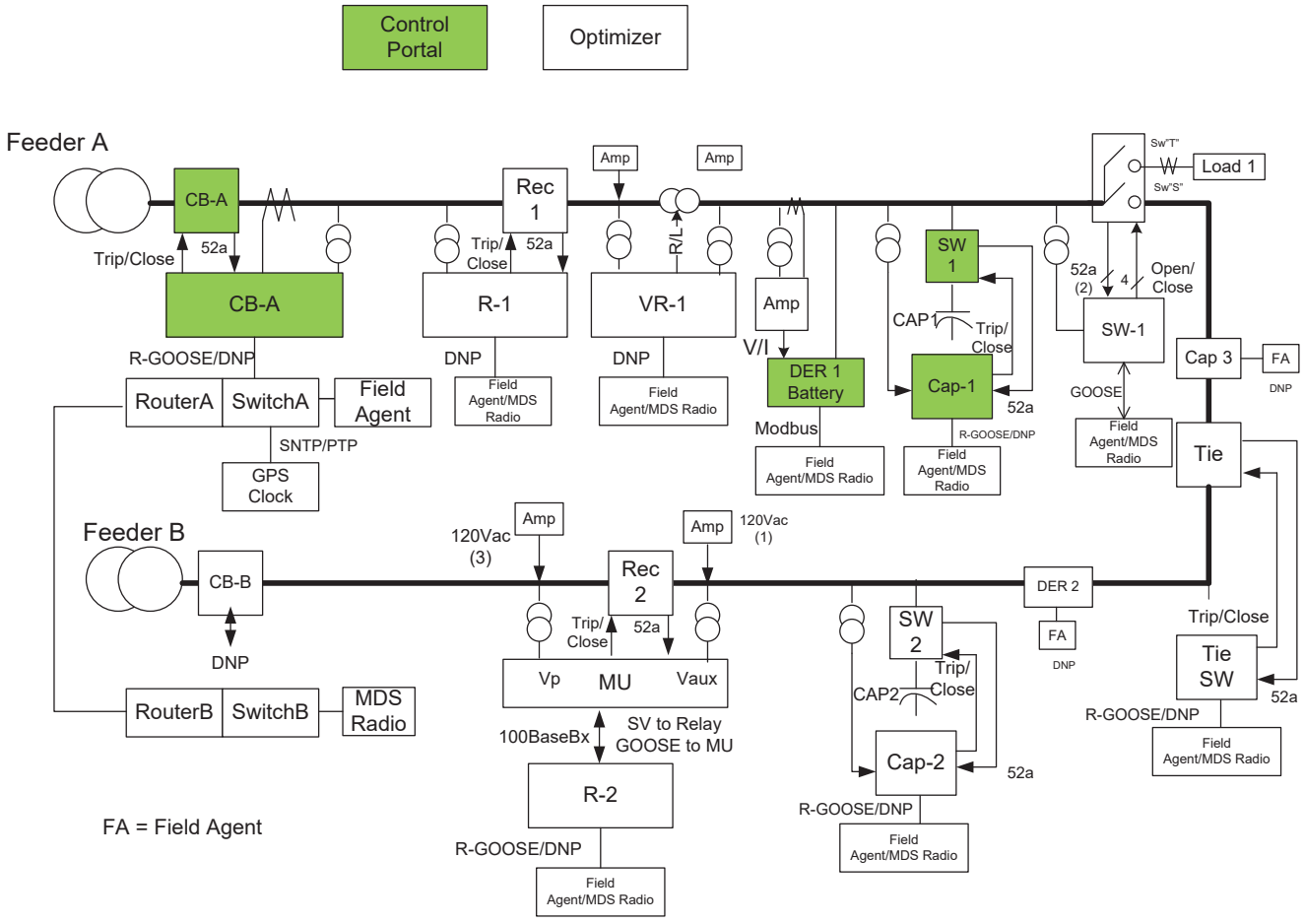
- Demonstrate use of R-Goose to improve system performance by communicating breaker status to DER 1 and thereby over-riding autonomous DER control functions.

Description:

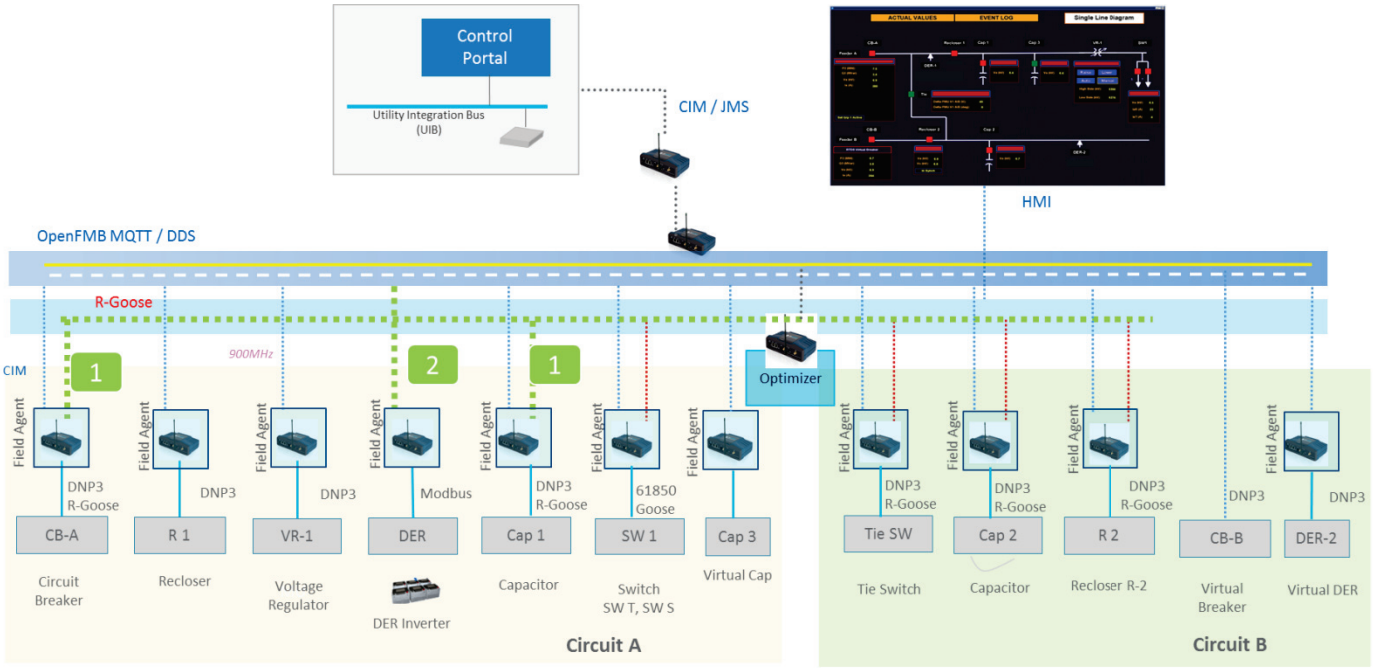
- To demonstrate enhanced DER 1 on-line/off-line via peer to peer
- Pushbutton on CB-A opens CB-A
- Upon detection of Breaker A open, CB-A sends a command to CAP 1.
- CAP 1 operates an output contact to take the DER 1 off-line
- Note: Present implementation of OpenFMB operates at speeds slower than the present disconnect speed of the DER 1.

13.2 Use Case Diagram – UC 5a DER on Line / off-line

Logical and IO Diagram



13.3 Use Case Diagram – UC 5a DER on Line / off-line



Data Flow	*Data Flow Summary*	*Protocol*
1.	CB-A → CAP 1 → DER 1 Inverter	CB-A → R-GOOSE → CAP 1 → Contact Output → DER 1 Inverter

13.4 Use Case Pre-Conditions – UC 5a DER on Line / off-line

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	Network Model with Switchable Devices (2 Circuits)
7.	Tie Switch (TIE SW) is Open
8.	Cap 1 is Close
9.	Cap 2 is Close
10.	R-1 is Closed
11.	VR-1 is Auto
12.	SW-1 is Closed (2 positions)
13.	Control Portal displays measurement values
14.	R-2 is Closed
15.	DER inverter or Simulator has heartbeat with RTDS with appropriate amplifier
16.	CB-A is Closed
17.	DER inverter set to maximum zero voltage ride thru

14. Use Case 6a – Enhanced Automatic Feeder re-deployment

14.1 Use Case Description – UC 6a Enhanced Automatic Feeder re-deployment

UC 6a Enhanced Automatic Feeder re-deployment

Objective:

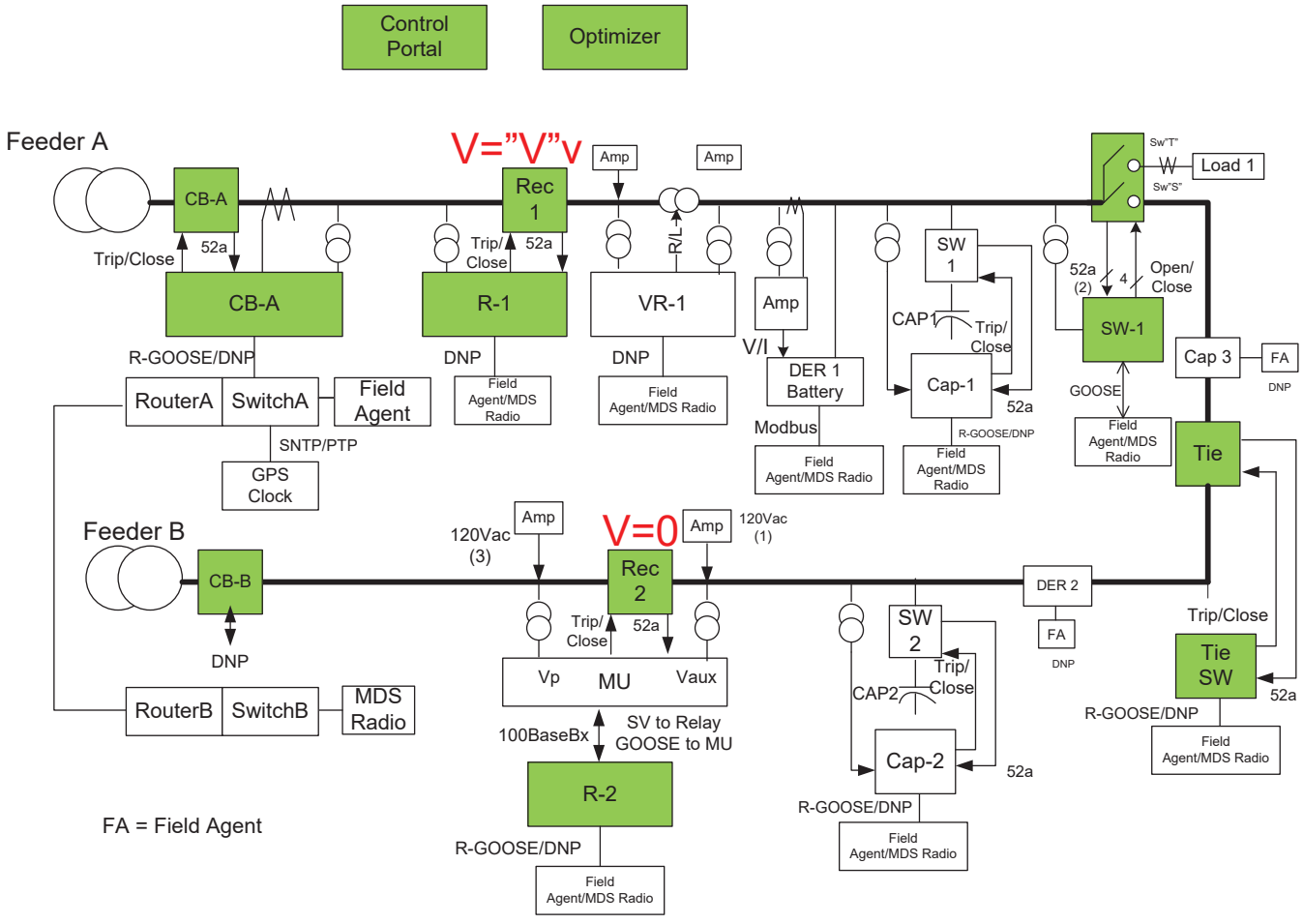
- Demonstrate the mapping of data from GOOSE messages into OpenFMB as well as complex inter-device communication.

Description:

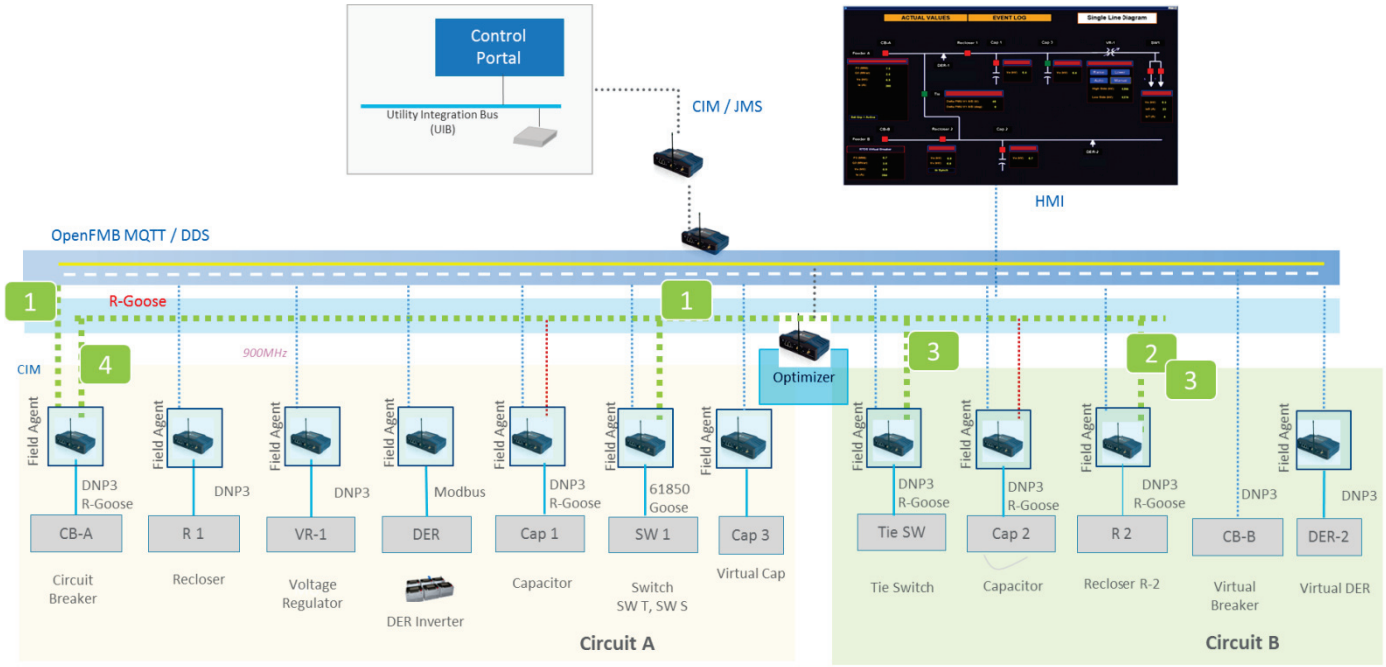
- *Healthy Feeder:*
  - If voltage on the breaker side of Recloser 2 is zero
  - AND there is voltage on Recloser 1 (PT to be located on the Line side of breaker A)
  - AND the feeder is configured for automatic re-deployment (Auto-reconfiguration Push-button on CB-A set to ENABLE)
  - AND the Feeder current (check on Phase A only) is BELOW the re-deployment threshold, the Healthy Feeder A Voltage status bit is set
- *Load Shed:*
  - If voltage on the Breaker side of Recloser 2 is zero
  - AND there is voltage on Recloser 1 AND the feeder is configured for automatic re-deployment (Auto-reconfiguration Push-button on CB-A set to ENABLE)
  - AND the Feeder current (check on Phase A only) is ABOVE the re-deployment threshold, the status bit "Load Shed" (DNP mapped point) is set.
- Message:
  - *If the "Load Shed" DNP point from CB-A is set, an OPEN command is to be sent, via OpenFMB, to OPEN Switch "T" on SW-1 to shed load on the feeder.*
  - *The R-2 on Recloser 2, upon receipt of the "Healthy Feeder A Voltage" status then sends a TRIP command to open Recloser 2*
  - R-2 THEN sends a command to Close the Tie SW – effectively back-feeding the second segment of Feeder B.
  - The CB-A, upon detection of the Tie SW being closed, will change setting groups to Group 2.
- Note: Healthy Feeder A Voltage status is NOT set if the Phase A current is above a user-specified level. A Load needs to be modeled on Switch T; connection to the Tie SW is to be connected to Switch "S"

14.2 Use Case Diagram – UC 6a Enhanced Automatic Feeder re-deployment

Logical and IO Diagram



14.3 Use Case Diagram – UC 6a Enhanced Automatic Feeder re-deployment



Data Flow	*Data Flow Summary*	*Protocol*
1.	CB-B → Open Breaker→ R-2	CB-B → Open Breaker, R-2 voltage = 0
2.	CB-A → R-Goose → R-2 → Healthy Feeder message	CB-A → R-Goose → R-2 → Healthy Feeder Message →Trip Open R-2
3.	R-2 → close Tie SW	R-2 → R-GOOSE → Tie SW
4.	CB-A → OpenFMB → SW-1	CB-A → *"Load Shed"* Open SW T Command (DNP) → OpenFMB (MQTT → Field Agent → OPC UA →61850 Goose message → SW-1 "Open Switch T"
5.	CB-A → Healthy Feeder message → close Tie SW → energize Feeder A	CB-A → R-GOOSE → Tie SW → energize Feeder A
6.	CB-A → change setting group	CB-A → change setting group to 2

14.4 Use Case Pre-Conditions – UC 6a Enhanced Automatic Feeder re-deployment

Pre-Conditions	***Description***
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	Network Model with Switchable Devices (2 Circuits)
7.	Tie Switch (TIE SW) is Open
8.	Cap 1 is Open or Closed
9.	Cap 2 is Open or Closed
10.	R-1 is Closed with Voltage > 0
11.	VR-1 is Auto
12.	SW-1 is Closed (S Switch & T Switch)
13.	Control Portal displays measurement values
14.	CB-B is Closed
15.	CB-A is Closed with Auto Re-deployment enabled
16.	Test Engineer to enable the CB-A Auto Re-deployment
17.	CB-A set over current threshold value IA = X (400 amps)
18.	Var Per Unit Condition = 2.5 MVAR; PU setting = 0.39 = 3.37 MVAR
19.	Voltage “OK” value = 0.9 PU

15. Use Case 7a – Automatic Feeder Re-Close

15.1 Use Case Description – UC 7a Automatic Feeder Re-Close

UC 7a Automatic Feeder Re-Close

Objective:

- Demonstration circuit re-configuration back to normal operating condition

Description:

- Precondition: Breaker B is Open and Recloser 2 is Open.

UC 7a -1 Inside the Limit

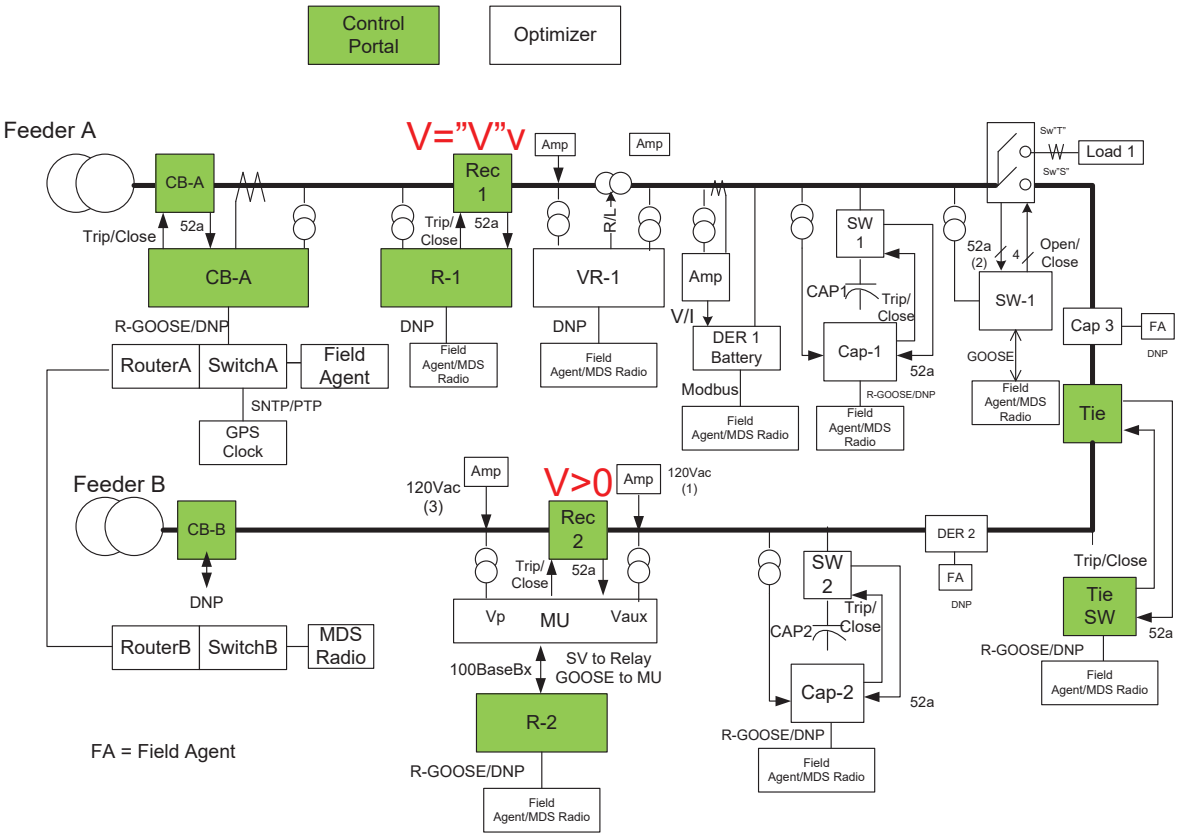
- Breaker B is then closed by RTDS / HMI – placing Voltage on the Breaker side of Recloser 2.
- Voltage is detected on both sides of the R-2 and the phase angle of the voltage across the recloser is less than 30 degrees (as measured by R-2)
- THEN reclose R-2 and Open the Tie SW from R-2.
- The CB-A identifies that the Tie SW is now open and changes back to the setting group 1.

UC 7a -2 Outside the Limit

- Breaker B is then closed by RTDS / HMI – placing Voltage on the Breaker side of Recloser 2.
- Voltage is detected on both sides of the R-2 and the phase angle of the voltage across the recloser is = 45 degrees
- Tie SW - measure phase Angle (RTDS observes phase angle) Verify Sync check.
- Recloser 2 (R-2) status fails to close

15.2 Use Case Diagram – UC 7a Automatic Feeder Re-Close

Logical and IO Diagram



15.3 Use Case Diagram – UC 7a Automatic Feeder Re-Close (Use Case Diagram & Data Flow Summary redacted due to IP confidentiality concerns).

15.4 Use Case Pre-Conditions – UC 7a Automatic Feeder Re-Close

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	Network Model with Switchable Devices (2 Circuits)
7.	Tie Switch (TIE SW) is Closed
8.	Cap 1 is Open or Closed
9.	Cap 2 is Open or Closed
10.	R-1 is Closed
11.	VR-1 is Auto
12.	SW-1 is Closed (2 positions)
13.	Control Portal displays measurement values
14.	R-2 is Open
15.	CB B is Open
16.	CB A is Closed

16. Use Case 8a – Sample Value Use Cases (Documentation only)

16.1 Use Case Description – UC 8a Sample Value Use Cases (Documentation only)

UC 8a Sample Value Use Cases
Objective:

- Demonstrate the high-speed transmission of sample values as to further develop communication requirements for OpenFMB

UC 8a Sample Value Use Cases (Documentation only)

- The measurement and transmission of Voltage and Current values from field equipment is known as Sample Values. Sample Values (SV) typically require high sample rates in the range of 3000 to 96,000 samples per second. Additionally, the device creating the Samples (known as the Merging Unit) can be located several kilometers away. IEC61850 introduced the concept of Sample Values as a digital interface to Optical Current and Voltage sensors as well as application-specific circumstances where remote location of Voltage and Current sensors is required/desirable. The 61850 standard addresses issues such as data synchronization and phase correction. Given the high bandwidth and low latency constraints of such data, further study of its applicability to OpenFMB is needed.
- Note: extend the write-up to include RSV documentation

17. Use Case 8b – Synchrophasors via R-Goose

17.1 Use Case Description – UC 8b Synchrophasors via R-Goose

UC 8b Synchrophasors via R-Goose
Objective:

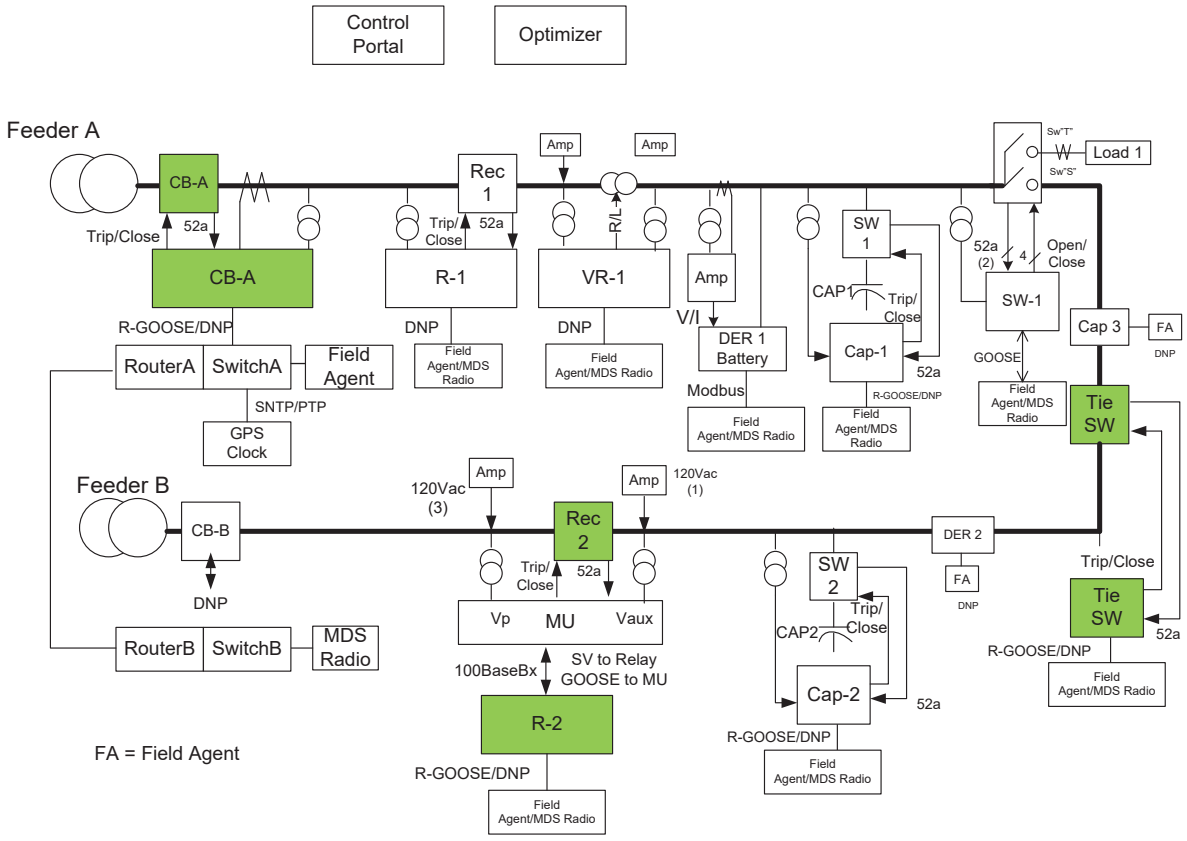
- Demonstrate the pub/sub of high speed data (e.g. synchrophasors) via routable GOOSE and evaluate the incorporation into OpenFMB standards.

Description:

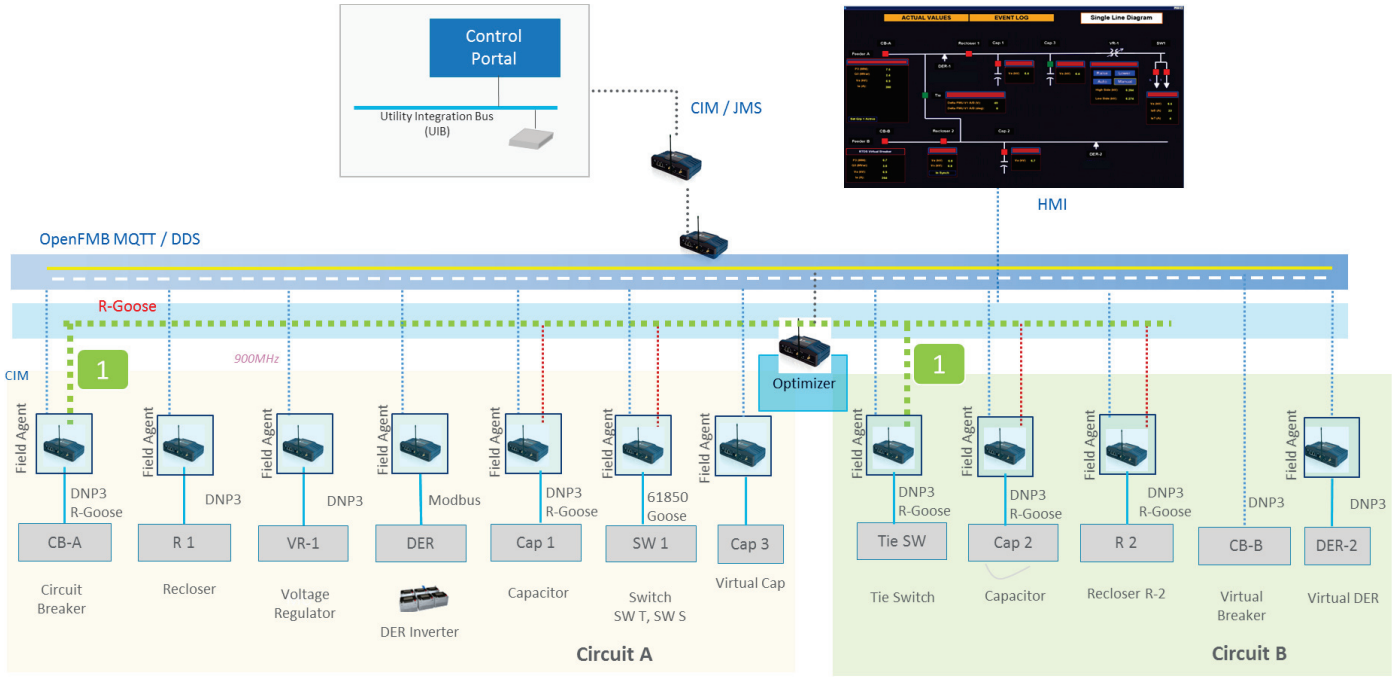
- Synchrophasors (V1 Magnitude and Angle) are to be mapped into Generic Analog 61850 data objects in CB-A and R-2 and then included in R-GOOSE messages.
- R-GOOSE reception by Tie SW.
- Tie SW commutes magnitude difference and angle difference

17.2 Use Case Diagram – UC 8b Synchrophasors via R-Goose

Logical and IO Diagram



17.3 Use Case Diagram – UC 8b Synchrophasors via R-Goose



Data Flow	*Data Flow Summary*	*Sequence*
1.	CB-A & R-2 send Synchrophasor data to Tie SW	F60 → R-Goose → Tie SW

17.4 Use Case Pre-Conditions – UC 8b Synchrophasors via R-Goose

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	Network Model with Switchable Devices (2 Circuits)
3.	Tie Switch (TIE SW) is Open
4.	Cap 1 is Open or Closed
5.	Cap 2 is Open or Closed
6.	R-1 is Closed
7.	VR-1 is Auto
8.	SW-1 is Closed (2 positions)
9.	Control Portal displays measurement values
10.	R-2 is Closed
11.	CB B is Closed
12.	CB A is Closed

18. Use Case 9a – Dynamic Subscription (Documentation Only)

18.1 Use Case Description – UC 9a Dynamic Subscription (Documentation)

UC 9a Dynamic Subscription
Objective:

- Identify the requirement for dynamic subscription for all messaging protocols for incorporation into OpenFMB standards.

Description:

- In the scenario when Feeder A and Feeder B are separated, there is no need to share messages between them. Once the Tie SW is closed, it becomes desirable for the devices on Feeder A to be able to "subscribe" to information from devices on the "extended" line.
- For this purpose, it is to be noted that Dynamic Subscription becomes a need in this Use case.
- Additionally, the definition of the data objects from the newly subscribed devices may be needed – especially if there had been setting changes in any of the newly-subscribed devices.

19. Use Case 10a – End-to-End Security (Documentation Only)

19.1 Use Case Description – UC 10 End-to-End Security (Documentation)

UC 10a End-to-End Security
Objective:

- Identify the requirement for end to end security into OpenFMB standards.

Description:

- When communicating device-to-device in the field, end-to-end secure communications are required.
- End-to-end security should be developed that addresses authentication, authorization, access control, confidentiality, integrity, non-repudiation, availability, and accountability.

20. Use Case 11a – Administration of Devices using OpenFMB

20.1 Use Case Description – UC 11a File transfer

UC 11a File transfer
Objective:

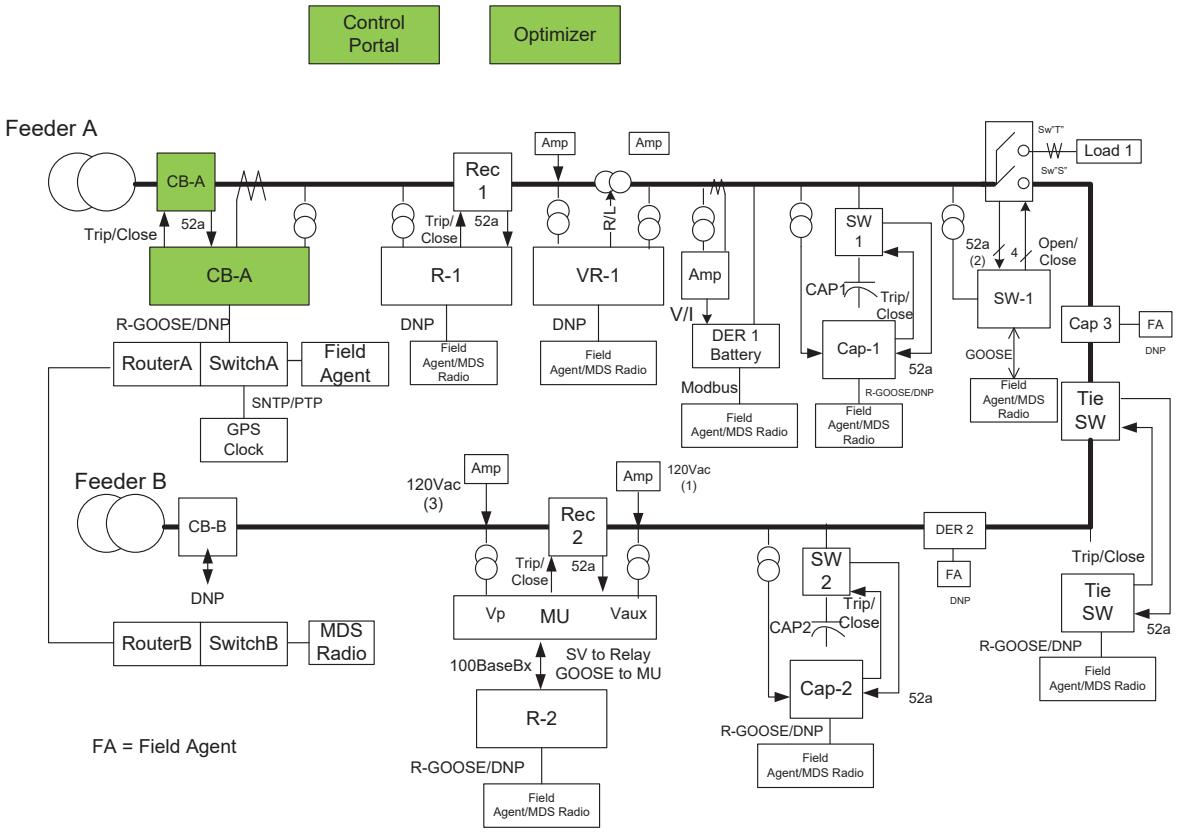
- Demonstrate file transfer using OpenFMB

Description:

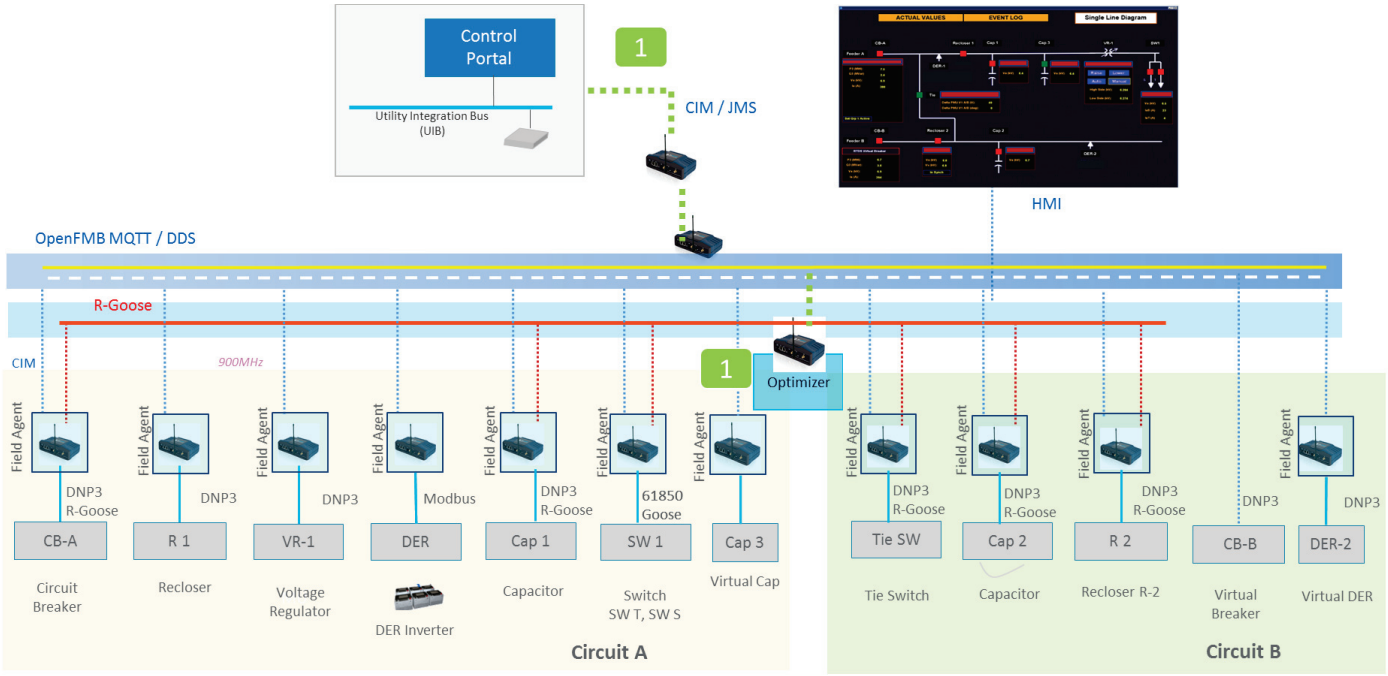
- To demonstrate the transfer of a settings file, a file will be transferred from the Administration Node to a Field Agent (OpenFMB Adapter). This file will be of a size representative of a settings file - ~10 KB. Settings files may also be unique to each OpenFMB node.

20.2 Use Case Diagram – UC 11a File transfer

Logical and IO Diagram



20.3 Use Case Diagram – UC 11a File transfer



Data Flow	*Data Flow Summary*	*Sequence*
1.	Control Portal → CB-A Optimizer	Control Portal → CB-A Optimizer

20.4 Use Case Pre-Conditions – UC 11a File transfer

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	Network Model with Switchable Devices (2 Circuits)
7.	Tie Switch (TIE SW) is Closed
8.	Cap 1 is Open or Closed
9.	Cap 2 is Open or Closed
10.	R-1 is Closed
11.	VR-1 is Auto
12.	SW-1 is Closed (2 positions)
13.	Control Portal displays measurement values
14.	R-2 is Closed
15.	CB B is Closed
16.	CB A is Closed
17.	CB-A running Optimizer

20.5 Use Case Description – UC 11b Firmware

UC 11b Firmware (Documentation Only)
Objective:

- Document Firmware transfer

Description:

- To demonstrate the transfer of a firmware image, a file will be transferred from the Administration Node to a Field Agent (OpenFMB Adapter). This file will be of a size representative of a firmware image - ~10 MB.
- It should be highlighted in the report that firmware images will need to have various security characteristics that may be unique to firmware such as manufacturer signing. Firmware images may also be unique to each OpenFMB node.
- Note: File size presently limited by file availability

20.6 Use Case Description – UC 11c Provisioning (Documentation Only)

UC 11c Provisioning (Documentation Only)
Objective:

- Document the requirement to provision field devices using OpenFMB

Description:

- To set up an OpenFMB network, the secure provisioning of OpenFMB nodes is critical. Each OpenFMB node will need to have its security credentials verified with the Administration Node. Various settings will also need to be communicated relating to both the node's network and the node's application functionality. Initial subscriptions to other OpenFMB nodes will also need to be created
- Provide example of documentation of provisioning of settings file for a Cap Bank similar to CAP 1 or CAP 2.

21. Use Case 12a – Operational Data File transfer using OpenFMB

21.1 Use Case Description – UC 12a Operational Data File transfer using OpenFMB

UC 12a File transfer (Documentation Only)
Objective:

- Demonstrate file transfer using OpenFMB

Description:

- Demonstrate file transfer from an Administration Node to other nodes through OpenFMB (MQTT) – field agent-to-field agent.

- Currently, OpenFMB does not define file transfer. In the future, OpenFMB may choose to Use another protocol better suited for file transfer (e.g., SFTP) as pub/sub protocols are not typically used for large, point-to-point, file transfers. Further, individual settings and firmware is likely not to be broadcast as security images, configuration, and other aspects are likely to be unique to each node. These are critical points that need to be clearly articulated in the final document.

- Note: Refer to Use Demonstration Use Case 11a

22. Use Case 13a – OpenFMB using DDS

22.1 Use Case Description – UC 13a OpenFMB using DDS

UC 13a OpenFMB using DDS
Objective:

- Demonstrate OpenFMB using DDS

Description:

- The Tie SW is set as the one of the DDS nodes.
- The Tie SW gets the data (measurement value) from DNP3 adaptor and publishes the data on the DDS virtual FMB
- Another DDS node subscribes to the data.
- Once the data is received, the data is published in the Audit Log

Appendix B. Test Cases

Test Case Contents:

1 Introduction 1

2 Test Case Reference Architecture 1

2.1 Reference Architecture – Figure 1 1

2.2 Reference Architecture – Figure 1 Device Names 2

3 Test Case 1a - OpenFMB Connection to Relays & Virtual DER / Cap Bank 3

3.1 Test Case Description - UC 1a OpenFMB Connection to Relays & Virtual DER / Cap Bank 3

3.2 Test Case Diagram - UC 1a OpenFMB Connection to Relays & Virtual DER / Cap Bank 4

3.3 Test Case Diagram - UC 1a OpenFMB Connection to Relays & Virtual DER / Cap Bank 5

3.4 Pre-Conditions - UC 1a OpenFMB Connection to Relays & Virtual DER / Cap Bank 6

3.5 Test Steps - UC 1a OpenFMB Connection to Relays & Virtual DER / Cap Bank 7

3.6 Test Case Results - UC 1a OpenFMB Connection to SEL Relays & Virtual DER / Cap Bank 9

4 Test Case 2a - Var Control 12

4.1 Test Case Description – UC 2a Var Control 12

4.2 Test Case Diagram - UC 2a Var Control 13

4.3 Test Case Diagram - UC 2a Var Control 14

4.4 Test Case Pre-Conditions – UC 2a Var Control 15

4.5 Test Case Test Steps – UC 2a Var Control 16

4.6 Test Case Results– UC 2a Var Control 17

5 Test Case 2b Man-in-the-Middle Augmented Voltage/Var Control 19

5.1 Test Case Description – UC 2b Man-in-the-Middle Augmented Voltage/Var Control 19

5.2 Test Case Diagram – UC 2b Man-in-the-Middle Augmented Voltage/Var Control 20

5.3 Test Case Diagram – UC 2b Man-in-the-Middle Augmented Voltage/Var Control 21

5.4 Test Case Pre-Conditions – UC 2b Man-in-the-Middle Augmented Voltage/Var Control 22

5.5 Test Case Test Steps – UC 2b Man-in-the-Middle Augmented Voltage/Var Control 23

5.6 Test Case Results – UC 2b Man-in-the-Middle Augmented Voltage/Var Control 24

6 Test Case 2c – Peer-to-Peer Voltage/Var Control 25

6.1 Test Case Description – UC 2c Peer-to-Peer Voltage/Var Control 25
6.2 Test Case Diagram – UC 2c Peer-to-Peer Voltage/Var Control 26
6.3 Test Case Diagram – UC 2c Peer-to-Peer Voltage/Var Control 27
6.4 Test Case Pre-Conditions – UC 2c Peer-to-Peer Voltage/Var Control 28
6.5 Test Case Test Steps – UC 2c Peer-to-Peer Voltage/Var Control 29
6.6 Test Case Results – UC 2c Peer-to-Peer Voltage/Var Control 30
7 Test Case 2d – Voltage Override 31
7.1 Test Case Description – UC 2d Voltage Override 31
7.2 Test Case Diagram – UC 2d Voltage Override 32
7.3 Test Case Diagram – UC 2d Voltage Override 33
7.4 Test Case Pre-Conditions – UC 2d Voltage Override 34
7.5 Test Case Test Steps – UC 2d Voltage Override 35
7.6 Test Case Results – UC 2d Voltage Override 36
8 Test Case 3a – Inter-network Var Control 39
8.1 Test Case Description – UC 3a Inter-network Var Control 39
8.2 Test Case Diagram – UC 3a Inter-network Var Control 40
8.3 Test Case Diagram – UC 3a Inter-network Var Control 41
8.4 Test Case Pre-Conditions – UC 3a Inter-network Var Control 42
8.5 Test Case Test Steps – UC 3a Inter-network Var Control 43
8.6 Test Case Results – UC 3a Inter-network Var Control 44
9 Test Case 3b – Peer-to-Peer Volt/Var Control 45
9.1 Test Case Description – UC 3b Peer-to-Peer Volt/Var Control 45
9.2 Test Case Diagram – UC 3b Peer-to-Peer Volt/Var Control 46
9.3 Test Case Diagram – UC 3b Peer-to-Peer Volt/Var Control 47
9.4 Test Case Pre-Conditions – UC 3b Peer-to-Peer Volt/Var Control 48
9.5 Test Case Test Steps – UC 3b Peer-to-Peer Volt/Var Control 49
9.6 Test Case Results – UC 3b Peer-to-Peer Volt/Var Control 50
10 Test Case 4a – DER Active Power Control 52
10.1 Test Case Description – UC 4a DER Active Power Control 52

10.2 Test Case Diagram – UC 4a DER Active Power Control 53
10.3 Test Case Diagram – UC 4a DER Active Power Control 54
10.4 Test Case Pre-Conditions – UC 4a DER Active Power Control 55
10.5 Test Case Test Steps – UC 4a DER Active Power Control (Old) 56
10.6 Test Case Results – UC 4a DER Active Power Control 58
11 Test Case 5a – DER on Line / off-line 61
11.1 Test Case Description – UC 5a DER on Line / off-line 61
11.2 Test Case Diagram – UC 5a DER on Line / off-line 62
11.3 Test Case Diagram – UC 5a DER on Line / off-line 63
11.4 Test Case Pre-Conditions – UC 5a DER on Line / off-line 64
11.5 Test Case Test Steps – UC 5a DER on Line / off-line 65
11.6 Test Case Results – UC 5a DER on Line / off-line 66
12 Test Case 6a – Enhanced Automatic Feeder re-deployment 68
12.1 Test Case Description – UC 6a Enhanced Automatic Feeder re-deployment 68
12.2 Test Case Diagram – UC 6a Enhanced Automatic Feeder re-deployment 69
12.3 Test Case Diagram – UC 6a Enhanced Automatic Feeder re-deployment 70
12.4 Test Case Pre-Conditions – UC 6a Enhanced Automatic Feeder re-deployment 71
12.5 Test Case Test Steps – UC 6a Enhanced Automatic Feeder re-deployment 72
12.6 Test Case Results – UC 6a Enhanced Automatic Feeder re-deployment 73
13 Test Case 7a – Automatic Feeder Re-Close 77
13.1 Test Case Description – UC 7a Automatic Feeder Re-Close 77
13.2 Test Case Diagram – UC 7a Automatic Feeder Re-Close 78
13.3 Test Case Diagram – UC 7a Automatic Feeder Re-Close 79
13.4 Test Case Pre-Conditions – UC 7a Automatic Feeder Re-Close 80
13.5 Test Case Test Steps – UC 7a Automatic Feeder Re-Close 81
13.6 Test Case Results – UC 7a Automatic Feeder Re-Close 82
14 Test Case 8a – Sample Value Test Cases (Documentation only) 84
14.1 Test Case Description – UC 8a Sample Value Test Cases (Documentation only) 84
15 Test Case 8b – Synchrophasors via R-Goose 85

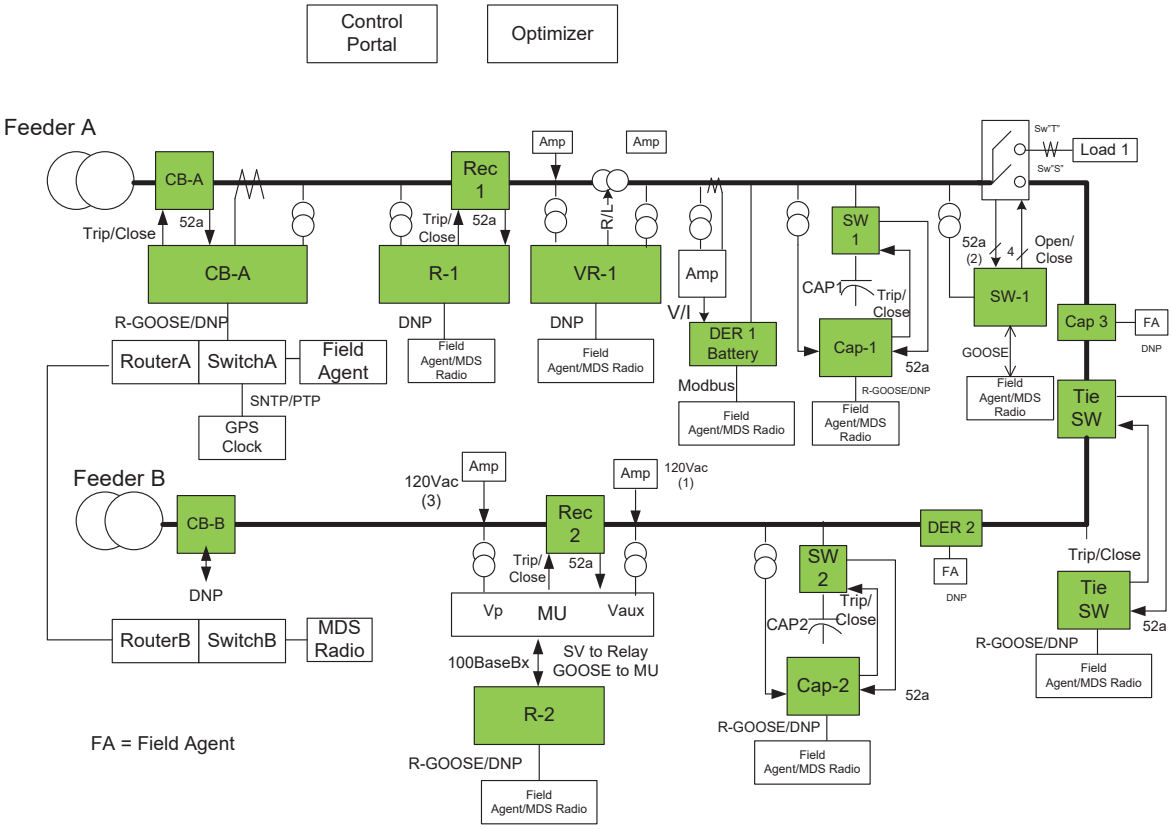
15.1 Test Case Description – UC 8b Synchrophasors via R-Goose 85
15.2 Test Case Diagram – UC 8b Synchrophasors via R-Goose 86
15.3 Test Case Diagram – UC 8b Synchrophasors via R-Goose 87
15.4 Test Case Pre-Conditions – UC 8b Synchrophasors via R-Goose 88
15.5 Test Case Test Steps – UC 8b Synchrophasors via R-Goose 89
15.6 Test Case Results – UC 8b Synchrophasors via R-Goose 90
16 Test Case 9a – Dynamic Subscription (Documentation Only) 93
16.1 Test Case Description – UC 9a Dynamic Subscription (Documentation) 93
17 Test Case 10a – End-to-End Security (Documentation Only) 94
17.1 Test Case Description – UC 10a End-to-End Security (Documentation) 94
18 Test Case 11a – Administration of Devices using OpenFMB 95
18.1 Test Case Description – UC 11a File transfer 95
18.2 Test Case Diagram – UC 11a File transfer 96
18.3 Test Case Diagram – UC 11a File transfer 97
18.4 Test Case Pre-Conditions – UC 11a File transfer 98
18.5 Test Case Test Steps – UC 11a File transfer 99
18.6 Test Case Results – UC 11a File Transfer 100
18.7 Test Case Description – UC 11b Firmware 100
18.8 Test Case Description – UC 11c Provisioning (Documentation Only) 101
19 Test Case 12a – Operational Data File transfer using OpenFMB 102
19.1 Test Case Description – UC 12a Operational Data File transfer using OpenFMB 102
20 Test Case 13a – OpenFMB using DDS 103
20.1 Test Case Description – UC 13a OpenFMB using DDS 103
20.2 Test Case Steps – UC 13a OpenFMB using DDS 104
20.3 Test Case Results – UC 13a OpenFMB using DDS 105
21 Equipment Analog Status and Control Point Testing 106

1 Introduction

The purpose of this section is to specify test procedures and steps for the OpenFMB test cases that were undertaken as part of the pre-commercial demonstration project. The test cases intended to demonstrate the functional and non-functional test cases for the OpenFMB setup used for testing at SDG&E's laboratory.

2 Test Case Reference Architecture

2.1 Reference Architecture – Figure 1



2.2 Reference Architecture – Figure 1 Device Names

Note: Device Names and abbreviations

Device Description	*Device Abb.*
Vendor A - Circuit Breaker A	CB-A
Vendor A - Capacitor 1	Cap 1
Vendor A - Capacitor 2	Cap 2
Vendor A - Tie Switch	Tie SW
Vendor A - Recloser 2	R-2
Vendor A - Virtual Capacitor 3	Cap 3
Vendor A - Virtual DER	Der 2
Vendor B Recloser 1	R-1
Vendor B Voltage Regulator	VR-1
Vendor B Load Switch	SW-1
Vendor C DER	DER 1
Vendor B Circuit Breaker B	CB-B

3 Test Case 1a - OpenFMB Connection to Relays & Virtual DER / Cap Bank

3.1 Test Case Description - UC 1a OpenFMB Connection to Relays & Virtual DER / Cap Bank

UC 1a: OpenFMB Connection to Relays and Virtual DER / Cap Bank

Objective:

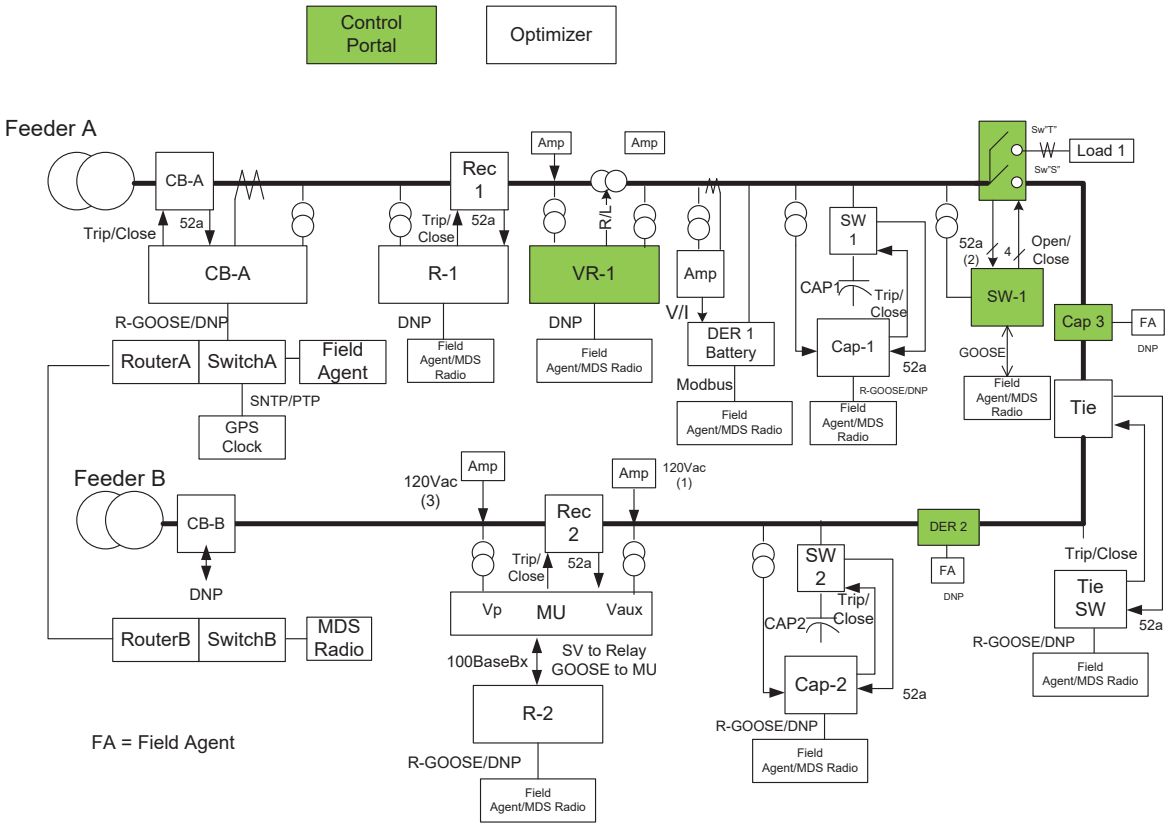
- Demonstrate the use of OpenFMB to communicate from a Control Portal to a field device showing:
    - Status – measurement values
    - Control – change status

Description:

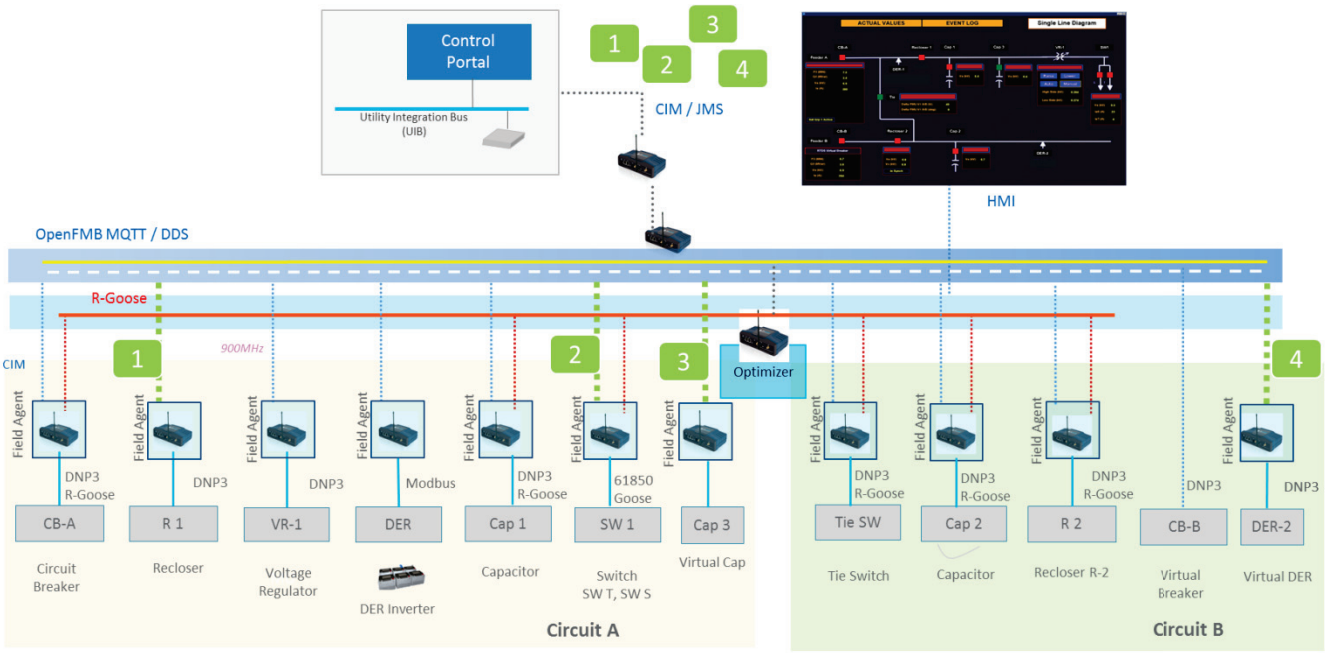
- Operation of Recloser 1 (R-1) (Open/Close) and Voltage measurements are to be made through OpenFMB messaging to the Recloser 1 (R-1) relay.
- Control and status of Switch 1 SW-1 are to be demonstrated from the Control Portal through OpenFMB to the Switch (SW-1).
- Control and Status of the Virtual DER (DER 2)
- Control and Status of the Virtual Cap Bank (Cap 3)

3.2 Test Case Diagram - UC 1a OpenFMB Connection to Relays & Virtual DER / Cap Bank

Logical and IO Diagram



3.3 Test Case Diagram - UC 1a OpenFMB Connection to Relays & Virtual DER / Cap Bank



Data Flow	*Data Flow Summary*	*Protocol*
1.	Control Portal (CP) → Field Agent → RECLOSER 1 (R-1)	CP →OpenFMB(MQTT) → DNP → RECLOSER 1 (R-1)
2.	Control Portal (CP) → Field Agent → Switch (SW-1)	CP →OpenFMB(MQTT) → DNP → Switch (SW-1)
3.	Control Portal (CP) → Field Agent → Virtual DER (DER 2)	CP →OpenFMB(MQTT) → DNP → Virtual DER (DER 2)
4.	Control Portal (CP) → Field Agent → Virtual Cap Bank (Cap 3)	CP →OpenFMB(MQTT) → DNP → Virtual Cap Bank (Cap 3)

3.4 Pre-Conditions - UC 1a OpenFMB Connection to Relays & Virtual DER / Cap Bank

Pre-Conditions	***Description***
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	RTDS is Active
7.	Network Model with Switchable Devices (2 Circuits)
8.	Tie Switch is Open
9.	Cap 1 is Open
10.	Cap 2 is Open
11.	R-1 is Closed
12.	VR-1 is Auto Mode
13.	SW-1 is Closed (2 positions)
14.	CB-A is Closed
15.	CB-B is Closed
16.	On Power-up of the Virtual DER and Field Agent, the following registers shall be WRITTEN as part of initialization OR via the Control Portal: 40007 – 2 – RESET 40008 – 2 – Set Voltage Source Inverter – PQ Mode 40101 – 256 – Set for Voltage / Watt mode of operation 40009 – 100 – Initial Real Power Set Point 40010 – 50 – Initial Reactive Power Set Point

3.5 Test Steps - UC 1a OpenFMB Connection to Relays & Virtual DER / Cap Bank

Steps	***Description***	***Acceptance Criteria***	***Pass / Fail***
#	*Step Description*	*Describe Acceptance Criteria*	*Pass (P) / Fail (F)*
1.	Start Control Portal	Check the Control Portal & logs to verify CP is running	P
2.	Start Field Agents	Check the log and verity Field Agents are up running. The measurement values shall be published and have values.	Measurement values are displayed
3.	Insert ALL GE devices • CB-A RTDS, Analog, Status Verified • Recloser R-2 – RTDS, Analogs (V, No I, No P); Status Verified • We verified Tie SW using DNP3 through control portal. • CAP 2 – RTDS, Analog, Status Verified. • CAP 1 – RTDS, Analog, Status verified		P
4.	Monitor measurement values on R-1	Measurement value = voltage reading RTDS, Analog (P,V,Q,I), Status verified.	P
5.	Control Portal send R-1 Open command	R-1 = Open	P
6.	Monitor measurement values on SW-1	Measurement value = voltage reading	P
7.	Control Portal send SW Open command	SW-1 = Open	F – 3rd party vendor software issue
8.	Monitor measurement values on Virtual DER 2	Measurement value = status	
9.	Control Portal exercise range of commands	DER 2 Commands: 40007 – 2 – RESET 40008 – 2 – Set Voltage Source Inverter – PQ Mode 40101 – 256 – Set for Voltage / Watt mode of operation 40009 – 100 – Initial Real Power Set Point 40010 – 50 – Initial Reactive Power Set Point	 P F F P P
10.	Monitor measurement values on Virtual Cap Bank (Cap 3)	Validate Measurement status values	P
11.	Control Portal sends Control values to Virtual Cap Bank	Virtual Cap Bank Control = Open/Close	F

Steps	*Description*	*Acceptance Criteria*	*Pass / Fail*
12.	OpenFMB communication to VR-1 is possible through control portal. The VR-1 configuration supports switching modes from manual to auto.	Measure Value Verification Status Verification Control mode verification Voltage Regulation (local) verification	MV Pass, Status Pass, Control Mode Pass,

3.6 Test Case Results - UC 1a OpenFMB Connection to SEL Relays & Virtual DER / Cap Bank

Operation:

In this first use case, communication to ALL relays was demonstrated via OpenFMB through the Control Portal. The Control Portal is an auto-generated HMI – the construction of which is based on the Common Information Model or CIM. The team was given the physical layout of two feeders on the SDG&E system which was converted to a geographic layout – on top of GOOGLE maps. Figure 1a-1 below shows an image of the Control Portal.

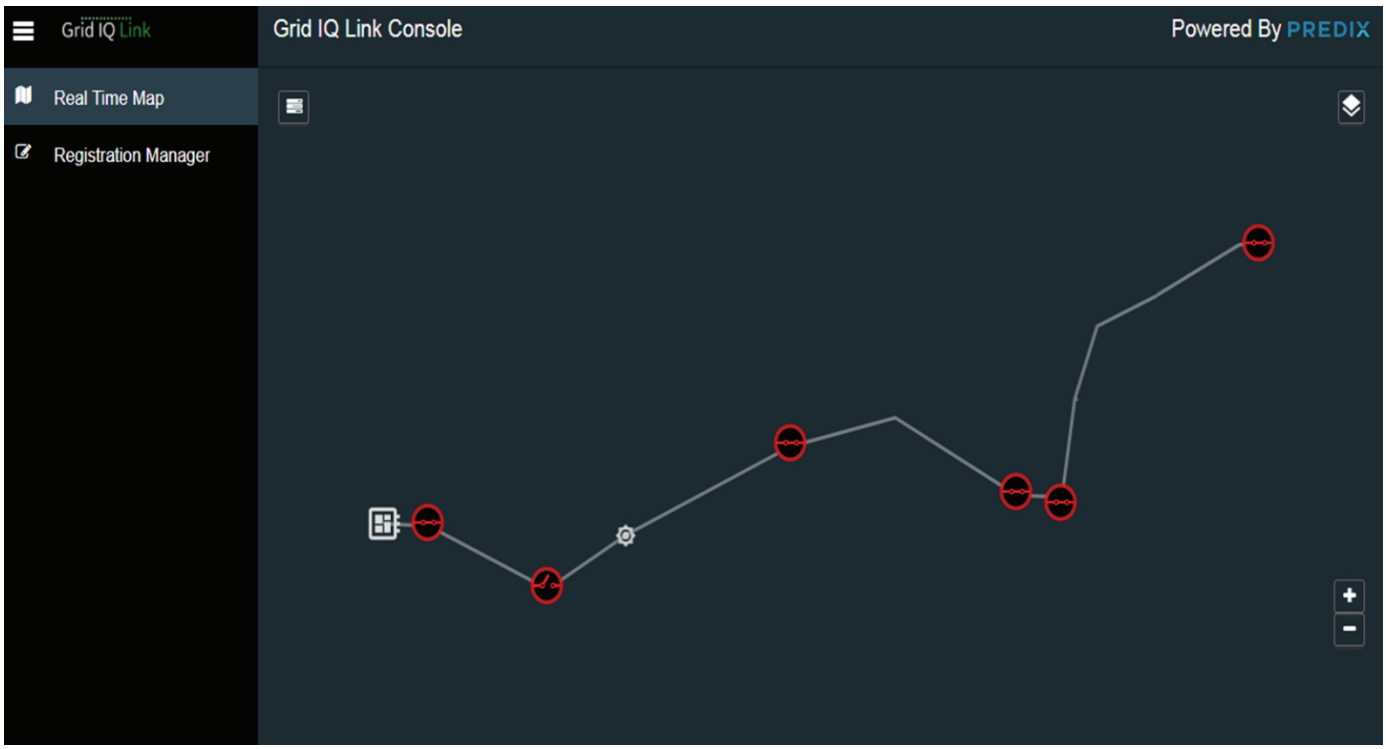


Figure 1a-1 – Control Portal

Line Layout from the Control Portal

From the control portal, a user could select a device with which to communicate. The available made available through the Control Portal was a function of the data made available either though DNP or Modbus. A GOOSE interface was attempted but due to 3rd party SW issues, was unable to be demonstrated at the time of this writing. Additionally, there were 2 mapping issues with the interface to the Distributed Energy Resource device and to the circuit switcher – otherwise, the ability to monitor and control all other devices was demonstrated.

The figure below shows an example of a device's available data and controllable items. In general, voltages, currents, Watts, Vars, status, and Control was available through the Control Portal.



Figure 1a-2
Typical Control Portal Device Data Display

Communication Observations:

Communication to the various network devices was split between direct communication at 100MB Ethernet for substation-connected devices and 500kb - 900MHz radio for the field connected devices. Variation in performance between the two networks was negligible.

Communication to the Switch controller was targeted to be OpenFMB to OPC-UA to GOOSE to the switch controller. Issues with the GOOSE to OPC-UA SW modules (including 3rd party SW) precluded implementation of a complete solution. Elements of the available data were visible on the GOOSE collection SW, however, integration between the OPC-UA Client and server proved to be problematic and unable to be established.

Of note, however, was the fact the messages from the Switching device over GOOSE were multicast on change of state and readily readable through the observation window on the 3rd party GOOSE capture SW.

OpenFMB Gaps:

In as much as the integration of data into OpenFMB on the project was performed through protocol translation and the mapping of data into the Common Information Model (CIM) XML format, there was a sizable increase in data packet size from the base message (e.g. – 10 bytes in Modbus) to maybe 5000 bytes when migrated into CIM and OpenFMB – most of which was the mapping into CIM XML. OpenFMB needs to evaluate the model of simple Datasets being carried by the appropriate OpenFMB protocol with Out of Band Dataset configuration.

Recommendations:

The items on the Control Portal were not labeled in the top-level view making discovery of circuit names and devices a challenge. Additionally, the device names on the exploded view were not representative of the actual devices being monitored. Implementation of this technology going forward needs to incorporate a naming convention to facilitate device identification. As Future versions of the Control Portal should consider on-screen names and Tool Tips that can provide additional information to a user.

Operation of the controls needs to be more user-friendly. Use of the words “Open” and “Close” and “Raise” and “Lower”, etc. need to be incorporated into the Control Portal language.

Timing of the open and close function through OpenFMB was timed via stop watch. Going forward, it would be expected that a Sequence of Events recorder would be embedded into the various elements of the communication system so that not only end-to-end but also link latency could be measured.

4 Test Case 2a - Var Control

4.1 Test Case Description – UC 2a Var Control

UC 2a: Var Control

Objective:

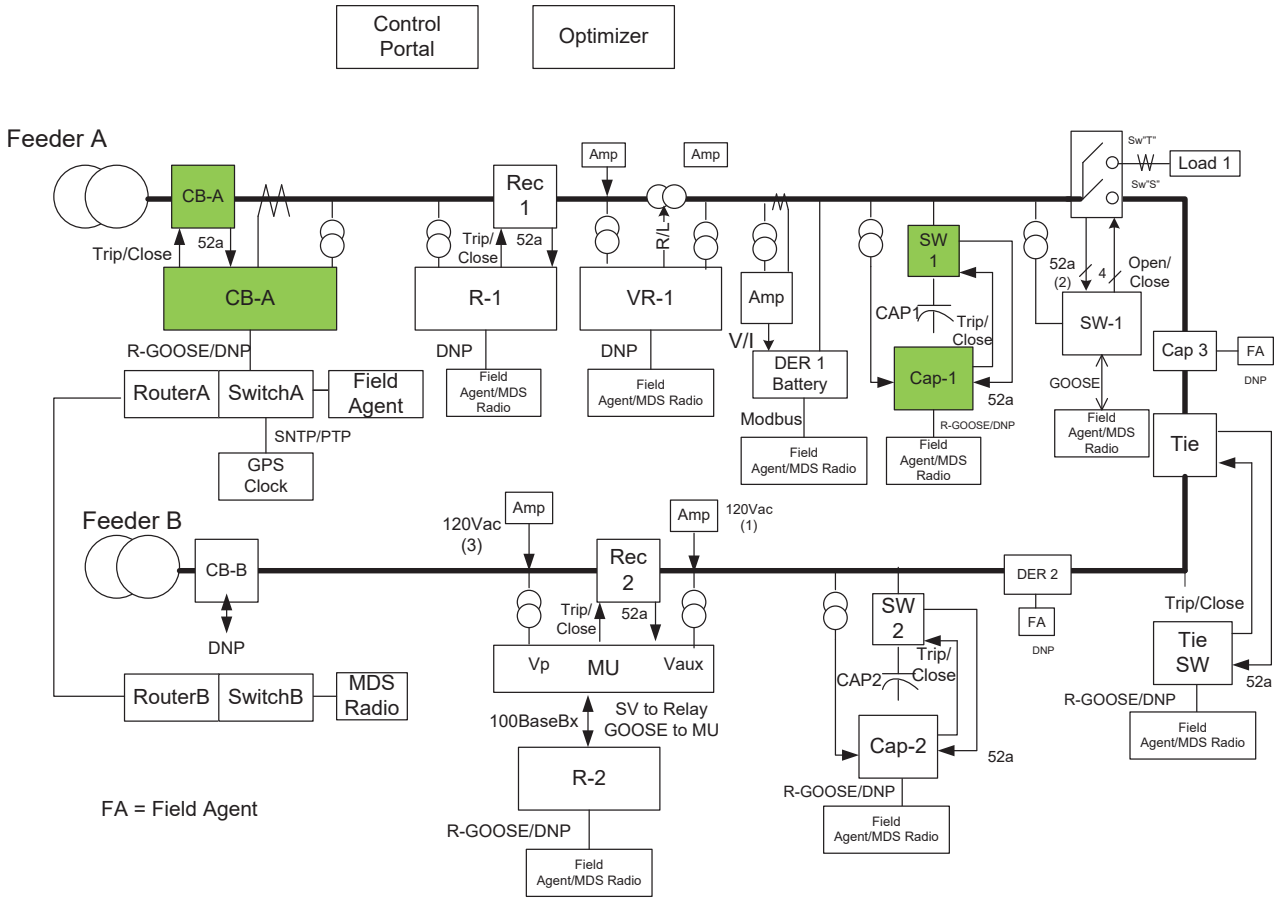
- Evaluate R-GOOSE as an alternative Pub-Sub protocol under the OpenFMB standard / framework.

Description:

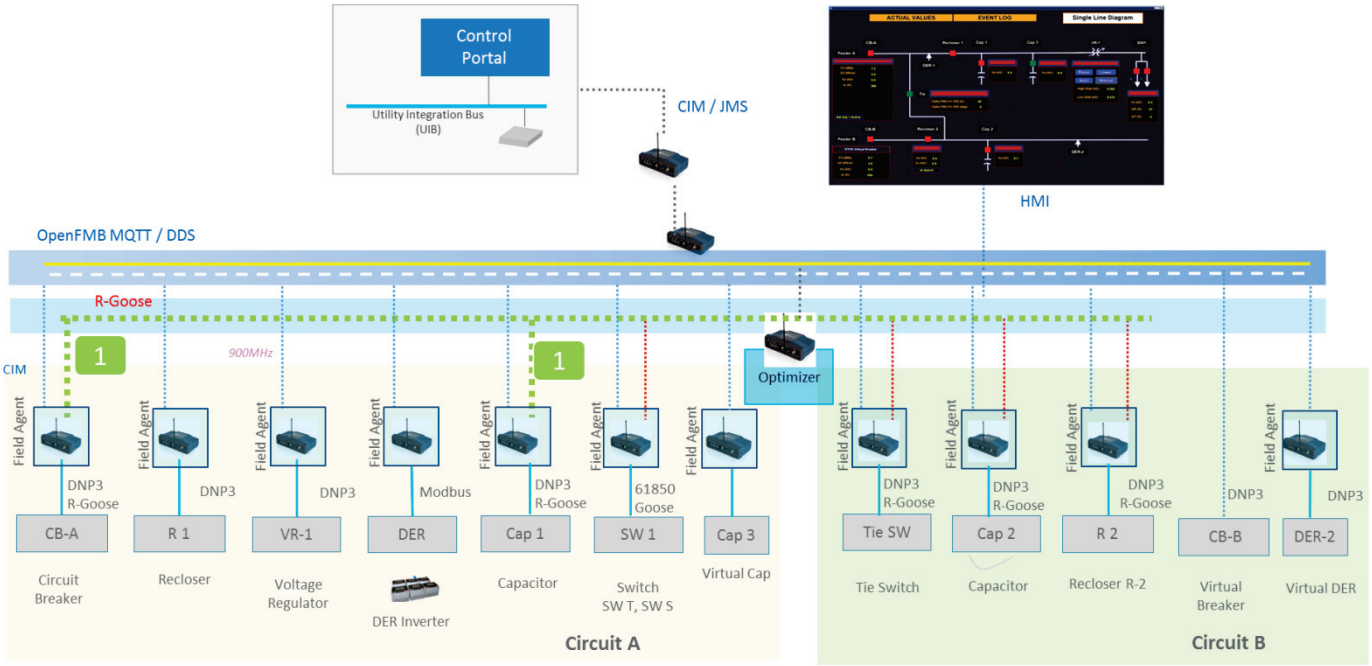
- Create a 2-line power system (Line A and Line B) with communicable devices on different networks on each line. Measure the Vars at the breaker end of Feeder A (CB-A).
- When the Vars exceed a set-point, send a R-GOOSE message from CB-A to Cap 1 to cut-in the capacitor at that location.
- Close Capacitor Cap 1

4.2 Test Case Diagram - UC 2a Var Control

Logical and IO Diagram



4.3 Test Case Diagram - UC 2a Var Control



Data Flow	*Data Flow Summary*	*Protocol*
1.	CB-A → CAP 1	CB-A → R-GOOSE → CAP 1

4.4 Test Case Pre-Conditions – UC 2a Var Control

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	RTDS is Active
7.	Network Model with Switchable Devices (2 Circuits)
8.	Tie Switch is Open
9.	Cap 1 is Open
10.	Cap 2 is Open
11.	R-1 is Closed
12.	VR-1 is Auto Mode
13.	SW-1 is Closed (2 positions)
14.	CB-A is Closed
15.	CB-B is Closed

4.5 Test Case Test Steps – UC 2a Var Control

Steps	***Description***	***Acceptance Criteria***	***Pass / Fail***
#	*Step Description*	*Describe Acceptance Criteria*	*Pass (P) / Fail (F)*
1.	Start Control Portal	Check the Control Portal & logs to verify CP is running	P
2.	Start Field Agents / Optimizer	Check the log and verity Field Agents are up running. The measurement values shall be published and have values.	P Measurement values are displayed
3.	Measure the VARS at the breaker Feeder A (CB-A).	Measurement value VARS at Feeder A Breaker (CB-A)	2.1 MVAr
4.	Change VARS in the RTDS model to exceed a set-point	VARS exceed set-point	3.5 MVAr > threshold of 3.36 MVAr
5.	Send R-GOOSE message from CB-A to CAP 1 to Close capacitor CAP 1	R-Goose Message (Close) sent CB-A --> CAP 1, record the new Var values	Pass
6.	Sent R-GOOSE message received by CAP 1 capacitor	R-Goose Message received by capacitor (CAP 1) Status change = Close	Pass
7.	Measure the VARS at the breaker Feeder A (CB-A).	Measure VARS at Breaker (Feeder A) (OpenFMB) - view the new Var values	3.5

4.6 Test Case Results– UC 2a Var Control

Operational:

In this use case, the VAR loading on Line A is increased to a value above the pick-up value set in the Feeder A relay. Upon detection of the Over VAR condition, a CLOSE message is sent to Capacitor 1 via R-GOOSE. The oscillography below in figure 2a-1 shows increase in VARS, the Closing of the Capacitor 2 breaker in 6 cycles and the subsequent drop in VARS when the capacitor cuts in. The 6 cycle delay can be broken down into a 4 cycle delay on over-VAR detection, a 1.5 cycle communication time through the radios, a 4ms receipt delay, a 3ms output operation time, and some RTDS contact recognition time.

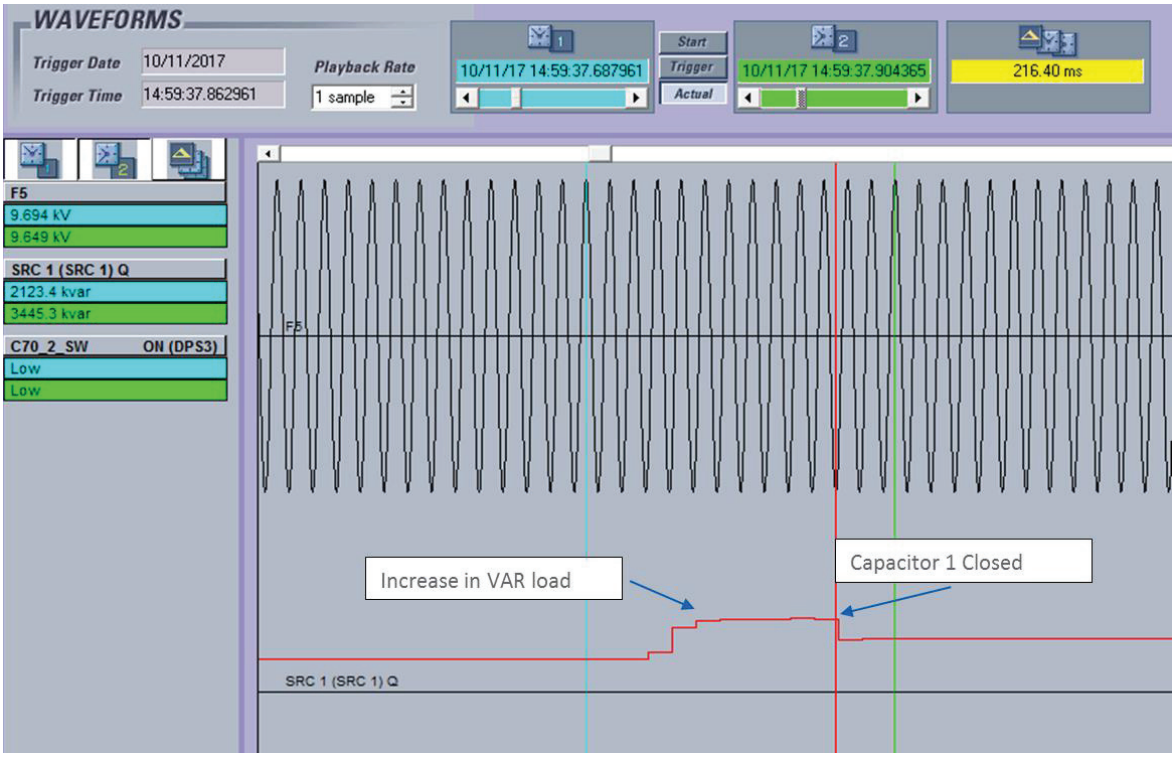


Figure 2a-1

Over-Var Line Condition with Capacitor Closing

Communication Observations:

During the implementation of this project, as the team learned about R-GOOSE, it was considered to play a roll in the "other" category of the OpenFMB Framework. R-GOOSE is a Pub-Sub protocol and is part of the IEC 61850 suite of profiles. R-GOOSE is similar to the non-guaranteed version of DDS in that it repeats a message continuously – independent of a Transport Layer time-out function. It is to be noted that this mode of communication optimizes performance for lost packets as there is no time delay in waiting for a lost packet "time-out". Also, similar to one of the modes of operation of DDS, R-GOOSE continues to send the message – the one difference being that DDS stops transmission when a "Packet Received" confirmation is received. Alternatively, R-GOOSE continues to send the last message state as a keep-alive. The Subscribers (all of them) can issue an alarm on loss of the keep-alive message after a

message-specified period of time. Additionally, R-GOOSE optimizes the packet payload through a binary mapping of data in the packet through the use of the Abstract Syntax Notation presentation protocol. Communication of the R-GOOSE message was through a combination of a 100Mb Substation switch and a 500kb radio. It is to be noted that there was a periodic flow of Multicast data on the overall network as all R-GOOSE publishers sent keep-alive messages every 10 seconds. It is to be noted, however, that the R-GOOSE message was only 300 bytes long on the average whereas, an OpenFMB message (as presently mapped) was 5,000 bytes long.

OpenFMB Gaps:

It is once again of interest to note the concise nature of the R-GOOSE message and the need for OpenFMB to adopt this concise communication profile if it is to be a contender for communication at the edge.

Recommendations:

In the capacitor control use case, it is clear that the Pub-Sub model is key so implementation of such profiles is optimal. In as much as R-GOOSE meets the Pub-Sub profile, it can be considered in the "Other" category of the OpenFMB reference architecture. Implementations of MQTT and DDS should consider using the Binary mapping payload data and using an out-of-band payload identification mechanism.

5 Test Case 2b Man-in-the-Middle Augmented Voltage/Var Control

5.1 Test Case Description – UC 2b Man-in-the-Middle Augmented Voltage/Var Control

UC 2b Man-in-the-Middle Augmented Voltage/Var Control

Objective:

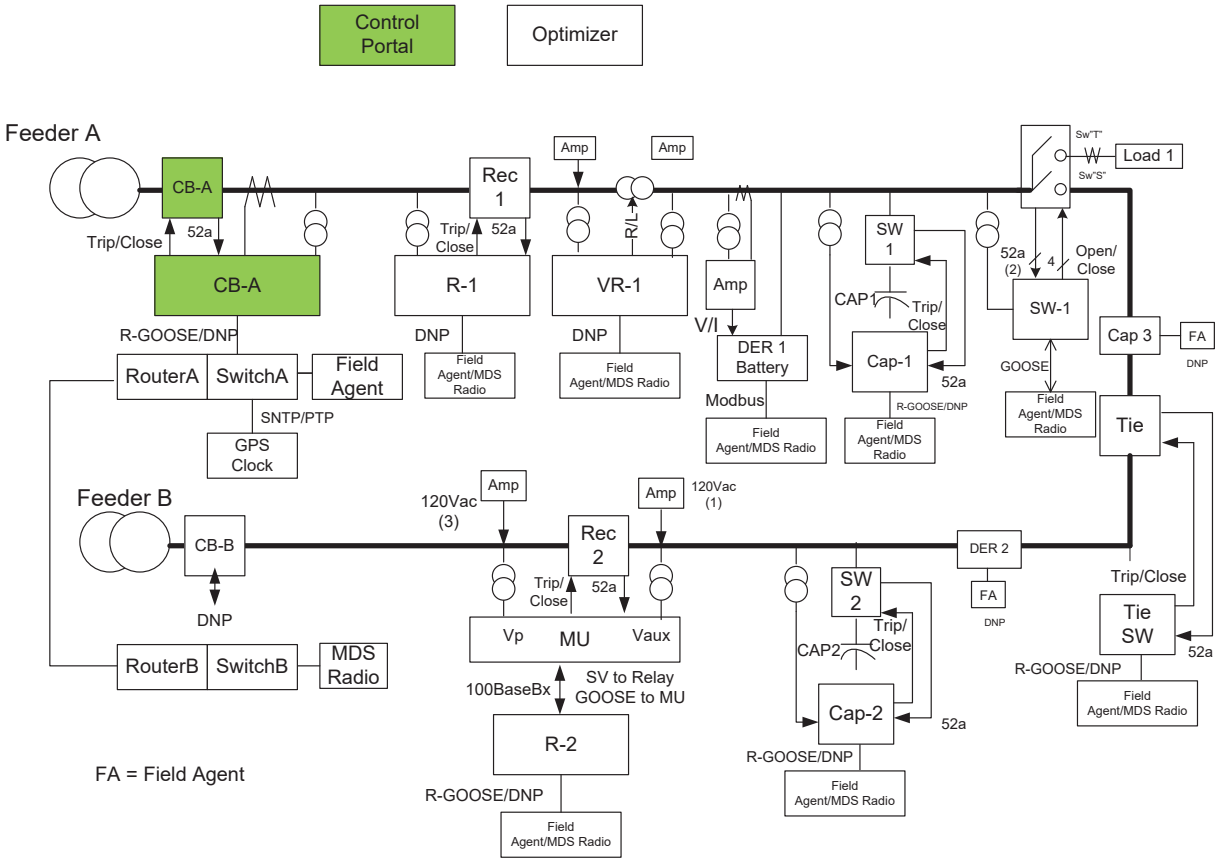
- Demonstrate manual control and operation using OpenFMB

Description:

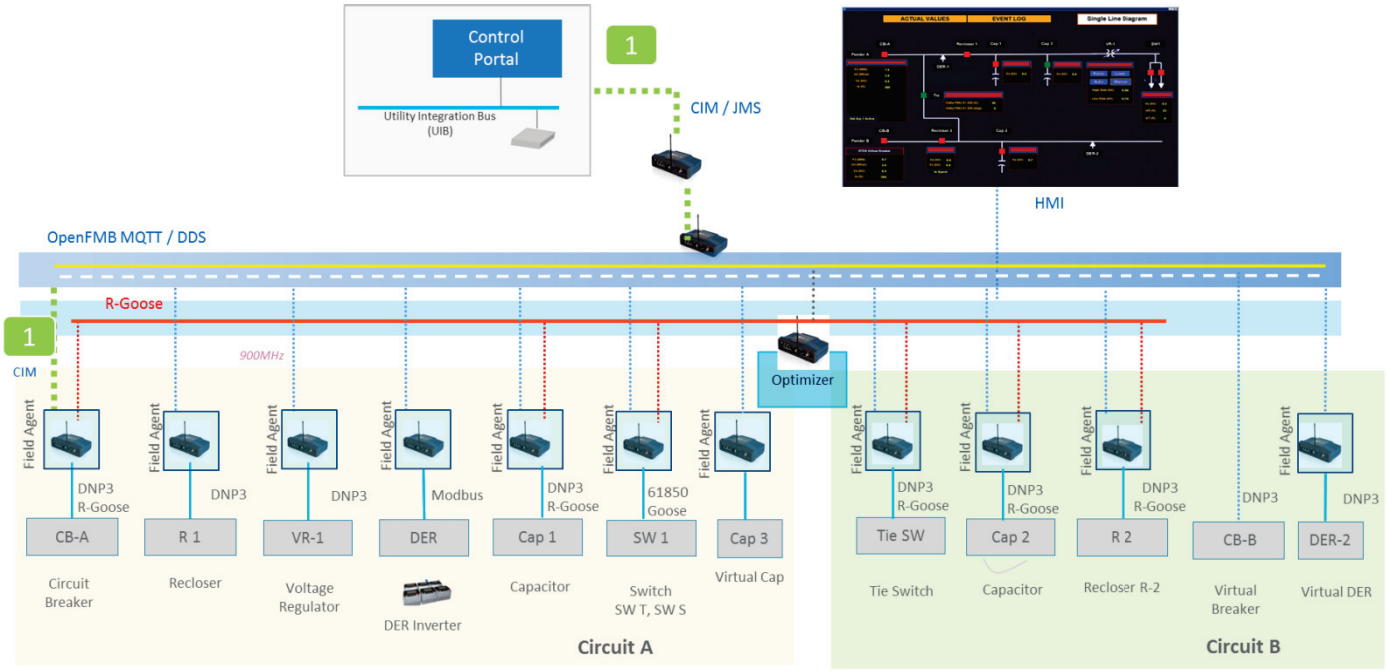
- If, after closing Capacitor 1, the var level is still above the setting threshold in the CB-A, a OpenFMB alarm of "over VAR" will be issued by the CB-A relay.
- This alarm is to be received by the Control Portal and indicated.
- Pre-condition VR-1 is in manual mode.

5.2 Test Case Diagram – UC 2b Man-in-the-Middle Augmented Voltage/Var Control

Logical and IO Diagram



5.3 Test Case Diagram – UC 2b Man-in-the-Middle Augmented Voltage/Var Control



Data Flow	*Data Flow Summary*	*Protocol*
1.	CB-A → Field Agent →Control Portal (CP)	CB-A → DNP → OpenFMB(MQTT) → CP

5.4 Test Case Pre-Conditions – UC 2b Man-in-the-Middle Augmented Voltage/Var Control

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	RTDS is Active
7.	Network Model with Switchable Devices (2 Circuits)
8.	Tie Switch is Open
9.	Cap 1 is Closed
10.	Cap 2 is Open
11.	R-1 is Closed
12.	VR-1 is Manual Mode (not a normal operating state)
13.	SW-1 is Closed (2 positions)
14.	CB-A is Closed
15.	CB-B is Closed

5.5 Test Case Test Steps – UC 2b Man-in-the-Middle Augmented Voltage/Var Control

Steps	***Description***	***Acceptance Criteria***	***Pass / Fail***
#	*Step Description*	*Describe Acceptance Criteria*	*Pass (P) / Fail (F)*
1.	Measure the VARS at the breaker Feeder A (CB-A).	Measurement value = VARS at Breaker (CB-A) still above normal	2.1MVAR
2.	Change VARS in the RTDS model to exceed a set-point if needed	VARS exceed set-point	3.4MVAR
3.	CB-A sends an alarm of “over VAR”	F-60-1 sent "over VAR" alarm (OpenFMB)	P
4.	Control Portal receives Alarm	Control Portal receives "over VAR" alarm (OpenFMB)	P
5.	Operator places VR-1 in Auto mode	Observe VR-1 in Auto mode	P

5.6 Test Case Results – UC 2b Man-in-the-Middle Augmented Voltage/Var Control

Operational:

As the VAR loading on the line was increased, as expected, the Over Var alarm from the feeder was observed on the control portal. From the Control Portal, the test engineer was able to manually CLOSE the Capacitor 1 breaker and manually add VAR support to the line.

Communication Observations:

The control command originated on the 100MHz network – which then transitioned to the 500KHz bandwidth of the radio network. Execution of the command was in the 1 to 3 second range – again, adequate for a HMI response time.

OpenFMB Gaps:

No gaps identified.

Recommendations:

The recommendations for this use car pertain only to the Control Portal where, again, better descriptions of the data items is needed as is a mechanism to pop-up alarms on the screen.

6 Test Case 2c – Peer-to-Peer Voltage/Var Control

6.1 Test Case Description – UC 2c Peer-to-Peer Voltage/Var Control

UC 2c Peer-to-Peer Voltage/Var Control

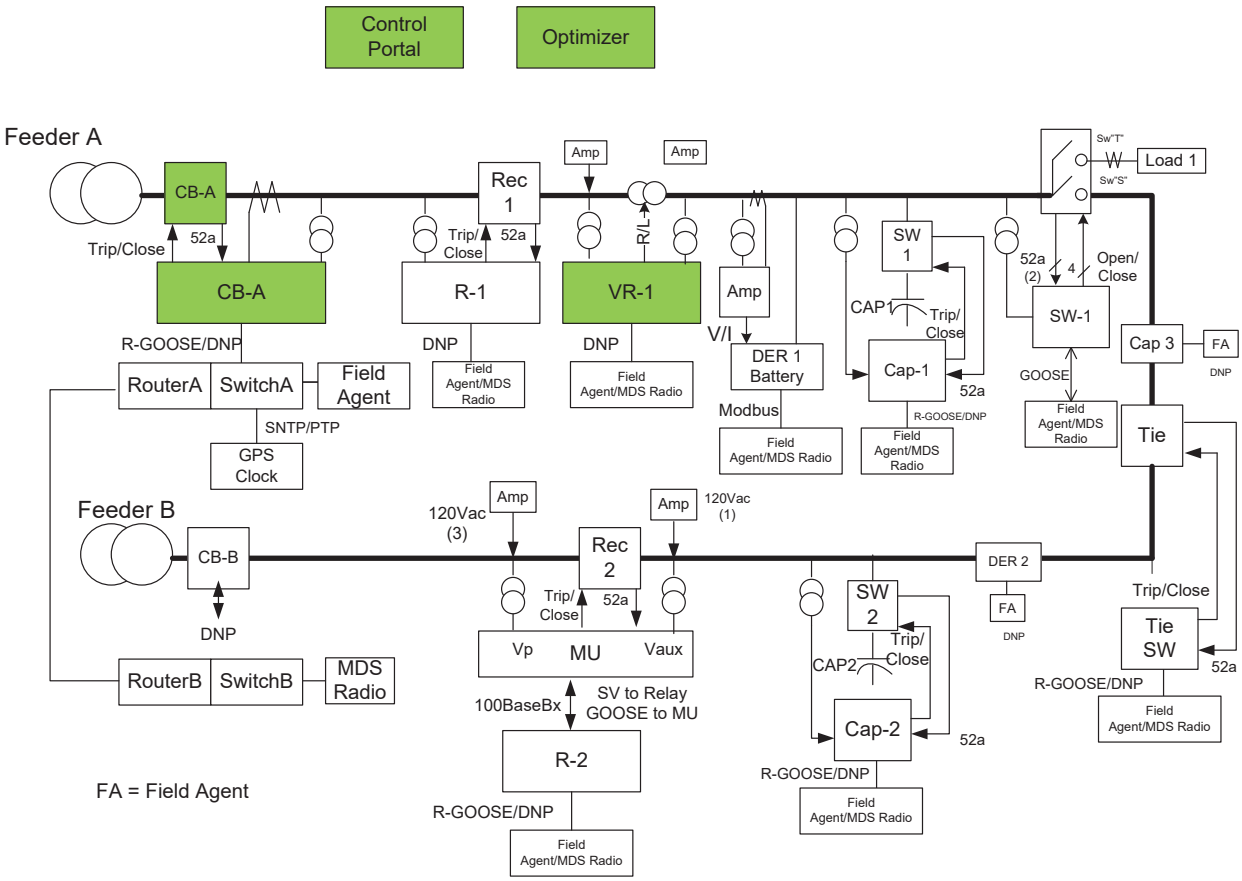
Objective:

- Demonstrate automated control or operation using OpenFMB

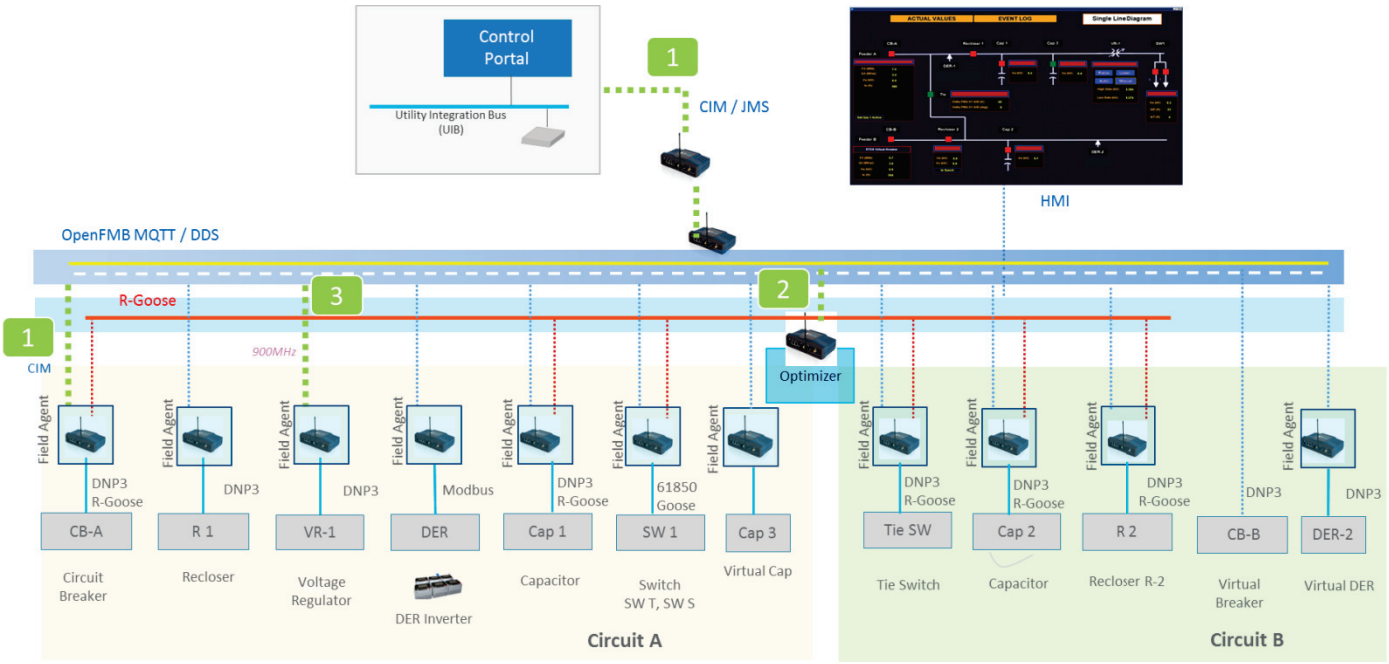
Description:

- If, after closing Capacitor 1, the var level is still above the setting threshold in the CB-A, an alarm of "over VAR" will be issued by the CB-A.
- This alarm is to be received by the Optimizer and the Optimizer then places VR-1 Voltage Regulator in auto mode via an OpenFMB command.
- Pre-Condition VR-1 manual mode
- Pre-Condition Cap 1 is closed
- RTDS raises VAR loading prior to start of test

6.2 Test Case Diagram – UC 2c Peer-to-Peer Voltage/Var Control



6.3 Test Case Diagram – UC 2c Peer-to-Peer Voltage/Var Control



Data Flow	*Data Flow Summary*	*Protocol*
1.	CB-A → Field Agent →Control Portal (CP)	CB-A → DNP → OpenFMB(MQTT) → CP
2.	CB-A → Field Agent →Optimizer	CB-A → DNP "over VAR "→ Field Agent (CIM) → OpenFMB(MQTT) → "over VAR" alarm Optimizer
3.	Optimizer → CIM → OpenFMB(MQTT) → VR-1	Optimizer → CIM → OpenFMB(MQTT) → Field Agent (CIM) → DNP → VR-1 (Auto Mode)

6.4 Test Case Pre-Conditions – UC 2c Peer-to-Peer Voltage/Var Control

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	RTDS is Active
7.	Network Model with Switchable Devices (2 Circuits)
8.	Tie Switch is Open
9.	Cap 1 is Closed
10.	Cap 2 is Open
11.	R-1 is Closed
12.	VR-1 is manual Mode
13.	SW-1 is Closed (2 positions)
14.	Control Portal displays measurement values
15.	CB-A is Closed
16.	CB-B is Closed
17.	RTDS lowers the VAR loading below threshold

6.5 Test Case Test Steps – UC 2c Peer-to-Peer Voltage/Var Control

Steps	***Description***	***Acceptance Criteria***	***Pass / Fail***
#	*Step Description*	*Describe Acceptance Criteria*	*Pass (P) / Fail (F)*
1.	Measure the VARS at the breaker Feeder A (CB-A).	Measurement value = VARS at Breaker (CB-A) still above normal	0.7 MVAr
2.	Change VARS to exceed a set-point	VARS exceed set-point	90% change in Load Q (i.e above 3.4 MVAr).
3.	CB-A sends an alarm of “over VAR”	F-60-1 sends "over VAR" alarm	Pass
4.	Control Portal & Optimizer receives Alarm	Control Portal & Optimizer receives "over VAR" alarm	Pass
5.	Optimizer sends command to VR-1 switch to manual mode	VR-1 switches to manual mode	Pass
6.	VR-1 regulates to a previously issued set-point in manual mode	VR-1 placed in manual mode	Pass
7.	VR-1 Regulator Control through Control Portal	Parking Lot Enhancement	Parking Lot
8.	Measure the VARS at the breaker Feeder A (CB-A).	Measurement value = VARS at Breaker (CB-A) still above normal	3.4 MVAr

6.6 Test Case Results – UC 2c Peer-to-Peer Voltage/Var Control

Operational:

In this use case, the continued Over VAV condition exists on the feeder and there is a need to adjust VAR flow through MANUAL control of the Voltage Regulator. As such, a "RULE" was created in the optimizer to set the Voltage Regulator to MANUAL mode. NOTE: this was an arbitrary decision as the rule could have as easily been switched from Manual to Auto mode.

Communication Observations:

Communication in this case was OpenFMB from the Substation relay through the 100MB Ethernet switch to the Control Portal and then from the Substation relay through the 500kB radio network to the Voltage Regulator. Communication performance in each stage was on the order of 2 seconds per stage.

OpenFMB Gaps:

Not part of OpenFMB today but configuration of the "RULES" engine and observation of its performance needs to be addressed. The RULES were implemented using a LINUX rules engine – DROOLS – into which there was no visibility from the Control Portal. Additionally, the logging of any RULE execution needs to be addressed.

Recommendations:

The incorporation of RULE and general logic development, monitoring, and logging should be considered in any OpenFMB profile. Ideally, all profiles would use the same LOGIC development profile and would use an internationally standardized logic language.

7 Test Case 2d – Voltage Override

7.1 Test Case Description – UC 2d Voltage Override

UC 2d Voltage Override

Objective:

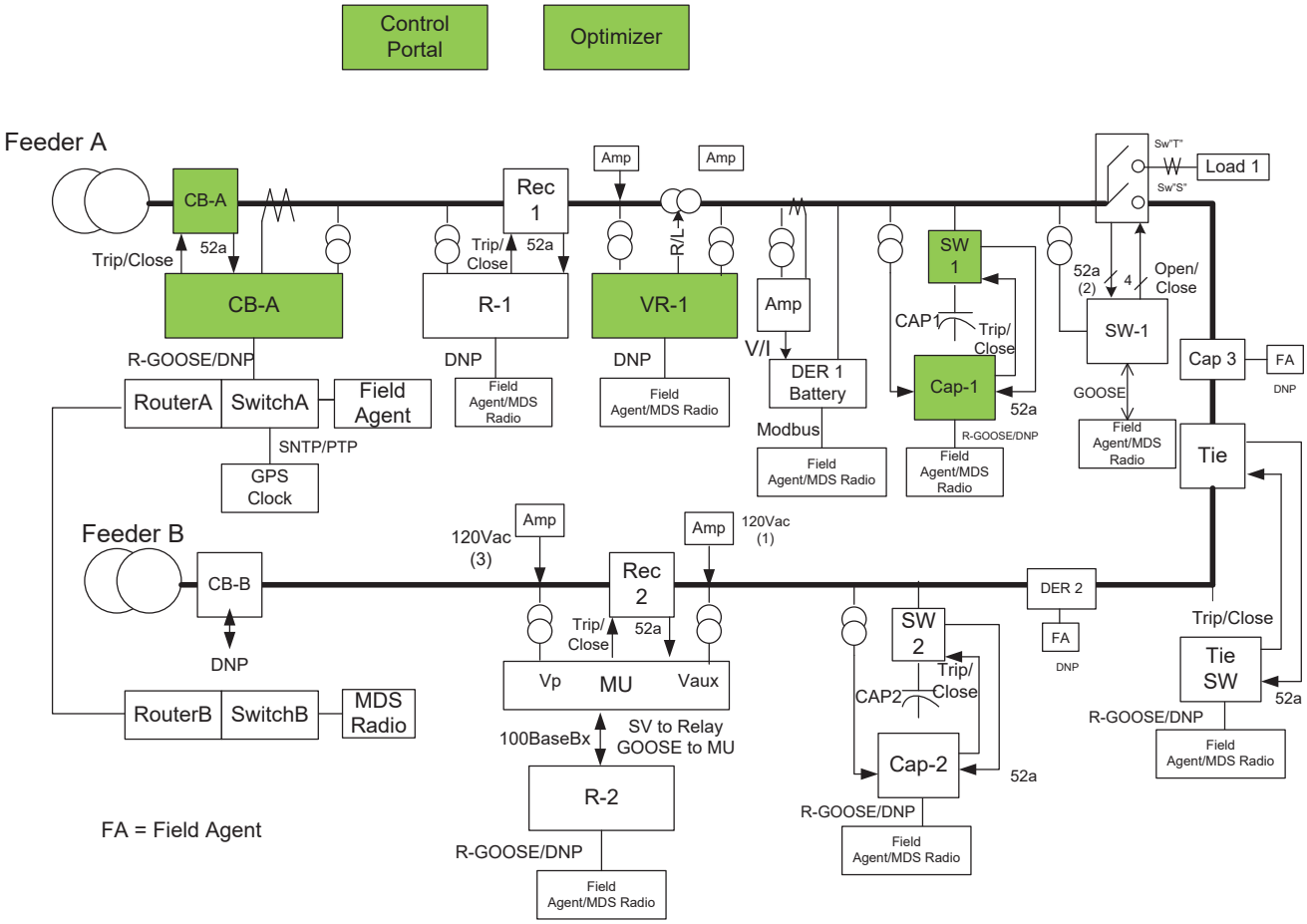
- Demonstrate the communication of the rejection of manual control and subsequent automatic response based on prevailing local condition using OpenFMB.

Description:

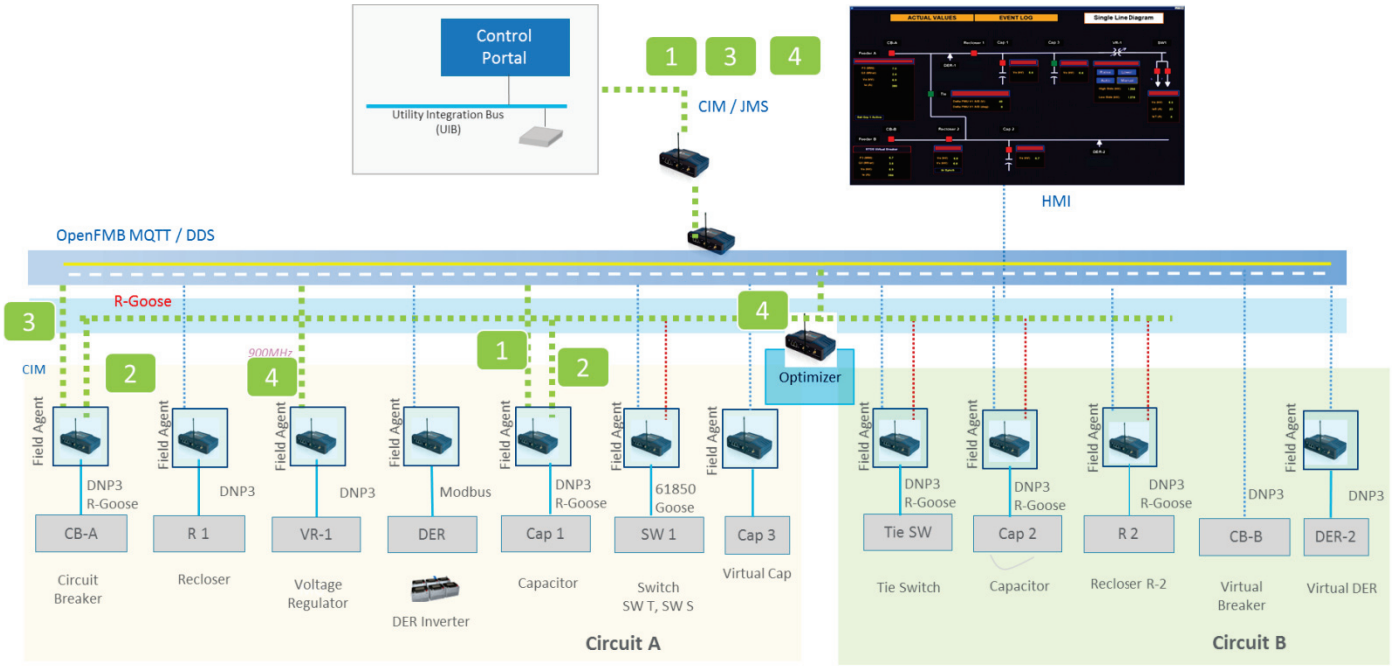
- Control Portal sends a close command to CAP 1
- If the voltage on CAP 1 is too high, CAP 1 refuse the CLOSE control and send a message to the CB-A indicating refusal of the Cap 1 devices to execute the requested close action.
- An OpenFMB message is issued indicating such from CB-A and is to be displayed on the Control Portal.
- Detection of Over-Voltage shall be transmitted to the Optimizer which will then enable the Voltage Regulator.
- Pre-condition: Voltage Regulator (VR-1) Manual Mode & high voltage (circuit A) through RTDS
- Post-condition: Voltage Regulator (VR-1) turned to Automatic Mode

7.2 Test Case Diagram – UC 2d Voltage Override

Logical and IO Diagram



7.3 Test Case Diagram – UC 2d Voltage Override



Data Flow	*Data Flow Summary*	*Protocol*
1.	Control Portal (CP) → OpenFMB(MQTT) → Field Agent → CAP 1	CP → CIM/JMS → OpenFMB(MQTT) → Field Agent (CIM) → DNP → CAP 1 (Close)
2.	CAP 1 → CB-A	CAP 1 → R-GOOSE → CB-A
3.	CB-A → Refuse Close → Control Portal (CP)	CB-A → DNP → Field Agent (CIM) → OpenFMB(MQTT) → CIM/JMS → CP
4.	Control Portal (CP) → Optimizer → VR-1	CP → CIM/JMS → OpenFMB(MQTT) → Optimizer → OpenFMB(MQTT) → Field Agent (CIM) → DNP → VR-1 (Auto Mode)

7.4 Test Case Pre-Conditions – UC 2d Voltage Override

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	RTDS is Active
7.	Network Model with Switchable Devices (2 Circuits)
8.	Tie Switch is Open
9.	Cap 1 is Open
10.	Cap 2 is Open
11.	R-1 is Closed
12.	VR-1 is Manual Mode
13.	SW-1 is Closed (2 positions)
14.	Control Portal displays measurement values
15.	CB-A is Closed
16.	CB-B is Closed
17.	RTDS voltage needs to raise to 1.6 PU

7.5 Test Case Test Steps – UC 2d Voltage Override

Steps	***Description***	***Acceptance Criteria***	***Pass / Fail***
#	*Step Description*	*Describe Acceptance Criteria*	*Pass (P) / Fail (F)*
1.	Monitor Voltage on Cap 1	CAP 1 measurement value (Voltage)	7.1kV
2.	Monitor Voltage on CAP 1	CAP 1 measurement value (Voltage)	6.8kV
3.	RTDS Simulate increase in voltage (High Voltage) on Cap 1 CAP 1	CAP 1 measurement value (High Voltage)	Voltage increased to the threshold of 7.416 on the Cap CAP 1
4.	Control Portal sends Close command CAP 1	CAP 1 receive command CAP 1 = closed	Closed
5.	Cap 1 refuse the CLOSE control	CAP 1 CLOSE control refused	Pass
6.	Cap 1 sends message to CB-A indicating refusal	CB-A monitors CAP 1 close control refusal	Pass
7.	CB-A creates message "Over-Voltage" sends to Optimizer	Optimizer receives "Over-Voltage" message	Received
8.	Optimizer sends message VR-1 to change to auto mode	Optimizer sends VR-1 to change to auto mode	Pass
9.	Voltage Regulator VR-1 receives command	VR-1 receives auto mode command	Auto
10.	Voltage Regulator VR-1 regulates voltage on the low side	VR-1 lowers the voltage on the low side	Voltage reduced to 7.47

7.6 Test Case Results – UC 2d Voltage Override

Operational:

In this use case, the voltage on Capacitor 1 is too high. When a manual close is attempted, the Capacitor Controller refuses the request and notifies the Feeder Breaker relay of such. In response to this situation, the Feeder Breaker relay issues an OpenFMB command to place the Voltage Regulator into Auto mode.

Figures 2d-1 and 2d-2 below shows this transaction in detail. In figure 2d-1, one can see the increase in voltage and decrease in current. Figure 2d-2 shows the VAR response of the feeder (drop in VARs as the Voltage increases) with the response of placing the regulator into AUTO mode. Note that there was a 10 second delay timer in the voltage regulator before the first step is taken. The stepping of the regulator can be clearly seen in figure 2d-2.

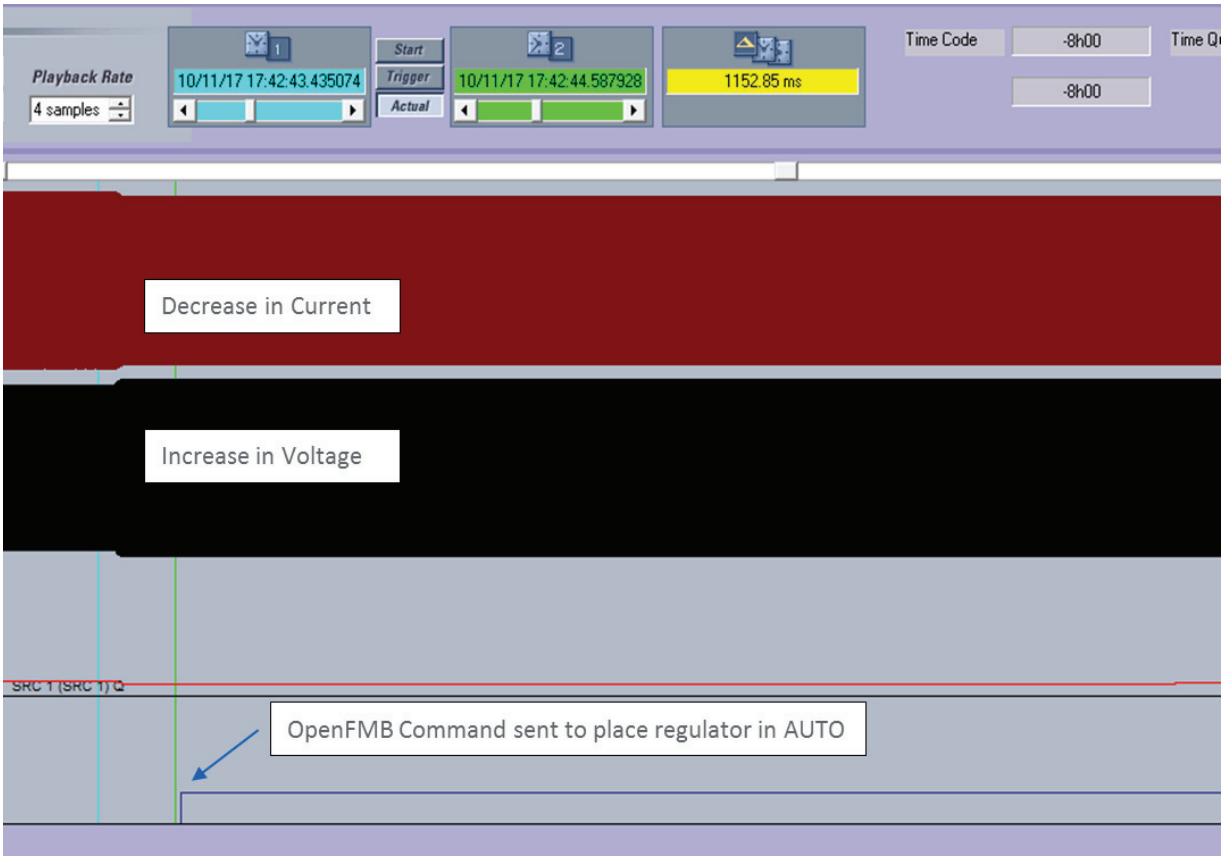


Figure 2d-1

Feeder A Voltage Increase

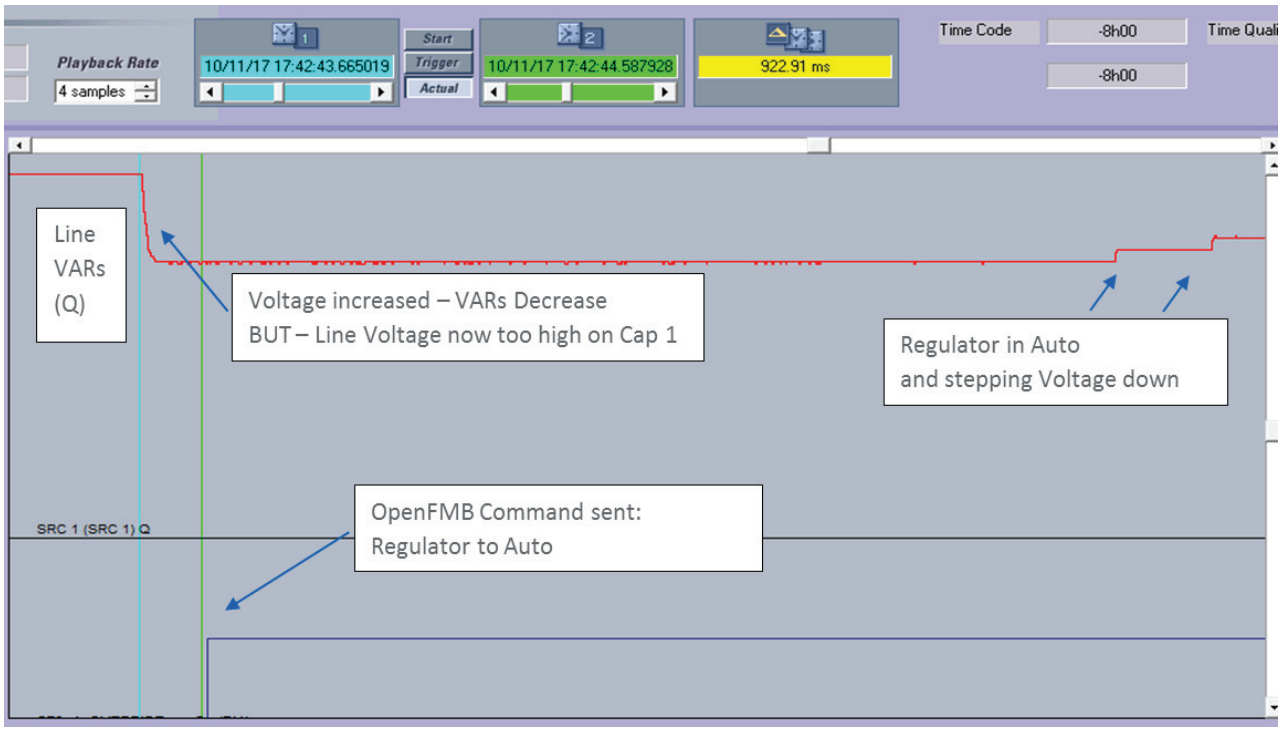


Figure 2d-2

Expanded VAR Response with Regulator Action

Communication Observations:

Device to device communication for this case used messaging from the Feeder A relay to the Optimizer (where the RULE engine resided) which then issued a message to the Voltage Regulator. The message transport to the Optimizer was the Message Queue Telemetry Transport protocol (MQTT). As captured by WireShark, the anatomy of this message can be seen in figure 2d-3. In this snippet from WireShark, one can see the protocol listed and the face that TCP combined packets of 1448, 1448, and 546 bytes for a total message length of 3442 bytes. The major part of the payload was the XML description of the data being transmitted over the wire.

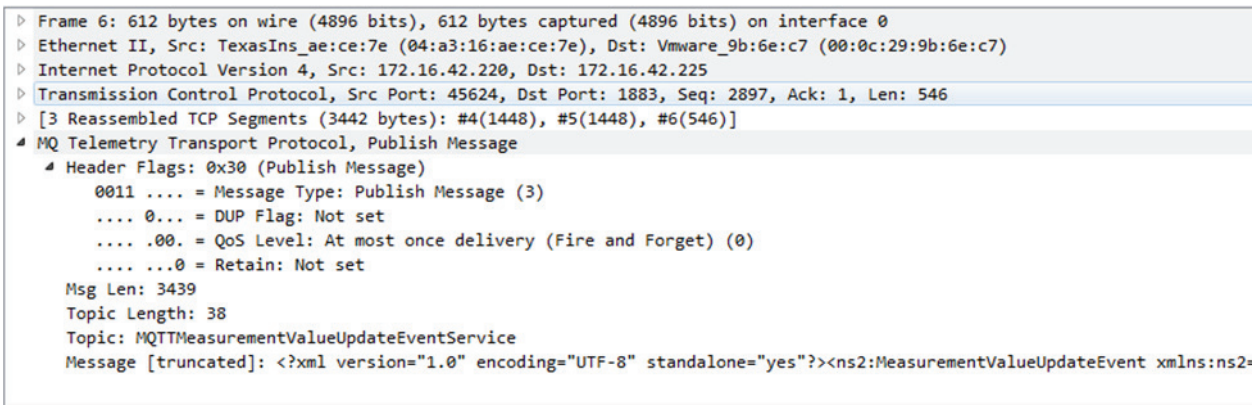


Figure 2d-3

MQTT Message Anatomy

OpenFMB Gaps:

Again, it is to be noted that the transmission of XML over the wire is verbose and needs to be re-structured into an itemized and structured dataset. Alto to be noted is that the Broker in MQTT add not only a time delay in the messaging but also adds a potential failure mode.

Recommendations:

A simple analysis of the MQTT architecture vs. the R-GOOSE architecture can be made. Using an MTBF of 30 years for the elements in an R-GOOSE and MQTT system, the MQTT architecture required 3 devices (Publisher, Subscriber, and Broker) for an overall MTBF of 10 years. The R-GOOSE system (ignoring the Ethernet switch in both cases) only has 2 elements – a Publisher and a Subscriber. The overall MTBF for this 2-element system is 15 years. The follow-up discussion must then compare the use of UDP vs. TCP. TCP will continue to re-request the transmission of a dataset for “minutes” whereas R-GOOSE does no re-request, however, R-GOOSE will re-transmit up to 4 times in a 16ms period – effectively imitating the TCP functionality. Additionally, while in “keep alive” mode, the R-GOOSE will continue to re-transmit the last changes message state – until a new change occurs. It is to be noted that although there is no “direct” acknowledgement of the receipt of an R-GOOSE message, application level messaging can be created to acknowledge the receipt of a message from any number of subscribers to the publisher.

8 Test Case 3a – Inter-network Var Control

8.1 Test Case Description – UC 3a Inter-network Var Control

UC 3a Inter-network Var Control

Objective:

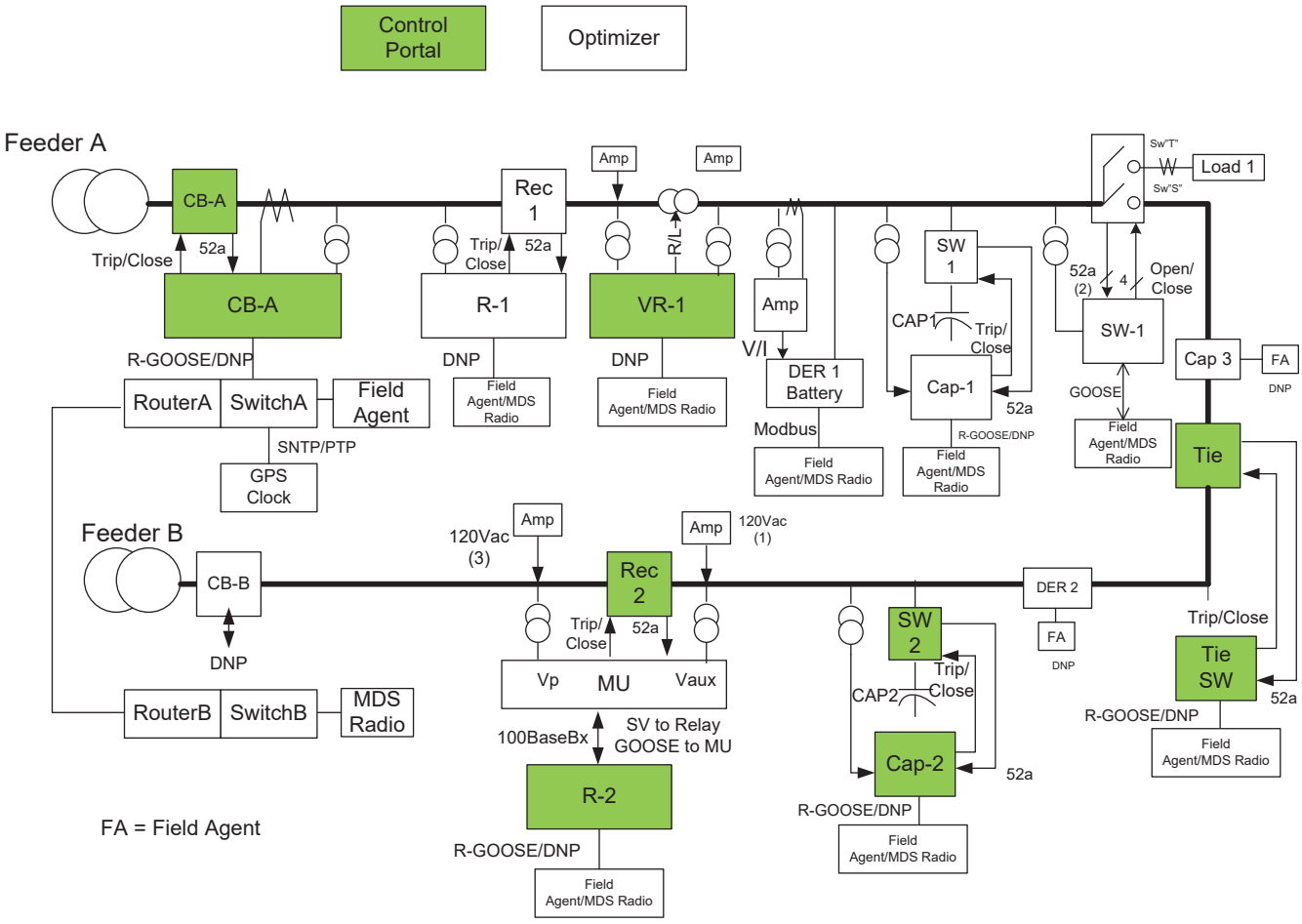
- Demonstrate Inter-network communication capability of OpenFMB

Description:

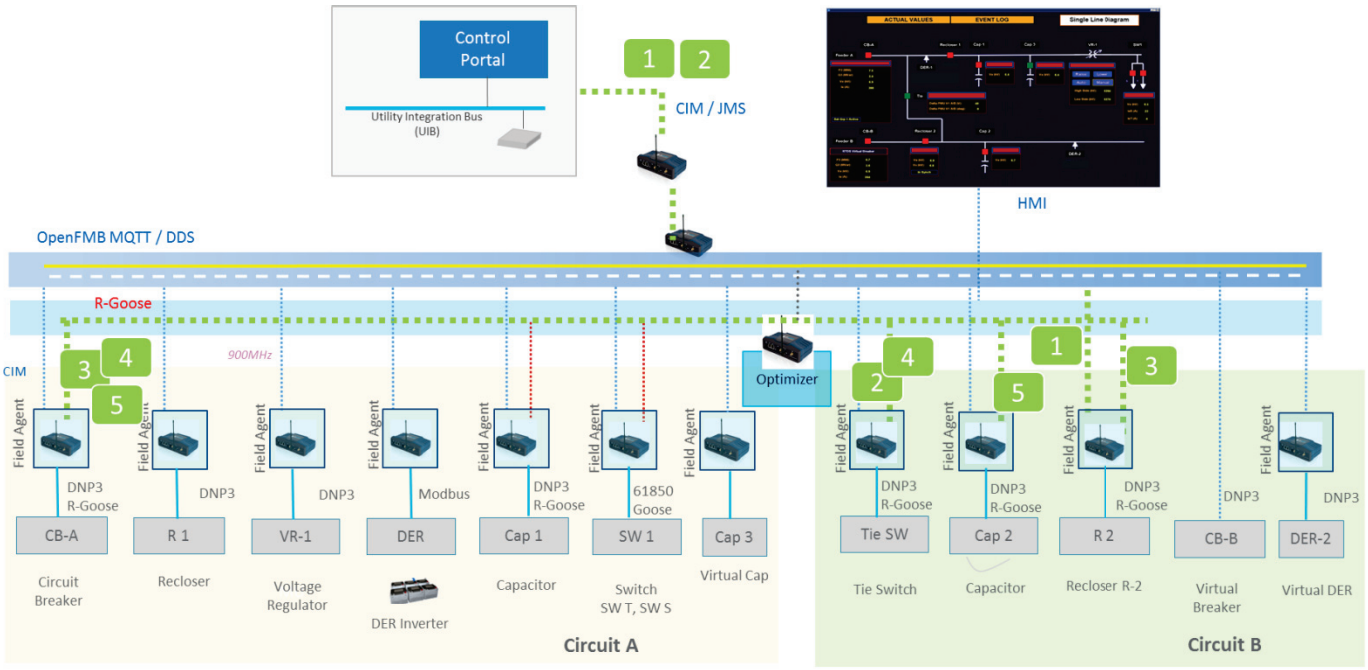
- Building on Test Case 2a, b, c, d.
- Using OpenFMB issues command from the Control Portal to open Recloser 2 R-2 and then close the TIE switch (Tie SW).
- The status of Recloser 2 and Tie Breaker are monitored by the R-2 and Tie SW relays respectively.
- This information is then sent – internetwork via R-GOOSE to CB-A.
- Var load on the feeder is then increased above the setting threshold.
- The CB-A then makes a determination to close Capacitor 2 for additional var support.
- Pre-condition: Capacitor Bank 1 is CLOSED and the Voltage Regulator (VR-1) is manual mode.
- Pre-condition: CB-B is open

8.2 Test Case Diagram – UC 3a Inter-network Var Control

Logical and IO Diagram



8.3 Test Case Diagram – UC 3a Inter-network Var Control



Data Flow	*Data Flow Summary*	*Protocol*
1.	Control Portal (CP) → OpenFMB(MQTT) → Field Agent → R-2	CP → CIM/JMS → OpenFMB(MQTT) → Field Agent (CIM) → DNP → R-2 (Open)
2.	Control Portal (CP) → OpenFMB(MQTT) → Field Agent → c	CP → CIM/JMS → OpenFMB(MQTT) → Field Agent (CIM) → DNP → Tie SW (Close)
3.	R-2 → CB-A	R-2 → R-GOOSE → CB-A (Status Change)
4.	Tie SW → CB-A	Tie SW → R-GOOSE → CB-A (Status Change)
5.	CB-A → CAP 2	CB-A → R-GOOSE → CAP 2 (Close)

8.4 Test Case Pre-Conditions – UC 3a Inter-network Var Control

Pre-Conditions	***Description***
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	Network Model with Switchable Devices (2 Circuits)
7.	Tie Switch is Open
8.	Cap 1 is Close
9.	Cap 2 is Open
10.	R-1 is Closed
11.	VR-1 is manual
12.	SW-1 is Closed (all 2 positions)
13.	Control Portal displays measurement values
14.	R-2 is Closed
15.	CB-B is Open

8.5 Test Case Test Steps – UC 3a Inter-network Var Control

Steps	***Description***	***Acceptance Criteria***	***Pass / Fail***
#	*Step Description*	*Describe Acceptance Criteria*	*Pass (P) / Fail (F)*
1.	Start Control Portal	Check the Control Portal & logs to verify the OpenFMB is up running	Pass
2.	Start Field Agents	Check the log and verity Field Agents are up running. The measurement value shall be published and have values.	P, Measurement values are displayed
3.	Control Portal - open Recloser 2 (R-2) Open Command	Recloser 2 open - status change R-2 = open	Pass
4.	Control Portal - close (TIE SW) Close Command	Tie SW Closed - status change Tie SW = close	Pass
5.	R-2 monitors device status R2 Open	R-2 Receives messages R-2 = open, Tie SW = close	Pass
6.	Tie SW monitors device status Tie SW Close	Tie SW Receives messages R-2 = open, Tie SW = close	Pass
7.	Var load on the feeder is increased above the setting threshold.	CB-A VAR load increased by simulation	3.2 MVAr to 6.3 MVAr to 5.8 MVAr
8.	CB-A Monitors network - determination to close Cap 2	CAP 2 close - Cap 2 = Close	Pass
9.	CB-A Closes Cap 2 (R-Goose)	CAP 2 close - Cap 2 = Close	Pass
10.	Control Portal Displays measurement values	CP displays measurement values	Pass

8.6 Test Case Results – UC 3a Inter-network Var Control

Operational:

In this use case, an OpenFMB command was issued from the Control Portal to open Recloser 2 and then close the TIE switch using MQTT. The var load on the feeder was then increased above the setting threshold requiring additional support from Capacitor 2.

Communication Observations:

The controls were carried via xml as mapped into a MQTT data frame. Periodically the command would fail however, all retries were successful. The reason for failure is theorized to be the traffic on the network. Specifically, on the 900 MHz network which was operating at 500bps.

OpenFMB Gaps:

The messages are large is size. A standardized binary mapping of the data items will be a requirement to review with future analysis.

Recommendations:

Increase the performance of the network by reducing packet size. Specifically, when considering operation over a radio network.

9 Test Case 3b – Peer-to-Peer Volt/Var Control

9.1 Test Case Description – UC 3b Peer-to-Peer Volt/Var Control

UC 3b Peer-to-Peer Volt/Var Control

Objective:

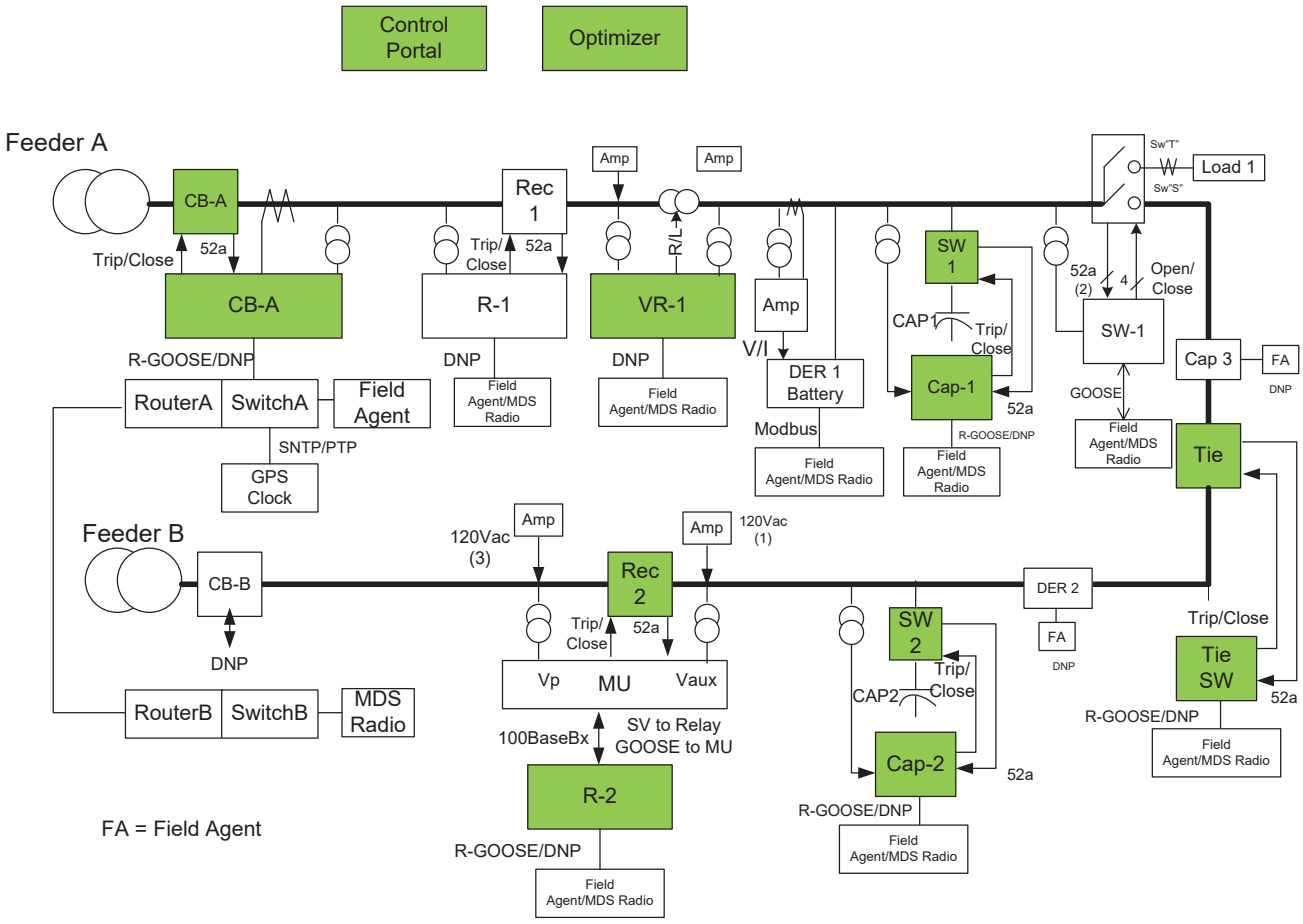
- Demonstrate Peer-to-Peer communication capability of OpenFMB to achieve progressive Var support.

Description:

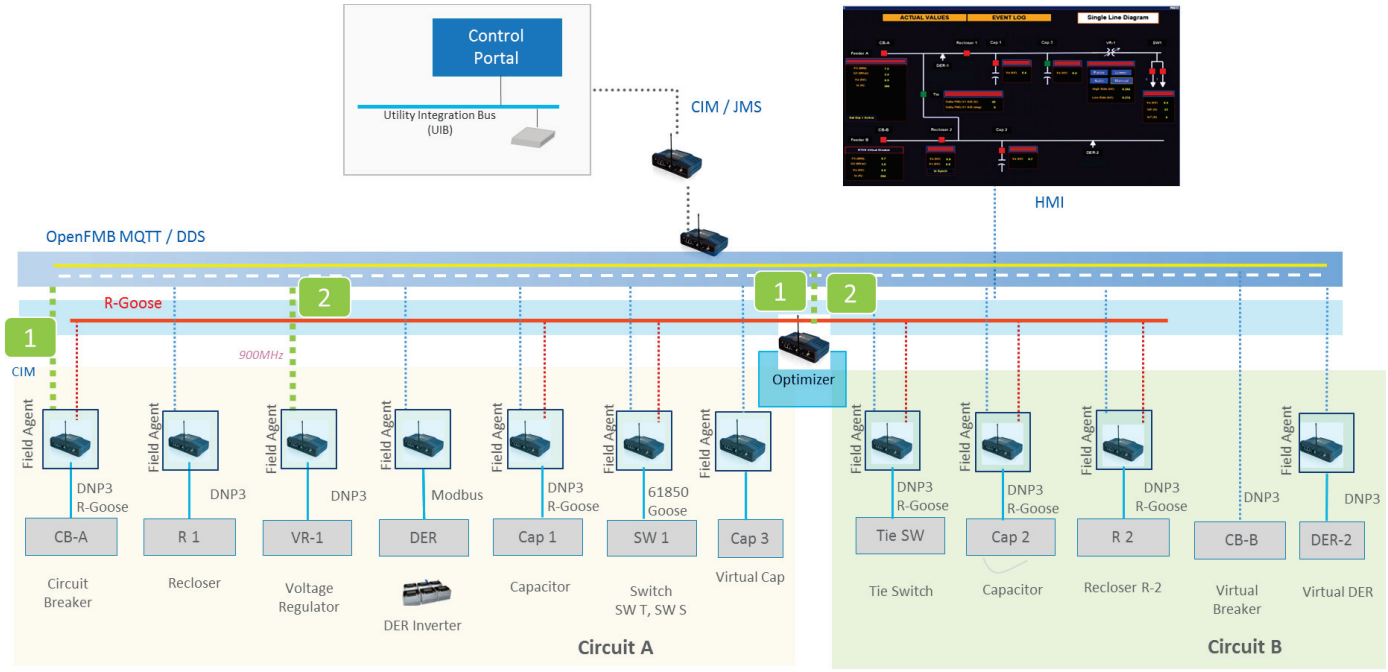
- Given that Capacitor 1 is closed AND the Tie SW is closed AND Capacitor Bank 2 is closed.
- The var load on the line is then further increased above the setting threshold.
- The CB-A then issues a signal (High Var) to the Optimizer that additional var support is needed.
- Upon receipt of a High Var message, the Optimizer will then switch the Voltage Regulator (VR-1) to manual mode.
- Pre-Condition: Voltage Regulator (VR-1) is in Auto mode

9.2 Test Case Diagram – UC 3b Peer-to-Peer Volt/Var Control

Logical and IO Diagram



9.3 Test Case Diagram – UC 3b Peer-to-Peer Volt/Var Control



Data Flow	*Data Flow Summary*	*Protocol*
1.	CB-A → Optimizer	CB-A → DNP → Field Agent (CIM) → OpenFMB(MQTT) → Optimizer
2.	Optimizer → VR-1	Optimizer → OpenFMB(MQTT) → Field Agent → DNP → VR-1 (Manual Mode)

9.4 Test Case Pre-Conditions – UC 3b Peer-to-Peer Volt/Var Control

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	RTDS is Active
7.	Network Model with Switchable Devices (2 Circuits)
8.	Tie Switch (Tie SW) is Closed
9.	Cap 1 is Close
10.	Cap 2 is Close
11.	R-1 is Closed
12.	VR-1 is Auto
13.	SW-1 is Closed
14.	Control Portal displays measurement values
15.	R-2 is Closed

9.5 Test Case Test Steps – UC 3b Peer-to-Peer Volt/Var Control

Steps	***Description***	***Acceptance Criteria***	***Pass / Fail***
#	*Step Description*	*Describe Acceptance Criteria*	*Pass (P) / Fail (F)*
1.	Var load on the feeder is increased above the setting threshold.	CB-A VAR load increased by simulation	3.2 MVAr to 4.2 MVAr
2.	CB-A Monitors network - determines Var above threshold	High Var Alarm	Pass
3.	CB-A issues a signal (High Var) to Optimizer for VAR support	CB-A sends High Var message	Pass
4.	Optimizer Receives message	High Var message received	Pass
5.	Optimizer sends command VR-1 to manual mode	VR-1 change status to Manual	Pass
6.	Control Portal Displays measurement values	CP displays measurement values	4.1 MVAr

9.6 Test Case Results – UC 3b Peer-to-Peer Volt/Var Control

Operational:

In this use case, the TIE breaker connecting Feeder A and part of Feeder B together is closed and an Over VAR threshold is exceeded at the Breaker A relay. To mitigate this situation, the Breaker A relay, having first closed Capacitor 1 on Feeder A, then proceeds to close Capacitor 2 on Feeder B using inter-network communication. Figure 3b-1 (below) shows the sequence of operation from the TIE breaker closing to the increase in VARS to Capacitor 2 closing and slightly decreasing VARS on the entire line. Note that there is a time delay between the TIE breaker closing and VARS rising. This delay is due to the fact that the relay only updates Watt and VAR calculations once every cycle as the calculation spans 1 cycle.

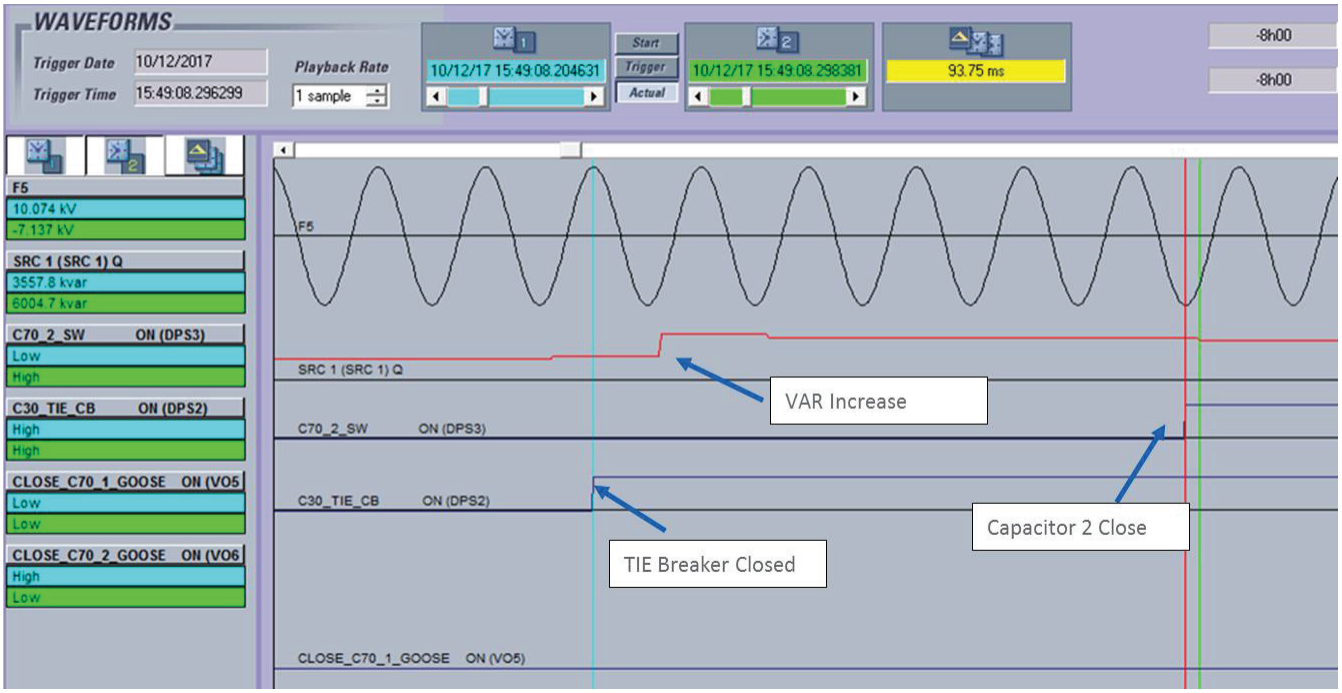


Figure 3b-1

Inter-Network VAR Control

Communication Observations:

The R-GOOSE message was used to send the CLOSE message to Capacitor 2. Of communication significance in this use case is that the message had to transit through a set of routers to get from the network for Feeder A to the network for Feeder B. The subscription for Capacitor 2 was initiated by an Internet Gateway Management Protocol (IGMP) "join" request from Capacitor 2. The request is shown in figure 3b-2 (below)

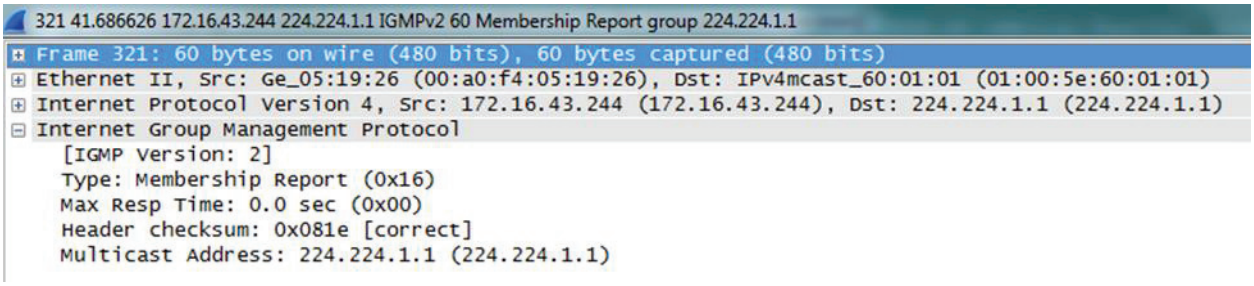


Figure 3b-2

"Join" Request from Cap Bank 2 (Network 43) Controller to the Feeder Controller (Network 42)

OpenFMB Gaps

Since MQTT uses a Broker to receive and re-transmit a message, the function of searching for a Multicast publisher is not needed, however, DDS can operate in a Multicast mode and can operate in this mode and use IGMP. Relating to Dynamic Subscription, if DDS can selectively enable and disable IGMP then a connection can be made on demand – and thus support Dynamic Subscription. In as much as MQTT is always point-to-point, routing to a new node can be accommodated as needed.

Recommendations

Do evaluate the ability of DDS to dynamically enable/disable Multicast subscription through the enabling and disabling of IGMP Join requests.

10 Test Case 4a – DER Active Power Control

10.1 Test Case Description – UC 4a DER Active Power Control

UC 4a DER Active Power Control

Objective:

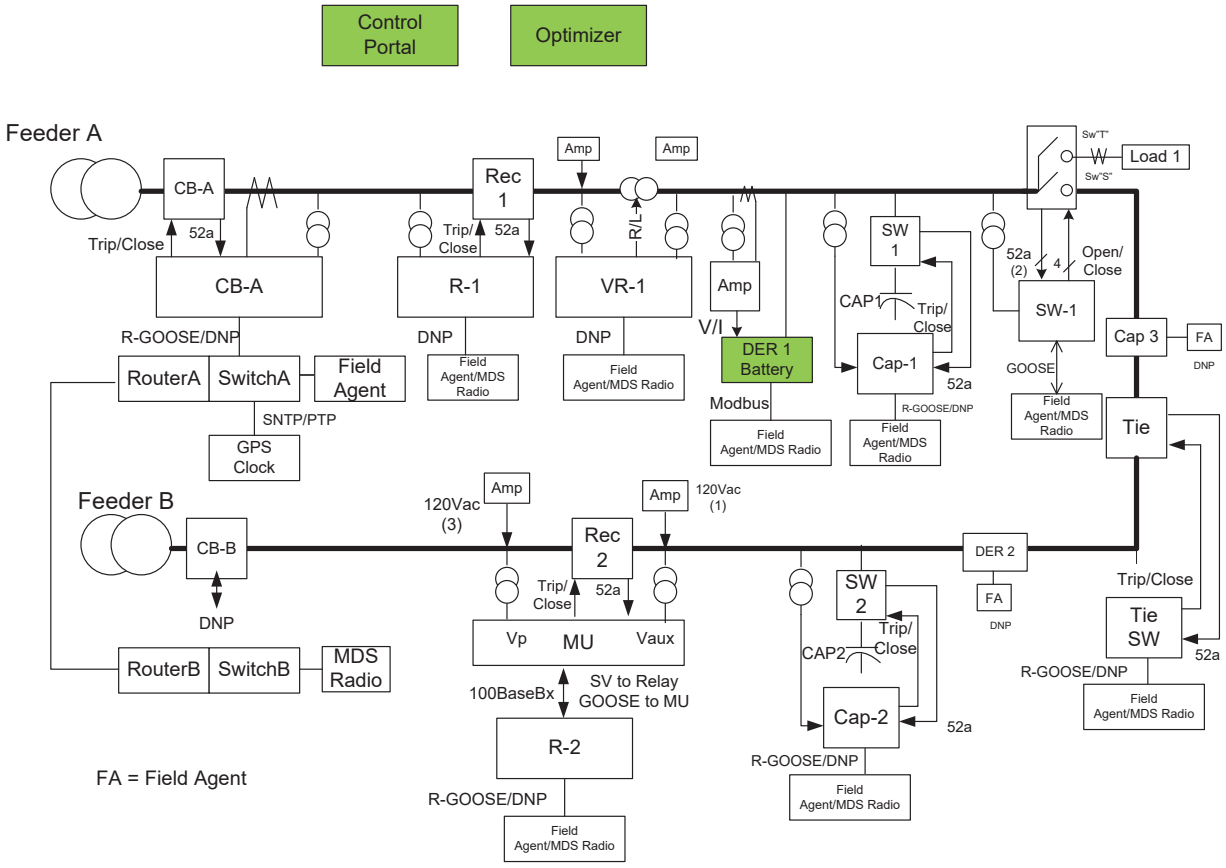
- Demonstrate the capability of OpenFMB using Modbus communication
- Demonstrate the interoperation of traditional IED's and DER using OpenFMB

Description:

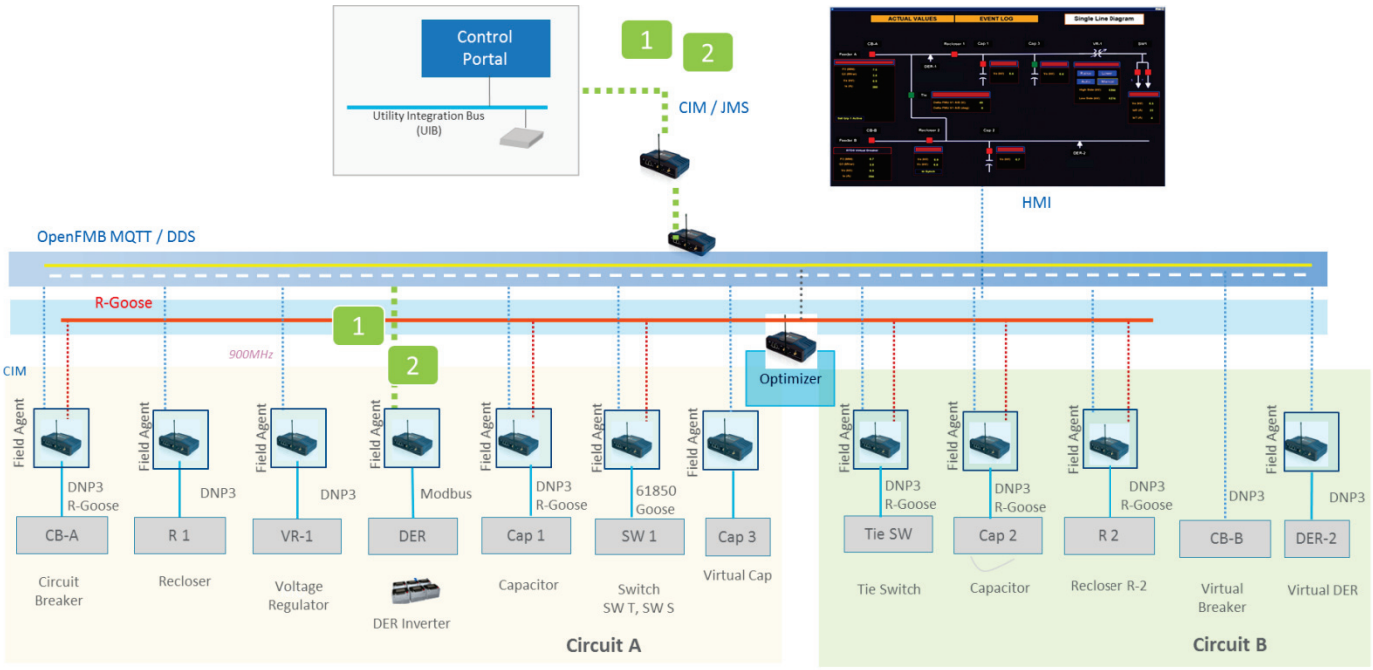
- The DER 1 inverter is to be connected into the RTDS with appropriate digital interface.
- A start command will be sent from the Control Portal to DER 1
- Operator to issue enable set point command. Enter value in the Heartbeat field
- Operator issues Real Power setpoint. Enter value in Active Power field
- Operator issues Reactive Power setpoint. Enter value in Reactive Power field
- Operator issues new High-Level Control Mode – Voltage Droop Reg. (Volts/Watts). Enter value in VoltControlMode field
- Operator issues new High Level Control Mode – Voltage Droop Reg. (Volts/Vars). Enter value in VoltControlMode field
- Test Engineer removes Ethernet connection to DER 1
- Test Engineer to re-connect Ethernet
- Operator issues reset command to DER 1 via Control Portal
- Operator to Open Breaker A and the response of the DER 1 will be recorded.

10.2 Test Case Diagram – UC 4a DER Active Power Control

Logical and IO Diagram



10.3 Test Case Diagram – UC 4a DER Active Power Control



Data Flow	*Data Flow Summary*	*Protocol*
1.	Control Portal → DER 1	Control Portal → OpenFMB(MQTT) → Field Agent → Modbus → DER 1 Inverter → Enable Start
2.	Control Portal → DER 1	Control Portal → OpenFMB(MQTT) → Field Agent → Modbus → DER 1 Inverter → Enable Joint Power/Reactive Power Set-point change
3.	Control Portal → DER 1	Control Portal → OpenFMB(MQTT) → Field Agent → Modbus → DER 1 Inverter → change Modes
4.	Control Portal → DER 1	Control Portal → OpenFMB(MQTT) → Field Agent → Modbus → DER 1 Inverter → Reset command
5.	Control Portal → DER 1	Control Portal → OpenFMB(MQTT) → Field Agent → Modbus → DER 1 Inverter → Enable Stop

10.4 Test Case Pre-Conditions – UC 4a DER Active Power Control

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	Network Model with Switchable Devices (2 Circuits)
7.	Tie Switch (TIE SW) is Open
8.	Cap 1 is Close
9.	Cap 2 is Close
10.	R-1 is Closed
11.	VR-1 is Auto
12.	SW-1 is Closed (2 positions)
13.	Control Portal displays measurement values
14.	R-2 is Closed
15.	DER inverter or Simulator has heartbeat
16.	On Power-up of the DER 1 and Field Agent, the following registers shall be WRITTEN as part of initialization via the Control Portal: 40003 – 2 – START (Enter 1 CP Switch Position) 40007 – 2 – RESET 40008 – 2 – Set Voltage Source Inverter – PQ Mode 40009 – 100 – Initial Real Power Set Point 40101 – 256 – Set for Voltage / Watt mode of operation 40010 – 50 – Initial Reactive Power Set Point

10.5 Test Case Test Steps – UC 4a DER Active Power Control (Old)

Steps	***Description***	***Acceptance Criteria***	***Pass / Fail***
#	*Step Description*	*Describe Acceptance Criteria*	*Pass (P) / Fail (F)*
1.	Start Control Portal	Check the Control Portal & logs to verify the OpenFMB is up running	P
2.	Start Field Agents	Check the log and verity Field Agents are up running. The measurement value shall be published and have values.	P Measurement values are displayed
3.	Operator issues start command via Control Portal Enter 1 in Switch Position field	Verify the DER 1 is On-Line by looking at status on DER 1 HMI Capture Wire Shark	P, PCAP: Use Case 4a DER On
4.	Operator to issue enable set point command. Enter 96 in the Heartbeat field	Verify settings change on DER 1 HMI	F, Heartbeat value of 96 mapped to PQControlMode 96. Use Case 4a Set Heartbeat 96 Fail. Nothing changed on DER HMI.
5.	Operator issues Real Power setpoint (12kW) Enter 12 in Active Power field	Verify Real Power setpoint on DER 1 HMI is changed to 12 Capture Wire Shark Observe new power flow in RSCAD	P, Use Case 4a Set Point Power 12
6.	Operator issues Reactive Power setpoint (5kVAR) Enter 5 in Reactive Power field	Verify Reactive Power setpoint on DER 1 HMI is changed to 5 Capture Wire Shark	P, Use Case 4a Change VARS 5

Steps	*Description*	*Acceptance Criteria*	*Pass / Fail*
7.	Operator issues new High Level Control Mode – Voltage Droop Reg. (Volts/Watts) Enter 256 in VoltControlMode field	On DER 1 HMI verify Voltage Droop Reg. (Volts/Watts) Status is On Capture Wire Shark	F, VoltControlMode value 256 mapped to PQControlMode field on the Control Portal. Use Case 4a Set Volts-Watts 256; Use Case 4a Set Volts-Watts 256 Fail. Nothing changed on the DER HMI.
8.	Operator issues new High Level Control Mode – Voltage Droop Reg. (Volts/Vars) Enter 192 in VoltControlMode field	On DER 1 HMI verify Voltage Droop Reg. (Volts/Vars) Status is On Capture Wire Shark	F, VoltControlMode value 192 was mapped to PQControlMode field on the Control Portal. Use Case 4a Set Volts-VAR Fail. Nothing changed on the DER HMI.
9.	Test Engineer removes Ethernet connection to DER 1	Verify communication loss error on DER 1 UI	Inconclusive. Since we can't set PQ Enabled cannot determine loss of communications.
10.	Test Engineer to re-connect Ethernet	Re-connection established	P
11.	Operator issues reset command to DER 1 (40007-2) via Control Portal	Verify communication loss error reset	N/A
12.	Operator to Open Breaker A	DER 1 response is recorded via Oscillography	P, Stop Watch timing = 1 second. Wire Shark: Use Case 4a Trip Breaker A. Oscillography: Use Case 4a Trip Breaker A.cfg

10.6 Test Case Results – UC 4a DER Active Power Control

Operational:

In Use Case 4, an OpenFMB adapter was used to interface with a Modbus-based DCS on a Distributed Energy Device. The Edge Device – upon receiving an OpenFMB request – issued the equivalent Modbus READ message. An example of a Modbus Read is shown in figure 4a-1 (below).

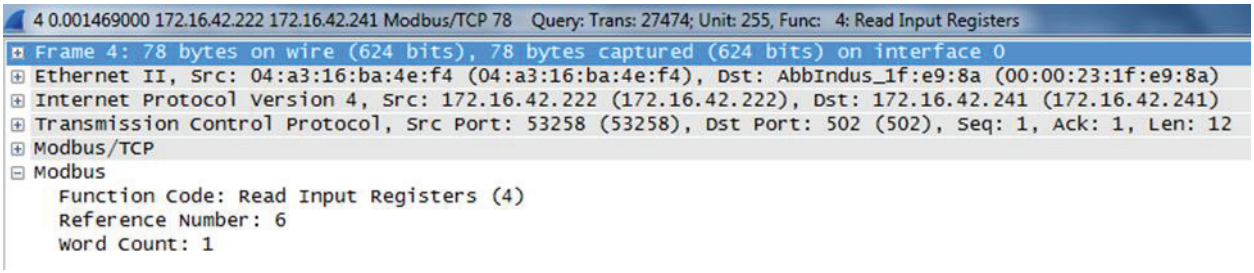


Figure 4a-1

DCS Register 40007 READ Command

One of the Use Case tests was to write a VAR set-point. Figure 4a-2 (below) is the Modbus Write to the VAR Set-Point register (40010). From the figure, one can see the value of 5kVAR being written into this register.

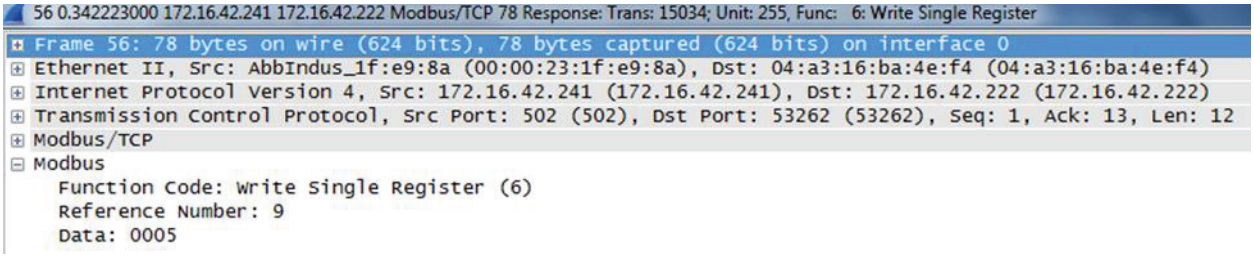


Figure 4a-2

Value Being Written into the VAR Set-Point Register

The MQTT message is encoded in XML and was captured in the related WireShark trace.

The ability to Write and Read the Watt and Var setpoints was demonstrated. The DER required a Heartbeat signal (a register write every 1 second). The Heartbeat was established through a Rule in the Optimizer. Due to the inability of the Control Portal to write to certain registers (PQ Mode and Volt/Watt-Volt/Var Mode), testing was never able to verify the efficacy of the Heartbeat. In addition, it was found that writing to one register in the Control Portal would result in the value showing up on another register (see Test results for exact behavior).

Communication Observations:

Overall Read/Write performance to the DER Edge was fast – on the order of 1 second which is quite adequate for a HMI response time. Of note, MOST DER devices (specifically, Solar inverters) presently

use Modbus for device interface. The functionality of this edge protocol is important for inter-action with future DER devices

OpenFMB Gaps:

No OpenFMB gaps were identified in this use case.

Recommendations:

The Modbus registers required for interaction with the DER were mapped through the Control Portal and into the Edge Devices and only the programmed registers were accessible. It would be very desirable to have a “generic” Modbus interface such that any register address could be entered into the on-line system in order to peek and poke values into other useful Modbus registers.

11 Test Case 5a – DER on Line / off-line

11.1 Test Case Description – UC 5a DER on Line / off-line

UC 5a DER on Line / off-line

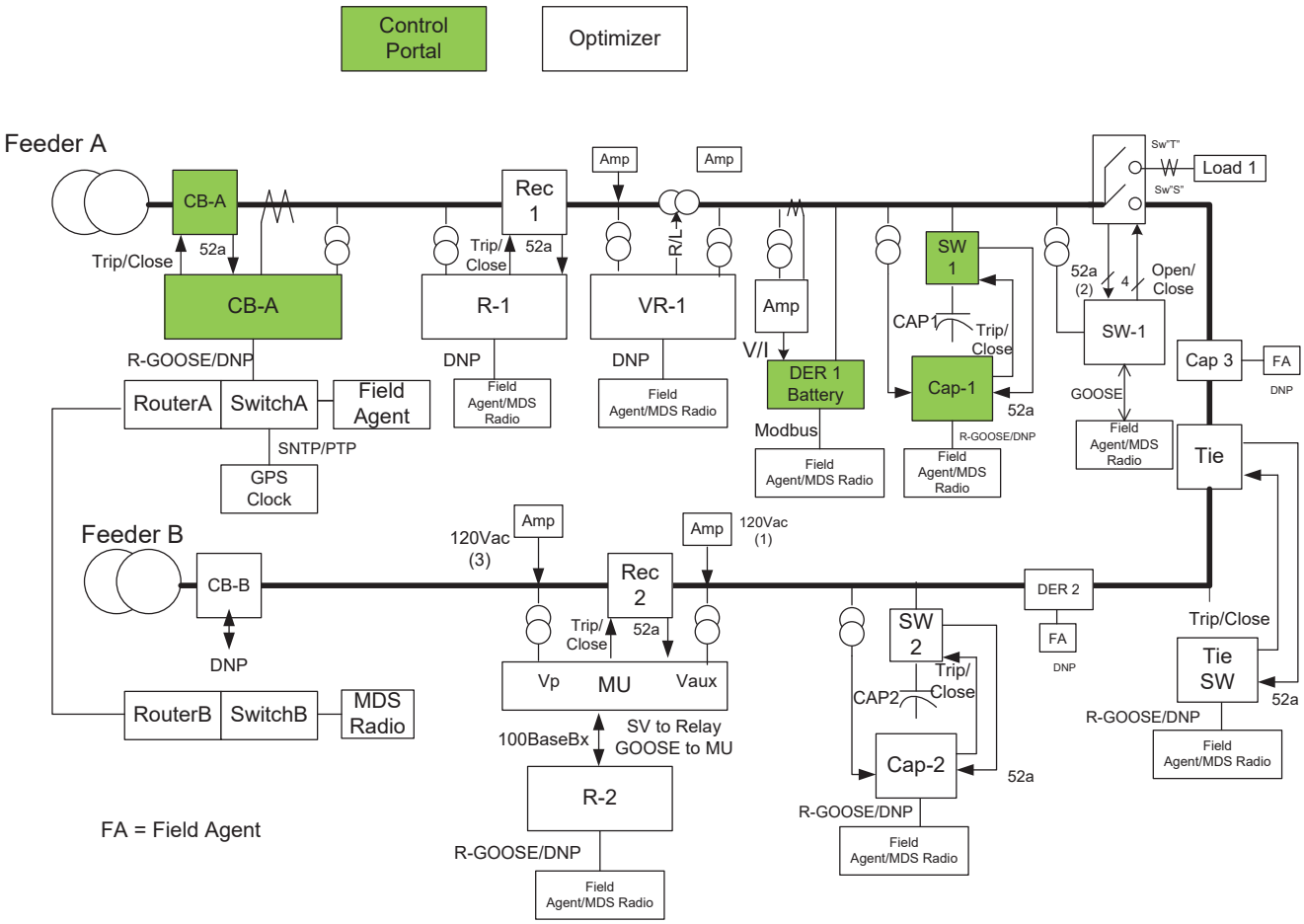
Objective:

- Demonstrate use of R-Goose to improve system performance by communicating breaker status to DER 1 and thereby over-riding autonomous DER control functions.

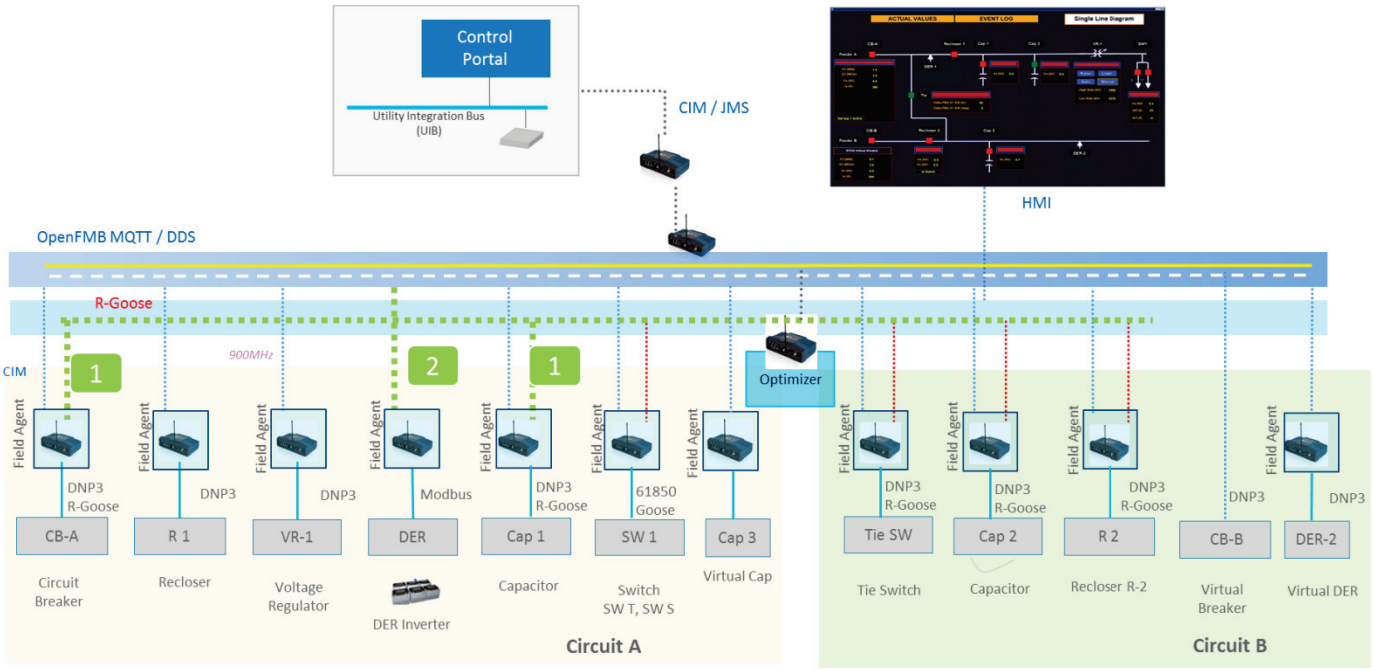
Description:

- To demonstrate enhanced DER 1 on-line/off-line via peer to peer
- Pushbutton on CB-A opens CB-A
- Upon detection of Breaker A open, CB-A sends a command to CAP 1.
- CAP 1 operates an output contact to take the DER 1 off-line
- Note: Present implementation of OpenFMB operates at speeds slower than the present disconnect speed of the DER 1.

11.2 Test Case Diagram – UC 5a DER on Line / off-line



11.3 Test Case Diagram – UC 5a DER on Line / off-line



Data Flow	*Data Flow Summary*	*Protocol*
1.	CB-A → CAP 1 → DER 1 Inverter	CB-A → R-GOOSE → CAP 1 → Contact Output → DER 1 Inverter

11.4 Test Case Pre-Conditions – UC 5a DER on Line / off-line

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	Network Model with Switchable Devices (2 Circuits)
7.	Tie Switch (TIE SW) is Open
8.	Cap 1 is Close
9.	Cap 2 is Close
10.	R-1 is Closed
11.	VR-1 is Auto
12.	SW-1 is Closed (2 positions)
13.	Control Portal displays measurement values
14.	R-2 is Closed
15.	DER inverter or Simulator has heartbeat with RTDS with appropriate amplifier
16.	CB-A is Closed
17.	DER inverter set to maximum zero voltage ride thru

11.5 Test Case Test Steps – UC 5a DER on Line / off-line

Steps	***Description***	***Acceptance Criteria***	***Pass / Fail***
#	*Step Description*	*Describe Acceptance Criteria*	*Pass (P) / Fail (F)*
1.	Pushbutton on CB-A to open CB-A	Pushbutton command to open CB-A	P; Use Case 5a RGOOSE Trip of DER
2.	CB-A De-Energizes Feeder A	Feeder CB-A De-energized - Load side measurement values = zero	P
3.	Upon detection of Breaker A open, CB-A sends a command to CAP 1.	CB-A Sends a command to CAP 1	P
4.	CAP 1 operates an output contact to take the DER off-line	CAP 1 Output Contact operates	P
5.	DER 1 operates and goes off line	DER 1 disconnects from Grid	P

11.6 Test Case Results – UC 5a DER on Line / off-line

Operational:

In this use-case, when a Breaker A OPEN condition was detected, an R-GOOSE message was sent from the Feeder A relay to the Capacitor 1 Controller (which, for this test, was assumed to be in the same location as the DER). An Output Contact from the Capacitor 1 Controller was connected to the TRIP input of the DER. Figure 5a-1 shows the oscillography from the capacitor controller (nearby monitoring device). It can be seen in figure 5a-1 that the DER, upon detection of loss of voltage, instantly goes into shut-down. What can also be seen is that the STOP command was issued in 10 ms after Breaker A was opened.

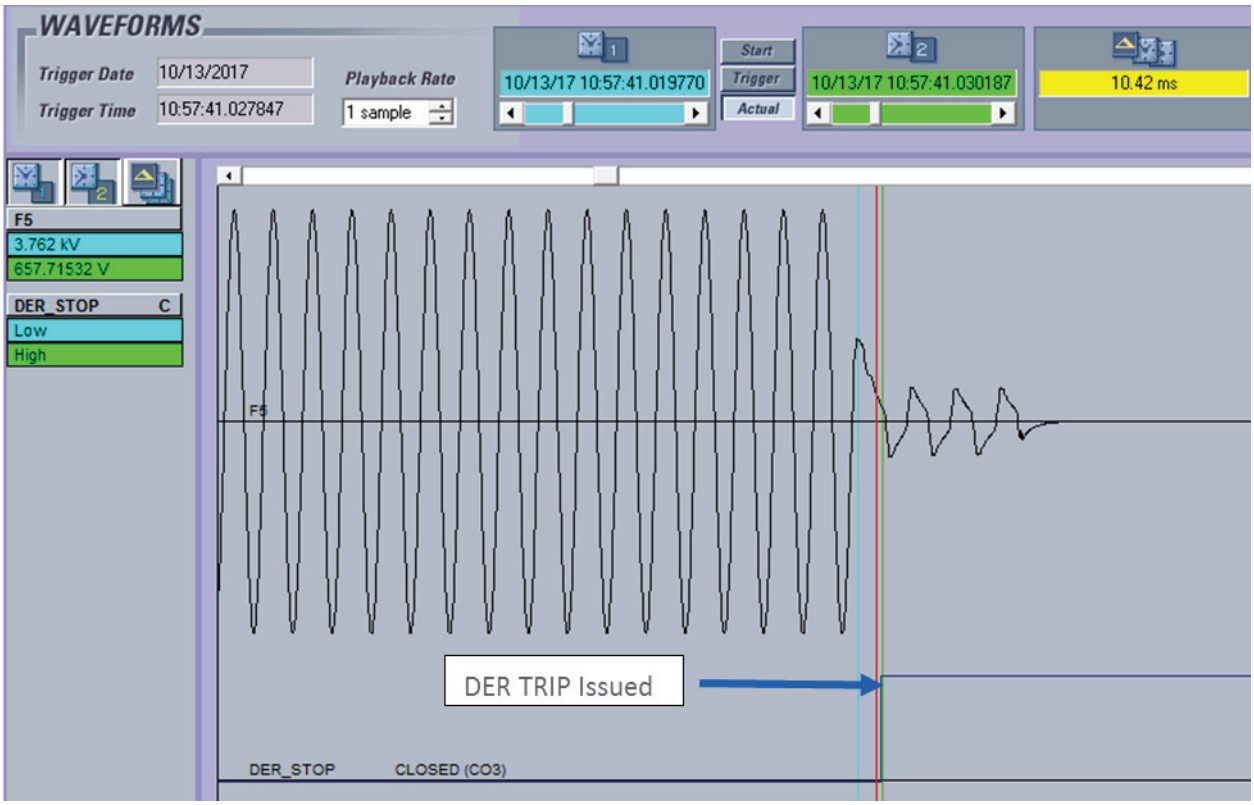


Figure 5a-1

DER Turn-off after Breaker A Open

Communication Observations:

The performance of the R-GOOSE message to trip the DER is quite notable – given that communications was through a pair of radios. Subtracting the 3ms operate time of the output contact, the TRIP input to the DER was transmitted from the Feeder Relay to the Capacitor Relay in 7ms.

OpenFMB Gaps:

For this project, the OpenFMB interface to the Edge device was through a Field Agent / Protocol Translator. When operating in this mode, the translation and encoding process increased the latency of the message to slightly over 1 second. When operating in protection control modes (e.g. – taking the DER off-line), this latency often exceeds the required performance limits. In the case of a DER, given that there is mandated ride-through time of 200ms (typical) of the inverters on the grid, it is then desirable to be able to force a DER off-line in the 1 to 2 cycle range. To achieve this goal, imbedded OpenFMB implementations will be required.

Recommendations:

Embedded OpenFMB implementations with sub-cycle performance are required for protection-based device-to-device communications. It is to be noted that the broker in the MQTT solution, even if embedded, would double the performance delay. Such applications may be better suited for the application of DDS which does not have to operate with a broker.

12 Test Case 6a – Enhanced Automatic Feeder re-deployment

12.1 Test Case Description – UC 6a Enhanced Automatic Feeder re-deployment

UC 6a Enhanced Automatic Feeder re-deployment

Objective:

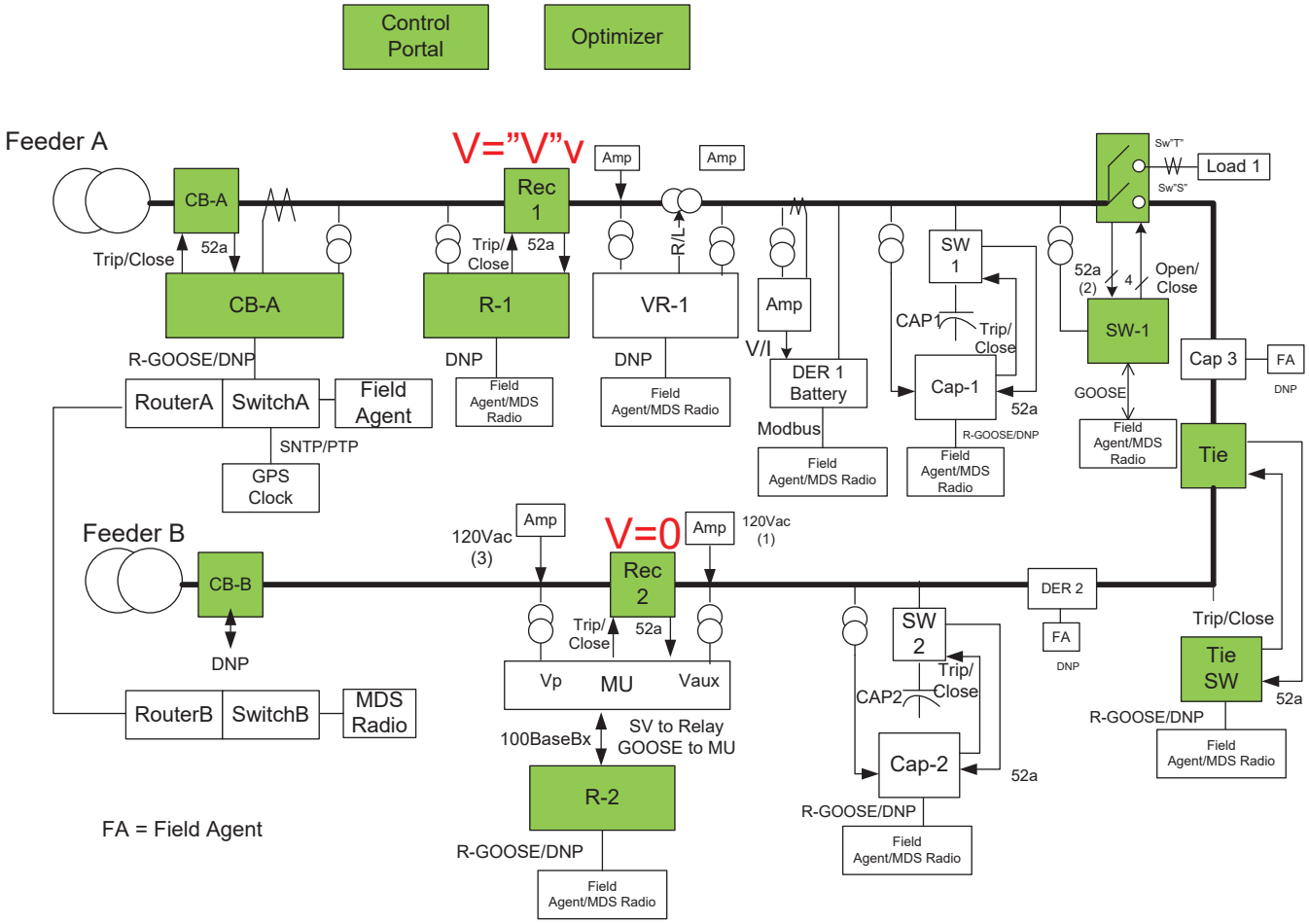
- Demonstrate the mapping of data from GOOSE messages into OpenFMB as well as complex inter-device communication.

Description:

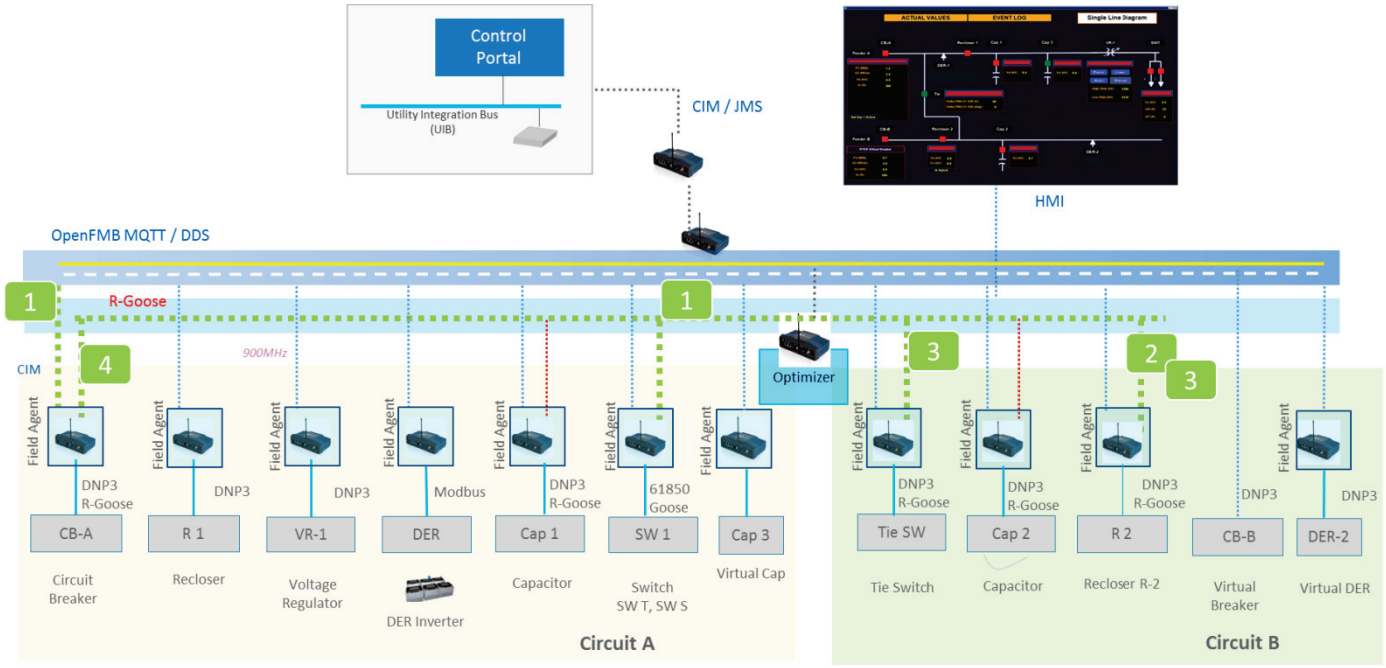
- *Healthy Feeder:*
  - If voltage on the breaker side of Recloser 2 is zero
  - AND there is voltage on Recloser 1 (PT to be located on the Line side of breaker A)
  - AND the feeder is configured for automatic re-deployment (Auto-reconfiguration Push-button on CB-A set to ENABLE)
  - AND the Feeder current (check on Phase A only) is BELOW the re-deployment threshold, the Healthy Feeder A Voltage status bit is set
- *Load Shed:*
  - If voltage on the Breaker side of Recloser 2 is zero
  - AND there is voltage on Recloser 1 AND the feeder is configured for automatic re-deployment (Auto-reconfiguration Push-button on CB-A set to ENABLE)
  - AND the Feeder current (check on Phase A only) is ABOVE the re-deployment threshold, the status bit "Load Shed" (DNP mapped point) is set.
- Message:
  - *If the "Load Shed" DNP point from CB-A is set, an OPEN command is to be sent, via OpenFMB, to OPEN Switch "T" on SW-1 to shed load on the feeder.*
  - *The R-2 on Recloser 2, upon receipt of the "Healthy Feeder A Voltage" status then sends a TRIP command to open Recloser 2*
  - R-2 THEN sends a command to Close the Tie SW – effectively back-feeding the second segment of Feeder B.
  - The CB-A, upon detection of the Tie SW being closed, will change setting groups to Group 2.
- Note: Healthy Feeder A Voltage status is NOT set if the Phase A current is above a user-specified level. A Load needs to be modeled on Switch T; connection to the Tie SW is to be connected to Switch "S"

12.2 Test Case Diagram – UC 6a Enhanced Automatic Feeder re-deployment

Logical and IO Diagram



12.3 Test Case Diagram – UC 6a Enhanced Automatic Feeder re-deployment



Data Flow	*Data Flow Summary*	*Protocol*
1.	CB-B → Open Breaker→ R-2	CB-B → Open Breaker, R-2 voltage = 0
2.	CB-A → R-Goose → R-2 → Healthy Feeder message	CB-A → R-Goose → R-2 → Healthy Feeder Message →Trip Open R-2
3.	R-2 → close Tie SW	R-2 → R-GOOSE → Tie SW
4.	CB-A → OpenFMB → SW-1	CB-A → *"Load Shed"* Open SW T Command (DNP) → OpenFMB (MQTT → Field Agent → OPC UA →61850 Goose message → SW-1 "Open Switch T"
5.	CB-A → Healthy Feeder message → close Tie SW → energize Feeder A	CB-A → R-GOOSE → Tie SW → energize Feeder A
6.	CB-A → change setting group	CB-A → change setting group to 2

12.4 Test Case Pre-Conditions – UC 6a Enhanced Automatic Feeder re-deployment

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	Network Model with Switchable Devices (2 Circuits)
7.	Tie Switch (TIE SW) is Open
8.	Cap 1 is Open or Closed
9.	Cap 2 is Open or Closed
10.	R-1 is Closed with Voltage > 0
11.	VR-1 is Auto
12.	SW-1 is Closed (S Switch & T Switch)
13.	Control Portal displays measurement values
14.	CB-B is Closed
15.	CB-A is Closed with Auto Re-deployment enabled
16.	Test Engineer to enable the CB-A Auto Re-deployment
17.	CB-A set over current threshold value IA = X (400 amps)
18.	Var Per Unit Condition = 2.5 MVAR; PU setting = 0.39 = 3.37 MVAR
19.	Voltage “OK” value = 0.9 PU

12.5 Test Case Test Steps – UC 6a Enhanced Automatic Feeder re-deployment

Steps	***Description***	***Acceptance Criteria***	***Pass / Fail***
#	*Step Description*	*Describe Acceptance Criteria*	*Pass (P) / Fail (F)*
1.	Start Control Portal	Check the Control Portal & logs to verify the OpenFMB is up running	P
2.	Start Field Agents	Check the log and verity Field Agents are up running. The measurement value shall be published and have values.	P Measurement values are displayed
3.	**"Healthy Feeder" UC 6a-1**		
4.	Test Engineer trips CB-B from HMI Note: CB-A Auto Re-Configuration Enabled Amplifiers turned on	Verify on HMI that CB-B is Open. Verify R-2 high side voltage = 0, voltage on Recloser 1 > 0	P CB-A = 252a increased to CB-A = 320a
5.	CB-A Phase A Current ≤ Threshold then the Healthy Circuit status issued	CB-A Current ≤ Threshold = Healthy Feeder	P
6.	CB-A Circuit A reconfiguration	Observe circuit reconfiguration CB-A Closes the Tie SW. Circuit re-configuration from CB-A to R-2.	P Screen Shot to be attached (Word document
7.	**"Load Shed" UC 6a-2**		
8.	Test Engineer trips CB-B from HMI Note: CB-A Auto Re-Configuration Enabled Amplifiers turned on	Verify on HMI that CB-B is Open. Verify R-2 high side voltage = 0, voltage on Recloser 1 > 0	P
9.	CB-A Phase A Current > Threshold then the "Load Shed status issued	CB-A Phase A Current ≥ Threshold = "Load Shed" Feeder A status	P
10.	CB-A sends "Load Shed" DNP point via OpenFMB to OPC UA (UAP) to SW-1 (T)	CB-A sends "Load Shed" → OPC UA (UAP) to SW-1 (T)	Fail OPC- UA issue
11.	CB-A Phase A Voltage ≤ Threshold then the Healthy Circuit status issued	CB-A Current ≤ Threshold = Healthy Feeder	Fail OPC- UA issue
12.	CB-A Circuit A reconfiguration	Observe circuit reconfiguration CB-A Closes the Tie SW	Fail OPC- UA issue
13.	CB-A detects Tie SW closed, change setting group	CB-A Changes Settings Group from 1 to 2. Observe setting group in actual values in CB-A.	Fail OPC- UA issue

12.6 Test Case Results – UC 6a Enhanced Automatic Feeder re-deployment

Operational:

In this use case, when the conditions for Feeder Re-deployment are met (Feeder 1 has voltage, load is low, and Recloser 2 has no voltage on the Breaker side), the feeder A IED sends a message to Recloser 2 – telling it to OPEN. Once OPEN, Recloser 2 then sends a message to the TIE Breaker controller to CLOSE the TIE. The WireShark capture (figure 6a-1) shows the FIRST in the sequence of R-GOOSE Transmissions that sets the "OK to Re-deploy" bit to "1" – which is subscribed-to by Recloser 2. Subsequently, Recloser 2 opens and then sends the CLOSE message to the TIE breaker controller. The expanded HMI screen in Figure 8 shows the state of the model system after these transactions. Of note, the Feeder A relay was re-configured to Setting Group 2 (because of the feeder re-configuration), the TIE breaker is CLOSED, and Recloser 2 is OPEN. Also, to be noted, is that the Voltage on the Breaker side of Recloser 2 is observed to be "0".

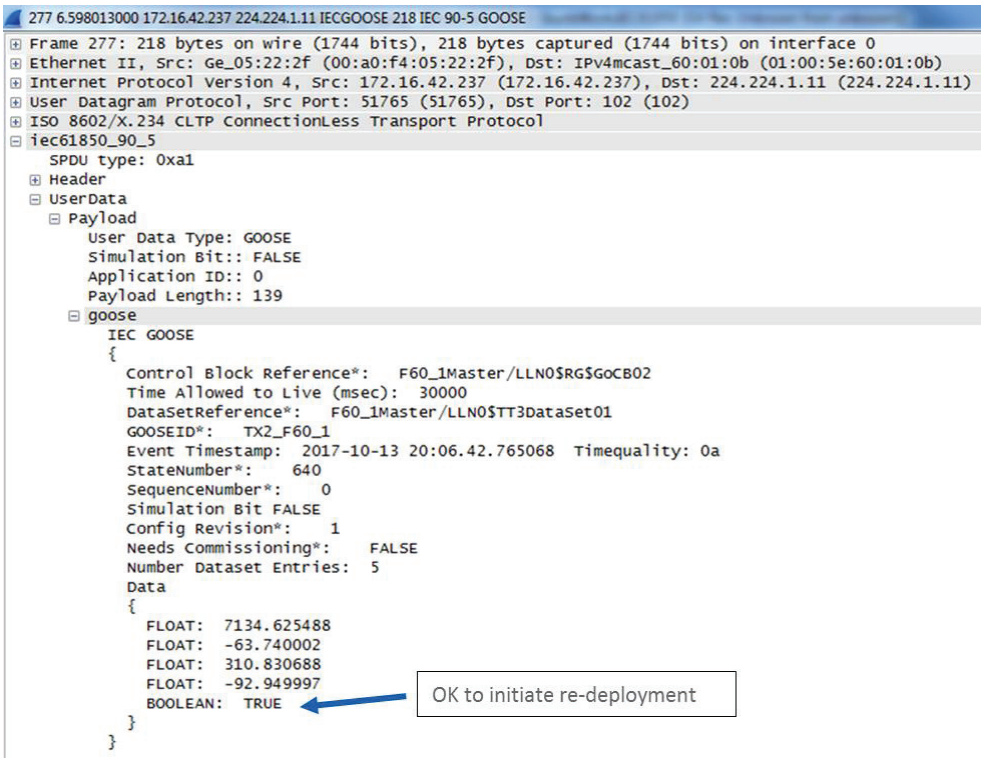


Figure 6a-1

"OK to Re-deploy" Message

The timing of the feeder re-deployment can be seen is figure 6a-2 (below). The time from loss of voltage (as detected by Recloser 2) and the remainder of the feeder being re-energized can be seen to be 245ms – less than ¼ of a second. It should also be noted that this use case requires inter-network communication.

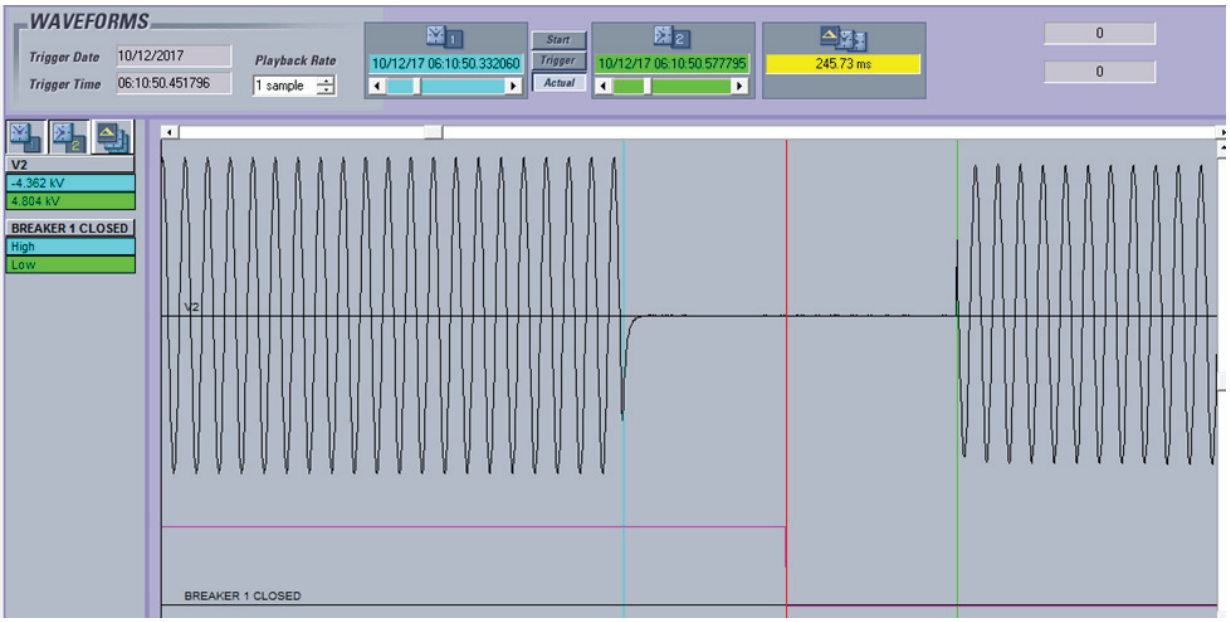


Figure 6a-2

Feeder Re-Energization Timing

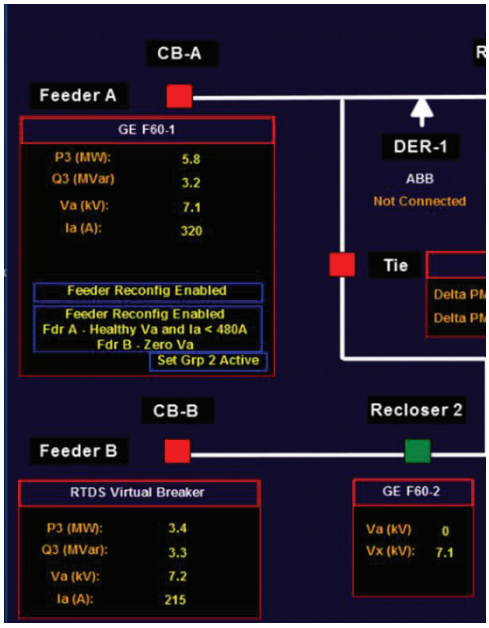


Figure 6a-3 Expanded HMI view after Feeder Re-deployment

In the re-run of Use Case 6a, the load on Feeder is increased and so the Feeder A relay sends an OpenFMB message to the Feeder Switch to Shed Load. In as much as the OPC-UA interface could not be implemented, the load was not shed, however, we note that the "OK to Re-deploy" bit from the Feeder A relay stays "FALSE" (figure 6a-4) below.

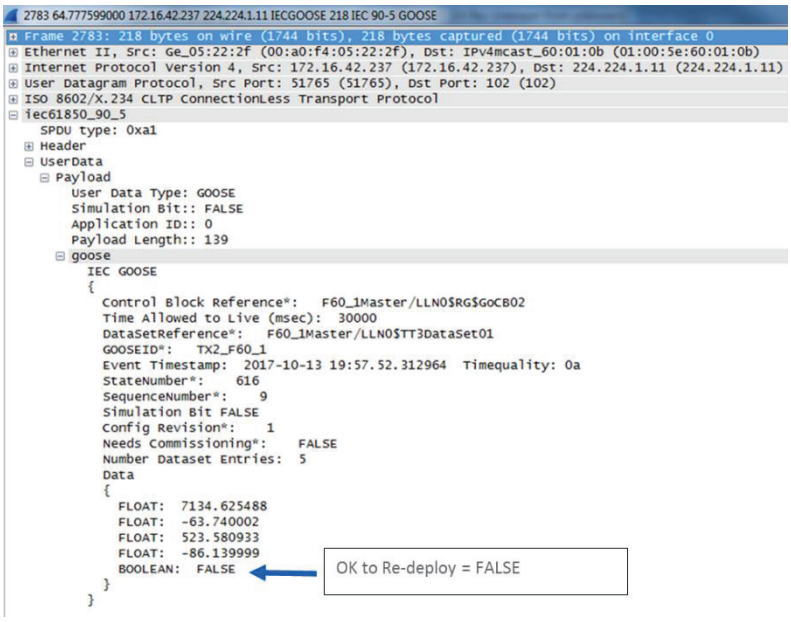


Figure 6a.4

NOT OK to Re-deploy

Communication Observations:

Device publication of GOOSE messages and the reception of these messages by 3rd party SW worked well, however, connection between the 3rd part SW and the Edge device via OP-UA proved problematic. To facilitate connection in the future, establishment of OPC-UA inter-operability test suites between clients and servers is recommended. Additionally, clear visibility into the plethora of configuration parameters and diagnostics to identify mis-matches between parameters should be developed. It is to be noted that WireShark does decode OPC-UA messages but does not provide mis-match analysis.

OpenFMB Gaps:

The gaps identified in this use-case are not OpenFMB related but more related to the need for tools to facilitate the interface between edge devices when performing protocol translation (see comments on Communication above).

Recommendations:

Better OPC-UA inter-operability tools to facilitate test and de-bug of OPC-UA interfaces are needed. A direct GOOSE to OpenFMB adapter is needed.

13 Test Case 7a – Automatic Feeder Re-Close

13.1 Test Case Description – UC 7a Automatic Feeder Re-Close

UC 7a Automatic Feeder Re-Close

Objective:

- Demonstration circuit re-configuration back to normal operating condition

Description:

- Precondition: Breaker B is Open and Recloser 2 is Open.

UC 7a -1 Inside the Limit

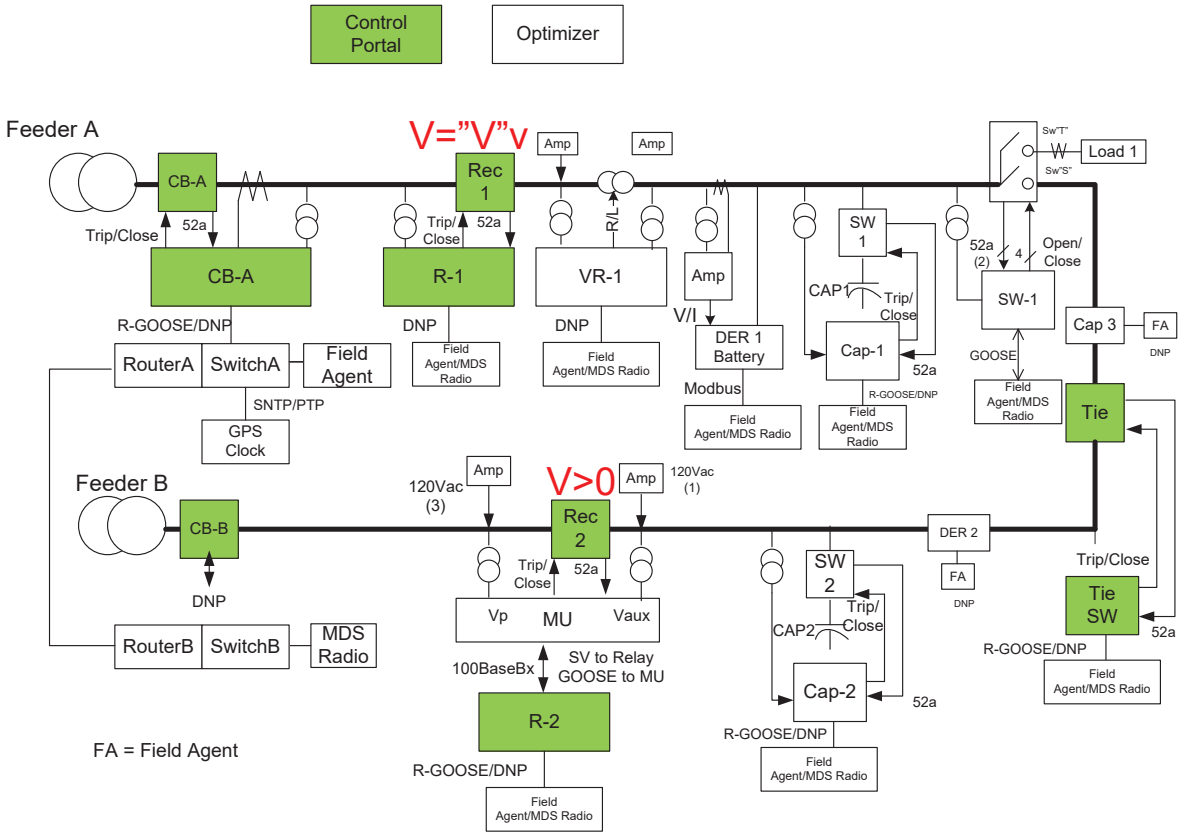
- Breaker B is then closed by RTDS / HMI – placing Voltage on the Breaker side of Recloser 2.
- Voltage is detected on both sides of the R-2 and the phase angle of the voltage across the recloser is less than 30 degrees (as measured by R-2)
- THEN reclose R-2 and Open the Tie SW from R-2.
- The CB-A identifies that the Tie SW is now open and changes back to the setting group 1.

UC 7a -2 Outside the Limit

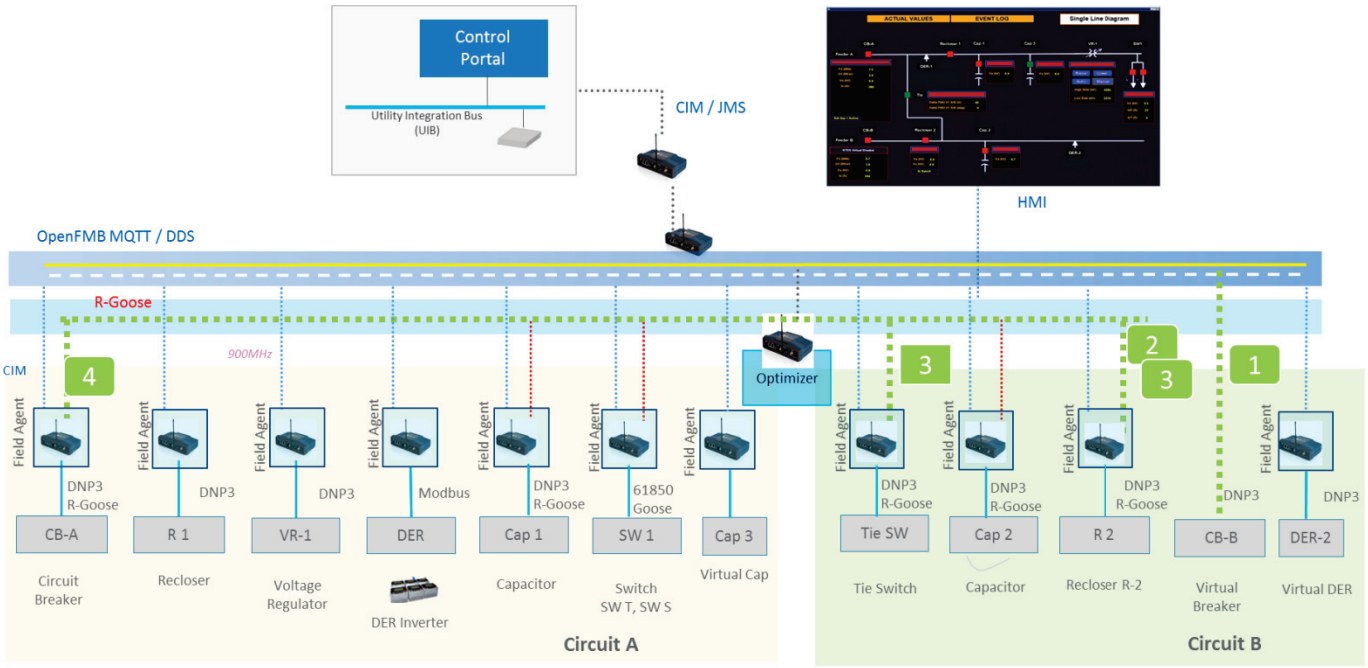
- Breaker B is then closed by RTDS / HMI – placing Voltage on the Breaker side of Recloser 2.
- Voltage is detected on both sides of the R-2 and the phase angle of the voltage across the recloser is = 45 degrees
- Tie SW - measure phase Angle (RTDS observes phase angle) Verify Sync check.
- Recloser 2 (R-2) status fails to close

13.2 Test Case Diagram – UC 7a Automatic Feeder Re-Close

Logical and IO Diagram



13.3 Test Case Diagram – UC 7a Automatic Feeder Re-Close



Data Flow	*Data Flow Summary*	*Sequence*
1.	RTDS Close CB-B	CB-B → Closed
2.	R-2 → Voltage ≥ 0 → Phase Angle ≤ 30 degree	R-2 → Voltage ≥ 0, Angle ≤ 30-degree Message R-GOOSE → Close R-2
3.	R-2 → Open Tie SW	R-2 → R-GOOSE → Tie SW
4.	CB-A → Feeder A (normal) → change setting group	Tie SW → R-Goose → CB-A → change setting group to 1
5.	R-2 → Voltage ≥ 0 → Phase Angle = 45 degrees	R-2 → Voltage ≥ 0, Angle = 45-degree → Fails to Close R-2

13.4 Test Case Pre-Conditions – UC 7a Automatic Feeder Re-Close

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	Network Model with Switchable Devices (2 Circuits)
7.	Tie Switch (TIE SW) is Closed
8.	Cap 1 is Open or Closed
9.	Cap 2 is Open or Closed
10.	R-1 is Closed
11.	VR-1 is Auto
12.	SW-1 is Closed (2 positions)
13.	Control Portal displays measurement values
14.	R-2 is Open
15.	CB B is Open
16.	CB A is Closed

13.5 Test Case Test Steps – UC 7a Automatic Feeder Re-Close

Steps	*Description*	*Acceptance Criteria*	*Pass / Fail*
#	*Step Description*	*Describe Acceptance Criteria*	*Pass (P) / Fail (F)*
1.	Start Control Portal	Check the Control Portal & logs to verify the OpenFMB is up running	P
2.	Start Field Agents	Check the log and verity Field Agents are up running. The measurement value shall be published and have values.	P Measurement values are displayed
3.	**UC 7a -1 Inside the Limit**		
4.	Close CB-B from RTDS Note: CB-A Auto Re-Configuration Enabled, Amplifiers turned on	CB-B = Close. Verify on HMI, RTDS & Control Portal	P
5.	R-2 - measure voltage (High & Load) side. Check	R-2 – Monitor Voltage measurement	P
6.	R-2 - Recloser 2 - measure phase Angle (RTDS observes phase angle) Sync check passed.	Pre-condition Recloser Measurement value (Phase Angle) ≤ 30 degrees. Observe angle on F-60-2. Sync check passed.	P
7.	Close Recloser 2	R-2 status is closed	P
8.	R-2 sends Open command to Tie SW	Tie SW = Open	P
9.	CB-A Monitors Tie SW = Open and changes back to the original setting group (1)	CB-A Setting group change from 2 to 1 Verify setting group in actual value in CB-A	P File: 7a Feeder Reclose
10.	**UC 7a -2 Outside the Limit**		
11.	Close CB-B from RTDS Note: CB-A Auto Re-Configuration Enabled, Amplifiers turned on	CB-B = Close. Verify on HMI & RTDS	P
12.	R-2 - measure voltage (High & Load) side. Check	R-2 – Monitor Voltage measurement	P
13.	Tie SW - measure phase Angle (RTDS observes phase angle) Sync check passed.	Pre-condition Recloser Measurement value (Phase Angle) = 45 degrees. Observe angle on Tie SW. Sync check passed.	P
14.	Recloser 2 status	R-2 status fails to close	P

13.6 Test Case Results – UC 7a Automatic Feeder Re-Close

Operational:
In this use case, upon the closing of Breaker B, the process to return the system back to normal is initiated. Recloser 2 detects voltage on the Breaker side of the line and there is already voltage on the line side of the recloser (Tie is closed). This initiates a Check Sync request by Recloser 2. In figure 7a-1 (below), the Line and Bus voltages can be seen to be exactly in phase (±1°). Being in phase and having the magnitudes within 1000 volts of one another (an arbitrary setting), the reclosing of Recloser 2 is allowed. Once Recloser 2 is closed, Recloser 2 sends an R-GOOSE message to the Tie Breaker controller to open the tie. The TIE, upon opening, sends Tie Breaker Status message to Breaker A which then return to Setting Group 1. Of note in this use case is the ability to establish pub-sub relationships among any set of devices in the network of interest.

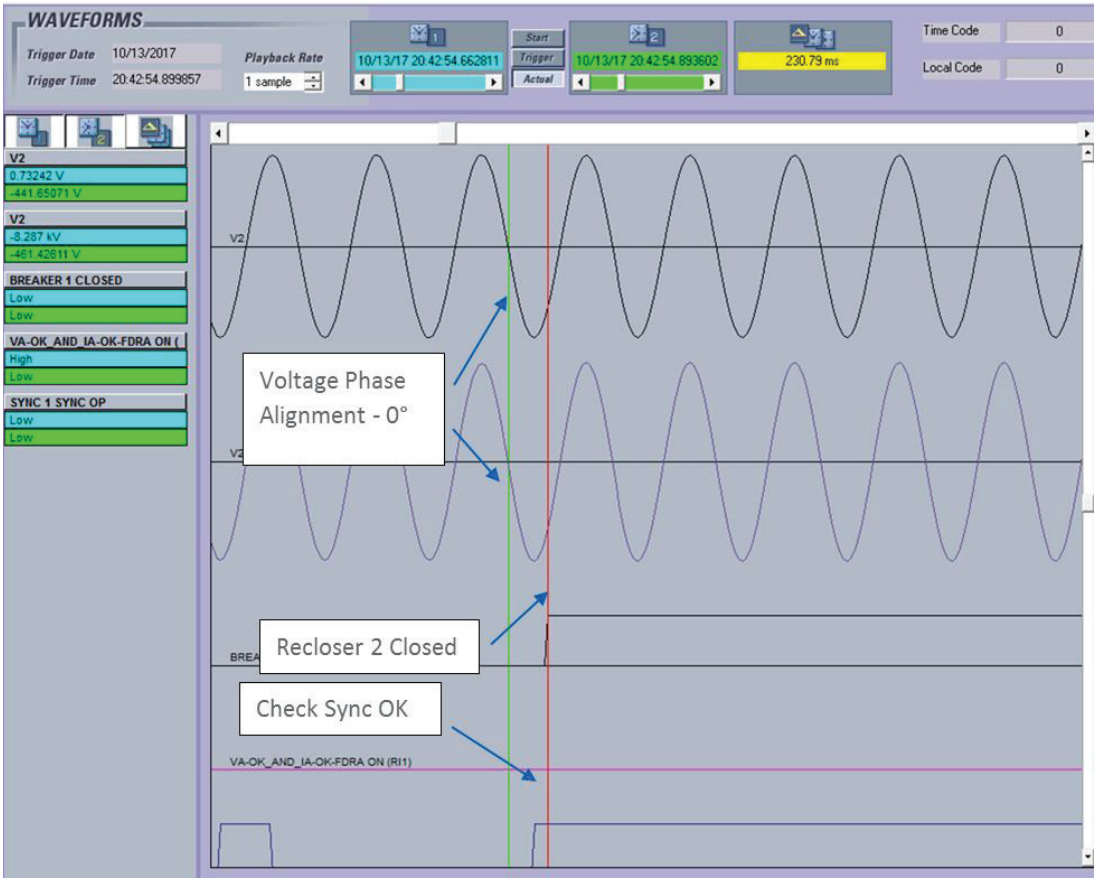


Figure 7a-1

0° Angular Difference between Line A and Line B

It is to be noted that the same test was run with a 45° phase angle difference (changing the phase angle of the source on Line B). With the phase angle difference across Recloser 2 greater than 30° (typical

setting), the reclose request failed to reclose. Again, the angle as set by the analog simulator and the vs. the value read on the display was +/- 1°.

Communication Observations:

The message communication between Recloser B and the Tie breaker was performed via R-GOOSE with all messaging taking place on the Network B communication subnet. As an embedded implementation, launch times of the R-GOOSE message averaged 1ms from an event detection. With R-GOOSE, an event was either a change of a binary value in the message or a change in an analog value that is greater than the set deadband for the measurement.

OpenFMB Gaps:

Computation of the angular difference between the Bus and Line Side voltages highlights the need to be able to implement programmable logic in a device and the need for the logic to be inter-operable among manufacturers.

Recommendations:

The OpenFMB work group should investigate the adoption of the IEC 61131 standard to facilitate the inter-operability of logic among various vendors. It is also recommended that OpenFMB investigate the use of “change” events to launch OpenFMB messages. The OpenFMB WG should consider creating a standard mechanism for the mapping of analog values into OpenFMB messages.

14 Test Case 8a – Sample Value Test Cases (Documentation only)

14.1 Test Case Description – UC 8a Sample Value Test Cases (Documentation only)

UC 8a Sample Value Test Cases

Objective:

- Demonstrate the high-speed transmission of sample values as to further develop communication requirements for OpenFMB

UC 8a Sample Value Test Cases (Documentation only)

- The measurement and transmission of Voltage and Current values from field equipment is known as Sample Values. Sample Values (SV) typically require high sample rates in the range of 3000 to 96,000 samples per second. Additionally, the device creating the Samples (known as the Merging Unit) can be located several kilometers away. IEC61850 introduced the concept of Sample Values as a digital interface to Optical Current and Voltage sensors as well as application-specific circumstances where remote location of Voltage and Current sensors is required/desirable. The 61850 standard addresses issues such as data synchronization and phase correction. Given the high bandwidth and low latency constraints of such data, further study of its applicability to OpenFMB is needed.
- Note: extend the write-up to include RSV documentation
- Documentation included in the Final Report

15 Test Case 8b – Synchrophasors via R-Goose

15.1 Test Case Description – UC 8b Synchrophasors via R-Goose

UC 8b Synchrophasors via R-Goose

Objective:

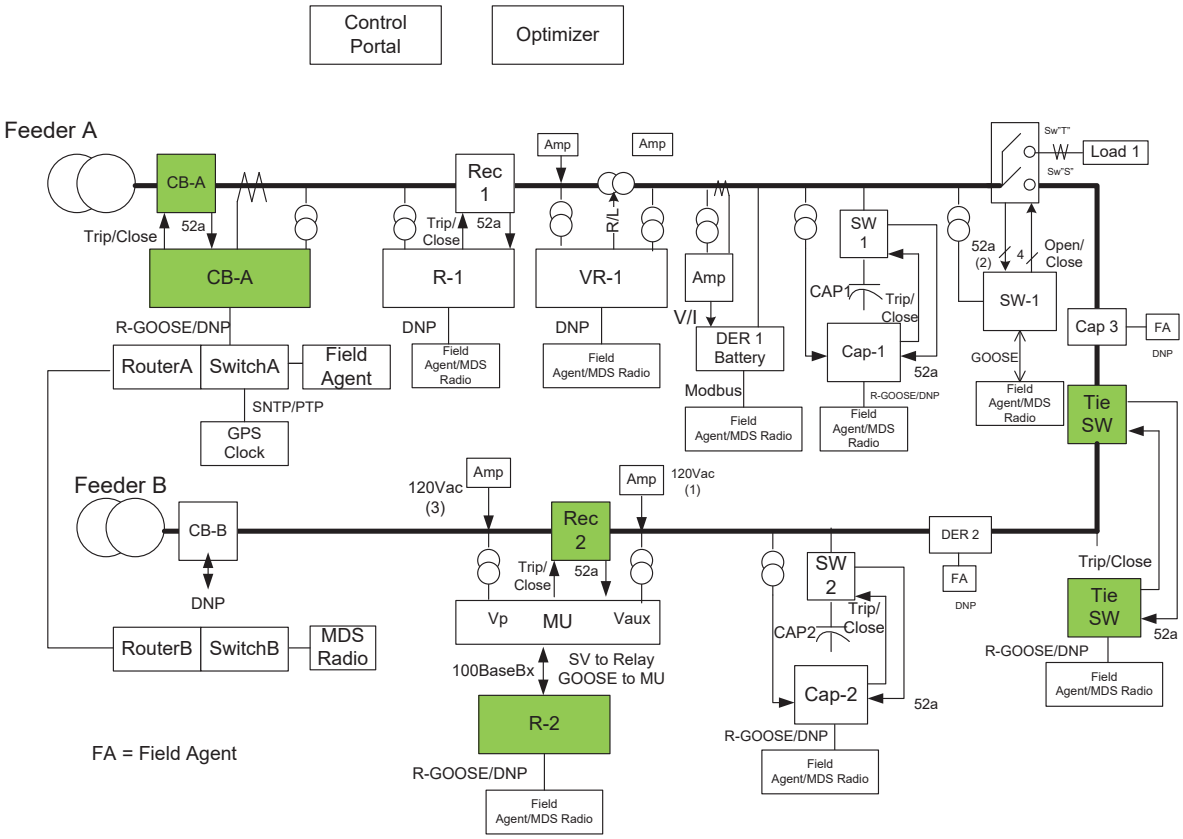
- Demonstrate the pub/sub of high speed data (e.g. synchrophasors) via routable GOOSE and evaluate the incorporation into OpenFMB standards.

Description:

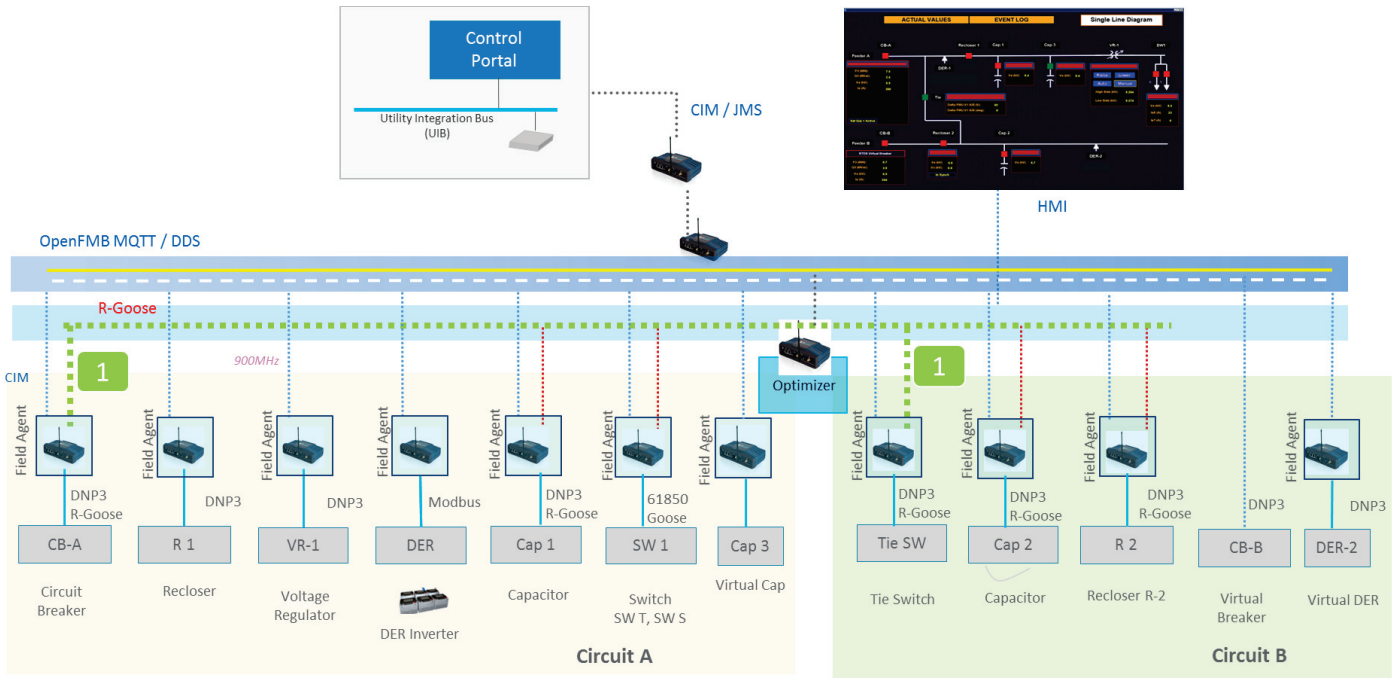
- Synchrophasors (V1 Magnitude and Angle) are to be mapped into Generic Analog 61850 data objects in CB-A and R-2 and then included in R-GOOSE messages.
- R-GOOSE reception by Tie SW.
- Tie SW commutes magnitude difference and angle difference
- Note: under evaluation – dynamic angle difference displayed on Tie SW

15.2 Test Case Diagram – UC 8b Synchrophasors via R-Goose

Logical and IO Diagram



15.3 Test Case Diagram – UC 8b Synchrophasors via R-Goose



Data Flow	*Data Flow Summary*	*Sequence*
1.	CB-A & R-2 send Synchrophasor data to Tie SW	F60 → R-Goose → Tie SW

15.4 Test Case Pre-Conditions – UC 8b Synchrophasors via R-Goose

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	Network Model with Switchable Devices (2 Circuits)
3.	Tie Switch (TIE SW) is Open
4.	Cap 1 is Open or Closed
5.	Cap 2 is Open or Closed
6.	R-1 is Closed
7.	VR-1 is Auto
8.	SW-1 is Closed (2 positions)
9.	Control Portal displays measurement values
10.	R-2 is Closed
11.	CB B is Closed
12.	CB A is Closed

15.5 Test Case Test Steps – UC 8b Synchrophasors via R-Goose

Steps	***Description***	***Acceptance Criteria***	***Pass / Fail***
#	*Step Description*	*Describe Acceptance Criteria*	*Pass (P) / Fail (F)*
1.	CB-A and R-2 send Synchrophasor data	Observe angle and magnitude difference on Tie SW	P
2.	Change source Voltage angle and magnitude between Feeder 1 & Feeder 2	Observe angle and magnitude change on Tie SW	P File: UC 8 Angle change

15.6 Test Case Results – UC 8b Synchrophasors via R-Goose

Operational:

To demonstrate the high-speed performance of the R-GOOSE transport, Synchrophasors (Voltage and Current Magnitude and Angle) were mapped into R-GOOSE datasets in the Feeder A relay and the Recloser 2 relay. The Tie Breaker controller was configured to subscribe to the R-GOOSE datasets from these two relays. Upon receipt in the controller, the values were sent to Magnitude and Angle difference functions. The differences in Magnitude and Angle were then displayed on the HMI and on the Control Portal. Although Synchrophasors are normally transmitted continuously, mapping the values into R-GOOSE AND configuring a tight deadband around the magnitude and angle values can result in transmission of Synchrophasor-based datasets every 100ms.

The R-GOOSE capture from Recloser 2 is shown in figure 8a-1 (below). In the dataset, the voltage Magnitude (first analog) and Voltage angle (second analog) can be observed.

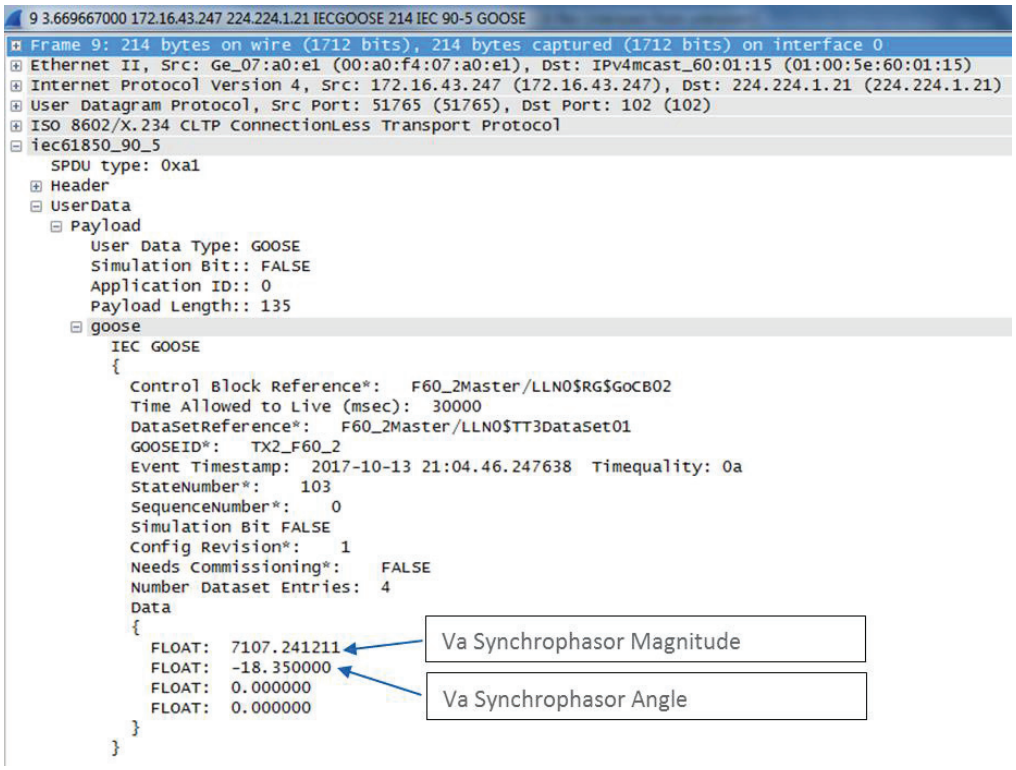


Figure 8b-1

R-GOOSE Capture from Recloser 2

The Tie Breaker Controller, upon receipt of R-GOOSE messages from the Breaker A relay and Recloser B, computed the magnitude and angle difference between these Synchrophasor values. The HMI screen (figure 8a-2 below) shows the values computed next to the Tie breaker. The value set in the RTDS was 45°and the value computed by the controller was 44°.

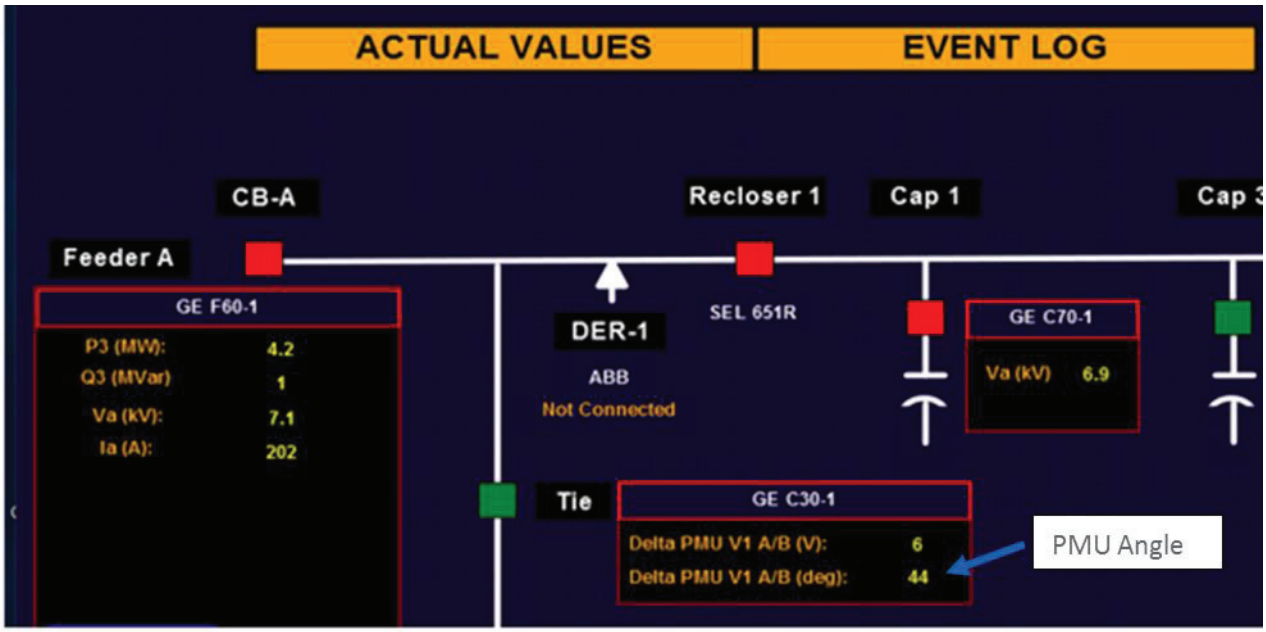


Figure 8b.2

Synchrophasor Angle Difference View in HMI

Communication Observations:

R-GOOSE over Radio Bandwidth Analysis

The R-GOOSE message (above) sending four Floating Point numbers requires a total of 1712 bits. The bandwidth of the radio network is about 500,000 bits/second. Rounding up to 2,000 bits per message, a radio network could potentially transport up to 250 R-GOOSE messages/sec. It should be noted that the transmission of R-GOOSE it typically event-based and uses minimal bandwidth. Use of a 0.1% Deadband will result in a Synchrophasor transmission when the angle changes 0.36° or a magnitude change of 15 volts. Operating in this mode, Synchrophasors between sources will never be more than 0.36°or 15V out of alignment.

Related to Synchrophasors via R-GOOSE/GOOSE, the IEC 61850 standard defines a periodic transport profile – based on the Process Bus profile – for the periodic transmission of Synchrophasors. This IP Address section of the protocol for this profile is identical to that of the R-GOOSE and, as such, implements an IP-Multicast – including a complete security profile.

OpenFMB Gaps:

The implementation of the MQTT OpenFMB protocol in edge devices would have been unable to keep up with the 10 messages per second transmission that was possible with R-GOOSE. Additionally, the MQTT Broker would have introduced additional communication delay. The limitation in the R-GOOSE implementation was the Scan time in the detection of changes in the Synchrophasor values – which could be enhanced.

Recommendations:

The mapping of Synchrophasors into R-GOOSE is a new way to send Synchrophasors. In existing implementations, synchrophasors are continuously streamed – requiring much bandwidth. By using the Deadband transmission mechanism of R-GOOSE, Synchrophasors were only sent when there was a user-defined change in the Synchrophasor value. In the implementation, a deadband of 1% was set – limiting Synchrophasor transmission in steady state conditions. An event on the line – such as a breaker or recloser operation – would trigger Synchrophasor transmission. In as much as R-GOOSE latency was low, transmitted Synchrophasors were self-aligning – meaning that a difference in values could be computed with the understanding that there was only, at most, a 1% difference is transmitted values. SDG&E has demonstrated the use of Synchrophasor differences for the detection of broken wires. It is suggested that SDG&E examine the use of R-GOOSE for Synchrophasor transmission instead of continuous transmission. Additionally, since R-GOOSE is a Pub-Sub protocol, an R-GOOSE message can be sent directly to another PMU where differences in the Synchrophasor values can be computed – simplifying the communication and computation architecture.

16 Test Case 9a – Dynamic Subscription (Documentation Only)

16.1 Test Case Description – UC 9a Dynamic Subscription (Documentation)

UC 9a Dynamic Subscription

Objective:

- Identify the requirement for dynamic subscription for all messaging protocols for incorporation into OpenFMB standards.

Description:

- In the scenario when Feeder A and Feeder B are separated, there is no need to share messages between them. Once the Tie SW is closed, it becomes desirable for the devices on Feeder A to be able to "subscribe" to information from devices on the "extended" line.
- For this purpose, it is to be noted that Dynamic Subscription becomes a need in this Test case.
- Additionally, the definition of the data objects from the newly subscribed devices may be needed – especially if there had been setting changes in any of the newly-subscribed devices.
- Note: Documentation included in Final Report

17 Test Case 10a – End-to-End Security (Documentation Only)

17.1 Test Case Description – UC 10a End-to-End Security (Documentation)

UC 10a End-to-End Security

Objective:

- Identify the requirement for end to end security into OpenFMB standards.

Description:

- When communicating device-to-device in the field, end-to-end secure communications are required.
- End-to-end security should be developed that addresses authentication, authorization, access control, confidentiality, integrity, non-repudiation, availability, and accountability.
- Note: Documentation included in Final Report

18 Test Case 11a – Administration of Devices using OpenFMB

18.1 Test Case Description – UC 11a File transfer

UC 11a File transfer

Objective:

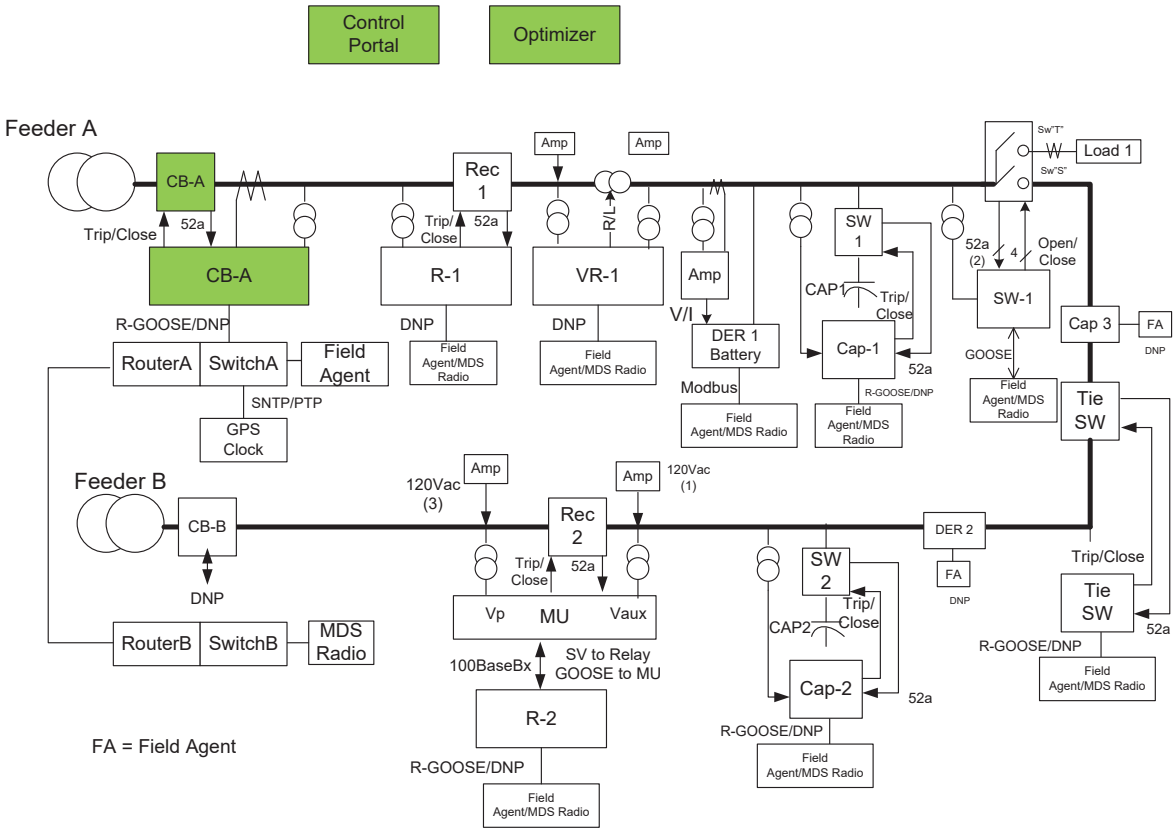
- Demonstrate file transfer using OpenFMB

Description:

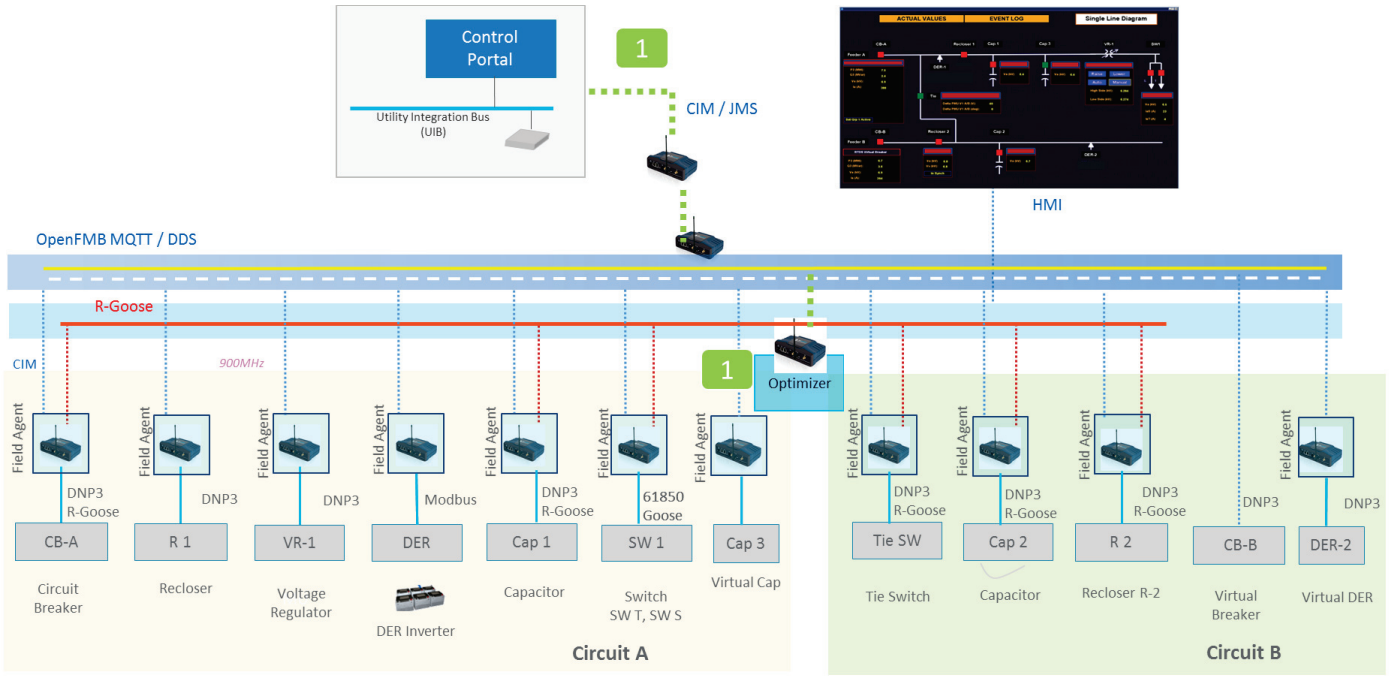
- To demonstrate the transfer of a settings file, a file will be transferred from the Administration Node to a Field Agent (OpenFMB Adapter). This file will be of a size representative of a settings file - ~10 KB. Settings files may also be unique to each OpenFMB node.

18.2 Test Case Diagram – UC 11a File transfer

Logical and IO Diagram



18.3 Test Case Diagram – UC 11a File transfer



Data Flow	*Data Flow Summary*	*Sequence*
1.	Control Portal → CB-A Optimizer	Control Portal → CB-A Optimizer

18.4 Test Case Pre-Conditions – UC 11a File transfer

Pre-Conditions	*Description*
1.	2 Circuits (Line A and Line B) with communicable devices on different networks on each line
2.	OpenFMB pre-configured
3.	Multiple field agents connected and communicating via OpenFMB
4.	Optimizer Pre-configured
5.	Control Portal Pre-configured
6.	Network Model with Switchable Devices (2 Circuits)
7.	Tie Switch (TIE SW) is Closed
8.	Cap 1 is Open or Closed
9.	Cap 2 is Open or Closed
10.	R-1 is Closed
11.	VR-1 is Auto
12.	SW-1 is Closed (2 positions)
13.	Control Portal displays measurement values
14.	R-2 is Closed
15.	CB B is Closed
16.	CB A is Closed
17.	CB-A running Optimizer

18.5 Test Case Test Steps – UC 11a File transfer

Steps	***Description***	***Acceptance Criteria***	***Pass / Fail***
#	*Step Description*	*Describe Acceptance Criteria*	*Pass (P) / Fail (F)*
1.	Control Portal → CB-A Optimizer	Control Portal → CB-A Optimizer	P

18.6 Test Case Results – UC 11a File Transfer

Operational:

File Transfer from the Enterprise was performed using the Active MQ profile – a profile that emulates the MQTT profile that is defined as part of OpenFMB. The demonstration transferred the RULES file from the Enterprise Server to the Optimizer (Rules execution engine).

Communication Observations:

The transfer time was excessively long - most likely due to the underlying network saturation caused by the frequent transfer of xml data and R-GOOSE Synchrophasor traffic on the bandwidth-constrained 900HHz Radio network.

OpenFMB Gaps:

A single file transfer mechanism needs to be defined for OpenFMB. Providing multiple options will confuse the market place and make OpenFMB more difficult to implement. In general, since OpenFMB defines multiple protocols, this poses a problem for the industry as a manufacturer will only be able to implement one profile at a time – making inter-operability problematic.

Recommendations:

A single file transfer mechanism for ALL profiled of OpenFMB needs to be chosen. Clearly, any mechanism chosen needs to be securable. It is to be noted that MQTT has been implemented with TLS to achieve secure data transfers in general but even with TLS, a file transfer protocol needs to be chosen.

18.7 Test Case Description – UC 11b Firmware

UC 11b Firmware (Documentation Only)

Objective:

- Document Firmware transfer

Description:

- To demonstrate the transfer of a firmware image, a file will be transferred from the Administration Node to a Field Agent (OpenFMB Adapter). This file will be of a size representative of a firmware image - ~10 MB.
- It should be highlighted in the report that firmware images will need to have various security characteristics that may be unique to firmware such as manufacturer signing. Firmware images may also be unique to each OpenFMB node.
- Note: File size presently limited by file availability
- Note: Documentation included in Final Report

18.8 Test Case Description – UC 11c Provisioning (Documentation Only)

UC 11c Provisioning (Documentation Only)

Objective:

- Document the requirement to provision field devices using OpenFMB

Description:

- To set up an OpenFMB network, the secure provisioning of OpenFMB nodes is critical. Each OpenFMB node will need to have its security credentials verified with the Administration Node. Various settings will also need to be communicated relating to both the node's network and the node's application functionality. Initial subscriptions to other OpenFMB nodes will also need to be created
- Provide example of documentation of provisioning of settings file for a Cap Bank similar to CAP 1 or CAP 2.
- Note: Documentation included in Final Report

19 Test Case 12a – Operational Data File transfer using OpenFMB

19.1 Test Case Description – UC 12a Operational Data File transfer using OpenFMB

UC 12a File transfer (Documentation Only)

Objective:

- Demonstrate file transfer using OpenFMB

Description:

- Demonstrate file transfer from an Administration Node to other nodes through OpenFMB (MQTT) – field agent-to-field agent.

- Currently, OpenFMB does not define file transfer. In the future, OpenFMB may choose to Test another protocol better suited for file transfer (e.g., SFTP) as pub/sub protocols are not typically used for large, point-to-point, file transfers. Further, individual settings and firmware is likely not to be broadcast as security images, configuration, and other aspects are likely to be unique to each node. These are critical points that need to be clearly articulated in the final document.

- Note: Refer to test demonstration Test Case 11a

20 Test Case 13a – OpenFMB using DDS

20.1 Test Case Description – UC 13a OpenFMB using DDS

UC 13a OpenFMB using DDS

Objective:

- Demonstrate OpenFMB using DDS

Description:

- The Tie SW is set as the one of the DDS nodes.
- The Tie SW gets the data (measurement value) from DNP3 adaptor and publishes the data on the DDS virtual FMB
- Another DDS node subscribes to the data.
- Once the data is received, the data is published in the Audit Log

20.2 Test Case Steps – UC 13a OpenFMB using DDS

Steps	***Description***	***Acceptance Criteria***	***Pass / Fail***
#	*Step Description*	*Describe Acceptance Criteria*	*Pass (P) / Fail (F)*
1.	Set Tie SW as one of the DDS nodes	Observe Tie SW as DDS node	P
2.	Tie SW (Node 1) receives data (DNP3 adaptor) and publishes data via DDS OpenFMB	Tie SW data publish to OpenFMB (DDS)	P
3.	Node 2 subscribes to data	Node 2 data is published in the Audit Log	P

20.3 Test Case Results – UC 13a OpenFMB using DDS

Operational:

With a terminal view configuration (figure 13a-1) we were able to watch the data get sent from the DNP3 scanner to the local FMB Broker then verify the expected data was sent by the local FMB broker. The Edge Device represented in the right-hand terminal was configured to listen ONLY DDS and write the received messages to the audit log. This identical xml message in the audit log implies DDS was, in fact, used to transfer the message from one node to another.

Communication Observations:

Although not visible in the Control Portal, the DDS message transfer was successful. The DDS header carried the same XML data description as the MQTT message.

OpenFMB Gaps:

DDS has multiple implementation options for Data Delivery and Quality of Service (QoS). It is noted that one of the DDS QoS options is “continuous” re-transmission of data until a receive receipt is obtained. This is similar to R-GOOSE with the exception that R-GOOSE does not have an explicit acknowledge function but messages can be acknowledged at the application level through implementation of an Acknowledge message – sent by the data receivers.

Recommendations:

In order for DDS to be adopted by the utility industry, a specific profile of a DDS implementation must be developed. The QoS function of Message Repeat is already accepted by the industry and is recommended moving forward. DDS does make use of the Internet Group Management Protocol (IGMP) which allows for Dynamic Subscription to be implemented with DDS.

21 Equipment Analog Status and Control Point Testing

Breaker A (CB-A)	***Control Portal***	***HMI***
Device Attribute	*Pass (P) / Fail (F)*	*Pass (P) / Fail (F)*
Voltage A (kV)	P	P
Volt Angle A (deg)	P	P
Voltage B (kV)	P	P
Volt Angle B (deg)	P	P
Voltage C (kV)	P	P
Volt Angle C (deg)	P	P
Current A (A)	P	P
Current Angle A (deg)	P	P
Current B (A)	P	P
Current Angle B (deg)	P	P
Current C (A)	P	P
Current Angle C (deg)	P	P
Current N (A)	P	P
Current Angle N (deg)	P	P
Active Power (MW)	P	P
Reactive Power (Mvar)	P	P
Apparent Power (MW)	P	P
Power Factor	P	P
Voltage X (kV)	P	P
Volt Angle X (deg)	P	P
Switch Open Status	P	P
Switch Closed Status	P	P
Switch Open Command	P	P
Switch Close Command	P	P
RxGOOSE off-line	P	P
Var Over Limit	P	P
CAP 1 Volt Override	P	P
CAP 2 Volt Override	P	P
Set Grp1 On	P	P

Breaker A (CB-A)	*Control Portal*	*HMI*
Set Grp2 On	P	P
Load Shed On	P	P
Fdr Re-Config Conditions True	P	P
Fdr Re-Config Enabled	P	P

Recloser 1 (R-1)	*Control Portal*	*HMI*
Device Attribute	*Pass (P) / Fail (F)*	*Pass (P) / Fail (F)*
Voltage A (kV)	P	P
Voltage B (kV)	P	P
Voltage C (kV)	P	P
Current A (A)	P	P
Current B (A)	P	P
Current C (A)	P	P
Active Power (MW)	P	P
Reactive Power (Mvar)	P	P
Apparent Power (MW)	P	P
Power Factor	P	P
Switch Open Status	P	P
Switch Closed Status	P	P
Switch Open Command	P	P
Switch Close Command	P	P
Voltage A (kV)	P	P
Voltage B (kV)	P	P

Voltage Regulator (VR-1)	*Control Portal*	*HMI*
Device Attribute	*Pass (P) / Fail (F)*	*Pass (P) / Fail (F)*
Voltage On HighSide (kV)	P	P
Voltage On LowSide (kV)	P	P
Remote Control Mode On	P	P
Local Control Mode On	P	P
Raise Control Command	NA	P
Lower Control Command	NA	P
Auto Control Mode	P	P
Manual Control Mode	P	P

Capacitor 1 (CAP 1)	*Control Portal*	*HMI*
Device Attribute	*Pass (P) / Fail (F)*	*Pass (P) / Fail (F)*
Voltage A (kV)	P	P
Volt Angle A (deg)	P	P
Voltage B (kV)	P	P
Volt Angle B (deg)	P	P
Voltage C (kV)	P	P
Volt Angle C (deg)	P	P
Current A (A)	NA	NA
Current Angle A (deg)	NA	NA
Current B (A)	NA	NA
Current Angle B (deg)	NA	NA
Current C (A)	NA	NA
Current Angle C (deg)	NA	NA
Current N (A)	NA	NA
Current Angle N (deg)	NA	NA
Active Power (MW)	NA	NA
Reactive Power (Mvar)	NA	NA
Apparent Power (MW)	NA	NA

Capacitor 1 (CAP 1)	*Control Portal*	*HMI*
Power Factor	NA	NA
Voltage X (kV)	NA	NA
Volt Angle X (deg)	NA	NA
Switch Open Status	P	P
Switch Closed Status	P	P
Switch Open Command	P	P
Switch Close Command	P	P
RxGOOSE off-line	P	P
Voltage Override Block	P	P

Switch (SW-1)	*Control Portal*	*HMI*
Device Attribute	*Pass (P) / Fail (F)*	*Pass (P) / Fail (F)*
A-Phase Voltage (kV), Z-PT	NA	P
B-Phase Voltage (kV), Z-PT	NA	P
C-Phase Voltage (kV), Z-PT	NA	P
A-Phase Current (A), S Terminal	NA	P
B-Phase Current (A), S Terminal	NA	P
C-Phase Current (A), S Terminal	NA	P
Three-Phase Real Power (MW), Terminal S	NA	P
Three-Phase Reactive Power (Mvar), Terminal S	NA	P
Three-Phase Apparent Power (MVA), Terminal S	NA	P
Three-Phase Displacement Power Factor, Terminal S	NA	P
A-Phase Current (A), T Terminal		P
B-Phase Current (A), T Terminal		P
C-Phase Current (A), T Terminal		P
Three-Phase Real Power (MW), Terminal T		P
Three-Phase Reactive Power (Mvar), Terminal T	NA	P
Three-Phase Apparent Power (MVA), Terminal T	NA	P
Three-Phase Displacement Power Factor, Terminal T	NA	P
Way 1 Closed, Terminal S	NA	P
Way 2 Closed, Terminal T		P

Switch (SW-1)	*Control Portal*	*HMI*
Open Terminal S Command	NA	P
Close, Terminal S Command	NA	P
Open Terminal T Command		P
Close Terminal T Command'		P

Tie Switch (Tie SW)	*Control Portal*	*HMI*
Device Attribute	*Pass (P) / Fail (F)*	*Pass (P) / Fail (F)*
Delta Pmu V1 Mag A/B (V)	P	P
Delta Pmu V1 Ang A/B (deg)	P	P
Delta Pmu I1 Mag A/B (V)	P	P
Delta Pmu I1 Ang A/B (deg)	P	P
Switch Open Status	P	P
Switch Closed Status	P	P
Switch Open Command	P	P
Switch Close Command	P	P
RxGOOSE off-line	P	P

Virtual Capacitor (Cap-3)	*Control Portal*	*HMI*
Device Attribute	*Pass (P) / Fail (F)*	*Pass (P) / Fail (F)*
Voltage A (kV)	P	P
Volt Angle A (deg)	P	P
Voltage B (kV)	P	P
Volt Angle B (deg)	P	P
Voltage C (kV)	P	P
Volt Angle C (deg)	P	P
Current A (A)	NA	NA
Current Angle A (deg)	NA	NA
Current B (A)	NA	NA
Current Angle B (deg)	NA	NA
Current C (A)	NA	NA

Virtual Capacitor (Cap-3)	*Control Portal*	*HMI*
Current Angle C (deg)	NA	NA
Current N (A)	NA	NA
Current Angle N (deg)	NA	NA
Active Power (MW)	NA	NA
Reactive Power (Mvar)	NA	NA
Apparent Power (MW)	NA	NA
Power Factor	NA	NA
Voltage X (kV)	NA	NA
Volt Angle X (deg)	NA	NA
Switch Open Status	P	P
Switch Closed Status	P	P
Switch Open Command		P
Switch Close Command		P

Capacitor 2 (CAP 2)	*Control Portal*	*HMI*
Device Attribute	*Pass (P) / Fail (F)*	*Pass (P) / Fail (F)*
Voltage A (kV)	P	P
Volt Angle A (deg)	P	P
Voltage B (kV)	P	P
Volt Angle B (deg)	P	P
Voltage C (kV)	P	P
Volt Angle C (deg)	P	P
Current A (A)	NA	NA
Current Angle A (deg)	NA	NA
Current B (A)	NA	NA
Current Angle B (deg)	NA	NA
Current C (A)	NA	NA
Current Angle C (deg)	NA	NA
Current N (A)	NA	NA
Current Angle N (deg)	NA	NA
Active Power (MW)	NA	NA
Reactive Power (Mvar)	NA	NA

Capacitor 2 (CAP 2)	*Control Portal*	*HMI*
Apparent Power (MW)	NA	NA
Power Factor	NA	NA
Voltage X (kV)	NA	NA
Volt Angle X (deg)	NA	NA
Switch Open Status	P	P
Switch Closed Status	P	P
Switch Open Command	P	P
Switch Close Command	P	P
RxGOOSE off-line	P	P
Voltage Override Block	P	P

Recloser 2 (R-2)	*Control Portal*	*HMI*
Device Attribute	*Pass (P) / Fail (F)*	*Pass (P) / Fail (F)*
Voltage A (kV)	P	P
Volt Angle A (deg)	P	P
Voltage B (kV)	P	P
Volt Angle B (deg)	P	P
Voltage C (kV)	P	P
Volt Angle C (deg)	P	P
Current A (A)	NA	NA
Current Angle A (deg)	NA	NA
Current B (A)	NA	NA
Current Angle B (deg)	NA	NA
Current C (A)	NA	NA
Current Angle C (deg)	NA	NA
Current N (A)	NA	NA
Current Angle N (deg)	NA	NA
Active Power (MW)	NA	NA
Reactive Power (Mvar)	NA	NA
Apparent Power (MW)	NA	NA
Power Factor	NA	NA
Voltage X (kV)	P	P

Recloser 2 (R-2)	*Control Portal*	*HMI*
Volt Angle X (deg)	P	P
Switch Open Status	P	P
Switch Closed Status	P	P
Switch Open Command	P	P
Switch Close Command	P	P
RxGOOSE off-line	P	P
In Synch	P	P
Fdr Re-Config Conditions True	P	P

Breaker B (CB-B)	*Control Portal*	*HMI*
Device Attribute	*Pass (P) / Fail (F)*	*Pass (P) / Fail (F)*
Voltage A (kV)	P	P
Volt Angle A (deg)	P	P
Voltage B (kV)	P	P
Volt Angle B (deg)	P	P
Voltage C (kV)	P	P
Volt Angle C (deg)	P	P
Current A (A)	P	P
Current Angle A (deg)	P	P
Current B (A)	P	P
Current Angle B (deg)	P	P
Current C (A)	P	P
Current Angle C (deg)	P	P
Current N (A)	NA	NA
Current Angle N (deg)	NA	NA
Active Power (MW)	P	P
Reactive Power (Mvar)	P	P
Apparent Power (MW)	P	P
Power Factor	P	P
Voltage X (kV)	P	P
Volt Angle X (deg)	P	P

Breaker B (CB-B)	*Control Portal*	*HMI*
Switch Open Status	P	P
Switch Closed Status	P	P
Switch Open Command	P	P
Switch Close Command	P	P

Appendix 12

EPIC-2, Project 4: System Operations Development and Advancement

EPIC Final Report

Program	**Electric Program Investment Charge (EPIC)**
Administrator	**San Diego Gas & Electric Company**
Project Number	**EPIC-2, Project 4**
Project Name	**System Operations Development and Advancement**
Date	**December 31, 2017**

Attribution

This comprehensive final report documents the work done in this EPIC project.

The project team for this work included the following individuals, listed alphabetically by last name.

Internal SDG&E Staff:

Alexander Jay Bick

Mike Espinoza

Frank Goodman

Zoltan Kertay

Iman Mazhari

Prajwal Raval

Kevin Roll

Amin Salmani

Marvin Zavala-Iraheta

Smarter Grid Solutions:

Chad Abbey

Craig Breaden

Fraser Watson

Richard West

Quanta Technology:

Ali Bidram

Shadi Chuangpishit

Masoud Davoudi

Farid Katiraei

Bahman Koosha

Dino Lelic

Zhuoning Liu

Ahmadreza Momeni

Baharak Soltani

Nima Yousefpoor

Amin Zamani

EXECUTIVE SUMMARY

This executive summary outlines the work performed and findings of EPIC-2, Project 4, System Operations Development and Advancement.

Project Objective and Focus

The objective of this project was to support continued modernization of SDG&E's power system via demonstrations of improved capabilities in system operations. The project demonstrated a systematic process for the realignment of operating practices with advances in technology, software, and standards used in the power system.

The chosen focus of this project was a pre-commercial demonstration of prospective changes in the control structure of distribution systems under the presence of distributed energy resources (DERs) to address new monitoring and control requirements, including (but not limited to):

- From control perspective: DER production control, DER reactive power control, and voltage and reactive power (Volt/VAr) optimization on the secondary side of distribution service transformers.
- From monitoring and recording perspective: intermittent and firm power production monitoring, short-term generation forecasting, reserve capacity estimate, and aggregation of centralized and distributed resources.

This project focused on a distributed, autonomous, and scalable architecture, which includes robust communication architecture and a hardware and software platform for aggregating and dispatching coordinated net-load resources (the difference between the load and power from DER in localized regions of the distribution system). The architecture includes a concept of Localized Residential Aggregation and Monitoring (LRAMs) and Regional Aggregation, Monitoring and Circuit Optimizer (RAMCOs) for control and aggregation of customer-owned distributed generation and controllable loads on distribution systems.

Project Methods

A project team was formed, which consisted of internal SDG&E technical staff, a contractor, and a subcontractor. The project team prepared the functional requirements for a distributed control platform and two new aggregation methods for managing large numbers of DERs of various nature (firm and variable) and of different sizes, distributed across the system and connected at primary and/or secondary systems. The functional requirements were discussed with various stakeholders to ensure broad agreement and acceptance among planning engineers and system operators.

A scaled down version of the control platform involving two RAMCOs and eight LRAMs was designed and implemented in the laboratory environment (pre-commercial demonstration system) to evaluate the proposed operating procedures and feasibility of aggregating and remote control in a coordinated fashion to achieve the assigned regional and/or local active and reactive targets. Several use cases were defined and tested to assess various proposed operating procedures and near-real time control and monitoring functionalities of the aggregation platform.

Conclusions and Key Findings

In this project, a highly distributed and modularly scalable control platform for monitoring, aggregation and control of DERs was proposed and demonstrated.

Through use cases and evaluation of test results, it was concluded that DERs in secondary systems can play an essential role in supporting primary DERs for the purpose of emergency dispatch, voltage and reactive power control. One of the salient features of the proposed control platform was the ability to control and utilize DERs on the secondary of service transformers (secondary systems). It was concluded that the proposed control platform can provide a promising solution for aggregating and managing control and operating of non-conventional resources – both utility-owned and non-utility-owned - such as solar PV systems, ESS units, electric vehicles, and controllable loads. The control platform is able to control and monitor the primary and secondary DERs in the system and provides a separate communication path from SCADA to DERs, which results in the improved reliability of control system.

Two of the secondary Volt/VAr regulating devices were successfully type tested and reviewed. Type testing of secondary system technologies showed that secondary Volt/VAr regulating devices from two different vendors provide promising solutions for secondary voltage regulation, localized reactive power compensation, and interaction with customer resources downstream of services transformers.

Recommendations

The key recommendations are:

- It is recommended that the operating practices introduced in this project be further examined for their commercial viability. The investigation should cover both utility-owned and non-utility assets to specify proper circuit level and service level aggregators and associated control/operation functions. A business case would need to be developed.
- To transition the proposed aggregation system to the product stage for deployment and operation in real-world distribution systems, the following steps are recommended.
    - Integration between DMS/SCADA and DER aggregation platform at control center level is recommended, so data and target system configuration and topology can be seamlessly exchanged between the field aggregators and control center platforms to avoid adverse effect on system operation, power quality and device to device coordination.
    - For the above-mentioned points, it is recommended to develop requirements for standard platforms for integrating DMS/SCADA and DER aggregation as part of the control center functions to properly utilize the existing controls, models, databases and the two-way status communications.
    - It is recommended to incorporate the proposed DER aggregation system into a field message bus platform that can accommodate all DER assets and the platform can be easily scaled up.
    - A pilot project incorporating part of distribution systems is recommended to learn unknown (field specific) challenges and to test real-world issues. The pilot project would also clarify the skills development and training requirements needed for widespread commercial adoption of the demonstrated concepts.

As a next step, it is recommended to assess performance of various control and monitoring schemes of the proposed aggregation platform from the real-world field deployment perspective to examine the scalability and reliability requirements in an actual distribution system environment.

TABLE OF CONTENTS

EXECUTIVE SUMMARY ..... **III**

LIST OF ACRONYMS AND ABBREVIATIONS ..... **XI**

1 INTRODUCTION **13**

1.1 Project Objective 13

1.2 Project Focus 13

1.3 Summary of Project's Scope of Work and Approach 14

1.3.1 Project Plan 14

1.3.2 Approach Utilized in Undertaking this Project 14

2 DESIGN AND TESTING **19**

2.1 Baseline Evaluation and Analysis 19

2.1.1 Present Architecture of Distribution System Control and Operation 19

2.1.2 Future Needs and Advancement of System Operation 24

2.2 Concept of Operations (CONOPS) 24

2.2.1 System Architecture 24

2.2.2 DSO Operating Principles 25

2.2.3 Use Cases 30

2.3 Design of Test System 33

2.3.1 Circuit Selection Criteria 33

2.3.2 Test System Development and Layout 37

2.4 Test System Setup and Integration 40

2.4.1 Type Testing of Secondary System Technologies 40

2.4.2 Factory Acceptance Test (FAT) 43

2.4.3 Site Acceptance Test (SAT) 45

2.5 Demonstration of Control and Operation Concept 48

3 PROJECT RESULTS **50**

3.1 Sample Test Results 52

3.1.1 Case 1-5: Variable market price (Load Management/Near Real Time-Resource Aggregation) 53

3.1.2 Case 2-3-1: Change of DSO target (Emergency Dispatch of DERs) 57

3.1.3 Case 2-4-1: LRAM dispatching when all primary DERs are off (Emergency Dispatch of DERs) 62

3.1.4 Case 3-1: Reactive power management: 67

4 KEY FINDINGS AND OPERATIONAL PROCEDURE EVALUATION **70**

4.1 Key Findings 70

4.2 System Operation Procedure Evaluation 72

5 SUMMARY OF RECOMMENDATIONS AND NEXT STEPS 74

6 METRICS AND VALUE PROPOSITION 75

6.1 Metrics 75

6.2 Primary Value Proposition 78

6.2.1 Greater Reliability 78

6.2.2 Lower Costs 78

6.3 Secondary Value Proposition 78

6.3.1 Increased Safety and/or Enhanced Environmental Sustainability 78

6.3.2 Adaptability to other utilities and/or the broader industry 78

7 REFERENCES 79

8 APPENDICES 80

8.1 Appendix A: RAMCO/LRAM Priority Stacks for Emergency Dispatch of DERs for Demand Side Management Use Case 80

8.2 Appendix B: Test Plan and Results for Type Tests of Secondary Regulating Devices 83

8.2.1 Type Test Plan 84

8.2.2 Type Test Results 89

8.3 Appendix C: FAT Test Plan and Results 96

8.3.1 FAT Test Plan 96

8.3.2 FAT Test Results 98

8.4 Appendix D: Demonstration Test Results 104

8.4.1 Use Case 1: Load Management 104

8.4.2 Use Case 2: Emergency Dispatch of DERs 122

8.4.3 Use Case 3: Reactive Power Management 141

List of Figures

Figure 2-1. Simplistic Representation of Conventional Distribution Control System 20
Figure 2-2. Proposed Aggregator-Base Architecture 26
Figure 2-3. Simplified Single Line Diagram of Selected Circuits 35
Figure 2-4. Proposed Digital Simulation Platform and PHIL Testbed Configuration for Demonstration of RAMCO/LRAM Concept 38
Figure 2-5. Testbed Installed at ITF 39
Figure 2-6 Type test system layout 42
Figure 2-7. Illustration of Test Setup for FAT 44
Figure 3-1. DSO HMI in case 1-5-2: energy price is $170 per MWh 54
Figure 3-2. DSO HMI in case 1-5-2: energy price is $40 per MWh 55
Figure 3-3. Setpoints and measurements for RAMCO 1 bulk resources in case 1-5-2 55
Figure 3-4. RAMCO 1 real power target and response, and response of primary connected assets associated with price drop 56
Figure 3-5. BESS11 power measurements in case 1-5-2 56
Figure 3-6. BESS21 power measurements in case 1-5-2 57
Figure 3-7. DSO HMI in case 2-3-1: DSO target is 12 MW 58
Figure 3-8. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 2-3-1 58
Figure 3-9. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 2-3-1 59
Figure 3-10. BESS11 and BESS21 P measurements in case 2-3-1 60
Figure 3-11. PV11, PV21, and FG21 P measurements in case 2-3-1 60
Figure 3-12. LRAMs 1 to 4 real power target and responses for DSO contribution target change from 12 MW to -4MW 61
Figure 3-13. RAMCO HMI in case 2-3-1 62
Figure 3-14. DSO HMI in case 2-4-1: DSO target is 250kW 63
Figure 3-15. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 2-4-1 63
Figure 3-16. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 2-4-1 64
Figure 3-17. RAMCO 1 HMI in case 2-4-1 66
Figure 3-18. LRAM 24 setpoints in case 2-4-1 66
Figure 3-19. Primary DERs reactive power target and measurement for each RAMCO 68
Figure 3-20. HMI screenshot for RAMCO2 LRAMs with DSO Q target at -7 MVAr 69
Figure 3-21. Reactive power contribution measurement for RAMCO 1 & 2 69
Figure 8-1. RMS Voltage Measurements for DUT A: Drop Off Voltage Test 90
Figure 8-2. RMS Voltage Measurements for DUT A: Voltage Ramp Test 91
Figure 8-3. Phase 1 P, Q & PF Measurements of Power Factor Regulation Test 91
Figure 8-4. RMS Voltage Measurements for DUT B: Drop Off Voltage Test 93
Figure 8-5. RMS Voltage Measurements for DUT B: Voltage Ramp Test 94
Figure 8-6. Active and Reactive Power Measurements for DUT B: Reactive Power Test 95
Figure 8-7. RMS Voltage Measurements for DUT B Reactive Power Test 95
Figure 8-8. Snapshot of DSO HMI (Top) and RAMCO HMI (Bottom) for the selected Case 101
Figure 8-9. Snapshot of DSO HMI (Top) and RAMCO HMI (Bottom) for Target=4MW 102
Figure 8-10. Snapshot of DSO HMI (Top) and RAMCO HMI (Bottom) for Target=6MW 103
Figure 8-11. DSO HMI in case 1-1-1 105
Figure 8-12. RAMCO 1 HMI in case 1-1-1 105
Figure 8-13. RAMCO 2 HMI in case 1-1-1 106
Figure 8-14. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 1-1-1 106
Figure 8-15. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 1-1-1 106

Figure 8-16. DSO HMI in case 1-1-2 107
Figure 8-17. RAMCO 1 HMI in case 1-1-2 107
Figure 8-18. RAMCO 2 HMI in case 1-1-2 108
Figure 8-19. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 1-1-2 108
Figure 8-20. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 1-1-2 108
Figure 8-21. DSO HMI in case 1-2-1 109
Figure 8-22. RAMCO 1 HMI in case 1-2-1 110
Figure 8-23. RAMCO 2 HMI in case 1-2-1 110
Figure 8-24. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 1-2-1 110
Figure 8-25. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 1-2-1 111
Figure 8-26. DSO HMI in case 1-2-2 111
Figure 8-27. RAMCO 1 HMI in case 1-2-2 112
Figure 8-28. RAMCO 2 HMI in case 1-2-2 112
Figure 8-29. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 1-2-2 112
Figure 8-30. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 1-2-2 113
Figure 8-31. DSO HMI in case 1-3-1 114
Figure 8-32. RAMCO 1 HMI in case 1-3-1 114
Figure 8-33. RAMCO 2 HMI in case 1-3-1 115
Figure 8-34. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 1-3-1 115
Figure 8-35. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 1-3-1 115
Figure 8-36. DSO HMI in case 1-3-2 116
Figure 8-37. RAMCO 1 HMI in case 1-3-2 116
Figure 8-38. RAMCO 2 HMI in case 1-3-2 117
Figure 8-39. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 1-3-2 117
Figure 8-40. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 1-3-2 117
Figure 8-41. DSO HMI in case 1-4-1 118
Figure 8-42. RAMCO 1 HMI in case 1-4-1 119
Figure 8-43. RAMCO 2 HMI in case 1-4-1 119
Figure 8-44. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 1-4-1 119
Figure 8-45. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 1-4-1 120
Figure 8-46. DSO HMI in case 1-4-2 120
Figure 8-47. RAMCO 1 HMI in case 1-4-2 121
Figure 8-48. RAMCO 2 HMI in case 1-4-2 121
Figure 8-49. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 1-4-2 121
Figure 8-50. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 1-4-2 122
Figure 8-51. DSO HMI in case 2-1-1 123
Figure 8-52. RAMCO 1 HMI in case 2-1-1 123
Figure 8-53. RAMCO 2 HMI in case 2-1-1 124
Figure 8-54. DSO HMI in case 2-1-2 124
Figure 8-55. RAMCO 1 HMI in case 2-1-2 125
Figure 8-56. RAMCO 2 HMI in case 2-1-2 125
Figure 8-57. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 2-1-2 125
Figure 8-58. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 2-1-2 126
Figure 8-59. DSO HMI before and after PV profile change in case 2-2 127
Figure 8-60. RAMCO 1 HMI before and after PV profile change in case 2-2 128
Figure 8-61. RAMCO 2 HMI before and after PV profile change in case 2-2 129
Figure 8-62. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 2-2 129
Figure 8-63. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 2-2 130

Figure 8-64. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 2-3-2 131
Figure 8-65. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 2-3-2 131
Figure 8-66. RAMCO 1 HMI in case 2-4-2 133
Figure 8-67. RAMCO 2 HMI in case 2-4-2 133
Figure 8-68. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 2-4-2 134
Figure 8-69. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 2-4-2 134
Figure 8-70. DSO HMI for Circuit Topology 1 in case 2-5 135
Figure 8-71. DSO HMI when Circuit Topology changes from 1 to 2 in case 2-5 136
Figure 8-72. DSO HMI when the Circuit Topology changes from 2 to 1 in case 2-5 136
Figure 8-73. DSO HMI when the Circuit Topology changes from 1 to 3 in case 2-5 137
Figure 8-74. DSO HMI before and after PV11 outage in case 2-6 138
Figure 8-75. RAMCO 1 HMI before and after PV11 outage in case 2-6 139
Figure 8-76. RAMCO 2 HMI before and after PV11 outage in case 2-6 140
Figure 8-77. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 2-6 140
Figure 8-78. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 2-6 140
Figure 8-79. RAMCO 2 HMI in case 3-2 141
Figure 8-80. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 3-2 142
Figure 8-81. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 3-2 142

List of Tables

Table 2-1. Voltage Ranges for CVR and Non-CVR Circuits 22
Table 2-2. DSO Operating Principles 27
Table 2-3. DERs and LRAMs Designations in Topology 1 36
Table 2-4. DERs and LRAMs Designations in Topology 2 36
Table 2-5. DERs and LRAMs Designations in Topology 3 36
Table 2-6. Test Summary for FAT Test Categories 44
Table 2-7. Test Plan for Use Case 1 (Load Management/NRT Resource Aggregation) 46
Table 2-8. Test Plan for Use Case 2 (Emergency Dispatch of DERs) 47
Table 2-9. Test Plan for Use Case 3 (Reactive Power Management) 48
Table 3-1. Summary of Findings for Load Management Test Cases 50
Table 3-2. Summary of Findings for Emergency Dispatch Test Cases 51
Table 3-3. Summary of Findings for Reactive Power Management Test Cases 52
Table 3-4. Settings for Case 1-5-2 53
Table 3-5. Setpoints for Case 1-5-2, price is $170/MWh 53
Table 3-6. Setpoints for Case 1-5-2, price is $40/MWh 54
Table 3-7. Changes in LRAM settings and their resources in case 2-4-1 64
Table 3-8. Summary of reactive power targets for each RAMCO and primary DERs 67
Table 6-1. Project Metrics 75
Table 8-1. Priority Stack of RAMCO1 in Topology 1 80
Table 8-2. Priority Stack of RAMCO1 in Topology 2 80
Table 8-3. Priority Stack of RAMCO1 in Topology 3 81
Table 8-4. Priority Stack of RAMCO2 in Topology 1 81
Table 8-5. Priority Stack of RAMCO2 in Topology 2 82
Table 8-6. Priority Stack of RAMCO2 in Topology 3 82
Table 8-7. Priority Stack of a typical LRAM 83
Table 8-8. Type Test Results Summary of DUT A for Each Test Category 89
Table 8-9. Type Test Results Summary of DUT B for Each Test Category 92
Table 8-10. Definition of Load and PV Profiles for Testing 96
Table 8-11. Results of FAT for Communication Tests 98
Table 8-12. SCADA Model Verification Test Cases 100
Table 8-13. DSO/RAMCO Verification Test Cases 100
Table 8-14. Case 1-1 Category Test Cases 104
Table 8-15. Case 1-2 Category Test Cases 108
Table 8-16. Case 1-3 Category Test Cases 113
Table 8-17. Case 1-4 Category Test Cases 118
Table 8-18. Case 2-1 Category Test Cases 122
Table 8-19. Case 2-3 Category Test Cases 130
Table 8-20. Case 2-4 Category Test Cases 132

LIST OF ACRONYMS AND ABBREVIATIONS

ADMS	Advanced DMS
AMI	Advanced Metering Infrastructure
BESS	Battery Energy Storage Systems
CAISO	California ISO
CONOP	Concept of Operation
CONOPS	Concept of Operations
CVR	Conservation Voltage Reduction
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DERS	Distributed Energy Resources
DMS	Distribution Management System
DOP	Distribution Operation Procedures
D-SCADA	Distribution SCADA
DSO	Distribution System Operator
DUT	Device under Test
DVC	Dynamic Voltage Controller
EDO	Electric Distribution Operation
EPIC	Electric Program Investment Charge
ESS	Energy Storage Systems
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FAT	Factory Acceptance Test
FES	Front End System
FG	Firm Generation
FLISR	Fault Location, Isolation, and Service Restoration
GIS	Global Information System
HIL	Hardware in-the-Loop
HMI	Human–Machine Interface
IEC	International Electro Technical Commission
IED	Intelligent Electronic Devices
IG	Intermittent Generation
ISO	Independent System Operators
ITF	Integrated Test Facility
kV	Kilo Volts
kW	Kilo Watt
LRAM	Local Resource Aggregation and Monitoring

LTC	Load Tap Changers
LV	Low Voltage
MW	Mega Watt
MWh	Mega Watt Hour
NA	Not Applicable
NMS	Network Management System
NRT	Near Real-Time
OMS	Outage Management System
P.U.	Per Unit
PEV	Plug-in Electric Vehicles
PF	Power Factor
PHIL	Power Hardware-in-Loop
POI	Point of Interconnection
PV	Photovoltaic
RAMCO	Regional Aggregation, Monitoring and Circuit Optimizers
RFP	Request for Proposal
RMS	Root-Mean Square
SAT	Site Acceptance Test
SCADA	Supervisory Control And Data Acquisition
SCOM	System Communications
SDG&E	San Diego Gas & Electric
SOC	State of Charge
SVVR	Secondary Volt/VAr Regulating
VAr	Volt Ampere Reactive
VR	Voltage Regulators
VVC	Volt/VAr Control
VVO	Volt/VAr Optimization

1 INTRODUCTION

1.1 Project Objective

The objective of this project was to support continued modernization of SDG&E's power system via demonstrations of improved capabilities in system operations. The project demonstrated a systematic process for the realignment of operating practices with advances in technology, software, and standards used in the power system. The realignment was broad, and addressed system integration issues, training programs, worker skill sets, and workforce readiness.

1.2 Project Focus

The focus of this project was to evaluate and demonstrate the changes in the control structure of distribution systems under the presence of Distributed Energy Resources (DERs) to address control objectives such as active and reactive power control and Volt/r control at both medium voltage level (primary system) and the secondary side of service transformers (secondary systems). For this purpose, the addition of aggregators to the distribution system control structure at both regional and local levels was proposed. The introduction of *Regional Aggregation, Monitoring and Circuit Optimizers* (RAMCO) and *Local Resource Aggregation and Monitoring* (LRAM) platforms enabled the proposed distribution control methodology to effectively coordinate and manage the operation of existing legacy and future control devices.

RAMCOs were envisioned to control large DERs that are directly connected to primary distribution feeders such as centralized MW size PV systems, and feeder/substation level battery energy storage systems (BESSs). LRAMs were designed to control and interact with smaller size DERs connected to the secondary side of service transformers in residential and small commercial level (secondary systems). In other words, LRAMs had autonomous control over the local resources to meet the RAMCO assigned targets.

The locations of RAMCOs and LRAMs were determined based on the concentration of DERs, energy storage systems, controllable loads and electric vehicle supply equipment (EVSE). In the hierarchical control structure of distribution systems, Distribution System Operator (DSO) stands as the first hierarchy that forecasts the real-time available capacities in each region, determines the requirements to provide ancillary services accordingly, and sends out the capacity request signals to RAMCOs. Based on the received capacity signals, RAMCOs are responsible for determination and optimization of control points for DERs and LRAMs.

At the secondary systems level, LRAMs were responsible for managing the service transformers' loading by controlling DERs, switchable loads, and charging level of Plug-in Electric Vehicles (PEVs). LRAMs use the aggregate charging demand, local production levels, and dynamic rating of service transformers to take effective actions to meet the RAMCO published target. In addition, they need to properly manage resources if the loading of service transformers gets close to its dynamic rating.

1.3 Summary of Project's Scope of Work and Approach

1.3.1 Project Plan

This project was completed in two phases:

- Phase 1 covered the tasks associated with selection of project technical lead, the project team, development of project plan, and selection of the contractor.
- Phase 2 had two parts: part 1 baseline evaluation and analysis, development of concept of operations, and designing the test system. Part 2 - aimed to setup and integrate the test system, conduct pre-commercial demonstration, evaluate the operational procedure, perform data assimilation and analysis, and prepare a comprehensive final report.

Each phase included frequent discussion sessions and review meetings with the SDG&E project team and stakeholders, as well as a final report and presentation to SDG&E. Monthly status updates and reports were also provided in a pre-defined format.

1.3.2 Approach Utilized in Undertaking this Project

This section provides a detailed description of the work approach and methodology, and the required outcome and deliverables of each task.

The tasks associated with Phase 1 were:

Phase 1 - Task 1 - Team Formation and Project Plan

The SDG&E EPIC program manager identified the technical lead for the project based on experience and technical expertise. Later, the internal project team was formed by identification of technical skills and expertise available within the organization. After forming the internal project team, the task to develop the project plan was given to the technical lead. The technical lead with the help of the project team wrote the project plan as per the guidance provided by the SDG&E EPIC program manager adhering to EPIC guidelines.

Phase 1 - Task 2 - Procurement of Contractor Services

Scope of the work was identified and written for the part of the project that needed to be contracted out to the engineering consulting firm. Standard company practices were followed for contractor selection.

The tasks associated the Phase 2 were:

Task 1 - Project Kickoff Meeting, Stakeholder Consultations, and Work Plan

This task involved an in-person Project Kickoff Meeting between SDG&E stakeholders and project team to discuss and finalize project details. This meeting was arranged immediately with SDG&E's Project Technical Lead after confirmation of project approval and included internal project team and stakeholders (intended uses of project results), and key contractors and subcontractor personnel. The

two main aspects discussed were project execution considerations and interfacing with the SDG&E project team.

Below is the summary of the outcomes and deliverables for this task:

Specification document was created for covering the project execution and interfacing logistics aspects discussed in the Kickoff Meeting (including project objectives, methodology, scheduling and resourcing plan, interface procedures, financial considerations, etc.). Additionally, a data request document was created for requesting details regarding SDG&E systems and practices.

Technology transfer aspect was given the highest priority. Throughout the project, key stakeholders and engineers from various department were included in the design and testing of the control system. The system operators and distribution planning group were key contributors in the development of the visualization screen, concept of operation document, and determination of priority stacks for managing DERs. In addition, several workshop and knowledge sharing sessions were held with the utility engineers and system operators to ensure they are fully informed about the system features and trained on utilizing the demonstration system. Below is a summary of various knowledge transfer sessions.

The following meetings and workshops were held to share the information with various stakeholders and public:

- Stakeholder fact finding workshop (April 2017): People from several department attended the workshop, discussing needs, gaps, and requirements of new systems.
- Three full days of training and testing of the control platform in the lab as part of the acceptance testing and scheme verifications (July 2017): 3 people attended extensive acceptance testing.
- Demonstration workshop of the tools and methodology (Oct 2017): workshop and knowledge transfer session at SDG&E on the project findings and recommendations.
- It is proposed to share the project information in various workshop and taskforces focusing on DERs and voltage/reactive power management of the systems.
- In addition, to further benefit the public, there are plans to publish conference papers and present at public forums on the project results.

Task 2 – Baseline Evaluation and Analysis

This task was performed in the following three stages:

- Review and assessment of SDGE's existing control strategies and operational practices
- Assessment and prioritization of existing and futuristic operational practices in industry
- Identification and selection of a circuit for test system

Task 3 – Concept of Operations (CONOPS)

This task involved the development of the overall concept of operations for the proposed aggregator-based technology including:

- Developing a conceptual system architecture
- Proposing system operational requirements
- Developing use cases

- Proposing the control approaches
- Determining the information exchange among system components

Task 4 – Design Test System

This task involved the development of the test plan and specification of the testbed with which to execute the test plan. This task was broken down into three distinct sub-tasks:

- Development of testing aspects, requirements, and implementation for the evaluation and demonstration of the Concept of Operations defined in Task 3. Included in this was the definition of the devices and controls which were investigated in the testing procedure to implement the plan.
- Type testing of the technologies which were included in the demonstration, to characterize and quantify performance and capability in a stand-alone environment (performance results of these devices are included in the following parts of this report).
- Development of testbed for demonstration of CONOPS in a fully integrated system and hardware testbed environment.

Below is the summary of the outcomes and deliverables for this task:

- Overview of the test plan and how it addresses the aspects and operational goals stated in the Concept of Operations from Task 3
- Control algorithms to be used in the devices
- Details on the test plan and use cases
- Report on stand-alone type testing of hardware devices under investigation
- Proposed PHIL testbed system architecture including:
  - Required hardware resources for construction of testbed and plan for integration
  - Distribution feeder model development and verification
  - Description of interfaces and intermediaries between software model and physical hardware

Task 5 –Test System Setup and Integration

This task involved the construction and integration of the proposed and agreed-upon PHIL testbed from Task 4. The following aspects were discussed:

- Required hardware resources including digital simulation platform racks and I/O cards, grid simulators, load banks, DER, etc.
- Efforts required for integration of hardware elements
- Development of interfaces and intermediaries between hardware elements and the digital simulation platform
- Testing efforts required to validate the testbed
- Timeline and access considerations
- Coordination and scheduling for the shipping of required hardware to the SDG&E testing facility
- Coordination and scheduling for demonstrations

In particular, various aspects of the test system development implementation were coordinated closely with the SDG&E Project Team to ensure that required resources, lab access schedule, and test demonstrations requirements were mutually agreed upon. Several validation tests were conducted on the hardware testbed to ensure that all hardware and software components and elements were correctly integrated. Once the test system setup and integration was finalized, the final site acceptance test (SAT) was performed at the SDG&E test facility.

Below is the summary of the outcomes and deliverables for this task:

- Successful construction and integration of the software and hardware testbed proposed in Task 4 at SDGE's Integrated Test Facility
- Report on validation tests to ensure proper assembly and integration of the testbed
- Coordination with SDG&E Project Team for evaluation and demonstration tests of the devices under investigation

Task 6 – Conduct Pre-Commercial Demonstration

This task covered the execution of the test plan developed in Task 4 to evaluate and demonstrate the capabilities and performance of the RAMCO/LRAM and control methodology. For each test, data gathering methodologies and procedures were defined. Included in the test plan were milestone tests; each of which defined when a particular operational aspect had been conclusively demonstrated, or whether further testing was required. The SDG&E Project Team were provided with the test plan prior to the scheduled demonstration tests.

Below is the summary of the outcomes and deliverables for this task:

- Test plan applicability to Concept of Operations developed in Task 4
- Development, integration, and validation of testbed and simulation assets
- Test plan for validation and demonstration of operational concepts
- Methodologies for analysis
- Analysis of test results
- Preliminary findings on viability of deployment of RAMCO/LRAM control methodology

Task 7 – Operational Procedure Evaluation and Advancement

This task utilized the knowledge gained and observations obtained from all other investigations and tests in the previous tasks to develop operating procedures and standards for the operation of the next generation of smart utilities. As a result of the new technologies and procedures, the distribution system design and planning methodology may need to be revisited and enhanced to incorporate some features offered by new technologies, particularly the value-added proposition of the aggregator-based control structure to increase the utilization factor of distribution-level DER assets.

Task 8 – Data Assimilation, Analysis, Formulation of Findings, Conclusions, and Recommendations

The project team collected data during testing performed at SDG&E ITF, and performed detailed analysis using the captured data, including functionality of control methodologies in the distribution system. The study also investigated the benefits, costs, challenges, and impact of adopted control structure on SDG&E distribution systems and equipment, particularly with respect to operational situations (use case

scenarios). The analysis also covered the possible effects on system reliability, financial impacts, and improved service quality for customers.

The project team assessed the impacts of the deployed control structure on the interoperability, reliability, power quality, power losses, financial impacts, and improved/deteriorated service quality for customers. The project team used the measurements of power quality, and improvements in electrical efficiency and ability to meet conservation voltage reduction targets as metrics in the project.

Below is the summary of the outcomes and deliverables for this task:

- Data analysis approach/methodology
- Data analysis
- Findings, conclusions, and recommendations
- Key algorithms and parameter selections

Task 9 – Comprehensive Final Report

This final report was developed, which is a comprehensive record of the work, findings, and recommendations. The report is intended to enable stakeholders to understand and use the project's output.

2 DESIGN AND TESTING

This section discusses the work performed to design and prepare the control architecture and test system utilized in the project. As one of the initial tasks of the project, a comprehensive baseline evaluation and analysis was performed on the present architecture of distribution system control and operation in SDG&E to identify the future needs and advancement of system operation under the presence of DERs and controllable assets on the secondary systems. Based on the outcomes of baseline evaluation and analysis, the concept of operations for the demonstration system was prepared to propose the control architecture and define the use cases that meet the identified requirements of distribution systems in presence of DERs. One of the major tasks of this project was to design and setup the demo test system that fully meets the project objectives and requirements. The test system was envisioned to include DERs and controllable assets in both primary and secondary systems. In particular, for secondary systems, two of commercially available secondary system Volt/VAr regulation devices were selected and type tested to ensure that they fully fit into the project functional requirements. Factory Acceptance Test (FAT) was performed to verify the basic functionality of the proposed aggregator-based architecture. The project was involved with a final Site Acceptance Test (SAT) at SDG&E testing facility to ensure the proper operation of RAMCOs and LRAMs and the rest of the testbed for the final demonstration.

In the following subsections, first, baseline evaluation and analysis of present architecture of distribution system control and operation in the SDG&E context is discussed. Then, the project Concept of Operations are presented. Next, the test system design and circuit selection criteria are described. Finally, the type testing, acceptance test plans and results of the pre-commercial demonstrations are presented.

2.1 Baseline Evaluation and Analysis

The first part of this section provides information about the architecture of distribution system control and operation. Then, in the second part, the future needs and advancement of system operation is elaborated to address the ongoing changes in the control structure of distribution systems under the presence of DERs and controllable assets on the secondary of service transformers (secondary systems). Based on these requirements, an aggregator-based architecture is proposed which is able to control and utilize all controllable assets on primary and secondary systems. Finally, the criteria used to select the candidate circuits for testing the proposed architecture are summarized.

2.1.1 Present Architecture of Distribution System Control and Operation

Conventional distribution control systems tend to be centralized in nature. As shown in Figure 2-1 below, a central control center, namely SCADA, communicates with an array of substation and field-based Intelligent Electronic Devices (IEDs) – polling them on a periodic basis to extract digital and analog data, and issuing commands to control primary apparatus and reconfigure the system, as and when human operators deem it necessary. In this architecture, primary assets located on the primary side of service transformers (e.g., 12 kV level) are the main players that are monitored and controlled [1].

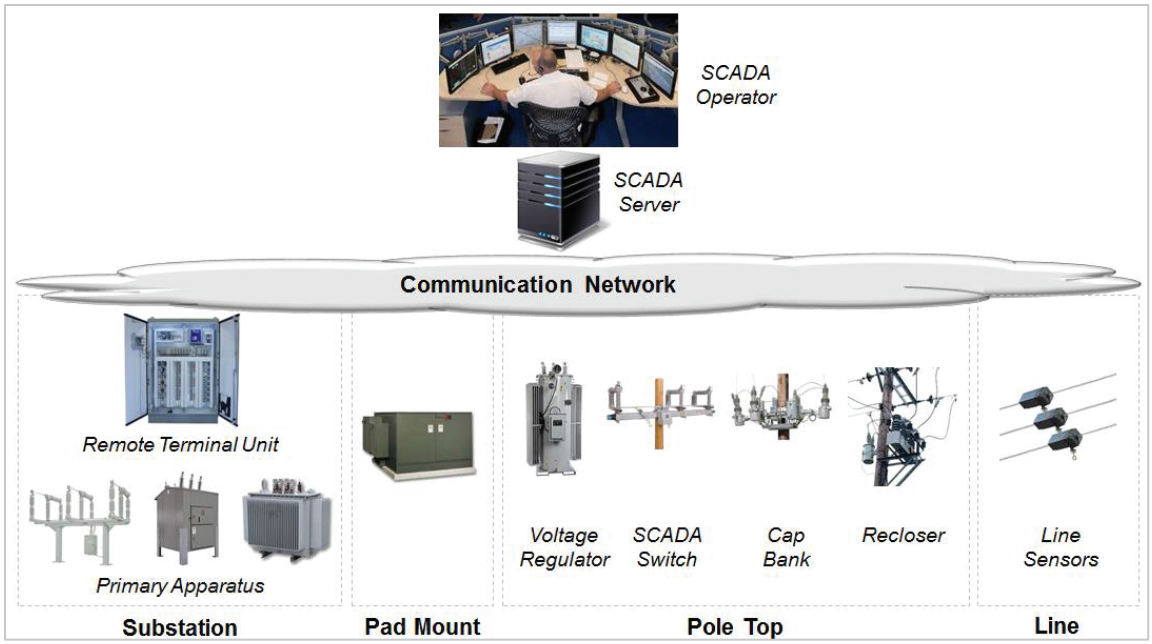


Figure 2-1. Simplistic Representation of Conventional Distribution Control System

Generally speaking, SDG&E has been one of the early adopters of distribution system SCADA (D-SCADA) to achieve real-time monitoring and control of distribution substations and field assets as part of the primary distribution circuits. It should be noted that SDG&E uses a completely different package and vendor product for transmission SCADA. Hence, the term D-SCADA is used in this report to specifically refer to the distribution SCADA. D-SCADA coverage can be summarized as follows:

- Over 80% of the distribution substations are covered by D-SCADA.
- Not all the field devices are connected through SCADA.
  - Almost all protective devices at substations or on the circuits (such as circuit breakers and reclosers), and some tie-switches and sectionalizing switches are SCADA-enabled switching devices.
  - There are about 130 SCADA controlled capacitor banks on the distribution circuits. Only voltage measurement is available on some older generations of pole-mounted SCADA capacitors and some pad-mounted capacitors when they are in submersed Vault.
  - There are a few SCADA-enabled line voltage regulators; they only provide voltage measurement (neither the current nor tap position is monitored).

SDG&E also utilizes the Network Management System (NMS) platform that brings together the Outage Management System (OMS) and Distribution Management System (DMS). This OMS/DMS platform interfaces with D-SCADA for processing the monitored data points and for executing the control commands issued by the operators or automatically generated through automation schemes or group functions.

The D-SCADA is like a Front-End System (FES) for the NMS; it communicates bi-directionally with the substation and field devices and provides data to, and accepts controls from, the NMS. The NMS is the primary interface for the operators to control and monitor the system. However, because the D-SCADA

preceded the NMS and was once used by the operators for control and monitoring, and since this functionality was never disabled, the D-SCADA can be used as a back-up to the NMS for operator control. In addition, the handling of some emergency situations, like rolling black-outs, fire threats, (involving disabling auto reclosers in the fire potential areas), or primary load shedding are strictly implemented in and executed from the D-SCADA.

The communications infrastructure that is presently used to enable D-SCADA control for the field devices has the following typical characteristics:

- Serial communications are dominantly applied, one or a maximum of two substations presently using IP-based communications,
- A mix of radio, T-lines, and in some cases fiber connections, are used for D-SCADA,
- SCADA Caps work with 900MHz radio with fixed channel which supports multiple addresses,
- There are no radio communications devices inside substations,
- SCADA for circuit devices on distribution systems including SCADA Caps are based on legacy protocols (SCOM) and in some cases using DNP3 protocol; the plan is to convert all communications to DNP3,
- SCADA measurements provide report by exception and at a fixed interval,
- Information from SCADA goes to DMS/OMS and they get archived in PI Historian database.

The key control and automation functions are described below.

2.1.1.1 Localized (Circuit Based) Voltage and Reactive Power Control

The general approach for circuit voltage control and regulation under varying load conditions is based on using:

- Load Tap Changers (LTC) on transformer banks at substation,
- Fixed or switched shunt capacitors on circuits, close to load centers,
- Line voltage regulators,
- Shunt capacitors at substation.

From the design consideration, to maintain voltages, the primary solution is to install capacitors on the circuits near the load centers. The voltage regulators and LTCs are also used on long circuits and when multiple circuits are supplied from a single transformer bank. Urban dense circuits may only have one or two fixed and/or switched shunt capacitors, while long rural circuits can have a combination of several shunt capacitors (up to 4 or 5 switched capacitors) and two or three line voltage regulators per backbone to maintain voltage levels within permissible ranges.

SDG&E presently categorizes the distribution circuits in two types from the voltage control view:

a. Conservation voltage reduction (CVR) circuits
b. Non-CVR circuits

The main difference between a CVR and Non-CVR circuit is the operating voltage range. The permissible voltage range for CVR and non-CVR circuits (normal circuit configuration) is given in the table below.

Table 2-1. Voltage Ranges for CVR and Non-CVR Circuits

	Maximum Voltage	Minimum Voltage	Contingency Voltage (min)	Service entrance voltage
Non-CVR circuits	12.6 kV (1.05 pu)	11.9 kV (0.992 pu)	11.5 kV (0.958 pu)	120 Vac
CVR circuits	12.3 kV (1.025 pu)	11.9 kV (0.992 pu)	11.5 kV (0.958 pu)	120 Vac

As shown in

Table 2-1, the main difference is in the upper voltage threshold applied to the circuits. The operating voltage for the CVR circuits is lowered to reduce consumption and losses. In either case, the voltage at the Residential Customer Service Entrance should not exceed 120 Vac to meet California Rule 2 requirements. The limit is 126 V maximum service voltage for agricultural and industrial distribution circuits.

2.1.1.2 ADMS Functions: VVO Tool

SDG&E DMS/OMS platform includes several advanced control and automation functions that are all packaged under ADMS (or Advanced DMS). Example functions are: Fault Location, Isolation, and Service Restoration (FLISR), Volt/VAr optimization scheme (VVO). ADMS is an ongoing development project; some functions are automatically applied in production stage (e.g. FLISR), while other functions (e.g. VVO) are primarily utilized in simulation mode and would only be performed by the operator as needed.

A summary of the VVO scheme is provided below.

SDG&E has been examining the VVO as part of the ADMS for a while, and running the tool in simulation mode (not in production stage yet). The key features of VVO tool that are implemented in SDG&E ADMS are as follows:

- The VVO tool is an optimization scheme; it can be used to perform a single objective function – either CVR or loss minimization.
- The VVO tool will aim to achieve as much reduction as possible in losses or voltage, while meeting voltage constraint. There is a chance that power flow does not converge and there will be no solution.
- Solar PV generation is scaled based on weather data forecasting and applied to the nameplate rating of existing DG units (e.g. aggregated roof-top PV systems per transformer) in the analysis. Solar data is based on day ahead forecast. Nameplate ratings of DG units are extracted from GIS.
- ADMS Volt/VAr optimization is built into NMS that also has the latest system topology (as-switched). In short, the optimization scheme follows the steps described below:
  - The list of feeder devices, (voltage and reactive power control devices), to be included in the optimization, will be selected to be part of a controllable set.
  - As-Switched system model is used. There is a model definition for each device. Any new device on the system should be defined; for example, DVC or load break switch will be introduced as a

library model using an existing template. Each model incorporates the basic nameplate data and control/operation characteristics.

- Options for load profile, (real time 3 week rolling average, with specific load scaling factors to be incorporated), and voltage limits are considered:
  - Every transformer has profiles; load profile gets adjusted based on measurement at feeder head which will be applied to all loads.
  - Specific periods can be analyzed; it can look at daily peak or annual peak condition.
  - Scaling factor for load growth is considered; it can set desired voltage limits for the entire circuit.
  - Load model is based on 50% constant power and 50% impedance (profile has P and Q, scale each individual P and Q according to SCADA on feeder head).

- Load profile for analysis is the key point:
  - Load per transformer is updated and adjusted to reflect contribution of distributed resources at the service transformer; this is the same planning load data that will be also used for any load restoration or load shedding purpose.
  - Load data is based on historical information, which is updated every day early morning for the representation of the power flow for that day.
  - Load data and transformer size are used to project secondary level voltage on 120V base for evaluation.
  - Real time and forecasted power flow solutions will take into account 48 hours of weather forecast data, or AMI data (imported once daily at 5:30am), for PV.
    - Based on ratings and types of DG the amount of generation is predicted; then, based on transformer profile, load is adjusted.
    - All solar PV systems are adjusted based on weather forecast (any size).
    - Batteries have profiles assigned to them based on applications, for instance a peak shaving profile.
    - All distributed resources are aggregated at service transformers
- The plan is to run optimization every hour to obtain and update status of SCADA field devices (LTC, capacitors and voltage regulators).
  - To apply optimization data to the field, SCADA devices should be in manual mode to receive new commands, for instance, for tap position.
  - SCADA response for controlling field devices is about 3 to 5 seconds round trip; this includes status verification that a command was received by a field device.
- Device actions and changes are determined from a priority list; for instance, tap changing has priority over capacitor switching. Priority selection is by assigning a number, a lower number means a higher priority.

The key aspect to consider is that VVO is an optimization tool that has to be executed by request or according to a pre-specified time schedule (for example, every day or every hour). The tool does not have the capability to be alerted of a high or low voltage situation, and initiate optimization to correct voltage issue within the given time schedule; however, an operator can re-run the tool on demand. Operators receive voltage alerts in SCADA and can re-run the VVO as needed.

2.1.1.3 Field-Based Controls: DERMS

DERMS is considered as a control platform for monitoring and managing DERs that are SDG&E owned or third party owned and operated as parts of the key automation applications such as microgrids in the field. An example of DERMS is presently under implementation and testing within the SDG&E territory. This DERMS is specifically designed for substation microgrid. It primarily controls two diesel generators and battery energy storage systems (BESSs). The coordination between DERMS and D-SCADA is performed through a substation automation controller at the substation level. For the specific purpose of an application such as microgrid, if DERMS needs to open or close a primary feeder device (e.g. a recloser or a switched capacitor), the command has to be executed through the associated automation controller unit following pre-established distribution operation procedures (DOPs).

2.1.2 Future Needs and Advancement of System Operation

Due to the presence of DERs in distribution systems and controllable assets on the secondary systems, the addition of DSO and aggregators to the distribution system control structure at both regional and local levels is proposed. The introduction of RAMCOs and LRAMs is expected to enable the proposed distribution control methodology to effectively coordinate and manage the operation of existing legacy and future control devices.

RAMCOs are designed to control large DERs that are directly connected to primary distribution feeders such as centralized MW size PV systems, and feeder/substation level BESSs. LRAMs are designed to control and interact with smaller size DERs connected to the secondary side of service transformers in residential and small commercial level (secondary systems). In the hierarchical control structure of distribution systems, DSO, a supplement to SCADA and DMS, stands as the first hierarchy that forecasts the real-time available capacities in each region, determines the requirements to provide ancillary services accordingly, and sends out the capacity request signals to RAMCOs. It should be noted that DERMS is an intermediate step toward developing a full and comprehensive DSO integrated into SCADA. Based on the received capacity signals, RAMCOs are responsible for determination and optimization of control points for DERs and LRAMs. RAMCOs are envisioned to have peer-to-peer communication with each other and shall update their reserve capacity level and information at DSO level.

At the secondary systems level, LRAMs are envisioned to be responsible for managing the service transformers' loading by controlling DERs, switchable loads and charging level, and the sequence and/or timing of charging for Plug-in Electric Vehicles (PEVs). LRAMs use the aggregate charging demand, local production levels, and dynamic rating of service transformers, and take effective actions to meet the RAMCO published target. In addition, they need to properly manage resources if the loading of service transformers gets close to its dynamic rating.

2.2 Concept of Operations (CONOPS)

2.2.1 System Architecture

The overall architecture of proposed aggregator-based control is shown in Figure 2-2. This architecture includes three main levels; control center, RAMCOs, and LRAMs, which are elaborated as follows:

Control Center: The control center brings together the Distribution Management System (DMS) and Distribution System Operator (DSO) which interface with the distribution SCADA (D-SCADA) system for processing the monitored data points and enables executing the control commands issued by the

operators or automatically generated through automation schemes or group functions. The control center sits at the top of the control hierarchy, which consists of the DSO, the DMS and the SCADA. The DMS acts as a decision support system to assist the control room and field operating personnel with the monitoring and control of the electric distribution system. Improving the reliability and quality of service in terms of reducing outages, minimizing outage time, maintaining acceptable frequency and voltage levels are the key deliverables of a DMS. No forecasting is done at the DSO. The DSO receives load forecast from DMS/SCADA and resource estimate from RAMCOs. SCADA is the front-end system for the control center that handles all of the communications to field devices (i.e. RAMCOs), and the market operator. For the purposes of the project, the control center is modeled as a basic representation of the DSO and SCADA that allows manual changes to setpoints and control modes, and provides basic visualization of real-time values. Ultimately, this representation would need to be reflected in the deployed NMS to enable interaction with a field-deployed RAMCO [2].

RAMCO: The RAMCOs act as aggregators, providing an interface between upstream entities (e.g. a utility operation center or another aggregator), and various downstream DERs and customer loads. They receive the signals from the DSO and manage the control and optimization of the operating points of the primary DERs in the medium voltage level of distribution system, as well as the LRAMs, for meeting the capacity request command – for both real time capacity (power level) and reserve capacity (energy level on 5 minute basis).

RAMCOs are envisioned to control large DERs that are directly connected to primary distribution feeders, such as centralized utility size PV systems, feeder/substation level energy storage systems (ESSs), and downstream LRAMs. RAMCOs are assigned regionally according to the divisions defined by geographical or operating service similarities.

LRAM: LRAMs are envisioned to have autonomous control over the local resources to meet the assigned targets by the corresponding RAMCO. LRAMs are designed to control and interact with smaller size secondary DERs connected to the secondary side of service transformers at residential and small commercial levels (secondary systems). LRAMs are also responsible for managing thermal loading and any reverse power flow constraint on associated service transformers. In general, LRAMs deal with resources connected to secondary systems at a low-voltage side of service transformers, while RAMCOs manage a set of LRAMs and any individually controlled large-scale centralized DERs connected directly to medium voltages of a distribution system.

2.2.2 DSO Operating Principles

Table 2-2**Error! Reference source not found.** summarizes the principles that drive the DSO control commands to ensure a smooth and safe operation of the network. This table covers the proposed operating principles for the DSO. In this project, two overall operating modes are considered for DSO:

- Normal: This mode is normally enabled under normal operating conditions when the control actions requested by the DSO can be taken in a relatively longer time.
- Emergency: In this mode, requested control actions from the controllers (RAMCO, LRAM, etc.) should be taken in a shorter time frame than that of Normal mode. In other words, there is a defined time from the instant the request is issued until it is executed.

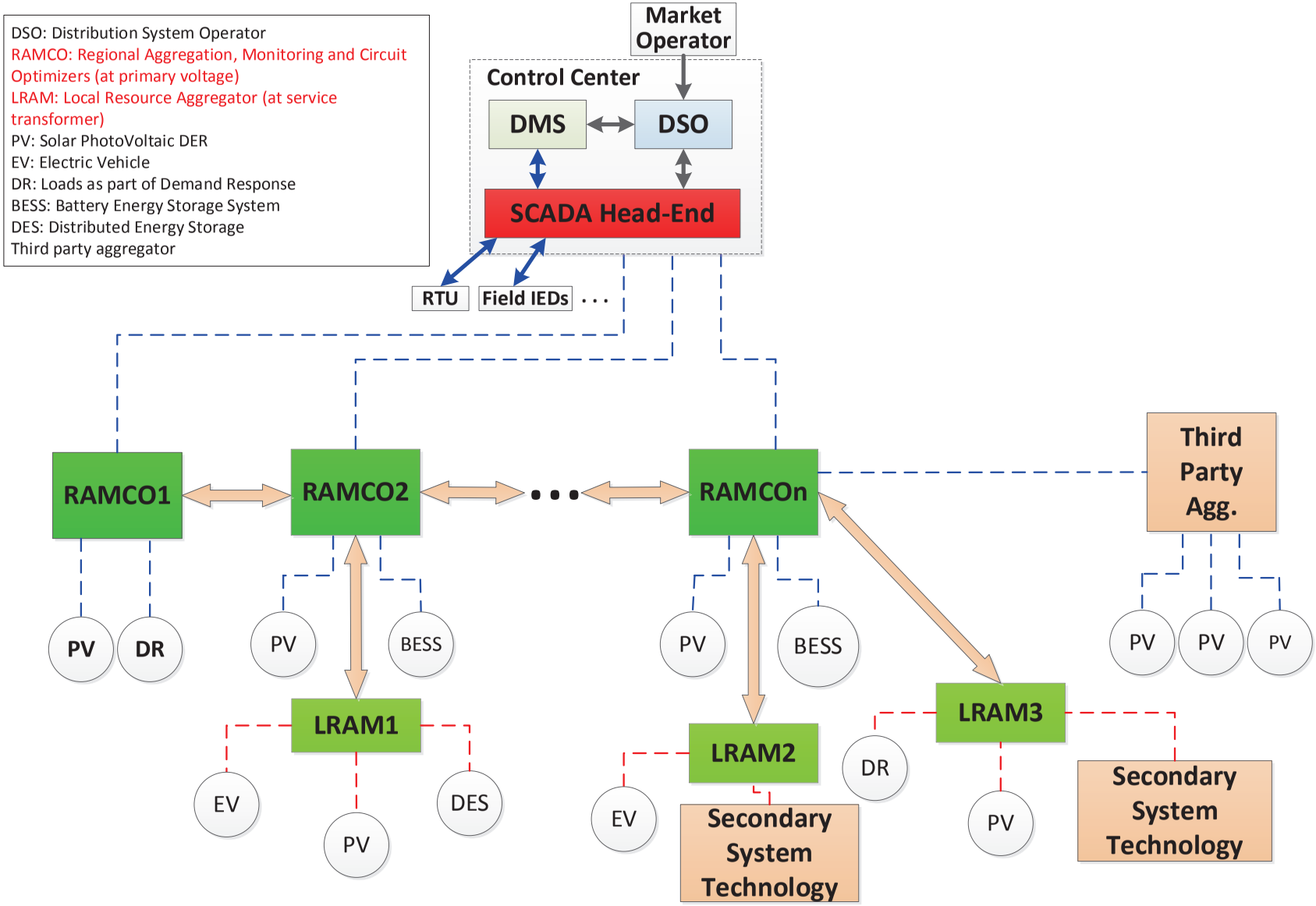


Figure 2-2. Proposed Aggregator-Base Architecture

Table 2-2. DSO Operating Principles

DSO Mode		Normal				Emergency		
Use case		Near real-time resource aggregation	Circuit reconfiguration	Load management	Reactive power management for VVC on secondary system	Near real-time resource aggregation	Circuit reconfiguration	Emergency dispatch of DERs for demand side management
Triggering Event		Every 5 min update in DSO	Switching device status (Tie Switch and reclosers 1 and 2)	Operator	Operator	Every 5 min update in DSO	Switching device status (Tie Switch and reclosers 1 and 2)	• Operator • Thermal limit violation (SCADA notification) • Load shedding request by CAISO
Actor	DSO	Monitoring and resource aggregation on RAMCOs	Monitor the status of switching devices through SCADA and send appropriate Topology ID to RAMCOs.	• Receiving the market price signal • Calculating the overall reserve capacity (%) • Defining the contribution targets and SOC targets for RAMCOs	• Defining the reactive power contribution targets for RAMCOs • Defining the voltage target for RAMCOs (e.g., for CVR)	Monitoring and resource aggregation on RAMCOs	Monitor the status of switching devices through SCADA and send appropriate Topology ID to RAMCOs.	Defining the active power contribution target for RAMCOs considering thermal limits.
	RAMCO	Monitoring and resource aggregation on primary DERs and LRAMs.	Use the lookup table and define LRAM IDs based on the Topology ID received from DSO.	• Define the active power contribution targets for LRAMs and primary DERs • Define SOC targets for LRAMs & primary BESS • Set the DER Q control to power factor control (pf=1 is target).	• Defining the reactive power contribution targets for LRAMs and primary DERs • Defining the voltage target for LRAMs (e.g., for CVR).	• Monitoring and resource aggregation on primary DERs and LRAMs • Set the DER Q control to V-Q droop at POI	Use the appropriate circuit topology lookup table based on the Topology ID received from DSO.	• Defining the active power contribution targets for LRAMs and primary DERs • Set the DER Q control to V-Q droop at POI
	Primary PV	Primary PVs are in dynamic power factor control mode with the unity pf target at POI (12kV).	Primary PVs are in dynamic power factor control mode with the unity pf target at POI (12kV).	• Curtailment/restoration of active power based on the RAMCO command. • Reactive power of primary PVs are set at zero to meet unity power factor at POI (pf=1).	Primary PVs are in power factor control mode to meet the reactive power setpoint defined by RAMCO.	Primary PVs are utilized in V-Q droop control mode.	Primary PVs are utilized in V-Q droop control mode.	• Curtailment/restoration of active power based on RAMCO command. • Reactive power setpoint is defined by V-Q droop control.

DSO Mode		Normal				Emergency		
Use case		Near real-time resource aggregation	Circuit reconfiguration	Load management	Reactive power management for VVC on secondary system	Near real-time resource aggregation	Circuit reconfiguration	Emergency dispatch of DERs for demand side management
	Primary BESS	BESS units are in dispatch mode with reactive power setpoint set at zero.	BESS units are in dispatch mode with reactive power setpoint set at zero.	• Charge/discharge based on RAMCO command • Alarm if SOC targets are violated. • Reactive power target is zero or defined by RAMCO (depending on DSO Ctrl Mode).	BESS units are in dispatch mode to meet the reactive power setpoint defined by RAMCO.	BESS units are utilized in Q-V droop control mode.	BESS units are utilized in Q-V droop control mode.	• Charge/discharge based on RAMCO commands • Reactive power setpoint is defined by V-Q droop control.
	Primary FG	Reactive power setpoint of primary FGs at POI (12kV) is set at zero.	Reactive power setpoint of primary FGs at POI (12kV) is set at zero.	• Primary FG units are used in dispatch mode to follow RAMCO P command • Reactive power setpoint of FGs is set at zero or defined by RAMCO (based on DSO Ctrl Mode)	FG units are in dispatch mode to meet the reactive power setpoint defined by RAMCO.	No reactive power control is done on FG units in emergency mode.	No reactive power control is done on FG units in emergency mode.	• Primary FG units are used in dispatch mode to meet RAMCO P command • No reactive power control by FG units in emergency mode.
	LRAM	• Secondary voltage control at the customer terminal (pre-set voltage target is 118V-123V secondary). • Power factor should be maintained at unity at the secondary of service transformer (voltage control has the priority) * Monitoring and resource aggregation on secondary systems	• Secondary voltage control at the customer terminal (pre-set voltage target is 118V-123V secondary). • Power factor should be maintained at unity at the secondary of service transformer (voltage control has the priority) • Monitoring and resource aggregation on secondary systems	• Defining the targets for secondary DERs to meet the active power target defined by RAMCO (Load shedding is not allowed). • Secondary voltage control at the customer terminal (The voltage target is defined by RAMCO or is the preset voltage reference depending on DSO control mode). • Determine the SOC target for secondary ES. • Reactive power control at the secondary of service transformer to meet the target defined by RAMCO, or unity power factor (based on DSO control mode)	• Secondary voltage control at the customer terminal (voltage target is defined by RAMCO). • Reactive power control at the secondary of service transformer (Reactive power target of LRAMs is defined by RAMCO).	• Secondary voltage control at the customer terminal (pre-set voltage target is 118V-123V secondary). • Power factor should be maintained at unity at the secondary of service transformer (voltage control has priority) * Monitoring and resource aggregation on secondary systems	• Secondary voltage control at the customer terminal (pre-set voltage target is 118V-123V secondary). • Power factor should be maintained at unity at the secondary of service transformer (voltage control has priority) * Monitoring and resource aggregation on secondary systems	• Defining the targets for secondary DERs to meet the RAMCO active power target (non-critical load shedding is allowed) • Secondary voltage control at the customer terminal (pre-set voltage reference). • Power factor should be maintained at unity at the secondary of service transformer (voltage control has priority)

DSO Mode		Normal				Emergency		
Use case		Near real-time resource aggregation	Circuit reconfiguration	Load management	Reactive power management for VVC on secondary system	Near real-time resource aggregation	Circuit reconfiguration	Emergency dispatch of DERs for demand side management
	Secondary PV	Secondary PVs are in power factor control mode, controlled by LRAM (Q setpoint).	Secondary PVs are in power factor control mode, controlled by LRAM (Q setpoint).	Secondary PVs are in power factor control mode, controlled by LRAM (curtailment/restoration and VAr control).	Secondary PVs are in power factor control mode, controlled by LRAM (Q setpoint).	Secondary PVs are in power factor control mode, controlled by LRAM (Q setpoint).	Secondary PVs are in power factor control mode, controlled by LRAM (Q setpoint).	Secondary PVs are in power factor control mode, controlled by LRAM (curtail/restore and VAr control).
	Secondary DES	Secondary DESs are in dispatch mode with reactive power controlled by LRAM (Q setpoint).	Secondary DESs are in dispatch mode with reactive power controlled by LRAM.	Secondary DESs are in dispatch mode and their P and Q are controlled by LRAM.	Secondary DESs are in dispatch mode, and their reactive power is controlled by LRAM.	Secondary DESs are in dispatch mode, and their reactive power is controlled by LRAM.	Secondary DESs are in dispatch mode, and their reactive power is controlled by LRAM.	Secondary DESs are in dispatch mode and their P and Q are controlled by LRAM.
	Level 2&3 EVSE	NA	NA	NA	NA	NA	NA	Throttling down the charging rate

2.2.3 Use Cases

This project addressed the following three use cases further described in the subsequent sections:

- Near Real-Time Resource Aggregation,
- Emergency Dispatch of DERs for Demand Management, and
- Volt/VAR Management on Secondary System.

2.2.3.1 Near Real-Time Resource Aggregation

2.2.3.1.1 Problem description

DSOs are mainly responsible for operating, maintaining and developing an efficient electricity distribution system; however, they are also taking a new role of facilitating effective and well-functioning retail markets that give options to the customers to choose the best supplier and allow suppliers to offer the best services to customers.

In this new role as neutral market facilitators, DSOs are evolving towards information hubs to perform a reliable and swift change of suppliers. In addition, a DSO should have near real-time information about available and estimated resources, (all controllable/switchable and intermittent/variable generation, energy storage, and loads), on a 5 minute basis. Such a role requires the DSO be aware of the real-time supply information in each control region.

To that end, it is essential for the DSO to collect and process appropriate information from the devices and/or subsystems within the distribution grid; this information is utilized by the DSO to perform operational/market optimizations.

2.2.3.1.2 Proposed Solution

The flow of information for this use case is from the secondary-level assets (through LRAMs) up to the RAMCOs, and from there to the DSO. More specifically, each LRAMs collects the near real-time (NRT) information of the resources which are under its control. The information is then sent to the upper-level control tier, i.e. RAMCO, which in turn collects and analyzes the NRT resource information of all the LRAMS that it is coordinating. After the analysis, the RAMCO provides the DSO with NRT resource availability information at 5-minute intervals.

The current and estimated resource capacity information was categorized by the type of the resources, including:

- Dispatch-able generation or firm generation (FG): conventional generators (e.g. rotating machine based generators) and/or non-conventional inverter-based generators, (e.g., fuel cell);
- Energy storage systems (ESSs) and available energy level (state of charge), future/forecasted state of charge (SOC) based on schedules, and control modes of the ESSs;
- Intermittent generation (IG): such as PV systems or wind turbine generators that can be curtailed;
- Switchable/controllable loads (demand response); and
- Critical (sensitive) and non-critical (non-sensitive) loads.

- The estimated resource capacity contribution and potential reserve capacity should also include any curtailed resources and time-adjustable loads.

In the normal operating mode of DSO, RAMCOS and LRAMs are expected to operate in the load management mode. In this mode, DSO adjusts the RAMCO active power contribution targets such that their reserve capacity is always above a specific target. Additionally, the contribution targets are calculated such that the state of charge (SOC) of BESS units in each RAMCO region is above a specific target that is determined by electricity market price.

2.2.3.2 Emergency Dispatch of DER for Demand Management

2.2.3.2.1 Problem description

With the proliferation of distributed energy resources (DERs) in distribution systems, it is imperative to involve them in managing the network demand in an effective and coordinated manner. In particular, since smart inverters offer several control functionalities (such as dynamic Volt/VAr control, soft-start reconnection, adjustable power factor, emergency ramp rate control, etc.), they can help with the distribution system load management. This, however, requires the dispatch setpoints of the DERs to be determined properly.

One of the DSO functions is to deal with flexible demand and operate networks that accommodate dispatch-able resources such as DERs. Local DER controllers might fail to achieve proper dispatch and demand management in distribution systems due to the lack of network-wide observability. For example, increased feed-in of DERs can lead to the reverse power flow, voltage violation, and/or other power quality issues. On the other hand, DER locations are not always ideal, and they may not be close enough to large loads to efficiently alleviate peak demands. Therefore, in modern distribution systems, the DSO along with its regional agents (RAMCOs) needs to analyze the network-wide information and effectively involve DERs in various control aspects of the system.

2.2.3.2.2 Proposed Solution

The DSO is the system operator that defines the contribution targets for all RAMCOs in order to meet its own contribution target dictated by the ISO (Market Operator). The DSO utilizes resource aggregation and estimation data from RAMCOs, as well as day-ahead load forecasting data from DMS/SCADA, to define the contribution targets for each RAMCO (one lump power/MW value). Based on these targets, RAMCOs might curtail or increase the amount of power generated in their own region and/or enforce load shedding through secondary systems (partial load reduction). RAMCOs utilize LRAMs and/or primary DERs in their region to meet these requirements. On the other hand, LRAMs receive the contribution target from their supervising RAMCO and determine the appropriate control setpoints for secondary DERs (generation/curtailment) and/or controllable loads (load shedding) to achieve the target.

If power curtailment controlled by a RAMCO is required in the region, the following actions should be taken:

- The priority is given to energy storage systems (ESSs) in both primary and secondary systems. ESSs are requested to charge as much as possible until the power curtailment target is met. The priority stack for ESSs is first to charge customer EVs, then utility storage units, then customer owned storage.

- If charging ESSs cannot meet the power curtailment target, PV systems are curtailed to achieve the target. The priority stack for variable generation is to curtail utility generation before customer generation.

If a RAMCO requires increasing the generation level in its region by utilizing reserve capacity, the following actions should be taken:

- The priority is given to the already curtailed PV systems from that region in both primary and secondary system; the goal is to fully utilize these PV systems and restore the curtailed portion of their generated power.
- This is followed by discharge of ESSs in both primary and secondary systems until the RAMCO contribution target is met.
- If after ESS discharging, the contribution target is not met yet, the reserve capacity of FG units are utilized to compensate for the unmet portion of RAMCO contribution target.
- Finally, if the target is still not fulfilled, the LRAMs have the ability to shed some loads in order to manage the demand (primarily EVs).

The priority stacks for RAMCOs and LRAMs are listed in Appendix A.

2.2.3.3 Volt/VAr Management

2.2.3.3.1 Problem description

The project work included demonstrating required changes in the control structure of distribution systems under the presence of DERs; to address integrated required changes in the control structure of distribution systems under the presence of DERs; to address integrated Volt/VAr control for the secondary systems (customer service entrance); and to utilize DER capabilities to provide reactive power support for transmission and sub-transmission systems. To achieve these objectives, an operating mode is defined for the DSO to deal with reactive power management for distribution systems and to coordinate voltage adjustment on secondary systems. In this mode, DSO is responsible for the reactive power management of DERs in the primary system (12 kV level) as well as DERs on the secondary side of service transformers.

For the purpose of secondary system controls, LRAMs are envisioned to autonomously provide Volt/VAr management by using the resources on secondary systems and/or through power electronic devices specifically installed to control voltage and reactive power. In other words, LRAMs should determine the reactive power setpoints of secondary-side DERs such as PV systems and Distributed Energy Storage (DES) units as well as dedicated power electronic-based Volt/VAr regulating devices (if available) in order to meet the reactive power contribution target and to regulate voltages of the secondary side of service transformers within an acceptable range(s).

The voltage and reactive power contribution targets of the LRAMs for the secondary systems are either fixed setpoints or defined through RAMCOs. Under normal conditions, LRAMs need to maintain unity power factor at the service transformer secondary side. If reactive power support from secondary system is needed, RAMCO sends reactive power factor setpoints to LRAMs. However, active or reactive power contribution in support of the primary systems or in response to RAMCOs should be performed independent of voltage control on secondary systems, where a secondary Volt/VAr regulating (SVVR) device exists. In other words, the secondary voltage setpoint has to be maintained by the LRAM's SVVR

device before or during contribution to RAMCO. Secondary voltage control should be given the highest priority to any active or reactive power contribution, particularly considering the statutory voltage limits.

As part of this use case, the DSO may send a request to all RAMCOs to reduce the voltages by some percentage (e.g. 4% reduction) across the secondary system (e.g. from 123V to 118V). The voltage reduction request would also be sent to LTC at the substation through SCADA controls. The DSO also determines the reactive power contribution for the grid that should be managed through RAMCOs.

2.2.3.3.2 Proposed Solution

The reactive power control strategy for primary DERs and LRAMs in the distribution circuit depends on the DSO operating mode.

In the normal case, the reactive power contribution from secondary systems is assumed to be zero (i.e., unity power factor at the point of interconnection (POI) of secondary system to the primary system). However, LRAM might be asked by RAMCOs to provide reactive power contribution to the upstream circuit; in this case, the reactive power contribution target should be defined by the RAMCO.

In the proposed control architecture, each LRAM is responsible for the controllable assets located at the secondary side of its service transformer. In this use case, the secondary Volt/VAr control (SVVC) system controls the following secondary assets:

1. An SVVR device or
2. Control of residential and commercial PV systems, energy storages, and controllable loads, where possible.

In the event, there is no SVVR device, the LRAM attempts to meet the reactive power target from the RAMCO, assuming this would not lead to a high or low voltage. For LRAMs with SVVR, both reactive power setpoints and voltage targets can be met, assuming the limits of the assets have not been met.

2.3 Design of Test System

In this task, the demonstration test system was designed. For this purpose, first, the appropriate circuits for demonstrating the performance of RAMCOs and LRAMs were selected. Then, the demonstration testbeds were designed to meet SDG&E requirements of demonstrating ten (10) aggregator devices.

2.3.1 Circuit Selection Criteria

The demonstration system included two of the SDG&E circuits connected to 12kV level substations. Figure 2-3 illustrates the simplified single-line diagram of the circuits selected. The criteria for selecting these circuits were as follows:

- Resource management and power quality issues
- High penetration of DERs (PVs and BESSs)
- Noticeable number of secondary systems
- Possibility of having different circuit topologies

The demonstration system modelled in digital simulation platform included the model of Load Tap Changers (LTC), capacitator banks, Voltage Regulators (VR), breakers, and reclosers. To take the presence and impact of large battery energy storage systems (BESSs) into consideration, a 2MW BESS unit has been added to each circuit. Additionally, a biogas generator has been added to one of the circuits representing a Firm Generation (FG) unit. RAMCO1 is responsible for controlling the DERs in North Circuit, and RAMCO2 is responsible for controlling DERs in South Circuit. The location of LRAMs in each circuit is highlighted by Node number using “ij” identifier as a subscript. Additionally, the controllable primary DERs in each circuit are highlighted as controllable nodes in Figure 2-3.

Tie Switch and reclosers 1 and 2 facilitate the investigation of the impacts of circuit configuration changes on the performance of proposed control system. Depending on the status of Tie Switch and reclosers 1 and 2, these two circuits can potentially create three different circuit topologies. Depending on the circuit topology RAMCO coverage may vary. The DERs and LRAMs designations for each topology are summarized in Table 2-3 to Table 2-5. As seen, when the circuit topology changes from Topology 1 to Topology 2, LRAM13 which was under RAMCO1 falls under RAMCO2 coverage. In Topology 3, LRAM22, LRAM23, and FG21 fall under RAMCO1 coverage.

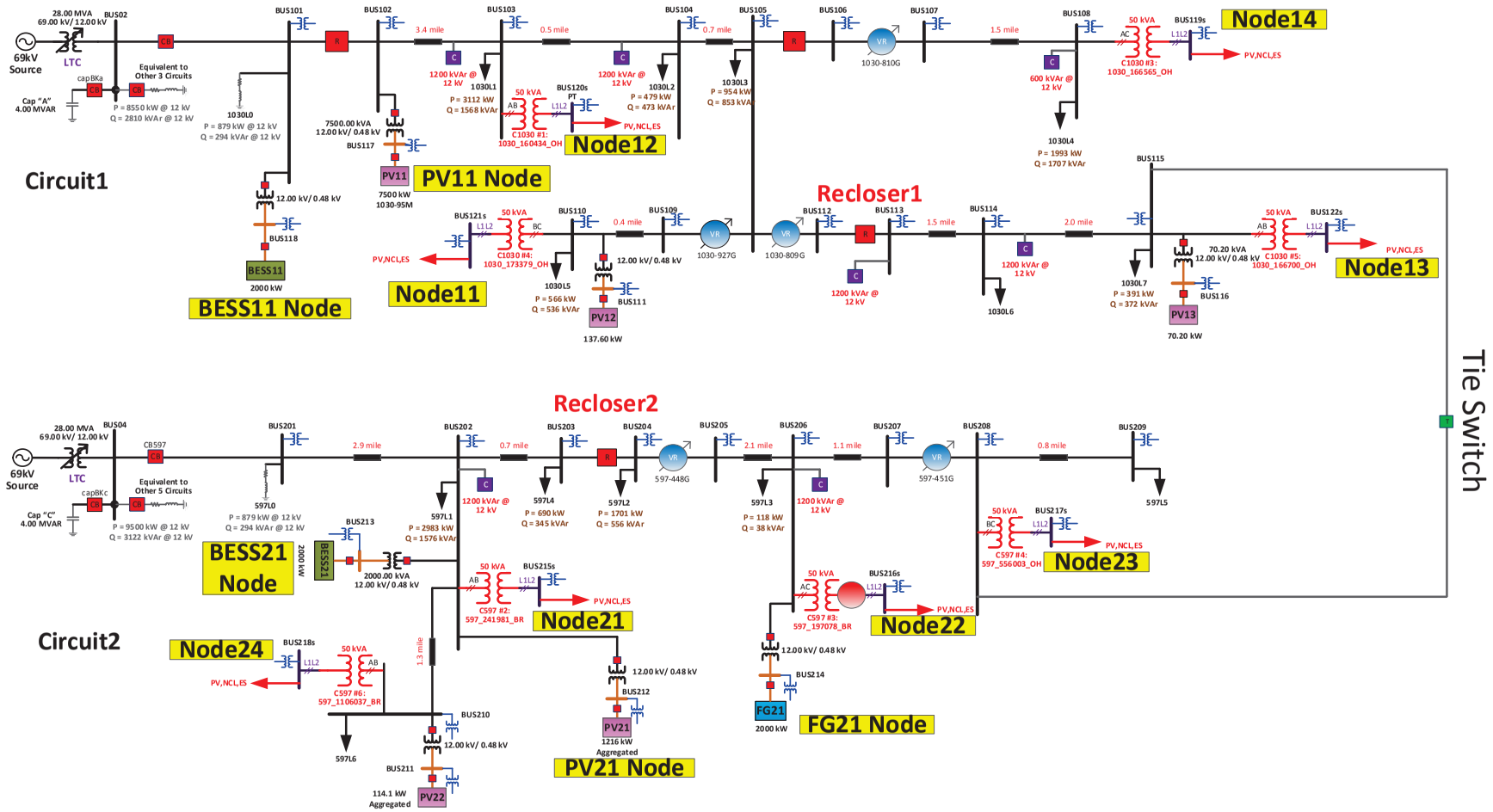


Figure 2-3. Simplified Single Line Diagram of Selected Circuits

Table 2-3. DERs and LRAMs Designations in Topology 1

Topology 1 (Normal), Topology_ID=1			
Switch	**Tie Switch**	**Recloser 1**	**Recloser 2**
Status	Open	Closed	Closed
RAMCO1		**RAMCO2**	
Actor	**ID**	**Actor**	**ID**
LRAM11	1	LRAM21	2
LRAM12	1	LRAM22	2
LRAM13	1	LRAM23	2
LRAM14	1	LRAM24	2
PV11	1	PV21	2
BESS11	1	BESS21	2
		FG21	2

Table 2-4. DERs and LRAMs Designations in Topology 2

Topology 2 (Transfer 1), Topology_ID=2			
Switch	**Tie Switch**	**Recloser 1**	**Recloser 2**
Status	Closed	Open	Closed
RAMCO1		**RAMCO2**	
Actor	**ID**	**Actor**	**ID**
LRAM11	1	LRAM21	2
LRAM12	1	LRAM22	2
LRAM13	2	LRAM23	2
LRAM14	1	LRAM24	2
PV11	1	PV21	2
BESS11	1	BESS21	2
		FG21	2

Table 2-5. DERs and LRAMs Designations in Topology 3

Topology 3 (Transfer 2), Topology_ID=3			
Switch	**Tie Switch**	**Recloser 1**	**Recloser 2**
Status	Closed	Closed	Open
RAMCO1		**RAMCO2**	
Actor	**ID**	**Actor**	**ID**
LRAM11	1	LRAM21	2
LRAM12	1	LRAM22	1
LRAM13	1	LRAM23	1
LRAM14	1	LRAM24	2
PV11	1	PV21	2
BESS11	1	BESS21	2
		FG21	1

2.3.2 Test System Development and Layout

The testbed for the evaluation and demonstration of the proposed system architecture is an integrated software and hardware environment consisting of the digital simulation platform operating in conjunction with Power Hardware-in-Loop (PHIL). The digital simulation platform was used to represent the distribution circuits used for demonstration, allowing for representation of operating conditions and provision of an environment which accurately recreates field conditions for the hardware devices in the demonstration system. Furthermore, the hardware response of devices was fed back into the digital simulation platform to allow for accurate power system response to hardware performance and control schemes.

For the integration of the devices, a power amplifier was utilized to convert the digital simulation platform representation of system parameters to a form that the hardware can use. The hardware output can then be returned to the digital simulation platform, allowing the demonstration circuit to respond realistically.

For the demonstration of the RAMCO/LRAM operation concept, the following system components were represented as follows:

- DSO – represented in a software platform
- 12kV distribution feeder, substation, and corresponding protective devices – represented in software digital simulation platform model
- 12kV DERs – represented in software digital simulation platform model
- 12kV/LV transformer – six of them simulated in digital simulation platform and two of them represented as hardware grid simulator
- RAMCO/LRAM – represented as hardware
- Secondary LV DERs and loads – represented as both hardware and in software digital simulation platform model

The selected 12kV distribution feeders were modeled and simulated in the digital simulation platform environment to generate real-time system parameters including voltages, currents, and power flow. Modeled circuits incorporated models of the conventional voltage and reactive power control devices on the circuits that are used to set the base-line voltage of the circuits, such as LTCs, voltage regulators, and shunt capacitors; they autonomously (locally) respond to system variations due to changes in daily loads and PV profiles.

Digital simulation platform modeling by necessity of limited computing capacity was approached where important points of system (including generation, storage, or switching and circuit device locations) were explicitly modeled, and sections of the circuit in between these points were lumped. Loads were lumped to the next downstream bus. Time-variant circuit aspects such as loads and generation were incorporated in the models through representative profiles.

Verifications were achieved through comparison of voltage, power flow, and fault current parameters with the reference circuit models provided by SDG&E to ensure model accuracy. Feeder and substation devices such as capacitors, regulators, protection were included in the digital simulation platform model, as discussed with the SDG&E Project Team.

The hardware components such as RAMCO/LRAM were interfaced with digital simulation platform through input/output signal modules or through intermediary power amplifier devices such as grid simulators. Two LRAMs, covering pre-commercial offerings from two partner vendors, were interacting with two fully implemented hardware secondary networks, including residential load, PV, and EV charging stations. To meet SDG&E requirements of ten (10) aggregator devices, an additional six (6) LRAMs were interacting with secondary networks modeled within the digital simulation platform. An overview of the proposed testbed is shown in Figure 2-4. The testbed installed at ITF is shown in Figure 2-5.

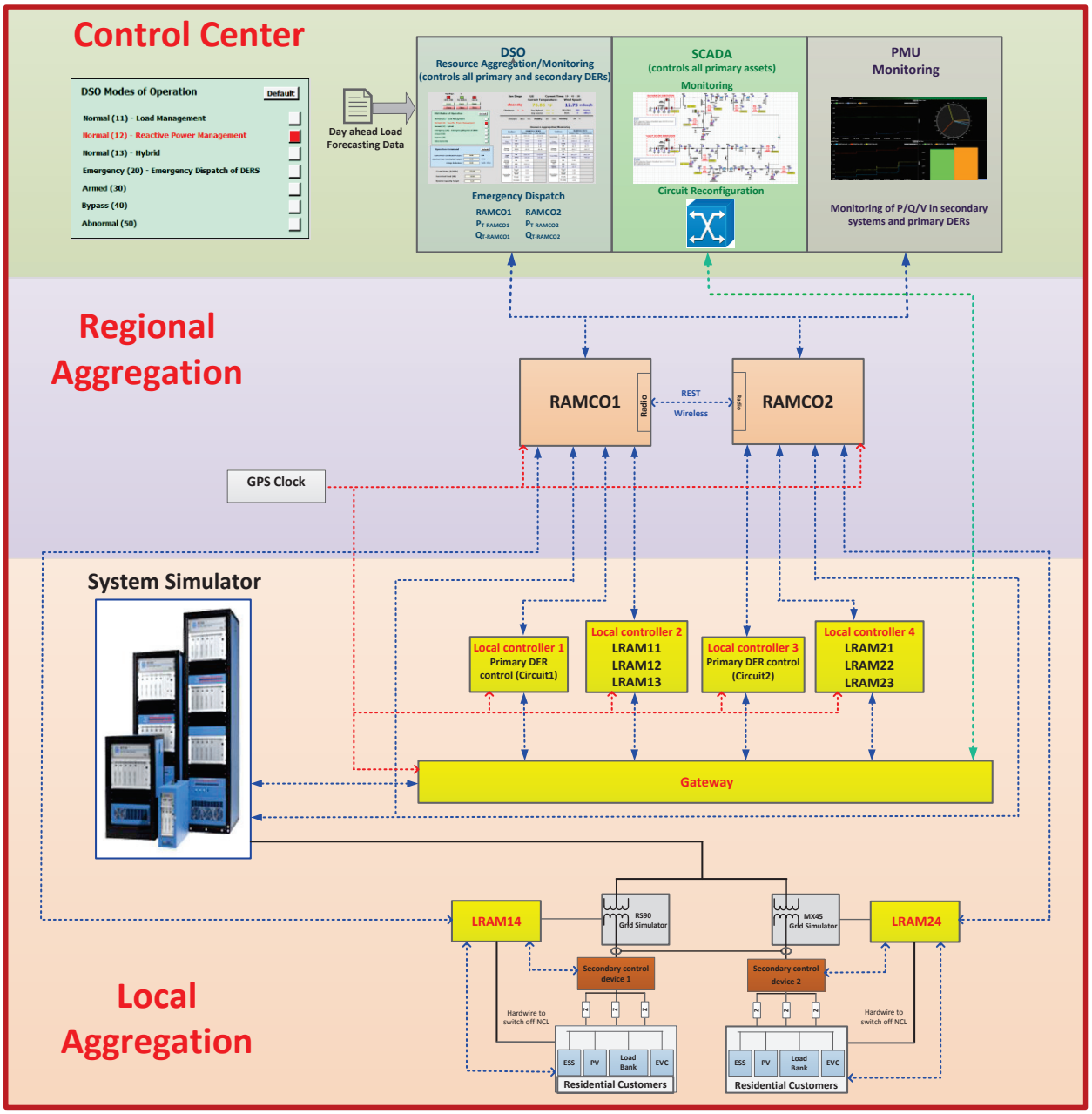


Figure 2-4. Proposed Digital Simulation Platform and PHIL Testbed Configuration for Demonstration of RAMCO/LRAM Concept

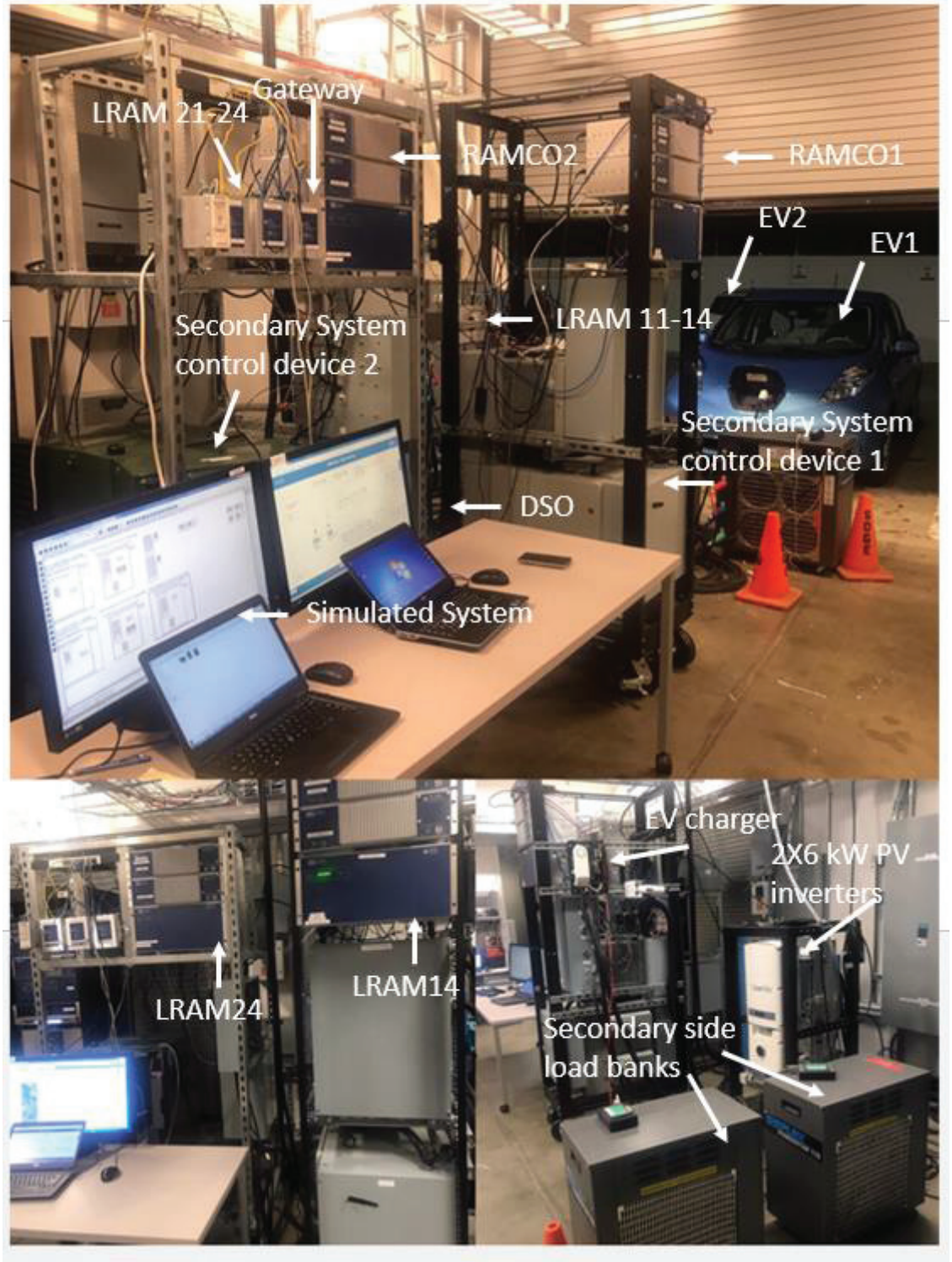


Figure 2-5. Testbed Installed at ITF

2.4 Test System Setup and Integration

Once the demo test system was designed, a three-stage testing process was conducted to ensure the readiness of test system for final demonstration:

- Type testing of secondary system technologies: The test system was envisioned to include DERs and controllable assets in both primary and secondary systems. In particular, for secondary systems, two of commercially available secondary system Volt/VAr regulation devices were selected and type tested to ensure that they fully fit into the project functional requirements.
- Factory Acceptance Test (FAT): The purpose of FAT was to demonstrate the basic functionality of the proposed aggregator-based architecture.
- Site Acceptance Test (SAT): The project was involved with a SAT at SDG&E testing facility to ensure the proper operation of RAMCOs and LRAMs and rest of the testbed for the final demonstration.

2.4.1 Type Testing of Secondary System Technologies

For secondary systems, two of commercially available secondary system Volt/VAr regulation devices were selected and type tested to ensure that they fully fit into the project functional requirements. Technologies for managing voltage and reactive power on secondary circuits are expected to dynamically control voltages and compensate reactive power for power factor correction when installed on the secondary of a service transformer suppling multiple residential customers. The key features include (but not limited to):

- Load Voltage Regulation: directly bucks and boosts voltage across a wide range during forward and reverse power flow
- Reactive Power Compensation: regulates power factor by dynamically injecting or absorbing reactive power
- Operational Flexibility: operates autonomously with options for remote management and visibility

The objective of the type testing was to evaluate the operation and performance of the secondary system technologies through a laboratory testbed setup, including a simple test circuit in digital simulation platform, grid simulator, load banks, and PV inverters to represent residential loads. Devices from two different vendors were selected as Device Under Test (DUTs) for the type test purpose. Both of the DUTs selected have similar functions for secondary voltage regulation, reactive power compensation or power factor correction. Main control specifications of the two DUTs are described below:

DUT A:

- Dynamic voltage regulation (cycle by cycle up to +/- 24V on 240V basis) toward a programmable setpoint (typically fixed at 240V RMS, but is dynamically settable)
- Providing up to additional +/- 5 kVAr support (or alternatively, set to power factor mode where it injects/absorbs up to 5kVAr to reach the desired power factor)
- DNP3 communication capability to dynamically change voltage and reactive power (or power factor), as well as direct retrieval of monitoring parameters and applying configuration changes.

DUT B:

- Dynamic voltage regulation (up to +/- 10V on 120V basis) toward a programmable setpoint (typically fixed at 120V RMS, but is dynamically settable)
- Providing up to additional +/- 10 kVAr support to regulate the power factor at source side at unity power factor.
- SSH communication capability to dynamically change voltage and reactive power (or power factor), as well as direct retrieval of monitoring parameters and applying configuration changes.

The hardware testbed for type test was set up and operated at the SDG&E ITF. Type test preparation consisted of a number of stages, including:

- Test system design based on SDG&E ITF configuration and equipment rating
- Test rack design and assembly for DUTs installation and connection preparation
- ITF Layout for accommodating equipment for the type test
- Testbed setup including equipment wiring and measurements connection
- Test communication setup

The layout of the testbed is illustrated in Figure 2-6, consisting of the following components:

- Digital simulation platform: used to represent the simplified 12kV power system including: a source, line impedances, loads, and interconnection transformers that represent service transformer.
- Grid Simulator (90kVA): used to emulate the voltage at the 240V side of the interconnection transformer.
- DUTs: Device Under Test (DUT) used for voltage regulation, sag/swell mitigation, reactive power compensation and power factor correction.
- Impedance Box: used for representing the service cables between residential customers and service transformer.
- Load Banks Racks: Two 10 kW and one 20 kW (70 kW capability at 240V) resistive load banks used for representing residential customer load downstream of the device under test. Two load banks are applied per line to neutral in order to individually change the loading on various lines and to create unbalanced conditions.
- PV Inverter: two 6 kW inverters used for representing residential PV system.
- Automation controller: used for communicating with DUT for remote control.
- Power analyzer monitors voltage and current at both the source and load side of DUTs for instantaneous waveform, RMS measurements, and power quality analysis

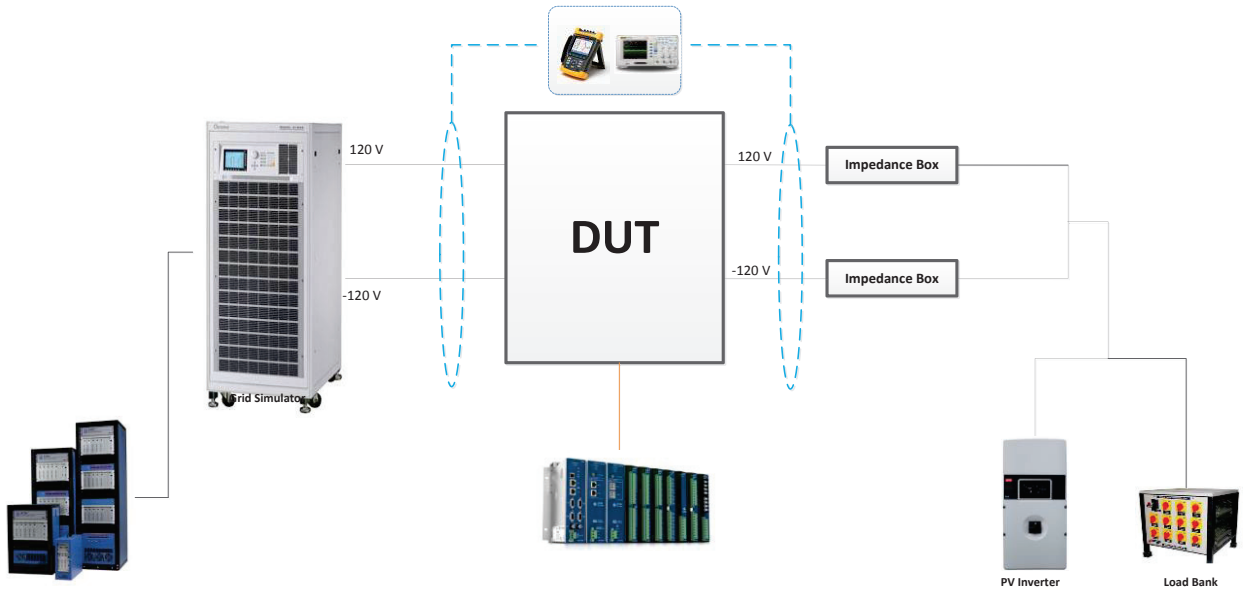


Figure 2-6 Type test system layout

Several test categories and groups were considered for the type test in order to evaluate different aspects of DUTs' operation, mainly focusing on:

1) Initialization and start up test:
The purpose of this test category is to test the operating threshold and limits of DUTs. Voltage output from grid simulator was reduced or increased until DUTs cannot regulate load voltage and stops or follows the voltage, to determine the drop off voltages.

2) Voltage regulation performance test:
The purpose of this test category is to verify the ability of DUTs to regulate the load voltage at a desired setpoint. Changes in system voltages are performed in this category, as well as load changes, to test the devices ability to regulate voltage at the load side.

3) Reactive power compensation / Power factor control performance test:
The purpose of this test category is to test DUTs' ability to compensate reactive power or regulate the power factor at desired setpoint of unity.

4) Communication test:
The purpose of this test category is to test the DUTs' communication capability for remote configuration/ setting change or monitoring.

The aforementioned tests are performed in different system operation modes besides the normal condition, such as off-nominal system frequency, reverse power flow, and unbalanced loading conditions, to account for abnormal system operations.

For all the tests performed in each category, test results were evaluated based on the following criteria:

Pass	Test result shows correct/expected operation behavior of device under test
Fail	Test result shows incorrect/unexpected operation behavior of device under test
Inconsistent	Test result shows inconsistent for certain test cases with pass or fail test results

The detailed type test plan is provided in Appendix B.

2.4.2 Factory Acceptance Test (FAT)

The primary objective of the FAT was to demonstrate the basic functionality of the proposed aggregator-based architecture; this was done by first verifying end-to-end connectivity between devices in the aforementioned hierarchies, and then demonstrating that specific use cases can be implemented in an automated fashion with minimal user intervention.

There was a total of three use cases to be studied during the execution of this project:

- Near Real-Time Resource Aggregation and Monitoring
- Emergency Dispatch of DERs and Demand Side Management
- Reactive power Management: Secondary Volt/VAr control

For the FAT, a simplified version of the first two use cases was tested as the remainder were under development at the time. However, all three use cases were verified during the SAT.

The FAT tests system, shown in Figure 2-7 , covered a portion of the full test system to ensure the proper operation and communication among different hierarchies of control system. As seen, the FAT test system covered one RAMCO and all LRAMs and the DER site controllers in that RAMCO region. One of the LRAMs (LRAM14) was controlling a physical Electric Vehicle (EV) charger and a PV inverter to facilitate hardware-in-the-loop (HIL) testing.

Throughout the FAT, communications among various major blocks in the proposed control architecture were tested and verified. Moreover, the performance of the control functions implemented in DSO, RAMCOs and LRAMs were evaluated through the execution of selected use cases.

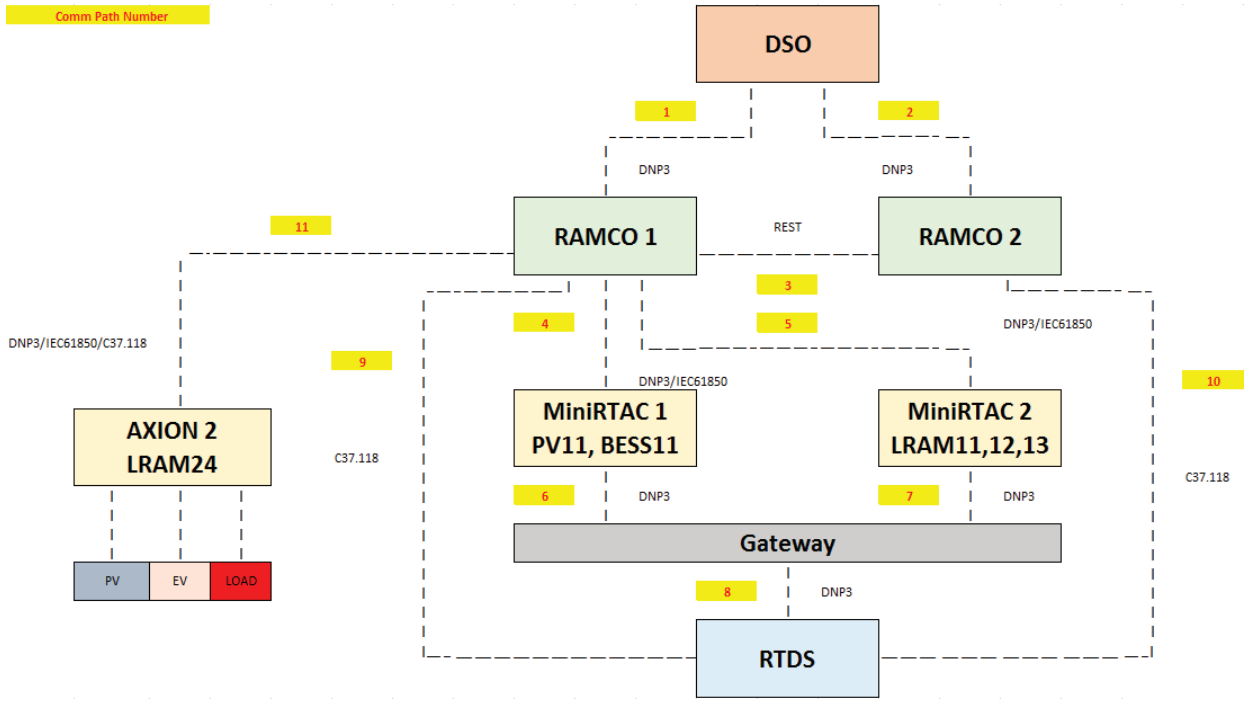


Figure 2-7. Illustration of Test Setup for FAT

To access the performance of the proposed system architecture during the acceptance testing. Two main test categories were considered: Verification Test Cases and Application Test Cases.

Table 2-6. Test Summary for FAT Test Categories

Test Category	Test Description	Test groups	Test Results
1	Verification Test	Communication Test	PASS
		SCADA/digital simulation platform Model Verification Test	PASS
		DSO/RAMCO Performance Verification Test	PASS
		PMU/Alarm Verification Test	PASS
2	Application Test	Near Real Time Resource Aggregation Test	PASS
		Emergency Dispatch of DERs and Demand Side Management Test	PASS

Several sample test cases were selected for validating the basic functionalities of the proposed system architecture. The summary of FAT test plan and results is provided in Appendix C.

2.4.3 Site Acceptance Test (SAT)

For SAT, the integrated testbed with software and hardware environment consisting of the digital simulation platform operating in conjunction with Power Hardware-in-Loop (PHIL) was implemented to validate the test system for final demonstration. The testbed included:

- Control center (DSO and SCADA) – represented in a software platform
- 12kV distribution feeder, substation, and corresponding protective devices – represented in software digital simulation platform model
- 12kV DERs – represented in software digital simulation platform model
- 12kV/LV transformer – six of them simulated in digital simulation platform and two of them represented as hardware grid simulator
- RAMCO/LRAM – represented as hardware
- Secondary LV DERs and loads – represented as both hardware and in software digital simulation platform model

The selected 12kV distribution feeder was modeled and simulated in the digital simulation platform environment to generate real-time system parameters including voltages, currents, and power flow. Modeled circuits incorporated models of the conventional voltage and reactive power control devices on the circuits that are used to set the base-line voltage of the circuits, such as LTCs, voltage regulators, and shunt capacitors; they autonomously (locally) respond to system variations due to changes in daily loads and PV profiles.

The hardware components such as RAMCO/LRAM were interfaced with digital simulation platform through input/output signal modules or through intermediary power amplifier devices such as grid simulators. Two LRAMs, covering pre-commercial offerings from two partner vendors, were interacting with two fully hardware secondary networks, including residential load, PV, and EV charging stations. An overview of the proposed testbed is shown in Figure 2-4, the testbed installed at ITF is shown in Figure 2-5.

For SAT, all three use cases were selected, implemented and tested in the laboratory environment - at the SDG&E testing facility – to cover and demonstrate various operation aspects of the proposed system architecture:

- **Load Management/NRT Resource Aggregation:** Update the DSO about the latest available resources in each region controlled by a RAMCO, allowing the DSO to use near real-time (NRT) information/constraints in its optimization algorithms.
- **Emergency Dispatch of DERs:** Proper dispatch of DERs under emergency conditions in the proposed aggregator-based architecture.
- **Reactive power management:** Effectively manage voltage and/or reactive power at primary-side DERs as well as service transformer level.

The test plan for each of the use cases performed are shown in Table 2-7 to Table 2-9. For each use case, a number test cases were selected to verify the proper operation of demonstration test system for all three use cases under different conditions. The SAT results verified the performance of test system for the project final demonstration. These test cases were later performed in project final demonstration.

Table 2-7. Test Plan for Use Case 1 (Load Management/NRT Resource Aggregation)

Use Case 1 (Load Management/NRT-Resource Aggregation)						
Use cases & Test Cases	**DSO Targets**	**Market Price**	**Reserve Capacity**	**Forecasted Load**	**Initial SOC (%)**	**PV (%)**
Case 1-1: High Market Price/Minimum Reserve Capacity=0.25/PV Profile=70%, topology 1	NA	High	25%			
Case 1-1-1: Initial SOC = 70%	NA	$170	25%	10	70%	70%
Case 1-1-2: Initial SOC = 70% (Initial value in digital simulation platform), PV drops to 20% (cloud condition) and keep for a few minutes, back to 70%.	NA	$170	25%	10	70%	70% to 20% to 70%
Case 1-2: Low Market Price/Minimum Reserve Capacity=0.25/PV Profile=70%, topology 1	NA	Low	25%			
Case 1-2-1: Initial SOC = 70%	NA	$40	25%	10	70%	70%
Case 1-2-2: Initial SOC = 70%, PV drops to 20% (cloud condition) and keep for a few minutes, back to 70%.	NA	$40	25%	10	70%	70% to 20% to 70%
Case 1-3: High Market Price/Minimum Reserve Capacity=0.35/PV Profile=70%, topology 1	NA	High	35%		NA	NA
Case 1-3-1: Initial SOC = 70%	NA	$170	35%	10	70%	70%
Case 1-3-2: Initial SOC = 70% (Initial value in digital simulation platform), PV drops to 20% (cloud condition) and keep for a few minutes, back to 70%.	NA	$170	35%	10	70%	70% to 20% to 70%
Case 1-4: Low Market Price/Minimum Reserve Capacity=0.35/PV Profile=70%, topology 1	NA	Low	35%			
Case 1-4-1: Initial SOC = 70%	NA	$40	35%	10	70%	70%
Case 1-4-2: Initial SOC = 70%, PV drops to 20% (cloud condition) and keep for a few minutes, back to 70%.	NA	$40	35%	10	70%	70% to 20% to 70%
Case 1-5: Variable price	NA	High to Low	25%	10	0.7	0.7
Case 1-5-1: Variable price; price drops from $170 to $40, SOC = 70%	NA	170 to 40	25%	10	70%	0.7
Case 1-5-2: Variable price; price drops from $170 to $40, SOC = 70%	NA	170 to 40	35%	10	70%	0.7

Table 2-8. Test Plan for Use Case 2 (Emergency Dispatch of DERs)

Use Case 2 (Emergency Dispatch of DERs)						
Use cases & Test Cases	**DSO Targets**	**Market Price**	**Reserve Capacity**	**Forecasted Load**	**Initial SOC (%)**	**PV (%)**
Case 2-1: DSO Contribution Target = 8MW, Test under different Generation Profiles	8 MW	NA	NA	NA		
Case 2-1-1: PV= 0.7p.u., BESS SOC=70%	8 MW	NA	NA	NA	70%	70%
Case 2-1-2: PV= 0.2p.u., BESS SOC=70%	8 MW	NA	NA	NA	70%	20%
Case 2-2: Initial SOC = 5% (Initial value in digital simulation platform), PV at 70%, then drop PV to 20%	8 MW	NA	NA	NA	5%	70 to 20%
Case 2-3: Change of DSO target and load profile	0 MW	NA	NA	NA	70%	70%
Case 2-3-1: Change DSO Contribution Target from 12MW to -4MW in steps	variable	NA	NA	NA	70%	70%
Case 2-3-2: DSO Contribution Target= 12MW, change load level in steps from 1 to 0.2	12 MW	NA	NA	NA	70%	70%
Case 2-4: Test dispatching in LRAMs when all primary DERs are off		NA	NA	NA	NA	
Case 2-4-1: Change P target in 50kW steps from 250kW to -200kW	variable	NA	NA	NA	NA	100%
Case 2-4-2: Changing P target and then PV profile: P_T changes from 150 to 50. Then PV changes to 0.1	variable	NA	NA	NA	NA	variable
Case 2-5: Test Under different circuit topologies: DSO Contribution Target = 3MW, PV Profile = 0.2p.u., BESS SOC=30%	3 MW	NA	NA	NA	30%	20%
Case 2-5-1: Change circuit topology from 1 to 2	3 MW	NA	NA	NA	30%	20%
Case 2-5-2: Change circuit topology from 2 to 1	3 MW	NA	NA	NA	30%	20%
Case 2-5-3: Change Pricing and verify that target does not change	3 MW	NA	NA	NA	30%	20%
Case 2-5-4: Change circuit topology from 1 to 3	3 MW	NA	NA	NA	30%	20%
Case 2-6: Test when PV11 is tripped suddenly (start with DSO Contribution Target = 4MW, PV Profile = 0.85p.u., BESS SOC=60%)	4 MW	NA	NA	NA	70%	70%

Table 2-9. Test Plan for Use Case 3 (Reactive Power Management)

Use Case 3 (Secondary Volt/VAr Control)						
Use Cases & Test Cases	**DSO Targets**	**Market Price**	**Reserve Capacity**	**Forecasted Load**	**Initial SOC (%)**	**PV (%)**
Case 3-1: DSO reactive power target change from 7 MVAr to -7MVAr (7, 4, 1, 0, -1,-7MVAr)	2 MVAr	NA	NA	NA	70%	70%
Case 3-2: Voltage target reduction test: start with Q target of 0 MVAr and change the voltage reduction setpoint as 0%, 1%, and 5%, then change the Q target to 2 MVAr and set the voltage reduction target to 5%.	variable	NA	NA	NA	70%	70%

2.5 Demonstration of Control and Operation Concept

In order to demonstrate the performance of the system for all three use cases several test cases were performed. These test cases are summarized in Section 2.4.3, Table 2-7 to Table 2-9. A brief explanation of test cases in each category is presented below. The demonstration test results are discussed in Section 3.

- **Use Case 1 (Load Management/Near Real Time-Resource Aggregation):**

In this use case, the focus is on updating the DSO with the latest available resources in each region controlled by a RAMCO. Therefore, the DSO would use near real-time (NRT) information/constraints in its optimization algorithms. Such information includes the status and measurements of resources like intermittent generation units, energy storage units and their available energy level (State of charge), switchable / shed-able loads, critical loads, etc. The flow of information for this use case is from the secondary-level assets (through LRAMs) up to the RAMCOs, and from there to the DSO. In order to verify the proper operation of this use case, various operating conditions including PV profile, feeder loads, forecasted load, market price, etc. are considered in several tests. Additionally, DSO can perform load management on the circuits by utilizing DERs based on the latest energy price. For example, if the energy price is changed from a high to a low value, DSO should assign new setpoints for each RAMCO based on the information it receives from RAMCOs. This new setpoint is then assigned to the resources in the feeder though primary DER site controllers and LRAMs. It is expected for the resources to contribute to the market more than the previous stage, as the price is decreased.

- **Use Case 2 (Emergency Dispatch of DERs):**

The objective of this use case is to ensure the proper dispatch of DERs under emergency conditions in the proposed aggregator-based architecture. For this purpose, flow of the commands in the hierarchy is as follows: Based on the information received from RAMCOs, DSO updated contribution targets for each RAMCO. These targets are then used to restore/curtail primary PVs, charge/discharge primary BESS

units, and determine contribution targets for LRAMs. Final level of the hierarchy is when each LRAM sets new targets for each secondary PV and distributed energy storage (DES) system. In order to evaluate the performance of the Emergency Dispatch use case, the modeled demonstration system is tested under various operating scenarios. A combination of load and PV generation profiles and initial state of charge of batteries are applied to the test system to create these operating conditions. The verification process is to ensure that targets generated by DSO are properly incorporated by RAMCOs through the proper dispatch of primary and secondary DERs.

- **Use Case 3 (Secondary Volt/VAr Control):**

The objective of this use case is to effectively manage voltage and/or reactive power of service transformers, using the available resources on the secondary systems. In the proposed control architecture, effective control of primary-side DERs are given to RAMCOs. On the other hand, the responsibility of each LRAM is to manage controllable assets located at the secondary side of its service transformer to meet the assigned setpoint from DSO based on the optimization goals considered. Consequently, the RAMCO determines the active and reactive power setpoints of DERs connected to the medium-voltage (primary) level of distribution systems, which further supports the SCADA control of primary utility assets such as shunt capacitors, voltage regulator, and load tap changers to enhance voltage profile or reactive power flow in primary feeders. Moreover, the setpoint sent by DSO to LRAMs are assigned to the controllable secondary assets such as a dedicated power electronic-based Volt/VAr regulating device, or used to control the operation and status of residential and commercial PV systems, energy storage, and loads.

3 PROJECT RESULTS

In the following tables, the detailed findings for all the test cases performed during final demonstration are summarized. For each test case associated with use cases, the summary results and observations are provided.

Table 3-1. Summary of Findings for Load Management Test Cases

Use Case 1 (Load Management/NRT-Resource Aggregation)	
Use cases & Test Cases	**Observation**
Case 1-1: High Market Price/Minimum Reserve Capacity=0.25/PV Profile=70%, topology 1	
Case 1-1-1: Initial SOC = 70%	At high market prices, batteries start to discharge as expected.
Case 1-1-2: Initial SOC = 70% (Initial value in digital simulation platform), PV drops to 20% (cloud condition) and keep for a few minutes, back to 70%.	At high market prices, batteries start to discharge as expected. FG unit in RAMCO2 also starts to contribute.
Case 1-2: Low Market Price/Minimum Reserve Capacity=0.25/PV Profile=70%, topology 1	
Case 1-2-1: Initial SOC = 70%	At low market prices, batteries start to charge as expected.
Case 1-2-2: Initial SOC = 70%, PV drops to 20% (cloud condition) and keep for a few minutes, back to 70%.	At low market prices, batteries start to charge as expected. The PV radiation drop does not impact the charging of batteries.
Case 1-3: High Market Price/Minimum Reserve Capacity=0.35/PV Profile=70%, topology 1	
Case 1-3-1: Initial SOC = 70%	At high market prices, batteries start to discharge as expected. The 35% minimum reserve capacity target is met.
Case 1-3-2: Initial SOC = 70% (Initial value in digital simulation platform), PV drops to 20% (cloud condition) and keep for a few minutes, back to 70%.	At high market prices, batteries start to discharge as expected. The 35% minimum reserve capacity target is met.
Case 1-4: Low Market Price/Minimum Reserve Capacity=0.35/PV Profile=70%, topology 1	
Case 1-4-1: Initial SOC = 70%	At low market prices, batteries start to charge as expected. The 35% minimum reserve capacity target is met.
Case 1-4-2: Initial SOC = 70%, PV drops to 20% (cloud condition) and keep for a few minutes, back to 70%.	At low market prices, batteries start to charge as expected. The 35% minimum reserve capacity target is met.

Use Case 1 (Load Management/NRT-Resource Aggregation)	
Use cases & Test Cases	**Observation**
Case 1-5: Variable price, price drops from $170 to $40, SOC = 70%	Initially with the high market price, batteries are discharging; after the price change, they start to charge as expected.

Table 3-2. Summary of Findings for Emergency Dispatch Test Cases

Use Case 2 (Emergency Dispatch of DERs)	
Use cases & Test Cases	**Observation**
Case 2-1: DSO Contribution Target = 8MW, Test under different Generation Profiles	
Case 2-1-1: PV= 0.7p.u., BESS SOC=70%	The requested 8 MW target by DSO is met. BESS 11 in RAMCO1 is charging while BESS 21 I RAMCO2 is discharging (due to smaller size PV in RAMCO 2)
Case 2-1-2: PV= 0.2p.u., BESS SOC=70%	The requested 8 MW target by DSO is met. After PV radiation drop, BESS11 in RAMCO1 also starts to discharge to help RAMCO1 meet the target requested by DSO.
Case 2-2: DSO Contribution Target = 8MW, Initial SOC = 5% (Initial value in digital simulation platform), PV at 70%, then drop PV to 20%	Batteries do not discharge because their SOC is below the minimum allowable SOC (10%). With PV profile of 70% the DSO target is met. However, with 20% of PV profile, there are not enough resources available to meet the DSO target.
Case 2-3: Change of DSO target and load profile	
Case 2-3-1: Change DSO Contribution Target from 12MW to -4MW in 2MW steps	Summary of observations for each target change step: 12MW to 10MW: BESS11 and 21 are discharging less as targets is decreasing. 10MW to 8MW: BESS11 is discharging less as targets is decreasing. BESS21 started charging. 8MW to 6MW: BESS 11 started to charge. 6MW to 4MW: PV 11 started to curtail. 4MW to 0MW: FG21 is curtailed, but PV21 is not curtailed yet. 0MW to -2MW: Still PV21 is not curtailed. -4MW: PV21 and some LRAMs started curtailing.
Case 2-3-2: DSO Contribution Target= 12MW, change load level in steps from 1 to 0.2	The target is successfully met regardless of load changes.
Case 2-4: Test dispatching in LRAMs when all primary DERs are off	

Use Case 2 (Emergency Dispatch of DERs)	
Use cases & Test Cases	**Observation**
Case 2-4-1: Change P target in 50kW steps from 200kW to -200kW	LRAM successfully meet the targets and successfully priorities the devices for dispatching. As the target was decreasing EVSE started to charge at a higher rate.
Case 2-4-2: Changing P target and then PV profile: P_T changes from 150 to 50. Then PV changes to 0.1	LRAM successfully meet the targets and successfully priorities the devices for dispatching. As the target was decreasing EVSE started to charge at a higher rate.
Case 2-5: Test Under different circuit topologies: DSO Contribution Target = 3MW, PV Profile = 0.2p.u., BESS SOC=30%	
Case 2-5-1: Change circuit topology from 1 to 2	LRAM13 is successfully moved to RAMCO2 coverage.
Case 2-5-2: Change circuit topology from 2 to 1	LRAM13 is back to RAMCO1 coverage.
Case 2-5-3: Change Pricing and verify that target does not change	The pricing in emergency dispatch mode is not effective.
Case 2-5-4: Change circuit topology from 1 to 3	FG unit that was under the coverage of RAMCO2, is now controlled and monitored by RAMCO1.
Case 2-6: Test when PV11 is tripped suddenly (start with DSO Contribution Target = 4MW, PV Profile = 0.85p.u., BESS SOC=60%)	BESS 11 was being charged. After PV11 is tripped, it starts to discharge. BESS 21 also discharges at a higher rate.

Table 3-3. Summary of Findings for Reactive Power Management Test Cases

Use Case 3 (Secondary Volt/VAr Control)	
Use cases & Test Cases	**Observation**
Case 3-1: DSO reactive power target change from 7 MVAr to -7MVAr (7, 4, 1, 0, -1,-7MVAr)	Primary DERs and LRAMs successfully share the reactive power target requested by DSO.
Case 3-2: Voltage target reduction test: start with Q target of 0 MVAr and change the voltage reduction setpoint as 0%, 1%, and 5%, then change the Q target to 2 MVAr and set the voltage reduction target to 5%.	Voltage reduction targets are successfully transferred to LRAMs. Secondary Volt/VAr control technology successfully controls the voltage of LRAM based on new target. Reactive power sharing is successfully performed by all DERs and LRAMs.

3.1 Sample Test Results

In this section, the test results for some sample test cases are presented to demonstrate three different DSO modes of operation. For this purpose, the DSO readings are compared against RAMCO

measurements and setpoints. The following four tests are presented as a scaled-down demonstration of the control concept, while more test results are presented in the Appendix D.

3.1.1 Case 1-5: Variable market price (Load Management/Near Real Time-Resource Aggregation)

In this test, PV profile is 70%, and initial SOC of the batteries is 70%. Full detail of the settings for this test are as follows:

Table 3-4. Settings for Case 1-5-2

Control mode	Market Price	Reserve Capacity	Forecast Load	Initial SOC (%)	PV (%)	Load in feeders
11	$170/MWh to $40	35%	10	70%	70%	1 p.u.

Price of energy is initially set at $170 per MWh. In this case, the setpoints of the bulk resources of each RAMCO are as follows:

Table 3-5. Setpoints for Case 1-5-2, price is $170/MWh

	setpoint (kW)	measurement (kW)
RAMCO 1		
BESS11	634	632
PV11	5250	5250
RAMCO 2		
BESS21	866	863
PV21	851	846
FG21	1088	1068

The DSO page setting is as follows, which shows the kW measurement of Energy Storage in RAMCO1 and RAMCO 2 separately, confirming their discharge status.

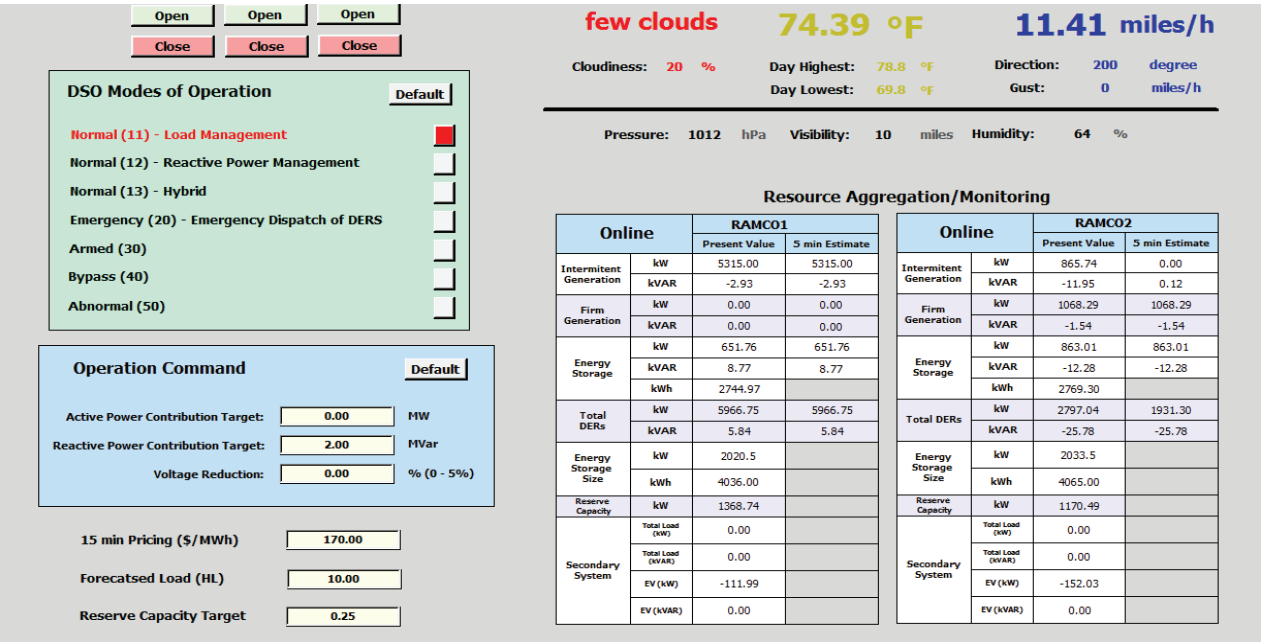


Figure 3-1. DSO HMI in case 1-5-2: energy price is $170 per MWh

After the market price is changed to $40 per MWh, it is expected for them to charge as the energy price is low. This is guaranteed with setting a higher minimum SOC target in lower energy prices compared to higher prices. When the SOC of batteries is 70%, they are meeting the required minimum SOC target at high price. When the energy price drops, the minimum SOC target is not met and hence the batteries start to charge to reach to this level. Setpoints of bulk resources of each RAMCO are presented in Table 3-6.

Table 3-6. Setpoints for Case 1-5-2, price is $40/MWh

	setpoint (kW)	measurement (kW)
RAMCO 1		
BESS11	-1685	-1678
PV11	5250	5250
RAMCO 2		
BESS21	-897	-893
PV21	851	846
FG21	1088	1068

The DSO HMI setting is as shown below, and confirms that both Energy Storage systems in RAMCO1 and RAMCO 2 are charging:

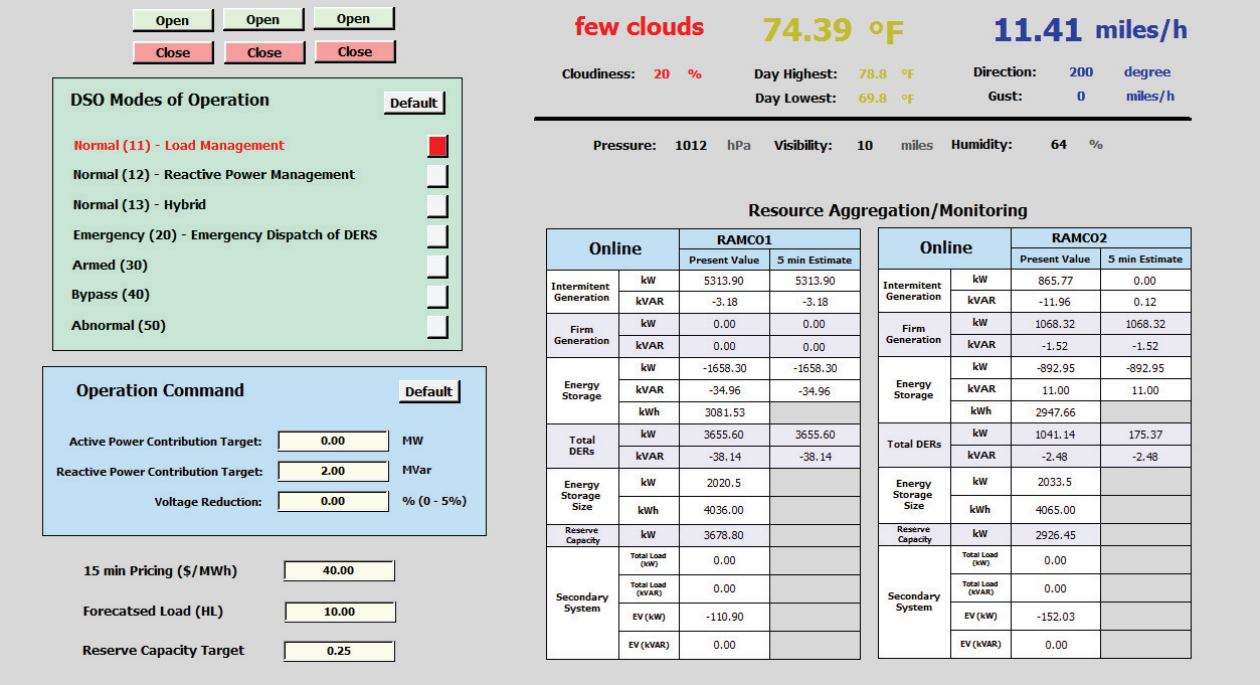
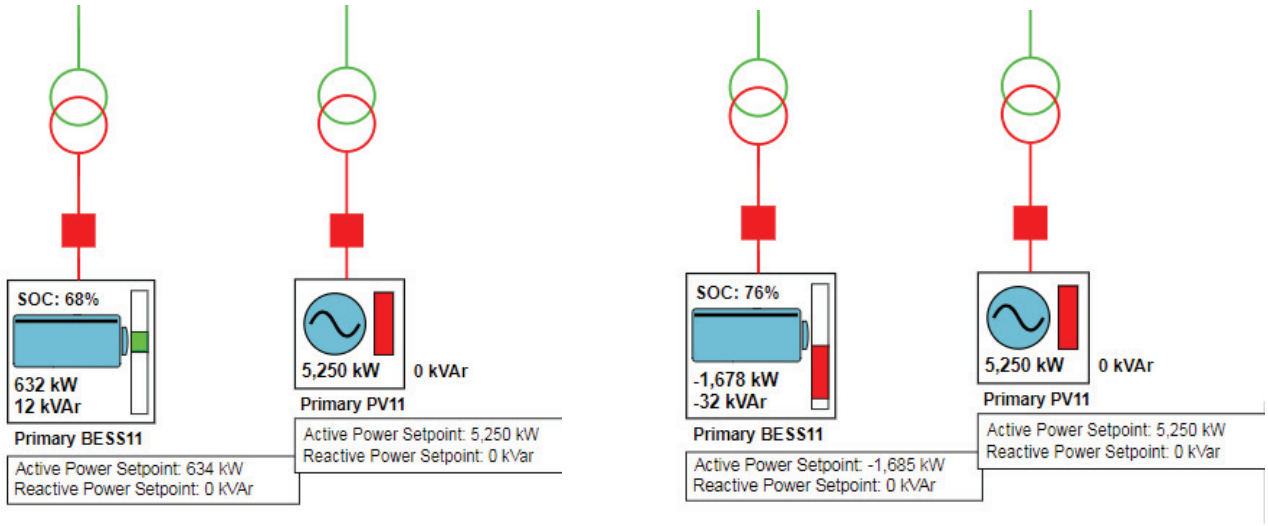


Figure 3-2. DSO HMI in case 1-5-2: energy price is $40 per MWh

As can be confirmed, batteries are now charging after the energy price has dropped. This can also be seen in the RAMCO HMI. Snapshot of RAMCO 1 HMI is shown below, and the response of RAMCO 1 to the price drop is shown in Figure 3-4.



a) Setpoints and measurements at price=$170 per MWh **b) Setpoints and measurements at price=$40 per MWh**

Figure 3-3. Setpoints and measurements for RAMCO 1 bulk resources in case 1-5-2

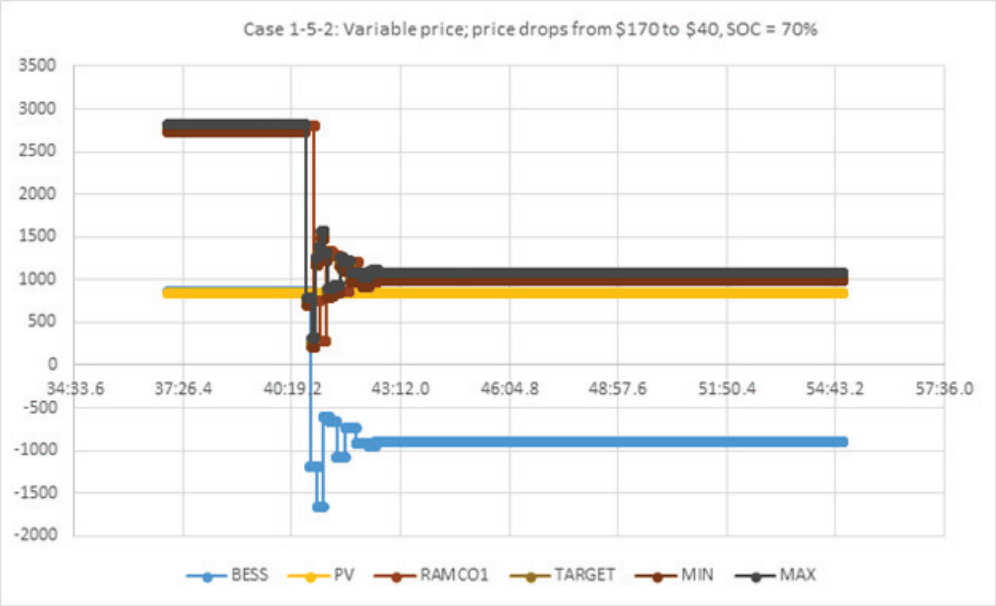


Figure 3-4. RAMCO 1 real power target and response, and response of primary connected assets associated with price drop

BESS11 and BESS21 active power measurements are shown in both energy prices in Figure 3-5 and Figure 3-6, and demonstrate that the battery changes status from discharge to charge after the new energy price signal is received.

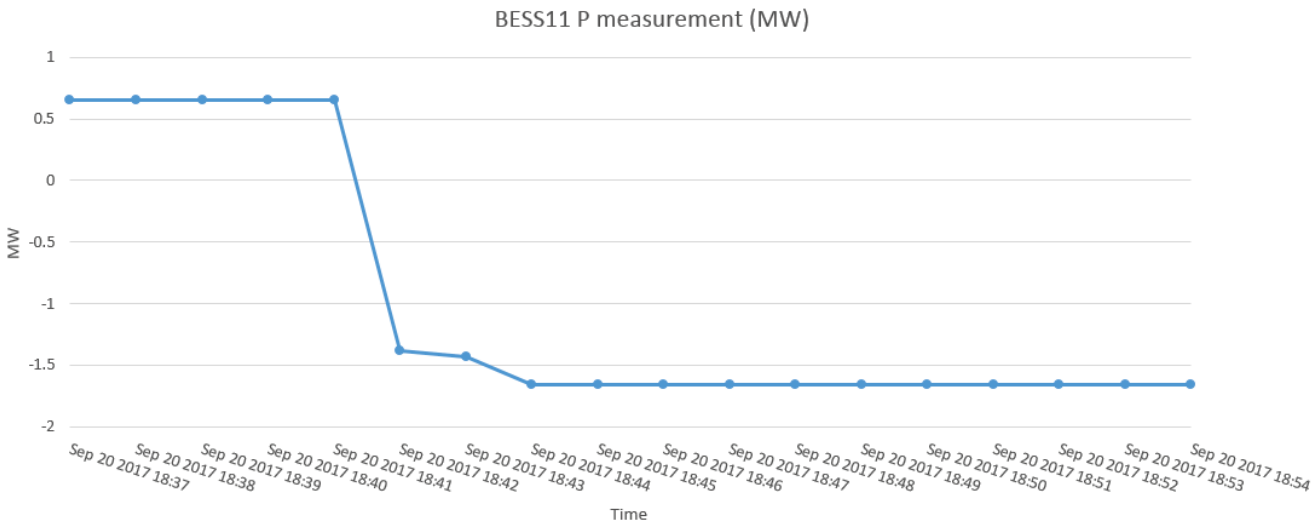


Figure 3-5. BESS11 power measurements in case 1-5-2

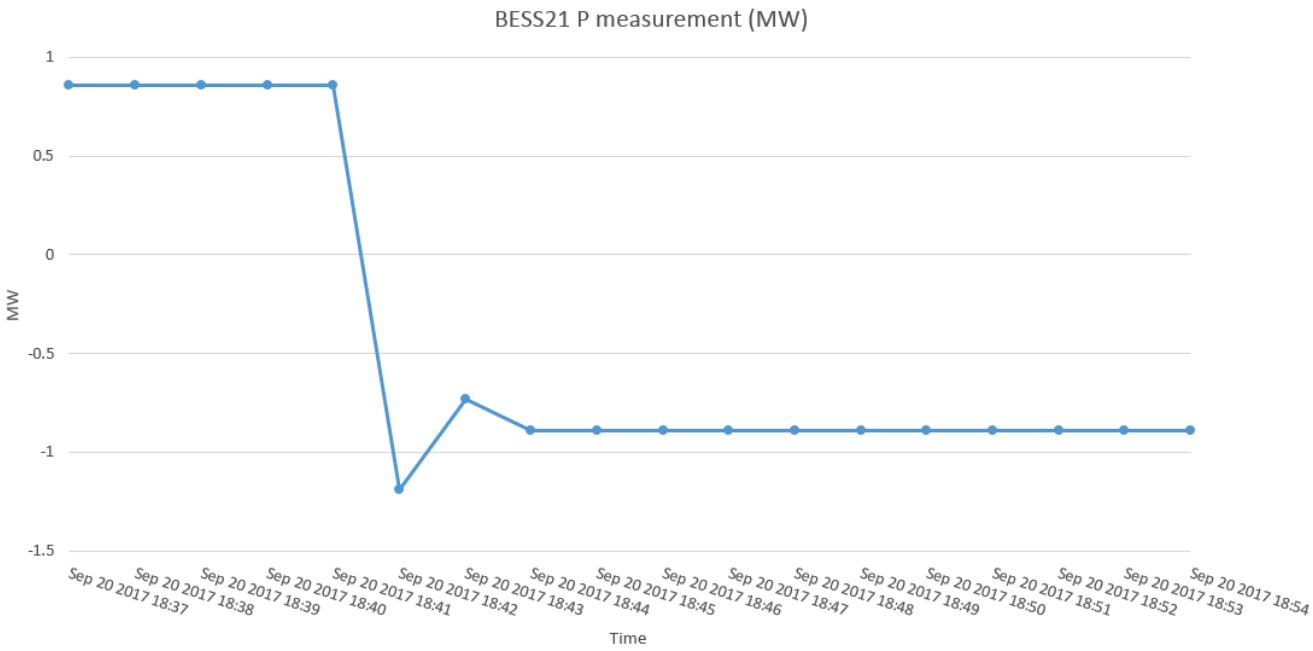


Figure 3-6. BESS21 power measurements in case 1-5-2

3.1.2 Case 2-3-1: Change of DSO target (Emergency Dispatch of DERs)

In this test, DSO Contribution Target is changed from 12MW to -4MW in 2MW steps. Load profile of the feeders is set at 1 p.u., PV profile is at 70%, and SOC of the batteries is at 70%. Changing the DSO contribution target is sent to RMACOs, and then to the individual resources. Initially, DSO target is set at 12 MW, as can be seen in Figure 3-7. The requested target is sent to the RAMCOs and the total system is capable of meeting the requested target, as seen by summing the generation of Total DERs in both feeders:

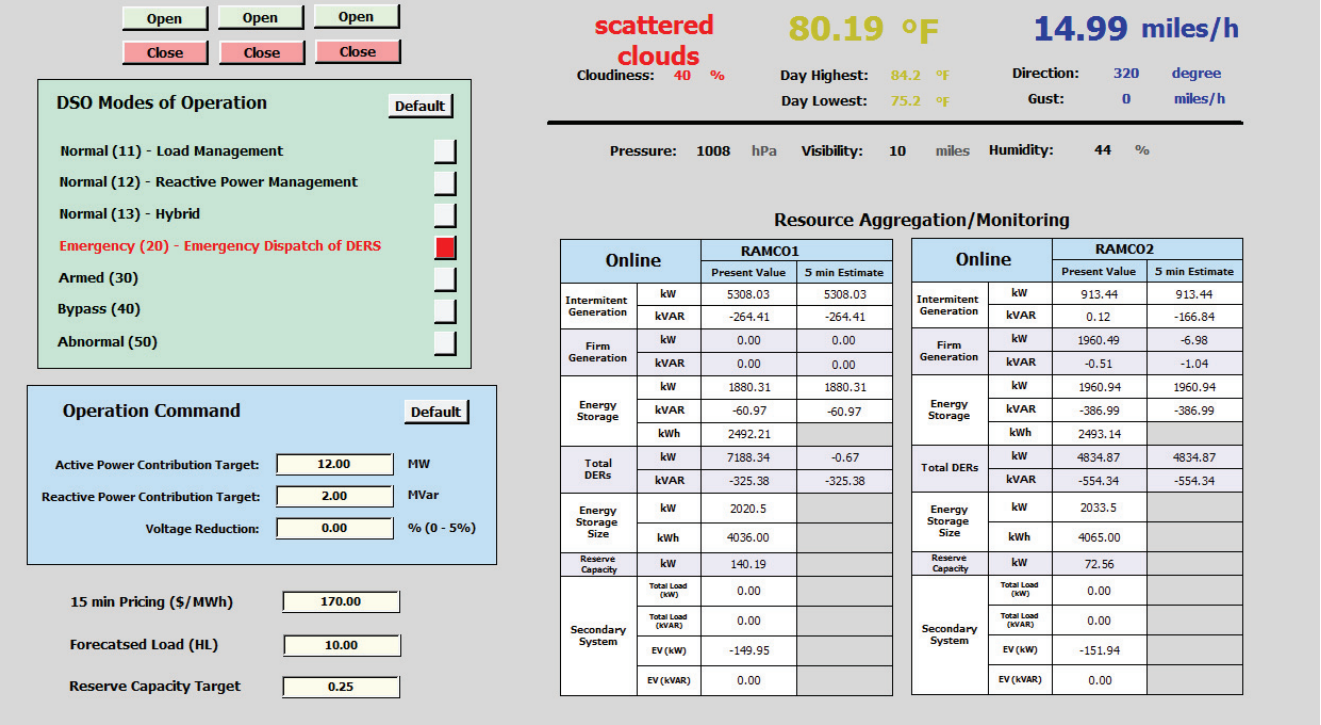


Figure 3-7. DSO HMI in case 2-3-1: DSO target is 12 MW

Changes in setpoints sent from DSO to each RAMCO can be seen below, which shows that each RAMCO has successfully responded to the DSO setpoint, as the Measured Power has well placed in between the desired thresholds.

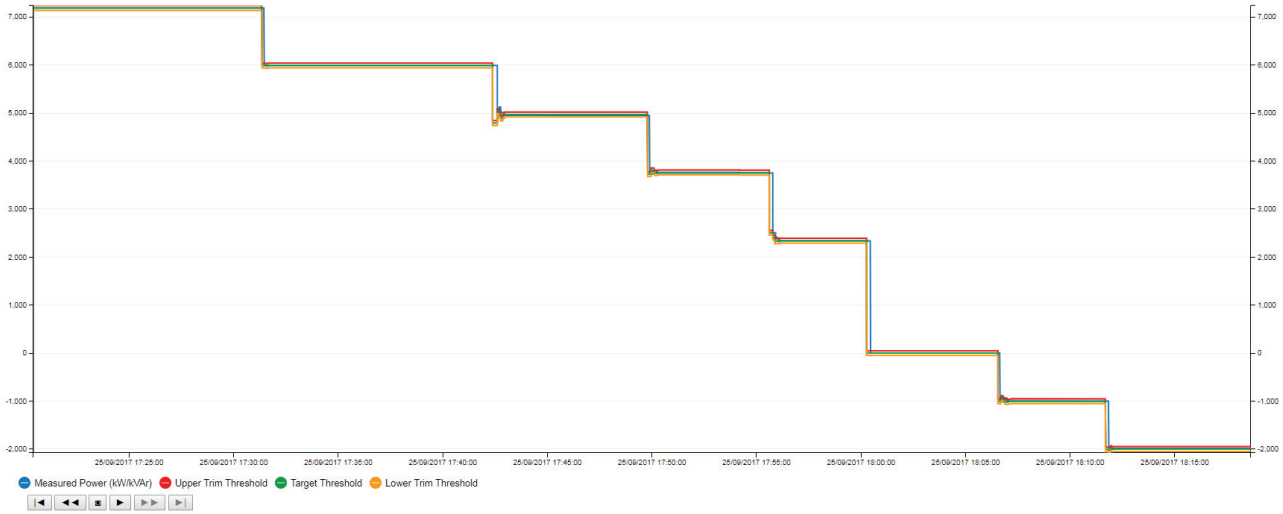


Figure 3-8. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 2-3-1

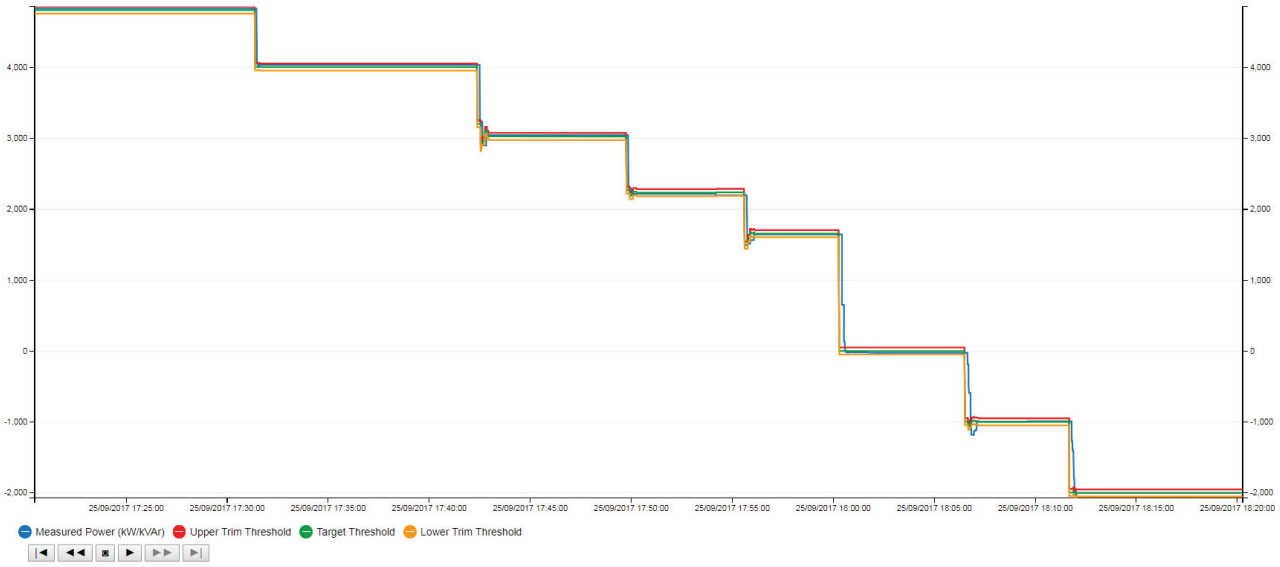


Figure 3-9. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 2-3-1

The following text summarizes observations when the DSO target is changed in steps:

- Target= 10 MW: BESS11 and BESS21 are discharging at a lower rate.
- Target= 8 MW: BESS21 started charging.
- Target= 6 MW: BESS 11 started to charge.
- Target= 4 MW: PV 11 is curtailed.
- Target= 0 MW: FG 21 is curtailed
- Target= -2 MW: FG 21 is curtailed.
- Target= -4 MW: PV 21 started curtailing

Plots of active power generation of PV11, PV21, and FG21 and plots of charging/discharging status of BESS11, BESS2 are presented below. As can be seen, each device is responding to the setpoint received from its respective RAMCO. Moreover, the case illustrates how the priority stack automatically selects the preferred resource to meet the target. The primary connected BESS is used in priority until it reaches its maximum charging capacity of -2000 kW, at which time curtailment of PV is required in order to maintain the target.

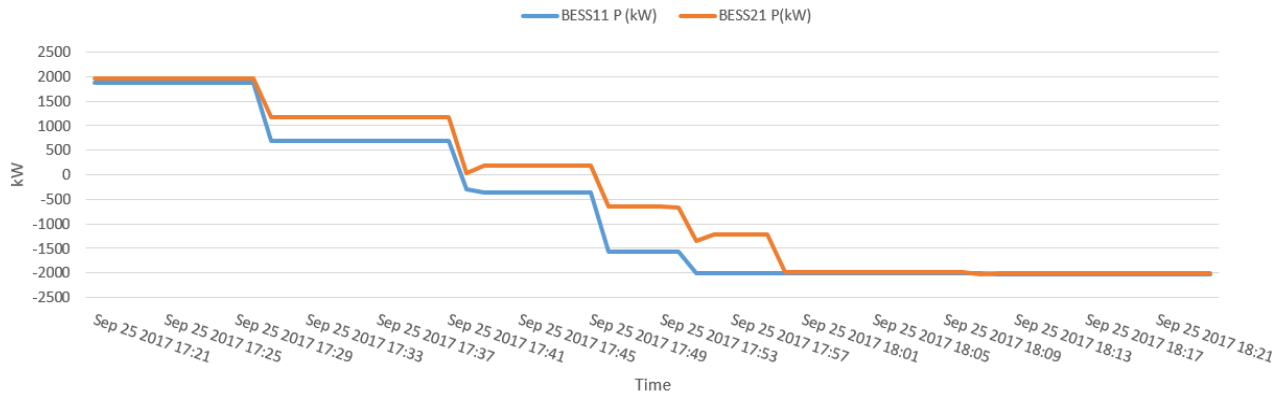


Figure 3-10. BESS11 and BESS21 P measurements in case 2-3-1

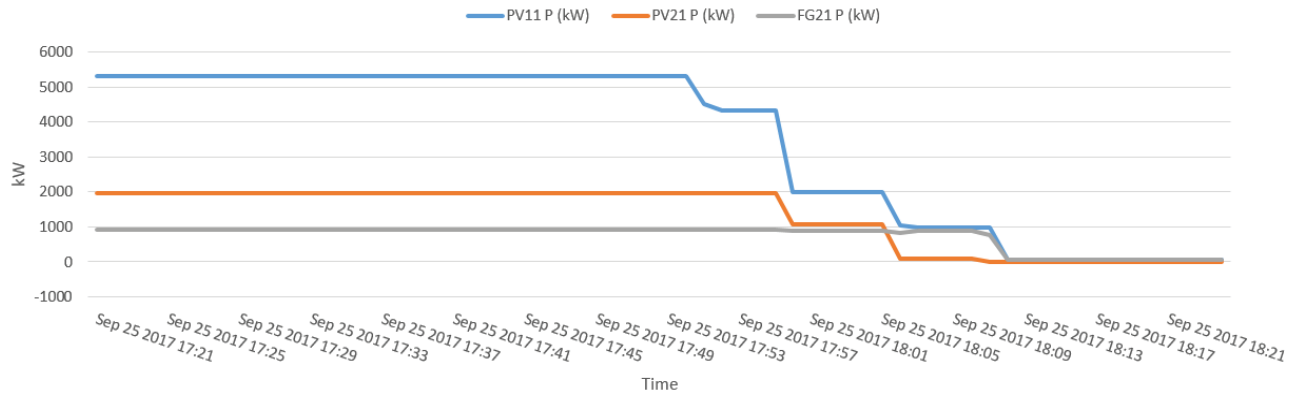


Figure 3-11. PV11, PV21, and FG21 P measurements in case 2-3-1

Moreover, LRAMs are also contributing to the new setpoint during the test. The LRAMs are used once the primary PV is fully curtailed. As can be noted in Figure 3-12, each individual LRAM is provided different targets, depending on the capabilities of the individual LRAMs and their resources.

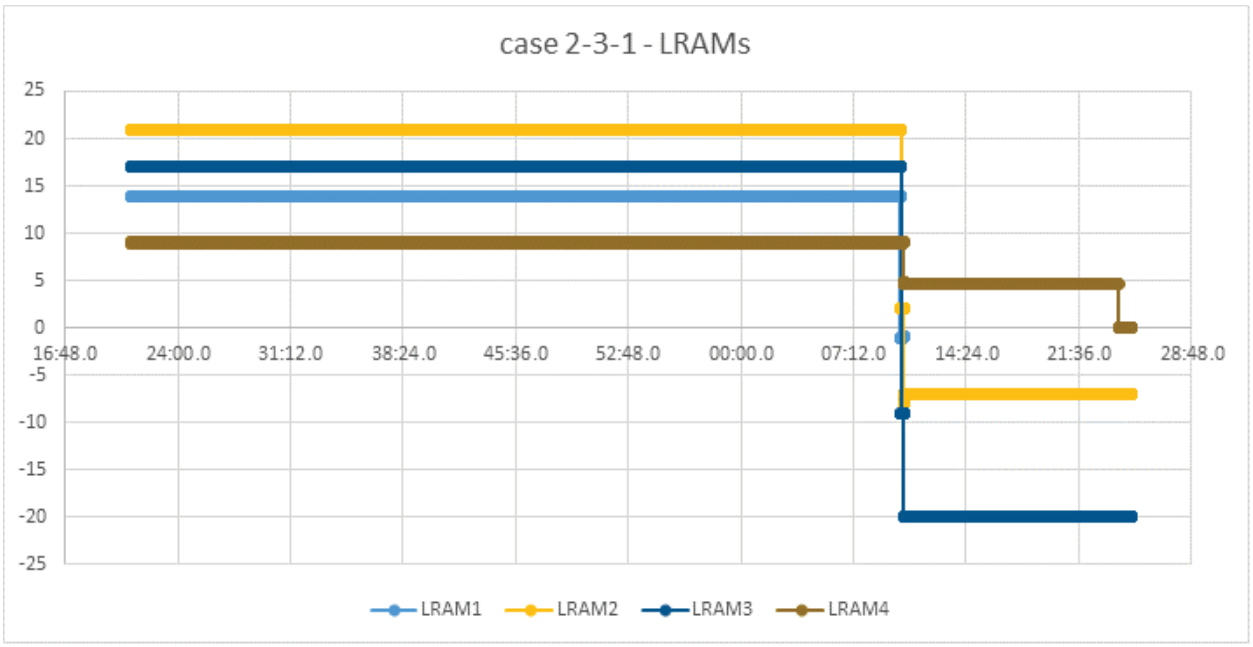
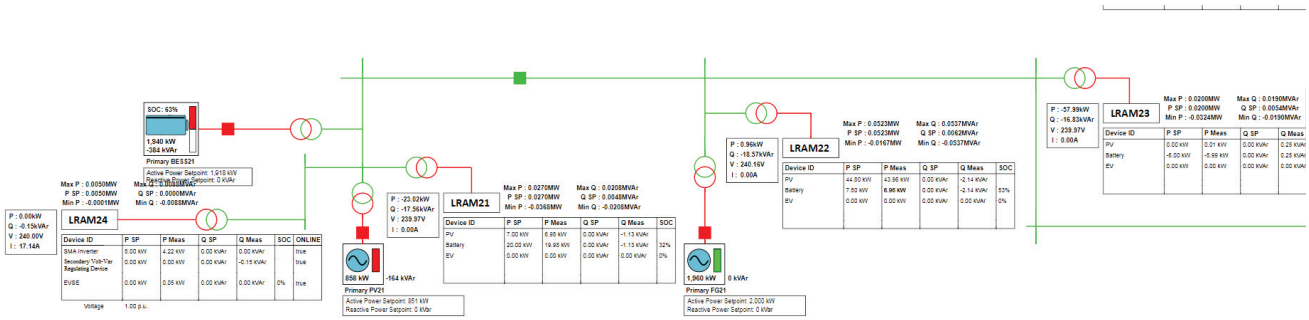
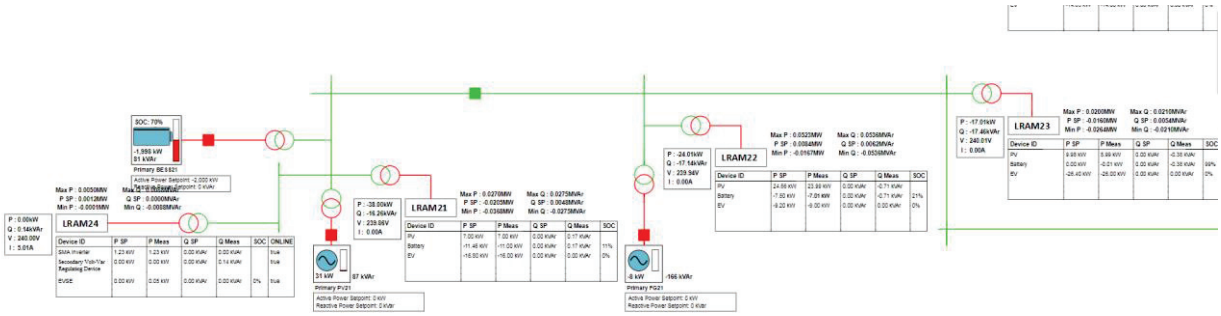


Figure 3-12. LRAMs 1 to 4 real power target and responses for DSO contribution target change from 12 MW to -4MW

A similar case is seen with RAMCO 2. Setpoints and measurements for the primary and secondary resources on the second feeder, controlled by RAMCO2, are seen in Figure 3-13 for two snapshots: when DSO target is 12 MW and when it is -4 MW. As can be seen, for instance, SMA inverter in LRAM24 is curtailed moving from 12 MW DSO setpoint to -4 MW. Also, Battery and EV on LRAM21 that were discharging/ curtailed when the DSO target was 12 MW are charging when DSO target is changed to -4 MW.



a) DSO target is 12 MW



b) DSO target is -4 MW

Figure 3-13. RAMCO HMI in case 2-3-1

3.1.3 Case 2-4-1: LRAM dispatching when all primary DERs are off (Emergency Dispatch of DERs)

In this test, which is also performed when the DSO operating mode is Emergency, the primary assets were disconnected in order to isolate the responses of the LRAMs. In this fashion the RAMCO targets are allocated directly to the LRAMs. DSO Contribution Target is changed from 250kW to -200kW in steps. Load profile of the feeders is set at 1 p.u. and PV profile is at 100%. Like the previous case, each DSO contribution target is sent to RMACOs, and then to the individual resources. Since the primary DERs are tripped, LRAMs are responsible for providing the required generation target using their resources.

Initially, DSO target is set at 250kW, as can be seen in Figure 3-14. The requested target is sent to the RAMCOs and the total system is capable of meeting the requested target, as seen by summing the generation of Total DERs in both feeders:

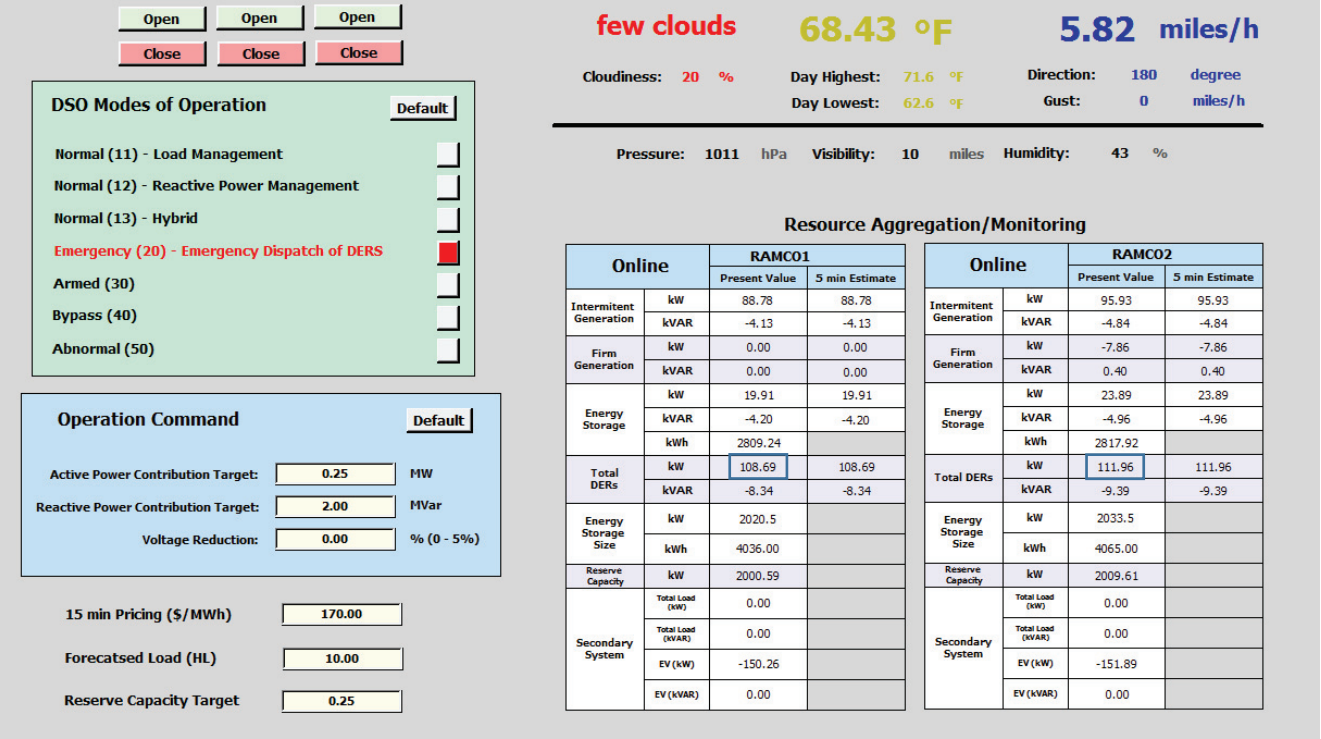


Figure 3-14. DSO HMI in case 2-4-1: DSO target is 250kW

Changes in setpoints sent from DSO to each RAMCO can be seen below, and each RAMCO has successfully responded to the DSO setpoint.

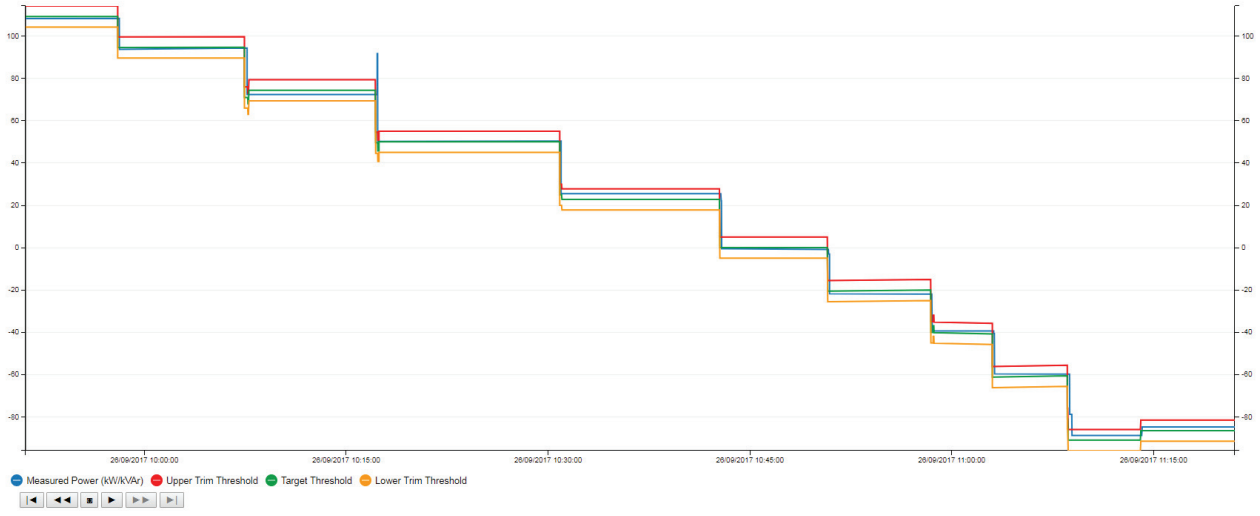


Figure 3-15. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 2-4-1

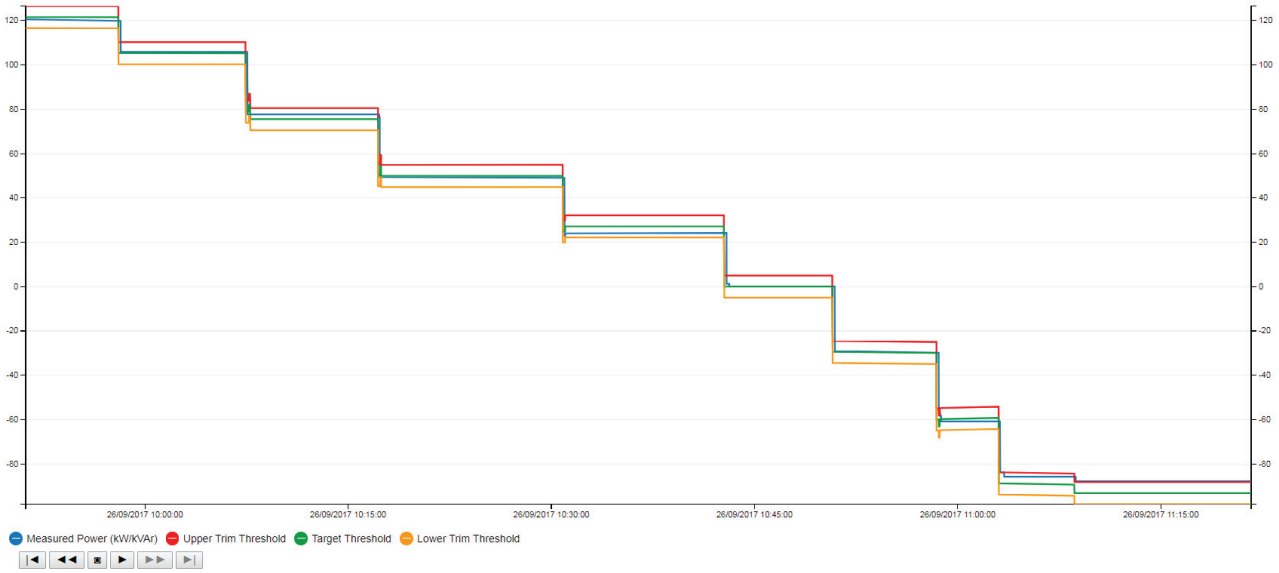


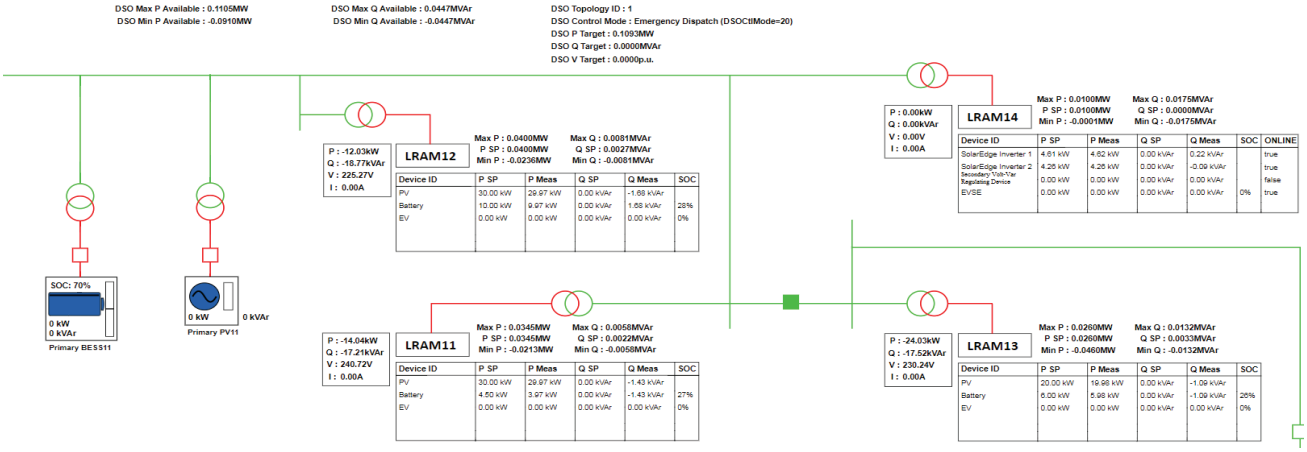
Figure 3-16. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 2-4-1

Table 3-7 summarizes observations when the DSO target is changed in steps.

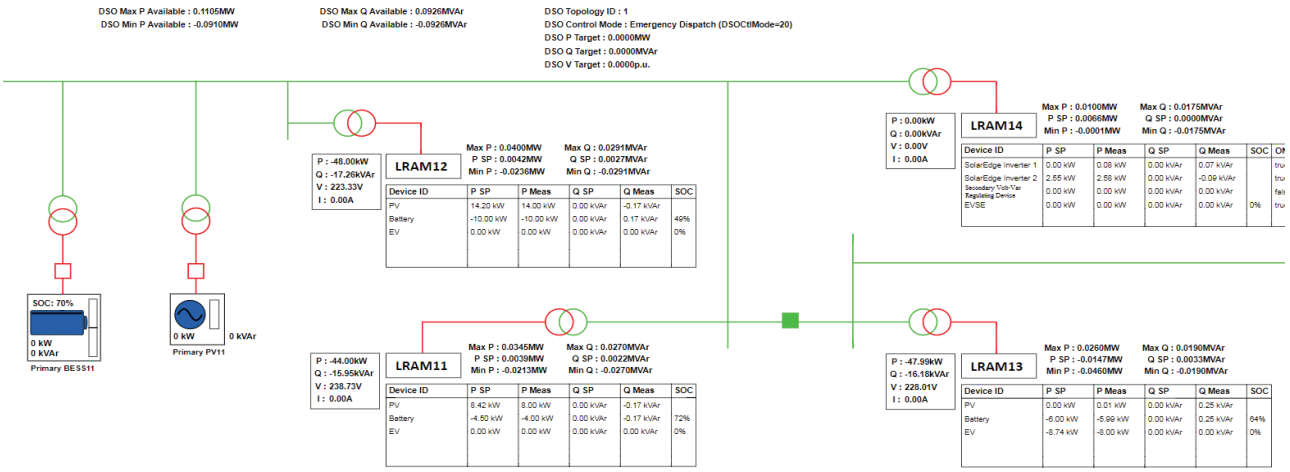
Table 3-7. Changes in LRAM settings and their resources in case 2-4-1

DSO target (kW)	Changes in LRAMs
250	- PVs are at full generation - Batteries are being discharged at full rate - EVs are curtailed
200 & 150	- PVs are being curtailed - Batteries are either curtailed or started charging - EVs are curtailed
100 & 50	- PVs are curtailed - Batteries are all charging - EVs are curtailed
0 to -100	- PVs are curtailed - Batteries are being discharged at full rate - Some EVs started charging
-150 & -200	- EVs are charging

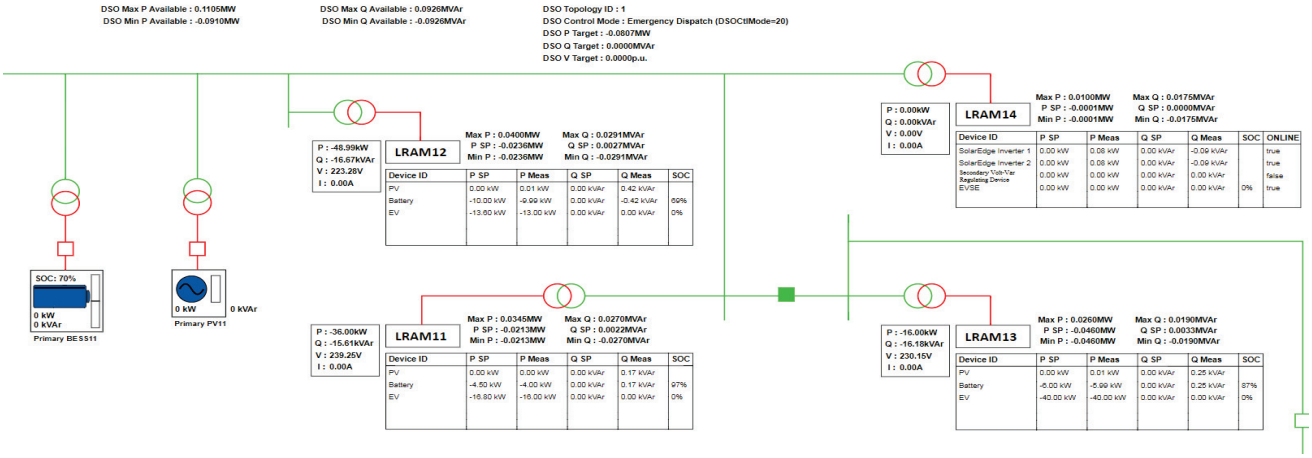
Snapshots of the RAMCO 1 HMI are shown in Figure 3-17, which verify the changes mentioned in this table. Similar behavior is seen in RAMCO 2. As can be seen, results of this use case illustrate that as LRAM target reduces, the LRAM allocates the target according to a similar priority stack: first bringing the BESS into a charging state, followed by curtailment of PV when the storage enters a fully maximum charging setpoint. The EV charging is brought on once the PV has been curtailed, enabling additional capacity, which allows the PV to be released.



a) DSO target is 250 kW



b) DSO target is 0 kW



c) DSO target is -200 kW

Figure 3-17. RAMCO 1 HMI in case 2-4-1

The setpoints of individual resources in LRAM 14 (hardware LRAM of RAMCO 2) are shown in Figure 3-18. As can be seen, initially the PV is being curtailed. When more reduction of the setpoint is observed, EVSE is allowed to charge at a higher power (kW), until the PV is fully curtailed and the EVSE is at its maximum power.

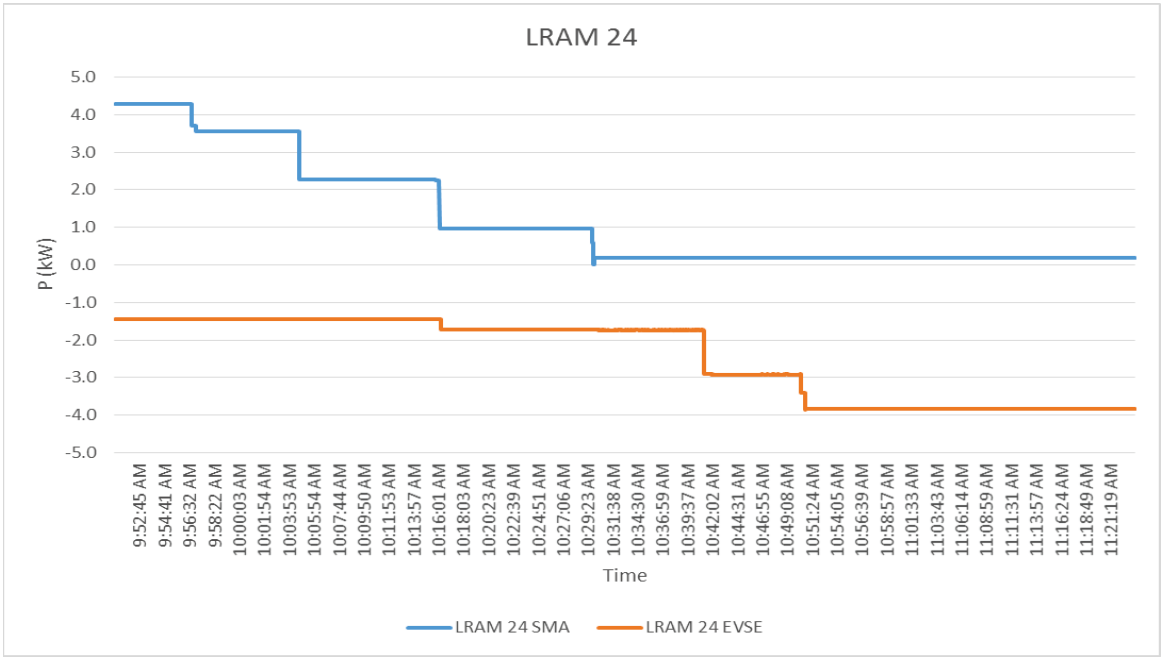


Figure 3-18. LRAM 24 setpoints in case 2-4-1

3.1.4 Case 3-1: Reactive power management:

In this use case, DSO is set to reactive power management mode to send the reactive power contribution target requests to all RAMCOs. Based on these targets, RAMCOs should define the reactive power contribution targets for primary DERs and LRAMs in their operating region. The initial SOC of the primary batteries were set at 70% and PV profile was set at 70%. The reactive power contribution target from DSO was reduced in steps from 7MVAr to -7MVAr to assess the responses from RAMCOs and LRAMs.

Table 3-8 shows data recorded from the DSO for reactive power target of each RAMCO and primary DER. As can be observed, when DSO sent request for new reactive power contribution target, the target for RAMCO1 and RAMCO2 were updated based on this latest request. Reactive power contribution for each primary DER was also calculated and updated by each RAMCO to meet the target. The response illustrates the overall contribution is dominated by the primary assets that share the contribution in a pro-rata fashion.

Table 3-8. Summary of reactive power targets for each RAMCO and primary DERs

Timestamp	DSO Q Target	RAMCO1 Q Target	RAMCO1_Batt Q Target	RAMCO1_PV Q Target	RAMCO2 Q Target	RAMCO2_Batt Q Target	RAMCO2_FG Q Target	RAMCO2_PV Q Target
Sep 27 2017 13:56	7.00	4.23	1.00	3.20	2.77	1.81	0.00	0.92
Sep 27 2017 14:07	4.00	2.42	0.50	1.89	1.58	1.07	0.00	0.55
Sep 27 2017 14:15	1.00	0.60	0.01	0.57	0.40	0.31	0.00	0.12
Sep 27 2017 14:22	0.00	0.00	-0.17	0.14	0.00	0.06	0.00	-0.03
Sep 27 2017 14:26	-1.00	-0.60	-0.35	-0.29	-0.40	-0.20	0.00	-0.18
Sep 27 2017 14:32	-7.00	-4.23	-1.12	-3.11	-2.77	-1.77	0.00	-0.95

Figure 3-19 shows the primary DERs reactive power measurements compared to the targets. It can be observed that for each step change from the DSO Q target, RAMCO1 and RAMCO2 could successfully send the updated Q target to the corresponding DERs, and reactive power measurements from each DER matched the target very well.

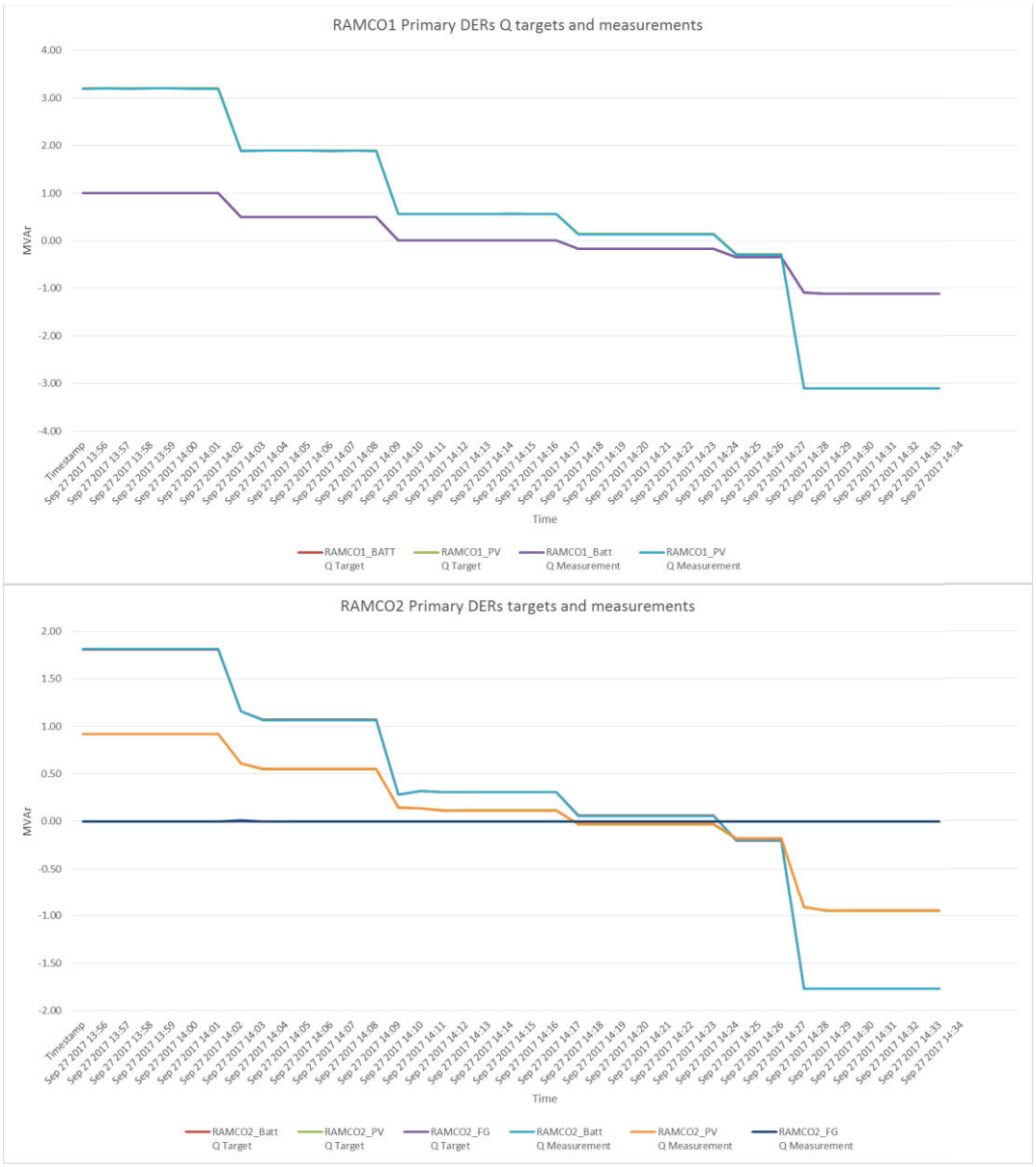


Figure 3-19. Primary DERs reactive power target and measurement for each RAMCO

Figure 3-20 below shows a sample snapshot of RAMCO2 HMI interface to present the LRAM responses for the reactive power contribution. It can be observed that RAMCO 2 has sent the Q setpoint to each of the LRAMs, and then LRAMs determine the reactive power setpoints of secondary assets. Measurements show that reactive power contribution from the secondary assets meets the LRAM targets.

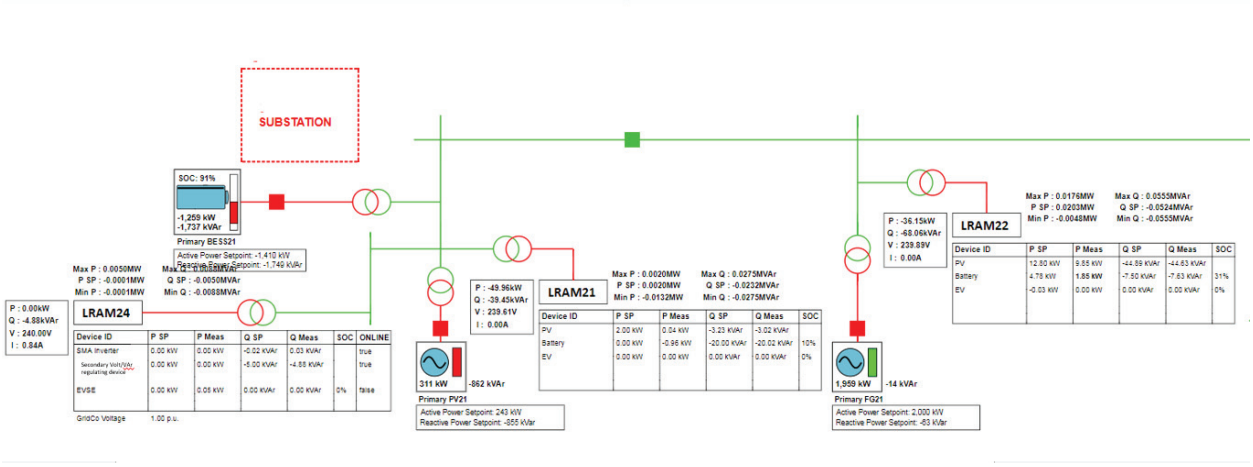


Figure 3-20. HMI screenshot for RAMCO2 LRAMs with DSO Q target at -7 MVAr

Figure 3-21 shows the HMI reactive power measurements for each RAMCO. As can be observed, at RAMCO level, for each of the reactive power contribution target change from DSO, RAMCO target was updated based on the request and overall contributions from primary DERs and LRAMs could meet the contribution target.

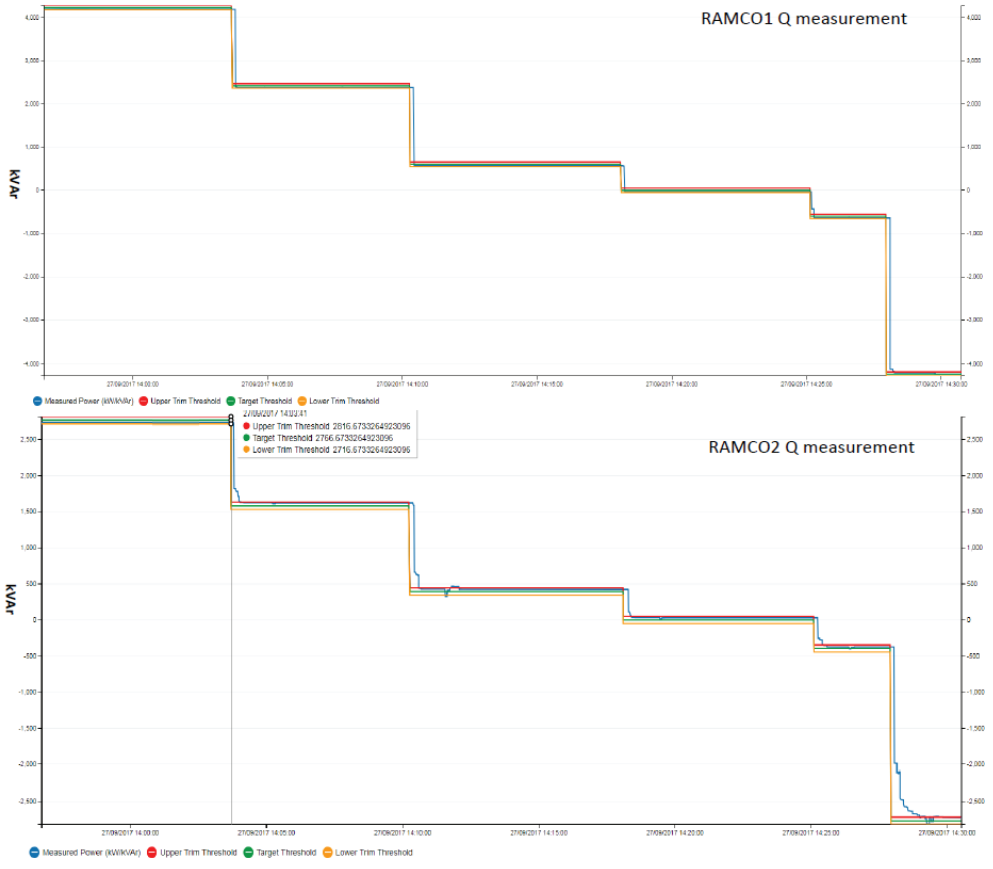


Figure 3-21. Reactive power contribution measurement for RAMCO 1 & 2

4 KEY FINDINGS AND OPERATIONAL PROCEDURE EVALUATION

In the following, the key findings of the project are summarized. Then, the operational procedure evaluation is discussed.

4.1 Key Findings

In this project, a highly distributed and modularly scalable control platform for monitoring, aggregation, and control of DERs was proposed and demonstrated. This project highlighted the important role of DERs in secondary systems to support primary DERs for the purpose of emergency dispatch and voltage and reactive power control. One of the salient features of the proposed control platform was the ability to control and utilize DERs on the secondary of service transformers (secondary systems). The proposed control platform has provided a promising solution for aggregating and managing control and operating of non-conventional resources – both utility owned and third party managed - such as solar PV systems, ESS units, electric vehicles, and controllable loads. The control platform is able to control and monitor the primary and secondary DERs in the system and provides a separate communication path from SCADA to DERs which results in the improved reliability of the control system.

Two of the secondary Volt/VAr regulating devices were successfully type tested and reviewed. Type testing of secondary system technologies showed that secondary Volt/VAr regulating devices from two different venders provided promising solutions for secondary voltage regulation, localized reactive power compensation, and interaction with customer resources downstream of services transformers.

The key findings of the project are summarized as follows:

- Proposed architecture provides a solution for aggregating and managing control and operating of non-conventional resources – both utility owned and third party managed - such as solar PV systems, ESS units, electric vehicles, and controllable loads. The proposed system can control and monitor the primary and secondary DERs in the system.
- Proposed architecture provides a separate communication path from SCADA to DERs which results in the improved reliability of the control system.
- This control platform has coordinated interaction with SCADA to detect the latest circuit topologies in the system.
- RAMCOs and LRAMs highly rely on the priority stacks to effectively utilize DERs for meeting the targets requested by DSO. These priority stacks are of paramount value for ensuring correct control actions are taken and effectively utilizing the ESS units, due to their limited energy level. It is essential to discuss and properly determine the priority stack for each RAMCO, based on control modes and available DER types.
- The results of this project highlighted the importance of small DERs in secondary systems for the purpose of voltage control at residential and commercial customers as well as supporting contribution from large DERs in the case of emergency mode. It would be critical to include their contribution as much as possible and is feasible (based on customer engagement and accessibility to resources).
- LRAMs can be designed to request for voltage support and/or active/re-active power target correction from RAMCOs in the case of shortage of resources (outage of PV or ESS). In this case, RAMCOs should utilize primary DERs and neighboring LRAMs to support the LRAM with shortage of resources.

- RAMCOs can be designed to request for support from each other in the case of sudden outage of primary DERs.
- A linkage between NMS and the DSO platform was proven to be beneficial and recommended to be implemented. The scheme can be used to coordinate the actions requiring both control systems working jointly. For instance, if the requested voltage reduction is not do-able, DSO can be designed to ask for SCADA help to change the voltage level of circuit by utilizing LTC and voltage regulators.
- Proposed architecture was tested and proven to properly operate in three different modes:
  - Load management: based on changes in the electricity market prices, while maintaining a reserve capacity.
    - Reliable aggregation and monitoring of resources
    - Fast response to market price changes to ensure the economical utilization of ESS units, FG units, and PV systems
    - Coordinated utilization of resources by monitoring ESS units' energy level, PV systems generation, and FG units' generation schedule.
  - Reactive power management and secondary voltages:
    - Reactive power control mode change on primary DERs:
      - Unity power factor control mode
      - Reactive power control mode
      - Q-V droop control mode
    - Coordinated reactive power sharing among DERs/LRAMs
      - DERs are asked for reactive power contribution according to their reactive power ratings.
    - Successfully enforces conservative voltage reduction on all primary DERs and LRAMs.
      - Use of secondary devices to successfully regulate the secondary voltages based on the setpoints send by DSO.
      - Successful utilization of secondary system Volt/VAr regulation technologies.
  - Emergency dispatch:
    - Successful utilization of resources with following priority stacks:
      - For releasing power:
        - Releasing the curtailed power of PVs
        - Releasing the curtailed power of FG units
        - Discharging ESS units
      - For curtailing power:
        - Charging ESS units
        - Curtailment of PVs if required
        - Curtailment of FG units if required
    - Successful utilization of LRAMS:
      - LRAMs performance were tested by turning off all primary DERs.
    - Primary DERs successfully switching to Q-V droop control mode to locally control their terminal voltage in emergency mode.

4.2 System Operation Procedure Evaluation

One of the key focus of the project was to propose practical operating procedures for the DER aggregation platform to ensure acceptance and coordination with commonly utilized procedures by system operators. In planning and performing this demonstration, several challenges needed to be addressed. The concept of operation was developed to address some of the challenges, both from the design perspective and operational procedures. The concept of operation was validated and adjusted as needed. Based on the test results and use cases, the final observations and conclusions were reflected in the proposed operating procedures, which covered several topics related to the design, technology selection and deployment, including:

- Field area broadband communications for data exchange among RAMCO units (at selected regions) and LRAM units (at selected service transformers).
  - Design aspect 1: the demo system design incorporated wireless radio devices to reflect the possible field challenges of dealing with wireless communications including: delays, latencies, and packet drops.
  - Design aspect 2: data reporting, commanding, and confirmation of the data receipt (handshaking) were handled in certain time steps and over pre-defined intervals that are long enough to ensure setpoints and status are properly exchanged, yet, the expected contribution targets are met within the market clearing time. For the real-time market, to avoid any penalties due to the lack of performances, the targets need to be confirmed within 5-minute intervals. In certain conditions, the setpoint changes as fast as 1 minute would be required. Hence, the time step of executing control signals and retrieving estimated values are managed to be in 30 second time frame.
- Scaling of the control architecture involving several RAMCO devices (for instance, 50 to 100 units), and thousands of LRAM devices (for instance, 100 LRAM units per RAMCO x 50 RAMCO units = 5000 devices). In addition, there will be several primary connected large DERs that would also have associated site controllers integrated into RAMCO devices. In other words, the control system has to be able to easily manage over 10,000 units.
  - Design aspect 3: the possible limitations in the ultimate number of devices that can be handled by the aggregation architecture depends on the vendor product capabilities. The demo system incorporated 10 physical hardware devices (control nodes) to investigate challenges that may rise from the scaling aspect; however, additional evaluation will be required to observe and resolve any limitations.
- Establish operating procedures to ensure separation of controls and monitoring for the aspects associated with managing DERs and participation in the energy and ancillary service markets, from conventional day-to-day operation system operation to supplying electricity to the customers.
  - Operating procedure 1: The design incorporated two distinct parts for the control center platform, namely: SCADA/DMS, and DSO. The SCADA/DMS will be primarily in charge of system operation (load and voltage management, circuit switching, and control of feeder devices). On the other hand, DSO is responsible for market interaction with ISO and determination of the contribution targets for the RAMCO units, based on the commands from SCADA and market price signals.
  - Operating procedure 2: Both RAMCO and LRAM design and operation procedures need to incorporate proper investigation of failsafe requirements, and provisions to mitigate adverse impact of DER products on the power quality of the distribution systems. The failsafe actions may vary by the type of the device and locations on the system; this does not necessarily mean

it would be a continuation of operation based on previous setpoint, and/or reverting to a default setpoint. This has to be decided and evaluated based on the system operating conditions and resource availability. To avoid adverse impact of DER production on the circuit voltages, especially during the emergency conditions, the voltage-droop control mode was suggested and evaluated in the demo system. Voltage-droop method ensures that reactive power of the DER units are dynamically adjusted to maintain voltages within permissible range.

- Operating procedures 3: Frequent charge and discharge of the energy storage units in response to market signals (especially regulation signals) and intermittent nature of large renewable energy resources can create other power quality concerns such as flicker issues or high frequency harmonic pollutions. These aspects were not investigated in the demo system, but they would require careful considerations in systems that include large number of DER units.

Other operational procedures need to be considered to assure proper involvement of and communications among third party (non-utility) aggregators at RAMCO or LRAM levels. Although the proposed architecture is capable of managing the third-party aggregators, this aspect was not covered in the scope of the demo system.

The project introduced and evaluated the proposed distributed control platform, and two new aggregation methods for managing large number of DERs of various nature (firm and variable) and of different sizes, distributed across the system and connected at primary and/or secondary systems. From the testing, demonstration, key findings and result analysis, it can be concluded that, the Regional Aggregation, Monitoring and Circuit Optimizers (RAMCO) and Local Resource Aggregators (LRAMs) can effectively coordinate and manage the operation of existing legacy and future control devices by utilizing the proposed distribution control methodology.

Several performance metrics were introduced and evaluated to address the level of aggregation, resource estimation and controllability required for a system with level of DER penetration. From these performance metrics and evaluation, it was demonstrated and concluded that the proposed control platform was able to perform DER dispatch and follow the contribution request based on various operating scenarios during normal and contingency conditions to effectively engage various types of energy resources on the system in managing circuit loading and voltage/reactive power profiles.

In lab testing and pre-commercial demonstration results concluded and demonstrated that, the operator’s ability to monitor and control DERs across the system with greater details and to make informed decisions, additional levels of complexity, increase in penetration and integration of customer technologies, will not become a barrier for deployment of DERs. It was also demonstrated that same level of reliability and efficiency can be achieved for a system with high penetration of DERs.

5 SUMMARY OF RECOMMENDATIONS AND NEXT STEPS

The recommendations and next steps are summarized as follows:

- It is recommended that the operating practices introduced in this project be further examined for their commercial viability. The investigation should cover both utility-owned and non-utility assets to specify proper circuit level and service level aggregators and associated control/operation functions. A business case would need to be developed.
- To transition the proposed aggregation system to the product stage for deployment and operation in real-world distribution systems, the following steps are recommended.
    - Integration between DMS/SCADA and DER aggregation platform at control center level is recommended, so data and target system configuration and topology can be seamlessly exchanged between the field aggregators and control center platforms to avoid adverse effect on system operation, power quality and device to device coordination.
    - For the above-mentioned points, it is recommended to develop requirements for standard platforms for integrating DMS/SCADA and DER aggregation as part of the control center functions to properly utilize the existing controls, models, databases and the two-way status communications.
    - It is recommended to incorporate the proposed DER aggregation system into a field message bus platform that can accommodate all DER assets and the platform can be easily scaled up.
    - A pilot project incorporating part of distribution systems is recommended to learn unknown (field specific) challenges and to test real-world issues. The pilot project would also clarify the skills development and training requirements needed for widespread commercial adoption of the demonstrated concepts.
    - It is also recommended to implement and evaluate other grid supporting applications of aggregated DER controls such as creation of a distributed primary frequency control approach to compensate for the absence of conventional generators with rotating mass.

It is recommended to consider various control and monitoring schemes of the proposed control platform from the real-world deployment perspective and scalability required for real world implementation. The design and verifications as part of the pre-commercial demonstration in the laboratory environment incorporated various considerations on this subject, primarily from the perspective of using wireless communications (radio modems), and adding multiple control agents to assess any impact of latency and packet losses on the performance of the schemes. Additional considerations and testing in the field environment will be needed to ensure proper design evaluation.

To publicize the proposed control platform and share the findings with the industry, SDG&E will widely announce the availability of the project report. Additionally, the project team will seek publication in top ranking journals and panel presentation on the topic in conference venues. The publications and presentation will focus on discussing key features of the concept of operation and demonstration results.

6 METRICS AND VALUE PROPOSITION

This section describes the metrics used in the project for evaluation of the results and performance of the aggregated control platform and secondary system Volt/VAr management technologies. In addition, the value proposition associated with the project is described in this section.

6.1 Metrics

The metrics in the Table 6-1 were identified for this project and are referenced to the appropriate section.

Table 6-1. Project Metrics

List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation) – See EPIC document for reference.	Remark & Reference
1. Potential energy and cost savings	
a. Number and total nameplate capacity of distributed generation facilities	Included & verified; 15 sites were included in the demo system and tested For more information, refer to section 2.
e. Peak load reduction (MW) from summer and winter programs	Included & verified; One of the implemented use cases was focused on Circuit Level Load Management and Emergency Dispatch. Based on aggregated resources, up to 20% load reduction was achieved For more information refer to section: 3
3. Economic benefits	
c. Reduction in electrical losses in the transmission and distribution system	Included & verified; The demonstrated method incorporated Volt/VAR management at primary and secondary level, to reduce kVA and losses; up to 3% in the tested case

List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation) – See EPIC document for reference.	Remark & Reference
	For more information refer to section: 3
d. Number of operations of various existing equipment types (such as voltage regulation) before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear	The propose method utilizes fast action of DERs and secondary resources to reduce voltage and load fluctuations, and enhance life cycle assessment. Unnecessary tap operations were eliminated. Cap switching was prevented. For more information refer to section: 2.
5. Safety, Power Quality, and Reliability (Equipment, Electricity System)	
b. Electric system power flow congestion reduction	Included & verified; In emergency mode of the control platform, the circuit level power flow and demand were managed through control of aggregated resources to prevent congestion. For more information refer to section: 3
i. Increase in the number of nodes in the power system at monitoring points	Real time monitoring and 5 min or 10 min system prediction were included as the integral part of the platform design. PMU system provided also high-resolution data for enhanced visualization. For more information refer to section: 2
7. Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy	
b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)	Included & verified; Integration between SCADA/DMS and the DER Aggregation platform was identified as a key cost-effective

List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation) – See EPIC document for reference.	Remark & Reference
	solution to ensure integrity of the system. For more information refer to section: 3
f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360)	Included and verified; Grid-edge devices at secondary level, and integration/aggregation platform for distributed controls were introduced as part of the proposed control system. For more information, refer to section: 2
8. Effectiveness of information dissemination	
d. Number of information sharing forums held	Included and Performed; Multiple meetings and workshop held with stakeholders and team. For more information, refer to sections: 1 and 2
e. Stakeholders attendance at workshops	Included and performed; Stakeholder from various departments and group related to operation and planning were selected and invited to workshops. For more information, refer to sections: 1 and 2
f. Technology transfer	Plan was made for knowledge transfer through open forum and conferences. A panel presentation was offered in DistribuTECH 2018, in San Antonio, TX. For more information, refer to section: 4.4

6.2 Primary Value Proposition

EPIC provides project funding for applied research and development, technology demonstration and deployment, and market facilitation for clean energy resources. To be approved, the projects must provide value to customers. This project has provided multiple values by supporting benefits related to improved reliability, lower costs, safety improvement, and environmental benefits.

6.2.1 Greater Reliability

Higher level of awareness and greater reliability indices are expected from a system that can effectively utilize DERs across the system to manage loads and generation locally and provide near real-time estimates of system status to the operator. It can be shown that system stability and reserve margins are greatly improved, by properly dispatching large centralized resources, as well as tapping into the resources on the secondary systems (low voltage level) that were previously neglected in the overall stability and performance assessment of the system. Instead of dropping loads, the resource estimate can be utilized during emergency to compensate for the load curtailment.

6.2.2 Lower Costs

Effective use of resources at local and regional scale will allow for proper reactive power flow management, voltage control, and localized load balancing, all of which will support reduction in losses and increase in system efficiency. In addition, enabling participation in wholesale market and optimizing the use of the resources based on variation in the price signal might bring in additional revenue for the ratepayers.

6.3 Secondary Value Proposition

This secondary value propositions for the project are safety improvement and environmental benefits.

6.3.1 Increased Safety and/or Enhanced Environmental Sustainability

Because the focus of the proposed advanced operating system is on improving the system visibility and dispatchability, as well as providing faster and more reliable methods for operating the system, safety and integrity enhancement of the system will be the main target. Fast actions are becoming possible based on processing and visualizing high resolution of field data in near real-time, and access to DERs for managing reserve capacity and production level. In addition, because the system becomes more observable and controllable, more customer system installation requests and interconnection applications can be processed to expedite the integration and increase the penetration levels.

6.3.2 Adaptability to other utilities and/or the broader industry

The findings and recommendations on the control system architecture and concept of operation procedures are relevant to various activities of other IOUs in California and elsewhere. Many utilities are focusing on developing remote dispatch and control capabilities for growing levels of DERs in their service territory. The initiatives are based on adding new control functions to existing DMS/SCADA, or introducing new DERMS concept. Either approach will be able to benefit from common aspects of this project and lessons learned on considerations for scalability and aggregation at two levels.

7 REFERENCES

[1] J. D. Taft and A. Becker-Dippmann, “Grid Architecture,” A report by Pacific Northwest National Lab (PNNL), Jan. 2015.

[2] L. Kristoff and P. de Martini, "21st Century Electric Distribution System Operations,", May 2014

8 APPENDICES

8.1 Appendix A: RAMCO/LRAM Priority Stacks for Emergency Dispatch of DERs for Demand Side Management Use Case

RAMCOs and LRAMs use a priority stack to utilize the DERs depending on the command received from the DSO. Depending on the DSO target update RAMCO might need to curtail or release DERs contribution. Depending on the contribution release or curtail request, RAMCO should use appropriate priority stack to effectively utilize DERs. In **Error! Reference source not found.** to Table 8-6, the priority stacks of RAMCO1 and RAMCO2 are summarized for different circuit configurations. The location of primary DERs and LRAMs is shown in Figure 2-3. Table 8-7 shows the priority stack used for a typical LRAM.

Table 8-1. Priority Stack of RAMCO1 in Topology 1

RAMCO1 - Topology1 - (Power Curtail)				
Priority				
1	BESS11			
2	PV11			
3	LRAM11	LRAM12	LRAM13	LRAM14

RAMCO1 - Topology1 - (Power Release)				
Priority				
1	PV11			
2	BESS11			
3	LRAM11	LRAM12	LRAM13	LRAM14

Table 8-2. Priority Stack of RAMCO1 in Topology 2

RAMCO1 - Topology2 - (Power Curtail)			
Priority			
1	BESS11		

2	PV11		
3	LRAM11	LRAM12	LRAM14

RAMCO1 - Topology2 - (Power Release)			
Priority			
1	PV11		
2	BESS11		
3	LRAM11	LRAM12	LRAM14

Table 8-3. Priority Stack of RAMCO1 in Topology 3

RAMCO1 - Topology3 - (Power Curtail)						
Priority						
1	BESS11					
2	FG21					
3	PV11					
4	LRAM11	LRAM12	LRAM13	LRAM14	LRAM22	LRAM23

RAMCO1 - Topology3 - (Power Release)						
Priority						
1	PV11					
2	FG21					
3	BESS11					
4	LRAM11	LRAM12	LRAM13	LRAM14	LRAM22	LRAM23

Table 8-4. Priority Stack of RAMCO2 in Topology 1

RAMCO2 - Topology1 - (Power Curtail)				
Priority				
1	BESS21			
2	FG21			

3	PV21			
4	LRAM21	LRAM22	LRAM23	LRAM24

RAMCO2 - Topology1 - (Power Release)				
Priority				
1	PV21			
2	FG21			
3	BESS21			
4	LRAM21	LRAM22	LRAM23	LRAM24

Table 8-5. Priority Stack of RAMCO2 in Topology 2

RAMCO2 - Topology2 - (Curtail)					
Priority					
1	BESS21				
2	FG21				
3	PV21				
4	LRAM21	LRAM22	LRAM23	LRAM24	LRAM13
RAMCO2 - Topology2 - (Release)					
Priority					
1	PV21				
2	FG21				
3	BESS21				
4	LRAM21	LRAM22	LRAM23	LRAM24	LRAM13

Table 8-6. Priority Stack of RAMCO2 in Topology 3

RAMCO2 - Topology3 - (Curtail)

Priority		
1	BESS21	
2	PV21	
3	LRAM21	LRAM24

RAMCO2 - Topology3 - (Release)		
Priority		
1	LRAM21	LRAM24
2	PV21	
3	BESS21	

Table 8-7. Priority Stack of a typical LRAM

Priority	**Power Curtail**	**Power Release**
1	Connect Non-Critical Load	Release PV if already curtailed
2	Charge EV	Discharge Batt
3	Charge Batt	Discharge EV
4	Curtail PV	Disconnect Non-Critical Load

8.2 Appendix B: Test Plan and Results for Type Tests of Secondary Regulating Devices

The objective of the type testing was to evaluate the operation and performance of the secondary system technologies through a laboratory testbed setup, including a simple test circuit in digital simulation platform, grid simulator, load banks, and PV inverters to represent residential loads. Devices from two different vendors were selected as DUTs for the type test purpose. Both of the DUTs selected have similar functions for secondary voltage regulation, reactive power compensation or power factor correction.

8.2.1 Type Test Plan

Based on the devices' specification, the following test categories and cases were considered in the test plan and performed during type test.

8.2.1.1 Category 1: DUT initialization and start up test

The purpose of this test category was to test the operating threshold and limits of DUT. DUT was connected with a fixed 5kW resistive load bank on each phase. Voltage output from grid simulator was reduced or increased until DUT cannot regulate load voltage and stops or follows the voltage, to determine the drop off voltages.

- Case 1-1: Set device voltage setpoint at nominal voltage, reduce grid simulator voltage by 5% step (12V) with 30 seconds interval between each step, until the system voltage went below the device drop off voltage, to test the drop off low voltage.
- Case 1-2: Set device voltage setpoint at nominal voltage, increase grid simulator voltage by 5% step (12V) with 30 seconds interval between each step, until the system voltage went above the device cut off voltage, to test the drop off high voltage.

8.2.1.2 Category 2: Voltage regulation performance test

The purpose of this test category was to test whether DUTs could regulate the load voltage at a desired setpoint. The following operating modes were considered based on the devices' specification and availability:

- Voltage regulation only
- Voltage regulation + reactive power adjustment
- Voltage regulation + power factor adjustment

Several test groups were considered in this test category.

8.2.1.2.1 Group1: Performance test with upstream voltage changes

Group 1 test is designed for voltage regulation test at setpoint with different upstream voltages. The tests were repeated for each of the three service transformer locations (A, B, and C). Set the voltage reference for device under test at 120V line to neutral / 240V line to line.

1) Upstream voltage variation (higher/lower than the DUT's setpoint) with downstream resistive load banks:
    - Light load condition (5 kW downstream resistive load on each phase)
        - Case 2-1-1: 5% / 10% step voltage increase at the source for 20 seconds, then change to initial value for 10 seconds, and then following by 5% / 10% voltage decrease for 20 seconds
        - Case 2-1-2: ramp up the voltage at the source by 5% / 10% with a ramp rate of 1% per second, following a sudden drop to initial value
        - Case 2-1-3: ramp down the voltage at the source by 5% / 10% with a ramp rate of -1% per second, following a sudden increase to initial value
    - Heavy load condition (20 kW downstream load on each phase)

        - Case 2-1-4: 5% / 10% step voltage increase at the source for 20 seconds, then change to initial value for 10 seconds, and then following by 5% / 10% voltage decrease for 20 seconds
        - Case 2-1-5: ramp up the voltage at the source by 5% / 10% with a ramp rate of 1% per second, following a sudden drop to initial value
        - Case 2-1-6: ramp down the voltage at the source by 5% / 10% with a ramp rate of -1% per second, following a sudden increase to initial value
2) Upstream voltage variation (higher/lower than the DUT's setpoint) with reverse power flow created by PV inverter
    - 5KW PV inverter reverse power flow:
        - Case 2-1-7: 5% / 10% step voltage increase at the source for 20 seconds, then change to initial value for 10 seconds, and then following by 5% / 10% voltage decrease for 20 seconds

Case 2-1-1 to 2-1-7 were also repeated for a higher voltage step change (10-15%) to evaluate the performance when input voltage exceeds devices' voltage regulation capability.

3) Voltage variations under off-nominal frequency test: Test cases with system frequency from 59.7Hz to 60.3Hz.
    - Set the source frequency at 59.7 Hz.
        - Repeat test cases 2-1-4 to 2-1-7
    - Set the source frequency at 60.3 Hz
        - Repeat test cases 2-1-4 to 2-1-7
    - Set downstream load at 40 kVA, ramp up the frequency at the source from 59.7Hz to 60.3Hz with a ramp rate of 0.03Hz per second, following a sudden drop to initial value

8.2.1.2.2 Group2: Performance test with downstream Load variation

Group 2 test was designed for voltage regulation test at setpoint with downstream load variation. The tests were performed for service transformer location C. Each designed test cases were repeated 3 times for test results validation.

1) Resistive downstream loads: load variation with resistive loads step change
    - Case 2-2-1: 5 kW initial load on each phase with 5 kW step load increase of resistive load bank until 20 kW on each phase, and 10 second interval between each step change.
2) Load variation with change in the load flow direction
    - Case 2-2-2: 2.5 kW resistance load on each phase for 10 second, then switch on 5 kW PV inverter (unit power factor) for 30 seconds, then switch off PV inverter.
    - Case 2-2-3: 1.5 kW resistance load on each phase for 10 second, then switch on 5 kW PV inverter (unit power factor) for 30 seconds, then switch off PV inverter.
    - Case 2-2-4: 0.5 kW resistance load on each phase for 10 second, then switch on 5 kW PV inverter (unit power factor) for 30 seconds, then switch off PV inverter.
    - Case 2-2-5: 0.5 kW resistance load on each phase for 10 second, then switch on 5 kW PV inverter (0.8 power factor leading) for 30 seconds, then switch off PV inverter.
    - Case 2-2-6: 0.5 kW resistance load on each phase for 10 second, then switch on 5 kW PV inverter (0.8 power factor lagging) for 30 seconds, then switch off PV inverter.

8.2.1.2.3 Group3: Performance test with system disturbance (sag/swell) at upstream

Group 3 test was designed for voltage regulation test at setpoint with system disturbance (voltage sag/swell) at upstream. The tests were repeated for each of the three service transformer locations (A, B and C). Digital simulation platform was used to simulate the voltage sag/swell at the upstream system. Set the voltage reference for device under test at 120 V per line (240 V line to line).

1) Voltage sag test:
    - Light load condition:
        - Case 2-3-1: Nominal source voltage with 5 kW resistive load bank on each phase for 10 second, then apply voltage sag of 80% of nominal voltage at source lasting 10 second and go back to nominal voltage.
        - Case 2-3-2: Nominal source voltage with 5 kW resistive load bank on each phase, and 5 kW PV inverter for 10 second, then apply voltage sag of 80% of nominal voltage at source lasting 10 second and go back to nominal voltage.
        - Case 2-3-3: Nominal source voltage with 5 kW resistive load bank on each phase for 10 second, then apply voltage sag of 70% of nominal voltage at source lasting 0.5 second and go back to nominal voltage.
        - Case 2-3-4: Nominal source voltage with 5 kW resistive load bank on each phase, and 5 kW PV inverter for 10 second, then apply voltage sag of 70% of nominal voltage at source lasting 0.5 second and go back to nominal voltage.
    - Heavy load condition:
        - Case 2-3-5: Nominal source voltage with 20 kW resistive load bank on each phase for 10 second, then apply voltage sag of 80% of nominal voltage at source lasting 10 second and go back to nominal voltage.
        - Case 2-3-6: Nominal source voltage with 20 kW resistive load bank on each phase, and 5 kW PV inverter for 10 second, then apply voltage sag of 80% of nominal voltage at source lasting 10 second and go back to nominal voltage.
        - Case 2-3-7: Nominal source voltage with 20 kW resistive load bank on each phase for 10 second, then apply voltage sag of 70% of nominal voltage at source lasting 0.5 second and go back to nominal voltage.
        - Case 2-3-8: Nominal source voltage with 20 kW resistive load bank on each phase, and 5 kW PV inverter for 10 second, then apply voltage sag of 70% of nominal voltage at source lasting 0.5 second and go back to nominal voltage.
2) Voltage swell test:
    - Light load condition:
        - Case 2-3-9: Nominal source voltage with 5 kW resistive load bank on each phase for 10 second, then apply voltage swell of 120% of nominal voltage at source lasting 0.5 second and go back to nominal voltage.
        - Case 2-3-10: Nominal source voltage with 5 kW resistive load bank on each phase, and 5 kW PV inverter for 10 second, then apply voltage swell of 120% of nominal voltage at source lasting 0.5 second and go back to nominal voltage.
    - Heavy load condition:
        - Case 2-3-11: Nominal source voltage with 20 kW resistive load bank on each phase for 10 second, then apply voltage swell of 120% of nominal voltage at source lasting 0.5 seconds and go back to nominal voltage.

- Case 2-3-12: Nominal source voltage with 20 kW resistive load bank on each phase, and 5 kW PV inverter for 10 second, then apply voltage swell of 120% of nominal voltage at source lasting 0.5 seconds and go back to nominal voltage.

8.2.1.3 Category 3: Reactive power compensation performance test

The purpose of this test category was to test whether DUT could inject/absorb reactive power, or regulate the power factor at desired setpoints. The tests were performed at service transformer locations C (or any location deemed sensitive to group 1 tests).

The following test groups were considered in this test category.

8.2.1.3.1 Group1: Performance test with reactive power injection/absorption (based on DUTs' capability)

Group 1 test was designed to test devices' reactive power injection/absorption capability at setpoint. For group 1 test, the source voltage was set to 120 V per line (240 V line to line).

1) 5 kVAr VAr injection/absorption setting with resistive load step change
    - Case 3-1-1: 5 kVAr injection setting of DUT, 5 kW step load increase of resistive load bank on each phase until 20 kW per phase, with 10 second interval between each step change.
    - Case 3-1-2: 5 kVAr absorption setting of DUT, 5 kW step load increase of resistive load bank on each phase until 20 kW per phase, with 10 second interval between each step change.
2) 5 kVAr VAr injection/absorption setting with PV inverter switching
    - Case 3-1-3: 5 kVAr injection setting of DUT, with 3 kW resistance load on each phase for 10 second, then switch on 5 kW PV inverter with 0.8 power factor lagging for 30 seconds, then switch off PV inverter.
    - Case 3-1-4: 5 kVAr injection setting of DUT, with 3 kW resistance load on each phase for 10 second, then switch on 5 kW PV inverter with 0.8 power factor leading for 30 seconds, then switch off PV inverter.
    - Case 3-1-6: 5 kVAr absorption setting of DUT, with 3 kW resistance load on each phase for 10 second, then switch on 5 kW PV inverter with 0.8 power factor lagging for 30 seconds, then switch off PV inverter.
    - Case 3-1-7: 5 kVAr absorption setting of DUT, with 3 kW resistance load on each phase for 10 second, then switch on 5 kW PV inverter with 0.8 power factor leading for 30 seconds, then switch off PV inverter.

8.2.1.3.2 Group2: Performance test with power factor regulation

Group 2 test was designed for downstream power factor regulation at setpoint. For group 2 test, the source voltage was set to the source voltage was set to 120 V per line (240 V line to line).

1) Power factor setting at 0.85 lagging: load variation with resistive loads step change
    - Case 3-2-1: 1 kW step load increase of resistive load bank on each phase until 5 kW per phase, with 20 second interval between each step change.
2) Power factor setting at 0.85 leading: load variation with resistive loads step change

- Case 3-2-2: 1 kW step load increase of resistive load bank on each phase until 5 kW per phase, with 20 second interval between each step change.

3) Unity power factor setting with PV inverter switching
   - Case 3-2-3: Unity power factor setting of DUT 1, with 3 kW resistance load on each phase for 10 second, then switch on 5 kW PV inverter with 0.8 power factor lagging for 30 seconds, then switch off PV inverter.
   - Case 3-2-4: Unity power factor setting of DUT 1, with 3 kW resistance load on each phase for 10 second, then switch on 5 kW PV inverter with 0.8 power factor leading for 30 seconds, then switch off PV inverter.

8.2.1.4 Category 4: Operation performance test (communication test)

The purpose of this test category was to test whether DUT could be controlled by communication. Device control settings were set through communication with LRAM device:

1) Voltage regulation setting test: Voltage setpoint/bandwidth change through communication
   - Case 4-1: Set initial voltage reference at 120V / 240V, send a setting command through LRAM to change the reference to125V / 250 V, and record the time it takes to apply reference.
   - Case 4-2: Set initial voltage reference at 120V / 240V, send a setting command through LRAM to change the reference to 115V / 230 V, and record the time it takes to apply reference
2) Reactive power setting test: reactive power setpoint change through communication
   - Case 4-3: Set initial reactive power reference at 0 kVAr, send a setting command through LRAM to change the reference to 1 kVAr, and record the time it takes to apply reference
   - Case 4-4: Set initial reactive power reference at 0 kVAr, send a setting command through LRAM to change the reference to -1 kVAr, and record the time it takes to apply reference
3) Power factor setting test: power factor setpoint change through communication
   - Case 4-5: Set initial reactive power factor reference at 1 (unit PF), send a setting command through LRAM to change the reference to 0.9 lagging, and record the time it takes to apply reference
   - Case 4-6: Set initial reactive power factor reference at 1 (unit PF), send a setting command through LRAM to change the reference to 0.9 leading, and record the time it takes to apply reference
   - Case 4-7: Set Device initial operation mode at voltage regulation with power factor correction off, with 5 kW PV inverter with 0.8 power factor leading for 30 seconds. Then send a setting command through LRAM to change DUT to voltage regulation mode with power factor correction on. Record the time it takes to apply the change.
   - Case 4-4: Set DUT initial operation mode at voltage regulation with power factor correction on, with 5 kW PV inverter with 0.8 power factor leading for 30 seconds. Then send a setting command through LRAM to change GDUT to voltage regulation mode with power factor correction off. Record the time it takes to apply the change.

8.2.2 Type Test Results

8.2.2.1 DUT A

Throughout most experiments, DUT A was successful in regulating the load side voltage, compensating the reactive power and/or correcting the power factor to the desired setpoint if possible, or using its maximum available capacity toward satisfying the aforementioned setpoints, as expected. Reverse power flow and off-nominal system frequency (59.7Hz to 60.3Hz considered in the test) show no impact on the performance with regard to voltage regulation, reactive power compensation, and power factor correction.

Table 8-8. Type Test Results Summary of DUT A for Each Test Category

Test Category	Test Description	Test groups	Test results
1	Initialization and start up test		PASS
2	Voltage regulation performance test	Source voltage change (Step change / Voltage Ramp)	PASS
		Voltage sag / swell	PASS
		Load step change	PASS
		Reverse power flow	PASS
		Off-nominal Frequency	PASS
3	Reactive power compensation performance test	Reactive power generation / Absorption	PASS
		Power factor correction	PASS
		Off-nominal Frequency	PASS
4	Communication test	Dynamic setting change	PASS

Initialization and startup test

- Set DUT A voltage reference at 240V, grid simulator starting voltage at 240V.
- Reduce grid simulator voltage by 2.5% - 5% step (6-12V), with about 30 seconds interval between each step, to test the drop off low voltage (Input voltage range is 132V to 300V).

Figure 8-1 shows the RMS voltage variation measurements for phase 1. Source voltage was reduced step by step and DUT A load side voltage was monitored. As can be observed, when source voltage stayed above 66V (0.55 p.u.), DUT A boosted the voltage by around 10% of the nominal value (12 V per phase). Immediately when the source voltage went below 0.55p.u. (65.36V 1 phase, 0.545 p.u.), DUT A entered bypass mode and source voltage was bypassed to the load side. A 6V bandwidth was observed to exit bypass mode due to low voltage. When the source voltage increased to greater than 0.6 p.u. (72V per phase), DUT A exited bypass mode after 55 seconds, and started to boost voltage by 10% (12 V).

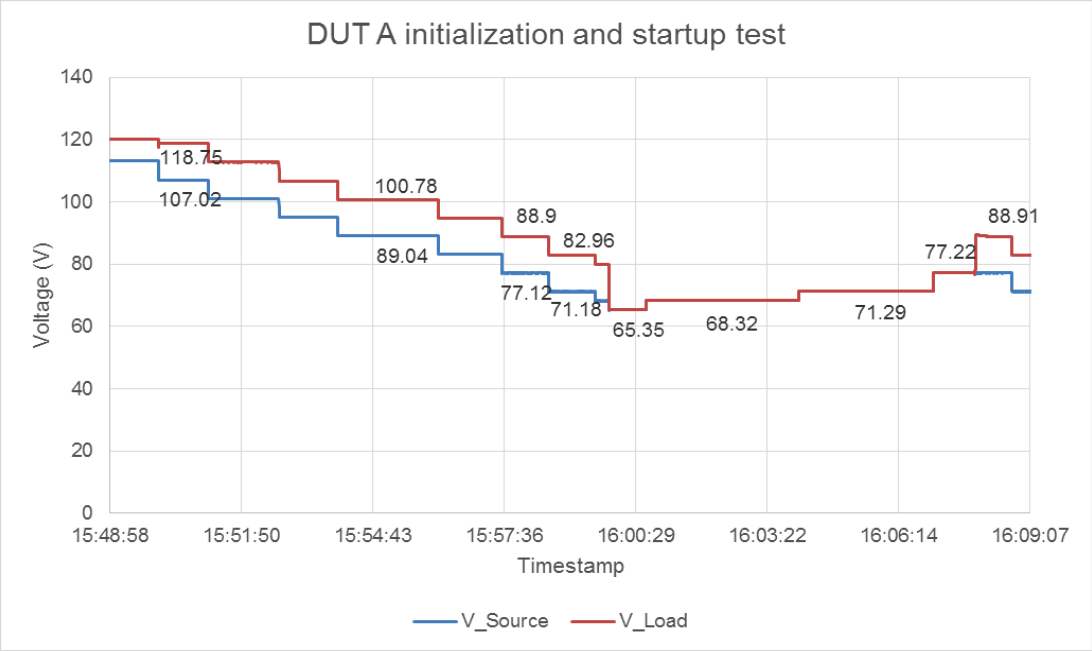


Figure 8-1. RMS Voltage Measurements for DUT A: Drop Off Voltage Test

Voltage ramp test:

- Ramp down the voltage at the source by 15% with a ramp rate of -1.5% per second, following a sudden increase to initial value.

Figure 8-2 shows the RMS voltage measurements of source and load voltage for the test case. As can be observed, before source voltage started to ramp down, load voltage was regulated very close to 120V. When phase 1 source voltage started to ramp down, since source voltage after 15% ramp up was out of the 10% regulation range, the load side voltage was regulated at round 120V and started to follow the source voltage after source voltage was lower than 90% of nominal voltage. An approximate 12V difference between source and load voltage could be observed after source voltage was below 90% of nominal voltage; similar performance was observed on phase 2.

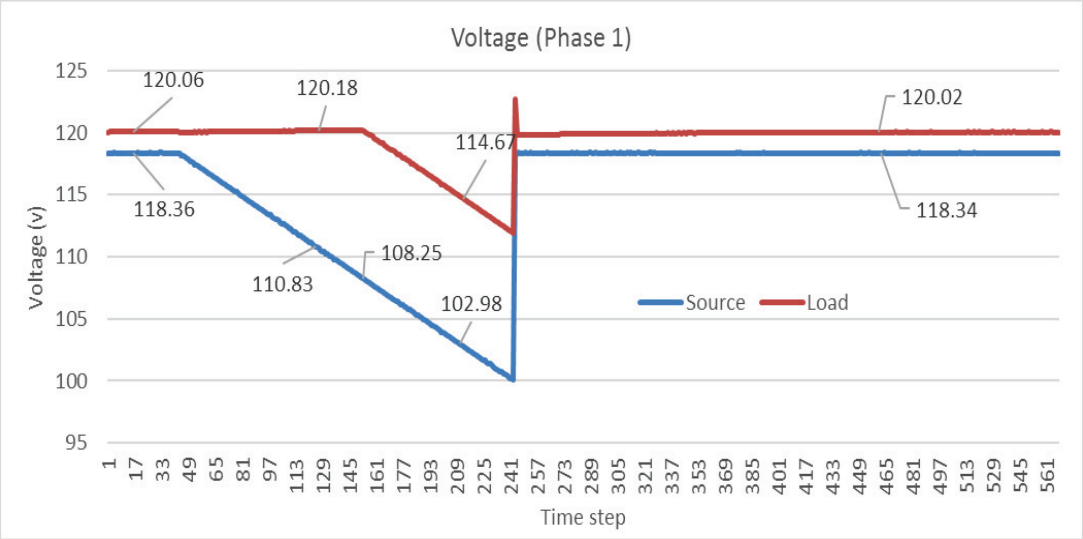


Figure 8-2. RMS Voltage Measurements for DUT A: Voltage Ramp Test

Power factor regulation test:

- 0.85 PF lagging setting of DUT A , step load increase of resistive load bank on each phase until 7 kW per phase, with 10 second interval between each step.

Figure 8-3 shows the RMS voltage measurements of DUT A source and load voltage, power and PF measurements at source side for Phase 1. As can be observed, during the load switching from 1kW to 7kW, since DUT A was set to PF regulation at 0.85 generating VAr, it can be observed that when resistive load was below 4kW (2.5 kVAr demand for 0.85 PF), power factor could be regulated at 0.85. When the load was increased to 5 kW, since the maximum VAr generation from DUT A is 2.5 kVAr per phase, DUT A remained the maximum VAr generation and power factor started to increase. A slow adjustment on the power factor to setpoint could be observed.

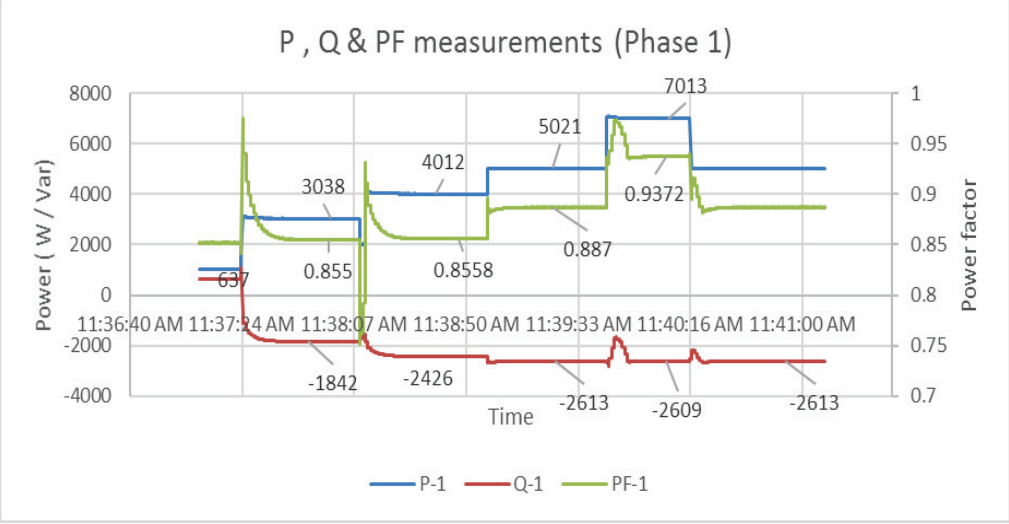


Figure 8-3. Phase 1 P, Q & PF Measurements of Power Factor Regulation Test

8.2.2.2 DUT B

Throughout most experiments, DUT B was successful in regulating the load side voltage, and correcting the power factor to unity power factor at source side. Reverse power flow and off-nominal system frequency (59.7Hz to 60.3Hz considered in the test) show no impact on the performance of voltage regulation and power factor correction.

Table 8-9. Type Test Results Summary of DUT B for Each Test Category

Test Category	Test Description	Test groups	Test results
1	Initialization and start up test		PASS
2	Voltage regulation performance test	Source voltage change (Step change / Voltage Ramp)	PASS
		Voltage sag / swell	PASS
		Load step change	PASS
		Reverse power flow	PASS
		Off-nominal Frequency	PASS
3	Reactive power compensation performance test	Power factor correction	PASS
		Off-nominal Frequency	PASS
4	Communication test	Dynamic setting change	PASS

Initialization and startup test:

- Set DUT B voltage reference at 120V per phase, grid simulator starting voltage at 120V.
- Reduce grid simulator voltage by 2.5% - 5% step (6-12V), with about 30 seconds interval between each step, to test the drop off low voltage (Input voltage range is 100V to 138V per phase).

Figure 8-4 shows the RMS voltage variation measurements for Phase 1. Source voltage was reduced step by step and DUT B load side voltage was monitored. As can be observed, when source voltage stayed above 100V, DUT B boosted the voltage by around 10V. When the source voltage went between 84V and 100V per phase, DUT B entered bypass mode and source voltage was bypassed to the load side after about 1 second. When the source voltage increased to greater than 103V, DUT B exited bypass mode after 5 minutes, and started to boost voltage by 10V per phase. When the source voltage went below 84V per phase, DUT B entered bypass mode and source voltage was bypassed to the load side after 1 cycle.

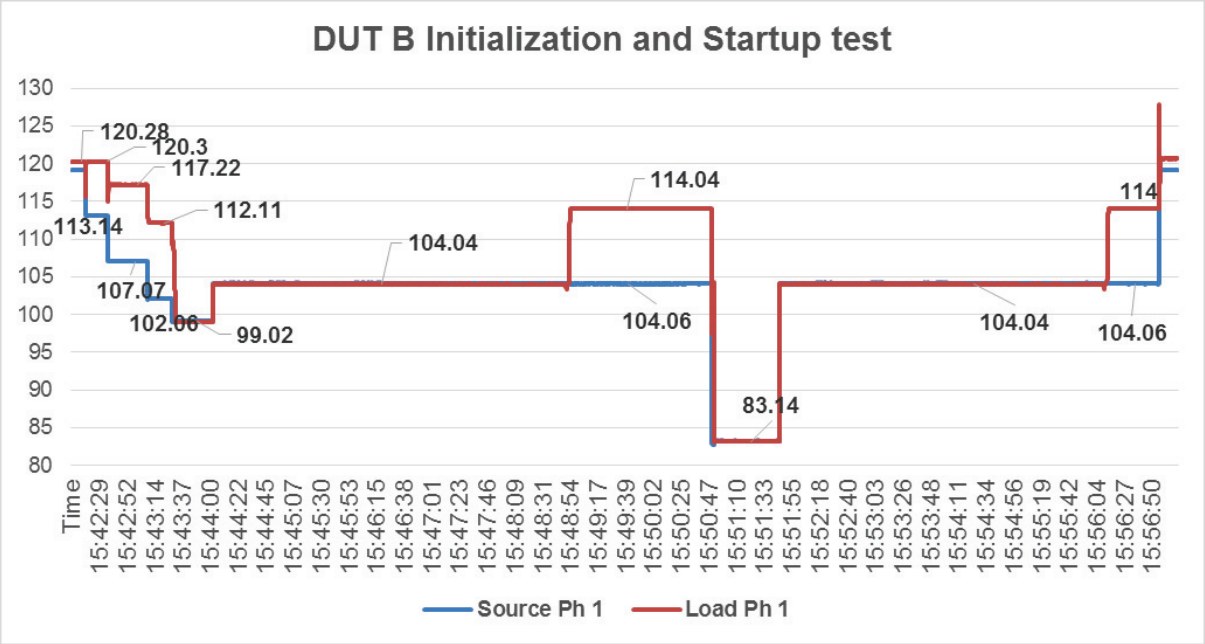


Figure 8-4. RMS Voltage Measurements for DUT B: Drop Off Voltage Test

Voltage ramp test:

- Ramp down the voltage at the source by 10% with a ramp rate of -1% per second, following a sudden increase to initial value.

In this test, voltage setpoint was 118 V for phase 2 and 122 V for phase 1. A 10% ramp down change in the source voltage was performed. Also, unbalanced loads were considered for this case, with 6 kW on phase 1 and 1 kW phase 2. As can be seen, DUT B regulated the voltage as expected. At point A, source voltage on phase 1 went below the 10 V difference with the DUT B voltage setpoint of phase 1; hence, the load voltage started to deviate from the setpoint. Similar condition is seen at point B for phase 2.

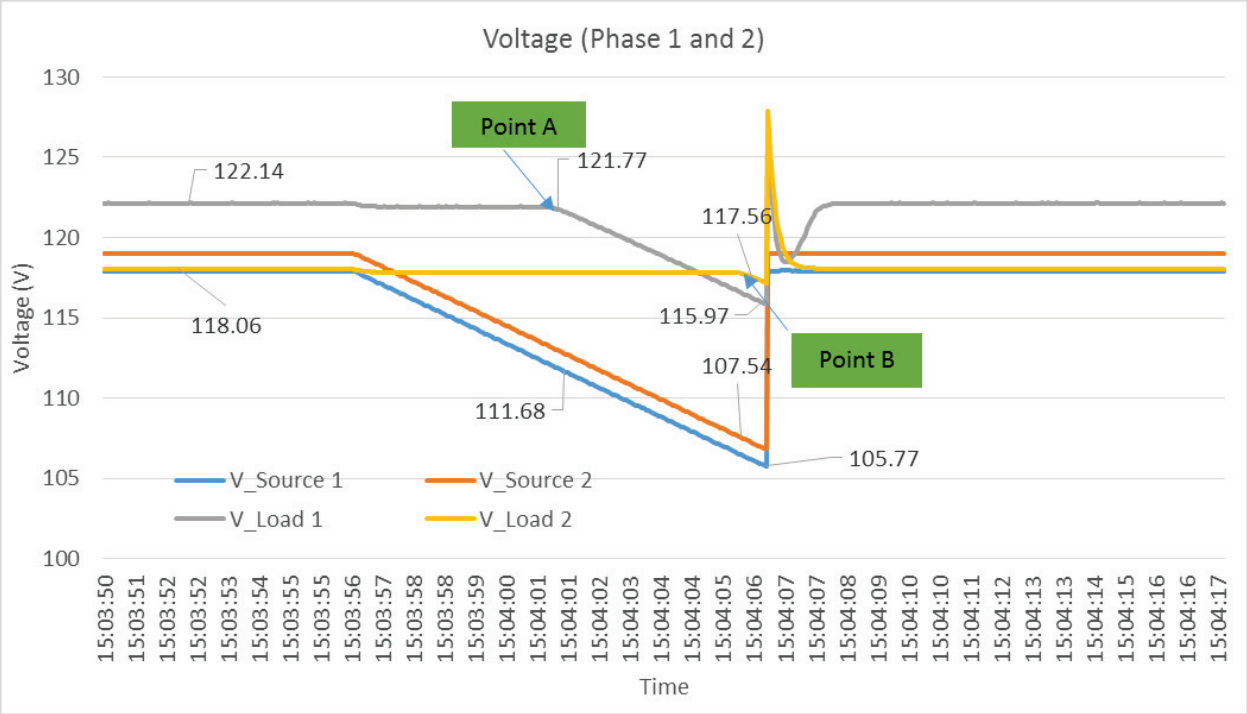


Figure 8-5. RMS Voltage Measurements for DUT B: Voltage Ramp Test

Reactive power test:

- 10 kW reverse power flow, change PF (for both PV inverters) from 1 to 0.8 lagging, then change to 0 (pushing 13 kVAr back to system), then follow the same process with leading power factor of inverter.

Figure 8-6 shows the active power measurement of both phases combined (total active power) at the source side, as well as the total reactive power at the source and load side. As can be seen in this figure, in cases where satisfying the unity power factor at the source side required less than 10 kVAr reactive support from DUT B, it kept the source power factor at unity. When the PV inverters power factor changed to zero, the reactive power injected to/absorbed from the system was around 13 kVAr. As can be seen, DUT B was capable of absorbing /providing 10 kVAr of this amount from/to the system. During this test, voltage of the load has been regulated at the desired setpoint, as seen in Figure 8-7.

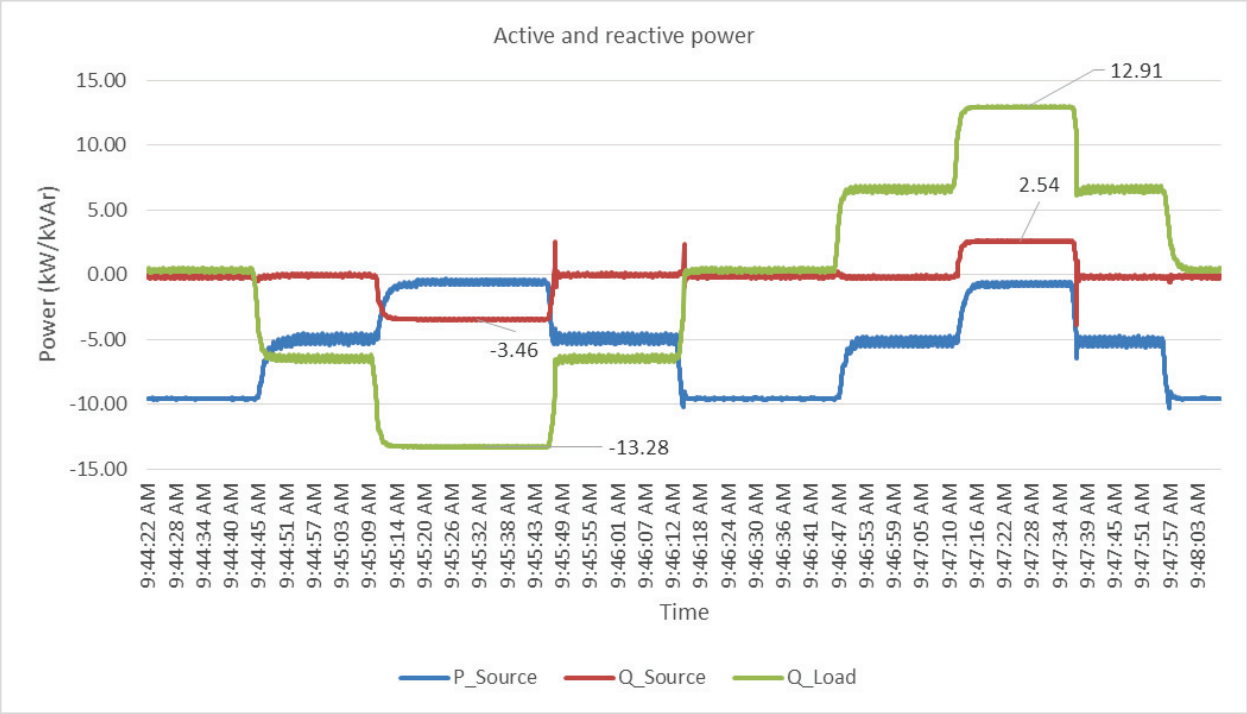


Figure 8-6. Active and Reactive Power Measurements for DUT B: Reactive Power Test

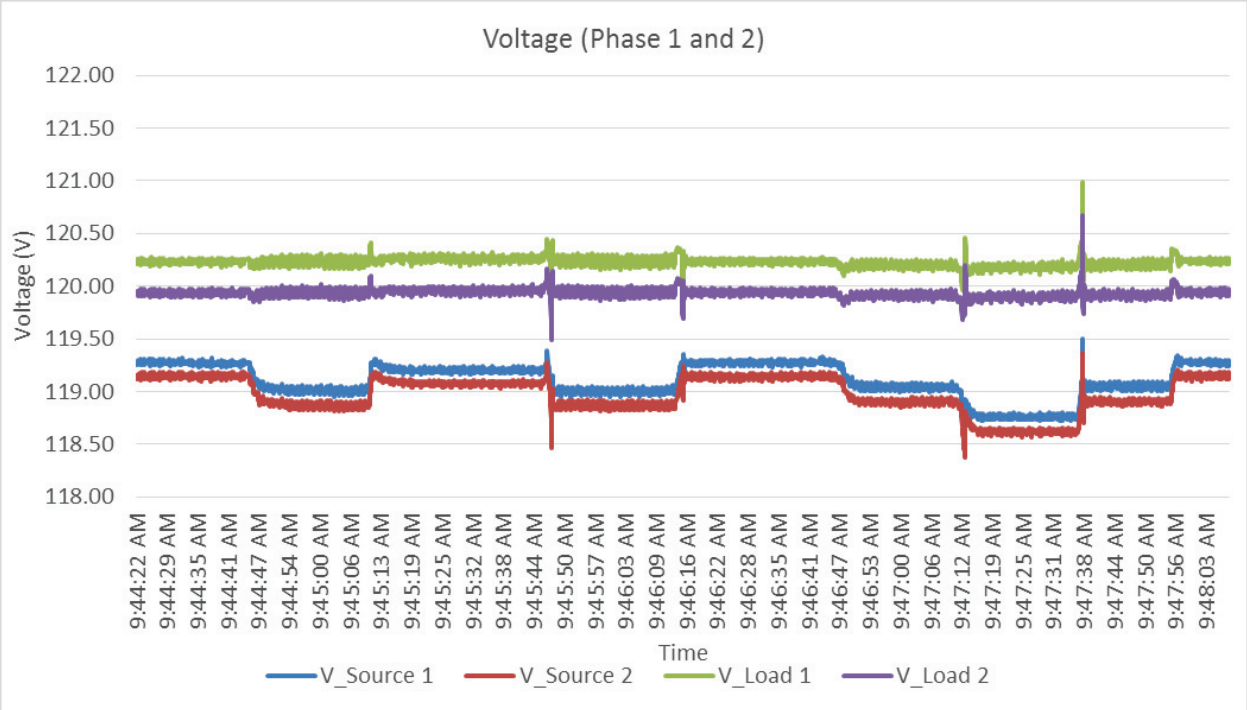


Figure 8-7. RMS Voltage Measurements for DUT B Reactive Power Test

8.3 Appendix C: FAT Test Plan and Results

8.3.1 FAT Test Plan

This section outlines the proposed test cases and steps taken to assess the performance of the project system architecture during the FAT. The test cases were categorized into two main categories, namely Verification Test Cases and Application Test Cases.

8.3.1.1 Verification Test Cases

8.3.1.1.1 Communication Test Cases

A number of tests were performed to verify communications among different players. The communication paths that were tested in FAT are shown in Figure 2-7.

For each communication path, the steps below were taken for verifying communication:

1. IP/Port number verification: In this test, connectivity between two devices was established through verification of IP and port numbers.
2. Analogue input (measurements) readings: This test verified that master device can read measurements from the slave device.
3. Analogue output (setpoints) writing by master device: This test verified that master device can write setpoints on the slave device.
4. Binary input (status) reading by master device: This test verified that master device can read status from the slave device.
5. Binary output (commands) writing by master device: This test verified that master device can write commands on the slave device (physical or digital simulation platform devices).

8.3.1.1.2 SCADA/Digital Simulation Platform Model Verification Test Cases

A number of tests were performed to ensure the validity of SCADA model with respect to the digital simulation platform model of study system. For this purpose, a number of tests were performed for different load and generation profiles (See Table 8-10).

Table 8-10. Definition of Load and PV Profiles for Testing

Load Profile	
Name	**Description**
Low	Winter profile – low season
High	Summer profile – high season
Generation (PV) Profile	
Low	4pm to 6:30pm Profile, when the solar radiation is moderate
High	11am to 1:30pm Profile, when the solar radiation is high

The following steps were taken to verify the model in SCADA system:

1. Compare the voltage measurement at some random buses in SCADA with the actual measurements in digital simulation platform model.

2. Compare the active and reactive power measurements at the main circuit breaker of each circuit as well as some random branches with the actual measurements in digital simulation platform model.
3. Change the status of breakers, reclosers, Tie Switch, and capacitor banks in digital simulation platform model and verify the status change in SCADA.
4. Send open/close command for breakers, reclosers, Tie Switch, and capacitor banks from SCADA and verify the status change in digital simulation platform model.

8.3.1.1.3 DSO/RAMCO Performance Verification Test Cases

A number of tests were performed to verify the performance of DSO modelled in Eventa and RAMCO1. The steps below were taken to verify DSO and RAMCO performance:

1. Change the circuit topology from SCADA and verify that DSO and RAMCO1 can properly detect the new circuit topology.
2. Change the operating mode of DSO from DSO HMI and verify that RAMCO1 can properly detect the latest DSO operating mode.
3. Change the active power contribution target in DSO and verify that RAMCO1 can properly detect the latest active power contribution target.
4. Verify the RAMCO measurements on primary DERs and LRAMs with digital simulation platform model.
5. Verify the DSO readings on aggregated resource data with RAMCO measurements.

8.3.1.2 Application Test Cases

8.3.1.2.1 Near Real-Time Resource Aggregation Test Cases

This case was mainly devised to evaluate the performance of DSO and RAMCO for the purpose of Near Real-Time Resource Aggregation use case. The test cases included the following:

1. Case 1-1: Test when Circuit1 load = 0.1p.u., Circuit1 PV profile = 0.85p.u., Circuit2 load = 1p.u., Circuit2 PV profile = 0.85p.u., DSO active power contribution target = 5 MW.
2. Case 1-2: Test when PV11 is outaged suddenly: Start with Circuit1 load = 0.6p.u., Circuit1 PV profile = 0.6p.u., Circuit2 load = 0.6p.u., Circuit2 PV profile = 0.6p.u., DSO active power contribution target = 3 MW.

8.3.1.2.2 Emergency Dispatch of DERs and Demand Side Management Test Cases

This case was mainly devised to evaluate the performance of DSO and RAMCO for the purpose of Near Real-Time Resource Aggregation use case. The test cases included the following:

1. Case 2-1: Test under different load and generation profiles:
    a) Case 2-1-1: Test when Circuit1 load = 1p.u., Circuit1 PV profile = 0.85p.u., Circuit2 load = 1p.u., Circuit2 PV profile = 0.85p.u., DSO active power contribution target = 5 MW.

b) Case 2-1-2: Test when Circuit1 load = 0.21p.u., Circuit1 PV profile = 0.2p.u., Circuit2 load = 0.3p.u., Circuit2 PV profile = 0.2p.u., DSO active power contribution target = 5 MW.

2. Case 2-2: Test under the DSO contribution target changes:
   a) Case 2-2-1: Test when Circuit1 load = 1p.u., Circuit1 PV profile = 0.85p.u., Circuit2 load = 1p.u., Circuit2 PV profile = 0.85p.u., Initial BESS11 SOC = 40%, DSO active power contribution target change = 4 to 6 MW.
   b) Case 2-2-2: Test when Circuit1 load = 1p.u., Circuit1 PV profile = 0.4p.u., Circuit2 load = 1p.u., Circuit2 PV profile = 0.4p.u., Initial BESS11 SOC = 40%, DSO active power contribution target change = 4 to 6 MW.
   c) Case 2-2-3: Test when Circuit1 load = 1 p.u., Circuit1 PV profile = 0.85p.u., Circuit2 load = 1p.u., Circuit2 PV profile = 0.85p.u., Initial BESS11 SOC = 40%, DSO active power contribution target change = 4 to 2 MW.
   d) Case 2-2-4: Test when Circuit1 load = 1p.u., Circuit1 PV profile = 0.85p.u., Circuit2 load = 1p.u., Circuit2 PV profile = 0.85p.u., Initial BESS11 SOC = 100%, DSO active power contribution target change = 4 to 2 MW.
3. Case 2-3: Test when PV11 is outaged suddenly: Start with Circuit1 load = 1p.u., Circuit1 PV profile = 0.85p.u., Circuit2 load = 1p.u., Circuit2 PV profile = 0.85p.u., Initial BESS11 SOC = 100%, DSO active power contribution target = 2 MW
4. Case 2-4: Test when all primary DERs are off: Start with Circuit1 load = 0.21p.u., Circuit1 PV profile = 0.85p.u., Circuit2 load = 0.3p.u., Circuit2 PV profile = 0.85p.u., DSO active power contribution target = 58 kW.

8.3.2 FAT Test Results

A detailed description of the FAT cases was provided in previous section. In this section, the results of the acceptance tests are presented.

8.3.2.1 Verification Test Results

8.3.2.1.1 Communication Test Results

Several tests were executed to verify communications amongst main entities involved in the test setup, i.e., digital simulation platform, LRAMs, RAMCO, and control center. The following table reports a summary of the results for these tests.

Table 8-11. Results of FAT for Communication Tests

Communication Test Cases	Status	Remark
DSO – RAMCO Communications		
IP/Port number verification	√	Done
Analogue input (measurements) reading by DSO	√	DSO can read measurements from RAMCO
Analogue output (setpoints) writing by substation controller	√	DSO can send setpoints to RAMCO
SCADA – digital simulation platform gateway Communications		
IP/Port number verification	√	Done
Analogue input (measurements) reading by SCADA	√	SCADA can read measurements

Analogue output (setpoints) writing by SCADA	√	SCADA can send setpoints to digital simulation platform
Binary input (status) reading by SCADA	√	SCADA can read statuses (switches, breakers, cap banks, etc.)
Binary output (commands) writing by SCADA	√	SCADA can send commands to digital simulation platform (switches, breakers, cap banks, etc.)
RAMCO – digital simulation platform gateway Communications		
IP/Port number verification	√	Done
Analogue input (measurements) reading by RAMCO	√	RAMCO can read measurements
Analogue output (setpoints) writing by RAMCO	√	RAMCO can send setpoints to LRAM and DER site controllers and LRAMs and DER site controllers send the setpoints to digital simulation platform.
RAMCO – Automation Controller Communications		
IP/Port number verification	√	Done
Analogue input (measurements) reading by RAMCO	√	RAMCO can read measurements
Analogue output (setpoints) writing by RAMCO	√	RAMCO can send setpoints to Automation Controller
Automation Controller – SolarCity inverter and Schneider Electric EVC Communications		
IP/Port number verification	√	Done
Analogue input (measurements) reading by Automation Controller	√	Automation Controller can read measurements
Analogue output (setpoints) writing by Automation Controller	√	Automation Controller can send setpoints to SolarCity inverter and Schneider Electric EVC

8.3.2.1.2 SCADA/Digital Simulation Platform Model Verification Test Results

The developed digital simulation platform model was verified against the pre-existing model of feeders in a planning software tool to ensure that power flow and short circuit value match in both models (base load case). To verify the developed SCADA model, a number of tests were performed against the digital simulation platform model which are summarized as follows:

Table 8-12. SCADA Model Verification Test Cases

SCADA Model Verification Test Cases	Status	Remark
Measurements Verification		
Bus voltage measurement verification	√	Voltage measurements in SCADA were compared and verified against the voltage values in digital simulation platform.
Active and reactive power measurement verification	√	Discrepancies were observed for two reclosers. The found issues were corrected and verified on the second day of FAT.
Status/Commanding Verification		
Change the status of breakers, reclosers, Tie Switch, and capacitor banks in digital simulation platform model and verify the status change in SCADA	√	Done
Send open/close command for breakers, reclosers, Tie Switch, and capacitor banks from SCADA and verify the status change in digital simulation platform model	√	It was noticed that the open/close command for one of cap banks is not transferred to digital simulation platform. The issue was solved and verified on the second day of FAT.

8.3.2.1.3 DSO/RAMCO Performance Verification Test Results

A number of tests were performed to verify the performance of DSO modelled in Eventa and RAMCO1. The steps below were performed to verify DSO and RAMCO performance:

Table 8-13. DSO/RAMCO Verification Test Cases

DSO/RAMCO Model Verification Test Case	Status	Remark
Change the circuit topology from SCADA and verify that DSO and RAMCO1 can properly detect the new circuit topology	√	DSO and RAMCO1 could successfully detect the latest circuit topology.
Change the operating mode of DSO from DSO HMI and verify that RAMCO1 can properly detect the latest DSO operating mode	√	RAMCO1 could successfully detect the DSO operating mode.
Change the active power contribution target in DSO and verify that RAMCO1 can properly detect the latest active power contribution target	√	RAMCO1 could successfully receive the active power contribution target.
Verify the RAMCO measurements on primary DERs and LRAMs with digital simulation platform model	√	RAMCO1 measurements on primary DERs and digital simulation platform model were verified successfully.
Verify the DSO readings on aggregated resource data with RAMCO measurements	√	DSO readings on verified against RAMCO measurements.

8.3.2.2 Application Test Results

8.3.2.2.1 Near Real-Time Resource Aggregation Test:

In the following the verification results for one of the test cases (Case 1-1) is provided. In order to verify the performance of control systems for the purpose of near real-time resource aggregation use case, the DSO readings were compared against RAMCO measurements for the following test cases:

- Test when circuit load = 1p.u., PV profile = 0.85p.u., DSO active power contribution target = 5 MW:

The DSO and RAMCO HMI screenshots for this test case are shown in the below figure. As seen in this figure, the reported aggregated data in DSO for intermittent generation units (PV) and energy storage systems matches with the summation of RAMCO measurements for PV and energy storage units (in primary and secondary systems).

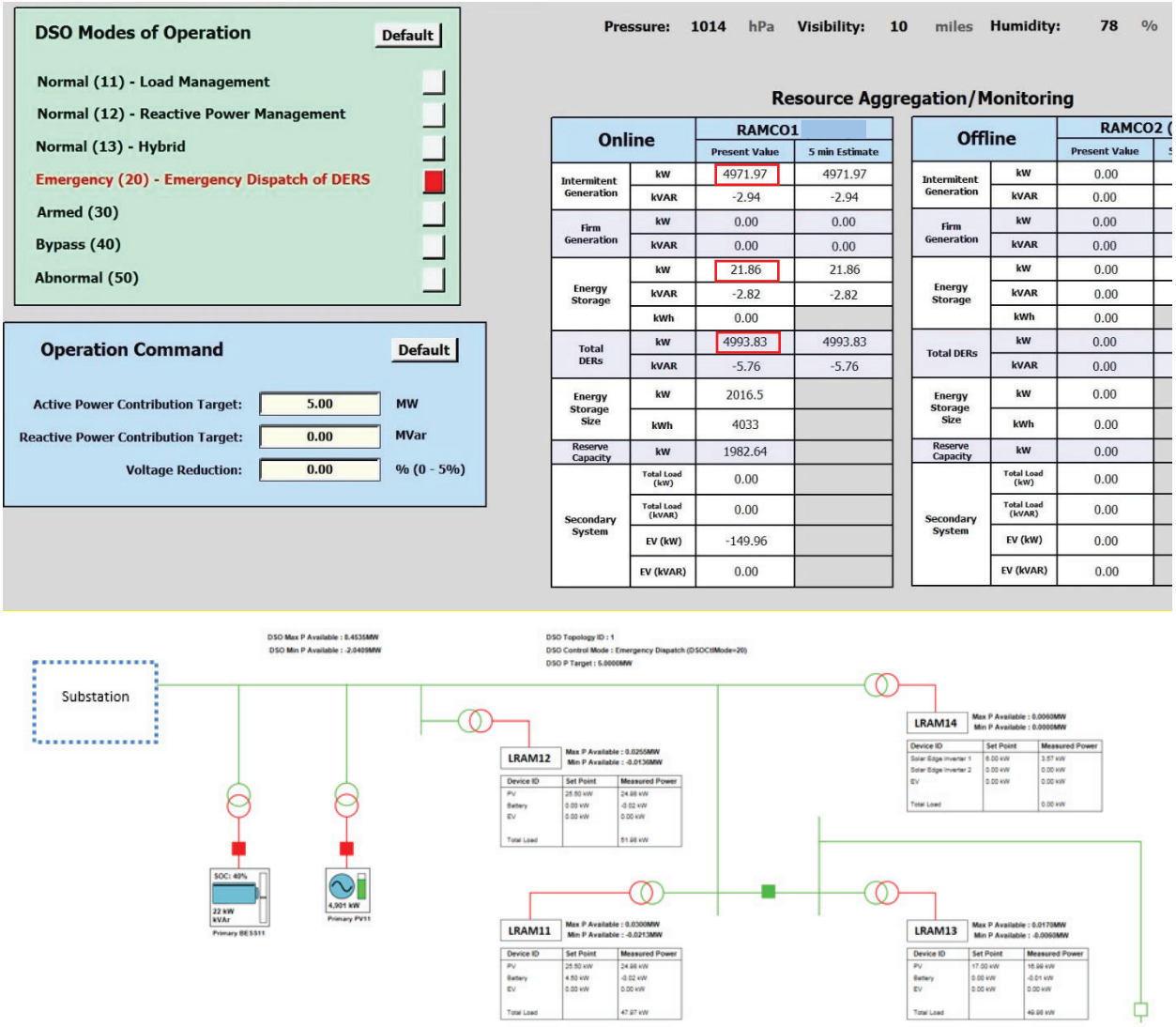


Figure 8-8. Snapshot of DSO HMI (Top) and RAMCO HMI (Bottom) for the selected Case

8.3.2.2.2 Emergency Dispatch of DERs and Demand Side Management Test

In the following, the verification results for one of the test cases (Case 2-2-1) is provided:

Test when circuit load = 1p.u., circuit PV profile = 0.85p.u., Initial BESS11 SOC = 40%, DSO active power contribution target change = 4 to 6 MW

The goal of this test case is to test the response of the control system with respect to the changes in contribution target. For this purpose, the DSO and RAMCO screenshots, shown in the figures below, were captured before and after the contribution target change. As seen, the control system can properly respond to the change of contribution target.

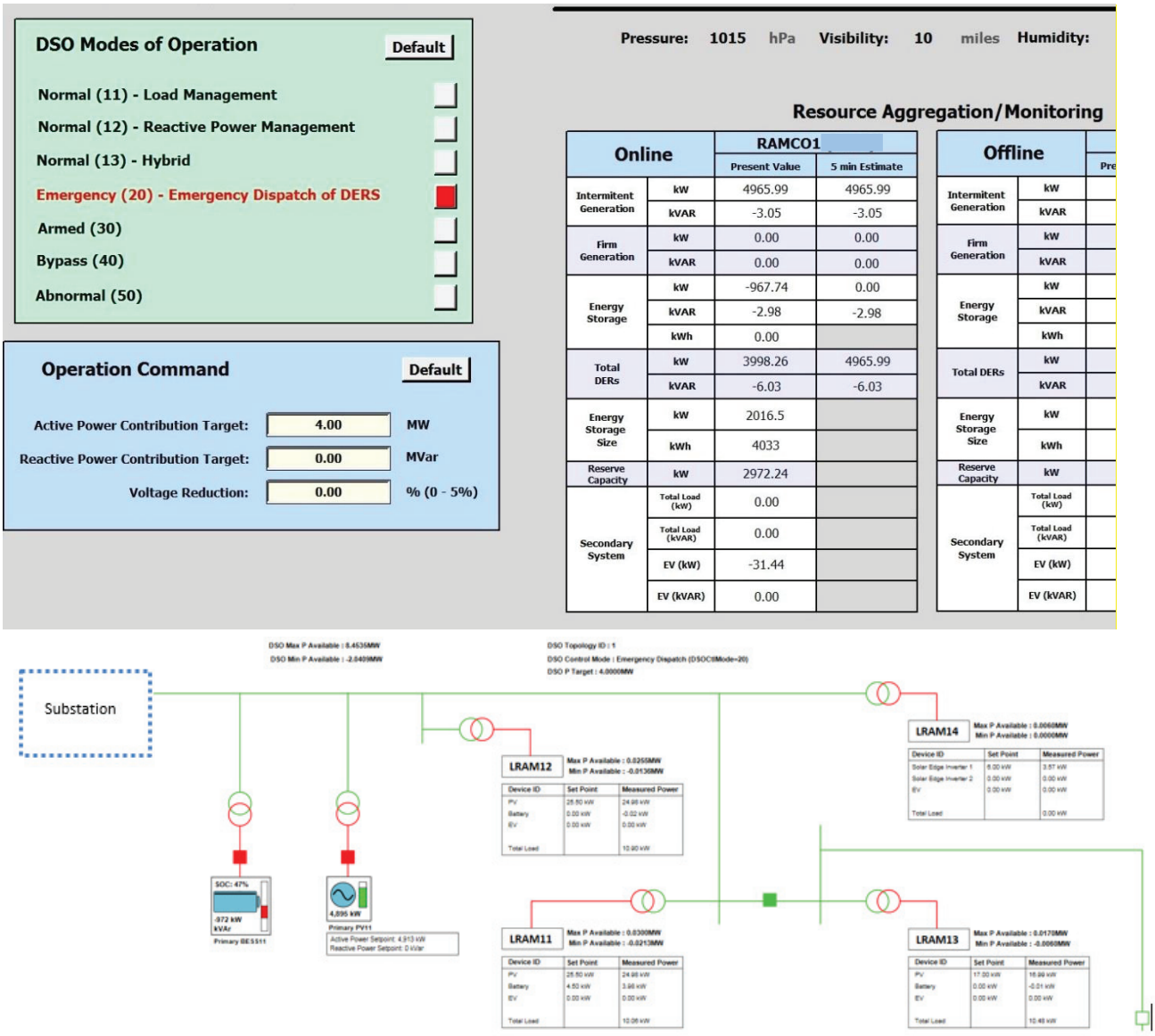


Figure 8-9. Snapshot of DSO HMI (Top) and RAMCO HMI (Bottom) for Target=4MW

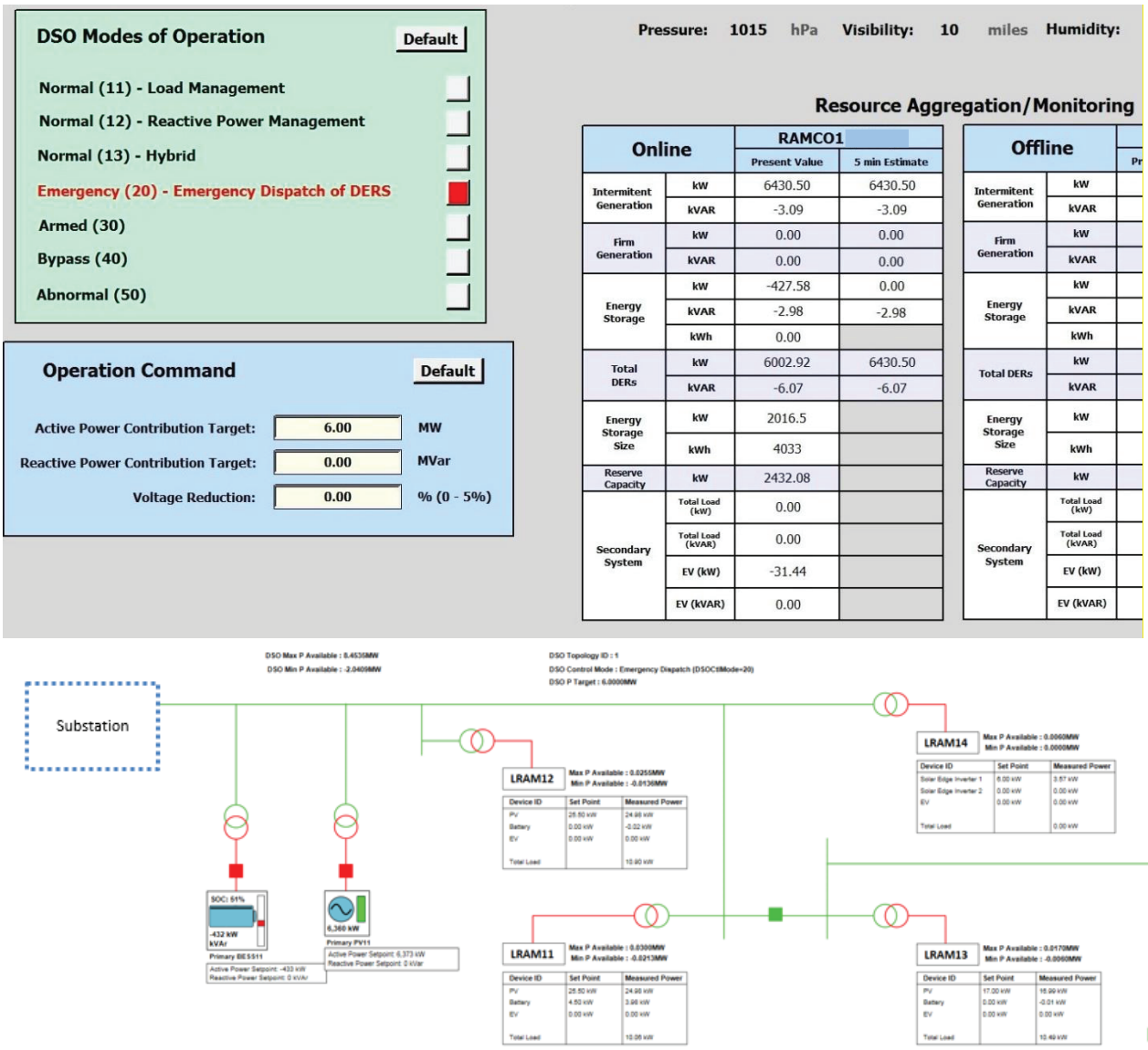


Figure 8-10. Snapshot of DSO HMI (Top) and RAMCO HMI (Bottom) for Target=6MW

8.3.2.2.3 Priority Stack Verification Test

One of the last portions of the FAT was to move the DSO target through minimum and maximum targets ranges to and back again to determine if the RAMCO/LRAM priority stacks were working as expected. For this purpose, the DSO is set in the emergency operating mode, and the setpoint is incrementally changed to trigger the dispatching of the next incremental DER. Initial observations verified that the primary assets were controlled by the RAMCOs as expected, shutting off battery charging first, dispatching maximum renewable generation second, dispatching battery storage third, and then finally dispatching the FG units. The LRAMS however, were not behaving in an optimal fashion initially. The primary issue was the LRAMs themselves were prioritized versus the assets downstream being treated with the same priority, (i.e. the generation on LRAM 1 was biased before LRAM 2 instead of being applied equally to eliminate customer discrimination). These issues were highlighted in the FAT and Resolved in time for implementing in the SAT.

8.4 Appendix D: Demonstration Test Results

In this Appendix, the results of demonstration test cases performed in SDG&E testing facility are presented. The detailed demonstration test plan and summary of test cases are summarized in Table 3-1 to Table 3-3.

8.4.1 Use Case 1: Load Management

Summary of test cases for Use Case 1 is provided in Table 3-1. In the following, the test results for Case 1-1, 1-2, 1-3, and 1-4 categories are discussed. The test results for Case 1-5 are discussed in the main body of report (Section 3.1.1).

8.4.1.1 Case 1-1: High Market Price/Minimum Reserve Capacity=0.25/PV Profile=70%, topology 1

Two test cases, namely Case 1-1-1 and Case 1-1-2, were performed in this test category. The details of each test case are summarized in Table 8-14. The control center HMI, RAMCO 1 and 2 HMIs, and RAMCO 1 and 2 power setpoint tracking graphs for Case 1-1-1 and Case 1-1-2 are shown in Figure 8-11 to Figure 8-20. The control center and RAMCO HMIs show that RAMCOs take appropriate actions to utilize DERs according to the market price. Since the energy market price is relatively high, batteries are expected to discharge as seen in these figures. The power setpoint tracking graphs verify that the setpoints issued by DSO are all met by RAMCOs. In Case 1-1-2, as the PV irradiance decreases from 70% to 20%, Firm Generation unit in RAMCO2 starts to generate to compensate for the loss of PV power.

Table 8-14. Case 1-1 Category Test Cases

Use cases & Test Cases	DSO Targets	Market Price	Reserve Capacity	Forecasted Load	Initial SOC (%)	PV (%)
Case 1-1: High Market Price/Minimum Reserve Capacity=0.25/PV Profile=70%, topology 1	NA	High	25%			
Case 1-1-1: Initial SOC = 70%	NA	$170	25%	10	70%	70%
Case 1-1-2: Initial SOC = 70%, PV drops to 20% (cloud condition) and keep for a few minutes, back to 70%.	NA	$170	25%	10	70%	70% to 20% to 70%

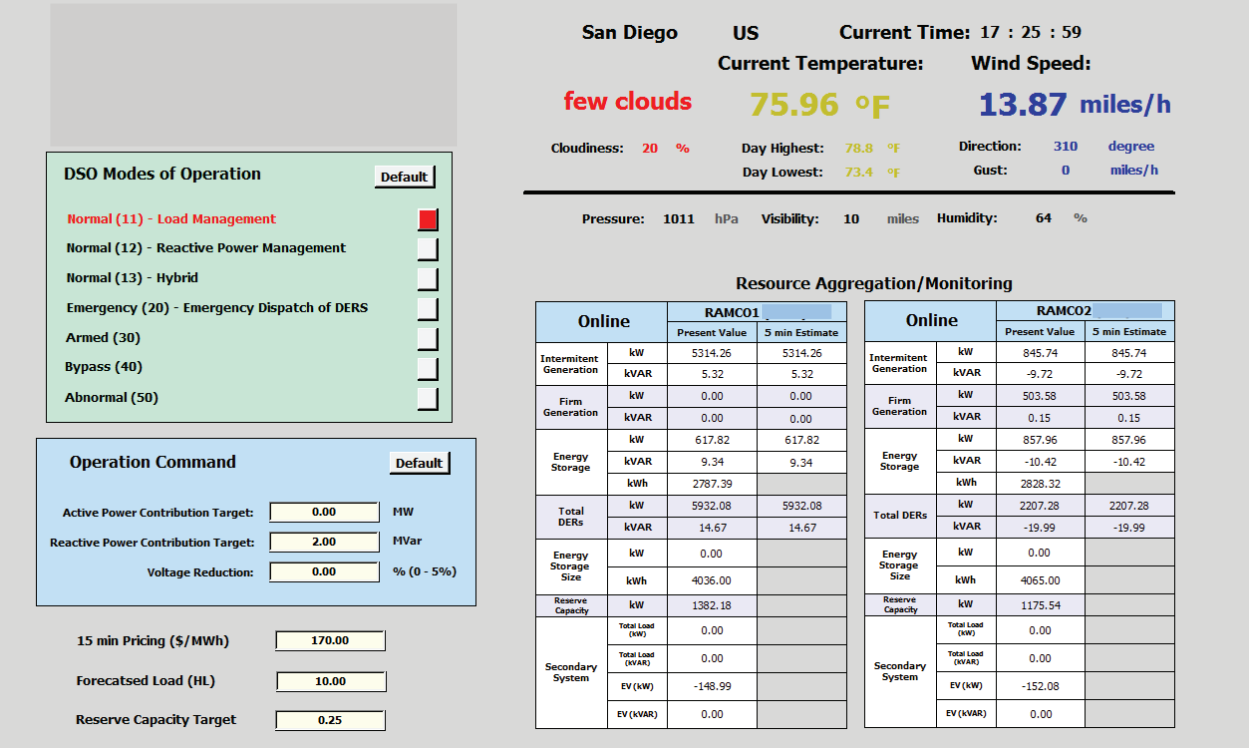


Figure 8-11. DSO HMI in case 1-1-1

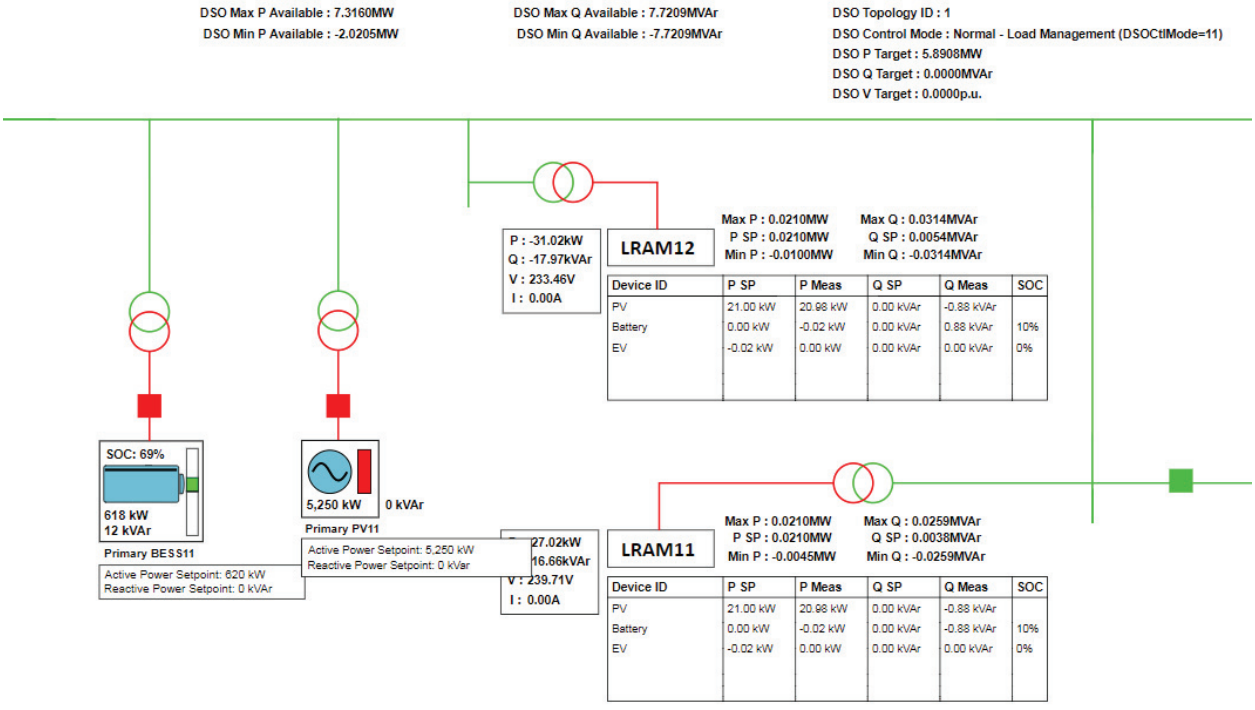


Figure 8-12. RAMCO 1 HMI in case 1-1-1

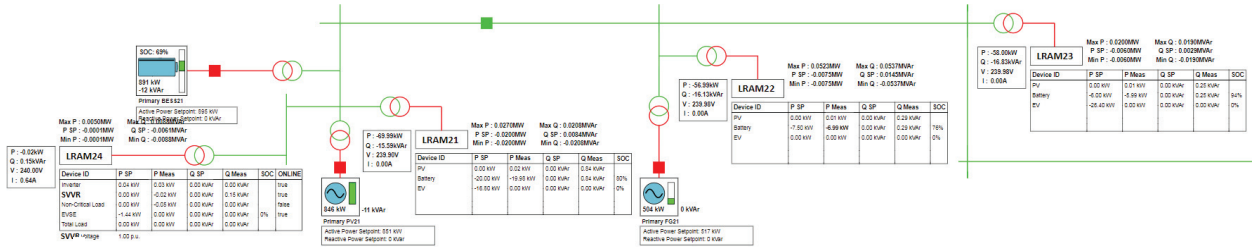


Figure 8-13. RAMCO 2 HMI in case 1-1-1

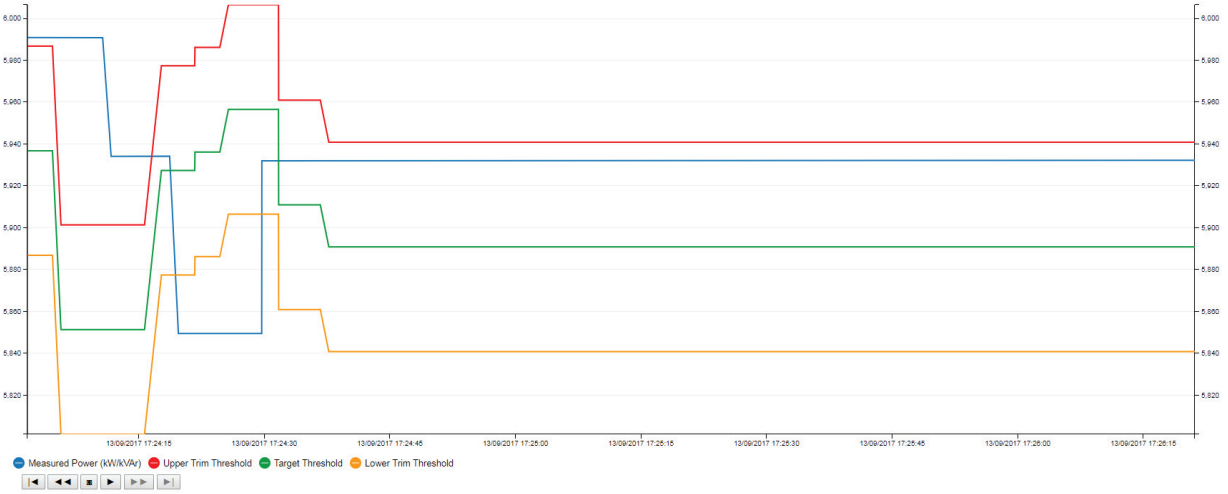


Figure 8-14. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 1-1-1

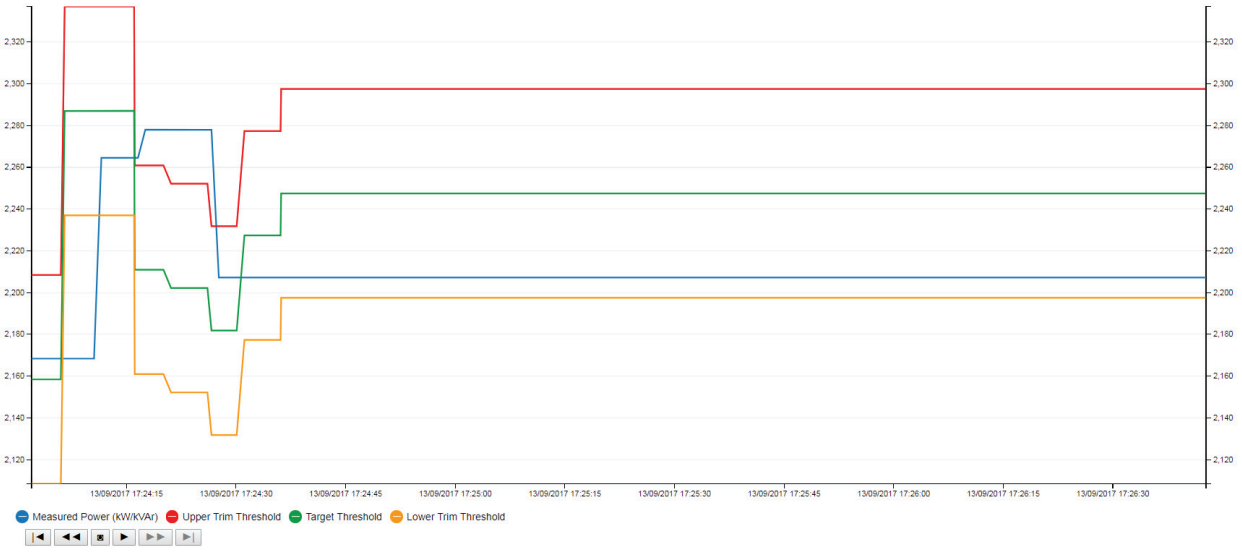


Figure 8-15. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 1-1-1

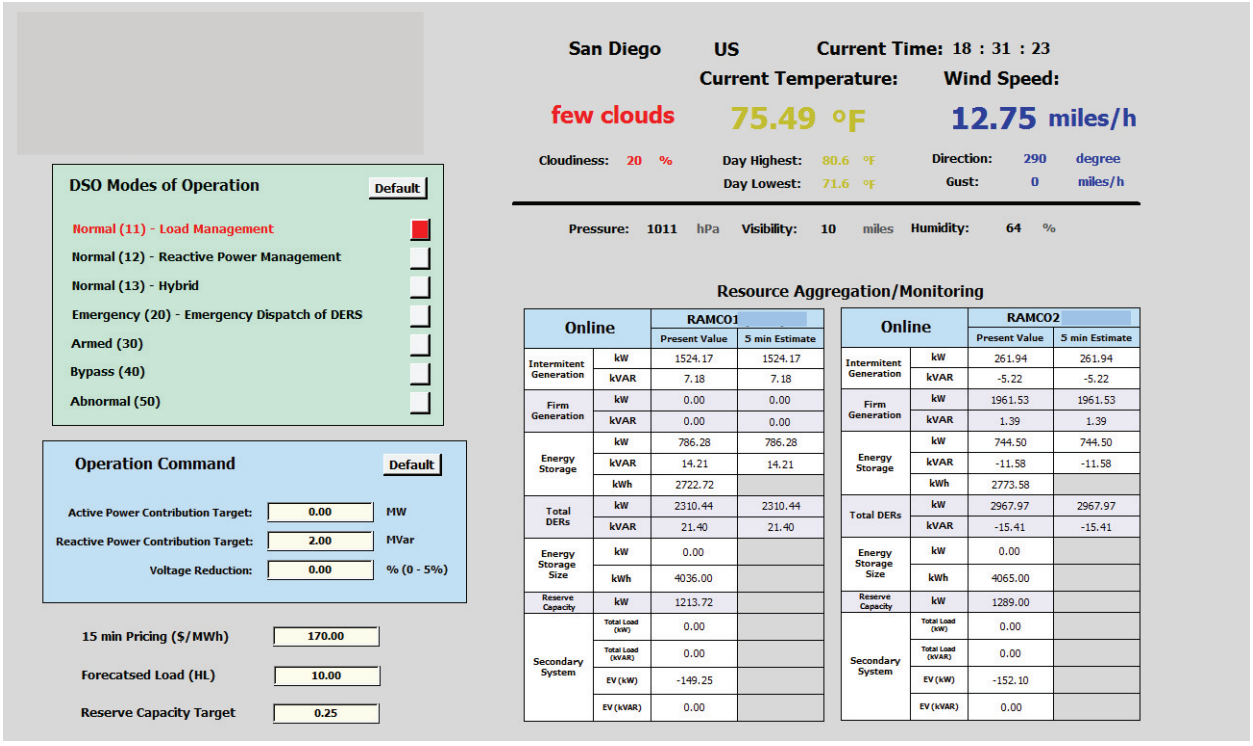


Figure 8-16. DSO HMI in case 1-1-2

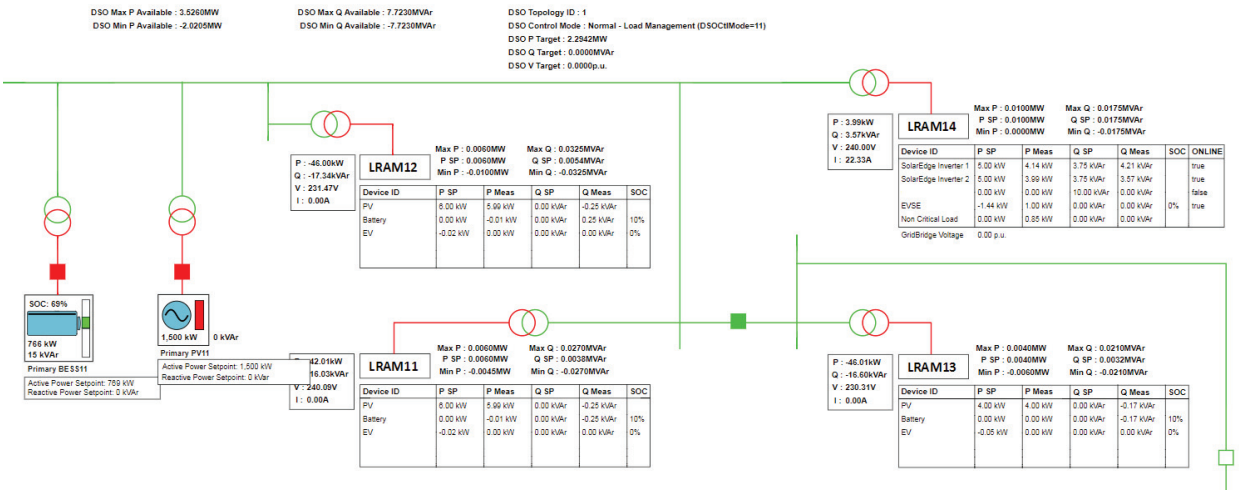


Figure 8-17. RAMCO 1 HMI in case 1-1-2

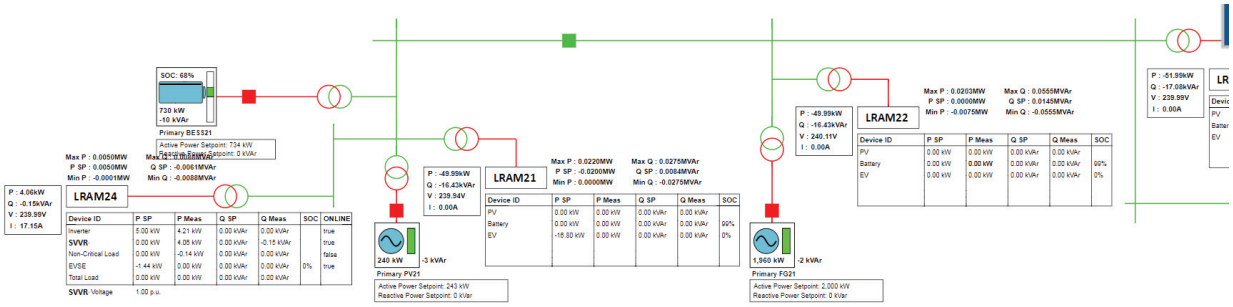


Figure 8-18. RAMCO 2 HMI in case 1-1-2

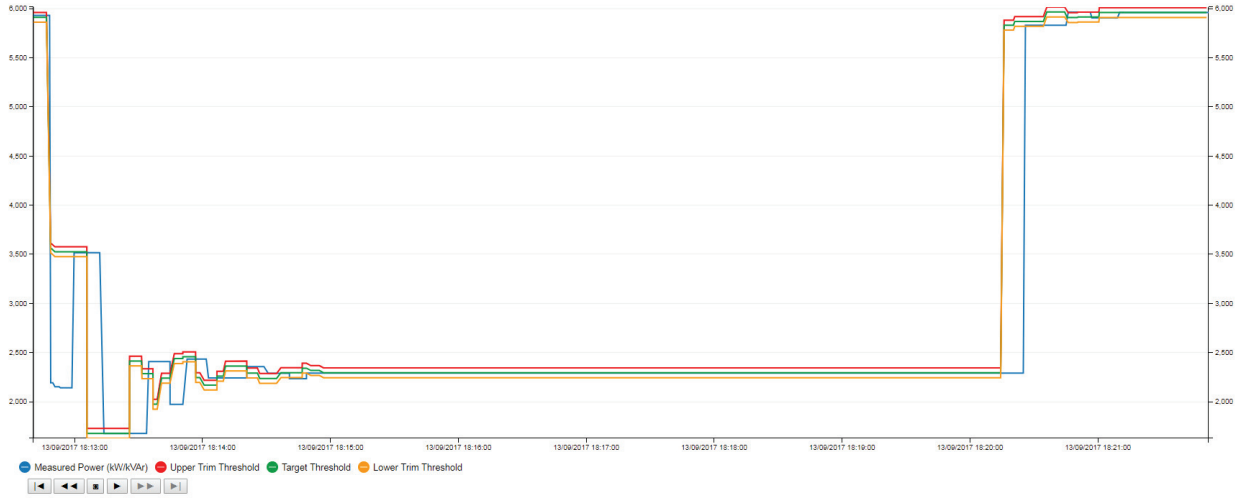


Figure 8-19. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 1-1-2

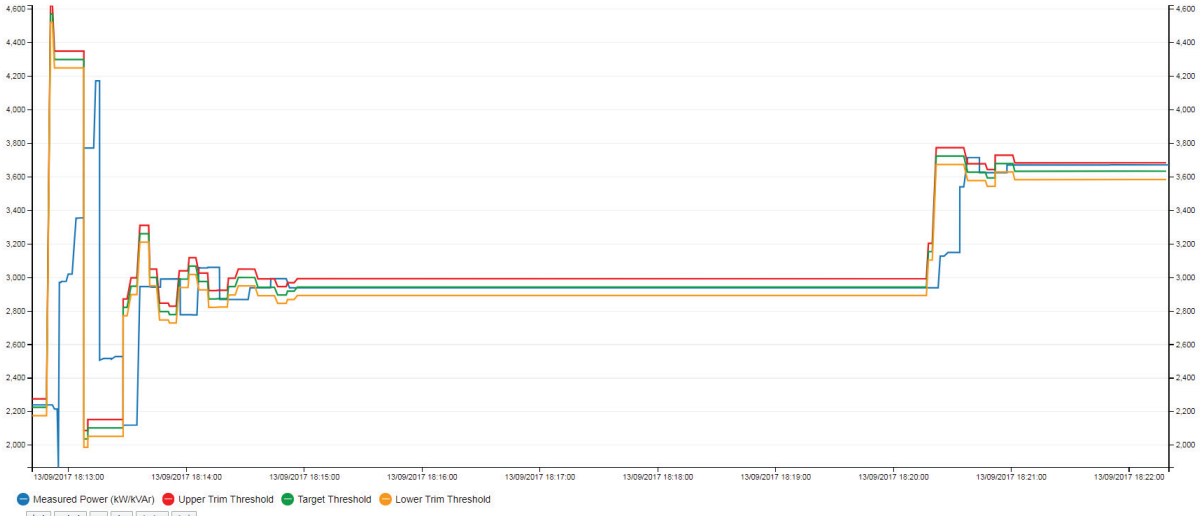


Figure 8-20. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 1-1-2

8.4.1.2 Case 1-2: Low Market Price/Minimum Reserve Capacity=0.25/PV Profile=70%, topology 1

Two test cases, namely Case 1-2-1 and Case 1-2-2, were performed in this test category. The details of each test case are summarized in Table 8-15. The control center HMI, RAMCO 1 and 2 HMIs, and RAMCO 1 and 2 power setpoint tracking graphs for Case 1-2-1 and Case 1-2-2 are shown in Figure 8-21 to Figure 8-30. The control center and RAMCO HMIs show that RAMCOs take appropriate actions to utilize DERs according to the market price. Since the energy market price is relatively low, batteries are expected to charge as seen in these figures. The power setpoint tracking graphs verify that the setpoints issued by DSO are all met by RAMCOs. As seen in Case 1-2-2, the PV irradiance drop from 70% to 20% does not impact the charging rate of batteries.

Table 8-15. Case 1-2 Category Test Cases

Use cases & Test Cases	DSO Targets	Market Price	Reserve Capacity	Forecasted Load	Initial SOC (%)	PV (%)
Case 1-2: Low Market Price/Minimum Reserve Capacity=0.25/PV Profile=70%, topology 1	NA	Low	25%			
Case 1-2-1: Initial SOC = 70%	NA	$40	25%	10	70%	70%
Case 1-2-2: Initial SOC = 70%, PV drops to 20% (cloud condition) and keep for a few minutes, back to 70%.	NA	$40	25%	10	70%	70% to 20% to 70%

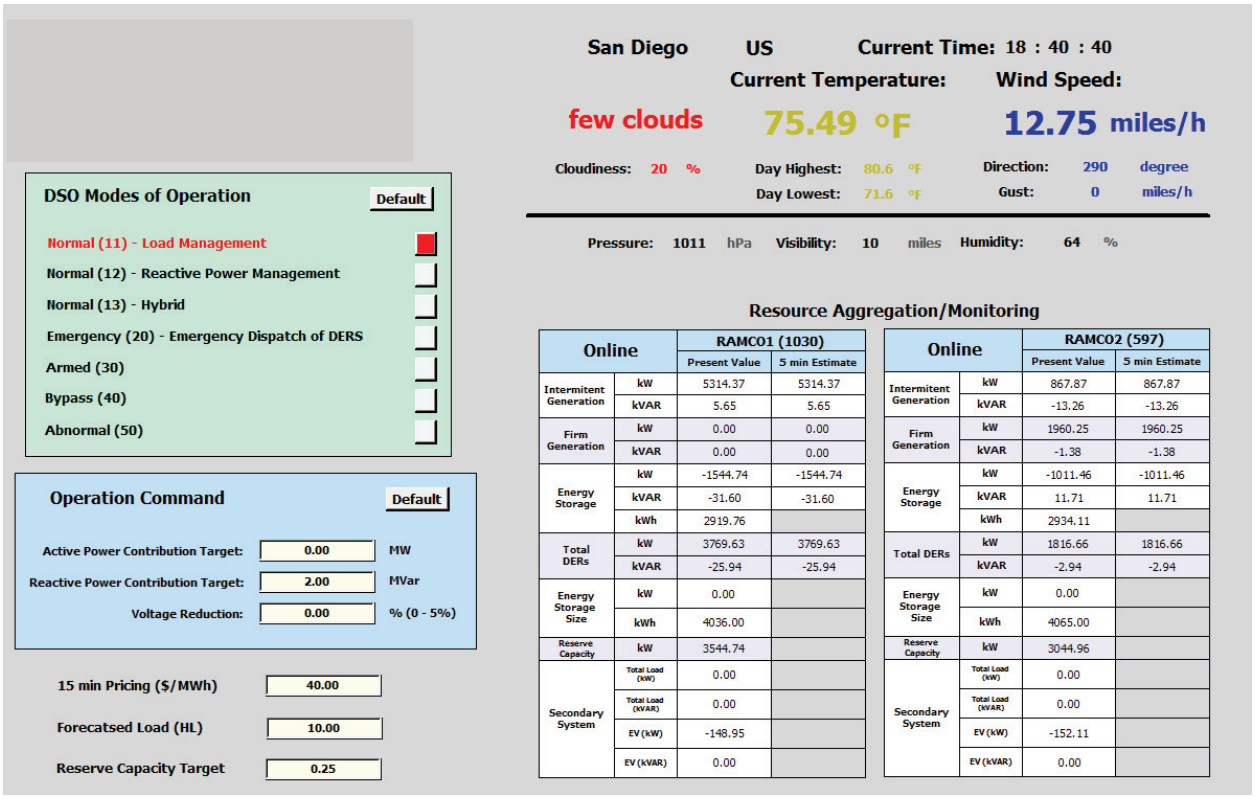


Figure 8-21. DSO HMI in case 1-2-1

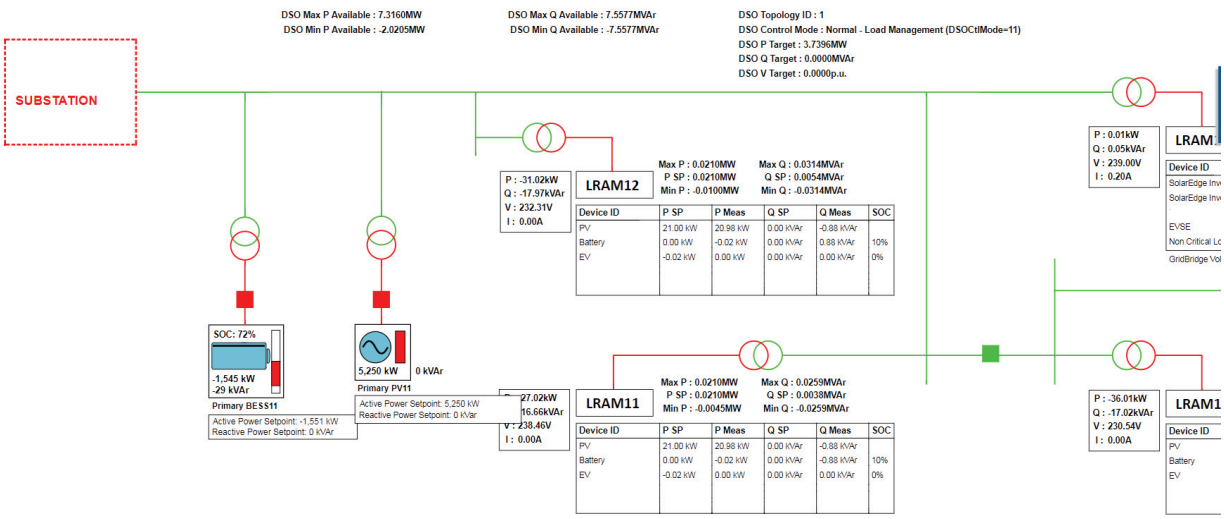


Figure 8-22. RAMCO 1 HMI in case 1-2-1

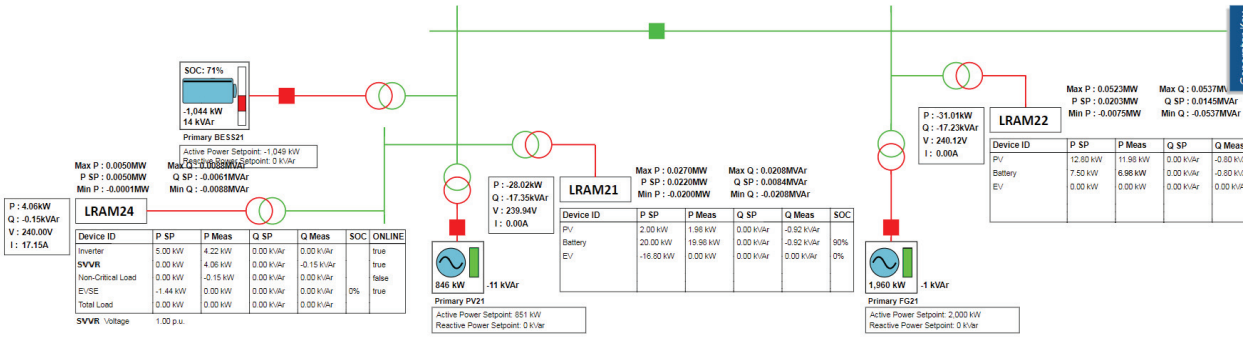


Figure 8-23. RAMCO 2 HMI in case 1-2-1

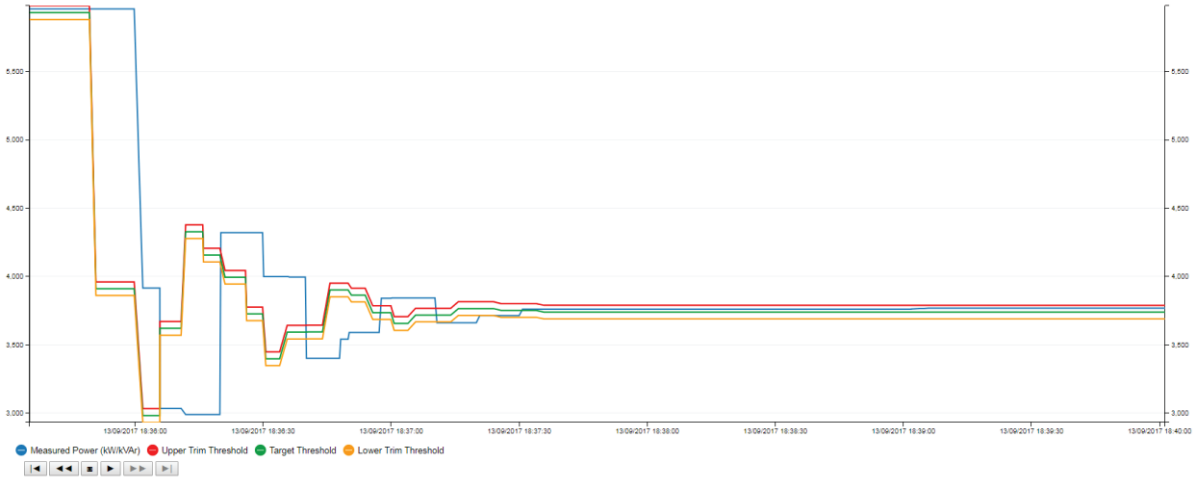


Figure 8-24. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 1-2-1

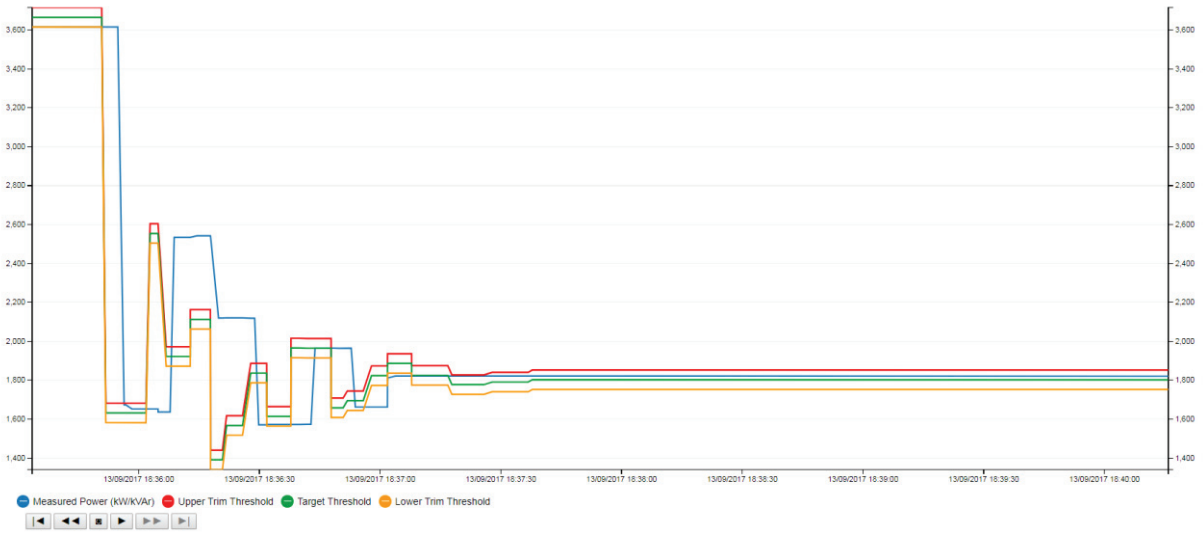
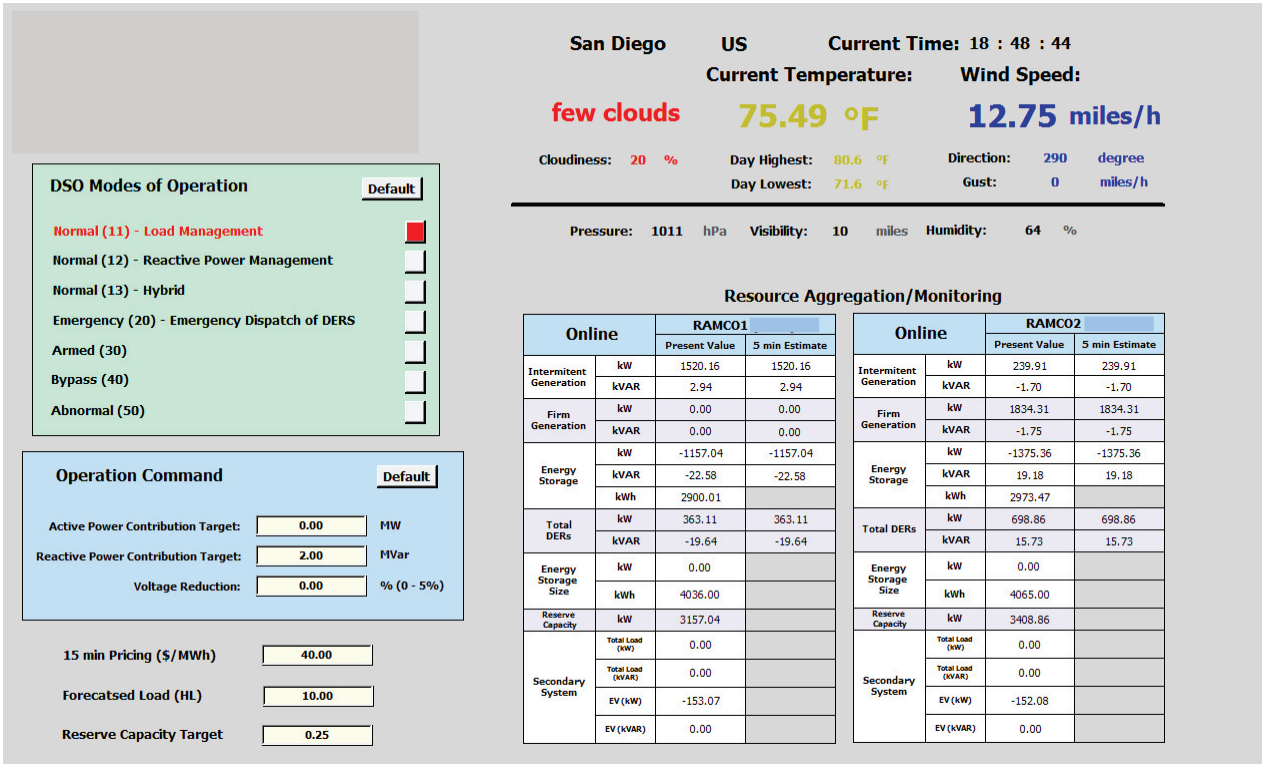


Figure 8-25. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 1-2-1



Online		RAMCO1 Present Value	RAMCO1 5 min Estimate
Intermitent Generation	kW	1520.16	1520.16
	kVAR	2.94	2.94
Firm Generation	kW	0.00	0.00
	kVAR	0.00	0.00
Energy Storage	kW	-1157.04	-1157.04
	kVAR	-22.58	-22.58
	kWh	2900.01	
Total DERs	kW	363.11	363.11
	kVAR	-19.64	-19.64
Energy Storage Size	kW	0.00	
	kWh	4036.00	
Reserve Capacity	kW	3157.04	
Secondary System	Total Load (kW)	0.00	
	Total Load (kVAR)	0.00	
	EV (kW)	-153.07	
	EV (kVAR)	0.00	

Online		RAMCO2 Present Value	RAMCO2 5 min Estimate
Intermitent Generation	kW	239.91	239.91
	kVAR	-1.70	-1.70
Firm Generation	kW	1834.31	1834.31
	kVAR	-1.75	-1.75
Energy Storage	kW	-1375.36	-1375.36
	kVAR	19.18	19.18
	kWh	2973.47	
Total DERs	kW	698.86	698.86
	kVAR	15.73	15.73
Energy Storage Size	kW	0.00	
	kWh	4065.00	
Reserve Capacity	kW	3408.86	
Secondary System	Total Load (kW)	0.00	
	Total Load (kVAR)	0.00	
	EV (kW)	-152.08	
	EV (kVAR)	0.00	

Figure 8-26. DSO HMI in case 1-2-2

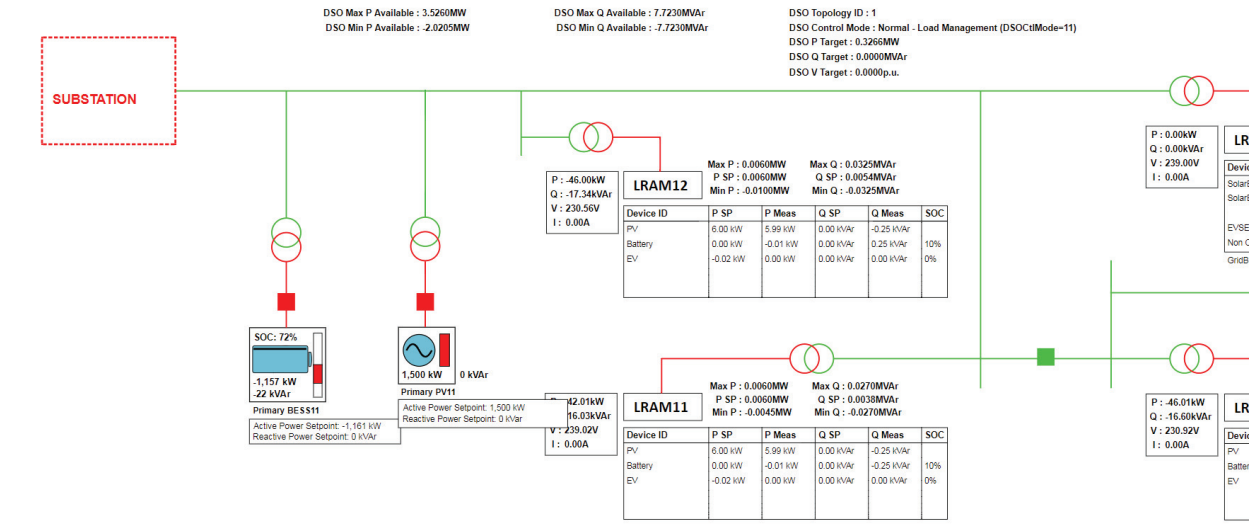


Figure 8-27. RAMCO 1 HMI in case 1-2-2

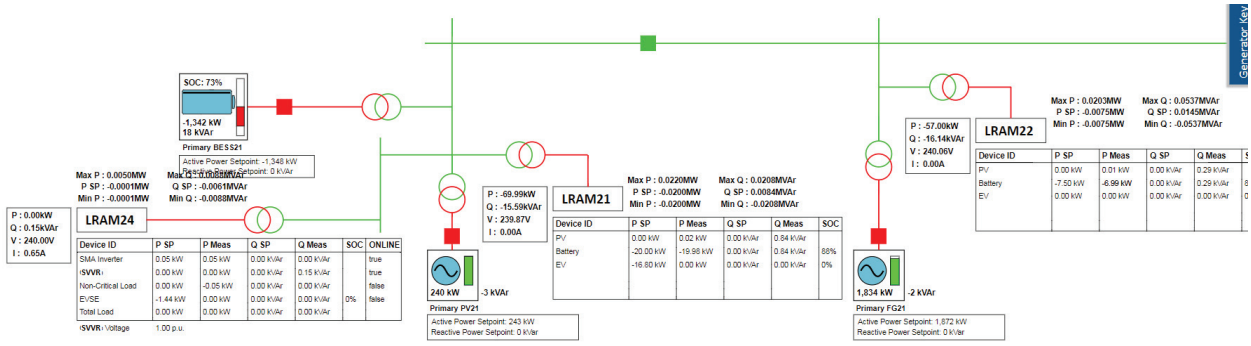


Figure 8-28. RAMCO 2 HMI in case 1-2-2

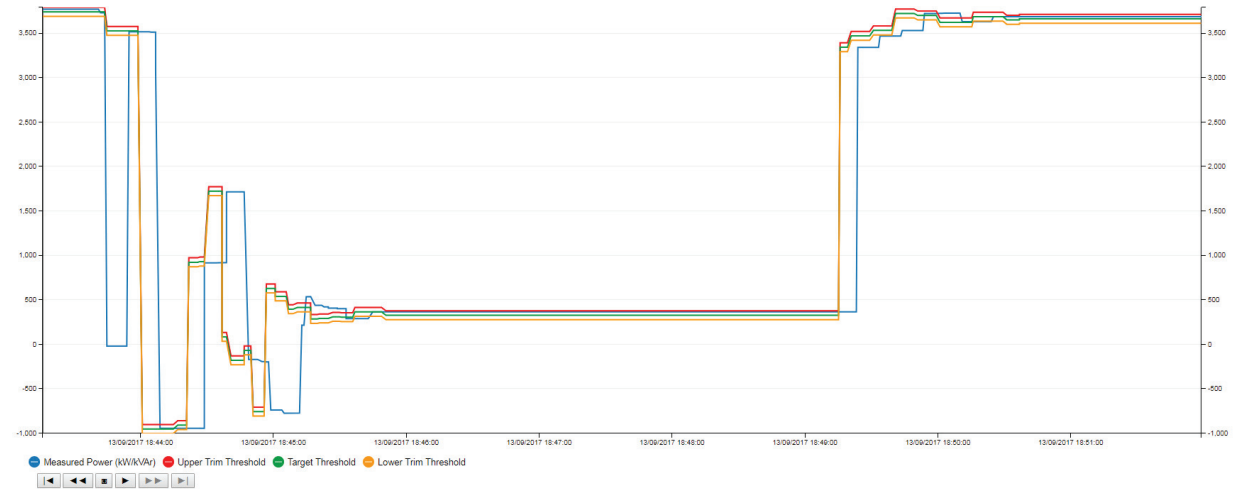


Figure 8-29. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 1-2-2

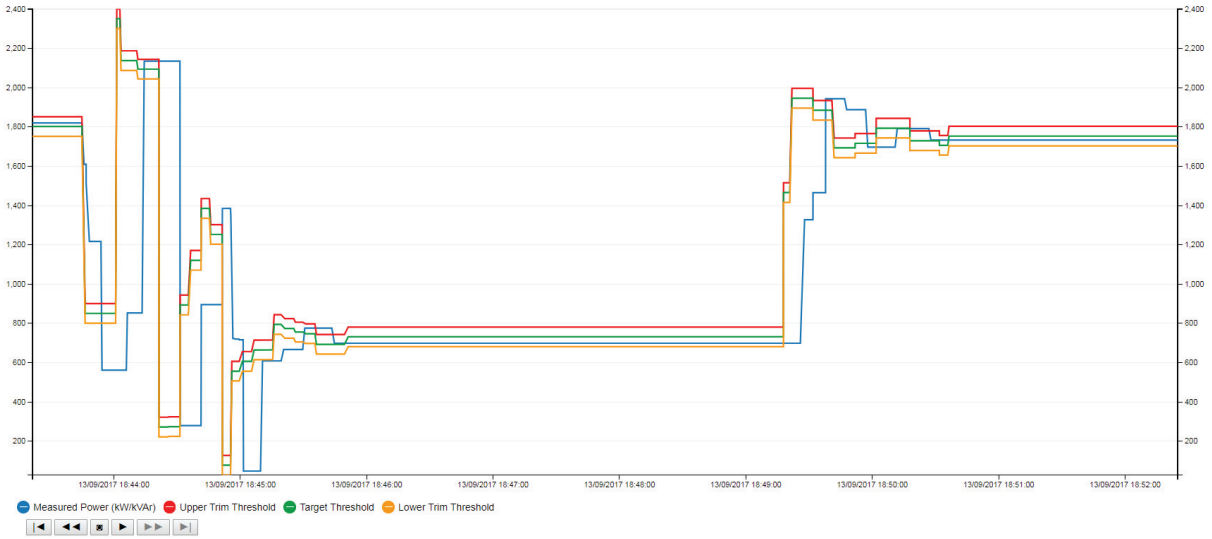


Figure 8-30. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 1-2-2

8.4.1.3 Case 1-3: High Market Price/Minimum Reserve Capacity=0.35/PV Profile=70%, topology 1

Two test cases, namely Case 1-3-1 and Case 1-3-2, were performed in this test category. The details of each test case are summarized in Table 8-16. The control center HMI, RAMCO 1 and 2 HMIs, and RAMCO 1 and 2 power setpoint tracking graphs for Case 1-3-1 and Case 1-3-2 are shown in Figure 8-31 to Figure 8-40. The control center and RAMCO HMIs show that RAMCOs take appropriate actions to utilize DERs according to the market price. Compared to Case 1-1, Case 1-3 is asking for a higher reserve capacity target (35%). Comparing Figure 8-31 and Figure 8-36 with Figure 8-11 and Figure 8-16, one can see that with a higher reserve capacity target batteries in RAMCO 1 and 2 have either stopped discharging or continued discharging at a lower rate which results in a higher reserve capacity.

Table 8-16. Case 1-3 Category Test Cases

Use cases & Test Cases	DSO Targets	Market Price	Reserve Capacity	Forecasted Load	Initial SOC (%)	PV (%)
Case 1-3: High Market Price/Minimum Reserve Capacity=0.35/PV Profile=70%, topology 1	NA	High	35%		NA	NA
Case 1-3-1: Initial SOC = 70%	NA	$170	35%	10	70%	70%
Case 1-3-2: Initial SOC = 70%, PV drops to 20% (cloud condition) and keep for a few minutes, back to 70%.	NA	$170	35%	10	70%	70% to 20% to 70%

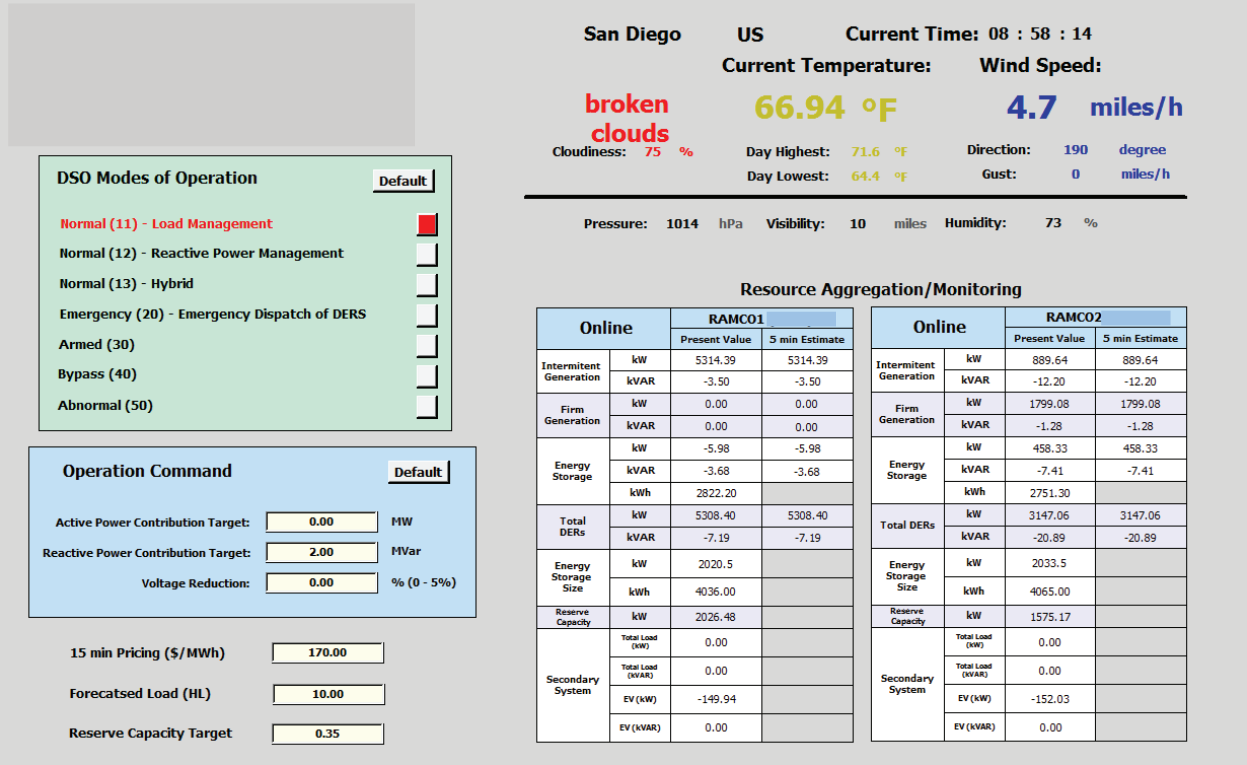


Figure 8-31. DSO HMI in case 1-3-1

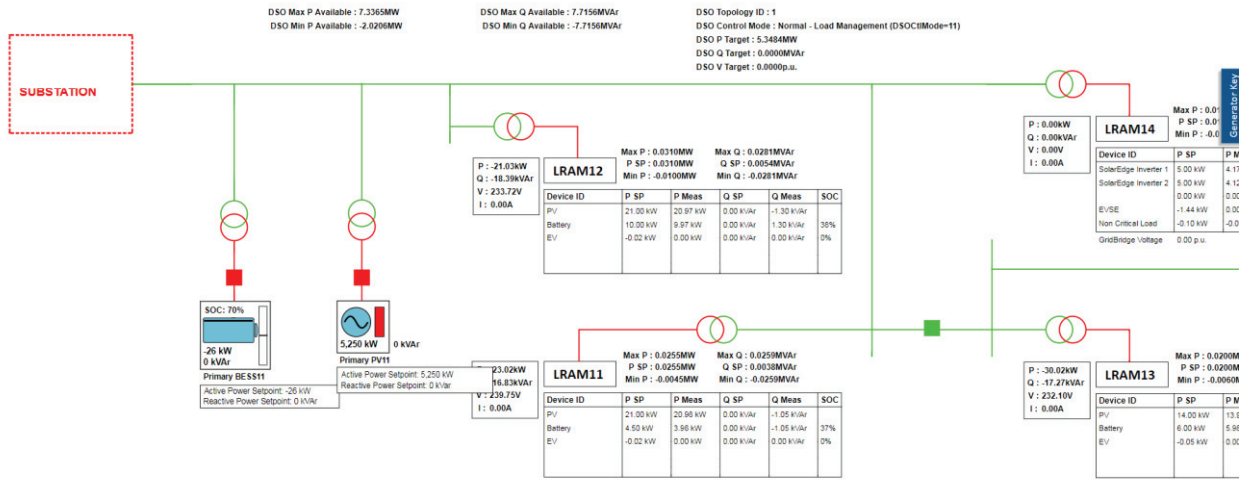


Figure 8-32. RAMCO 1 HMI in case 1-3-1

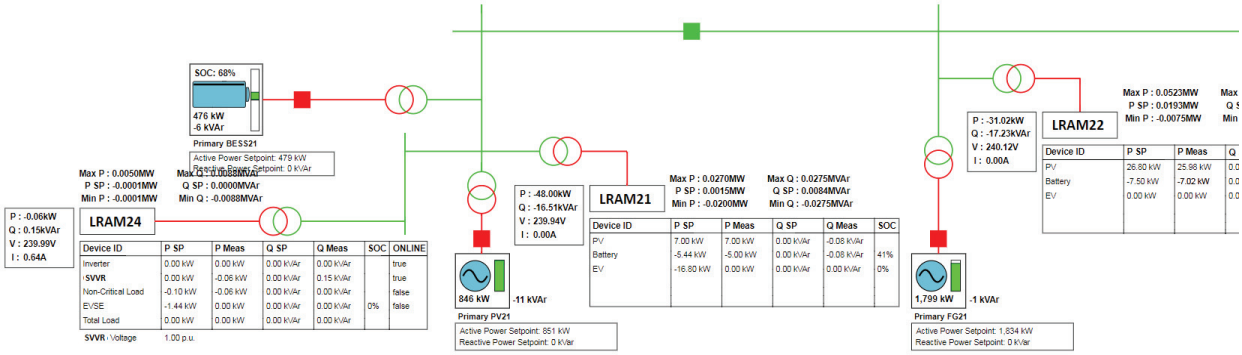


Figure 8-33. RAMCO 2 HMI in case 1-3-1



Figure 8-34. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 1-3-1

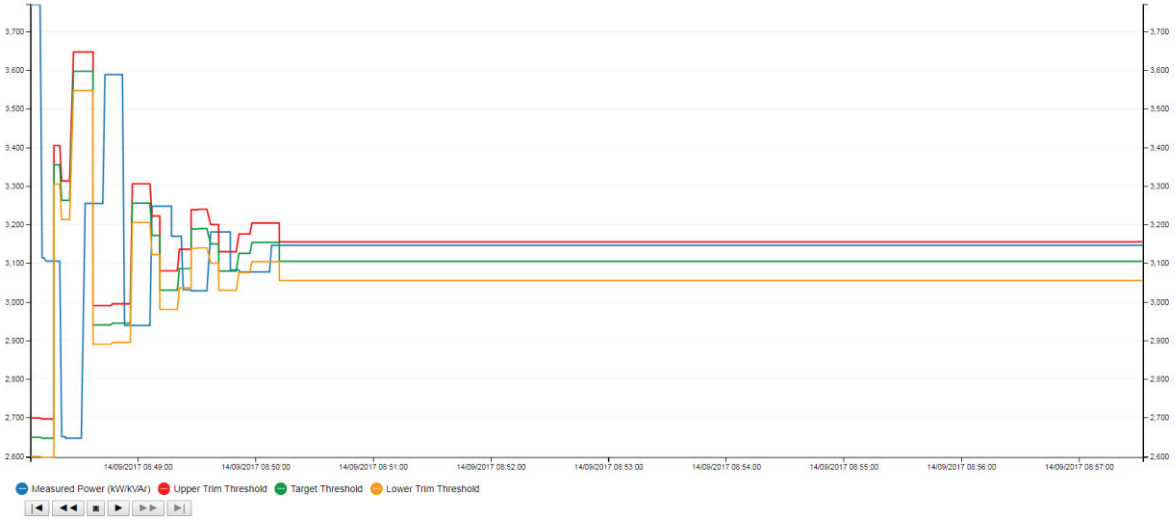


Figure 8-35. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 1-3-1

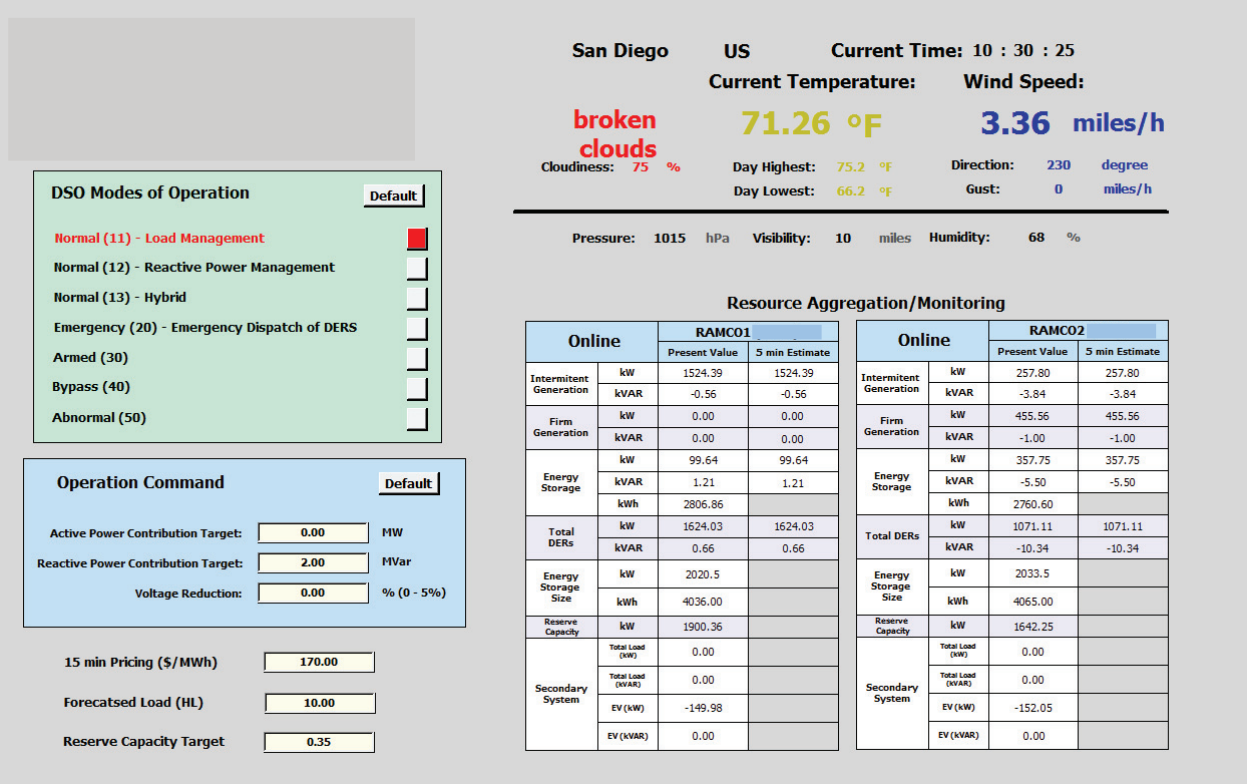


Figure 8-36. DSO HMI in case 1-3-2

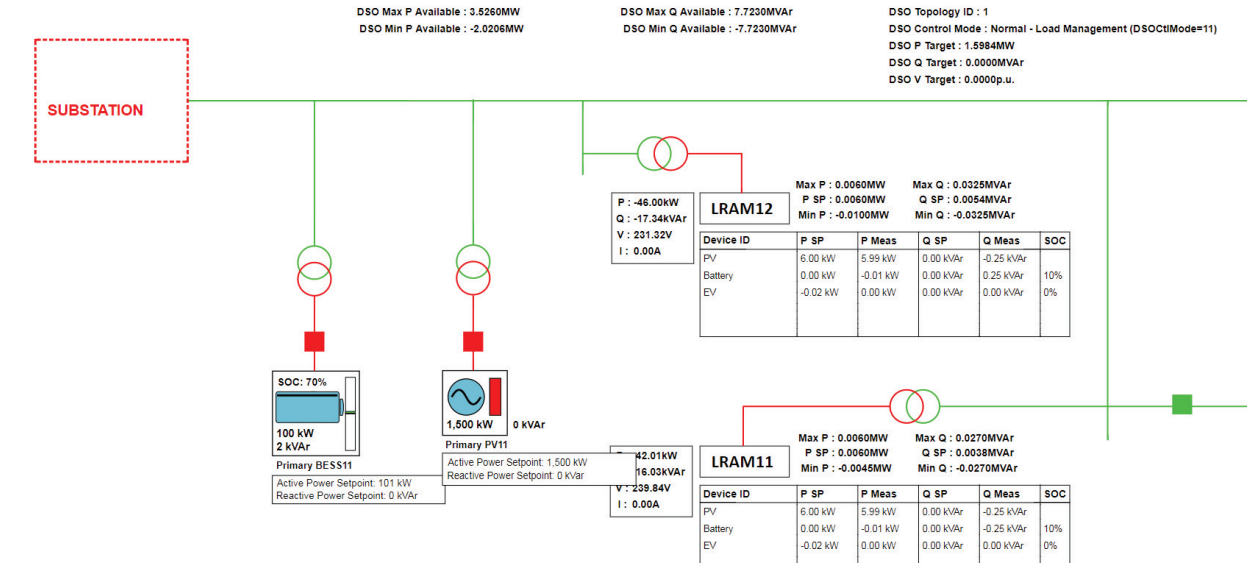


Figure 8-37. RAMCO 1 HMI in case 1-3-2

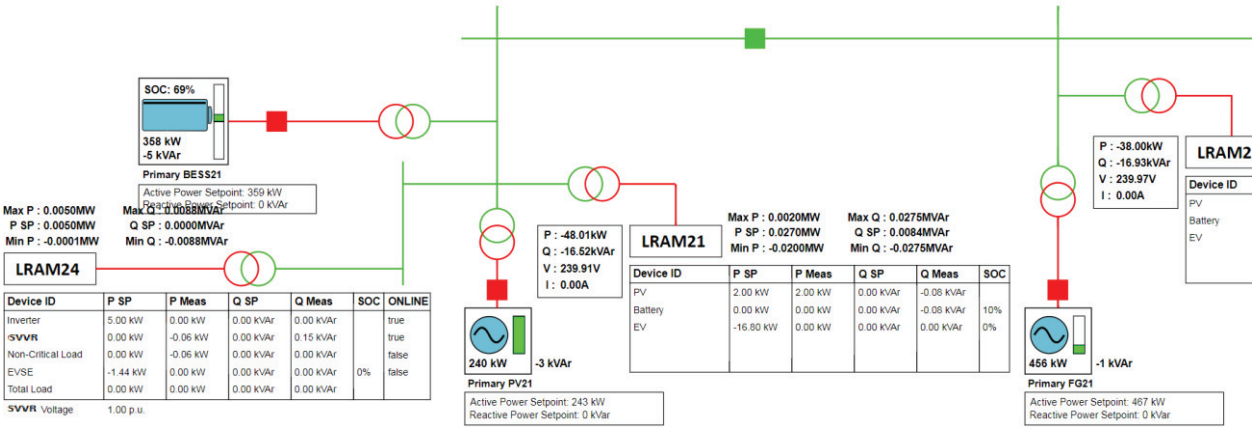


Figure 8-38. RAMCO 2 HMI in case 1-3-2

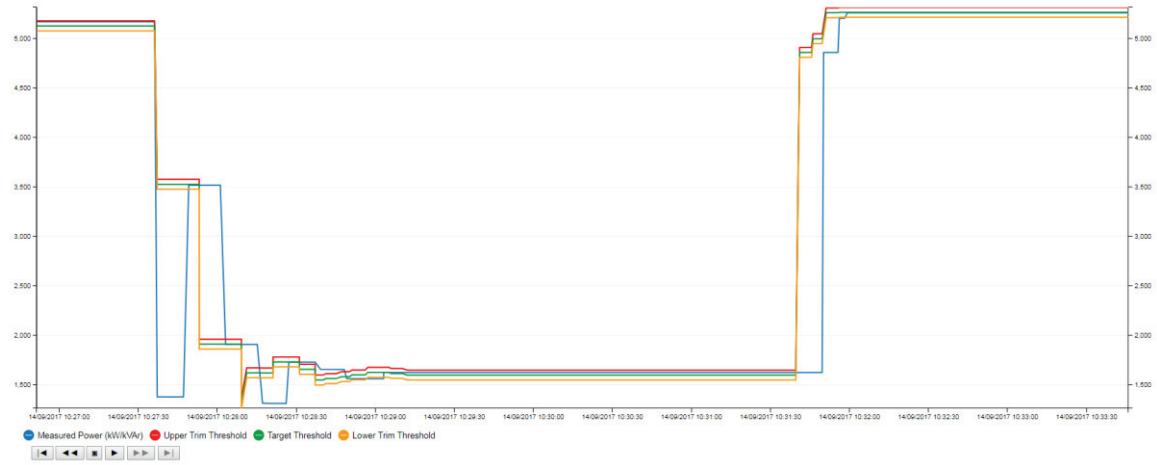


Figure 8-39. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 1-3-2

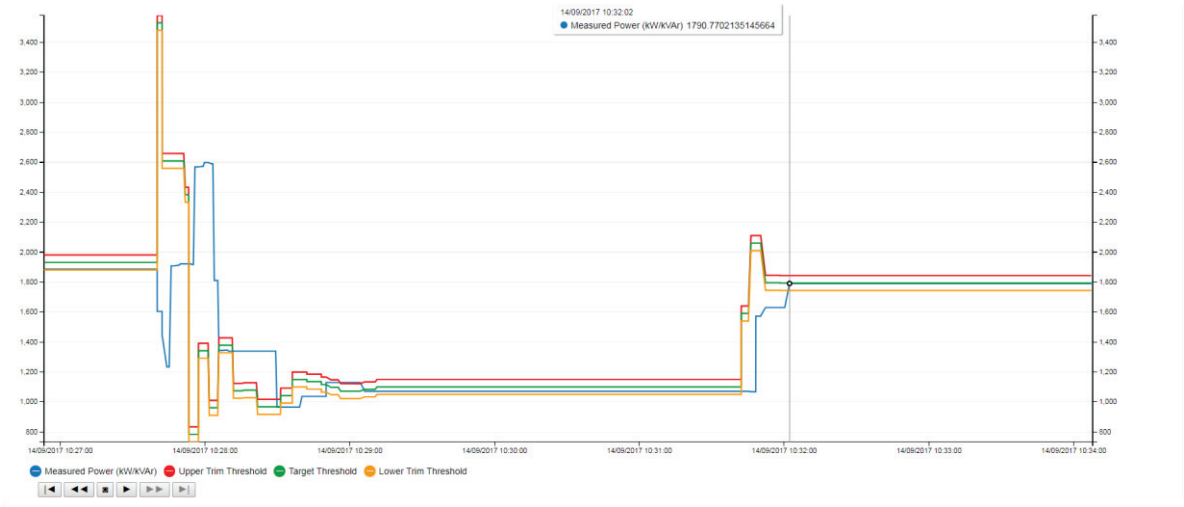


Figure 8-40. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 1-3-2

8.4.1.4 Case 1-4: High Market Price/Minimum Reserve Capacity=0.35/PV Profile=70%, topology 1

Two test cases, namely Case 1-4-1 and Case 1-4-2, were performed in this test category. The details of each test case are summarized in Table 8-17. The control center HMI, RAMCO 1 and 2 HMIs, and RAMCO 1 and 2 power setpoint tracking graphs for Case 1-4-1 and Case 1-4-2 are shown in Figure 8-41 to Figure 8-50. The control center and RAMCO HMIs show that RAMCOs take appropriate actions to utilize DERs according to the market price. Compared to Case 1-2, Case 1-4 is asking for a higher reserve capacity target (35%). Comparing Figure 8-41 and Figure 8-46 with Figure 8-21 and Figure 8-26, one can see that with a higher reserve capacity target, batteries in RAMCO 1 and 2 are charging at a higher rate which results in a higher reserve capacity.

Table 8-17. Case 1-4 Category Test Cases

Use cases & Test Cases	DSO Targets	Market Price	Reserve Capacity	Forecasted Load	Initial SOC (%)	PV (%)
Case 1-4: Low Market Price/Minimum Reserve Capacity=0.35/PV Profile=70%, topology 1	NA	Low	35%			
Case 1-4-1: Initial SOC = 70%	NA	$40	35%	10	70%	70%
Case 1-4-2: Initial SOC = 70%, PV drops to 20% (cloud condition) and keep for a few minutes, back to 70%.	NA	$40	35%	10	70%	70% to 20% to 70%

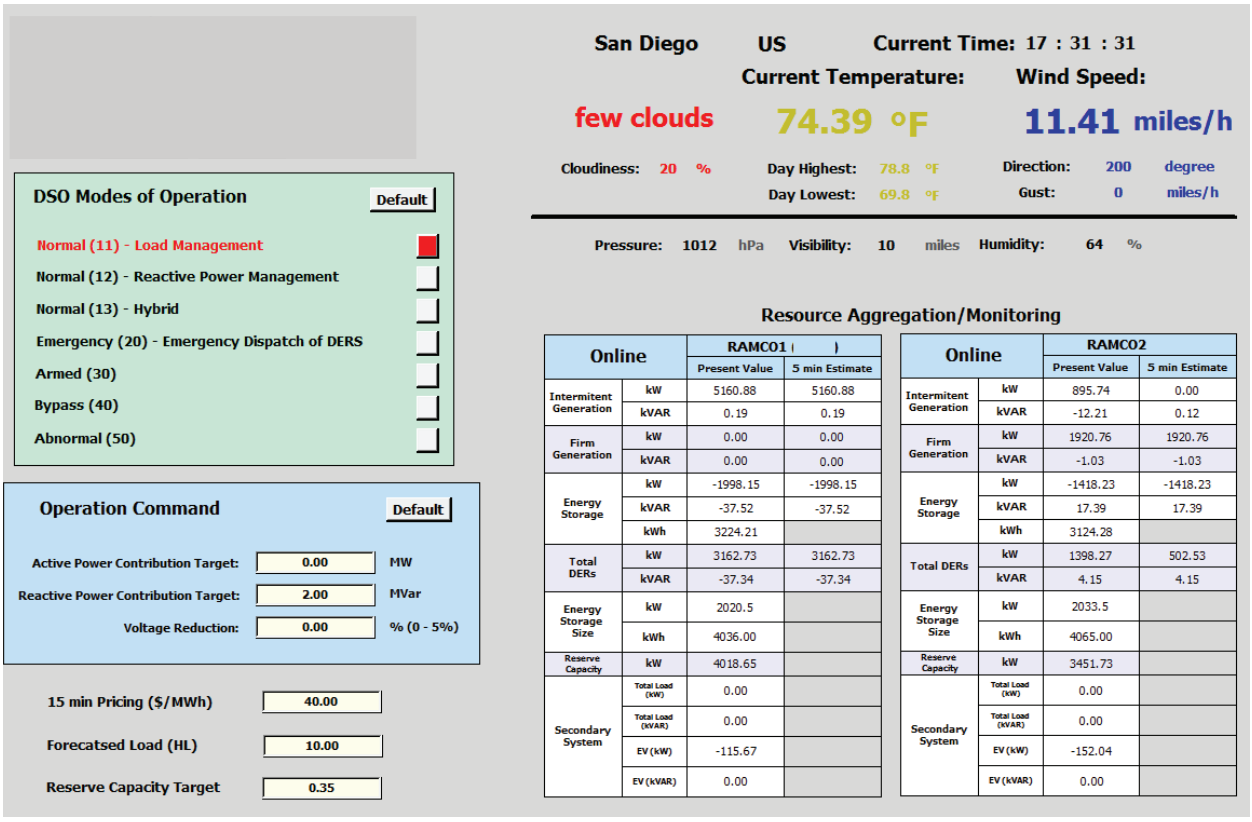


Figure 8-41. DSO HMI in case 1-4-1

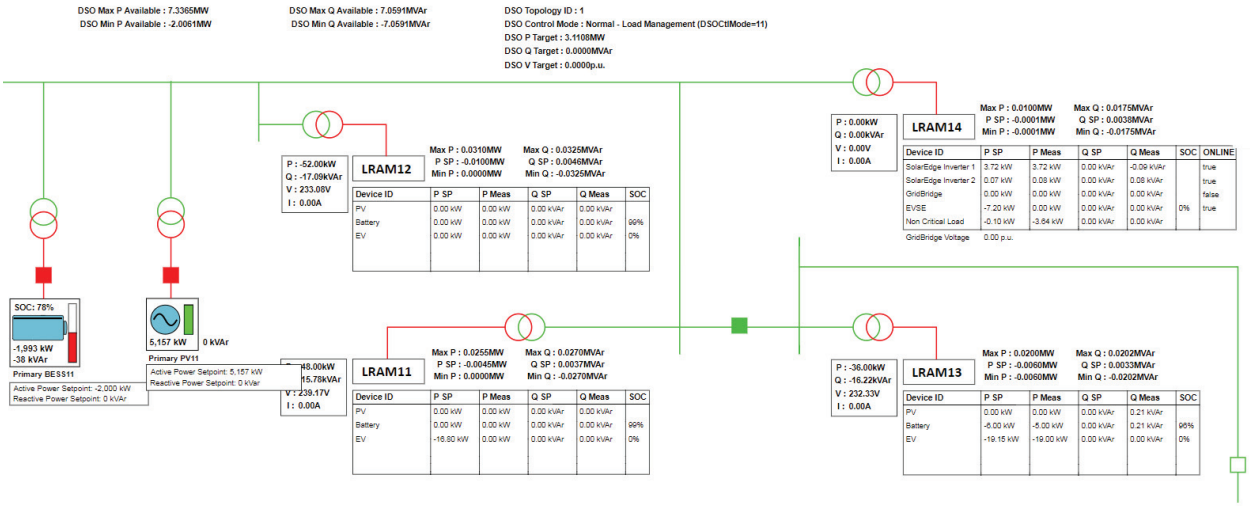


Figure 8-42. RAMCO 1 HMI in case 1-4-1

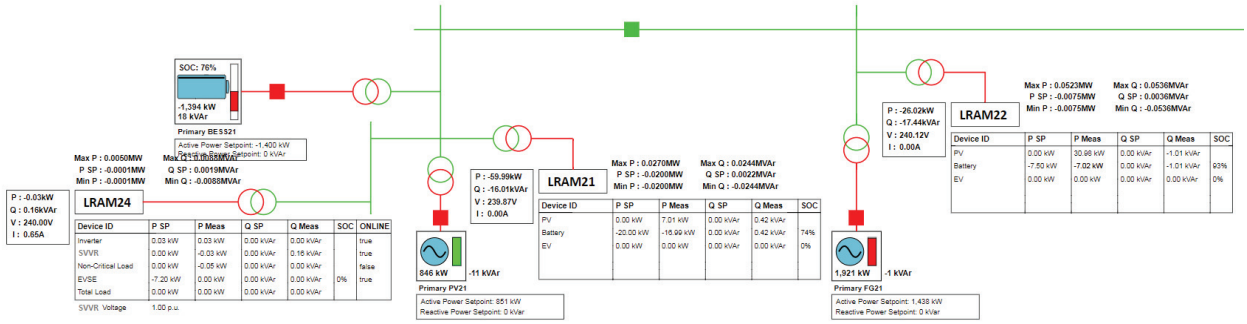


Figure 8-43. RAMCO 2 HMI in case 1-4-1



Figure 8-44. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 1-4-1

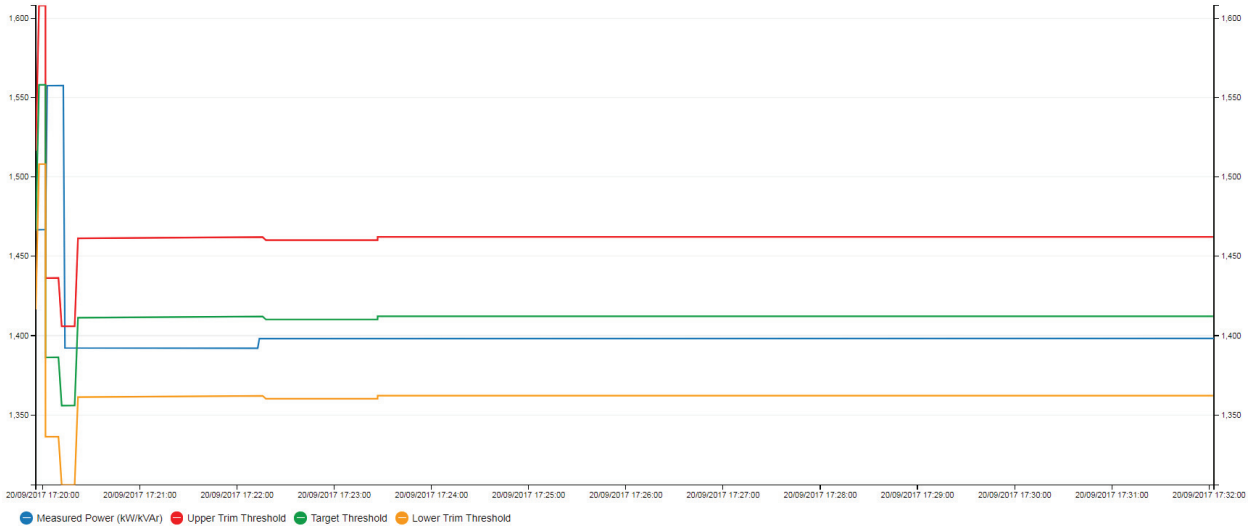


Figure 8-45. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 1-4-1

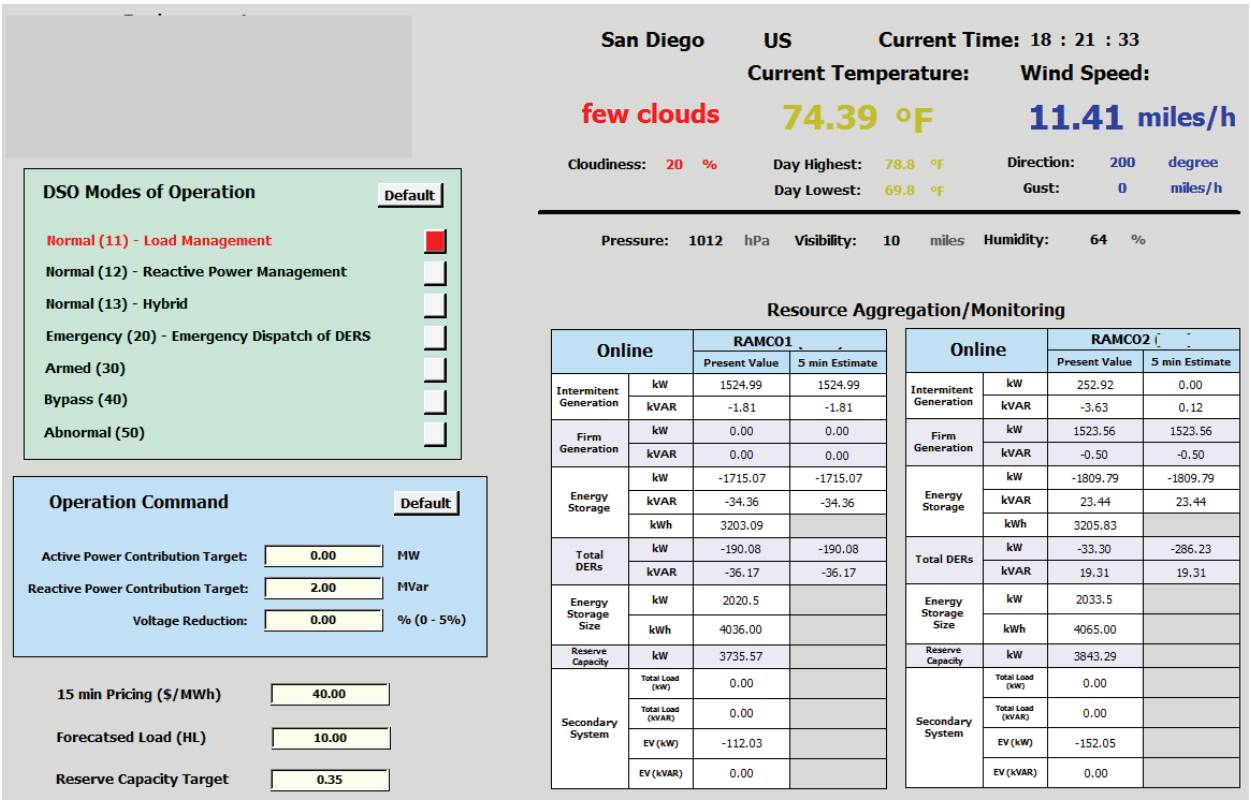


Figure 8-46. DSO HMI in case 1-4-2

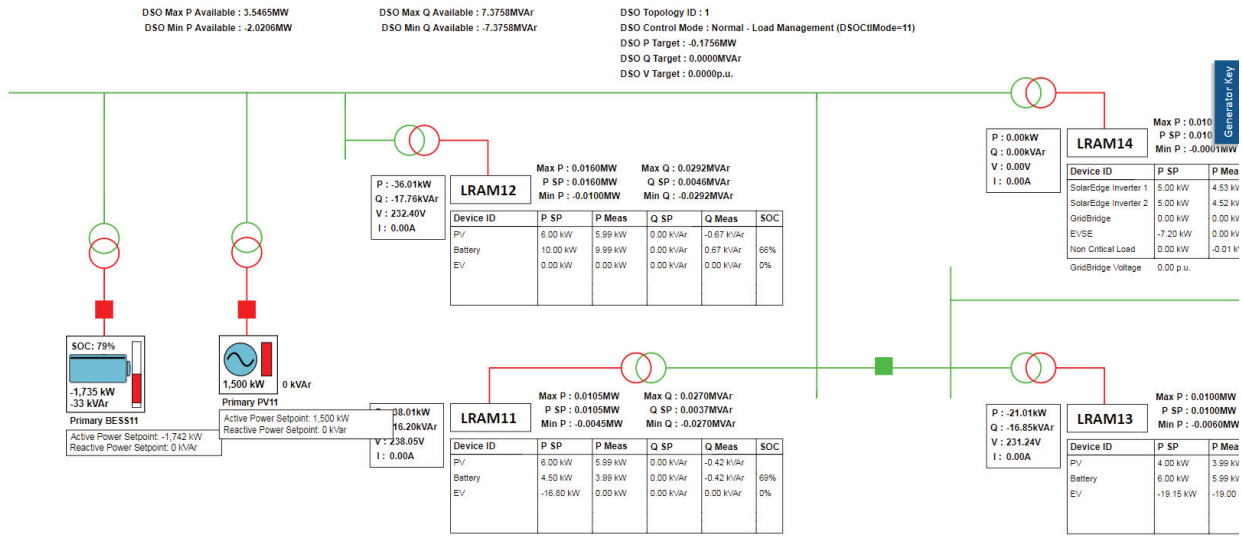


Figure 8-47. RAMCO 1 HMI in case 1-4-2

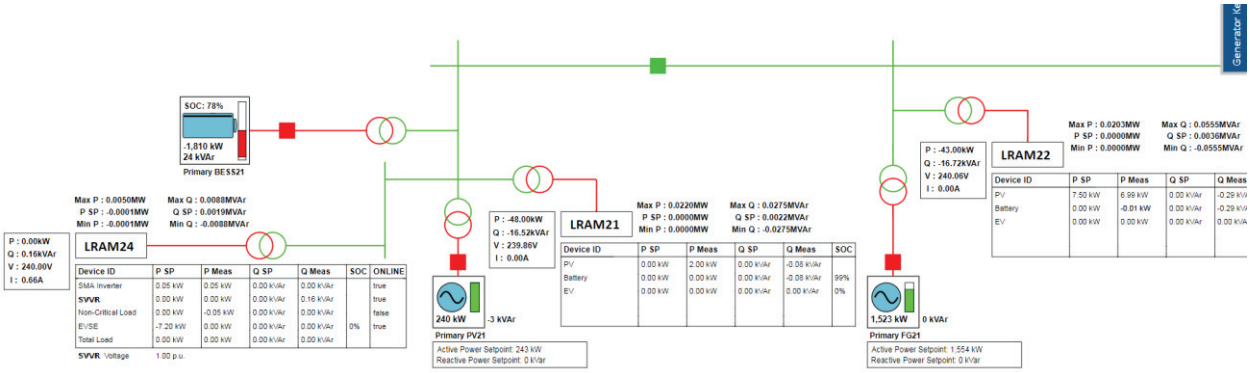


Figure 8-48. RAMCO 2 HMI in case 1-4-2

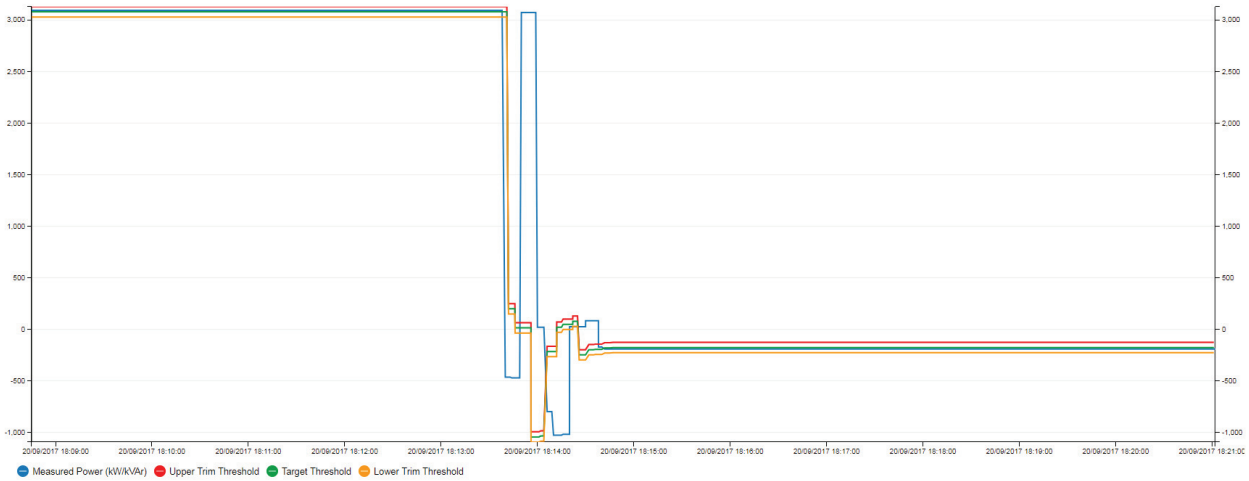


Figure 8-49. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 1-4-2

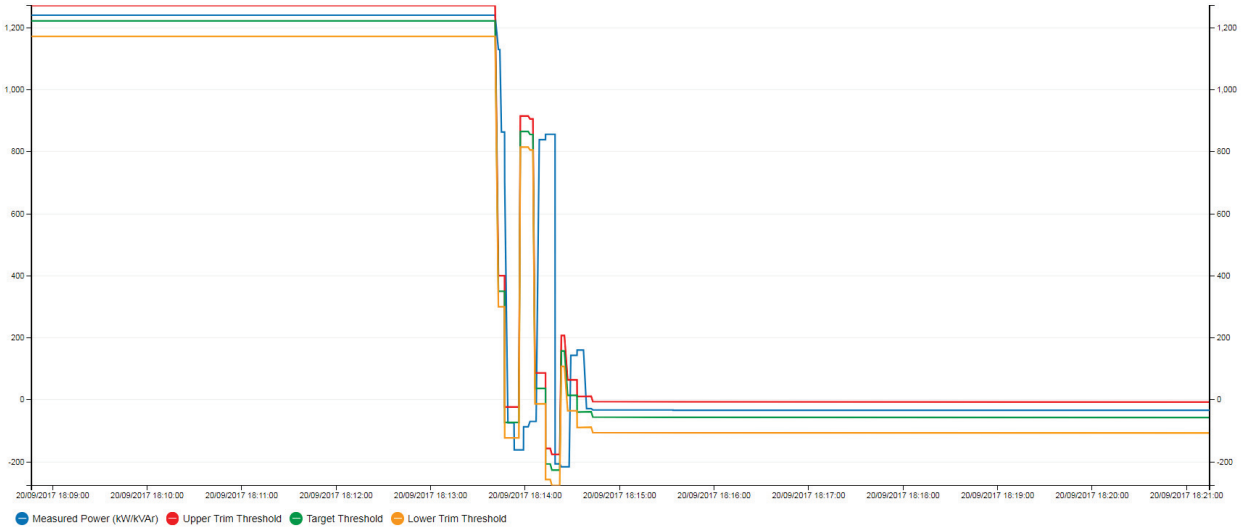


Figure 8-50. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 1-4-2

8.4.2 Use Case 2: Emergency Dispatch of DERs

A summary of test cases for Use Case 2 is provided in Table 3-2. In the following, the test results for Case 2-1 to 2-6 categories are also discussed.

8.4.2.1 Case 2-1: DSO Contribution Target = 8MW, Test under different Generation Profiles

Two test cases, namely Case 2-1-1 and Case 2-1-2, were performed in this test category. The details of each test case are summarized in Table 8-18. The control center HMI, RAMCO 1 and 2 HMIs, and RAMCO 1 and 2 power setpoint tracking graphs for Case 2-1-1 and Case 2-1-2 are shown in Figure 8-51 to Figure 8-58. The DSO and RAMCO HMI screenshots verify that RAMCOs are utilizing DERs properly to meet the 8 MW contribution target requested by DSO. The power setpoint tracking graphs verify that the setpoints issued by DSO are all met by RAMCOs. As seen, in Case 2-1-2 the PV profile drops to 20% which forces RAMCOs to utilize BESS units more.

Table 8-18. Case 2-1 Category Test Cases

Use cases & Test Cases	DSO Targets	Market Price	Reserve Capacity	Forecasted Load	Initial SOC (%)	PV (%)
Case 2-1: DSO Contribution Target = 8MW, Test under different Generation Profiles	8 MW	NA	NA	NA		
Case 2-1-1: PV= 0.7p.u., BESS SOC=70%	8 MW	NA	NA	NA	70%	70%
Case 2-1-2: PV= 0.2p.u., BESS SOC=70%	8 MW	NA	NA	NA	70%	20%

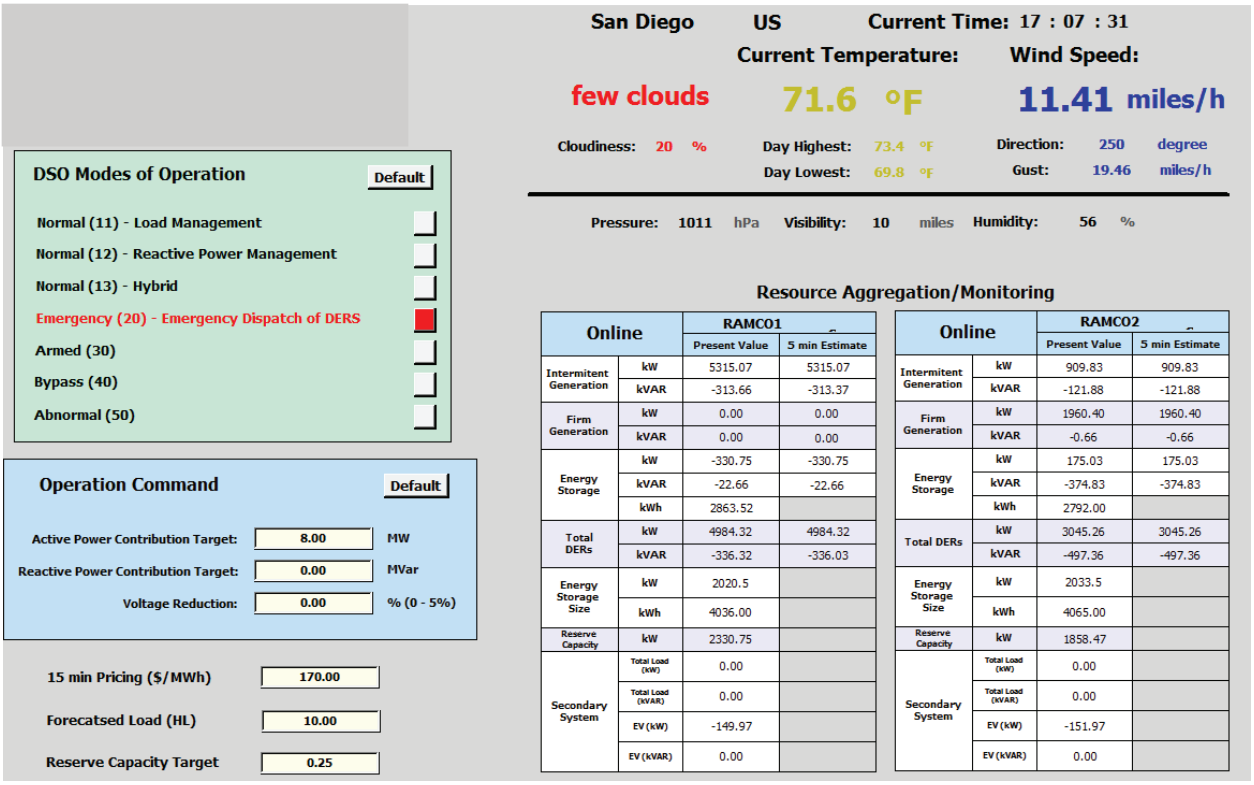


Figure 8-51. DSO HMI in case 2-1-1

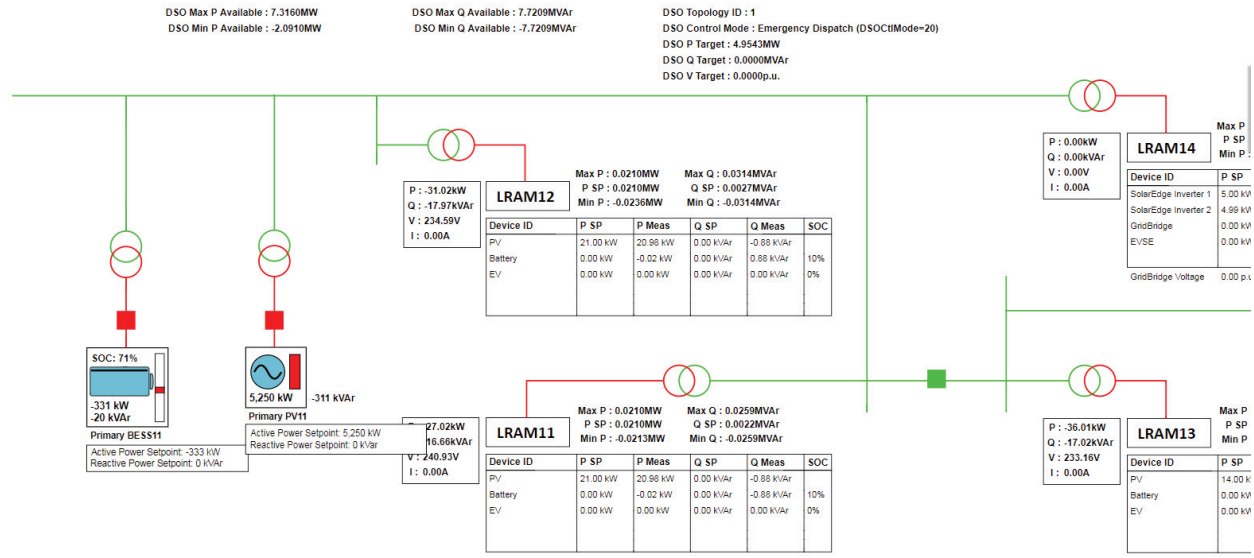


Figure 8-52. RAMCO 1 HMI in case 2-1-1

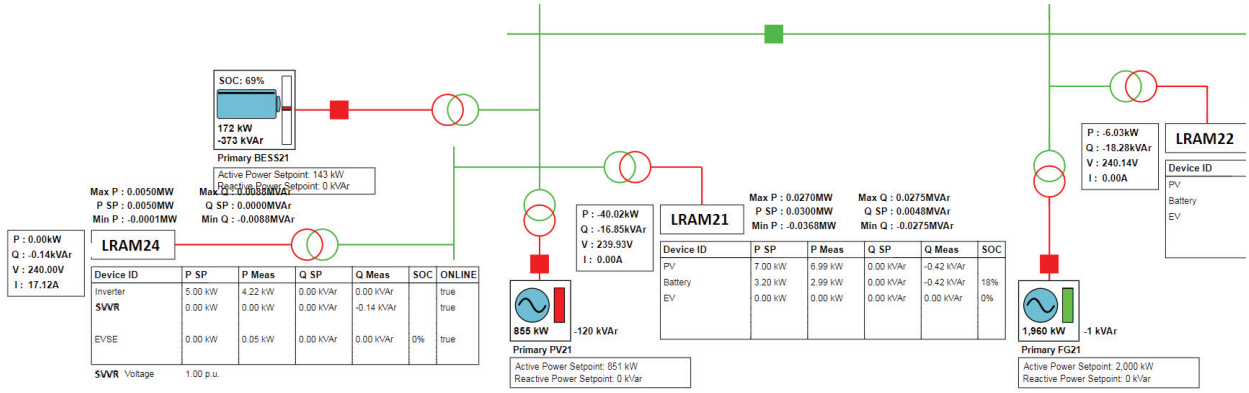


Figure 8-53. RAMCO 2 HMI in case 2-1-1

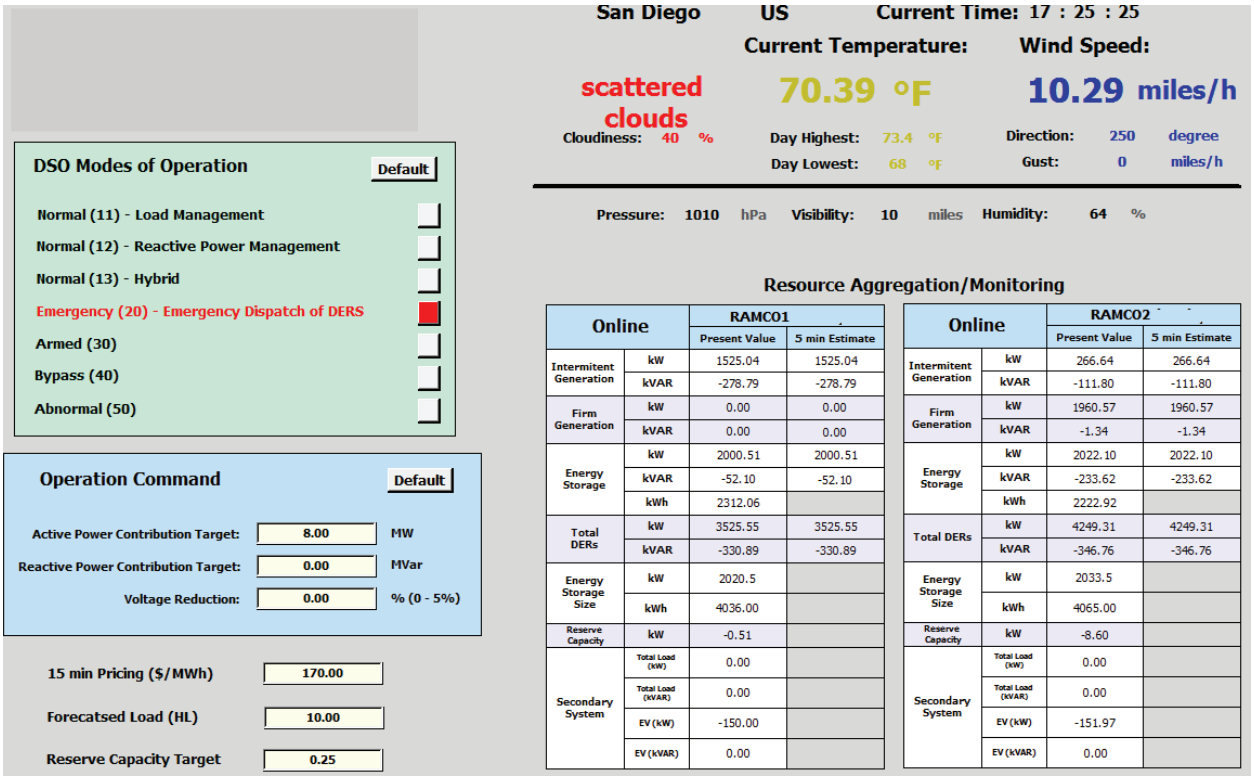


Figure 8-54. DSO HMI in case 2-1-2

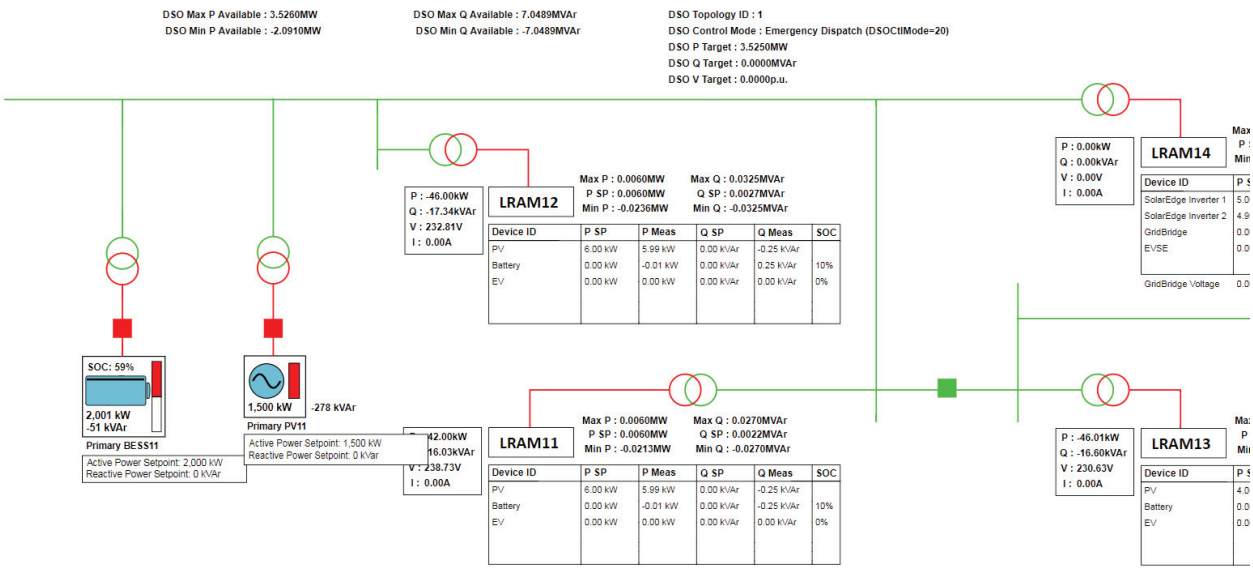


Figure 8-55. RAMCO 1 HMI in case 2-1-2

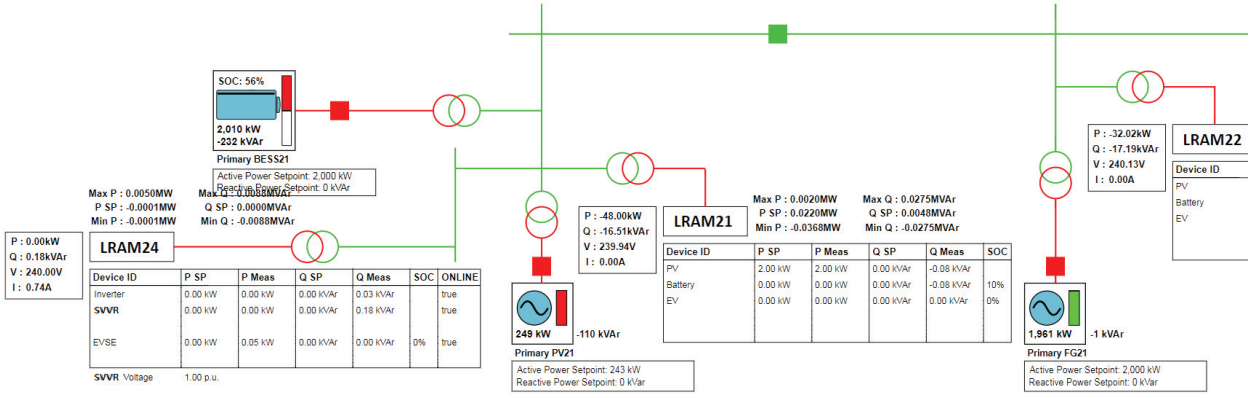


Figure 8-56. RAMCO 2 HMI in case 2-1-2

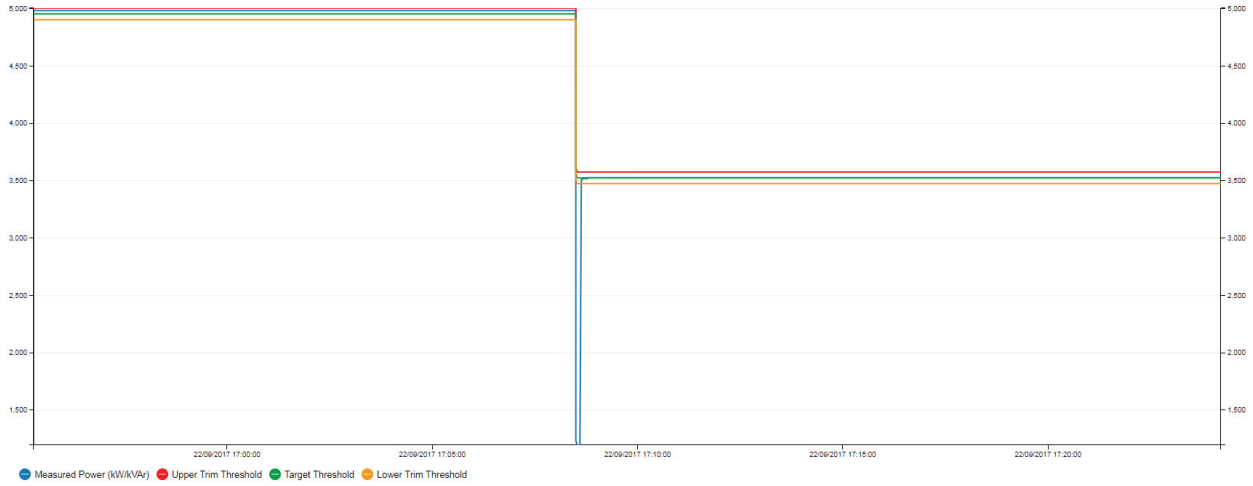


Figure 8-57. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 2-1-2

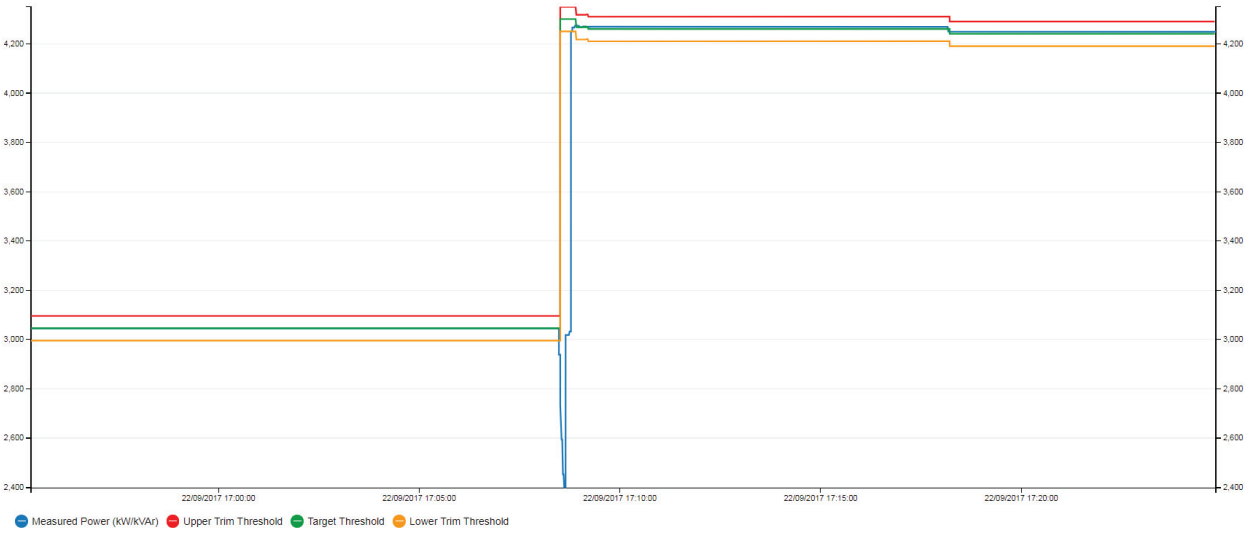
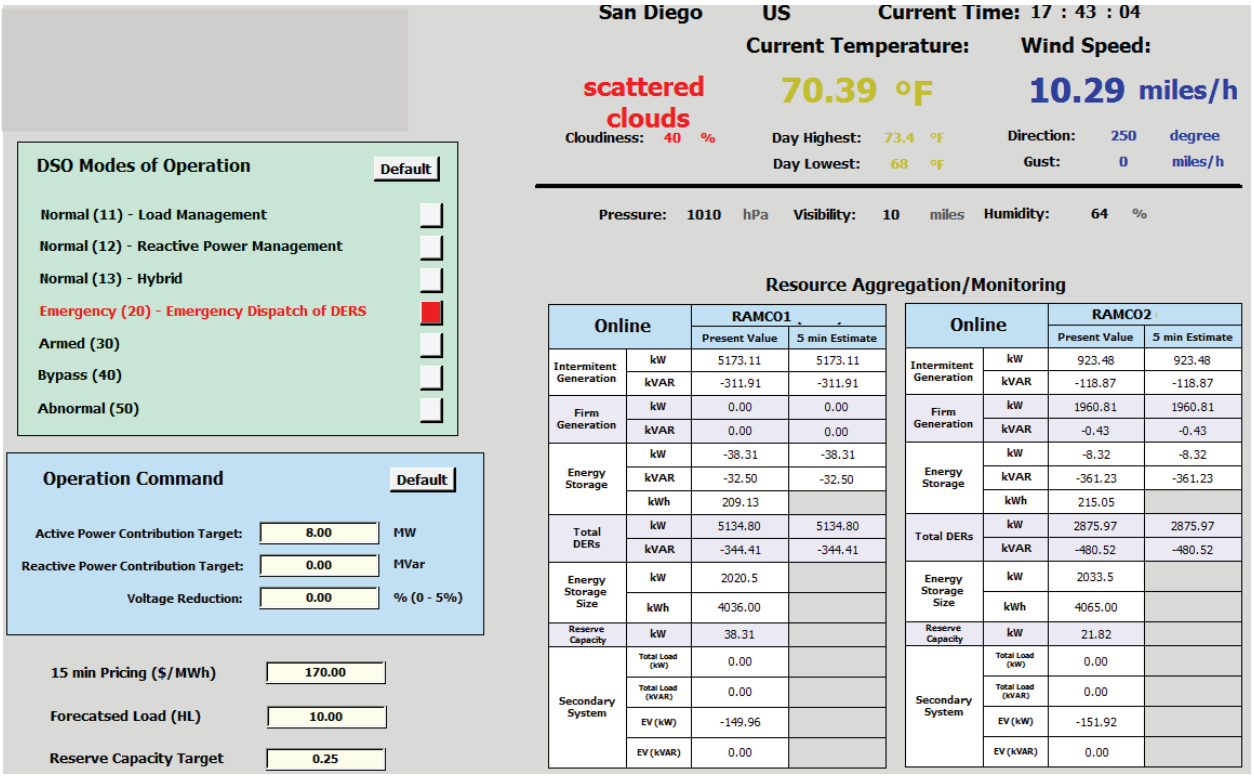


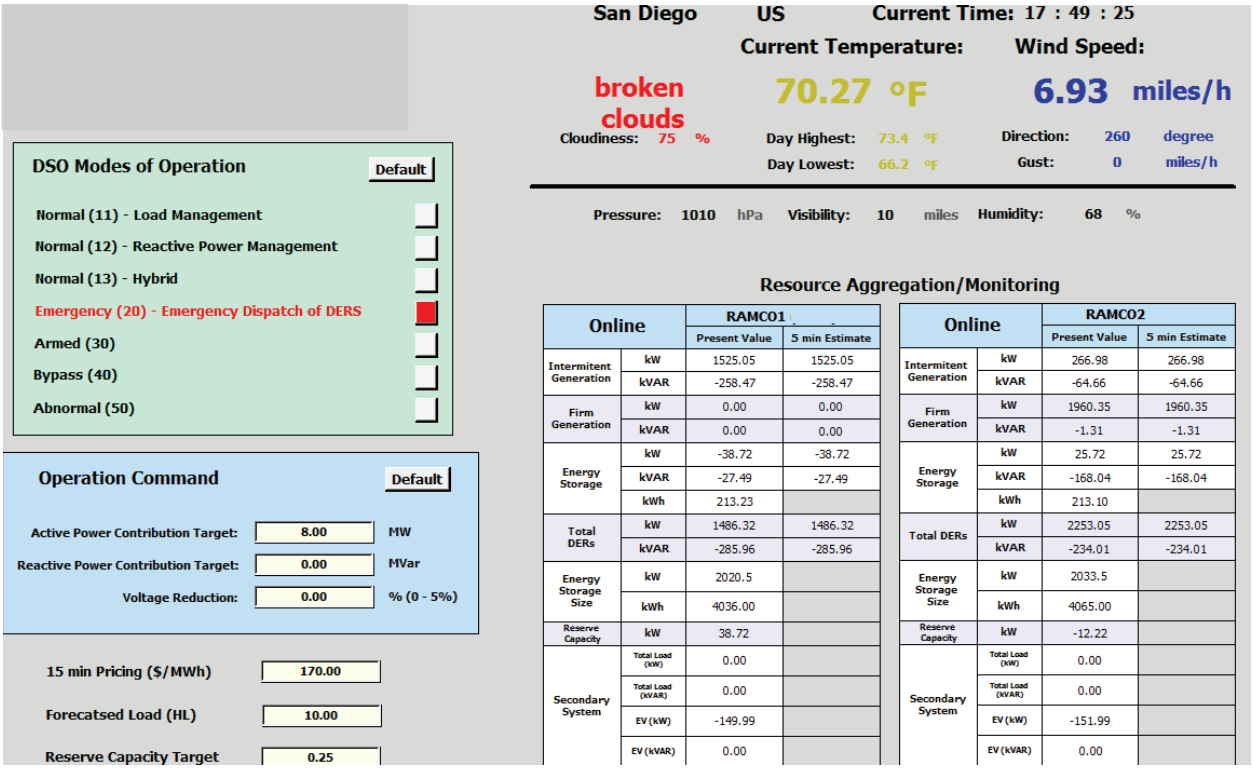
Figure 8-58. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 2-1-2

8.4.2.2 Case 2-2: Initial SOC = 5% (Initial value in digital simulation platform), PV at 70%, then drop PV to 20%

The control center HMI, RAMCO 1 and 2 HMIs, and RAMCO 1 and 2 power setpoint tracking graphs for this case are shown in Figure 8-59 to Figure 8-63. The power setpoint tracking graphs verify that the setpoints issued by DSO are all met by RAMCOs. As seen, batteries do not discharge because their SOC is below the minimum allowable SOC (10%). With PV profile of 70% the DSO target is met. However, with 20% of PV profile, there are not enough resources available to meet the DSO target.

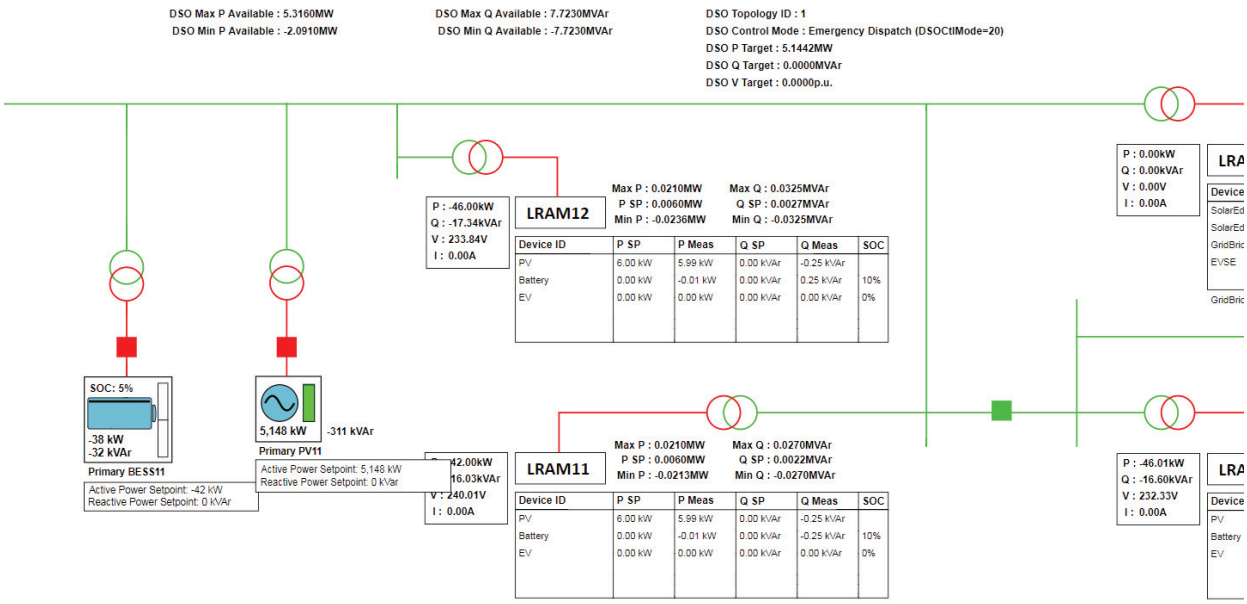


with 70% PV Profile

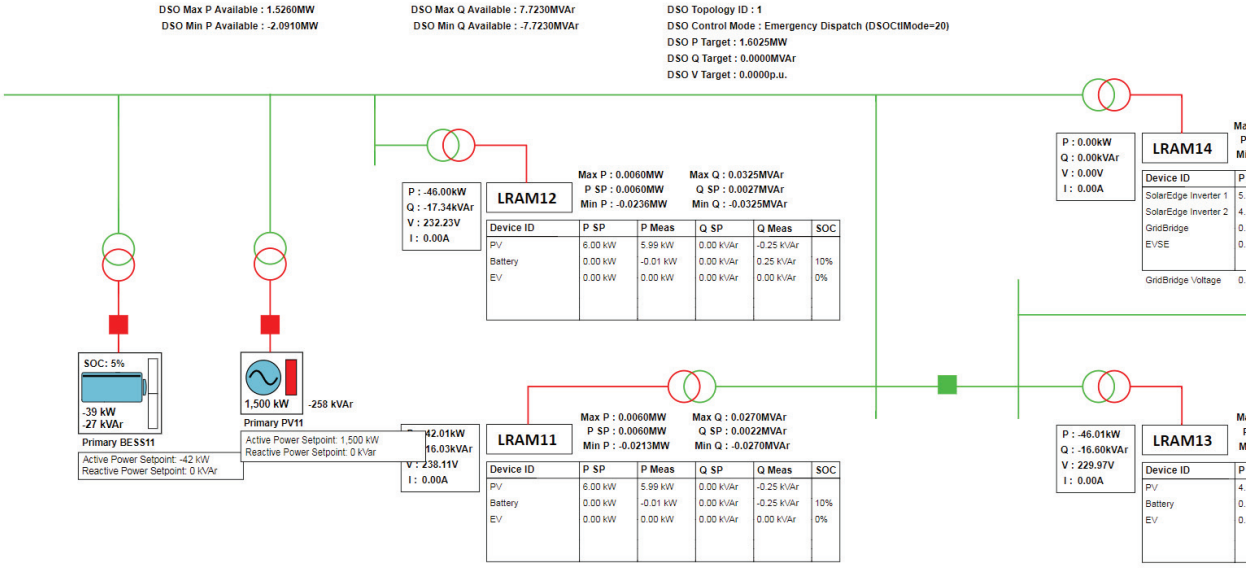


with 20% PV Profile

Figure 8-59. DSO HMI before and after PV profile change in case 2-2

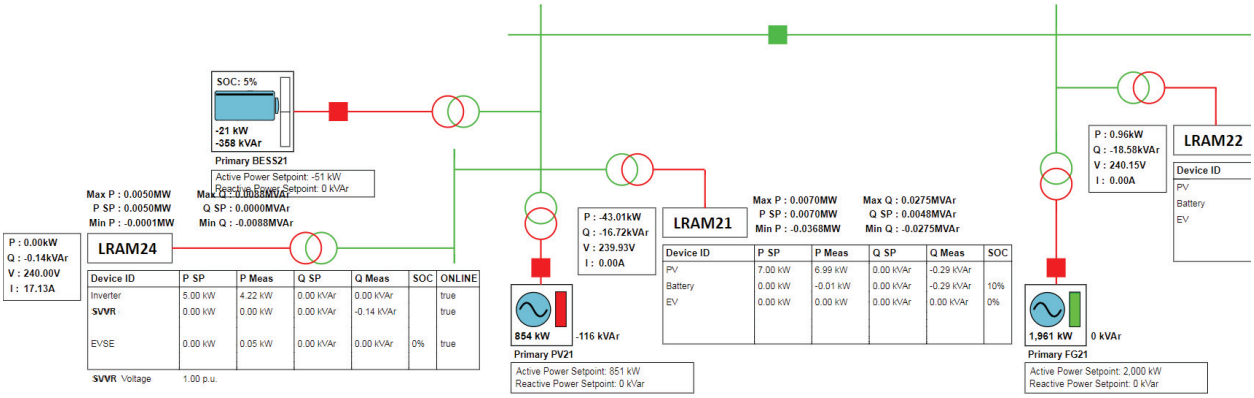


with 70% PV Profile

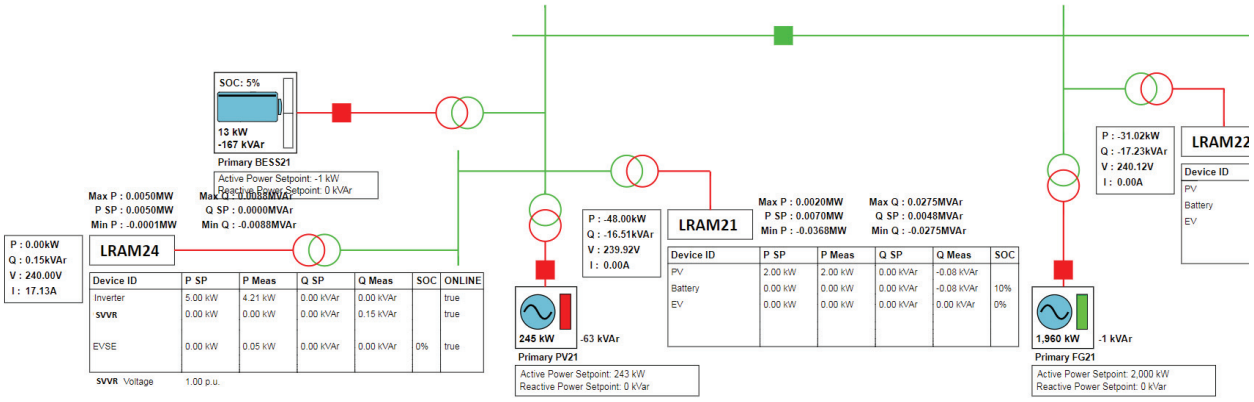


with 20% PV Profile

Figure 8-60. RAMCO 1 HMI before and after PV profile change in case 2-2



with 70% PV Profile



with 20% PV Profile

Figure 8-61. RAMCO 2 HMI before and after PV profile change in case 2-2

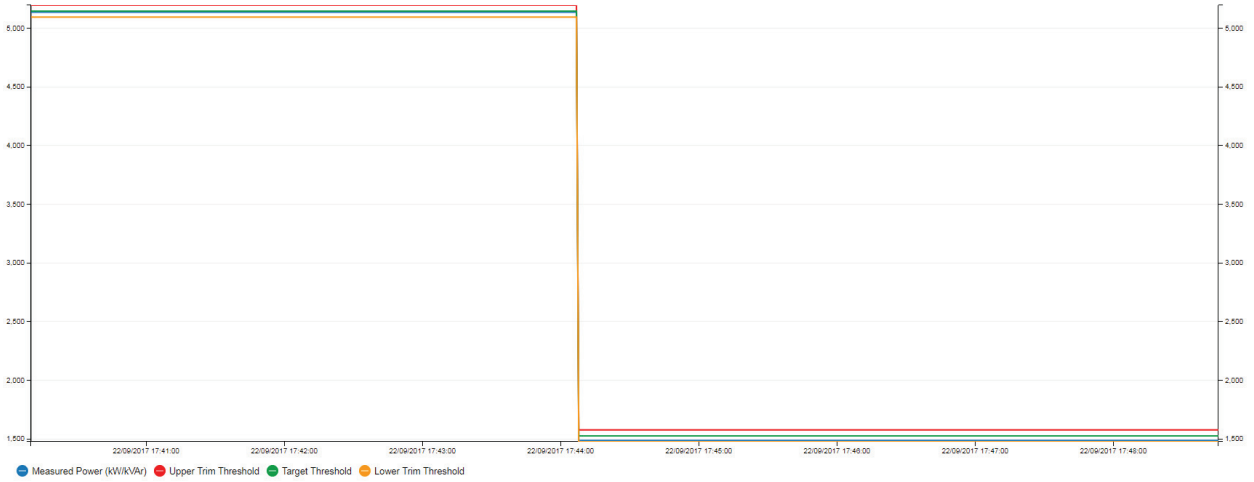


Figure 8-62. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 2-2

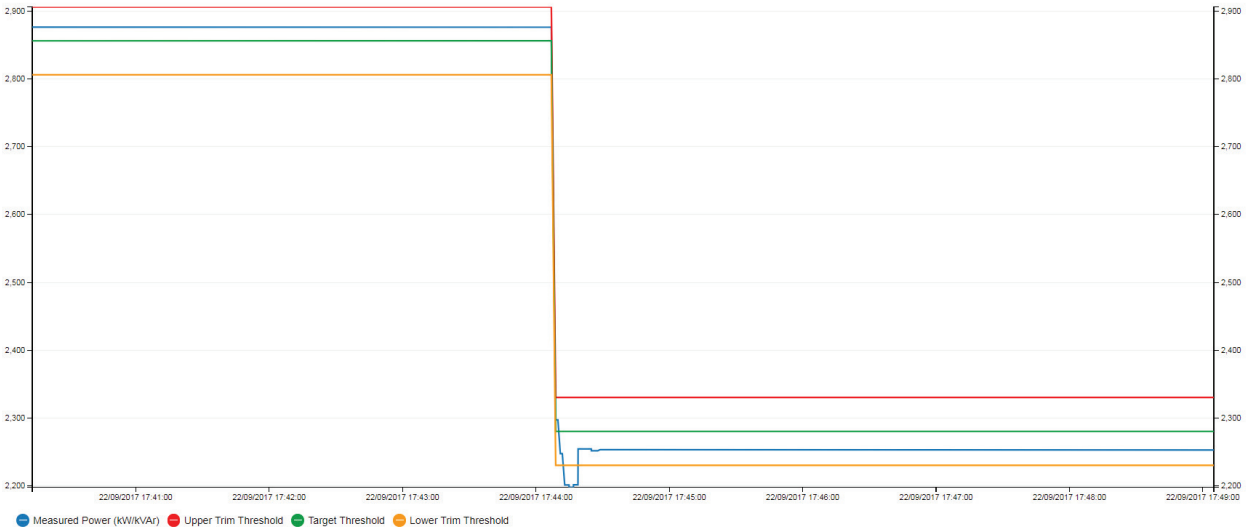


Figure 8-63. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 2-2

8.4.2.3 Case 2-3: Change of DSO Target and Load Profile

The purpose of this test case was to verify the response of RAMCOs with respect to the DSO target and load level changes. Two test cases, namely Case 2-3-1 and Case 2-3-2, were performed in this test category. The details of each test case are summarized in Table 8-19. The test results for Case 2-3-1 were already discussed in Section 3.1.2. Herein, the RAMCO 1 and 2 power setpoint tracking graphs for Case 2-3-2 are shown in Figure 8-64 to Figure 8-65. These figures show that RAMCOs can effectively meet DSO targets under load profiles changes.

Table 8-19. Case 2-3 Category Test Cases

Use cases & Test Cases	DSO Targets	Market Price	Reserve Capacity	Forecasted Load	Initial SOC (%)	PV (%)
Case 2-3: Change of DSO target and load profile	0 MW	NA	NA	NA	70%	70%
Case 2-3-1: Change DSO Contribution Target from 12MW to -4MW in steps	variable	NA	NA	NA	70%	70%
Case 2-3-2: DSO Contribution Target= 12MW, change load level in steps from 1 to 0.2	12 MW	NA	NA	NA	70%	70%

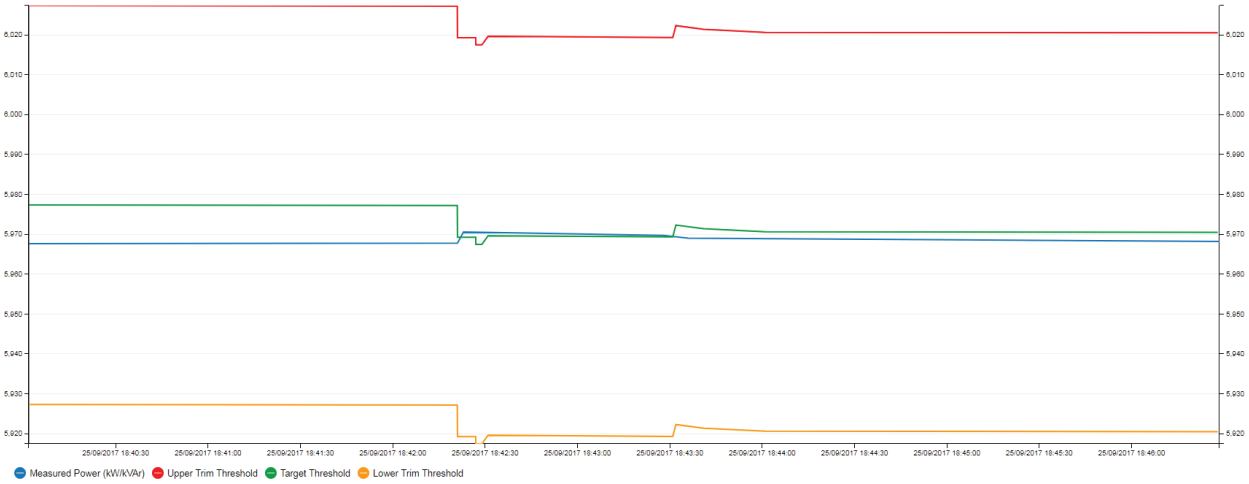


Figure 8-64. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 2-3-2

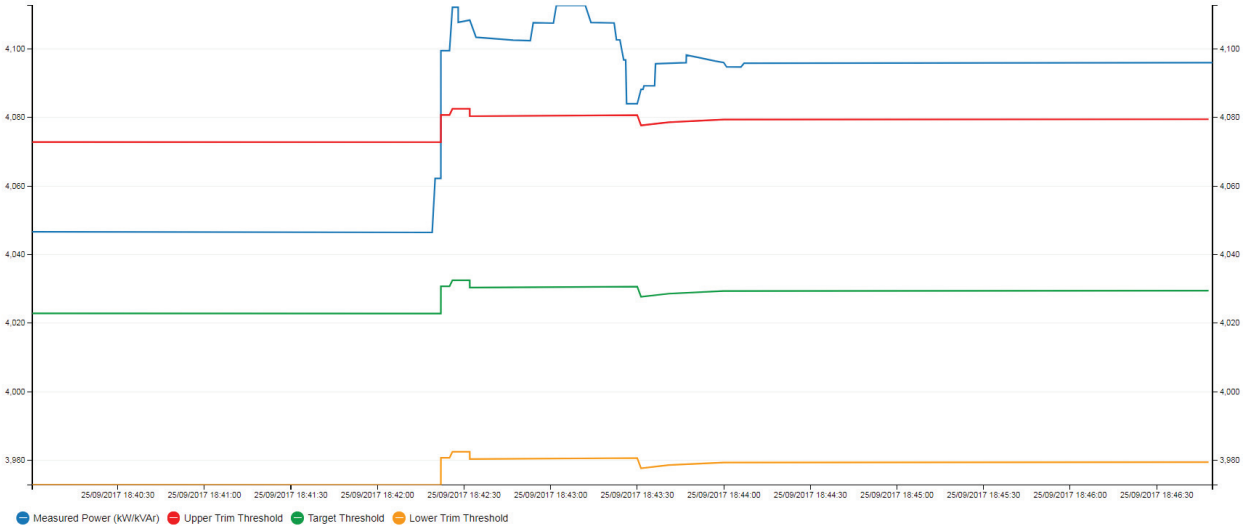


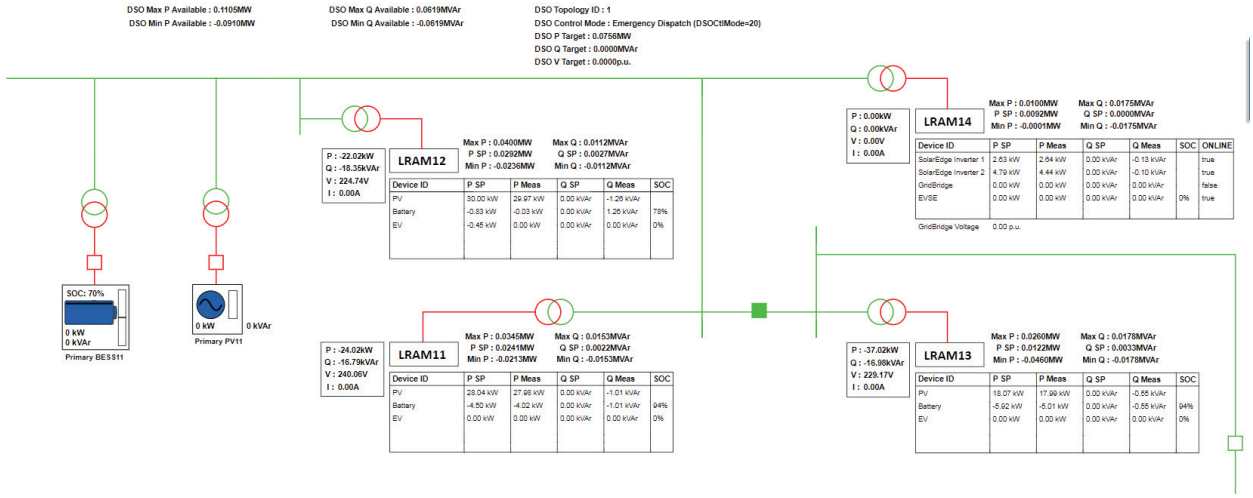
Figure 8-65. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 2-3-2

8.4.2.4 Case 2-4: Test Dispatching in LRAMs When All Primary DERs Are Off

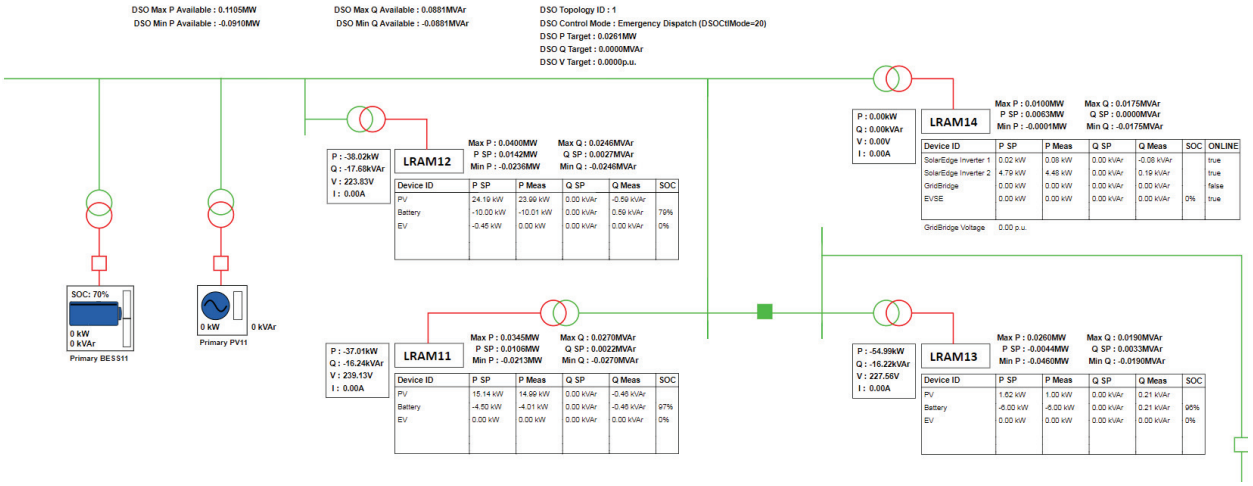
Two test cases, namely Case 2-4-1 and Case 2-4-2, were performed in this test category. The details of each test case are summarized in Table 8-20. The test results for Case 2-4-1 were already discussed in Section 3.1.3. Herein, the results for Case 2-4-2 are presented. The RAMCO 1 and 2 HMIs, and RAMCO 1 and 2 power setpoint tracking graphs are shown in Figure 8-66 to Figure 8-69. The HMI screens are illustrated for three different cases, namely, when DSO P target is 150 kW, when DSO P target drops to 50 kW, and when the PV profile drops to 10% with 50 kW of DSO target.

Table 8-20. Case 2-4 Category Test Cases

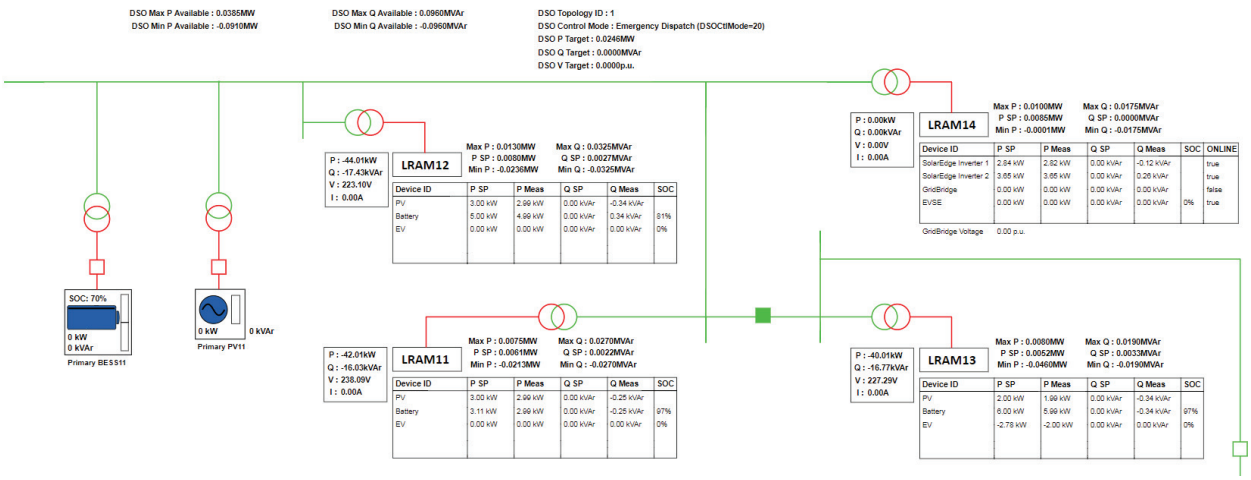
Use cases & Test Cases	DSO Targets	Market Price	Reserve Capacity	Forecasted Load	Initial SOC (%)	PV (%)
Case 2-4: Test dispatching in LRAMs when all primary DERs are off		NA	NA	NA	NA	
Case 2-4-1: Change P target in 50kW steps from 250kW to -200kW	variable	NA	NA	NA	NA	100%
Case 2-4-2: Changing P target and then PV profile: P_T changes from 150 to 50. Then PV changes to 0.1	variable	NA	NA	NA	NA	variable



DSO P target equal to 150kW

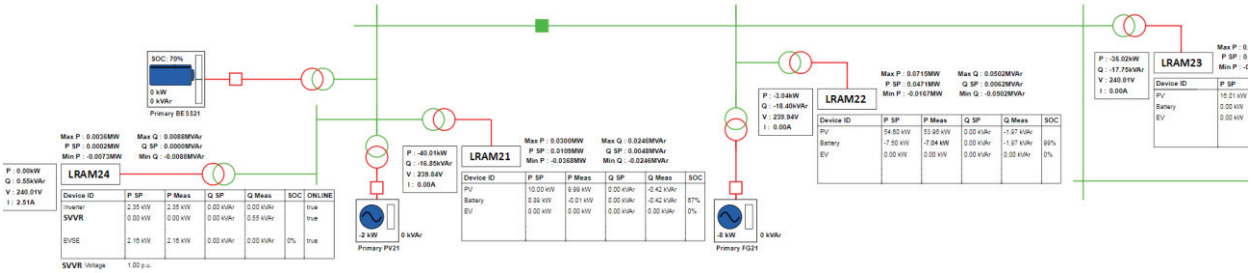


DSO P target drops to 50kW

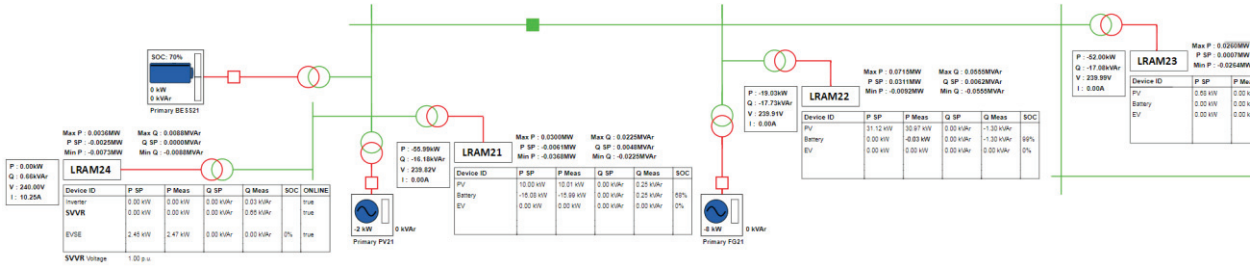


PV profile drops to 10%

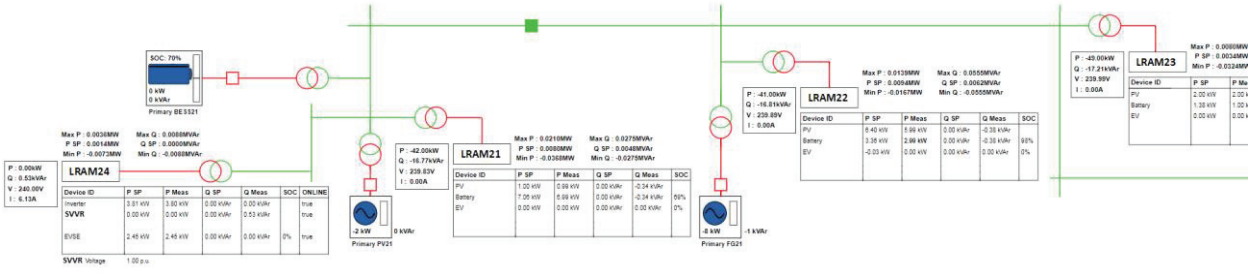
Figure 8-66. RAMCO 1 HMI in case 2-4-2



DSO P target equal to 150kW



DSO P target drops to 50kW



PV profile drops to 10%

Figure 8-67. RAMCO 2 HMI in case 2-4-2

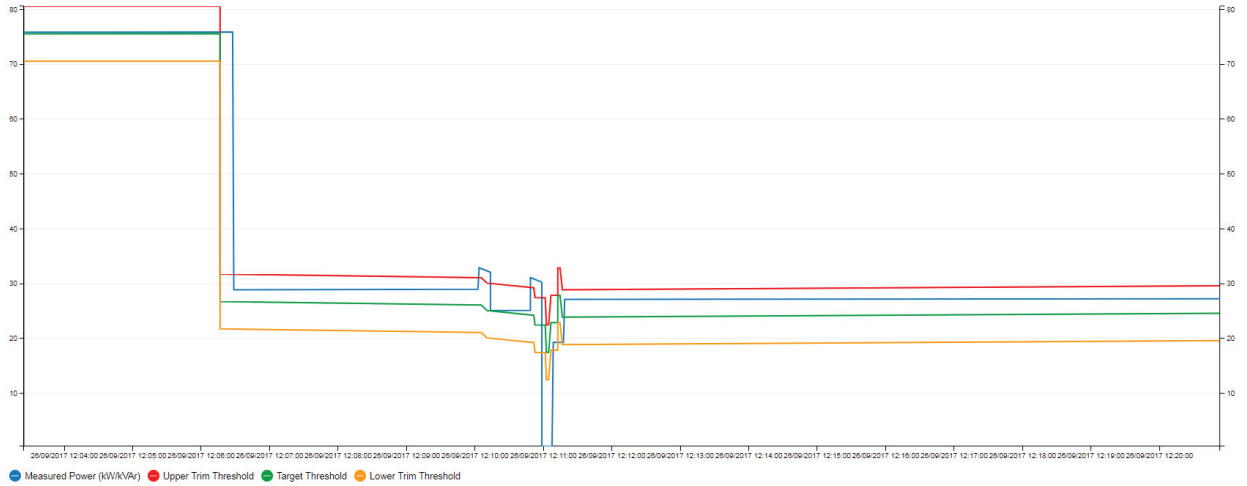


Figure 8-68. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 2-4-2

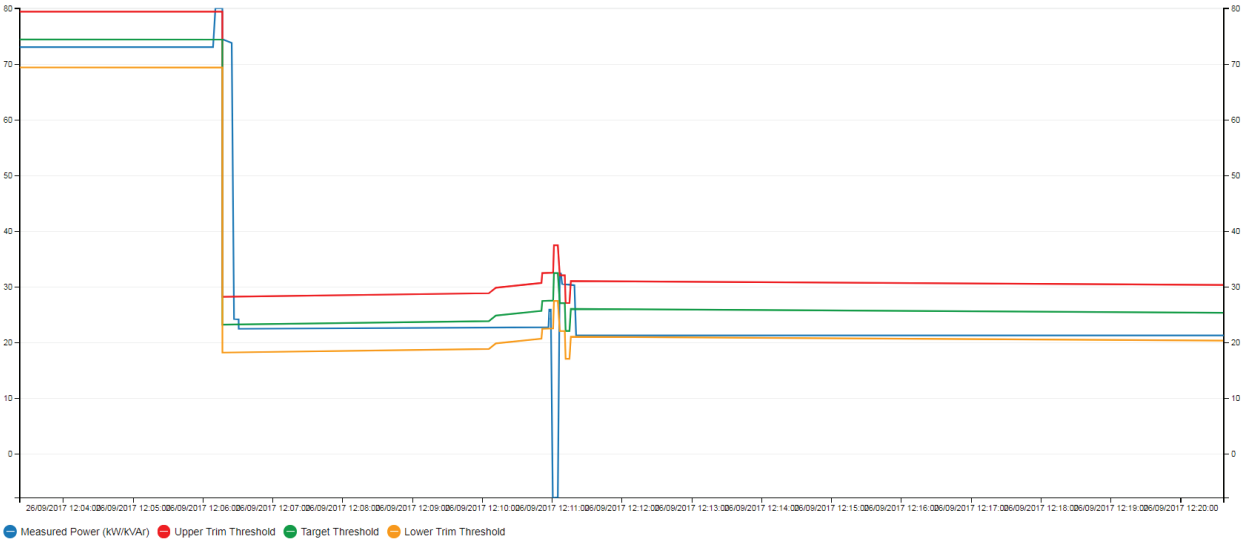


Figure 8-69. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 2-4-2

8.4.2.5 Case 2-5: Test under Different Circuit Topologies: DSO Contribution Target = 3MW, PV Profile = 0.2p.u., BESS SOC=30%

The purpose of this test case is to verify the performance of the demonstration system in response to the changes in the circuit configuration. As discussed in Section 2.3.1, according to the status of reclosers and Tie switch, three different circuit configurations can be applied to the demonstration test system. Depending on the circuit topology RAMCO coverage may vary. The DERs and LRAMs designations for each topology are summarized in Table 2-3 to Table 2-5. The testing started with Topology 1. Using SCADA interface, Recloser 1 was opened and Tie Switch was closed to switch to Topology 2. Then, the circuit topology was switched back to Topology 1. Finally, to see the response of demonstration system in Topology 3, Recloser 2 was opened and Tie Switch was closed to switch to Topology 3. It is expected that when the circuit topology changes from Topology 1 to Topology 2, LRAM13 which is under RAMCO1 falls under RAMCO2 coverage. This can be seen in Figure 8-71

compared to Figure 8-70. As seen, RAMCO2 contribution has slightly increased which shows that LRAM13 is utilized by RAMCO2. When the circuit topology changes from Topology 1 to Topology 3, LRAM22, LRAM23, and FG21 should fall under RAMCO1 coverage. This is illustrated in Figure 8-73 compared to Figure 8-72. As seen, RAMCO1 contribution has significantly increased and RAMCO2 contribution has decreased in Topology 3. More specifically, it can be noticed that, in Topology 3, Firm Generation unit contribution is reported under RAMCO1 instead of RAMCO2.

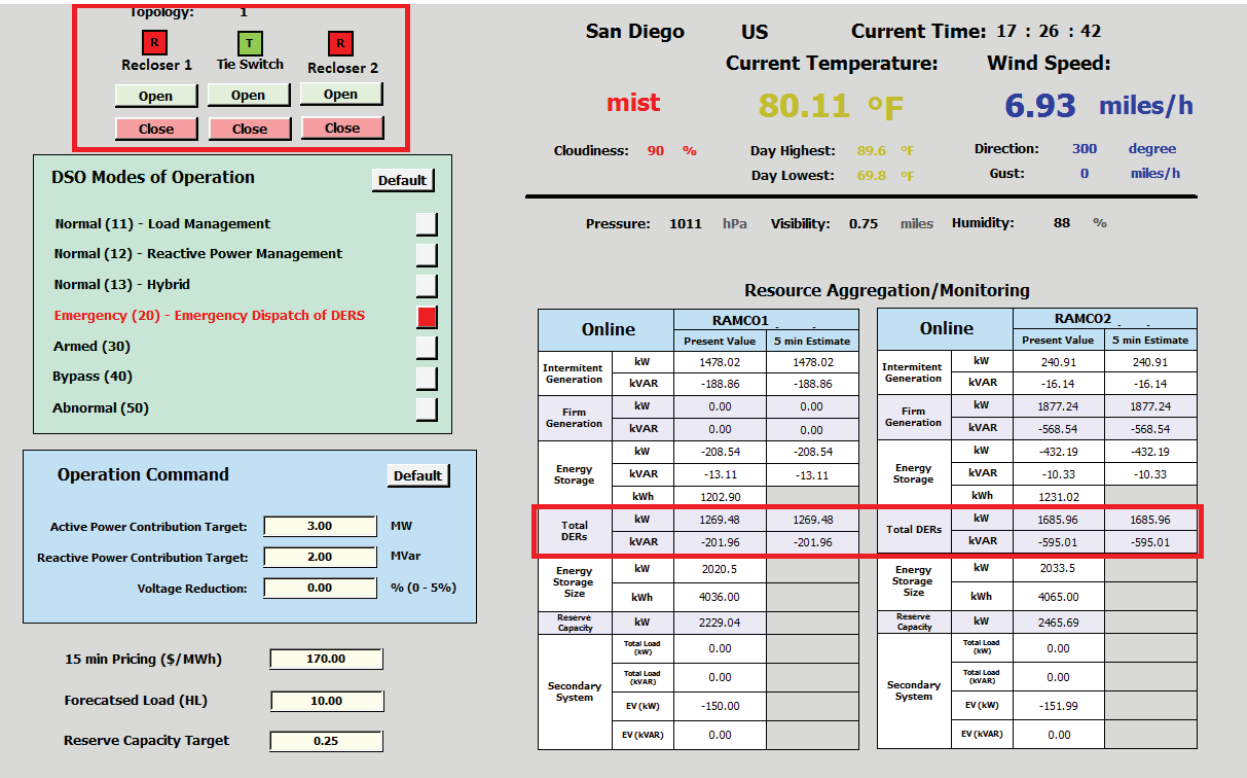


Figure 8-70. DSO HMI for Circuit Topology 1 in case 2-5

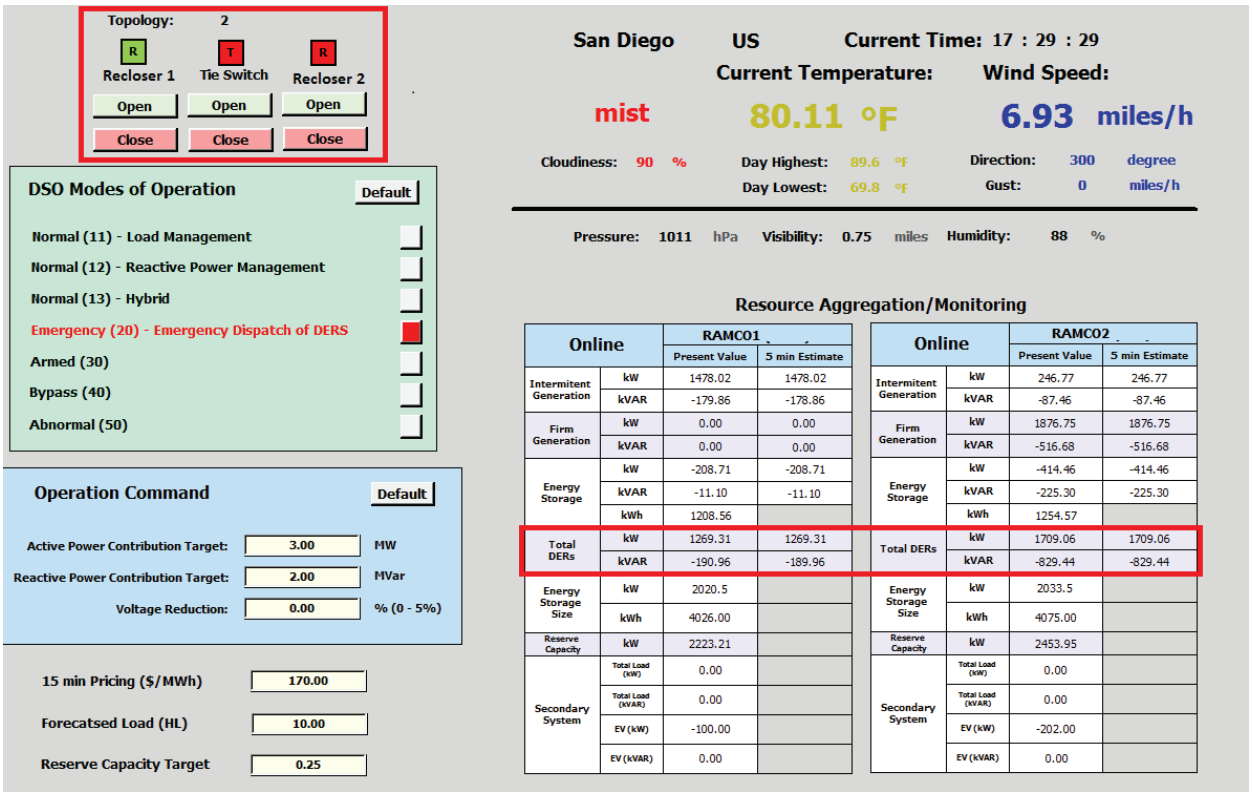


Figure 8-71. DSO HMI when Circuit Topology changes from 1 to 2 in case 2-5

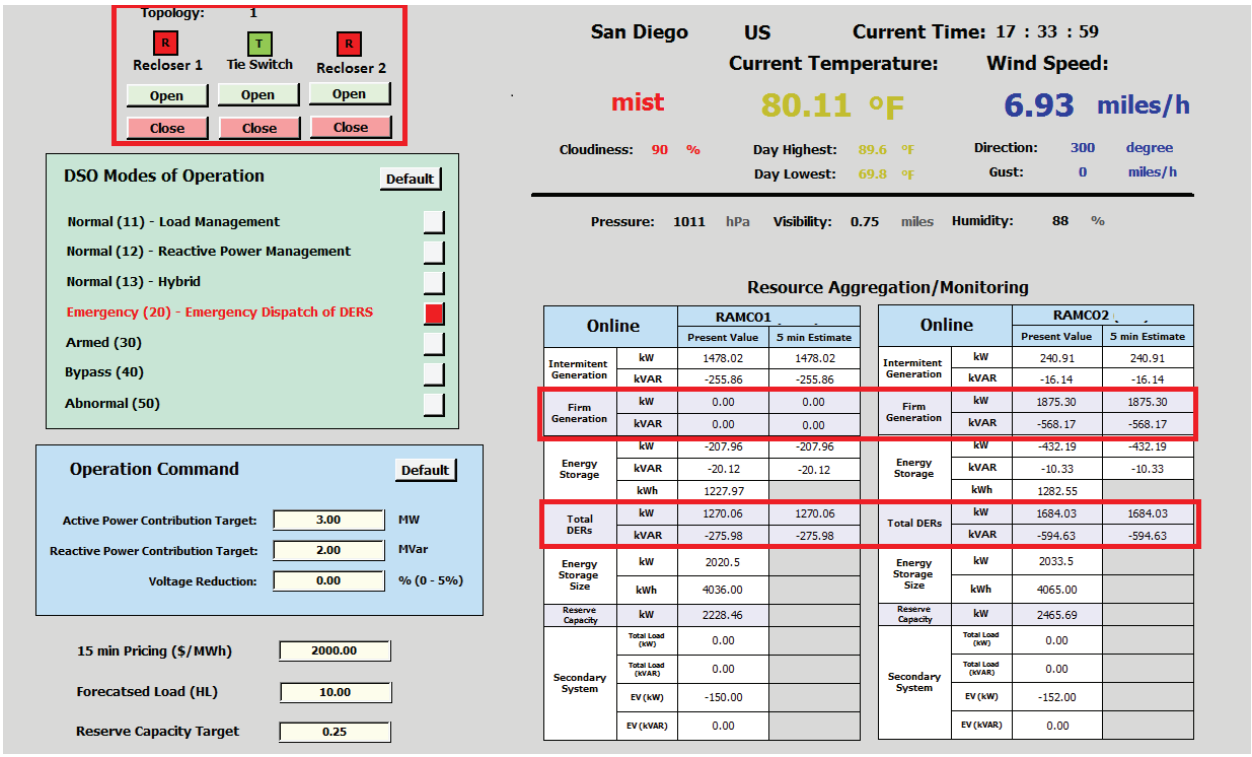


Figure 8-72. DSO HMI when the Circuit Topology changes from 2 to 1 in case 2-5

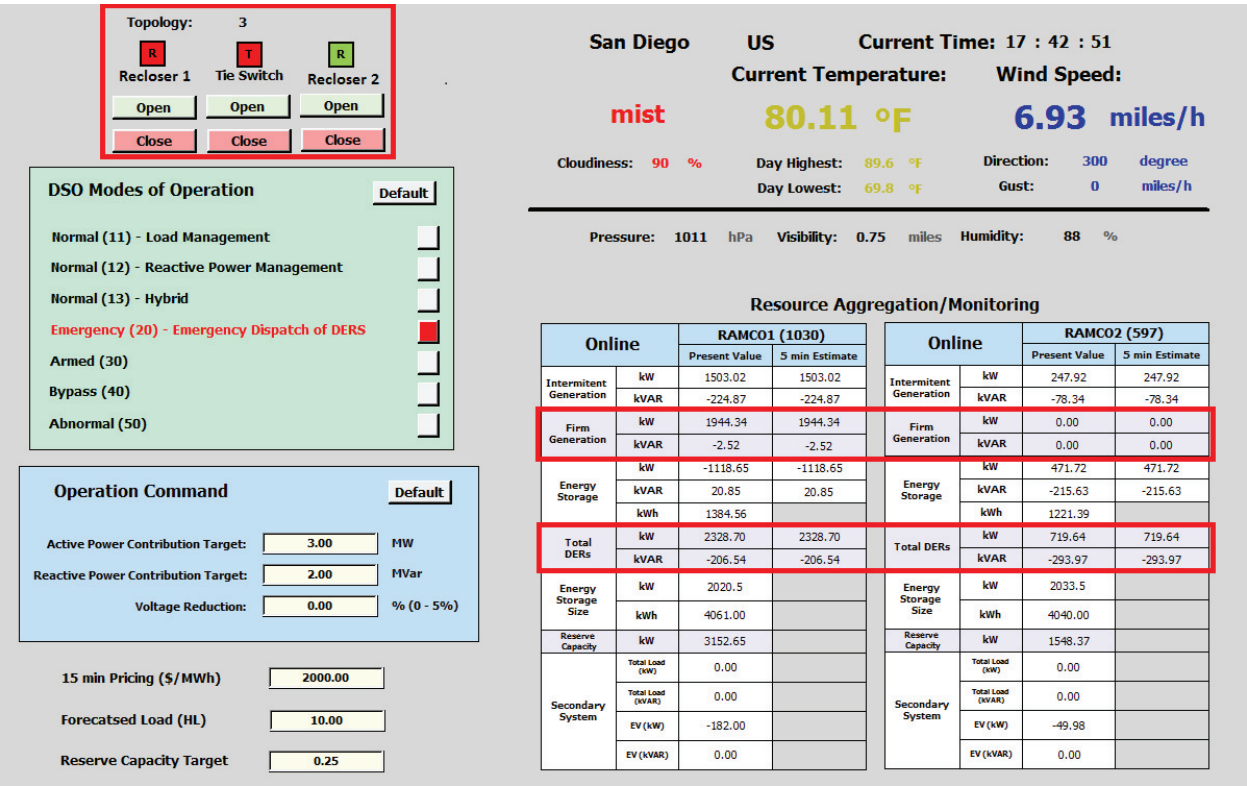
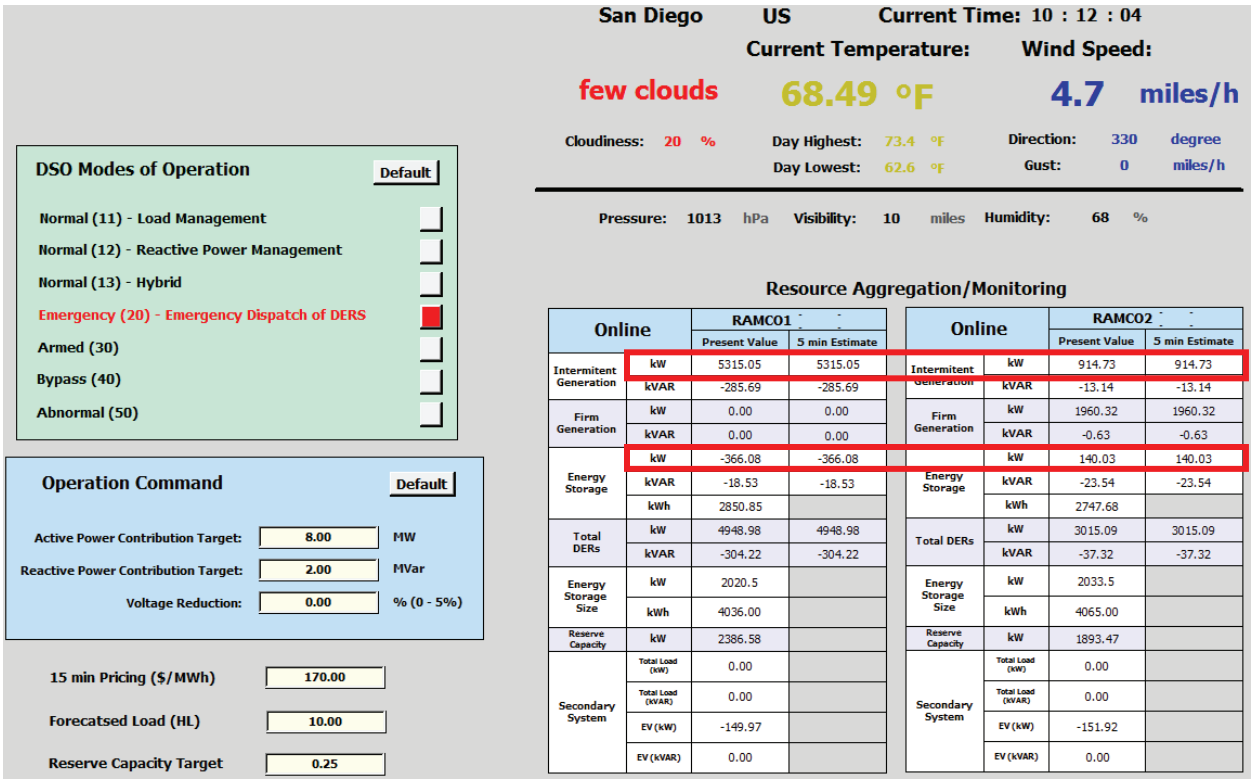


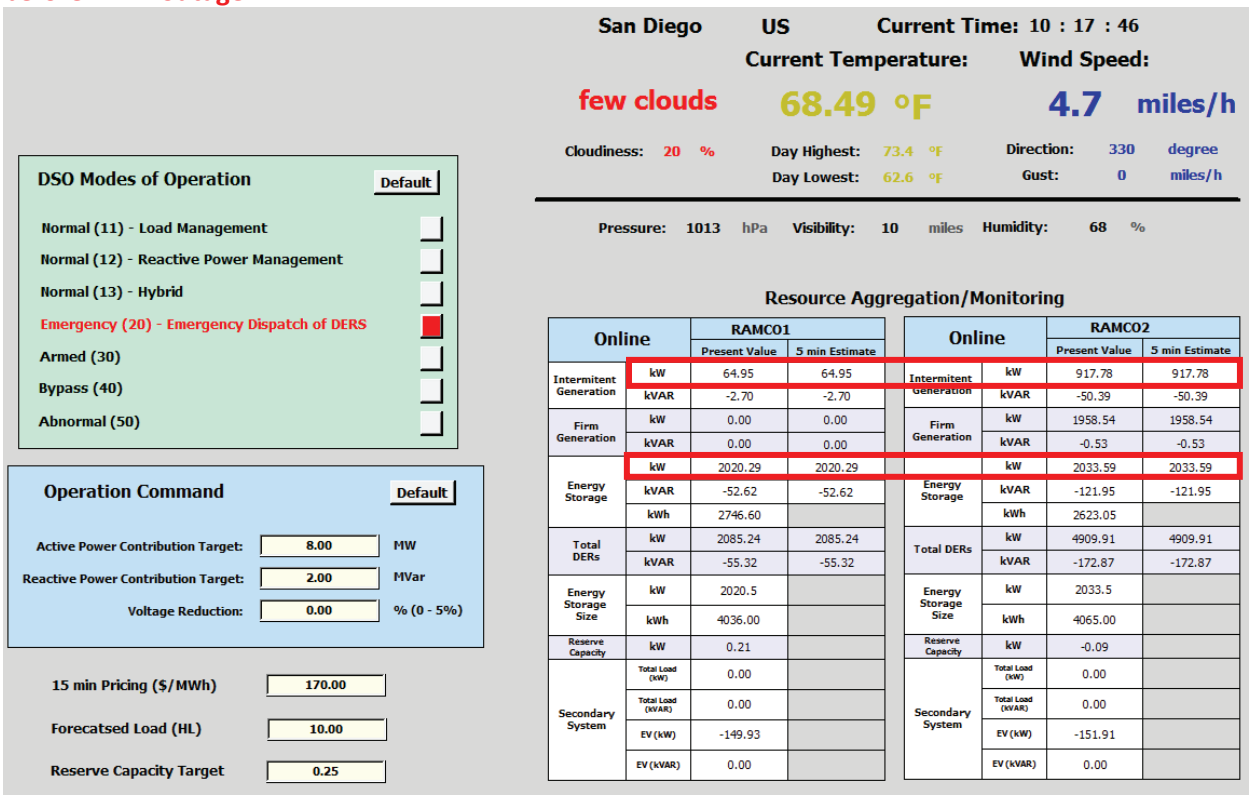
Figure 8-73. DSO HMI when the Circuit Topology changes from 1 to 3 in case 2-5

8.4.2.6 Case 2-6: Test when PV11 is suddenly tripped (Start with DSO Contribution Target = 4MW, PV Profile = 0.85p.u., BESS SOC=60%)

The purpose of this test case is to verify the performance of demonstration system in response to the sudden trip of large DERs in the RAMCO regions. For this purpose, the large PV system in RAMCO1 is suddenly tripped to verify the reaction of RAMCO1 and RAMCO2 under this condition. The control center HMI, RAMCO 1 and 2 HMIs, and RAMCO 1 and 2 power setpoint tracking graphs are shown in Figure 8-74 to Figure 8-78. As seen in these figures, after the PV11 is outaged, DSO sends updated targets to RAMCOs and RAMCOs are forced to utilize batteries to compensate for the shortage of generation caused by PV11 outage.

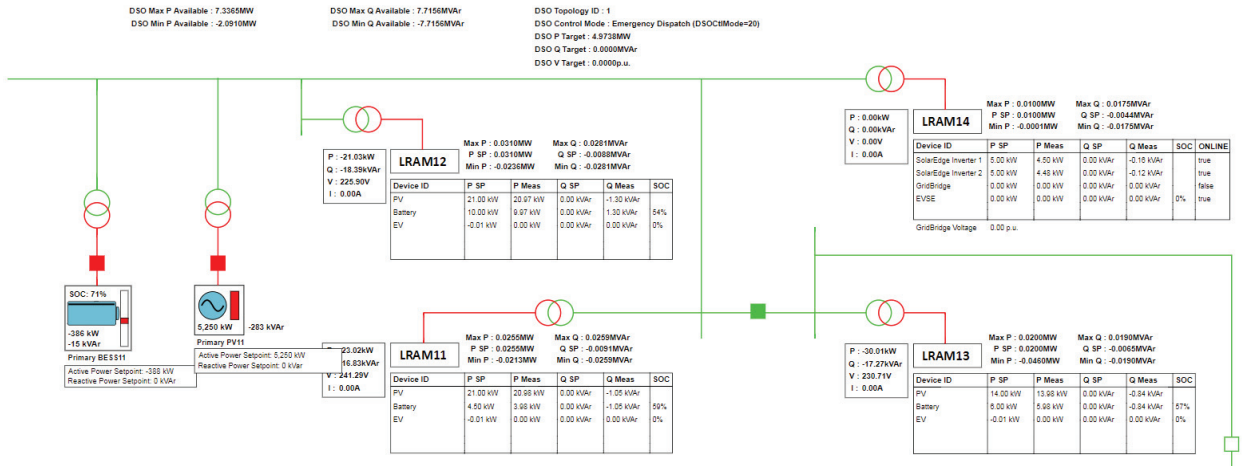


before PV11 outage

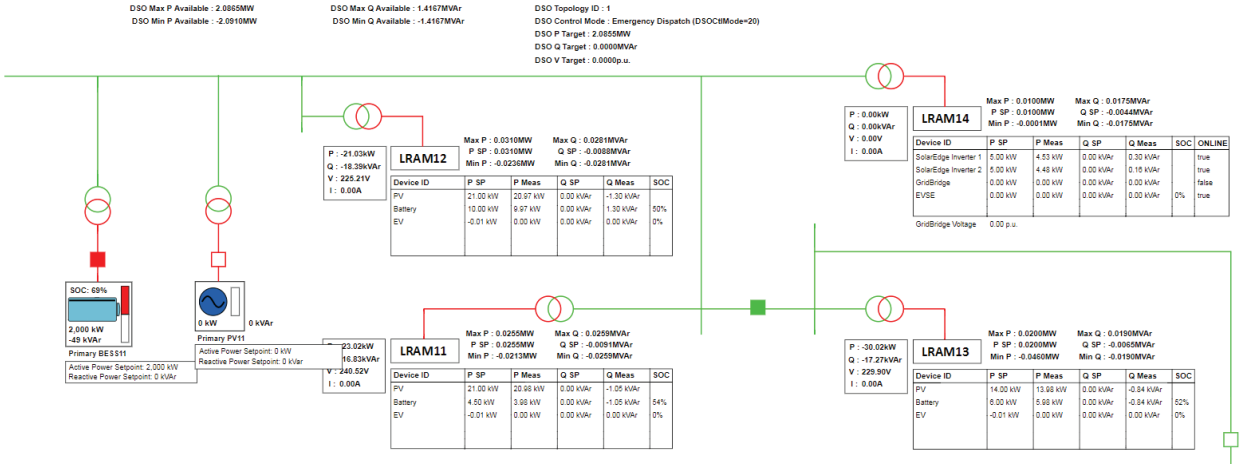


after PV11 outage

Figure 8-74. DSO HMI before and after PV11 outage in case 2-6

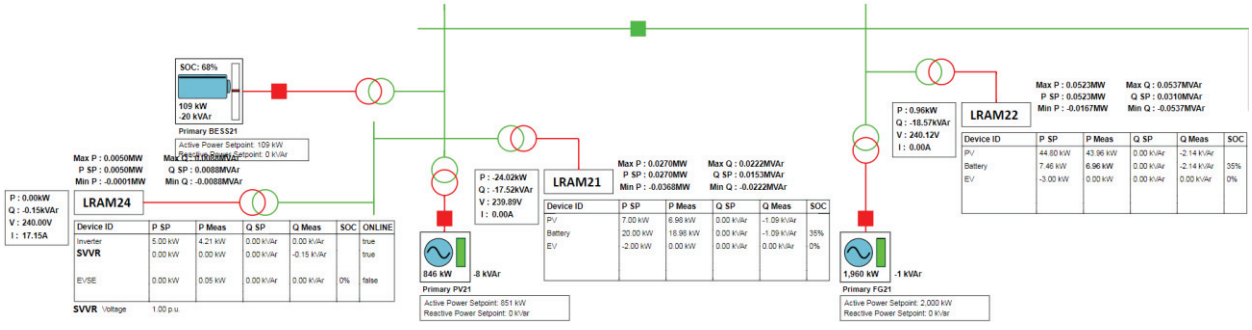


before PV11 outage

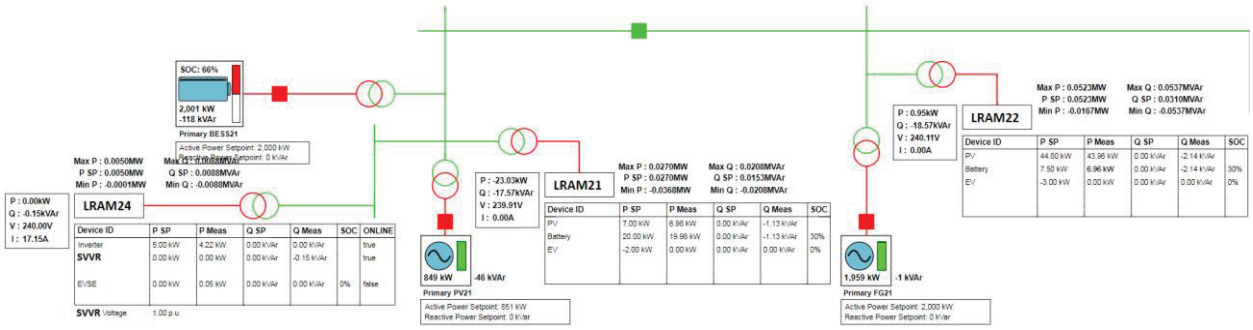


after PV11 outage

Figure 8-75. RAMCO 1 HMI before and after PV11 outage in case 2-6



before PV11 outage



after PV11 outage

Figure 8-76. RAMCO 2 HMI before and after PV11 outage in case 2-6

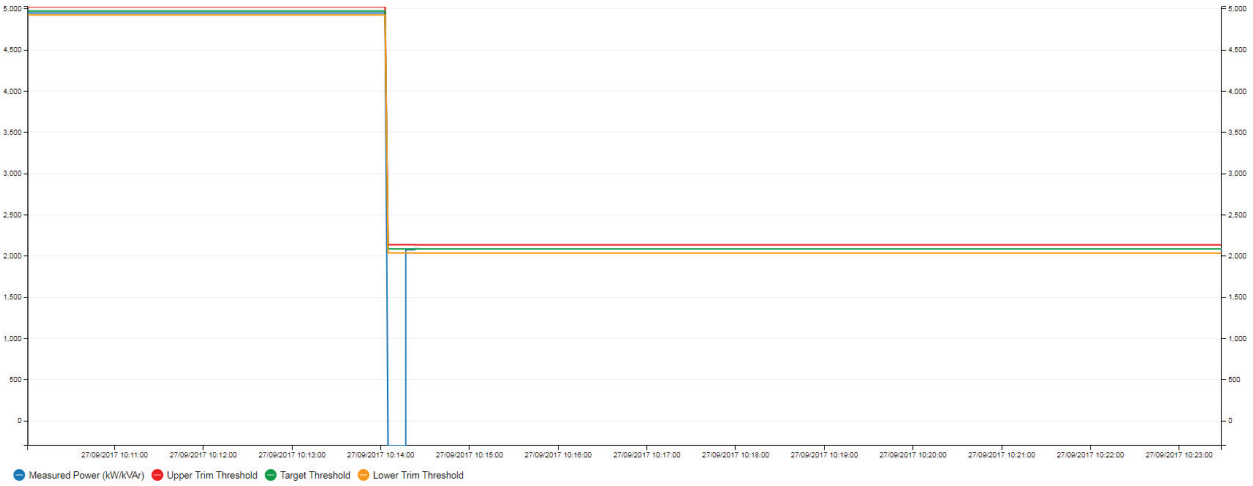


Figure 8-77. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 2-6

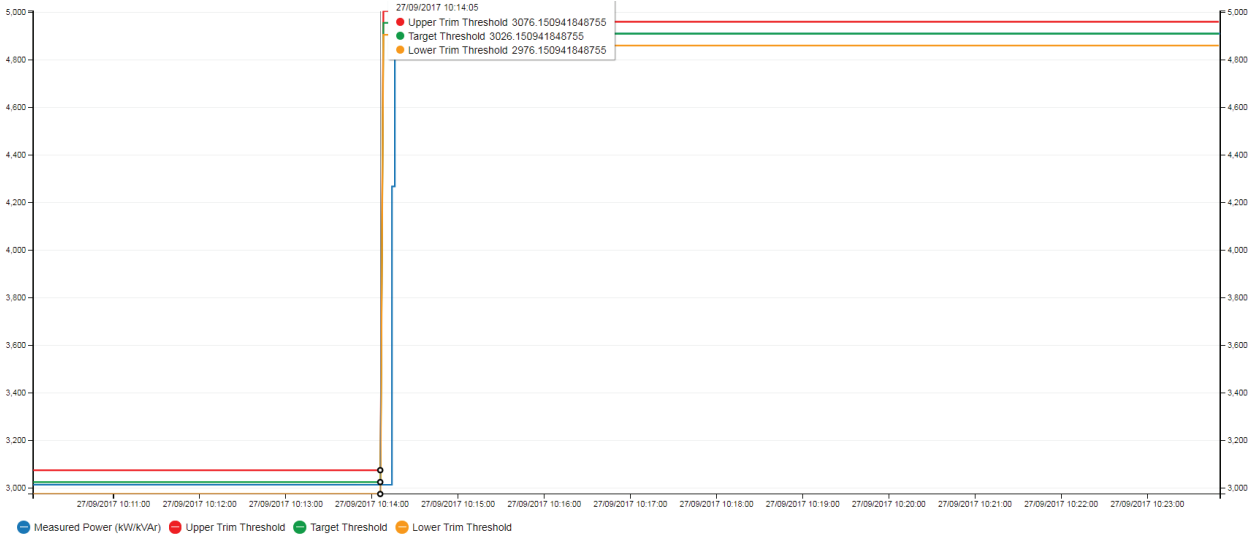
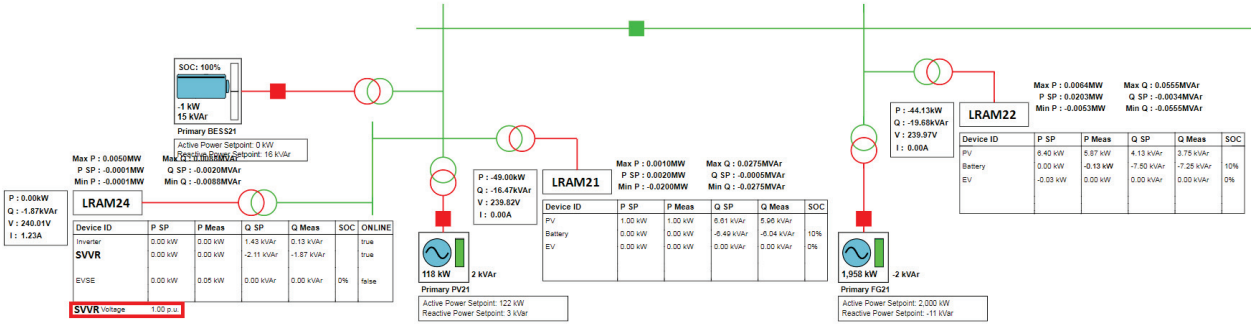


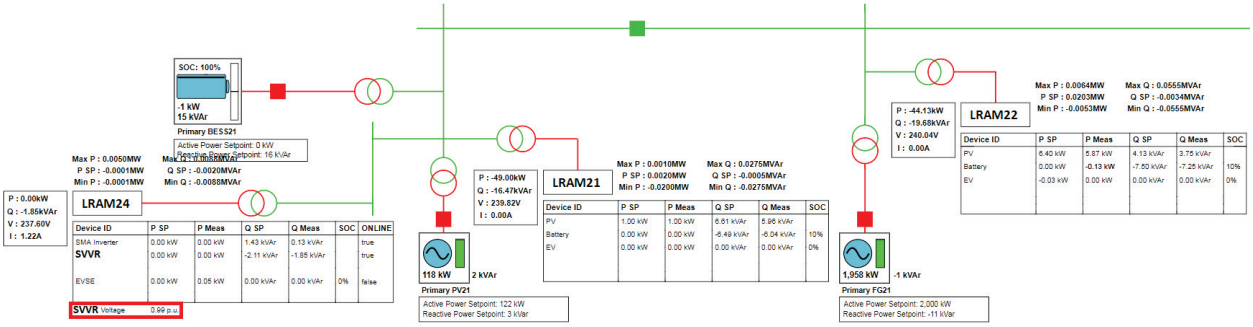
Figure 8-78. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 2-6

8.4.3 Use Case 3: Reactive Power Management

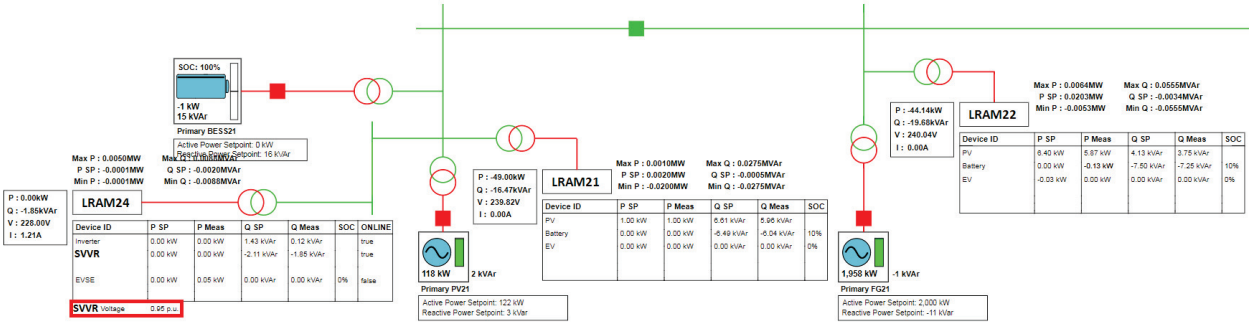
Table 2-9 lists the Use Case 3 test cases. The results for Case 3-1 were discussed in Section 3.1.4. Herein, the results for Case 3-2 are provided. The purpose of this test case is to verify the performance of the demonstration system for the purpose of secondary Volt/VAr control. DSO initially sets the reactive power and voltage reduction targets as zero. Then, the voltage reduction target is changed to 1% and 5% into two consecutive steps. Finally, the reactive power target changes to 2 MVAr while the voltage reduction target remains at 5%. The RAMCO2 (RAMCO2 includes secondary Volt/VAr regulator) HMI is shown in Figure 8-79. As seen, as the voltage reduction in DSO is updated, the secondary Volt/VAr regulator under RAMCO2 gets the updated voltage target and regulates the secondary system voltage accordingly. Additionally, Figure 8-80 and Figure 8-81 verify that RAMCO1 and RAMCO2 successfully follow the reactive power targets updates by DSO. As seen, once the DSO reactive power target increases to 2 MVAr, DSO updates the individual reactive power targets for each RAMCO and RAMCOs respond to the new targets in a timely manner.



when voltage reduction target = 0%



when voltage reduction target = 1%



when voltage reduction target = 5%

Figure 8-79. RAMCO 2 HMI in case 3-2

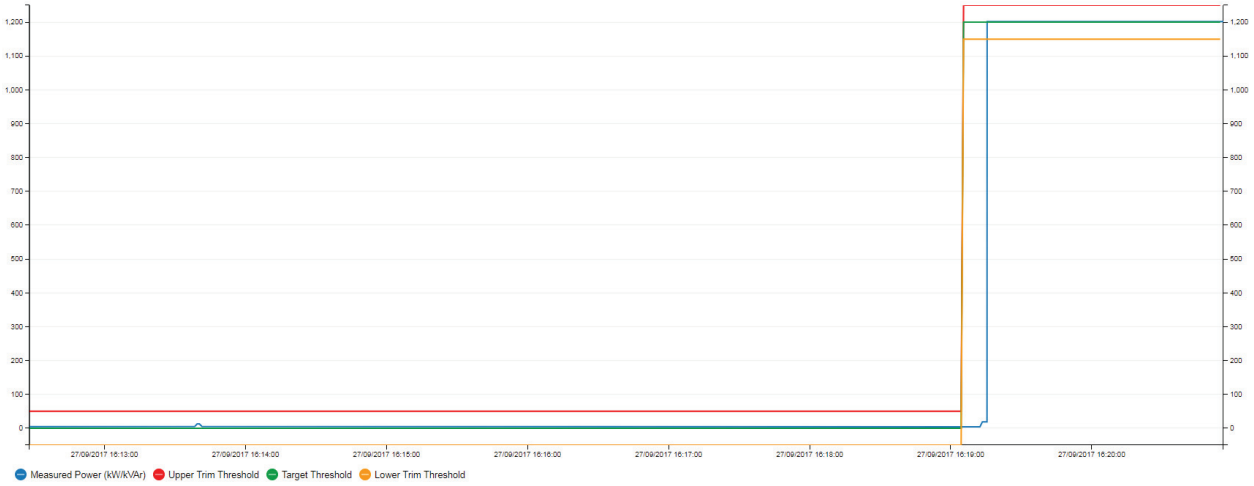


Figure 8-80. RAMCO 1 HMI: Plot for RAMCO 1 power setpoint in case 3-2

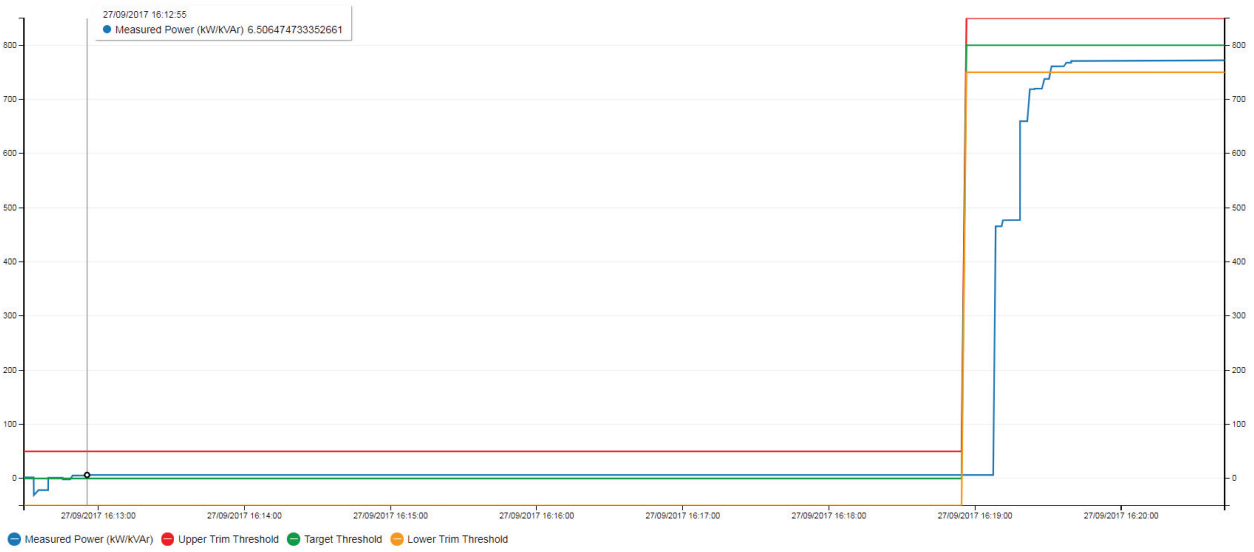


Figure 8-81. RAMCO 2 HMI: Plot for RAMCO 2 power setpoint in case 3-2

EPIC Final Report

Program	**Electric Program Investment Charge (EPIC)**
Administrator	**San Diego Gas & Electric Company**
Project Number	**EPIC-2, Project 5**
Project Name	**Integration of Customer Systems into Electric Utility Infrastructure**
Date	**December 31, 2017**

Attribution

This comprehensive final report documents the work done in EPIC-2, Project 5.

The project team that contributed to the project definition, execution, and reporting included the following individuals, listed alphabetically by last name.

Internal SDG&E Staff:

Michael Espinoza
Frank Goodman
Kyle Kewley
Zoltan Kertay
Iman Mazhari
William O'Brien
Prajwal Raval
Subburaman Sankaran
Marvin Zavala-Iraheta

Quanta Technology:
Shadi Chuangpishit
Farid Katiraei
Dino Lelic
Baharak Soltani
Mehrdad Yazdanian

Executive Summary

This report outlines the work performed under EPIC-2, Project 5 on Integration of Customer Systems into Electric Utility Infrastructure.

Project Objective and Focus:
The primary objective of EPIC-2, Project 5 was to investigate and address the evolving gateway between customers and utilities to facilitate increase in reliable deployment of clean energy technologies to support distribution systems.

More specifically, the project focus was on performing pre-commercial demonstration of advanced monitoring schemes, root-cause analysis tools, and assessment methodologies for safe and reliable integration and interoperability of customer systems with the distribution system to improve power system operations and thereby increase ratepayer satisfaction and benefits.

Project Approach:
At the early stage of the project work, the project team held a series of meetings and fact finding workshops with various stakeholders from the operation and engineering departments within SDG&E. The main purpose of these sessions was to assess the present stage of monitoring and control system capabilities and to investigate gaps in existing tools and approaches (such as capturing and alarming of fast changing power system phenomena). In parallel, a survey of customer systems and technologies that are being deployed or expected to be integrated into the SDG&E distribution systems was performed. The survey targeted common technologies and customer initiatives to determine potential impact of those technologies on operation practices and integrity of the system.

The outcome of the above investigation and information gathering activities was used to develop functional requirement documents and to describe system specifications for control and monitoring schemes, based on data from phasor measurement units (PMU) in the context of Advanced SCADA Devices (ASD). The new requirements were discussed with both field/substation engineers and distribution operators to ensure they meet the day-to-day system operation needs. A combination of simulated data, historical data, and real-world data streaming, as applicable, was used to calculate indices and validate the analytical methods. Based on the demonstration results, dashboards and requirement documents were revised to reflect the finally agreed list of performance indices and data analytics that would be incorporated in the visualization tool and/or applied automatically in the real-time data processing.

Key Findings and Accomplishments:
The project demonstrated new technologies and analysis methods for monitoring, visualization, and root-cause analysis of distribution systems by using various measurement techniques, data sources and integrating them in one platform to provide a unique monitoring and visualization user experience.

The key system capabilities that were successfully demonstrated and validated were:

- Being able to monitor distribution assets in the field (outside of substations) in real-time, based on measurements received from PMUs, the AMI system, power quality measurement devices, and the SCADA system. The real-time data enabled power quality impact investigations.
- Being able to tap into historical data collected to playback and investigate events over extended periods of time as selected and required by an operator or an engineer. This approach resolved

major issues in previous systems dues to lack of proper time synchronization and difficulty of alignment of the data points from various devices.

- Providing a set of tools for pre/post event analysis based on various data types and sources; this feature was shown to be very effective for root cause analysis, training of operators and engineers, and assessment of operation and design procedures for new technologies and approaches.

As part of the demonstration, it was shown that there are many monitoring features and analysis capabilities that can be added to existing systems to greatly support the needs of operation and engineering users. New capabilities are essential for evaluating system performance and analyzing dynamic events associated with distributed energy resources (DER) and customer-introduced technologies. It was also found that there is a major need for introducing uniformly defined performance indices, monitoring features and power quality indices directly related to assessment of emerging customer technologies, beyond the capabilities of conventional SCADA systems.

Recommendations and Next Steps:

Key recommendations are:

- It is recommended to further validate the use of performance indices introduced in the project and further expand the list, based on proposing new use cases. The project introduced a series of monitoring parameters, operation indicators, and performance indices that can be utilized by system operators and engineers to assess the status of the system, identify the root causes of events, and make informed decisions.
- It is recommended to explore the applications of proposed system indicators and visualization dashboards developed in this project with other stakeholders beyond just distribution planners, protection engineers and system operators. The monitoring approaches have potential to provide detailed data and assessment means for groups such as reliability, substation engineering and automation engineers. Some aspects of the monitoring parameters and indices introduced in this project were unique (such as field total harmonic distortion (THD) measurements and/or use of phase angle in automatic load transfer schemes) and were proven to be very effective in detecting and unfolding the nature of specific fast dynamic events caused by new technologies. However, changes in operating procedures and distribution system standards will be required to bring those features to the real-world applications.
- This project evaluated several new methods of utilizing PMU data and functionalities offered with synchronized data streaming, including the use of analog and digital data transfer channels to monitor and transfer locally measured system parameters such as THD and tap counts. These features are expected to become more beneficial and effective in distribution systems. It is recommended to conduct a business case analysis for the new PMU data applications.

As a next step, it is recommended to provide training on the monitoring and analytical feature of the project to several distribution system operators and field engineers that are involved in day-to-day operation and root-cause analysis of the event to further gather their feedback and to validate the use of performance metrics. The additional discussions will also help develop a strategy and technology roadmap to bring various aspects of monitoring and visualization technologies introduced in this project into production level. This roadmap should address the improvement of the existing platform and application and development of new applications, infrastructure and procedures to bring it to operations and the control room, and to streamline its use by engineering and planning groups.

Table of Contents

EXECUTIVE SUMMARY ..... **III**

1 INTRODUCTION **1**

1.1 Project Objective 1

1.2 Issues/Problems Being Addressed 1

1.3 Project Approach 3

1.4 Major tasks, Milestones Achieved and Deliverables Produced 3

2 SYSTEM REQUIREMENTS AND EVALUATION **11**

2.1 Survey of Customer Systems and Their Impact on the Distribution Systems 11

2.2 Baseline Evaluation and System Characterization for Potential Targeted Circuits 17

2.3 Use Case Development 31

2.4 System Monitoring, Visualization and Analytical Application Requirements 31

2.5 Development of Monitoring, Control and Operation Practices in Support of Customer Installations 43

2.6 Demo System Setup and Customer System Integration 80

3 PRE-COMMERCIAL DEMONSTRATION RESULTS WITH FIELD DATA **85**

3.1 PI Coresight Screens 85

3.2 Real-time measurement examples 93

3.3 Visualization displays on the GIS map 96

3.4 Power quality monitoring examples 103

3.5 Key performance indices monitoring 105

4 PRE-COMMERCIAL DEMONSTRATION RESULTS BASED ON LABORATORY SETUP **106**

4.1 Circuit 1 Test Results 106

4.2 Circuit 2 and Circuit 3 Test Results 139

4.3 Use Case 6 (Circuit 4) – Water Treatment Facility Monitoring and Reactive Power Management 164

5 CONCLUSIONS AND FINDINGS **168**

5.1 Conclusions and Findings Related to Assessment of Integration and Monitoring Tools 168

5.2 Findings Related to the Demonstrated Technology 171

6 RECOMMENDATIONS AND NEXT STEPS 173

6.1 Recommended next steps 173

6.2 Adaptability to other utilities and/or the broader industry....174

7 METRICS AND VALUE PROPOSITION 175

7.1 Metrics 175

7.2 Value Proposition....176

8 REFERENCES 178

List of Figures

Figure 1-1. Project tasks structure 4

Figure 2-1. Existing PMU Locations on Circuit 1 and identifying monitoring areas with amount of PV 22

Figure 2-2. The single line diagram of a selected Circuit 1 with PMU locations (existing and recommended) 30

Figure 2-3. High-Level System Diagram and Data Flow for Visualization and Analytics Applications 35

Figure 2-4. Real-time RTDS View of the Distribution Circuit Used for Device Tests 46

Figure 2-5. PMU Testbed Setup layout 47

Figure 2-6. PMU Test Setup at the ITF lab....48

Figure 2-7. TVE, FE, and RFE Comparison for Nominal Voltage (Case 1-1-1) 50

Figure 2-8. TVE, FE, and RFE Comparison for 50% of the Nominal Voltage (Case 1-1-2)....51

Figure 2-9. TVE, FE, RFE for 130% of Nominal Voltage (Case 1-1-3) 52

Figure 2-10. TVE and Magnitude of the Positive Sequence Subsequent to the Disconnection of Phase B (Case 1-1-4) 53

Figure 2-11. TVE and Magnitude of the Negative Sequence Subsequent to the Disconnection of Phase B (Case 1-1-4) 54

Figure 2-12. TVE and Magnitude of the Negative Sequence (Case 1-1-7) 55

Figure 2-13. TVE and Magnitude of the Negative Sequence (Case 1-1-7) 56

Figure 2-14. Frequency, FE, RFE, and Angle Subsequent to the Step Change of Frequency from 59.7 Hz to 60 Hz (Case 1-2-2) 57

Figure 2-15. Positive Sequence Magnitude Subsequent to the Step Change of Frequency from 59.7 Hz to 60 Hz (Case 1-1-2) 58

Figure 2-16. Frequency, FE, RFE, and Angle Subsequent to the Step Change of Frequency from 61 Hz to 60 Hz (Case 1-2-5) 59

Figure 2-17. Positive Sequence Magnitude Subsequent to the Step Change of Frequency from 61 Hz to 60 Hz (Case 1-2-5) 60

Figure 2-18. TVE and FE during the Injection of 3% Magnitude of 5th Harmonic (Case 1-3-1) 61

Figure 2-19. TVE and FE during the Injection of 5% Magnitude of 5th Harmonic (Case 1-3-2) 62

Figure 2-20. TVE and FE during the Injection of 10% Magnitude of 5th Harmonic (Case 1-3-3) 63

Figure 2-21. TVE and FE during the Injection of Multiple Harmonics (Case 1-3-7) 64

Figure 2-22. Positive Sequence Magnitude and TVE Subsequent to Voltage Changes (Case 2-1-1) 65

Figure 2-23. Zoom-In Plot of the Positive Sequence Magnitude (Case 2-1-1) 66

Figure 2-24. Positive Sequence Magnitude and TVE of Voltage Subsequent to Load Changes (Case 2-1-2) 67

Figure 2-25. TVE, Phase, and Magnitude of the Positive Sequence Subsequent to Phase Angle Changes (Case 2-1-3). 68

Figure 2-26. Zoom-In Plot of the Phase and Magnitude of the Positive Sequence (Case 2-1-3) 69

Figure 2-27. Frequency, TVE, and RFE Subsequent to Frequency Ramp (Case 2-2-1) 70

Figure 2-28. Frequency, TVE, and RFE Subsequent to Frequency Ramp (Case 2-2-2) 71

Figure 2-29. TVE and FE Subsequent to Capacitor Switching (Case 2-3-1) 72

Figure 2-30. TVE of Voltage and Angle Subsequent to Single Line-to-Ground Fault (case 2-4-1) 73

Figure 2-31. TVE and angle subsequent to line-to-line fault (2-4-2). 74

Figure 2-32. FE and angle subsequent to line-to-line fault (2-4-5). 75

Figure 2-33. TVE, angle, and FE Subsequent to 3-Phase Fault (Case 2-4-6) 76

Figure 2-34. Voltage Magnitude during the Fault (case 2-4-6) 77

Figure 2-35. High level architecture for of the demonstration system 81

Figure 2-36. High level system architecture for integration and visualization of field data and information 82

Figure 2-37. Main visualization system implementation dashboard 83

Figure 2-38. Test System Single Line Diagram for laboratory testing 84

Figure 3-1. An example of a dashboard that utilize historical data base 85

Figure 3-2. Monitoring of voltage unbalance factor 86
Figure 3-3. THD measured at various locations of selected circuits (all three phase); source: SCADA 86
Figure 3-4. Harmonic distortion (time frame) at one of the switches on circuit 1 (obtained from SCADA) 87
Figure 3-5: Voltage difference (in pu) on Circuit 1 87
Figure 3-6. Active and reactive power flow for Circuit 1 88
Figure 3-7. Thermal loading asset monitoring on Main branch, Branch #1 and Branch #2 of the Circuit 1 89
Figure 3-8. Thermal loading asset monitoring for Circuits 2, 3 and 4 90
Figure 3-9. Active/Reactive power along Circuit 1 91
Figure 3-10. Overloading bar chart display for Circuit 1 based on PMU data 91
Figure 3-11. Tabular reporting of device loadings for Circuit 1 based on PMU data 92
Figure 3-12. Voltage deviations (from base voltage) in percentage along the selected circuit length (circuit 1) 93
Figure 3-13. Voltage phase angle in phasor time domain 93
Figure 3-14. Polar version of real time monitoring of voltage phase angles 94
Figure 3-15. Voltage magnitude of the Circuit 1 PMUs (standard view) 95
Figure 3-16. Voltage phase angle of the Circuit 1 PMUs (standard view) 95
Figure 3-17. Numeric display for selected PMUs 96
Figure 3-18. Total active power generated by PVs 97
Figure 3-19. Real time monitoring of customer loads 97
Figure 3-20. Monitoring of Tap changer status (left) and tap positions change over time (right) 98
Figure 3-21. Real-time monitoring of cap banks status 98
Figure 3-22. Demonstration of KPI monitoring 99
Figure 3-23. Sample of the captured voltage sag versus the acceptable thresholds and durations 100
Figure 3-24. Sample of captured voltage swell versus 100
Figure 3-25. Frequency violation monitoring 101
Figure 3-26. Power sensitivity trending for Circuit 1 102
Figure 3-27. Voltage monitoring demonstration – Use Case 1 103
Figure 3-28. Monitoring of odd/even harmonics 104

Figure 3-29. Visualization of total harmonic distortion (THD) on one of the selected circuits 104

Figure 3-30. Illustration of Flicker factor monitoring and visualization 105

Figure 4-1. Single Line Diagram and PMU Locations of the Circuit 1 107

Figure 4-2. Magnitude of Positive Sequence Voltages.....109

Figure 4-3. Magnitude of Positive Sequence Currents.....109

Figure 4-4. Phase Angles of Positive Sequence Voltages 110

Figure 4-5. Phase Angles of Positive Sequence Currents 111

Figure 4-6. Active Powers.....111

Figure 4-7. Reactive Powers.....112

Figure 4-8. Apparent Powers 112

Figure 4-9. Calculated Delta V (pu) in Automation Controller 113

Figure 4-10. Tap positions streamed through the analog value 113

Figure 4-11. Active Powers during Low Loading without PV and with a Tie Switch Opened.....114

Figure 4-12. Phase Angles of the Two Sides of the 520-1048 during Low Loading without PV. 115

Figure 4-13. Active Powers after the Connection of the Maximum PV. 116

Figure 4-14. Phase Angles for the Two Sides of the 520-1048 after the Connection of the Maximum PV. 116

Figure 4-15. Active Powers after Closing 520-1048 117

Figure 4-16. Phase Angles for the Two Sides of the 520-1048 after Closing 520-1048 117

Figure 4-17. Active powers after the load transfer 118

Figure 4-18. Magnitude of the Positive Voltages during the Load Transfer (changes are shown by arrows) 119

Figure 4-19. Active Powers during the Load Transfer (time of change is shown by the arrow) 119

Figure 4-20. Tap Positions during the Load Transfer 120

Figure 4-21. Reactive Powers during the Load Transfer 120

Figure 4-22. Magnitude of Positive Sequence Voltages Subsequent to Capacitor Switching.....121

Figure 4-23. Magnitude of Positive Sequence Currents Subsequent to Capacitor Switching.....122

Figure 4-24. Reactive Powers Subsequent to Capacitor Switching On and Off 123

Figure 4-25. Tap Positions Subsequent to Capacitor Switching 123

Figure 4-26. Magnitude of Positive Sequence Voltages Subsequent to Adding Harmonic Voltage 124
Figure 4-27. THDs Captured by Different PMUs 125
Figure 4-28. Magnitude of Positive Sequence Voltages.....126
Figure 4-29. Demonstration of Changes in Alpha across the Branch without PV 127
Figure 4-30. Demonstration of Changes in Alpha across the Branch with PV 127
Figure 4-31. Change in Beta across the Branch without PV.....128
Figure 4-32. Change in Beta across the Branch with PV 128
Figure 4-33. Magnitude of Positive Sequence Voltages.....129
Figure 4-34. Flickers Subsequent to the Capacitor Switching 130
Figure 4-35. Magnitude of the Positive Sequence Voltages 132
Figure 4-36. Magnitude of Positive Sequence Currents.....132
Figure 4-37. Extreme Voltage Sag Statistics.....133
Figure 4-38. Magnitude of Positive Sequence Voltages.....134
Figure 4-39. Magnitude of Positive Sequence Currents.....134
Figure 4-40. Extreme Voltage Sag Statistics.....135
Figure 4-41. Magnitude of Positive Sequence Voltages.....136
Figure 4-42. Magnitude of Positive Sequence Currents.....136
Figure 4-43. Magnitude of Positive Sequence Voltages.....137
Figure 4-44. Magnitude of Positive Sequence Currents.....138
Figure 4-45. Moderate Voltage Sag Statistics 138
Figure 4-46. Single Line Diagram and PMU Locations of Circuit 2 and Circuit 3 140
Figure 4-47. Magnitude of Positive Sequence Voltages.....141
Figure 4-48. Magnitude of Positive Sequence Currents.....142
Figure 4-49. Active Powers.....142
Figure 4-50. Reactive Powers.....143
Figure 4-51. Active Powers of Different PMUs 144
Figure 4-52. Active Powers of Different PMUs Subsequent to the Closing of the Tie Switch.....144

Figure 4-53. Active Powers of Different PMUs Subsequent to the Load Transfer 145
Figure 4-54. Active Powers of Different PMUs Subsequent to the Load Shedding 145
Figure 4-55. Magnitude of Positive Sequence Voltages, Capturing Exact Time of Load Transfer 146
Figure 4-56. Magnitude of Positive Sequence Currents 146
Figure 4-57. Active Powers 147
Figure 4-58. Reactive Powers 147
Figure 4-59. Active Powers of Different PMUs 148
Figure 4-60. Active Powers of Different PMUs Subsequent to Turning on the Generators 149
Figure 4-61. Magnitude of Positive Sequence Voltages during Islanding Process 149
Figure 4-62. Active Powers during Islanding Process 150
Figure 4-63. Frequency Changes during Islanding Process 150
Figure 4-64. Phase Angle Changes during Islanding Process 151
Figure 4-65. Active Powers of Different PMUs Subsequent to Turning on the Generators 152
Figure 4-66. Active Powers of Different PMUs after Load Shedding 152
Figure 4-67. Magnitude of the Positive Sequence Voltages 153
Figure 4-68. Active Powers 153
Figure 4-69. Reactive Powers 154
Figure 4-70. Phase Angle Changes during Islanding Process 154
Figure 4-71. Magnitude of the Positive Sequence Voltages 155
Figure 4-72. Unbalanced Factors 156
Figure 4-73. Magnitude of Positive Sequence Voltages 156
Figure 4-74. Unbalance Factors 157
Figure 4-75. Magnitude of Positive Sequence Voltages 157
Figure 4-76. Magnitude of Positive Sequence Currents 158
Figure 4-77. Active Powers 158
Figure 4-78. Reactive Powers 159
Figure 4-79. Magnitude of Positive Sequence Voltages 160

Figure 4-80. Real Power of PMU 10 160
Figure 4-81. Real Power of PMU 2 161
Figure 4-82. Real Power of PMU 3 161
Figure 4-83. Magnitude of the Positive Sequence Voltages 162
Figure 4-84. Real Powers of PMU 4 163
Figure 4-85. Reactive Powers of PMU 4 163
Figure 4-86. Circuit 4 Topology and Location of Line Monitoring (LM) Devices 164
Figure 4-87. A High-level Sequence Diagram for Reactive Power Management 166
Figure 4-88. Voltage, Line Loss, Reactive Power, and Real Power 166
Figure 4-89. Voltage, Line Loss, Reactive Power, and Real Power 167

List of Tables

Table 2-1. Key Performance Indices Considered on the Project 14
Table 2-2. Summary of New Technologies, Their Impact, and Parameters Utilized to Characterize Impacts 16
Table 2-3. Summary of Selected Circuit Status 18
Table 2-4. Circuit 1 Loading Condition 18
Table 2-5. Thermal Rating of Major Equipment on Circuit 1 (SDG&E data from SynerGI model) 20
Table 2-6. Thermal Rating of Conductors along Circuit 1 (SDG&E data from SynerGI model) 21
Table 2-7. List of Potential PMU Application in Distribution Systems 25
Table 2-8. Recommended Locations for PMUs for Various Classes of Applications 26
Table 2-9. Recommended Location of PMU Installations for Analyzed Circuits 28
Table 2-10. Measurement Parameters of Monitoring Schemes 36
Table 2-11. Indicators for Visualizing Data 37
Table 2-12. Key Performance Indices for Visualization of Field Monitoring 39
Table 2-13. List of applications based on use cases 40
Table 2-14. Available Phasors in Different PMUs 77

Table 2-15. Available Analog and Digital Data Streams in Different PMUs 78

Table 4-1: Interconnection System Default Response to Abnormal Voltages [IEEE 1547a] 131

Table 4-2: Interconnection System Default Response to Abnormal Frequencies [IEEE 1457a] 131

Table 7-1: Metrics and Value Propositions 175

List of Acronyms and Abbreviations

ACSR	Aluminium conductor steel-reinforced cable
AL	Aluminium
AMI	Advanced metering Infrastructure
ASD	Advanced SCADA Devices
CB	Circuit Breaker
CBC	Circuit Breaker
CBEMA	Computer Business Equipment Manufacturers Association
DAMD	Distribution Asset Operation monitoring and Diagnostics
DCI	Daily Clearness Index
DER	Distributed energy resources
DERICC	DER Interconnection Compliance
DMS	Distribution Management System
DQV-FM	Data Quality Validation of Field Measurement
DUT	Device Under Test
DVC	Dynamic Voltage Control
DVI	Daily Variability Index
DVR	Dynamic Voltage Regulator
EOLD	Equipment Overloading Detection
EPIC	Electric Program Investment Charge
FE	Frequency Error
FLISR	Fault Location, Isolation and Service Restoration
GIS	Geographical Information System
GUI	Graphic User Interface
HW	Hardware
IEC	International Electro technical Commission
IEEE	Institute of Electrical and Electronics Engineers
ITF	Integrated Test Facility
ITIC	Information Technology Industry Council Curve
IVVC	Integrated Volt VAR Control
KPI	Key performance indices
KW	Kilowatt
LGU	Local Generation Usage
LICFM	Large Industrial Customer Facility Monitoring
LTC	Load Tap Changer
ms	Milliseconds
MVAr	Mega Volt-Ampere Reactive

MW	Megawatt
NIST standard	National Institute of Standards and Technology
NMS	Network Management System
PDC	Phasor Data Concentrator
PMU	Phasor Measurement Units
PQ	Power Quality
pu	Perunit
PV	Photovoltaic
REC	Reclosers
RFE	Rate of Change of Frequency Error
RMS	Root Mean Square
ROCOF	Rate of Change of Frequency
RPM	Reactive Power Management
RTAC	Real-Time Automation Controller
RTDS	Real Time Digital Simulator
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SARFI	System Average RMS Variation Frequency Index
SCADA	Supervisory Control and Data Acquisition
SDG&E	San Diego Gas & Electric
SDGE	San Diego Gas & Electric
SDO	Standards Development Organizations
SEL	Schweitzer Engineering Laboratories
SEMI	Semiconductor Equipment and Materials Institute
TDD	Total Demand Distortion
THD	Total Harmonic Distortion
TVE	Total Vector Error
UPS	Uninterruptable Power System
VAr	Volt-Ampere Reactive
VFD	Variable-Frequency Drive
VPFM	Voltage and Power Flow Monitoring
VR	Voltage Regulators
WTP	Water Treatment Plant

1 Introduction

1.1 Project Objective

The primary objective of EPIC-2, Project 5 was to investigate and address the evolving gateway between customers and utilities to facilitate increase in reliable deployment of clean energy technologies to support distribution systems.

More specifically, the project focus was on performing pre-commercial demonstration of advanced monitoring schemes, root-cause analysis tools, and assessment methodologies for safe and reliable integration and interoperability of customer systems with the distribution system to improve power system operations and thereby increase ratepayer satisfaction and benefits.

To achieve the above objective, the key focus areas were:

- To demonstrate monitoring and visualization schemes for distribution operators, at higher resolutions and with more advanced functionalities as required for capturing and investigating fast dynamics in the system,
- To demonstrate integration and interoperability of customer systems with the distribution system with ability to monitor, visualize and respond to fast phenomena,
- To demonstrate monitoring systems with superior capabilities compared to conventional distribution SCADA monitoring systems, such as:
    - Higher resolutions, higher communication speed, higher bandwidth, and time stamping.
    - Combining multiple sources of data – all with common data format.
- To demonstrate advanced tools and techniques for monitoring and evaluation of customer technology integration.

In addition, the final results and observations from the pre-commercial system were used to provide recommendations for design of the next generation of advanced SCADA systems.

1.2 Issues/Problems Being Addressed

Reliable operation of modern power systems requires close monitoring of the system operating conditions. Until recently, the measurements were only provided by supervisory control and data acquisition (SCADA) system, including power flows and bus voltage magnitudes. Distribution SCADA does not cover all utility assets. As an example, line voltage regulators may not report tap positions or line voltages to SCADA. Conventional SCADA measurements are reported by exception and their time resolution is 1-2 seconds or slower (depending on communications performance and how many data points are pulled in one request).

AMI data recording only provides cumulative energy exchange data (consumption or production) and RMS voltage at 5 to 15 minute intervals at the meter level. Furthermore, AMI devices only monitor secondary systems (downstream of service transformers).

Therefore, fast dynamics and transient phenomena (such as transient switching) and almost any power quality impacts (i.e. harmonics and resonance-based instability) cannot be identified from conventional SCADA meas-

urements or AMI data. In order to address these shortcomings, an enhancement of existing technologies in the area of high-resolution monitoring, advanced visualization and fast controls will be needed to provide adequate tools for operators and system engineers to assess the fast dynamic events.

The deployment of phasor measurement units (PMUs) enables various applications with the use of synchronized measurements. A PMU installed at a node can make direct measurements of the voltage phasor of the bus and the current phasors of some or all its incoming/outgoing branches, based on the PMU available channels.

This project performed the following activities:

- Defining circuit candidate selection criteria and data gathering requirements that can facilitate project objectives in terms of design and development of the advanced monitoring, analysis and visualization
- Planning for the logistical aspects of field data gathering and building into the visualization tools
- Identifying the design and location selection requirements for possible additions to the field device population to increase observability
- Introducing data analytics, evaluation methodologies and metrics to assess the system performance in near-real time
- Laboratory testing and analysis of expected phenomena through simulations
- Evaluation of monitoring and control device capabilities and validation in the laboratory environment
- Enhancement of the visualization tools to incorporate proposed metrics and data analytics
- Preparation of test plans and determination of field conditions/durations for data gathering and demonstration
- Data analysis from the field
- Demonstration of applications and tools that can facilitate safe and reliable operation to mitigate any issue introduced by customer services
- Proposing operator control strategies for managing the circuits and customer systems via SCADA
- Demonstrating the methods through laboratory testing and/or applying in the field and gathering field measurements

In addition, the project incorporated considerations to address requirements to increase the reliability and enhance power quality of services to the customers. Some additional value-added propositions (Metrics) introduced for the project were:

- To expand distribution system control, monitoring and operation capabilities beyond conventional SCADA approaches to gain visibility and control on secondary networks
- To investigate advanced monitoring and visualization practices using high-resolution measurement and data analytics to provide tools and investigation methods for distribution system operators and engineers to capture, examine and react to fast dynamic events
- To facilitate superior customer involvement and deployment of renewable and sustainable technologies by providing the means for investigation of real-world impact of customer systems and high PV penetration cases on distribution system and utility assets
- To prepare requirements and introduced advanced tools for monitoring and visualization of the data and the results, as well as analytical applications for post-processing and performance evaluation in

close to real-time environment to support challenging work load of the system operator in new environment.

1.3 Project Approach

The preliminary part of the project covered the tasks associated with selection of project technical lead, the project team, development of project plan and selection of the contractor.

The technical part of the project was executed in two phases:

- **Phase 1** – Design pre-commercial demonstration system: in this phase of the project, a preliminary analysis was performed to evaluate the likely impacts of customer integration on distribution system operation; the system was characterized for potential targets and the system visualization and analytical applications requirements were identified. Monitoring, control and operation practices in support of customer system installations were developed and in the final stage, a demonstration system was designed.

- **Phase 2 –** Demonstrate an advanced customer integrating and monitoring system: The demo system designed in Phase 1 was implemented and integrated, and a pre-commercial demonstration was done. Based on the test results, the customer system integration was evaluated and a final report was prepared including the analysis results.

1.4 Major tasks, Milestones Achieved and Deliverables Produced

This section provides a detailed description of the work approach and methodology, and the required outcome and deliverables of each task.

The tasks associated with preliminary work were:

Preliminary Phase - Task 1 - Team Formation and Project Plan

The SDG&E EPIC program manager identified the technical lead for the project based on experience and technical expertise. Later, the internal project team was formed by identification of technical skills and expertise available within the organization. After forming the internal project team, the task to develop the project plan was given to the technical lead. The technical lead with the help of the project team wrote the project plan as per the guidance provided by the SDG&E EPIC program manager adhering to EPIC guidelines.

Preliminary Phase - Task 2 - Procurement of Contractor Services

Scope of the work was identified and written for the part of the project needed to be contracted out to engineering consulting firm. Standard company practices were followed for contractor selection.

The tasks associated with technical part of the project were divided in two phases as shown in figure below.

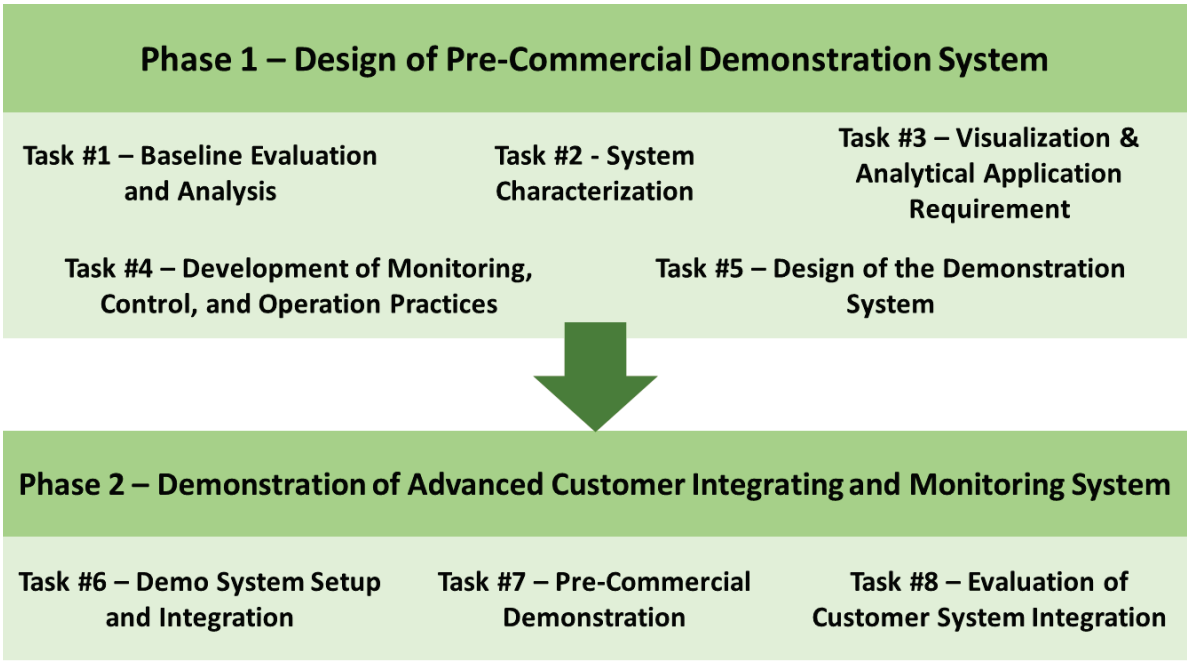


Figure 1-1. Project tasks structure

The following sections provide additional description of the technical part of the work, and details about the accomplishments with regards to the major milestones and deliverables.

1.4.1 Phase 1 – Design of pre-commercial demonstration system

Task 1 - Baseline Evaluation and Analysis

The objective of this activity was to assess the preset state of monitoring and control in distribution systems and analyze the impact of new customer technologies on the system.

A detailed list of activities performed in this task was:

- Performing a survey of customer systems and technologies that are being deployed or expected to be integrated into the SDG&E distribution systems
- Investigating impact on operation practices and integrity of the system due to new technologies and customer initiatives
- Determining the present state of the monitoring and controls, and the level of the visibility into customer systems, including:
    - Distribution SCADA measurement
    - AMI systems and data availability
    - PMU on distribution systems
    - Other sources of measurements
- Investigating the present status of PMU deployment on distribution systems at SDG&E, and select circuits with PMU and communications system in operation as the target circuits for enhanced monitoring and operation analysis. A list of criteria should has been developed for circuit/region selection. Ex-

ample factors in circuit selection were the available level of PV penetration and types of technologies deployed.

The outcome of this task was:

- Baseline review and assessment
- Preparing circuit selection criteria and list of candidate circuits for further analysis, simulation and integration.

Task 2 - System Characterization for Potential Target Circuits

The objective of this task was to evaluate data availability and system coverage from the potential target circuits. The evaluation will be used to proposed additional measurement and/or visualization capabilities to strengthen the visibility and control of the system. The main activities as part of this task were:

- Determine circuit loadings and amount of PV
- Identify the number and locations of PMU devices to determine the circuit coverage
- Prepare a circuit map showing all critical devices and customer installations
- Determine device settings and control modes
- Document any special operating procedures and circuit conditions that can benefit from enhance monitoring and near real-time controls
- Examine access to the devices and their control system connections
- Evaluate PMU data streaming and data availability, and logistic aspects of accessing data
- Examine access to non-PMU data from target circuit locations, including wideband power quality data snapshots and metrics
- Prepare a summary report on what the gaps in the measurement, monitoring and operation are when it comes to awareness and management of customer systems
- Evaluate the data streaming in to PI Historian and any other data warehouses and the linkage among databases

The outcome of this task was:

- Identification of existing data availability and gaps
- Recommendations for additional data requirements.

Task 3 - System Visualization and Analytical Applications Requirements

The task objective was to assess advanced visualization system capabilities, prepare functional specifications and identification of key needed applications and performance indices.

This task was addressed by conducting the following activities:

- Investigation of visualization methods to present the PMU data on circuit maps and to create graphical view of the system events and power quality issues based on performance indices:
    - Evaluating the capability that exists today and what needs to be developed or added to the visualization system,

- Identification of key applications (data analytics, statistical evaluation methods), and set of Key Performance Indices (KPIs) for power quality and operation performance monitoring:
    - Using simulation and/or historical data, as appropriate, to calculate indices and validate the analytical methods
    - Finalizing and documenting a list of performance indices and data analytics that will be incorporated in the visualization tool and/or applied automatically in the real-time data processing

The task outcome was:

- Visualization requirements and description of data processing applications
- Identification of key performance indices and targeted used cases.

Task 4 - Development of Monitoring, Control and Operation Practices in Support of Customer System Installations

This task objective was to propose and develop advanced monitoring and control practices that can close the gaps in the existing operation schemes to expand operator visibility beyond substations to support system impact assessments as part of the customer system integration process. The primary focus was on enhancing the system monitoring and operator's capability to characterize the system dynamics and to provide methods for fast data analysis and event diagnostics. The design incorporated all aspects of: system capabilities, monitoring devices and data capturing and post-mortem analysis. The main activities in undertaking this task were:

- Determining the response requirements and operational practices to support customer systems
- Defining the monitoring requirements and system architecture, including the communications and controls for advancement of system operation
- Investigating capabilities of commercially available sensors, power quality and/ revenue metering devices, and phasor measurement units (stand-alone or as part of other IEDs) that can provide high resolution data measurement and power quality data capturing and transient event recordings, such as:
    - Voltage and current phasors
    - Power flow (active and reactive)
    - Frequency tracking and reporting rate of change of frequency (ROCOF)
    - Harmonics and THD/TDD measurements
    - Fast transients
    - System status information, including switch position, voltage regulators tap positions, and
    - Circuit connectivity information
- Evaluating product capability documents from vendors; or perform laboratory tests on selected measurement devices (sensors, IEDs, PMUs) to determine accuracy, measurement resolution and quality and type of measurement data such as transient events, to understand and document expected device performance
- Defining PMU requirements specific to distribution systems
- Developing settings and configuration files for the devices in the field to support project data gathering and device control needs
- For cases of inadequate device capability and/or coverage, propose temporary methods and devices to be incorporated in the real-time simulation environment to supplement the existing devices and data coming from the field for the purpose of evaluating the tools under investigations.

The task output was:

- Outlining of the design and needed system development for the advanced monitoring, control and operation
- Evaluating the capabilities of selected devices (sensors, IEDs, PMUs) to measure transient events and power quality
- List of data and measurement points as the basis for the simulation system design.

Task 5 - Design of the Demonstration System

This task objective was to develop detailed plan and infrastructure for the demonstration system requirements for the purpose of verifying the advanced monitoring, visualization and customer integration practices. The design of the proposed demo system included:

- Demo system architecture incorporating both the field measurements and monitoring and the interfaces to a real-time simulation environment in the laboratory to provide additional data in support of full realization of the analytical schemes
- Documenting the requirements for demonstration system design
- Use cases for the customer system integration demonstration
- Identifying proper control algorithms for enhancing the safety and reliability of the system (control system validation will be performed on the real-time simulator)
- Integrating with existing monitoring and controls in the field to develop demo system platform
- Preparing high level interface descriptions for the proposed demo system.

The task output included:

- Demonstration system specifications
- Demonstration system implementation and field integration plan.

1.4.2 Phase 2 – Demonstration of Advanced Customer System Integration

Task 6 – Demo System Setup and Integration

This task was about implementation of the demonstration system that incorporates both remote monitoring and control of the selected devices on the SDG&E Distribution systems, as well as the real-time simulation of the same system in the laboratory environment for capturing and transferring additional measurement data to the visualization system and operator screens.

As part of this process the following sub-tasks were executed:

- Determination of type and availability (accessibility through remote control) of field power apparatus and emerging technologies (smart PV inverters, Dynamic VAR Controllers, BESSs. Electric vehicles, building automation and demand response programs) associated with the customer systems that can be incorporated in a demo system

- Determination of SCADA based control schemes (such as voltage/VAR control, fault locators, automatic load transfer schemes) on the selected circuits that can be used to create various pre-specified system changes and realistic operating scenarios:
    - Change in voltage profiles through LTC at the substation or at cap banks
    - Interaction with circuit device operation (load transfer, operator controlled voltage and VAR optimization a few times per day)
    - Control and dispatch of Dynamic VAR Controllers
    - Change in PV system production according to time of day and season
- Utilizing real-time simulation models for the part of the system that is simulated for additional data gathering and monitoring support:
    - The model incorporated customer systems and interfaces for capturing data and characterizing the impacts on the distribution system
    - The model needed to reflect similar field devices and feeder level controls associated with SCADA or existing localized (automatic) control to execute and investigate interaction of typical operator controls with those of the customer system controls
- Incorporating additional measurement devices as required and identified in a supporting role:
    - Selecting devices based on the results of device evaluations and specifications
    - Integrating devices in the demo system and program them.
    - Preparing settings and configuration files
- Providing means of data streaming and capturing in the simulation and field data in PI historian as infeed to the visualization tool:
    - Visualization tool is primarily driven by field data measurement
    - Measurements from the real-time simulator to be provided as a secondary infeed to fill out the gap in field data monitoring
- Verifying the enhancement of the visualization and monitoring tools:
    - Evaluating the visualization tools based on the data inputs and key performance indices identified as part of the design stage.
- Verifying and preparing the hybrid demonstration system for the demo, consisting of the field data, real-time simulation data and visualization tool

The task output included:

- Demonstration of the system setup integration
- Successful setup of the demonstration system
- Training of the SDG&E internal project team on utilization of the demonstration system.

Task 7 – Pre-commercial Demonstration

This task involved development of test plan and schedule for testing, as well as performing the demonstration tests. The main activities were:

- Detailed plans for each of the tests to be run, including identification of the objectives of the tests, use cases under investigation, test methodologies, information to be captured, Contractor's staff, system/equipment, SDG&E lab system/equipment required, circuit models required, and contractor and SDG&E project team support needed for specific items
- Methodology for capturing test data and comparing with simulation data

- Decision points at which preliminary data assessment is used to determine if more test iterations or alternative new test cases should be run
- Simulating scenarios and test cases in the laboratory environment
- Collecting live data streams as well as the output from the visualization tools
- Creating transient events and outages associated with customer systems to determine operator responses and to demonstrate how the visualization system will be used for post-mortem analysis
    - Root cause investigation of the failure and outage
- Performing data analysis and documenting test results and observations
    - Collecting test data and results for the report
    - Collecting event and operating records from field devices

The output for this task included:

- Test plan and schedule
- Test results
- Root cause investigation approach
- Analysis of test results
- Analysis methods for determining benefits of the advanced visualization schemes and lessons learned.

Task 8 – Evaluation of Customer System Integration

The objective of this task was to identify and describe system improvements obtained by introducing advanced monitoring and customer system integration schemes demonstrated in this project. The results from the system demonstrations and test cases were utilized to analyze and propsoe standard practices for the customer integration and system monitoring tools. The main activities as part of the system evaluation and standardizations were:

- Determination of data accuracy and possible or expected errors in live streaming and/or event captures
    - Utilizing sample data from various devices in the field
    - Comparing data sources and calculate percent error
    - Using laboratory testing of the specific devices, as needed to verify percent error and/or potential sources of error
    - Calculating level of offset in measurements
    - Investigating calibration and correction methods
- Analyzing data to determine issues and possible adverse impacts on circuits, equipment, and customers. Summarizing observations in relationship to correlated events and conditions:
    - Voltage profiles
    - Losses and reactive power profile
    - Power flow including reverse flow
    - Interactions among circuit devices and control systems
    - Effect of PV penetration, based on changes in the level of PV production versus load at various time intervals
    - Changes in the waveform distortion or harmonic content of voltages and currents
    - Power device operation and status changes, including wear or stress impact
    - Identify improvement opportunities
- Preparing guidelines for addition of new sensors and measurement device installations

- Determination of minimum number of measurement points and locations on the system to install sensors and meters
- Defining device specifications and functional requirements to support advanced monitoring and integration of the customer systems
- Defining communication needed for capturing and data streaming from the measurement point
  - Determination of minimum communication infrastructure requirements, such as data bandwidth needed, minimum required speeds for the data transfer, and list of use cases for those data transfer needs.
- Determination of requirements for visualization and operator interface to support customer systems.

The task output included:

- Tool and application evaluation
- Requirements for new systems

Task 9 – Comprehensive Final Report

This task incorporated the work on preparing the final report for the project, which is a comprehensive record of the work completed, findings, and recommendations. The report was intended to enable stakeholders to understand and use the project's output.

2 System Requirements and Evaluation

This section outlines the outcome of system requirement investigation, test system development and evaluation of the functionalities, using both real-world data (from devices deployed in the field) and simulated data (from test setup in the laboratory environment).

2.1 Survey of Customer Systems and Their Impact on the Distribution Systems

Prior to developing the functional requirement for the test system, a survey of customer technologies was performed. The survey incorporated common technologies that are presently installed by customers and integrated into utility grid (such as roof-top solar systems), as well as the technologies that are expected to be introduced and become mainstream, such as Electric Vehicle Charging Stations (EVCS), and behind the meter hybrid energy storage systems. Technology characteristics and impact on distribution systems from the perspective of day-to-day operation were analyzed. Common measurement and performance indices were also introduced to characterize their power exchange with the grid and to quantify their contribution in affecting power quality of the system.

2.1.1 List of Customer Systems and Technologies

One of the Tasks on the project was to assess the present state of monitoring and controls and to analyze the impact of new customer technologies on the distribution systems. Extensive research was performed to determine a list of customer systems and technologies that are being deployed or expected to be integrated into utilities' distribution systems. Potential impacts on operation practices and integrity of the system due to those new technologies have been also investigated.

The following list provides the identified customer systems and technologies that are being deployed or expected to be integrated into the distribution systems in the next 2-5 years:

- Roof top PV systems (< 50 kW) – with micro inverters, and mostly residential systems;
- Roof top PV systems (< 50 kW) – with string inverters, and mostly residential systems;
- Roof top PV systems (< 1 MW) on commercial buildings, such as warehouses or large department stores;
- Ground mounted PV systems that are privately owned;
- Electric Vehicle charging stations, level 2 or fast chargers;
- Fuel Cell Systems (> 100 kW, for industrial facilities);
- Residential Energy Storage Systems (< 10 kW, 2-4 hrs.);
- Community Energy Storage Systems (50 kW to 500 kW, 2-4 hrs.);
- Commercial Energy Storage System (50 - 500 kW, 2-4 hrs.);
- Traction systems (electric train or autobus) with AC interface;
- Dynamic Voltage Control (DVC) (1MVA+) that may be used in conjunction with large PV plants
- Secondary voltage control devices, by utilizing power electronic systems that can provide voltage regulation and reactive power compensation downstream of service transformers,
- Variable Frequency Drives (VFDs), and
- Customers with non-linear loads such as Arc Furnace, or large motor loads without VFD.

2.1.2 Impact Categories

The impact of identified new technologies on distribution systems was investigated and summarized. The potential impact categories are listed below:

- Overvoltage issues
- Under voltage issues
- Voltage ring down (damped voltage oscillation)
- Transformer overloading issues
- Distribution system loss increase
- Extensive reverse power flow
- Increased number of tap operations in voltage regulators and load tap changers
- Increased number of switched capacitor operations
- Changes in short circuit capacity of distribution systems which in turn affects the rating of equipment (e.g., circuit breakers, switches, etc.)
- Deterioration of protection system coordination
- Increased chance of incidental faults
- High frequency switching transients - that can cause resonances or increase losses
- Load imbalance increase
- Ground fault over voltage phenomena
- Increased risk of apparatus failure
- Increased risk of cable failure
- Increased risk of unplanned islanding
- Harmonics
- Voltage flicker.

2.1.3 Key Performance Indices for Quantifying System Performance and Imapcts

In order to identify and monitor each impact category or distinguish events, various measurements, indicators and indices are required to associate causes with an effect. It was assumed that various type of measurements are gathered and available from metering devices or specialized Intelligent Electronic Devices (IEDs) across the circuits. Collected measurements were processed to create indictors and performance indices which are informative of system conditions and any potential events.

The proposed measurements, indicators and key performance indices (KPIs) that were considered for identifying and classifying specific events are listed as follows:

Measurement type parameters:

- Voltage magnitude,
- Voltage phase angle,
- Current magnitude,
- Current phase angle,
- Active power (from load),

- Active power (from PV systems or various DERs),
- Reactive power (from load, generation, or passive shunt capacitive/reactive elements, and static compensators),
- Tap Position & capacitor/reactor status,
- Power frequency.

Indicator type parameters:

- Voltage trends,
- Phasor diagrams,
- Rate of change of frequency (ROCOF) trend,
- Harmonic histograms,
- Odd/even harmonics spectrum,
- Symmetrical component plots,
- Vector jump plot,
- Neutral voltage shift plot,
- Short duration transients (cycle by cycle event record).

Key Performance Indices (KPIs):

The main KPIs used in the project were:

- Voltage Swell (SARFI-110) [1]
- Voltage Sag (SARFI-80, SARFI-90) [1]
- SARFI-SEMI [1]
- SARFI-ITIC (CBEMA) [2]
- Harmonic indices such as: TDD, THD [3]
- K-factor (transformer derating) [4]
- Crest factor (distortion factor) [5]
- Voltage unbalance factor [5]
- Flicker factor (short term) [4]
- Flicker factor (long term) [6]
- Solar intermittency factors, such as: DCI and DVI [7]
- Reliability indices such as: SAIDI, SAIFI, CAIDI, and CAIFI [8].

Table below provides the list and definition of the KPIs.

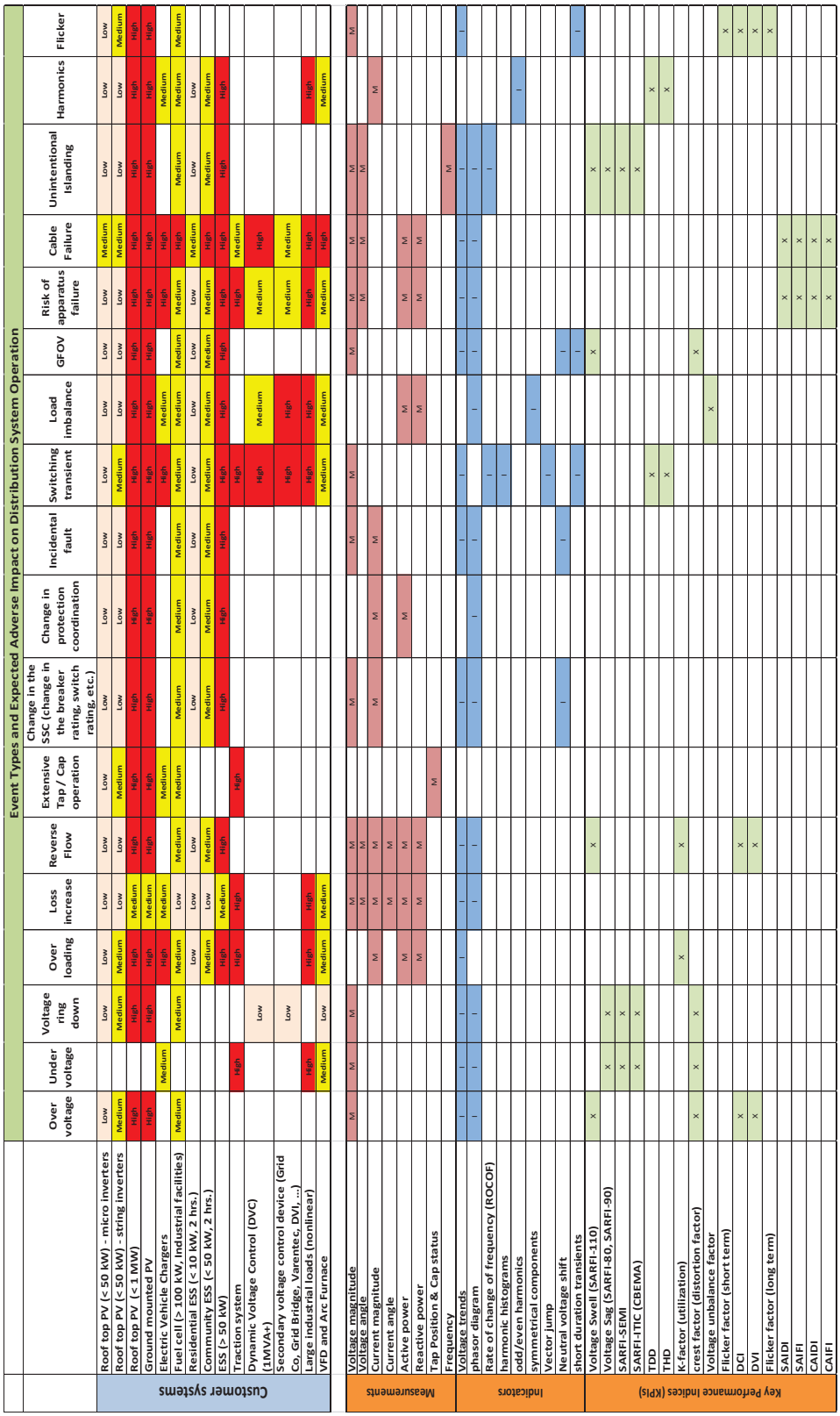
Table 2-1. Key Performance Indices Considered on the Project

Index	Key Performance Index Definition
SARFI-80	Count or rate of voltage sags with retained voltage above 80% of voltage refere
SARFI-90	Count or rate of voltage sags with retained voltage above 90% of voltage refere
SARFI-110	Count or rate of voltage swells with retained voltage above 110% of voltage ref
SARFI-SEMI	Count or rate of voltage sags and interuptions with reatined voltage and duration below the ITI(CBEMA) Curve.
SARFI-ITIC (CBEMA)	Count or rate of voltage sags and interuptions with reatined voltage and duration below the lower portion of the SEMI F47 Curve.
TDD (Total Demand Distortion)	$TDD_I = \frac{\sqrt{I_2^2 + I_3^2 + I_4^2 + I_5^2 + \ldots}}{I_L}$
THD (Total Harmonic Distortion)	$THD_I = \frac{\sqrt{I_2^2 + I_3^2 + I_4^2 + I_5^2 + \ldots}}{I_1}$
K factor (Transfromer derating)	$\left(\sum_{h=1}^{\infty} h^2 I_h^2\right) / \sum_{h=1}^{\infty} I_h^2$
Crest factor (Dielectric stress)	V_{peak} / V_{rms}
Voltage unbalance factor	$\lvert V_- \rvert / \lvert V_+ \rvert$
Flicker factor	$\Delta V / \lvert V \rvert$
DCI	Daily Clearness Index $= \frac{\text{Measured Solar Insolation}}{\text{Calculated Clear Sky Solar Insolation}}$
DVI	Daily Variability Index $= \frac{\text{Length of measured irradiance plot}}{\text{Length of clear sky irradiance plot}}$
CAIDI	Customer Average Interruption Duration Index $\text{CAIDI} = \frac{\sum \text{Customer Minutes of Interruption}}{\text{Total Number of Customers Interrupted}}$
CAIFI	Customer Average Interruption Frequency Index $\text{CAIFI} = \frac{\sum \text{Total Number of Customer Interruptions}}{\text{Total Number of Distinct Customers Interrupted}}$
SAIDI	System Average Interuption Duration Index $\text{SAIDI} = \frac{\sum \text{Customer Minutes of Interruption}}{\text{Total Number of Customers Served}}$
SAIFI	System Average Interuption Frequency Index $\text{SAIFI} = \frac{\sum \text{Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}}$

Table 3-2 summarizes the correlation between the new technologies identified in the survey and their impacts on the distribution system.

The severity of each technology on the events and impacts is organized as low, medium and high. The measurements, indicators and indices required for identifying and monitoring the impacts or events are also listed in the table.

Table 2-2. Summary of New Technologies, Their Impact, and Parameters Utilized to Characterize Impacts



2.2 Baseline Evaluation and System Characterization for Potential Targeted Circuits

The objective of this task was to assess the present state of monitoring and controls and to analyze the impact of new customer technologies on the distribution systems. In order to develop monitoring and visualization for current distribution network, it was of great importance to conduct a baseline analysis of the system and evaluate the gaps between current and required state of monitoring.

The baseline analysis was conducted for five selected circuits within SDG&E distribution systems. The baseline analysis focused on the loading conditions of the circuits, the customer PV integration along the circuits and the existing PMU locations of the circuit. The baseline analysis provided an insight into the amount of PV generated and its distribution along the circuit and how effective the existing PMUs can monitor and capture the impacts of PV integration into the distribution circuit.

A detailed set of PMU placement criteria for distribution systems has been then discussed in next step to provide full coverage of the circuit and key locations of interest. Considering distribution PMU installation costs, the communication system availability and/or cost and the practical constraints, the optimal placement of PMUs is an essential task, involving both application assessment and economic justifications (business case). In this section, the PMU placement criteria in general has been investigated and prioritization method has been discussed. Furthermore, these criteria have been tailored for specific applications, for this project.

2.2.1 Circuit Selection Criteria for Baseline Analysis

In selecting the five distribution circuits both technical and practical aspects were considered. The criteria included:

- Presence of medium to high levels of PV integration to the circuit,
- Existing PMU devices in operation in the field,
- Potential distribution assets to be monitored and visualized (including line reclosers, capacitor banks, voltage regulators and similar devices),
- Availability of a real time digital simulation model (RTDS model) of the circuit (based on the SDG&E Library of circuit models) , to facilitate laboratory investigations
- Focusing on circuits that were not investigated recently in similar EPIC studies.

Table 3-3 summarizes characteristics of selected circuits and their device status, including number/amount of PV installed, number of major components (switched capacitors, tie switches, reclosers and voltage regulators), number of field PMUs and loading conditions. In the following sections, the selected circuits have been investigated more elaborately.

Table 2-3. Summary of Selected Circuit Status

Substation	Sub 1	Sub 2		
Circuits	Circuit 1	Circuit 2	Circuit 3	Circuit 4
Total No. of Tie Switch	1	0	3	0
No. of PVs	246	76	81	82
Installed PV capacity (kW)	4604.705	1015.96	652.026	1364.816
No. of Storage	0	0	0	0
No. of Voltage Regulators	6	1	2	1
No. of Switched Capacitors	1	1	2	3
No. of Reclosers	6	2	3	2
No. of field PMUs	12	4	8	2
Installed storage capacity (kW)	N/A	N/A	N/A	N/A
Large DERs (>500 KW)	2	0	0	1
Daytime Peak load (MW)	6.6	4.272	3.24	3.264

2.2.1.1 Example of Baseline Analysis for Circuit 1

2.2.1.1.1 Loading Conditions

The 2016 load data from SCADA has been analyzed and the results are summarized in Table 3-4. In addition to minimum and maximum load, data has been analyzed for minimum and maximum daytime load during the noon time (i.e. 11:00 am – 2:55 pm). The data has been collected based on a 5-minute resolution for 2016 year-around.

Table 2-4. Circuit 1 Loading Condition

Load	Date Time	MW	MVAR	Percent Load	Ia (A)	Ib (A)	Ic (A)	BRKR Status
Minimum load	3/6/2016 13:00	-0.312	0.072	2.30	11.4	12.6	13.8	CLOSE
Maximum load	9/26/2016 18:20	7.992	3.252	71.81	353.4	416.4	438	CLOSE
Average load	--	3.417	0.734	--	--	--	--	--
Min daytime load	3/6/2016 13:00	-0.312	0.072	2.30	11.4	12.6	13.8	CLOSE
Max daytime load	9/27/2016 14:55	6.6	3.492	60.9	315.6	349.8	368.4	CLOSE

Due to PV generation in the circuit, the gross load would be calculated as the difference of the total load and the PV generation.

Thermal Rating

In this section, the thermal rating (ampacity) of all major equipment including reclosers, capacitors, regulators and cables have been summarized and the thermal rating of different sections on the circuit has been determined. Different sections of the circuit (main branch, branch 1 and branch 2) have been marked on Figure 3-1. Table 2-5 shows the ratings of different devices located on different sections of the circuit (main branch, branch 1 and branch 2) and

Table 2-6 shows the rating of all conductors along the different branches of the circuit.

Table 2-5. Thermal Rating of Major Equipment on Circuit 1 (SDG&E data from SynerGI model)

Main Branch					
#	Name	Device Type	Manufacturer	Section ID (Node number)	Rating (Amps)
1	C1-22R	Recloser		C1_360492_MC	630
2	C1-10R	Recloser		C1_357284_MC	630
Branch 1					
#	Name	Device Type	Manufacturer	Section ID (Node number)	Rating (Amps)
1	C1-18R	Recloser		C1_605304_MC	630
2	C1 - 1228CW	Cap		C1_1793943_MC	
3	C1-838G	Regulator		C1_199701_OH	200
4	C1-33R	Recloser		C1_359640_MC	630
5	C1-1224G	Regulator		C1_200233_OH	200
6	C1-1020G	Regulator		C1_500322_OH	200
Branch 2					
#	Name	Device Type	Manufacturer	Section ID (Node number)	Rating (Amps)
1	C1-26R	Recloser		C1_1446954_MC	630
2	C1-1334G	Regulator		C1_467252_OH	200
3	C1- 1340CM	Cap		C1_355049_MC	
4	C1- 1225G	Regulator		C1_203961_OH	200
5	C1-1045R	Recloser		C1_2302813_MC	800
6	C1-1116G	Regulator		C1_200449_OH	200

Table 2-6. Thermal Rating of Conductors along Circuit 1 (SDG&E data from SynerGI model)

Main Branch		
#	Conductor Type	Rating for load calculating (Amps)
1	1000 XLPECN-PEJ AL	580
2	636 ACSR	770
3	336.4 ACSR	530
Branch 1		
#	Conductor Type	Rating (Amps)
1	3/0 ACSR	300
2	336.4 ACSR	530
3	#2 5005	185
4	#2 ACSR	180
5	#4 B.STRD	180
Branch 2		
#	Device Type	Rating (Amps)
1	336.4 ACSR	530
2	1000 XLPECN-PEJ AL	580
3	#2 ACSR	180
4	#2 5005	185
5	#6 B.STRD	130
6	#4 B.STRD	180

Based on the provided data, the thermal rating of each section would be the minimum rating of all devices in that section. Therefore, the thermal rating for main branch, branch 1 and branch 2 would be **530 Amps**, **180 Amps** and **130 Amps,** respectively.

2.2.1.1.2 PV Generation and Existing PMU Locations

In this section, a single line diagram of the circuit 1 has been provided which shows the location of existing field PMU devices as well as PV generation along the circuit (Figure 3-1). The DVR on the circuit is used as the representation of future customer-owned Voltage Control devices that may be needed to manage voltage and reactive power requirements for large PV installations.

As shown on the single line diagram, the areas of the circuit located between two or more feeder control devices (reclosers, regulators, shunt capacitors) are identified as monitoring areas. The total existing PV systems in each monitoring area were extracted from the GIS maps and shown on the SLD.

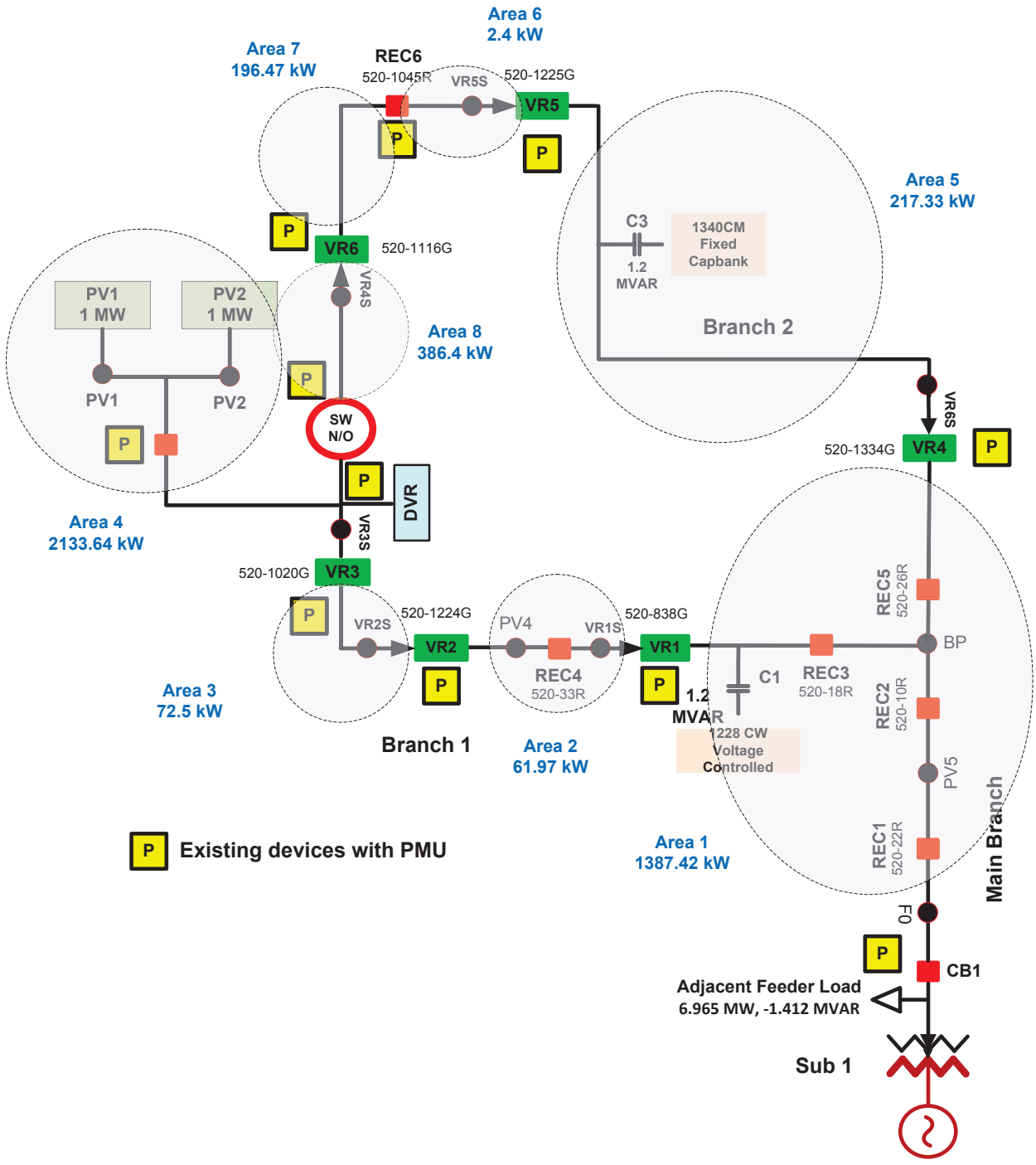


Figure 2-1. Existing PMU Locations on Circuit 1 and identifying monitoring areas with amount of PV

2.2.2 PMU Analysis and Placement Criteria

Reliable operation of modern power systems requires close monitoring of the system operating conditions. Until recently, the measurements were provided by supervisory control and data acquisition (SCADA) system, including power flows and bus voltage magnitudes. The deployment of phasor measurement units (PMUs) enables various applications with the use of synchronized measurements. A PMU installed at a node can make direct measurements of the voltage phasor of the bus and the current phasors of some or all its incoming/outgoing branches, based on the PMU available channels.

Considering PMU procurement and installation cost, the communication system availability and/or cost (which may be higher than that of the PMUs), and the practical constraints, the optimal placement of PMUs has become an essential task. While there have been multiple efforts to analyze and optimize PMU placement, the majority of these works is focused on transmission systems. Some important factors in PMU placement include network reliability, redundancy, system observability, and the required applications. In the following paragraphs some of the PMU placement considerations and recommendations are discussed.

2.2.2.1 Prioritization

To maximize the value from a PMU-based system, the communications system and software analytics need to be designed with a clear plan that suits system design, acquisition, siting and installation requirements that are tailored to the intended applications. In the initial stage of PMU system deployment, it is essential for the utility to prioritize short- and long-term objectives as well as applications of interest; this is usually done through some sort of roadmap developed for this purpose. Subsequently, those circuits where PMUs need to be deployed can be selected. The following provides a generic list of circuit priority criteria (sorted from higher priority to lower priority):

1) Availability of communications infrastructure
2) Existing location of distributed energy resources (DERs), especially intermittent ones
3) Expected penetration of DERs (especially intermittent ones)
4) Reliability level
5) Power quality level
6) Feeder type (Residential, Industrial, Commercial).

Once the circuit priorities are determined, the next step would be to find the optimal (or close to optimal) locations of PMUs that enable successful implementation of the application of interest. The favorable locations are areas with pre-installed feeder control devices which provide CT and PT connection. For uncovered areas, new nodes can be identified and incorporated in the new device installations.

2.2.2.2 Intended Applications

PMU placement should reflect the needs and functionalities of the intended applications for the distribution system. More specifically, PMUs should be located in a manner to maximize system benefits, beyond those provided by conventional meters. In the case of distribution systems, and potential future implementation at SDG&E, PMU applications were grouped in five broad categories. The following is a list of five categories along with some examples for each category:

1) System monitoring
    a) Wide-area situational awareness
    b) Phase angle monitoring for voltages and currents

2) Assessment and analysis
    a) Voltage stability monitoring and prediction
    b) Enhanced state estimation

3) Model validation
    a) Short circuit study validation
    b) Load characterization, load modeling and load forecasting

4) Protection and automation (mitigation, enhancement, and detection)
    a) Fault location
    b) Islanding detection in the presence of DERs

5) Control and optimization
    a) Volt/Var control
    b) Fault location and load restoration

Table 3-7 below offers a more detailed list of potential PMU applications in distribution systems. The list has been compiled from survey of various distribution automation applications and proposed use cases by several smart grid working groups, such as DOE smartgrid interoperability group (SGIP). As it can be observed in the table, synchrophasor measurements can be utilized for an array of applications and, thus, PMU placement should support the requirements of these applications.

Table 2-8 provides a list of recommended key PMU locations and PMU coverages for various automation and smartgrid applications. The list was prepared by applying the aforementioned criteria.

Table 2-7. List of Potential PMU Application in Distribution Systems

No	APPLICATIONS	CATEGORY				
		SYSTEM MONITORING	MODEL VALIDATION	ANALYSIS	PROTECTION & AUTOMATION	CONTROL
1	Conservation Voltage Reduction (CVR)					X
2	Faulted Circuit Indication(FCI) for expediting service restoration				X	
3	Falling conductor and high-impedance fault detection				X	
4	Distribution system computational model validation		X			
5	Voltage impact assessment and mitigation due to high penetration of intermittent DER			X		X
6	Voltage and current phase angle monitoring	X				
7	DER islanding detection				X	
8	Volt-Var Control					X
9	Power flow measurement for circuit design evaluation and balancing (passive approach)	X		X		
10	Monitoring and integration of intermittent DERs	X				
11	Incipient fault & failure detection				X	
12	Improved wide-area situational awareness	X				
13	Customer/smart inverter control					X
14	Voltage profile monitoring			X		
15	Dynamic rating of distribution lines and equipment (including thermal limit assessment)	X		X		
16	Improved load shedding schemes					X
17	Condition monitoring and asset managment of power apparatus	X				
18	Phase identification					X
19	Near real-time event monitoring and trending	X				
20	Active and reactive reverse power flow management					X
21	Planned islanding and restoration of microgrids					X
22	Short circuit study validation		X			
23	Fault protection and reclosing assistance (real-time values to relays and reclosers to adapt to system changes)				X	
24	High accuracy fault location, specific for maintenance dispatch plus OMS interface				X	
25	Control instablility, oscillation detection - Volt/Var switching					X
26	Load shedding (real-time compensative arming to balance 1547-compliant PV that will drop during wide area disturbances)				X	
27	Enhanced FLISR operation				X	
28	Closed-loop circuit operation					X
29	Power quality measurement and management information per customer group - voltage profile, CBEMA/ITIC violations	X				
30	Recording, retrieval, trigger marking, archiving, and disposal of gathered synchrophasor and other circuit data	X		X		
31	Monitoring of communications system performance with management metrics - availability, latency, lost packets, etc.	X				
32	Communications failure location for maintenance dispatch	X			X	
33	Monitoring, alarming and compensating of malfunctioning PMU installations by integrated comparison with surrounding data	X		X		
34	DER management and energy balancing					X
35	Synchronized load transfer on same circuit or between adjacent circuits (under normal operating conditions)				X	
36	Circuit loss minimization			X		X
37	Improved distribution reliability analysis (index calculation)			X		
38	Distribution system state estimation			X		
39	Open conductor fault detection				X	
40	Load characterization and forecasting			X		
41	Post-mortem analysis			X		
42	Energy accounting/non-technical losses estimation and location via cross-feed to AMI and CIS	X		X		
43	Real-time event monitoring and trending	X				
44	Frequency monitoring and analysis	X		X		
45	Voltage stability monitoring and prediction	X				X
46	Visualization of dynamic system response	X				

Table 2-8. Recommended Locations for PMUs for Various Classes of Applications

Item #	Application	Recommended PMU Placement
1	Improved situational awareness	• DERs with a combined capacity above certain kW rating (500kW) • Key buses, e.g., those with VRs, LTCs, and capacitor banks • Major load centers • Flowgates requiring loading relief • Interfaces to transmission systems • Pre-defined islands
2	Real-time monitoring and trending	Similar to recommended locations for Item #1
3	Distribution system state estimation (Phasor-based or enhanced)	• (N-2) line current phasors are needed for N interconnected buses • More PMUs neded if robustness again single PMU failure is needed • Observability criteria should be considered
4	Voltage stability monitoring and prediction	• DERs with a combined capacity above certain kW rating (500kW) • Large reactive power control installations (DSTATCOM, synchronous condensers, Large capacitor banks, etc.) • Voltage control installations (LTCs, VRs, etc.) • Theoritically, a minimum of (N-1) line current phasors are needed for N interconnected buses
5	Dynamic rating, thermal limit, and stability limit assessment (e.g., islanded microgrid)	• Voltage and current of the distribution line(s) • DERs with a combined capacity above certain kW rating (500kW) • Large load centers • Tie lines between sub-systems (e.g., in a looped configuration) • Interfaces to transmission systems
6	Synchronized load transfer, distribution sub-system separation, and phase identification	• PMUs to be installed at both sides of the interface/tie • Single-phase control devices (VRs, Cap banks, etc.)
7	Model verification/calibration	Components of interest (DERs, grid power controllers, loads, etc.)
8	(Frequency) Oscillation detection	• All DERs (espacially wind power plants) • Large loads (especially industrial loads with cyclic loadings) • Grid control devices (DSTATCOM, switched capacitors)
9	DER islanding detection	• All DERs • Points of interconnection (POIs)
10	Blackstart and system restoration	• Every generator included in the blackstart restoration plan • Every substation included in the blackstart restoration plan • Key substations, lines, and breakers that will synchronize the blackstart islands created during the blackstart restoration plan
11	Vol/Var control	• Volt/Var control devices (sub LTC, VR, Cap Banks) • DERs with a capacity above certain kW rating (particulalry dispatchable ones) • Large loads/customers and circuit reclosers (supplimentary)
12	Fault location, isolation, and system restoration (FLISR)	• Substation (monitoring circuit breaker current) • Circuit reclosers • Remote control switches • Sectionalizer and tie breakers/switches • Load centers • Large customers and beginning of large branches (supplimentary)
13	Falling conductor detection	• Substation (monitoring circuit breaker power) • Circuit reclosers • Branch end point
14	Monitoring and integration of intermittent DERs	• POI of variable DERs (and other DERs as supplimentary location) • Substation (monitoring circuit breaker power) • Circuit reclosers

Based on the intended applications, the criteria and practices for PMU placement will vary. Table 3-8 provides generally recommended locations for a selected number of PMU applications in distribution systems.

As indicated in this table, some of the PMU locations are mandatory while the rest are supplementary for enhanced operation of the application. The following is a list of recommendations for prioritizing PMU placement based on the applications of interest:

- Key applications that will bring value to the organization (e.g., engineering analysis and real-time operational applications) should be identified and prioritized as soon as possible. Applications require different levels of accuracy, resolution, as well as placement; these should be taken into account prior to concerted deployment of PMUs.
- Determine the placement coverage required for successful operation of the application(s) of interest. Determine if partial coverage can suit the needs of some applications while others may require full observability/deployment.
- An application matrix can be developed to track the locations that PMUs can meet the needs of multiple applications. These locations may be considered higher priority since they provide cross-cutting value to multiple PMU-based applications.
- Data quality is important in most cases, but some applications have less stringent requirements for data quality and accuracy than others. This should be considered in the deployment stage, and efforts should focus on ensuring a high availability, high accuracy, and low latency synchrophasor network.

It is should be noted that one of the major criteria for PMU placement is the system observability. If the full observability of the system is fulfilled by PMUs, the majority of applications can be performed properly (but it is usually not practical due to the cost constraints). The following subsection discusses the criteria for the optimal placement of PMUs when the system observability is the optimization objective.

Other additional factors that influence PMU placement include:

1. Practical constraints for PMU installation (e.g., non-existent virtual buses or unavailability of instrument transformers)
2. The number of distribution lines and transformers in the substation (possibility of installing more PMUs at a substation)
3. Equipment considerations (number of inputs, signal availability, local access, communication interface, timing signal, etc.)
4. The redundancy requirements for PMUs
5. Possibility of using existing intelligent electronic devices (IEDs) as PMU
6. Communication & IT considerations (Bandwidth, latency, reliability, security, etc.)
7. Data quality requirements (data loss, data corruption, inaccuracy, etc.)
8. Reporting rate as related to communication restrictions, application requirements, data handling equipment, and data storage capacity

Based on the discussion above and the scope of this project and its related applications, the following table (Table 3-9) provides a high-level guideline for placement of PMUs in target distribution systems. The table lists a generic prioritization for distribution assets that are proper candidates for PMU locations in selected circuits.

However, it should be emphasized that PMU placement should be investigated in the context of the system under study.

Table 2-9. Recommended Location of PMU Installations for Analyzed Circuits

Priority level	Description	Recommended Locations
1	Major locations that are critical for majority of PMU-based applications or have high potential for PMU installation	• Substation circuit breakers • Circuit reclosers • Utility side of DERs with a capacity more than 500kW • New SCADA control devices • Automated assets that are monitored by SCADA, and their control & communication can be replaced with PMUs, e.g., VRs, cap. banks, SCADA switches/ties, reclosers, etc.
2	Automated assets that are not monitored by SCADA, but their control & communication can be replaced with PMUs	• Residential DER clusters (areas with more than 100 residential DERs eache smaller than 10kW) • Voltage Regulators (VRs) • Switched capacitor banks • Sectionalizers, and DA switches/ties • reclosers, etc.
3	Critical locations for specific PMU applications	• Load centers and/or mid-circuit point • Beginning of large branches • large custumer and industrial loads
4	Automated assets that are not monitored by SCADA, and their control & communication cannot be replaced with PMUs	• Voltage Regulators (VRs) • Switched capacitor banks • Sectionalizers, and DA switches/ties • reclosers, etc.
NOTE: PMUs will be placed at the above recommended locations, provided that no other control device (VR, cap bank, recloser, or SCADA switch/tie) with synchrophasor measurement capability is located less than half a mile from it.		

2.2.3 PMU Placement Case Study

In order to investigate and further modify the applicability of the proposed PMU allocation criteria, the method was examined on a few circuits in SDG&E territory. There are some PMUs already deployed in distribution circuits. The objective of this approach was to show whether additional PMU devices were needed or the existing units can provide proper coverage for the selected use cases.

Three circuits were selected and studied for this purpose; however, in this report, the results applied to one of the circuits (Circuit 1) are presented. Similar analysis for other circuits were also performed as part of lab setup development.

Figure 3-1 presented above shows a schematic of Circuit 1. A normally open switch divides the circuit into two main branches. All key devices including voltage regulators, capacitor banks, reclosers and DERs have been drawn in this schematic. Currently there are 24 PMU devices located on Circuit 1. Two of these PMU devices are at the substation and the rest are located along the circuit at:

- Voltage Regulators (VR1, VR2, VR3, VR4, VR5 and VR6)
- Dynamic Voltage Regulator (DVR)
- Two reclosers (REC3 and REC5)
- Trayer switch.

In circuit 1, there were two capacitor banks (one switched and the other one fixed) with no PMU coverage. Only two reclosers had PMU devices in the circuit.

The intended application was distribution system monitoring in presence of DERs integrated to the system. The intended applications in the scope of this work included:

1. Monitoring and integration of intermittent DERs
2. Real time monitoring and trending
3. Improved situational awareness.

Based on the recommended PMU locations described in Table 3-7, the following locations were hence recommended:

- Point of Interconnection (POI) of variable DERs (and other DERs as supplementary location)
- Substation (monitoring circuit breaker power)
- Circuit reclosers
- DERs with a combined capacity above certain kW rating (500 kW)
- Key buses, e.g. those with VRs, LTCs and capacitor banks
- Major load centers
- Flowgates (transformers, circuit heads, laterals) requiring loading relief
- Interfaces to transmission systems
- Pre-defined islands.

Figure 3-2 shows a single line diagram of the Circuit 1 with proposed PMU locations. Similar study was done for other two circuits. Based on these recommendations, an RTDS model was developed and used for the purpose of pre-commercial demonstration of system integration and visualization in the laboratory environment.

The existing PMUs are located at the circuit substation, all the voltage regulators, DERs and two of the reclosers (REC3 and REC5). There is no PMU devices located at the remaining four reclosers and two key buses with capacitor.

Therefore, four new locations were recommended for PMU placement as shown in Figure 3-2. PMU placement at the capacitor back supports enhancing the visibility of the system and monitoring the reactive power injections due to the DERs power variations.

Note that REC1 location is electrically the same as CB1 location. Also, instead of REC2 location, it is more applicable to add PMU to REC3 and REC5 for monitoring each branches.

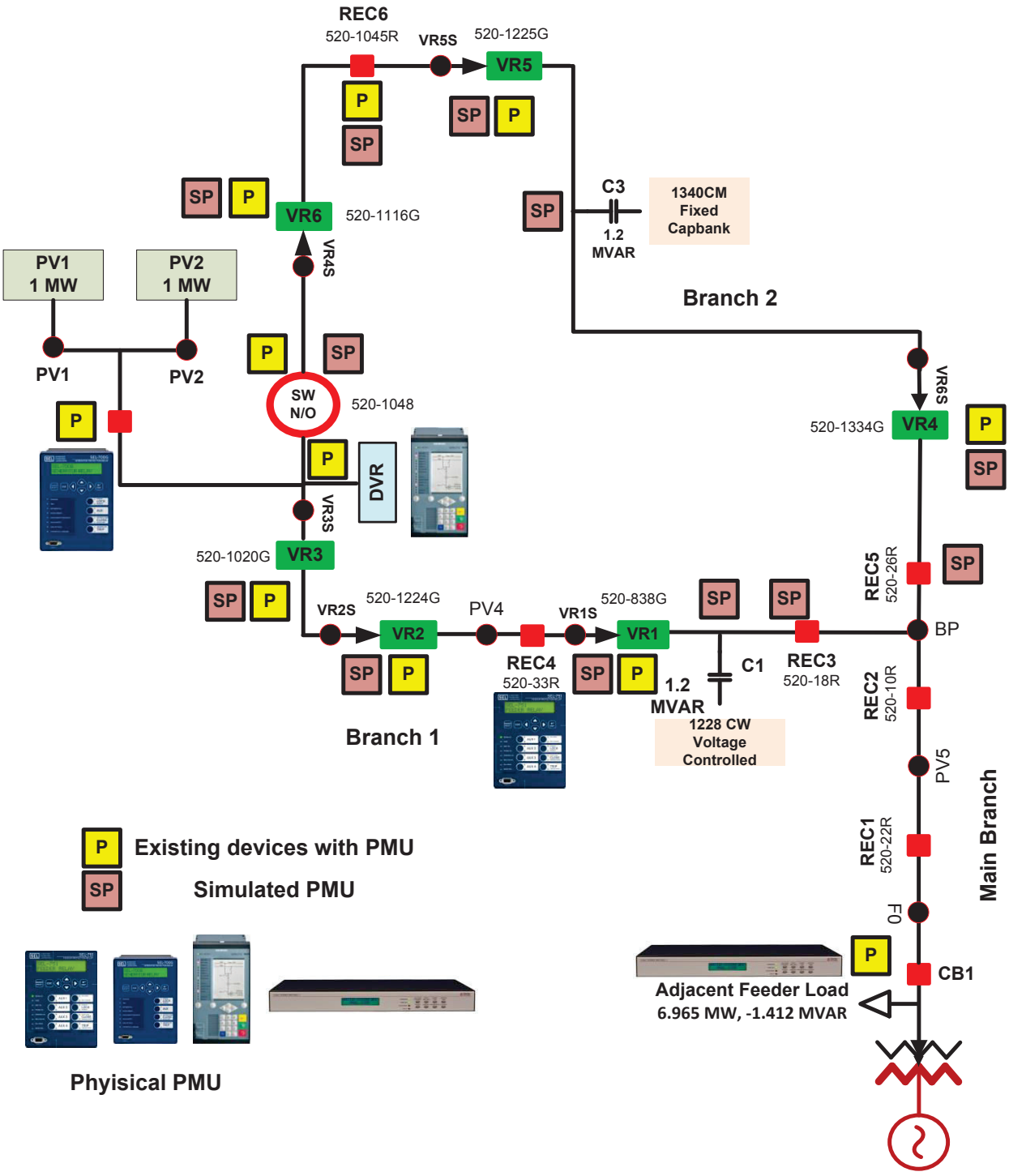


Figure 2-2. The single line diagram of a selected Circuit 1 with PMU locations (existing and recommended)

2.3 Use Case Development

For the purpose of demonstration of the technology, a set of use cases were developed. The proposed use cases were associated with monitoring, investigation and identification of Customer Systems Impact on distribution systems. Three categories of use cases were proposed in order of priority for development and implementation (tier 1, tier 2, and tier 3).

The use cases are by nature also of three types:

a. System monitoring only in real-time (without any analysis)
b. Using monitoring data for diagnostic based on simple logic or intelligent data analytics
c. Post mortem root-cause analysis of events and reported casualties in the system.

An extensive list of use cases was proposed and they were categorized in three tiers, by relevance. For the purpose of design and implementation of the system on this project, the following use cases were selected as the most important ones:

1. Voltage and power flow monitoring of customer systems
2. Primary Distribution Asset Operation Monitoring and Diagnostics
3. Data Quality Validation for Field PMUs
4. Equipment overloading detection
5. DER Interconnection Compliance
6. Water Treatment Facility Monitoring and Reactive Power Management

Use case documentation report was prepared to provide detail description of each of the use cases and they were used for the design and implementation of the system.

2.4 System Monitoring, Visualization and Analytical Application Requirements

During project execution, a functional requirement document was prepared to address a set of requirements for distribution system monitoring and visualization. This document provided functional requirements for developing monitoring and visualization of distribution systems in support of integrating customer systems.

In this document, different methods of data analytics (applications) and various forms of data presentation (displays) were suggested to allow for advanced monitoring and detection of events on the circuits. Synchophasor (PMU) data could increase quality and accuracy of system monitoring and observability for the fast system events, as a critical step in enhancing the reliability of fast evolving distribution systems.

As a benchmark for studies and evaluations, several PMU devices that are presently installed on 12 kV distribution circuits in SDG&E service territory were monitored through SynchroWAVe Central software tool. Display dashboards were created for monitoring phasor magnitude and phasor angles, and compared with simulated data.

Data Sources: The main data source for the visualization application was the PMU data, either streaming from PMUs in the field, or extracted from the historical database (i.e. PI historian). In addition, SCADA data – especially for device status and loads - and any power quality data from substation power quality meter, or any customer related data from revenue meters (such as demand and secondary voltages), as available and accessible were used.

For the demonstration purposes, PMU related data from the real-time test setup that was stored in a simulation PI Historian located at SDG&E ITF were also used.

Measurements & monitoring types and format: Following is a selected list of measurements, indicators and performance indices being calculated locally at each PMU location as phasors and/or analog values. All measurements were reported in real time for monitoring purpose, including:

- Voltage and current phasors
- Active and reactive power and power factor
- Voltage and Current phase angles
- RMS voltage and current magnitude per phase and phase to phase
- Voltage and current unbalance levels
- Frequency, Rate of Change of Frequency (ROCOF)
- Harmonic distortion levels (THD for voltage and TDD for current)
- Harmonic histograms
- Voltage symmetrical components
- Voltage sag and swell, and
- Short duration transients.

Most PMU-based IEDs can provide data at 60 samples/second or even at higher sampling rate. Specific devices may provide lower data resolution. However, in this project, we used 30 frames per second for phasor data and analog values coming from PMUs, to be consistent with standard practice for PMU devices that were already installed and configured in the field.

In order to capture fast transients and issues associated with power electronic based DERs, higher data sampling resolution will be beneficial. The project shown that most transient events could be captured and reported with 30 samples per second. Lower resolution may be acceptable for the voltage quality analysis such as momentary outage, voltage sags/swell or profiling/trending.

2.4.1 Monitoring Requirements

Monitoring of the distribution circuits under consideration in this project was considered from the following two aspects:

- Operator requirements
- Engineer needs.

Operators are interested to get a ‘big picture’ view of the system in real or near real-time and want to be able to make informed actionable decisions based on the information presented by a system, similar to the opera-

tion control room. An environment that suits well this kind of visualization is Geospatial Information System (GIS) platform.

On the other hand, engineers prefer to have tools that can provide more insight into the system, so they can see more details at faster sampling rates, or to look at historical data and perform all sorts of analyses.

The proposed design and visualization provided parameters and indicators addressing the needs of both group (i.e. operators and engineers).

2.4.1.1 Modes of Operation

The visualization applications described in this document needed to have three operation modes:

a. Real-time monitoring: These applications operate on streaming data inputs in real-time. They are mainly intended for real-time or ear-real time visualizations and alarm generation. Applications are mostly based on the data streaming from PMU or SCADA measurements.
b. Near-Real-time for quick access to recent events (events retrieval).
c. Off line/replay mode for post-event forensic analysis: These applications operate on archived data. They are mainly intended for an analysis of past events.

2.4.1.2 Real-Time Monitoring Mode

In the real-time monitoring mode, users will be provided with the measurements using real-time PMU, SCADA[1] and other input monitoring and measurements[2]. Examples were: Trending of voltage, current, active and reactive power profiles across the system.

Trending may be done:

- as a function of time, by stacking the PMU measurements from various devices in time frame, or
- as a function of PMU locations on a circuit, covering the circuit coverage and monitoring extent.

[1] SCADA data sampling rates are between 1 and several seconds and, but we consider it as real-time data since they can be presented to operators as soon as they become available.

[2] NOTE: In this project, some of the measurements were simulated by RTDS system but they will be generated at the rates equal to data rates provided by actual PMU devices. The visualization platform does not differ the simulated from field data, and for this reason we will treat both simulated and field data the same way, and both categories will be referred to as 'real-time data'

2.4.1.3 Data Retrieval and Events Replay Mode

This mode of operation allowed search for data stored in the historical database (historian). Selected events could be retrieved and replayed in a similar manner as live data coming from the field. Once the data was selected for replay (based of the time stamp and duration), the data was retrieved from the data historian replayed to user. The GUI provided same look and feel as if the data was streamed from the field in real-time. The only difference was an indicator showing that the data is being replayed.

2.4.1.4 Graphical User Interface

A graphical user interface (GUI) was required for visualization of input data and for visualization of outputs created by various analytics tools and applications. The GUI consisted of a multitude of displays that served various purposes. GUI is described in more detail later in this document. Some of the more important displays of the GUI are:

- Control Panel, also known as a Dashboard
- Applications buttons used to call up additional applications, dashboard and displays
- Additional displays embedded within the Dashboard.

The control panel allowed the user to do the following:

- Allow use to see at high level what is going on in the monitored area of interest
- Select real time mode or event replay mode
- Start various internal or external applications
- Start various displays based on variety of data sources
- Start, pause, resume, rewind or stop event replay.

Visualization Displays could be called from the Dashboard or within other applications. For instance, the Dashboard can have a push button that opens another display with applications based on PMU data. Similarly, a push button may be created to start a set of applications addressing Power Quality, or system reliability, to name a few.

Various custom-designed displays allowed users to monitor the status of the distribution system of interest, to provide awareness about what is going on in real-time, and to help assess the situation and provide useful tools for making informed decisions about necessary control of the system. This functional requirements document provided a more detail description of displays relevant for the Integration of Customer Systems into Electric Utility Infrastructure project, but it can be easily customized and expanded to serve additional objectives.

2.4.1.5 Computations

Graphical user interface and visualization were needed to show the operator what's going on in the system in a graphical manner. However, raw field data obtained through PMU (high resolution data) or SCADA measurements (data reporting by exception at low resolution) was not very useful for assessing what's going on in the distribution system beyond seeing how directly measured data from the field changed in time. To have a better assessment of the status of the network under consideration, there was a need to process the measurements to provide information about the system that operator can understand and act upon. This pro-

cessing was done through a well-defined analytical computations, defined as a set of applications. The computational engine for these applications performed in the background and the results were presented via a set of customized displays.

Some of the computations involved a very simple processing, such as averaging, counting, simple arithmetic operation and similar. On the other hand, there were applications that required more elaborate calculations and they were based on computational and programming tool such as MATLAB and C#, to name a few.

2.4.1.6 Data Flow

A high-level system architecture and corresponding data flow is shown in the Figure 2-3 below. In this architecture, fast sampled real-time data is streamed from PMU measurements and received by Phasor Data Concentrator (PDC) to capture and store phasor data. The PMU data is sent to SynchroWAVe Central for further processing and visualization. Another class of data, is collected via SCADA system and processed by DMS in the control center. SCADA measurements and application results are retained in PI Historian, which is the repository for other data types as well (including Power Quality data, for instance).

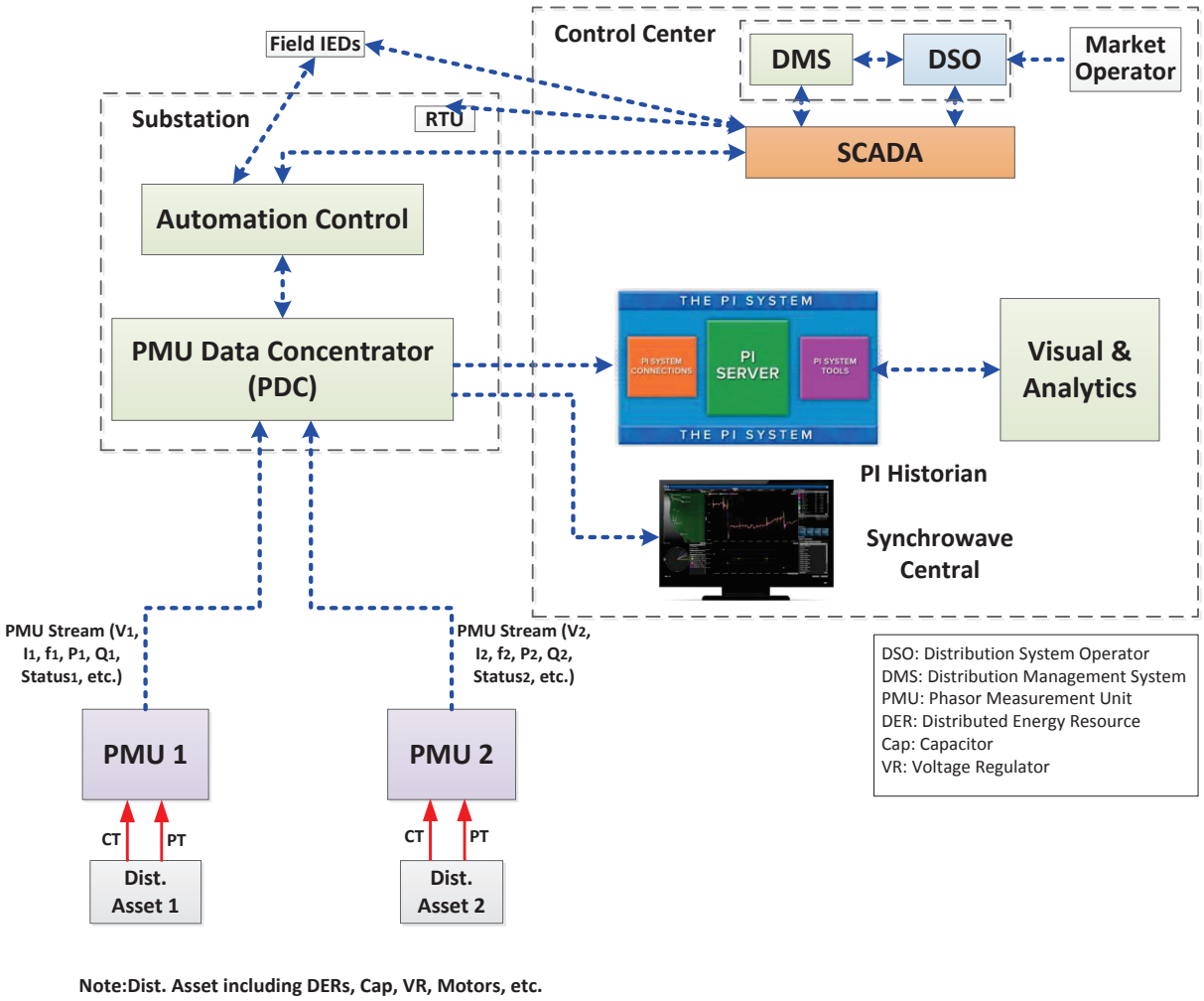


Figure 2-3. High-Level System Diagram and Data Flow for Visualization and Analytics Applications

2.4.2 Analytical Approach and Performance Indices to Streamline Operator Observations

This section describes list of methods and applications that were processing the input data and providing visualization of calculated values. For some visualization displays, a rudimentary data processing was needed, while other may require more elaborate data processing using programing tools such as MATLAB, C#, and similar programs.

The complete list of all categories of the data and information that needed to be visualized, how the information (either based on measurements or as a result of some processing) could be displayed, and possible users (Distribution Operators) or the Engineering Analysis group) are described in the following sections. These categories are listed in order of complexity to implement, as follows:

a. Measurements

b. Indicators
c. Performance Indices
d. Applications based on use case

Note that visualization aspects of these four categories above are discussed in more detail in Section 5, Operator Visualization and Display Screens.

2.4.2.1 Visualization and Measurements

This category of graphical displays takes data values coming from two sources, PMU and SCADA and presents them in appropriate format. Depending on the mode of operation (*real-time* or *post event analysis*) data source the real time PMU and SCADA measurements or their replay is used to feed the displays. The Table 2-10below shows the list of the measured parameters and possible ways to display them. The monitored data may be used by operators (for the purpose of day to day operation) or by engineers performing root-cause analysis or investigating certain events.

Table 2-10. Measurement Parameters of Monitoring Schemes

				Display Type							Users	
No	Method	Source	Description	Display in Time	Tabular	Alarm	Histogram	Phasor Diagram	Map Display	Trending	Operators	Engineers
1	Real-time Field Data	PMU	Voltage magnitude	Y	Y	Y		Y			Y	Y
2		PMU	Voltage angle	Y	Y	Y					Y	Y
3		PMU	Current magnitude	Y	Y	Y		Y			Y	Y
4		PMU	Current angle	Y	Y						Y	Y
5		PMU	Active power (total load)	Y	Y	Y	Y	Y			Y	Y
6		PMU	Reactive power	Y	Y	Y	Y				Y	Y
7		SCADA	Active power (total PV or various DERs)	Y	Y	Y	Y		Y	Y	Y	Y
8		SCADA	Customer Load				Y					
9		SCADA	Tap Position & Cap status	Y	Y				Y		Y	Y
10		PMU	Frequency	y	Y	Y					Y	Y

2.4.2.2 Indicators

Indicators are the second category of data that are of interest to present to operators or engineers. The list of indicators of interest is shown in Table 2-11. It is important to mention that for some of these indicators (such as Voltage trends, Phasor diagrams, Rate of change of frequency) can be displayed in a straightforward manner, using a standard set of displays within existing commercial platforms. Other indicators, such as those related to harmonics cannot be obtained from PMUS. Instead, other SW packages that can handle Power Quality parameters need to be used. Currently, SDG&E is using PQ View package. In this case, there needs to be a means to invoke PQView within the Visualization dashboard so Harmonic Histograms and Odd/Even Harmonics can be presented visually.

The list of indicators include parameters obtained from PMUs or PQ meters, such as:

- Voltage trends
- Phasor diagram
- Rate of change of frequency (ROCOF)
- Harmonic histograms and harmonics
- Symmetrical components
- Vector jump

- Voltage Phase Balance
- Neutral Voltage Shift

Table 2-11. Indicators for Visualizing Data

				Display Type							Users	
No	Method	Source	Description	Display in Time	Tabular	Alarm	Histogram	Phasor Diagram	Map Display	Trending	Operators	Engineers
1	Measurement data or Simple Processing	PMU	Voltage trends					Y		Y	Y	Y
2		PMU	Phasor diagram	Y	Y			Y	Y			Y
3		PMU	Rate of change of frequency (ROCOF)	Y	Y	Y	Y	Y	Y	Y	Y	Y
4		PQ meters	Harmonic histograms (obtained from PQ View)				Y					Y
5		PQ meters	Odd/even harmonics* (obtained from PW View)		Y					Y		Y
6		PMU	Symmetrical components (discuss if it is		Y			Y				Y
7		PMU	Vector jump (need to discuss further)		Y	Y	Y			Y		
8		PMU	Voltage Phase Balance									
9		PMU	Neutral voltage shift						Y			
10		Post Processor	Short duration transients (obtained from PQView)	Y	Y					Y		Y

2.4.2.3 Key Performance Indices for Visualization of Data Monitoring

Several key performance indices (KPI) are of interest for both operators and engineers. The indices clearly define the status of the system and expected impacts with pre-specified criteria to determine the level of violations. Table 2-12 below shows the list of the KPIs of interest.

2.4.2.3.1 KPI Based on Count Rate Calculations

Some of the performance indices are based on count rate calculations and they include System Average RMS Variation Frequency Index (SARFI), and tap position and capacitor counts. SARFI gives the average number of events (sags, swells, or interruptions) of a system over the assessment period, usually one year, per customer served. The size of the system is scalable: it can be defined as a single monitoring location, a single customer service, a feeder, substation, a group of substations, or an entire power delivery system. There are two types of SARFI indices: SARFI-X and SARFI-Curve.

SARFI-X corresponds to a count or rate of voltage sags, interruptions, and/or swells below or above a specified voltage threshold. For example, SARFI-90 considers voltage sags and interruptions that are below 0.90 per unit, or 90% of the reference voltage. SARFI-70 considers voltage sags and interruptions that are below 0.70 per unit, or 70% of the reference voltage. SARFI-110 considers voltage swells that are above 1.1 per unit, or 110% of the reference voltage. It is important to mention that the SARFI-X indices are meant to assess short-duration rms variation events only, meaning that the only events included in its computation are those with durations less than the minimum duration of a sustained interruption as defined by IEEE Standard 1159, which is 1 min.

SARFI-Curve corresponds to a rate of voltage sags below an equipment compatibility curve. For example, SARFI-CBEMA considers voltage sags and interruptions that are below the lower Computer Business Equipment Manufacturers Association (CBEMA) curve (CBEMA is now the ITI).8 SARFI-ITIC considers voltage sags and interruptions that are below the lower ITIC curve. SARFI-SEMI considers voltage sags and interruptions that are below the lower SEMI curve. Again, these curves limit the duration of an rms variation event to the minimum duration of a sustained interruption as defined by IEEE Std 1159, which is 1 min.

K-factor for an electrical network primarily relates to non-linear loads and is defined as a number representing the effect of harmonics on heating of transformer. For calculating the K-factor all the harmonics up to a predefined limit are considered. For industrial loads of induction motors, up to 25th harmonic currents are considered but the limit can be up to 50th.The formula for calculating the K factor of a network is[1]

$$K_{factor} = \sum (I_h) h^2$$

As from the formula, while calculating the K-factor, the harmonic current is being multiplied by the square of its number. Therefore, for higher order harmonics, being multiplied by the square of their number even small harmonic current will give considerable effects on the K-factor. For a linear network, the K factor will always be 1. As the harmonic content increases in the current, the K factor moves upwards from 1. Electronic ballasts, induction motors, UPS and all diode based switching circuits come under non-linear loads causing harmonics.

K-factor of the electrical distribution network is the reason why transformers need to be de-rated. While supplying the non-linear loads, harmonic currents flow in the transformer and to protect the windings and transformer oil from overheating, load on it needs to be reduced.

2.4.2.3.2 KPI based on near real-time calculations

Some of KPIs are based on Power Quality (PQ) measurements, and therefore cannot be obtained from PMU or SCADA data. Instead, they are measured by power quality (PQ) meters:

a. Total Demand Distortion (TDD)
b. Total Harmonic Distortion (THD)
c. Voltage unbalance factor
d. Short and long-term flicker factor

More info about these parameters and how they are calculated can be found in IEEE standards 519-2014, 1159-2009, and 1453-2005.

2.4.2.3.3 KPI based on long-term calculations

This category of indices includes:

- Solar radiation related parameters, such as
  - Daily Clearness Index (DCI) [7,8] and
  - Daily Variability Index (DVI) [7,14]
- Thermal limit (short and long-term), and
- Reliability indices, such as
  - System Average Interruption Duration Index (SAIDI),

[1] See https://zenatix.com/k-factor-for-transformer/

- System Average Interruption Frequency Index (SAIFI),
- Customer Average Interruption Duration Index (CAIDI), and
- Customer Average Interruption Frequency Index (CAIFI).

Table 2-12. Key Performance Indices for Visualization of Field Monitoring

				Display Type							Users	
No	Method	Source	Description	Display in Time	Tabular	Alarm	Histogram	Phasor Diagram	Map Display	Trending	Operators	Engineers
1	Count Rates Calc.	PI Historian	Voltage Swell (SARFI-110) - post-processing based		Y		Y		Y	Y	Y	
2		PI Historian	Voltage Sag (SARFI-80, SARFI-90), post-		Y		Y		Y	Y	Y	
3		Post Processor	Cummulative Tap and Cap Status counts		Y							
4		PI Historian	SARFI-SEMI		Y		Y		Y	Y	Y	
5		PI Historian	SARFI-ITIC (CBEMA)		Y		Y		Y	Y	Y	
6		PI Historian	K-factor (transformer derating) (Substation transformers, as it has sensors)		Y	Y	Y		Y	Y	Y	
7	(Near) Real Time Calculations	PMU/PQ meter	TDD (Available from PQ View)		Y		Y		Y	Y		Y
8		PMU/PQ meter	THD (Available from PQ View)		Y		Y		Y	Y		Y
9		Post Processor	Crest factor (distortion factor)		Y		Y		Y	Y		Y
10		PI Historian	Voltage unbalance factor (doing it in SCADA, pull this information)		Y		Y		Y	Y		Y
11		PI Historian	Flicker factor (short term)	Y	Y		Y			Y		Y
12		PI Historian	Flicker factor (long term)		Y		Y			Y		Y
13	Long-term Calculations	Post Processor	DCI (Daily Clearness Index)		Y		Y			Y	Y	
14		Post Processor	DVI (Daily Variability Index)		Y		Y			Y	Y	
15		Post Processor	Thermal limit (Lookup table for short and long-term limits)		Y	Y	Y			Y	Y	
16		Post Processor	SAIDI (available, for the whole network) (minute basis)		Y		Y			Y		
17		Post Processor	SAIFI (available, for the whole network)		Y		Y			Y	Y	
18		Post Processor	CAIDI (available, for the whole network)		Y		Y			Y	Y	
19		Post Processor	CAIFI (available, for the whole network)		Y		Y			Y	Y	

2.4.2.4 Applications of Field Monitoring

The applications are based on the functions described in use case documents that were selected, as shown in Table 2-13 below.

Table 2-13. List of applications based on use cases

				Display Type							Users	
No	Method	Source	Description	Display in Time	Tabular	Alarm	Histogram	Phasor Diagram	Map Display	Trending	Operators	Engineers
1	More elaborate Calculations (From Use Cases)	PI Historian	Voltage Power Flow Monitoring (VPFM)	Y	Y	Y	Y	Y	Y	Y	Y	Y
2		PI Historian	Primary Distribution Asset Operation Monitoring and Diagnostics (PDAMD)	Y	Y	Y	Y	Y	Y	Y	Y	Y
3		PI Historian	Data Quality Validation for Field PMUs (DQV-FP)	Y	Y	Y	Y	Y	Y	Y	Y	Y
4		PI Historian	Equipment Overload Detection (EOLD)									
5		PI Historian	DER Interconnection Compliance (DER-IC)	Y	Y	Y	Y	Y	Y	Y	Y	Y
6		PI Historian	Water Treatment Facility Monitoring and Reactive Power Management (LICFM)	Y	Y	Y	Y	Y	Y	Y	Y	Y

Explanation below provides more details about each of the applications from this table. Implementation details for each of these applications are provided in the Use Case documents (see attachments), prepared during this project for the purpose of the system design.

2.4.2.4.1 Voltage Power Flow Monitoring (VPFM)

The application based on this use case is relatively simple. The phasor data is used to calculate various power quality aspects of a circuit, in addition to voltage and current profiles, including:

- Voltage profiles based on measurements as selected nodes
- Active and reactive power flow across circuit
- Rate of change of power (ramp rate)
- Rate of change of frequency
- Power factor
- Phase angle jump (or vector jump)
- Sequence components (V1, V2, V0, I1, I2, I0)

Also, logic and mathematical functions based on the information reported from the device can be used to calculate and publish various indices in real-time measurement.

Examples are:

- Voltage sensitivity to change in active and reactive power (dV/dQ and dV/dP)
- Voltage unbalance factor (V2/V1).

Some statistical information is also important and can be extracted from the records of historical data, such as:

- Number and level of voltage sags and swells (per day, per week or user selected timeframe such as the last 2 days or so)
- Number and duration of any momentary or extended interruptions (per day, per week or user selected timeframe such as the last 2 days or so).

In addition, PMU data is used to provide:

- Demand and generation information in various parts of the circuits based on pre-defined zones
- Trends and heat maps of total generation versus loads,
- Comparison of equipment loading and ampacity (load carrying capacity), as well as flagging any possible overloading issue.

2.4.2.4.2 Primary Asset Operation Monitoring and Diagnostics

The objective of this application is:

- To monitor the distribution assets operation and gather supportive data and information that can help quantify the possible wear and tear of assets
- To identify potential issues with assets and provide diagnostic solutions
- To use asset monitoring data along with appropriate data analytics to serve the purpose of implementing condition-based monitoring, diagnostics and scheduled maintenance of asset.

This application focuses on PMU use for monitoring of distribution asset operation including status of switched capacitor banks, number of tap operation for voltage regulators and LTC, operation of reclosers and automated switches, and loading of distribution transformers. The installed PMUs at these assets can stream digital information regarding the asset status (open/close, tap position), in addition to the voltage, current and

power flow values that are used to determine asset loading and utilization factors. Based on the asset status information reported by PMU devices, statistical data on the asset operation intervals and asset condition are traced and reported, such as the number of daily and cumulative tap operation for voltage regulators and load tap changer, number of switched capacitor operation and daily counts, and cumulative load curves.

It should be noted that generally distribution assets are the number one candidates for placing PMU-based intelligent electronic devices (IEDs) such as relays or digital controllers. Hence, obtaining information about the device operation should be easily achievable. The raw data about device status or number of operation will naturally come as part of data reporting from PMU devices associated with selected switchable assets. Hence, the main requirement would be to use the raw data and track the life cycle related information of the devices.

2.4.2.4.3 Data Quality Validation of Field PMU

The objective of this use case is to determine methods for validating field data quality. These include adding measurement reference points and defining expected patterns of variations and ranges of measurements for cross-checking. Reference points can be generated from neighboring locations in the field, or through simulation. Acceptable deviations from reference points should be added for flagging and alarming probable data quality deterioration. In some cases, probable root-cause of the data quality issue may be easily identified, for instance - being a sensor problem, a device problem or a communication link issue. In other cases, a deeper analysis may be needed. This may allow SDG&E to improve the logic for data quality flagging and alarming.

2.4.2.4.4 Equipment Overload Detection

The objective of this application is to:

- Detect equipment overloading
- Identify areas under stress
- Identify circuit congestions (with limitation in power flow).

Sizing for overload is important to avoid serious damage for distribution equipment such as transformers, overhead lines and cables, motors/generators and etc. A real-time measurement of distribution assets support monitoring loading of the equipment all the time and providing different level of alarming to recognize and size the loading of equipment in system normal or under stress operations. Most of the assets are equipped with overload protection devices to disconnect device and avoid serious damage under the overload situation. Having real-time monitoring of loading, system operators can follow loadings of equipment and the trend of its behavior under different normal operation scenarios as well as network events.

2.4.2.4.5 DER Interconnection Compliance

The main objectives of this applications are:

- To use the real-time PMU measurements to assess real-world operational conditions of circuit and response of interconnected DERs
- To use monitored data to evaluate and validate DER behavior under the different circumstances such as:

- DER response to changes in voltage levels, including verification of ride-through curves, and Volt/VAr schemes applied by DERs
- DER inverter behavior under the faults and their fault contribution
- DER connection, disconnection and re-connection timing, any existing ramp up, and time segregation requirements for plants with multiple units.

- To provide recommendations and solutions to planning engineers and system operators to better manage DER interconnections.

2.4.2.4.6 Large Industrial Customer Facility Monitoring

This function is divided in two applications:

1. Reactive power management
2. Flexible local generation usage.

2.4.2.4.7 Reactive Power Management

The main objective of this application is to coordinate and mange operation of large/critical industrial facilities such as Water Treatment Plants with the grid. The key operation aspects from the grid point of view are Real and Reactive power consumption, as well as potential adverse power quality issues (harmonics).

Specifically, for the reactive power management, the main value-added feature and advantage offered by the use case will be coordination of reactive power requirements from the plant with operation of shunt capacitors on the associated circuit feeding the plant.

Proper reactive power management supports loss reduction on circuits. Through reactive power control, voltage profile of the circuit can also be controlled and maintained within standard range. In selected circuit, specifically, there are three Line Monitoring locations which monitor two large pumping stations and one end-of-line circuit branch. The end-of-line location does not monitor any water facilities and therefore will be used only to monitor the overall power quality of the circuit. The other two locations monitor Water Treatment Plant's east and west pumping station. There are also two switched capacitors installed at two pumping stations which could be used as a reactive power support when the reactive power demand exceeds a certain threshold.

2.4.2.4.8 Flexible Local Generation Usage

The main purpose of this application is to shift most of the water treatment plant (WTP) demand to the daytime hours with high PV production. If a circuit has large amount of PV, one of the major operational issue is to manage power flow and corresponding voltage profile. The issue is more severe under light load condition of the circuit, causing reverse power flow.

If the circuit load can be controlled by the operator to coordinate operation with customer demands to provide a flexible usage schedule, additional load can be brought online, as needed, during high production time. Hence, coordinating load and generation can be applied by the operator to manage voltage profile and extensive operation of voltage control devices on a circuit.

To reduce energy cost in a WTP, the operating schedule for major load (large motor pumps) is closely planned during the off-peak time of the system (10 pm to 5 am). However, if proper energy cost policies can be agreed for daytime usage, to provide low cost and/or incentive driven energy consumption, the method can be used to control voltage and frequency. This approach is essentially beneficial during emergency water shortage time, when the facility has to operate pumps during daytime to fill up water tower, due to unplanned excessive water usage.

To implement flexible usage application, a new energy cost structure should be prepared to encourage daytime usage. In addition, integrating large load facilities into overall system planning and operation can make them part of critical system asset to balance load and generation. Using the dispatchability aspect of the WTP, and solar prediction, the load can be controlled to match with high PV production and avoid reverse power flow.

Furthermore, performing operation during times when renewable energy is abundant can minimize the carbon footprint needed to treat and deliver potable water to the county and thus impacting the overall Water Energy Nexus.

2.5 Development of Monitoring, Control and Operation Practices in Support of Customer Installations

The task objective was to propose and design advanced monitoring and control practices that can close the gaps in the exiting schemes to properly investigate any adverse impact and facilitate customer system integration. All of the following aspects have been incorporated: system capabilities, monitoring devices and data capturing and post-mortem analysis. The main activities in undertaking this task were:

- To determine the response requirements and operational practices to support customer systems
- To define the monitoring requirements and system architecture, including the communications and controls for advancement of system operation
- To investigate capabilities of commercially available sensors, power quality and/ revenue metering devices, and phasor measurement units (stand-alone or as part of other IEDs) that can provide high resolution data measurement and power quality data capturing and transient event recordings, such as:
    - Voltage and current phasors
    - Power flow (active and reactive)
    - Frequency tracking and reporting rate of change of frequency (ROCOF)
    - Harmonics and THD/TDD measurements
    - Fast transients
    - System status information, including switch position, voltage regulators, tap positions; and
    - circuit connectivity information

- To evaluate product capability documents from vendors; or perform laboratory tests on selected measurement devices (sensors, IEDs, PMUs) to determine accuracy, measurement resolution and quality and type of measurement data such as transient events, to understand and document expected device performance
- To define PMU requirements specific to distribution systems
- To prepare settings and configuration files for the devices in the field to support project data gathering and device control needs
- For cases of inadequate device capability and/or coverage, propose temporary methods and devices to be incorporated in the real-time simulation environment to supplement the existing devices and data coming from the field for the purpose of evaluating the tools under development.

2.5.1 Survey of Commercially Available PMU Devices

As part of identification of the devices suitable for the system integration and pre-commercial demonstration, a survey of available automation/protection/monitoring devices with PMU capability was conducted. The survey focused on devices commercially available in the market for deployment in electric distribution systems. For the purposed of comparison, the result of this survey was used to select vendor devices for the demo set-up in the lab.

A number of the listed devices in the survey table have been already deployed in SDG&E distribution circuits, and their phasor data have been monitored in near real time.

Based on the survey and desired features, 4 devices have been selected for a detailed performance evaluation based on a hardware-in-the-loop RTDS testing (Type test). They were compared with a reference PMU device that has PMU certification based on NIST certification standard. Furthermore, the same devices have been utilized in the pre-commercial demonstration.

The selected devices were:

1. PMU Device 1: a protective relay usually installed at DER location; e.g., PV site, diesel generator POI to the feeder,
2. PMU Device 2: a commonly used feeder protection relay in SDG&E distribution circuits,
3. PMU Device 3: an offering from a new vendor in PMU market.
4. PMU Device 4: a new generation of fault recorder that has been considered by SDG&E as a potential option for future installation).

In the rest of this section, methodology and results of the type tests have been reported.

2.5.2 Type Test: Performance Comparison of the Selected PMU Devices

The objective of these tests was to evaluate the performance and capabilities of the aforementioned PMUs from the following aspects:

- Evaluating compliance of vendor products that are not commonly used at SDG&E distribution system
- Evaluating of the devices under test (DUTs) for providing high resolution data measurement (60 and 30 frames per second) and power quality data capturing and transient event recordings
- Determining accuracy, measurement resolution, quality and type of measurement data such as transient events for specific distribution system applications
- Evaluating interoperability of the PMU devices and measurement/communication features to make sure devices can be integrated with products from other vendors in a multi-vendor environment
- Capability to transfer analog and digital signals in C37.118 format – for values internally calculated at device level (for example, THD or flicker, etc.)

The test results were used to select appropriate devices and to develop measurement features for the integration testing and monitoring of distribution applications in support of customer technology integrations.

Note that only the results of selected tests from each test group are presented in this document. The reason is that many of the tests are very similar in each test group and repeating similar results does not provide any additional information. However, all the results of different tests were submitted in a complete test report to SDG&E.

2.5.2.1 Type Test Approach Description

A real-time digital simulator (RTDS) has been used to represent a 12 kV simplified distribution circuit where the devices under test (DUT) are connected at certain locations for voltage and current measurements. A simplified single line diagram of the RTDS real time view of the model is shown in Figure 2-4. The location of the PMU device under the test is shown with a red rectangular (PQ meter) where the voltage and current signals are taken.

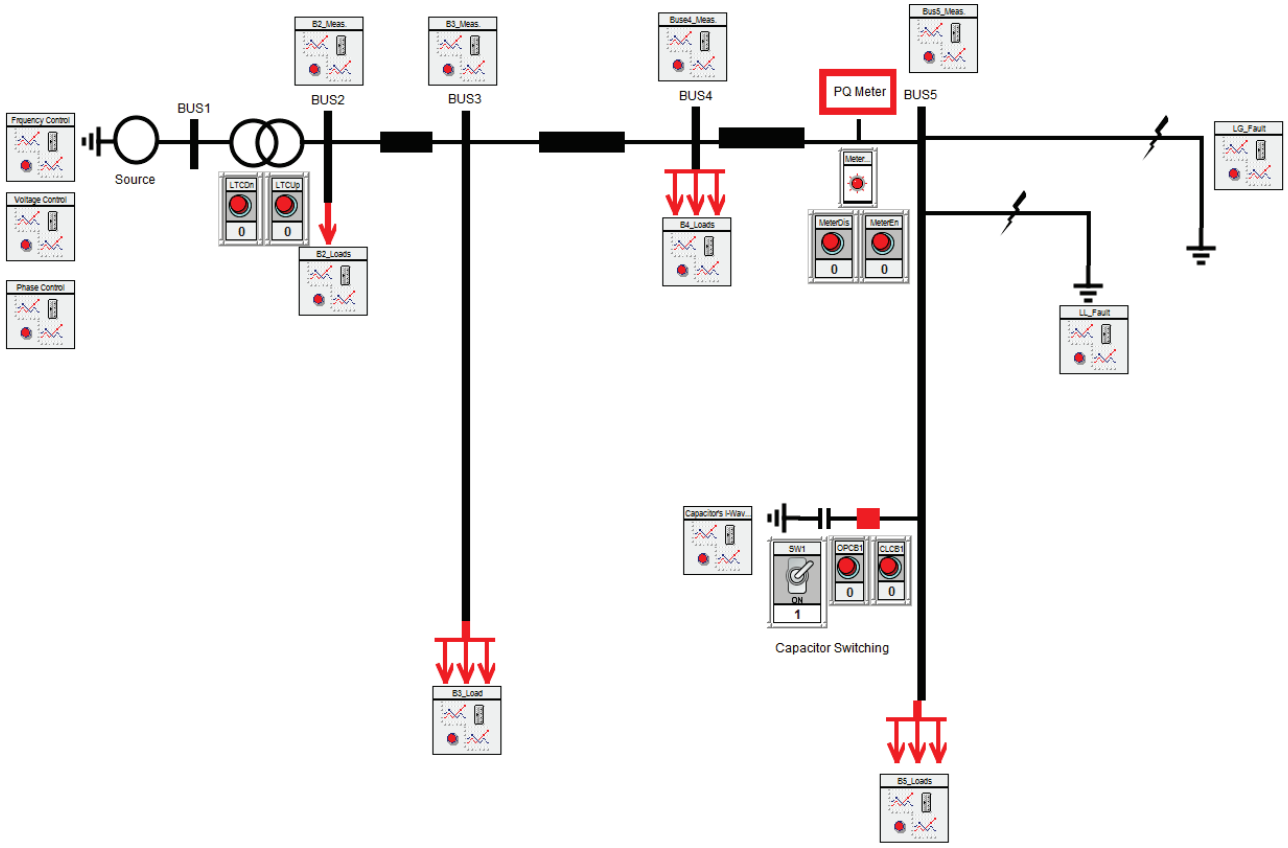


Figure 2-4. Real-time RTDS View of the Distribution Circuit Used for Device Tests

A Phasor Data Concentrator (PDC) was used to communicate with DUTs, capturing PMU data streams for data analysis and performance evaluation. Different test categories under either steady state system conditions or dynamic system conditions were performed to evaluate the performance of each DUT. For the test categories to be performed, all DUTs were configured with the maximum available phasor and analog measurements based on the DUT capability.

Depending on the test, the performance of PMUs was evaluated through Total Vector Error (TVE), Frequency Error (FE), Rate of change of Frequency Error (RFE), or the transient response comparison of the PMUs.

2.5.2.2 Testbed setup

The hardware testbed for PMU performance testing was setup and operated at the RTDS lab in SDG&E ITF. A PDC unit was setup for data stream capturing and interoperability tests. The general layout of the testbed is illustrated in Figure 3-5, consisting of the following components:

- **RTDS:** used to simulate the virtual PMU and a 12kV simplified distribution circuit including: a source, line impedances and loads.
- **PMU Device 1:** DUT1 for phasor data measurement and streaming

- **PMU Device 1:** DUT2 for phasor data measurement and streaming
- **PMU Device 3:** DUT3 for phasor data measurement and streaming
- **Reference PMU:** DUT4 for phasor data measurement and streaming. It is used as the reference PMU.
- **GPS clock** used for time synchronization of RTDS, DUTs.
- **PDC** for communicating with DUTs, capturing PMU data streams and evaluating DUTs' performance
- **Power amplifier**

Figures 3-5 and 3-6 show the block diagram of the type test setup as well as actual setup at the SDG&E ITF Lab.

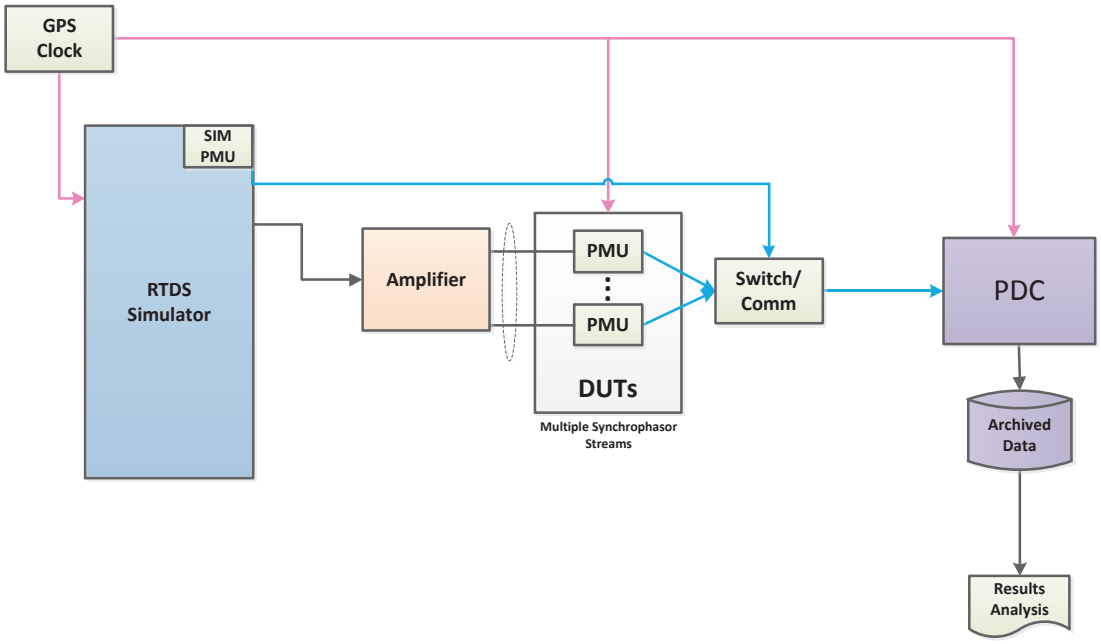


Figure 2-5. PMU Testbed Setup layout



Figure 2-6. PMU Test Setup at the ITF lab

2.5.2.3 Summary of Test Cases and Categories

Test cases have been categorized in 3 main groups:

a. Category 1: Steady state performance test. In this test category, the performance of the PMUs subsequent to different steady state conditions such as frequency variations and harmonics was studied.

b. Category 2: Dynamic performance test. Different transient scenarios such as cap switching, frequency ramp, and voltage and phase angle step change were applied to the PMUs, and their responses were compared.

c. Category 3: Verification of analog and digital data streaming. In this test category, aim was to verify a DUT capability for streaming locally measured power quality parameters or any parameter that was calculated at device level using mathematical and logical blocks.

2.5.2.4 Evaluation Method

PMU type tests focused on testing the M performance class of DUTs according to the definition in IEEE C37.118 - 2011. Before the representation of the results, it is necessary to provide some definitions:

Total Vector Error (TVE): TVE is defined as:

$$TVE = \frac{|V_{measured} - V_{true}|}{|V_{true}|}$$

In which (V_{true}) is the reference phasor and $V_{measured}$ is the phasor obtained from the PMU. In this report, the reference phasor(V_{true}) is considered as the output of the Reference PMU, because it is a certified PMU.

Frequency Error (FE): FE is defined as

$$FE = |f_{true} - f_{measured}|$$

Rate of Change of Frequency Error (ROCOF or RFE): RFE is defined as

$$RFE = |\left(\frac{df}{dt}\right)_{true} - \left(\frac{df}{dt}\right)_{measured}$$

2.5.2.5 Category 1: Steady-State Performance Test

The purpose of this test category was to test the DUTs' performance under steady state conditions. The phasor measurements estimate under steady-state conditions were compared with the Reference PMU measurement and FE and ROCOF are compared to the nominal values.

TVE, FE, and RFE was calculated and compared with defined limits in IEEE C37.118.1. Several test groups was considered in this test category. All the test groups in category 1 were performed with DUTs' reporting rate set at 60 frames/second.

2.5.2.5.1 Group 1: Voltage Magnitude Test

Group 1 tests were designed for evaluating the DUTs' performance for steady state voltage magnitude measurements. For group 1 tests, balanced three phase system voltages and currents at nominal system frequency were applied to the DUTs. Each of the following test cases was repeated 3 times for test results validation.

- **Case 1-1-1:** System voltage was set at nominal system voltage and the PMU data streams were captured for 5 seconds. The following figures show the TVE for voltage phasors, FE and RFE.

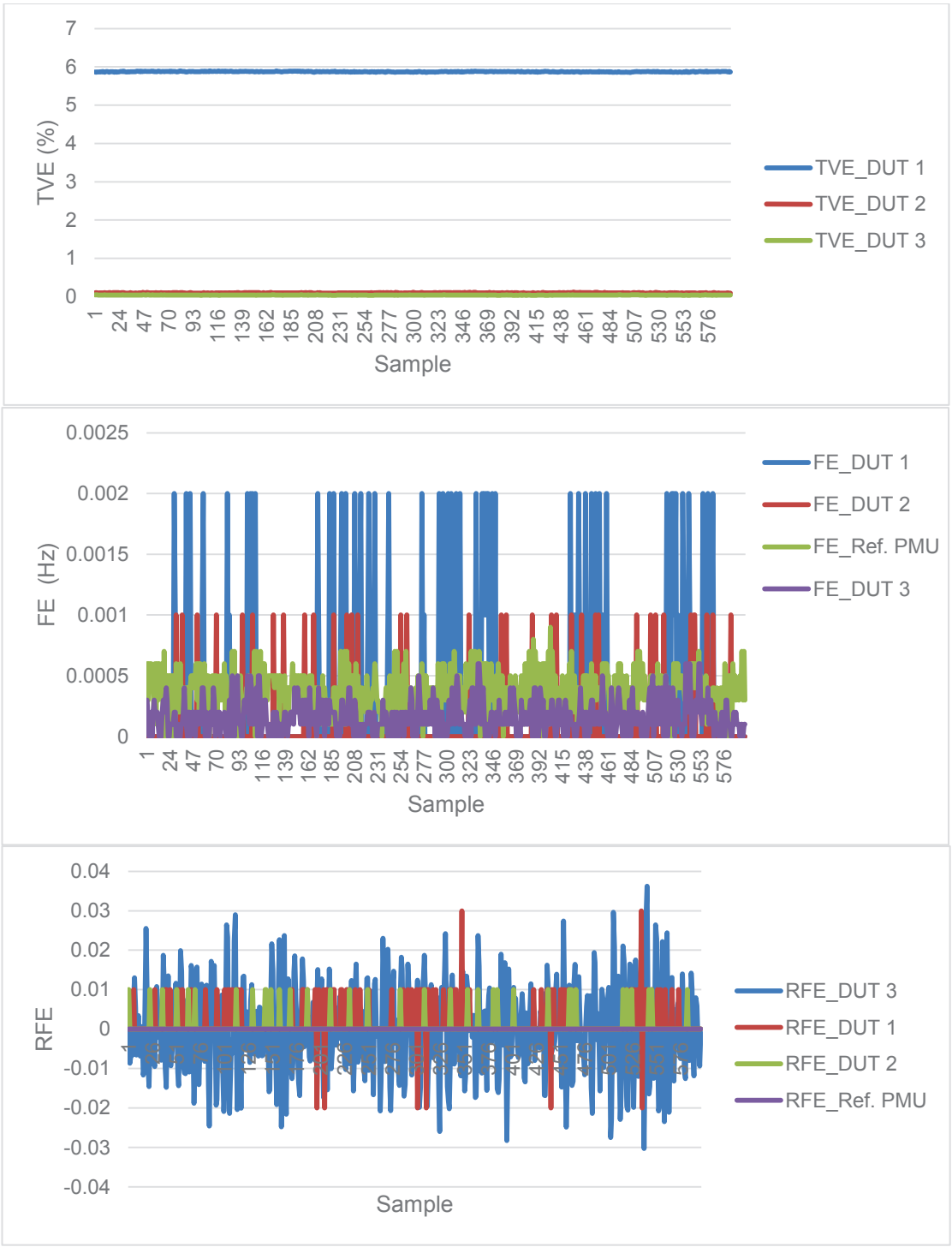


Figure 2-7. TVE, FE, and RFE Comparison for Nominal Voltage (Case 1-1-1)

- **Case 1-1-2:** System voltage was set at 50% of nominal system voltage and the PMU data streams were captured for 5 seconds. The following figures show the TVE for voltage phasors, FE and RFE. Except DUT1, all other devices showed acceptable results and errors within the expected range. The measurement offset of DUT1 created a large TVE % error comparing to others.

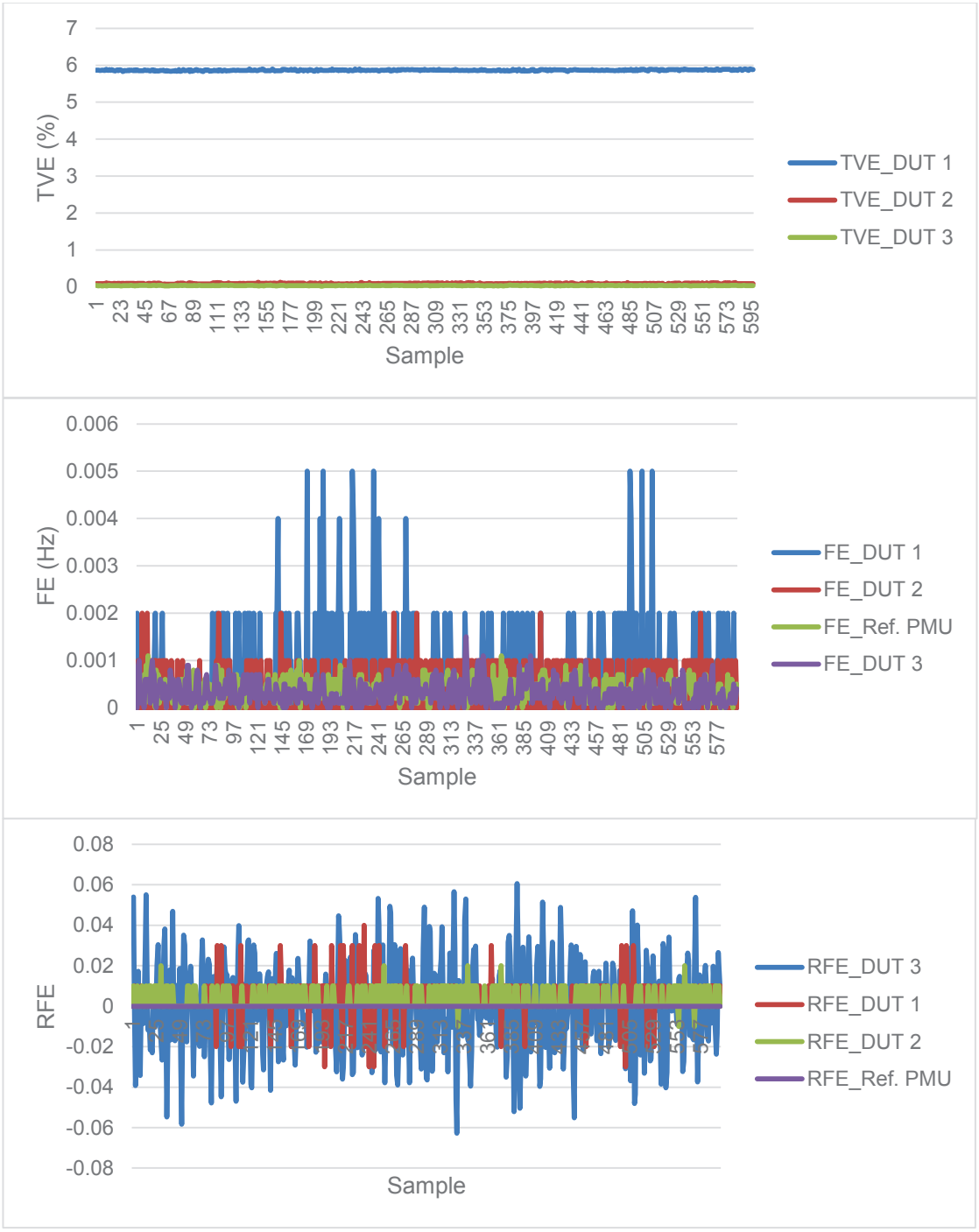


Figure 2-8. TVE, FE, and RFE Comparison for 50% of the Nominal Voltage (Case 1-1-2)

- **Case 1-1-3:** System voltage was set at 130% of nominal system voltage and the PMU data streams were captured for 5 seconds. The following figures show the TVE for voltage phasors, FE and RFE. As can be seen, DUT 1 had a 6% error due to inaccuracy in phasor measurements.

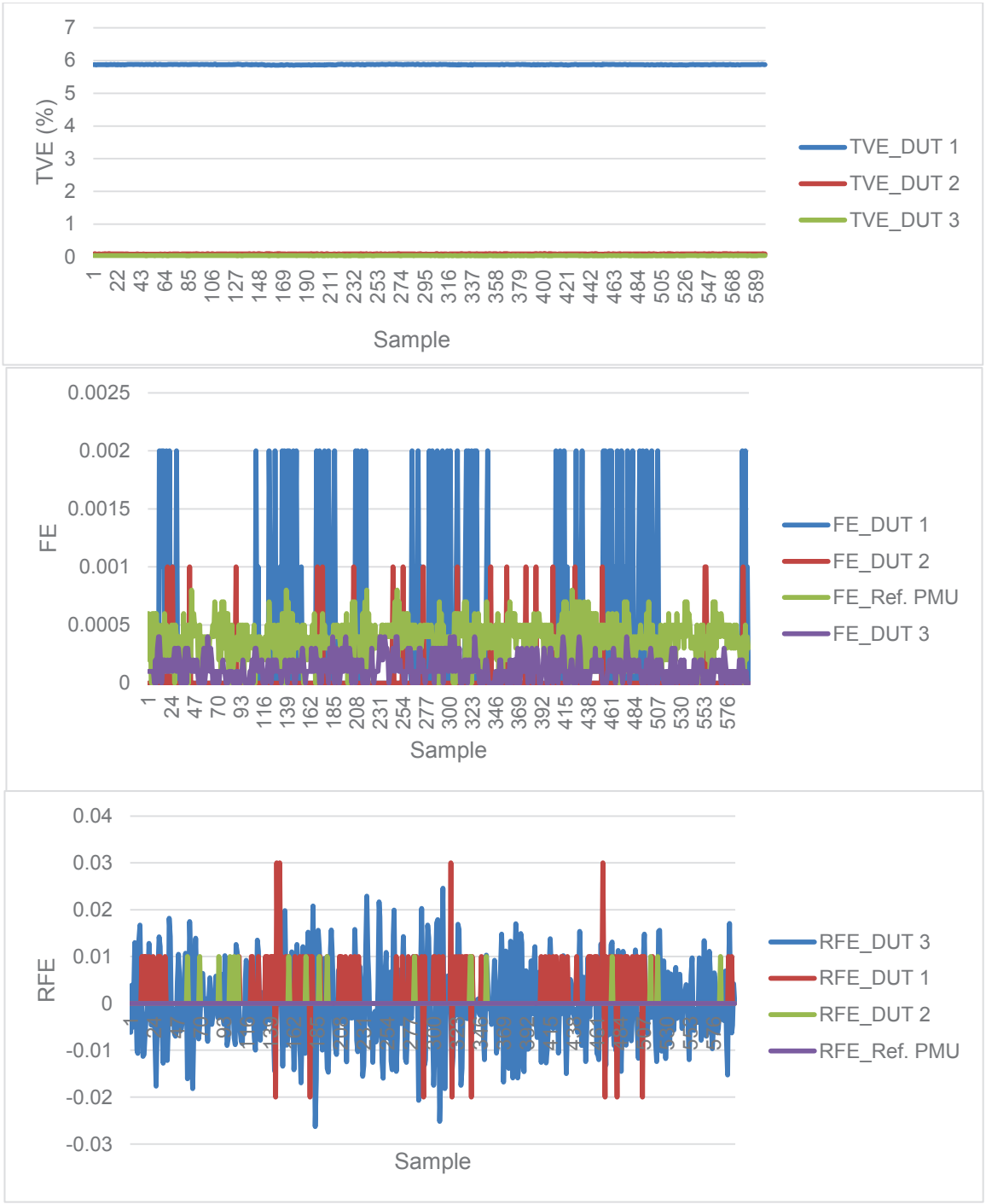


Figure 2-9. TVE, FE, RFE for 130% of Nominal Voltage (Case 1-1-3)

- **Case 1-1-4:** System voltage was set at nominal system voltage and run for 20 seconds. Phase B was disconnected at the source, and positive and negative sequence measurements from PMUs were recorded before and after the disconnection. It should be noted that DUT1 and DUT2 do not provide negative sequence measurements; therefore, the values had to be calculated using ABC phasors. The following figure shows the magnitude and TVE for positive sequence.

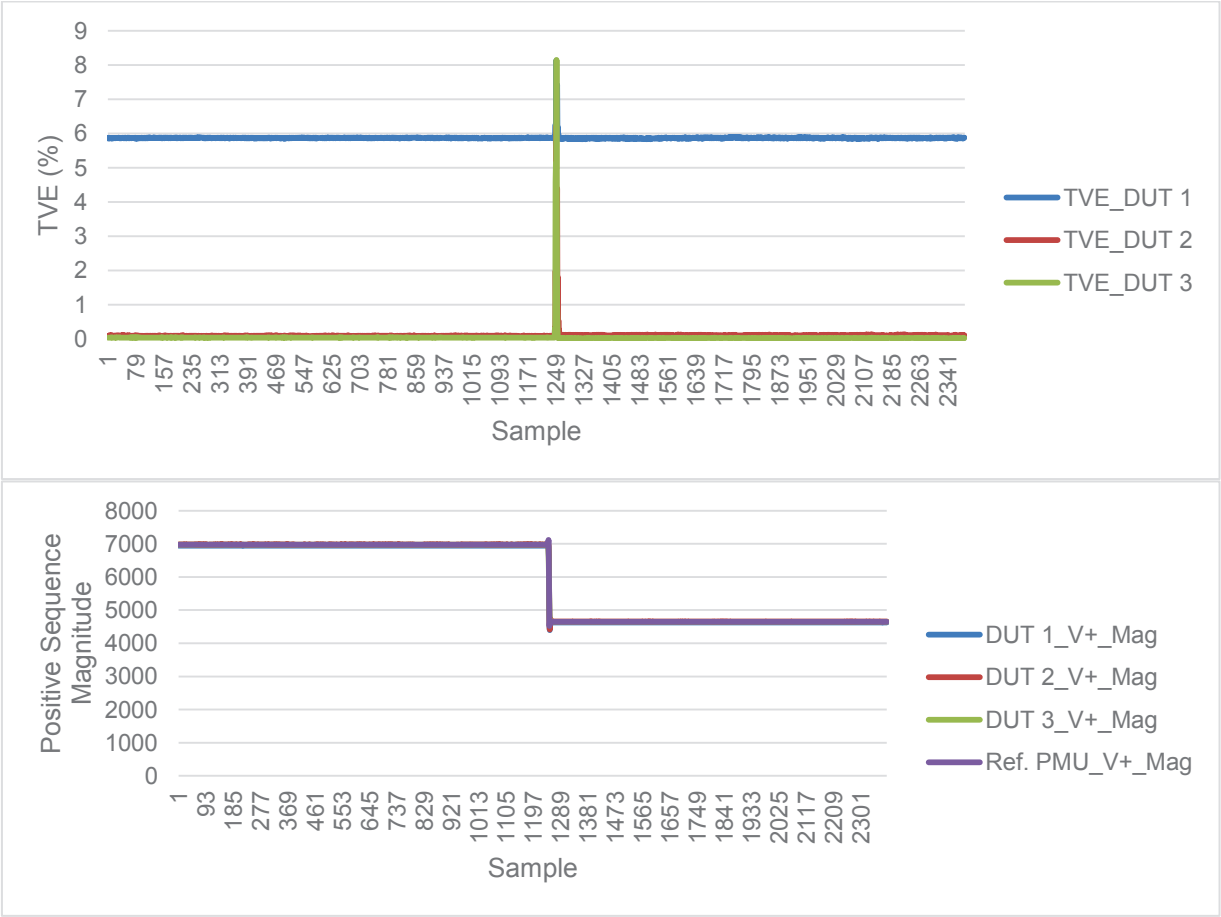


Figure 2-10. TVE and Magnitude of the Positive Sequence Subsequent to the Disconnection of Phase B (Case 1-1-4)

It can be seen that during the step change, a spike happened in the TVE. The duration of this spike was around 8 samples for all PMUs, which showed the convergence rate of the PMUs.

The next figure shows the TVE and magnitude of negative sequence. It should be noted that TVE was just shown during unbalanced operation of the system.

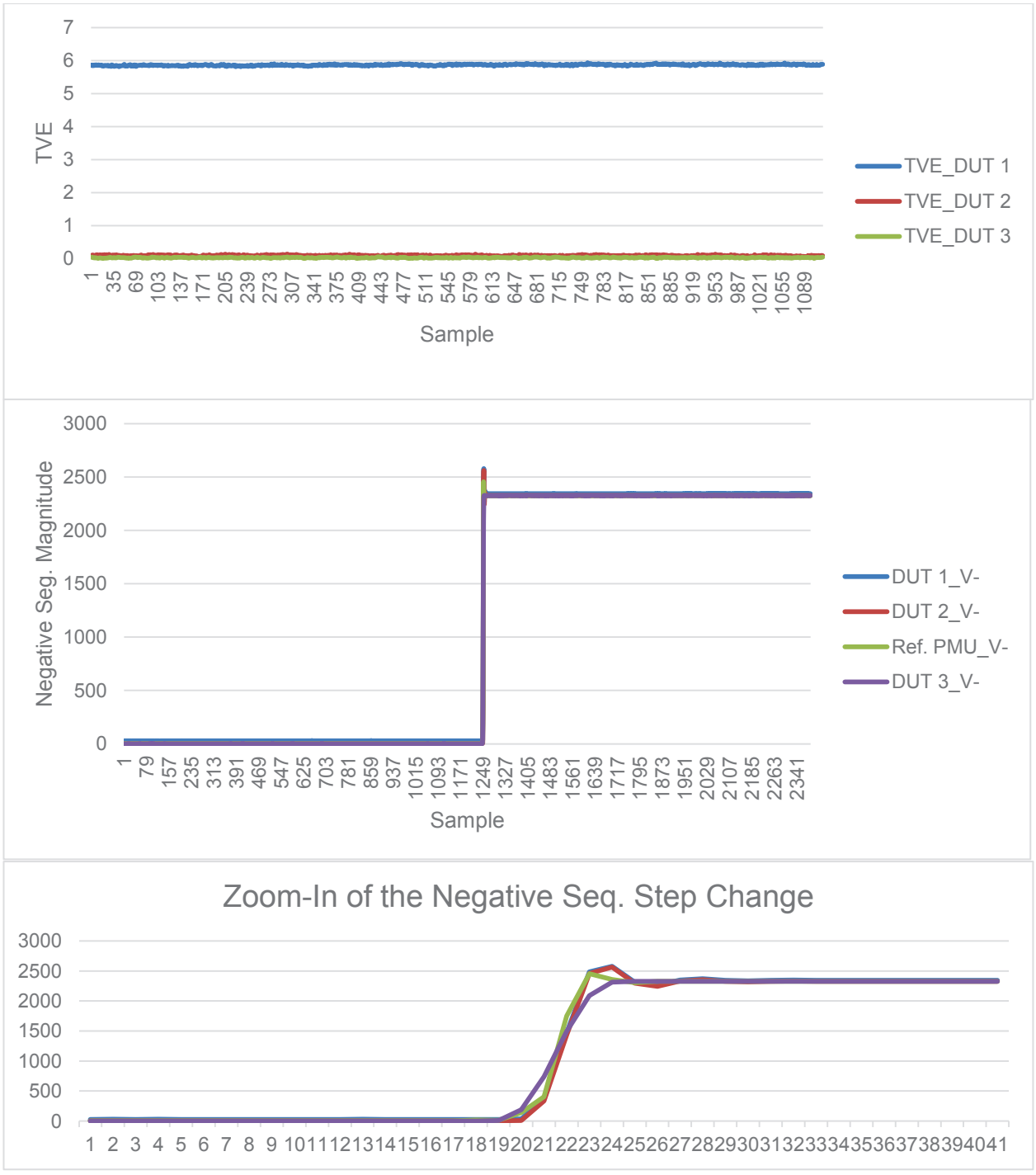


Figure 2-11. TVE and Magnitude of the Negative Sequence Subsequent to the Disconnection of Phase B (Case 1-1-4)

Note: Case 1-1-5 and case 1-1-6 are excluded because of their similarity to the previous results.

- **Case 1-1-7:** System was set at the nominal frequency, two phase voltages at nominal voltage and the third at 105% of nominal voltage. PMU data were captured for 5 seconds. The magnitude and TVE of the positive sequence as well as the magnitude and TVE of the negative sequence are shown in the following figures.

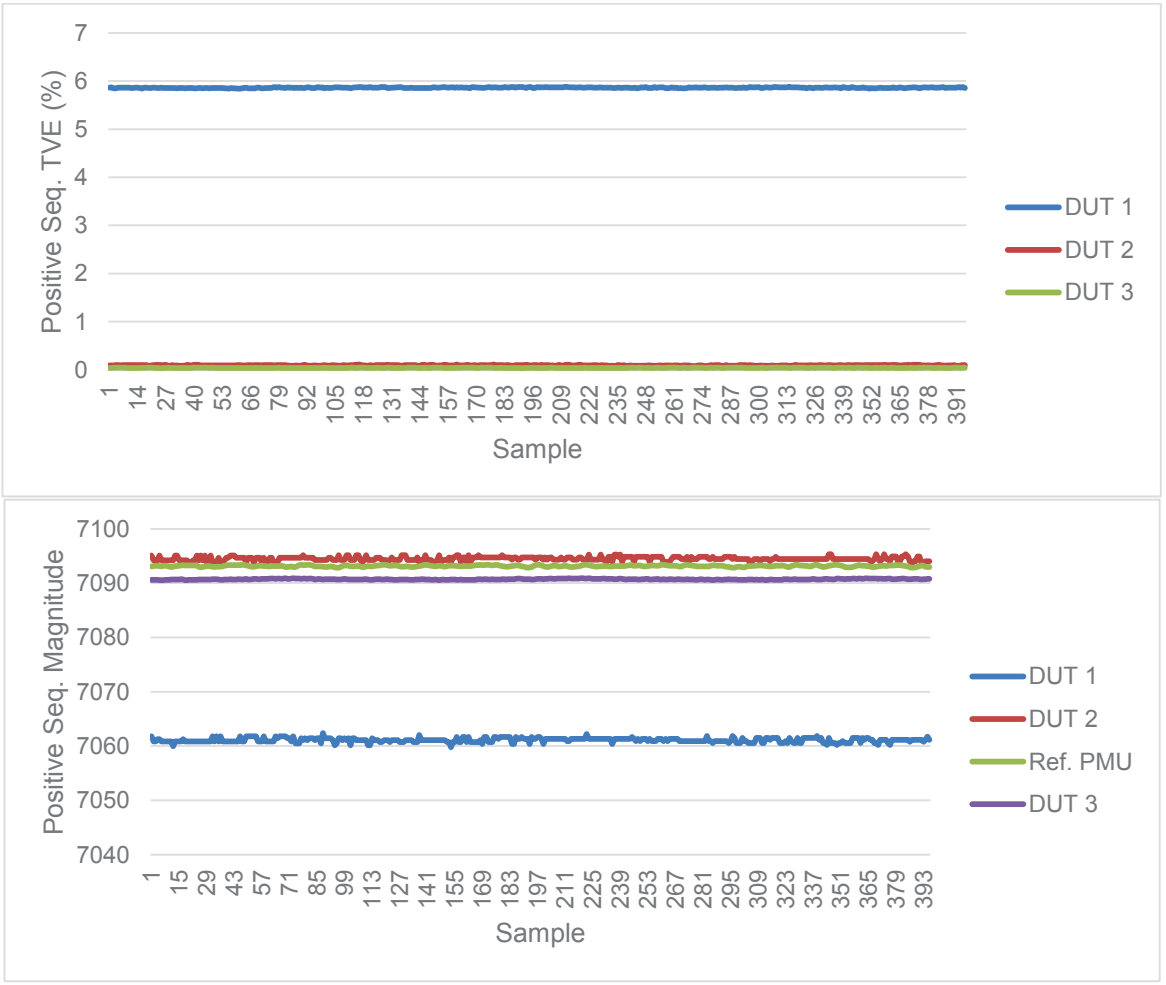


Figure 2-12. TVE and Magnitude of the Negative Sequence (Case 1-1-7)



Figure 2-13. TVE and Magnitude of the Negative Sequence (Case 1-1-7)

2.5.2.5.2 Group 2: Frequency Step Test

Group 2 tests are designed for evaluating the DUTs' performance for frequency measurements. For group 2 tests, balanced three phase system voltages and currents were applied to the DUTs. Each of the following test cases was repeated 3 times for test results validation.

Note: Case 1-2-1 was excluded because it is exactly similar to case 1-1-1.

- **Case 1-2-2:** The system frequency was set at 59.7 Hz and the PMU data was captured for 5 seconds. Then, the frequency was changed back to 60 Hz, to continue capturing for another 5 seconds. The following figures show the frequency captured from different devices as well as the FE and RFE. It can be seen from the last figure that the 360 rotation happens within 200 samples. This is consistent with the frequency variation of 0.3 because $200 = \frac{1}{0.3} \times 60$. Furthermore, all PMUs have angle recovery after the frequency gets back to 60 Hz.



Figure 2-14. Frequency, FE, RFE, and Angle Subsequent to the Step Change of Frequency from 59.7 Hz to 60 Hz (Case 1-2-2)

An interesting observation that we made in this test is that the Arbiter lost the accuracy of its magnitude (for around 0.5 sec) due to the frequency step change. The positive sequence magnitudes from different PMUs can be seen in the following figure.

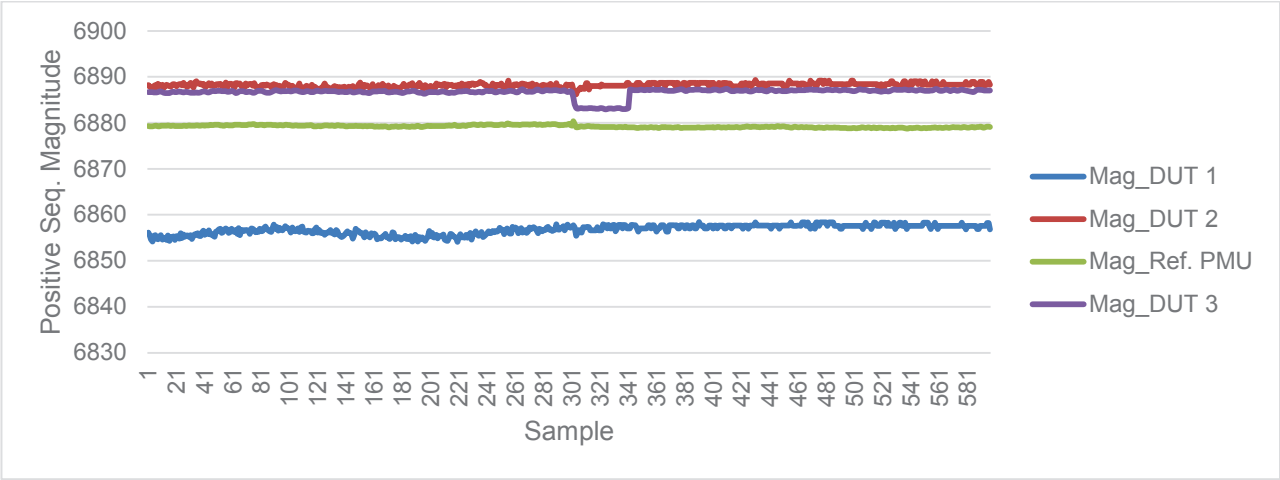


Figure 2-15. Positive Sequence Magnitude Subsequent to the Step Change of Frequency from 59.7 Hz to 60 Hz (Case 1-1-2)

Note: Case 1-2-3 and case 1-2-4 were excluded because of their similarity to the previous results.

- **Case 1-2-5:** The system frequency was set at 61 Hz and the PMU data was captured for 5 seconds. Then, the frequency was changed back to 60 Hz, continue capturing for another 5 seconds. The following figures show the frequency captured from different devices as well as the FE and RFE. The last figure shows that all PMUs have angle recovery after the frequency gets back to 60 Hz.

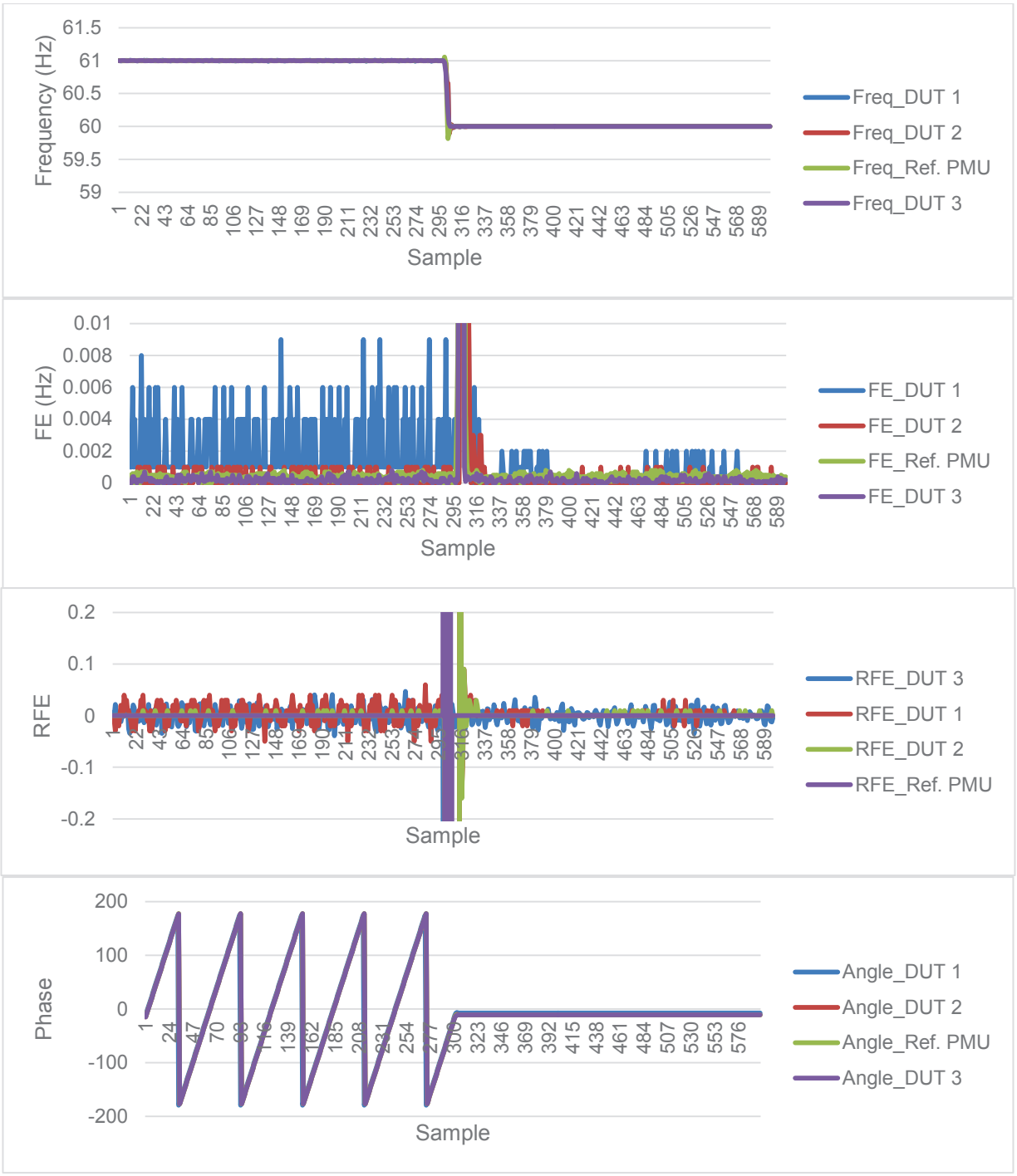


Figure 2-16. Frequency, FE, RFE, and Angle Subsequent to the Step Change of Frequency from 61 Hz to 60 Hz (Case 1-2-5)

The same effect we observed on the previous test case for DUT3 PMU happened for this test case as well, as shown in the following figure. These test cases suggested that the estimated magnitude of the DUT3 could be dependent on the change of the frequency.

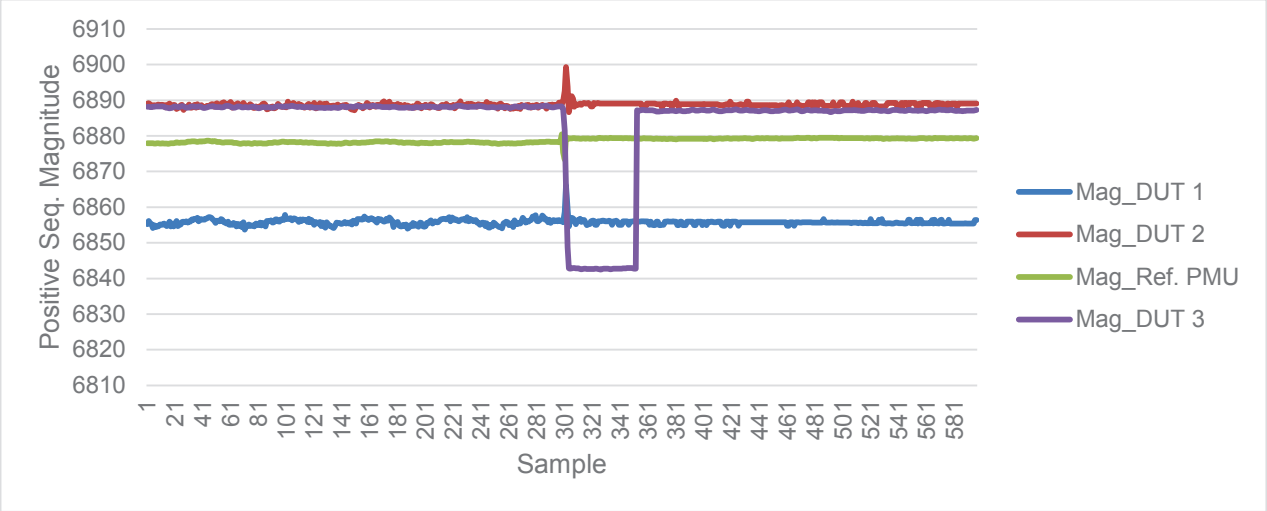


Figure 2-17. Positive Sequence Magnitude Subsequent to the Step Change of Frequency from 61 Hz to 60 Hz (Case 1-2-5)

2.5.2.5.3 Group 3: Harmonic Distortion Test

Group 3 test was designed for evaluating the DUTs' responses to harmonic distortion. For group 3 test, balanced three phase system voltage, current and nominal system frequency was applied as input to the DUTs. Each of the following test cases was repeated 3 times for test results validation. It should be noted that the TVE of Device 1 was very large (around 6%) compared with Device 2 and Device 3 (around 0.1%). Therefore, in order to provide a better comparison between DUT2 and DUT3, the TVE for DUT1 is not shown in this test group.

- **Case 1-3-1:** The system was started at nominal levels for voltage and frequency, while injecting the 5th harmonic with 3% magnitude of voltage and current into DUTs' measurement location. PMU data was captured for 5 seconds. TVE and FE are shown in the following figures.



Figure 2-18. TVE and FE during the Injection of 3% Magnitude of 5th Harmonic (Case 1-3-1)

- **Case 1-3-2:** The system was started at nominal levels for voltage and frequency, while injecting the 5th harmonic with 5% magnitude of voltage and current into DUTs' measurement location. PMU data was captured for 5 seconds. TVE and FE are shown in the following figures.



Figure 2-19. TVE and FE during the Injection of 5% Magnitude of 5th Harmonic (Case 1-3-2)

- **Case 1-3-3:** The system was started at nominal levels for voltage and frequency, while injecting the 5th harmonic with 10% magnitude of voltage and current into DUTs' measurement location. PMU data was captured for 5 seconds. TVE and FE are shown in the following figures.



Figure 2-20. TVE and FE during the Injection of 10% Magnitude of 5th Harmonic (Case 1-3-3)

Note: Case 1-3-4, 1-3-5, and 1-3-6 are excluded because of their similarity to the previous results.

- **Case 1-3-7:** The system was started at nominal levels for voltage and frequency, while injecting multiple harmonics (3% of 7th order harmonic, 5% of 5th order harmonic and 10% of 3rd order harmonic) into DUTs' measurement location. A harmonic generator model was used in RTDS circuit model to inject various harmonic orders or a combination of harmonics. PMU data was captured for 5 seconds. TVE and FE are shown in the following figures.



Figure 2-21. TVE and FE during the Injection of Multiple Harmonics (Case 1-3-7)

By comparing the results of this test group, it can be concluded that by increasing the Harmonics the FE increases. Furthermore, the TVE of DUT3 was very robust against harmonics, while the TVE of DUT1 and DUT2 increased by increasing the THD of the voltage.

2.5.2.6 Category 2: Dynamic Performance Tests

The purpose of this test category is to test the DUTs' performance under dynamic system conditions. The phasor, frequency, and ROCOF estimates obtained from DUTs under different system conditions are compared to the corresponding input measurements. TVE, FE, and RFE is calculated and compared with defined limits in IEEE C37.118.1. Several test groups will be considered in this test category. For category 2 tests, all the test groups were repeated with DUTs' reporting rate set at 60 frames / second and 30 frames / second. However, in this report, only the data at 60 frames/second is reported. Each of the following test cases was repeated 3 times for test results validation

2.5.2.6.1 Group 1: Response to Step Change in Amplitude and Phase

Group 1 tests are designed for evaluating the DUTs' responses to the step changes applied to voltage, current and phase angle. Step changes were applied to voltage, current and phase angle and PMU data streams were captured to calculate TVE.

- **Case 2-1-1:** System voltage and frequency was set at nominal value for 20 seconds. The following actions was applied to the voltage:
    - 10% step voltage increase was applied at the source for 0.5 seconds;
    - Voltage was changed to initial value for 20 seconds;
    - 10% voltage decrease was applied at the source for 0.5 seconds;
    - Voltage was changed to initial value.

The following figures shows positive sequence magnitude and TVE subsequent to the voltage change.



Figure 2-22. Positive Sequence Magnitude and TVE Subsequent to Voltage Changes (Case 2-1-1)

To better compare the dynamic performances, a zoom-in plot of the positive sequence magnitude is shown in the next figure.

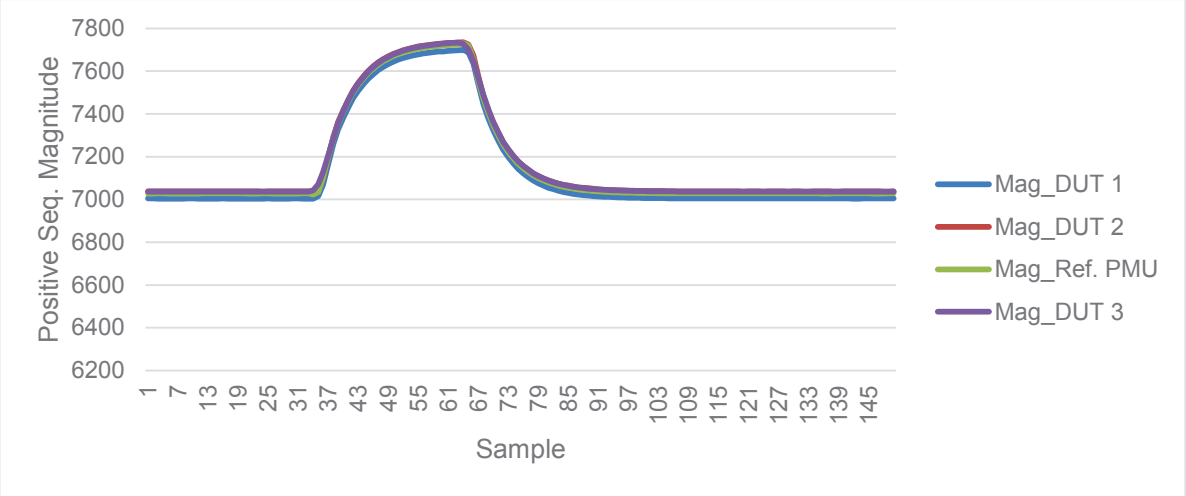


Figure 2-23. Zoom-In Plot of the Positive Sequence Magnitude (Case 2-1-1)

- **Case 2-1-2:** System voltage and frequency were set at nominal value with a 3 phase balanced inductive load with the power factor of 0.75. Load was increased by 10% for 20 seconds and changed back to initial value for 20 seconds. Then, it was decreased by 10% for 20 seconds. The following figures show positive sequence magnitude and TVE subsequent to the load change.

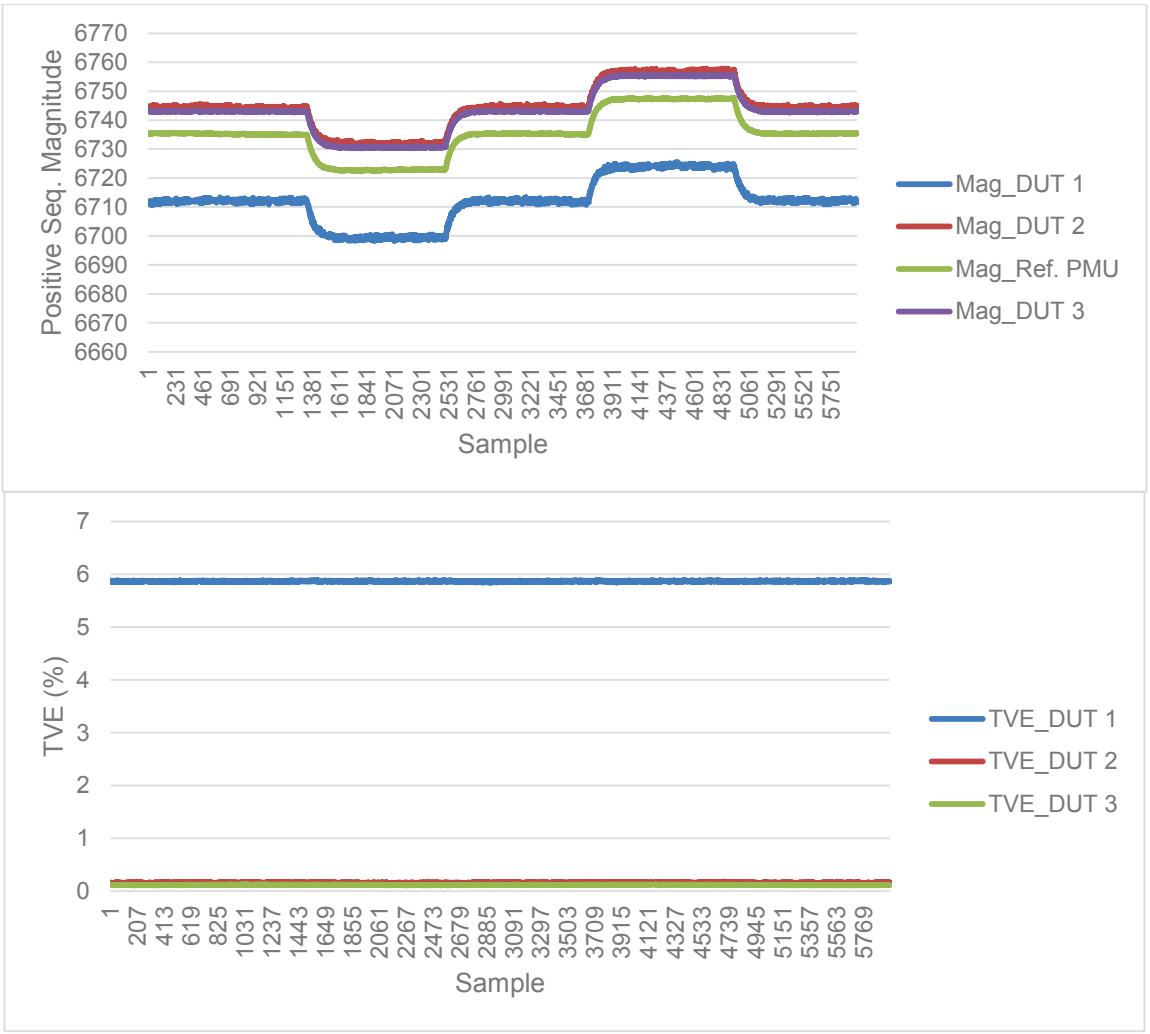


Figure 2-24. Positive Sequence Magnitude and TVE of Voltage Subsequent to Load Changes (Case 2-1-2)

- **Case 2-1-3:** System voltage and frequency were set at nominal value. After 20 seconds, phase angle was increased 45 degrees for all three phases for 0.5 seconds and changed back to its initial value for 20 seconds. Then, phase angle was decreased by 45 degree for all three phases for 0.5 seconds and changed back to its initial value. Note that the phase angle change through the model was used to create sudden vector jump to evaluate DUT responses.

  The following figures shows TVE, magnitude, and phase of the positive sequence subsequent to the voltage change.

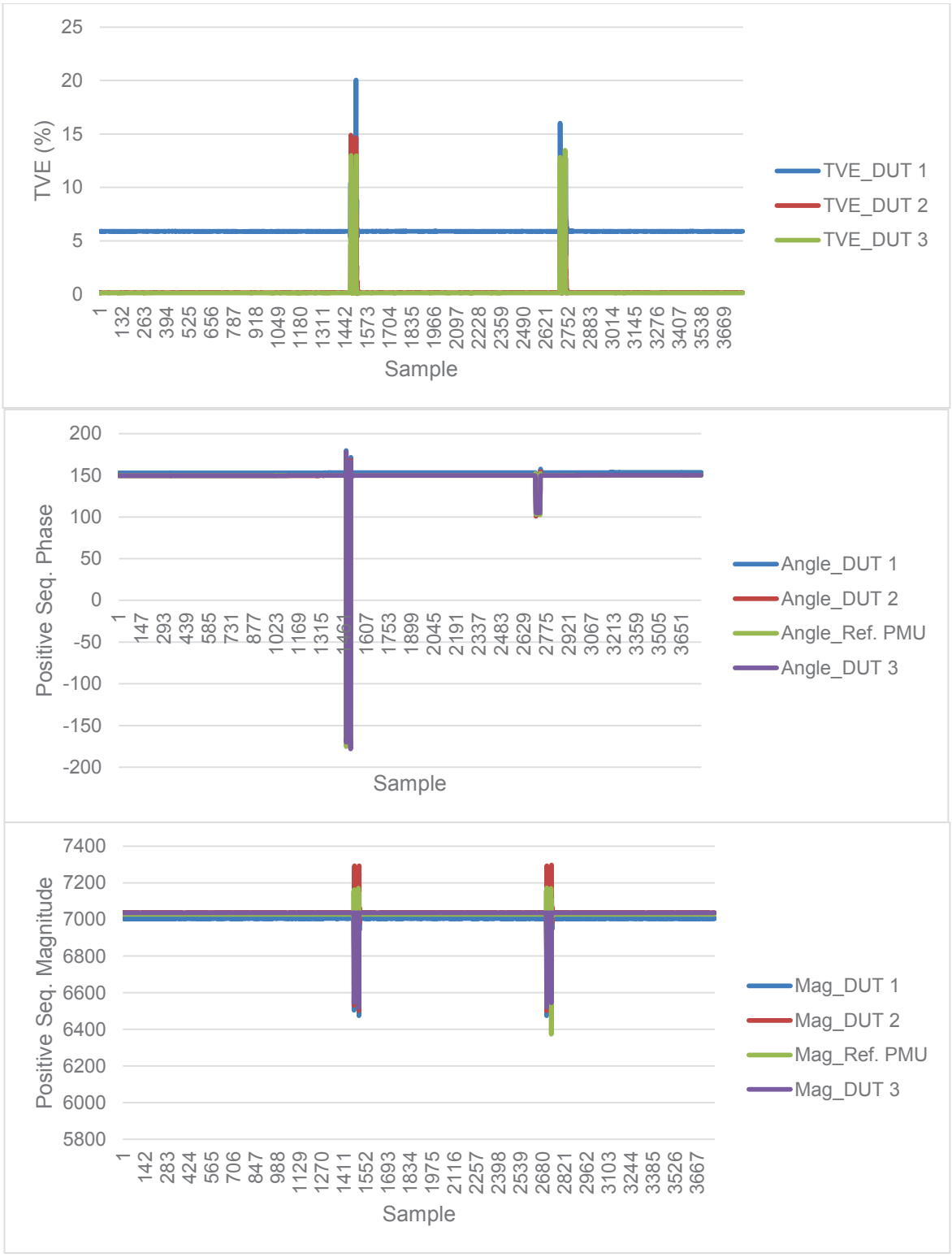


Figure 2-25. TVE, Phase, and Magnitude of the Positive Sequence Subsequent to Phase Angle Changes (Case 2-1-3).

To better compare the dynamic performances, a zoom-in plot of the positive sequence magnitude is shown in the next figure. It can be seen that based on the definition of phase angle, adding 45 degree to the vector has changed the phase angle direction of measurement (150 + 45 = 195 which is greater than 180 degrees).

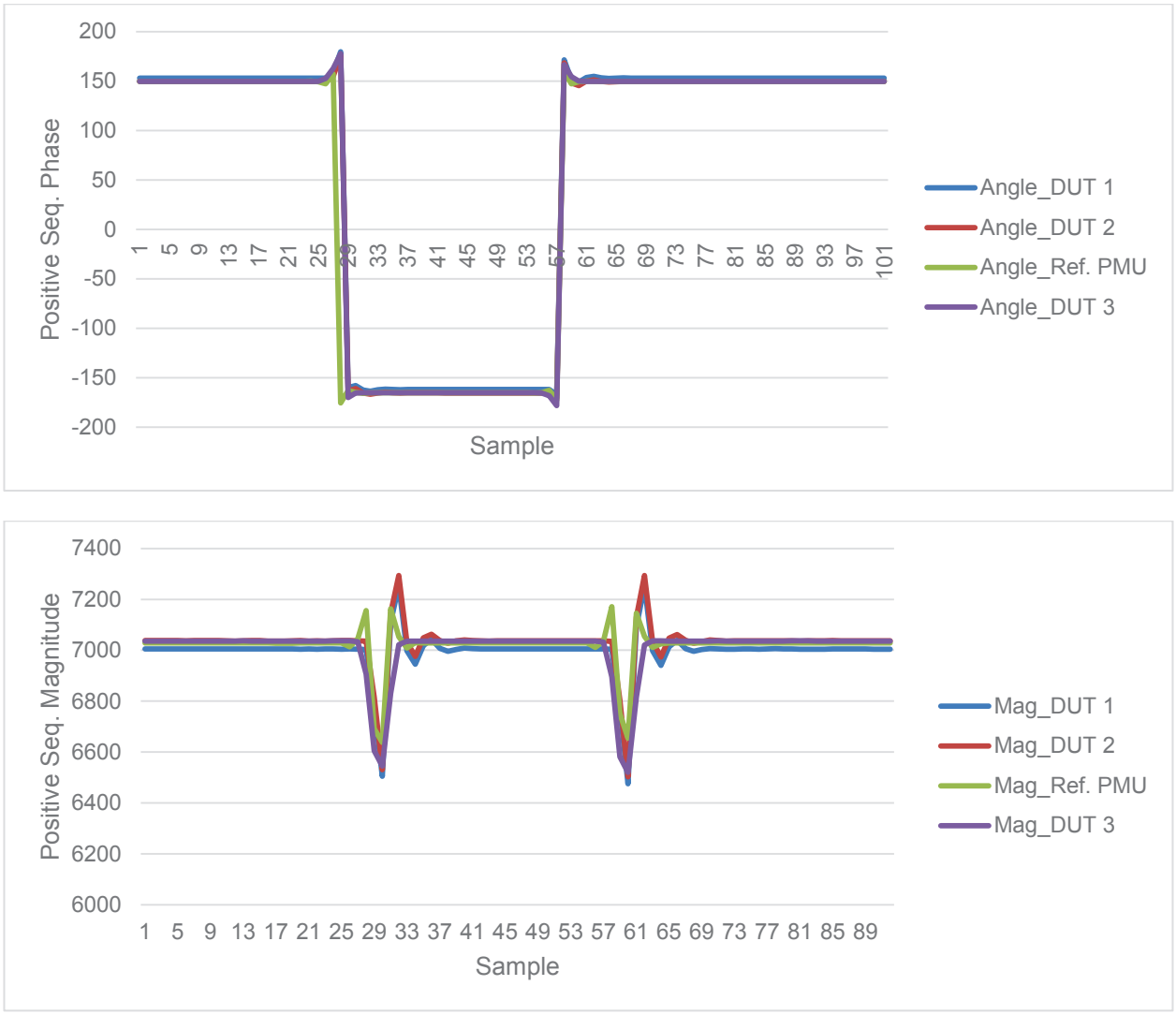


Figure 2-26. Zoom-In Plot of the Phase and Magnitude of the Positive Sequence (Case 2-1-3)

2.5.2.6.2 Group 2: Performance Test during Ramp of System Frequency

This test was designed for evaluating the DUTs' responses to the ramp changes of system frequency. Positive and negative ramps of frequency was applied to the system. PMU data streams were captured to see the DUTs' response.

- **Case 2-2-1:** System frequency was set at 59.7 Hz. After 10 seconds, the positive ramp of frequency was started with the ramp rate of 0.1 Hz/second until reaching 60.3 Hz. Frequency, TVE, and RFE for the test duration can be seen in the following figure.

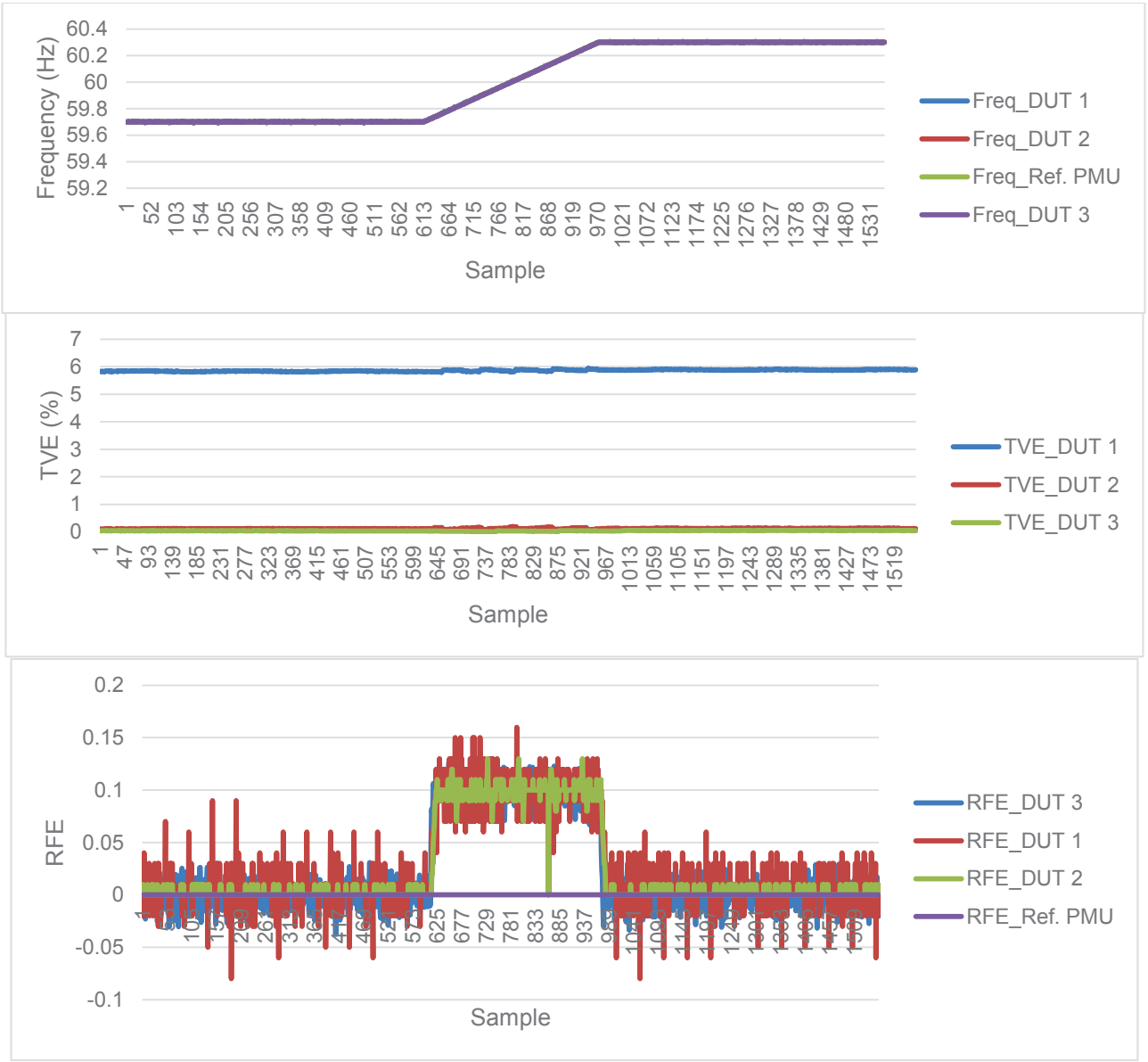


Figure 2-27. Frequency, TVE, and RFE Subsequent to Frequency Ramp (Case 2-2-1)

- **Case 2-2-2:** System frequency was set at 60.3 Hz. After 10 seconds, negative ramp of frequency was started with the ramp rate of 0.1 Hz/second until reaching 59.7 Hz. Frequency, TVE, and RFE for the test duration can be seen in the following figure.

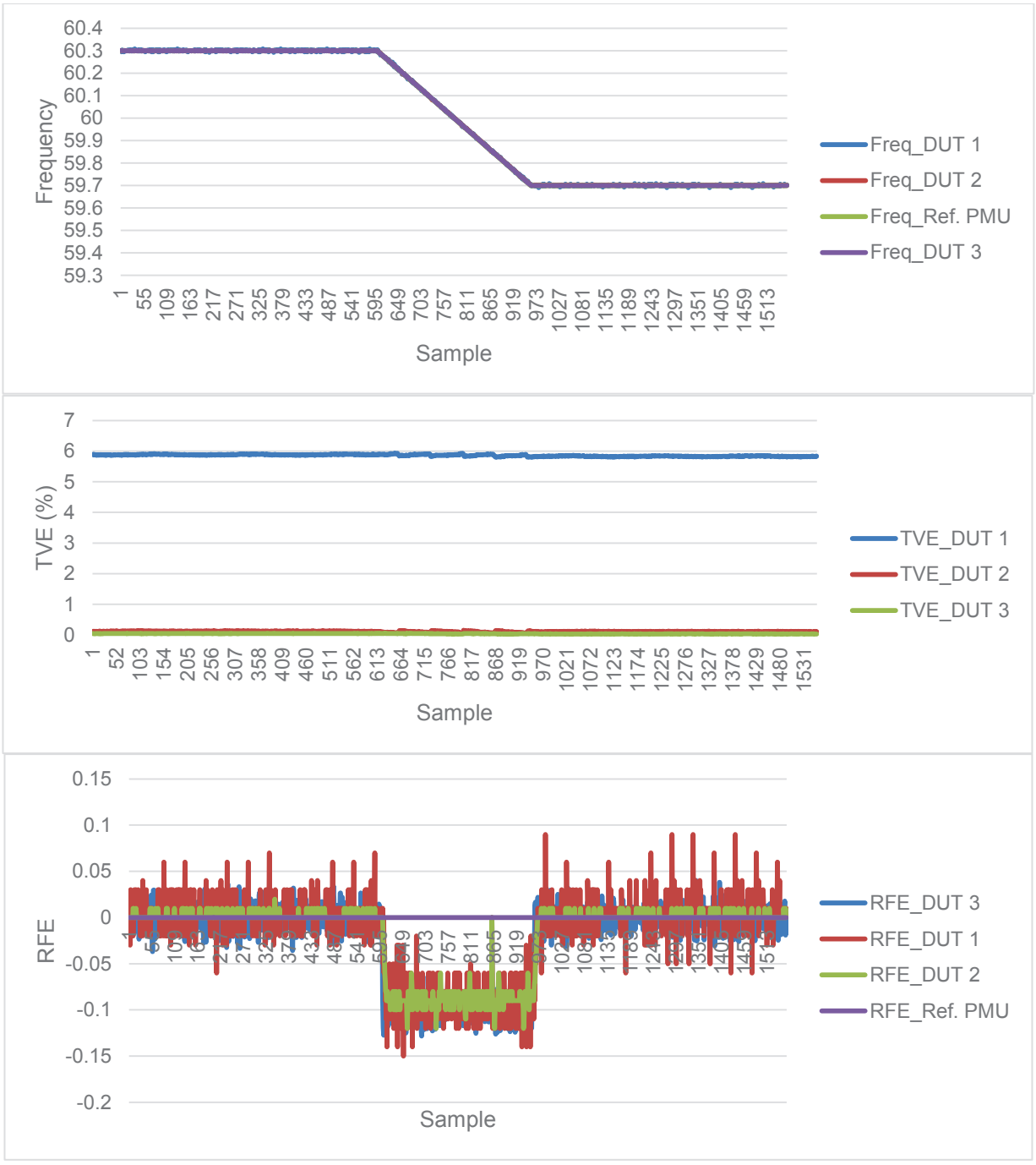


Figure 2-28. Frequency, TVE, and RFE Subsequent to Frequency Ramp (Case 2-2-2)

2.5.2.6.3 Group 3: Performance Test during Capacitor Switching

This group of tests was designed for evaluating the DUTs' performance to record system a sample transient event. This transient event was generated by switching on a capacitor bank. Capacitor switching event was simulated in RTDS and measurements from PMUs were captured and analyzed.

- **Case 2-3-1:** System voltage and frequency were set at nominal value. After 10 seconds, 1.2 MVAR 3 phase cap bank downstream of the DUTs was switched on. Frequency, TVE of voltage, and RFE subsequent to this frequency ramp can be seen in the following figure.



Figure 2-29. TVE and FE Subsequent to Capacitor Switching (Case 2-3-1)

2.5.2.6.4 Group 4: Performance Test during System Faults

This group of tests was designed for evaluating the DUTs' performance to record system fault events. Different types of faults were simulated in RTDS and measurements from PMUs were captured and analyzed.

- **Case 2-4-1:** System voltage and frequency were set at nominal value. After 10 seconds, temporary single line-to-ground fault was applied for 0.2 seconds. The results are shown below.

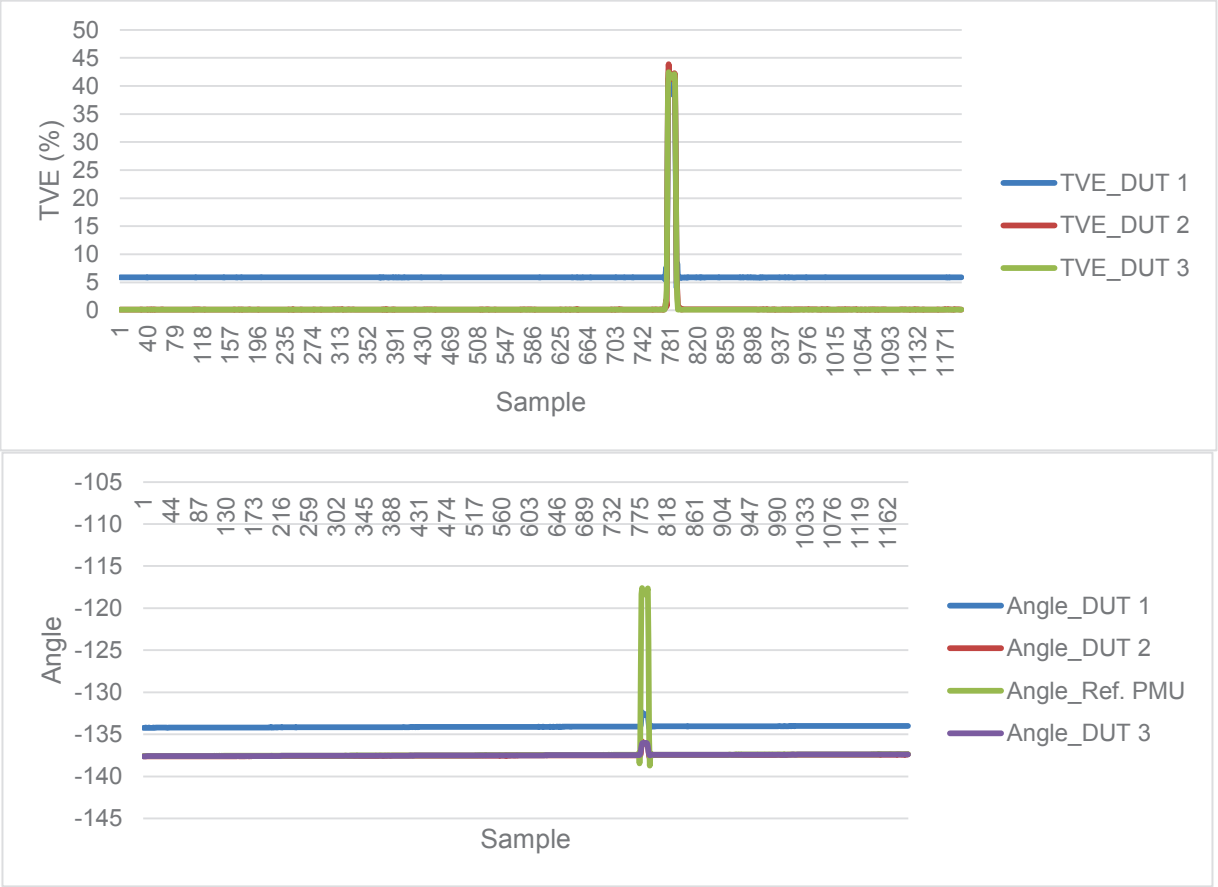


Figure 2-30. TVE of Voltage and Angle Subsequent to Single Line-to-Ground Fault (case 2-4-1)

- **Case 2-4-2:** System voltage and frequency were set at nominal value. After 10 seconds, temporary line-to-line fault was applied for 0.2 seconds. The results are shown below.

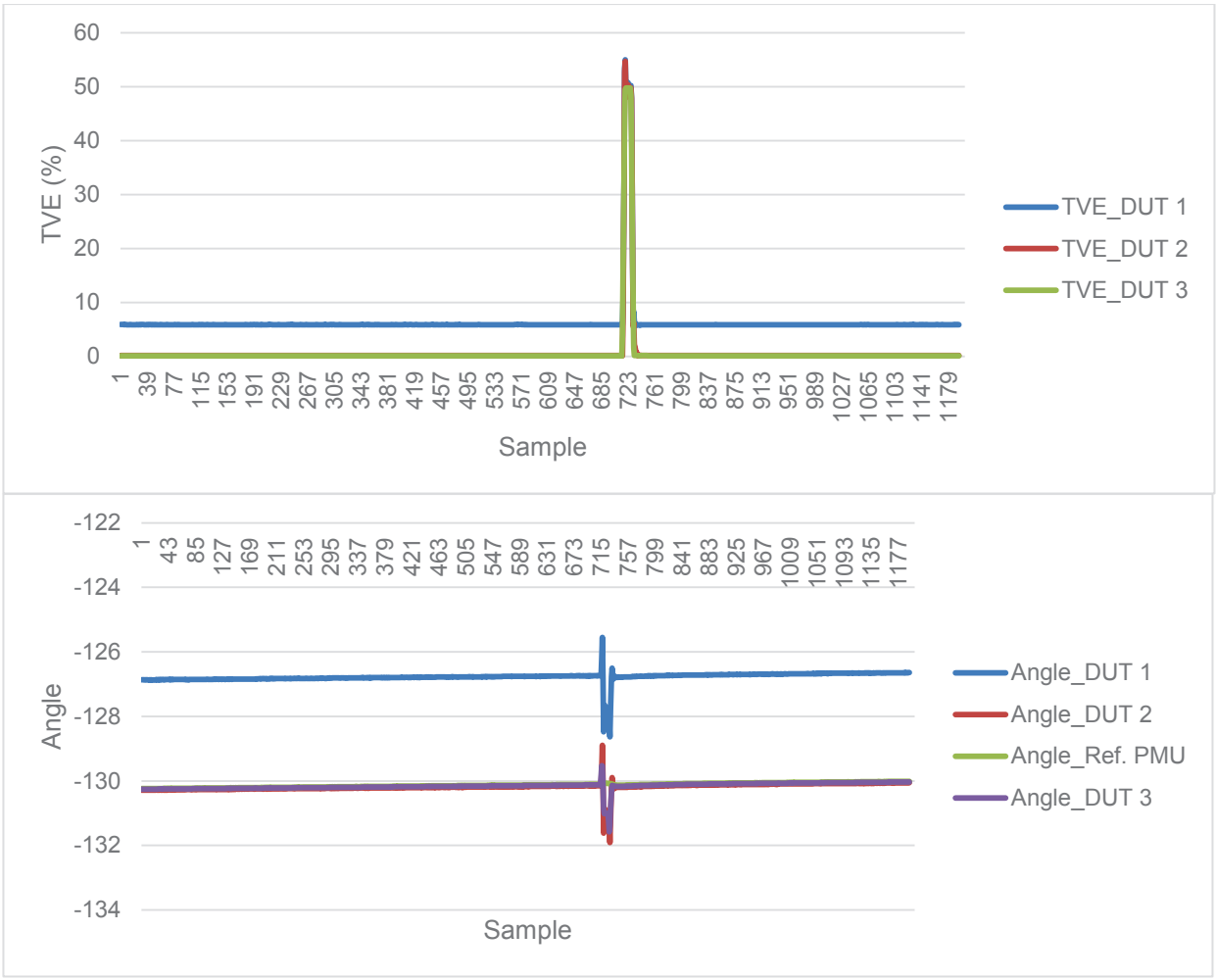


Figure 2-31. TVE and angle subsequent to line-to-line fault (2-4-2).

Case 2-4-5: System voltage and frequency were set at nominal value. After 10 seconds, temporary line-to-line fault was applied for 1 seconds. The results are shown below.

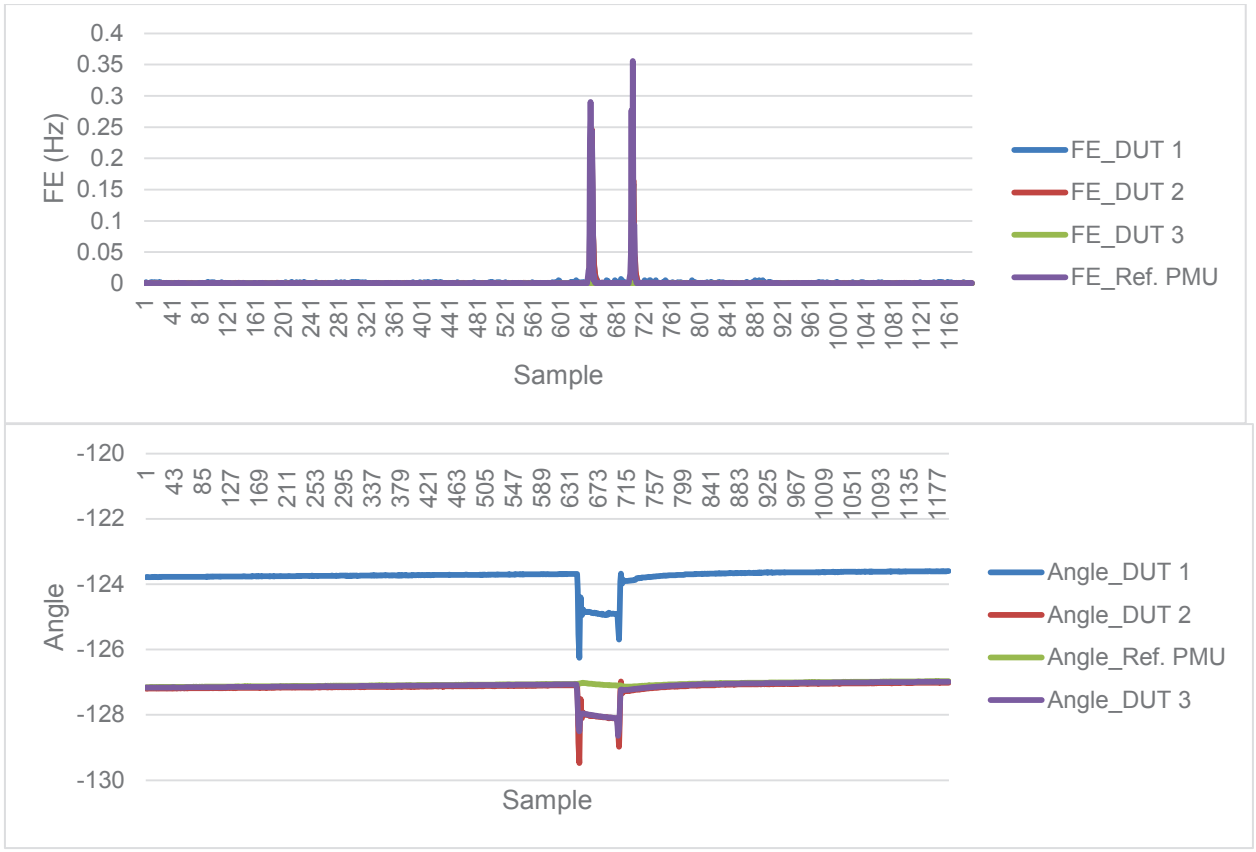


Figure 2-32. FE and angle subsequent to line-to-line fault (2-4-5).

An interesting observation from this test was that there is no change in the phase angle estimation of the reference PMU during the fault, while the other devices had a certain phase shift during the fault. The fault was long enough so that all the PMUs converge to the new values during the fault; therefore, it was expected to have a zero TVE during the fault. However, we cannot see zero TVE during this event. The reason is that it seems that the reference PMU was not working properly.

- **Case 2-4-6:** System voltage and frequency were set at nominal value. After 10 seconds, temporary three-phase fault was applied for 1 seconds. The results are shown below.

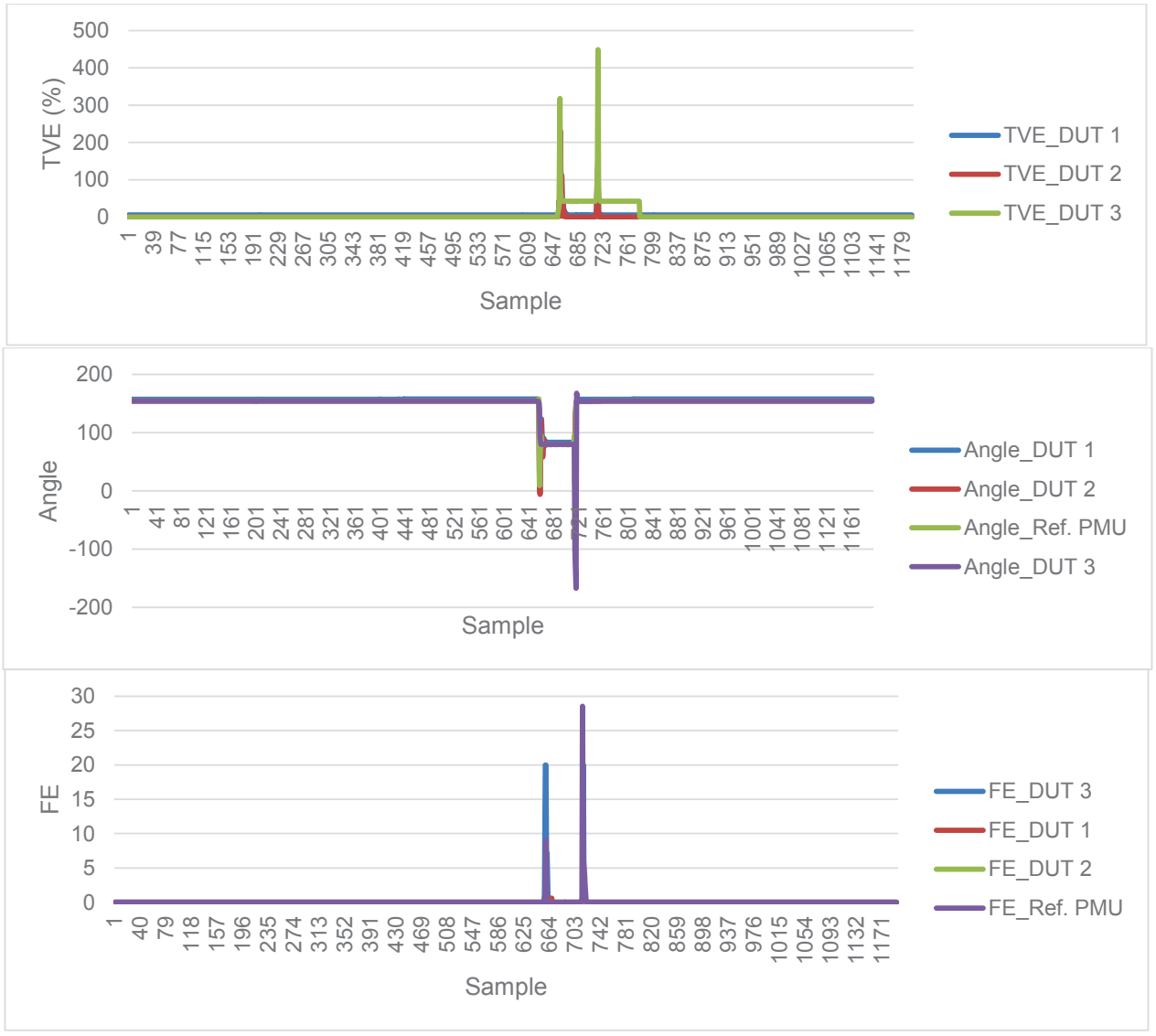


Figure 2-33. TVE, angle, and FE Subsequent to 3-Phase Fault (Case 2-4-6)

It can be seen that the TVE of the DUT3 remains high even after the clearance of the fault. The reason is that, as it can be seen in the following figure, the arbiter is not able to correctly estimate the magnitude of the positive seq. voltage after the fault for about 1 second.

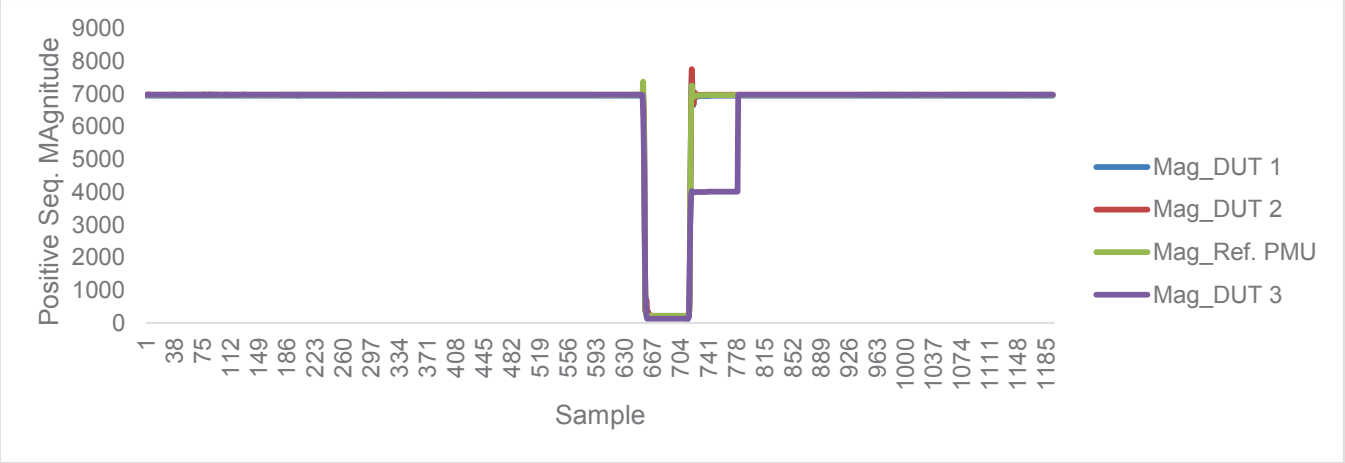


Figure 2-34. Voltage Magnitude during the Fault (case 2-4-6)

2.5.2.7 Category 3: Analog and Digital Data Streaming Capability

In this section, the DUT capability for streaming locally measured power quality parameters or any parameter that is calculated at device level using mathematical and logical blocks is investigated. It should be noted that reference PMU is not listed here because its measurements and capabilities depend on the added module to the device. The following table summarizes the available phasors through IEEE C37.118 Synchrophasor protocol from different PMUs.

Table 2-14. Available Phasors in Different PMUs

Phasor	DUT1	DUT2	DUT3	DUT4
V_a	☑	☑	☑	☑
V_b	☑	☑	☑	☑
V_c	☑	☑	☑	☑
V_s	☒	☑	☒	☒
I_a	☑	☑	☑	☑
I_b	☑	☑	☑	☑
I_c	☑	☑	☑	☑

Phasor	DUT1	DUT2	DUT3	DUT4
I_N	☑	☑	☒	☒
V_1	☑	☑	☑	☑
V_2	☒	☒	☑	☒
V_0	☒	☒	☑	☒
I_1	☑	☑	☑	☑
I_2	☒	☒	☑	☒
I_0	☒	☒	☑	☒

In addition to the phasors, IEEE C37.118 provides the capability for the analog and digital data streaming. The following table summarize this capability for different PMUs.

Table 2-15. Available Analog and Digital Data Streams in Different PMUs

Data Stream	DUT1	DUT2	DUT3	DUT4
Assignable Analog Value	4	4	0	0
Unassignable Analog Value	0	0	20	0
DSP Trigger	16	16	32	8
Event input			4	

It should be noted that:

a. PMU in DUT1 and PMU in DUT2 can stream 4 assignable analog values and 16 digital values.

b. PMU in DUT3 can stream 20 analog values through PMU. However, all of these analog values are predefined and cannot be changed. It should be noted that the triggering logic in PMU Device 3 can just

compare the analog values with some limits, while in PMU in DUT1 and DUT2 can perform mathematical and logical operations.

c. PMU in DUT3, depending on the settings sends either the voltage and current abc-phasors or voltage and current positive sequence phasors, while other devices sends at least both abc-phasors and positive sequence phasor. However, this PMU does not provide analog value streaming; however, it can stream up to 8 digital values.

2.5.3 Type Test Conclusions

Based on the steady state performance, dynamic performance, and digital/analog capability of four tested PMUs the following can be concluded:

1. DUT1

    a. Based on the test results, it was shown that it added around 3 degrees of error in phase angle; however, it has the capability to be calibrated.

    b. It showed a very good dynamic performance. It never lost the convergence due to the rapid changes in the voltage, frequency, or phase angle.

    c. It can stream 4 analog values and 16 digital values. There is a lot of flexibility on defining a logic for the digital value or a calculation for analog value.

    d. Device configuration is straightforward.

2. DUT2

    a. Based on the results, it was shown that it had less than a 0.5degree error in phase angle. Furthermore, it has the capability to be calibrated.

    b. It showed a very good dynamic performance. It never lost the convergence due to the rapid changes in the voltage, frequency, or phase angle.

    c. It can stream 4 assignable analog values and 16 digital values. There is a lot of flexibility on defining a logic for the digital value or a calculation for analog value.

    d. Device configuration is straightforward.

3. DUT3

    a. It had shown less than a 0.5-degree error in phase angle. However, it has the capability to be calibrated.

    b. It showed poor dynamic performance. In few case studies, it was observed that the device lost the convergence for few seconds after a transient.

c. It can stream 20 pre-defined analog values and 36 digital values. The analog values are pre-defined and cannot be changed. Furthermore, very basic logics can be defined for the digital value.

d. Device configuration is straightforward.

e. It can operate as a PQ meter as well.

4. DUT4

a. The test results showed that it had around 2 degree error in phase angle. However, this error was increased to 45 degrees in case of the utilization of the extension module due to the communication delay between the extension module and relay. Currently, the phase angle doesn't have calibration capability. However, the discussions with vendor had suggested that there will be future firmware upgrade to accommodate the issue.

b. It cannot stream any analog value.

c. It can stream up to 8 digital value.

d. Device configuration is difficult.

2.6 Demo System Setup and Customer System Integration

Based on the proposed approach, various data sources have been employed to monitor and visualize the status of the selected circuits of the SDG&E distribution systems. More details about this are provided earlier in this report. One aspect of the project has been to look at the actual field data, both in real-time form, but also the data and information retrieved from historical data base, power quality meters, as well as from other sources such as reliability department.

Another aspect of the project has been to look at the simulated environment that would enable to add additional devices to models of selected circuits, and enable monitoring and analysis of use case that are not available in the actual distribution network.

The diagram shown in Figure 2-35 below describes at high level this hybrid approach. There are two parallel data streaming and monitoring paths: 1) field data streaming path through substation PDC, and 2) simulated data streaming from laboratory through a dedicated PDC in the lab. The data from both paths gets ultimately collected at control center for processing and visualization.

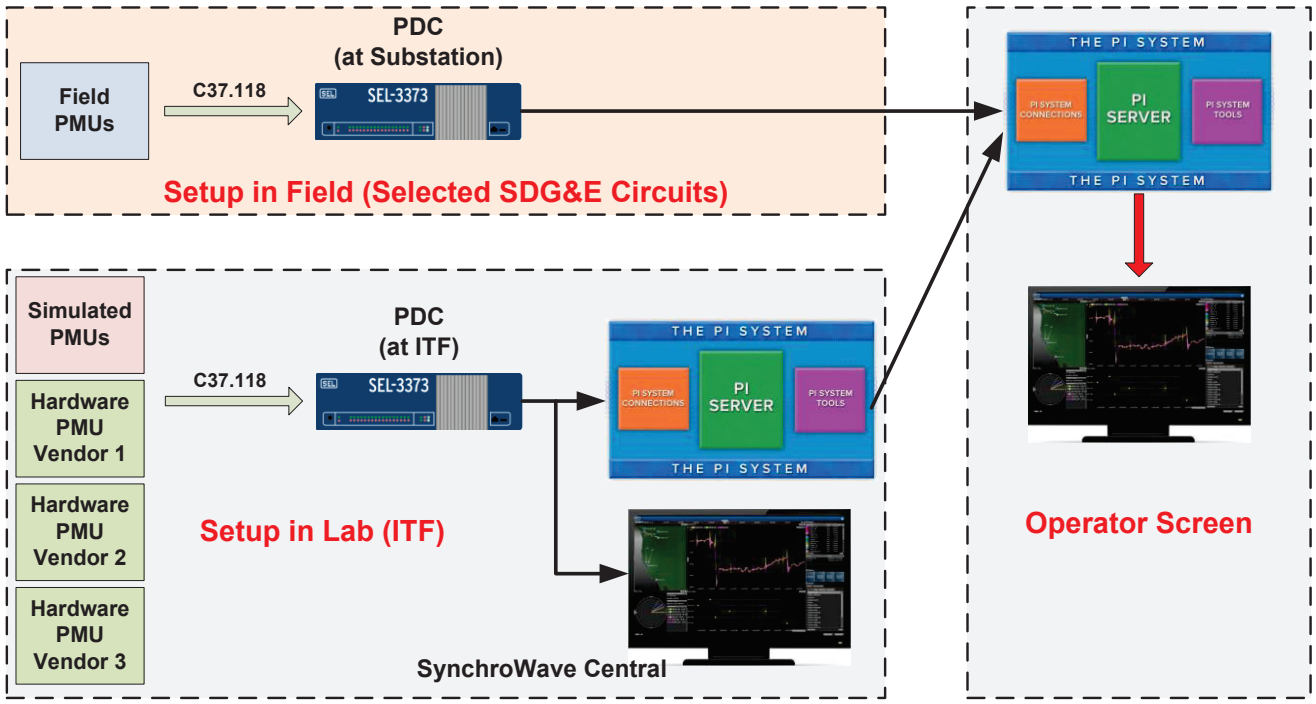


Figure 2-35. High level architecture for of the demonstration system

2.6.1 System architecture that employs field data

As described earlier in the report, field data can come from various devices, such as PMUs, IEDs, RTUs (remote terminal devices for SCADA), AMIs, power quality meters, as well as from PI historian, or other offline sources in form of reports or additional documents. Figure 2-36 shows a high-level architecture that has been used for this purpose. Visualization and analytics box in this diagram was used for post processing data to calculate performance indices and/or to create data infeed for trends and histograms, as described in the visualization system functional requirements and the six proposed use cases.

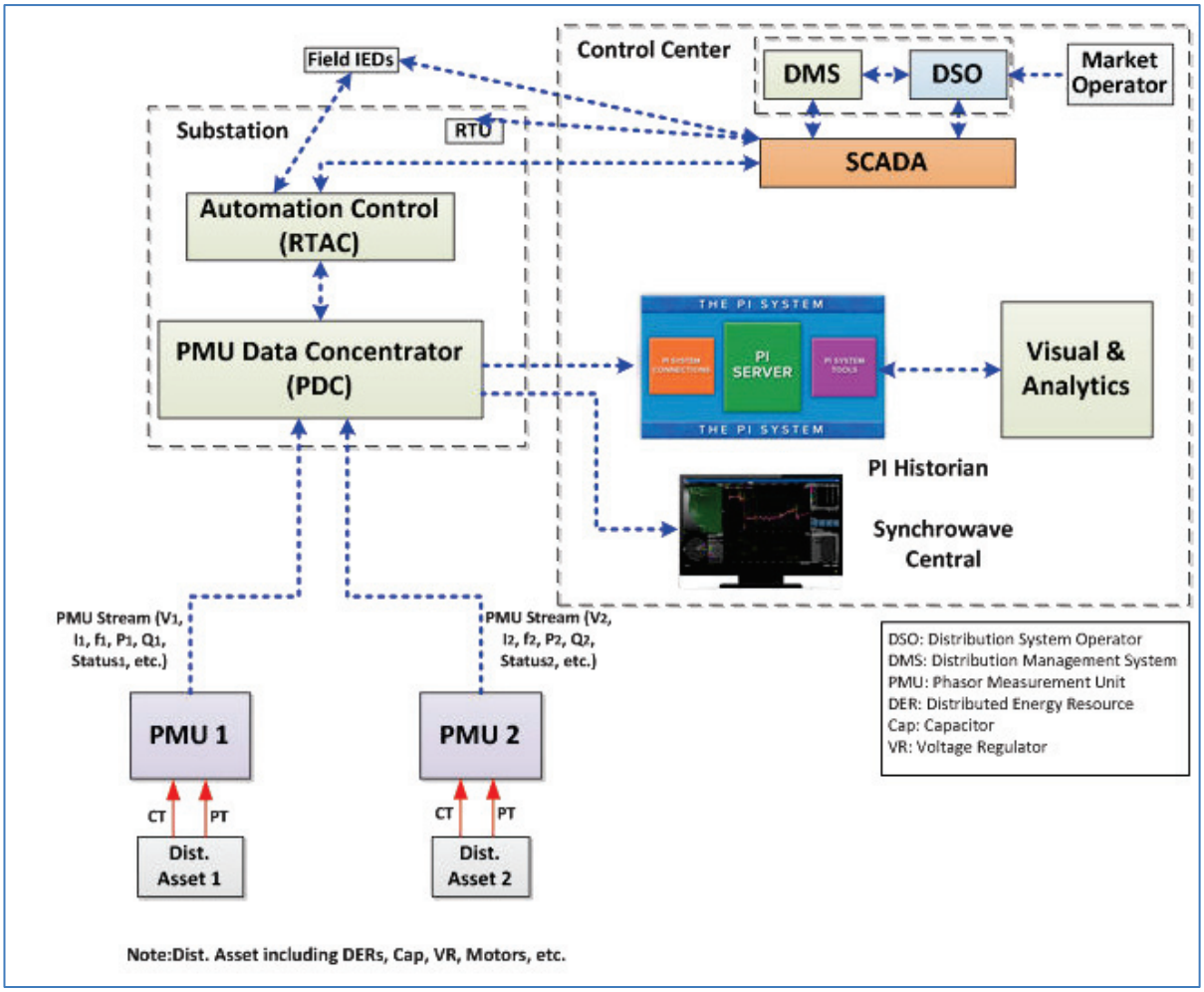


Figure 2-36. High level system architecture for integration and visualization of field data and information

One of the challenges in implementation of this system was to resolve how to combine various visualization and data platforms in one, user friendly system. For instance, PMU data is managed using a synchrophasor management system, power quality is managed by the technology that can process and visualize data such as harmonics, distortion, swell and sag, and similar; and, historian system has its own platform to manage, process and visualize the measurements and processed results. In addition to this, some of the requirements were to have access to reliability data, and these are managed by a separate group at SDG&E.

Also, one needed having in mind that the main anticipated users of this system would be system operators and engineering analysis group, as well as planning group, to a lesser extent.

This challenge of fusing and integration of diverse data set was addressed by creating a dashboard within Geospatial Information System (GIS) as a convenient means that provides geographical information about the circuits' infrastructure.

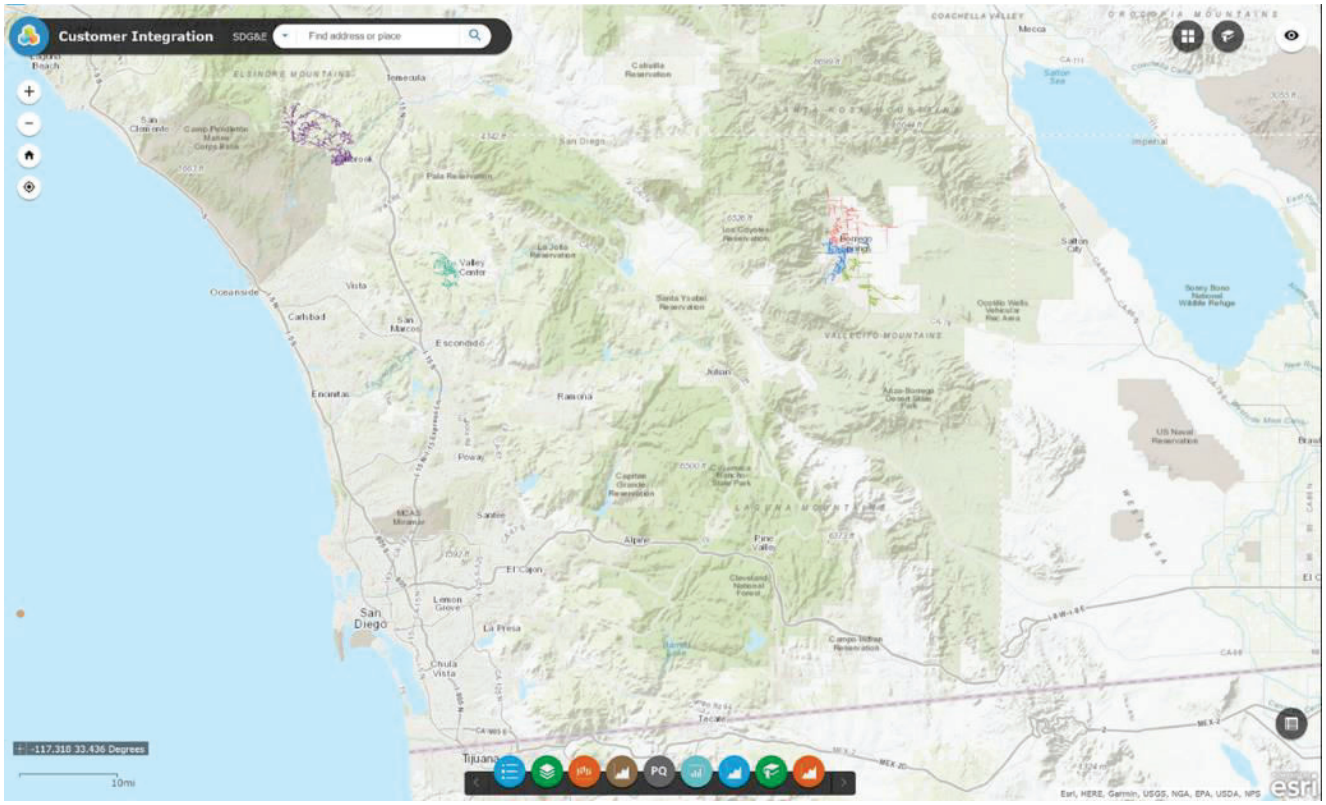


Figure 2-37. Main visualization system implementation dashboard

The SDG&E team has successfully implemented all requirements and the results are presented in the following sections.

2.6.2 System Test Setup at ITF Lab

The general layout of the testbed has been illustrated in Figure 2-38. The testbed consists of the following components:

- **Real-time digital simulator (RTDS)** – which is used for the representation of circuit 1 with all major controllable assets modeled.
- **GTNET PMU** – which is used for phasor data measurement and streaming of PMU1 to PMU8 in the simulation environment.
- **GTAO1 and GTAO2** – analog output cards that are used to send the low level voltage and current signals to the physical PMU devices.
- **Amplifier** – which is used to amplify low level voltage/current signals from RTDS to the secondary level for injection to the physical PMU devices (it should be noted that some physical devices use low level signals directly).
- **PMU Device 2** used for phasor data measurement and streaming of PMU9.
- **PMU Device 3** used for phasor data measurement and streaming of PMU10.
- **PMU Device 4** used for phasor data measurement and streaming of PMU11.

- **PMU Device 1** used for phasor data measurement and streaming of PMU12.
- **Real-Time Automation Controller unit** used for the processing of the available PMU data
- **GPS clock** used for time synchronization of RTDS, Automation Controller and PMU devices.
- **A PDC Software** used for PMU and Automation Controller data aggregation and time alignment for downstream applications
- **PMU Visualization Software** used for translating PMU data into visual information.

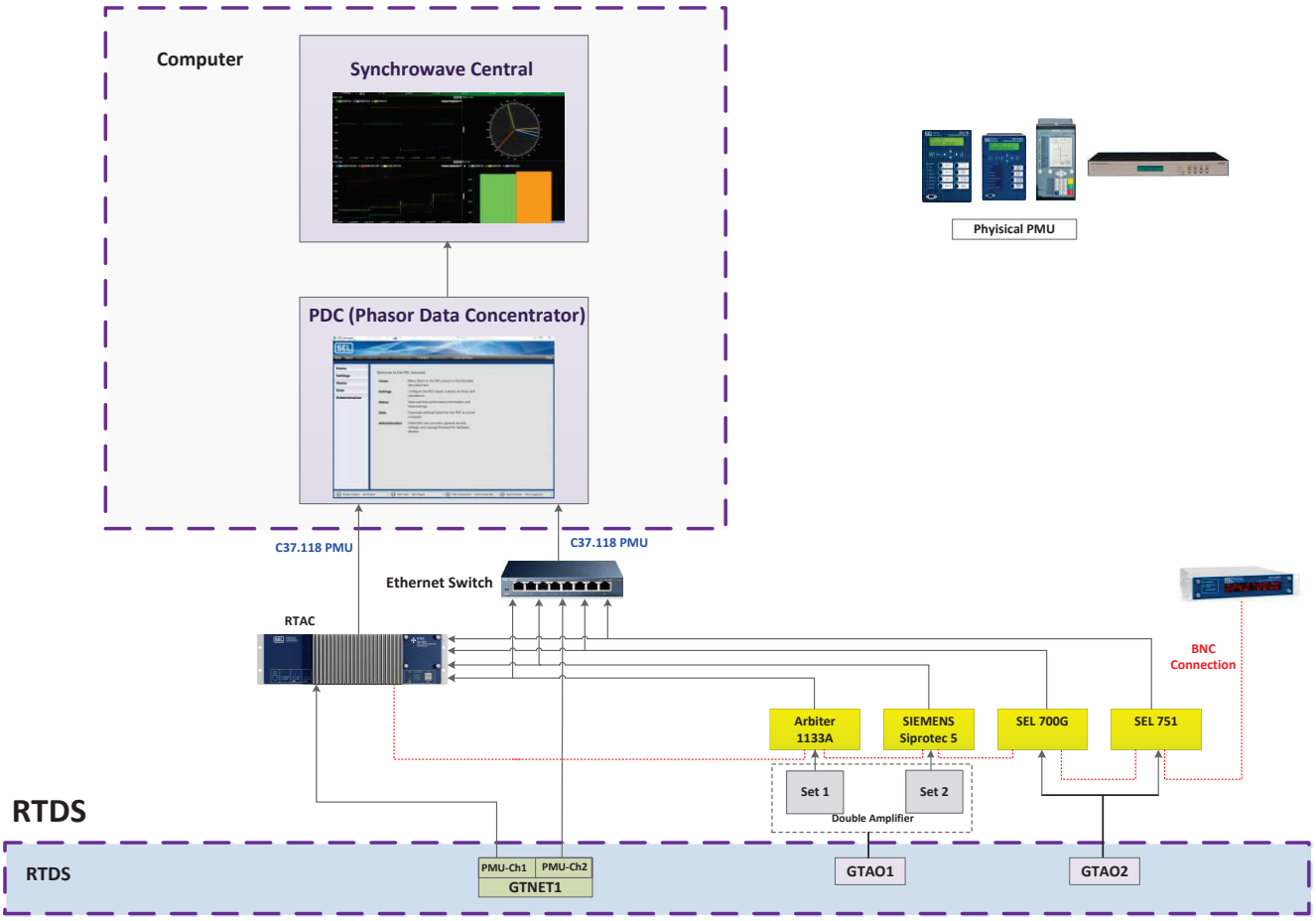


Figure 2-38. Test System Single Line Diagram for laboratory testing

3 Pre-Commercial Demonstration Results with Field data

This section provides the results of demonstrations on the capabilities of measurement, monitoring and visualization platform of the system described earlier in this report. The implementation was based on the requirements developed in six use cases and the proposed (extensive) list of visualization requirement.

3.1 PI Coresight Screens

The main system dashboard (Figure 2-37) developed for this project is a web based GIS application, with a series of widgets/buttons, each representing a separate application of visualization environment. One of the widgets calls up a PI Coresight dashboard, as shown in Figure 3-1.

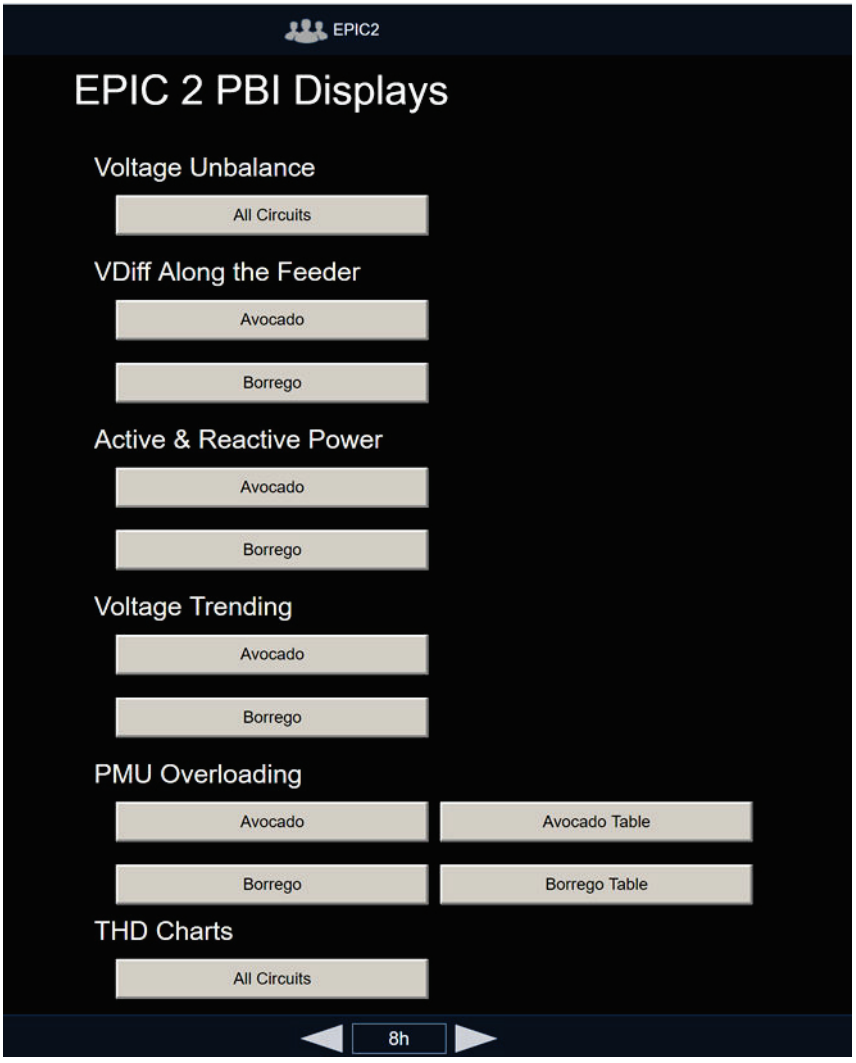


Figure 3-1. An example of a dashboard that utilize historical data base

As shown in this figure, several screens (such as Voltage Unbalance, PMU Overloading, THD charts, and etc) have been integrated in the PI Coresight dashboard. The remaining of the section provides example of various screens demonstrated.

The following figure shows visualization of voltage unbalanced factor using positive and negative sequence components at each PMU location ($\frac{V_1}{V_2}$). The values are calculated every 30 seconds in the PI system. The result are displayed on this PI Vision screen with limit lines at 3% and 10%. By using a multi-state symbol, the bars on the chart will turn to orange and then to red as they exceed the two thresholds.



Figure 3-2. Monitoring of voltage unbalance factor

The following screen shows voltage total harmonic distortion (THD) data being displayed on a bar chart with limit lines. The data comes through the SCADA system, so updates occur every 2-5 seconds. By selecting a THD percentage value, a trending chart is displayed with a configurable time range as shown in Figure 3-4.

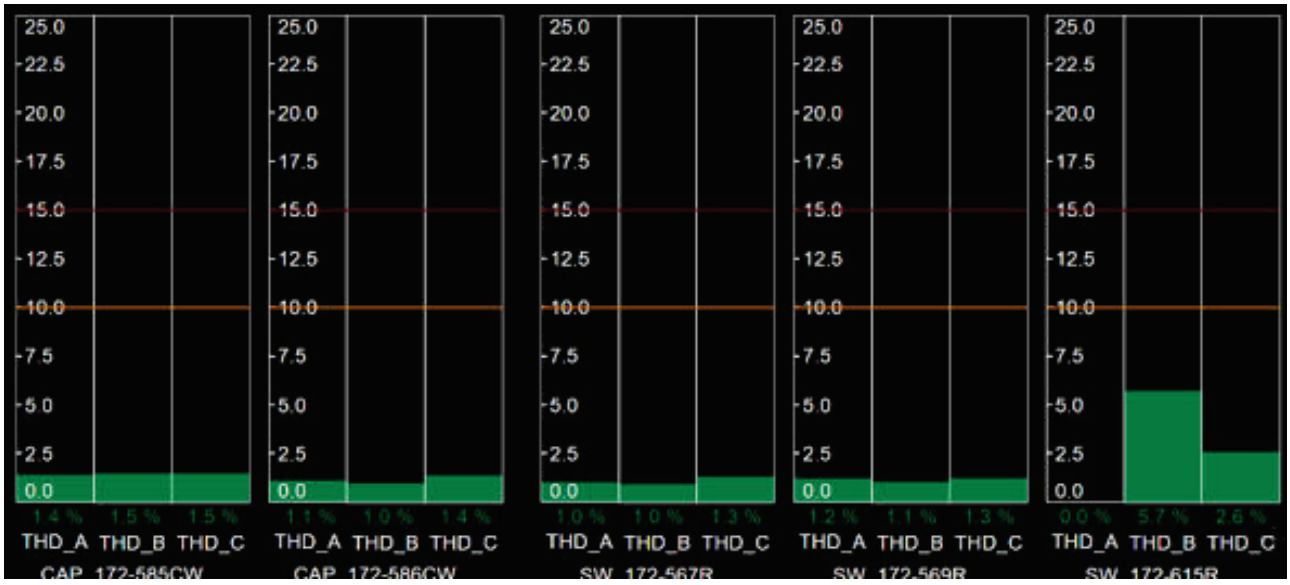


Figure 3-3. THD measured at various locations of selected circuits (all three phase); source: SCADA



Figure 3-4. Harmonic distortion (time frame) at one of the switches on circuit 1 (obtained from SCADA)

The following screen shows voltage difference from nominal value (in pu) measured at each PMU location on circuit 1. The upper and lower bars are +/-5% target levels from the nominal voltage (on 12 kV basis).

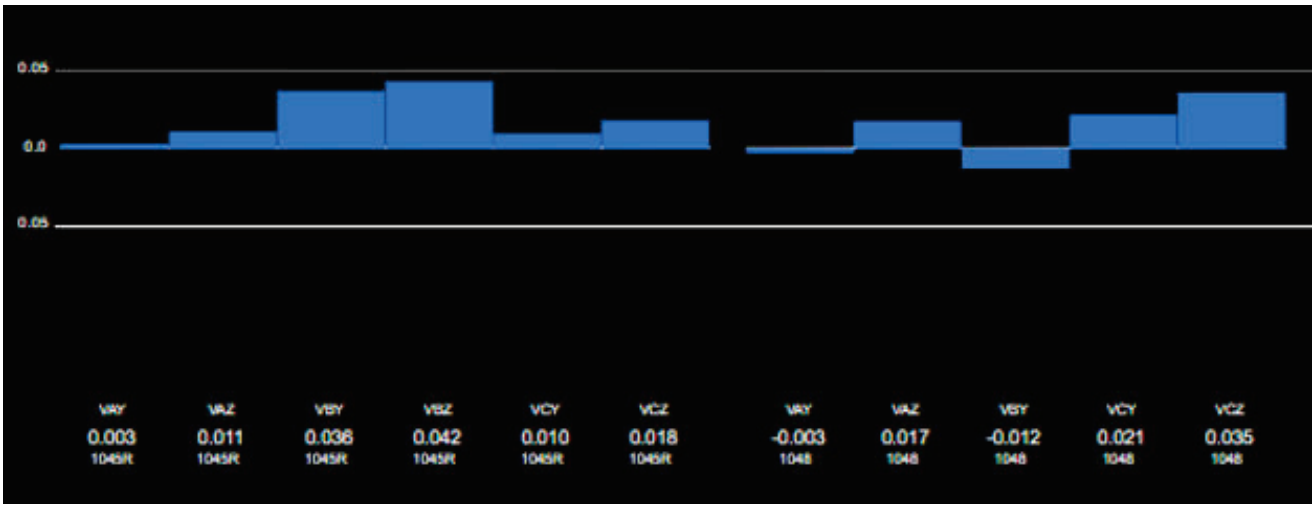


Figure 3-5: Voltage difference (in pu) on Circuit 1

The following screen shows active and reactive power by device as a bar chart. Active and reactive power are calculated for each existing phasor in real-time based on the data from OpenPDC and fed into the PI system. By using PI Vision for this visualization, the user can select any data and time to view the historical active/reactive power data on the devices. Negative values represent areas that reverse power flow occurs on the circuit.

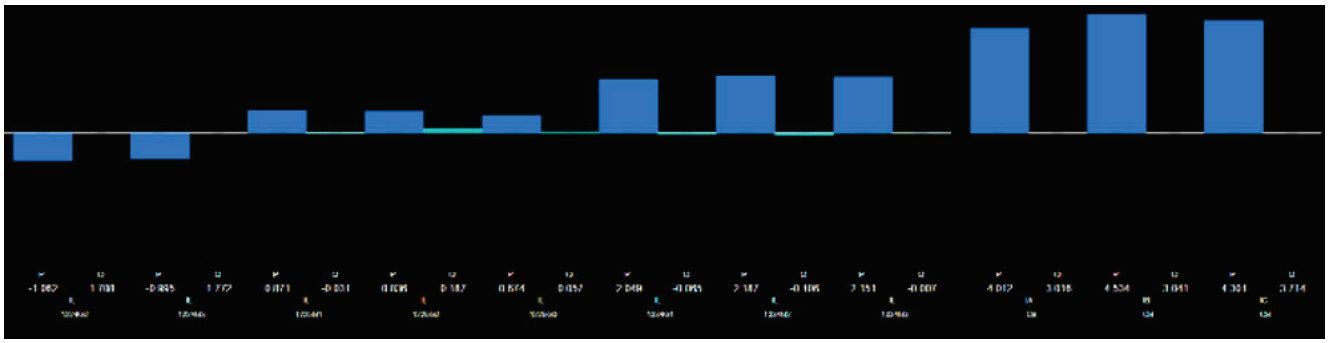


Figure 3-6. Active and reactive power flow for Circuit 1

The following two screen shots show thermal loading plots for Circuit 1, 2, and 3. The bars will change colors when they reach the rating limit lines, defined by a look up table for each feeder device and section of the line.



Figure 3-7. Thermal loading asset monitoring on Main branch, Branch #1 and Branch #2 of the Circuit 1

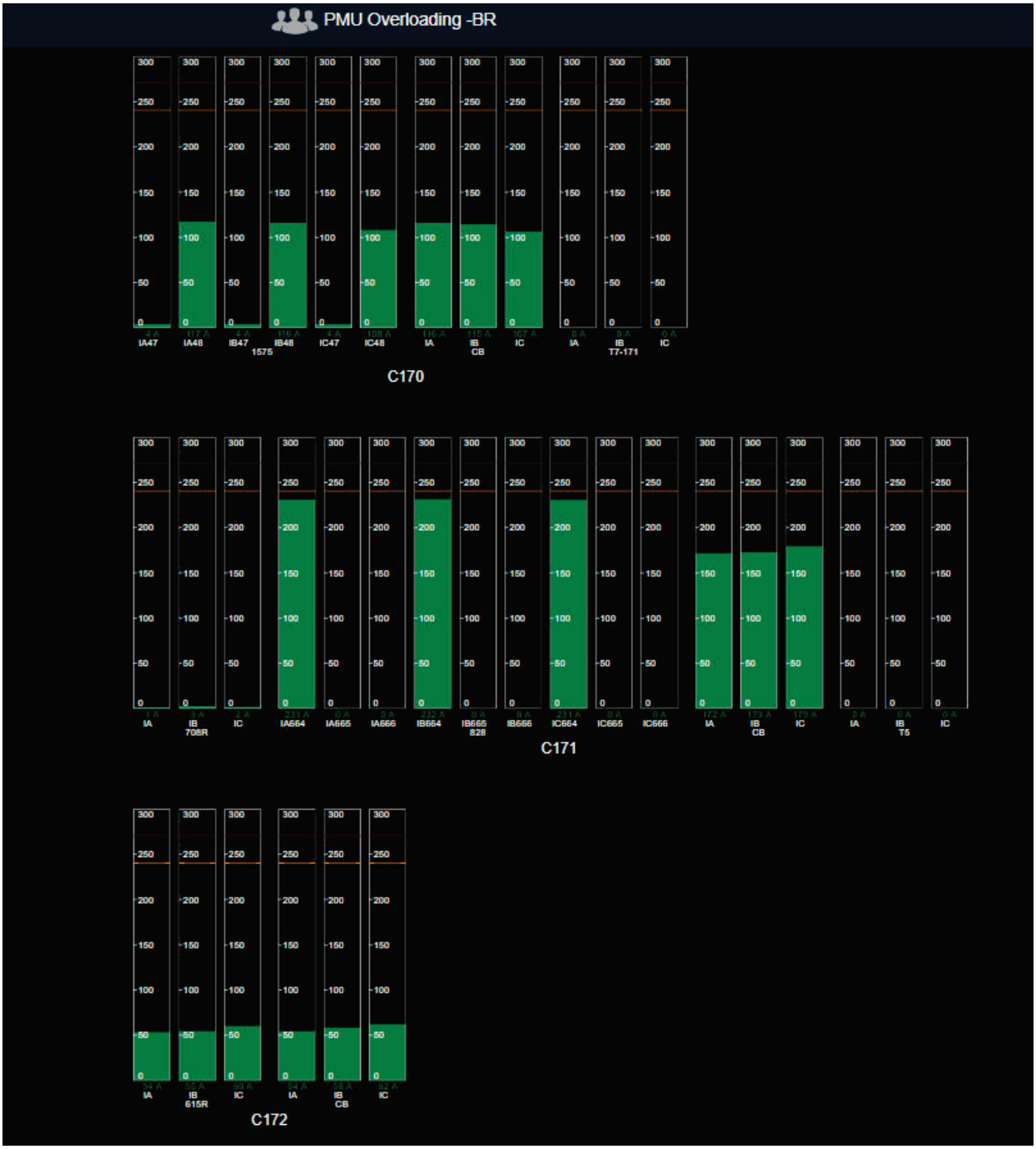


Figure 3-8. Thermal loading asset monitoring for Circuits 2, 3 and 4

The following is a screenshot from the Active/Reactive power values on Circuit 1. It can be seen that some of the PMUs with high MVAR values have bars that are displayed in red so they stand out in a large list.

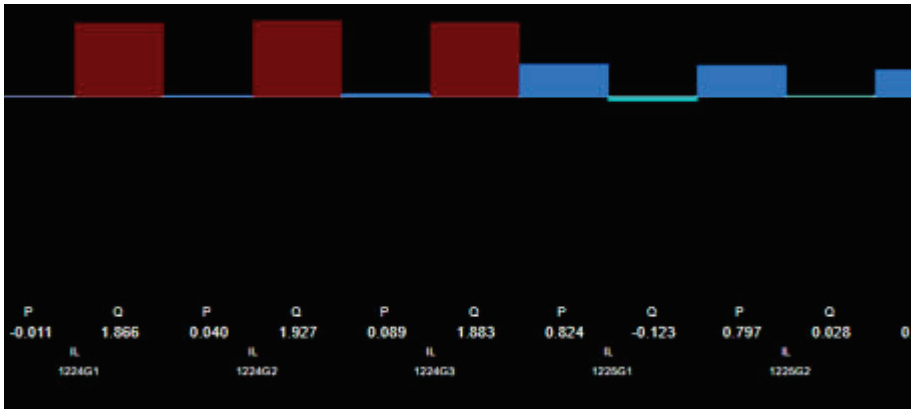


Figure 3-9. Active/Reactive power along Circuit 1

Figure 3-10 is the screenshot for reporting and visualizing the overloading conditions. The limit lines are accurately calculated for circuit breakers. The limits for the field devices are not determined because there are many factors down the line that effect the rating. The feature uses a look up table for field data update.

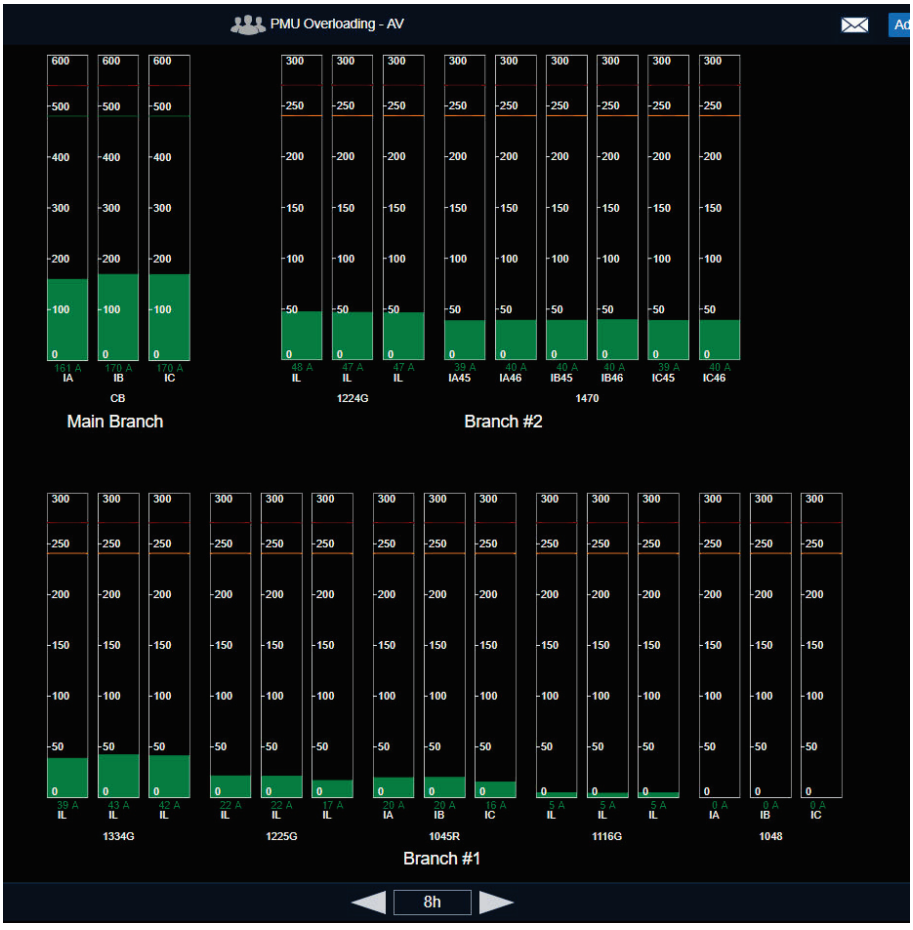


Figure 3-10. Overloading bar chart display for Circuit 1 based on PMU data

The following screenshot provides the tabular reporting format of the circuit level device loading. The report is organized by the main branch (backbone) and each individual branches (laterals). In the advanced visualization the aim is to move from tabular data to graphics and summary reports that can fuse multiple measures into specific metrics to support fast-decision making by operators.

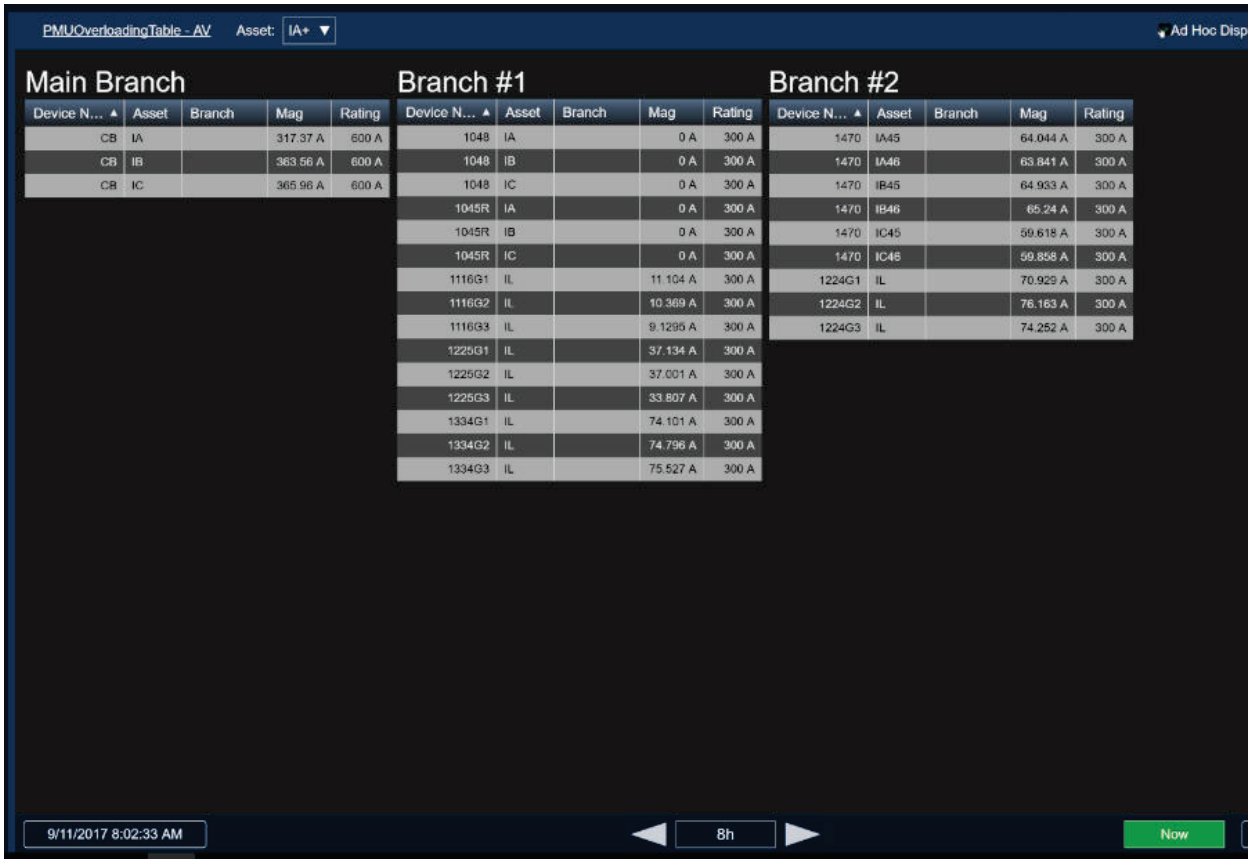


Figure 3-11. Tabular reporting of device loadings for Circuit 1 based on PMU data

The following display shows another PIVision display with voltage along the feeder. This display gives the operator a clear view of voltages over the entire circuit. The limit lines and color changing bars draw attention to large voltage deviations.

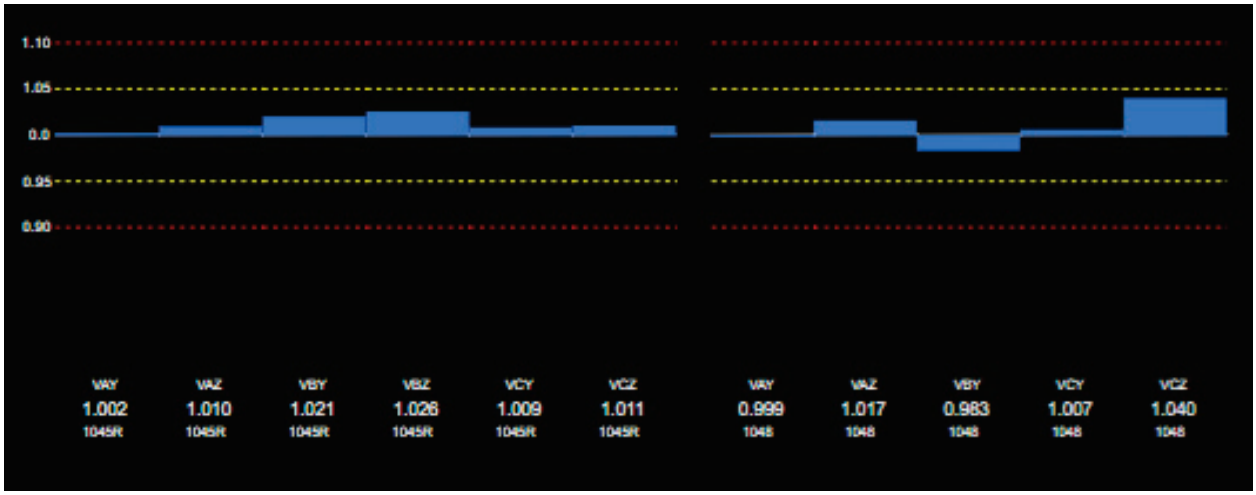


Figure 3-12. Voltage deviations (from base voltage) in percentage along the selected circuit length (circuit 1)

3.2 Real-time measurement examples

One of the menu selection options on the visualization screen navigates to real–time PMU visualization software platform. In this subsection, several real-time screens (based on the visualization requirements) obtained from field PDC are shown to demonstrate the built in capabilities and type of data visualization available.

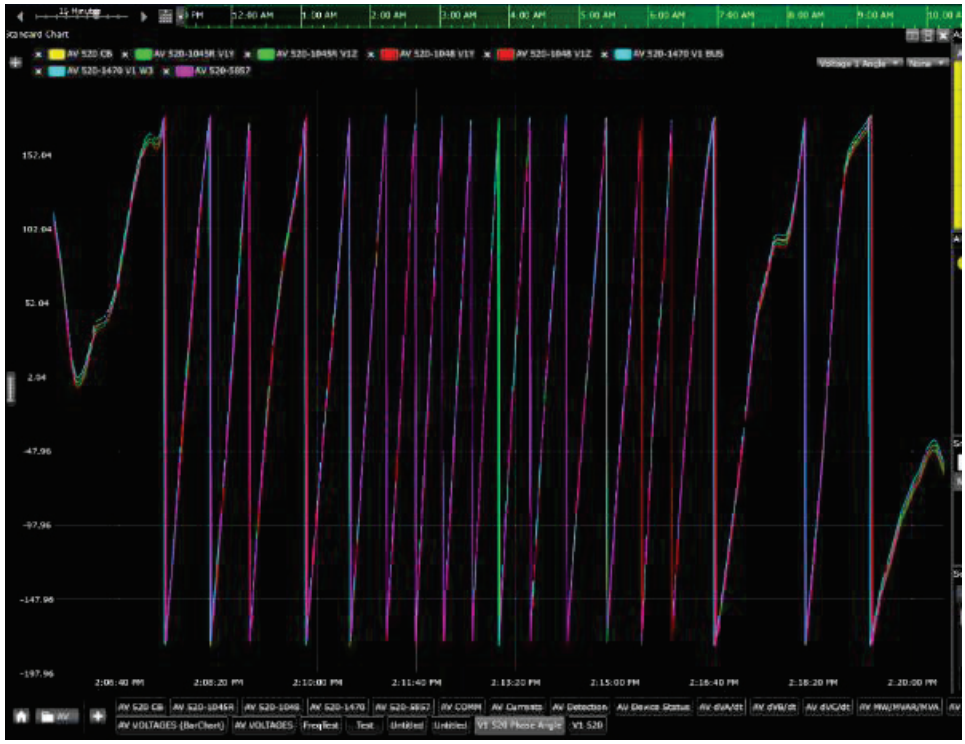


Figure 3-13. Voltage phase angle in phasor time domain

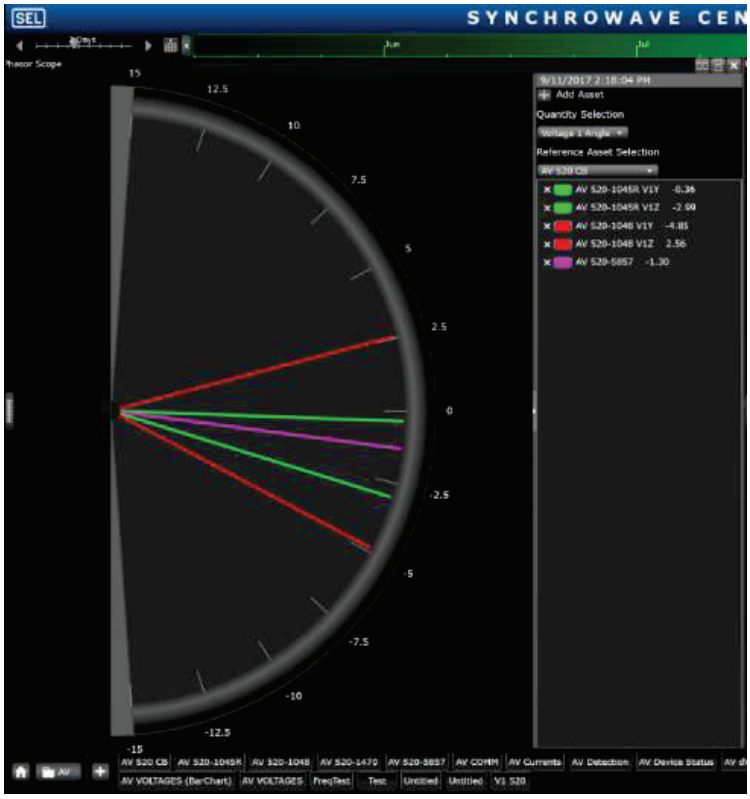


Figure 3-14. Polar version of real time monitoring of voltage phase angles

The following displays show voltage magnitude and phase angle for the device 520-1470 (near the large 2MW solar site toward the end of circuit 1). The displays are built out for several circuit breakers and recloser on the line, such as: 1045R, 1048, 1470, and 5857.

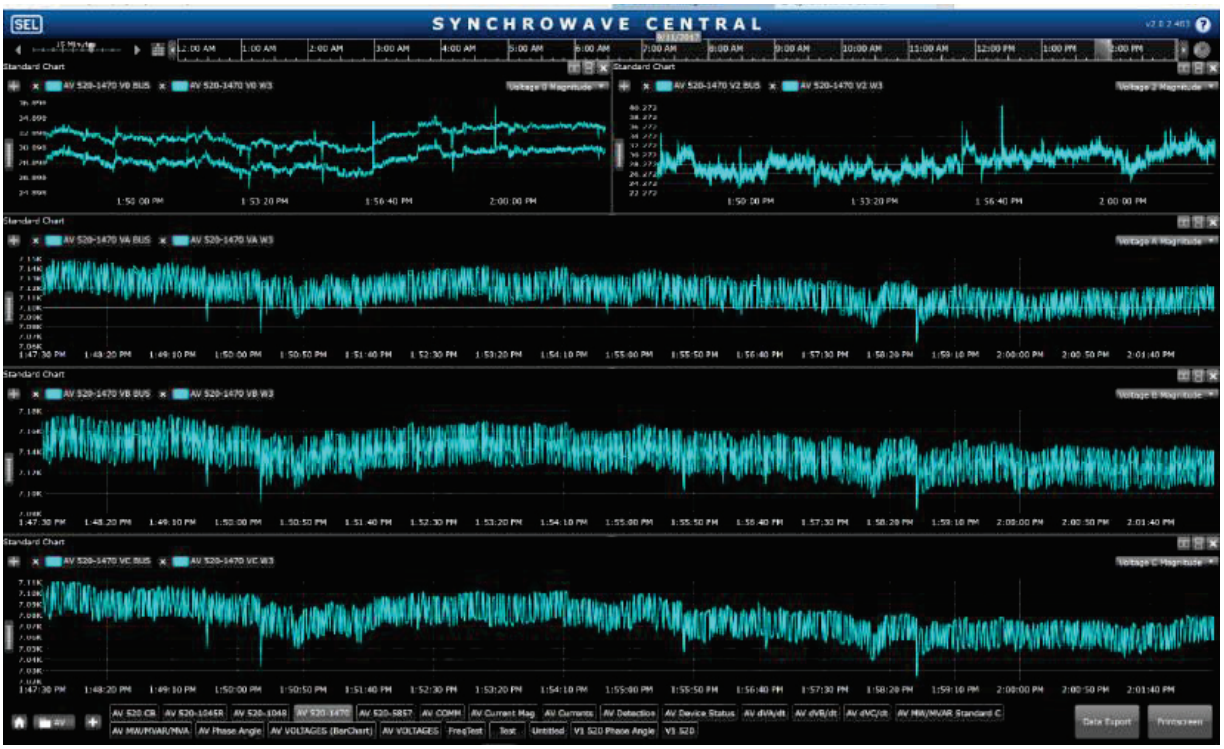


Figure 3-15. Voltage magnitude of the Circuit 1 PMUs (standard view)

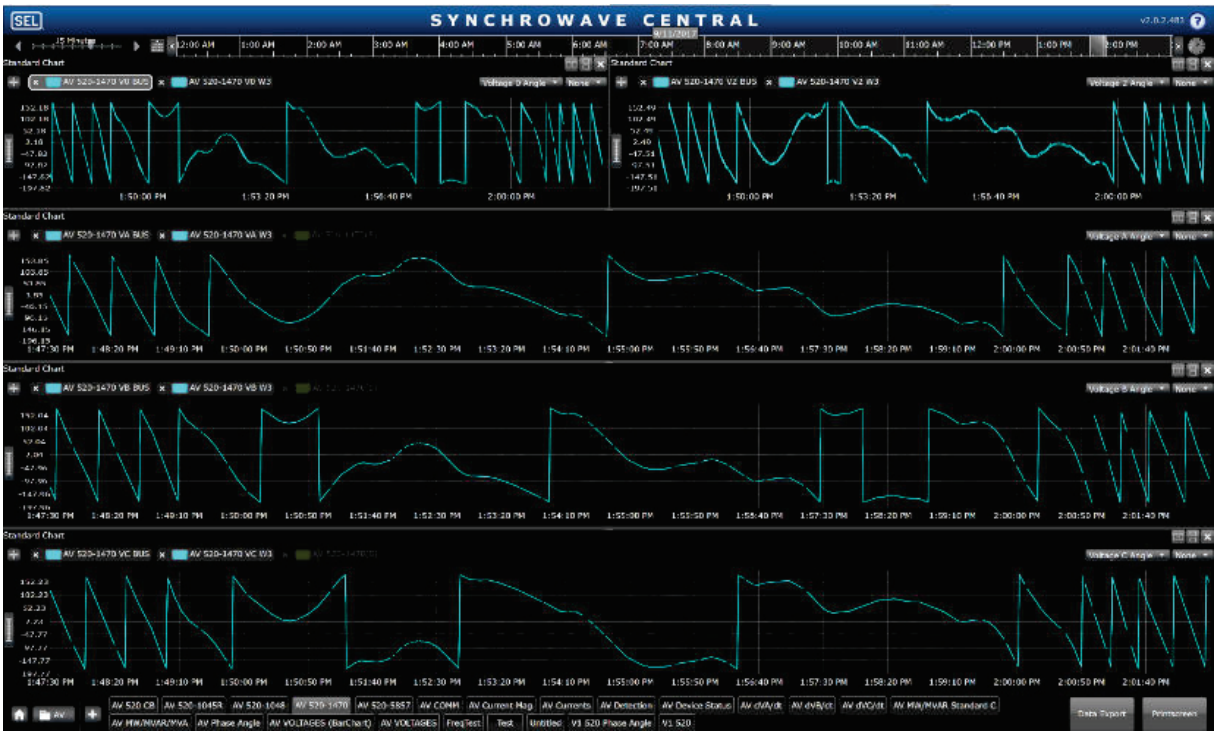


Figure 3-16. Voltage phase angle of the Circuit 1 PMUs (standard view)

The following display shows active, reactive, apparent power for the circuit breaker, and PMU 5857 which is located just outside of the 2MW solar PV site.



Figure 3-17. Numeric display for selected PMUs

3.3 Visualization displays on the GIS map

In addition to the aforementioned screens, some of the visualization requirements were based on the GIS maps to show the distributed and geographical nature of the distribution circuits. Examples of GIS map based screens and built in functionalities are shown in this section.

The next two figures demonstrate visualization of real-time measurements for total active power generation units in the PV plant, and customer loads, respectively. The data is also obtained from the field and the blue circles show geographical measurements locations. The active power data displayed for PV Customer generation is the nameplate rating of the PV system rather than real-time. All of the other data on the map is real-time PMU data.

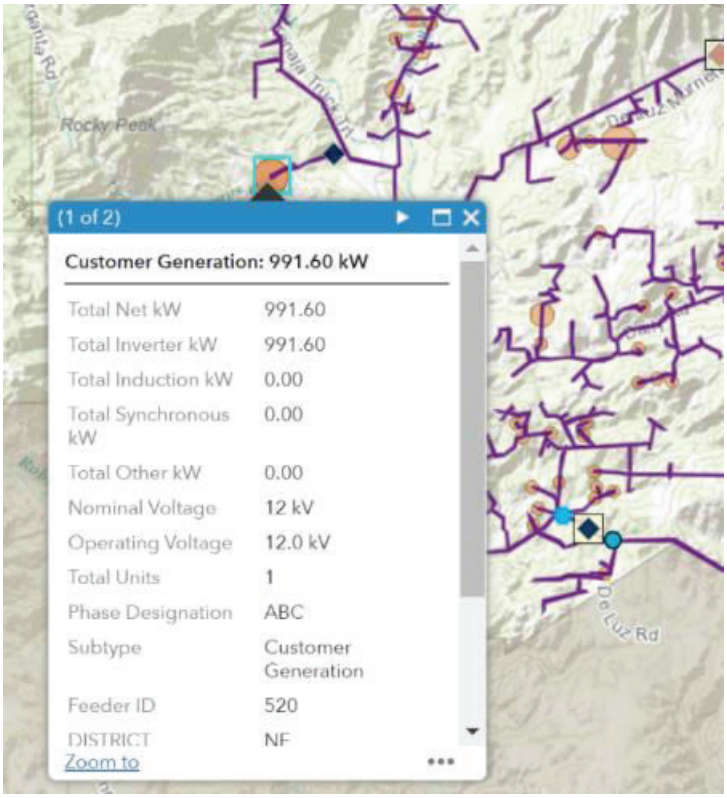


Figure 3-18. Total active power generated by PVs

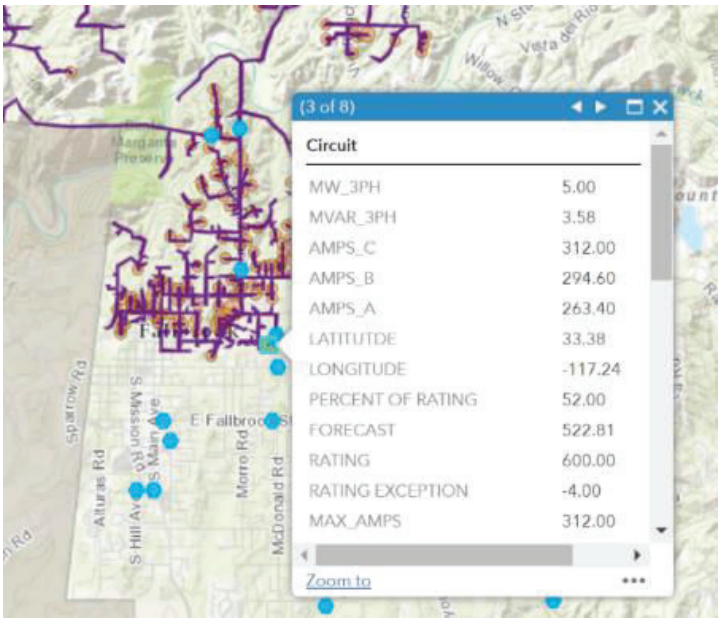


Figure 3-19. Real time monitoring of customer loads

The next two figures show real-time measurements of voltage regulator tap positions and capacitors status, respectively. The screenshots show capacitor switching on the cap information popup and the time series display of that value. The values are incremented whenever a capacitor switches on or off. The status changes can be because of time bias or changes in the voltage level of the circuit. PV production fluctuation is also a key contributing factor. The number of tap changes need to be monitored.

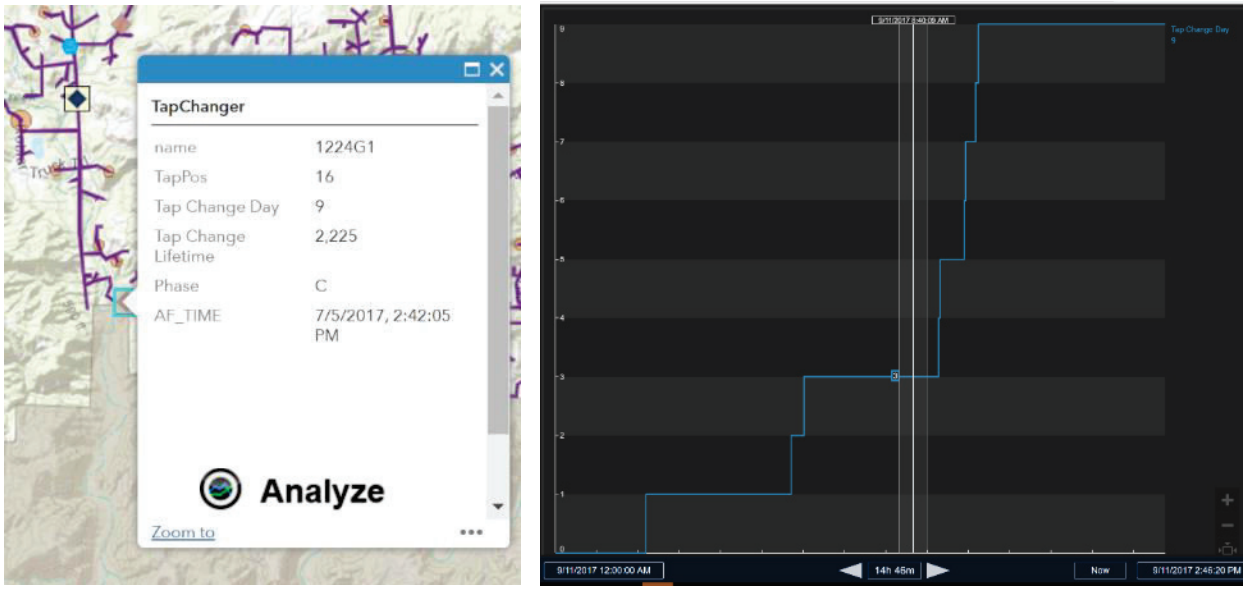


Figure 3-20. Monitoring of Tap changer status (left) and tap positions change over time (right)

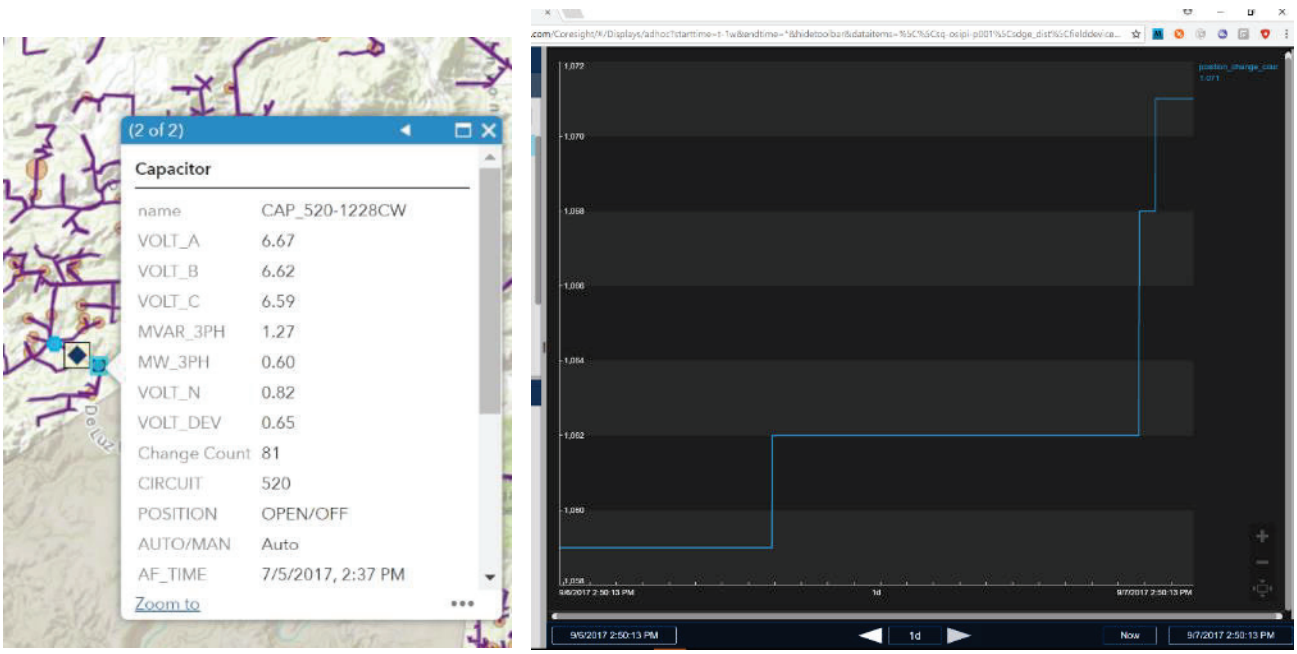


Figure 3-21. Real-time monitoring of cap banks status

Voltage Sag and Swell are some of the KPIs that need to be monitored and visualized as described in the system requirements. Figure below illustrates one of the implementation cases for these requirements.

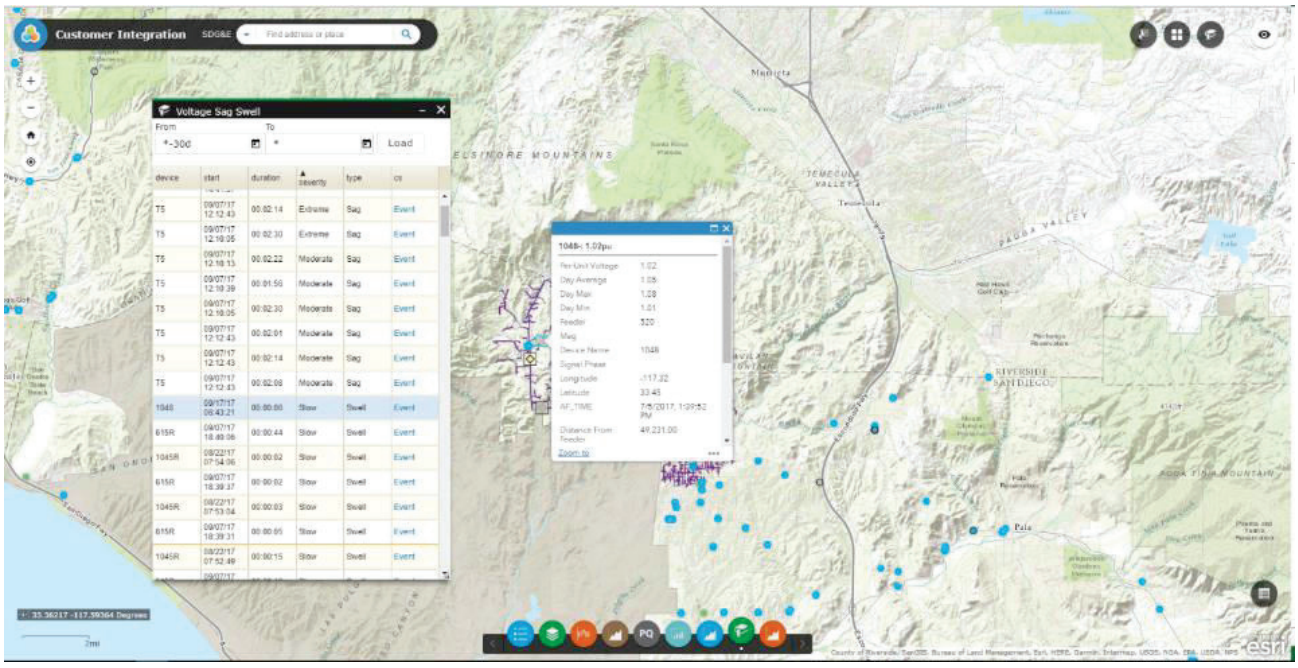


Figure 3-22. Demonstration of KPI monitoring

By clicking on an event on the table, it selects the matching attribute in the map. By clicking on the "Event" link, it brings up a PI Vision display showing the per unit voltage with limit lines for the time range of the event.

To create this display, the processing engine behind it has to detect the events using a custom extension on the OpenECA platform written in C#. OpenECA provides the custom program with synchronized real-time synchrophasor data. The program is configurable, so it can specify different thresholds for different sag/swell severities. Each severity has a set time duration and percent exceedance that must be reached for the event to be counted. Once an event is detected, an event frame is created in PI and linked to the correct device and phase. When the event concludes, the end time is updated in PI as well.

Once the data captured in PI, the processing engine uses a custom widget used to display the data in our web app. The user specifies a start/end for the search and clicks load. The widget makes a request to a custom web service that uses the PI macros to load and return the relevant event frames.

The following screens show the "interconnection violation" indicators for voltage sags, voltage swells, and power frequency. The ride-through thresholds and durations are determined from CA Rule 21 requirements.

The bar charts at the bottom count total number of voltage sags/swells for the current date. The threshold lines (blue and yellow lines) are calculated using the 30 sample per second OpenECA data and fed into PI. When the voltage reaches a configured threshold, the threshold line immediately jumps to the next threshold for a specified amount of time. To not violate the Rule 21 specifications, the voltage should recover within that time limit.

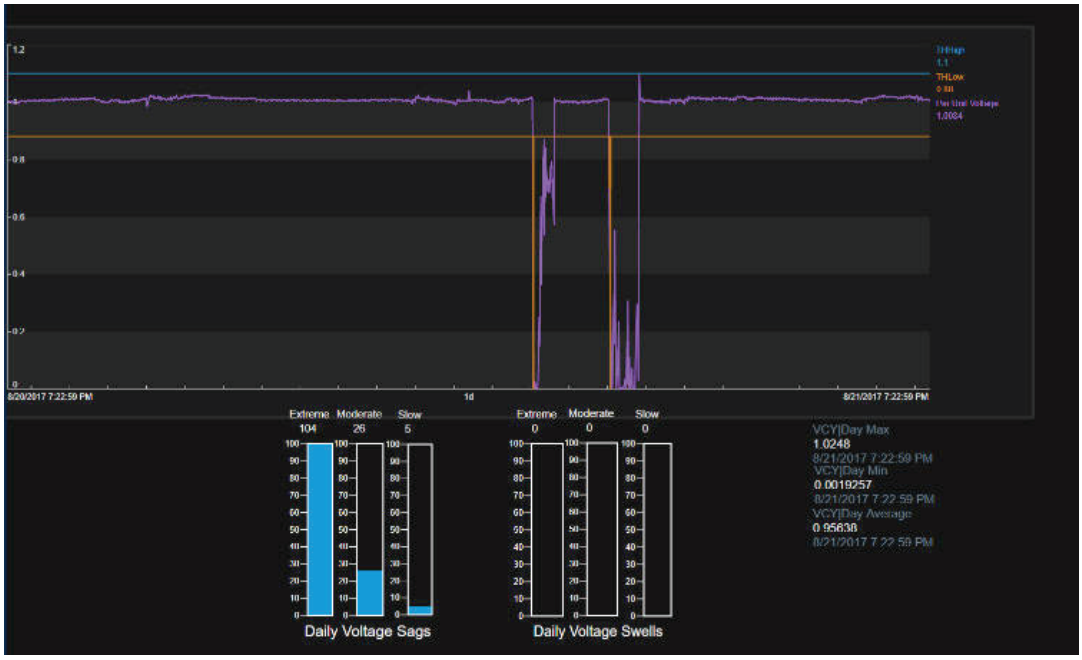


Figure 3-23. Sample of the captured voltage sag versus the acceptable thresholds and durations

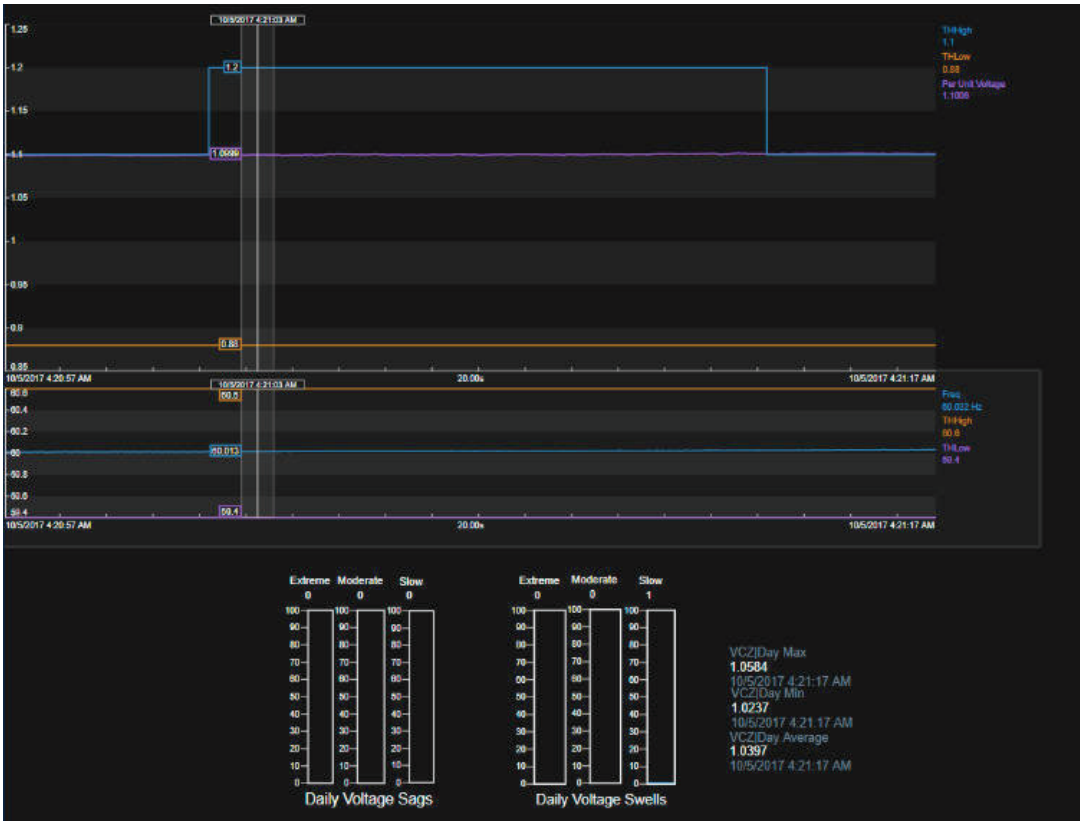


Figure 3-24. Sample of captured voltage swell versus

The voltage sag cases reported in the previous plots were caused by a sensor measurement problem on a line recloser. The voltage drops were only became observable when the PMU data streaming and visualization put in place.

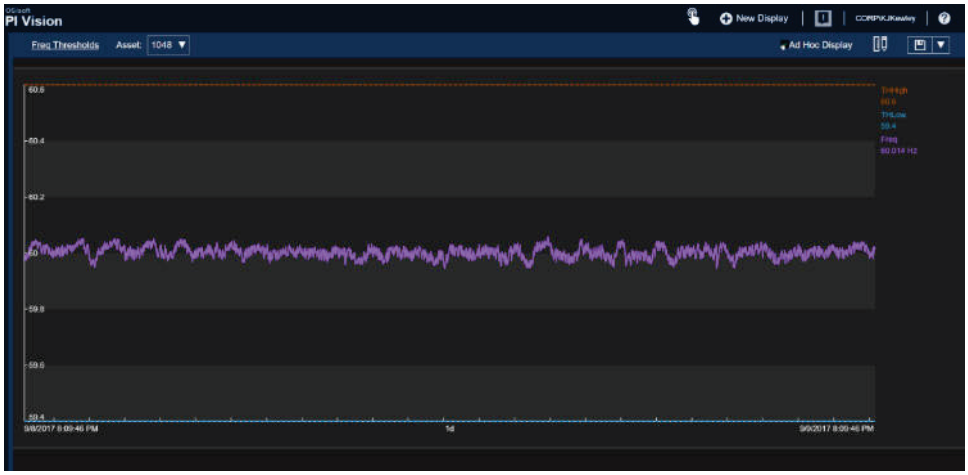


Figure 3-25. Frequency violation monitoring

Above screenshot uses similar calculations, but the thresholds are configured for frequency data. In this case, the high threshold is 60.6Hz and the low is 59.4Hz. Generally, frequency in distribution system is more stable and there should not be any violation of these thresholds on the circuits. However, if a cascading fault and outage event on transmission system causes a sudden frequency change and restoration, the distribution PMUs should be able to detect that.

The following screen calculates the voltage sensitivity of the PMUs. This PI process book screen is linked to the map. The values on the XY plot come from a calculation done in OpenECA. When there is a large change in voltage, the calculation returns $\frac{\Delta V}{\Delta P}$ and $\frac{\Delta V}{\Delta Q}$. This is plotted on a chart with the y axis as the calculated value and the x axis as the per unit voltage. On the left hand side, different PMU locations can be selected for display.

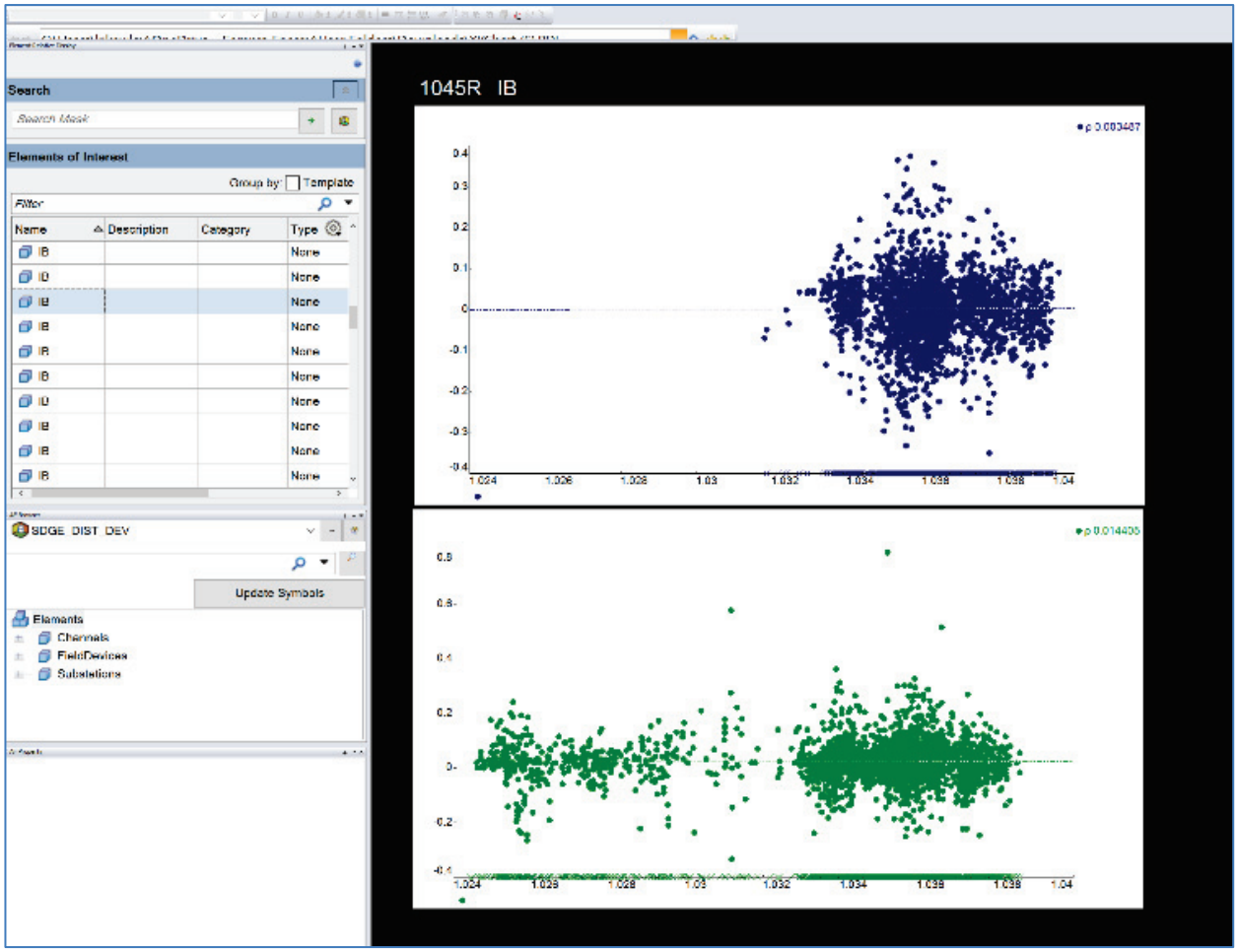


Figure 3-26. Power sensitivity trending for Circuit 1

The next figure shows the min/average/max voltage profiling plot for the entire circuit. Small horizontal line shows the average voltage, and the two ends of the long vertical line show minimum and maximum voltages in a day.

This visualization was created with a custom widget in Web AppBuilder. When opened, the widget subscribes to feature selection on the map. When a feature from the layer specified in the configuration is selected, the widget gets the “feeder” attribute of the selected feature. Then it makes a request for all the min, max, average, distance, and name attributes of features with the same feeder ID. Once the data is returned, the candlestick chart is drawn using the “dojo” framework charting library.

The plots was considered very beneficial for engineering analysis purpose and operator troubleshooting. In one glance, the engineer or the operator can determine the worst case locations on the circuit and narrow down the focus on analyzing those locations.

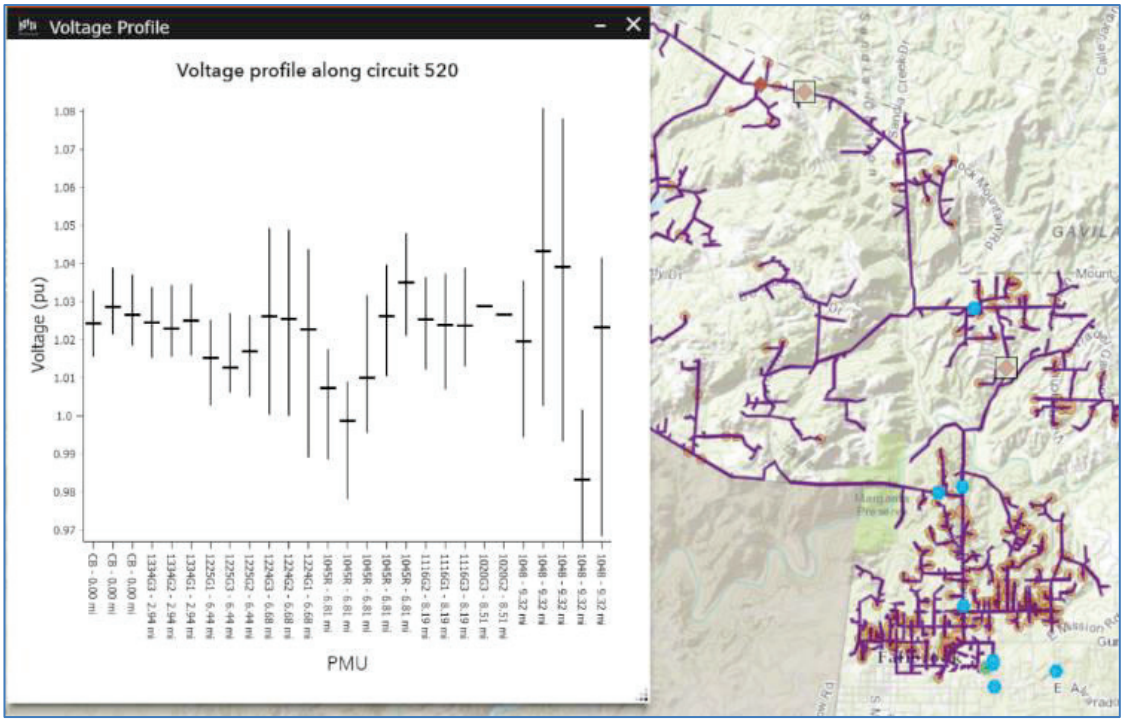


Figure 3-27. Voltage monitoring demonstration – Use Case 1

3.4 Power quality monitoring examples

Figures below illustrate visualization of odd/even harmonics and total harmonic distortion for selected substations. The detail harmonic information was extracted from PQview data base and incorporated in the visualization screen of this project. During the course of the project, it was noted that several SDG&E distribution substations are already equipped with power quality meters. The harmonic data are captured for pre-defined disturbance conditions (such as sudden voltage changes beyond 20%, or RHD greater than 3%) in PQdiff format. The PQview database collects and organize the PQdiff event records which will be the source of extracting harmonic information.

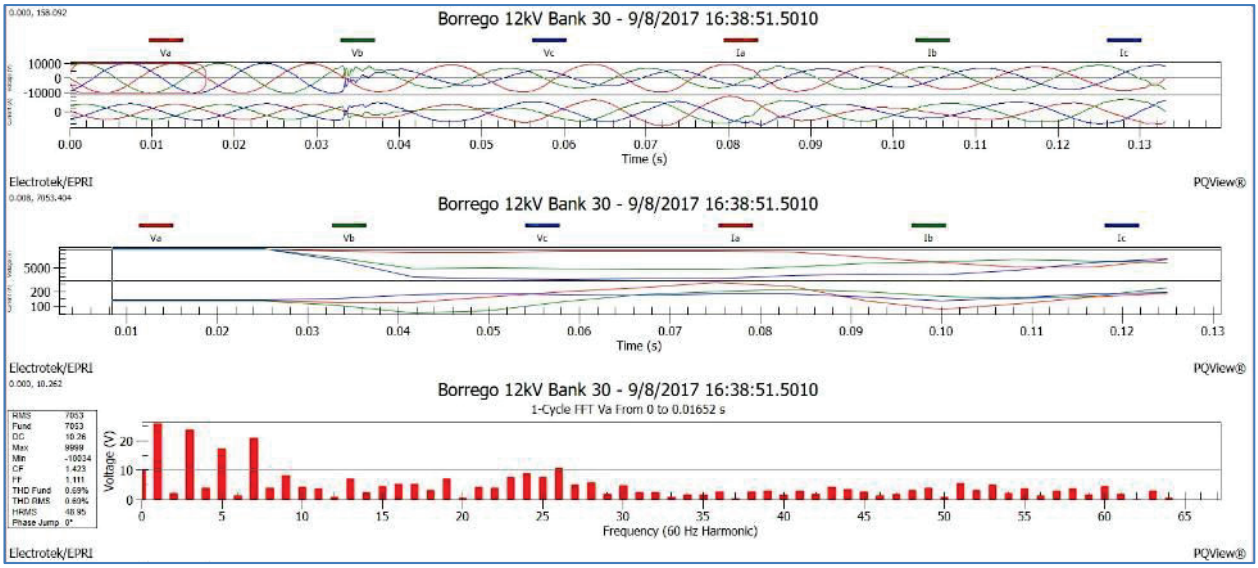


Figure 3-28. Monitoring of odd/even harmonics

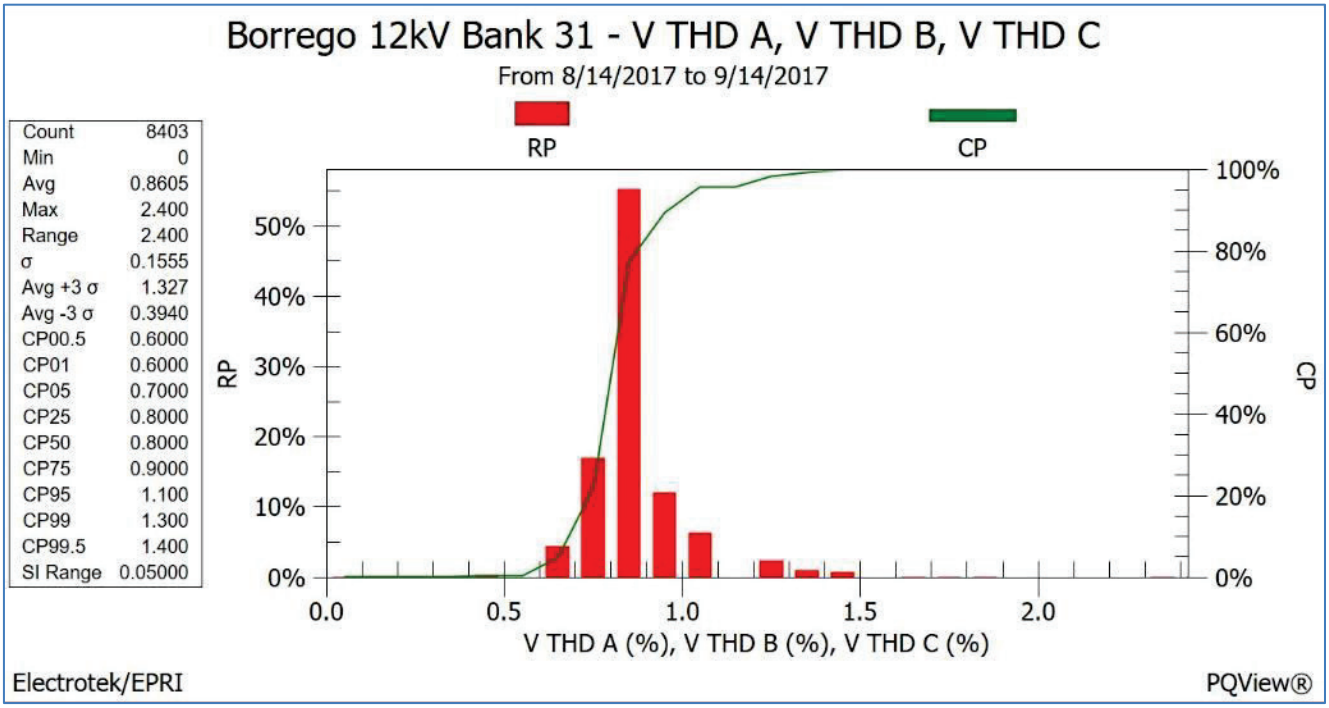


Figure 3-29. Visualization of total harmonic distortion (THD) on one of the selected circuits

3.5 Key performance indices monitoring

Figure below shows the data captured form one of the PQ meters at a distribution substation. The PQ meter provided a measurement of long term flicker factor as an example of the proposed performance indices. In order to calculate flicker factor, the number of voltage dips per minute has to be monitored and counted over the long moving window. However, the substation PQ devices already have internal calculation capability of the flicker factor. The feature was integrated in the visualization screen.

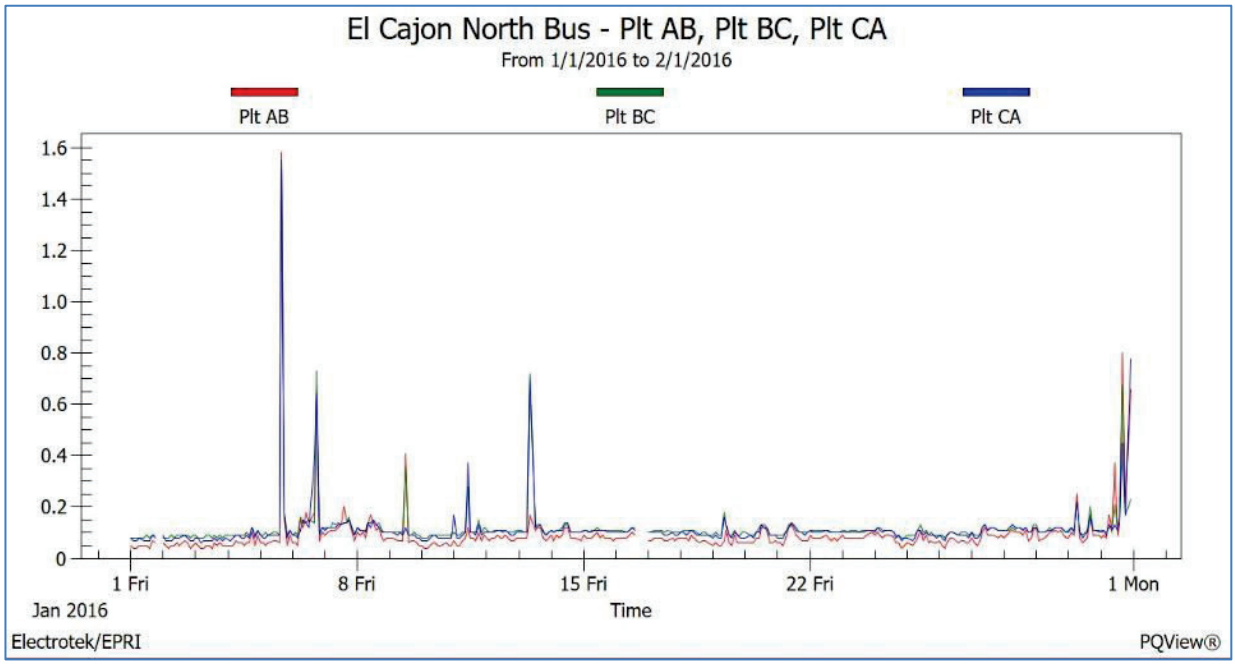


Figure 3-30. Illustration of Flicker factor monitoring and visualization

4 Pre-Commercial Demonstration Results based on Laboratory Setup

In this section, the results of the test cases for selected circuits (Circuit 1, Circuit 2, Circuit 3, and Circuit 4) based on different use cases demonstrated in the ITF laboratory are provided.

4.1 Circuit 1 Test Results

A simplified single line diagram of the Circuit 1 and the test setup are shown in Figure 4-1. The single line diagram is an overall representation of the model built in the RTDS environment for the laboratory testing and evaluations.

As indicated in this figure, there is a 2 MW PV system at the end of the circuit. The circuit backbone branches out in two directions. There is a normally open tie switch (520-1048) between the two branches of this circuit. For load transfer cases, the tie switch can be closed and one of the upstream reclosers can be opened to change the load flow and voltage profile of the circuit. Six voltage regulators and two switched shunt capacitors are installed on this circuit. A Dynamic Voltage Regulator (DVR) is also installed on the branch to the PV site, upstream of the PV location. DVR is used to mitigate significant voltage issues due to high PV production and loading condition. For the purpose of this study, this circuit has been modeled in RSCAD[1]. 12 PMUs including 8 simulated PMUs (PMU1 to PMU8) and 4 physical PMUs (PMU9 to PMU12) are located at various nodes in the study system to facilitate system monitoring during the tests.

[1] All controllable assets (voltage regulators, load tap changers, and capacitor banks) are also modeled in details in the real-time digital simulator (RTDS) to enable integrated voltage/var control in the distribution circuit under study.

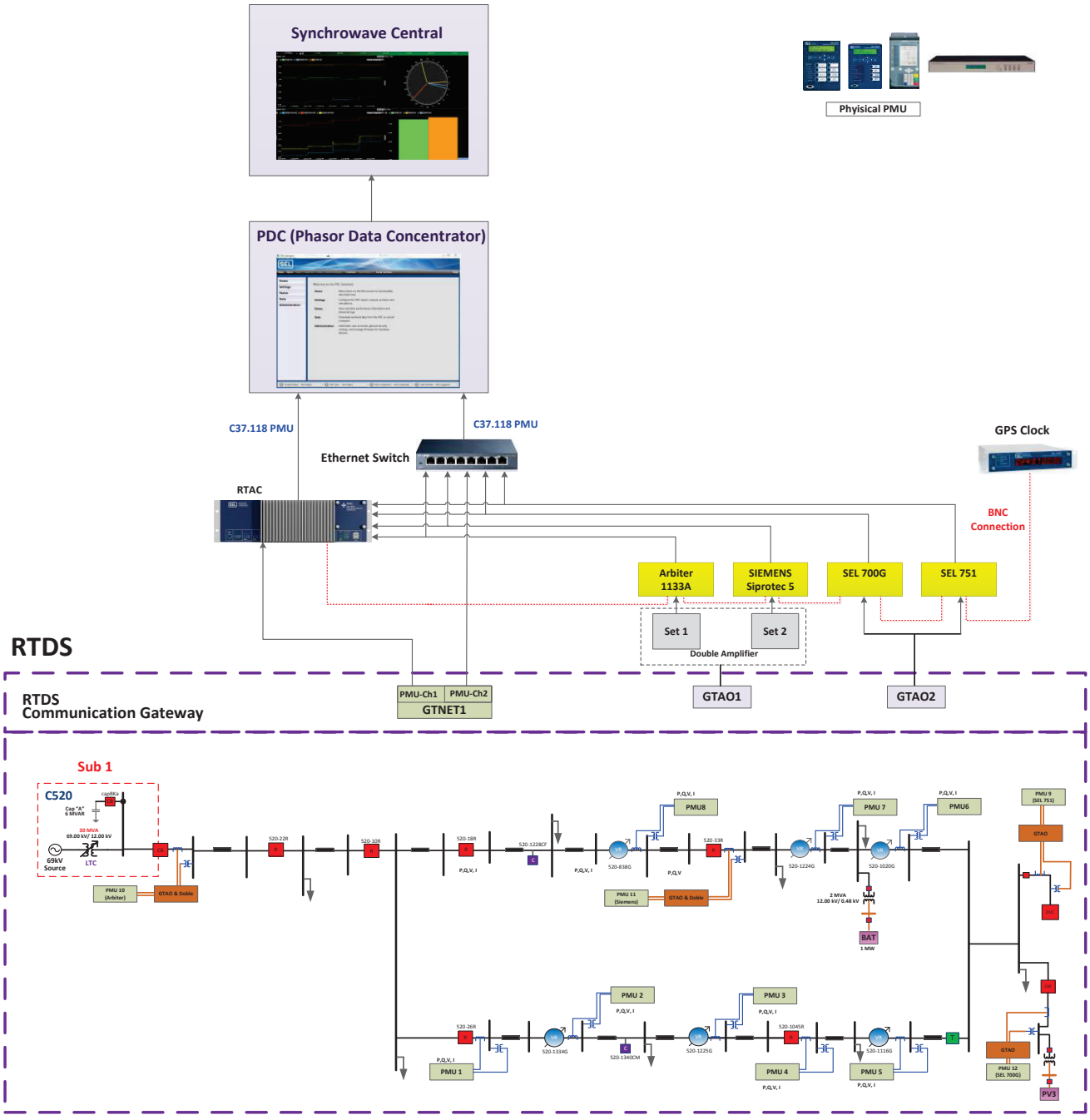


Figure 4-1. Single Line Diagram and PMU Locations of the Circuit 1

The PMUs data (either obtained from the real-time digital simulator or actual physical hardware) is streamed to PDC and RTAC. Simultaneously, RTAC processes the input PMU data and sends the calculated parameters

into the PDC. Finally, all data obtained from PMUs and RTAC will be time aligned and sent to SynchroWAVe for monitoring and visualization purposes. The calculated values in RTAC are as follows:

- Delta V in per unit (with respect to the base voltage of 12 kV)
- Unbalance factor in % (using V2/V1 – negative to positive sequence voltage ratio)
- Extreme voltage sag count (V<0.2 pu for 10 cycles)
- Moderate voltage swell count (0.2 <V< 0.4 pu for one second)
- Extreme voltage swell count (V > 1.3 pu for 10 cycles)
- Moderate voltage swell count (1.2< V < 1.3 pu for 1 second)
- Alpha factor (dV/dP) in pu/MW
- Beta factor (dV/dQ) in pu/Mvar
- Flicker index (calculated based on the number of voltage dips per minute)

In addition to these calculations, THD and tap positions are directly sent to the PDC using the analog values of the simulated PMUs.

In the following section, different case studies are investigated and reported for the validation of the test set-up and the calculations in the Avocado circuit.

4.1.1 Voltage/Power Flow Monitoring

The purpose of this test category is to verify proper communications amongst various components of the test setup and to demonstrate the built-in visualization capability of the SynchroWAVe Central. Furthermore, it will evaluate the calculation of Delta V (per unit) in RTAC.

4.1.2 Long-term Monitoring

In this test, the winter load profile was run for 90 minutes with PV and the following measurements were captured from SynchroWAVe Central for all PMUs.

- Magnitude of positive sequence voltage
- Magnitude of positive sequence current
- Phase angle of positive sequence voltage
- Phase angle of positive sequence current
- Active power
- Reactive power
- Apparent power
- Delta V (per unit).



Figure 4-2. Magnitude of Positive Sequence Voltages

The fluctuations in the voltages and currents are caused by the changes in the load profile, PV profile, and tap position changes of the voltage regulators. The changes in load and generations are observable from a visualization graph such as the one shown below for capturing positive sequence currents at PMU locations.

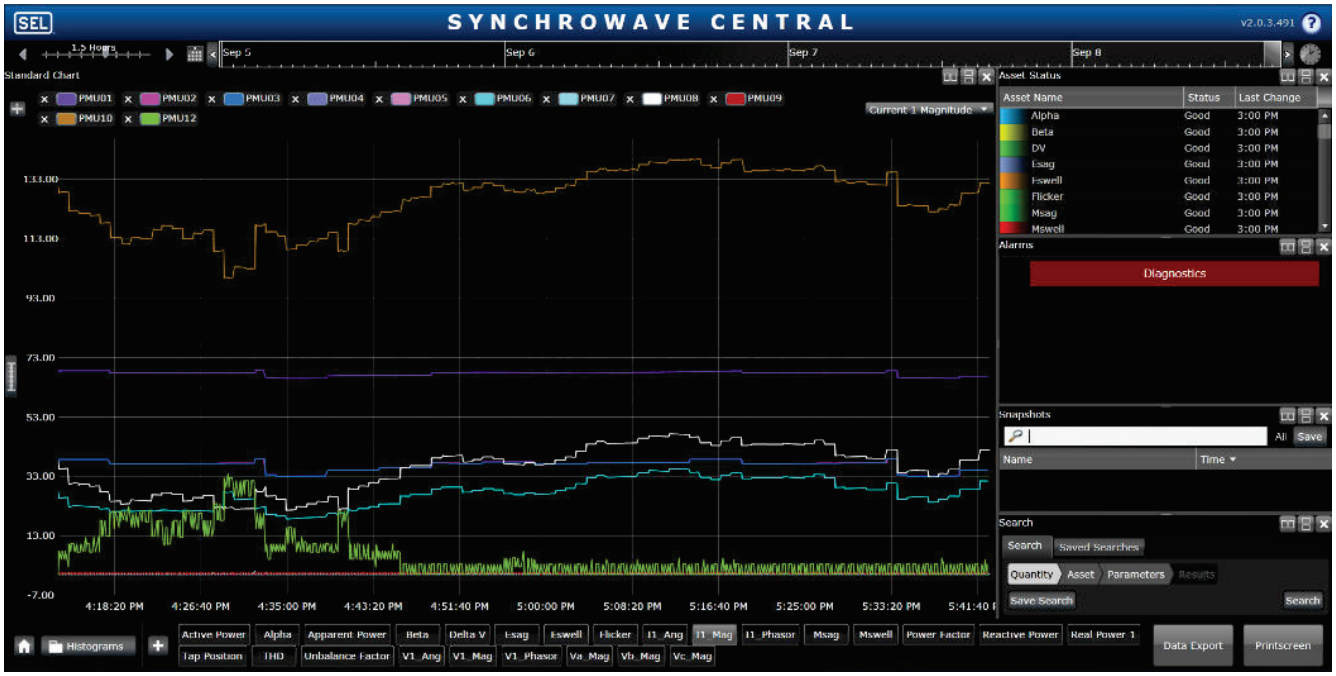


Figure 4-3. Magnitude of Positive Sequence Currents

Other visualization screens were used to capture phase angles of the voltage and current phasors as shown below. Phase angle visualization were primarily used during synchronization and load transfer schemes. Sudden changes in load or issues associated with customer introduced disturbances can also be identified from phase angle measurements by noticing any sudden jumps (typically called vector jump).



Figure 4-4. Phase Angles of Positive Sequence Voltages

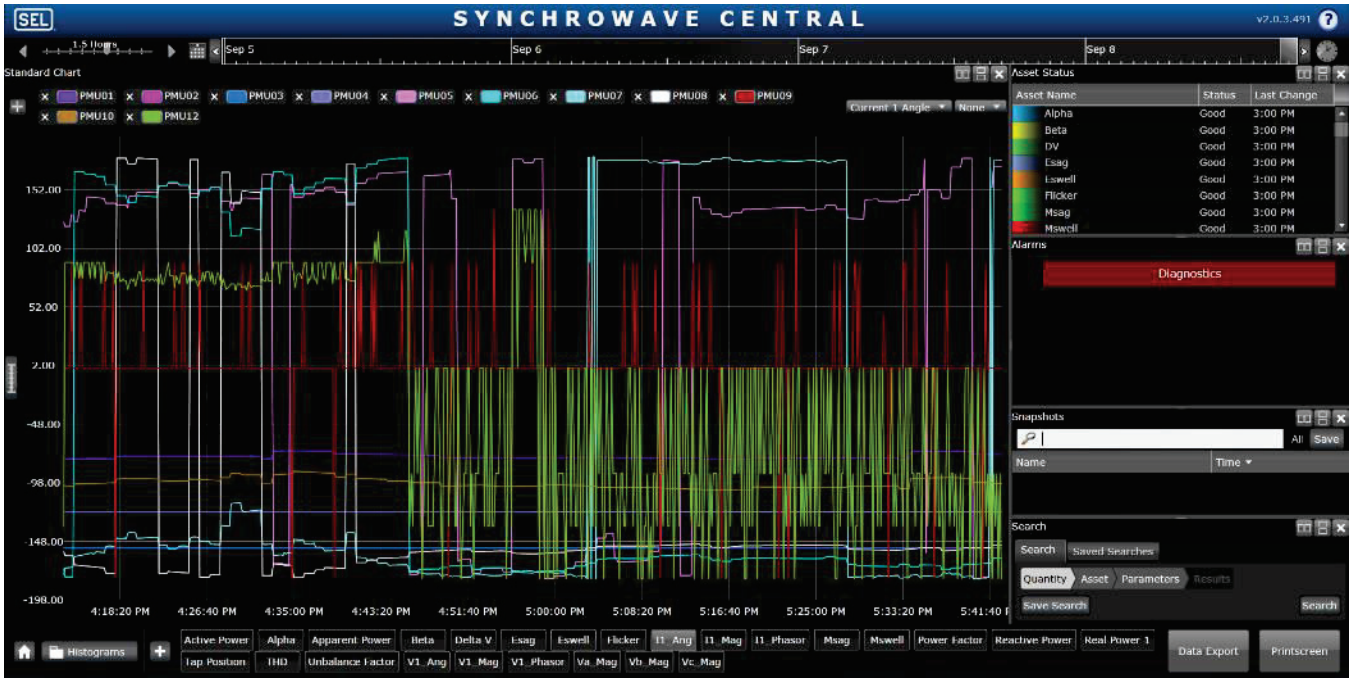


Figure 4-5. Phase Angles of Positive Sequence Currents

The reason for the current phase angles fluctuations in PMU 09 and PMU 12 is that the currents of the afore-mentioned PMUs are zero; therefore, the PMUs cannot correctly calculate phase angles from noises.

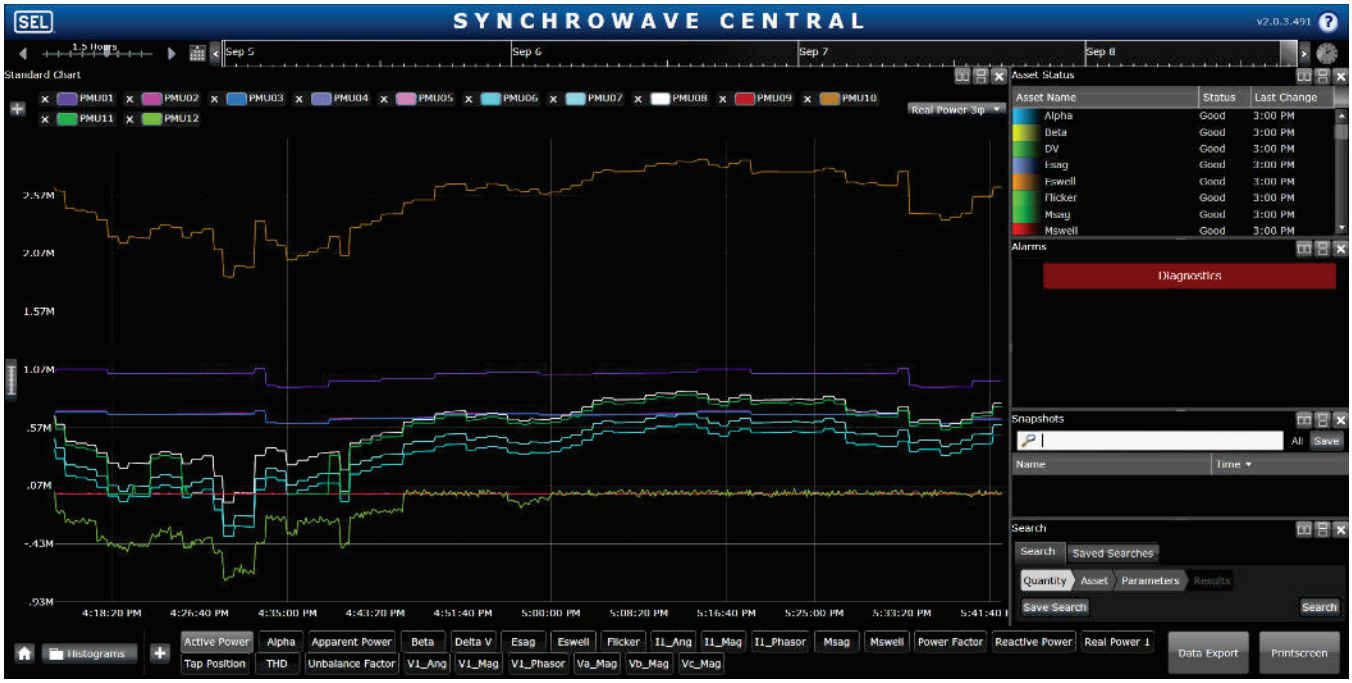


Figure 4-6. Active Powers

Active and reactive power visualization screens were used to investigate power flow across the circuits.

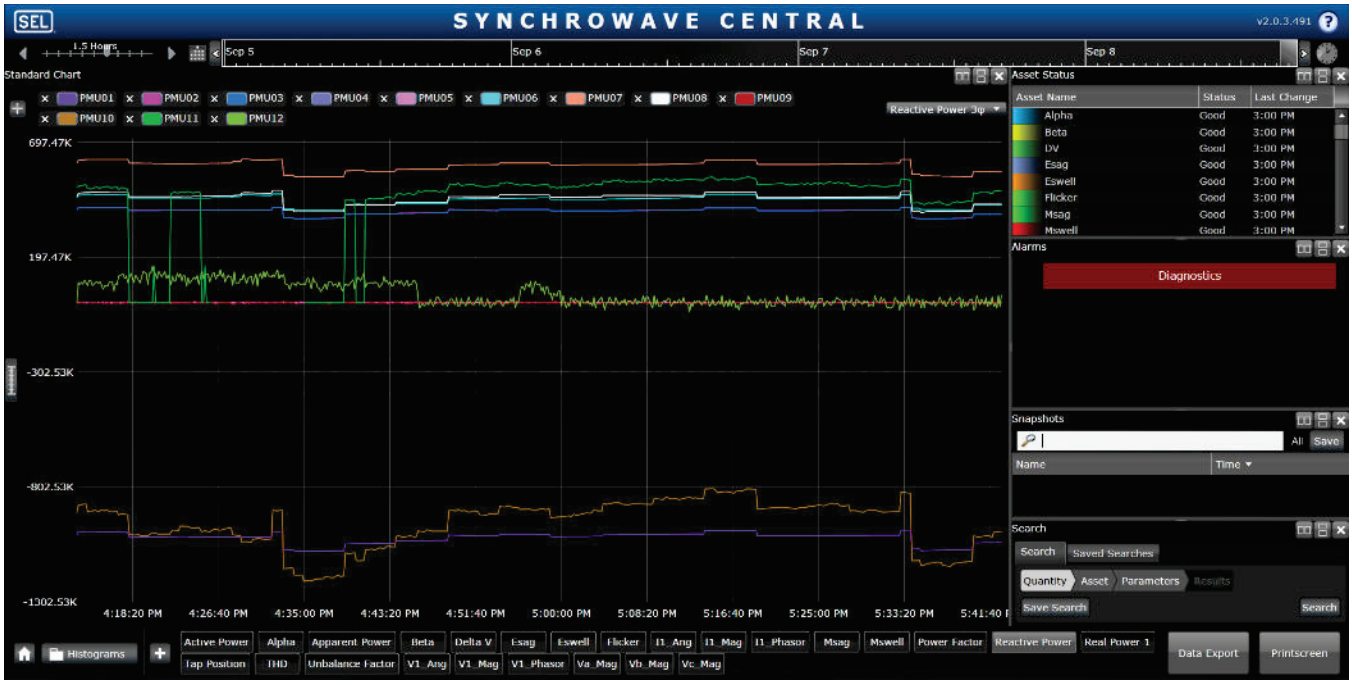


Figure 4-7. Reactive Powers

The apparent power screen was used to evaluate the thermal rating of the circuit and feeder devices.

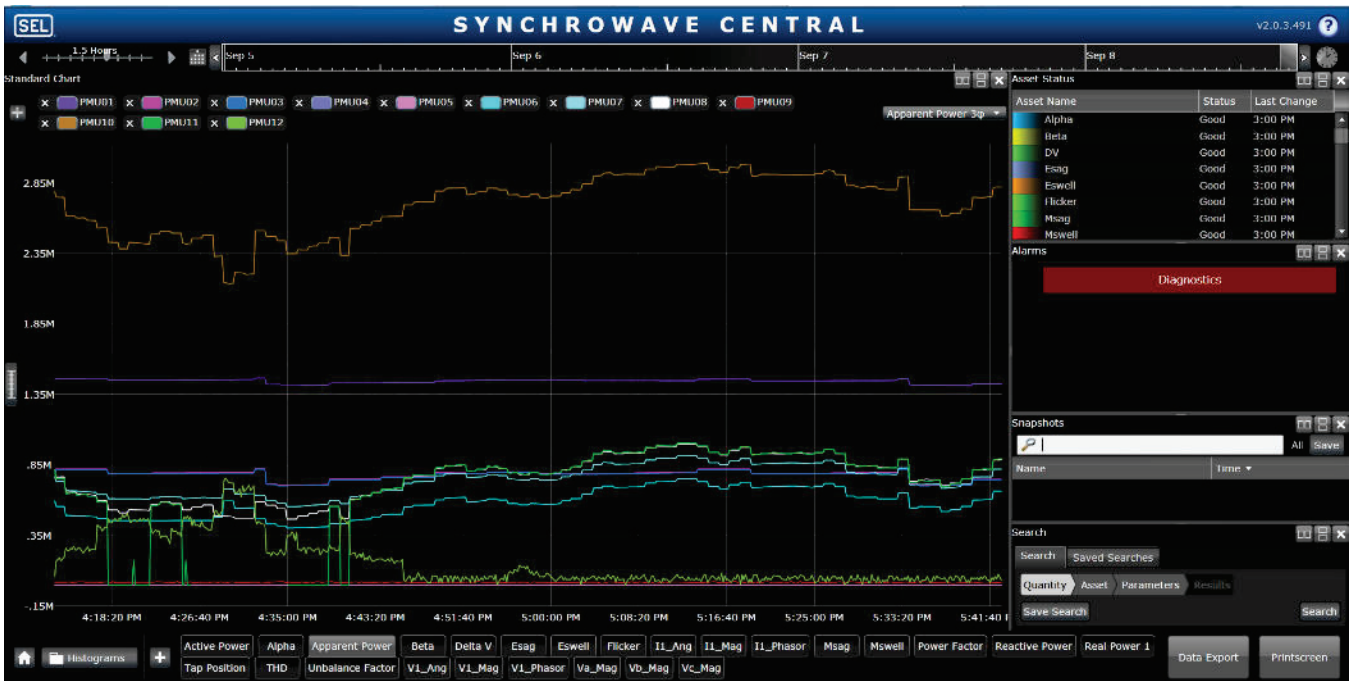


Figure 4-8. Apparent Powers



Figure 4-9. Calculated Delta V (pu) in Automation Controller

From the above graph, it can be simply observed that the voltage differences (compared to the nominal voltage) across the circuit do not violate 0.05 pu.

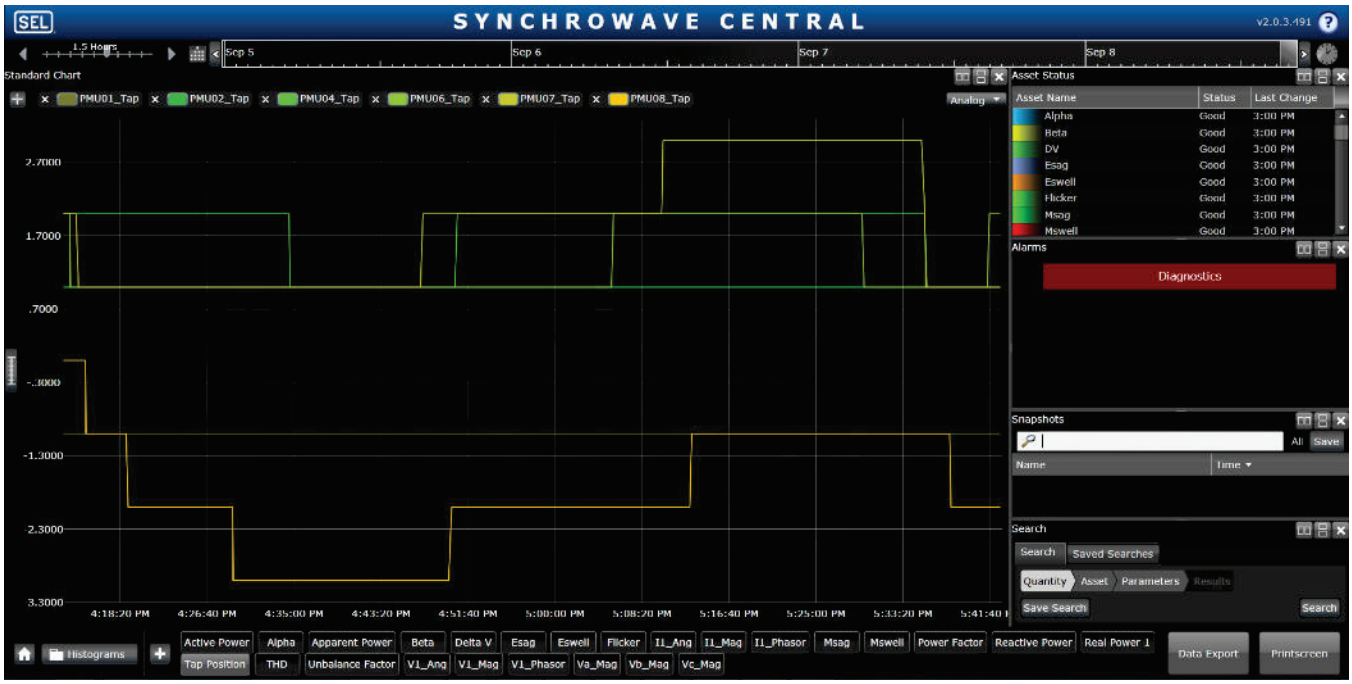


Figure 4-10. Tap positions streamed through the analog value

4.1.2.1 Phasor Monitoring

In this test, the behavior of the circuit 1 was studied during a load transfer.

Initially, the circuit was set at constant low load condition (0.3 pu) with no PV. Figure 4-11 shows the active powers before the connection of the PV. It can be observed that there is no reverse power flow in any of the PMUs as expected. Figure 4-12 shows the phase angle difference between the two sides of the normally open tie switch (520-1048) which is 1.27 degrees.

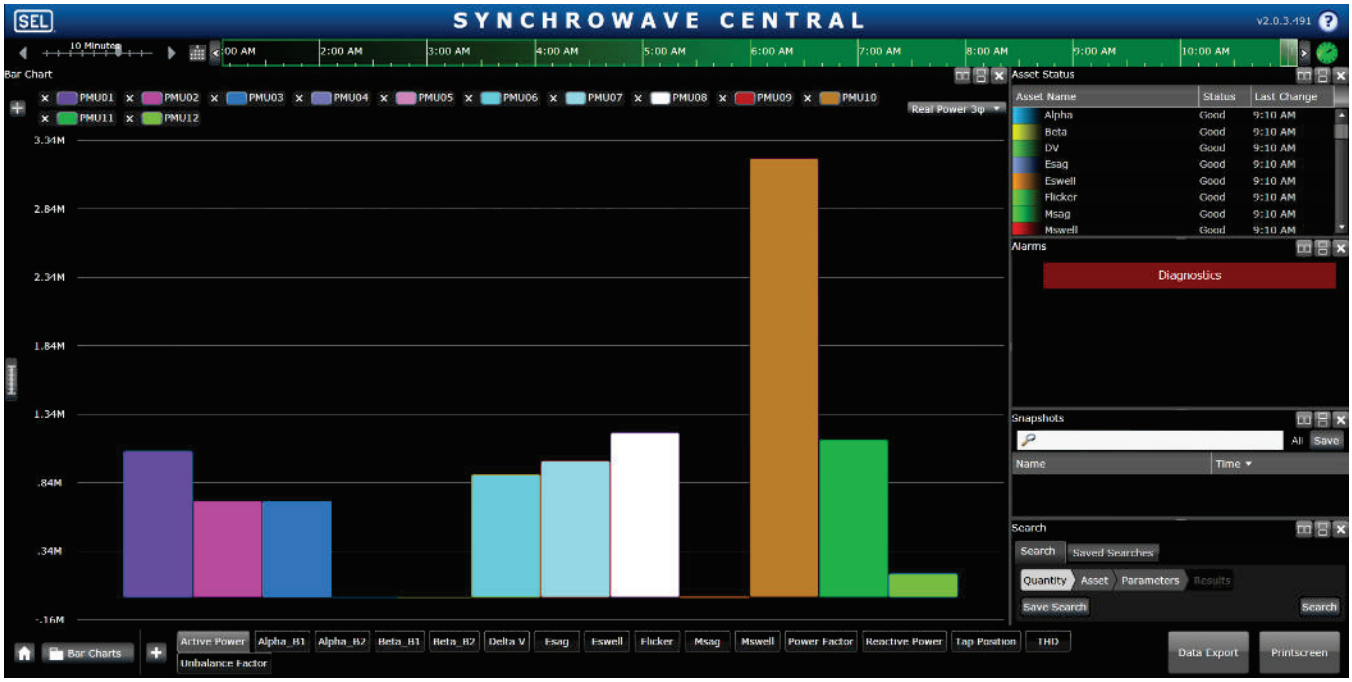


Figure 4-11. Active Powers during Low Loading without PV and with a Tie Switch Opened

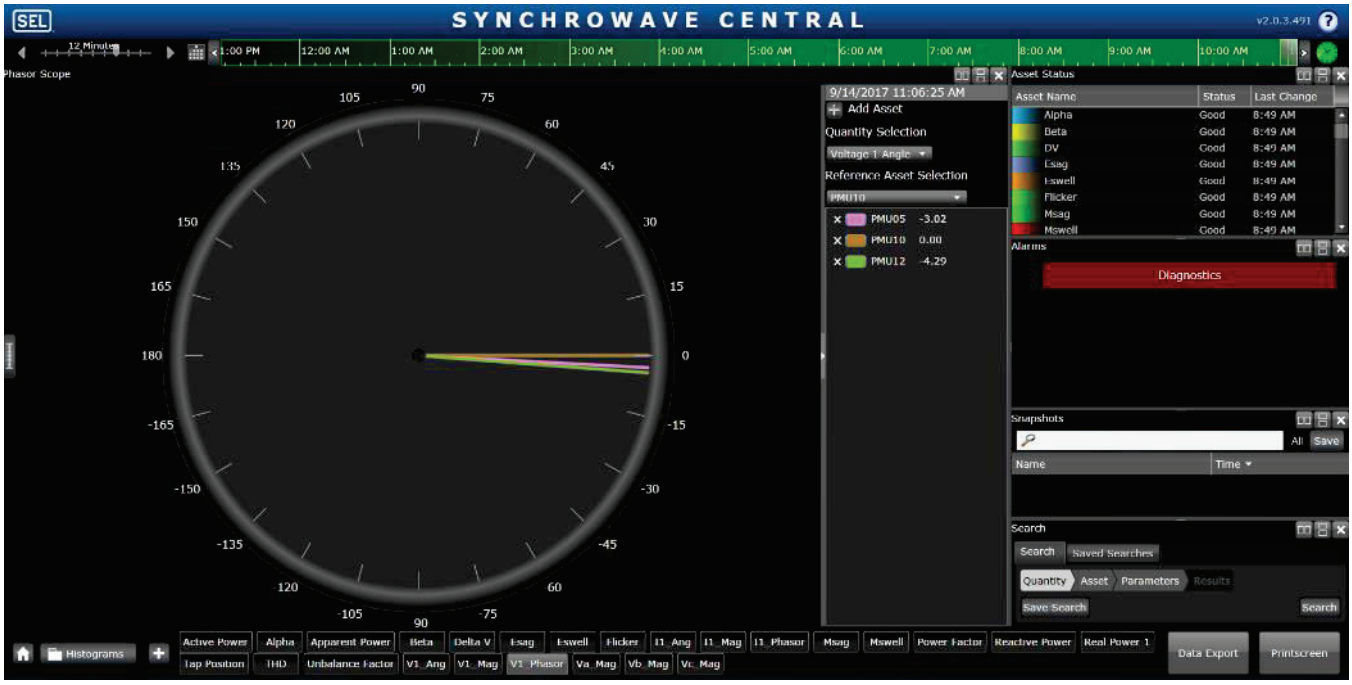


Figure 4-12. Phase Angles of the Two Sides of the 520-1048 during Low Loading without PV.

In the next step, suddenly, the maximum PV was added to the circuit. It can be seen in Figure 4-13 that this event created reverse power flow in the branch with PV (PMU 6, PMU 7, PMU 8, and PMU11, and PMU12).

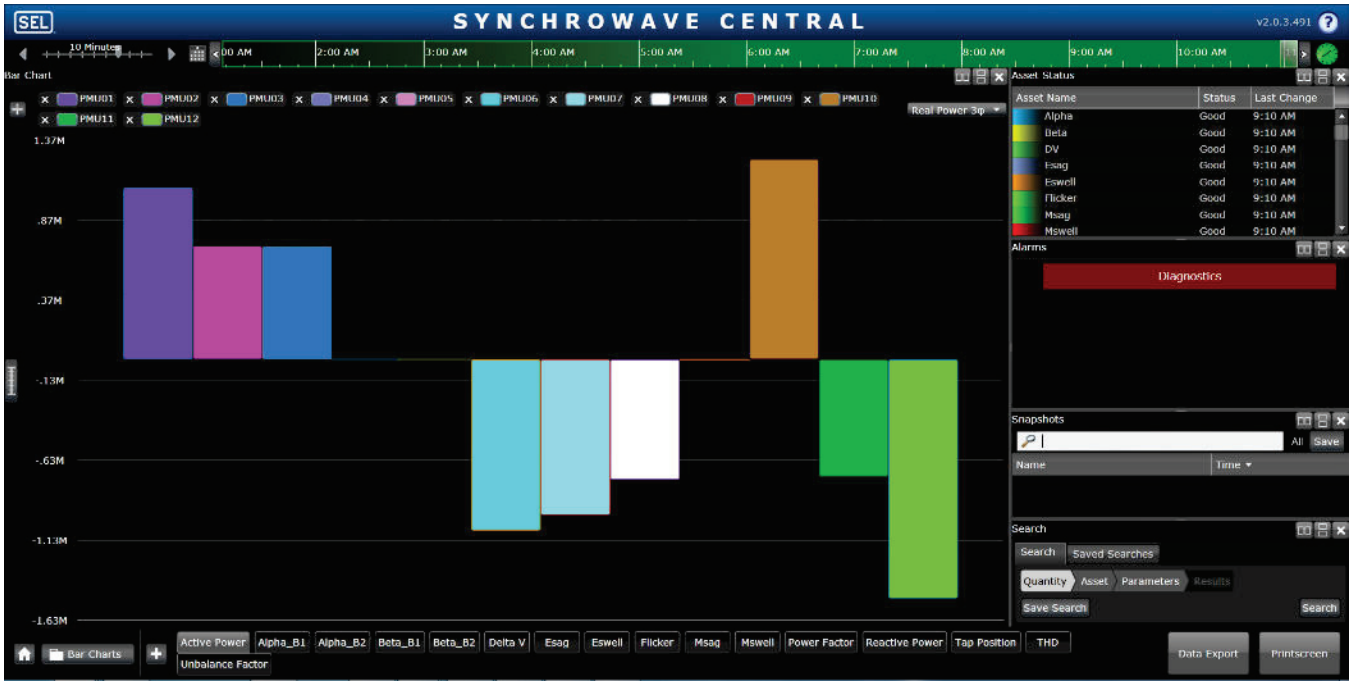


Figure 4-13. Active Powers after the Connection of the Maximum PV.



Figure 4-14. Phase Angles for the Two Sides of the 520-1048 after the Connection of the Maximum PV.

The phase angle across the open switch of the circuit was 2.11 degrees and the voltage magnitude difference is 0.5%, which gives the permission for closing REC 520-1048. The general requirements are voltage differences less than 5% and phase angle differences less than 10 degrees.

The following figures show the active powers and phase angles subsequent to the closing of REC 520-1048. It can be seen that this action caused a small amount of reverse power flow on the branch without PV (PMU 4 and PMU 5).

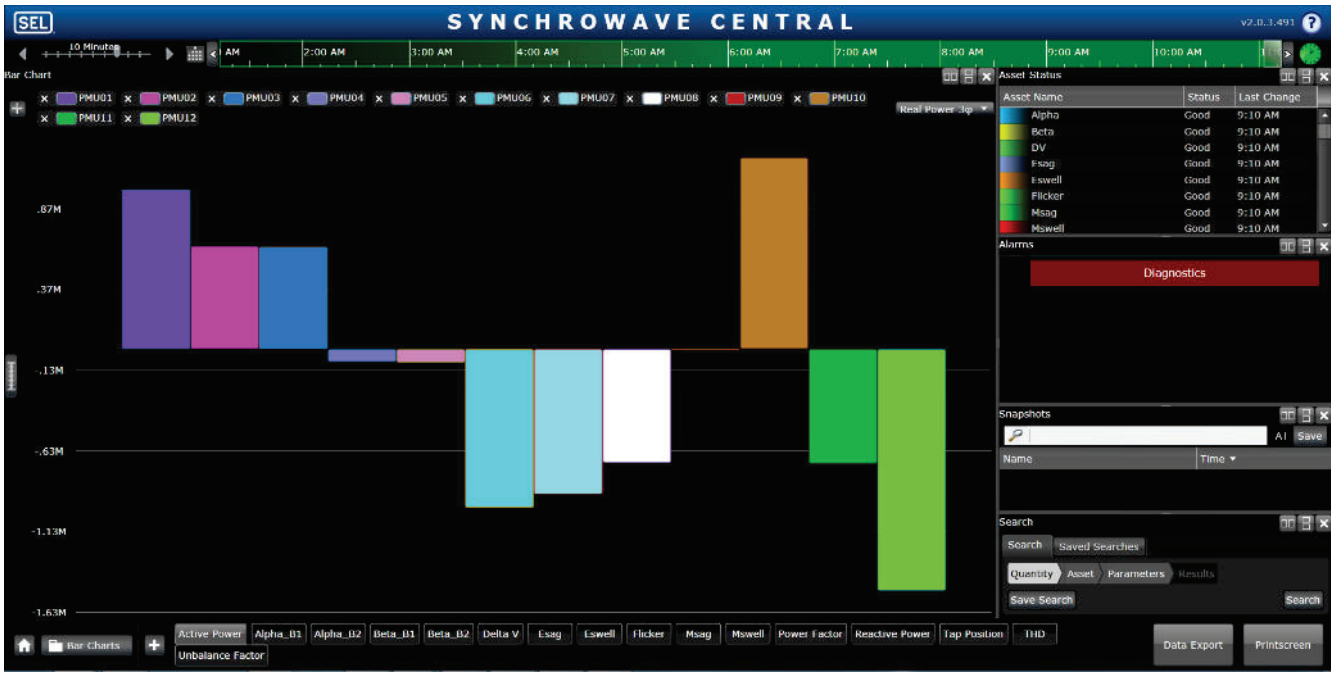


Figure 4-15. Active Powers after Closing 520-1048

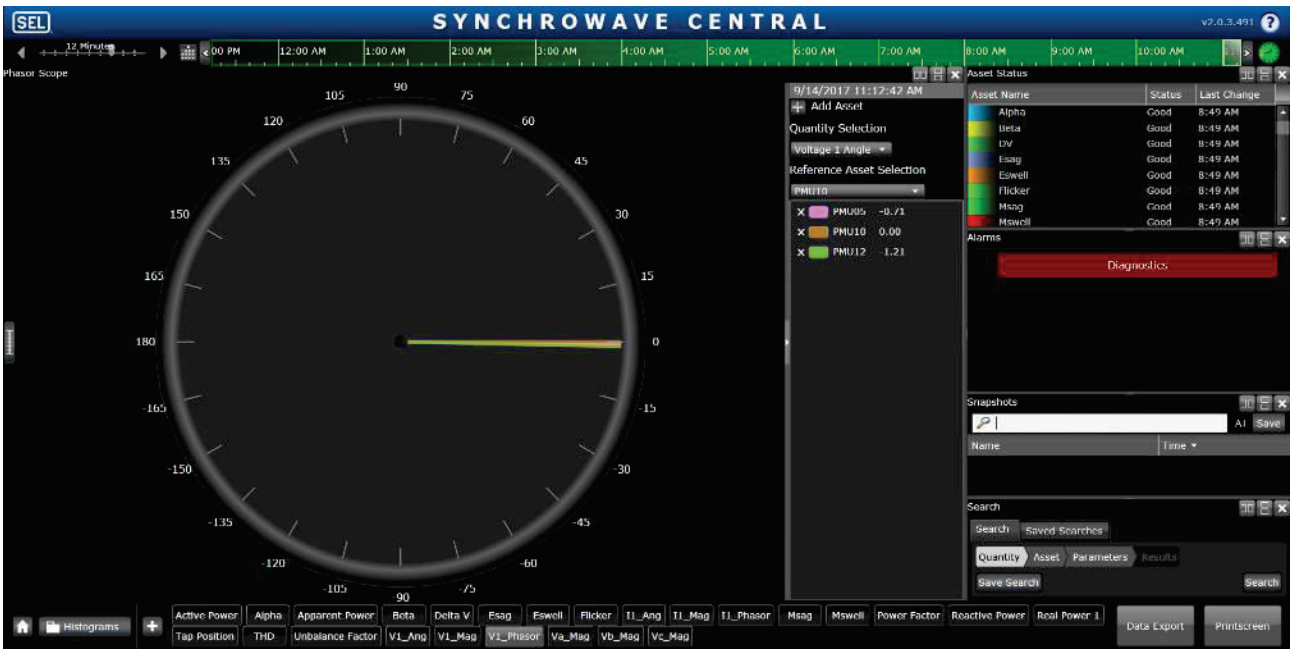


Figure 4-16. Phase Angles for the Two Sides of the 520-1048 after Closing 520-1048

A recloser on the branch without PV was identified where the power flow is below 1 MW (REC 520-1045). This recloser was opened to perform a load transfer. The following figure show the active powers subsequent to the opening of REC 520-1045. It can be seen that this action causes a huge reverse power flow in PMU 5 and PMU 4.

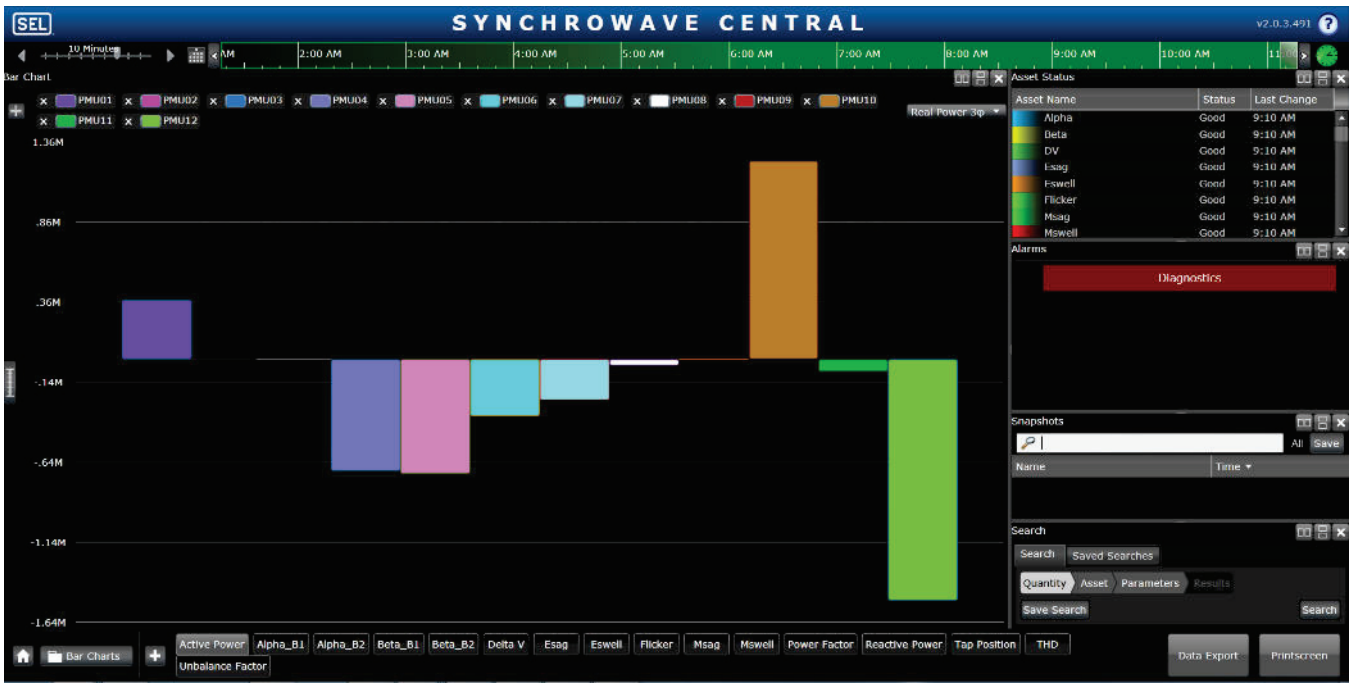


Figure 4-17. Active powers after the load transfer

To summarize, the sequence of actions during the load transfer was:

- Connecting PV to the System
- Closing tie switch 520-1048
- Opening recloser 520-1045

The PMU data including voltages, active powers, reactive powers, and tap positions are captured during the load transfer as shown in the following figures to better understand the effect of each action on the parameters of the system.

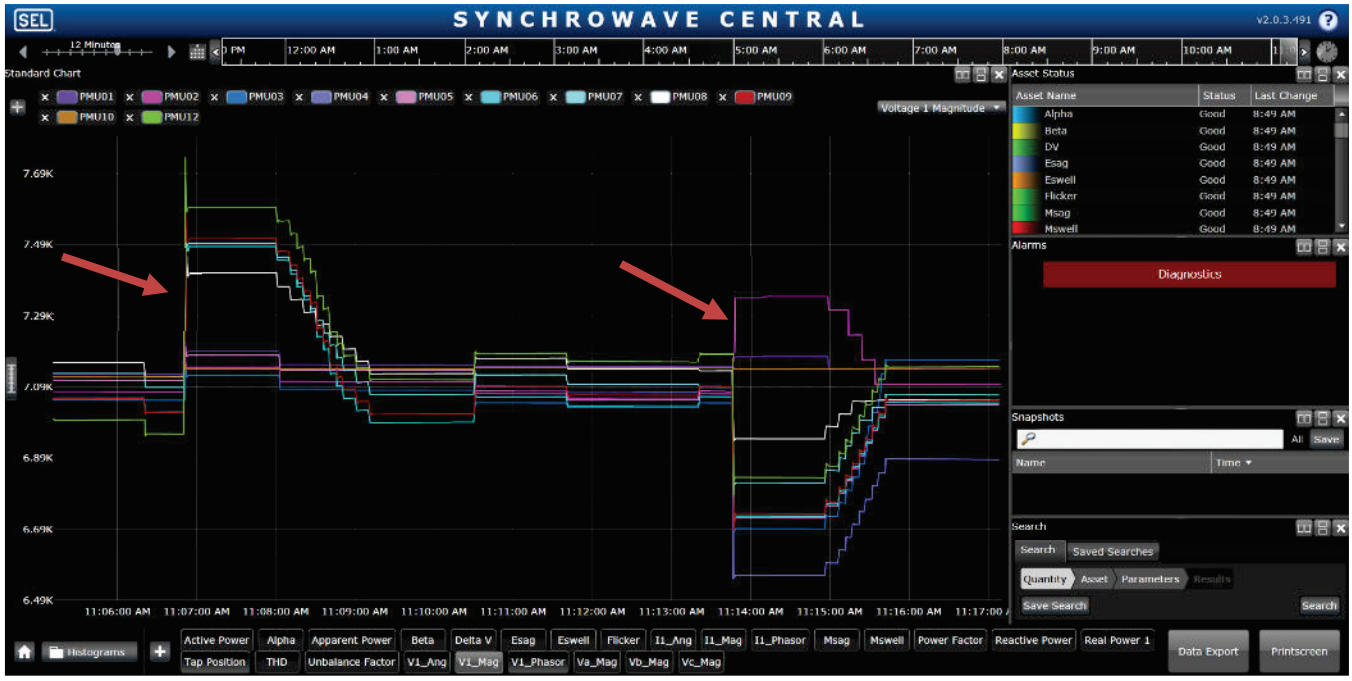


Figure 4-18. Magnitude of the Positive Voltages during the Load Transfer (changes are shown by arrows)

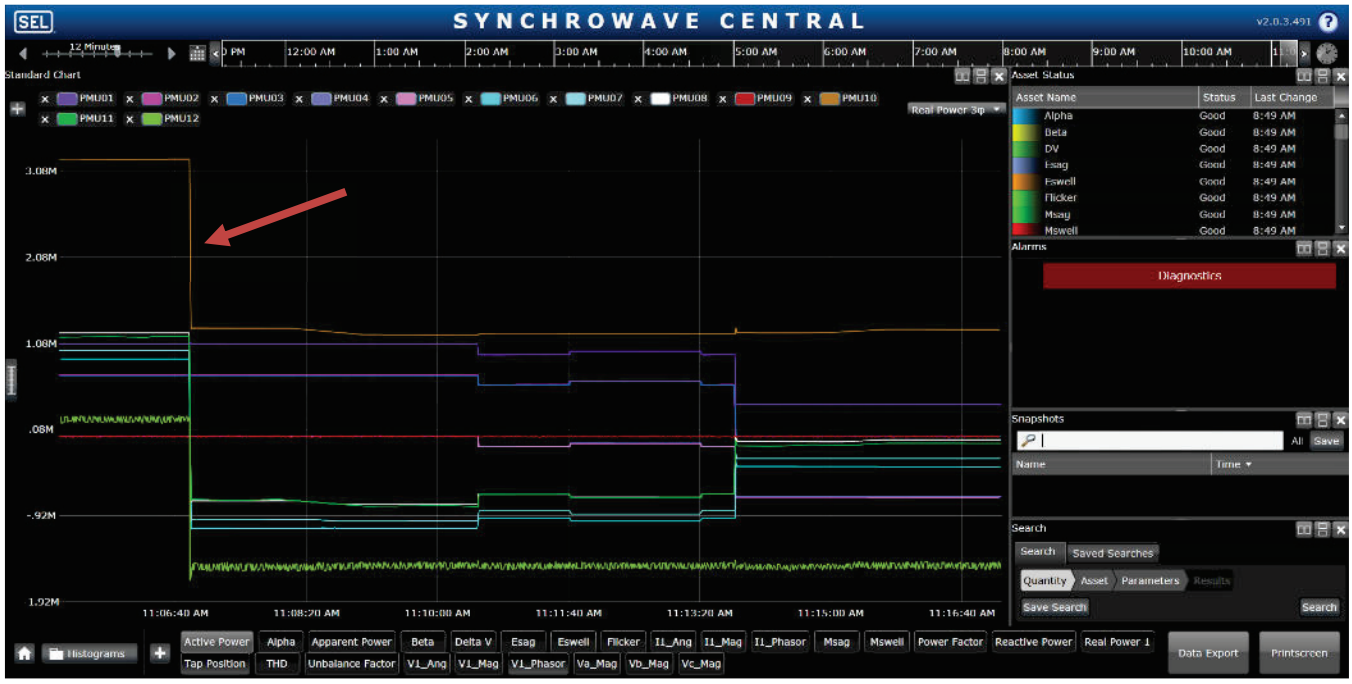


Figure 4-19. Active Powers during the Load Transfer (time of change is shown by the arrow)

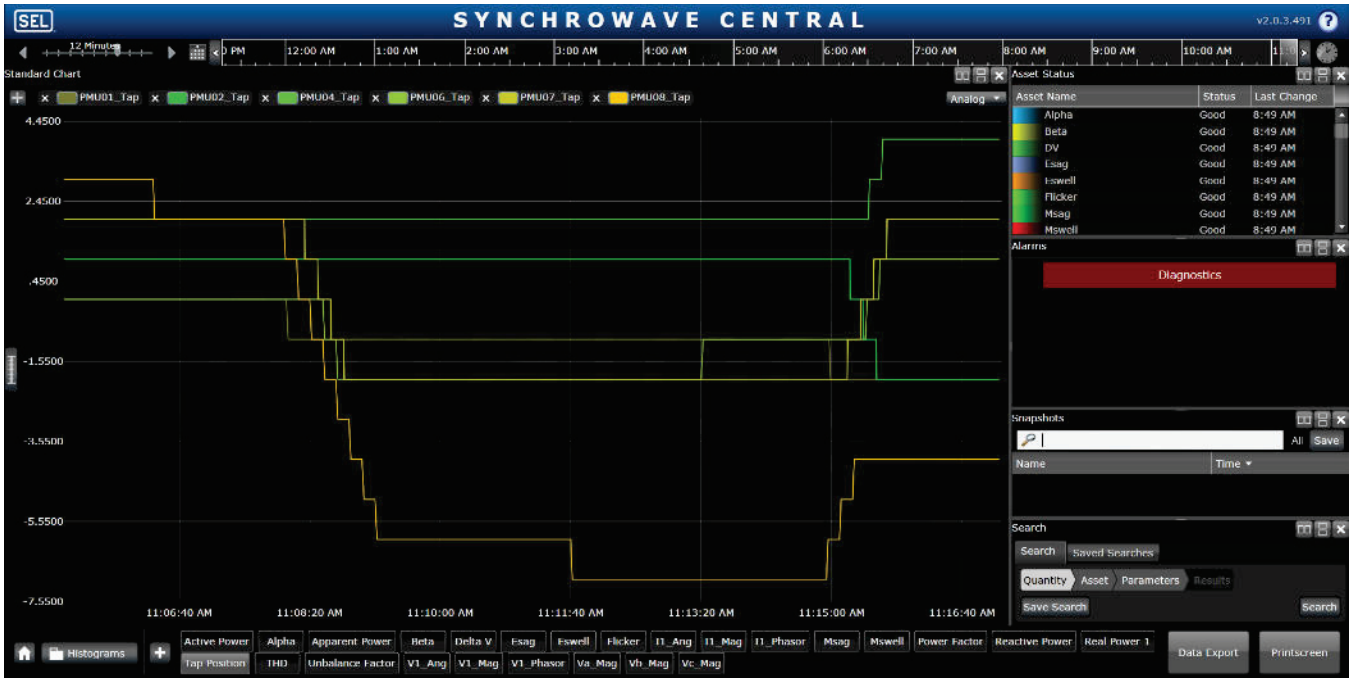


Figure 4-20. Tap Positions during the Load Transfer

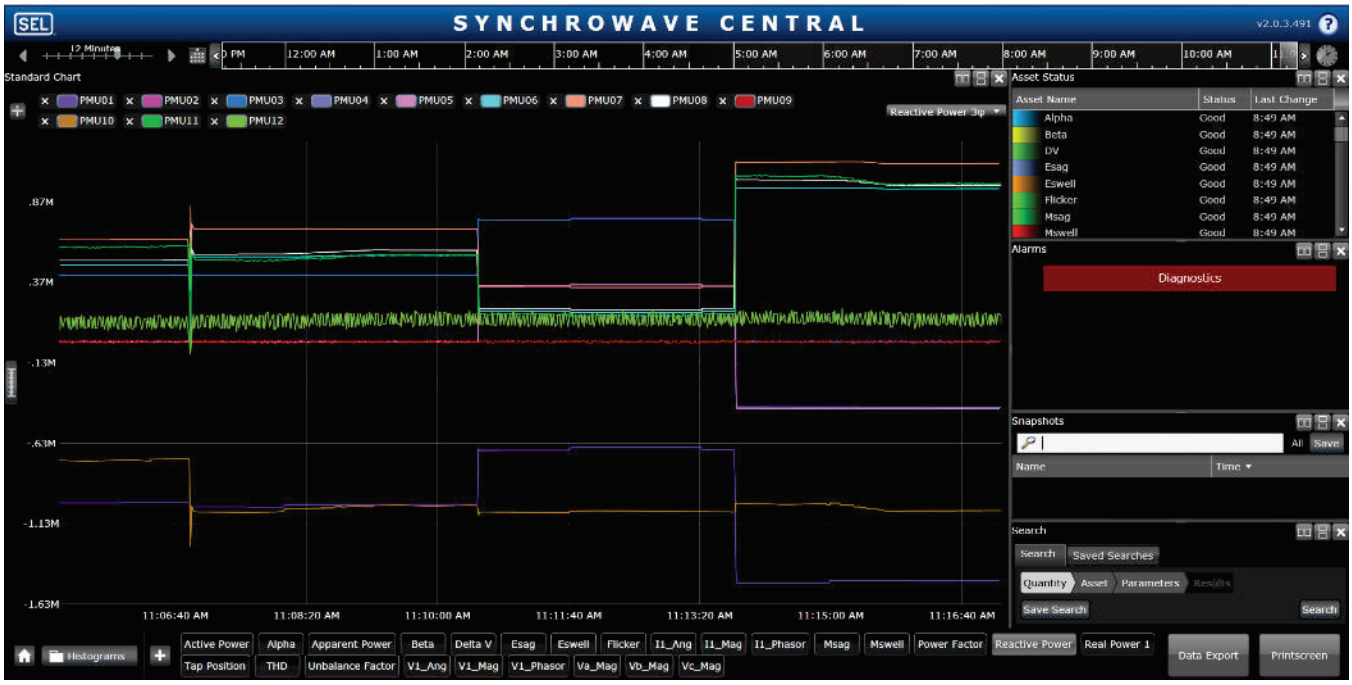


Figure 4-21. Reactive Powers during the Load Transfer

It can be seen from the visualization screen that PMUs can detect and visualize step changes in the load and resulted power flow variations.

4.1.3 Primary Asset Operation Monitoring and Diagnostics

The objective of this test category is to verify the streaming capability of the analog value assigned to the tap positions and THD.

4.1.3.1 Tap Position Streaming

Constant load (0.75 pu) profile was applied. Initially capacitor C1 and C3 were turned on. We turned off capacitor C1 and waited for the voltages to get to the steady state condition; then, turned it on and waited for the voltages to get to the steady state condition. Similar condition was repeated for C3, and the following measurements were captured:

- Magnitude of positive sequence voltage
- Magnitude of positive sequence current
- Active power
- Reactive power
- Tap positions for all voltage regulators

It should be noted that the sequence of capacitor switching actions were introduced to create dynamic events and to introduce disturbances that can be detected by the PMUs to test and evaluate the functionalities of the proposed monitoring and visualization schemes.

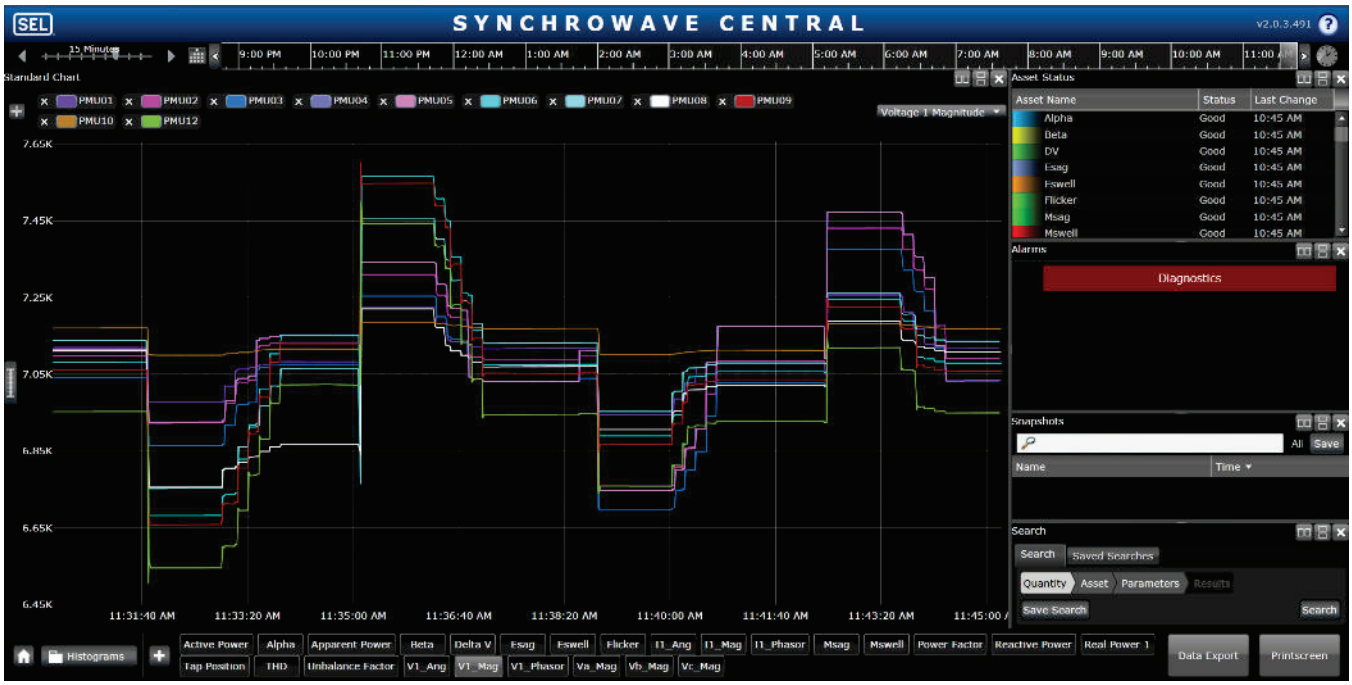


Figure 4-22. Magnitude of Positive Sequence Voltages Subsequent to Capacitor Switching



Figure 4-23. Magnitude of Positive Sequence Currents Subsequent to Capacitor Switching

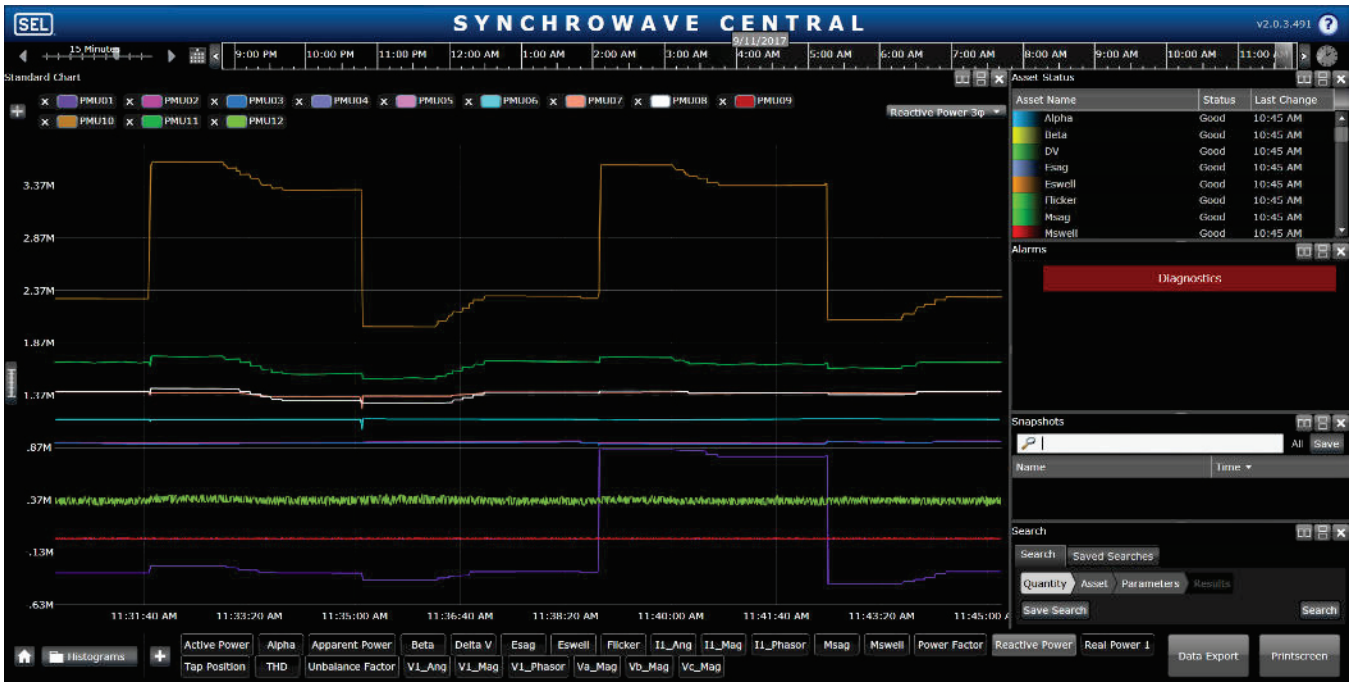


Figure 4-24. Reactive Powers Subsequent to Capacitor Switching On and Off

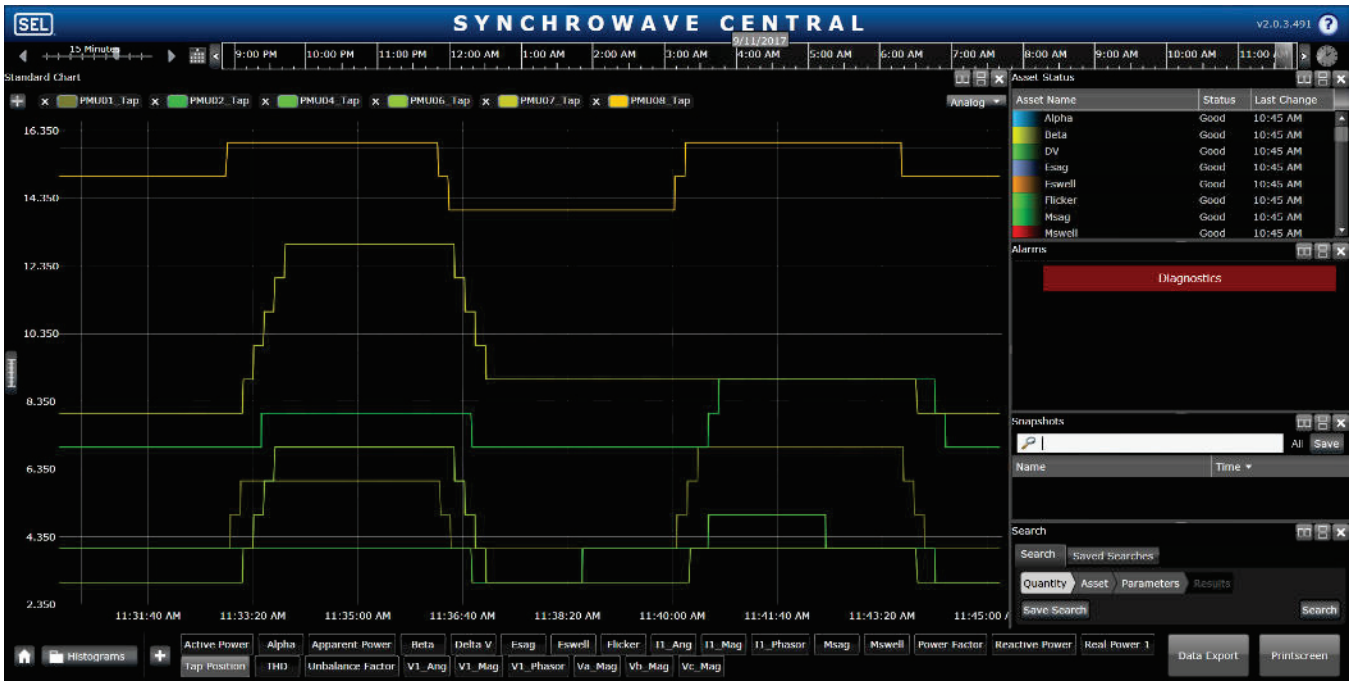


Figure 4-25. Tap Positions Subsequent to Capacitor Switching

4.1.3.2 THD Streaming

In this test, the constant load profile (0.5) was used with no PV. REC 520-1048 was in closed position. To investigate the THD level, 5th harmonic voltage component was added to the circuit, through non-linear harmonic load injection downstream of the voltage regulator 3, which increased the voltage as well as harmonics. The magnitude of the harmonic injection was increased (every 30 seconds) to 0.03 pu, 0.08 pu, 0.15 pu, and 0.3 pu of the fundamental component.

The following measurements were captured before and after the injection of the harmonics:

- Magnitude of positive sequence voltage
- THDs

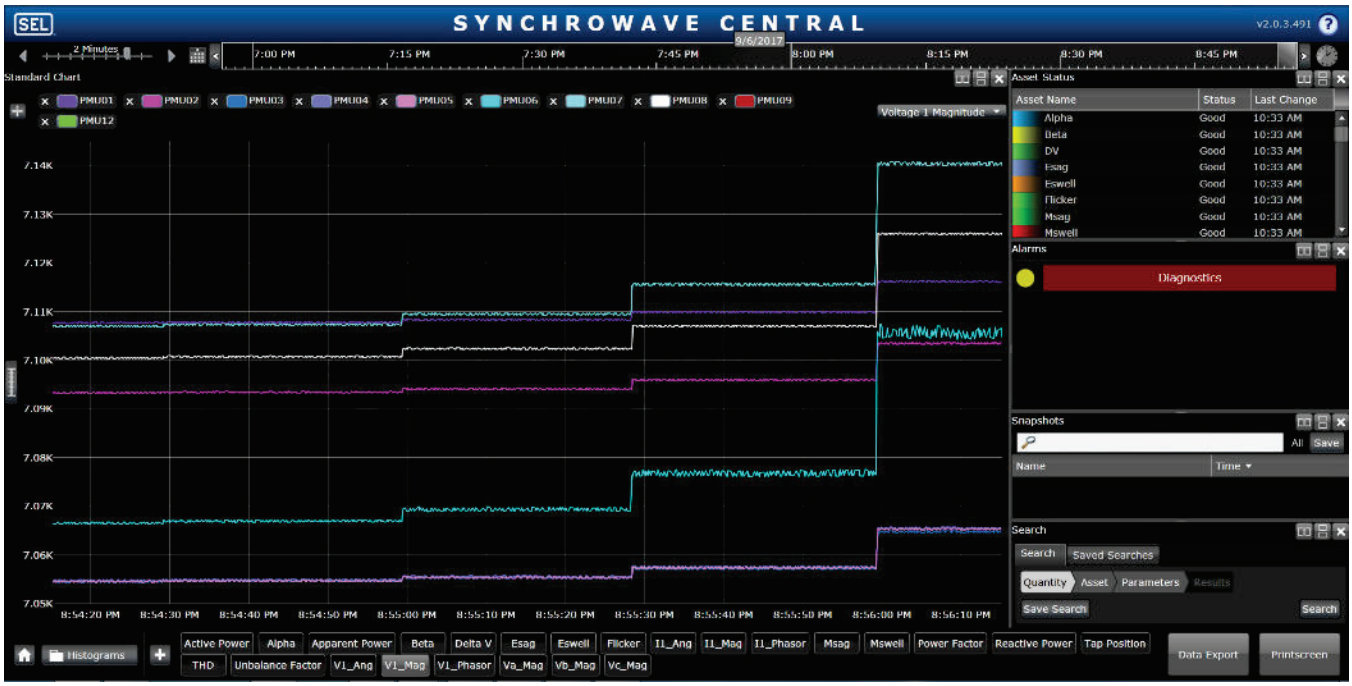


Figure 4-26. Magnitude of Positive Sequence Voltages Subsequent to Adding Harmonic Voltage



Figure 4-27. THDs Captured by Different PMUs

As expected, different PMUs depending on their location streamed different values of THD (the closer the PMU to the source of the harmonic, the larger the value of the THD). PMU5 is the closest PMU to the harmonic source; therefore, it observed the maximum THD value. To evaluate the performance of the THD streaming of the PMUs, the THD value obtained from PMU5 is compared with the injected harmonic.

Injected THD	0.03	0.08	0.15	0.3
Observed THD from PMU5	0.026	0.068	0.121	0.236

4.1.3.3 Sensitivity

The objective of this test category was to verify the capability of RTAC in the calculation of the following parameters and indices:

- Alpha factor (dV/dP) in pu/MW
- Beta factor (dV/dQ) in pu/Mvar

4.1.3.3.1 Calculation of Alpha and Beta

In this test, the summer load profile was run for 1 hour with summer PV profile and the following measurements were captured for all PMUs. The following parameters were captured accordingly:

- Magnitude of positive sequence voltage
- Alpha in the branch with PV (PMU 1, PMU 2, PMU 3, PMU 4, and PMU 5)
- Alpha in the branch without PV (PMU 8, PMU 11, PMU 7, and PMU 6)
- Beta in the branch with PV
- Beta in the branch without PV

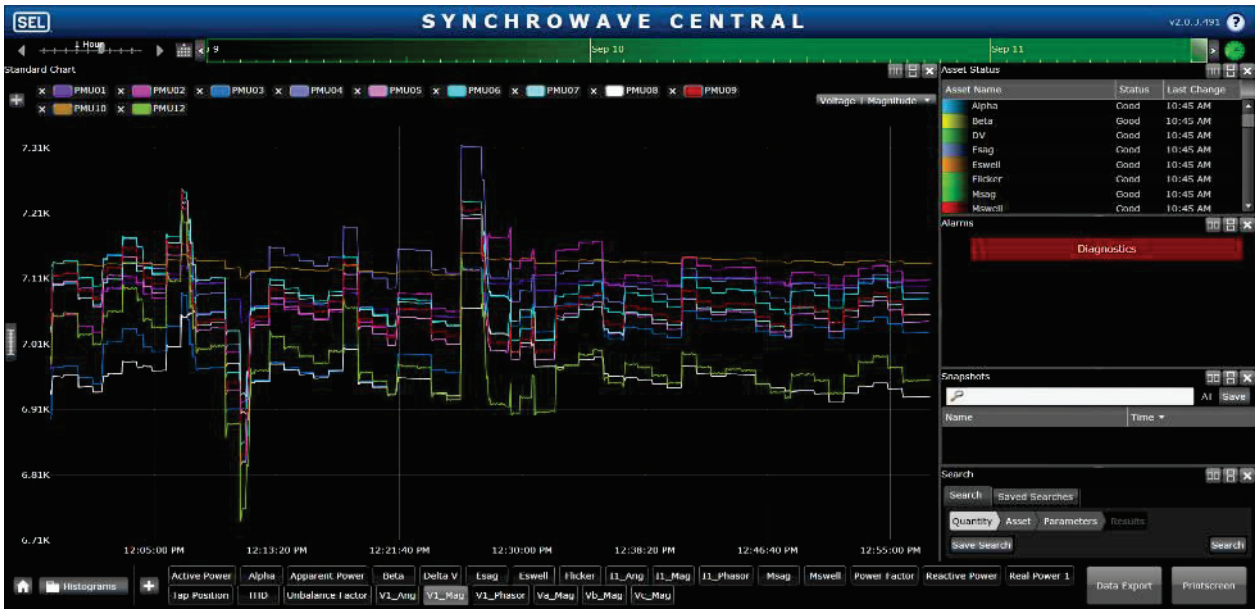


Figure 4-28. Magnitude of Positive Sequence Voltages

The magnitude of positive sequence voltages are generally in the range of the rms circuit voltages, since the amount of zero sequence and negative sequence voltages are negligible.

In Figure 4-29, the sensitivity of different PMUs (in the branch without PV) is shown in bar graphs in the order of their distance to the substation circuit breaker. It can be seen that the sensitivity increases by getting away from the substation transformer toward the end of the circuit.

Similar behavior can be seen in the branch with PV as shown in Figure 4-30, but the PMU12 placed near the PV has a small sensitivity.

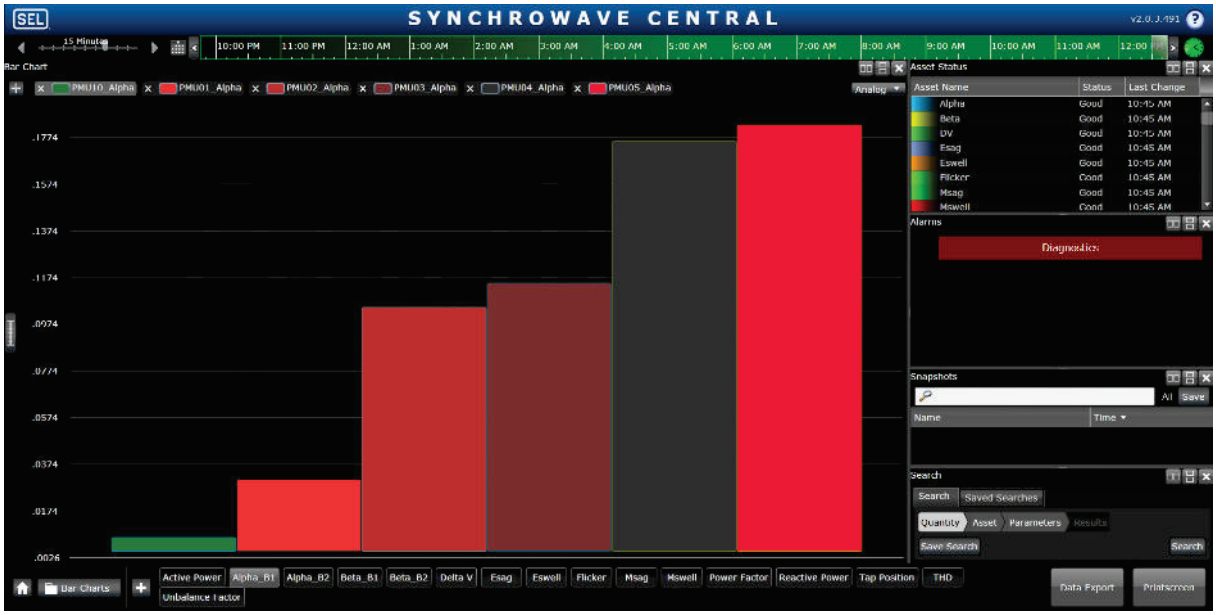


Figure 4-29. Demonstration of Changes in Alpha across the Branch without PV

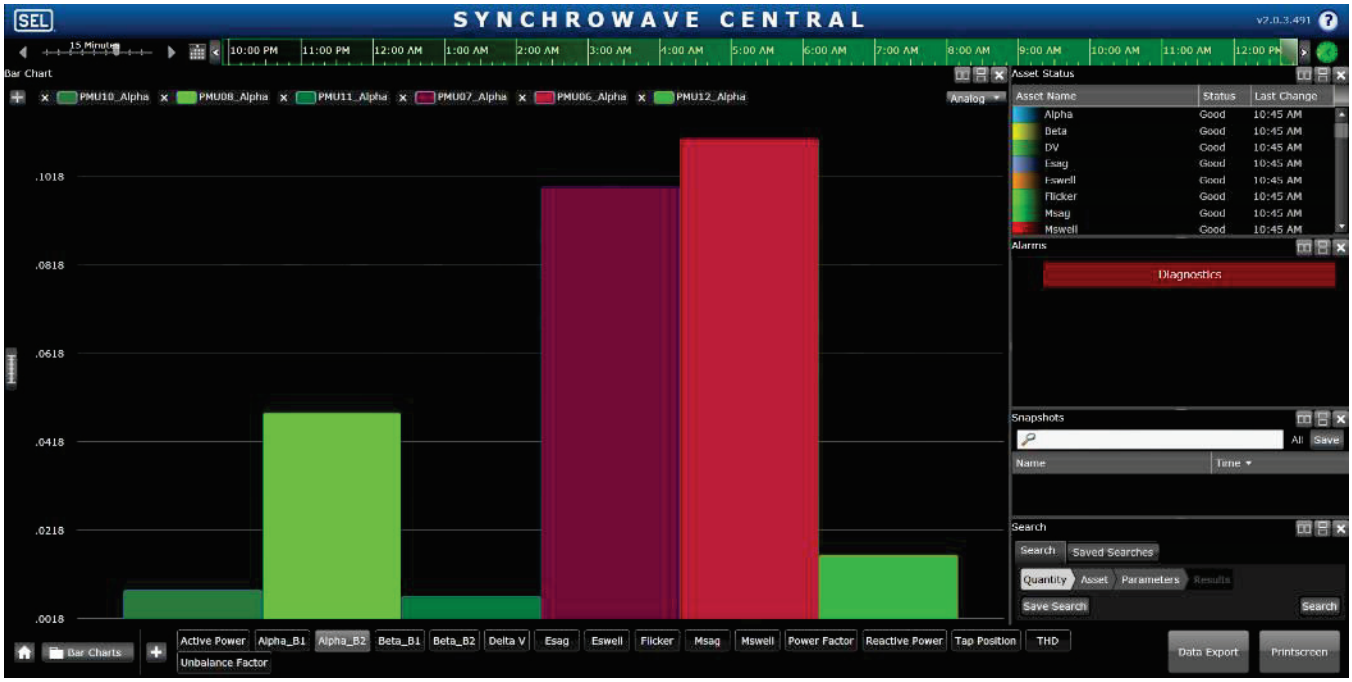


Figure 4-30. Demonstration of Changes in Alpha across the Branch with PV

As observed, presence of PV system toward the end of the circuit create a less sensitive area. The PV system has contributed in strengthening the stiffness of the system.

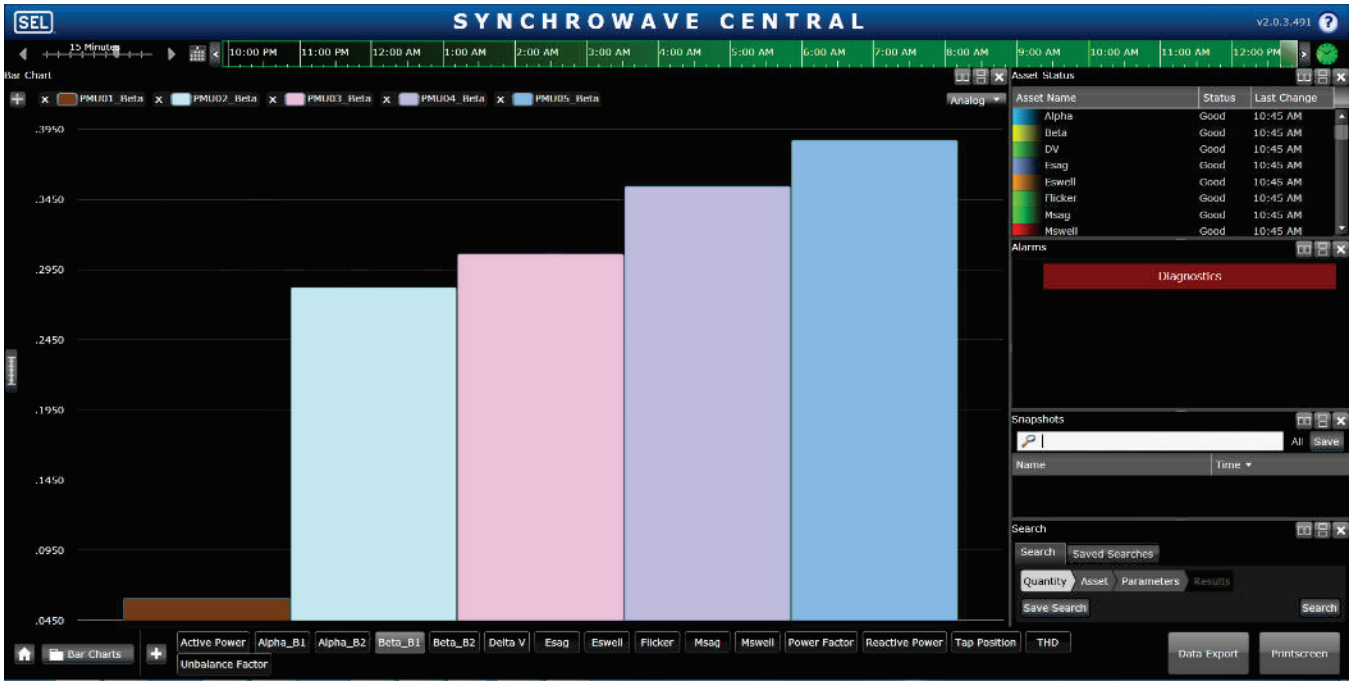


Figure 4-31. Change in Beta across the Branch without PV

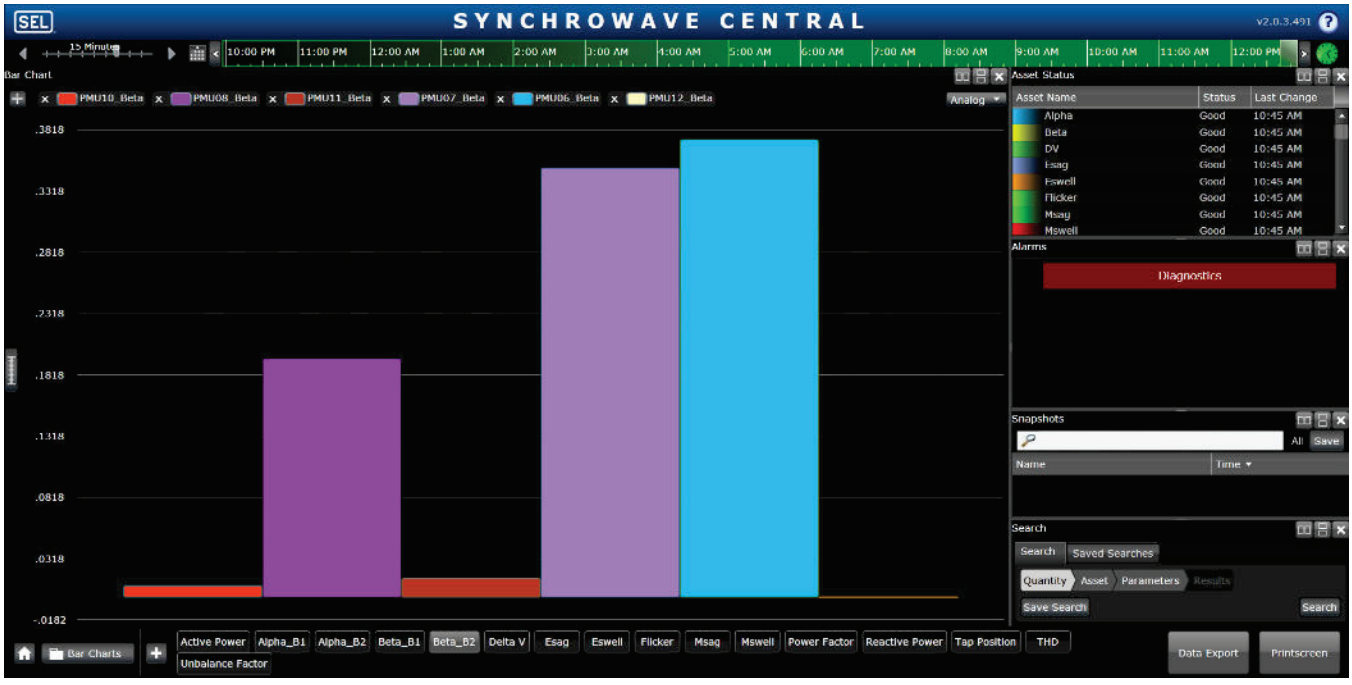


Figure 4-32. Change in Beta across the Branch with PV

Beta trend across the circuit is very similar to Alpha trend across the circuit; however, Beta is larger than Alpha. In this case, presence of the PV plant improved the system stiffness and reduce the sensitivity.

4.1.3.4 Faults

This section investigate the performance of the visualization in calculating the following parameters caused by different kind of faults and device malfunction

- Extreme Sag
- Extreme Swell
- Moderate Sag
- Moderate Swell
- Flickers
- Voltage unbalance

4.1.3.4.1 Calculation of Flickers

In this test case, C1 was turned off and on quickly. As shown in Figure 4-33, there are two voltage steps (falling and rising caused by turning off and on C1) in less than 2 seconds for all PMUs, which is qualified for a flicker. It can be seen in Figure 4-34 that this flicker is captured by visualization system and reported on the screen.

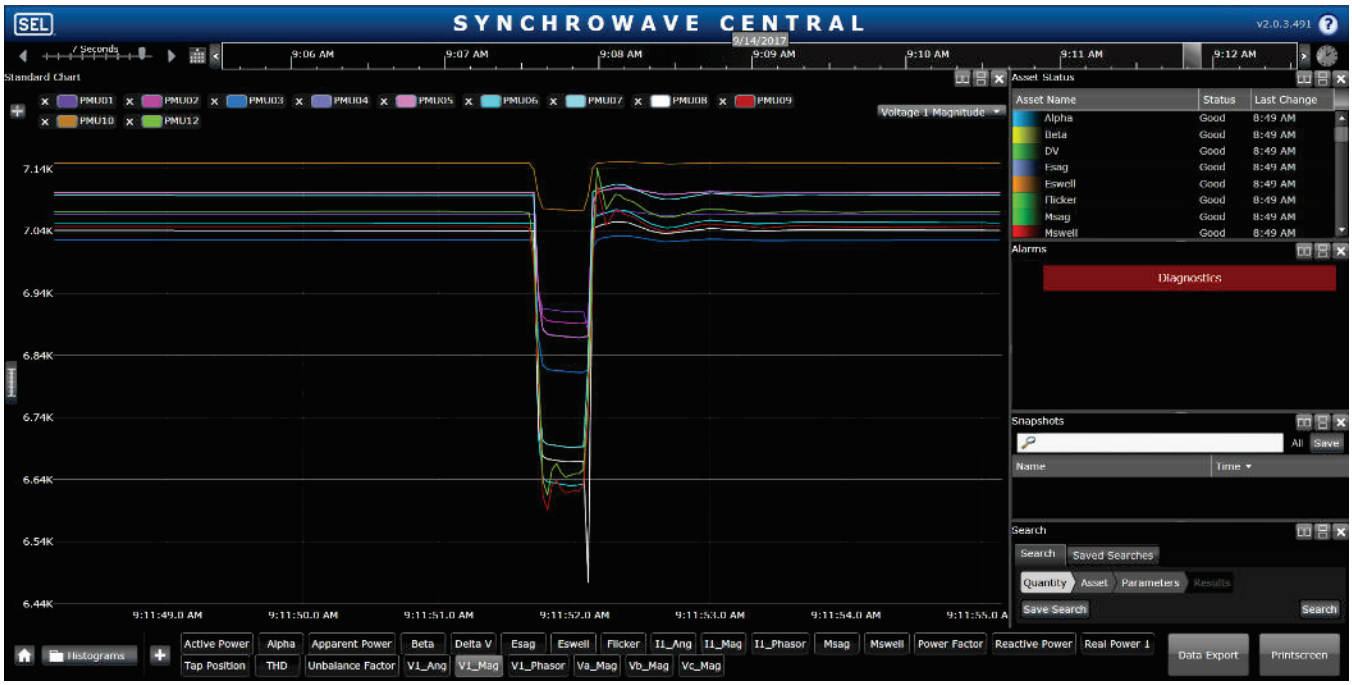


Figure 4-33. Magnitude of Positive Sequence Voltages

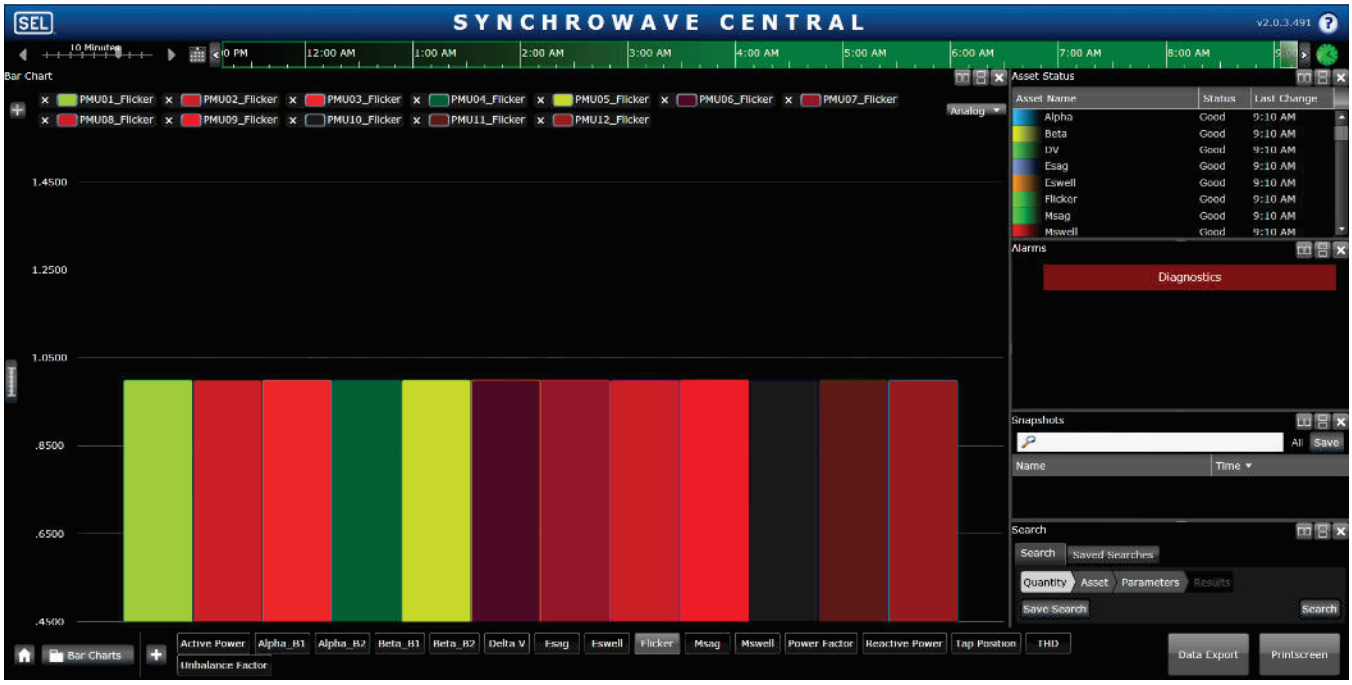


Figure 4-34. Flickers Subsequent to the Capacitor Switching

4.1.3.4.2 Calculations of Extreme Sag, Extreme Swell, Moderate Sag, and Moderate Swell

In this use case, we try to create a transient event to verify the performance of the RTAC in the calculation of extreme sag, extreme swell, moderate sag, and moderate swell.

4.1.4 Test Case 1

In this test, the summer load model was run with 2MW PV generation (PV protection settings are incorporated for the 2 MW system to match the IEEE 1547a (IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems) as shown in the following tables).

Table 4-1: Interconnection System Default Response to Abnormal Voltages [IEEE 1547a]

Default settings[a]		
Voltage range (% of base voltage[b])	Clearing time (s)	Clearing time: adjustable up to and including (s)
V < 45	0.16	0.16
45 ≤ V < 60	1	11
60 ≤ V < 88	2	21
110 < V < 120	1	13
V ≥ 120	0.16	0.16

[a] Under mutual agreement between the EPS and DR operators, other static or dynamic voltage and clearing time trip settings shall be permitted

[b] Base voltages are the nominal system voltages stated in ANSI C84.1-2011, Table 1.

Table 4-2: Interconnection System Default Response to Abnormal Frequencies [IEEE 1457a]

	Default settings		Ranges of adjustability	
Function	Frequency (Hz)	Clearing time (s)	Frequency (Hz)	Clearing time (s) adjustable up to and including
UF1	< 57	0.16	56 – 60	10
UF2	< 59.5	2	56 – 60	300
OF1	> 60.5	2	60 – 64	300
OF2	> 62	0.16	60 – 64	10

A single line to ground fault was applied at Bus 101 (upstream of the VR5) for 35 cycles immediately downstream of the REC5 and the following measurements were captured: (note that REC5 is expected to trip and clear fault after 20 cycle – this value represent typical operation time of distribution protection schemes).

- Magnitude of positive sequence voltage
- Extreme sag
- Extreme swell
- Moderate sag
- Moderate swell

Figure 4-35 and Figure 4-36 show the magnitude of voltage and current subsequent to this fault. It can be seen in Figure 4-35 that there is an extreme voltage sag for PMU 1, PMU 2, PMU 3, PMU 4, and PMU5, which is compatible with the results obtained from RTAC in Figure 4-37. The level of voltage sag and depth of voltages characterize the severity. During this fault, the PV did not trip.

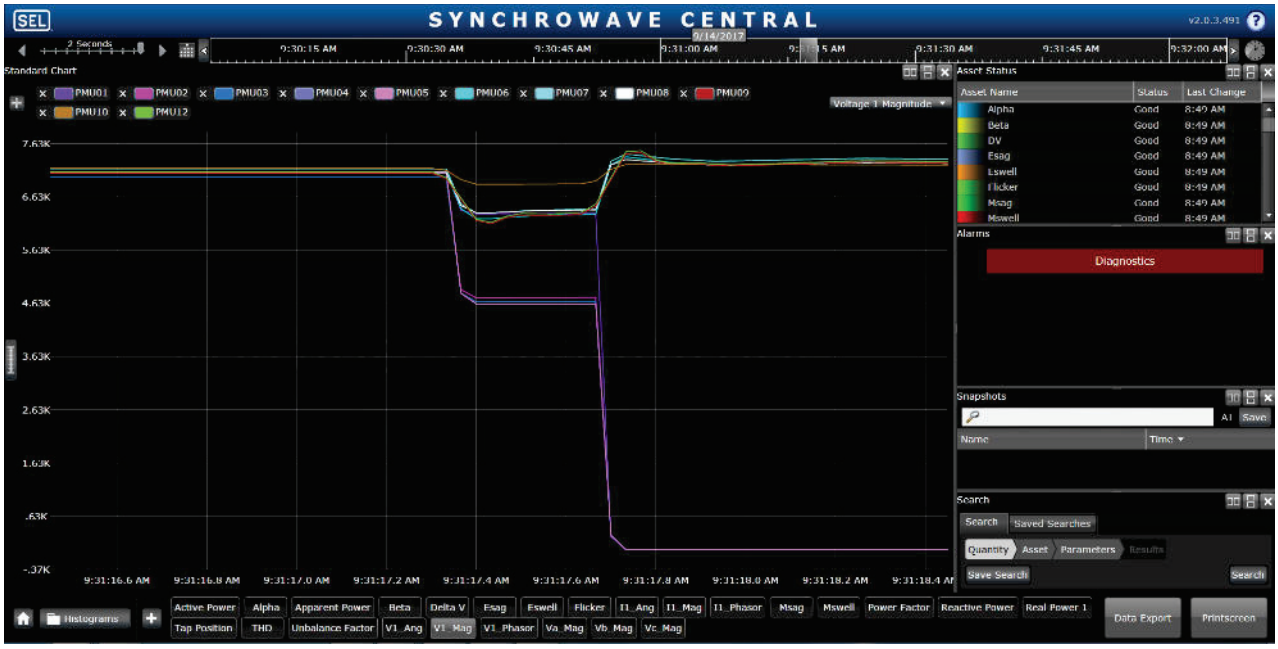


Figure 4-35. Magnitude of the Positive Sequence Voltages

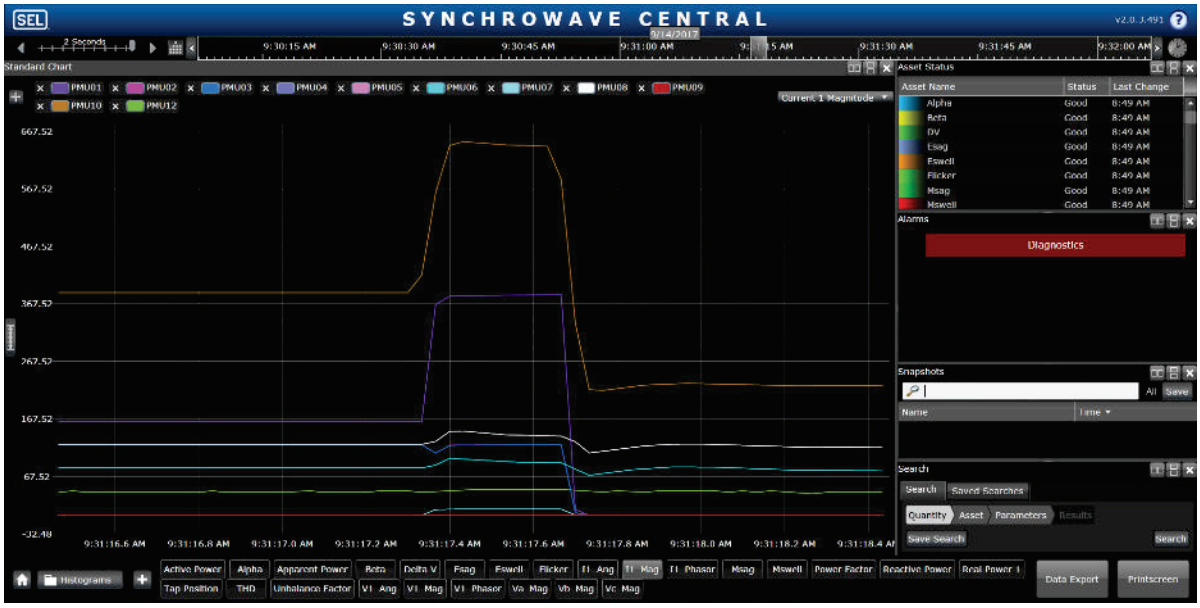


Figure 4-36. Magnitude of Positive Sequence Currents

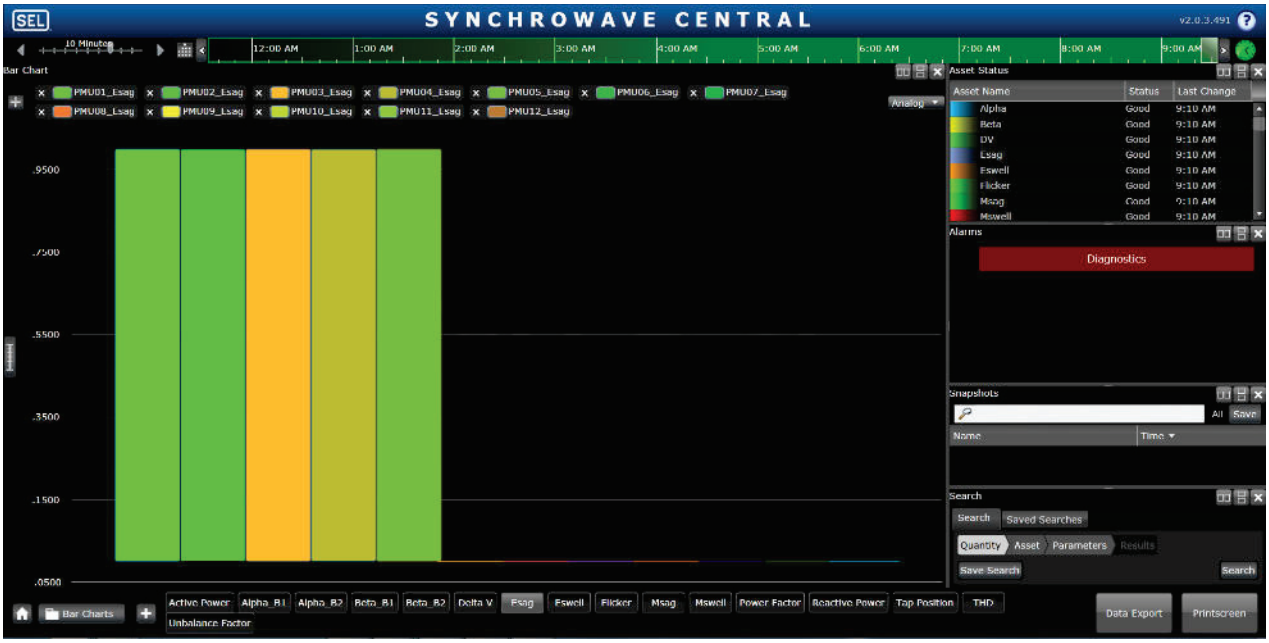


Figure 4-37. Extreme Voltage Sag Statistics

Then, the similar test was run for a two-line to ground fault (applying for 35 cycles immediately downstream of the REC5) and the following measurements were captured: (note that REC5 is expected to trip and clear fault after 8 cycles).

- Magnitude of positive sequence voltage
- Extreme sag
- Extreme swell
- Moderate sag
- Moderate swell

Similar to the previous test, it can be observed that this fault causes extreme voltage sags in PMU 2, PMU 3, PMU 4, and PMU5, which is compatible with the results obtained from visualization in Figure 4-40. During this fault, the PV did not trip.

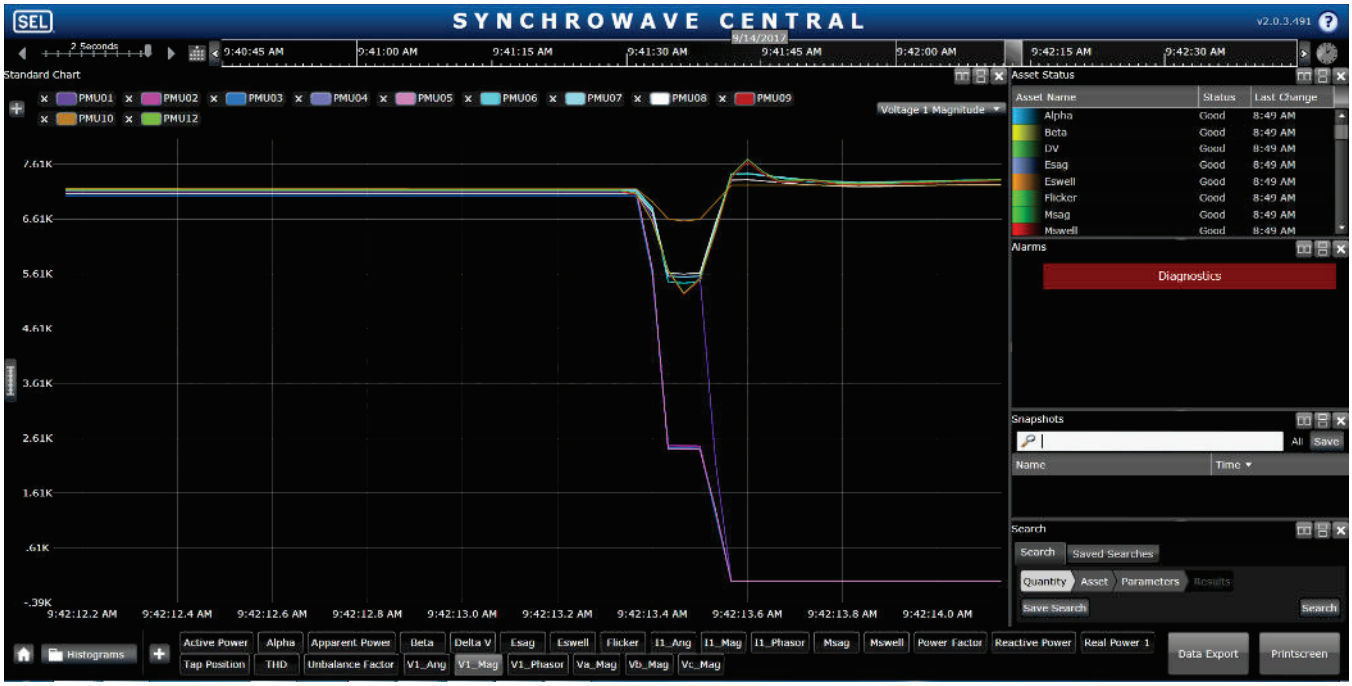


Figure 4-38. Magnitude of Positive Sequence Voltages

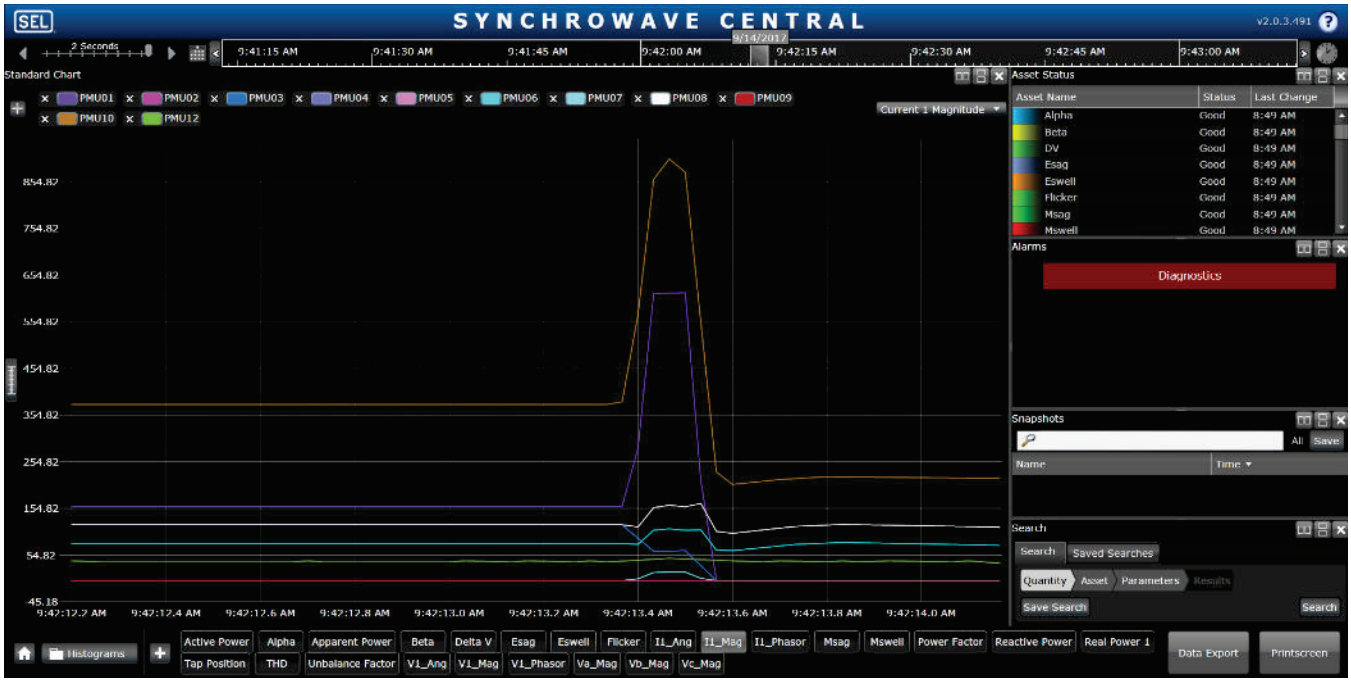


Figure 4-39. Magnitude of Positive Sequence Currents



Figure 4-40. Extreme Voltage Sag Statistics

4.1.5 Test Case 2

In this test, the summer load model performed with 2MW PV generation (PV protection settings are incorporated for the 2 MW system to match the IEEE 1547a). A three-phase fault was applied for 10 cycles close to the REC1 (located at Bus N06) and the following measurements were captured:

- Magnitude of positive sequence voltage
- Extreme sag
- Extreme swell
- Moderate sag
- Moderate swell

This fault generated a very quick voltage variation. Based on our definition from voltage sag and swell, this voltage variation cannot be considered as a voltage sag because it was very fast. RTAC did not report this event as voltage sag because the duration of violating voltage sag threshold (0.2 pu) wasn't more than 10 cycles.

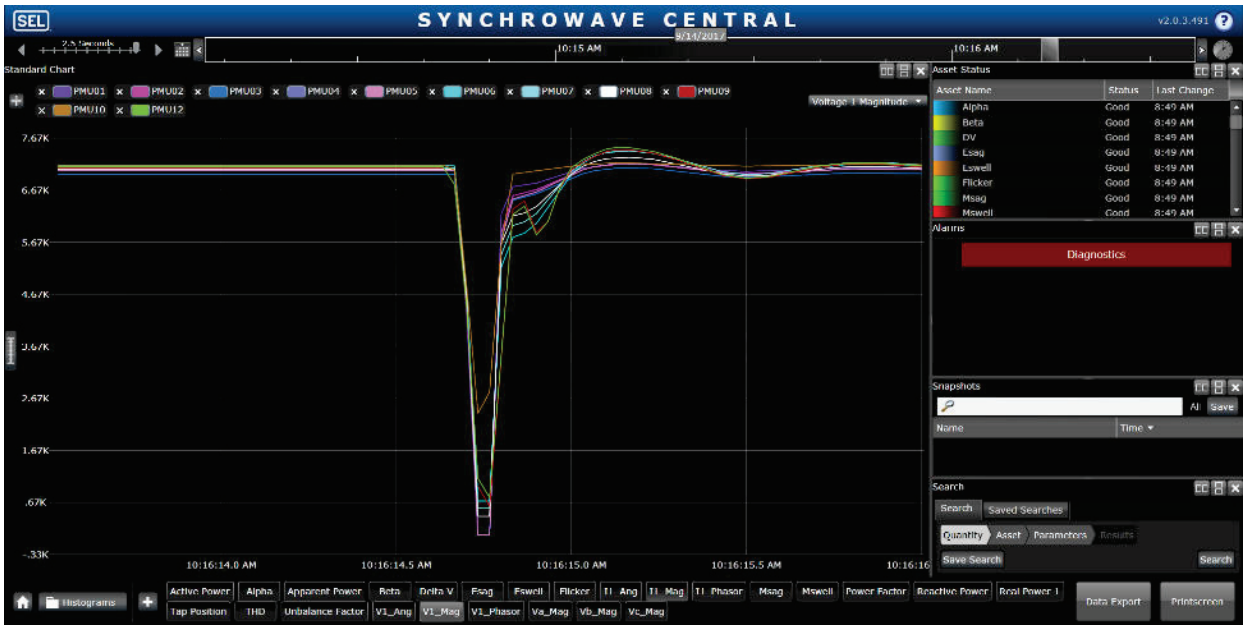


Figure 4-41. Magnitude of Positive Sequence Voltages

From the magnitude of the positive sequence current (as captured below) the fault location can be identified.

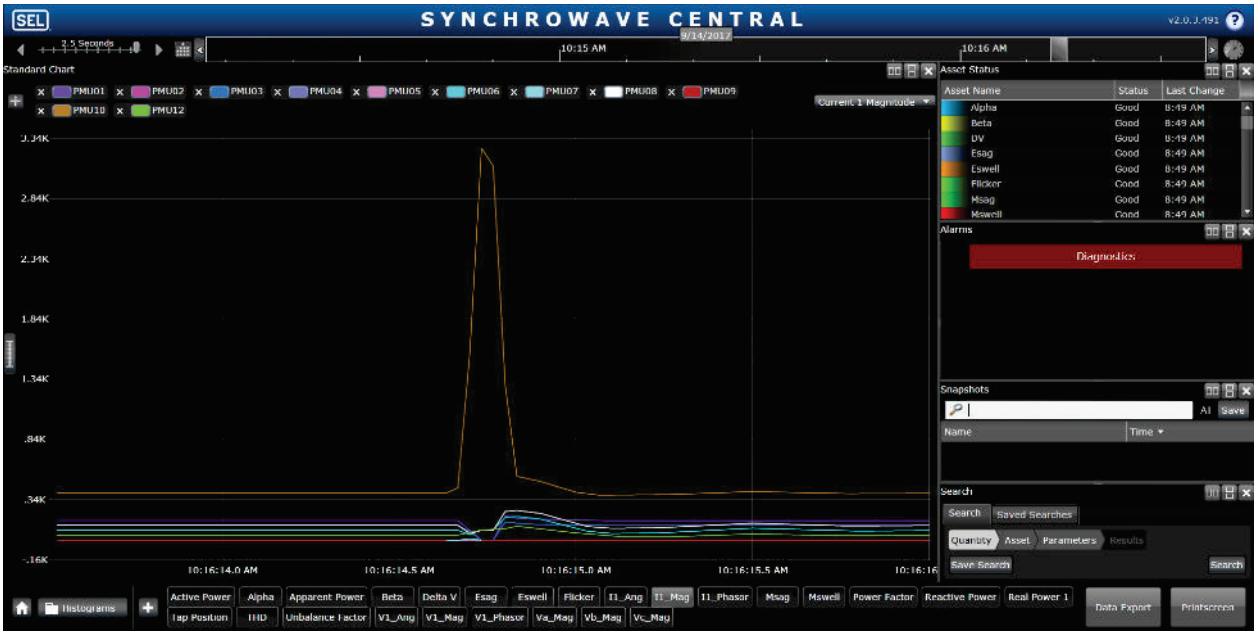


Figure 4-42. Magnitude of Positive Sequence Currents

This fault also did not trip the PV.

4.1.6 Test Case 3

In this test, the summer load model was run with 2MW PV generation (PV protection settings are incorporated for the 2 MW system to match the IEEE 1547a). A single line to ground fault (permanent) was applied close to DVC (N117) and the following measurements were captured:

- Magnitude of positive sequence voltage
- Extreme sag
- Extreme swell
- Moderate sag
- Moderate swell

Figure 4-43 shows that the PMU 12, PMU 9, PMU 8, and PMU 7 experienced a moderate voltage sag, which is compatible with the results obtained from RTAC in Figure 4-45. The main reason is that those PMUs were located electrically farther from the fault. This fault tripped the PV.

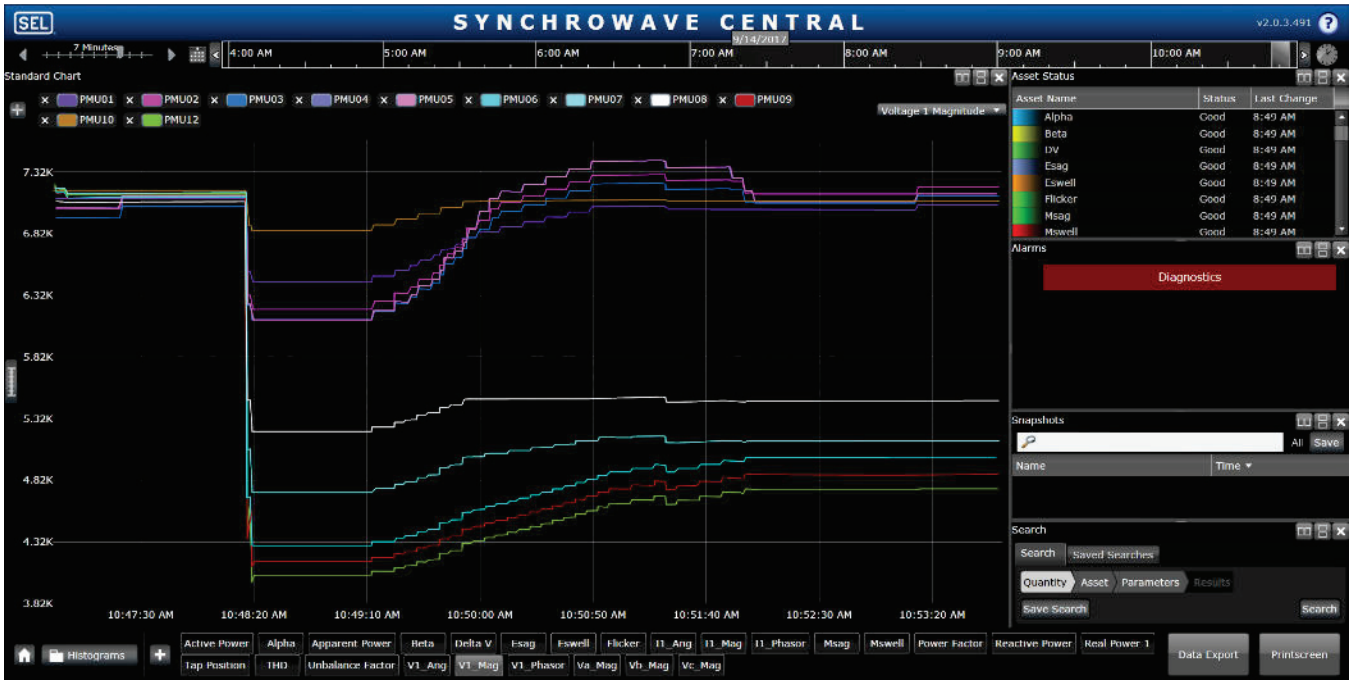


Figure 4-43. Magnitude of Positive Sequence Voltages

The above visualization screen can be utilized for fault detection and analysis. The level of voltage changes (voltage sag level) can be correlated with the fault type and fault locations.

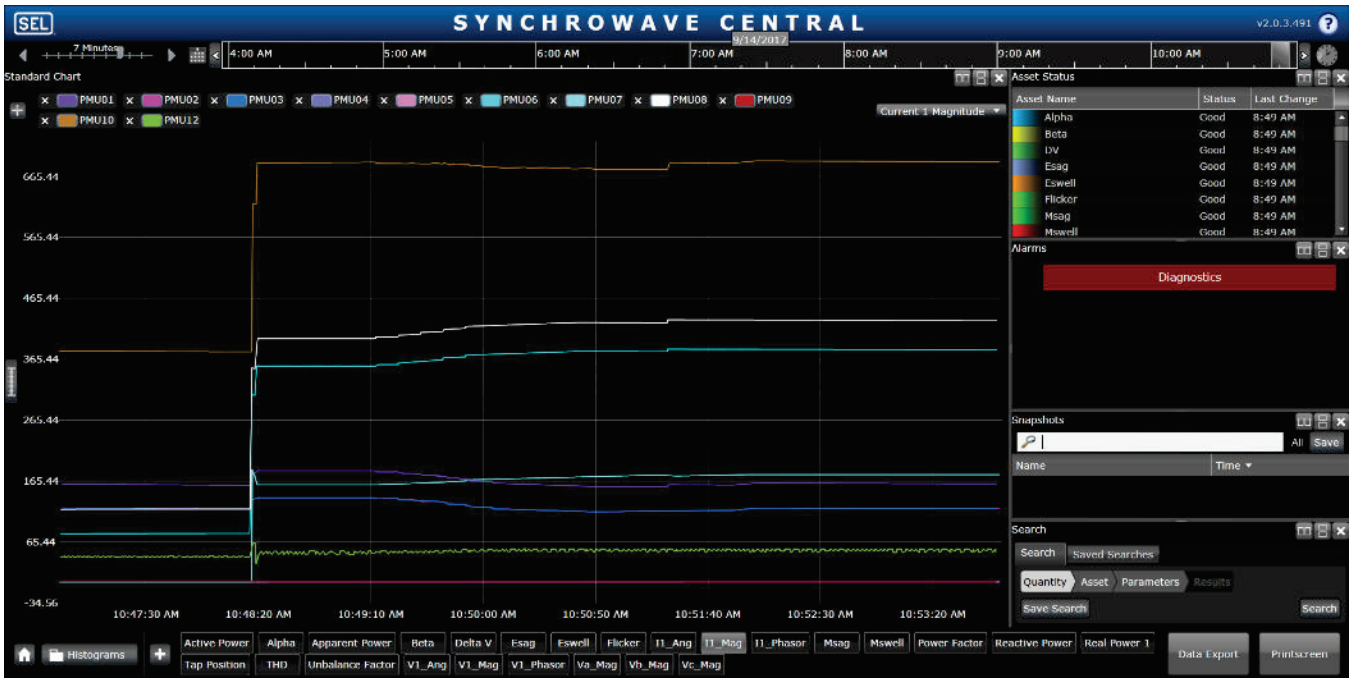


Figure 4-44. Magnitude of Positive Sequence Currents

As shown in the above figure, the PMU located electrically closer to the fault location showed the highest change in current.



Figure 4-45. Moderate Voltage Sag Statistics

4.2 Circuit 2 and Circuit 3 Test Results

A simplified single line diagram of the circuits 2 and 3 in Sub 2 is shown in Figure 4-46. The single line diagram is an overall representation of the model built in the RTDS environment for the laboratory testing and evaluations.

As indicated in this figure, there is a 6 MW PV system on circuit 3, located downstream of the circuit breaker CB3 and two generators downstream of the CB2. There is a normally open tie switch (CB0T21) between the two circuits. For load transfer cases, the tie switch can be closed and one of the upstream reclosers can be opened to change the load flow and voltage profile of the circuit.

Circuit 2 has one voltage regulator (VR1) and circuit 3 has two voltage regulators (VR2, and VR3). For the purpose of this study, this circuit has been modeled in RSCAD. 12 PMUs including 8 simulated PMUs (PMU1 to PMU8) and 4 physical PMUs (PMU9 to PMU12) are located at various nodes in the study system to facilitate system monitoring during the tests.

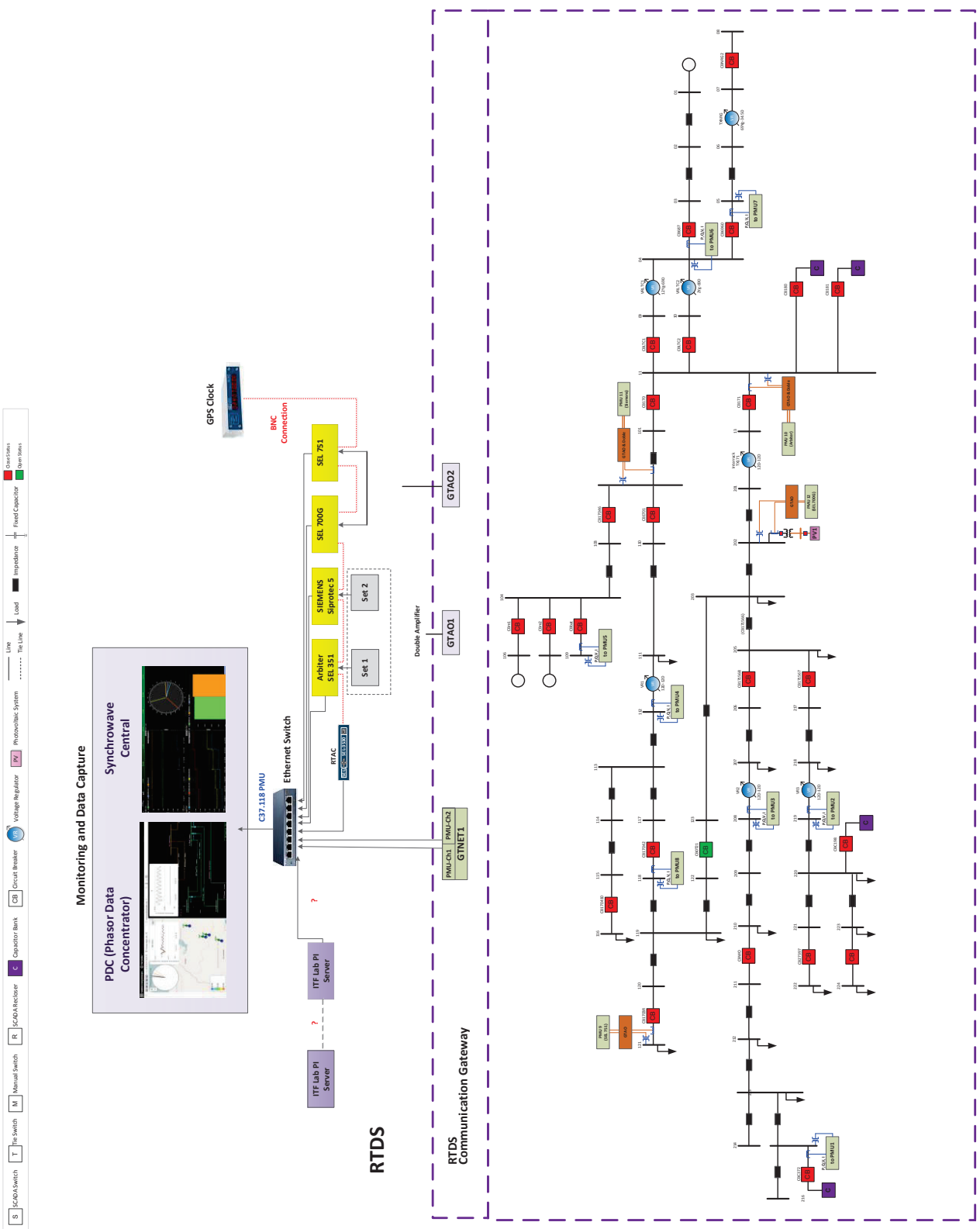


Figure 4-46. Single Line Diagram and PMU Locations of Circuit 2 and Circuit 3

In the following section, different case studies are presented to study the behavior of circuit 2 and 3.

4.2.1 Voltage/Power Flow Monitoring for Summer Load and with PV

In this case study the voltages, currents, real, and reactive power of different PMUs are captured, while the circuit was run with summer load profile and PV.

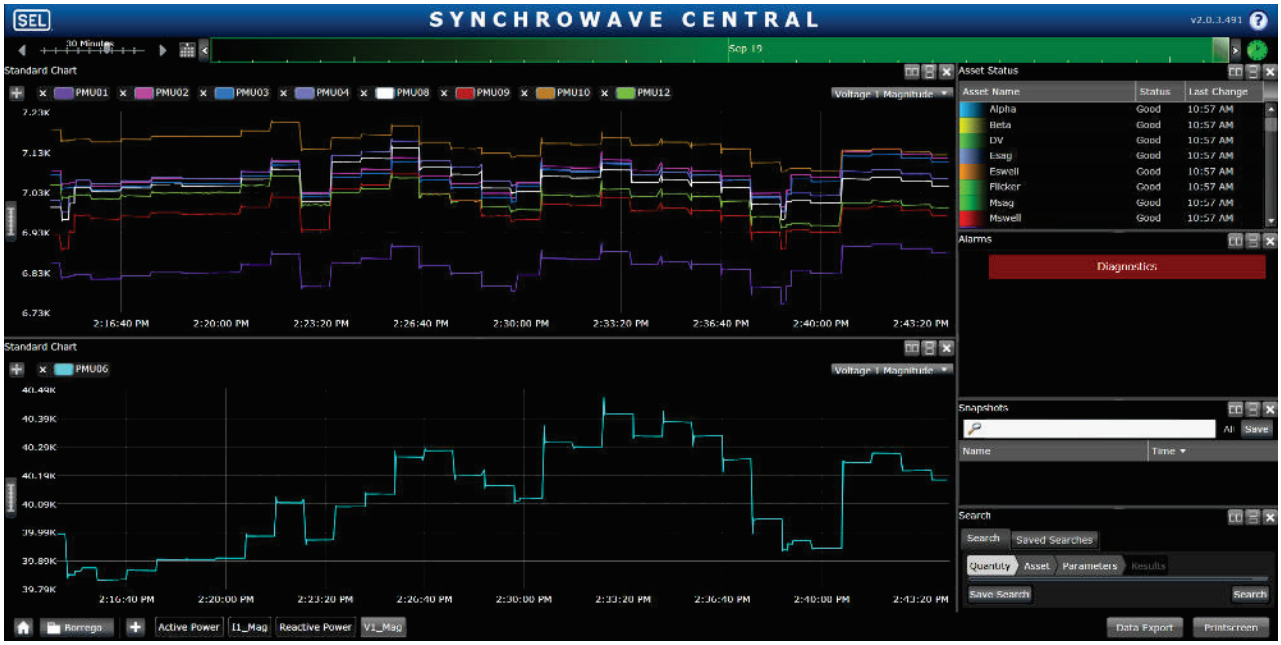


Figure 4-47. Magnitude of Positive Sequence Voltages

The proposed visualization screens and their applications are similar to the ones utilized for analysis of circuit 1. Each measurement screen provides one way of visualizing circuit events and dynamic nature of the disturbances.

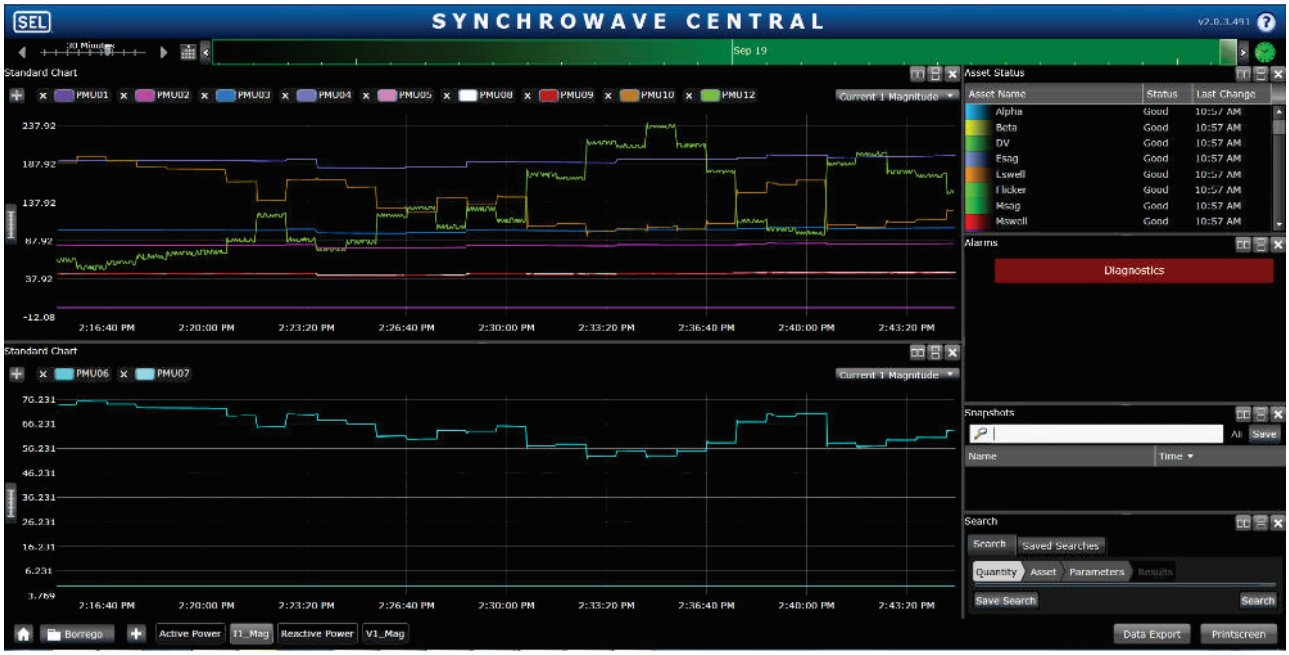


Figure 4-48. Magnitude of Positive Sequence Currents

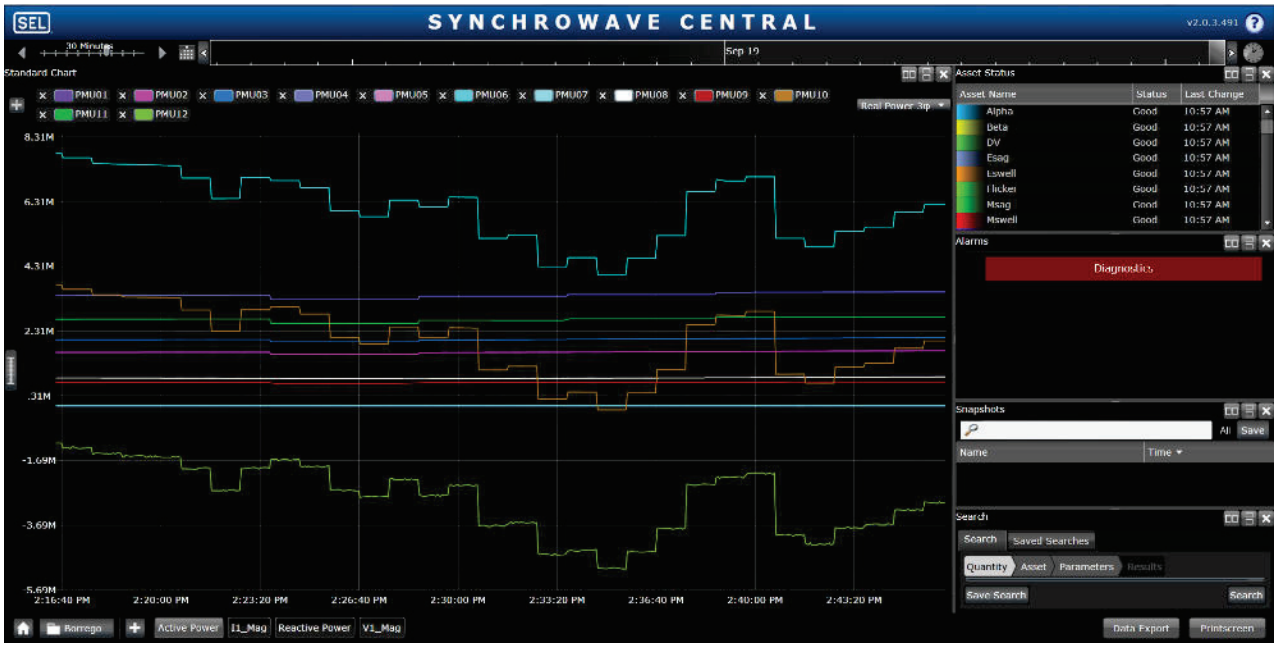


Figure 4-49. Active Powers

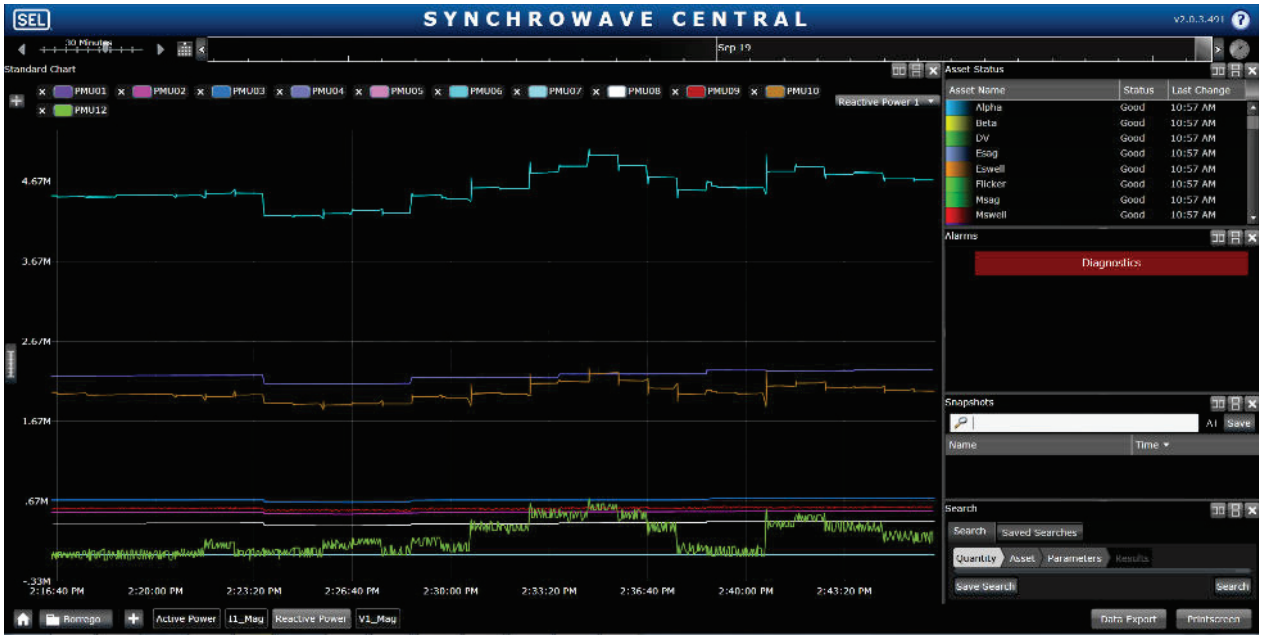


Figure 4-50. Reactive Powers

The approaches utilized in implementing and analysis the screens were generally similar to circuit 1. However, because of the availability of two diesel generators and significantly higher PV generation on circuit 2 and circuit 3, they were used to perform test cases associated with islanding and visualization of stability issues.

4.2.2 Primary Asset Operation Monitoring and Diagnostics

4.2.2.1 Load Transfer

In this case study, the loads were set at 0.75 pu and the PV was set at its maximum. The following figure shows the active power flow at different PMUs. It can be seen that there is reverse power flow in the PMUs close to the PV.

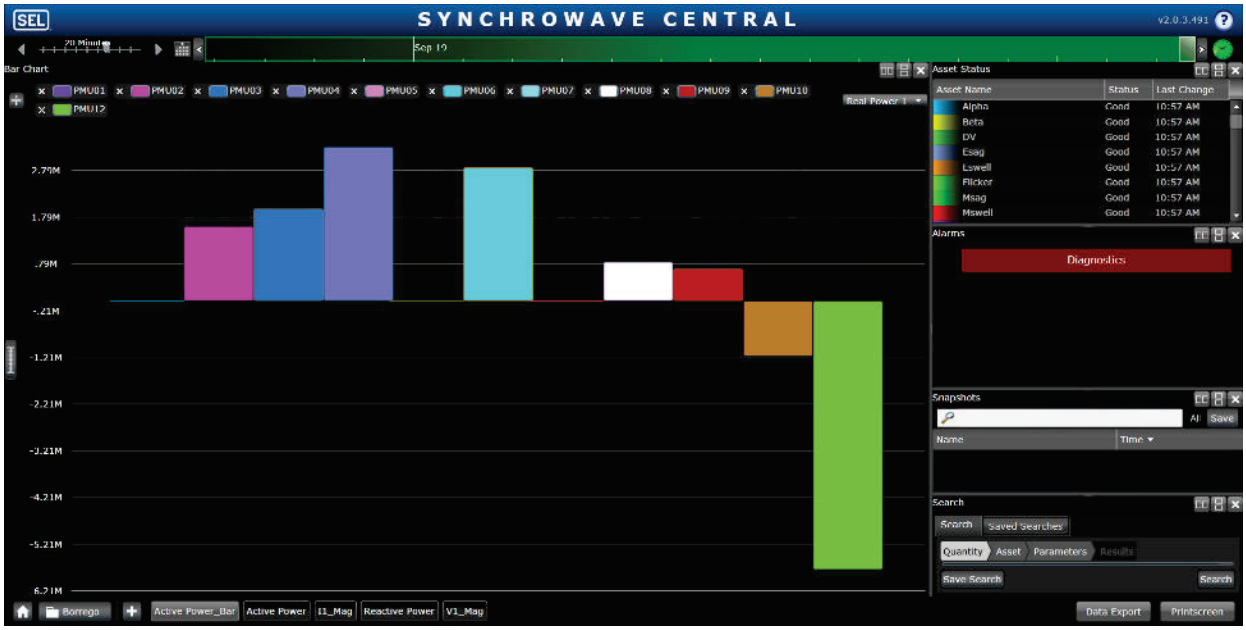


Figure 4-51. Active Powers of Different PMUs

The tie switch between two circuits was closed, and we can observe that this action created a reverse power flow in circuit 2.

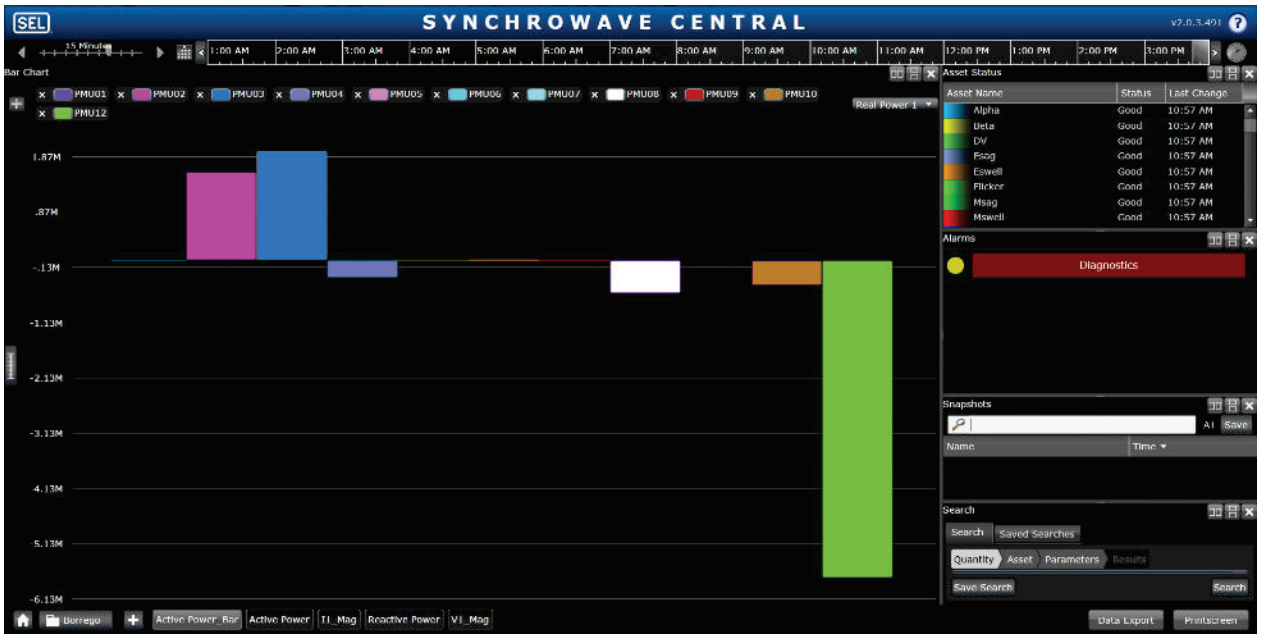


Figure 4-52. Active Powers of Different PMUs Subsequent to the Closing of the Tie Switch

Then, the recloser 1701 on the second branch was opened to perform the load transfer.

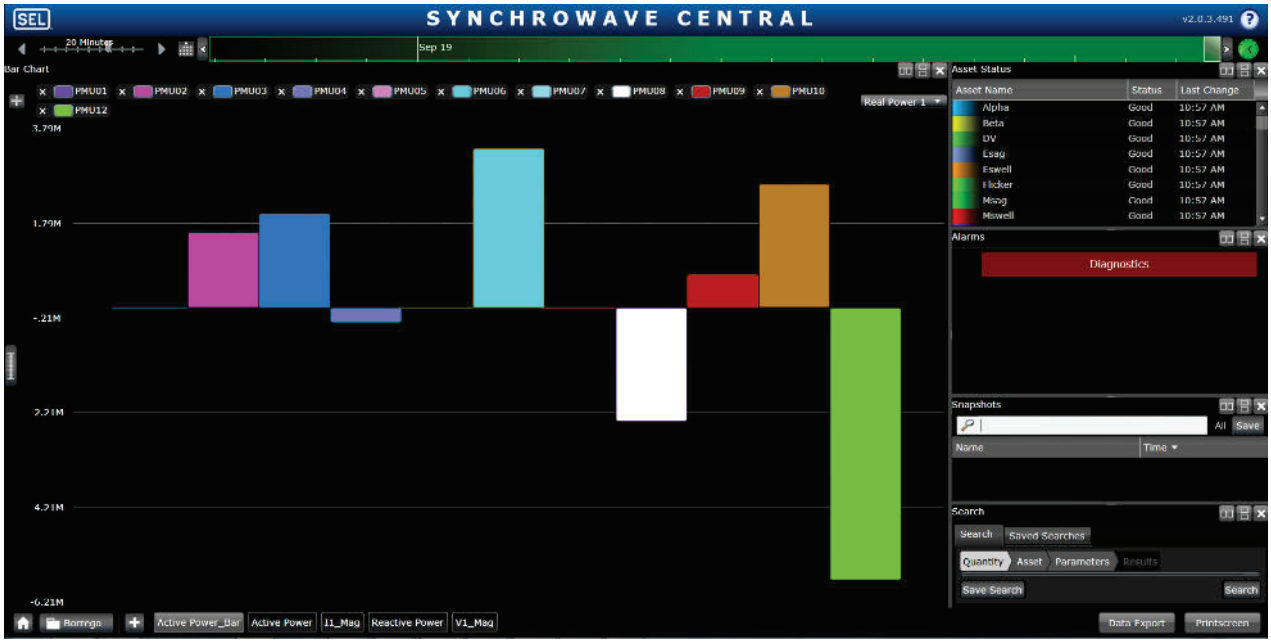


Figure 4-53. Active Powers of Different PMUs Subsequent to the Load Transfer

However, after the load transfer the voltages were out of the permissible range, because of the significant reduction in load. Therefore, the load shedding needs to be done to bring back the voltages to the standard limits.

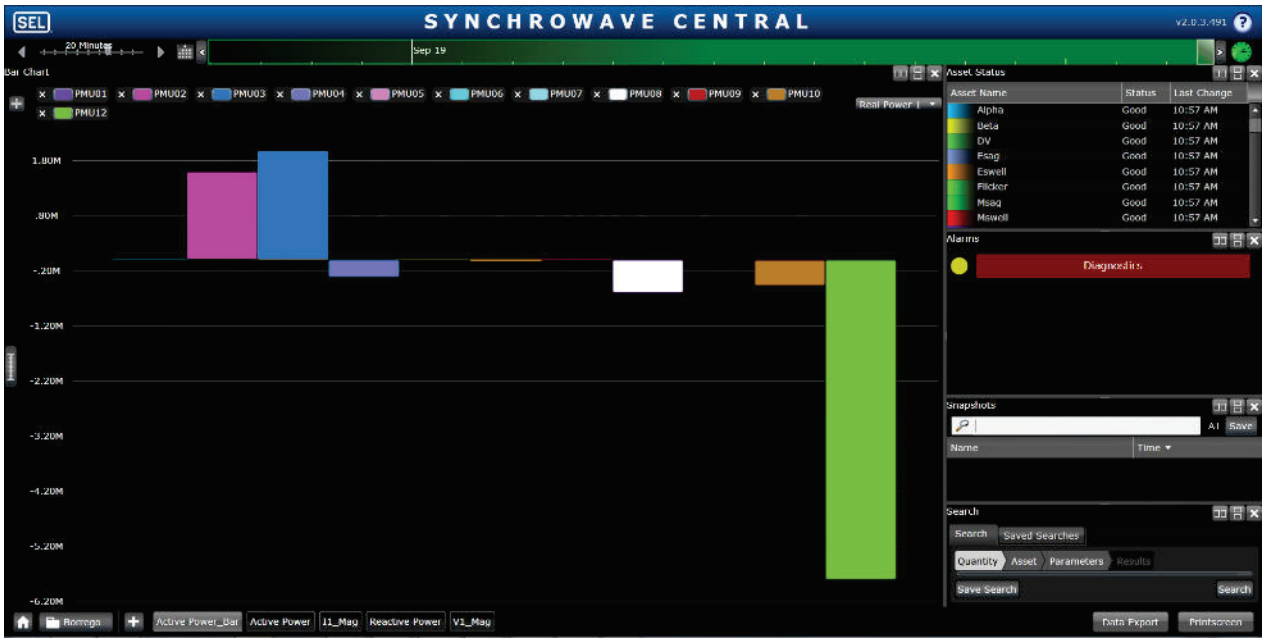


Figure 4-54. Active Powers of Different PMUs Subsequent to the Load Shedding

The following figures show the voltages, currents, real powers, and reactive powers of different PMUs during the load transfer test case. For transferring the load, the tie switch was closed first to establish the power

flow. In the next step, the upstream recloser (on the second branch) was opened to reach a redial system configuration as expected by the operator.

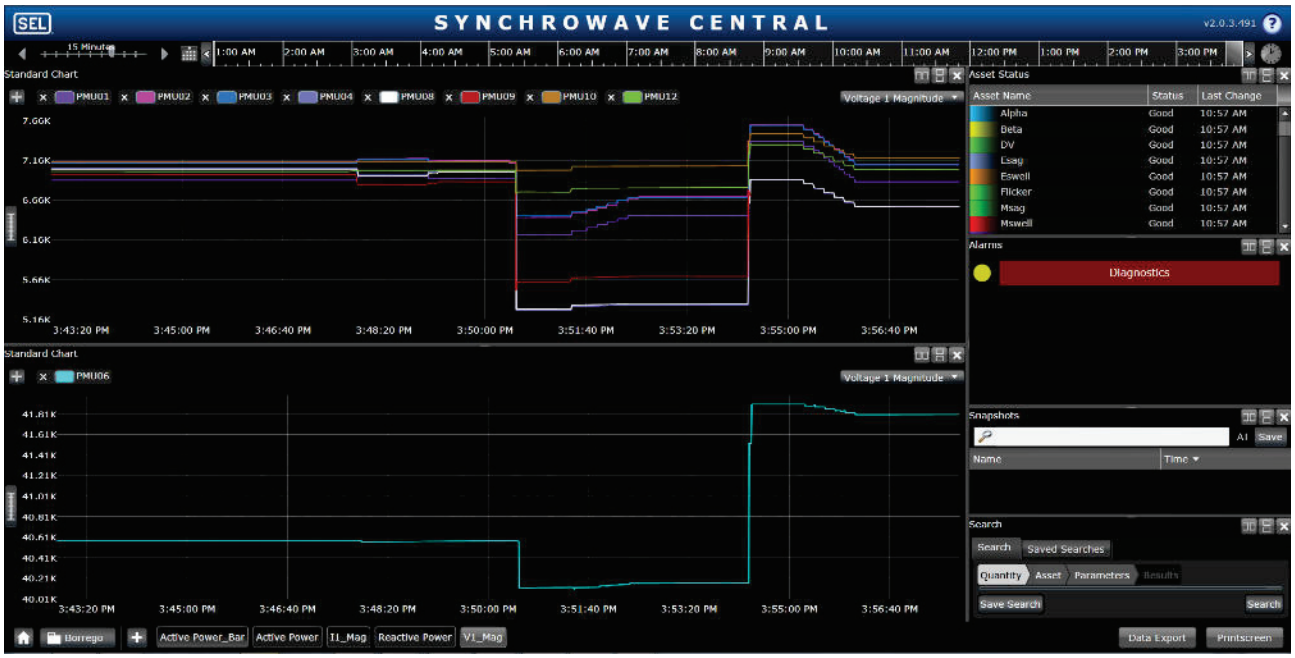


Figure 4-55. Magnitude of Positive Sequence Voltages, Capturing Exact Time of Load Transfer

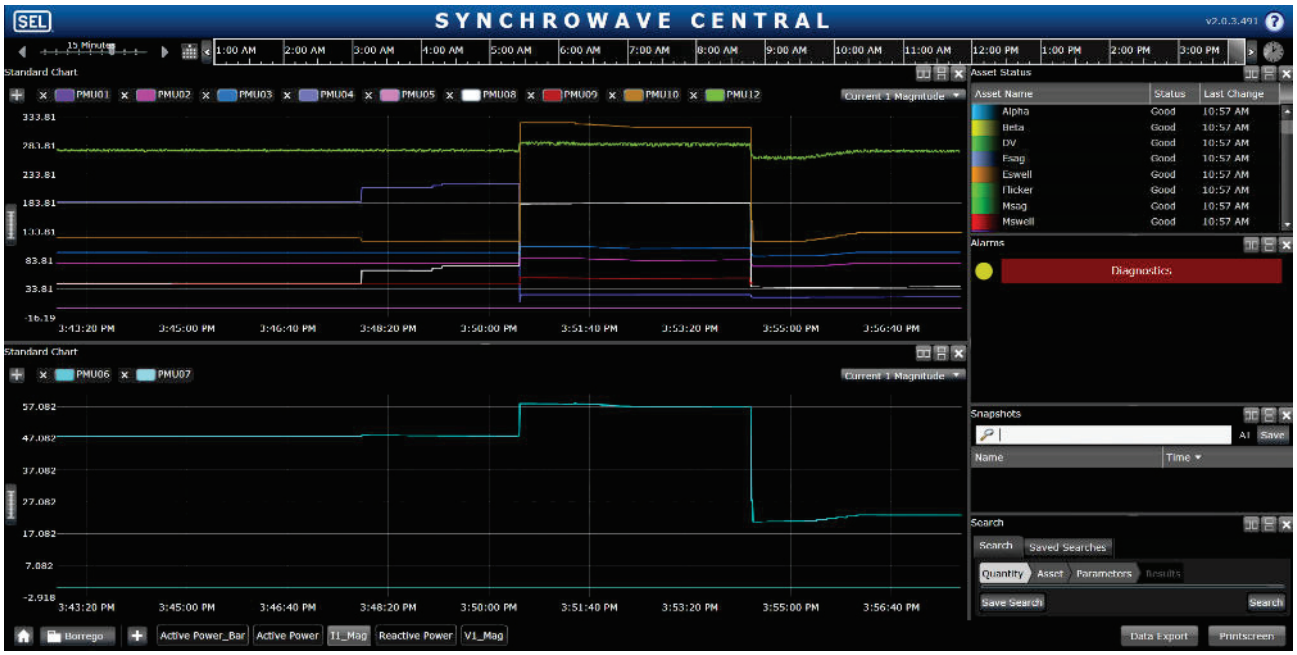


Figure 4-56. Magnitude of Positive Sequence Currents

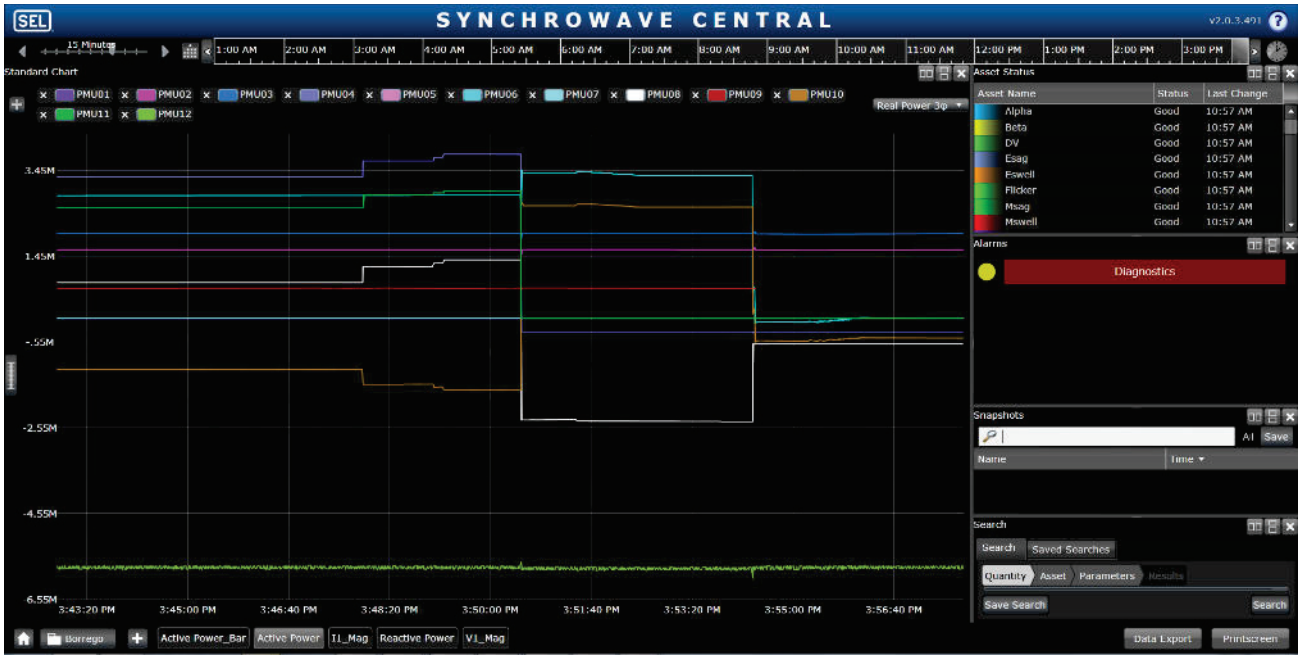


Figure 4-57. Active Powers

Change in both active and reactive power flow of the circuit that were captured by various PMUs across the circuit also demonstrated the disturbance caused by transferring load. In general, depending on the nature of a disturbance or an event, the impact can be observed by visualizing multiple system parameters.

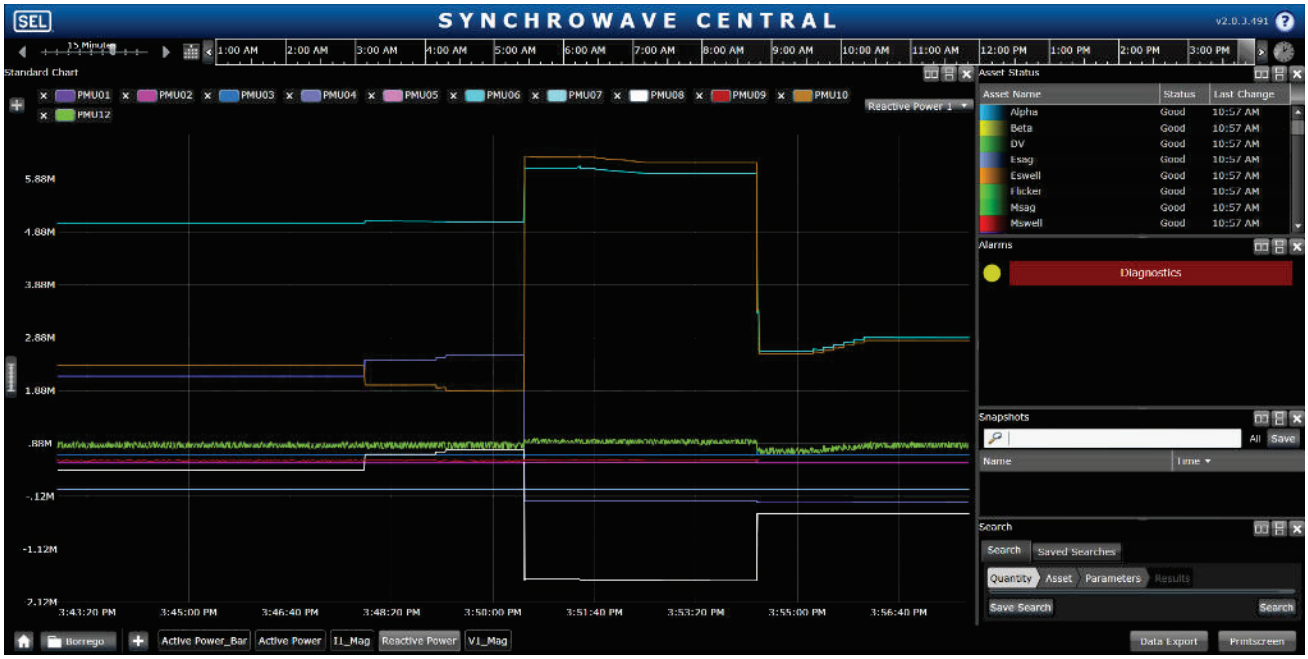


Figure 4-58. Reactive Powers

4.2.2.2 Intentional Islanding with 0.75 pu Loading Condition

In this case study, the loads were set at 0.75 pu and the PV was set at its maximum. The following figure shows the active power flow at different PMUs.

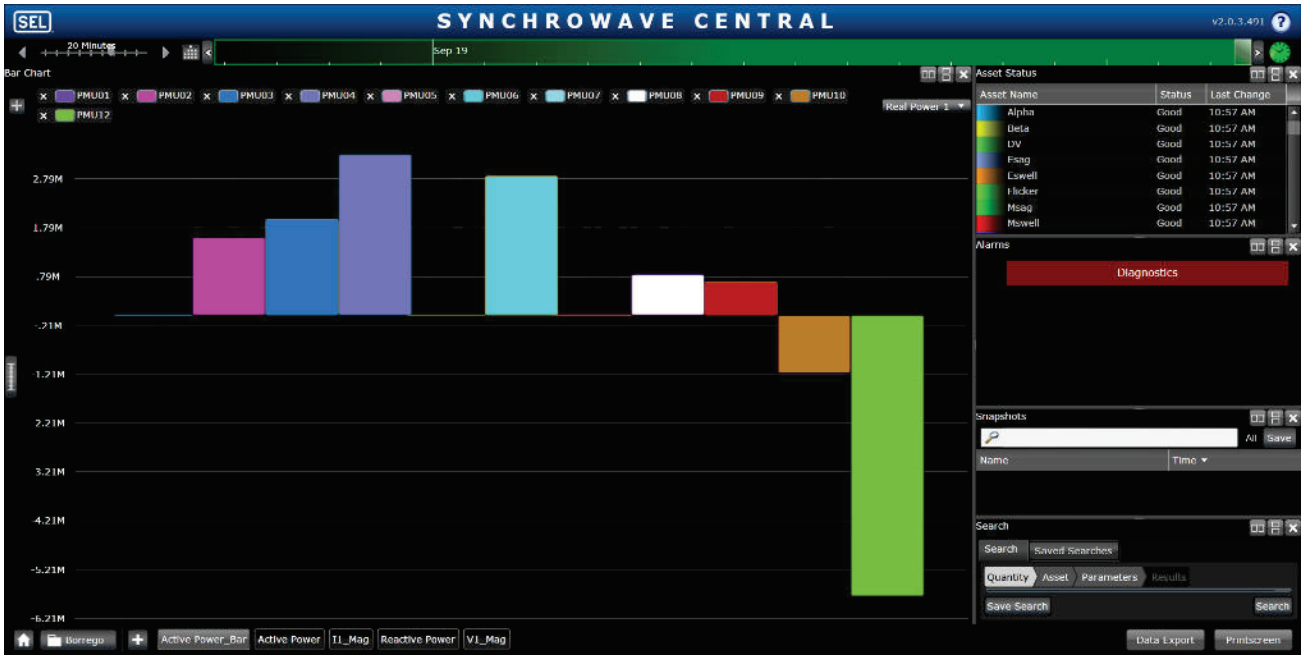


Figure 4-59. Active Powers of Different PMUs

Turning on the generators created reverse power flow in circuit 2 as shown in the following figure.

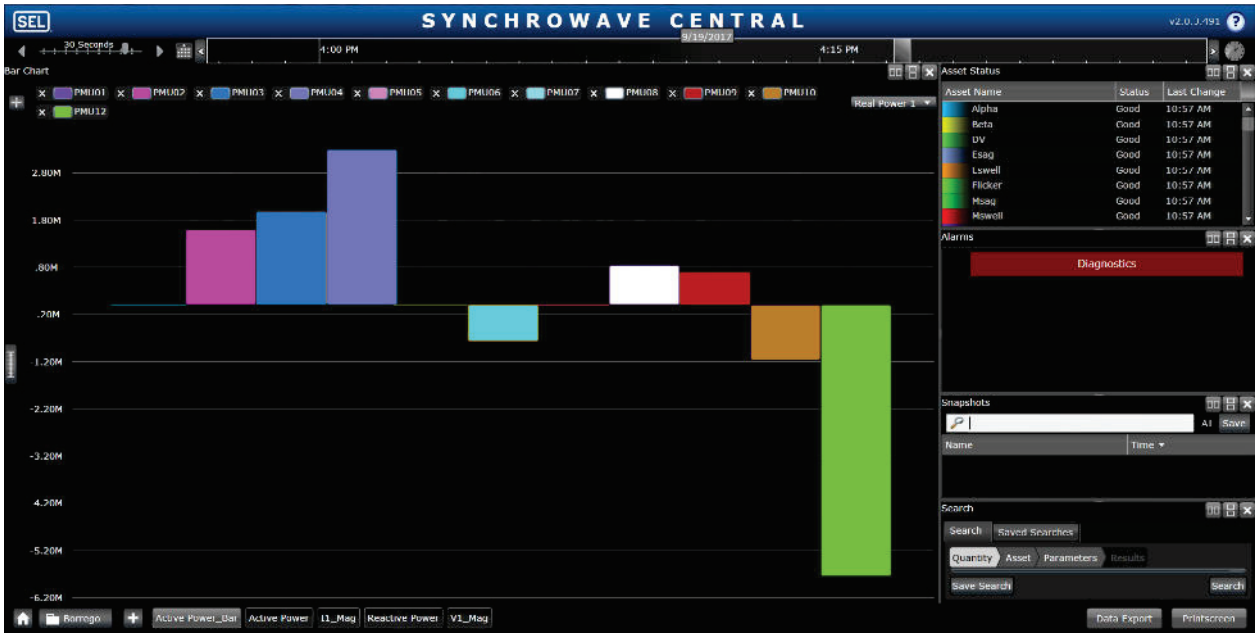


Figure 4-60. Active Powers of Different PMUs Subsequent to Turning on the Generators

Then, circuit 2 was islanded by opening CBC2. It can be observed that the system became unstable as shown in the following figure.

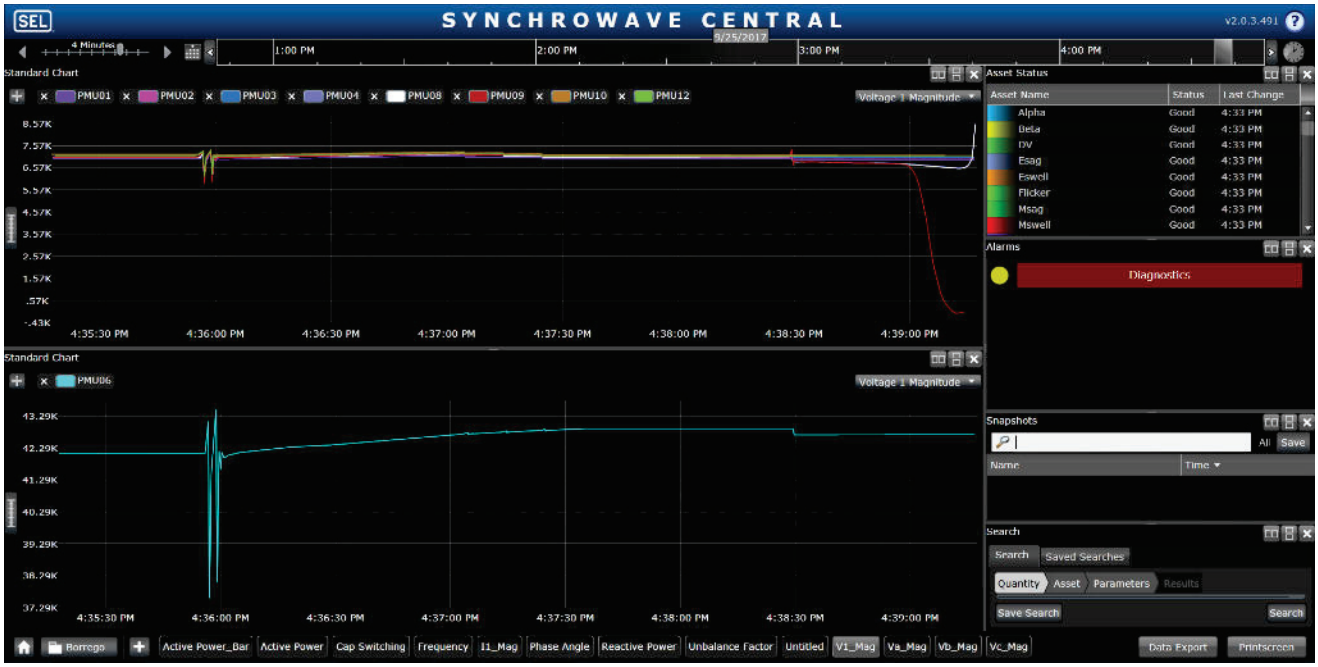


Figure 4-61. Magnitude of Positive Sequence Voltages during Islanding Process

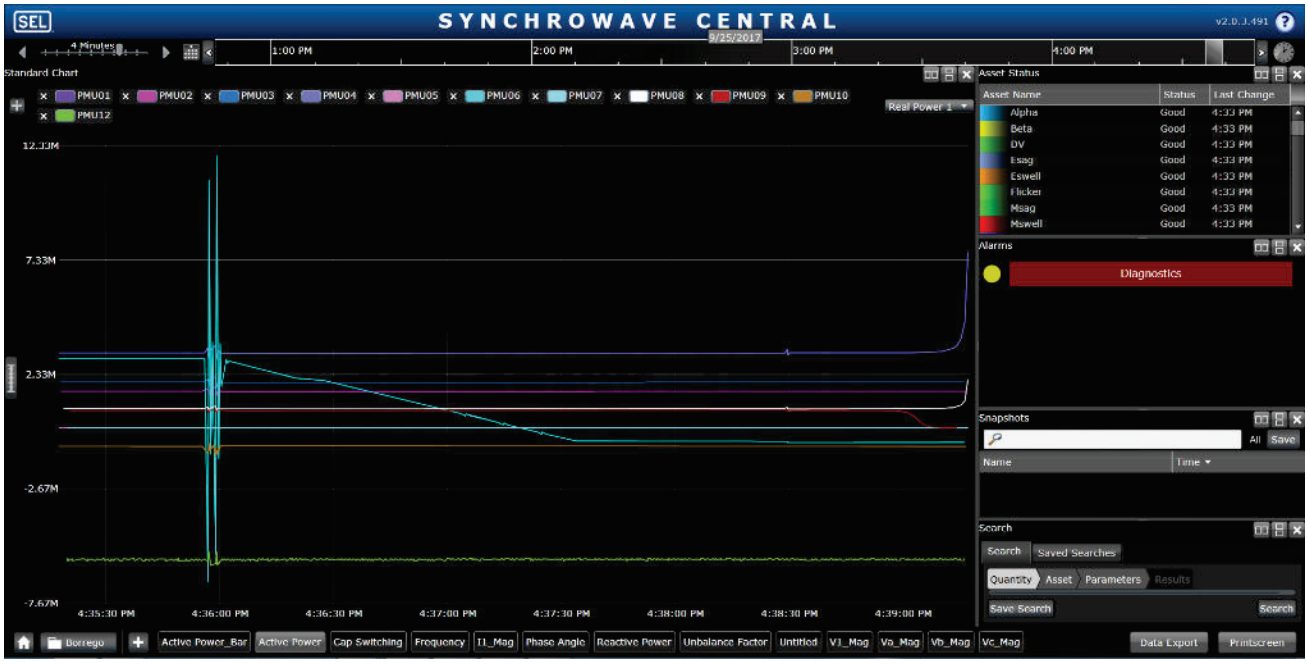


Figure 4-62. Active Powers during Islanding Process



Figure 4-63. Frequency Changes during Islanding Process

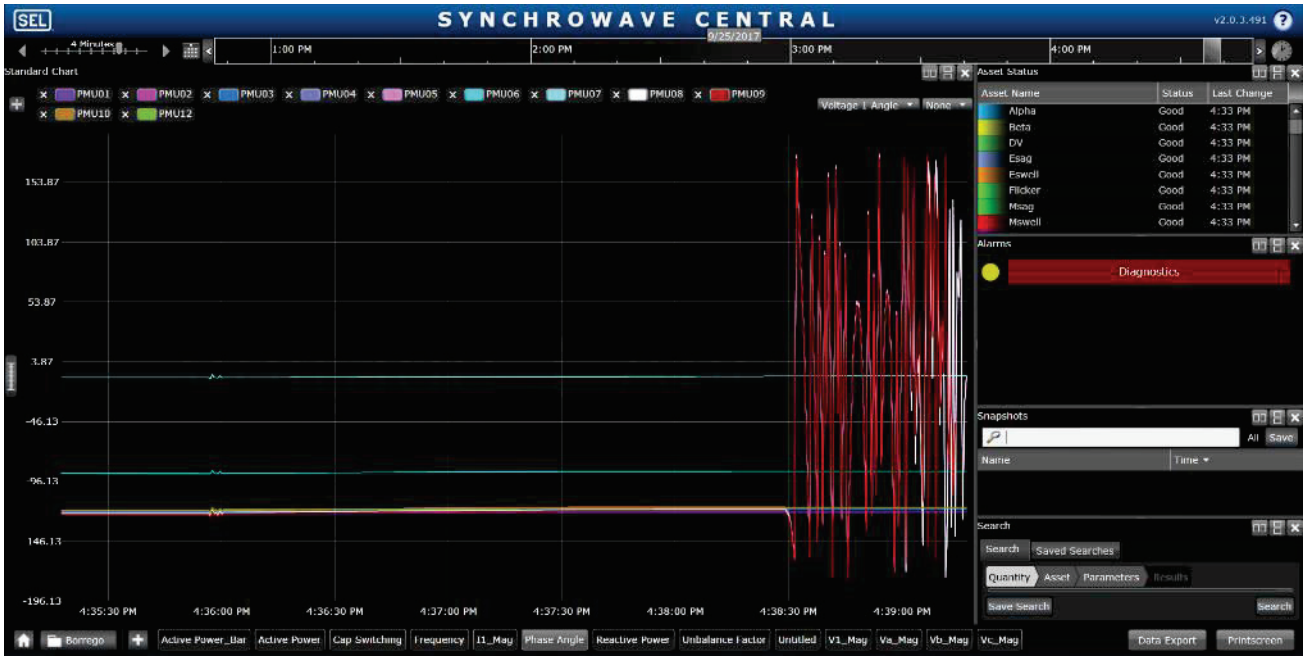


Figure 4-64. Phase Angle Changes during Islanding Process

4.2.2.3 Intentional Islanding with 0.7 Loading Condition

In this case study, the loads were reduced to 0.7 pu. In this condition, the generation of the two generators are sufficient for the loads of the microgrid. The following figure shows the active power of different PMUs after turning on the generators.

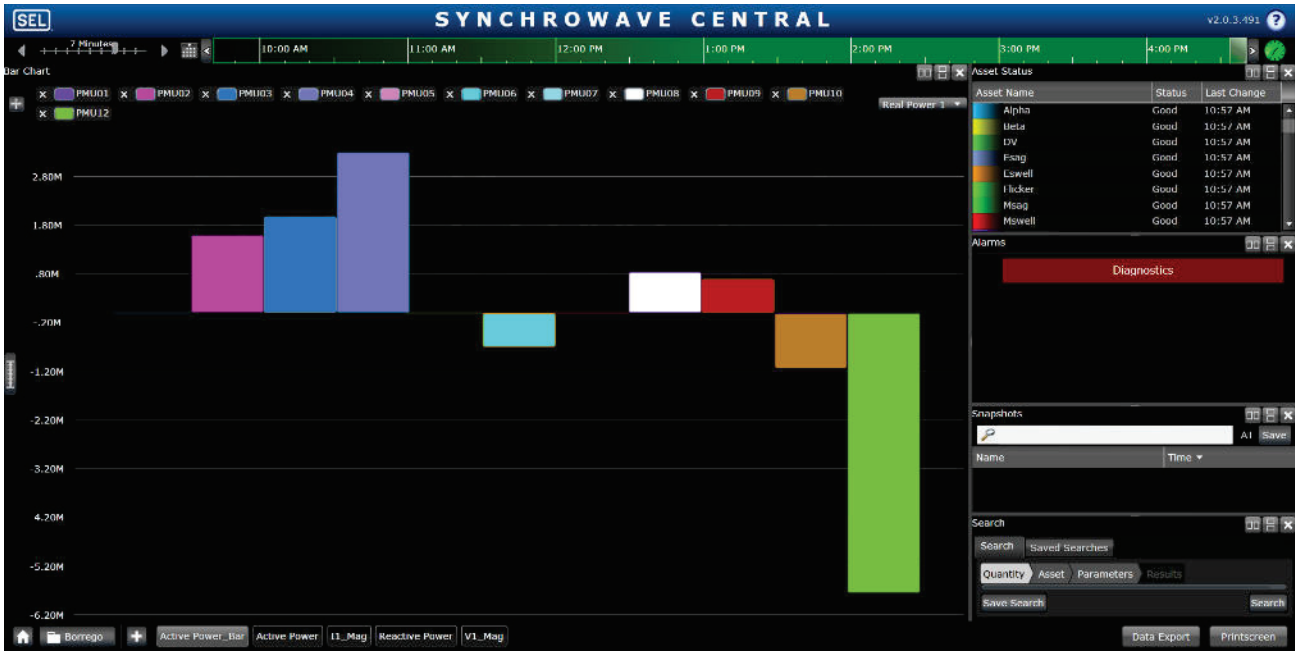


Figure 4-65. Active Powers of Different PMUs Subsequent to Turning on the Generators

In this case study, load shedding was performed before the islanding of circuits 3. Hence, the islanded circuit was stabilized based on available reserve capacity of the generation units under a reduced load condition.

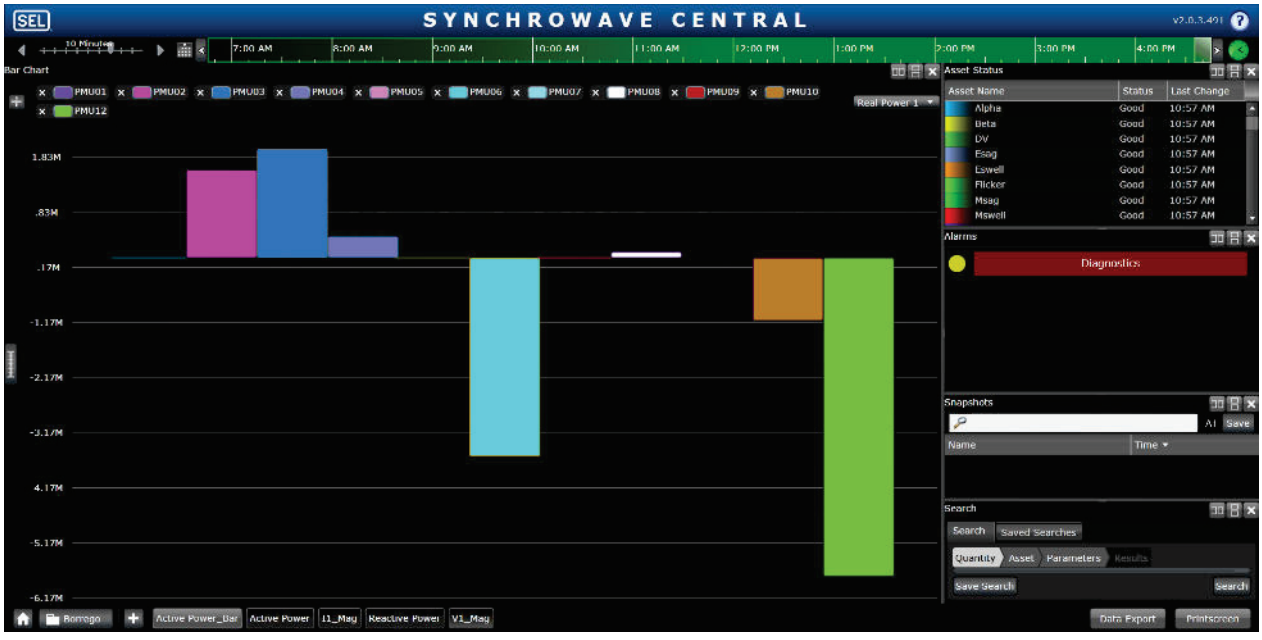


Figure 4-66. Active Powers of Different PMUs after Load Shedding

It can be observed that in this case study (unlike the case study with 0.75 loading condition), the islanded circuit was able to preserve its stability. The following figures show voltages, currents, active powers, and reactive powers of different PMUs during the islanding process.



Figure 4-67. Magnitude of the Positive Sequence Voltages

Voltage and power across the circuit were restored after a short period of transients.



Figure 4-68. Active Powers

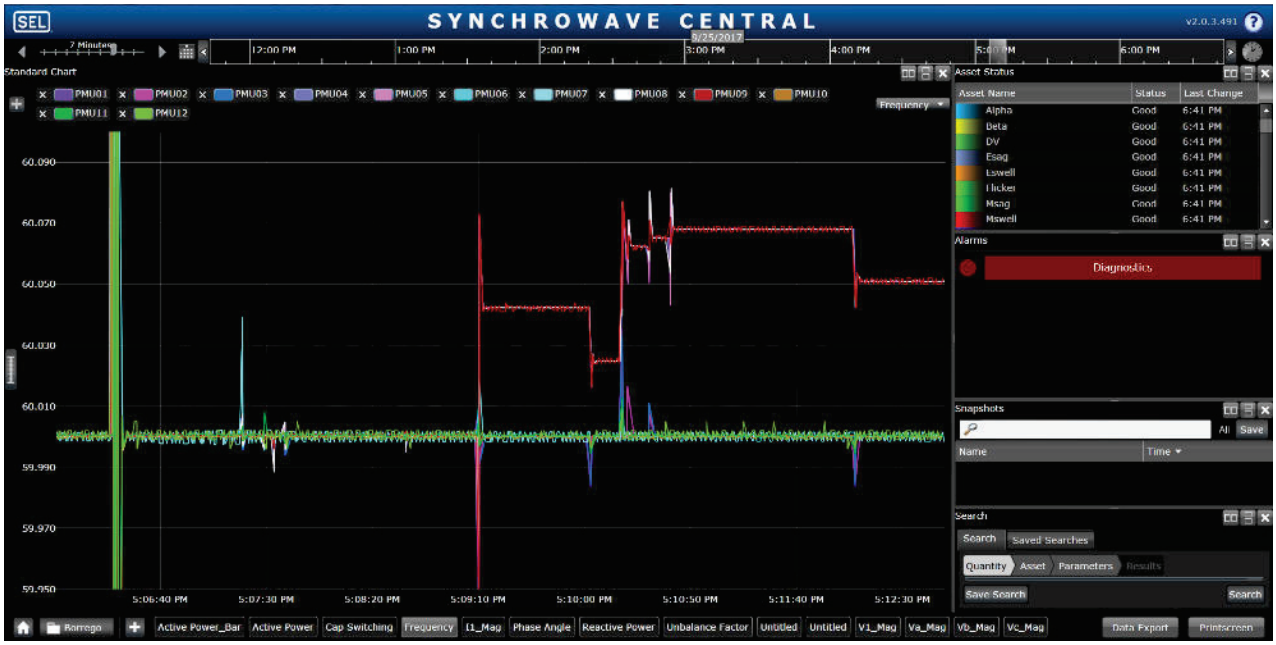


Figure 4-69. Reactive Powers

Because the frequency during island operation is not 60 Hz, the phase angle of the phasor measurement shows an oscillatory behavior. Most PMU devices are very sensitive to frequency changes (such as the case of islanding) can only tolerate a small deviation in power frequency from 60 Hz.

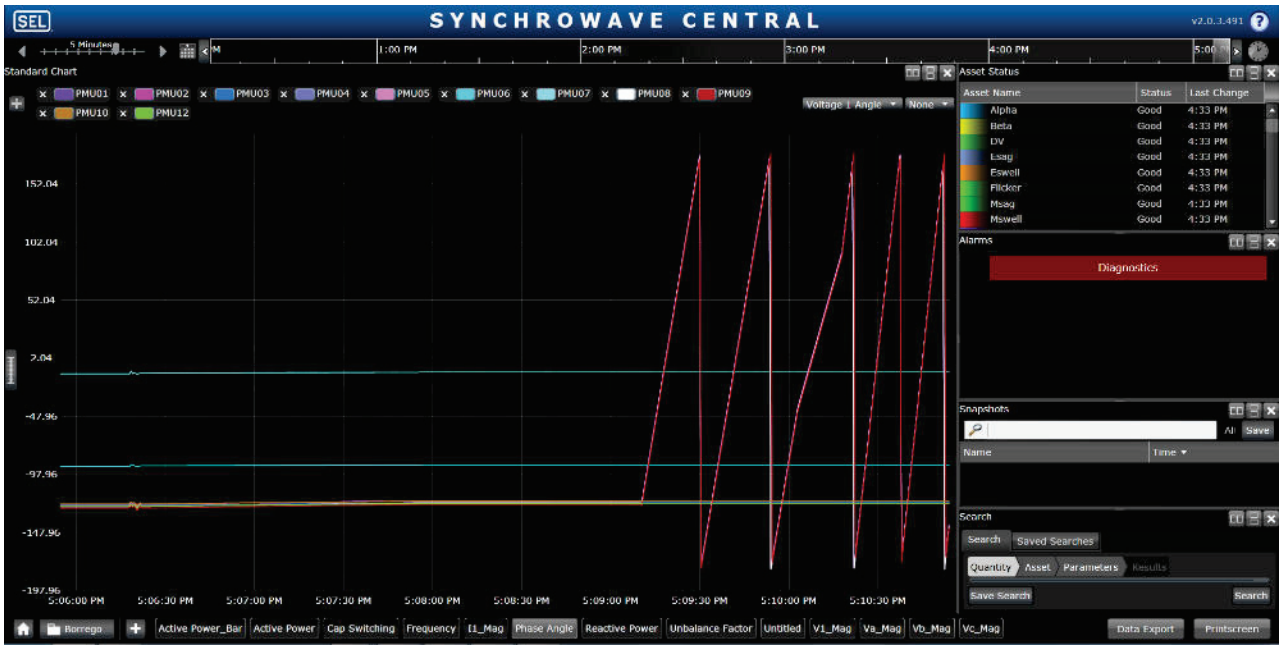


Figure 4-70. Phase Angle Changes during Islanding Process

4.2.2.4 Unbalance Factor

Loads were set to 0.75 pu and PV was set to its maximum value (6MW). In this case study, severe unbalanced condition caused by the malfunction of a circuit breaker was applied to the circuit to investigate its effect across the circuit. For this purpose in the first case study, phase A of the CB171 was opened. Figure 4-71 shows that this action caused a huge voltage variation in the downstream PMUs (PMU 12, PMU 1, PMU 2, and PMU3), while it did not creat a tangible positive voltage change in the upstream PMUs.

This malfunction can be identified more easily (even in the upstream PMUs or even Circuit 2 PMUs) by monitoring the unbalanced factor as shown in Figure 4-72. It can be seen that all PMUs have higher unbalanced factor than the threshold (0.3%).



Figure 4-71. Magnitude of the Positive Sequence Voltages



Figure 4-72. Unbalanced Factors

The similar malfunction was applied to recloser CB171567. The magnitude of the positive sequence voltage is shown in Figure 4-73. It can be seen that, except PMU 2 in the downstream of CB171567, this malfunction cannot be detected by observing positive sequence voltage. However, it can be detected from the unbalanced factor of all PMUs as shown in Figure 4-74.



Figure 4-73. Magnitude of Positive Sequence Voltages



Figure 4-74. Unbalance Factors

4.2.2.5 Fault

In this case study, a single line to ground fault was applied for 20 ms to the downstream of the VR2. Voltage, current, real power, and reactive power of different PMUs are shown in the following figures.

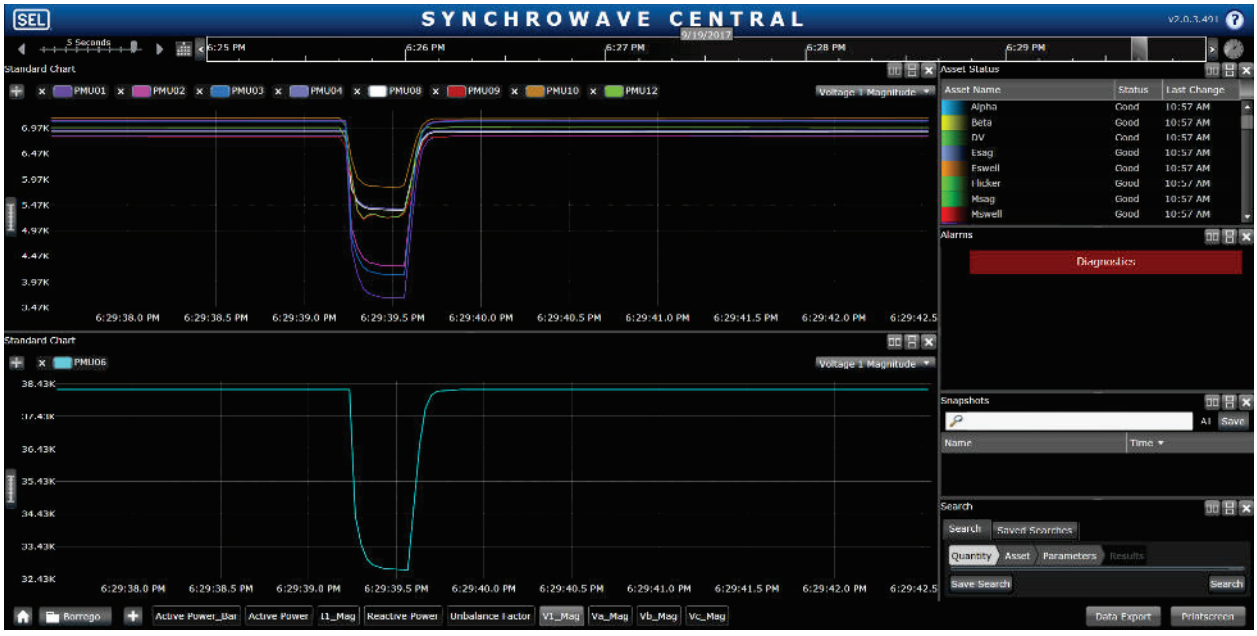


Figure 4-75. Magnitude of Positive Sequence Voltages

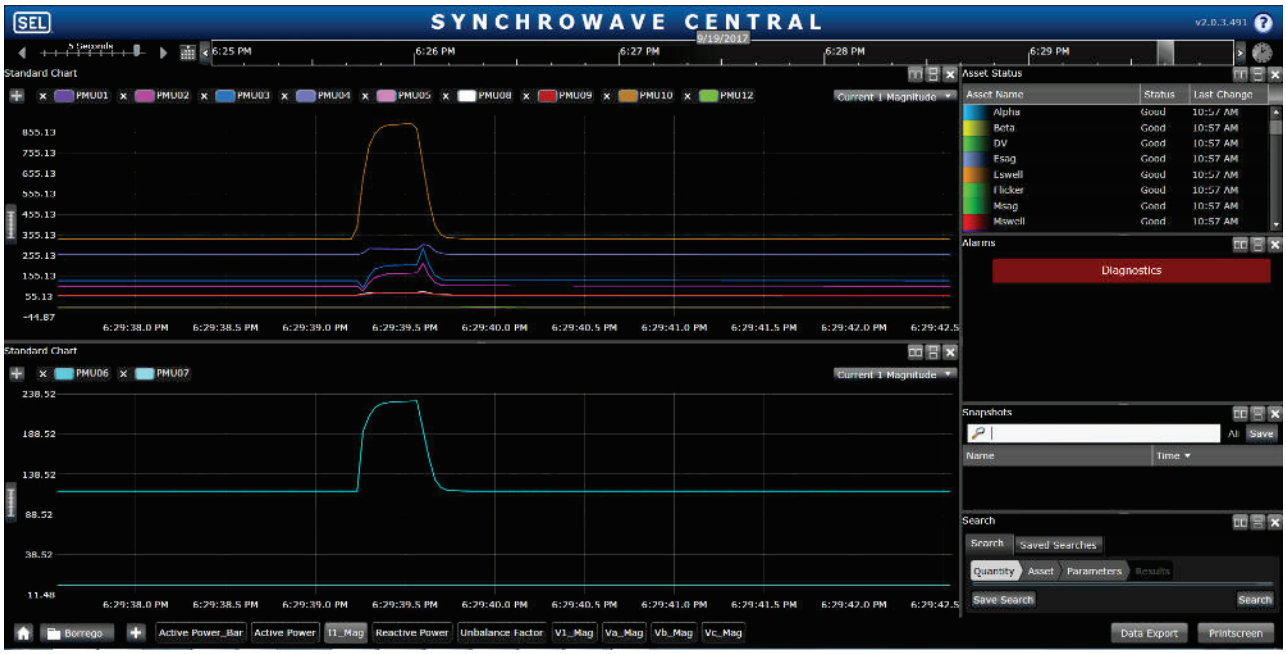


Figure 4-76. Magnitude of Positive Sequence Currents

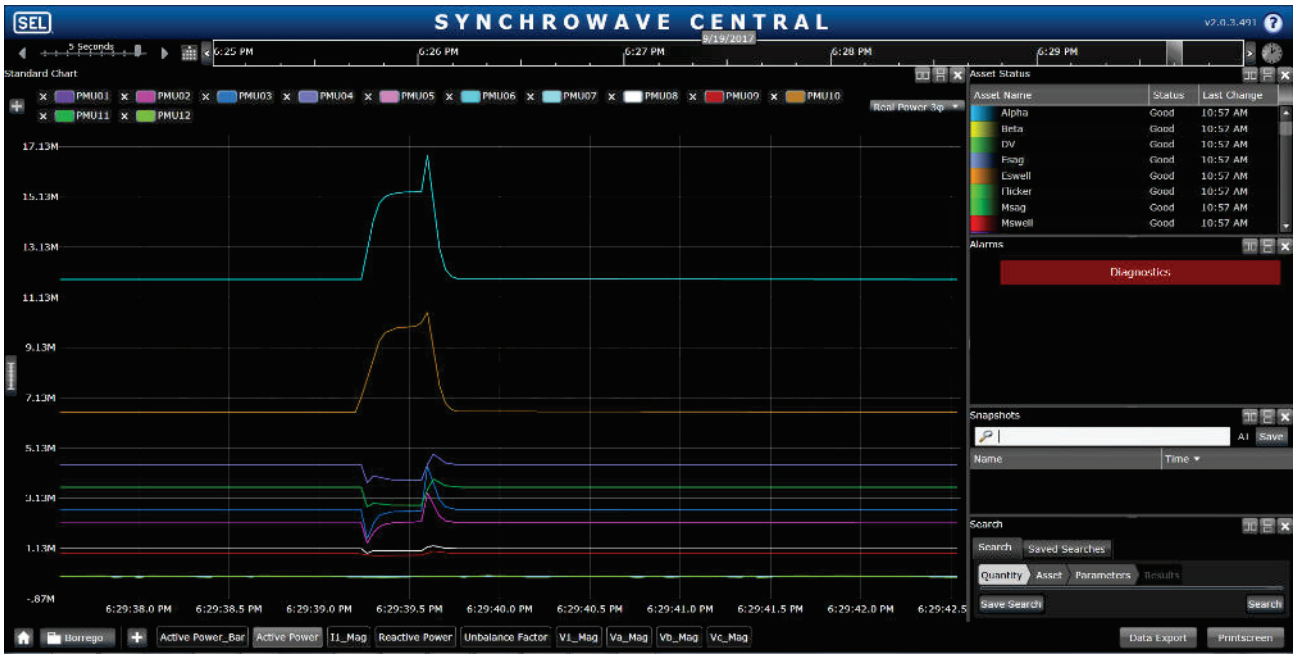


Figure 4-77. Active Powers

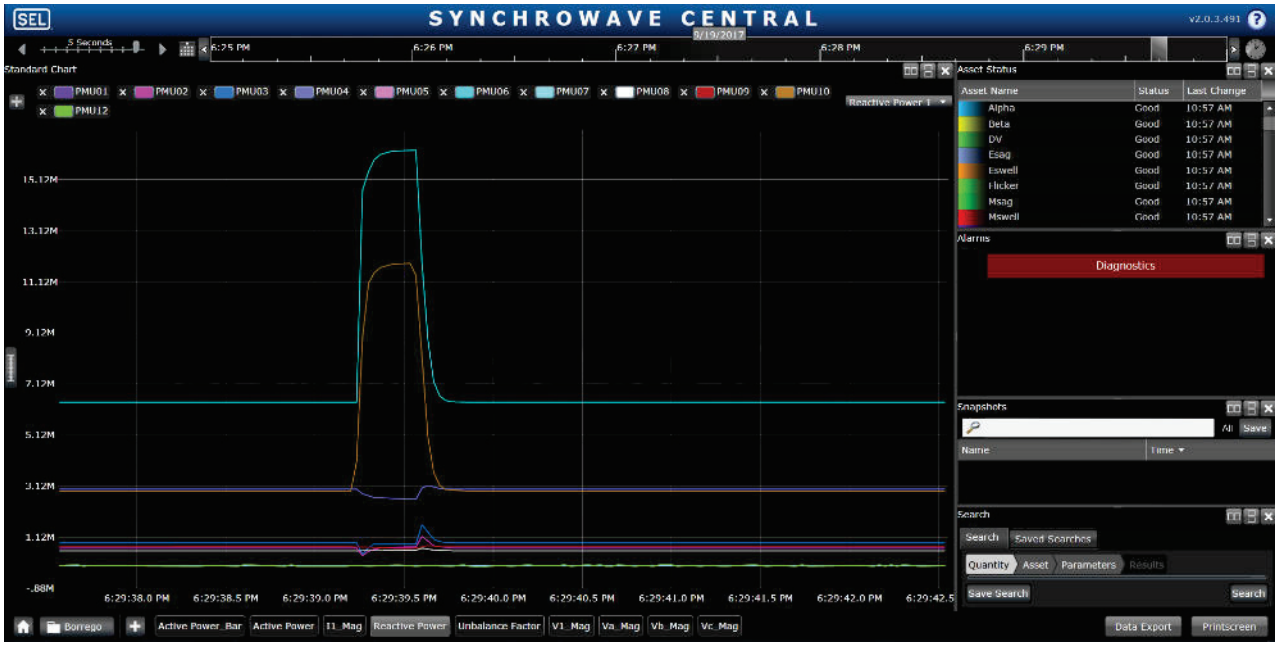


Figure 4-78. Reactive Powers

4.2.2.6 Capacitor Switching

In this section, the capacitor switching in Circuit 2 and Circuit 3 is investigated in two separate test cases.

In the first test case, the capacitor switching in circuit 3 is studied. Initially, CBC372 and CBC198 were open. The sequence of actions and the real/reactive power of the circuit breaker CB171 are summarized in the following table.

Switch Status	Real Power (MW)	Reactive Power (MVAr)
Open CBC372 / Open CBC198	6.758	2.210
Close CBC372 / Close CBC198	6.773	-0.050
Open CBC372 / Closed CBC198	6.750	1.050
Closed CBC372 / Open CBC198	6.763	1.101
Open CBC372 / Open CBC198	6.756	2.210

The following figures show voltage and real power of different PMUs. It can be seen in Figure 4-80 that when both of the capacitors were switched on, the losses in the circuit 3 was maximum.

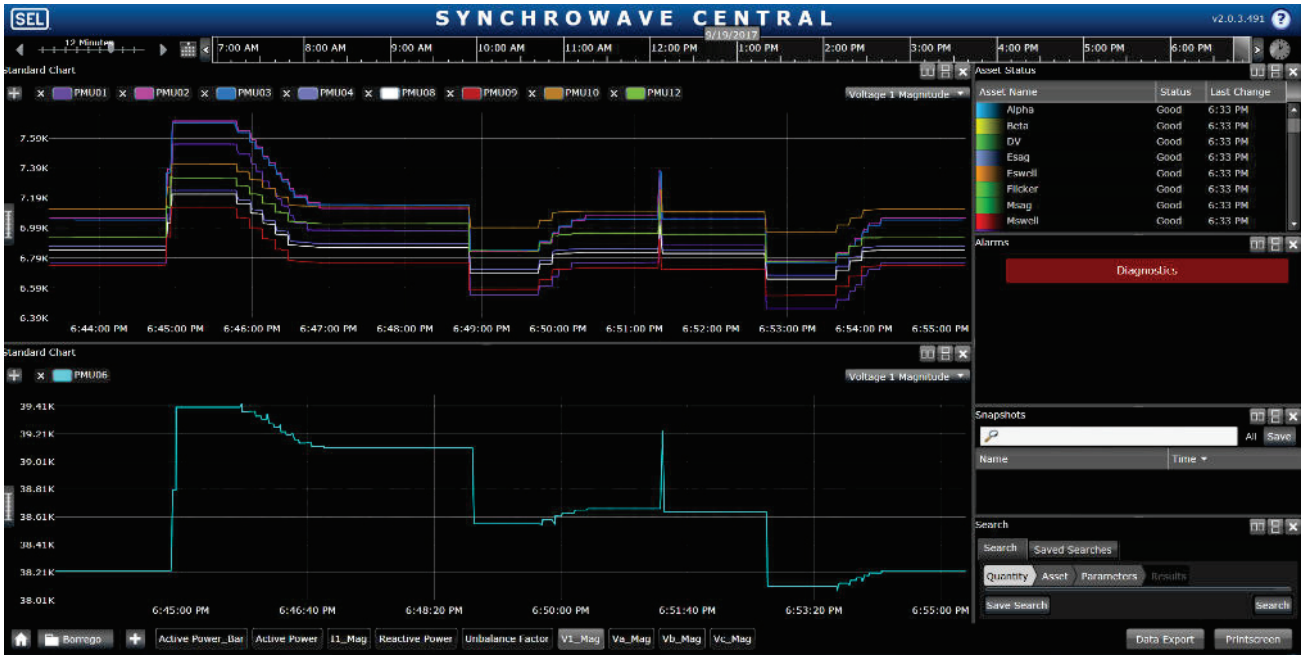


Figure 4-79. Magnitude of Positive Sequence Voltages

The step changes in voltages caused by variations in tap positions are clearly observable from the results.

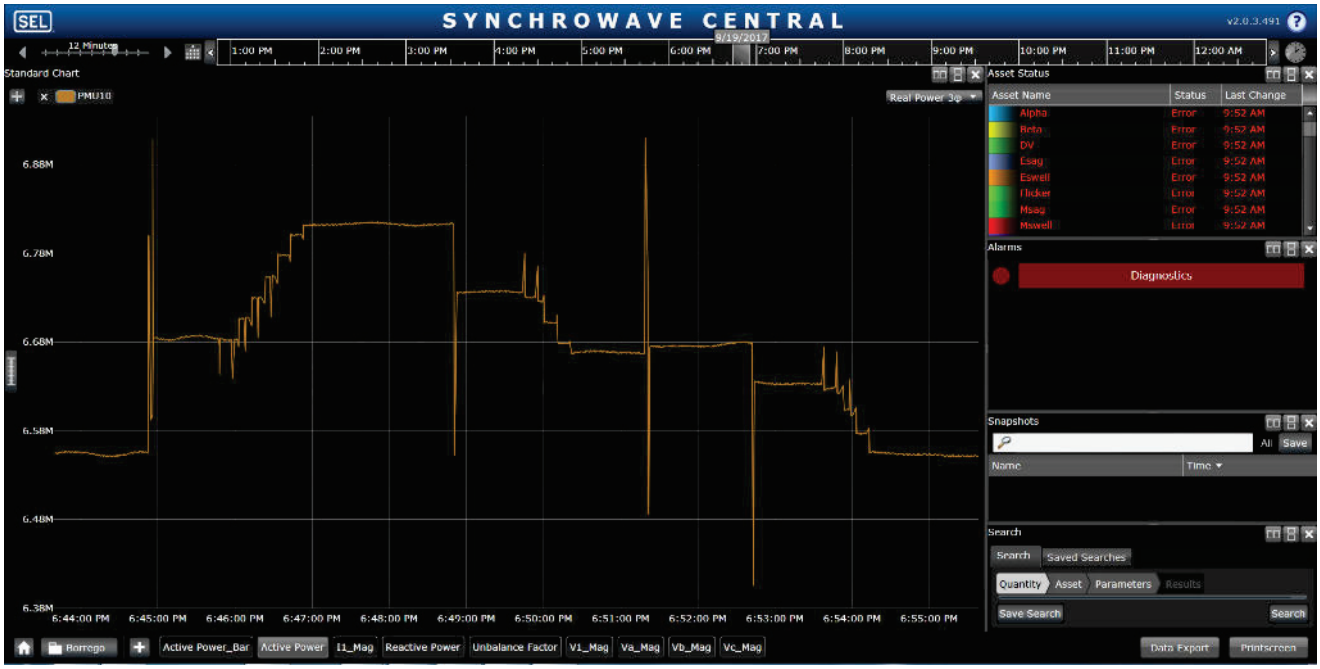


Figure 4-80. Real Power of PMU 10

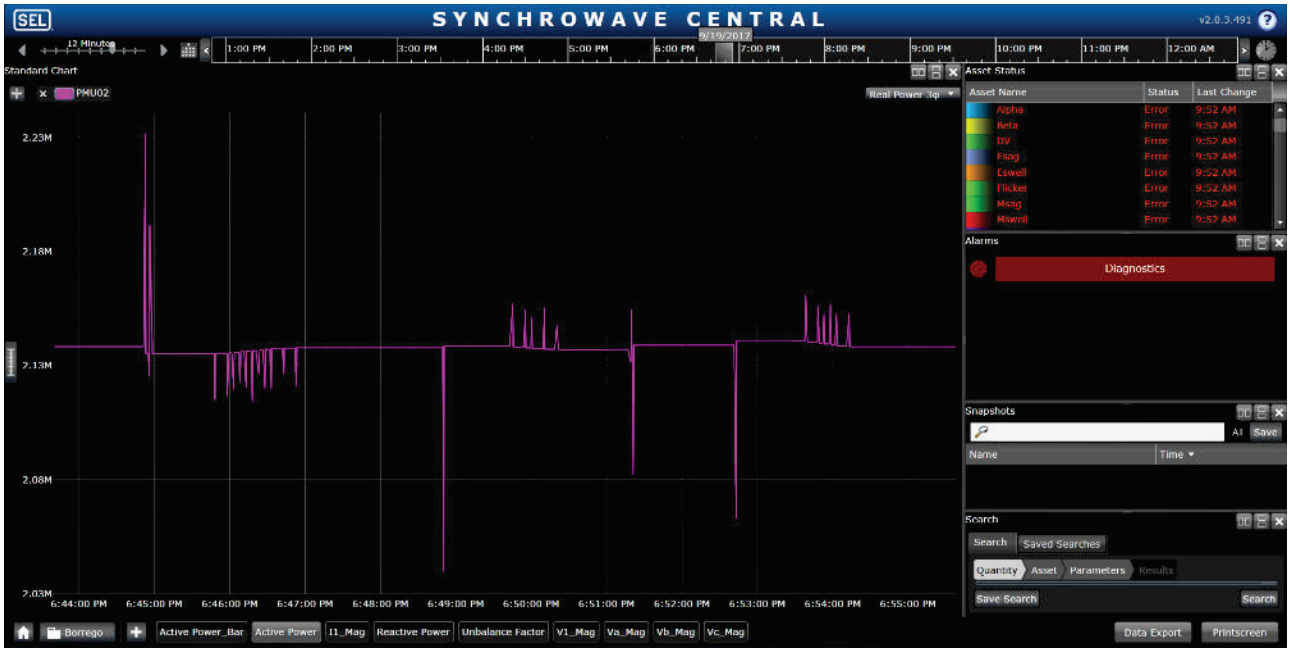


Figure 4-81. Real Power of PMU 2

Although the tap position changes are observable in the real power screen, power flow screens are not generally the best visualization screen for detecting and analyzing these events, since the impact is on voltages.

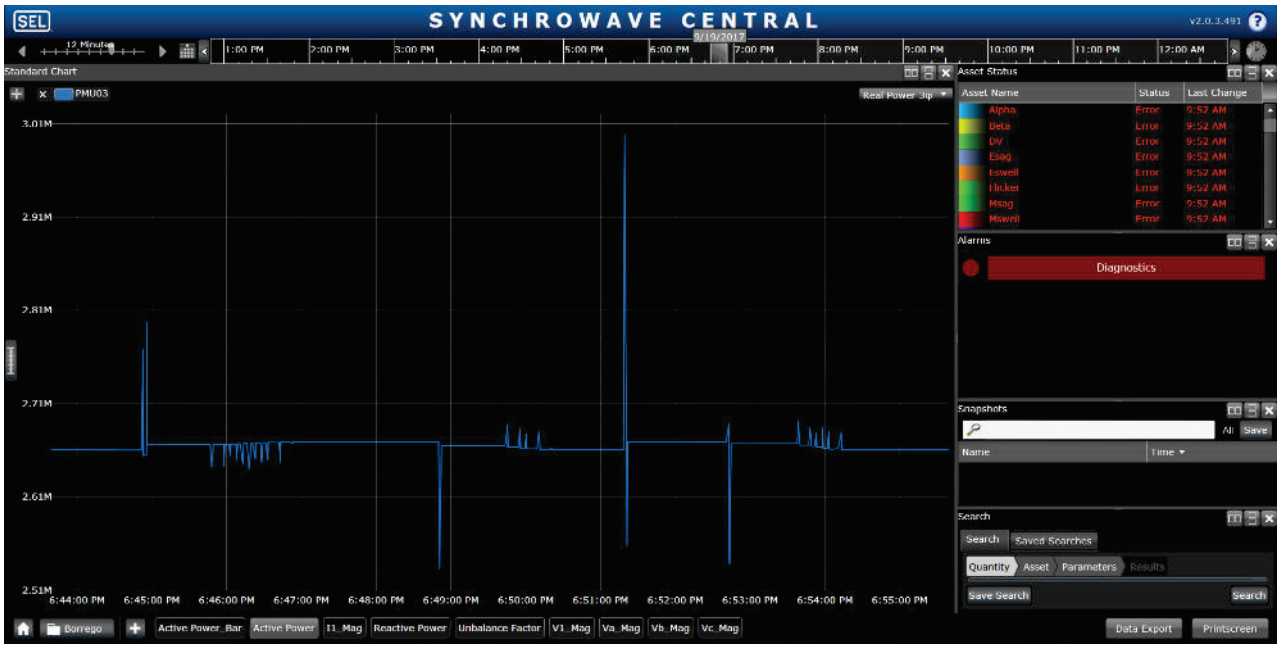


Figure 4-82. Real Power of PMU 3

A similar case study was performed for circuit 2. Initially, CBC393 and CBC17016 were open. The sequence of actions and the real/reactive power of the circuit breaker are summarized in the following table.

Switch Status	Real Power (MW)	Reactive Power (MVAr)
Open CBC393 / Open CBC17016	4.974	3.392
Open CBC393 / Close CBC17016	4.827	2.215
Close CBC393 / Close CBC 17016	4.806	1.004
Close CBC393 / Open CBC 17016	4.856	2.135
Open CBC393 / Open CBC17016	4.984	3.405

The following figures show voltages and real powers of different PMUs. It can be seen in Figure 4-84 that when both of the capacitors were switched on, the losses in the circuit 3 was minimum.

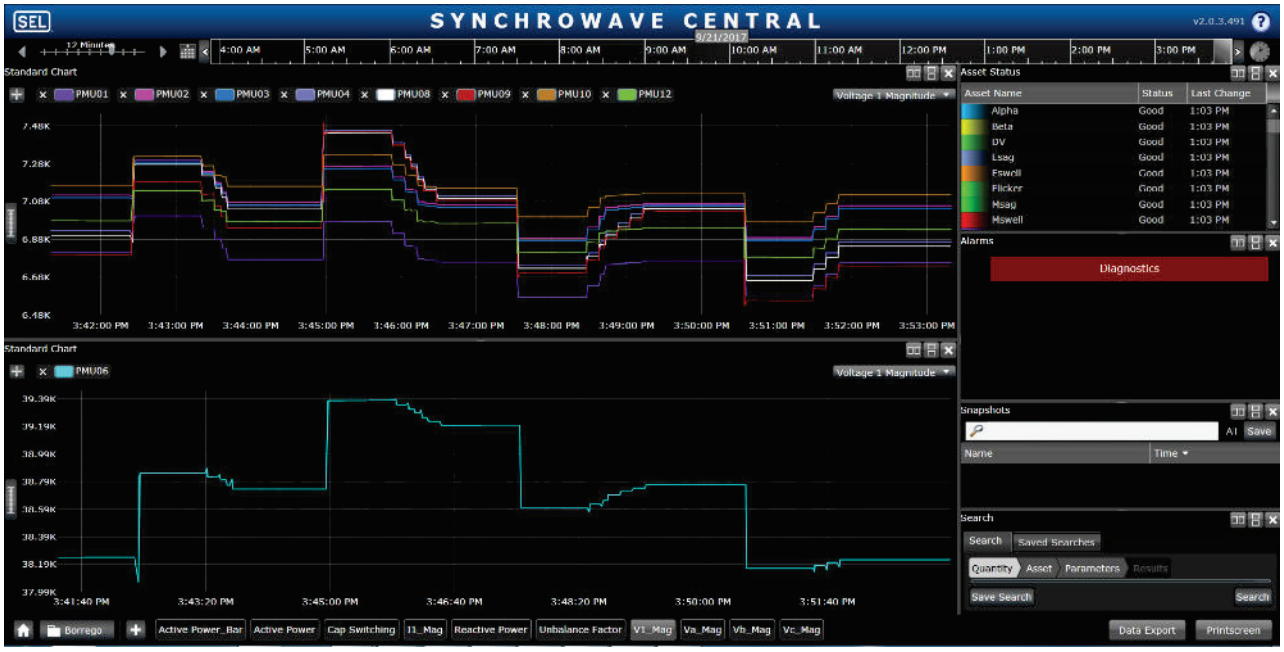


Figure 4-83. Magnitude of the Positive Sequence Voltages



Figure 4-84. Real Powers of PMU 4

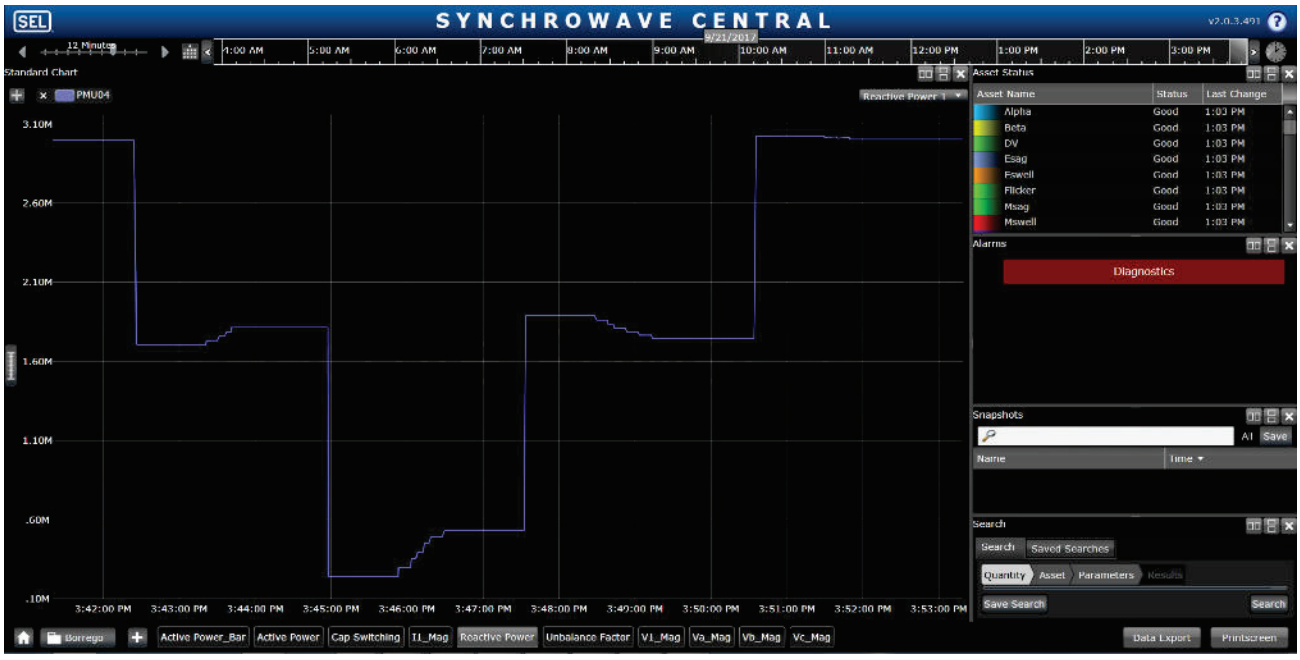


Figure 4-85. Reactive Powers of PMU 4

4.3 Use Case 6 (Circuit 4) – Water Treatment Facility Monitoring and Reactive Power Management

Following figure shows circuit 4 topology and location of the Water treatment plants (WTPs), line monitors (LMs) and switched capacitors. Due to the unavailability of the data for this circuit, one of the branches of the circuit 1 with PV is modified such that have similar behavior to the circuit 4 west branch.

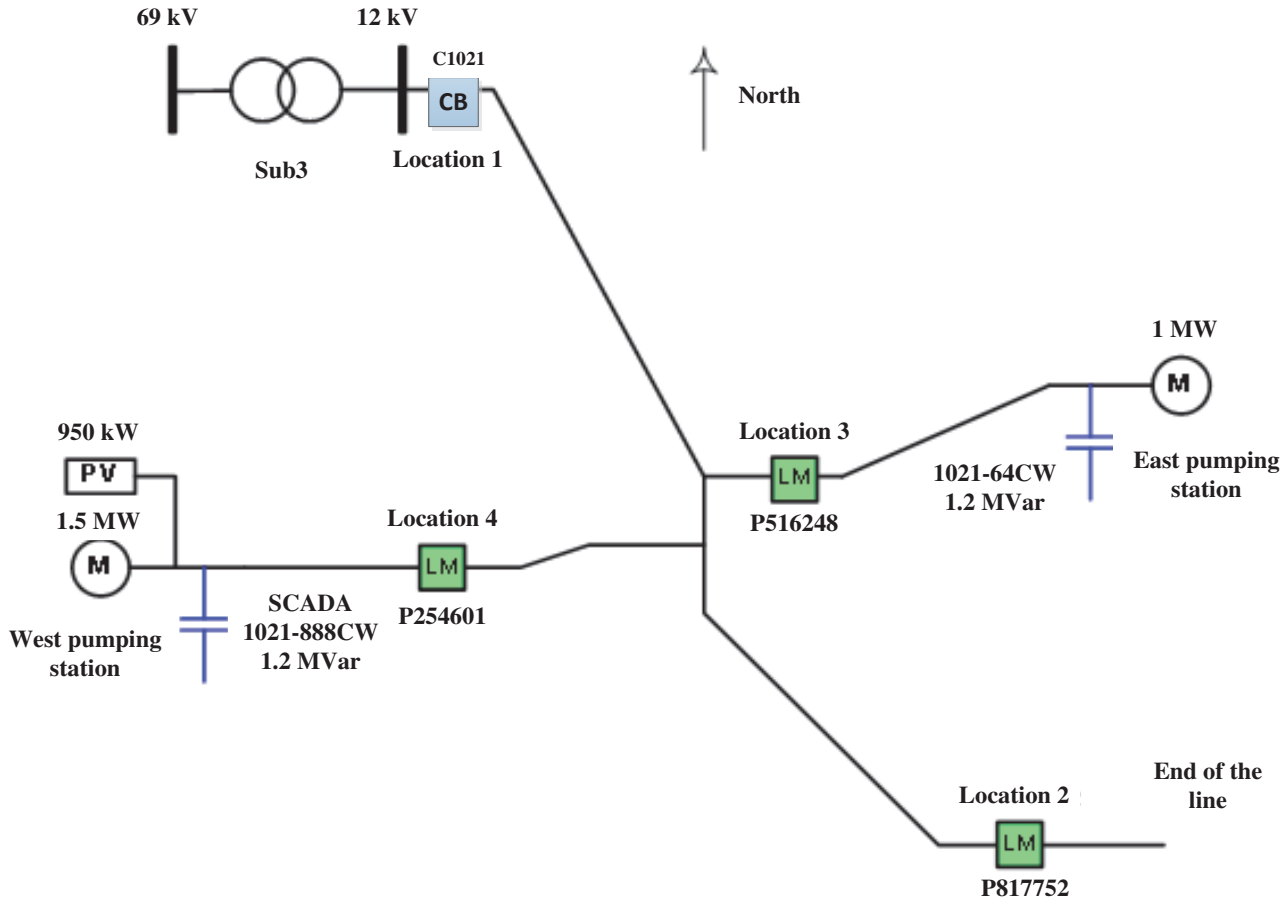


Figure 4-86. Circuit 4 Topology and Location of Line Monitoring (LM) Devices

The main objective of this use case is to coordinate and mange operation of large/critical industrial facilities such as Water Treatment Plants with the grid. The key operation aspects from the grid point of view are Real and Reactive power consumption. Specifically, for the reactive power management, the main value-added feature and advantage offered by the use case will be coordination of reactive power requirements from the plant with operation of shunt capacitors on the associated circuit feeding the plant.

The high-level sequence diagram for reactive power management application has been depicted Figure 4-87. The main approach is to observe the reactive power flow of the line through the PMU and switch in/out the capacitor banks (with a 15-second delay).

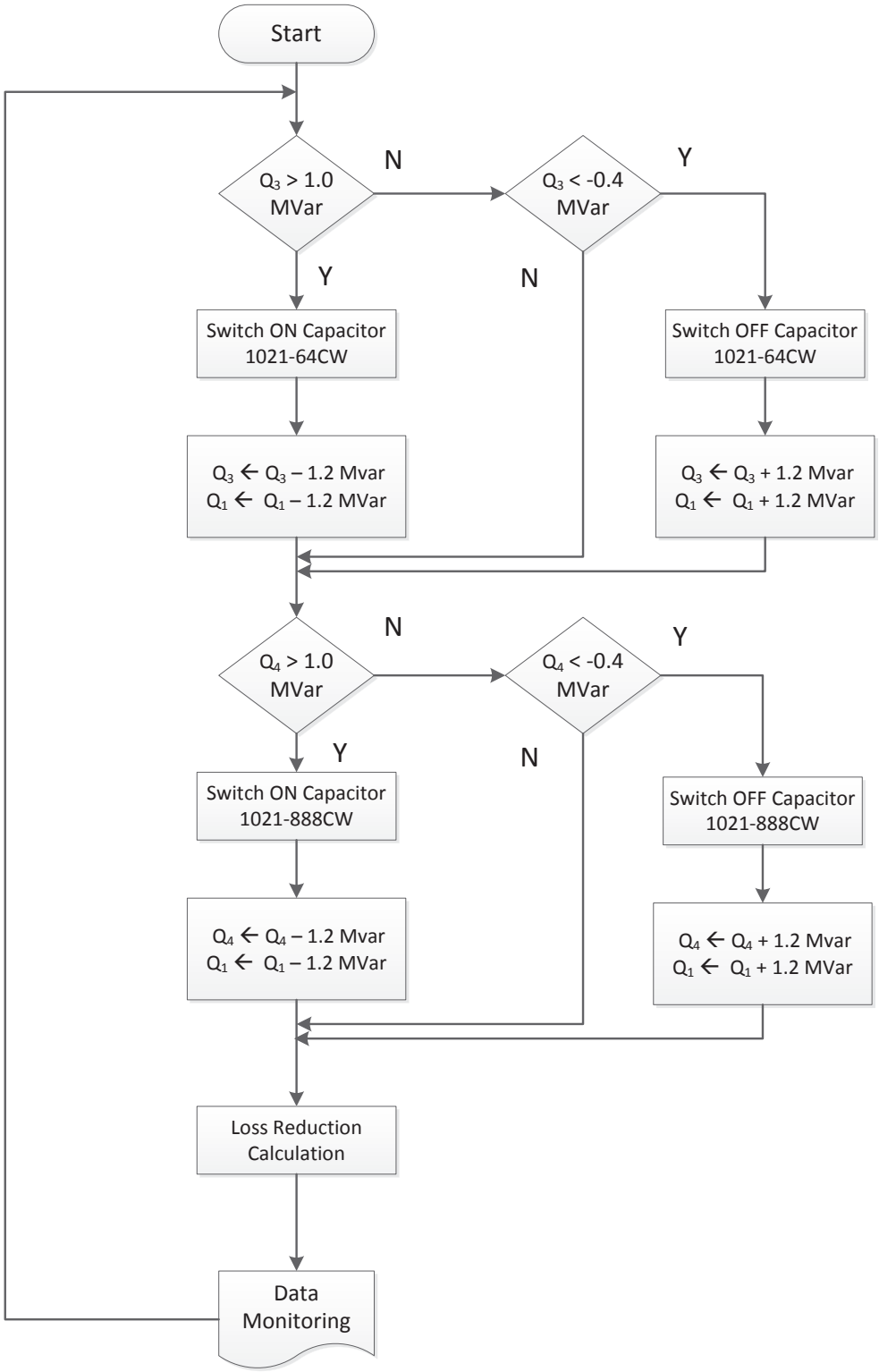

Start
Q_3 > 1.0 MVar
N
Q_3 < -0.4 MVar
Y
Y
N
Switch ON Capacitor 1021-64CW
Switch OFF Capacitor 1021-64CW
$Q_3 \leftarrow Q_3 - 1.2$ Mvar
$Q_1 \leftarrow Q_1 - 1.2$ MVar
$Q_3 \leftarrow Q_3 + 1.2$ Mvar
$Q_1 \leftarrow Q_1 + 1.2$ MVar
Q_4 > 1.0 MVar
N
Q_4 < -0.4 MVar
Y
Y
N
Switch ON Capacitor 1021-888CW
Switch OFF Capacitor 1021-888CW
$Q_4 \leftarrow Q_4 - 1.2$ Mvar
$Q_1 \leftarrow Q_1 - 1.2$ MVar
$Q_4 \leftarrow Q_4 + 1.2$ Mvar
$Q_1 \leftarrow Q_1 + 1.2$ MVar
Loss Reduction Calculation
Data Monitoring

Figure 4-87. A High-level Sequence Diagram for Reactive Power Management

4.3.2.1 Reactive Power Management without PV

For this test, initially, the load was 0.3 MW with the power factor of 0.8. Load was increased to 1.5 MW for 2 minutes and decreased back to 0.3 MW. The following figure shows voltage, active power, reactive power, and the loss of the line. It can be seen that when the load is increased, the reactive power observed by the PMU increased to 1.14 MW which is higher than the threshold; therefore, due to the defined logic, the capacitor turned on automatically after 15 seconds. Switching on the capacitor decreased the line loss by locally compensating the reactive power requirements.

Similarly, reactive power decreased to -1.3 MW after the load decreased to 0.3 MW. Because of the defined logic, the capacitor turned off automatically after 15 seconds. In this case, switching off the capacitor decreased the line loss to avoid overcompensation of the circuit.

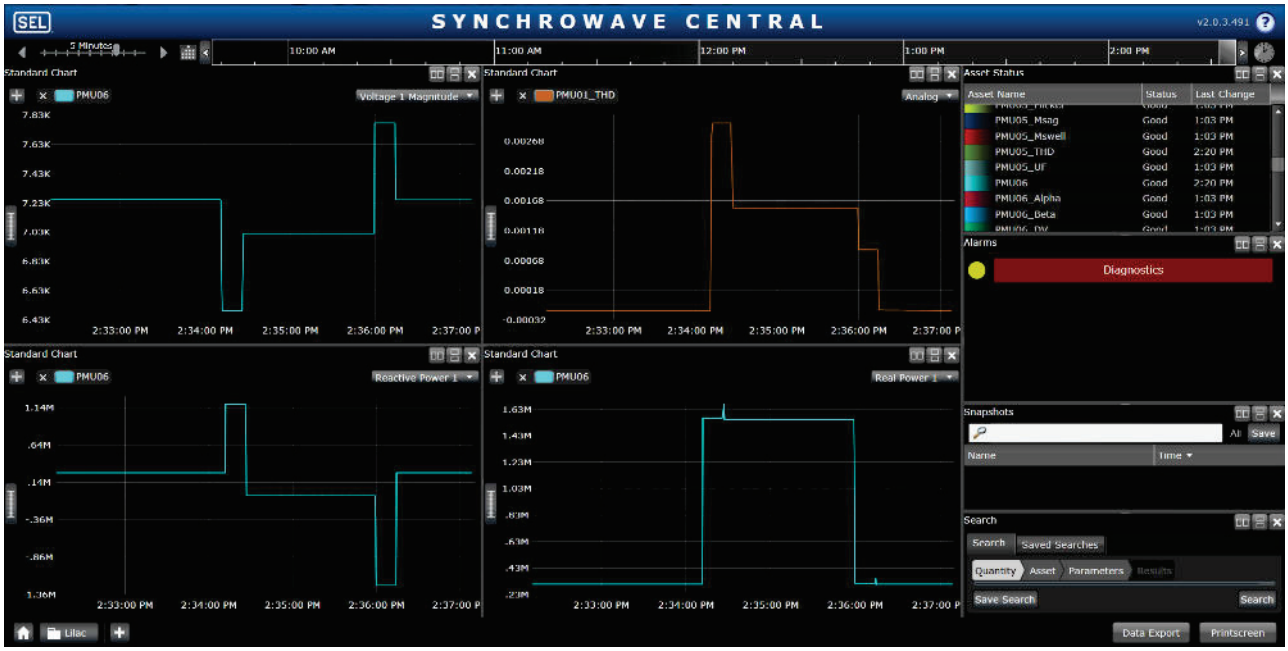


Figure 4-88. Voltage, Line Loss, Reactive Power, and Real Power

4.3.2.2 Reactive Power Management with PV

A similar test case was repeated with injecting 1 MW PV. It was observed from the following figure that the reactive power management along with local generation (PV) minimizes the line loss and improve the voltage profile. The test case confirms the effectiveness of the hybrid approach by utilizing both active and reactive power management of the customer load locally.

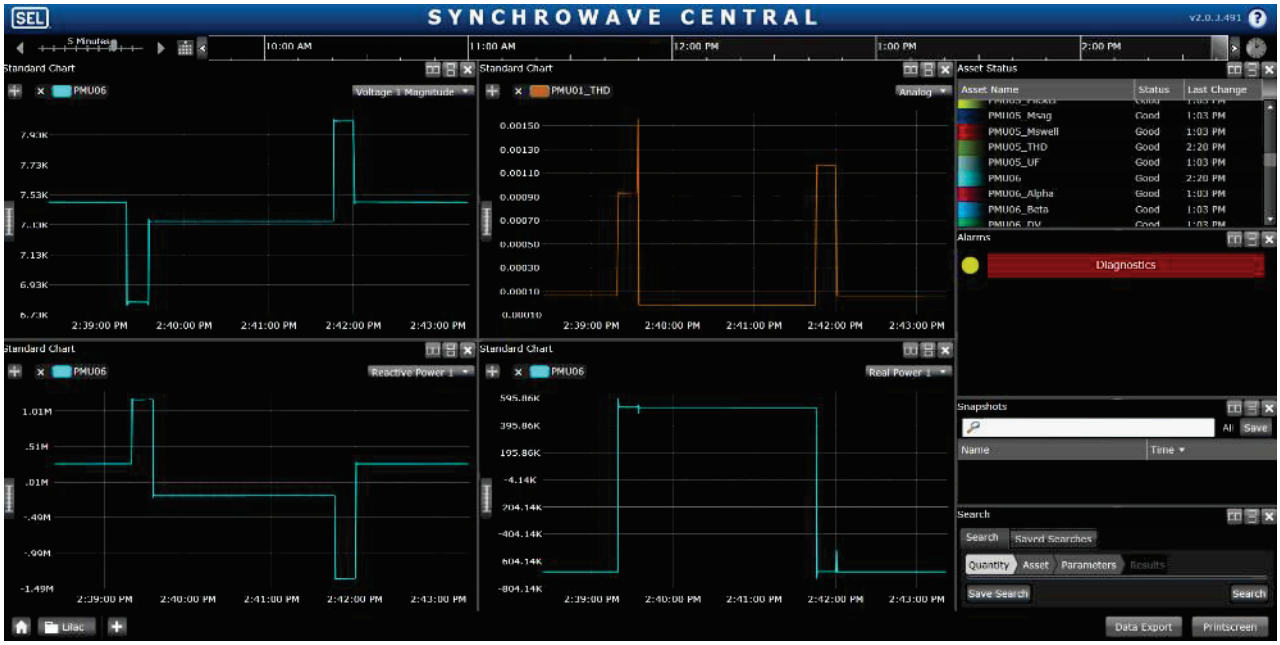


Figure 4-89. Voltage, Line Loss, Reactive Power, and Real Power

In general, the visualization screens were effective in detecting and analyzing various system disturbances. As observed, each screen and measured parameters or indices are primarily tailored for specific event detections and analysis. The combination of the proposed visualization screens and associated KPIs are needed to properly perform root-cause analysis.

5 Conclusions and Findings

This section provides a summary of key observations and conclusions from performing the pre-commercial demonstration of the monitoring and visualization technology, as well as analysis of the results and findings about the technology implementation and opportunities for system operation improvements.

5.1 Conclusions and Findings Related to Assessment of Integration and Monitoring Tools

5.1.1 Monitoring approaches

This project demonstrated new technologies and analysis methods for monitoring, visualization, and root-cause analysis of distribution systems by using various measurement techniques, data sources and integrating them in one platform to provide a unique monitoring and visualization user experience. In the advent of new customer technologies integrating with the utility systems, the proposed platform provides unique set of tools for distribution system operators and engineering analysis groups to monitor dynamic events, especially ones caused by varying characteristics of DER productions, loading effect of electric vehicle charging stations, and power electronic apparatus.

The novel concept of proposed visualization system is the ability of integration and utilization of multiple measurement platforms in one operation screen to achieve interoperability among various measurement tools and data format already exist for monitoring of customer systems and distribution systems. The key capabilities demonstrated included:

- Being able to monitor distribution assets in real-time, based on measurements received from PMUs, AMI system, Power Quality measurement devices, and SCADA system.
- Being able to tap onto historical data collected to playback and investigate events over extended period of time as selected and required by an operator or an engineer,
- Being able to view and analyze past events and to derive a range of parameters, key performance indicators, and more complex calculations or applications with the data to assist operators with analyzing behavior and health of distribution systems to make informed decisions.
- Providing a set of tools for pre/post event analysis based on various data types and sources; this can be used for root cause analysis, operator and engineers training, and assessment of operation and design procedures for new technologies and approaches.
- Demonstrating that the proposed monitoring, analysis and visualization system can be used as a base platform for further development of data analytics and real-time monitoring systems, as become required for monitoring and evaluation of newly introduced applications and integration of customer equipment.

It was also concluded that the laboratory setup prepared for integration and demonstration of use cases has clearly facilitated the troubleshooting and analysis of use cases and in performing what-if scenarios, and that would not be possible to accomplish using just data from the actual distribution systems.

5.1.2 Standards, tools and analysis approach applied

The approach for the pre-commercial system demonstration was to use the standard features and functions of the available, off-the-shelf products and to integrate them with existing tools to enhance and achieve the functional requirements for the proposed visualization system that was demonstrated. To achieve that goal, commercially available software and hardware products were used for the test setup. It was concluded that any measurements are available within the capabilities of existing feeder control and monitoring devices that can be used to define new indices and visualize performance aspects of the customer interconnections as parts of use cases. The simulations and test procedures provided successful demonstration of proposed visualization technologies in support of enhanced visibility in distribution circuits and defining greater analytical tools.

5.1.3 Technologies and performances of existing approaches

In the process of demonstration of the monitoring and visualization of measurement data extracted from actual selected distribution circuits, all available technologies present on the distribution circuits were used (e.g. PMUs, SCADA, historian, power quality monitoring). In the process of the circuit selection, in the system design phase (Phase 1 of the project) the objective was to select the circuits with rich set of measurement and control devices, with proper communication infrastructure, and presence of DER.

In cases where the selected circuit did not have sufficient number and type of devices needed to demonstrate some of the developed use cases, RTDS models were used to complement field data. For instance, for demonstration of the visualization capability for a Large Industrial Customer Facility (such as Water Treatment Facility) monitoring use case (Use Case 6), the focus was on reactive power management and flexible local generation use. However, the selected circuit (the Circuit 4) that served such a facility did not have proper communication and data measurement and streaming infrastructure completed at this time, so this use case was successfully demonstrated at ITF lab.

Based on the simulation results, it was concluded that additional values can be provided both to the customer and in enhancing of the circuit operation by closely monitoring and compensating reactive power during load fluctuations.

From the technology survey performed, it was concluded that several promising devices with promising technologies are offered by vendors in the present market that can be used for distribution systems. Selected set

of devices was exposed to a rigorous set of the tests (as part of type tests) and the results were quite extensively presented in this report.

From the type tests, it was concluded that although all devices meet the common requirements, defined by the standards (for instance, IEC 37-118 standard for synchrophasor technology), there were differences in their accuracy and available features in measurement quantities that are not commonly used in transmission systems. This finding suggested that there are further opportunities to improve measurement functions for the specific purpose of distribution systems.

5.1.4 Gap analysis and needs

Below is a list of key findings and conclusions related to the gap analysis and areas requiring technology enhancements by vendors:

- During project implementation, it was realized that one of the main barriers associated with PMU utilization is the insufficient communication infrastructure to stream data to control center at high bandwidth and resolution. In todays' utility environment, transmission PMUs don't have problems with communication systems; however, data streaming from distribution PMUs come across challenges such as packets loss and communication data quality. To achieve the full benefit of the system, it is essential to ensure that a reliable communication infrastructure is available. To some extent, data buffering and data interpolation/extrapolation techniques can be applied to mitigate data loss; yet, the fast changing phenomena in new environments are unpredictable and hard to reproduce if actual data does not exist. In addition, enhancing the data processing of the devices can also support localized (device base) data analysis to avoid transferring large amount of raw data to the control centers.
- Dealing with a new technology such as PMUs in distribution systems, it was noted that several commercial products and their features still require significant development and enhancement to meet certain characteristics of distribution systems. In addition, improper pairing and calibration issues of PMU IED along with the voltage/current sensors are more critical and difficult in distribution systems as compared to transmission systems, which adversely affect data quality.
- From the analysis, it was concluded that the phase angle differences across distribution circuits are usually less than 10 degrees; while typically the phase angle error of a physical PMU is around 1 degree to 4 degrees which is considerable (compared with 10 degrees); therefore, it is important to: 1) choose PMUs with proper calibration capability, and 2) calibrate PMUs along with other sensors in the field as part of periodical inspections.
- In one of the selected circuits for the demonstration of use cases (Circuit 4), there were several PMUs installed in the field whose data could not be accessed due to the unavailability of a PDC at the substation. This issue emphasizes the fact that for this technology to be utilized many components are re-

quired to work together in various environments, inside and outside of substations and/or control center. Possible solutions were identified and discussed including standardization of the PMU infrastructure installation and possible data sharing among adjacent substations to facilitate the data concentration and transfer to control center.

- During the project, an event viewer for capturing and analyzing voltage sag and swell of various durations and nature was introduced. This event viewer was proven to be very helpful in identifying and resolving issues with malfunctioning field devices as well as visualizing many events that would not be readily reported by typical SCADA systems and power quality devices. The root-cause analysis was performed by analyzing the data from PMUs in the vicinity and comparing the measurements versus expected outcome. In the absence of a field-base device calibration process, it was concluded that the viewer has the potential to be used as a common tool and component of monitoring platforms for distribution systems.
- During this project, a tap position counter and operation tracker was proposed and demonstrated to monitor performance of voltage regulators in the field. It was concluded that this approach can be utilized as part of field device performance monitoring process to identify the potential wear and tear of the voltage regulators due to frequent tap changes. The approach was proposed as a practical method for identifying and analyzing root causes of the frequent tap changes to manage maintenance aspects and to achieve expected asset life.

5.1.5 Deployment and operational challenges

The main findings were:

- To achieve full benefits of deployment of advanced monitoring and visualization technologies such as the ones proposed and demonstrated during this project, it is necessary to have a measurement, control and communication infrastructure that can reliably handle and support streaming of large amount of data at high resolution with minimum downtime.
- It was concluded that, due to the fact that most PMU technologies are primarily targeted for transmission applications, available PMU devices have limitations for distribution system use. They do not provide a complete set of measurement parameters and indices desirable for distribution system monitoring and analysis. Custom design codes and schemes at PDC level or the post processing of data will be required to calculate and provide indices and statistical data that are readily useable by the engineers.

5.2 Findings Related to the Demonstrated Technology

This section provides findings and conclusions related to prospective adoption of the demonstrated system.

5.2.1 Scaling and large-scale deployment

The main findings were:

- At present, the pre-commercial system was demonstrated with data and measurements from two circuits and a handful of PMU devices. However, based on the amount of data processed and the capability of the visualization tool to incorporate large number of measurement devices, it was determined that system can be scaled up and various data sources can be incorporated.
- The scaling-up can be tested in the simulated environment with the test setup at the laboratory; however, most likely additional enhancement of the lab setup will be needed to also incorporate representation of large scale communication systems with mixed media in a meshed network architecture, to reflect the data traffics and possible latency that can be expected in large scale deployment.

5.2.2 Business considerations

- The proposed monitoring and visualization system was developed with two groups of users in mind, namely, a) distribution system operators, and b) engineers and technicians involved in the event analysis and root-cause assessment of system issues.
- The new monitoring and evaluation schemes could be used for enhancement of the operations by providing additional means of awareness about the system behavior. To bring the technology in the control room and to put it in operational use, a production version needs to be developed; additionally, the GUI needs to be customized to meet operators' needs; operation procedures and training are necessary.

6 Recommendations and Next Steps

The project recommended and demonstrated an advanced monitoring and visualization platform for increasing the visibility into distribution systems to facilitate integration of customer equipment in a safe and reliable environment. The combined utilization of field data monitoring and visualization, and using the simulation environment (in this case the test setup developed at SDG&E Integrated Test Facility) were introduced to model, test and demonstrate some of the features and applications that cannot be demonstrated by using actual field data, due to the limited field data availability and/or limited ability to run into events or create phenomena such as faults, transient changes, circuit reconfigurations, and equipment failure.

Below is a list of key recommendations to further enhance the demonstrated monitoring and visualization technologies in support of enabling distribution system monitoring and visualization beyond substations and to get the monitoring technology ready for utilization by operators and engineers:

- Develop a strategy and technology roadmap to bring the technology into control center to be used by operator as a production level tool. This roadmap should address improvement of existing platform and application and development of new applications, infrastructure and procedures to bring it to operations and the control room and to streamline its use by engineering and planning groups.
- Specify the requirements for new measurement devices, such as distribution PMUs that can provide power quality measurements, in addition to existing standard features.
- Conduct business case analysis to justify cost benefits for various implementation scenarios. PMU in distribution system is an emerging technologies and require involvement from various utility groups and stakeholders to properly define and assign values on the use cases. The business case should consider combination of use cases that provide most value to a larger group of stakeholders. Many root-cause analysis aspects of the proposed technologies may not be readily understood by operators and engineers.
- The project team interacted with many stakeholders, engineers and potential users of the proposed monitoring and visualization system. The application and visualization matrix proposed in the project was shared and discussed to ensure capturing the needs of various groups and common daily operators and engineering activities. It is recommended to further enhance the functional requirement matrix by getting feedback from other departments and by surveying similar approaches used by other utilities. This survey can be later used for developing PI Coresight screens based on the needs of those groups.

6.1 Recommended next steps

To further enhance the demonstrated technology and to resolve some of the accuracy and calibration issues of the commercial PMU devices, it is recommended to share the PMU functional requirements for distribution

systems monitoring, and results of the type tests from the project, with vendors interested to enhance the technology. The lack of understanding related to the use cases and measurement approaches for distribution system were associated with some of the accuracy problems observed, which provides areas for future industry collaborations.

It is recommended to work with qualified vendors to develop a portable PMU calibration test equipment for use in the field. The pre-commercial demonstration of the monitoring and visualization technologies showed that periodical testing and calibration of the PMU based devices are essential to avoid large inaccuracy and erroneous measurements. However, for performing the calibrations in the field proper test equipment and testing procedures will be required to safely and accurately test and calibrate devices.

It is recommended to work with standard development agencies and working groups to publish and incorporate some of the findings of and measurement approaches proposed in the project in the distribution PMU guidelines and industry standards. From the type tests, it was concluded that although all devices meet the common requirements, defined by the standards (for instance, IEC 37-118 standard for PMU technology), there were differences in their accuracy and available features in measurement quantities that are not commonly used in transmission systems. This finding suggested that there are further opportunities to improve measurement functions for the specific purpose of distribution systems.

6.2 Adaptability to other utilities and/or the broader industry

It is anticipated that the visualization technology and advanced monitoring demonstrated in this project will be highly appealing to other utilities and beyond. Use of PMU in distribution systems is relatively new, and not many utilities have started to explore advantages and value offering of this technology. The widespread deployment of PV systems and exposing the system to new technologies installed by customers will change the dynamics of the distribution system to the extent that the SCADA system alone would not be able to provide all the information and data required for analyzing the system issues and for operating the system.

7 Metrics and Value Proposition

7.1. Metrics

The main focus of this project was on demonstrating new applications and methods for analyzing the impact of new customer systems on the utility distribution system. The project demonstrated an advanced monitoring and visualization platform that can support operators and engineering in managing the requirement of future complex systems.

The following metrics were identified for this project as potential metrics to consider project benefits at full scale. Given the proof of concept nature of this EPIC project, these metrics are forward looking. Sections 5 and 7 of this report outline the benefits that could potentially be gained from full deployment of this technology.

Table 7-1: Metrics for EPIC 2- Project 5
(Integration of Customer Systems into Electric Utility Infrastructure)

D.13-11-025, Attachment 4. List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation)	See Section
1. Potential energy and cost savings	
a. Number and total nameplate capacity of distributed generation facilities	See Sections 5 & 7
c. Avoided procurement and generation costs	See Sections 5 & 7
i. Nameplate capacity (MW) of grid-connected energy storage	See Sections 5 & 7
3. Economic benefits	See Sections 5 & 7
a. Maintain / Reduce operations and maintenance costs	See Sections 5 & 7
5. Safety, Power Quality, and Reliability (Equipment, Electricity System)	See Sections 5 & 7
b. Electric system power flow congestion reduction	See Sections 5 & 7
c. Forecast accuracy improvement.	See Sections 5 & 7
e. Utility worker safety improvement and hazard exposure reduction	See Sections 5 & 7
i. Increase in the number of nodes in the power system at monitoring points	See Sections 5 & 7
7. Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy	

b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)	See Sections 5 & 7
d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360)	See Sections 5 & 7
f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360)	See Sections 5 & 7
j. Provide consumers with timely information and control options (PU Code § 8360)	See Sections 5 & 7

7.2. Value Proposition

Several value propositions of the demonstrated technology and methods introduced in this project are explained below.

7.2.1 Greater awareness about the system

A higher level of awareness and greater values for monitoring and analysis of the system is expected from a system that can utilize and process high resolution of measurement data, along with traditional SCADA type data and AMI data. Traditionally, there has been limitation on providing observability across the circuits (beyond substations). The proposed platform can combine data from various sources to report on power quality and operation of the devices.

7.2.2 Greater reliability

The proposed advanced monitoring and data processing platform utilizes various sources of data at the same time to calculate a series of performance indices for the operation and analysis of the system. Redundant data and combining data from various sources, not only increase the observability and deterministic aspects of the system, it also ensures that events can be analyzed and conclusions can be reached faster to make informed decision on various events, to either prevent a failure, or determine the root-cause in much faster fashion and resolve the stations.

7.2.3 Lower Costs in monitoring and control of the network

In the first glance, the proposed system may not look cost-effective, due to the emerging nature of the technology and the fact that a reliable communication system infrastructure is required to bring the high resolution data back to control center. However, the demonstrated technology enables many fast monitoring and control applications feasible that collectively the portfolio of projects can offer a very high benefit to cost ra-

tio. Several projects and applications should be analyzed and deployed together to ensure the best value propositions can be achieved from the projects.

7.2.4 Increased safety and/or enhanced environmental sustainability

Because the main focus on the proposed advanced monitoring and analysis system is on improving the system visibility and providing fasters and reliable methods for operating the system, safety and integrity enhancement of the system will be the main target. Fast actions are becoming possible based on processing and visualizing high resolution of field data. In addition, because the system becomes more observable, more customer system installation requests and interconnection applications can be processed to expedite the integration and increase the penetration levels.

8 References

[1] IEEE 1564-2014: IEEE Guide for Voltage Sag Indices.
[2] ITI (CBEMA) CURVE APPLICATION NOTE (http://.www.itic.org/technical/iticurv.pdf).
[3] IEEE 519-2014: IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems.
[4] IEEE 1100-1992: IEEE Recommended Practice for Powering and Grounding Sensitive Electronic Equipment.
[5] IEEE 1159-2009: IEEE Recommended Practice for Monitoring Electric Power Quality.
[6] IEEE 1453-2015: IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems.
[7] C. Trueblood, S. Coley, T. Key, L. Rogers, A. Ellis, C. Hansen, and E. Philpot, "PV Measures Up for Fleet Duty: Data from a Tennessee Plant Are Used to Illustrate Metrics That Characterize Plant Performance", IEEE Power and Energy Magazine, 11, 2013.
[8] IEEE 1366-2012: IEEE Guide for Electric Power Distribution Reliability Indices.
[9] https://cdn.selinc.com/assets/Literature/Publications/Technical%20Papers/6706_CatchingFalling_KG_20160215_Web3.pdf?v=20170706-140455

Appendix 13

EPIC-2, Project 5: Integration of Customer Systems into Electric Utility Infrastructure



EPIC Final Report

Program	**Electric Program Investment Charge (EPIC)**
Administrator	**San Diego Gas & Electric Company**
Project Number	**EPIC-2, Project 5**
Project Name	**Integration of Customer Systems into Electric Utility Infrastructure**
Date	**December 31, 2017**

Attribution

This comprehensive final report documents the work done in EPIC-2, Project 5.

The project team that contributed to the project definition, execution, and reporting included the following individuals, listed alphabetically by last name.

Internal SDG&E Staff:

Michael Espinoza
Frank Goodman
Kyle Kewley
Zoltan Kertay
Iman Mazhari
William O'Brien
Prajwal Raval
Subburaman Sankaran
Marvin Zavala-Iraheta

Quanta Technology:
Shadi Chuangpishit
Farid Katiraei
Dino Lelic
Baharak Soltani
Mehrdad Yazdanian

Executive Summary

This report outlines the work performed under EPIC-2, Project 5 on Integration of Customer Systems into Electric Utility Infrastructure.

Project Objective and Focus:
The primary objective of EPIC-2, Project 5 was to investigate and address the evolving gateway between customers and utilities to facilitate increase in reliable deployment of clean energy technologies to support distribution systems.

More specifically, the project focus was on performing pre-commercial demonstration of advanced monitoring schemes, root-cause analysis tools, and assessment methodologies for safe and reliable integration and interoperability of customer systems with the distribution system to improve power system operations and thereby increase ratepayer satisfaction and benefits.

Project Approach:
At the early stage of the project work, the project team held a series of meetings and fact finding workshops with various stakeholders from the operation and engineering departments within SDG&E. The main purpose of these sessions was to assess the present stage of monitoring and control system capabilities and to investigate gaps in existing tools and approaches (such as capturing and alarming of fast changing power system phenomena). In parallel, a survey of customer systems and technologies that are being deployed or expected to be integrated into the SDG&E distribution systems was performed. The survey targeted common technologies and customer initiatives to determine potential impact of those technologies on operation practices and integrity of the system.

The outcome of the above investigation and information gathering activities was used to develop functional requirement documents and to describe system specifications for control and monitoring schemes, based on data from phasor measurement units (PMU) in the context of Advanced SCADA Devices (ASD). The new requirements were discussed with both field/substation engineers and distribution operators to ensure they meet the day-to-day system operation needs. A combination of simulated data, historical data, and real-world data streaming, as applicable, was used to calculate indices and validate the analytical methods. Based on the demonstration results, dashboards and requirement documents were revised to reflect the finally agreed list of performance indices and data analytics that would be incorporated in the visualization tool and/or applied automatically in the real-time data processing.

Key Findings and Accomplishments:
The project demonstrated new technologies and analysis methods for monitoring, visualization, and root-cause analysis of distribution systems by using various measurement techniques, data sources and integrating them in one platform to provide a unique monitoring and visualization user experience.

The key system capabilities that were successfully demonstrated and validated were:

- Being able to monitor distribution assets in the field (outside of substations) in real-time, based on measurements received from PMUs, the AMI system, power quality measurement devices, and the SCADA system. The real-time data enabled power quality impact investigations.
- Being able to tap into historical data collected to playback and investigate events over extended periods of time as selected and required by an operator or an engineer. This approach resolved

major issues in previous systems dues to lack of proper time synchronization and difficulty of alignment of the data points from various devices.

- Providing a set of tools for pre/post event analysis based on various data types and sources; this feature was shown to be very effective for root cause analysis, training of operators and engineers, and assessment of operation and design procedures for new technologies and approaches.

As part of the demonstration, it was shown that there are many monitoring features and analysis capabilities that can be added to existing systems to greatly support the needs of operation and engineering users. New capabilities are essential for evaluating system performance and analyzing dynamic events associated with distributed energy resources (DER) and customer-introduced technologies. It was also found that there is a major need for introducing uniformly defined performance indices, monitoring features and power quality indices directly related to assessment of emerging customer technologies, beyond the capabilities of conventional SCADA systems.

Recommendations and Next Steps:

Key recommendations are:

- It is recommended to further validate the use of performance indices introduced in the project and further expand the list, based on proposing new use cases. The project introduced a series of monitoring parameters, operation indicators, and performance indices that can be utilized by system operators and engineers to assess the status of the system, identify the root causes of events, and make informed decisions.
- It is recommended to explore the applications of proposed system indicators and visualization dashboards developed in this project with other stakeholders beyond just distribution planners, protection engineers and system operators. The monitoring approaches have potential to provide detailed data and assessment means for groups such as reliability, substation engineering and automation engineers. Some aspects of the monitoring parameters and indices introduced in this project were unique (such as field total harmonic distortion (THD) measurements and/or use of phase angle in automatic load transfer schemes) and were proven to be very effective in detecting and unfolding the nature of specific fast dynamic events caused by new technologies. However, changes in operating procedures and distribution system standards will be required to bring those features to the real-world applications.
- This project evaluated several new methods of utilizing PMU data and functionalities offered with synchronized data streaming, including the use of analog and digital data transfer channels to monitor and transfer locally measured system parameters such as THD and tap counts. These features are expected to become more beneficial and effective in distribution systems. It is recommended to conduct a business case analysis for the new PMU data applications.

As a next step, it is recommended to provide training on the monitoring and analytical feature of the project to several distribution system operators and field engineers that are involved in day-to-day operation and root-cause analysis of the event to further gather their feedback and to validate the use of performance metrics. The additional discussions will also help develop a strategy and technology roadmap to bring various aspects of monitoring and visualization technologies introduced in this project into production level. This roadmap should address the improvement of the existing platform and application and development of new applications, infrastructure and procedures to bring it to operations and the control room, and to streamline its use by engineering and planning groups.

Table of Contents

EXECUTIVE SUMMARY ..... **III**

1 INTRODUCTION **1**

1.1 Project Objective 1

1.2 Issues/Problems Being Addressed 1

1.3 Project Approach 3

1.4 Major tasks, Milestones Achieved and Deliverables Produced 3

2 SYSTEM REQUIREMENTS AND EVALUATION **11**

2.1 Survey of Customer Systems and Their Impact on the Distribution Systems 11

2.2 Baseline Evaluation and System Characterization for Potential Targeted Circuits 17

2.3 Use Case Development 31

2.4 System Monitoring, Visualization and Analytical Application Requirements 31

2.5 Development of Monitoring, Control and Operation Practices in Support of Customer Installations 43

2.6 Demo System Setup and Customer System Integration 80

3 PRE-COMMERCIAL DEMONSTRATION RESULTS WITH FIELD DATA **85**

3.1 PI Coresight Screens 85

3.2 Real-time measurement examples 93

3.3 Visualization displays on the GIS map 96

3.4 Power quality monitoring examples 103

3.5 Key performance indices monitoring 105

4 PRE-COMMERCIAL DEMONSTRATION RESULTS BASED ON LABORATORY SETUP **106**

4.1 Circuit 1 Test Results 106

4.2 Circuit 2 and Circuit 3 Test Results 139

4.3 Use Case 6 (Circuit 4) – Water Treatment Facility Monitoring and Reactive Power Management 164

5 CONCLUSIONS AND FINDINGS **168**

5.1 Conclusions and Findings Related to Assessment of Integration and Monitoring Tools 168

5.2 Findings Related to the Demonstrated Technology 171

6 RECOMMENDATIONS AND NEXT STEPS 173

6.1 Recommended next steps 173

6.2 Adaptability to other utilities and/or the broader industry 174

7 METRICS AND VALUE PROPOSITION 175

7.1 Metrics 175

7.2 Value Proposition 176

8 REFERENCES 178

List of Figures

Figure 1-1. Project tasks structure 4

Figure 2-1. Existing PMU Locations on Circuit 1 and identifying monitoring areas with amount of PV 22

Figure 2-2. The single line diagram of a selected Circuit 1 with PMU locations (existing and recommended) 30

Figure 2-3. High-Level System Diagram and Data Flow for Visualization and Analytics Applications 35

Figure 2-4. Real-time RTDS View of the Distribution Circuit Used for Device Tests 46

Figure 2-5. PMU Testbed Setup layout 47

Figure 2-6. PMU Test Setup at the ITF lab 48

Figure 2-7. TVE, FE, and RFE Comparison for Nominal Voltage (Case 1-1-1) 50

Figure 2-8. TVE, FE, and RFE Comparison for 50% of the Nominal Voltage (Case 1-1-2) 51

Figure 2-9. TVE, FE, RFE for 130% of Nominal Voltage (Case 1-1-3) 52

Figure 2-10. TVE and Magnitude of the Positive Sequence Subsequent to the Disconnection of Phase B (Case 1-1-4) 53

Figure 2-11. TVE and Magnitude of the Negative Sequence Subsequent to the Disconnection of Phase B (Case 1-1-4) 54

Figure 2-12. TVE and Magnitude of the Negative Sequence (Case 1-1-7) 55

Figure 2-13. TVE and Magnitude of the Negative Sequence (Case 1-1-7) 56

Figure 2-14. Frequency, FE, RFE, and Angle Subsequent to the Step Change of Frequency from 59.7 Hz to 60 Hz (Case 1-2-2) 57

Figure 2-15. Positive Sequence Magnitude Subsequent to the Step Change of Frequency from 59.7 Hz to 60 Hz (Case 1-1-2) 58

Figure 2-16. Frequency, FE, RFE, and Angle Subsequent to the Step Change of Frequency from 61 Hz to 60 Hz (Case 1-2-5) 59

Figure 2-17. Positive Sequence Magnitude Subsequent to the Step Change of Frequency from 61 Hz to 60 Hz (Case 1-2-5) 60

Figure 2-18. TVE and FE during the Injection of 3% Magnitude of 5th Harmonic (Case 1-3-1) 61

Figure 2-19. TVE and FE during the Injection of 5% Magnitude of 5th Harmonic (Case 1-3-2) 62

Figure 2-20. TVE and FE during the Injection of 10% Magnitude of 5th Harmonic (Case 1-3-3) 63

Figure 2-21. TVE and FE during the Injection of Multiple Harmonics (Case 1-3-7) 64

Figure 2-22. Positive Sequence Magnitude and TVE Subsequent to Voltage Changes (Case 2-1-1) 65

Figure 2-23. Zoom-In Plot of the Positive Sequence Magnitude (Case 2-1-1) 66

Figure 2-24. Positive Sequence Magnitude and TVE of Voltage Subsequent to Load Changes (Case 2-1-2) 67

Figure 2-25. TVE, Phase, and Magnitude of the Positive Sequence Subsequent to Phase Angle Changes (Case 2-1-3). 68

Figure 2-26. Zoom-In Plot of the Phase and Magnitude of the Positive Sequence (Case 2-1-3) 69

Figure 2-27. Frequency, TVE, and RFE Subsequent to Frequency Ramp (Case 2-2-1) 70

Figure 2-28. Frequency, TVE, and RFE Subsequent to Frequency Ramp (Case 2-2-2) 71

Figure 2-29. TVE and FE Subsequent to Capacitor Switching (Case 2-3-1) 72

Figure 2-30. TVE of Voltage and Angle Subsequent to Single Line-to-Ground Fault (case 2-4-1) 73

Figure 2-31. TVE and angle subsequent to line-to-line fault (2-4-2). 74

Figure 2-32. FE and angle subsequent to line-to-line fault (2-4-5). 75

Figure 2-33. TVE, angle, and FE Subsequent to 3-Phase Fault (Case 2-4-6) 76

Figure 2-34. Voltage Magnitude during the Fault (case 2-4-6) 77

Figure 2-35. High level architecture for of the demonstration system 81

Figure 2-36. High level system architecture for integration and visualization of field data and information 82

Figure 2-37. Main visualization system implementation dashboard 83

Figure 2-38. Test System Single Line Diagram for laboratory testing 84

Figure 3-1. An example of a dashboard that utilize historical data base 85

Figure 3-2. Monitoring of voltage unbalance factor 86
Figure 3-3. THD measured at various locations of selected circuits (all three phase); source: SCADA 86
Figure 3-4. Harmonic distortion (time frame) at one of the switches on circuit 1 (obtained from SCADA) 87
Figure 3-5: Voltage difference (in pu) on Circuit 1 87
Figure 3-6. Active and reactive power flow for Circuit 1 88
Figure 3-7. Thermal loading asset monitoring on Main branch, Branch #1 and Branch #2 of the Circuit 1 89
Figure 3-8. Thermal loading asset monitoring for Circuits 2, 3 and 4 90
Figure 3-9. Active/Reactive power along Circuit 1 91
Figure 3-10. Overloading bar chart display for Circuit 1 based on PMU data 91
Figure 3-11. Tabular reporting of device loadings for Circuit 1 based on PMU data 92
Figure 3-12. Voltage deviations (from base voltage) in percentage along the selected circuit length (circuit 1) 93
Figure 3-13. Voltage phase angle in phasor time domain 93
Figure 3-14. Polar version of real time monitoring of voltage phase angles 94
Figure 3-15. Voltage magnitude of the Circuit 1 PMUs (standard view) 95
Figure 3-16. Voltage phase angle of the Circuit 1 PMUs (standard view) 95
Figure 3-17. Numeric display for selected PMUs 96
Figure 3-18. Total active power generated by PVs 97
Figure 3-19. Real time monitoring of customer loads 97
Figure 3-20. Monitoring of Tap changer status (left) and tap positions change over time (right) 98
Figure 3-21. Real-time monitoring of cap banks status 98
Figure 3-22. Demonstration of KPI monitoring 99
Figure 3-23. Sample of the captured voltage sag versus the acceptable thresholds and durations 100
Figure 3-24. Sample of captured voltage swell versus 100
Figure 3-25. Frequency violation monitoring 101
Figure 3-26. Power sensitivity trending for Circuit 1 102
Figure 3-27. Voltage monitoring demonstration – Use Case 1 103
Figure 3-28. Monitoring of odd/even harmonics 104

Figure 3-29. Visualization of total harmonic distortion (THD) on one of the selected circuits 104

Figure 3-30. Illustration of Flicker factor monitoring and visualization 105

Figure 4-1. Single Line Diagram and PMU Locations of the Circuit 1 107

Figure 4-2. Magnitude of Positive Sequence Voltages 109

Figure 4-3. Magnitude of Positive Sequence Currents 109

Figure 4-4. Phase Angles of Positive Sequence Voltages 110

Figure 4-5. Phase Angles of Positive Sequence Currents 111

Figure 4-6. Active Powers 111

Figure 4-7. Reactive Powers 112

Figure 4-8. Apparent Powers 112

Figure 4-9. Calculated Delta V (pu) in Automation Controller 113

Figure 4-10. Tap positions streamed through the analog value 113

Figure 4-11. Active Powers during Low Loading without PV and with a Tie Switch Opened 114

Figure 4-12. Phase Angles of the Two Sides of the 520-1048 during Low Loading without PV. 115

Figure 4-13. Active Powers after the Connection of the Maximum PV. 116

Figure 4-14. Phase Angles for the Two Sides of the 520-1048 after the Connection of the Maximum PV. 116

Figure 4-15. Active Powers after Closing 520-1048 117

Figure 4-16. Phase Angles for the Two Sides of the 520-1048 after Closing 520-1048 117

Figure 4-17. Active powers after the load transfer 118

Figure 4-18. Magnitude of the Positive Voltages during the Load Transfer (changes are shown by arrows) 119

Figure 4-19. Active Powers during the Load Transfer (time of change is shown by the arrow) 119

Figure 4-20. Tap Positions during the Load Transfer 120

Figure 4-21. Reactive Powers during the Load Transfer 120

Figure 4-22. Magnitude of Positive Sequence Voltages Subsequent to Capacitor Switching 121

Figure 4-23. Magnitude of Positive Sequence Currents Subsequent to Capacitor Switching 122

Figure 4-24. Reactive Powers Subsequent to Capacitor Switching On and Off 123

Figure 4-25. Tap Positions Subsequent to Capacitor Switching 123

Figure 4-26. Magnitude of Positive Sequence Voltages Subsequent to Adding Harmonic Voltage 124
Figure 4-27. THDs Captured by Different PMUs 125
Figure 4-28. Magnitude of Positive Sequence Voltages.....126
Figure 4-29. Demonstration of Changes in Alpha across the Branch without PV 127
Figure 4-30. Demonstration of Changes in Alpha across the Branch with PV 127
Figure 4-31. Change in Beta across the Branch without PV 128
Figure 4-32. Change in Beta across the Branch with PV 128
Figure 4-33. Magnitude of Positive Sequence Voltages.....129
Figure 4-34. Flickers Subsequent to the Capacitor Switching 130
Figure 4-35. Magnitude of the Positive Sequence Voltages 132
Figure 4-36. Magnitude of Positive Sequence Currents.....132
Figure 4-37. Extreme Voltage Sag Statistics 133
Figure 4-38. Magnitude of Positive Sequence Voltages.....134
Figure 4-39. Magnitude of Positive Sequence Currents.....134
Figure 4-40. Extreme Voltage Sag Statistics 135
Figure 4-41. Magnitude of Positive Sequence Voltages.....136
Figure 4-42. Magnitude of Positive Sequence Currents.....136
Figure 4-43. Magnitude of Positive Sequence Voltages.....137
Figure 4-44. Magnitude of Positive Sequence Currents.....138
Figure 4-45. Moderate Voltage Sag Statistics 138
Figure 4-46. Single Line Diagram and PMU Locations of Circuit 2 and Circuit 3 140
Figure 4-47. Magnitude of Positive Sequence Voltages.....141
Figure 4-48. Magnitude of Positive Sequence Currents.....142
Figure 4-49. Active Powers.....142
Figure 4-50. Reactive Powers 143
Figure 4-51. Active Powers of Different PMUs 144
Figure 4-52. Active Powers of Different PMUs Subsequent to the Closing of the Tie Switch 144

Figure 4-53. Active Powers of Different PMUs Subsequent to the Load Transfer 145
Figure 4-54. Active Powers of Different PMUs Subsequent to the Load Shedding 145
Figure 4-55. Magnitude of Positive Sequence Voltages, Capturing Exact Time of Load Transfer 146
Figure 4-56. Magnitude of Positive Sequence Currents 146
Figure 4-57. Active Powers 147
Figure 4-58. Reactive Powers 147
Figure 4-59. Active Powers of Different PMUs 148
Figure 4-60. Active Powers of Different PMUs Subsequent to Turning on the Generators 149
Figure 4-61. Magnitude of Positive Sequence Voltages during Islanding Process 149
Figure 4-62. Active Powers during Islanding Process 150
Figure 4-63. Frequency Changes during Islanding Process 150
Figure 4-64. Phase Angle Changes during Islanding Process 151
Figure 4-65. Active Powers of Different PMUs Subsequent to Turning on the Generators 152
Figure 4-66. Active Powers of Different PMUs after Load Shedding 152
Figure 4-67. Magnitude of the Positive Sequence Voltages 153
Figure 4-68. Active Powers 153
Figure 4-69. Reactive Powers 154
Figure 4-70. Phase Angle Changes during Islanding Process 154
Figure 4-71. Magnitude of the Positive Sequence Voltages 155
Figure 4-72. Unbalanced Factors 156
Figure 4-73. Magnitude of Positive Sequence Voltages 156
Figure 4-74. Unbalance Factors 157
Figure 4-75. Magnitude of Positive Sequence Voltages 157
Figure 4-76. Magnitude of Positive Sequence Currents 158
Figure 4-77. Active Powers 158
Figure 4-78. Reactive Powers 159
Figure 4-79. Magnitude of Positive Sequence Voltages 160

Figure 4-80. Real Power of PMU 10 160
Figure 4-81. Real Power of PMU 2 161
Figure 4-82. Real Power of PMU 3 161
Figure 4-83. Magnitude of the Positive Sequence Voltages 162
Figure 4-84. Real Powers of PMU 4 163
Figure 4-85. Reactive Powers of PMU 4 163
Figure 4-86. Circuit 4 Topology and Location of Line Monitoring (LM) Devices 164
Figure 4-87. A High-level Sequence Diagram for Reactive Power Management 166
Figure 4-88. Voltage, Line Loss, Reactive Power, and Real Power 166
Figure 4-89. Voltage, Line Loss, Reactive Power, and Real Power 167

List of Tables

Table 2-1. Key Performance Indices Considered on the Project 14
Table 2-2. Summary of New Technologies, Their Impact, and Parameters Utilized to Characterize Impacts 16
Table 2-3. Summary of Selected Circuit Status 18
Table 2-4. Circuit 1 Loading Condition 18
Table 2-5. Thermal Rating of Major Equipment on Circuit 1 (SDG&E data from SynerGI model) 20
Table 2-6. Thermal Rating of Conductors along Circuit 1 (SDG&E data from SynerGI model) 21
Table 2-7. List of Potential PMU Application in Distribution Systems 25
Table 2-8. Recommended Locations for PMUs for Various Classes of Applications 26
Table 2-9. Recommended Location of PMU Installations for Analyzed Circuits 28
Table 2-10. Measurement Parameters of Monitoring Schemes 36
Table 2-11. Indicators for Visualizing Data 37
Table 2-12. Key Performance Indices for Visualization of Field Monitoring 39
Table 2-13. List of applications based on use cases 40
Table 2-14. Available Phasors in Different PMUs 77

Table 2-15. Available Analog and Digital Data Streams in Different PMUs 78

Table 4-1: Interconnection System Default Response to Abnormal Voltages [IEEE 1547a] 131

Table 4-2: Interconnection System Default Response to Abnormal Frequencies [IEEE 1457a] 131

Table 7-1: Metrics and Value Propositions 175

List of Acronyms and Abbreviations

ACSR	Aluminium conductor steel-reinforced cable
AL	Aluminium
AMI	Advanced metering Infrastructure
ASD	Advanced SCADA Devices
CB	Circuit Breaker
CBC	Circuit Breaker
CBEMA	Computer Business Equipment Manufacturers Association
DAMD	Distribution Asset Operation monitoring and Diagnostics
DCI	Daily Clearness Index
DER	Distributed energy resources
DERICC	DER Interconnection Compliance
DMS	Distribution Management System
DQV-FM	Data Quality Validation of Field Measurement
DUT	Device Under Test
DVC	Dynamic Voltage Control
DVI	Daily Variability Index
DVR	Dynamic Voltage Regulator
EOLD	Equipment Overloading Detection
EPIC	Electric Program Investment Charge
FE	Frequency Error
FLISR	Fault Location, Isolation and Service Restoration
GIS	Geographical Information System
GUI	Graphic User Interface
HW	Hardware
IEC	International Electro technical Commission
IEEE	Institute of Electrical and Electronics Engineers
ITF	Integrated Test Facility
ITIC	Information Technology Industry Council Curve
IVVC	Integrated Volt VAR Control
KPI	Key performance indices
KW	Kilowatt
LGU	Local Generation Usage
LICFM	Large Industrial Customer Facility Monitoring
LTC	Load Tap Changer
ms	Milliseconds
MVAr	Mega Volt-Ampere Reactive

MW	Megawatt
NIST standard	National Institute of Standards and Technology
NMS	Network Management System
PDC	Phasor Data Concentrator
PMU	Phasor Measurement Units
PQ	Power Quality
pu	Perunit
PV	Photovoltaic
REC	Reclosers
RFE	Rate of Change of Frequency Error
RMS	Root Mean Square
ROCOF	Rate of Change of Frequency
RPM	Reactive Power Management
RTAC	Real-Time Automation Controller
RTDS	Real Time Digital Simulator
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SARFI	System Average RMS Variation Frequency Index
SCADA	Supervisory Control and Data Acquisition
SDG&E	San Diego Gas & Electric
SDGE	San Diego Gas & Electric
SDO	Standards Development Organizations
SEL	Schweitzer Engineering Laboratories
SEMI	Semiconductor Equipment and Materials Institute
TDD	Total Demand Distortion
THD	Total Harmonic Distortion
TVE	Total Vector Error
UPS	Uninterruptable Power System
VAr	Volt-Ampere Reactive
VFD	Variable-Frequency Drive
VPFM	Voltage and Power Flow Monitoring
VR	Voltage Regulators
WTP	Water Treatment Plant

1 Introduction

1.1 Project Objective

The primary objective of EPIC-2, Project 5 was to investigate and address the evolving gateway between customers and utilities to facilitate increase in reliable deployment of clean energy technologies to support distribution systems.

More specifically, the project focus was on performing pre-commercial demonstration of advanced monitoring schemes, root-cause analysis tools, and assessment methodologies for safe and reliable integration and interoperability of customer systems with the distribution system to improve power system operations and thereby increase ratepayer satisfaction and benefits.

To achieve the above objective, the key focus areas were:

- To demonstrate monitoring and visualization schemes for distribution operators, at higher resolutions and with more advanced functionalities as required for capturing and investigating fast dynamics in the system,
- To demonstrate integration and interoperability of customer systems with the distribution system with ability to monitor, visualize and respond to fast phenomena,
- To demonstrate monitoring systems with superior capabilities compared to conventional distribution SCADA monitoring systems, such as:
    - Higher resolutions, higher communication speed, higher bandwidth, and time stamping.
    - Combining multiple sources of data – all with common data format.
- To demonstrate advanced tools and techniques for monitoring and evaluation of customer technology integration.

In addition, the final results and observations from the pre-commercial system were used to provide recommendations for design of the next generation of advanced SCADA systems.

1.2 Issues/Problems Being Addressed

Reliable operation of modern power systems requires close monitoring of the system operating conditions. Until recently, the measurements were only provided by supervisory control and data acquisition (SCADA) system, including power flows and bus voltage magnitudes. Distribution SCADA does not cover all utility assets. As an example, line voltage regulators may not report tap positions or line voltages to SCADA. Conventional SCADA measurements are reported by exception and their time resolution is 1-2 seconds or slower (depending on communications performance and how many data points are pulled in one request).

AMI data recording only provides cumulative energy exchange data (consumption or production) and RMS voltage at 5 to 15 minute intervals at the meter level. Furthermore, AMI devices only monitor secondary systems (downstream of service transformers).

Therefore, fast dynamics and transient phenomena (such as transient switching) and almost any power quality impacts (i.e. harmonics and resonance-based instability) cannot be identified from conventional SCADA meas-

urements or AMI data. In order to address these shortcomings, an enhancement of existing technologies in the area of high-resolution monitoring, advanced visualization and fast controls will be needed to provide adequate tools for operators and system engineers to assess the fast dynamic events.

The deployment of phasor measurement units (PMUs) enables various applications with the use of synchronized measurements. A PMU installed at a node can make direct measurements of the voltage phasor of the bus and the current phasors of some or all its incoming/outgoing branches, based on the PMU available channels.

This project performed the following activities:

- Defining circuit candidate selection criteria and data gathering requirements that can facilitate project objectives in terms of design and development of the advanced monitoring, analysis and visualization
- Planning for the logistical aspects of field data gathering and building into the visualization tools
- Identifying the design and location selection requirements for possible additions to the field device population to increase observability
- Introducing data analytics, evaluation methodologies and metrics to assess the system performance in near-real time
- Laboratory testing and analysis of expected phenomena through simulations
- Evaluation of monitoring and control device capabilities and validation in the laboratory environment
- Enhancement of the visualization tools to incorporate proposed metrics and data analytics
- Preparation of test plans and determination of field conditions/durations for data gathering and demonstration
- Data analysis from the field
- Demonstration of applications and tools that can facilitate safe and reliable operation to mitigate any issue introduced by customer services
- Proposing operator control strategies for managing the circuits and customer systems via SCADA
- Demonstrating the methods through laboratory testing and/or applying in the field and gathering field measurements

In addition, the project incorporated considerations to address requirements to increase the reliability and enhance power quality of services to the customers. Some additional value-added propositions (Metrics) introduced for the project were:

- To expand distribution system control, monitoring and operation capabilities beyond conventional SCADA approaches to gain visibility and control on secondary networks
- To investigate advanced monitoring and visualization practices using high-resolution measurement and data analytics to provide tools and investigation methods for distribution system operators and engineers to capture, examine and react to fast dynamic events
- To facilitate superior customer involvement and deployment of renewable and sustainable technologies by providing the means for investigation of real-world impact of customer systems and high PV penetration cases on distribution system and utility assets
- To prepare requirements and introduced advanced tools for monitoring and visualization of the data and the results, as well as analytical applications for post-processing and performance evaluation in

close to real-time environment to support challenging work load of the system operator in new environment.

1.3 Project Approach

The preliminary part of the project covered the tasks associated with selection of project technical lead, the project team, development of project plan and selection of the contractor.

The technical part of the project was executed in two phases:

- **Phase 1** – Design pre-commercial demonstration system: in this phase of the project, a preliminary analysis was performed to evaluate the likely impacts of customer integration on distribution system operation; the system was characterized for potential targets and the system visualization and analytical applications requirements were identified. Monitoring, control and operation practices in support of customer system installations were developed and in the final stage, a demonstration system was designed.

- **Phase 2 –** Demonstrate an advanced customer integrating and monitoring system: The demo system designed in Phase 1 was implemented and integrated, and a pre-commercial demonstration was done. Based on the test results, the customer system integration was evaluated and a final report was prepared including the analysis results.

1.4 Major tasks, Milestones Achieved and Deliverables Produced

This section provides a detailed description of the work approach and methodology, and the required outcome and deliverables of each task.

The tasks associated with preliminary work were:

Preliminary Phase - Task 1 - Team Formation and Project Plan

The SDG&E EPIC program manager identified the technical lead for the project based on experience and technical expertise. Later, the internal project team was formed by identification of technical skills and expertise available within the organization. After forming the internal project team, the task to develop the project plan was given to the technical lead. The technical lead with the help of the project team wrote the project plan as per the guidance provided by the SDG&E EPIC program manager adhering to EPIC guidelines.

Preliminary Phase - Task 2 - Procurement of Contractor Services

Scope of the work was identified and written for the part of the project needed to be contracted out to engineering consulting firm. Standard company practices were followed for contractor selection.

The tasks associated with technical part of the project were divided in two phases as shown in figure below.

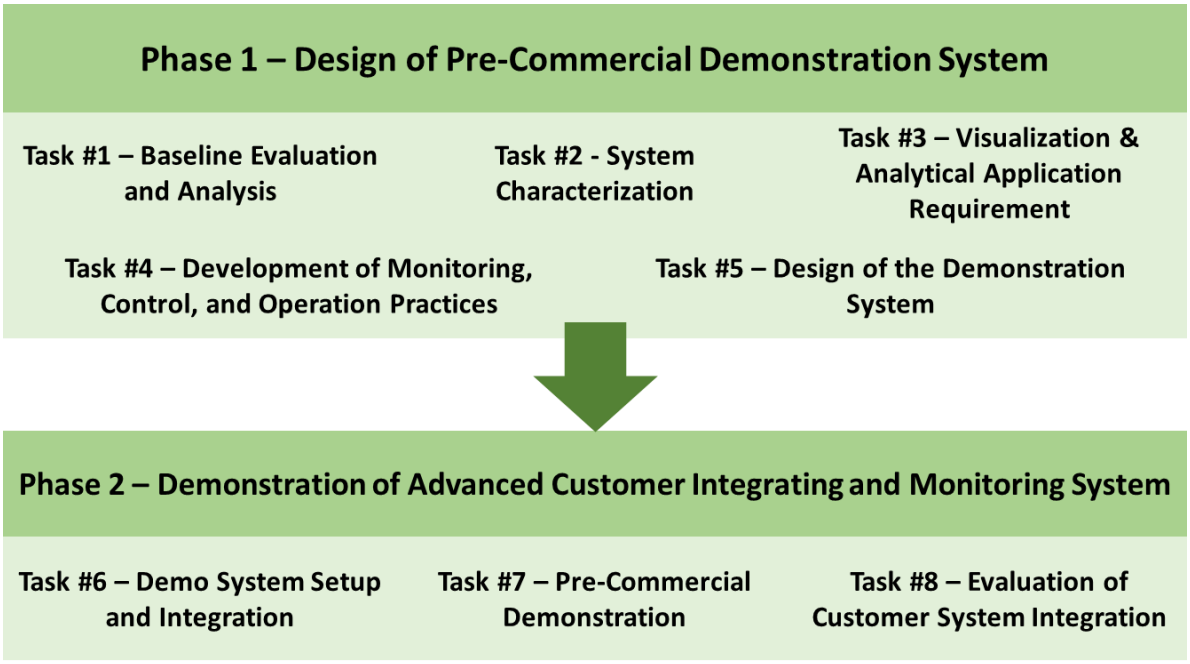


Figure 1-1. Project tasks structure

The following sections provide additional description of the technical part of the work, and details about the accomplishments with regards to the major milestones and deliverables.

1.4.1 Phase 1 – Design of pre-commercial demonstration system

Task 1 - Baseline Evaluation and Analysis

The objective of this activity was to assess the preset state of monitoring and control in distribution systems and analyze the impact of new customer technologies on the system.

A detailed list of activities performed in this task was:

- Performing a survey of customer systems and technologies that are being deployed or expected to be integrated into the SDG&E distribution systems
- Investigating impact on operation practices and integrity of the system due to new technologies and customer initiatives
- Determining the present state of the monitoring and controls, and the level of the visibility into customer systems, including:
    - Distribution SCADA measurement
    - AMI systems and data availability
    - PMU on distribution systems
    - Other sources of measurements
- Investigating the present status of PMU deployment on distribution systems at SDG&E, and select circuits with PMU and communications system in operation as the target circuits for enhanced monitoring and operation analysis. A list of criteria should has been developed for circuit/region selection. Ex-

ample factors in circuit selection were the available level of PV penetration and types of technologies deployed.

The outcome of this task was:

- Baseline review and assessment
- Preparing circuit selection criteria and list of candidate circuits for further analysis, simulation and integration.

Task 2 - System Characterization for Potential Target Circuits

The objective of this task was to evaluate data availability and system coverage from the potential target circuits. The evaluation will be used to proposed additional measurement and/or visualization capabilities to strengthen the visibility and control of the system. The main activities as part of this task were:

- Determine circuit loadings and amount of PV
- Identify the number and locations of PMU devices to determine the circuit coverage
- Prepare a circuit map showing all critical devices and customer installations
- Determine device settings and control modes
- Document any special operating procedures and circuit conditions that can benefit from enhance monitoring and near real-time controls
- Examine access to the devices and their control system connections
- Evaluate PMU data streaming and data availability, and logistic aspects of accessing data
- Examine access to non-PMU data from target circuit locations, including wideband power quality data snapshots and metrics
- Prepare a summary report on what the gaps in the measurement, monitoring and operation are when it comes to awareness and management of customer systems
- Evaluate the data streaming in to PI Historian and any other data warehouses and the linkage among databases

The outcome of this task was:

- Identification of existing data availability and gaps
- Recommendations for additional data requirements.

Task 3 - System Visualization and Analytical Applications Requirements

The task objective was to assess advanced visualization system capabilities, prepare functional specifications and identification of key needed applications and performance indices.

This task was addressed by conducting the following activities:

- Investigation of visualization methods to present the PMU data on circuit maps and to create graphical view of the system events and power quality issues based on performance indices:
    - Evaluating the capability that exists today and what needs to be developed or added to the visualization system,

- Identification of key applications (data analytics, statistical evaluation methods), and set of Key Performance Indices (KPIs) for power quality and operation performance monitoring:
    - Using simulation and/or historical data, as appropriate, to calculate indices and validate the analytical methods
    - Finalizing and documenting a list of performance indices and data analytics that will be incorporated in the visualization tool and/or applied automatically in the real-time data processing

The task outcome was:

- Visualization requirements and description of data processing applications
- Identification of key performance indices and targeted used cases.

Task 4 - Development of Monitoring, Control and Operation Practices in Support of Customer System Installations

This task objective was to propose and develop advanced monitoring and control practices that can close the gaps in the existing operation schemes to expand operator visibility beyond substations to support system impact assessments as part of the customer system integration process. The primary focus was on enhancing the system monitoring and operator's capability to characterize the system dynamics and to provide methods for fast data analysis and event diagnostics. The design incorporated all aspects of: system capabilities, monitoring devices and data capturing and post-mortem analysis. The main activities in undertaking this task were:

- Determining the response requirements and operational practices to support customer systems
- Defining the monitoring requirements and system architecture, including the communications and controls for advancement of system operation
- Investigating capabilities of commercially available sensors, power quality and/ revenue metering devices, and phasor measurement units (stand-alone or as part of other IEDs) that can provide high resolution data measurement and power quality data capturing and transient event recordings, such as:
    - Voltage and current phasors
    - Power flow (active and reactive)
    - Frequency tracking and reporting rate of change of frequency (ROCOF)
    - Harmonics and THD/TDD measurements
    - Fast transients
    - System status information, including switch position, voltage regulators tap positions, and
    - Circuit connectivity information
- Evaluating product capability documents from vendors; or perform laboratory tests on selected measurement devices (sensors, IEDs, PMUs) to determine accuracy, measurement resolution and quality and type of measurement data such as transient events, to understand and document expected device performance
- Defining PMU requirements specific to distribution systems
- Developing settings and configuration files for the devices in the field to support project data gathering and device control needs
- For cases of inadequate device capability and/or coverage, propose temporary methods and devices to be incorporated in the real-time simulation environment to supplement the existing devices and data coming from the field for the purpose of evaluating the tools under investigations.

The task output was:

- Outlining of the design and needed system development for the advanced monitoring, control and operation
- Evaluating the capabilities of selected devices (sensors, IEDs, PMUs) to measure transient events and power quality
- List of data and measurement points as the basis for the simulation system design.

Task 5 - Design of the Demonstration System

This task objective was to develop detailed plan and infrastructure for the demonstration system requirements for the purpose of verifying the advanced monitoring, visualization and customer integration practices. The design of the proposed demo system included:

- Demo system architecture incorporating both the field measurements and monitoring and the interfaces to a real-time simulation environment in the laboratory to provide additional data in support of full realization of the analytical schemes
- Documenting the requirements for demonstration system design
- Use cases for the customer system integration demonstration
- Identifying proper control algorithms for enhancing the safety and reliability of the system (control system validation will be performed on the real-time simulator)
- Integrating with existing monitoring and controls in the field to develop demo system platform
- Preparing high level interface descriptions for the proposed demo system.

The task output included:

- Demonstration system specifications
- Demonstration system implementation and field integration plan.

1.4.2 Phase 2 – Demonstration of Advanced Customer System Integration

Task 6 – Demo System Setup and Integration

This task was about implementation of the demonstration system that incorporates both remote monitoring and control of the selected devices on the SDG&E Distribution systems, as well as the real-time simulation of the same system in the laboratory environment for capturing and transferring additional measurement data to the visualization system and operator screens.

As part of this process the following sub-tasks were executed:

- Determination of type and availability (accessibility through remote control) of field power apparatus and emerging technologies (smart PV inverters, Dynamic VAR Controllers, BESSs. Electric vehicles, building automation and demand response programs) associated with the customer systems that can be incorporated in a demo system

- Determination of SCADA based control schemes (such as voltage/VAR control, fault locators, automatic load transfer schemes) on the selected circuits that can be used to create various pre-specified system changes and realistic operating scenarios:
    - Change in voltage profiles through LTC at the substation or at cap banks
    - Interaction with circuit device operation (load transfer, operator controlled voltage and VAR optimization a few times per day)
    - Control and dispatch of Dynamic VAR Controllers
    - Change in PV system production according to time of day and season
- Utilizing real-time simulation models for the part of the system that is simulated for additional data gathering and monitoring support:
    - The model incorporated customer systems and interfaces for capturing data and characterizing the impacts on the distribution system
    - The model needed to reflect similar field devices and feeder level controls associated with SCADA or existing localized (automatic) control to execute and investigate interaction of typical operator controls with those of the customer system controls
- Incorporating additional measurement devices as required and identified in a supporting role:
    - Selecting devices based on the results of device evaluations and specifications
    - Integrating devices in the demo system and program them.
    - Preparing settings and configuration files
- Providing means of data streaming and capturing in the simulation and field data in PI historian as infeed to the visualization tool:
    - Visualization tool is primarily driven by field data measurement
    - Measurements from the real-time simulator to be provided as a secondary infeed to fill out the gap in field data monitoring
- Verifying the enhancement of the visualization and monitoring tools:
    - Evaluating the visualization tools based on the data inputs and key performance indices identified as part of the design stage.
- Verifying and preparing the hybrid demonstration system for the demo, consisting of the field data, real-time simulation data and visualization tool

The task output included:

- Demonstration of the system setup integration
- Successful setup of the demonstration system
- Training of the SDG&E internal project team on utilization of the demonstration system.

Task 7 – Pre-commercial Demonstration

This task involved development of test plan and schedule for testing, as well as performing the demonstration tests. The main activities were:

- Detailed plans for each of the tests to be run, including identification of the objectives of the tests, use cases under investigation, test methodologies, information to be captured, Contractor's staff, system/equipment, SDG&E lab system/equipment required, circuit models required, and contractor and SDG&E project team support needed for specific items
- Methodology for capturing test data and comparing with simulation data

- Decision points at which preliminary data assessment is used to determine if more test iterations or alternative new test cases should be run
- Simulating scenarios and test cases in the laboratory environment
- Collecting live data streams as well as the output from the visualization tools
- Creating transient events and outages associated with customer systems to determine operator responses and to demonstrate how the visualization system will be used for post-mortem analysis
    - Root cause investigation of the failure and outage
- Performing data analysis and documenting test results and observations
    - Collecting test data and results for the report
    - Collecting event and operating records from field devices

The output for this task included:

- Test plan and schedule
- Test results
- Root cause investigation approach
- Analysis of test results
- Analysis methods for determining benefits of the advanced visualization schemes and lessons learned.

Task 8 – Evaluation of Customer System Integration

The objective of this task was to identify and describe system improvements obtained by introducing advanced monitoring and customer system integration schemes demonstrated in this project. The results from the system demonstrations and test cases were utilized to analyze and propsoe standard practices for the customer integration and system monitoring tools. The main activities as part of the system evaluation and standardizations were:

- Determination of data accuracy and possible or expected errors in live streaming and/or event captures
    - Utilizing sample data from various devices in the field
    - Comparing data sources and calculate percent error
    - Using laboratory testing of the specific devices, as needed to verify percent error and/or potential sources of error
    - Calculating level of offset in measurements
    - Investigating calibration and correction methods
- Analyzing data to determine issues and possible adverse impacts on circuits, equipment, and customers. Summarizing observations in relationship to correlated events and conditions:
    - Voltage profiles
    - Losses and reactive power profile
    - Power flow including reverse flow
    - Interactions among circuit devices and control systems
    - Effect of PV penetration, based on changes in the level of PV production versus load at various time intervals
    - Changes in the waveform distortion or harmonic content of voltages and currents
    - Power device operation and status changes, including wear or stress impact
    - Identify improvement opportunities
- Preparing guidelines for addition of new sensors and measurement device installations

- Determination of minimum number of measurement points and locations on the system to install sensors and meters
- Defining device specifications and functional requirements to support advanced monitoring and integration of the customer systems
- Defining communication needed for capturing and data streaming from the measurement point
  - Determination of minimum communication infrastructure requirements, such as data bandwidth needed, minimum required speeds for the data transfer, and list of use cases for those data transfer needs.
- Determination of requirements for visualization and operator interface to support customer systems.

The task output included:

- Tool and application evaluation
- Requirements for new systems

Task 9 – Comprehensive Final Report

This task incorporated the work on preparing the final report for the project, which is a comprehensive record of the work completed, findings, and recommendations. The report was intended to enable stakeholders to understand and use the project's output.

2 System Requirements and Evaluation

This section outlines the outcome of system requirement investigation, test system development and evaluation of the functionalities, using both real-world data (from devices deployed in the field) and simulated data (from test setup in the laboratory environment).

2.1 Survey of Customer Systems and Their Impact on the Distribution Systems

Prior to developing the functional requirement for the test system, a survey of customer technologies was performed. The survey incorporated common technologies that are presently installed by customers and integrated into utility grid (such as roof-top solar systems), as well as the technologies that are expected to be introduced and become mainstream, such as Electric Vehicle Charging Stations (EVCS), and behind the meter hybrid energy storage systems. Technology characteristics and impact on distribution systems from the perspective of day-to-day operation were analyzed. Common measurement and performance indices were also introduced to characterize their power exchange with the grid and to quantify their contribution in affecting power quality of the system.

2.1.1 List of Customer Systems and Technologies

One of the Tasks on the project was to assess the present state of monitoring and controls and to analyze the impact of new customer technologies on the distribution systems. Extensive research was performed to determine a list of customer systems and technologies that are being deployed or expected to be integrated into utilities' distribution systems. Potential impacts on operation practices and integrity of the system due to those new technologies have been also investigated.

The following list provides the identified customer systems and technologies that are being deployed or expected to be integrated into the distribution systems in the next 2-5 years:

- Roof top PV systems (< 50 kW) – with micro inverters, and mostly residential systems;
- Roof top PV systems (< 50 kW) – with string inverters, and mostly residential systems;
- Roof top PV systems (< 1 MW) on commercial buildings, such as warehouses or large department stores;
- Ground mounted PV systems that are privately owned;
- Electric Vehicle charging stations, level 2 or fast chargers;
- Fuel Cell Systems (> 100 kW, for industrial facilities);
- Residential Energy Storage Systems (< 10 kW, 2-4 hrs.);
- Community Energy Storage Systems (50 kW to 500 kW, 2-4 hrs.);
- Commercial Energy Storage System (50 - 500 kW, 2-4 hrs.);
- Traction systems (electric train or autobus) with AC interface;
- Dynamic Voltage Control (DVC) (1MVA+) that may be used in conjunction with large PV plants
- Secondary voltage control devices, by utilizing power electronic systems that can provide voltage regulation and reactive power compensation downstream of service transformers,
- Variable Frequency Drives (VFDs), and
- Customers with non-linear loads such as Arc Furnace, or large motor loads without VFD.

2.1.2 Impact Categories

The impact of identified new technologies on distribution systems was investigated and summarized. The potential impact categories are listed below:

- Overvoltage issues
- Under voltage issues
- Voltage ring down (damped voltage oscillation)
- Transformer overloading issues
- Distribution system loss increase
- Extensive reverse power flow
- Increased number of tap operations in voltage regulators and load tap changers
- Increased number of switched capacitor operations
- Changes in short circuit capacity of distribution systems which in turn affects the rating of equipment (e.g., circuit breakers, switches, etc.)
- Deterioration of protection system coordination
- Increased chance of incidental faults
- High frequency switching transients - that can cause resonances or increase losses
- Load imbalance increase
- Ground fault over voltage phenomena
- Increased risk of apparatus failure
- Increased risk of cable failure
- Increased risk of unplanned islanding
- Harmonics
- Voltage flicker.

2.1.3 Key Performance Indices for Quantifying System Performance and Imapcts

In order to identify and monitor each impact category or distinguish events, various measurements, indicators and indices are required to associate causes with an effect. It was assumed that various type of measurements are gathered and available from metering devices or specialized Intelligent Electronic Devices (IEDs) across the circuits. Collected measurements were processed to create indictors and performance indices which are informative of system conditions and any potential events.

The proposed measurements, indicators and key performance indices (KPIs) that were considered for identifying and classifying specific events are listed as follows:

Measurement type parameters:

- Voltage magnitude,
- Voltage phase angle,
- Current magnitude,
- Current phase angle,
- Active power (from load),

- Active power (from PV systems or various DERs),
- Reactive power (from load, generation, or passive shunt capacitive/reactive elements, and static compensators),
- Tap Position & capacitor/reactor status,
- Power frequency.

Indicator type parameters:

- Voltage trends,
- Phasor diagrams,
- Rate of change of frequency (ROCOF) trend,
- Harmonic histograms,
- Odd/even harmonics spectrum,
- Symmetrical component plots,
- Vector jump plot,
- Neutral voltage shift plot,
- Short duration transients (cycle by cycle event record).

Key Performance Indices (KPIs):

The main KPIs used in the project were:

- Voltage Swell (SARFI-110) [1]
- Voltage Sag (SARFI-80, SARFI-90) [1]
- SARFI-SEMI [1]
- SARFI-ITIC (CBEMA) [2]
- Harmonic indices such as: TDD, THD [3]
- K-factor (transformer derating) [4]
- Crest factor (distortion factor) [5]
- Voltage unbalance factor [5]
- Flicker factor (short term) [4]
- Flicker factor (long term) [6]
- Solar intermittency factors, such as: DCI and DVI [7]
- Reliability indices such as: SAIDI, SAIFI, CAIDI, and CAIFI [8].

Table below provides the list and definition of the KPIs.

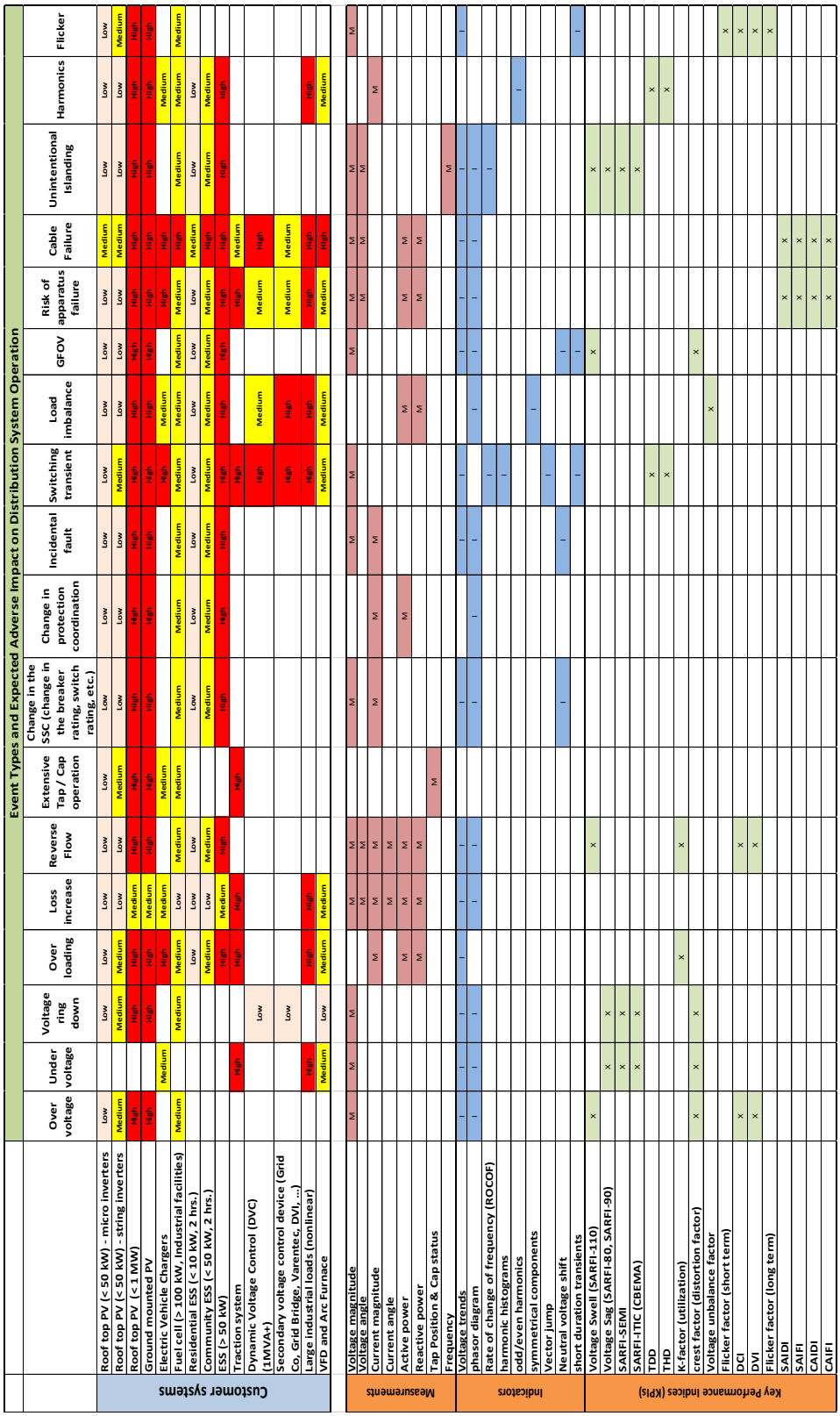
Table 2-1. Key Performance Indices Considered on the Project

Index	Key Performance Index Definition
SARFI-80	Count or rate of voltage sags with retained voltage above 80% of voltage refere
SARFI-90	Count or rate of voltage sags with retained voltage above 90% of voltage refere
SARFI-110	Count or rate of voltage swells with retained voltage above 110% of voltage ref
SARFI-SEMI	Count or rate of voltage sags and interuptions with reatined voltage and duration below the ITI(CBEMA) Curve.
SARFI-ITIC (CBEMA)	Count or rate of voltage sags and interuptions with reatined voltage and duration below the lower portion of the SEMI F47 Curve.
TDD (Total Demand Distortion)	$TDD_I = \frac{\sqrt{I_2^2 + I_3^2 + I_4^2 + I_5^2 + \ldots}}{I_L}$
THD (Total Harmonic Distortion)	$THD_I = \frac{\sqrt{I_2^2 + I_3^2 + I_4^2 + I_5^2 + \ldots}}{I_1}$
K factor (Transfromer derating)	$\left(\sum_{h=1}^{\infty} h^2 I_h^2\right) / \sum_{h=1}^{\infty} I_h^2$
Crest factor (Dielectric stress)	V_{peak} / V_{rms}
Voltage unbalance factor	$\lvert V_- \rvert / \lvert V_+ \rvert$
Flicker factor	$\Delta V / \lvert V \rvert$
DCI	Daily Clearness Index $= \frac{\text{Measured Solar Insolation}}{\text{Calculated Clear Sky Solar Insolation}}$
DVI	Daily Variability Index $= \frac{\text{Length of measured irradiance plot}}{\text{Length of clear sky irradiance plot}}$
CAIDI	Customer Average Interruption Duration Index $\text{CAIDI} = \frac{\sum \text{Customer Minutes of Interruption}}{\text{Total Number of Customers Interrupted}}$
CAIFI	Customer Average Interruption Frequency Index $\text{CAIFI} = \frac{\sum \text{Total Number of Customer Interruptions}}{\text{Total Number of Distinct Customers Interrupted}}$
SAIDI	System Average Interuption Duration Index $\text{SAIDI} = \frac{\sum \text{Customer Minutes of Interruption}}{\text{Total Number of Customers Served}}$
SAIFI	System Average Interuption Frequency Index $\text{SAIFI} = \frac{\sum \text{Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}}$

Table 3-2 summarizes the correlation between the new technologies identified in the survey and their impacts on the distribution system.

The severity of each technology on the events and impacts is organized as low, medium and high. The measurements, indicators and indices required for identifying and monitoring the impacts or events are also listed in the table.

Table 2-2. Summary of New Technologies, Their Impact, and Parameters Utilized to Characterize Impacts



2.2 Baseline Evaluation and System Characterization for Potential Targeted Circuits

The objective of this task was to assess the present state of monitoring and controls and to analyze the impact of new customer technologies on the distribution systems. In order to develop monitoring and visualization for current distribution network, it was of great importance to conduct a baseline analysis of the system and evaluate the gaps between current and required state of monitoring.

The baseline analysis was conducted for five selected circuits within SDG&E distribution systems. The baseline analysis focused on the loading conditions of the circuits, the customer PV integration along the circuits and the existing PMU locations of the circuit. The baseline analysis provided an insight into the amount of PV generated and its distribution along the circuit and how effective the existing PMUs can monitor and capture the impacts of PV integration into the distribution circuit.

A detailed set of PMU placement criteria for distribution systems has been then discussed in next step to provide full coverage of the circuit and key locations of interest. Considering distribution PMU installation costs, the communication system availability and/or cost and the practical constraints, the optimal placement of PMUs is an essential task, involving both application assessment and economic justifications (business case). In this section, the PMU placement criteria in general has been investigated and prioritization method has been discussed. Furthermore, these criteria have been tailored for specific applications, for this project.

2.2.1 Circuit Selection Criteria for Baseline Analysis

In selecting the five distribution circuits both technical and practical aspects were considered. The criteria included:

- Presence of medium to high levels of PV integration to the circuit,
- Existing PMU devices in operation in the field,
- Potential distribution assets to be monitored and visualized (including line reclosers, capacitor banks, voltage regulators and similar devices),
- Availability of a real time digital simulation model (RTDS model) of the circuit (based on the SDG&E Library of circuit models) , to facilitate laboratory investigations
- Focusing on circuits that were not investigated recently in similar EPIC studies.

Table 3-3 summarizes characteristics of selected circuits and their device status, including number/amount of PV installed, number of major components (switched capacitors, tie switches, reclosers and voltage regulators), number of field PMUs and loading conditions. In the following sections, the selected circuits have been investigated more elaborately.

Table 2-3. Summary of Selected Circuit Status

Substation	Sub 1	Sub 2		
Circuits	Circuit 1	Circuit 2	Circuit 3	Circuit 4
Total No. of Tie Switch	1	0	3	0
No. of PVs	246	76	81	82
Installed PV capacity (kW)	4604.705	1015.96	652.026	1364.816
No. of Storage	0	0	0	0
No. of Voltage Regulators	6	1	2	1
No. of Switched Capacitors	1	1	2	3
No. of Reclosers	6	2	3	2
No. of field PMUs	12	4	8	2
Installed storage capacity (kW)	N/A	N/A	N/A	N/A
Large DERs (>500 KW)	2	0	0	1
Daytime Peak load (MW)	6.6	4.272	3.24	3.264

2.2.1.1 Example of Baseline Analysis for Circuit 1

2.2.1.1.1 Loading Conditions

The 2016 load data from SCADA has been analyzed and the results are summarized in Table 3-4. In addition to minimum and maximum load, data has been analyzed for minimum and maximum daytime load during the noon time (i.e. 11:00 am – 2:55 pm). The data has been collected based on a 5-minute resolution for 2016 year-around.

Table 2-4. Circuit 1 Loading Condition

Load	Date Time	MW	MVAR	Percent Load	Ia (A)	Ib (A)	Ic (A)	BRKR Status
Minimum load	3/6/2016 13:00	-0.312	0.072	2.30	11.4	12.6	13.8	CLOSE
Maximum load	9/26/2016 18:20	7.992	3.252	71.81	353.4	416.4	438	CLOSE
Average load	--	3.417	0.734	--	--	--	--	--
Min daytime load	3/6/2016 13:00	-0.312	0.072	2.30	11.4	12.6	13.8	CLOSE
Max daytime load	9/27/2016 14:55	6.6	3.492	60.9	315.6	349.8	368.4	CLOSE

Due to PV generation in the circuit, the gross load would be calculated as the difference of the total load and the PV generation.

Thermal Rating

In this section, the thermal rating (ampacity) of all major equipment including reclosers, capacitors, regulators and cables have been summarized and the thermal rating of different sections on the circuit has been determined. Different sections of the circuit (main branch, branch 1 and branch 2) have been marked on Figure 3-1. Table 2-5 shows the ratings of different devices located on different sections of the circuit (main branch, branch 1 and branch 2) and

Table 2-6 shows the rating of all conductors along the different branches of the circuit.

Table 2-5. Thermal Rating of Major Equipment on Circuit 1 (SDG&E data from SynerGI model)

Main Branch					
#	Name	Device Type	Manufacturer	Section ID (Node number)	Rating (Amps)
1	C1-22R	Recloser		C1_360492_MC	630
2	C1-10R	Recloser		C1_357284_MC	630
Branch 1					
#	Name	Device Type	Manufacturer	Section ID (Node number)	Rating (Amps)
1	C1-18R	Recloser		C1_605304_MC	630
2	C1 - 1228CW	Cap		C1_1793943_MC	
3	C1-838G	Regulator		C1_199701_OH	200
4	C1-33R	Recloser		C1_359640_MC	630
5	C1-1224G	Regulator		C1_200233_OH	200
6	C1-1020G	Regulator		C1_500322_OH	200
Branch 2					
#	Name	Device Type	Manufacturer	Section ID (Node number)	Rating (Amps)
1	C1-26R	Recloser		C1_1446954_MC	630
2	C1-1334G	Regulator		C1_467252_OH	200
3	C1- 1340CM	Cap		C1_355049_MC	
4	C1- 1225G	Regulator		C1_203961_OH	200
5	C1-1045R	Recloser		C1_2302813_MC	800
6	C1-1116G	Regulator		C1_200449_OH	200

Table 2-6. Thermal Rating of Conductors along Circuit 1 (SDG&E data from SynerGI model)

Main Branch		
#	Conductor Type	Rating for load calculating (Amps)
1	1000 XLPECN-PEJ AL	580
2	636 ACSR	770
3	336.4 ACSR	530
Branch 1		
#	Conductor Type	Rating (Amps)
1	3/0 ACSR	300
2	336.4 ACSR	530
3	#2 5005	185
4	#2 ACSR	180
5	#4 B.STRD	180
Branch 2		
#	Device Type	Rating (Amps)
1	336.4 ACSR	530
2	1000 XLPECN-PEJ AL	580
3	#2 ACSR	180
4	#2 5005	185
5	#6 B.STRD	130
6	#4 B.STRD	180

Based on the provided data, the thermal rating of each section would be the minimum rating of all devices in that section. Therefore, the thermal rating for main branch, branch 1 and branch 2 would be **530 Amps**, **180 Amps** and **130 Amps,** respectively.

2.2.1.1.2 PV Generation and Existing PMU Locations

In this section, a single line diagram of the circuit 1 has been provided which shows the location of existing field PMU devices as well as PV generation along the circuit (Figure 3-1). The DVR on the circuit is used as the representation of future customer-owned Voltage Control devices that may be needed to manage voltage and reactive power requirements for large PV installations.

As shown on the single line diagram, the areas of the circuit located between two or more feeder control devices (reclosers, regulators, shunt capacitors) are identified as monitoring areas. The total existing PV systems in each monitoring area were extracted from the GIS maps and shown on the SLD.

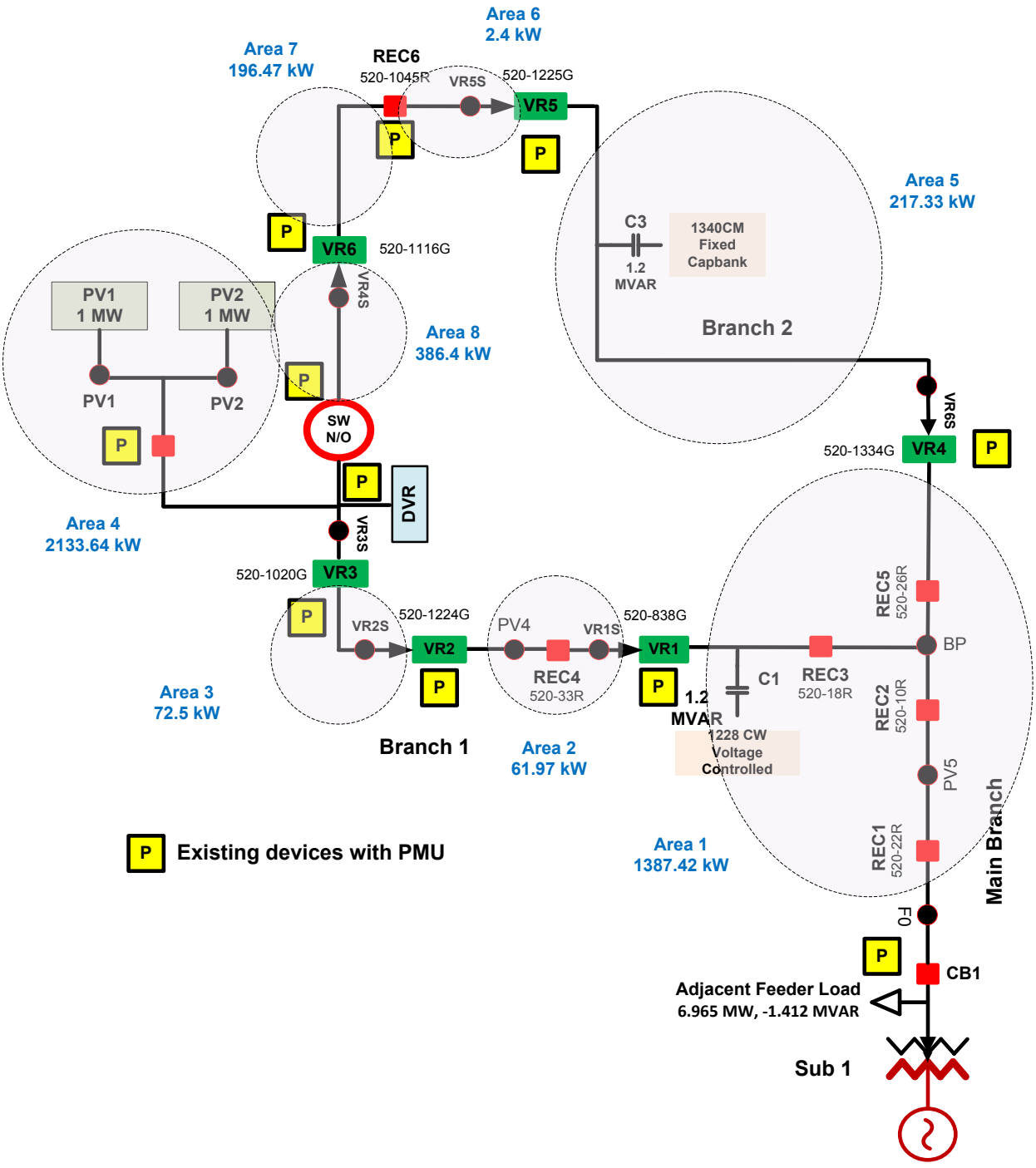


Figure 2-1. Existing PMU Locations on Circuit 1 and identifying monitoring areas with amount of PV

2.2.2 PMU Analysis and Placement Criteria

Reliable operation of modern power systems requires close monitoring of the system operating conditions. Until recently, the measurements were provided by supervisory control and data acquisition (SCADA) system, including power flows and bus voltage magnitudes. The deployment of phasor measurement units (PMUs) enables various applications with the use of synchronized measurements. A PMU installed at a node can make direct measurements of the voltage phasor of the bus and the current phasors of some or all its incoming/outgoing branches, based on the PMU available channels.

Considering PMU procurement and installation cost, the communication system availability and/or cost (which may be higher than that of the PMUs), and the practical constraints, the optimal placement of PMUs has become an essential task. While there have been multiple efforts to analyze and optimize PMU placement, the majority of these works is focused on transmission systems. Some important factors in PMU placement include network reliability, redundancy, system observability, and the required applications. In the following paragraphs some of the PMU placement considerations and recommendations are discussed.

2.2.2.1 Prioritization

To maximize the value from a PMU-based system, the communications system and software analytics need to be designed with a clear plan that suits system design, acquisition, siting and installation requirements that are tailored to the intended applications. In the initial stage of PMU system deployment, it is essential for the utility to prioritize short- and long-term objectives as well as applications of interest; this is usually done through some sort of roadmap developed for this purpose. Subsequently, those circuits where PMUs need to be deployed can be selected. The following provides a generic list of circuit priority criteria (sorted from higher priority to lower priority):

1) Availability of communications infrastructure
2) Existing location of distributed energy resources (DERs), especially intermittent ones
3) Expected penetration of DERs (especially intermittent ones)
4) Reliability level
5) Power quality level
6) Feeder type (Residential, Industrial, Commercial).

Once the circuit priorities are determined, the next step would be to find the optimal (or close to optimal) locations of PMUs that enable successful implementation of the application of interest. The favorable locations are areas with pre-installed feeder control devices which provide CT and PT connection. For uncovered areas, new nodes can be identified and incorporated in the new device installations.

2.2.2.2 Intended Applications

PMU placement should reflect the needs and functionalities of the intended applications for the distribution system. More specifically, PMUs should be located in a manner to maximize system benefits, beyond those provided by conventional meters. In the case of distribution systems, and potential future implementation at SDG&E, PMU applications were grouped in five broad categories. The following is a list of five categories along with some examples for each category:

1) System monitoring
    a) Wide-area situational awareness
    b) Phase angle monitoring for voltages and currents

2) Assessment and analysis
    a) Voltage stability monitoring and prediction
    b) Enhanced state estimation

3) Model validation
    a) Short circuit study validation
    b) Load characterization, load modeling and load forecasting

4) Protection and automation (mitigation, enhancement, and detection)
    a) Fault location
    b) Islanding detection in the presence of DERs

5) Control and optimization
    a) Volt/Var control
    b) Fault location and load restoration

Table 3-7 below offers a more detailed list of potential PMU applications in distribution systems. The list has been compiled from survey of various distribution automation applications and proposed use cases by several smart grid working groups, such as DOE smartgrid interoperability group (SGIP). As it can be observed in the table, synchrophasor measurements can be utilized for an array of applications and, thus, PMU placement should support the requirements of these applications.

Table 2-8 provides a list of recommended key PMU locations and PMU coverages for various automation and smartgrid applications. The list was prepared by applying the aforementioned criteria.

Table 2-7. List of Potential PMU Application in Distribution Systems

No	APPLICATIONS	CATEGORY				
		SYSTEM MONITORING	MODEL VALIDATION	ANALYSIS	PROTECTION & AUTOMATION	CONTROL
1	Conservation Voltage Reduction (CVR)					X
2	Faulted Circuit Indication(FCI) for expediting service restoration				X	
3	Falling conductor and high-impedance fault detection				X	
4	Distribution system computational model validation		X			
5	Voltage impact assessment and mitigation due to high penetration of intermittent DER			X		X
6	Voltage and current phase angle monitoring	X				
7	DER islanding detection				X	
8	Volt-Var Control					X
9	Power flow measurement for circuit design evaluation and balancing (passive approach)	X		X		
10	Monitoring and integration of intermittent DERs	X				
11	Incipient fault & failure detection				X	
12	Improved wide-area situational awareness	X				
13	Customer/smart inverter control					X
14	Voltage profile monitoring			X		
15	Dynamic rating of distribution lines and equipment (including thermal limit assessment)	X		X		
16	Improved load shedding schemes					X
17	Condition monitoring and asset managment of power apparatus	X				
18	Phase identification					X
19	Near real-time event monitoring and trending	X				
20	Active and reactive reverse power flow management					X
21	Planned islanding and restoration of microgrids					X
22	Short circuit study validation		X			
23	Fault protection and reclosing assistance (real-time values to relays and reclosers to adapt to system changes)				X	
24	High accuracy fault location, specific for maintenance dispatch plus OMS interface				X	
25	Control instablility, oscillation detection - Volt/Var switching					X
26	Load shedding (real-time compensative arming to balance 1547-compliant PV that will drop during wide area disturbances)				X	
27	Enhanced FLISR operation				X	
28	Closed-loop circuit operation					X
29	Power quality measurement and management information per customer group - voltage profile, CBEMA/ITIC violations	X				
30	Recording, retrieval, trigger marking, archiving, and disposal of gathered synchrophasor and other circuit data	X		X		
31	Monitoring of communications system performance with management metrics - availability, latency, lost packets, etc.	X				
32	Communications failure location for maintenance dispatch	X			X	
33	Monitoring, alarming and compensating of malfunctioning PMU installations by integrated comparison with surrounding data	X		X		
34	DER management and energy balancing					X
35	Synchronized load transfer on same circuit or between adjacent circuits (under normal operating conditions)				X	
36	Circuit loss minimization			X		X
37	Improved distribution reliability analysis (index calculation)			X		
38	Distribution system state estimation			X		
39	Open conductor fault detection				X	
40	Load characterization and forecasting			X		
41	Post-mortem analysis			X		
42	Energy accounting/non-technical losses estimation and location via cross-feed to AMI and CIS	X		X		
43	Real-time event monitoring and trending	X				
44	Frequency monitoring and analysis	X		X		
45	Voltage stability monitoring and prediction	X				X
46	Visualization of dynamic system response	X				

Table 2-8. Recommended Locations for PMUs for Various Classes of Applications

Item #	Application	Recommended PMU Placement
1	Improved situational awareness	• DERs with a combined capacity above certain kW rating (500kW) • Key buses, e.g., those with VRs, LTCs, and capacitor banks • Major load centers • Flowgates requiring loading relief • Interfaces to transmission systems • Pre-defined islands
2	Real-time monitoring and trending	Similar to recommended locations for Item #1
3	Distribution system state estimation (Phasor-based or enhanced)	• (N-2) line current phasors are needed for N interconnected buses • More PMUs neded if robustness again single PMU failure is needed • Observability criteria should be considered
4	Voltage stability monitoring and prediction	• DERs with a combined capacity above certain kW rating (500kW) • Large reactive power control installations (DSTATCOM, synchronous condensers, Large capacitor banks, etc.) • Voltage control installations (LTCs, VRs, etc.) • Theoritically, a minimum of (N-1) line current phasors are needed for N interconnected buses
5	Dynamic rating, thermal limit, and stability limit assessment (e.g., islanded microgrid)	• Voltage and current of the distribution line(s) • DERs with a combined capacity above certain kW rating (500kW) • Large load centers • Tie lines between sub-systems (e.g., in a looped configuration) • Interfaces to transmission systems
6	Synchronized load transfer, distribution sub-system separation, and phase identification	• PMUs to be installed at both sides of the interface/tie • Single-phase control devices (VRs, Cap banks, etc.)
7	Model verification/calibration	Components of interest (DERs, grid power controllers, loads, etc.)
8	(Frequency) Oscillation detection	• All DERs (espacially wind power plants) • Large loads (especially industrial loads with cyclic loadings) • Grid control devices (DSTATCOM, switched capacitors)
9	DER islanding detection	• All DERs • Points of interconnection (POIs)
10	Blackstart and system restoration	• Every generator included in the blackstart restoration plan • Every substation included in the blackstart restoration plan • Key substations, lines, and breakers that will synchronize the blackstart islands created during the blackstart restoration plan
11	Vol/Var control	• Volt/Var control devices (sub LTC, VR, Cap Banks) • DERs with a capacity above certain kW rating (particulalry dispatchable ones) • Large loads/customers and circuit reclosers (supplimentary)
12	Fault location, isolation, and system restoration (FLISR)	• Substation (monitoring circuit breaker current) • Circuit reclosers • Remote control switches • Sectionalizer and tie breakers/switches • Load centers • Large customers and beginning of large branches (supplimentary)
13	Falling conductor detection	• Substation (monitoring circuit breaker power) • Circuit reclosers • Branch end point
14	Monitoring and integration of intermittent DERs	• POI of variable DERs (and other DERs as supplimentary location) • Substation (monitoring circuit breaker power) • Circuit reclosers

Based on the intended applications, the criteria and practices for PMU placement will vary. Table 3-8 provides generally recommended locations for a selected number of PMU applications in distribution systems.

As indicated in this table, some of the PMU locations are mandatory while the rest are supplementary for enhanced operation of the application. The following is a list of recommendations for prioritizing PMU placement based on the applications of interest:

- Key applications that will bring value to the organization (e.g., engineering analysis and real-time operational applications) should be identified and prioritized as soon as possible. Applications require different levels of accuracy, resolution, as well as placement; these should be taken into account prior to concerted deployment of PMUs.
- Determine the placement coverage required for successful operation of the application(s) of interest. Determine if partial coverage can suit the needs of some applications while others may require full observability/deployment.
- An application matrix can be developed to track the locations that PMUs can meet the needs of multiple applications. These locations may be considered higher priority since they provide cross-cutting value to multiple PMU-based applications.
- Data quality is important in most cases, but some applications have less stringent requirements for data quality and accuracy than others. This should be considered in the deployment stage, and efforts should focus on ensuring a high availability, high accuracy, and low latency synchrophasor network.

It is should be noted that one of the major criteria for PMU placement is the system observability. If the full observability of the system is fulfilled by PMUs, the majority of applications can be performed properly (but it is usually not practical due to the cost constraints). The following subsection discusses the criteria for the optimal placement of PMUs when the system observability is the optimization objective.

Other additional factors that influence PMU placement include:

1. Practical constraints for PMU installation (e.g., non-existent virtual buses or unavailability of instrument transformers)
2. The number of distribution lines and transformers in the substation (possibility of installing more PMUs at a substation)
3. Equipment considerations (number of inputs, signal availability, local access, communication interface, timing signal, etc.)
4. The redundancy requirements for PMUs
5. Possibility of using existing intelligent electronic devices (IEDs) as PMU
6. Communication & IT considerations (Bandwidth, latency, reliability, security, etc.)
7. Data quality requirements (data loss, data corruption, inaccuracy, etc.)
8. Reporting rate as related to communication restrictions, application requirements, data handling equipment, and data storage capacity

Based on the discussion above and the scope of this project and its related applications, the following table (Table 3-9) provides a high-level guideline for placement of PMUs in target distribution systems. The table lists a generic prioritization for distribution assets that are proper candidates for PMU locations in selected circuits.

However, it should be emphasized that PMU placement should be investigated in the context of the system under study.

Table 2-9. Recommended Location of PMU Installations for Analyzed Circuits

Priority level	Description	Recommended Locations
1	Major locations that are critical for majority of PMU-based applications or have high potential for PMU installation	• Substation circuit breakers • Circuit reclosers • Utility side of DERs with a capacity more than 500kW • New SCADA control devices • Automated assets that are monitored by SCADA, and their control & communication can be replaced with PMUs, e.g., VRs, cap. banks, SCADA switches/ties, reclosers, etc.
2	Automated assets that are not monitored by SCADA, but their control & communication can be replaced with PMUs	• Residential DER clusters (areas with more than 100 residential DERs eache smaller than 10kW) • Voltage Regulators (VRs) • Switched capacitor banks • Sectionalizers, and DA switches/ties • reclosers, etc.
3	Critical locations for specific PMU applications	• Load centers and/or mid-circuit point • Beginning of large branches • large custumer and industrial loads
4	Automated assets that are not monitored by SCADA, and their control & communication cannot be replaced with PMUs	• Voltage Regulators (VRs) • Switched capacitor banks • Sectionalizers, and DA switches/ties • reclosers, etc.
NOTE: PMUs will be placed at the above recommended locations, provided that no other control device (VR, cap bank, recloser, or SCADA switch/tie) with synchrophasor measurement capability is located less than half a mile from it.		

2.2.3 PMU Placement Case Study

In order to investigate and further modify the applicability of the proposed PMU allocation criteria, the method was examined on a few circuits in SDG&E territory. There are some PMUs already deployed in distribution circuits. The objective of this approach was to show whether additional PMU devices were needed or the existing units can provide proper coverage for the selected use cases.

Three circuits were selected and studied for this purpose; however, in this report, the results applied to one of the circuits (Circuit 1) are presented. Similar analysis for other circuits were also performed as part of lab setup development.

Figure 3-1 presented above shows a schematic of Circuit 1. A normally open switch divides the circuit into two main branches. All key devices including voltage regulators, capacitor banks, reclosers and DERs have been drawn in this schematic. Currently there are 24 PMU devices located on Circuit 1. Two of these PMU devices are at the substation and the rest are located along the circuit at:

- Voltage Regulators (VR1, VR2, VR3, VR4, VR5 and VR6)
- Dynamic Voltage Regulator (DVR)
- Two reclosers (REC3 and REC5)
- Trayer switch.

In circuit 1, there were two capacitor banks (one switched and the other one fixed) with no PMU coverage. Only two reclosers had PMU devices in the circuit.

The intended application was distribution system monitoring in presence of DERs integrated to the system. The intended applications in the scope of this work included:

1. Monitoring and integration of intermittent DERs
2. Real time monitoring and trending
3. Improved situational awareness.

Based on the recommended PMU locations described in Table 3-7, the following locations were hence recommended:

- Point of Interconnection (POI) of variable DERs (and other DERs as supplementary location)
- Substation (monitoring circuit breaker power)
- Circuit reclosers
- DERs with a combined capacity above certain kW rating (500 kW)
- Key buses, e.g. those with VRs, LTCs and capacitor banks
- Major load centers
- Flowgates (transformers, circuit heads, laterals) requiring loading relief
- Interfaces to transmission systems
- Pre-defined islands.

Figure 3-2 shows a single line diagram of the Circuit 1 with proposed PMU locations. Similar study was done for other two circuits. Based on these recommendations, an RTDS model was developed and used for the purpose of pre-commercial demonstration of system integration and visualization in the laboratory environment.

The existing PMUs are located at the circuit substation, all the voltage regulators, DERs and two of the reclosers (REC3 and REC5). There is no PMU devices located at the remaining four reclosers and two key buses with capacitor.

Therefore, four new locations were recommended for PMU placement as shown in Figure 3-2. PMU placement at the capacitor back supports enhancing the visibility of the system and monitoring the reactive power injections due to the DERs power variations.

Note that REC1 location is electrically the same as CB1 location. Also, instead of REC2 location, it is more applicable to add PMU to REC3 and REC5 for monitoring each branches.

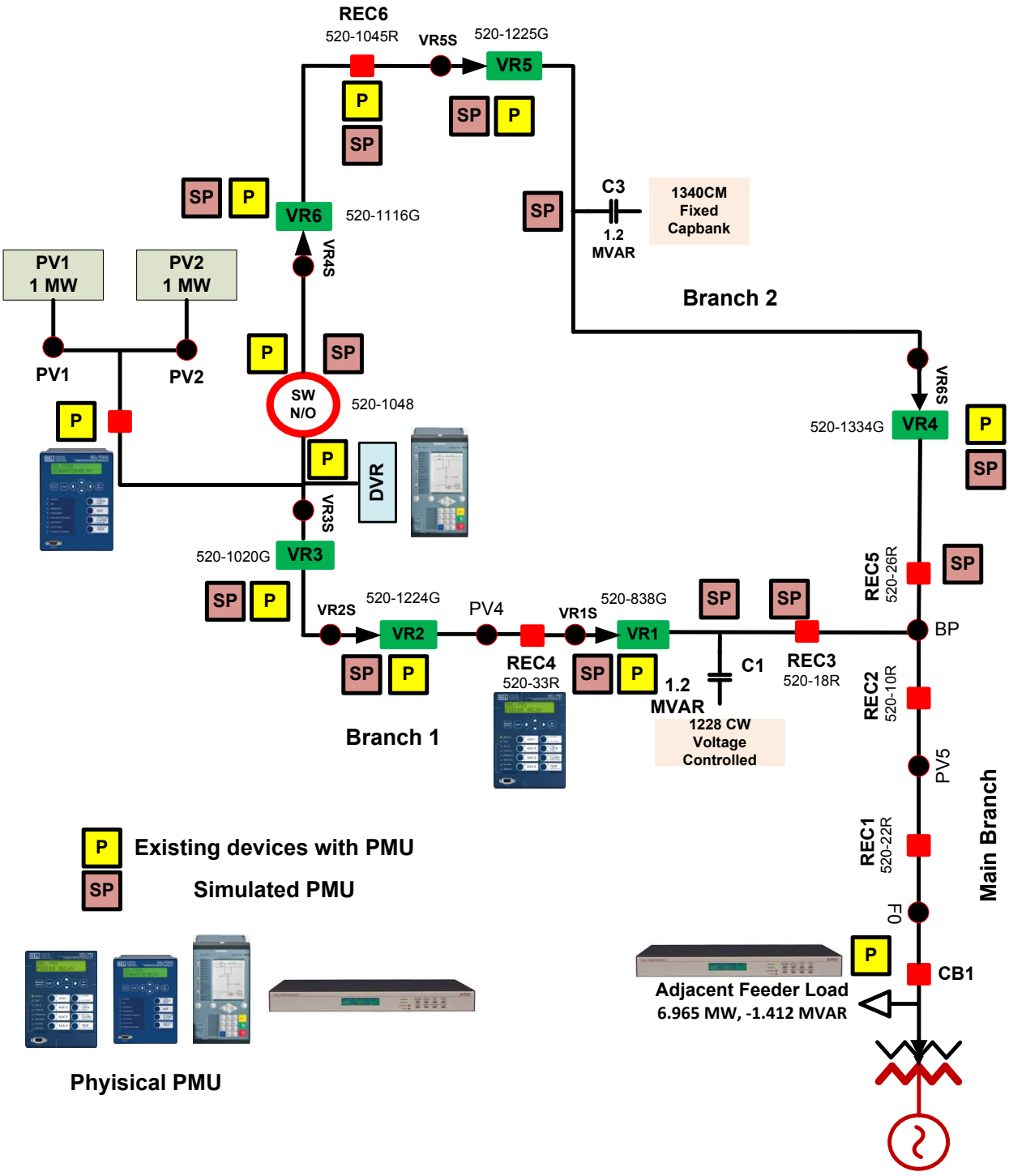


Figure 2-2. The single line diagram of a selected Circuit 1 with PMU locations (existing and recommended)

2.3 Use Case Development

For the purpose of demonstration of the technology, a set of use cases were developed. The proposed use cases were associated with monitoring, investigation and identification of Customer Systems Impact on distribution systems. Three categories of use cases were proposed in order of priority for development and implementation (tier 1, tier 2, and tier 3).

The use cases are by nature also of three types:

a. System monitoring only in real-time (without any analysis)
b. Using monitoring data for diagnostic based on simple logic or intelligent data analytics
c. Post mortem root-cause analysis of events and reported casualties in the system.

An extensive list of use cases was proposed and they were categorized in three tiers, by relevance. For the purpose of design and implementation of the system on this project, the following use cases were selected as the most important ones:

1. Voltage and power flow monitoring of customer systems
2. Primary Distribution Asset Operation Monitoring and Diagnostics
3. Data Quality Validation for Field PMUs
4. Equipment overloading detection
5. DER Interconnection Compliance
6. Water Treatment Facility Monitoring and Reactive Power Management

Use case documentation report was prepared to provide detail description of each of the use cases and they were used for the design and implementation of the system.

2.4 System Monitoring, Visualization and Analytical Application Requirements

During project execution, a functional requirement document was prepared to address a set of requirements for distribution system monitoring and visualization. This document provided functional requirements for developing monitoring and visualization of distribution systems in support of integrating customer systems.

In this document, different methods of data analytics (applications) and various forms of data presentation (displays) were suggested to allow for advanced monitoring and detection of events on the circuits. Synchophasor (PMU) data could increase quality and accuracy of system monitoring and observability for the fast system events, as a critical step in enhancing the reliability of fast evolving distribution systems.

As a benchmark for studies and evaluations, several PMU devices that are presently installed on 12 kV distribution circuits in SDG&E service territory were monitored through SynchroWAVe Central software tool. Display dashboards were created for monitoring phasor magnitude and phasor angles, and compared with simulated data.

Data Sources: The main data source for the visualization application was the PMU data, either streaming from PMUs in the field, or extracted from the historical database (i.e. PI historian). In addition, SCADA data – especially for device status and loads - and any power quality data from substation power quality meter, or any customer related data from revenue meters (such as demand and secondary voltages), as available and accessible were used.

For the demonstration purposes, PMU related data from the real-time test setup that was stored in a simulation PI Historian located at SDG&E ITF were also used.

Measurements & monitoring types and format: Following is a selected list of measurements, indicators and performance indices being calculated locally at each PMU location as phasors and/or analog values. All measurements were reported in real time for monitoring purpose, including:

- Voltage and current phasors
- Active and reactive power and power factor
- Voltage and Current phase angles
- RMS voltage and current magnitude per phase and phase to phase
- Voltage and current unbalance levels
- Frequency, Rate of Change of Frequency (ROCOF)
- Harmonic distortion levels (THD for voltage and TDD for current)
- Harmonic histograms
- Voltage symmetrical components
- Voltage sag and swell, and
- Short duration transients.

Most PMU-based IEDs can provide data at 60 samples/second or even at higher sampling rate. Specific devices may provide lower data resolution. However, in this project, we used 30 frames per second for phasor data and analog values coming from PMUs, to be consistent with standard practice for PMU devices that were already installed and configured in the field.

In order to capture fast transients and issues associated with power electronic based DERs, higher data sampling resolution will be beneficial. The project shown that most transient events could be captured and reported with 30 samples per second. Lower resolution may be acceptable for the voltage quality analysis such as momentary outage, voltage sags/swell or profiling/trending.

2.4.1 Monitoring Requirements

Monitoring of the distribution circuits under consideration in this project was considered from the following two aspects:

- Operator requirements
- Engineer needs.

Operators are interested to get a ‘big picture’ view of the system in real or near real-time and want to be able to make informed actionable decisions based on the information presented by a system, similar to the opera-

tion control room. An environment that suits well this kind of visualization is Geospatial Information System (GIS) platform.

On the other hand, engineers prefer to have tools that can provide more insight into the system, so they can see more details at faster sampling rates, or to look at historical data and perform all sorts of analyses.

The proposed design and visualization provided parameters and indicators addressing the needs of both group (i.e. operators and engineers).

2.4.1.1 Modes of Operation

The visualization applications described in this document needed to have three operation modes:

a. Real-time monitoring: These applications operate on streaming data inputs in real-time. They are mainly intended for real-time or ear-real time visualizations and alarm generation. Applications are mostly based on the data streaming from PMU or SCADA measurements.
b. Near-Real-time for quick access to recent events (events retrieval).
c. Off line/replay mode for post-event forensic analysis: These applications operate on archived data. They are mainly intended for an analysis of past events.

2.4.1.2 Real-Time Monitoring Mode

In the real-time monitoring mode, users will be provided with the measurements using real-time PMU, SCADA[1] and other input monitoring and measurements[2]. Examples were: Trending of voltage, current, active and reactive power profiles across the system.

Trending may be done:

- as a function of time, by stacking the PMU measurements from various devices in time frame, or
- as a function of PMU locations on a circuit, covering the circuit coverage and monitoring extent.

[1] SCADA data sampling rates are between 1 and several seconds and, but we consider it as real-time data since they can be presented to operators as soon as they become available.

[2] NOTE: In this project, some of the measurements were simulated by RTDS system but they will be generated at the rates equal to data rates provided by actual PMU devices. The visualization platform does not differ the simulated from field data, and for this reason we will treat both simulated and field data the same way, and both categories will be referred to as 'real-time data'

2.4.1.3 Data Retrieval and Events Replay Mode

This mode of operation allowed search for data stored in the historical database (historian). Selected events could be retrieved and replayed in a similar manner as live data coming from the field. Once the data was selected for replay (based of the time stamp and duration), the data was retrieved from the data historian replayed to user. The GUI provided same look and feel as if the data was streamed from the field in real-time. The only difference was an indicator showing that the data is being replayed.

2.4.1.4 Graphical User Interface

A graphical user interface (GUI) was required for visualization of input data and for visualization of outputs created by various analytics tools and applications. The GUI consisted of a multitude of displays that served various purposes. GUI is described in more detail later in this document. Some of the more important displays of the GUI are:

- Control Panel, also known as a Dashboard
- Applications buttons used to call up additional applications, dashboard and displays
- Additional displays embedded within the Dashboard.

The control panel allowed the user to do the following:

- Allow use to see at high level what is going on in the monitored area of interest
- Select real time mode or event replay mode
- Start various internal or external applications
- Start various displays based on variety of data sources
- Start, pause, resume, rewind or stop event replay.

Visualization Displays could be called from the Dashboard or within other applications. For instance, the Dashboard can have a push button that opens another display with applications based on PMU data. Similarly, a push button may be created to start a set of applications addressing Power Quality, or system reliability, to name a few.

Various custom-designed displays allowed users to monitor the status of the distribution system of interest, to provide awareness about what is going on in real-time, and to help assess the situation and provide useful tools for making informed decisions about necessary control of the system. This functional requirements document provided a more detail description of displays relevant for the Integration of Customer Systems into Electric Utility Infrastructure project, but it can be easily customized and expanded to serve additional objectives.

2.4.1.5 Computations

Graphical user interface and visualization were needed to show the operator what's going on in the system in a graphical manner. However, raw field data obtained through PMU (high resolution data) or SCADA measurements (data reporting by exception at low resolution) was not very useful for assessing what's going on in the distribution system beyond seeing how directly measured data from the field changed in time. To have a better assessment of the status of the network under consideration, there was a need to process the measurements to provide information about the system that operator can understand and act upon. This pro-

cessing was done through a well-defined analytical computations, defined as a set of applications. The computational engine for these applications performed in the background and the results were presented via a set of customized displays.

Some of the computations involved a very simple processing, such as averaging, counting, simple arithmetic operation and similar. On the other hand, there were applications that required more elaborate calculations and they were based on computational and programming tool such as MATLAB and C#, to name a few.

2.4.1.6 Data Flow

A high-level system architecture and corresponding data flow is shown in the Figure 2-3 below. In this architecture, fast sampled real-time data is streamed from PMU measurements and received by Phasor Data Concentrator (PDC) to capture and store phasor data. The PMU data is sent to SynchroWAVe Central for further processing and visualization. Another class of data, is collected via SCADA system and processed by DMS in the control center. SCADA measurements and application results are retained in PI Historian, which is the repository for other data types as well (including Power Quality data, for instance).

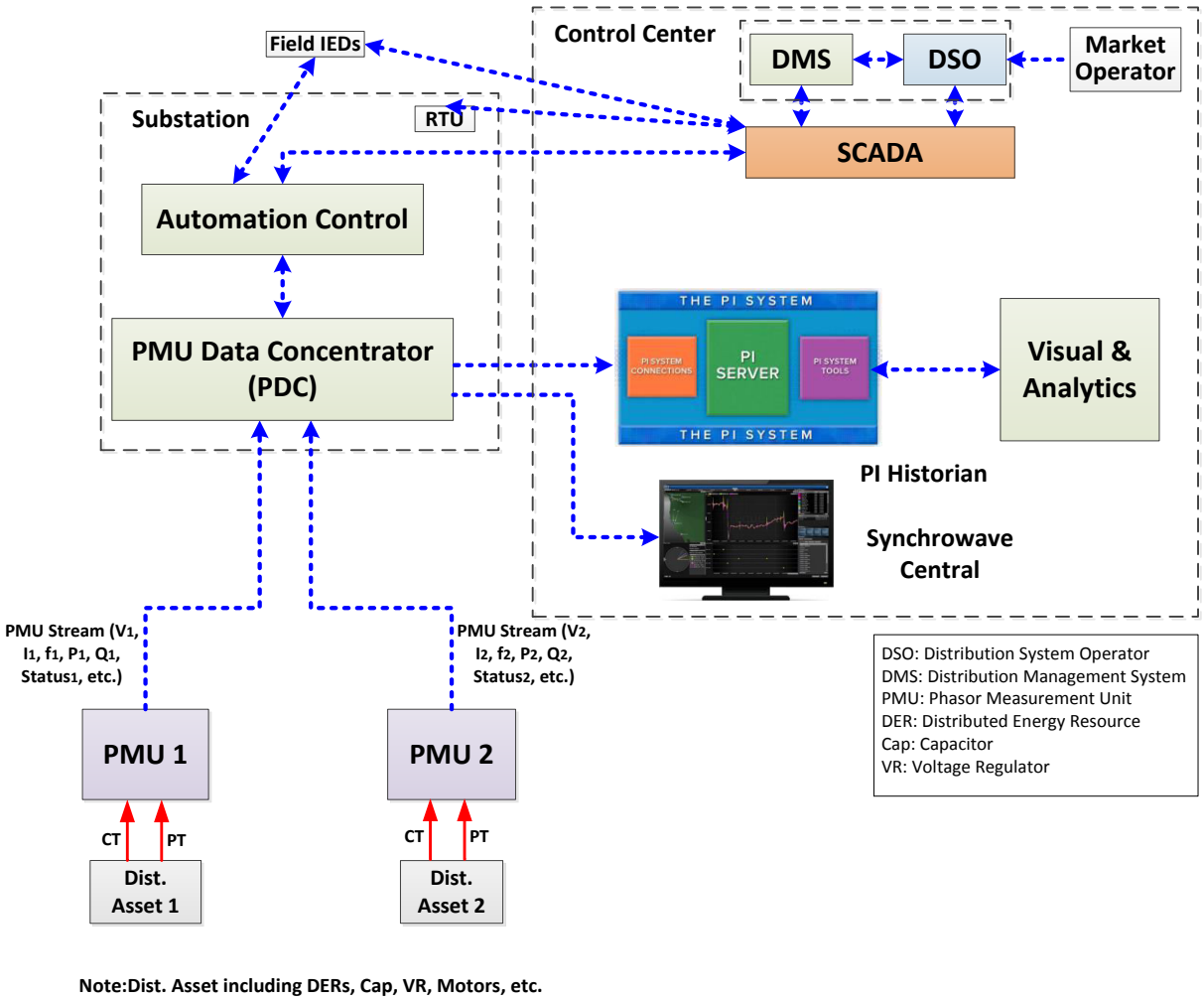


Figure 2-3. High-Level System Diagram and Data Flow for Visualization and Analytics Applications

2.4.2 Analytical Approach and Performance Indices to Streamline Operator Observations

This section describes list of methods and applications that were processing the input data and providing visualization of calculated values. For some visualization displays, a rudimentary data processing was needed, while other may require more elaborate data processing using programing tools such as MATLAB, C#, and similar programs.

The complete list of all categories of the data and information that needed to be visualized, how the information (either based on measurements or as a result of some processing) could be displayed, and possible users (Distribution Operators) or the Engineering Analysis group) are described in the following sections. These categories are listed in order of complexity to implement, as follows:

a. Measurements

b. Indicators
c. Performance Indices
d. Applications based on use case

Note that visualization aspects of these four categories above are discussed in more detail in Section 5, Operator Visualization and Display Screens.

2.4.2.1 Visualization and Measurements

This category of graphical displays takes data values coming from two sources, PMU and SCADA and presents them in appropriate format. Depending on the mode of operation (*real-time* or *post event analysis*) data source the real time PMU and SCADA measurements or their replay is used to feed the displays. The Table 2-10below shows the list of the measured parameters and possible ways to display them. The monitored data may be used by operators (for the purpose of day to day operation) or by engineers performing root-cause analysis or investigating certain events.

Table 2-10. Measurement Parameters of Monitoring Schemes

				Display Type							Users	
No	Method	Source	Description	Display in Time	Tabular	Alarm	Histogram	Phasor Diagram	Map Display	Trending	Operators	Engineers
1	Real-time Field Data	PMU	Voltage magnitude	Y	Y	Y		Y			Y	Y
2		PMU	Voltage angle	Y	Y	Y					Y	Y
3		PMU	Current magnitude	Y	Y	Y		Y			Y	Y
4		PMU	Current angle	Y	Y						Y	Y
5		PMU	Active power (total load)	Y	Y	Y	Y	Y			Y	Y
6		PMU	Reactive power	Y	Y	Y	Y				Y	Y
7		SCADA	Active power (total PV or various DERs)	Y	Y	Y	Y		Y	Y	Y	Y
8		SCADA	Customer Load				Y					
9		SCADA	Tap Position & Cap status	Y	Y				Y		Y	Y
10		PMU	Frequency	y	Y	Y					Y	Y

2.4.2.2 Indicators

Indicators are the second category of data that are of interest to present to operators or engineers. The list of indicators of interest is shown in Table 2-11. It is important to mention that for some of these indicators (such as Voltage trends, Phasor diagrams, Rate of change of frequency) can be displayed in a straightforward manner, using a standard set of displays within existing commercial platforms. Other indicators, such as those related to harmonics cannot be obtained from PMUS. Instead, other SW packages that can handle Power Quality parameters need to be used. Currently, SDG&E is using PQ View package. In this case, there needs to be a means to invoke PQView within the Visualization dashboard so Harmonic Histograms and Odd/Even Harmonics can be presented visually.

The list of indicators include parameters obtained from PMUs or PQ meters, such as:

- Voltage trends
- Phasor diagram
- Rate of change of frequency (ROCOF)
- Harmonic histograms and harmonics
- Symmetrical components
- Vector jump

- Voltage Phase Balance
- Neutral Voltage Shift

Table 2-11. Indicators for Visualizing Data

				Display Type							Users	
No	Method	Source	Description	Display in Time	Tabular	Alarm	Histogram	Phasor Diagram	Map Display	Trending	Operators	Engineers
1	Measurement data or Simple Processing	PMU	Voltage trends					Y		Y	Y	Y
2		PMU	Phasor diagram	Y	Y			Y	Y			Y
3		PMU	Rate of change of frequency (ROCOF)	Y	Y	Y	Y	Y	Y	Y	Y	Y
4		PQ meters	Harmonic histograms (obtained from PQ View)				Y					Y
5		PQ meters	Odd/even harmonics* (obtained from PW View)		Y					Y		Y
6		PMU	Symmetrical components (discuss if it is		Y			Y				Y
7		PMU	Vector jump (need to discuss further)		Y	Y	Y			Y		
8		PMU	Voltage Phase Balance									
9		PMU	Neutral voltage shift						Y			
10		Post Processor	Short duration transients (obtained from PQView)	Y	Y					Y		Y

2.4.2.3 Key Performance Indices for Visualization of Data Monitoring

Several key performance indices (KPI) are of interest for both operators and engineers. The indices clearly define the status of the system and expected impacts with pre-specified criteria to determine the level of violations. Table 2-12 below shows the list of the KPIs of interest.

2.4.2.3.1 KPI Based on Count Rate Calculations

Some of the performance indices are based on count rate calculations and they include System Average RMS Variation Frequency Index (SARFI), and tap position and capacitor counts. SARFI gives the average number of events (sags, swells, or interruptions) of a system over the assessment period, usually one year, per customer served. The size of the system is scalable: it can be defined as a single monitoring location, a single customer service, a feeder, substation, a group of substations, or an entire power delivery system. There are two types of SARFI indices: SARFI-X and SARFI-Curve.

SARFI-X corresponds to a count or rate of voltage sags, interruptions, and/or swells below or above a specified voltage threshold. For example, SARFI-90 considers voltage sags and interruptions that are below 0.90 per unit, or 90% of the reference voltage. SARFI-70 considers voltage sags and interruptions that are below 0.70 per unit, or 70% of the reference voltage. SARFI-110 considers voltage swells that are above 1.1 per unit, or 110% of the reference voltage. It is important to mention that the SARFI-X indices are meant to assess short-duration rms variation events only, meaning that the only events included in its computation are those with durations less than the minimum duration of a sustained interruption as defined by IEEE Standard 1159, which is 1 min.

SARFI-Curve corresponds to a rate of voltage sags below an equipment compatibility curve. For example, SARFI-CBEMA considers voltage sags and interruptions that are below the lower Computer Business Equipment Manufacturers Association (CBEMA) curve (CBEMA is now the ITI).8 SARFI-ITIC considers voltage sags and interruptions that are below the lower ITIC curve. SARFI-SEMI considers voltage sags and interruptions that are below the lower SEMI curve. Again, these curves limit the duration of an rms variation event to the minimum duration of a sustained interruption as defined by IEEE Std 1159, which is 1 min.

K-factor for an electrical network primarily relates to non-linear loads and is defined as a number representing the effect of harmonics on heating of transformer. For calculating the K-factor all the harmonics up to a predefined limit are considered. For industrial loads of induction motors, up to 25th harmonic currents are considered but the limit can be up to 50th.The formula for calculating the K factor of a network is[1]

$$K_{factor} = \sum (I_h) h^2$$

As from the formula, while calculating the K-factor, the harmonic current is being multiplied by the square of its number. Therefore, for higher order harmonics, being multiplied by the square of their number even small harmonic current will give considerable effects on the K-factor. For a linear network, the K factor will always be 1. As the harmonic content increases in the current, the K factor moves upwards from 1. Electronic ballasts, induction motors, UPS and all diode based switching circuits come under non-linear loads causing harmonics.

K-factor of the electrical distribution network is the reason why transformers need to be de-rated. While supplying the non-linear loads, harmonic currents flow in the transformer and to protect the windings and transformer oil from overheating, load on it needs to be reduced.

2.4.2.3.2 KPI based on near real-time calculations

Some of KPIs are based on Power Quality (PQ) measurements, and therefore cannot be obtained from PMU or SCADA data. Instead, they are measured by power quality (PQ) meters:

a. Total Demand Distortion (TDD)
b. Total Harmonic Distortion (THD)
c. Voltage unbalance factor
d. Short and long-term flicker factor

More info about these parameters and how they are calculated can be found in IEEE standards 519-2014, 1159-2009, and 1453-2005.

2.4.2.3.3 KPI based on long-term calculations

This category of indices includes:

- Solar radiation related parameters, such as
  - Daily Clearness Index (DCI) [7,8] and
  - Daily Variability Index (DVI) [7,14]
- Thermal limit (short and long-term), and
- Reliability indices, such as
  - System Average Interruption Duration Index (SAIDI),

[1] See https://zenatix.com/k-factor-for-transformer/

- System Average Interruption Frequency Index (SAIFI),
- Customer Average Interruption Duration Index (CAIDI), and
- Customer Average Interruption Frequency Index (CAIFI).

Table 2-12. Key Performance Indices for Visualization of Field Monitoring

				Display Type							Users	
No	Method	Source	Description	Display in Time	Tabular	Alarm	Histogram	Phasor Diagram	Map Display	Trending	Operators	Engineers
1	Count Rates Calc.	PI Historian	Voltage Swell (SARFI-110) - post-processing based		Y		Y		Y	Y	Y	
2		PI Historian	Voltage Sag (SARFI-80, SARFI-90), post-		Y		Y		Y	Y	Y	
3		Post Processor	Cummulative Tap and Cap Status counts		Y							
4		PI Historian	SARFI-SEMI		Y		Y		Y	Y	Y	
5		PI Historian	SARFI-ITIC (CBEMA)		Y		Y		Y	Y	Y	
6		PI Historian	K-factor (transformer derating) (Substation transformers, as it has sensors)		Y	Y	Y		Y	Y	Y	
7	(Near) Real Time Calculations	PMU/PQ meter	TDD (Available from PQ View)		Y		Y		Y	Y		Y
8		PMU/PQ meter	THD (Available from PQ View)		Y		Y		Y	Y		Y
9		Post Processor	Crest factor (distortion factor)		Y		Y		Y	Y		Y
10		PI Historian	Voltage unbalance factor (doing it in SCADA, pull this information)		Y		Y		Y	Y		Y
11		PI Historian	Flicker factor (short term)	Y	Y		Y			Y		Y
12		PI Historian	Flicker factor (long term)		Y		Y			Y		Y
13	Long-term Calculations	Post Processor	DCI (Daily Clearness Index)		Y		Y			Y	Y	
14		Post Processor	DVI (Daily Variability Index)		Y		Y			Y	Y	
15		Post Processor	Thermal limit (Lookup table for short and long-term limits)		Y	Y	Y			Y	Y	
16		Post Processor	SAIDI (available, for the whole network) (minute basis)		Y		Y			Y		
17		Post Processor	SAIFI (available, for the whole network)		Y		Y			Y	Y	
18		Post Processor	CAIDI (available, for the whole network)		Y		Y			Y	Y	
19		Post Processor	CAIFI (available, for the whole network)		Y		Y			Y	Y	

2.4.2.4 Applications of Field Monitoring

The applications are based on the functions described in use case documents that were selected, as shown in Table 2-13 below.

Table 2-13. List of applications based on use cases

				Display Type							Users	
No	Method	Source	Description	Display in Time	Tabular	Alarm	Histogram	Phasor Diagram	Map Display	Trending	Operators	Engineers
1	More elaborate Calculations (From Use Cases)	PI Historian	Voltage Power Flow Monitoring (VPFM)	Y	Y	Y	Y	Y	Y	Y	Y	Y
2		PI Historian	Primary Distribution Asset Operation Monitoring and Diagnostics (PDAMD)	Y	Y	Y	Y	Y	Y	Y	Y	Y
3		PI Historian	Data Quality Validation for Field PMUs (DQV-FP)	Y	Y	Y	Y	Y	Y	Y	Y	Y
4		PI Historian	Equipment Overload Detection (EOLD)									
5		PI Historian	DER Interconnection Compliance (DER-IC)	Y	Y	Y	Y	Y	Y	Y	Y	Y
6		PI Historian	Water Treatment Facility Monitoring and Reactive Power Management (LICFM)	Y	Y	Y	Y	Y	Y	Y	Y	Y

Explanation below provides more details about each of the applications from this table. Implementation details for each of these applications are provided in the Use Case documents (see attachments), prepared during this project for the purpose of the system design.

2.4.2.4.1 Voltage Power Flow Monitoring (VPFM)

The application based on this use case is relatively simple. The phasor data is used to calculate various power quality aspects of a circuit, in addition to voltage and current profiles, including:

- Voltage profiles based on measurements as selected nodes
- Active and reactive power flow across circuit
- Rate of change of power (ramp rate)
- Rate of change of frequency
- Power factor
- Phase angle jump (or vector jump)
- Sequence components (V1, V2, V0, I1, I2, I0)

Also, logic and mathematical functions based on the information reported from the device can be used to calculate and publish various indices in real-time measurement.

Examples are:

- Voltage sensitivity to change in active and reactive power (dV/dQ and dV/dP)
- Voltage unbalance factor (V2/V1).

Some statistical information is also important and can be extracted from the records of historical data, such as:

- Number and level of voltage sags and swells (per day, per week or user selected timeframe such as the last 2 days or so)
- Number and duration of any momentary or extended interruptions (per day, per week or user selected timeframe such as the last 2 days or so).

In addition, PMU data is used to provide:

- Demand and generation information in various parts of the circuits based on pre-defined zones
- Trends and heat maps of total generation versus loads,
- Comparison of equipment loading and ampacity (load carrying capacity), as well as flagging any possible overloading issue.

2.4.2.4.2 Primary Asset Operation Monitoring and Diagnostics

The objective of this application is:

- To monitor the distribution assets operation and gather supportive data and information that can help quantify the possible wear and tear of assets
- To identify potential issues with assets and provide diagnostic solutions
- To use asset monitoring data along with appropriate data analytics to serve the purpose of implementing condition-based monitoring, diagnostics and scheduled maintenance of asset.

This application focuses on PMU use for monitoring of distribution asset operation including status of switched capacitor banks, number of tap operation for voltage regulators and LTC, operation of reclosers and automated switches, and loading of distribution transformers. The installed PMUs at these assets can stream digital information regarding the asset status (open/close, tap position), in addition to the voltage, current and

power flow values that are used to determine asset loading and utilization factors. Based on the asset status information reported by PMU devices, statistical data on the asset operation intervals and asset condition are traced and reported, such as the number of daily and cumulative tap operation for voltage regulators and load tap changer, number of switched capacitor operation and daily counts, and cumulative load curves.

It should be noted that generally distribution assets are the number one candidates for placing PMU-based intelligent electronic devices (IEDs) such as relays or digital controllers. Hence, obtaining information about the device operation should be easily achievable. The raw data about device status or number of operation will naturally come as part of data reporting from PMU devices associated with selected switchable assets. Hence, the main requirement would be to use the raw data and track the life cycle related information of the devices.

2.4.2.4.3 Data Quality Validation of Field PMU

The objective of this use case is to determine methods for validating field data quality. These include adding measurement reference points and defining expected patterns of variations and ranges of measurements for cross-checking. Reference points can be generated from neighboring locations in the field, or through simulation. Acceptable deviations from reference points should be added for flagging and alarming probable data quality deterioration. In some cases, probable root-cause of the data quality issue may be easily identified, for instance - being a sensor problem, a device problem or a communication link issue. In other cases, a deeper analysis may be needed. This may allow SDG&E to improve the logic for data quality flagging and alarming.

2.4.2.4.4 Equipment Overload Detection

The objective of this application is to:

- Detect equipment overloading
- Identify areas under stress
- Identify circuit congestions (with limitation in power flow).

Sizing for overload is important to avoid serious damage for distribution equipment such as transformers, overhead lines and cables, motors/generators and etc. A real-time measurement of distribution assets support monitoring loading of the equipment all the time and providing different level of alarming to recognize and size the loading of equipment in system normal or under stress operations. Most of the assets are equipped with overload protection devices to disconnect device and avoid serious damage under the overload situation. Having real-time monitoring of loading, system operators can follow loadings of equipment and the trend of its behavior under different normal operation scenarios as well as network events.

2.4.2.4.5 DER Interconnection Compliance

The main objectives of this applications are:

- To use the real-time PMU measurements to assess real-world operational conditions of circuit and response of interconnected DERs
- To use monitored data to evaluate and validate DER behavior under the different circumstances such as:

- DER response to changes in voltage levels, including verification of ride-through curves, and Volt/VAr schemes applied by DERs
- DER inverter behavior under the faults and their fault contribution
- DER connection, disconnection and re-connection timing, any existing ramp up, and time segregation requirements for plants with multiple units.

- To provide recommendations and solutions to planning engineers and system operators to better manage DER interconnections.

2.4.2.4.6 Large Industrial Customer Facility Monitoring

This function is divided in two applications:

1. Reactive power management
2. Flexible local generation usage.

2.4.2.4.7 Reactive Power Management

The main objective of this application is to coordinate and mange operation of large/critical industrial facilities such as Water Treatment Plants with the grid. The key operation aspects from the grid point of view are Real and Reactive power consumption, as well as potential adverse power quality issues (harmonics).

Specifically, for the reactive power management, the main value-added feature and advantage offered by the use case will be coordination of reactive power requirements from the plant with operation of shunt capacitors on the associated circuit feeding the plant.

Proper reactive power management supports loss reduction on circuits. Through reactive power control, voltage profile of the circuit can also be controlled and maintained within standard range. In selected circuit, specifically, there are three Line Monitoring locations which monitor two large pumping stations and one end-of-line circuit branch. The end-of-line location does not monitor any water facilities and therefore will be used only to monitor the overall power quality of the circuit. The other two locations monitor Water Treatment Plant's east and west pumping station. There are also two switched capacitors installed at two pumping stations which could be used as a reactive power support when the reactive power demand exceeds a certain threshold.

2.4.2.4.8 Flexible Local Generation Usage

The main purpose of this application is to shift most of the water treatment plant (WTP) demand to the daytime hours with high PV production. If a circuit has large amount of PV, one of the major operational issue is to manage power flow and corresponding voltage profile. The issue is more severe under light load condition of the circuit, causing reverse power flow.

If the circuit load can be controlled by the operator to coordinate operation with customer demands to provide a flexible usage schedule, additional load can be brought online, as needed, during high production time. Hence, coordinating load and generation can be applied by the operator to manage voltage profile and extensive operation of voltage control devices on a circuit.

To reduce energy cost in a WTP, the operating schedule for major load (large motor pumps) is closely planned during the off-peak time of the system (10 pm to 5 am). However, if proper energy cost policies can be agreed for daytime usage, to provide low cost and/or incentive driven energy consumption, the method can be used to control voltage and frequency. This approach is essentially beneficial during emergency water shortage time, when the facility has to operate pumps during daytime to fill up water tower, due to unplanned excessive water usage.

To implement flexible usage application, a new energy cost structure should be prepared to encourage daytime usage. In addition, integrating large load facilities into overall system planning and operation can make them part of critical system asset to balance load and generation. Using the dispatchability aspect of the WTP, and solar prediction, the load can be controlled to match with high PV production and avoid reverse power flow.

Furthermore, performing operation during times when renewable energy is abundant can minimize the carbon footprint needed to treat and deliver potable water to the county and thus impacting the overall Water Energy Nexus.

2.5 Development of Monitoring, Control and Operation Practices in Support of Customer Installations

The task objective was to propose and design advanced monitoring and control practices that can close the gaps in the exiting schemes to properly investigate any adverse impact and facilitate customer system integration. All of the following aspects have been incorporated: system capabilities, monitoring devices and data capturing and post-mortem analysis. The main activities in undertaking this task were:

- To determine the response requirements and operational practices to support customer systems
- To define the monitoring requirements and system architecture, including the communications and controls for advancement of system operation
- To investigate capabilities of commercially available sensors, power quality and/ revenue metering devices, and phasor measurement units (stand-alone or as part of other IEDs) that can provide high resolution data measurement and power quality data capturing and transient event recordings, such as:
    - Voltage and current phasors
    - Power flow (active and reactive)
    - Frequency tracking and reporting rate of change of frequency (ROCOF)
    - Harmonics and THD/TDD measurements
    - Fast transients
    - System status information, including switch position, voltage regulators, tap positions; and
    - circuit connectivity information

- To evaluate product capability documents from vendors; or perform laboratory tests on selected measurement devices (sensors, IEDs, PMUs) to determine accuracy, measurement resolution and quality and type of measurement data such as transient events, to understand and document expected device performance
- To define PMU requirements specific to distribution systems
- To prepare settings and configuration files for the devices in the field to support project data gathering and device control needs
- For cases of inadequate device capability and/or coverage, propose temporary methods and devices to be incorporated in the real-time simulation environment to supplement the existing devices and data coming from the field for the purpose of evaluating the tools under development.

2.5.1 Survey of Commercially Available PMU Devices

As part of identification of the devices suitable for the system integration and pre-commercial demonstration, a survey of available automation/protection/monitoring devices with PMU capability was conducted. The survey focused on devices commercially available in the market for deployment in electric distribution systems. For the purposed of comparison, the result of this survey was used to select vendor devices for the demo set-up in the lab.

A number of the listed devices in the survey table have been already deployed in SDG&E distribution circuits, and their phasor data have been monitored in near real time.

Based on the survey and desired features, 4 devices have been selected for a detailed performance evaluation based on a hardware-in-the-loop RTDS testing (Type test). They were compared with a reference PMU device that has PMU certification based on NIST certification standard. Furthermore, the same devices have been utilized in the pre-commercial demonstration.

The selected devices were:

1. PMU Device 1: a protective relay usually installed at DER location; e.g., PV site, diesel generator POI to the feeder,
2. PMU Device 2: a commonly used feeder protection relay in SDG&E distribution circuits,
3. PMU Device 3: an offering from a new vendor in PMU market.
4. PMU Device 4: a new generation of fault recorder that has been considered by SDG&E as a potential option for future installation).

In the rest of this section, methodology and results of the type tests have been reported.

2.5.2 Type Test: Performance Comparison of the Selected PMU Devices

The objective of these tests was to evaluate the performance and capabilities of the aforementioned PMUs from the following aspects:

- Evaluating compliance of vendor products that are not commonly used at SDG&E distribution system
- Evaluating of the devices under test (DUTs) for providing high resolution data measurement (60 and 30 frames per second) and power quality data capturing and transient event recordings
- Determining accuracy, measurement resolution, quality and type of measurement data such as transient events for specific distribution system applications
- Evaluating interoperability of the PMU devices and measurement/communication features to make sure devices can be integrated with products from other vendors in a multi-vendor environment
- Capability to transfer analog and digital signals in C37.118 format – for values internally calculated at device level (for example, THD or flicker, etc.)

The test results were used to select appropriate devices and to develop measurement features for the integration testing and monitoring of distribution applications in support of customer technology integrations.

Note that only the results of selected tests from each test group are presented in this document. The reason is that many of the tests are very similar in each test group and repeating similar results does not provide any additional information. However, all the results of different tests were submitted in a complete test report to SDG&E.

2.5.2.1 Type Test Approach Description

A real-time digital simulator (RTDS) has been used to represent a 12 kV simplified distribution circuit where the devices under test (DUT) are connected at certain locations for voltage and current measurements. A simplified single line diagram of the RTDS real time view of the model is shown in Figure 2-4. The location of the PMU device under the test is shown with a red rectangular (PQ meter) where the voltage and current signals are taken.

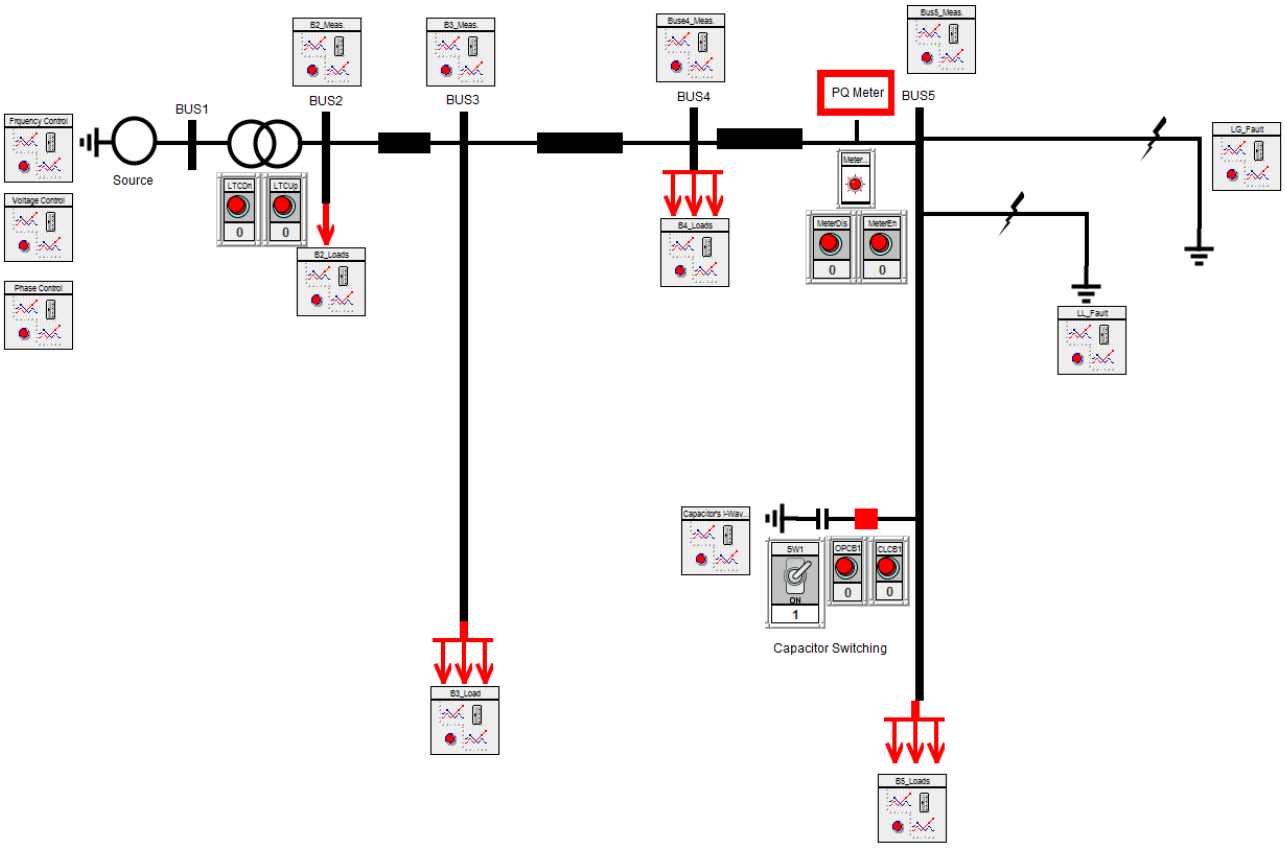


Figure 2-4. Real-time RTDS View of the Distribution Circuit Used for Device Tests

A Phasor Data Concentrator (PDC) was used to communicate with DUTs, capturing PMU data streams for data analysis and performance evaluation. Different test categories under either steady state system conditions or dynamic system conditions were performed to evaluate the performance of each DUT. For the test categories to be performed, all DUTs were configured with the maximum available phasor and analog measurements based on the DUT capability.

Depending on the test, the performance of PMUs was evaluated through Total Vector Error (TVE), Frequency Error (FE), Rate of change of Frequency Error (RFE), or the transient response comparison of the PMUs.

2.5.2.2 Testbed setup

The hardware testbed for PMU performance testing was setup and operated at the RTDS lab in SDG&E ITF. A PDC unit was setup for data stream capturing and interoperability tests. The general layout of the testbed is illustrated in Figure 3-5, consisting of the following components:

- **RTDS:** used to simulate the virtual PMU and a 12kV simplified distribution circuit including: a source, line impedances and loads.
- **PMU Device 1:** DUT1 for phasor data measurement and streaming

- **PMU Device 1:** DUT2 for phasor data measurement and streaming
- **PMU Device 3:** DUT3 for phasor data measurement and streaming
- **Reference PMU:** DUT4 for phasor data measurement and streaming. It is used as the reference PMU.
- **GPS clock** used for time synchronization of RTDS, DUTs.
- **PDC** for communicating with DUTs, capturing PMU data streams and evaluating DUTs' performance
- **Power amplifier**

Figures 3-5 and 3-6 show the block diagram of the type test setup as well as actual setup at the SDG&E ITF Lab.

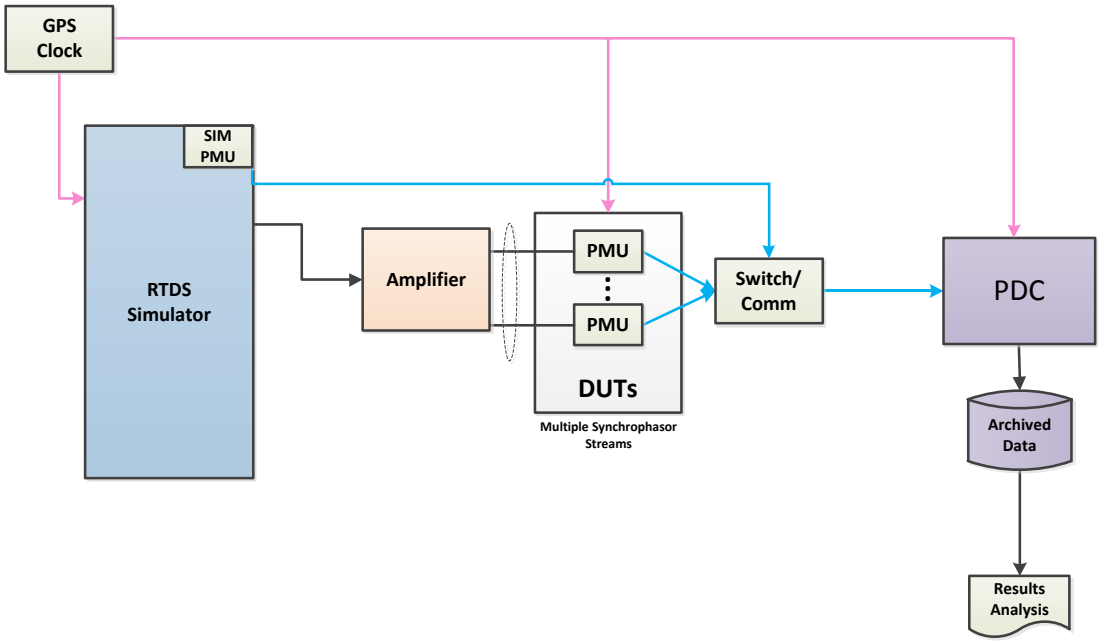


Figure 2-5. PMU Testbed Setup layout



Figure 2-6. PMU Test Setup at the ITF lab

2.5.2.3 Summary of Test Cases and Categories

Test cases have been categorized in 3 main groups:

a. Category 1: Steady state performance test. In this test category, the performance of the PMUs subsequent to different steady state conditions such as frequency variations and harmonics was studied.

b. Category 2: Dynamic performance test. Different transient scenarios such as cap switching, frequency ramp, and voltage and phase angle step change were applied to the PMUs, and their responses were compared.

c. Category 3: Verification of analog and digital data streaming. In this test category, aim was to verify a DUT capability for streaming locally measured power quality parameters or any parameter that was calculated at device level using mathematical and logical blocks.

2.5.2.4 Evaluation Method

PMU type tests focused on testing the M performance class of DUTs according to the definition in IEEE C37.118 - 2011. Before the representation of the results, it is necessary to provide some definitions:

Total Vector Error (TVE): TVE is defined as:

$$TVE = \frac{|V_{measured} - V_{true}|}{|V_{true}|}$$

In which (V_{true}) is the reference phasor and $V_{measured}$ is the phasor obtained from the PMU. In this report, the reference phasor(V_{true}) is considered as the output of the Reference PMU, because it is a certified PMU.

Frequency Error (FE): FE is defined as

$$FE = |f_{true} - f_{measured}|$$

Rate of Change of Frequency Error (ROCOF or RFE): RFE is defined as

$$RFE = |\left(\frac{df}{dt}\right)_{true} - \left(\frac{df}{dt}\right)_{measured}$$

2.5.2.5 Category 1: Steady-State Performance Test

The purpose of this test category was to test the DUTs' performance under steady state conditions. The phasor measurements estimate under steady-state conditions were compared with the Reference PMU measurement and FE and ROCOF are compared to the nominal values.

TVE, FE, and RFE was calculated and compared with defined limits in IEEE C37.118.1. Several test groups was considered in this test category. All the test groups in category 1 were performed with DUTs' reporting rate set at 60 frames/second.

2.5.2.5.1 Group 1: Voltage Magnitude Test

Group 1 tests were designed for evaluating the DUTs' performance for steady state voltage magnitude measurements. For group 1 tests, balanced three phase system voltages and currents at nominal system frequency were applied to the DUTs. Each of the following test cases was repeated 3 times for test results validation.

- **Case 1-1-1:** System voltage was set at nominal system voltage and the PMU data streams were captured for 5 seconds. The following figures show the TVE for voltage phasors, FE and RFE.

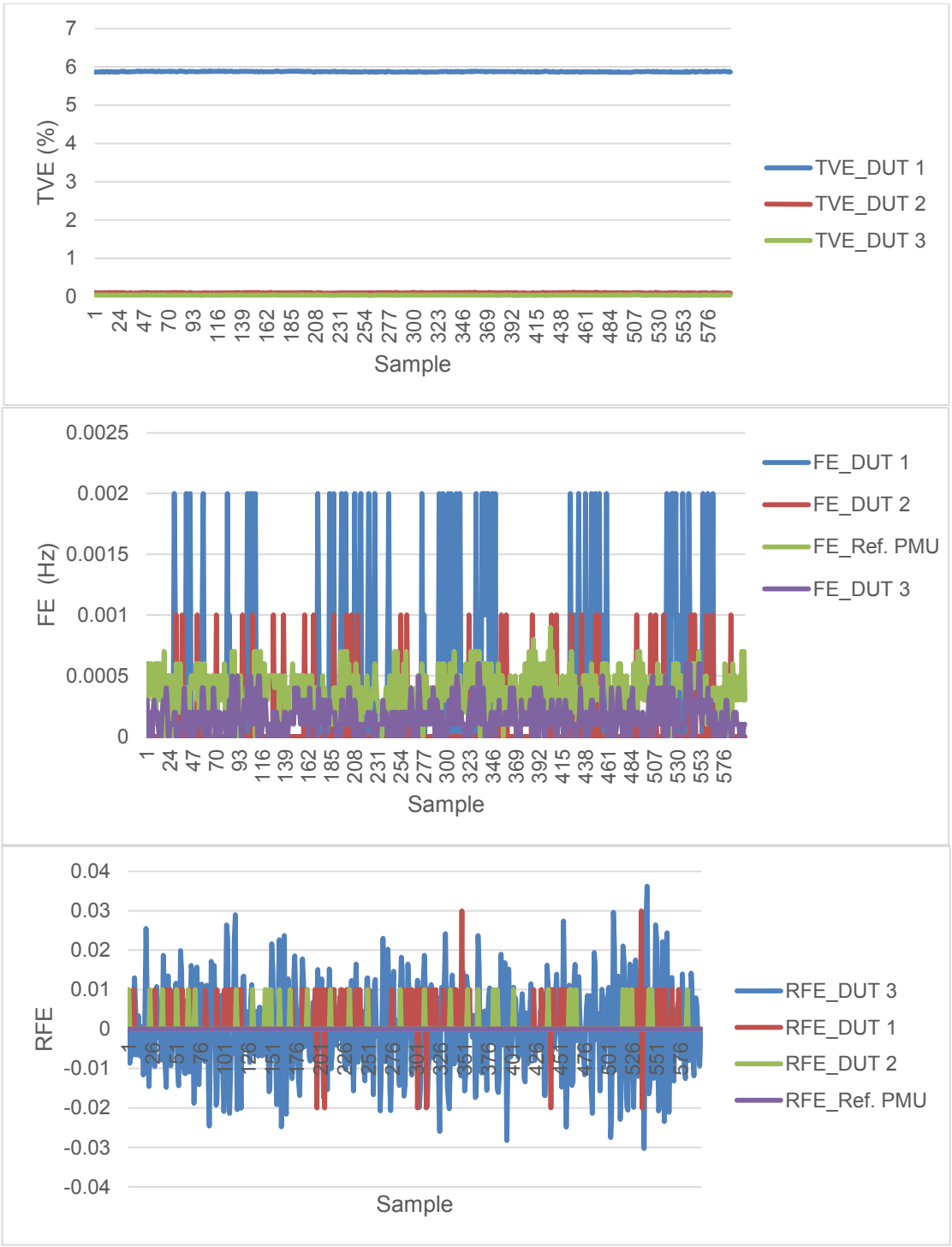


Figure 2-7. TVE, FE, and RFE Comparison for Nominal Voltage (Case 1-1-1)

- **Case 1-1-2:** System voltage was set at 50% of nominal system voltage and the PMU data streams were captured for 5 seconds. The following figures show the TVE for voltage phasors, FE and RFE. Except DUT1, all other devices showed acceptable results and errors within the expected range. The measurement offset of DUT1 created a large TVE % error comparing to others.

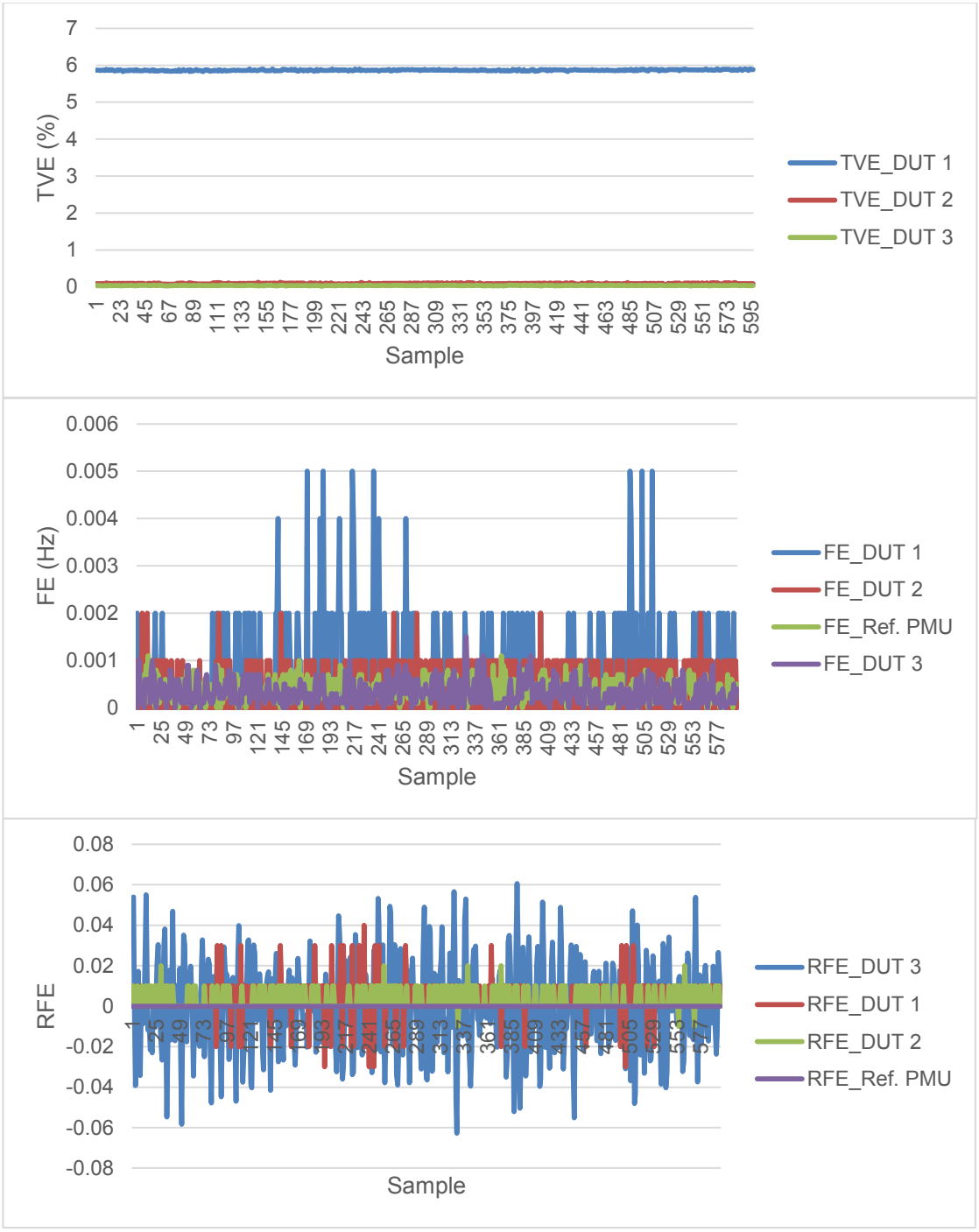


Figure 2-8. TVE, FE, and RFE Comparison for 50% of the Nominal Voltage (Case 1-1-2)

- **Case 1-1-3:** System voltage was set at 130% of nominal system voltage and the PMU data streams were captured for 5 seconds. The following figures show the TVE for voltage phasors, FE and RFE. As can be seen, DUT 1 had a 6% error due to inaccuracy in phasor measurements.

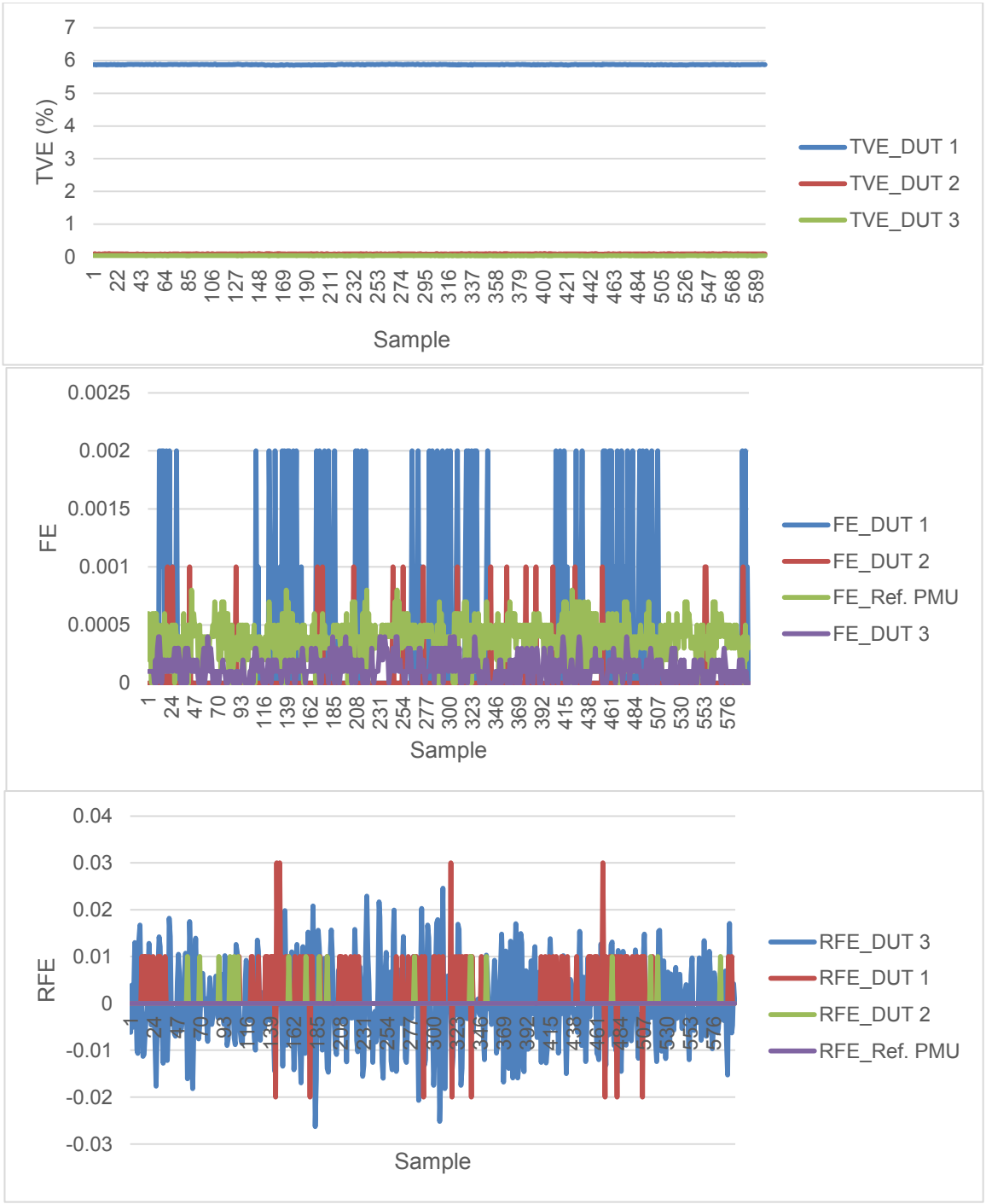


Figure 2-9. TVE, FE, RFE for 130% of Nominal Voltage (Case 1-1-3)

- **Case 1-1-4:** System voltage was set at nominal system voltage and run for 20 seconds. Phase B was disconnected at the source, and positive and negative sequence measurements from PMUs were recorded before and after the disconnection. It should be noted that DUT1 and DUT2 do not provide negative sequence measurements; therefore, the values had to be calculated using ABC phasors. The following figure shows the magnitude and TVE for positive sequence.

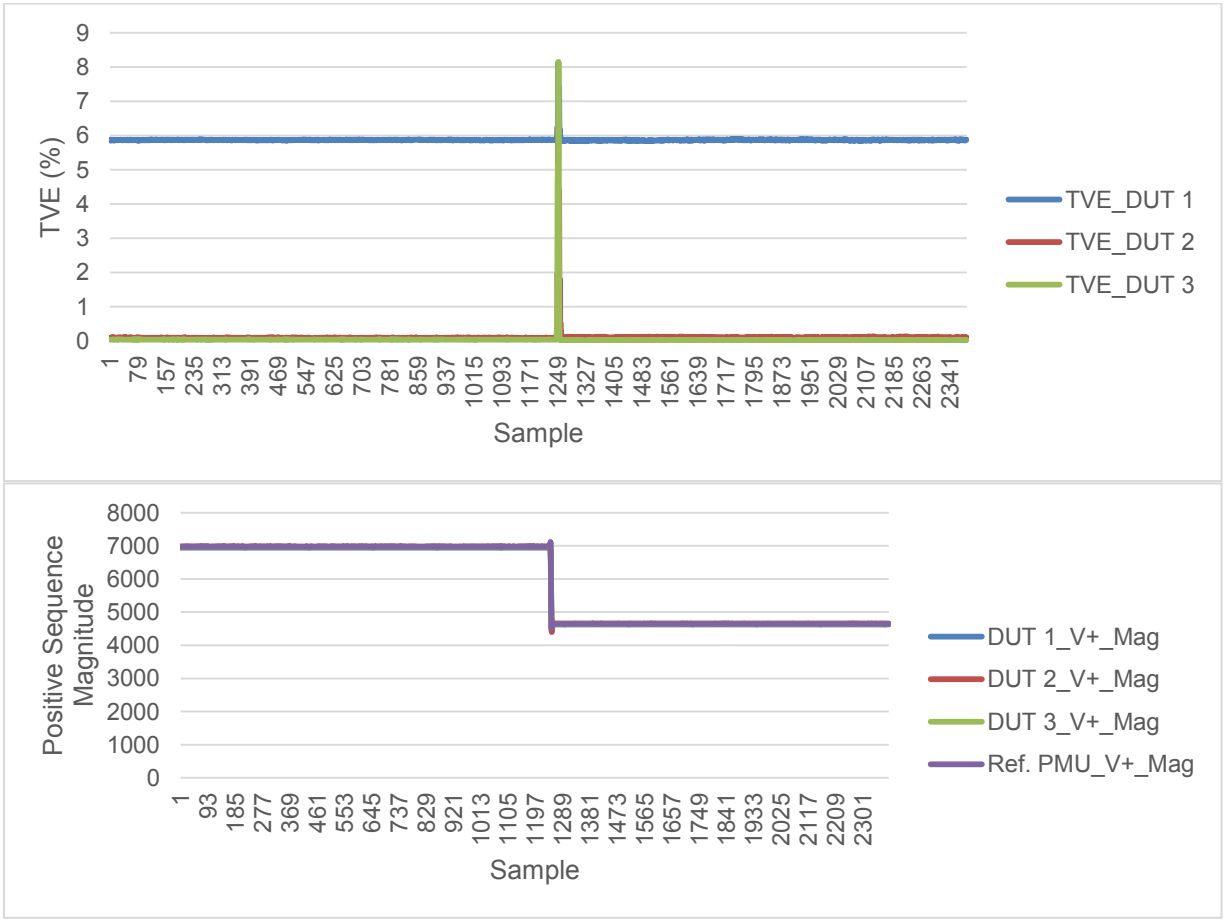


Figure 2-10. TVE and Magnitude of the Positive Sequence Subsequent to the Disconnection of Phase B (Case 1-1-4)

It can be seen that during the step change, a spike happened in the TVE. The duration of this spike was around 8 samples for all PMUs, which showed the convergence rate of the PMUs.

The next figure shows the TVE and magnitude of negative sequence. It should be noted that TVE was just shown during unbalanced operation of the system.

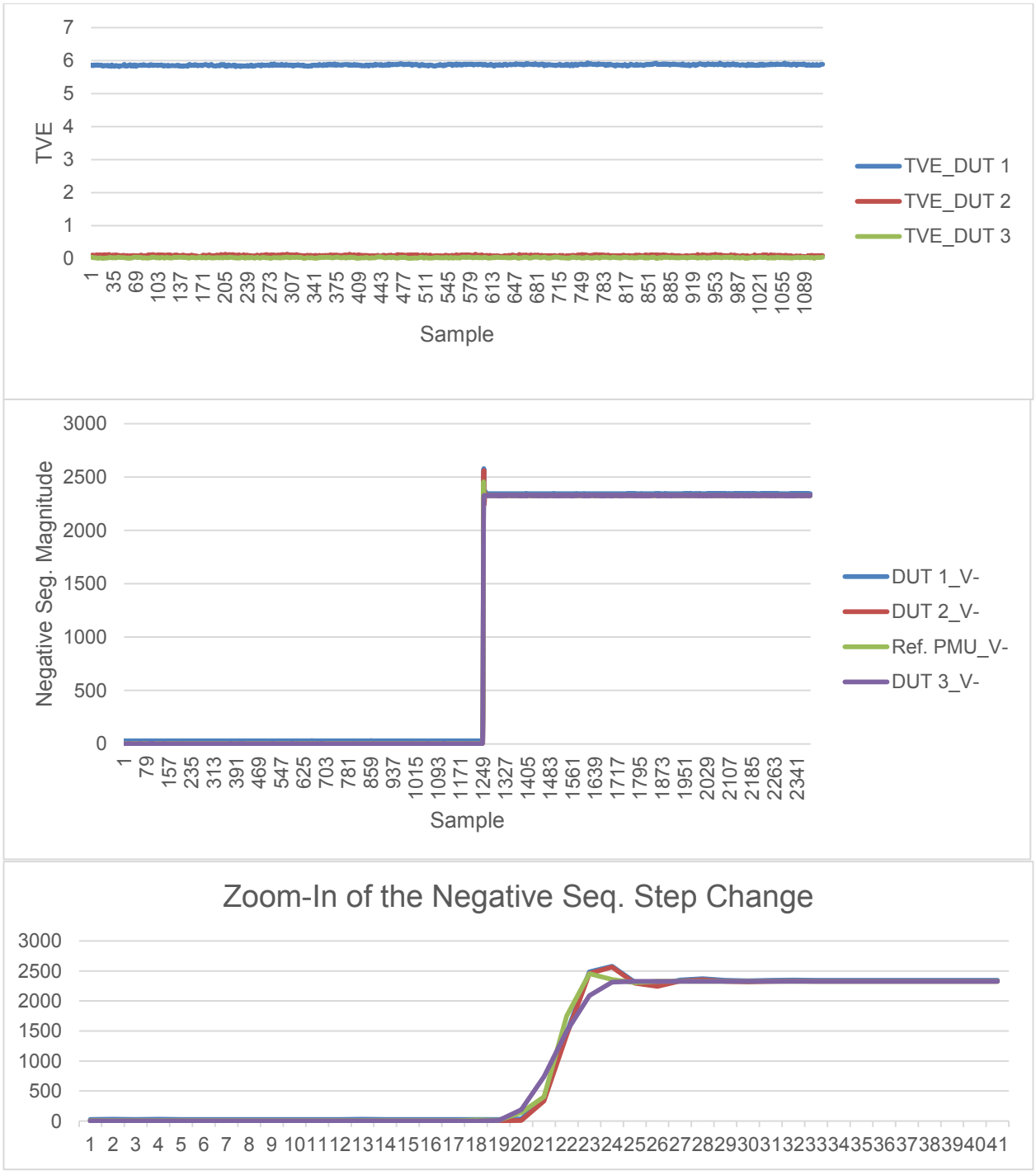


Figure 2-11. TVE and Magnitude of the Negative Sequence Subsequent to the Disconnection of Phase B (Case 1-1-4)

Note: Case 1-1-5 and case 1-1-6 are excluded because of their similarity to the previous results.

- **Case 1-1-7:** System was set at the nominal frequency, two phase voltages at nominal voltage and the third at 105% of nominal voltage. PMU data were captured for 5 seconds. The magnitude and TVE of the positive sequence as well as the magnitude and TVE of the negative sequence are shown in the following figures.

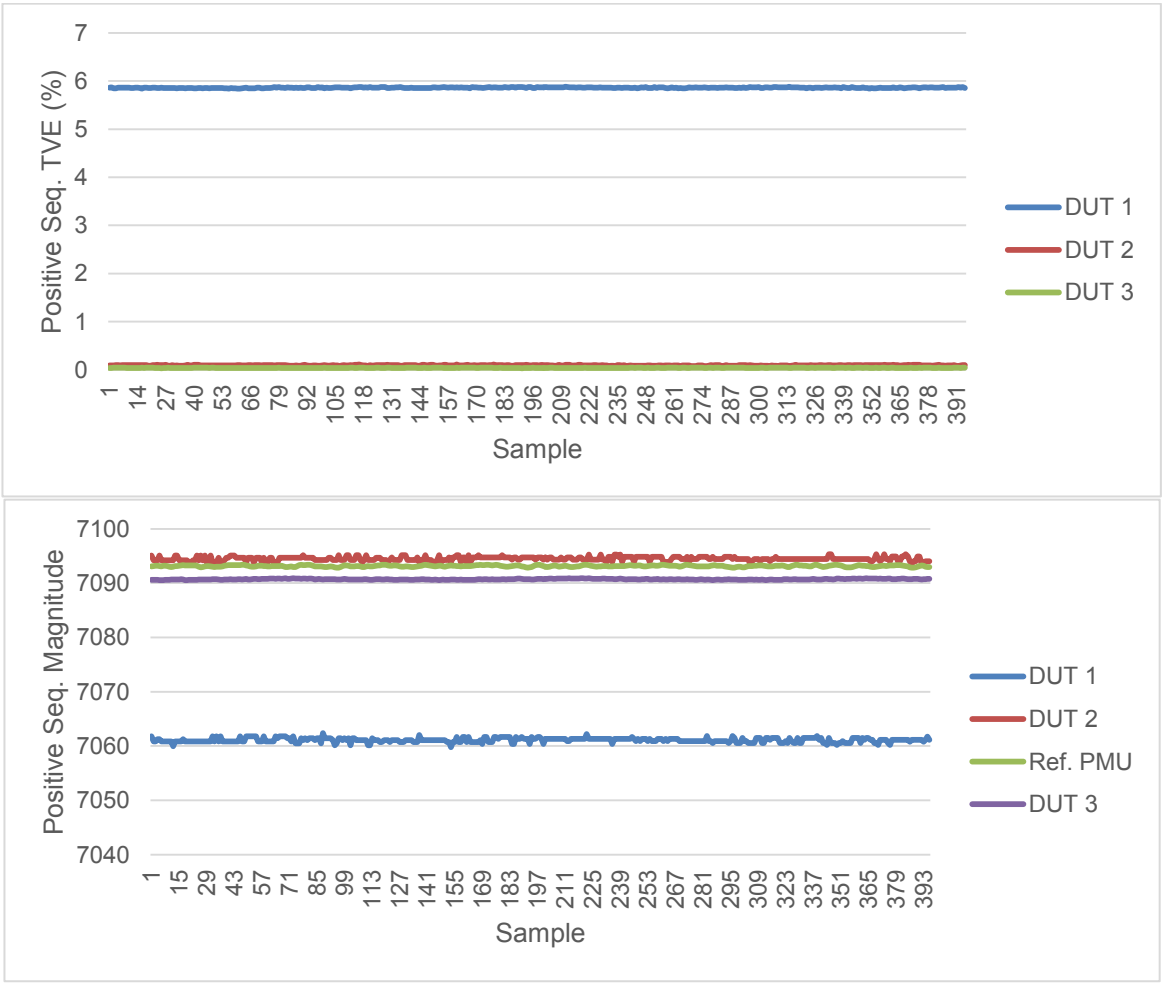


Figure 2-12. TVE and Magnitude of the Negative Sequence (Case 1-1-7)

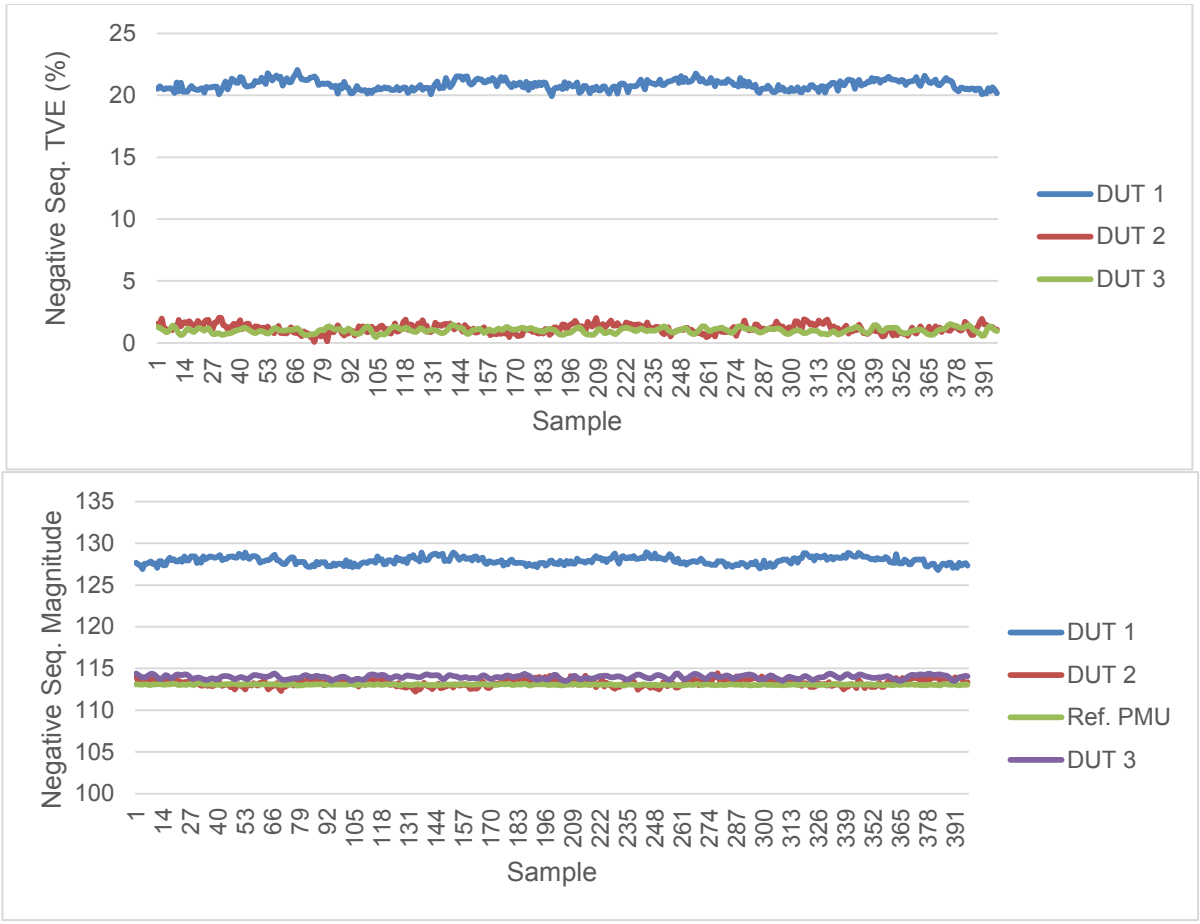


Figure 2-13. TVE and Magnitude of the Negative Sequence (Case 1-1-7)

2.5.2.5.2 Group 2: Frequency Step Test

Group 2 tests are designed for evaluating the DUTs' performance for frequency measurements. For group 2 tests, balanced three phase system voltages and currents were applied to the DUTs. Each of the following test cases was repeated 3 times for test results validation.

Note: Case 1-2-1 was excluded because it is exactly similar to case 1-1-1.

- **Case 1-2-2:** The system frequency was set at 59.7 Hz and the PMU data was captured for 5 seconds. Then, the frequency was changed back to 60 Hz, to continue capturing for another 5 seconds. The following figures show the frequency captured from different devices as well as the FE and RFE. It can be seen from the last figure that the 360 rotation happens within 200 samples. This is consistent with the frequency variation of 0.3 because $200 = \frac{1}{0.3} \times 60$. Furthermore, all PMUs have angle recovery after the frequency gets back to 60 Hz.

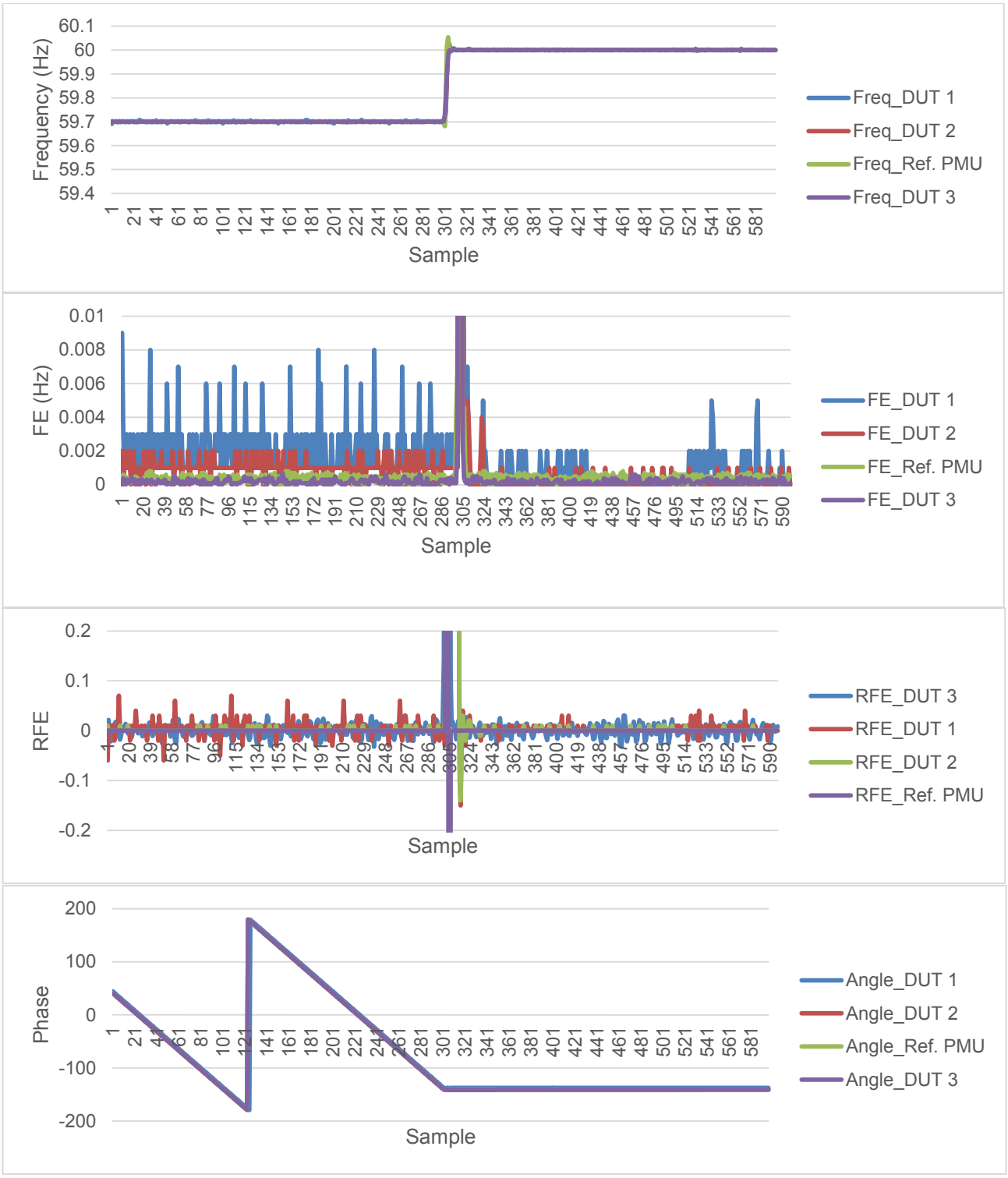


Figure 2-14. Frequency, FE, RFE, and Angle Subsequent to the Step Change of Frequency from 59.7 Hz to 60 Hz (Case 1-2-2)

An interesting observation that we made in this test is that the Arbiter lost the accuracy of its magnitude (for around 0.5 sec) due to the frequency step change. The positive sequence magnitudes from different PMUs can be seen in the following figure.

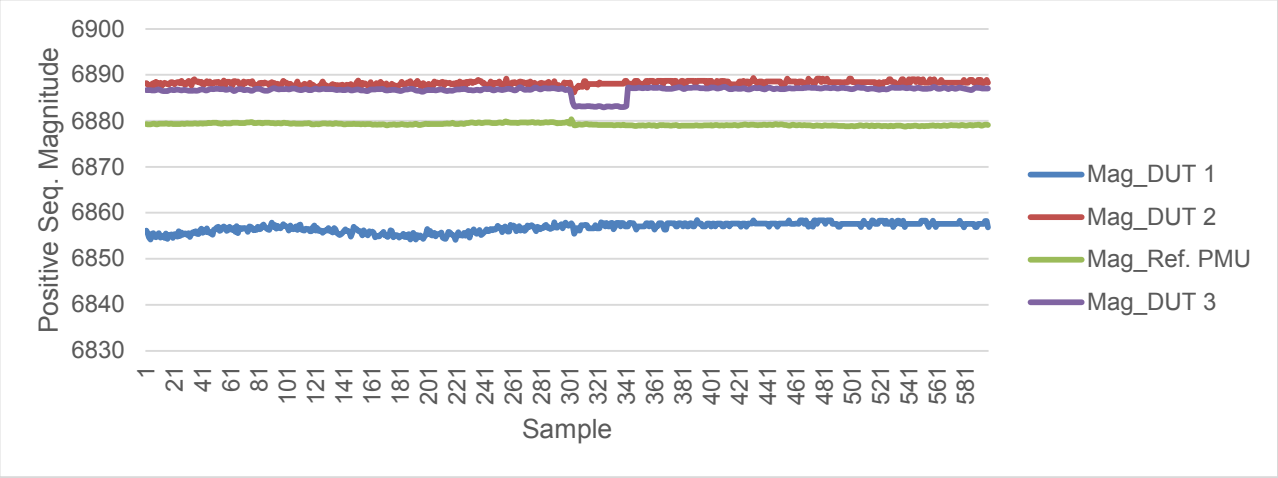


Figure 2-15. Positive Sequence Magnitude Subsequent to the Step Change of Frequency from 59.7 Hz to 60 Hz (Case 1-1-2)

Note: Case 1-2-3 and case 1-2-4 were excluded because of their similarity to the previous results.

- **Case 1-2-5:** The system frequency was set at 61 Hz and the PMU data was captured for 5 seconds. Then, the frequency was changed back to 60 Hz, continue capturing for another 5 seconds. The following figures show the frequency captured from different devices as well as the FE and RFE. The last figure shows that all PMUs have angle recovery after the frequency gets back to 60 Hz.

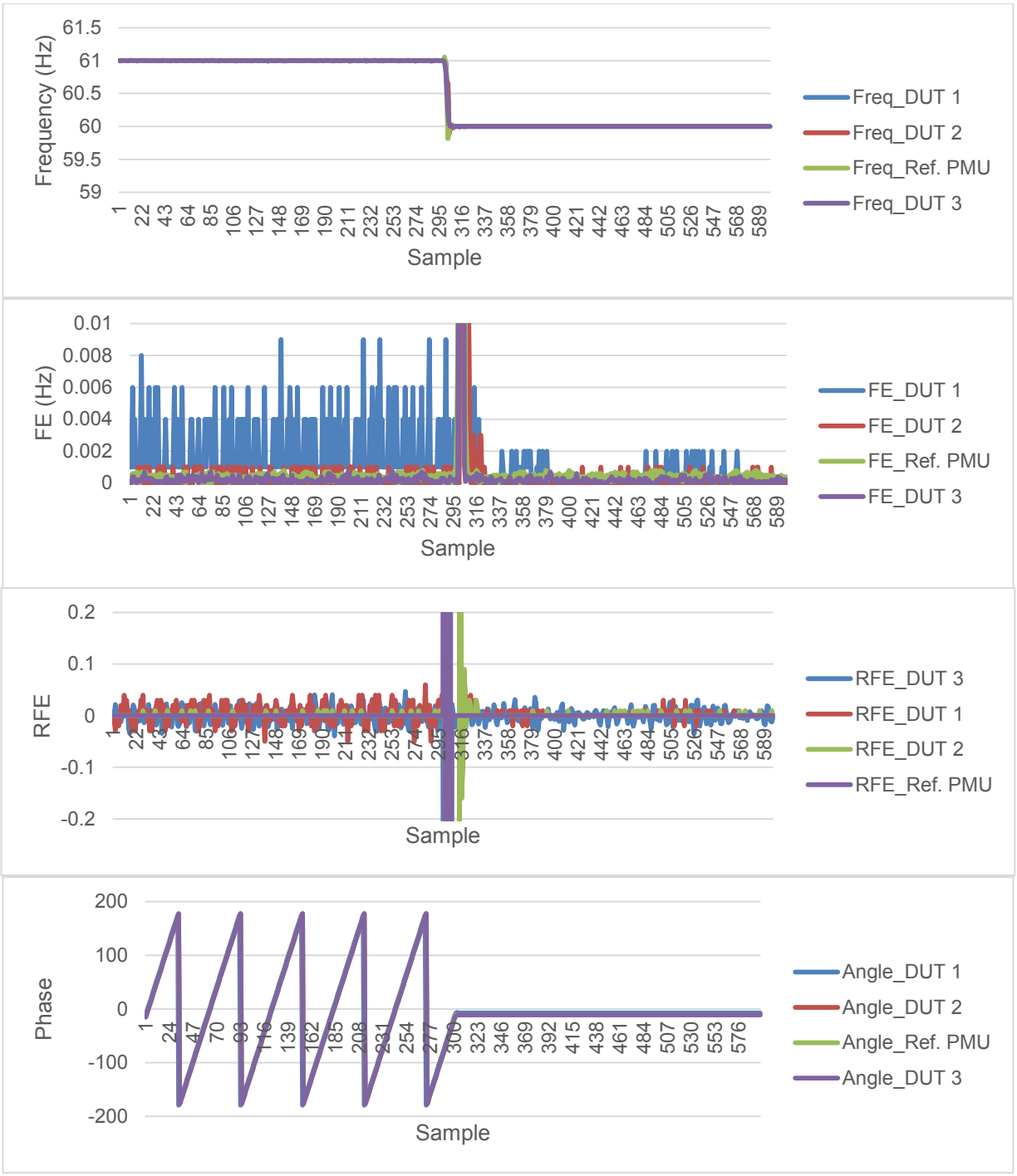


Figure 2-16. Frequency, FE, RFE, and Angle Subsequent to the Step Change of Frequency from 61 Hz to 60 Hz (Case 1-2-5)

The same effect we observed on the previous test case for DUT3 PMU happened for this test case as well, as shown in the following figure. These test cases suggested that the estimated magnitude of the DUT3 could be dependent on the change of the frequency.

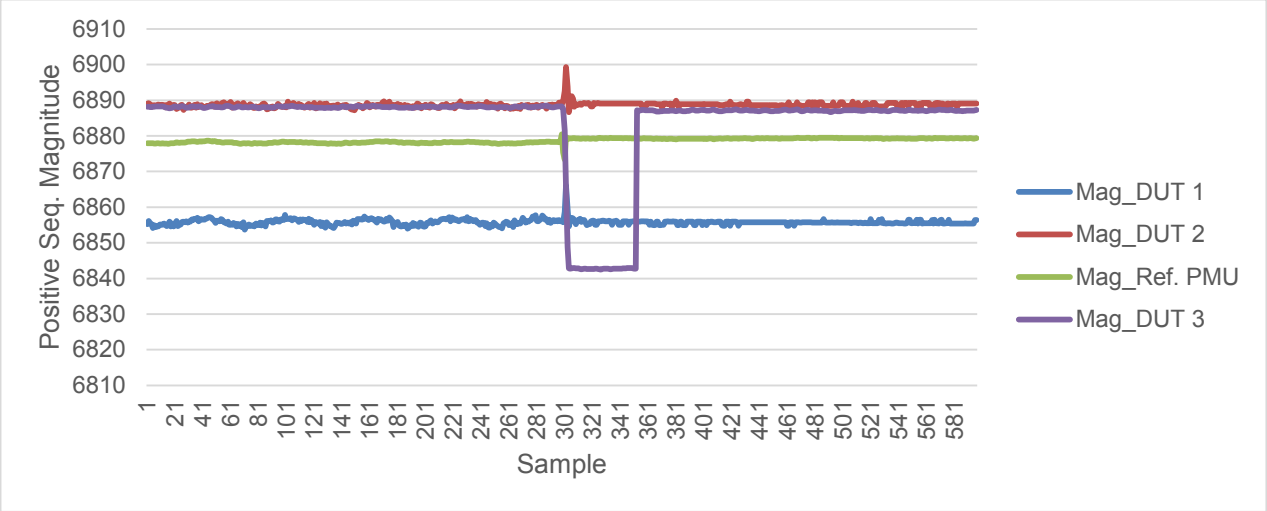


Figure 2-17. Positive Sequence Magnitude Subsequent to the Step Change of Frequency from 61 Hz to 60 Hz (Case 1-2-5)

2.5.2.5.3 Group 3: Harmonic Distortion Test

Group 3 test was designed for evaluating the DUTs' responses to harmonic distortion. For group 3 test, balanced three phase system voltage, current and nominal system frequency was applied as input to the DUTs. Each of the following test cases was repeated 3 times for test results validation. It should be noted that the TVE of Device 1 was very large (around 6%) compared with Device 2 and Device 3 (around 0.1%). Therefore, in order to provide a better comparison between DUT2 and DUT3, the TVE for DUT1 is not shown in this test group.

- **Case 1-3-1:** The system was started at nominal levels for voltage and frequency, while injecting the 5th harmonic with 3% magnitude of voltage and current into DUTs' measurement location. PMU data was captured for 5 seconds. TVE and FE are shown in the following figures.



Figure 2-18. TVE and FE during the Injection of 3% Magnitude of 5th Harmonic (Case 1-3-1)

- **Case 1-3-2:** The system was started at nominal levels for voltage and frequency, while injecting the 5th harmonic with 5% magnitude of voltage and current into DUTs' measurement location. PMU data was captured for 5 seconds. TVE and FE are shown in the following figures.



Figure 2-19. TVE and FE during the Injection of 5% Magnitude of 5th Harmonic (Case 1-3-2)

- **Case 1-3-3:** The system was started at nominal levels for voltage and frequency, while injecting the 5th harmonic with 10% magnitude of voltage and current into DUTs' measurement location. PMU data was captured for 5 seconds. TVE and FE are shown in the following figures.



Figure 2-20. TVE and FE during the Injection of 10% Magnitude of 5th Harmonic (Case 1-3-3)

Note: Case 1-3-4, 1-3-5, and 1-3-6 are excluded because of their similarity to the previous results.

- **Case 1-3-7:** The system was started at nominal levels for voltage and frequency, while injecting multiple harmonics (3% of 7th order harmonic, 5% of 5th order harmonic and 10% of 3rd order harmonic) into DUTs' measurement location. A harmonic generator model was used in RTDS circuit model to inject various harmonic orders or a combination of harmonics. PMU data was captured for 5 seconds. TVE and FE are shown in the following figures.

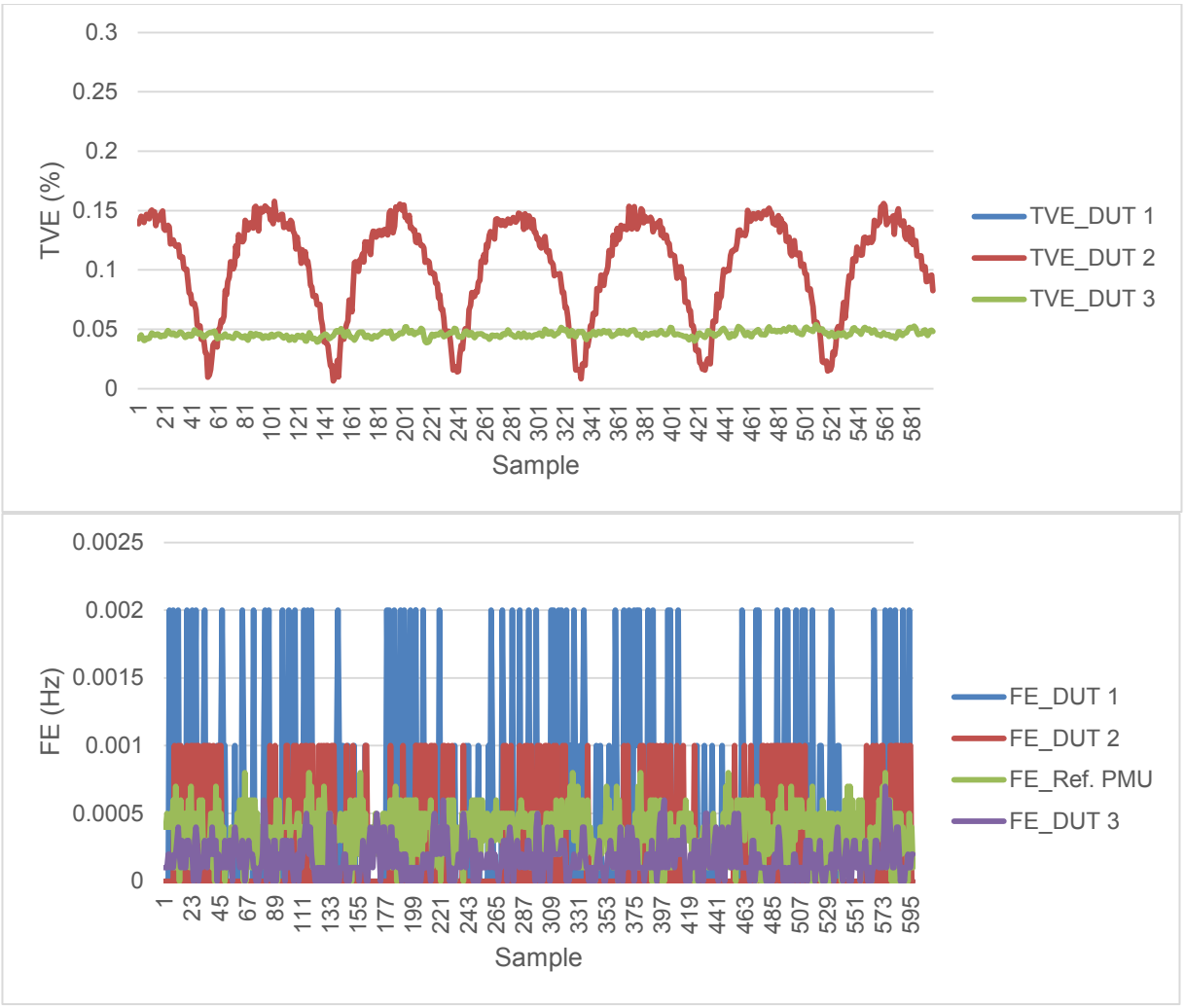


Figure 2-21. TVE and FE during the Injection of Multiple Harmonics (Case 1-3-7)

By comparing the results of this test group, it can be concluded that by increasing the Harmonics the FE increases. Furthermore, the TVE of DUT3 was very robust against harmonics, while the TVE of DUT1 and DUT2 increased by increasing the THD of the voltage.

2.5.2.6 Category 2: Dynamic Performance Tests

The purpose of this test category is to test the DUTs' performance under dynamic system conditions. The phasor, frequency, and ROCOF estimates obtained from DUTs under different system conditions are compared to the corresponding input measurements. TVE, FE, and RFE is calculated and compared with defined limits in IEEE C37.118.1. Several test groups will be considered in this test category. For category 2 tests, all the test groups were repeated with DUTs' reporting rate set at 60 frames / second and 30 frames / second. However, in this report, only the data at 60 frames/second is reported. Each of the following test cases was repeated 3 times for test results validation

2.5.2.6.1 Group 1: Response to Step Change in Amplitude and Phase

Group 1 tests are designed for evaluating the DUTs' responses to the step changes applied to voltage, current and phase angle. Step changes were applied to voltage, current and phase angle and PMU data streams were captured to calculate TVE.

- **Case 2-1-1:** System voltage and frequency was set at nominal value for 20 seconds. The following actions was applied to the voltage:
  - 10% step voltage increase was applied at the source for 0.5 seconds;
  - Voltage was changed to initial value for 20 seconds;
  - 10% voltage decrease was applied at the source for 0.5 seconds;
  - Voltage was changed to initial value.

The following figures shows positive sequence magnitude and TVE subsequent to the voltage change.

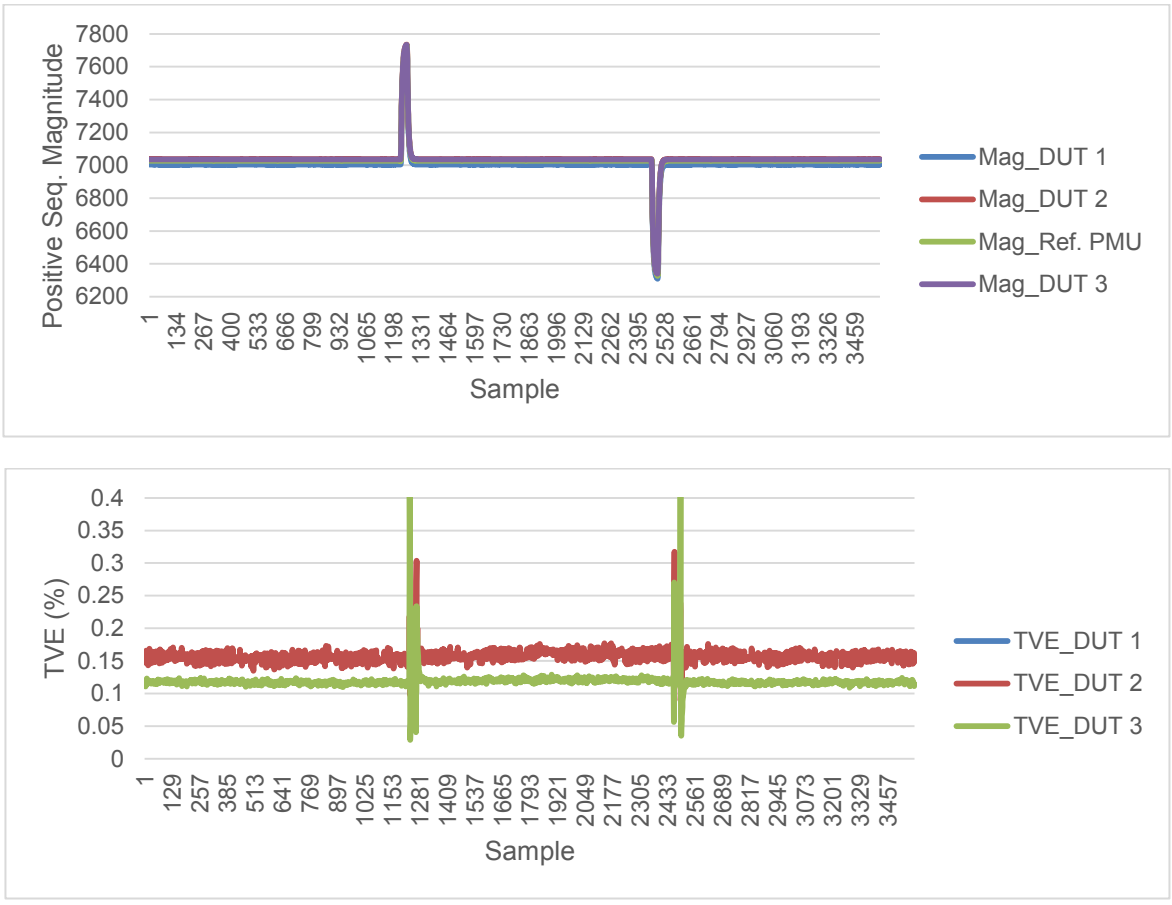


Figure 2-22. Positive Sequence Magnitude and TVE Subsequent to Voltage Changes (Case 2-1-1)

To better compare the dynamic performances, a zoom-in plot of the positive sequence magnitude is shown in the next figure.

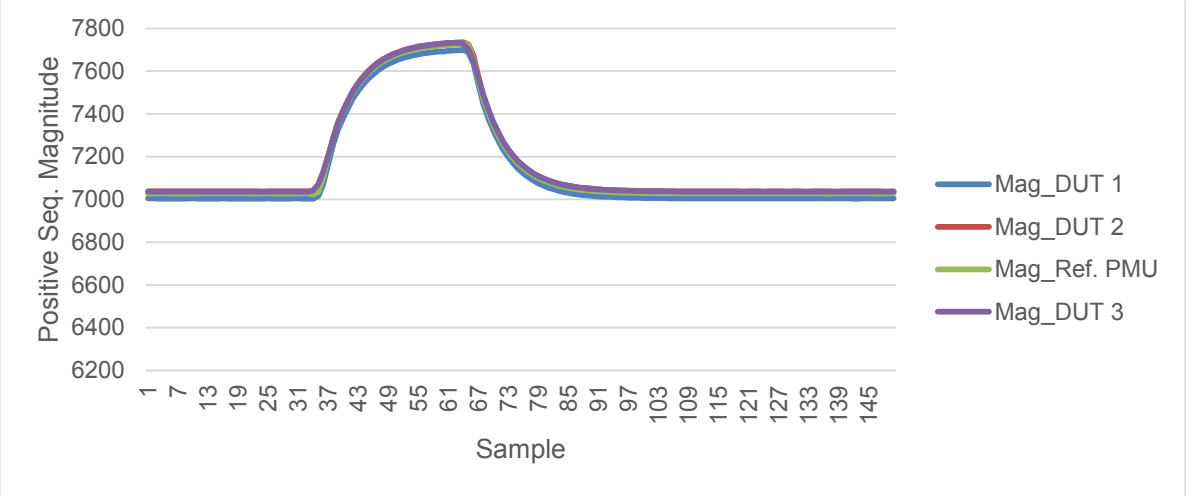


Figure 2-23. Zoom-In Plot of the Positive Sequence Magnitude (Case 2-1-1)

- **Case 2-1-2:** System voltage and frequency were set at nominal value with a 3 phase balanced inductive load with the power factor of 0.75. Load was increased by 10% for 20 seconds and changed back to initial value for 20 seconds. Then, it was decreased by 10% for 20 seconds. The following figures show positive sequence magnitude and TVE subsequent to the load change.

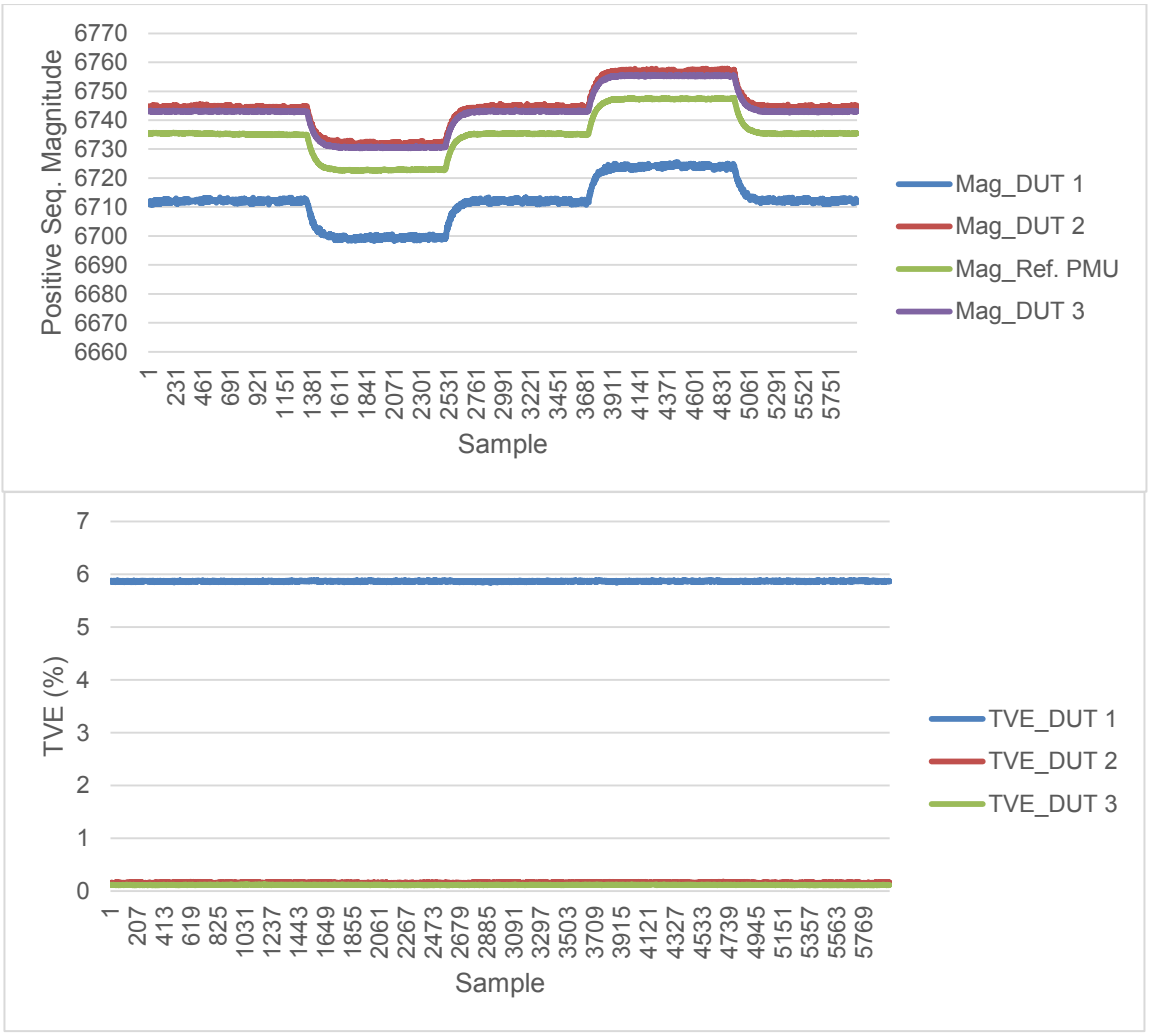


Figure 2-24. Positive Sequence Magnitude and TVE of Voltage Subsequent to Load Changes (Case 2-1-2)

- **Case 2-1-3:** System voltage and frequency were set at nominal value. After 20 seconds, phase angle was increased 45 degrees for all three phases for 0.5 seconds and changed back to its initial value for 20 seconds. Then, phase angle was decreased by 45 degree for all three phases for 0.5 seconds and changed back to its initial value. Note that the phase angle change through the model was used to create sudden vector jump to evaluate DUT responses.

  The following figures shows TVE, magnitude, and phase of the positive sequence subsequent to the voltage change.

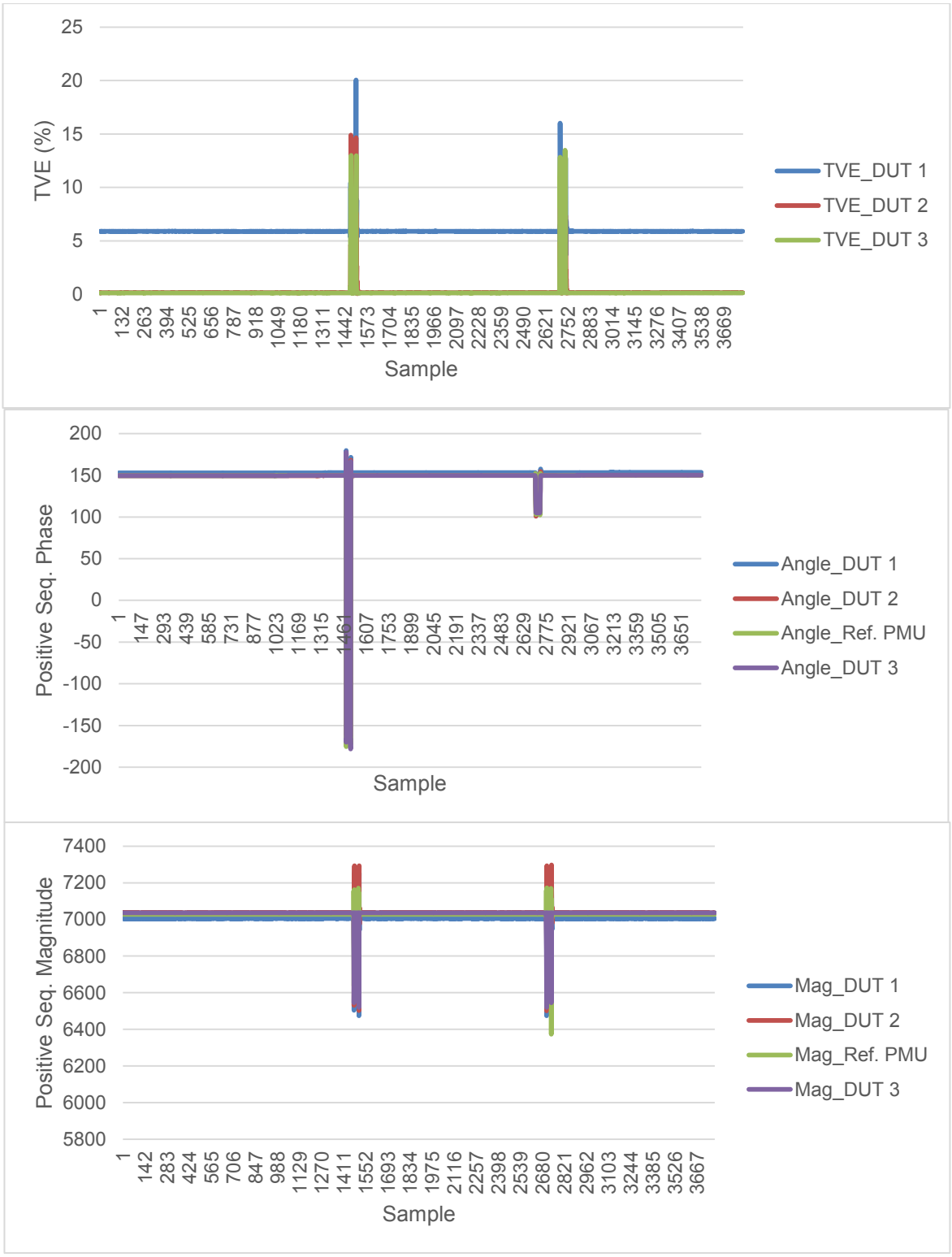


Figure 2-25. TVE, Phase, and Magnitude of the Positive Sequence Subsequent to Phase Angle Changes (Case 2-1-3).

To better compare the dynamic performances, a zoom-in plot of the positive sequence magnitude is shown in the next figure. It can be seen that based on the definition of phase angle, adding 45 degree to the vector has changed the phase angle direction of measurement (150 + 45 = 195 which is greater than 180 degrees).

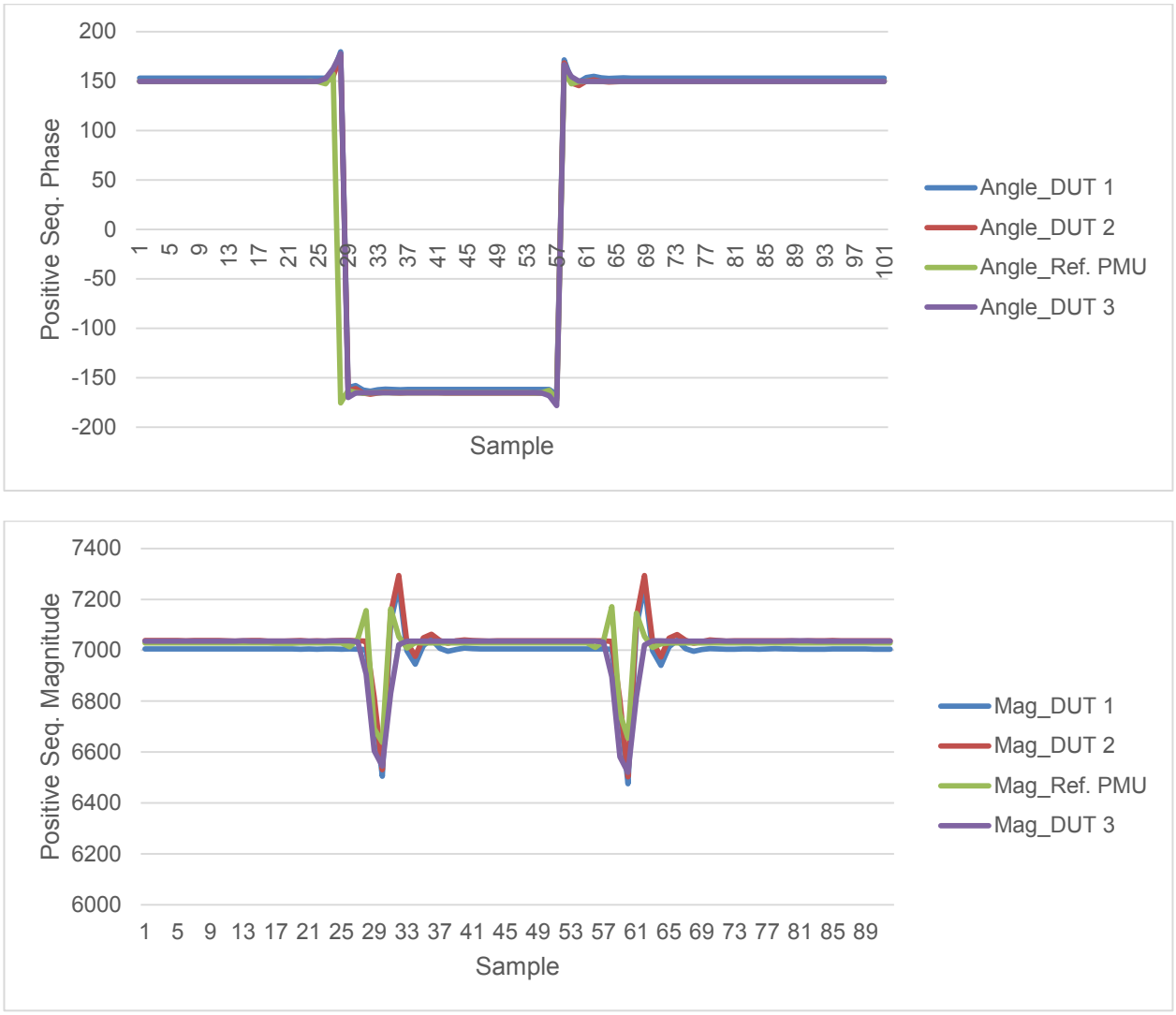


Figure 2-26. Zoom-In Plot of the Phase and Magnitude of the Positive Sequence (Case 2-1-3)

2.5.2.6.2 Group 2: Performance Test during Ramp of System Frequency

This test was designed for evaluating the DUTs' responses to the ramp changes of system frequency. Positive and negative ramps of frequency was applied to the system. PMU data streams were captured to see the DUTs' response.

- **Case 2-2-1:** System frequency was set at 59.7 Hz. After 10 seconds, the positive ramp of frequency was started with the ramp rate of 0.1 Hz/second until reaching 60.3 Hz. Frequency, TVE, and RFE for the test duration can be seen in the following figure.

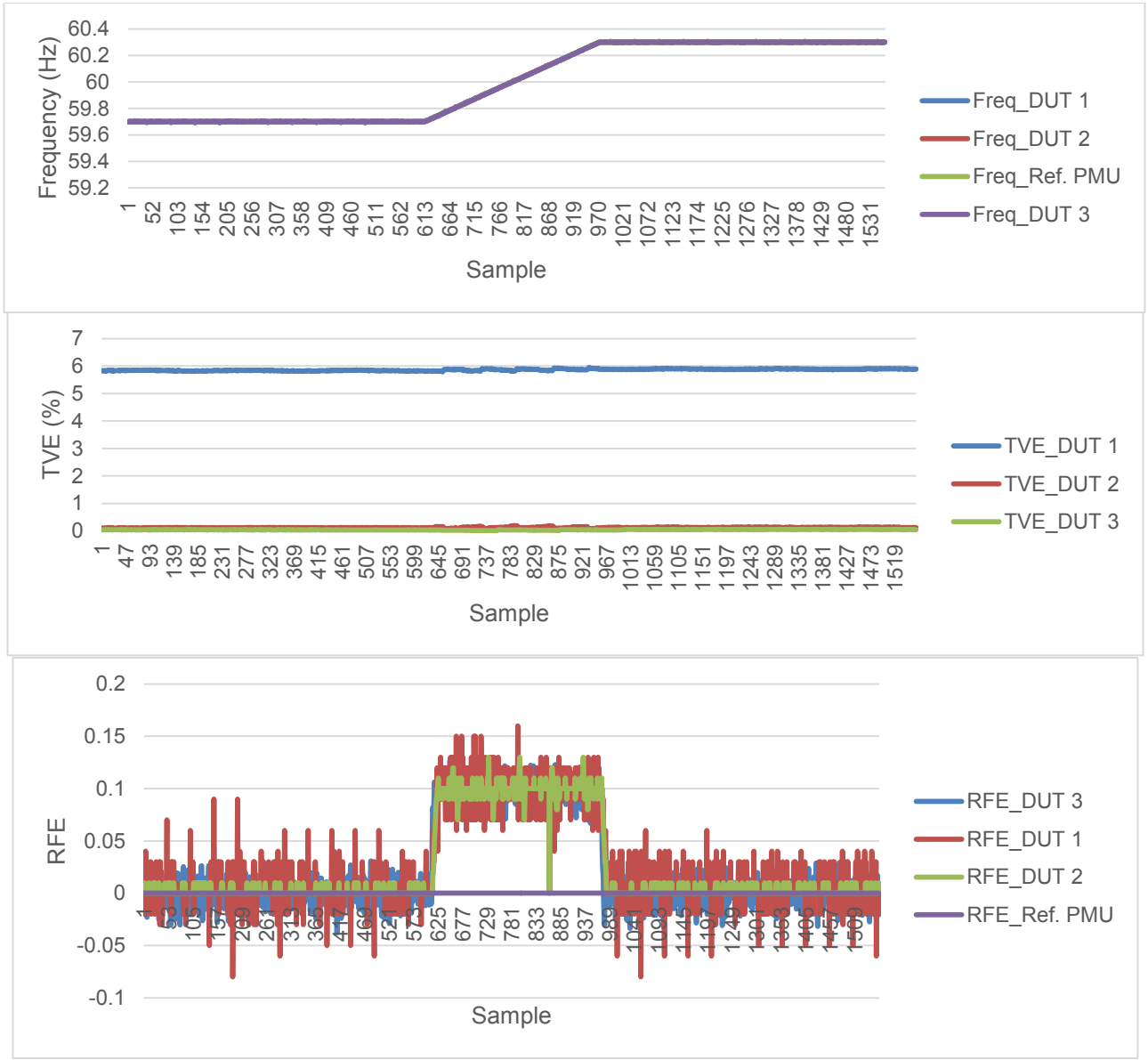


Figure 2-27. Frequency, TVE, and RFE Subsequent to Frequency Ramp (Case 2-2-1)

- **Case 2-2-2:** System frequency was set at 60.3 Hz. After 10 seconds, negative ramp of frequency was started with the ramp rate of 0.1 Hz/second until reaching 59.7 Hz. Frequency, TVE, and RFE for the test duration can be seen in the following figure.

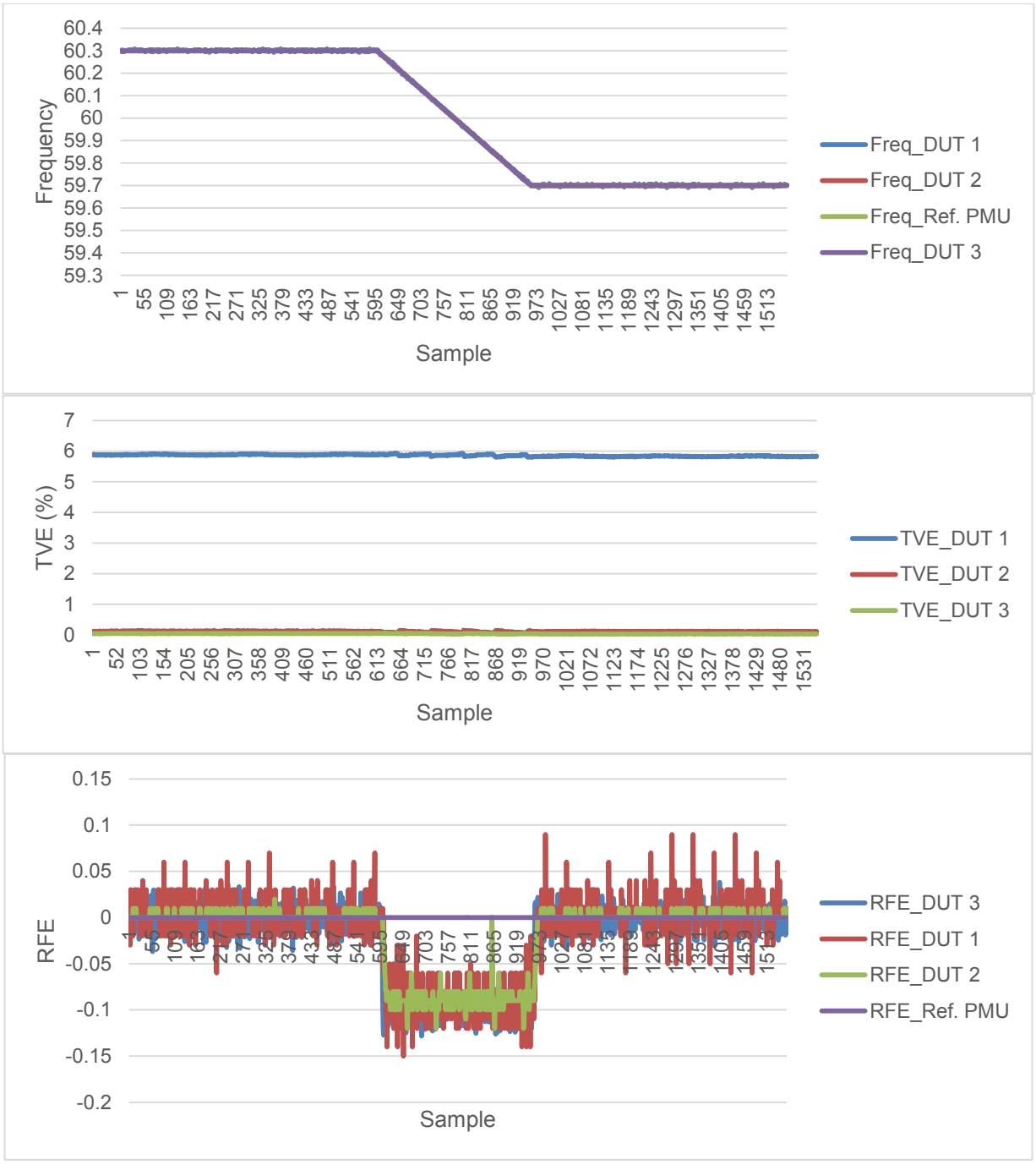


Figure 2-28. Frequency, TVE, and RFE Subsequent to Frequency Ramp (Case 2-2-2)

2.5.2.6.3 Group 3: Performance Test during Capacitor Switching

This group of tests was designed for evaluating the DUTs' performance to record system a sample transient event. This transient event was generated by switching on a capacitor bank. Capacitor switching event was simulated in RTDS and measurements from PMUs were captured and analyzed.

- **Case 2-3-1:** System voltage and frequency were set at nominal value. After 10 seconds, 1.2 MVAR 3 phase cap bank downstream of the DUTs was switched on. Frequency, TVE of voltage, and RFE subsequent to this frequency ramp can be seen in the following figure.

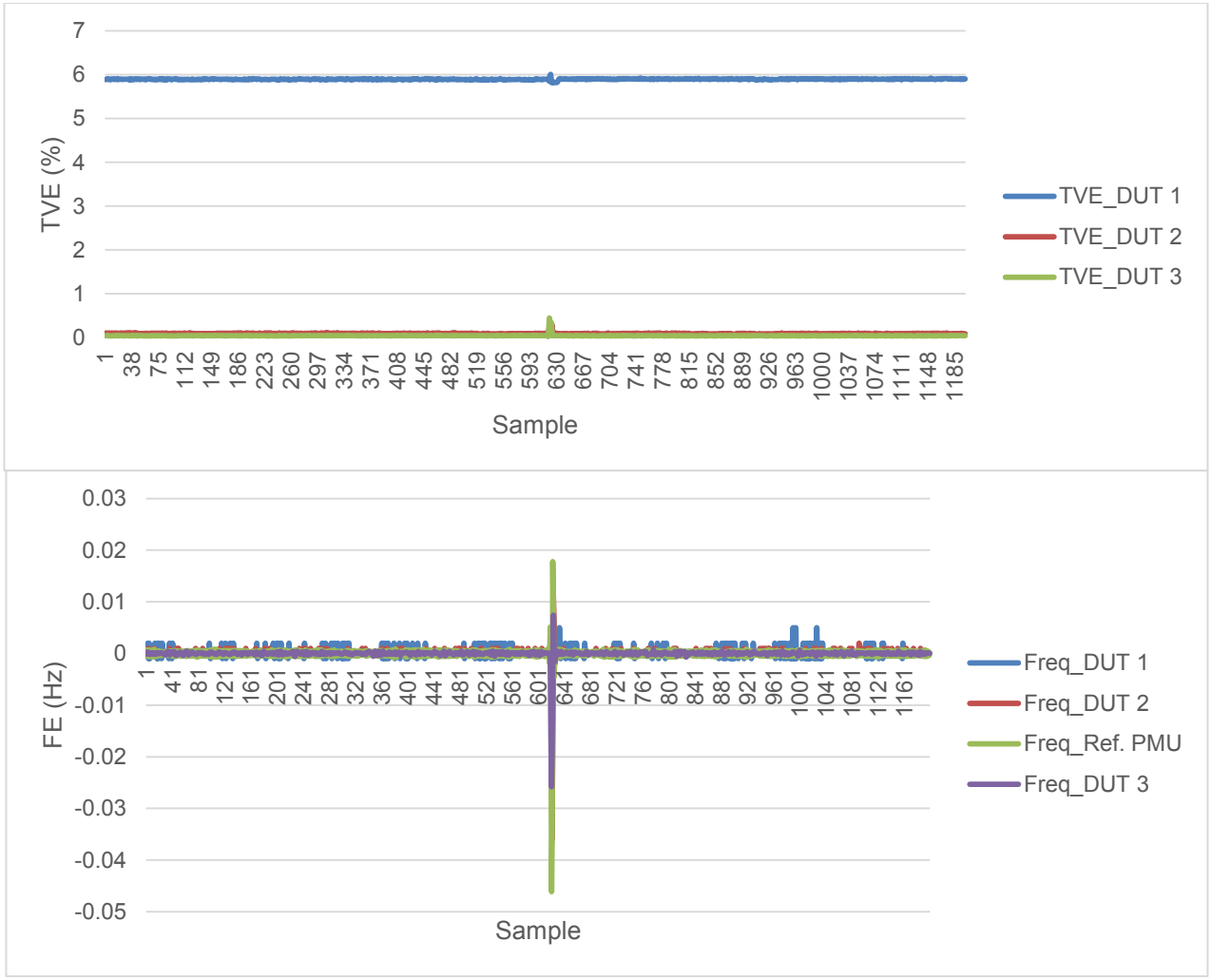


Figure 2-29. TVE and FE Subsequent to Capacitor Switching (Case 2-3-1)

2.5.2.6.4 Group 4: Performance Test during System Faults

This group of tests was designed for evaluating the DUTs' performance to record system fault events. Different types of faults were simulated in RTDS and measurements from PMUs were captured and analyzed.

- **Case 2-4-1:** System voltage and frequency were set at nominal value. After 10 seconds, temporary single line-to-ground fault was applied for 0.2 seconds. The results are shown below.

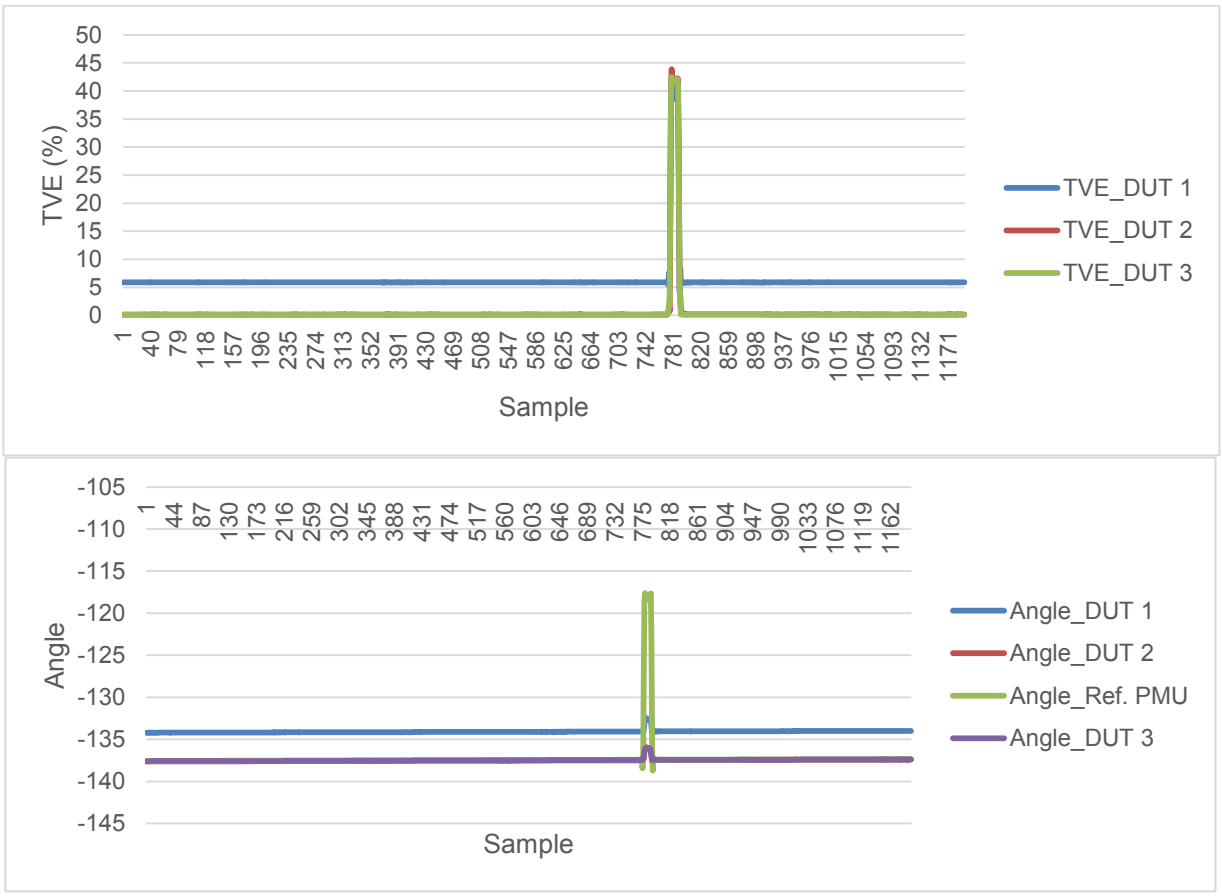


Figure 2-30. TVE of Voltage and Angle Subsequent to Single Line-to-Ground Fault (case 2-4-1)

- **Case 2-4-2:** System voltage and frequency were set at nominal value. After 10 seconds, temporary line-to-line fault was applied for 0.2 seconds. The results are shown below.

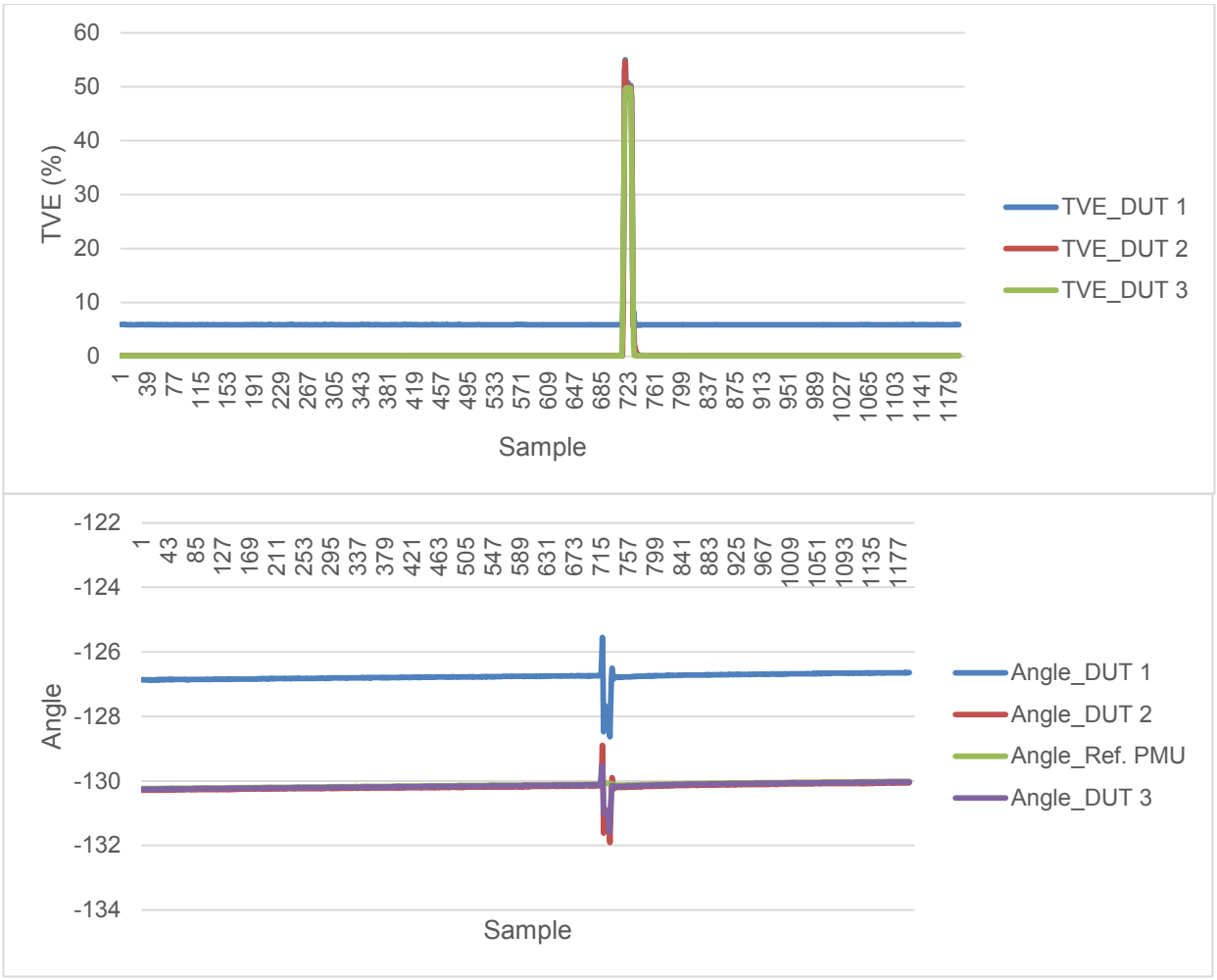


Figure 2-31. TVE and angle subsequent to line-to-line fault (2-4-2).

Case 2-4-5: System voltage and frequency were set at nominal value. After 10 seconds, temporary line-to-line fault was applied for 1 seconds. The results are shown below.

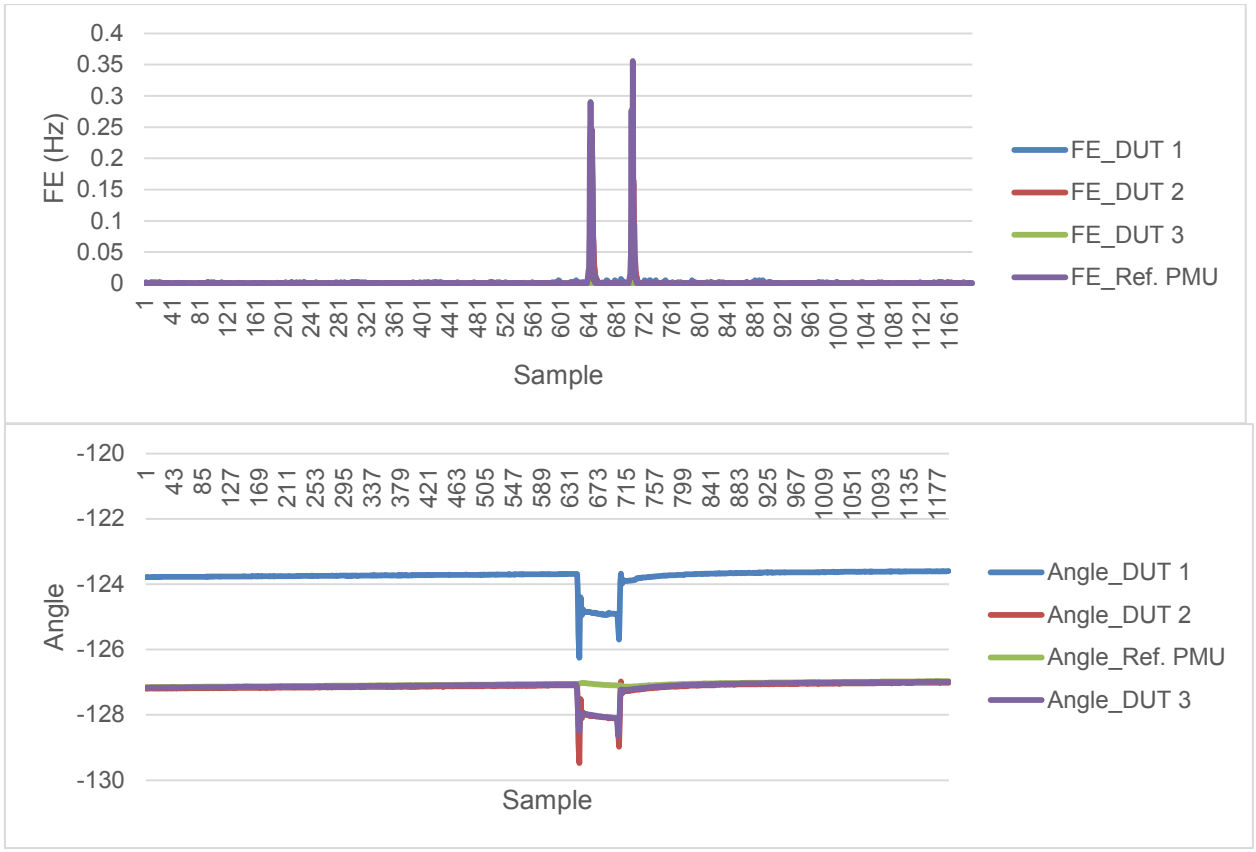


Figure 2-32. FE and angle subsequent to line-to-line fault (2-4-5).

An interesting observation from this test was that there is no change in the phase angle estimation of the reference PMU during the fault, while the other devices had a certain phase shift during the fault. The fault was long enough so that all the PMUs converge to the new values during the fault; therefore, it was expected to have a zero TVE during the fault. However, we cannot see zero TVE during this event. The reason is that it seems that the reference PMU was not working properly.

- **Case 2-4-6:** System voltage and frequency were set at nominal value. After 10 seconds, temporary three-phase fault was applied for 1 seconds. The results are shown below.

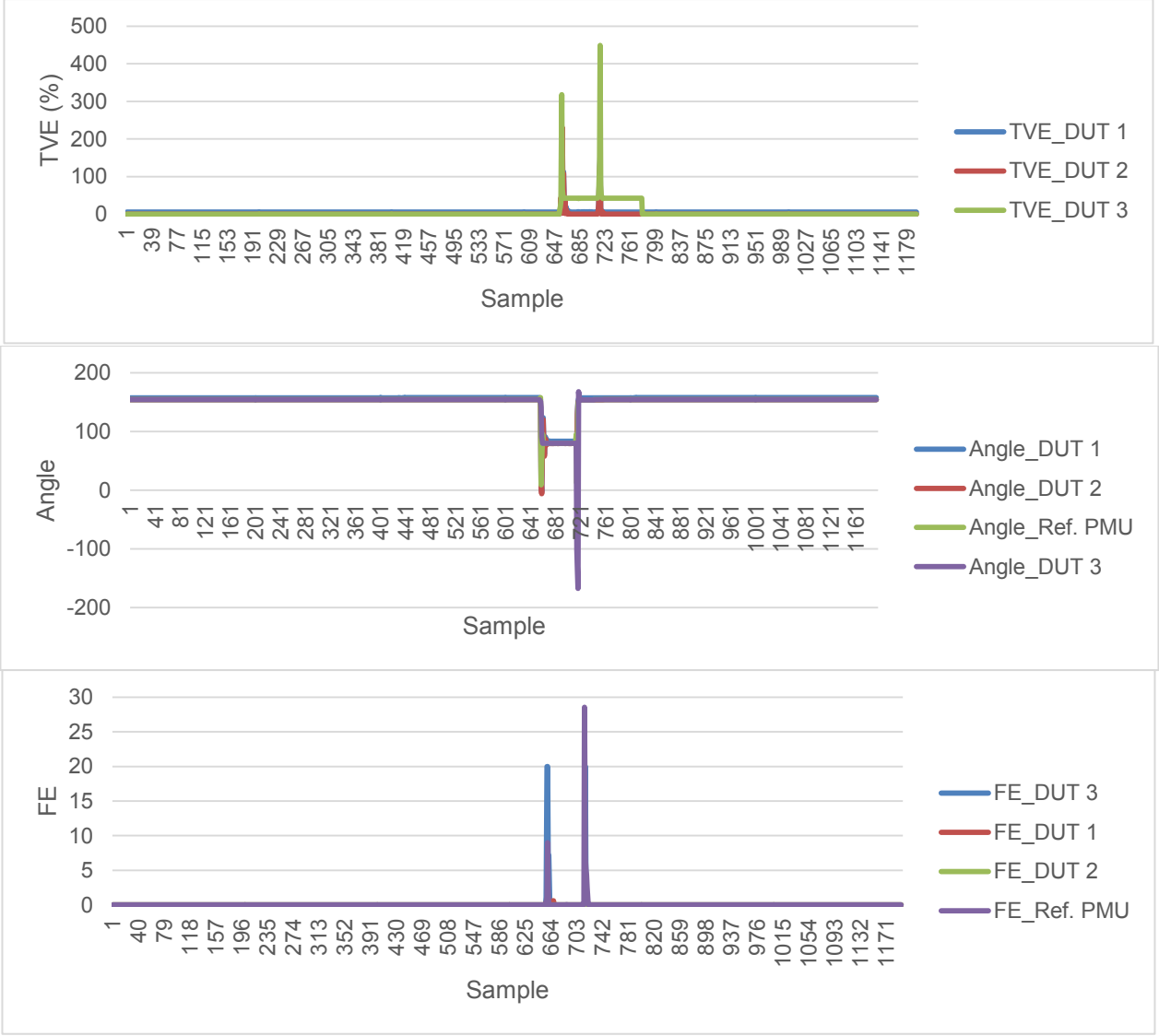


Figure 2-33. TVE, angle, and FE Subsequent to 3-Phase Fault (Case 2-4-6)

It can be seen that the TVE of the DUT3 remains high even after the clearance of the fault. The reason is that, as it can be seen in the following figure, the arbiter is not able to correctly estimate the magnitude of the positive seq. voltage after the fault for about 1 second.

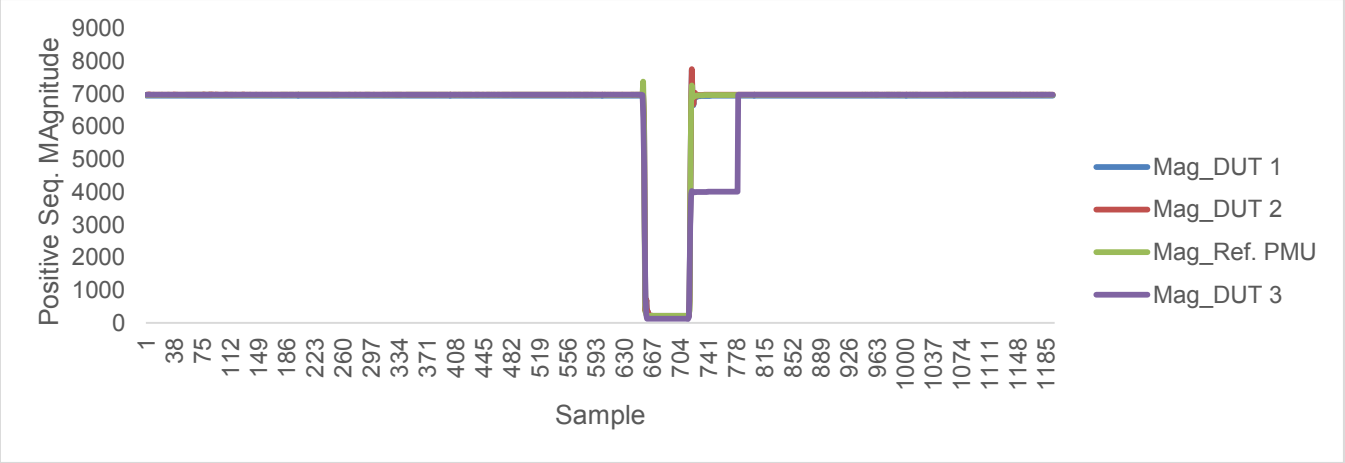


Figure 2-34. Voltage Magnitude during the Fault (case 2-4-6)

2.5.2.7 Category 3: Analog and Digital Data Streaming Capability

In this section, the DUT capability for streaming locally measured power quality parameters or any parameter that is calculated at device level using mathematical and logical blocks is investigated. It should be noted that reference PMU is not listed here because its measurements and capabilities depend on the added module to the device. The following table summarizes the available phasors through IEEE C37.118 Synchrophasor protocol from different PMUs.

Table 2-14. Available Phasors in Different PMUs

Phasor	DUT1	DUT2	DUT3	DUT4
V_a	☑	☑	☑	☑
V_b	☑	☑	☑	☑
V_c	☑	☑	☑	☑
V_s	☒	☑	☒	☒
I_a	☑	☑	☑	☑
I_b	☑	☑	☑	☑
I_c	☑	☑	☑	☑

Phasor	DUT1	DUT2	DUT3	DUT4
I_N	☑	☑	☒	☒
V_1	☑	☑	☑	☑
V_2	☒	☒	☑	☒
V_0	☒	☒	☑	☒
I_1	☑	☑	☑	☑
I_2	☒	☒	☑	☒
I_0	☒	☒	☑	☒

In addition to the phasors, IEEE C37.118 provides the capability for the analog and digital data streaming. The following table summarize this capability for different PMUs.

Table 2-15. Available Analog and Digital Data Streams in Different PMUs

Data Stream	DUT1	DUT2	DUT3	DUT4
Assignable Analog Value	4	4	0	0
Unassignable Analog Value	0	0	20	0
DSP Trigger	16	16	32	8
Event input			4	

It should be noted that:

a. PMU in DUT1 and PMU in DUT2 can stream 4 assignable analog values and 16 digital values.

b. PMU in DUT3 can stream 20 analog values through PMU. However, all of these analog values are pre-defined and cannot be changed. It should be noted that the triggering logic in PMU Device 3 can just

compare the analog values with some limits, while in PMU in DUT1 and DUT2 can perform mathematical and logical operations.

c. PMU in DUT3, depending on the settings sends either the voltage and current abc-phasors or voltage and current positive sequence phasors, while other devices sends at least both abc-phasors and positive sequence phasor. However, this PMU does not provide analog value streaming; however, it can stream up to 8 digital values.

2.5.3 Type Test Conclusions

Based on the steady state performance, dynamic performance, and digital/analog capability of four tested PMUs the following can be concluded:

1. DUT1

    a. Based on the test results, it was shown that it added around 3 degrees of error in phase angle; however, it has the capability to be calibrated.

    b. It showed a very good dynamic performance. It never lost the convergence due to the rapid changes in the voltage, frequency, or phase angle.

    c. It can stream 4 analog values and 16 digital values. There is a lot of flexibility on defining a logic for the digital value or a calculation for analog value.

    d. Device configuration is straightforward.

2. DUT2

    a. Based on the results, it was shown that it had less than a 0.5degree error in phase angle. Furthermore, it has the capability to be calibrated.

    b. It showed a very good dynamic performance. It never lost the convergence due to the rapid changes in the voltage, frequency, or phase angle.

    c. It can stream 4 assignable analog values and 16 digital values. There is a lot of flexibility on defining a logic for the digital value or a calculation for analog value.

    d. Device configuration is straightforward.

3. DUT3

    a. It had shown less than a 0.5-degree error in phase angle. However, it has the capability to be calibrated.

    b. It showed poor dynamic performance. In few case studies, it was observed that the device lost the convergence for few seconds after a transient.

c. It can stream 20 pre-defined analog values and 36 digital values. The analog values are pre-defined and cannot be changed. Furthermore, very basic logics can be defined for the digital value.

d. Device configuration is straightforward.

e. It can operate as a PQ meter as well.

4. DUT4

a. The test results showed that it had around 2 degree error in phase angle. However, this error was increased to 45 degrees in case of the utilization of the extension module due to the communication delay between the extension module and relay. Currently, the phase angle doesn't have calibration capability. However, the discussions with vendor had suggested that there will be future firmware upgrade to accommodate the issue.

b. It cannot stream any analog value.

c. It can stream up to 8 digital value.

d. Device configuration is difficult.

2.6 Demo System Setup and Customer System Integration

Based on the proposed approach, various data sources have been employed to monitor and visualize the status of the selected circuits of the SDG&E distribution systems. More details about this are provided earlier in this report. One aspect of the project has been to look at the actual field data, both in real-time form, but also the data and information retrieved from historical data base, power quality meters, as well as from other sources such as reliability department.

Another aspect of the project has been to look at the simulated environment that would enable to add additional devices to models of selected circuits, and enable monitoring and analysis of use case that are not available in the actual distribution network.

The diagram shown in Figure 2-35 below describes at high level this hybrid approach. There are two parallel data streaming and monitoring paths: 1) field data streaming path through substation PDC, and 2) simulated data streaming from laboratory through a dedicated PDC in the lab. The data from both paths gets ultimately collected at control center for processing and visualization.

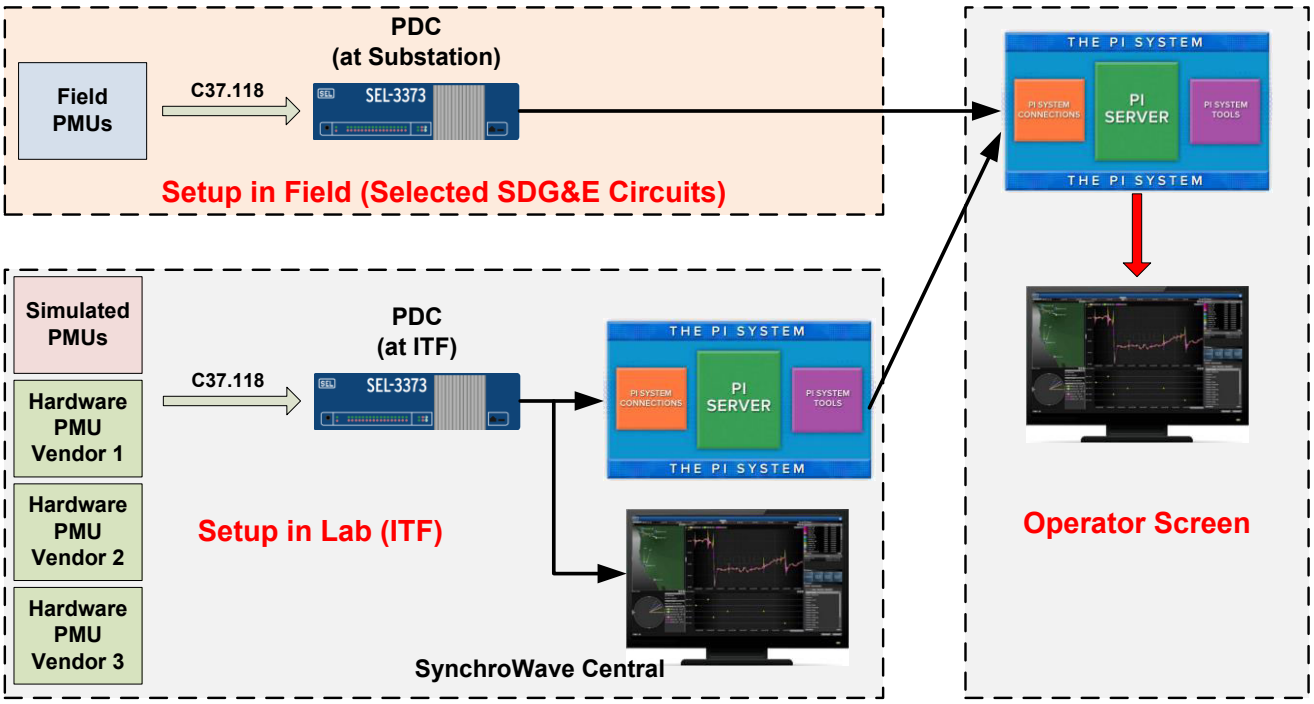


Figure 2-35. High level architecture for of the demonstration system

2.6.1 System architecture that employs field data

As described earlier in the report, field data can come from various devices, such as PMUs, IEDs, RTUs (remote terminal devices for SCADA), AMIs, power quality meters, as well as from PI historian, or other offline sources in form of reports or additional documents. Figure 2-36 shows a high-level architecture that has been used for this purpose. Visualization and analytics box in this diagram was used for post processing data to calculate performance indices and/or to create data infeed for trends and histograms, as described in the visualization system functional requirements and the six proposed use cases.

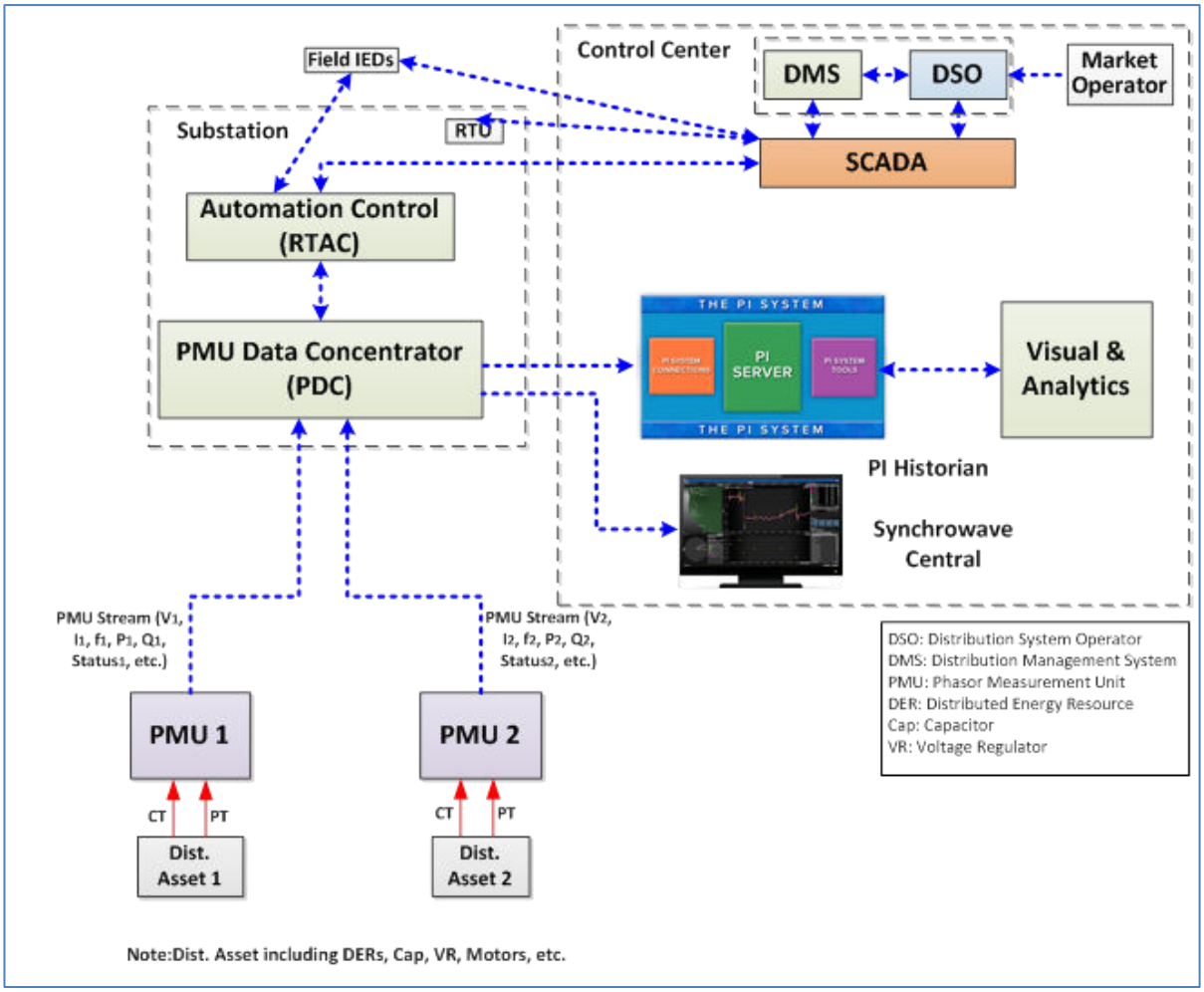


Figure 2-36. High level system architecture for integration and visualization of field data and information

One of the challenges in implementation of this system was to resolve how to combine various visualization and data platforms in one, user friendly system. For instance, PMU data is managed using a synchrophasor management system, power quality is managed by the technology that can process and visualize data such as harmonics, distortion, swell and sag, and similar; and, historian system has its own platform to manage, process and visualize the measurements and processed results. In addition to this, some of the requirements were to have access to reliability data, and these are managed by a separate group at SDG&E.

Also, one needed having in mind that the main anticipated users of this system would be system operators and engineering analysis group, as well as planning group, to a lesser extent.

This challenge of fusing and integration of diverse data set was addressed by creating a dashboard within Geospatial Information System (GIS) as a convenient means that provides geographical information about the circuits' infrastructure.

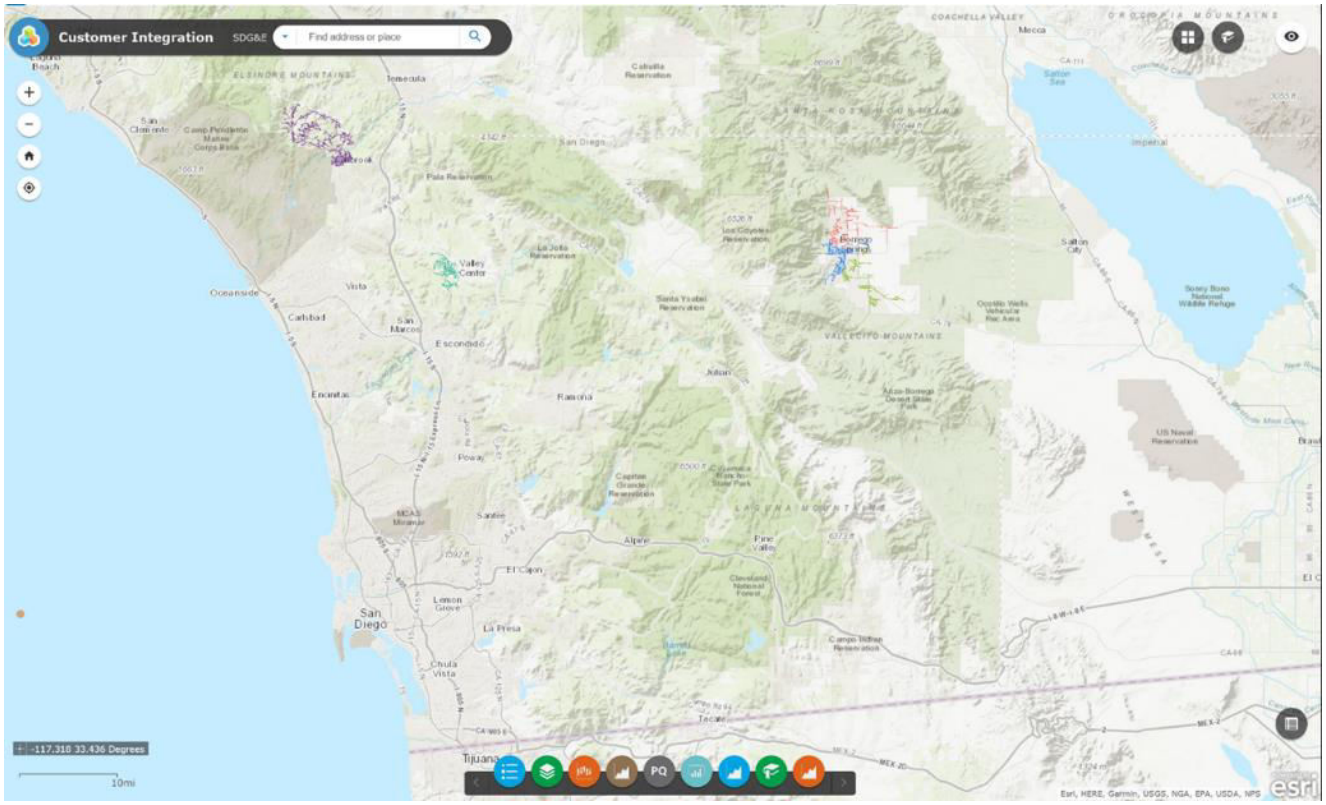


Figure 2-37. Main visualization system implementation dashboard

The SDG&E team has successfully implemented all requirements and the results are presented in the following sections.

2.6.2 System Test Setup at ITF Lab

The general layout of the testbed has been illustrated in Figure 2-38. The testbed consists of the following components:

- **Real-time digital simulator (RTDS)** – which is used for the representation of circuit 1 with all major controllable assets modeled.
- **GTNET PMU** – which is used for phasor data measurement and streaming of PMU1 to PMU8 in the simulation environment.
- **GTAO1 and GTAO2** – analog output cards that are used to send the low level voltage and current signals to the physical PMU devices.
- **Amplifier** – which is used to amplify low level voltage/current signals from RTDS to the secondary level for injection to the physical PMU devices (it should be noted that some physical devices use low level signals directly).
- **PMU Device 2** used for phasor data measurement and streaming of PMU9.
- **PMU Device 3** used for phasor data measurement and streaming of PMU10.
- **PMU Device 4** used for phasor data measurement and streaming of PMU11.

- **PMU Device 1** used for phasor data measurement and streaming of PMU12.
- **Real-Time Automation Controller unit** used for the processing of the available PMU data
- **GPS clock** used for time synchronization of RTDS, Automation Controller and PMU devices.
- **A PDC Software** used for PMU and Automation Controller data aggregation and time alignment for downstream applications
- **PMU Visualization Software** used for translating PMU data into visual information.

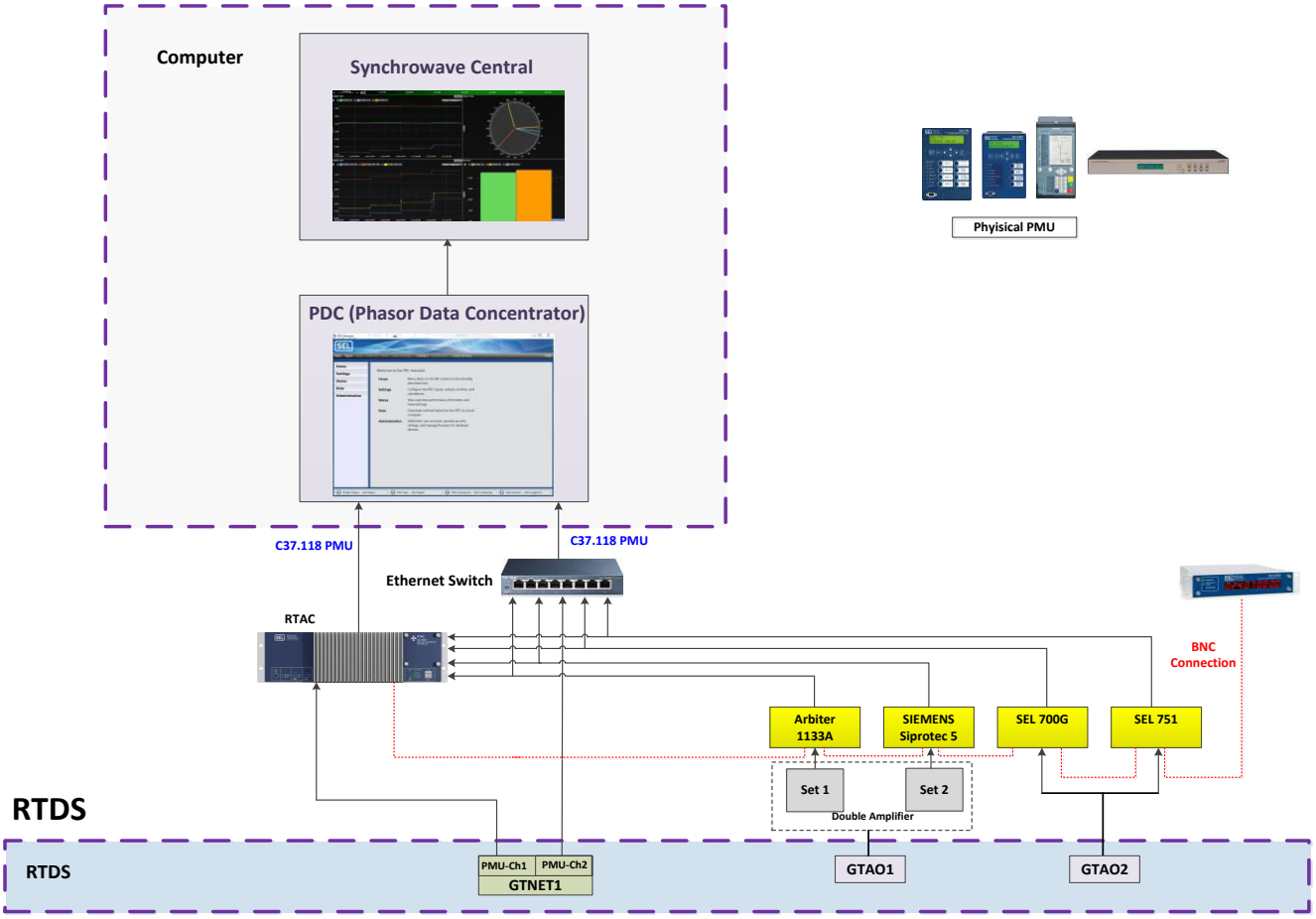


Figure 2-38. Test System Single Line Diagram for laboratory testing

3 Pre-Commercial Demonstration Results with Field data

This section provides the results of demonstrations on the capabilities of measurement, monitoring and visualization platform of the system described earlier in this report. The implementation was based on the requirements developed in six use cases and the proposed (extensive) list of visualization requirement.

3.1 PI Coresight Screens

The main system dashboard (Figure 2-37) developed for this project is a web based GIS application, with a series of widgets/buttons, each representing a separate application of visualization environment. One of the widgets calls up a PI Coresight dashboard, as shown in Figure 3-1.

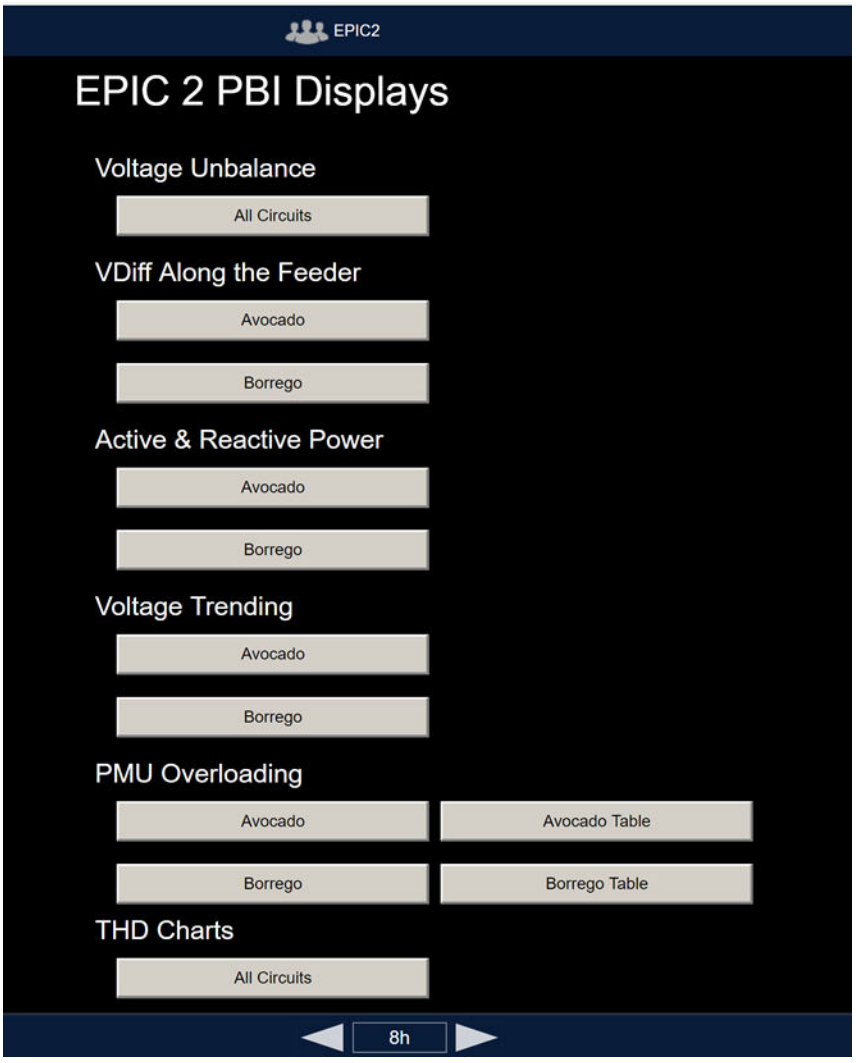


Figure 3-1. An example of a dashboard that utilize historical data base

As shown in this figure, several screens (such as Voltage Unbalance, PMU Overloading, THD charts, and etc) have been integrated in the PI Coresight dashboard. The remaining of the section provides example of various screens demonstrated.

The following figure shows visualization of voltage unbalanced factor using positive and negative sequence components at each PMU location ($\frac{V_1}{V_2}$). The values are calculated every 30 seconds in the PI system. The result are displayed on this PI Vision screen with limit lines at 3% and 10%. By using a multi-state symbol, the bars on the chart will turn to orange and then to red as they exceed the two thresholds.



Figure 3-2. Monitoring of voltage unbalance factor

The following screen shows voltage total harmonic distortion (THD) data being displayed on a bar chart with limit lines. The data comes through the SCADA system, so updates occur every 2-5 seconds. By selecting a THD percentage value, a trending chart is displayed with a configurable time range as shown in Figure 3-4.

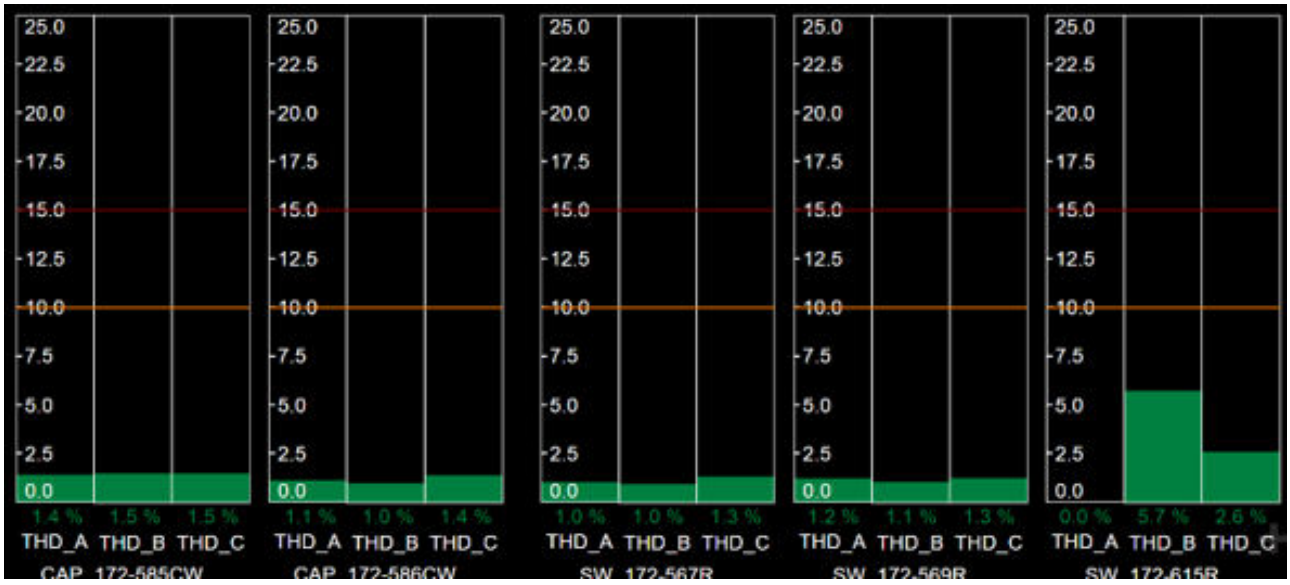


Figure 3-3. THD measured at various locations of selected circuits (all three phase); source: SCADA

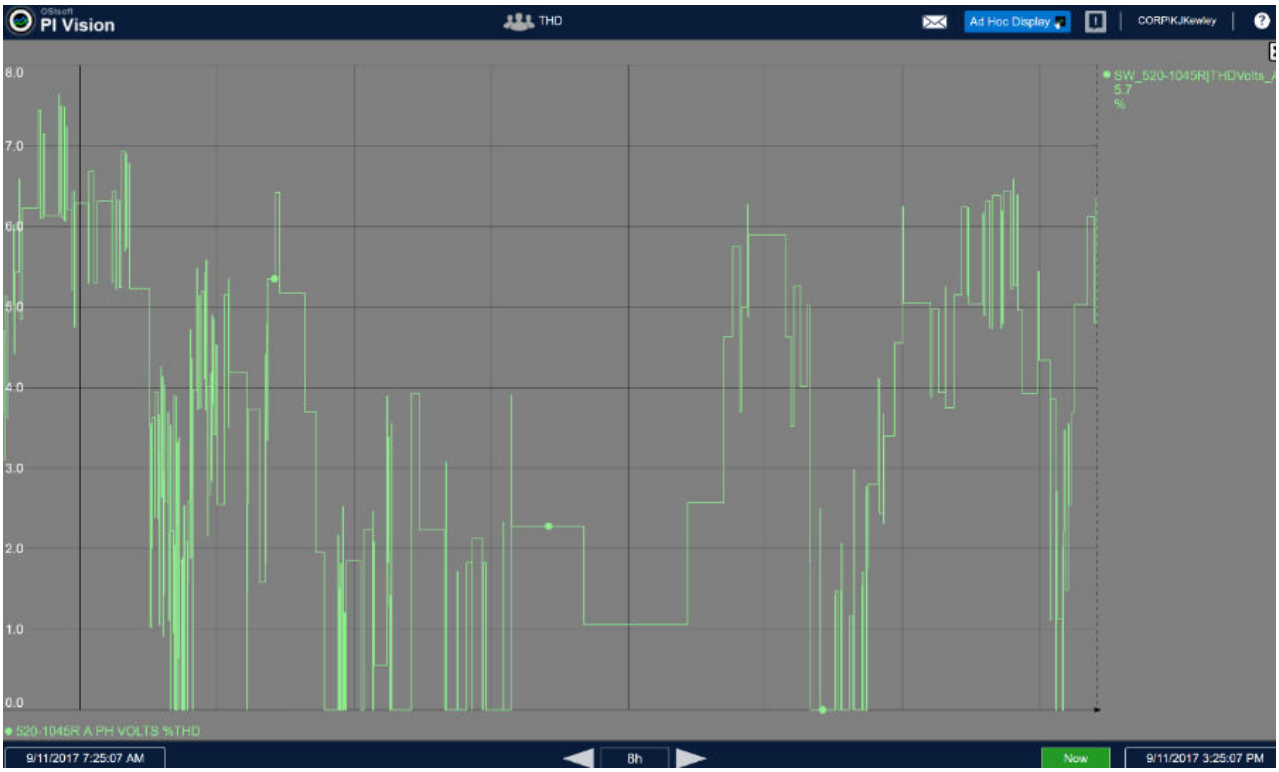


Figure 3-4. Harmonic distortion (time frame) at one of the switches on circuit 1 (obtained from SCADA)

The following screen shows voltage difference from nominal value (in pu) measured at each PMU location on circuit 1. The upper and lower bars are +/-5% target levels from the nominal voltage (on 12 kV basis).

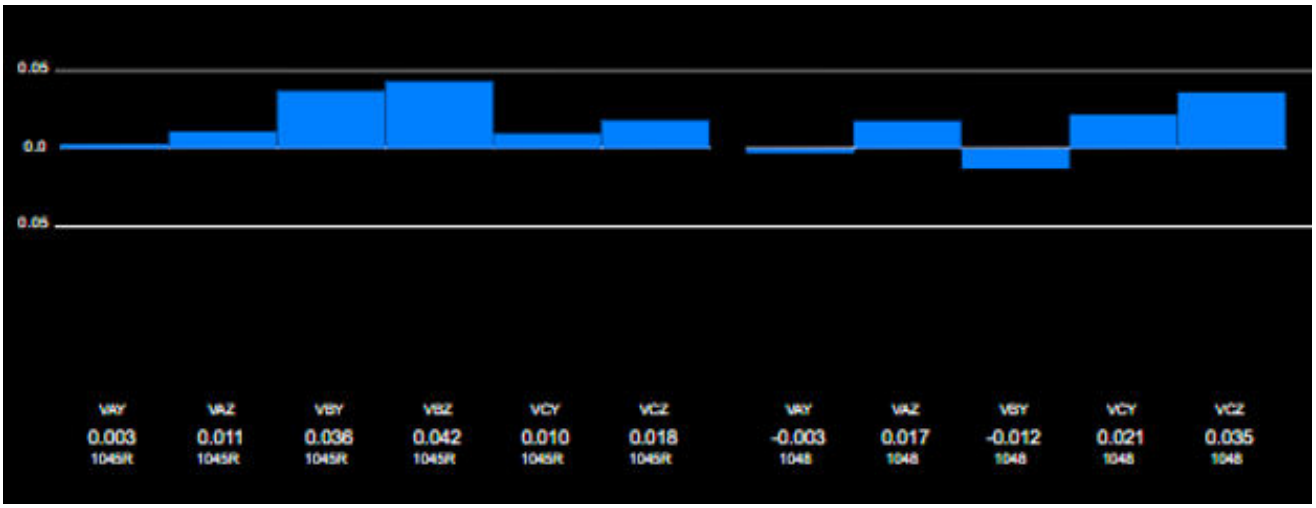


Figure 3-5: Voltage difference (in pu) on Circuit 1

The following screen shows active and reactive power by device as a bar chart. Active and reactive power are calculated for each existing phasor in real-time based on the data from OpenPDC and fed into the PI system. By using PI Vision for this visualization, the user can select any data and time to view the historical active/reactive power data on the devices. Negative values represent areas that reverse power flow occurs on the circuit.

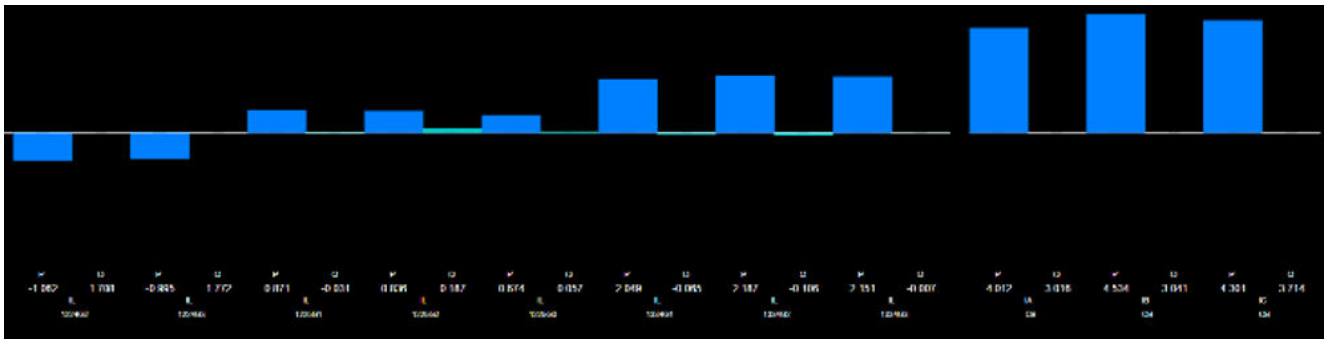


Figure 3-6. Active and reactive power flow for Circuit 1

The following two screen shots show thermal loading plots for Circuit 1, 2, and 3. The bars will change colors when they reach the rating limit lines, defined by a look up table for each feeder device and section of the line.

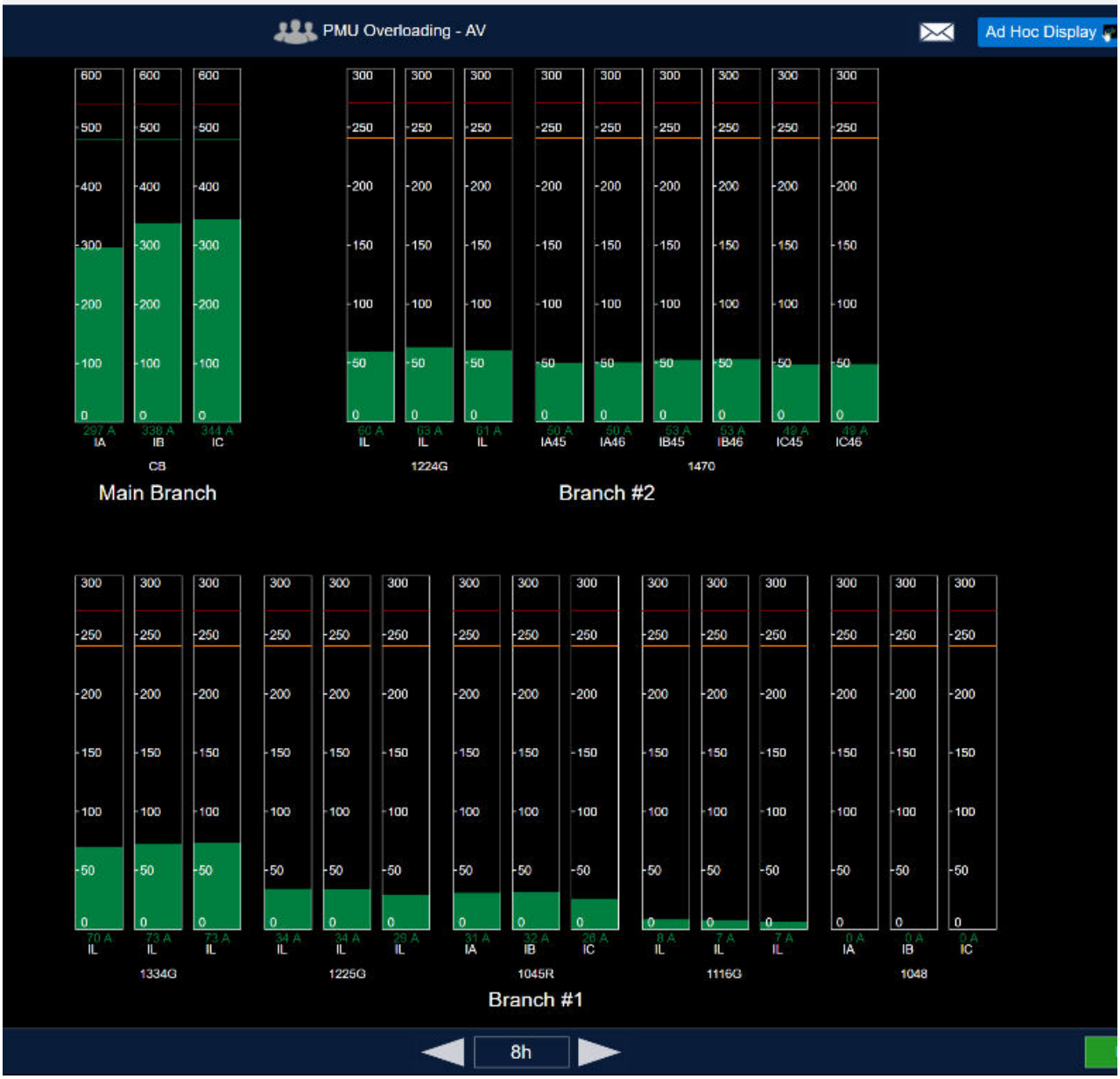


Figure 3-7. Thermal loading asset monitoring on Main branch, Branch #1 and Branch #2 of the Circuit 1

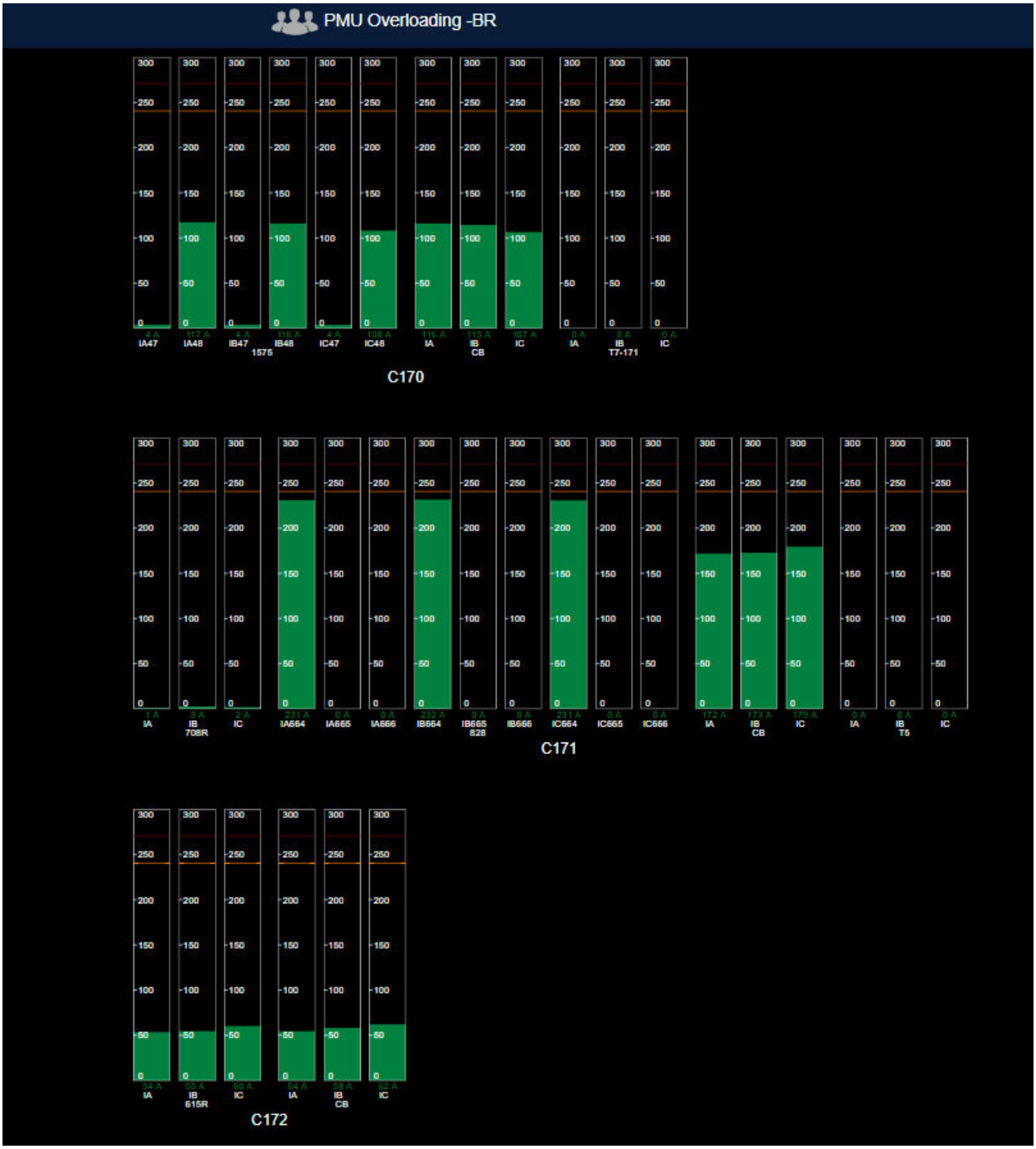


Figure 3-8. Thermal loading asset monitoring for Circuits 2, 3 and 4

The following is a screenshot from the Active/Reactive power values on Circuit 1. It can be seen that some of the PMUs with high MVAR values have bars that are displayed in red so they stand out in a large list.

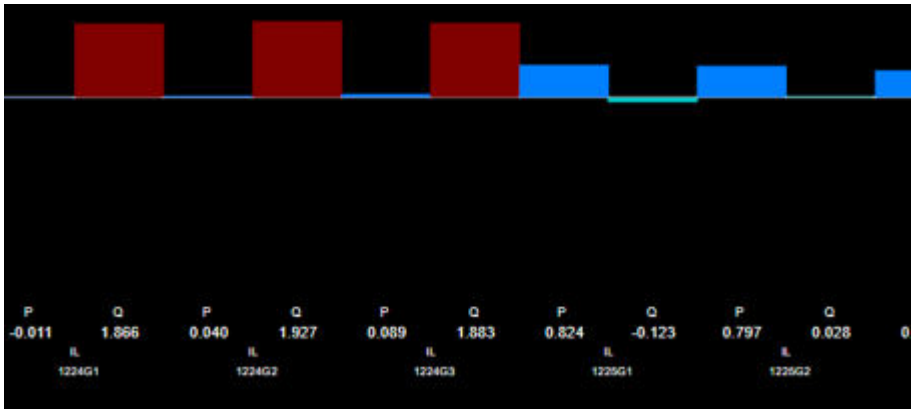


Figure 3-9. Active/Reactive power along Circuit 1

Figure 3-10 is the screenshot for reporting and visualizing the overloading conditions. The limit lines are accurately calculated for circuit breakers. The limits for the field devices are not determined because there are many factors down the line that effect the rating. The feature uses a look up table for field data update.

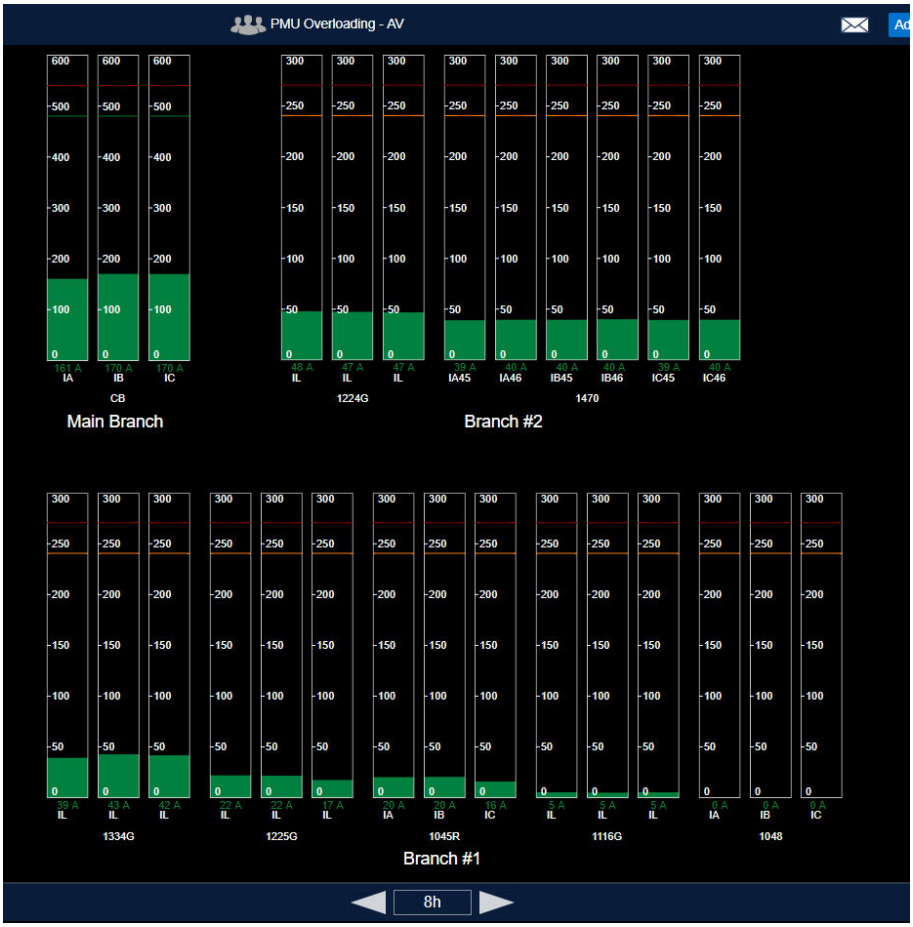


Figure 3-10. Overloading bar chart display for Circuit 1 based on PMU data

The following screenshot provides the tabular reporting format of the circuit level device loading. The report is organized by the main branch (backbone) and each individual branches (laterals). In the advanced visualization the aim is to move from tabular data to graphics and summary reports that can fuse multiple measures into specific metrics to support fast-decision making by operators.

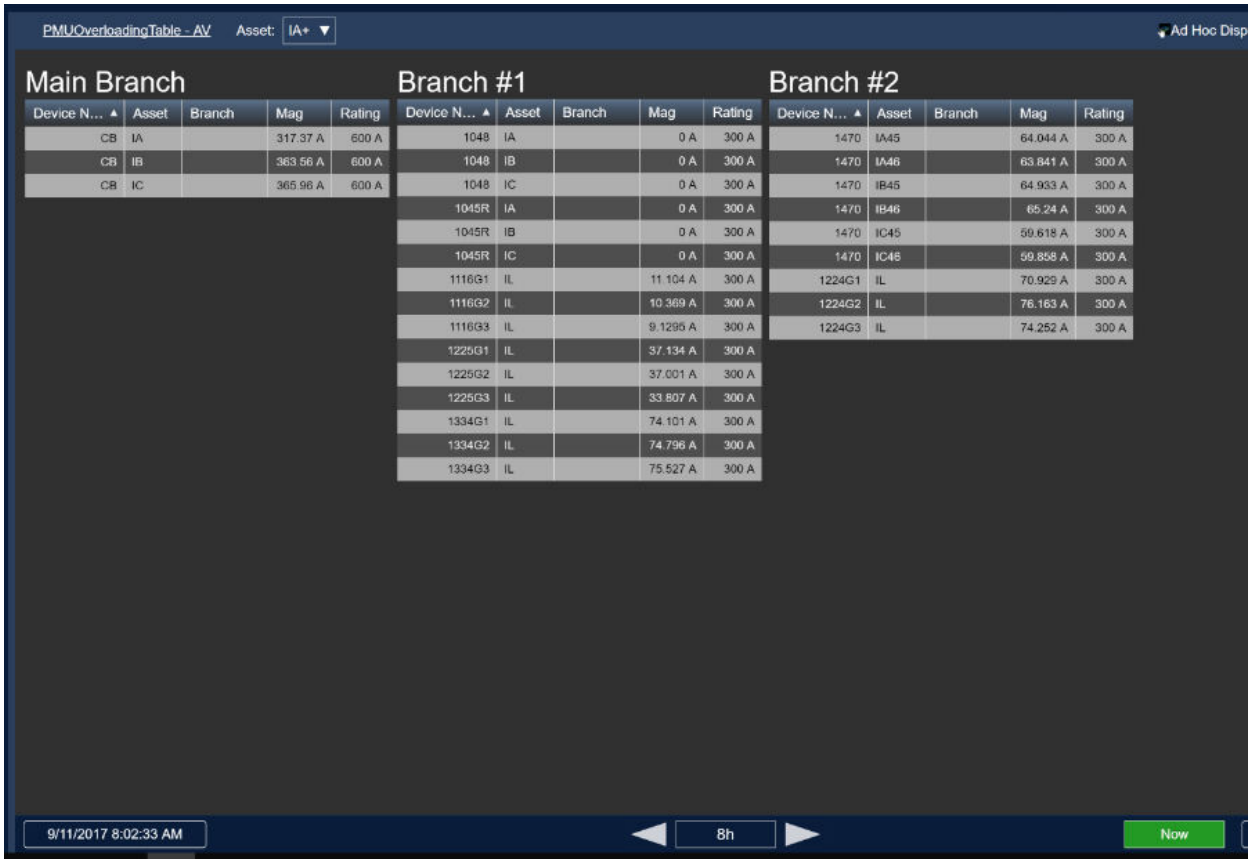


Figure 3-11. Tabular reporting of device loadings for Circuit 1 based on PMU data

The following display shows another PIVision display with voltage along the feeder. This display gives the operator a clear view of voltages over the entire circuit. The limit lines and color changing bars draw attention to large voltage deviations.

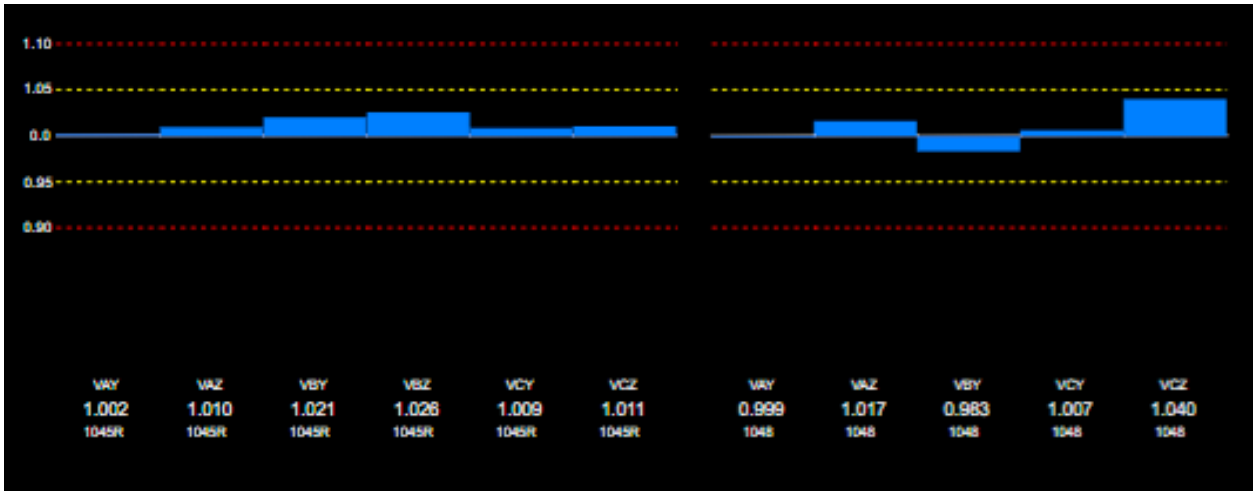


Figure 3-12. Voltage deviations (from base voltage) in percentage along the selected circuit length (circuit 1)

3.2 Real-time measurement examples

One of the menu selection options on the visualization screen navigates to real–time PMU visualization software platform. In this subsection, several real-time screens (based on the visualization requirements) obtained from field PDC are shown to demonstrate the built in capabilities and type of data visualization available.

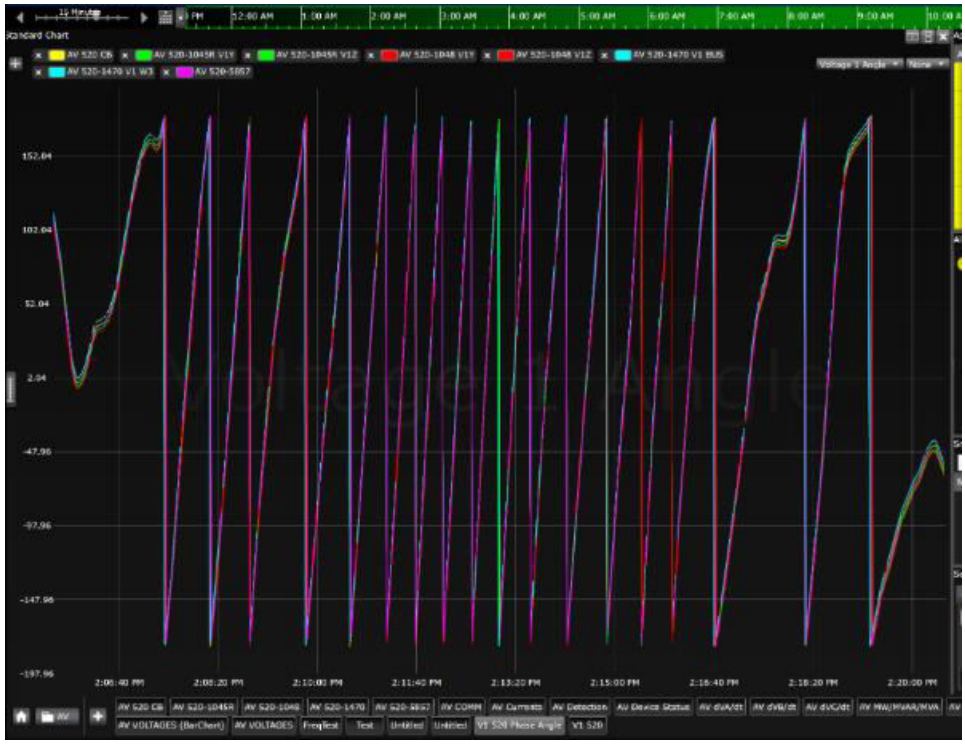


Figure 3-13. Voltage phase angle in phasor time domain

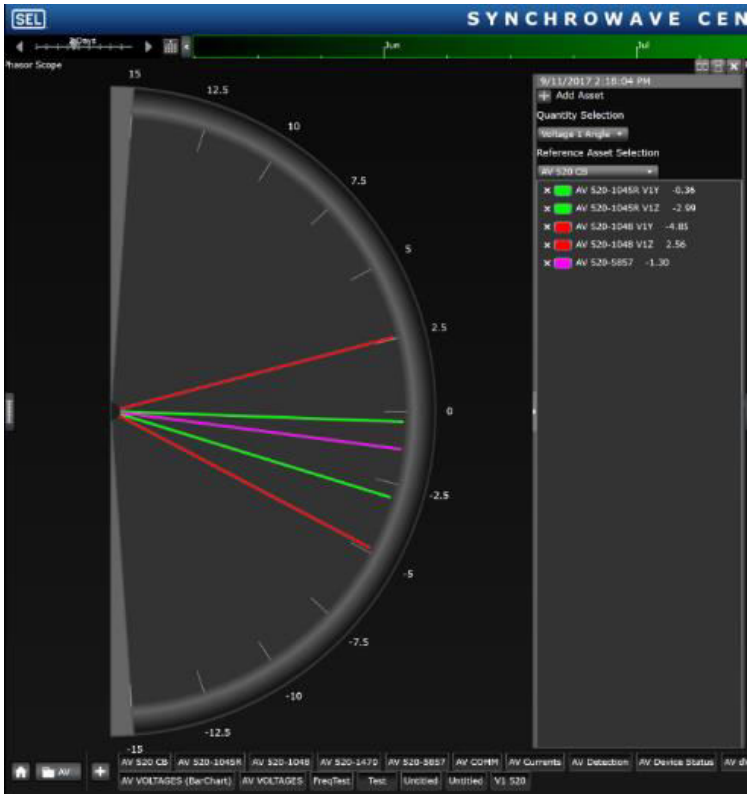


Figure 3-14. Polar version of real time monitoring of voltage phase angles

The following displays show voltage magnitude and phase angle for the device 520-1470 (near the large 2MW solar site toward the end of circuit 1). The displays are built out for several circuit breakers and recloser on the line, such as: 1045R, 1048, 1470, and 5857.



Figure 3-15. Voltage magnitude of the Circuit 1 PMUs (standard view)



Figure 3-16. Voltage phase angle of the Circuit 1 PMUs (standard view)

The following display shows active, reactive, apparent power for the circuit breaker, and PMU 5857 which is located just outside of the 2MW solar PV site.



Figure 3-17. Numeric display for selected PMUs

3.3 Visualization displays on the GIS map

In addition to the aforementioned screens, some of the visualization requirements were based on the GIS maps to show the distributed and geographical nature of the distribution circuits. Examples of GIS map based screens and built in functionalities are shown in this section.

The next two figures demonstrate visualization of real-time measurements for total active power generation units in the PV plant, and customer loads, respectively. The data is also obtained from the field and the blue circles show geographical measurements locations. The active power data displayed for PV Customer generation is the nameplate rating of the PV system rather than real-time. All of the other data on the map is real-time PMU data.

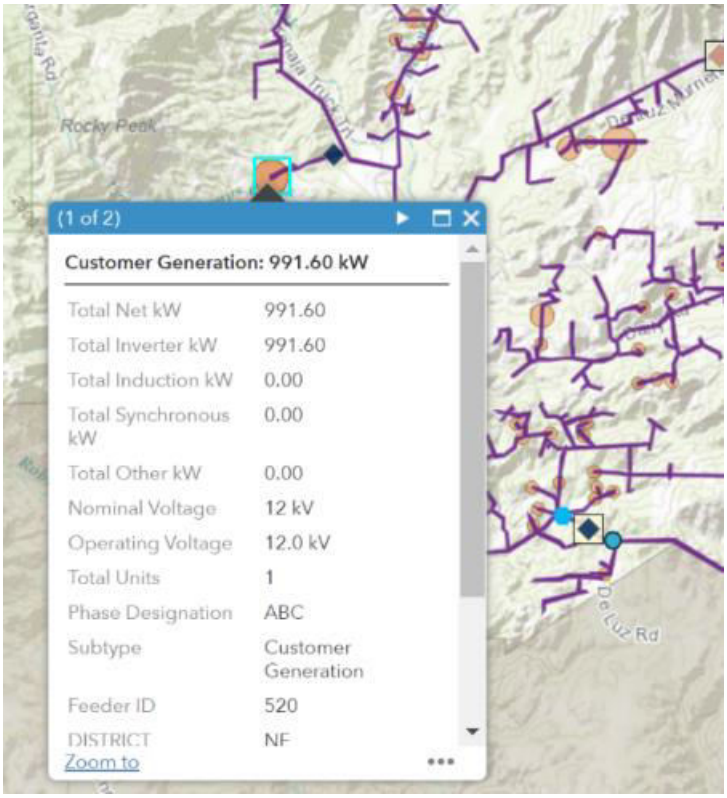


Figure 3-18. Total active power generated by PVs

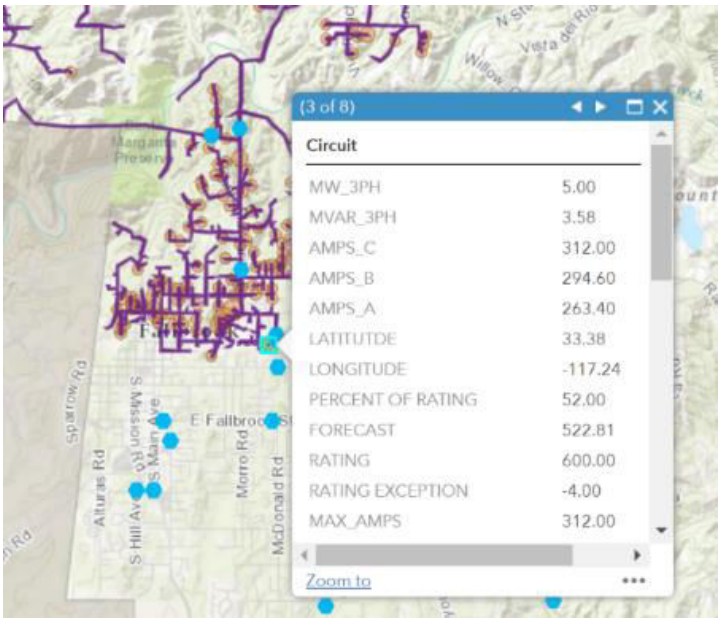


Figure 3-19. Real time monitoring of customer loads

The next two figures show real-time measurements of voltage regulator tap positions and capacitors status, respectively. The screenshots show capacitor switching on the cap information popup and the time series display of that value. The values are incremented whenever a capacitor switches on or off. The status changes can be because of time bias or changes in the voltage level of the circuit. PV production fluctuation is also a key contributing factor. The number of tap changes need to be monitored.

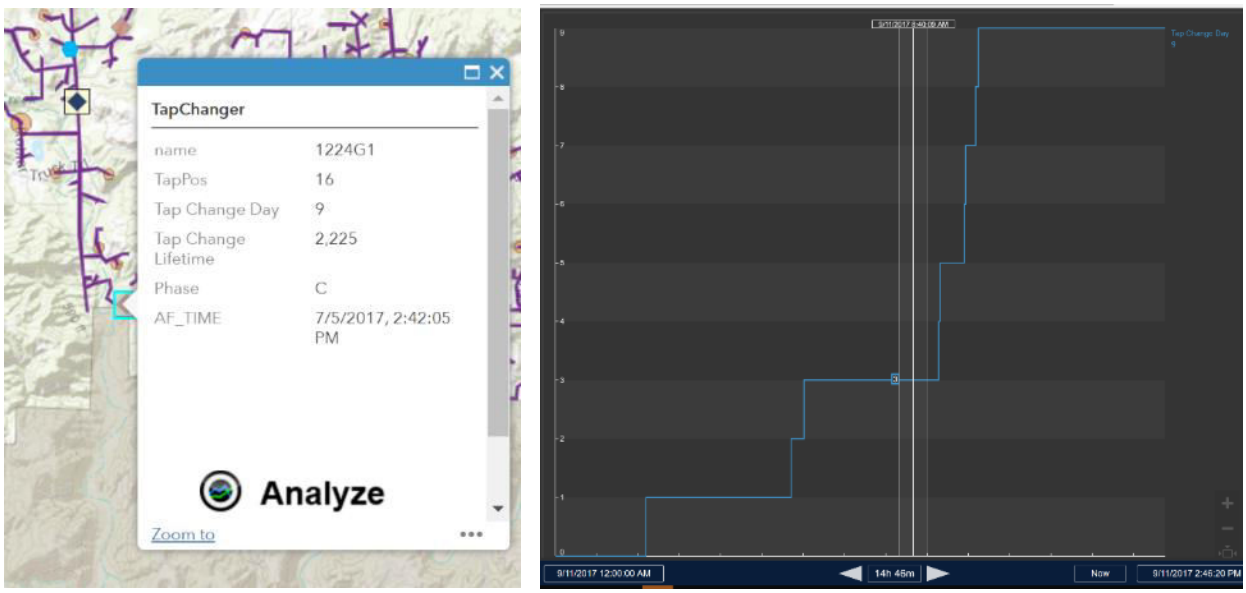


Figure 3-20. Monitoring of Tap changer status (left) and tap positions change over time (right)

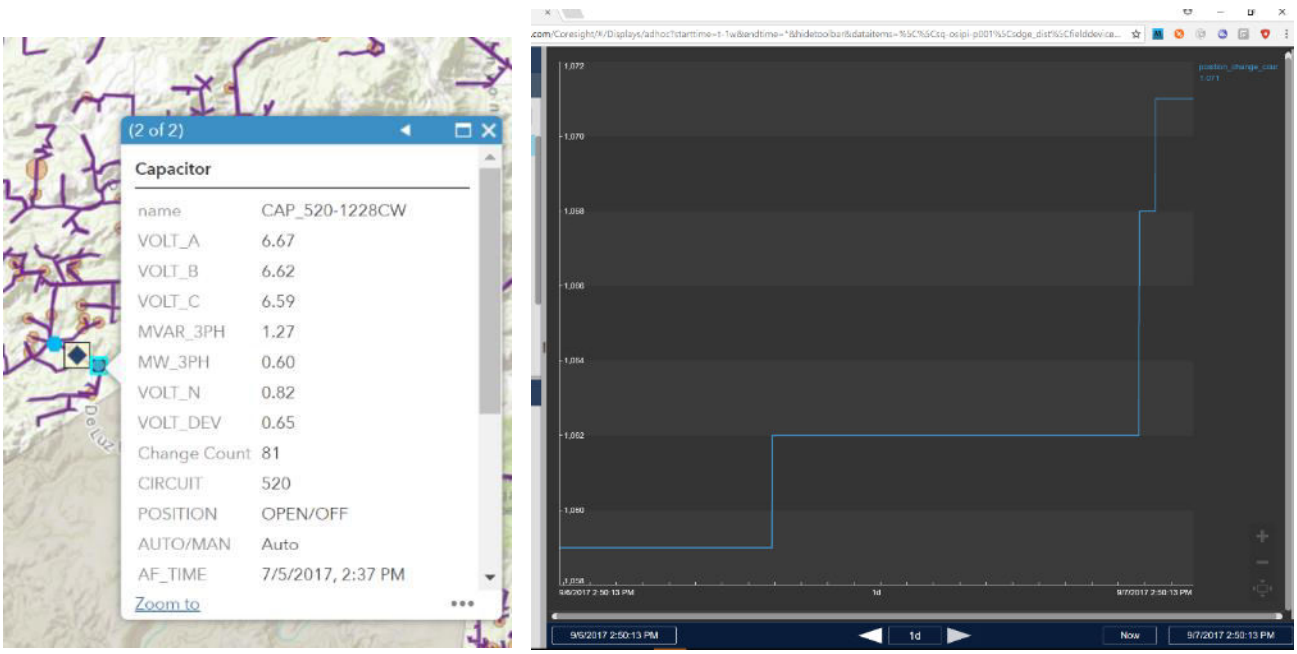


Figure 3-21. Real-time monitoring of cap banks status

Voltage Sag and Swell are some of the KPIs that need to be monitored and visualized as described in the system requirements. Figure below illustrates one of the implementation cases for these requirements.

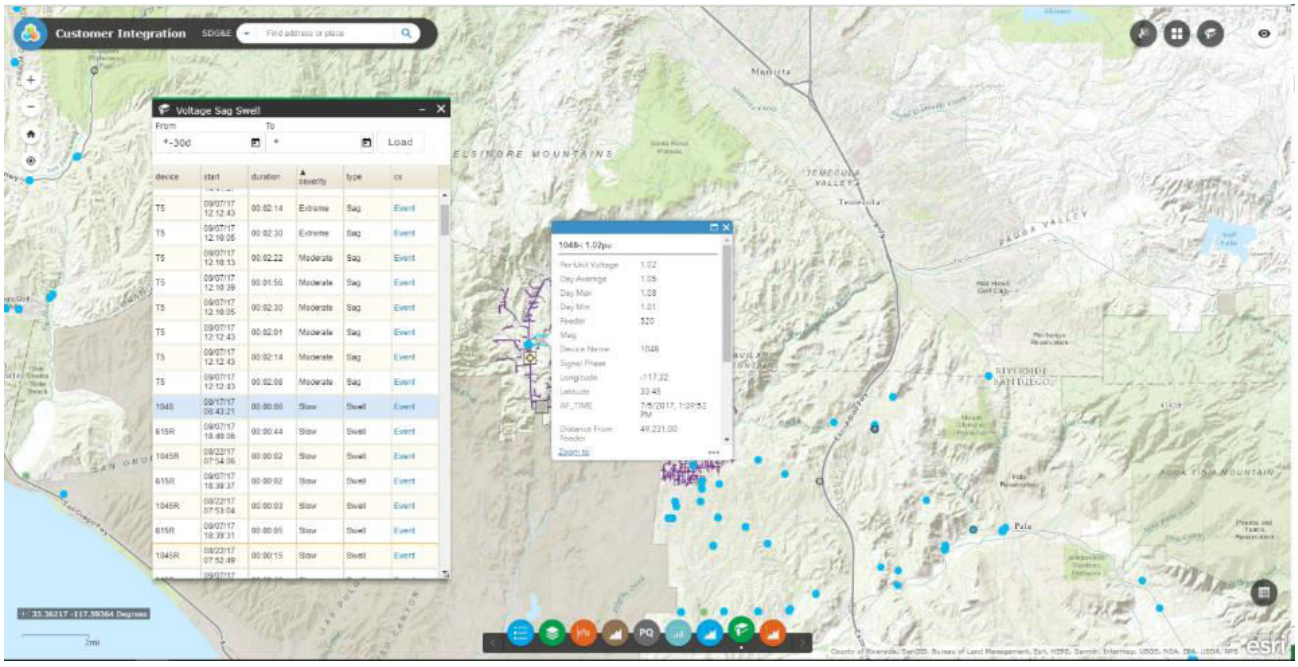


Figure 3-22. Demonstration of KPI monitoring

By clicking on an event on the table, it selects the matching attribute in the map. By clicking on the "Event" link, it brings up a PI Vision display showing the per unit voltage with limit lines for the time range of the event.

To create this display, the processing engine behind it has to detect the events using a custom extension on the OpenECA platform written in C#. OpenECA provides the custom program with synchronized real-time synchrophasor data. The program is configurable, so it can specify different thresholds for different sag/swell severities. Each severity has a set time duration and percent exceedance that must be reached for the event to be counted. Once an event is detected, an event frame is created in PI and linked to the correct device and phase. When the event concludes, the end time is updated in PI as well.

Once the data captured in PI, the processing engine uses a custom widget used to display the data in our web app. The user specifies a start/end for the search and clicks load. The widget makes a request to a custom web service that uses the PI macros to load and return the relevant event frames.

The following screens show the "interconnection violation" indicators for voltage sags, voltage swells, and power frequency. The ride-through thresholds and durations are determined from CA Rule 21 requirements.

The bar charts at the bottom count total number of voltage sags/swells for the current date. The threshold lines (blue and yellow lines) are calculated using the 30 sample per second OpenECA data and fed into PI. When the voltage reaches a configured threshold, the threshold line immediately jumps to the next threshold for a specified amount of time. To not violate the Rule 21 specifications, the voltage should recover within that time limit.

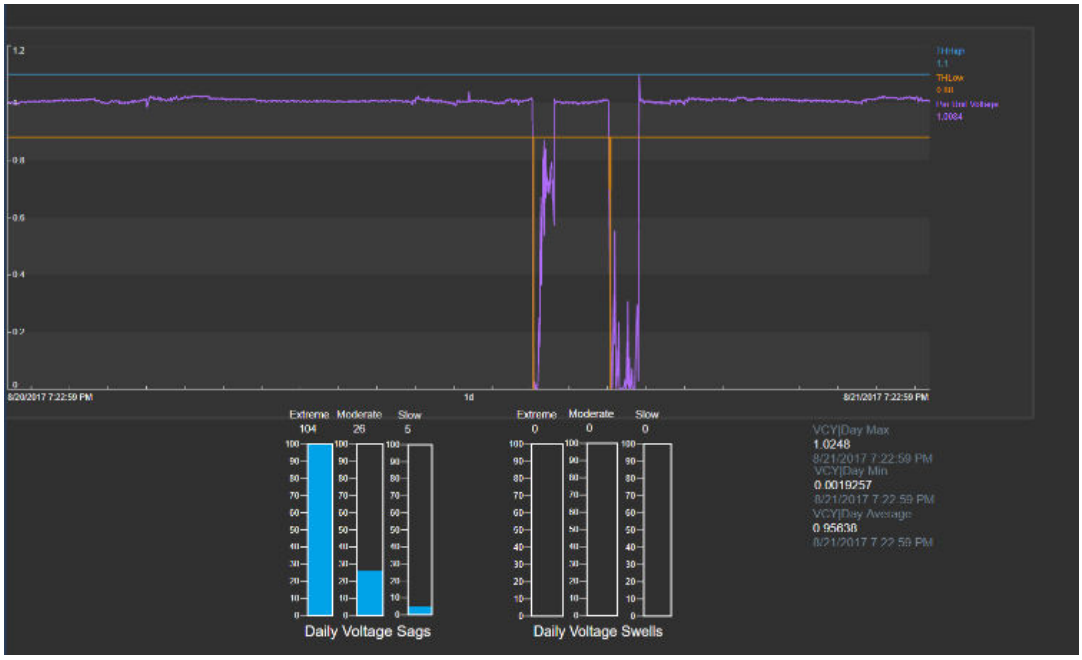


Figure 3-23. Sample of the captured voltage sag versus the acceptable thresholds and durations

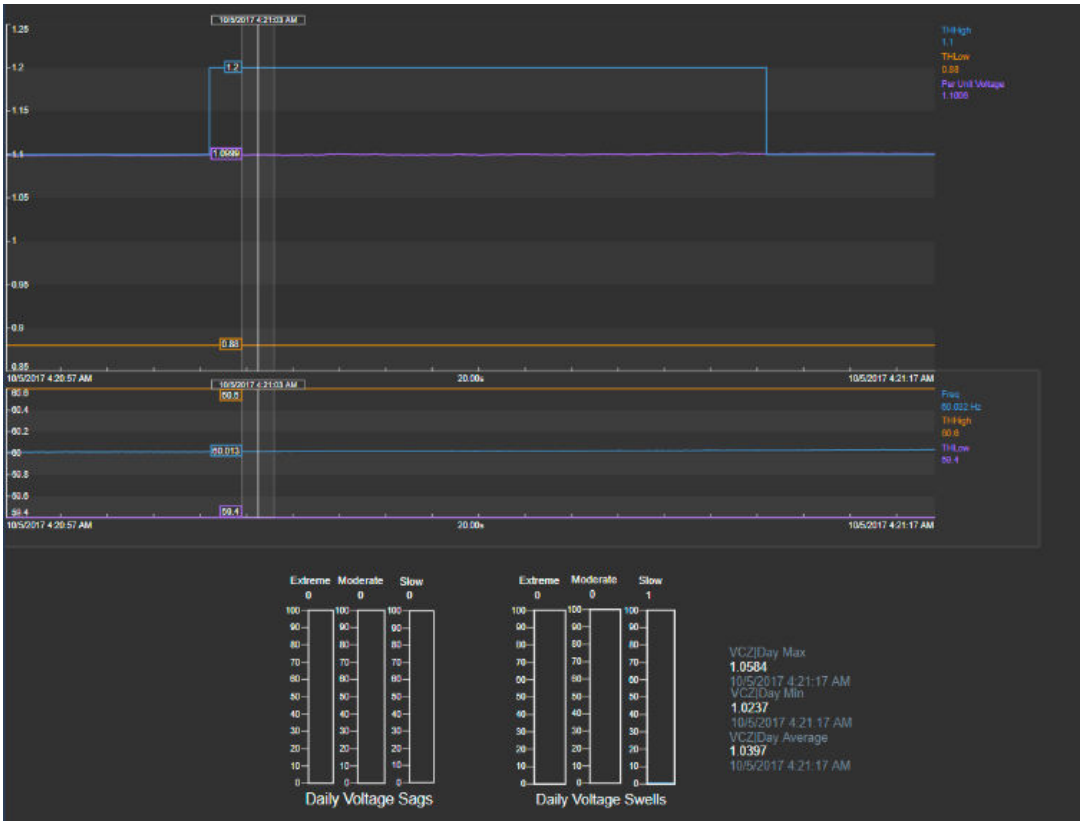


Figure 3-24. Sample of captured voltage swell versus

The voltage sag cases reported in the previous plots were caused by a sensor measurement problem on a line recloser. The voltage drops were only became observable when the PMU data streaming and visualization put in place.

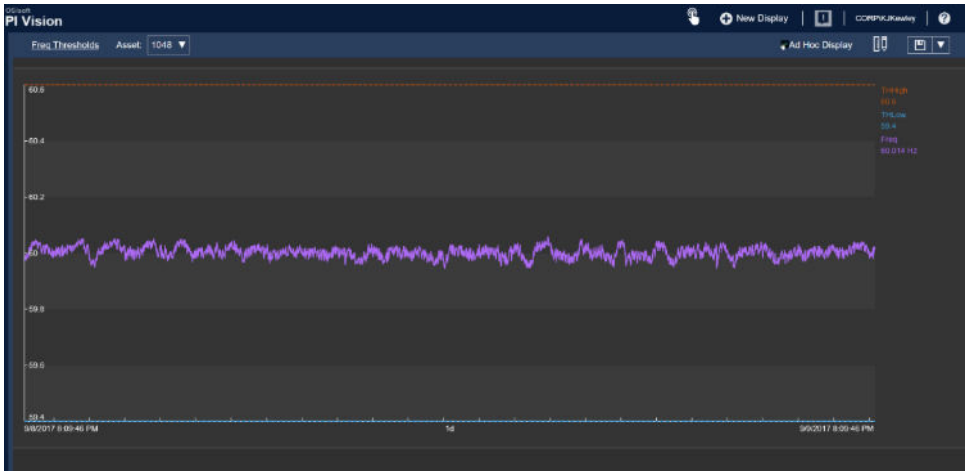


Figure 3-25. Frequency violation monitoring

Above screenshot uses similar calculations, but the thresholds are configured for frequency data. In this case, the high threshold is 60.6Hz and the low is 59.4Hz. Generally, frequency in distribution system is more stable and there should not be any violation of these thresholds on the circuits. However, if a cascading fault and outage event on transmission system causes a sudden frequency change and restoration, the distribution PMUs should be able to detect that.

The following screen calculates the voltage sensitivity of the PMUs. This PI process book screen is linked to the map. The values on the XY plot come from a calculation done in OpenECA. When there is a large change in voltage, the calculation returns $\frac{\Delta V}{\Delta P}$ and $\frac{\Delta V}{\Delta Q}$. This is plotted on a chart with the y axis as the calculated value and the x axis as the per unit voltage. On the left hand side, different PMU locations can be selected for display.

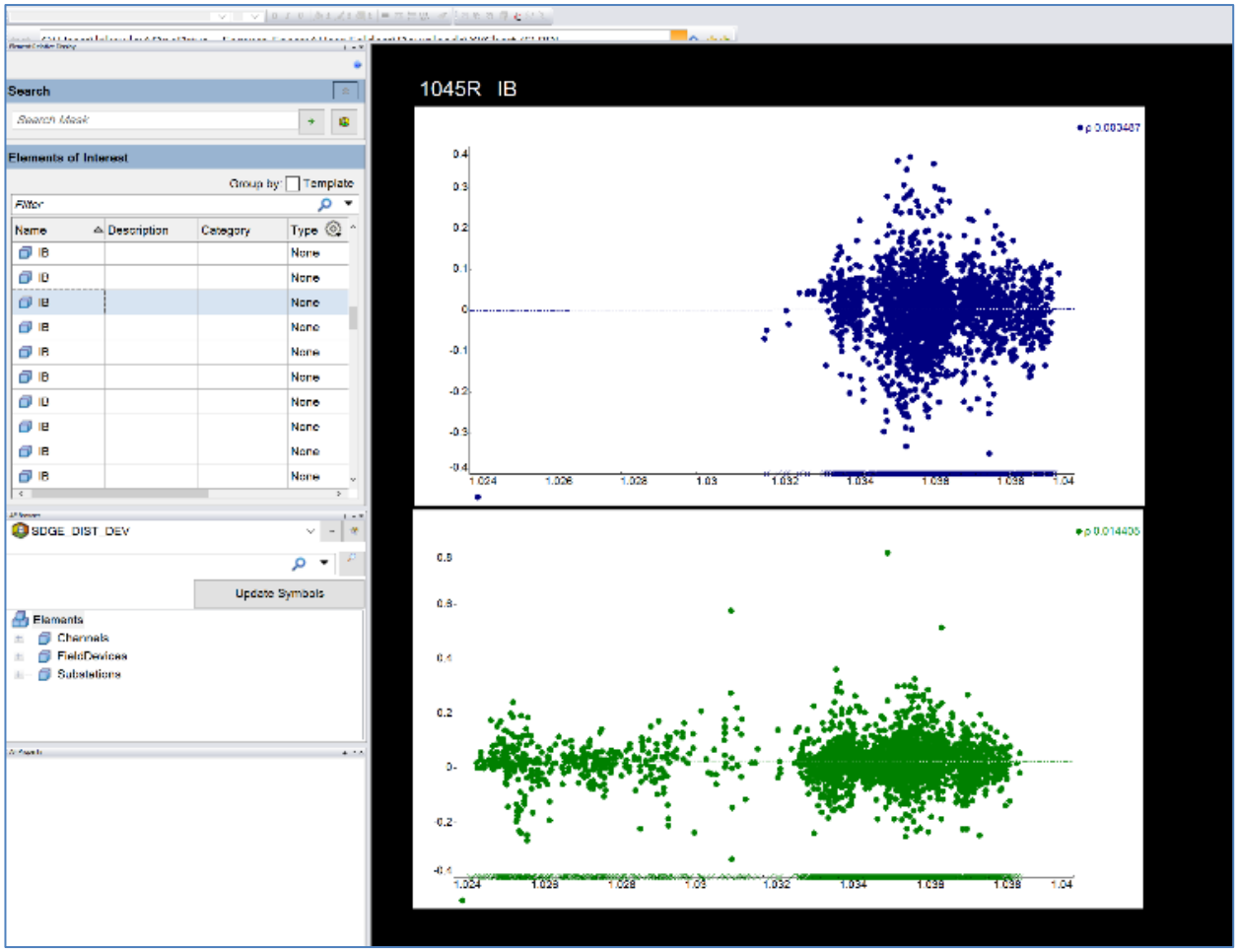


Figure 3-26. Power sensitivity trending for Circuit 1

The next figure shows the min/average/max voltage profiling plot for the entire circuit. Small horizontal line shows the average voltage, and the two ends of the long vertical line show minimum and maximum voltages in a day.

This visualization was created with a custom widget in Web AppBuilder. When opened, the widget subscribes to feature selection on the map. When a feature from the layer specified in the configuration is selected, the widget gets the “feeder” attribute of the selected feature. Then it makes a request for all the min, max, average, distance, and name attributes of features with the same feeder ID. Once the data is returned, the candlestick chart is drawn using the “dojo” framework charting library.

The plots was considered very beneficial for engineering analysis purpose and operator troubleshooting. In one glance, the engineer or the operator can determine the worst case locations on the circuit and narrow down the focus on analyzing those locations.

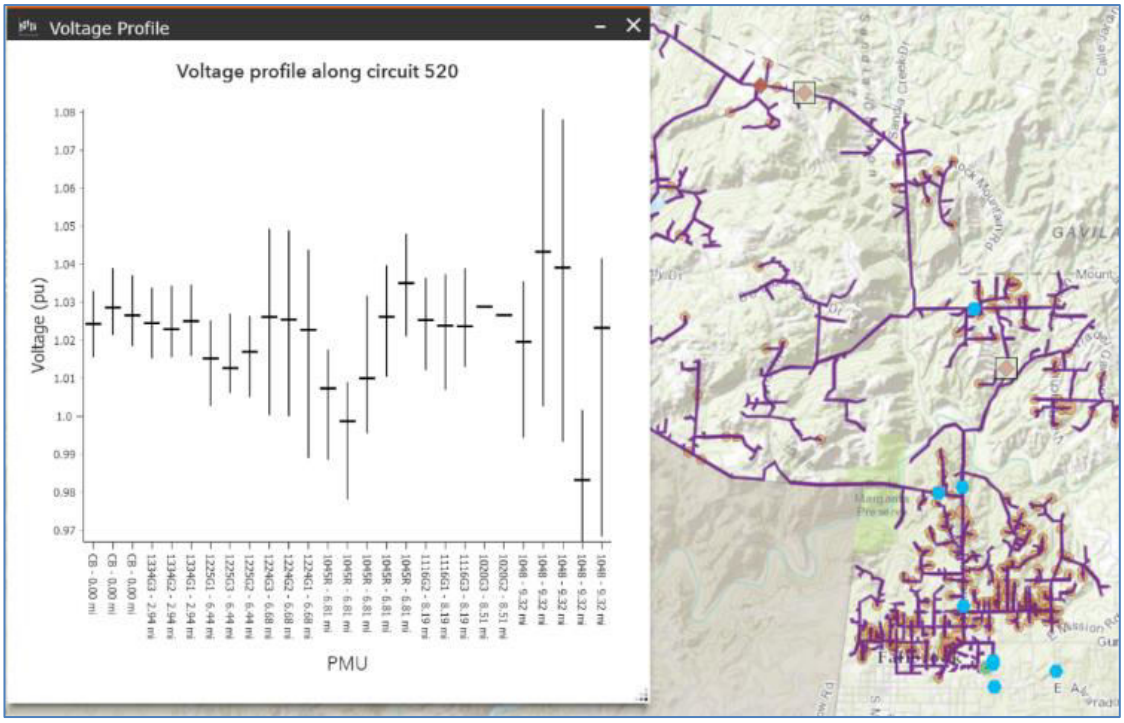


Figure 3-27. Voltage monitoring demonstration – Use Case 1

3.4 Power quality monitoring examples

Figures below illustrate visualization of odd/even harmonics and total harmonic distortion for selected substations. The detail harmonic information was extracted from PQview data base and incorporated in the visualization screen of this project. During the course of the project, it was noted that several SDG&E distribution substations are already equipped with power quality meters. The harmonic data are captured for pre-defined disturbance conditions (such as sudden voltage changes beyond 20%, or RHD greater than 3%) in PQdiff format. The PQview database collects and organize the PQdiff event records which will be the source of extracting harmonic information.

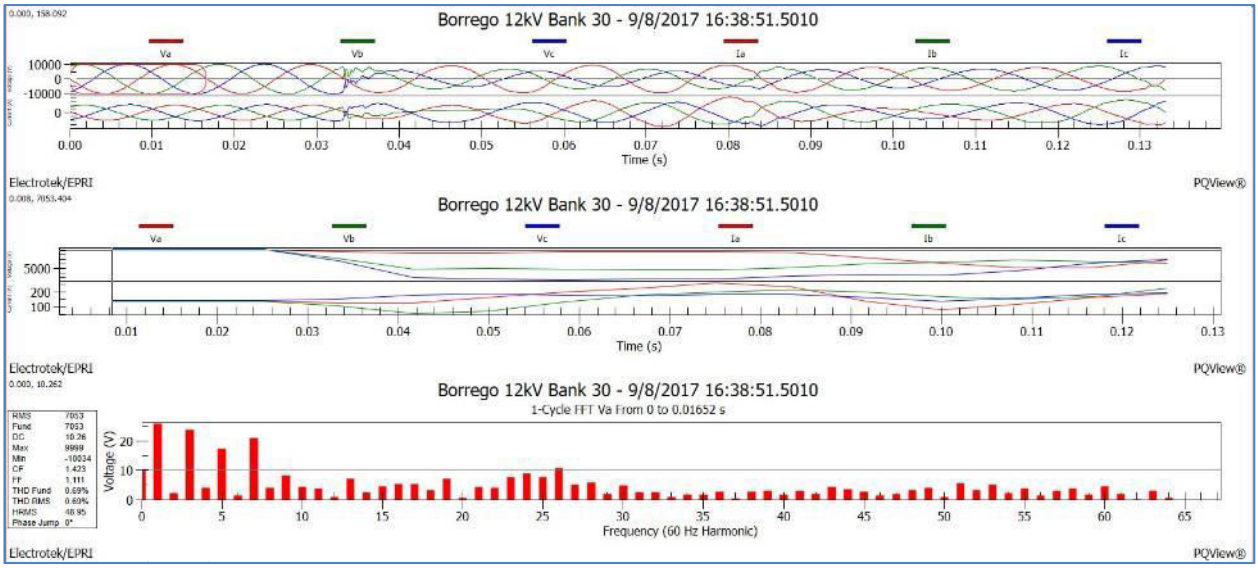


Figure 3-28. Monitoring of odd/even harmonics

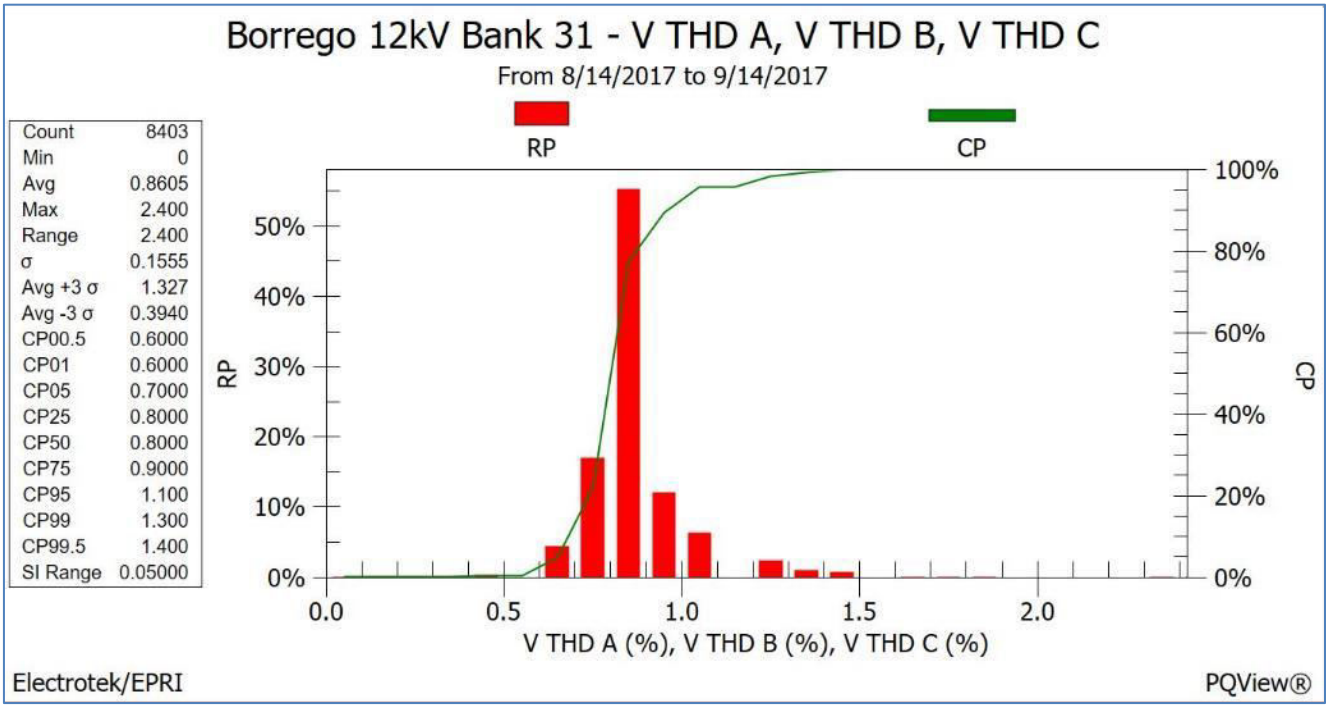


Figure 3-29. Visualization of total harmonic distortion (THD) on one of the selected circuits

3.5 Key performance indices monitoring

Figure below shows the data captured form one of the PQ meters at a distribution substation. The PQ meter provided a measurement of long term flicker factor as an example of the proposed performance indices. In order to calculate flicker factor, the number of voltage dips per minute has to be monitored and counted over the long moving window. However, the substation PQ devices already have internal calculation capability of the flicker factor. The feature was integrated in the visualization screen.

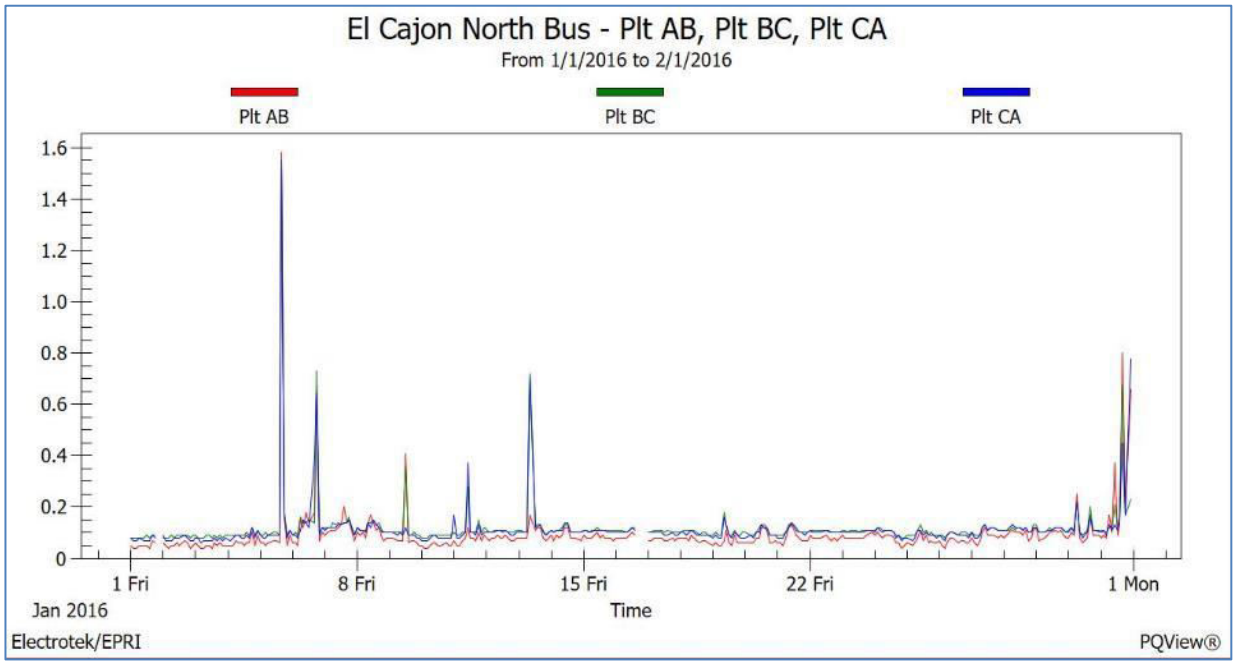


Figure 3-30. Illustration of Flicker factor monitoring and visualization

4 Pre-Commercial Demonstration Results based on Laboratory Setup

In this section, the results of the test cases for selected circuits (Circuit 1, Circuit 2, Circuit 3, and Circuit 4) based on different use cases demonstrated in the ITF laboratory are provided.

4.1 Circuit 1 Test Results

A simplified single line diagram of the Circuit 1 and the test setup are shown in Figure 4-1. The single line diagram is an overall representation of the model built in the RTDS environment for the laboratory testing and evaluations.

As indicated in this figure, there is a 2 MW PV system at the end of the circuit. The circuit backbone branches out in two directions. There is a normally open tie switch (520-1048) between the two branches of this circuit. For load transfer cases, the tie switch can be closed and one of the upstream reclosers can be opened to change the load flow and voltage profile of the circuit. Six voltage regulators and two switched shunt capacitors are installed on this circuit. A Dynamic Voltage Regulator (DVR) is also installed on the branch to the PV site, upstream of the PV location. DVR is used to mitigate significant voltage issues due to high PV production and loading condition. For the purpose of this study, this circuit has been modeled in RSCAD[1]. 12 PMUs including 8 simulated PMUs (PMU1 to PMU8) and 4 physical PMUs (PMU9 to PMU12) are located at various nodes in the study system to facilitate system monitoring during the tests.

[1] All controllable assets (voltage regulators, load tap changers, and capacitor banks) are also modeled in details in the real-time digital simulator (RTDS) to enable integrated voltage/var control in the distribution circuit under study.

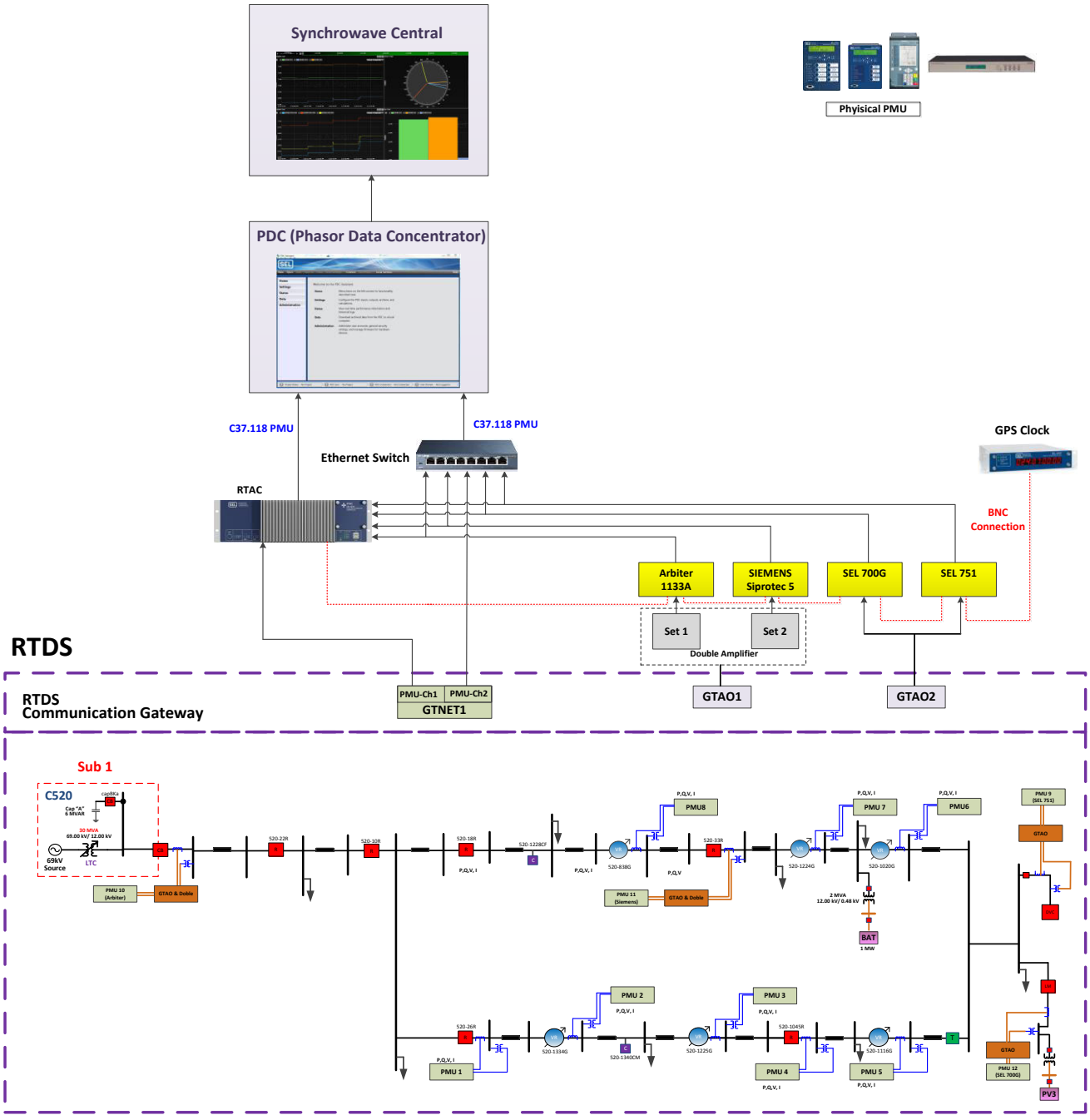


Figure 4-1. Single Line Diagram and PMU Locations of the Circuit 1

The PMUs data (either obtained from the real-time digital simulator or actual physical hardware) is streamed to PDC and RTAC. Simultaneously, RTAC processes the input PMU data and sends the calculated parameters

into the PDC. Finally, all data obtained from PMUs and RTAC will be time aligned and sent to SynchroWAVe for monitoring and visualization purposes. The calculated values in RTAC are as follows:

- Delta V in per unit (with respect to the base voltage of 12 kV)
- Unbalance factor in % (using V2/V1 – negative to positive sequence voltage ratio)
- Extreme voltage sag count (V<0.2 pu for 10 cycles)
- Moderate voltage swell count (0.2 <V< 0.4 pu for one second)
- Extreme voltage swell count (V > 1.3 pu for 10 cycles)
- Moderate voltage swell count (1.2< V < 1.3 pu for 1 second)
- Alpha factor (dV/dP) in pu/MW
- Beta factor (dV/dQ) in pu/Mvar
- Flicker index (calculated based on the number of voltage dips per minute)

In addition to these calculations, THD and tap positions are directly sent to the PDC using the analog values of the simulated PMUs.

In the following section, different case studies are investigated and reported for the validation of the test set-up and the calculations in the Avocado circuit.

4.1.1 Voltage/Power Flow Monitoring

The purpose of this test category is to verify proper communications amongst various components of the test setup and to demonstrate the built-in visualization capability of the SynchroWAVe Central. Furthermore, it will evaluate the calculation of Delta V (per unit) in RTAC.

4.1.2 Long-term Monitoring

In this test, the winter load profile was run for 90 minutes with PV and the following measurements were captured from SynchroWAVe Central for all PMUs.

- Magnitude of positive sequence voltage
- Magnitude of positive sequence current
- Phase angle of positive sequence voltage
- Phase angle of positive sequence current
- Active power
- Reactive power
- Apparent power
- Delta V (per unit).



Figure 4-2. Magnitude of Positive Sequence Voltages

The fluctuations in the voltages and currents are caused by the changes in the load profile, PV profile, and tap position changes of the voltage regulators. The changes in load and generations are observable from a visualization graph such as the one shown below for capturing positive sequence currents at PMU locations.

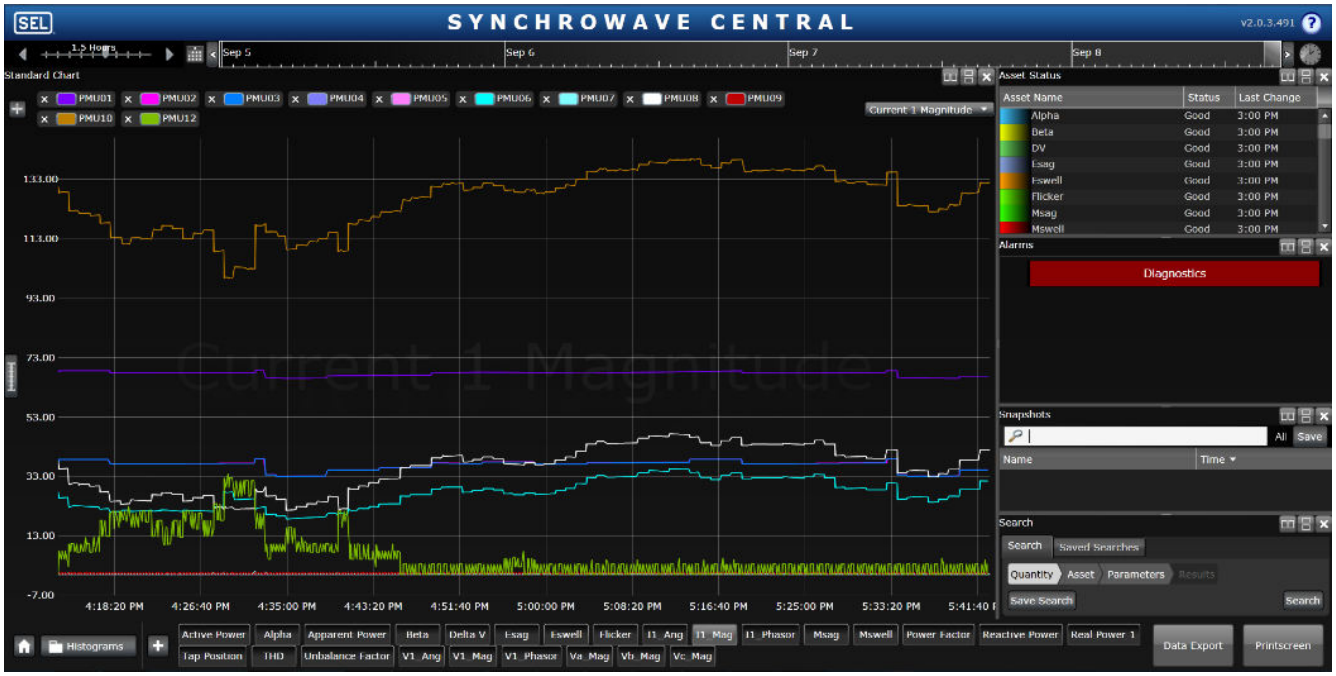


Figure 4-3. Magnitude of Positive Sequence Currents

Other visualization screens were used to capture phase angles of the voltage and current phasors as shown below. Phase angle visualization were primarily used during synchronization and load transfer schemes. Sudden changes in load or issues associated with customer introduced disturbances can also be identified from phase angle measurements by noticing any sudden jumps (typically called vector jump).



Figure 4-4. Phase Angles of Positive Sequence Voltages

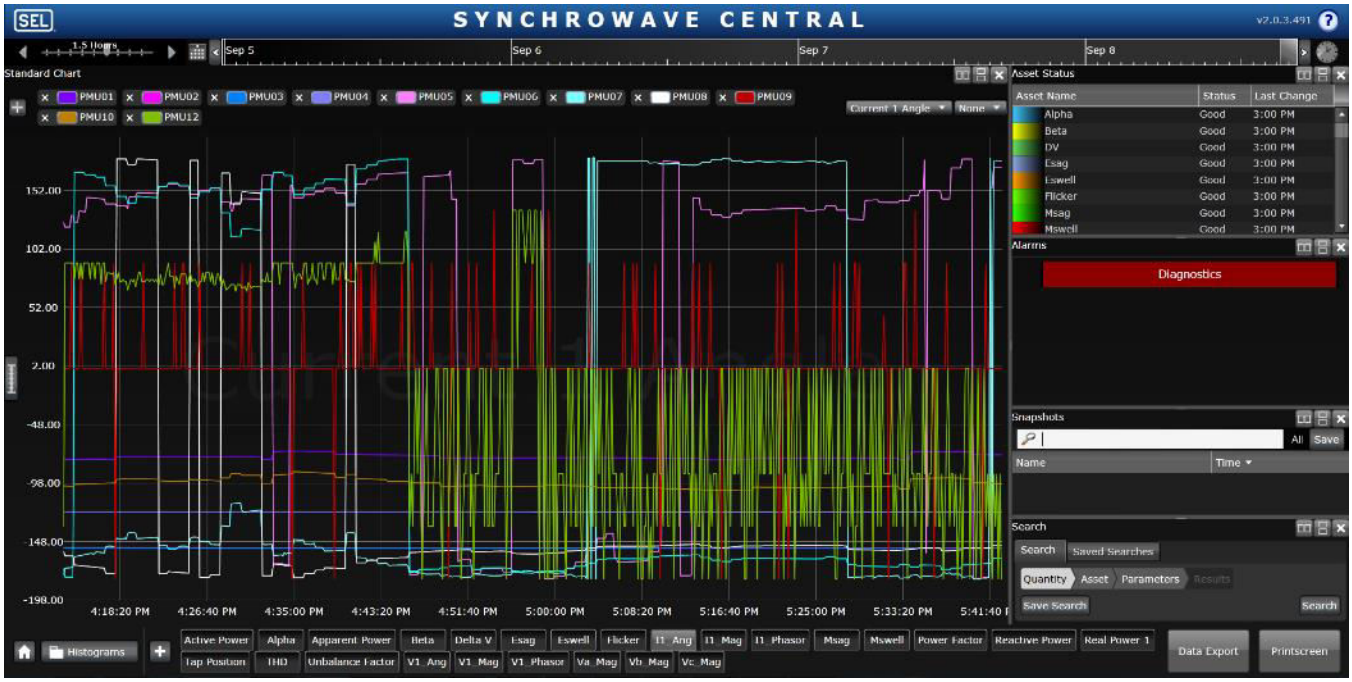


Figure 4-5. Phase Angles of Positive Sequence Currents

The reason for the current phase angles fluctuations in PMU 09 and PMU 12 is that the currents of the afore-mentioned PMUs are zero; therefore, the PMUs cannot correctly calculate phase angles from noises.



Figure 4-6. Active Powers

Active and reactive power visualization screens were used to investigate power flow across the circuits.

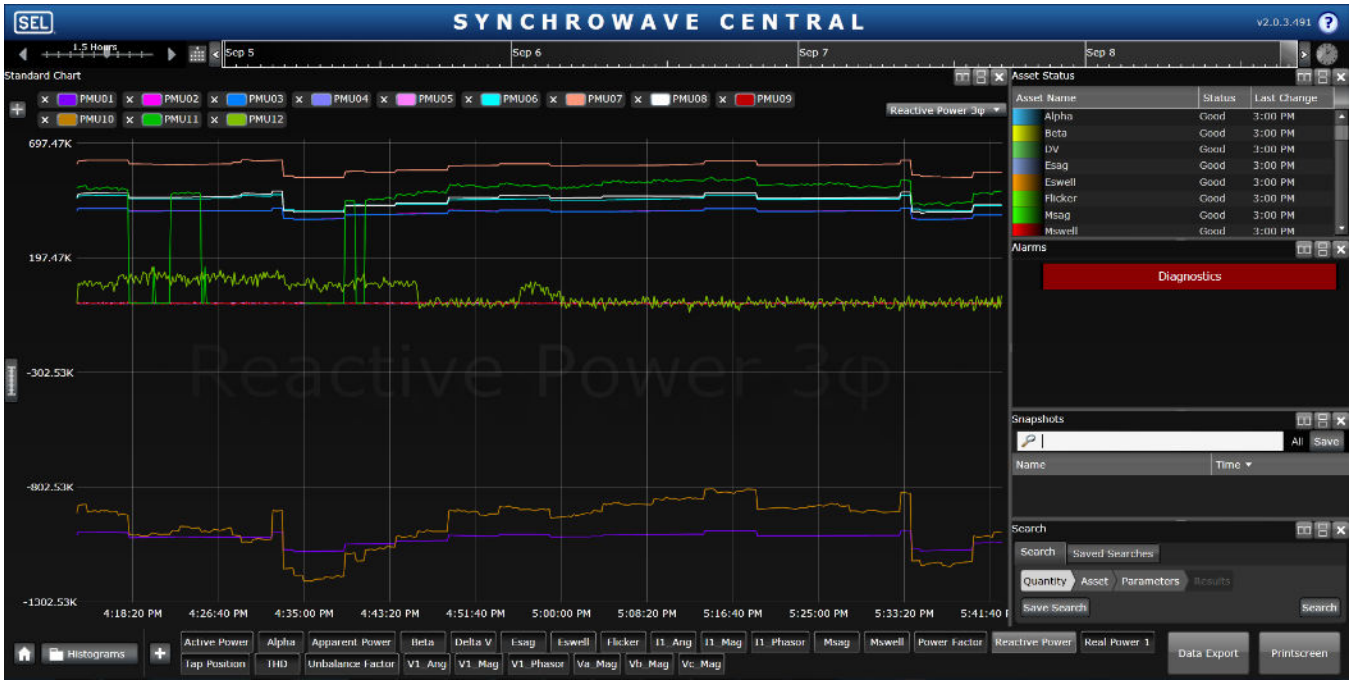


Figure 4-7. Reactive Powers

The apparent power screen was used to evaluate the thermal rating of the circuit and feeder devices.



Figure 4-8. Apparent Powers



Figure 4-9. Calculated Delta V (pu) in Automation Controller

From the above graph, it can be simply observed that the voltage differences (compared to the nominal voltage) across the circuit do not violate 0.05 pu.

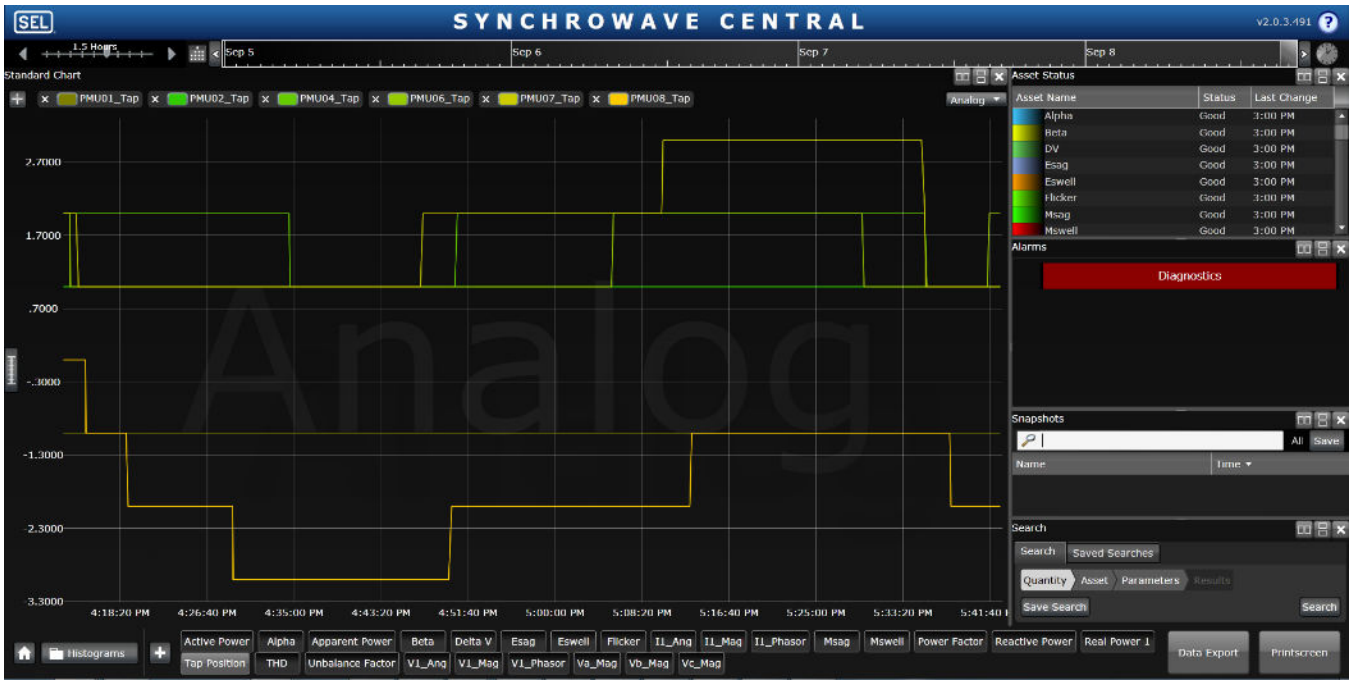


Figure 4-10. Tap positions streamed through the analog value

4.1.2.1 Phasor Monitoring

In this test, the behavior of the circuit 1 was studied during a load transfer.

Initially, the circuit was set at constant low load condition (0.3 pu) with no PV. Figure 4-11 shows the active powers before the connection of the PV. It can be observed that there is no reverse power flow in any of the PMUs as expected. Figure 4-12 shows the phase angle difference between the two sides of the normally open tie switch (520-1048) which is 1.27 degrees.

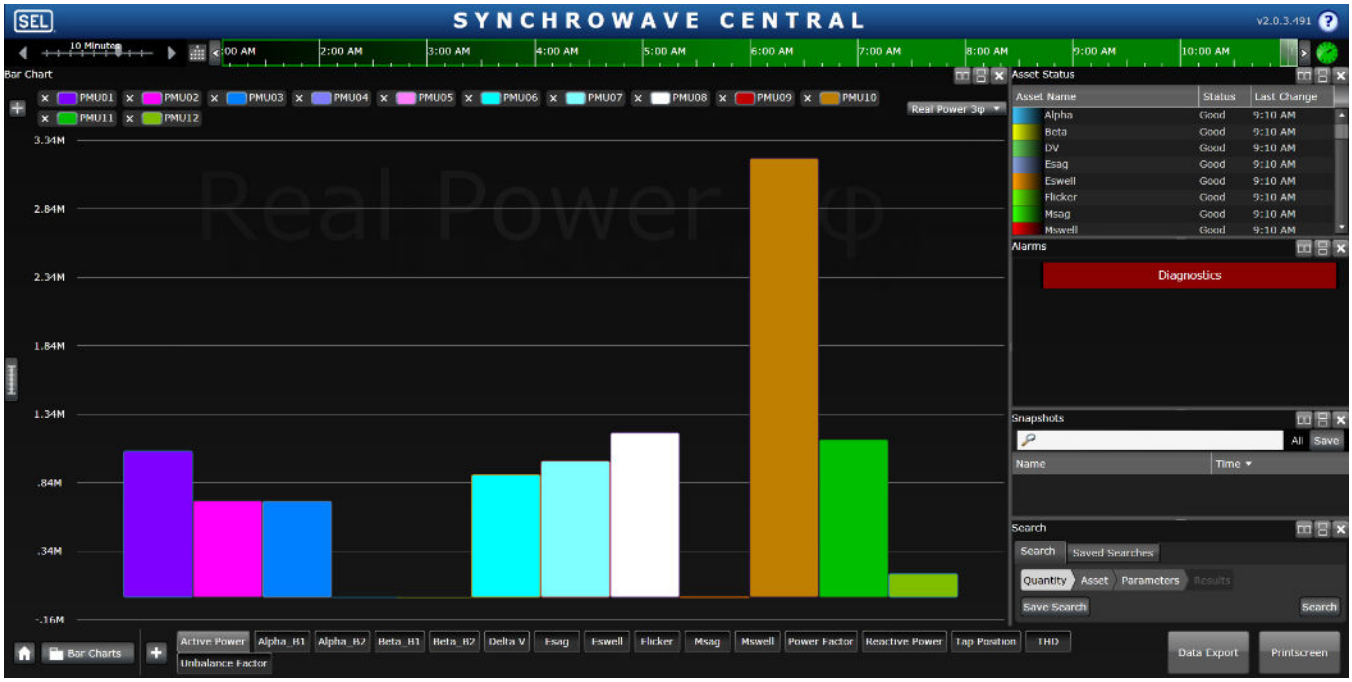


Figure 4-11. Active Powers during Low Loading without PV and with a Tie Switch Opened

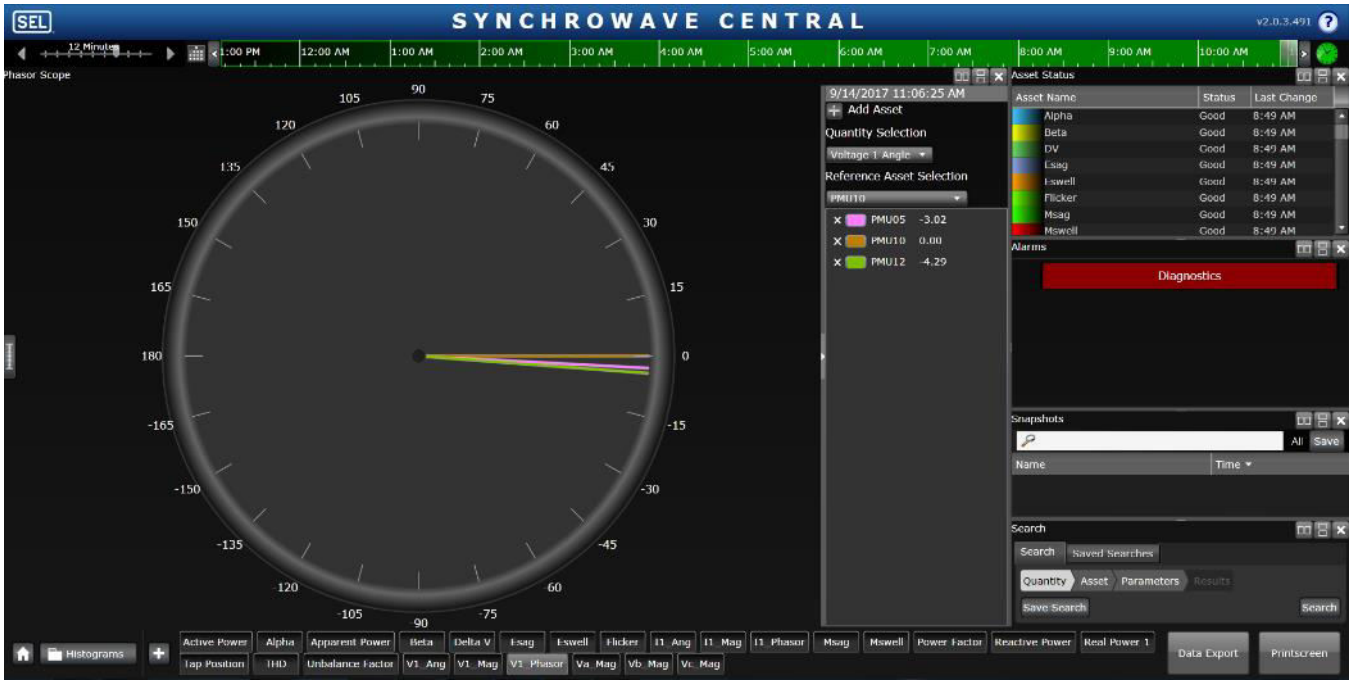


Figure 4-12. Phase Angles of the Two Sides of the 520-1048 during Low Loading without PV.

In the next step, suddenly, the maximum PV was added to the circuit. It can be seen in Figure 4-13 that this event created reverse power flow in the branch with PV (PMU 6, PMU 7, PMU 8, and PMU11, and PMU12).

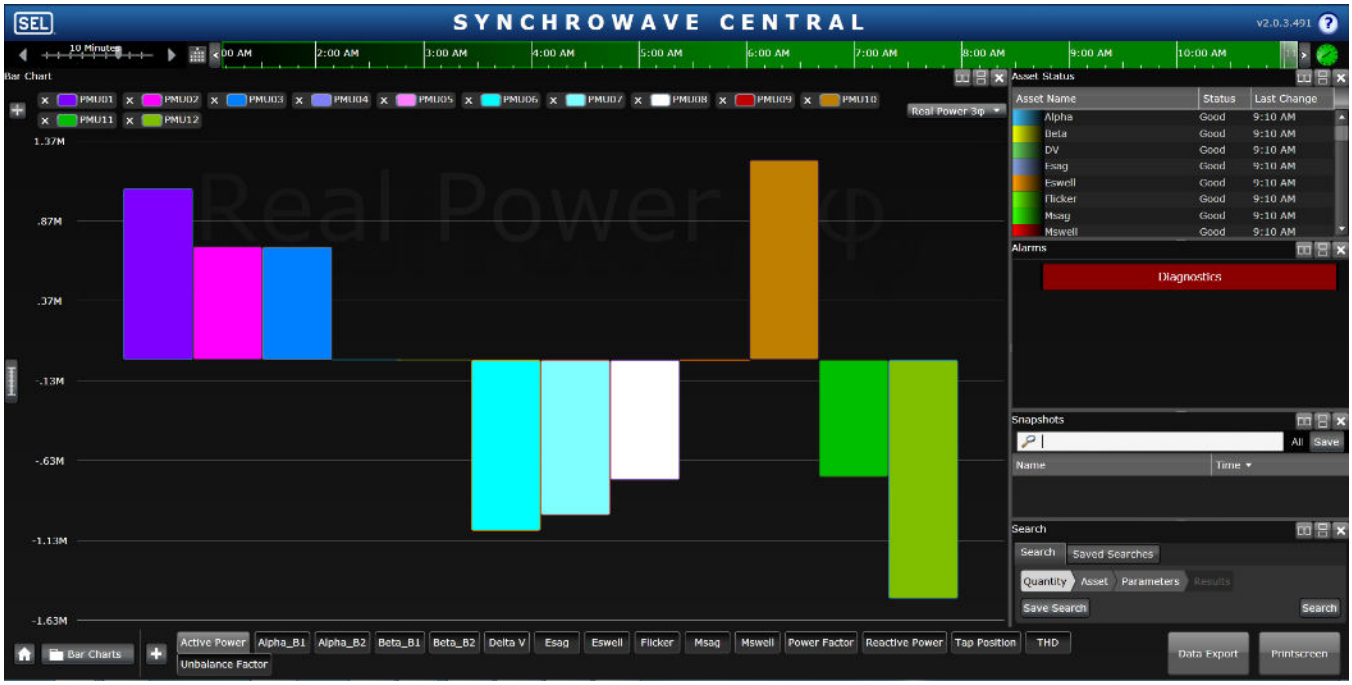


Figure 4-13. Active Powers after the Connection of the Maximum PV.

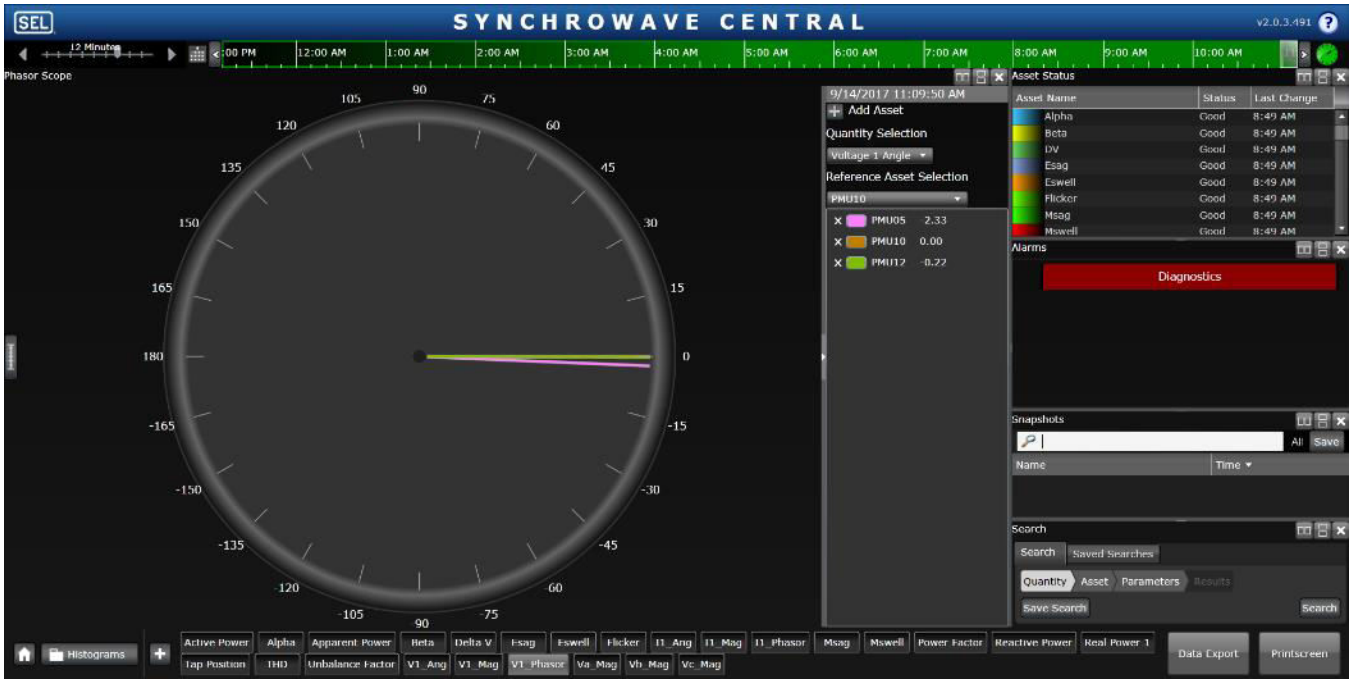


Figure 4-14. Phase Angles for the Two Sides of the 520-1048 after the Connection of the Maximum PV.

The phase angle across the open switch of the circuit was 2.11 degrees and the voltage magnitude difference is 0.5%, which gives the permission for closing REC 520-1048. The general requirements are voltage differences less than 5% and phase angle differences less than 10 degrees.

The following figures show the active powers and phase angles subsequent to the closing of REC 520-1048. It can be seen that this action caused a small amount of reverse power flow on the branch without PV (PMU 4 and PMU 5).

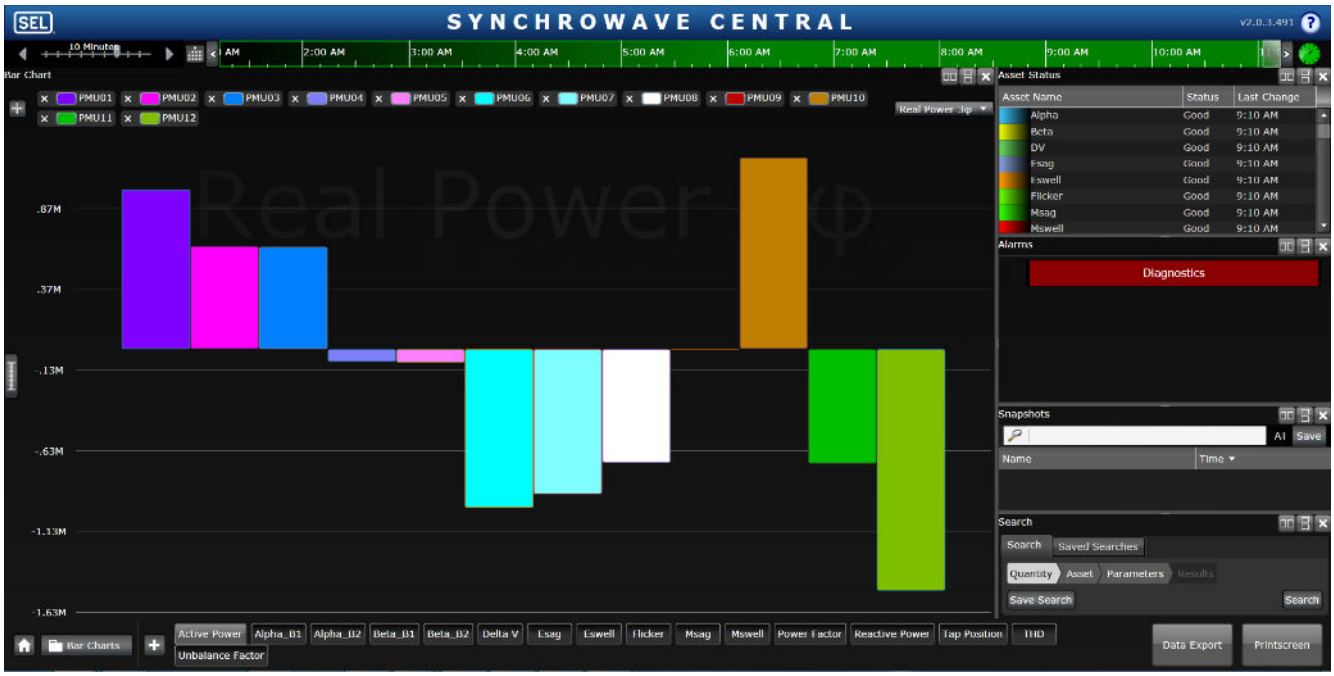


Figure 4-15. Active Powers after Closing 520-1048

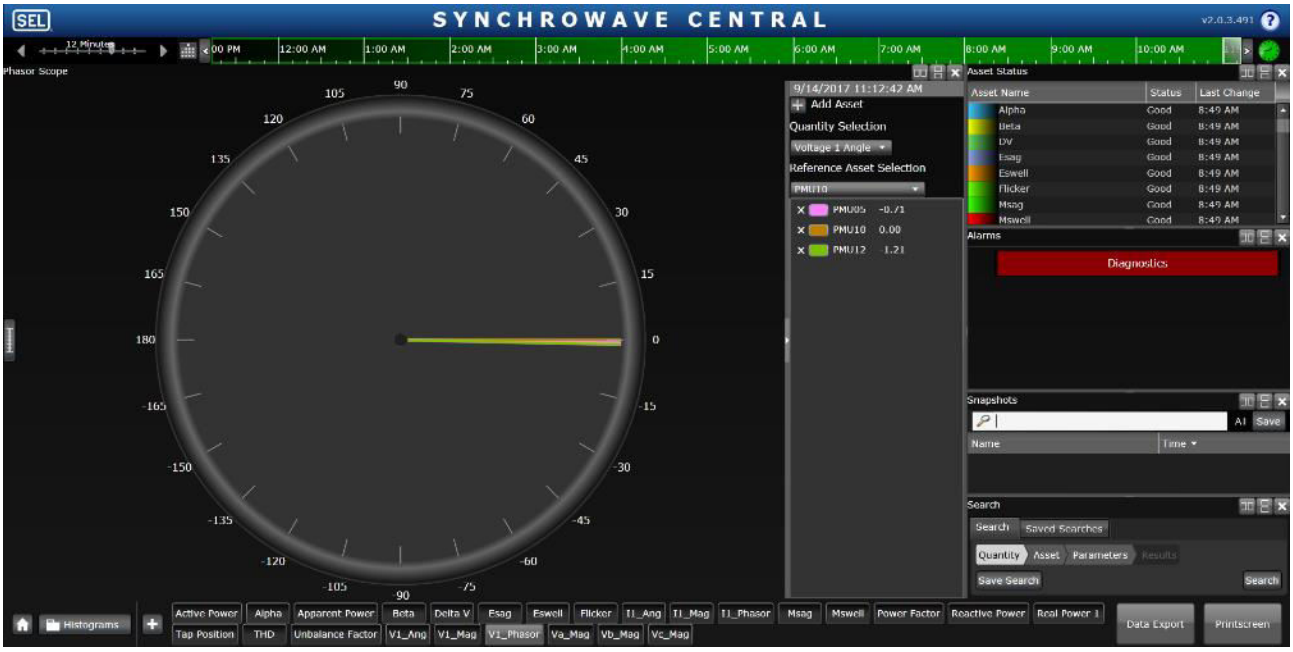


Figure 4-16. Phase Angles for the Two Sides of the 520-1048 after Closing 520-1048

A recloser on the branch without PV was identified where the power flow is below 1 MW (REC 520-1045). This recloser was opened to perform a load transfer. The following figure show the active powers subsequent to the opening of REC 520-1045. It can be seen that this action causes a huge reverse power flow in PMU 5 and PMU 4.

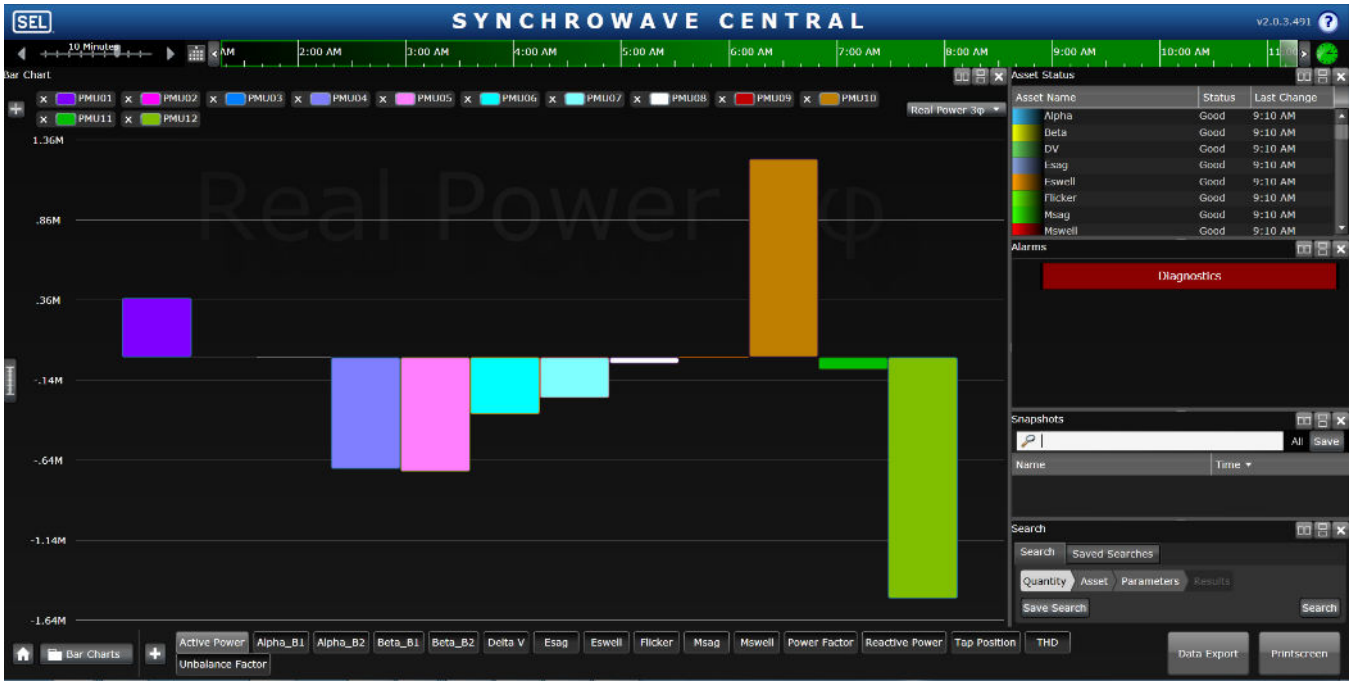


Figure 4-17. Active powers after the load transfer

To summarize, the sequence of actions during the load transfer was:

- Connecting PV to the System
- Closing tie switch 520-1048
- Opening recloser 520-1045

The PMU data including voltages, active powers, reactive powers, and tap positions are captured during the load transfer as shown in the following figures to better understand the effect of each action on the parameters of the system.

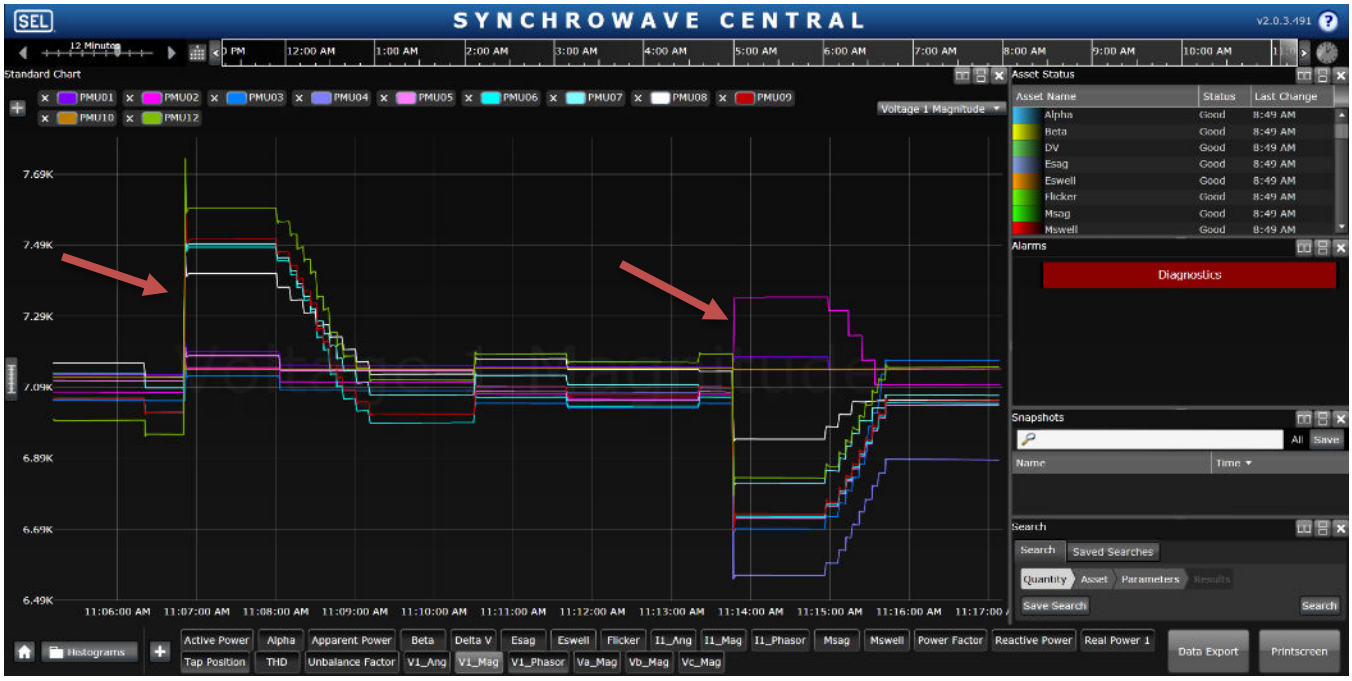


Figure 4-18. Magnitude of the Positive Voltages during the Load Transfer (changes are shown by arrows)

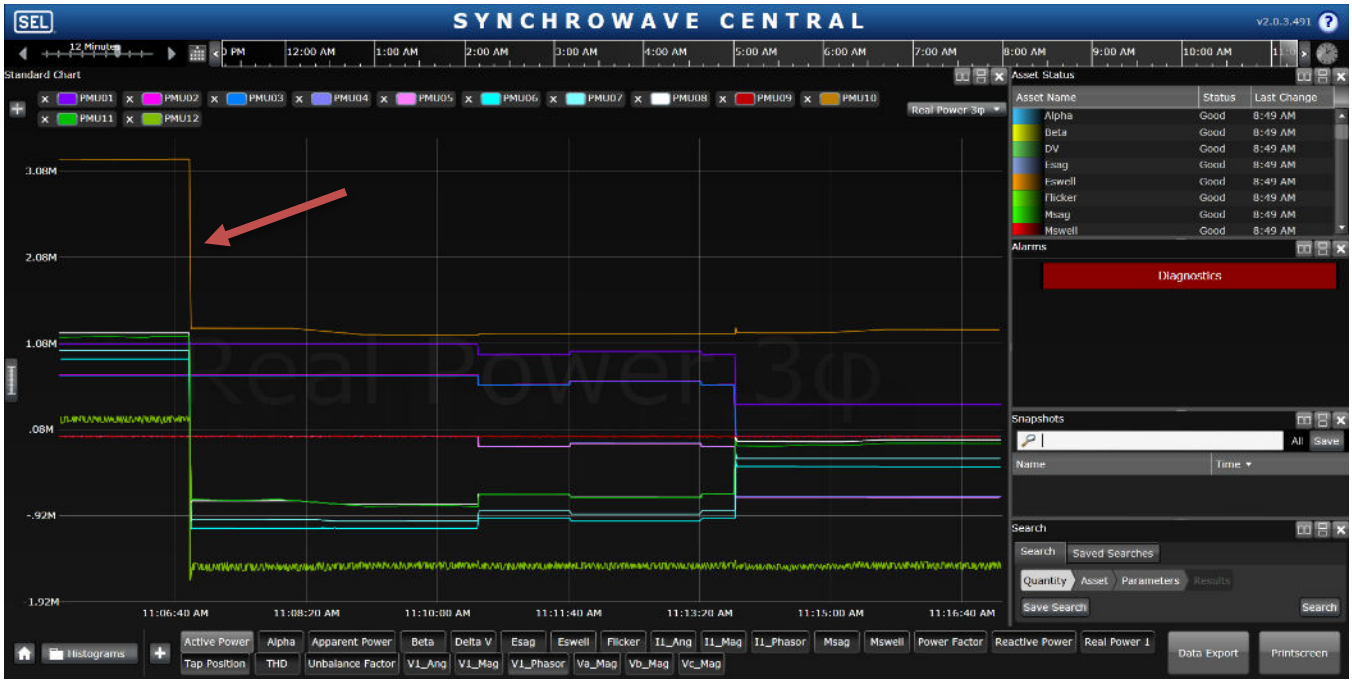


Figure 4-19. Active Powers during the Load Transfer (time of change is shown by the arrow)

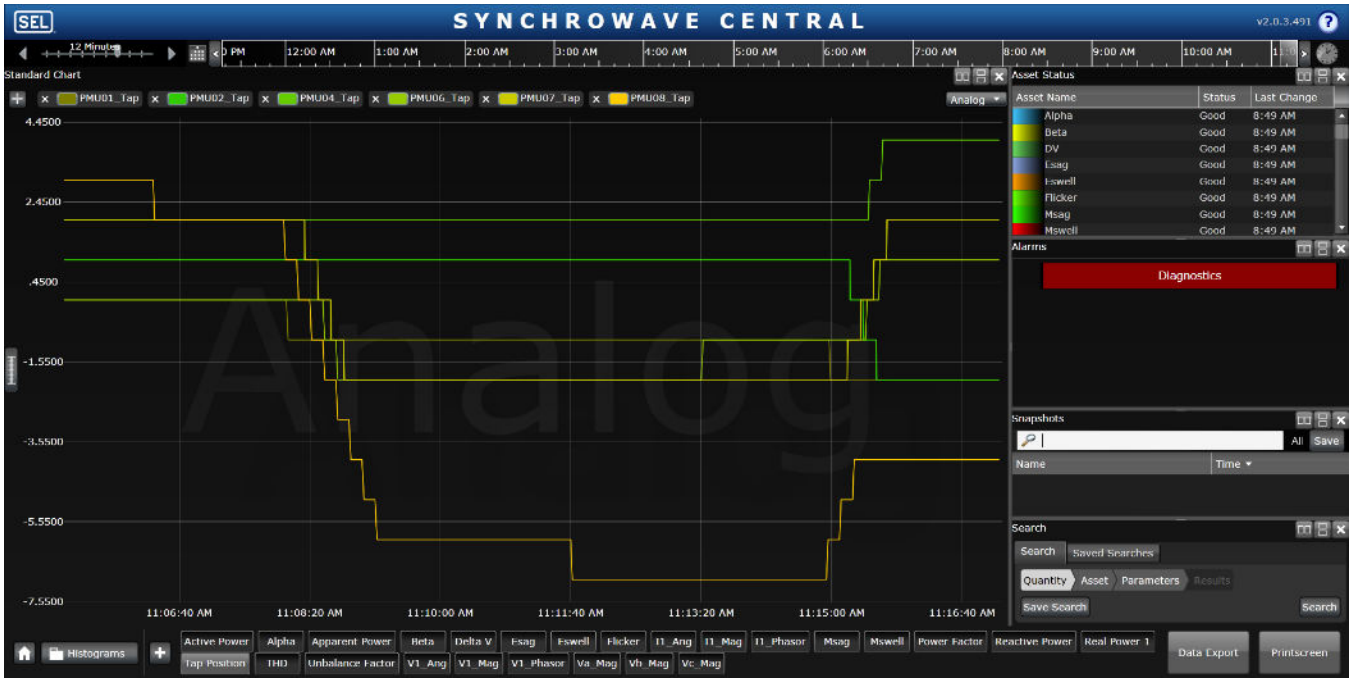


Figure 4-20. Tap Positions during the Load Transfer

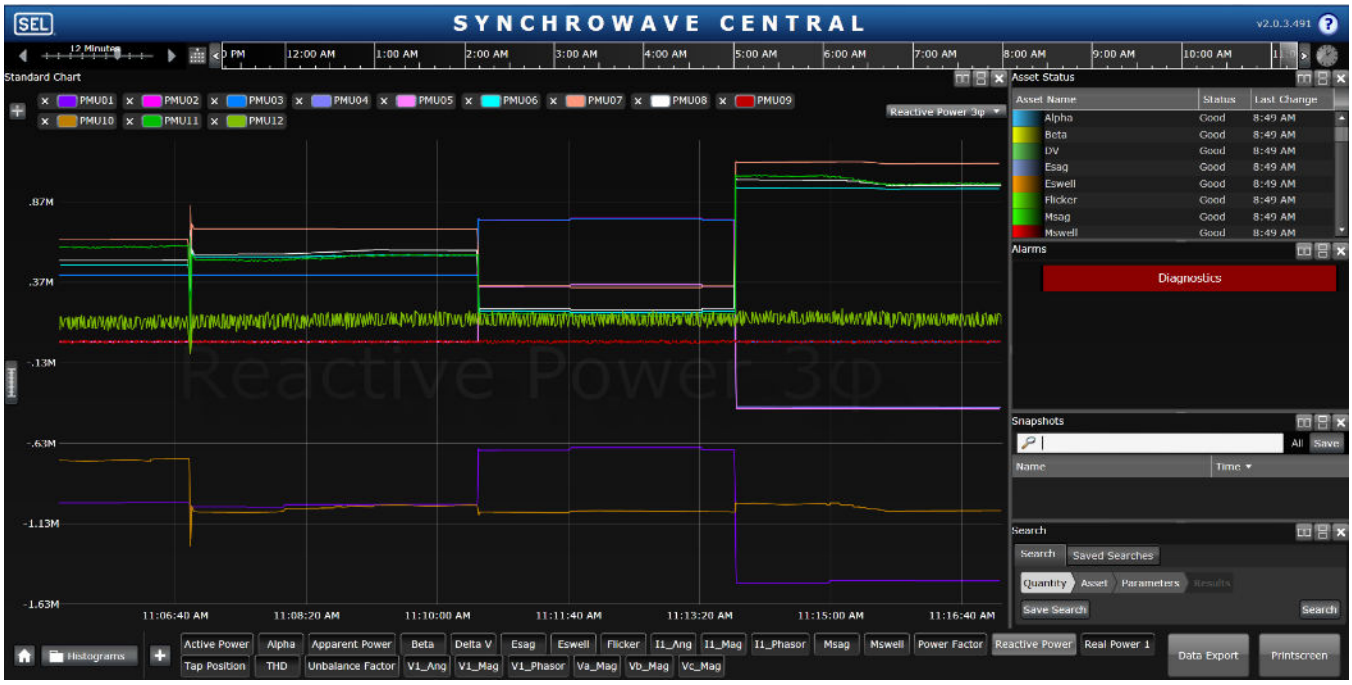


Figure 4-21. Reactive Powers during the Load Transfer

It can be seen from the visualization screen that PMUs can detect and visualize step changes in the load and resulted power flow variations.

4.1.3 Primary Asset Operation Monitoring and Diagnostics

The objective of this test category is to verify the streaming capability of the analog value assigned to the tap positions and THD.

4.1.3.1 Tap Position Streaming

Constant load (0.75 pu) profile was applied. Initially capacitor C1 and C3 were turned on. We turned off capacitor C1 and waited for the voltages to get to the steady state condition; then, turned it on and waited for the voltages to get to the steady state condition. Similar condition was repeated for C3, and the following measurements were captured:

- Magnitude of positive sequence voltage
- Magnitude of positive sequence current
- Active power
- Reactive power
- Tap positions for all voltage regulators

It should be noted that the sequence of capacitor switching actions were introduced to create dynamic events and to introduce disturbances that can be detected by the PMUs to test and evaluate the functionalities of the proposed monitoring and visualization schemes.

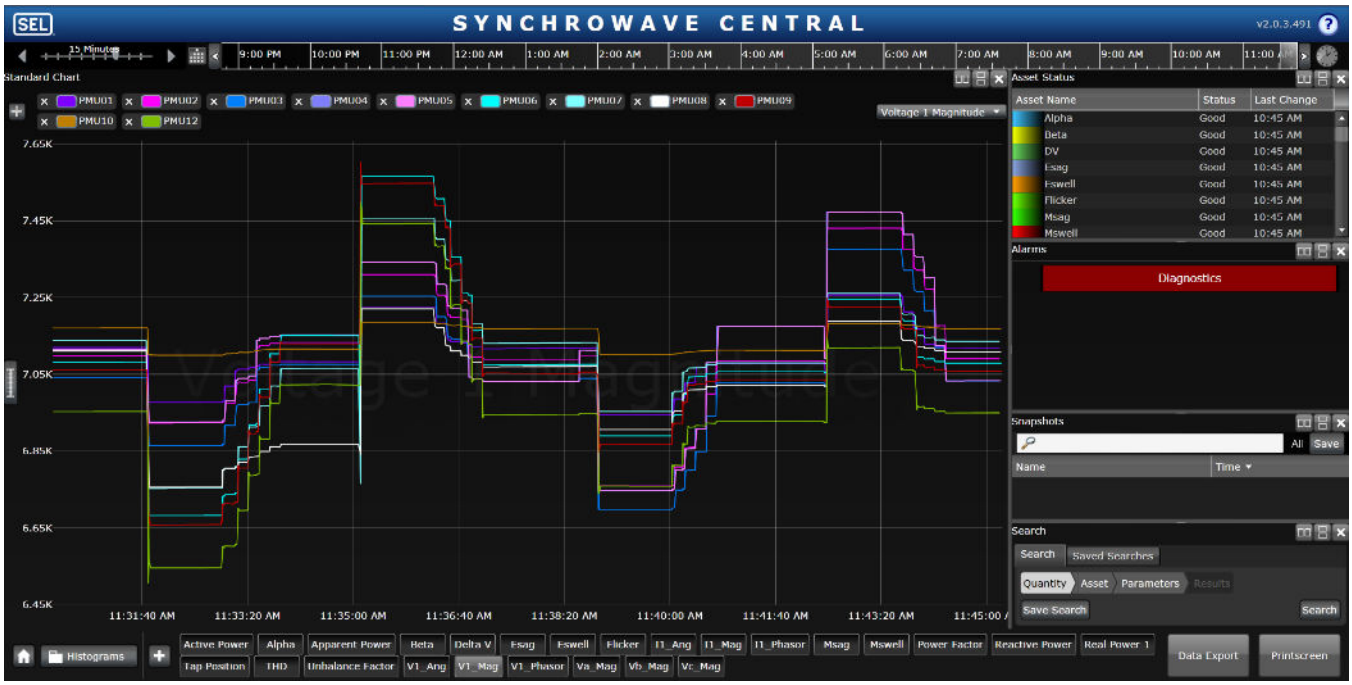


Figure 4-22. Magnitude of Positive Sequence Voltages Subsequent to Capacitor Switching

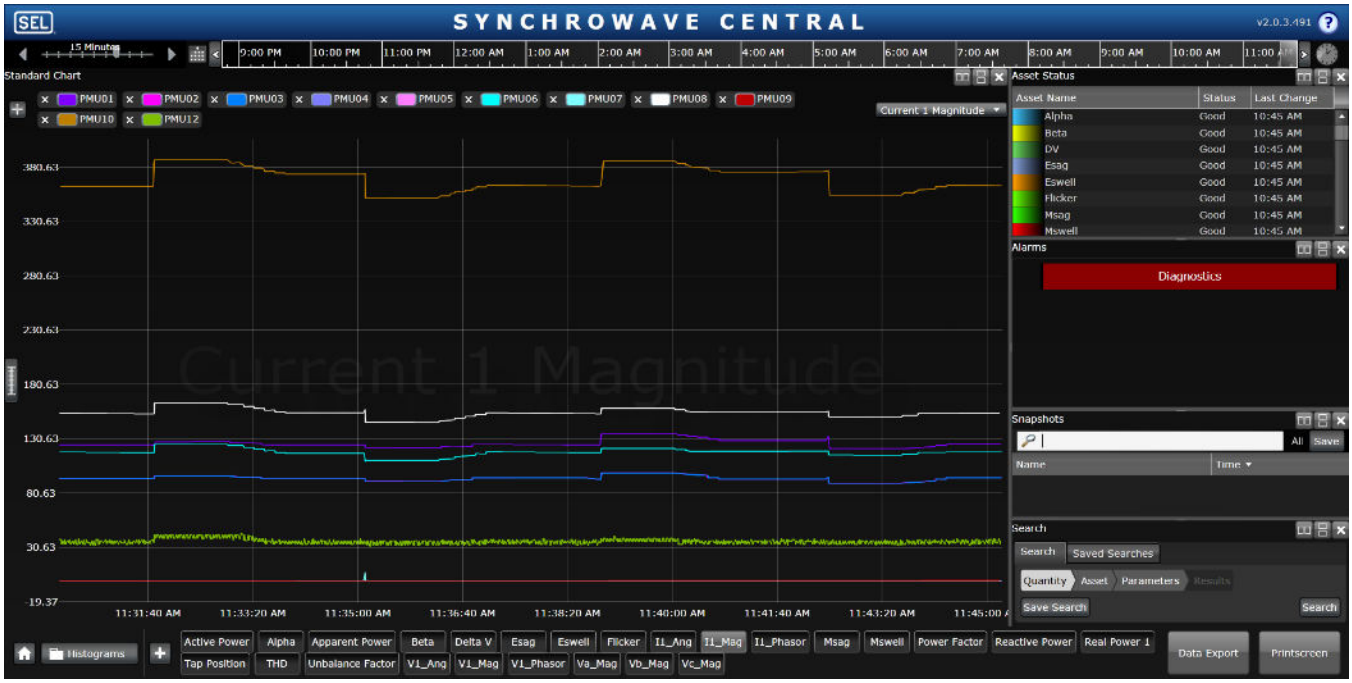


Figure 4-23. Magnitude of Positive Sequence Currents Subsequent to Capacitor Switching

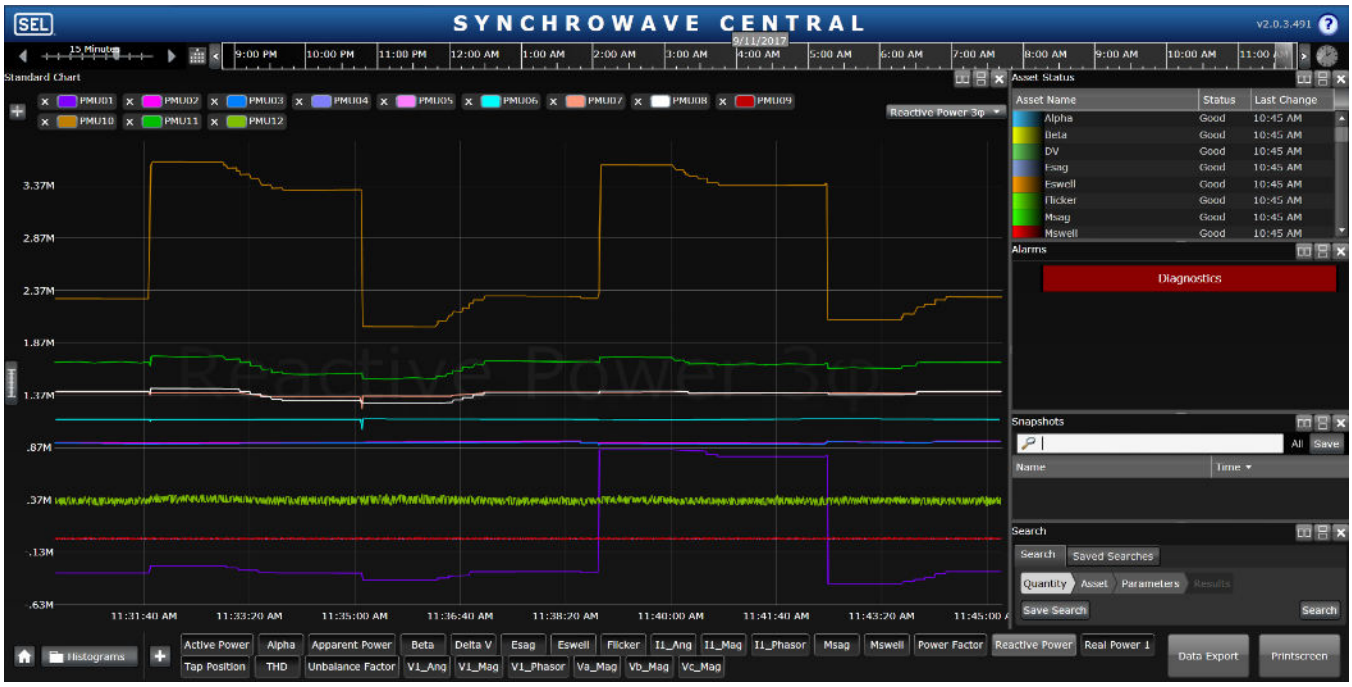


Figure 4-24. Reactive Powers Subsequent to Capacitor Switching On and Off

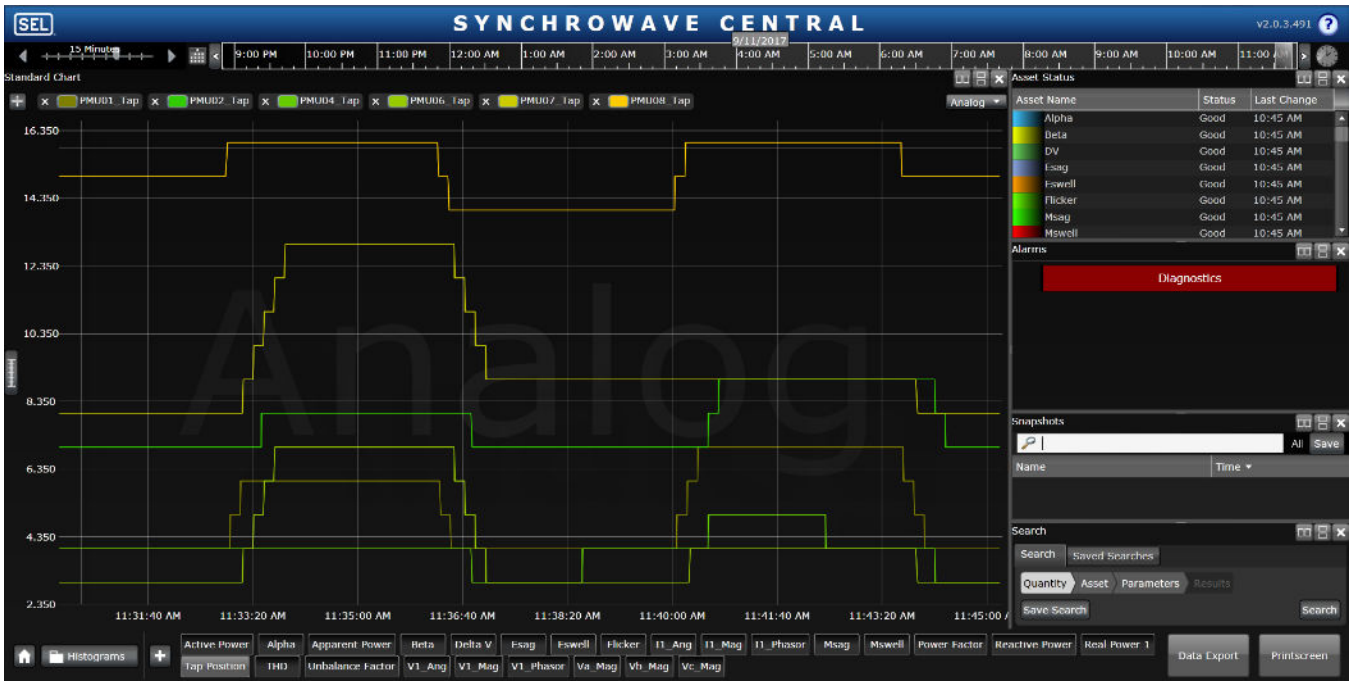


Figure 4-25. Tap Positions Subsequent to Capacitor Switching

4.1.3.2 THD Streaming

In this test, the constant load profile (0.5) was used with no PV. REC 520-1048 was in closed position. To investigate the THD level, 5th harmonic voltage component was added to the circuit, through non-linear harmonic load injection downstream of the voltage regulator 3, which increased the voltage as well as harmonics. The magnitude of the harmonic injection was increased (every 30 seconds) to 0.03 pu, 0.08 pu, 0.15 pu, and 0.3 pu of the fundamental component.

The following measurements were captured before and after the injection of the harmonics:

- Magnitude of positive sequence voltage
- THDs

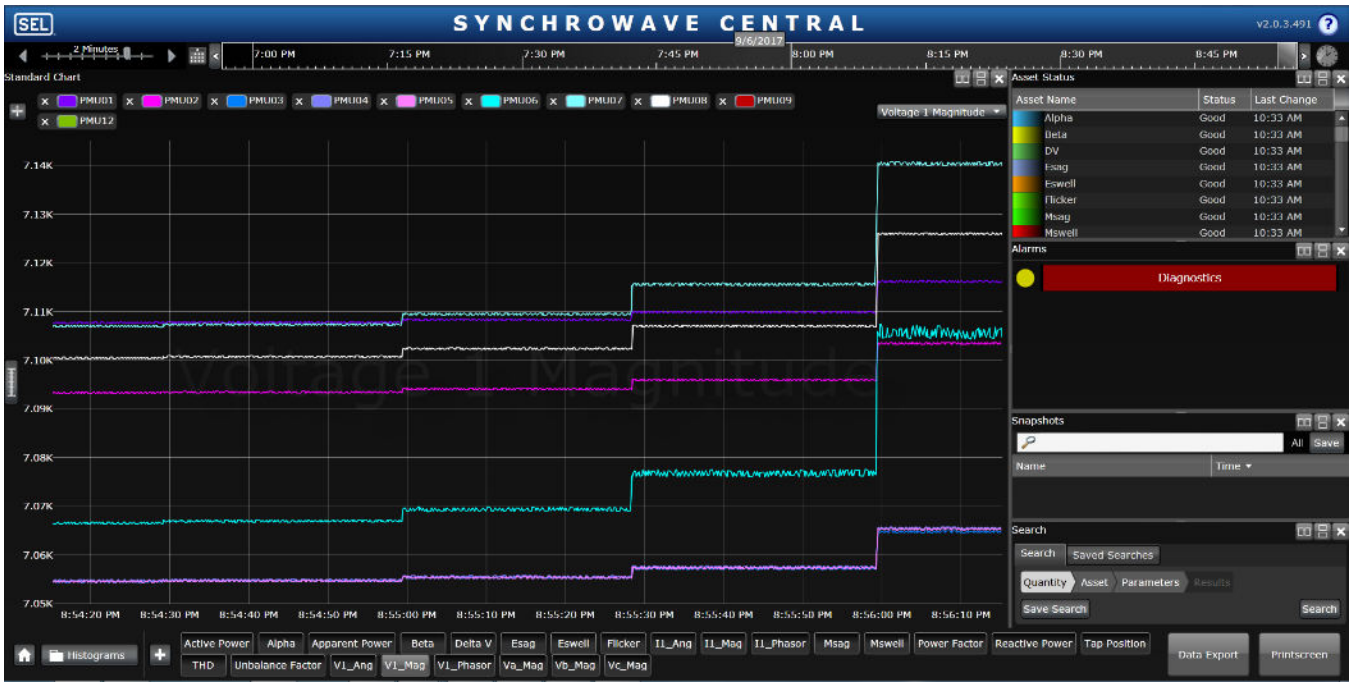


Figure 4-26. Magnitude of Positive Sequence Voltages Subsequent to Adding Harmonic Voltage



Figure 4-27. THDs Captured by Different PMUs

As expected, different PMUs depending on their location streamed different values of THD (the closer the PMU to the source of the harmonic, the larger the value of the THD). PMU5 is the closest PMU to the harmonic source; therefore, it observed the maximum THD value. To evaluate the performance of the THD streaming of the PMUs, the THD value obtained from PMU5 is compared with the injected harmonic.

Injected THD	**0.03**	**0.08**	**0.15**	**0.3**
Observed THD from PMU5	0.026	0.068	0.121	0.236

4.1.3.3 Sensitivity

The objective of this test category was to verify the capability of RTAC in the calculation of the following parameters and indices:

- Alpha factor (dV/dP) in pu/MW
- Beta factor (dV/dQ) in pu/Mvar

4.1.3.3.1 Calculation of Alpha and Beta

In this test, the summer load profile was run for 1 hour with summer PV profile and the following measurements were captured for all PMUs. The following parameters were captured accordingly:

- Magnitude of positive sequence voltage
- Alpha in the branch with PV (PMU 1, PMU 2, PMU 3, PMU 4, and PMU 5)
- Alpha in the branch without PV (PMU 8, PMU 11, PMU 7, and PMU 6)
- Beta in the branch with PV
- Beta in the branch without PV



Figure 4-28. Magnitude of Positive Sequence Voltages

The magnitude of positive sequence voltages are generally in the range of the rms circuit voltages, since the amount of zero sequence and negative sequence voltages are negligible.

In Figure 4-29, the sensitivity of different PMUs (in the branch without PV) is shown in bar graphs in the order of their distance to the substation circuit breaker. It can be seen that the sensitivity increases by getting away from the substation transformer toward the end of the circuit.

Similar behavior can be seen in the branch with PV as shown in Figure 4-30, but the PMU12 placed near the PV has a small sensitivity.

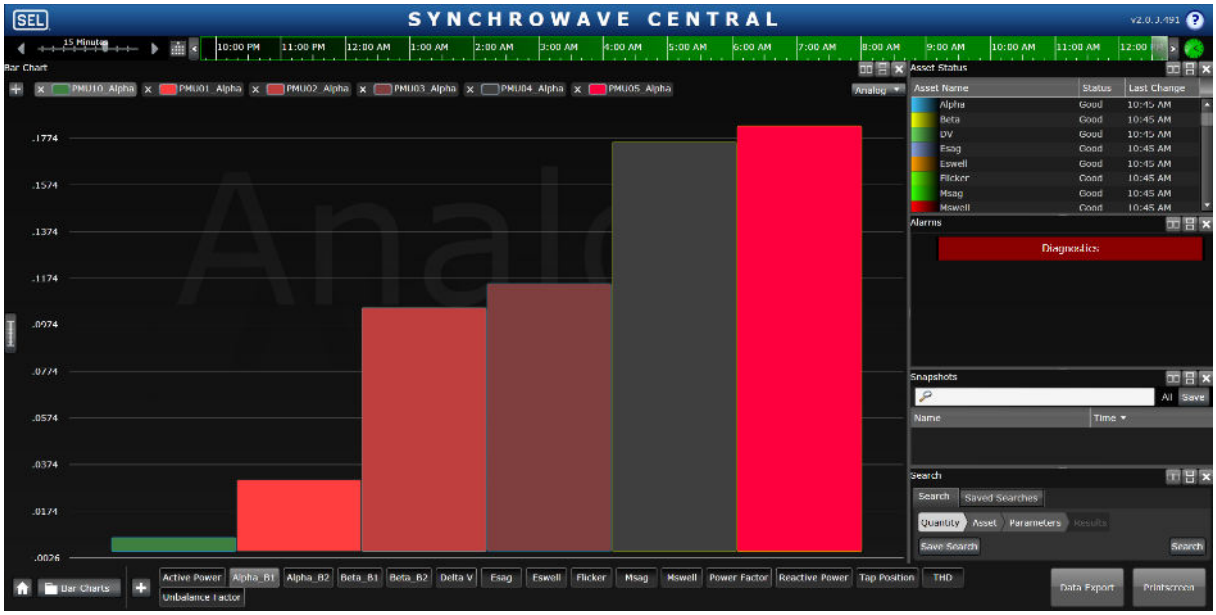


Figure 4-29. Demonstration of Changes in Alpha across the Branch without PV



Figure 4-30. Demonstration of Changes in Alpha across the Branch with PV

As observed, presence of PV system toward the end of the circuit create a less sensitive area. The PV system has contributed in strengthening the stiffness of the system.



Figure 4-31. Change in Beta across the Branch without PV

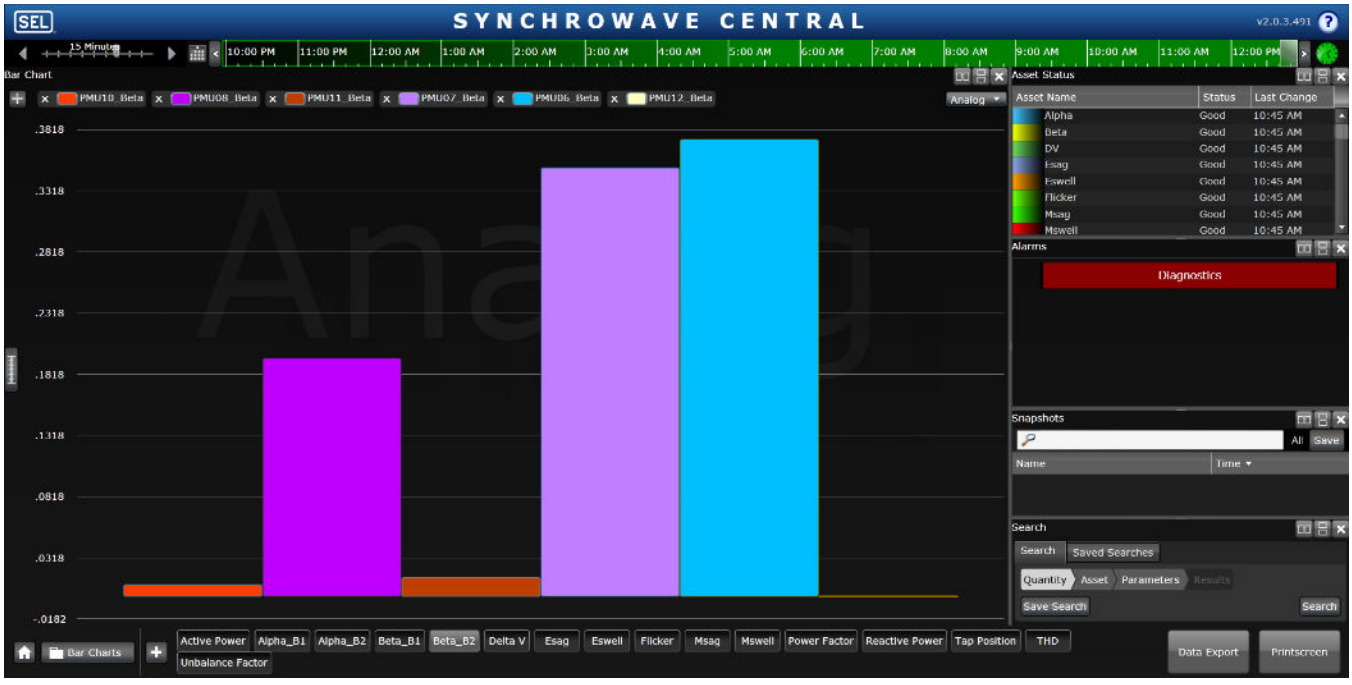


Figure 4-32. Change in Beta across the Branch with PV

Beta trend across the circuit is very similar to Alpha trend across the circuit; however, Beta is larger than Alpha. In this case, presence of the PV plant improved the system stiffness and reduce the sensitivity.

4.1.3.4 Faults

This section investigate the performance of the visualization in calculating the following parameters caused by different kind of faults and device malfunction

- Extreme Sag
- Extreme Swell
- Moderate Sag
- Moderate Swell
- Flickers
- Voltage unbalance

4.1.3.4.1 Calculation of Flickers

In this test case, C1 was turned off and on quickly. As shown in Figure 4-33, there are two voltage steps (falling and rising caused by turning off and on C1) in less than 2 seconds for all PMUs, which is qualified for a flicker. It can be seen in Figure 4-34 that this flicker is captured by visualization system and reported on the screen.

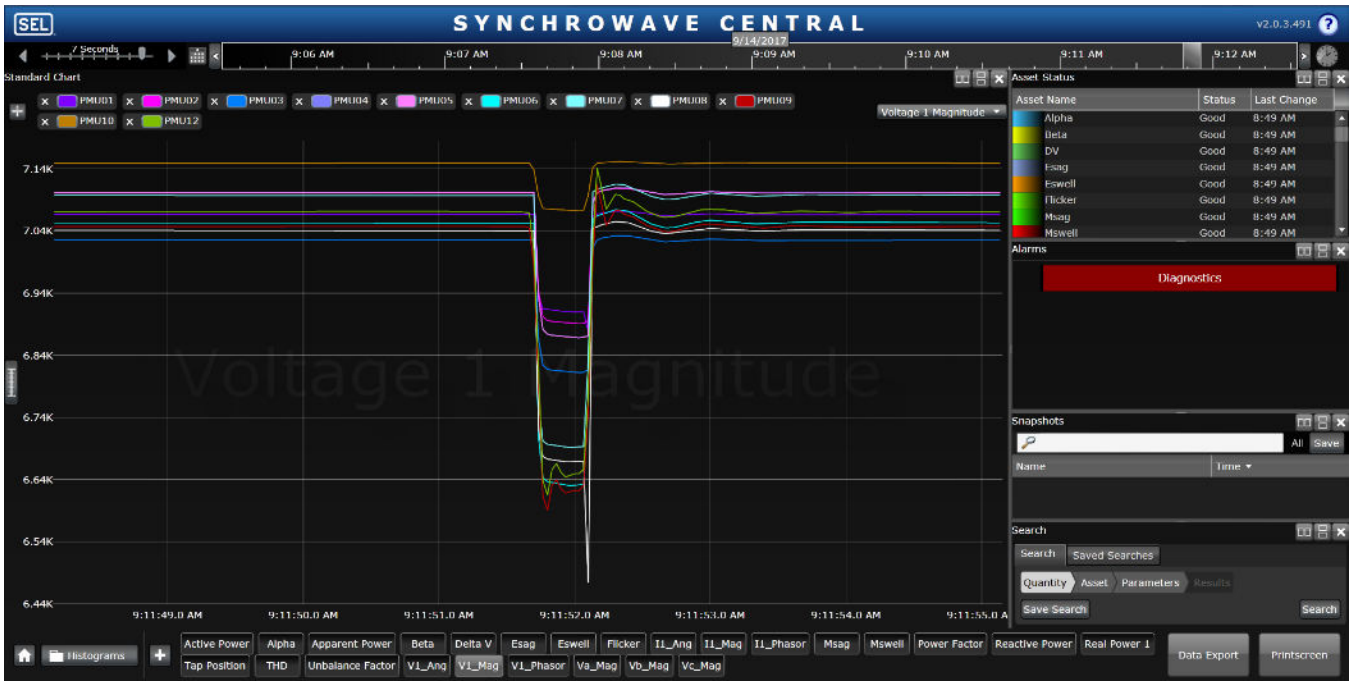


Figure 4-33. Magnitude of Positive Sequence Voltages

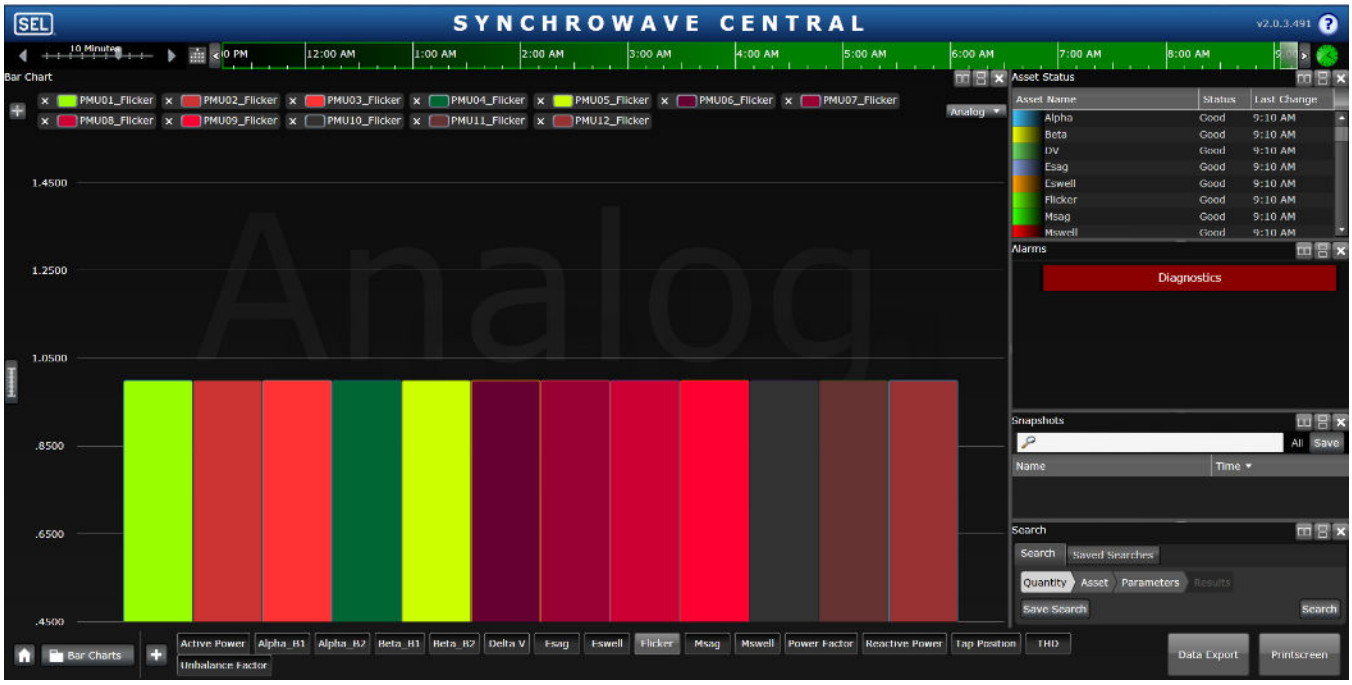


Figure 4-34. Flickers Subsequent to the Capacitor Switching

4.1.3.4.2 Calculations of Extreme Sag, Extreme Swell, Moderate Sag, and Moderate Swell

In this use case, we try to create a transient event to verify the performance of the RTAC in the calculation of extreme sag, extreme swell, moderate sag, and moderate swell.

4.1.4 Test Case 1

In this test, the summer load model was run with 2MW PV generation (PV protection settings are incorporated for the 2 MW system to match the IEEE 1547a (IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems) as shown in the following tables).

Table 4-1: Interconnection System Default Response to Abnormal Voltages [IEEE 1547a]

Default settings[a]		
Voltage range (% of base voltage[b])	Clearing time (s)	Clearing time: adjustable up to and including (s)
V < 45	0.16	0.16
45 ≤ V < 60	1	11
60 ≤ V < 88	2	21
110 < V < 120	1	13
V ≥ 120	0.16	0.16

[a] Under mutual agreement between the EPS and DR operators, other static or dynamic voltage and clearing time trip settings shall be permitted

[b] Base voltages are the nominal system voltages stated in ANSI C84.1-2011, Table 1.

Table 4-2: Interconnection System Default Response to Abnormal Frequencies [IEEE 1457a]

	Default settings		Ranges of adjustability	
Function	Frequency (Hz)	Clearing time (s)	Frequency (Hz)	Clearing time (s) adjustable up to and including
UF1	< 57	0.16	56 – 60	10
UF2	< 59.5	2	56 – 60	300
OF1	> 60.5	2	60 – 64	300
OF2	> 62	0.16	60 – 64	10

A single line to ground fault was applied at Bus 101 (upstream of the VR5) for 35 cycles immediately down-stream of the REC5 and the following measurements were captured: (note that REC5 is expected to trip and clear fault after 20 cycle – this value represent typical operation time of distribution protection schemes).

- Magnitude of positive sequence voltage
- Extreme sag
- Extreme swell
- Moderate sag
- Moderate swell

Figure 4-35 and Figure 4-36 show the magnitude of voltage and current subsequent to this fault. It can be seen in Figure 4-35 that there is an extreme voltage sag for PMU 1, PMU 2, PMU 3, PMU 4, and PMU5, which is compatible with the results obtained from RTAC in Figure 4-37. The level of voltage sag and depth of voltages characterize the severity. During this fault, the PV did not trip.

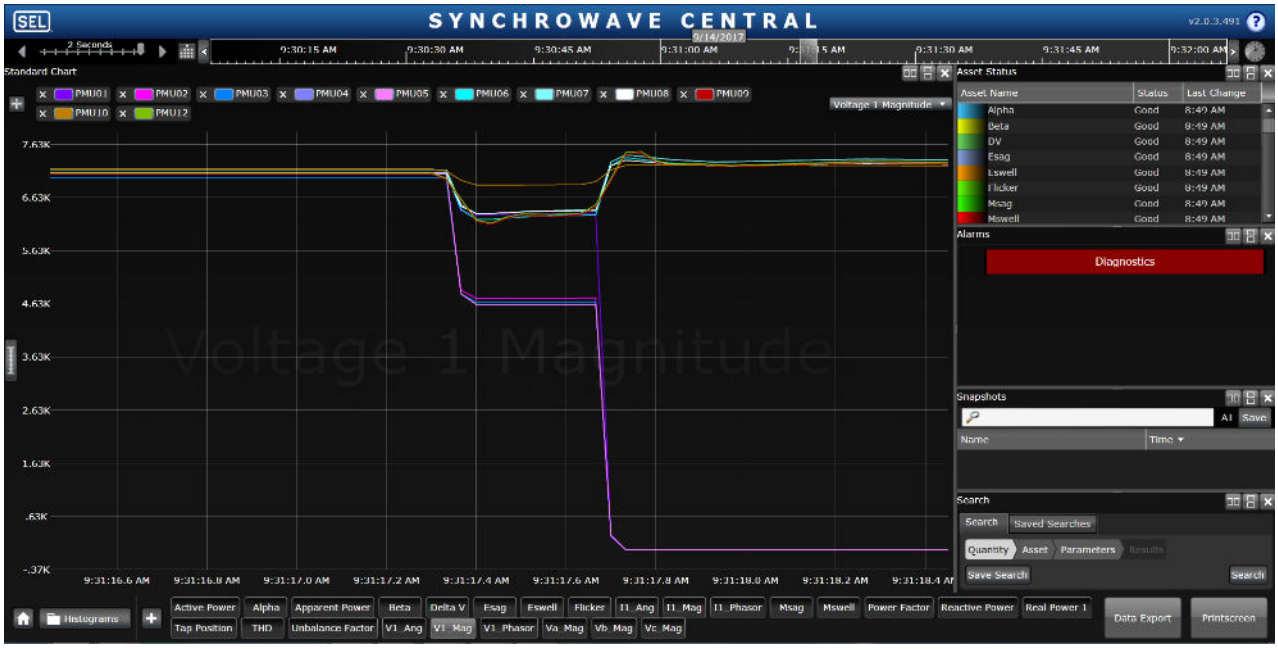


Figure 4-35. Magnitude of the Positive Sequence Voltages

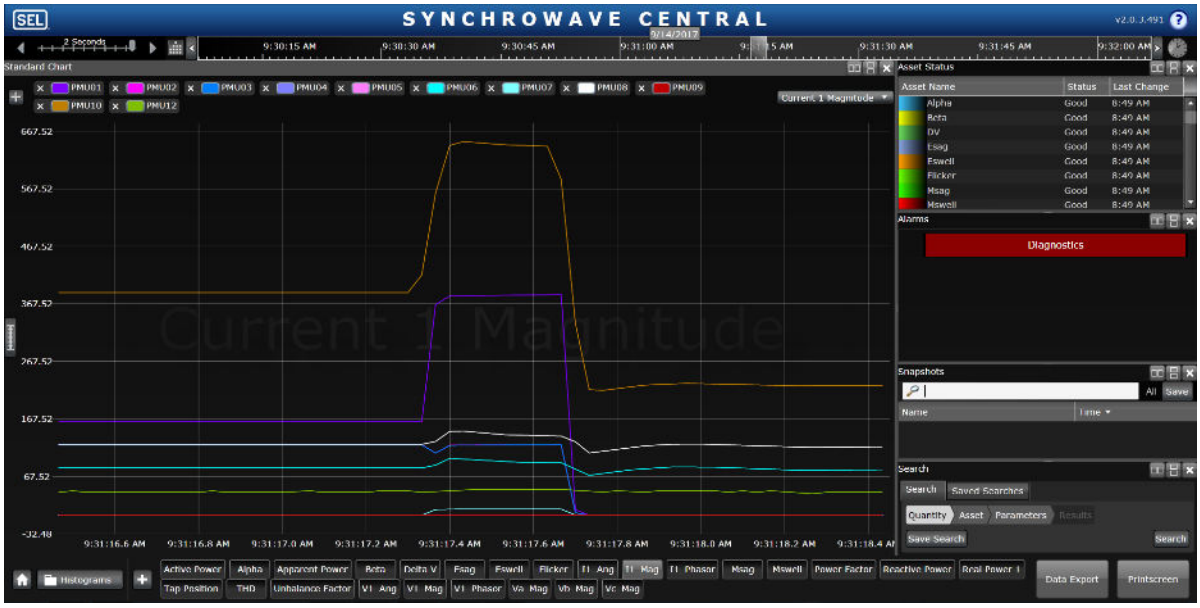


Figure 4-36. Magnitude of Positive Sequence Currents

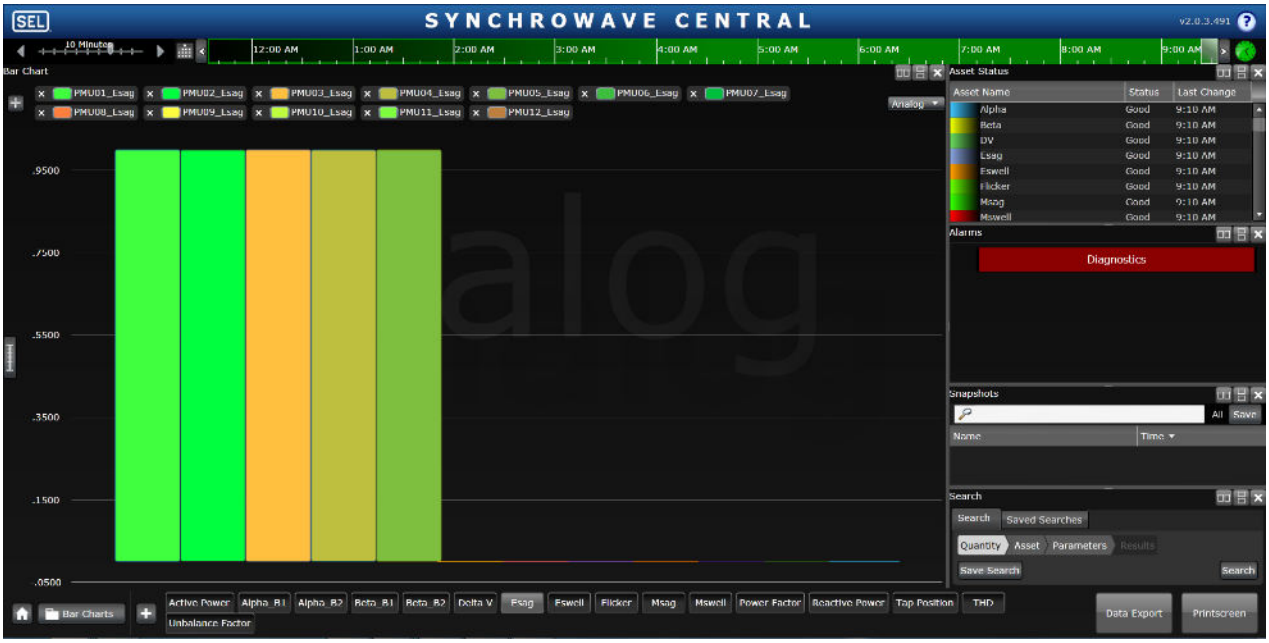


Figure 4-37. Extreme Voltage Sag Statistics

Then, the similar test was run for a two-line to ground fault (applying for 35 cycles immediately downstream of the REC5) and the following measurements were captured: (note that REC5 is expected to trip and clear fault after 8 cycles).

- Magnitude of positive sequence voltage
- Extreme sag
- Extreme swell
- Moderate sag
- Moderate swell

Similar to the previous test, it can be observed that this fault causes extreme voltage sags in PMU 2, PMU 3, PMU 4, and PMU5, which is compatible with the results obtained from visualization in Figure 4-40. During this fault, the PV did not trip.

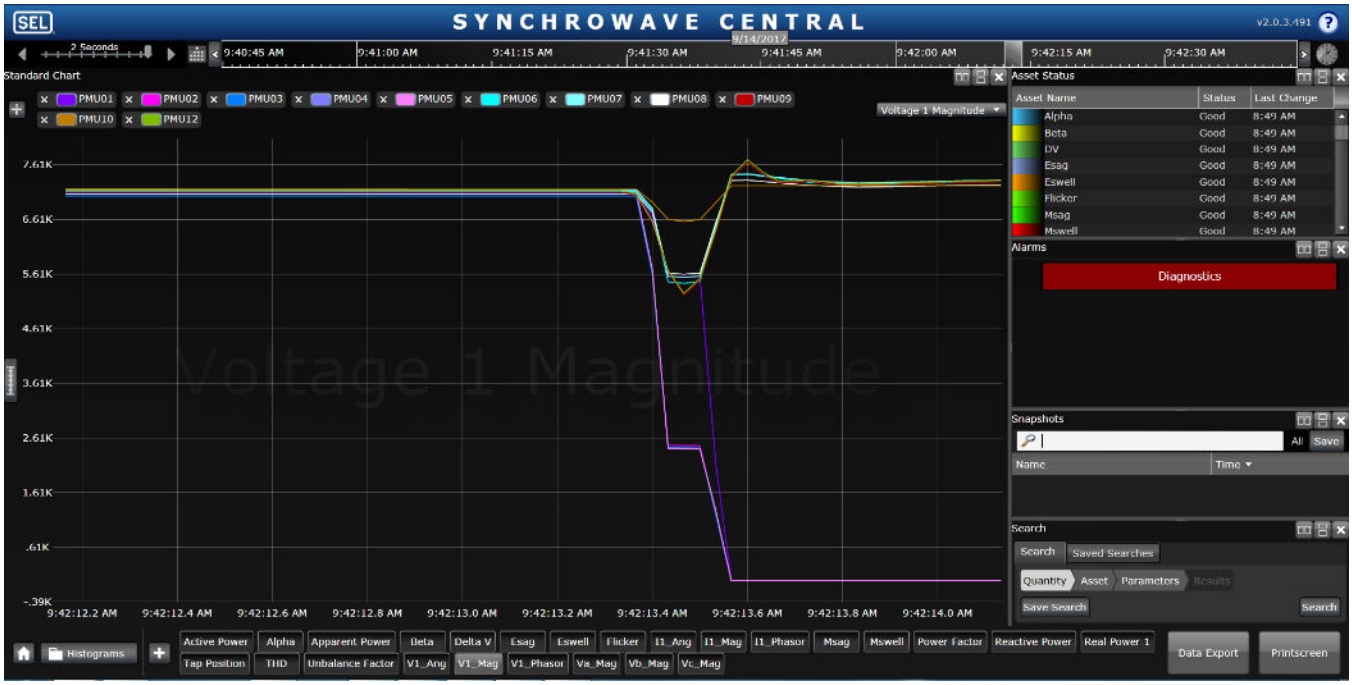


Figure 4-38. Magnitude of Positive Sequence Voltages

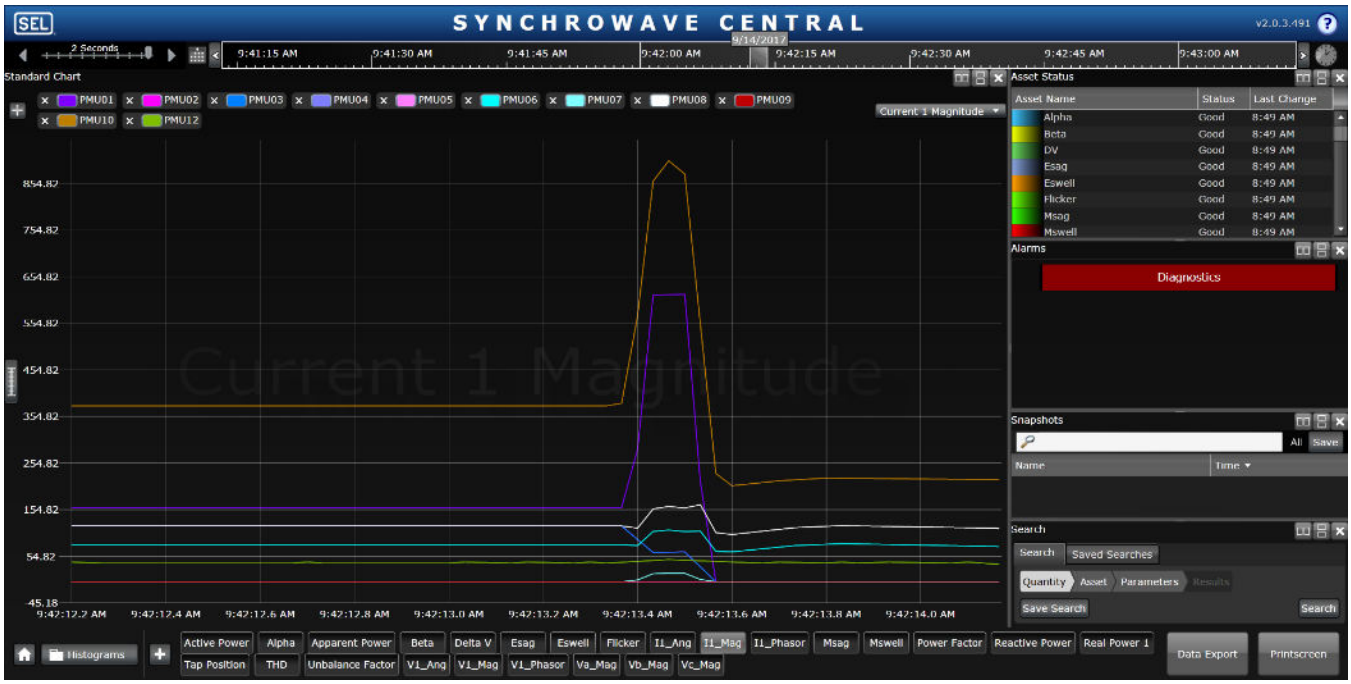


Figure 4-39. Magnitude of Positive Sequence Currents



Figure 4-40. Extreme Voltage Sag Statistics

4.1.5 Test Case 2

In this test, the summer load model performed with 2MW PV generation (PV protection settings are incorporated for the 2 MW system to match the IEEE 1547a). A three-phase fault was applied for 10 cycles close to the REC1 (located at Bus N06) and the following measurements were captured:

- Magnitude of positive sequence voltage
- Extreme sag
- Extreme swell
- Moderate sag
- Moderate swell

This fault generated a very quick voltage variation. Based on our definition from voltage sag and swell, this voltage variation cannot be considered as a voltage sag because it was very fast. RTAC did not report this event as voltage sag because the duration of violating voltage sag threshold (0.2 pu) wasn't more than 10 cycles.

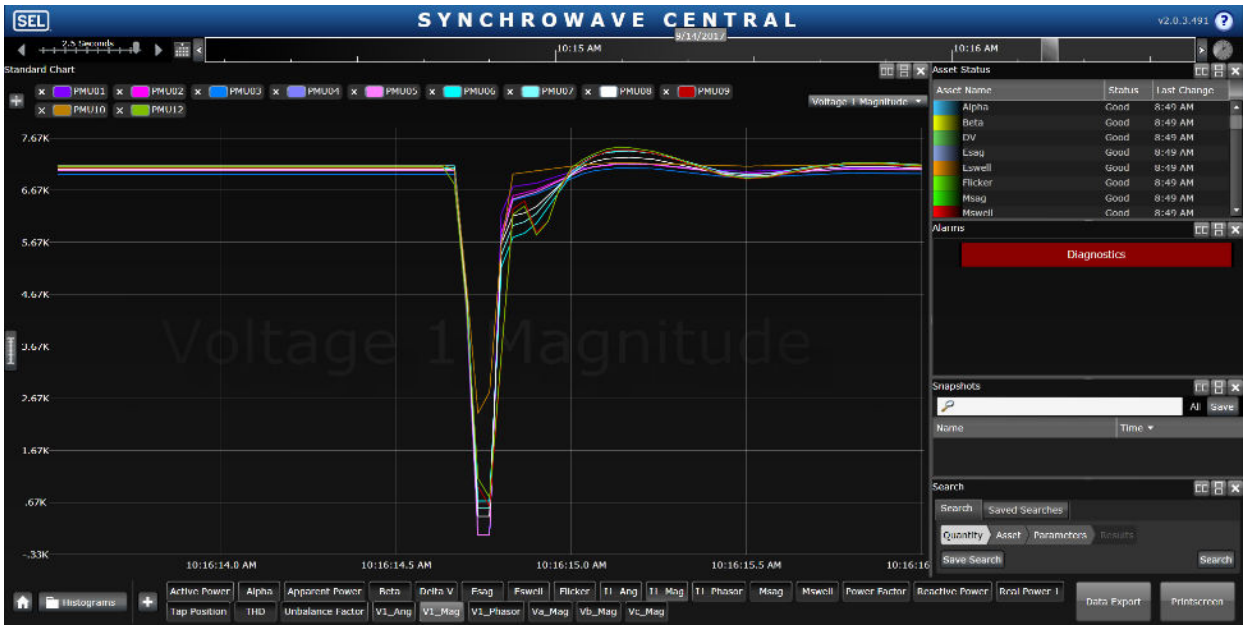


Figure 4-41. Magnitude of Positive Sequence Voltages

From the magnitude of the positive sequence current (as captured below) the fault location can be identified.

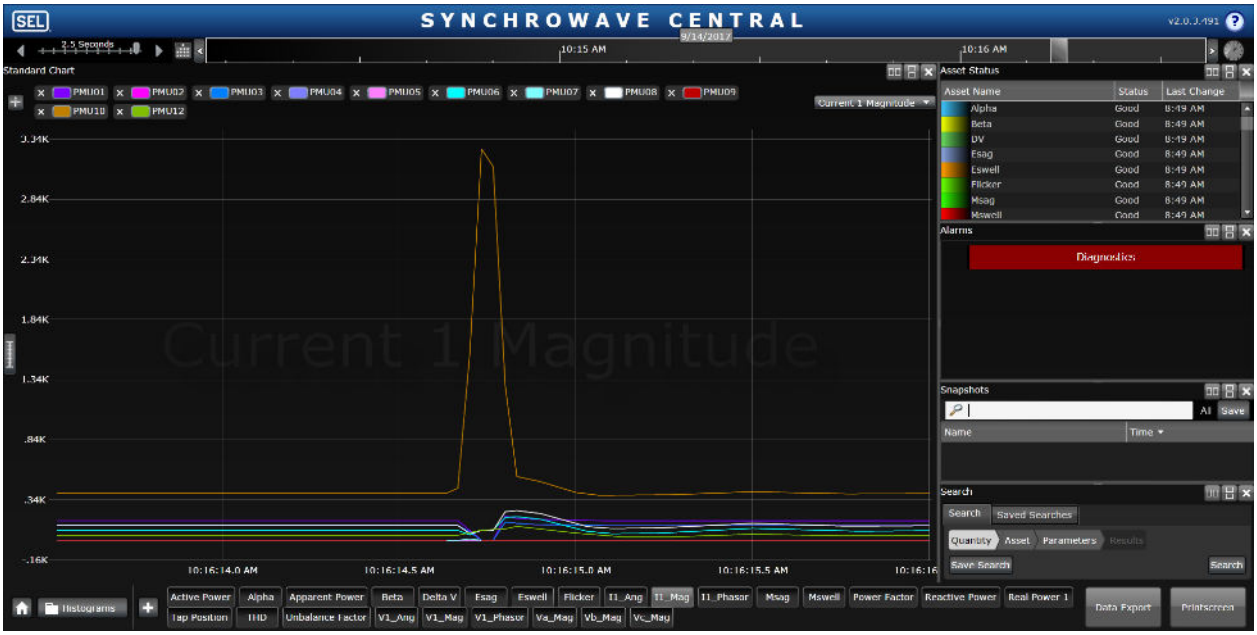


Figure 4-42. Magnitude of Positive Sequence Currents

This fault also did not trip the PV.

4.1.6 Test Case 3

In this test, the summer load model was run with 2MW PV generation (PV protection settings are incorporated for the 2 MW system to match the IEEE 1547a). A single line to ground fault (permanent) was applied close to DVC (N117) and the following measurements were captured:

- Magnitude of positive sequence voltage
- Extreme sag
- Extreme swell
- Moderate sag
- Moderate swell

Figure 4-43 shows that the PMU 12, PMU 9, PMU 8, and PMU 7 experienced a moderate voltage sag, which is compatible with the results obtained from RTAC in Figure 4-45. The main reason is that those PMUs were located electrically farther from the fault. This fault tripped the PV.

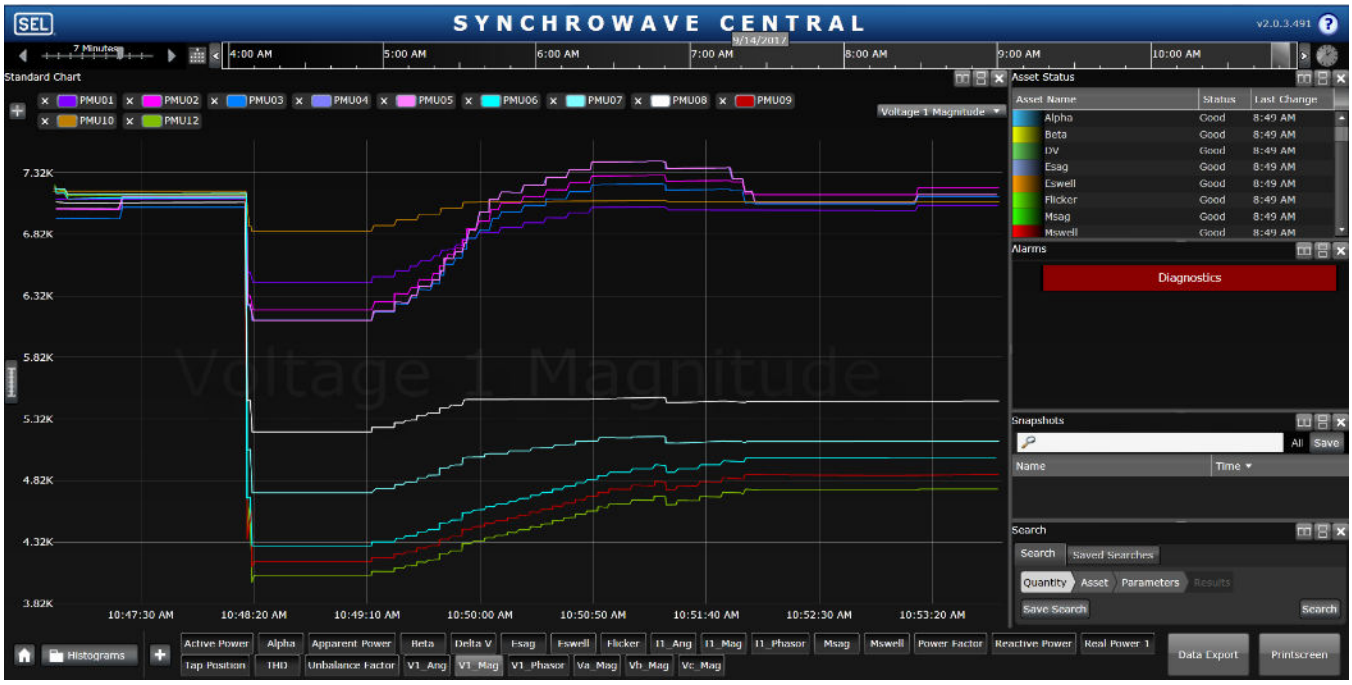


Figure 4-43. Magnitude of Positive Sequence Voltages

The above visualization screen can be utilized for fault detection and analysis. The level of voltage changes (voltage sag level) can be correlated with the fault type and fault locations.

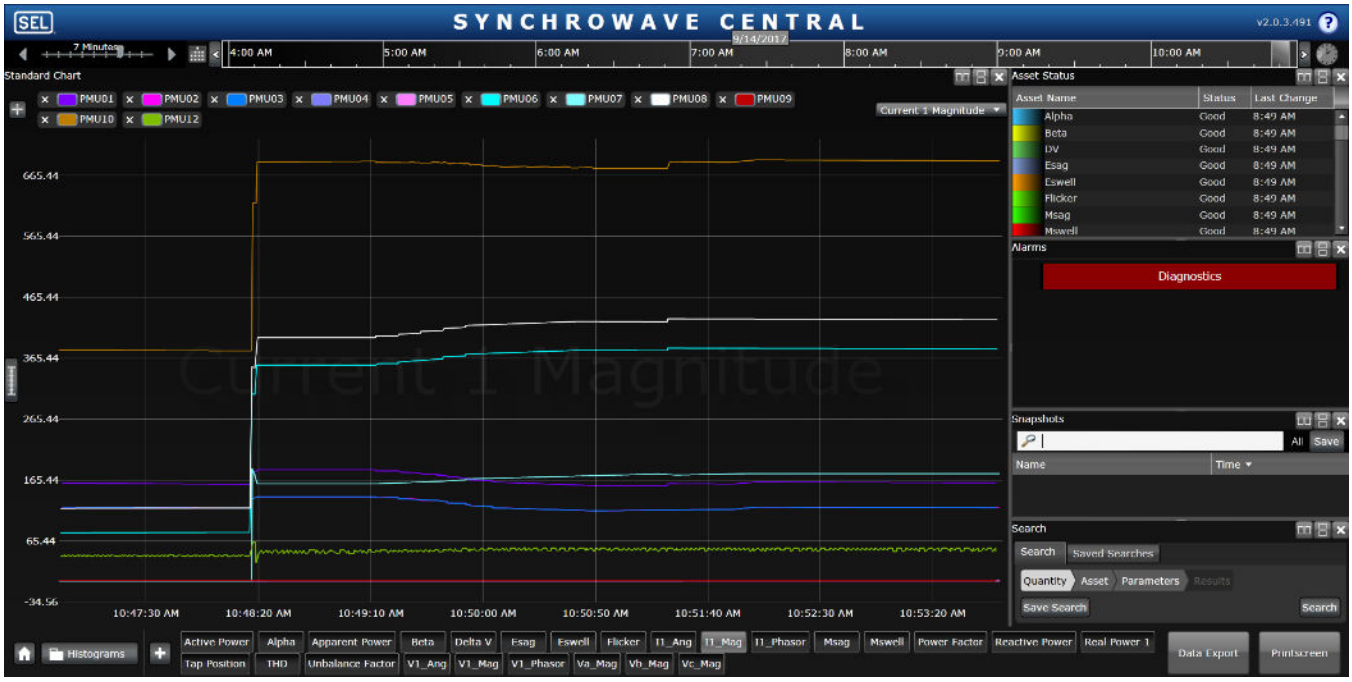


Figure 4-44. Magnitude of Positive Sequence Currents

As shown in the above figure, the PMU located electrically closer to the fault location showed the highest change in current.



Figure 4-45. Moderate Voltage Sag Statistics

4.2 Circuit 2 and Circuit 3 Test Results

A simplified single line diagram of the circuits 2 and 3 in Sub 2 is shown in Figure 4-46. The single line diagram is an overall representation of the model built in the RTDS environment for the laboratory testing and evaluations.

As indicated in this figure, there is a 6 MW PV system on circuit 3, located downstream of the circuit breaker CB3 and two generators downstream of the CB2. There is a normally open tie switch (CB0T21) between the two circuits. For load transfer cases, the tie switch can be closed and one of the upstream reclosers can be opened to change the load flow and voltage profile of the circuit.

Circuit 2 has one voltage regulator (VR1) and circuit 3 has two voltage regulators (VR2, and VR3). For the purpose of this study, this circuit has been modeled in RSCAD. 12 PMUs including 8 simulated PMUs (PMU1 to PMU8) and 4 physical PMUs (PMU9 to PMU12) are located at various nodes in the study system to facilitate system monitoring during the tests.

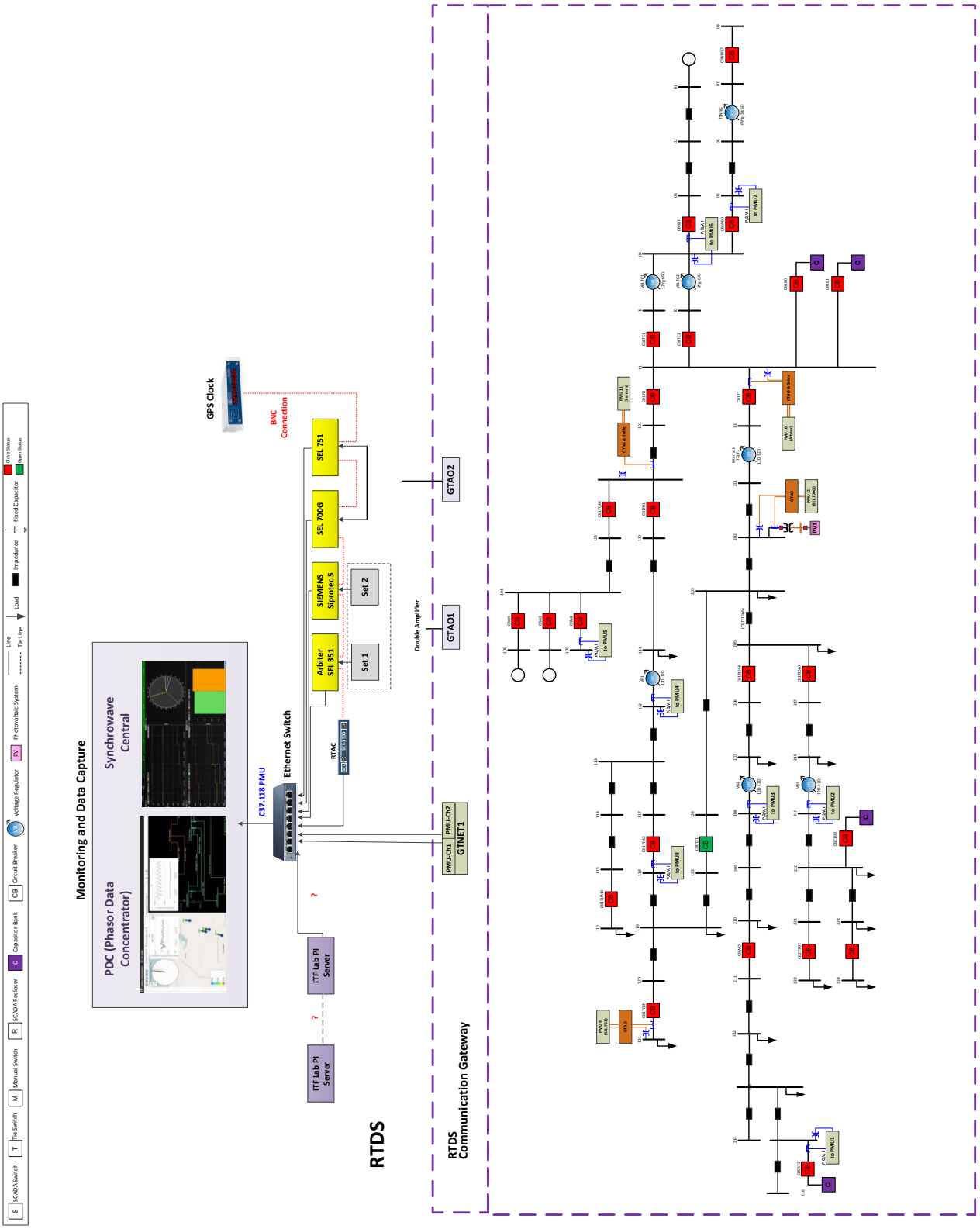


Figure 4-46. Single Line Diagram and PMU Locations of Circuit 2 and Circuit 3

In the following section, different case studies are presented to study the behavior of circuit 2 and 3.

4.2.1 Voltage/Power Flow Monitoring for Summer Load and with PV

In this case study the voltages, currents, real, and reactive power of different PMUs are captured, while the circuit was run with summer load profile and PV.

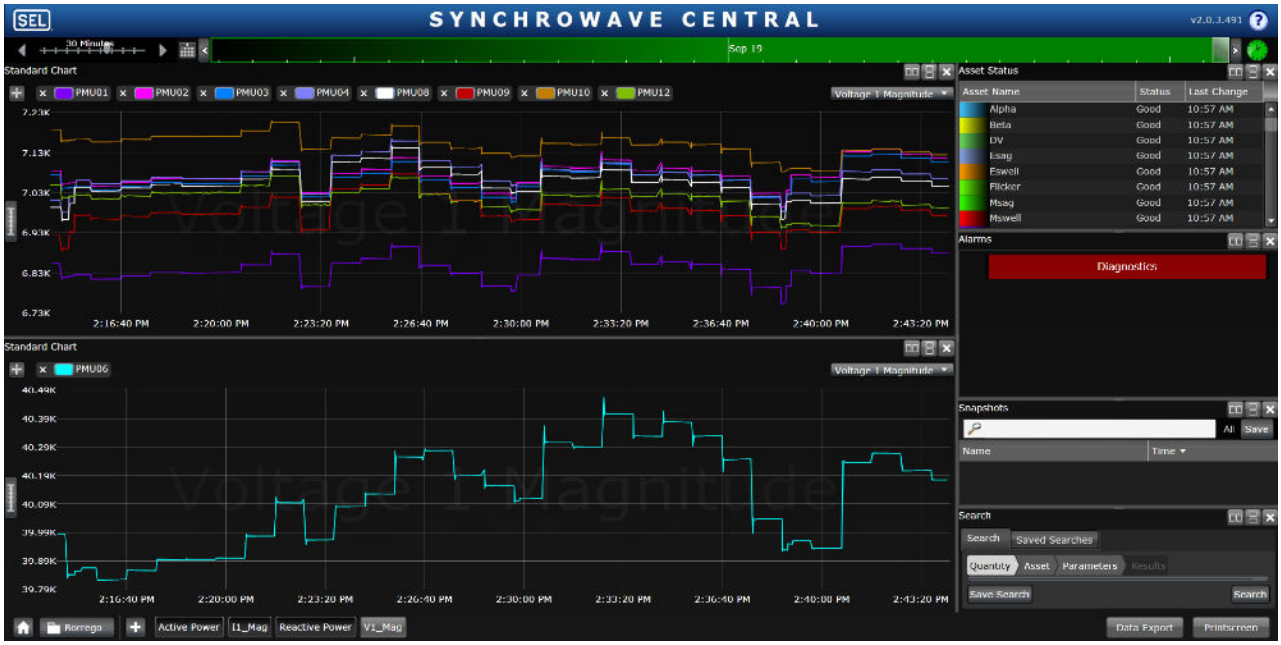


Figure 4-47. Magnitude of Positive Sequence Voltages

The proposed visualization screens and their applications are similar to the ones utilized for analysis of circuit 1. Each measurement screen provides one way of visualizing circuit events and dynamic nature of the disturbances.

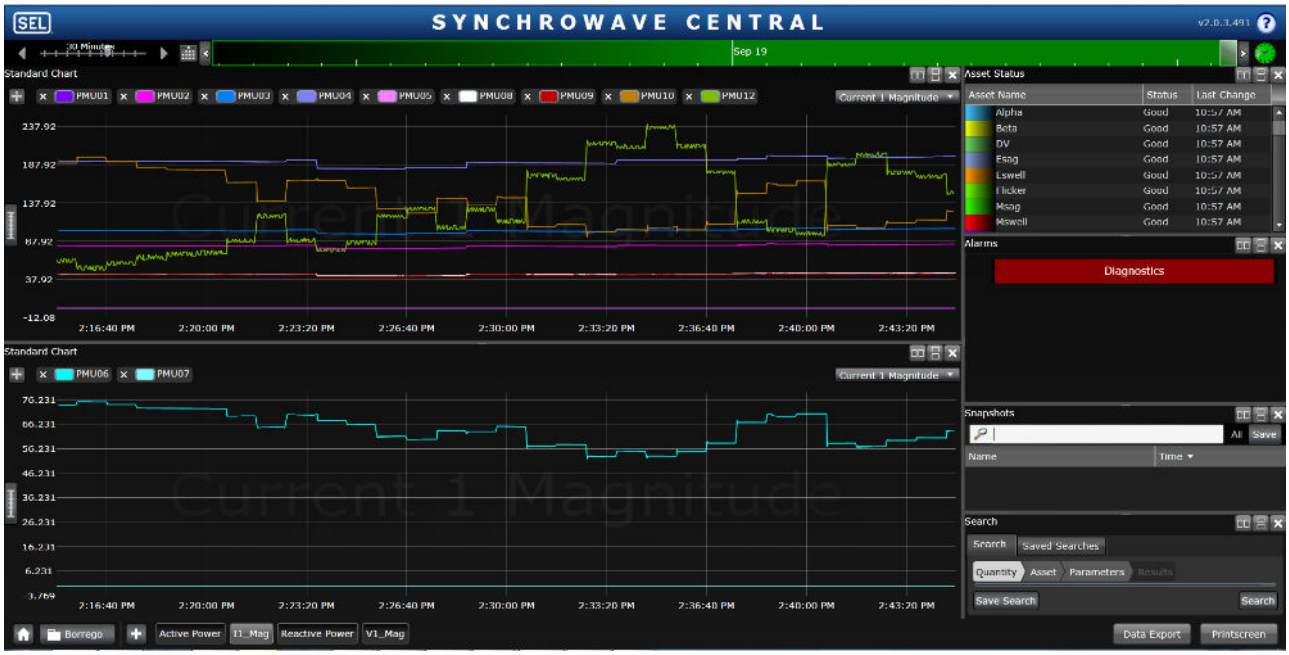


Figure 4-48. Magnitude of Positive Sequence Currents

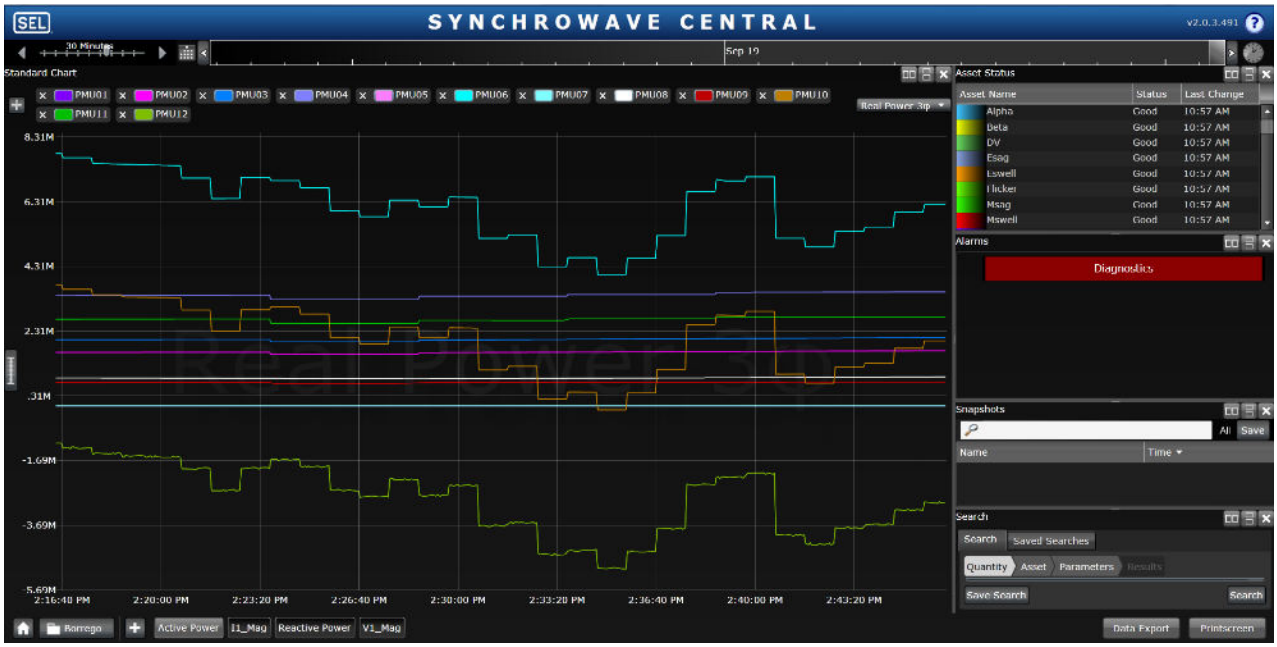


Figure 4-49. Active Powers

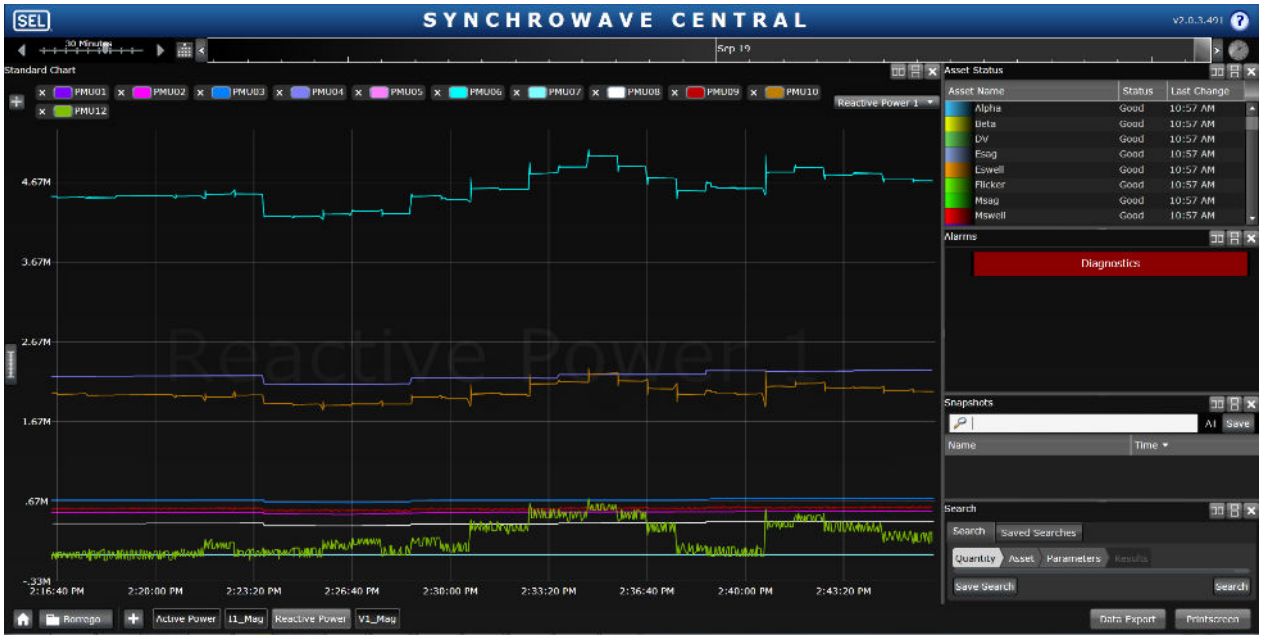


Figure 4-50. Reactive Powers

The approaches utilized in implementing and analysis the screens were generally similar to circuit 1. However, because of the availability of two diesel generators and significantly higher PV generation on circuit 2 and circuit 3, they were used to perform test cases associated with islanding and visualization of stability issues.

4.2.2 Primary Asset Operation Monitoring and Diagnostics

4.2.2.1 Load Transfer

In this case study, the loads were set at 0.75 pu and the PV was set at its maximum. The following figure shows the active power flow at different PMUs. It can be seen that there is reverse power flow in the PMUs close to the PV.

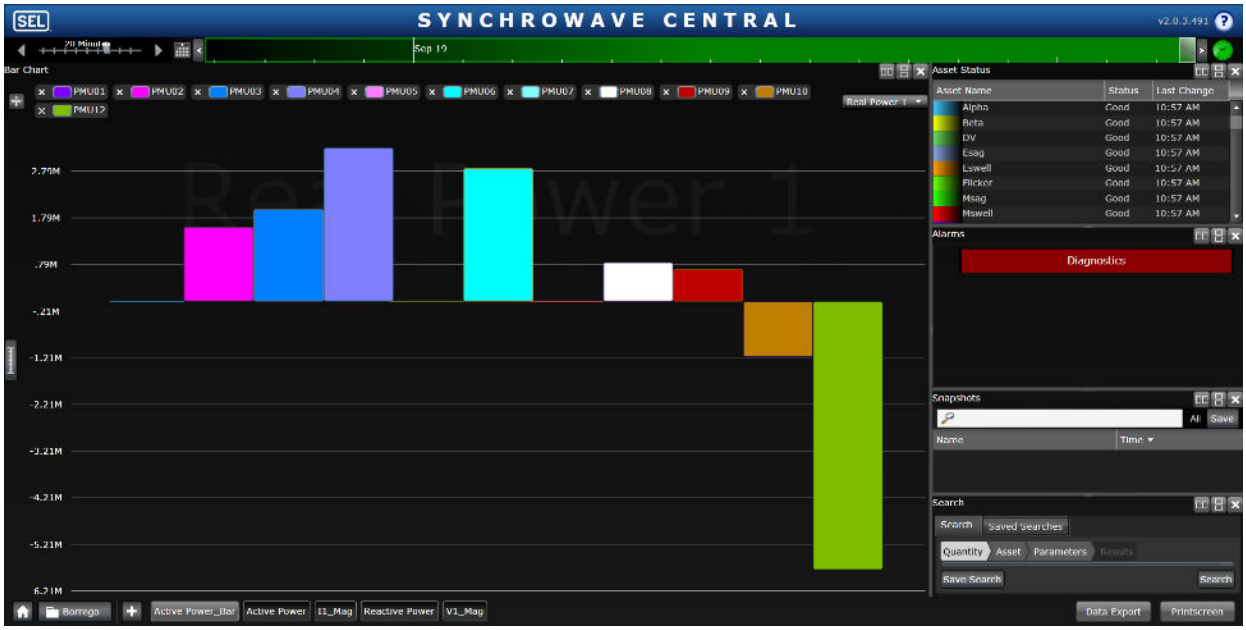


Figure 4-51. Active Powers of Different PMUs

The tie switch between two circuits was closed, and we can observe that this action created a reverse power flow in circuit 2.

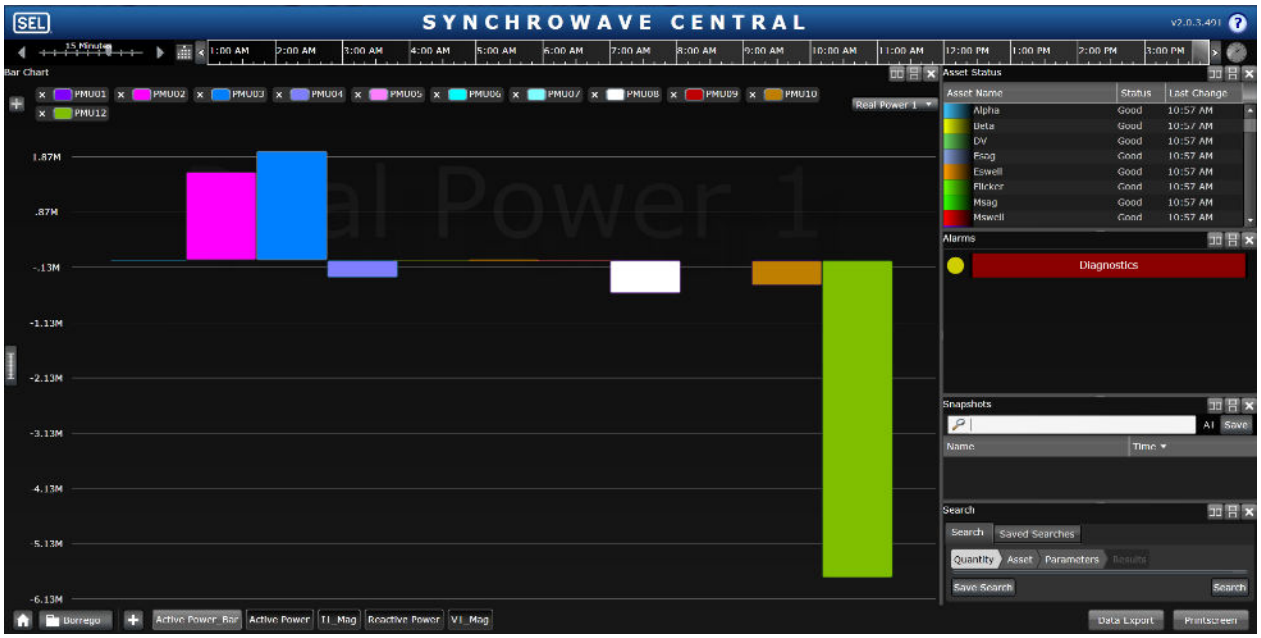


Figure 4-52. Active Powers of Different PMUs Subsequent to the Closing of the Tie Switch

Then, the recloser 1701 on the second branch was opened to perform the load transfer.

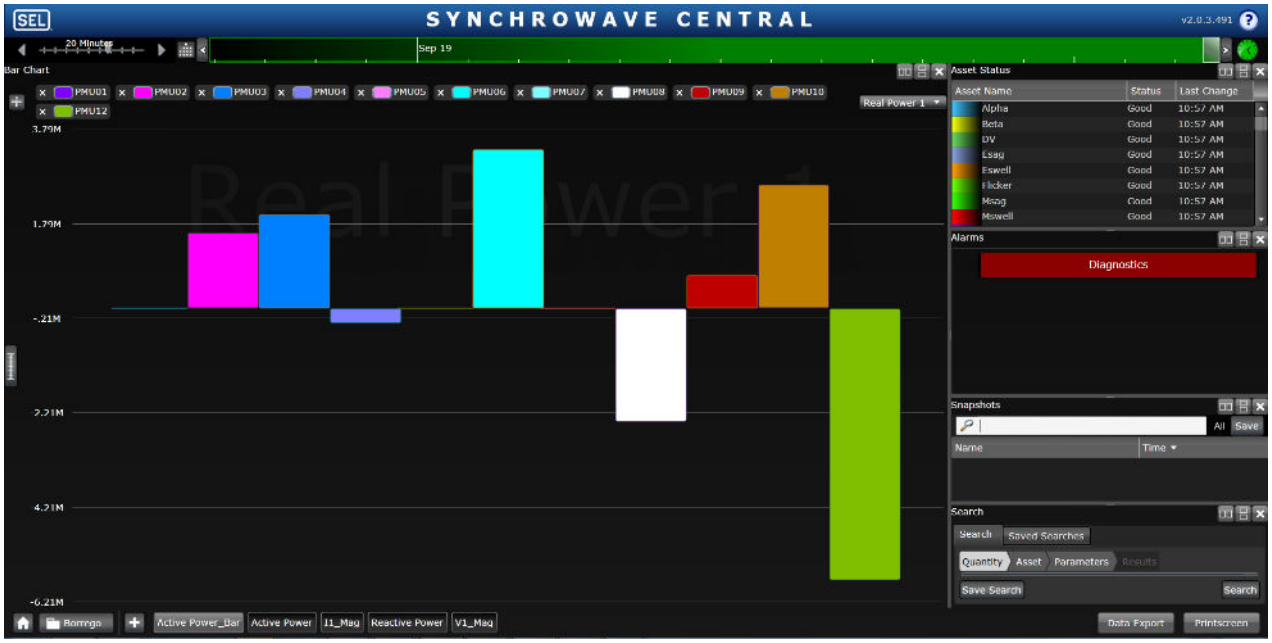


Figure 4-53. Active Powers of Different PMUs Subsequent to the Load Transfer

However, after the load transfer the voltages were out of the permissible range, because of the significant reduction in load. Therefore, the load shedding needs to be done to bring back the voltages to the standard limits.

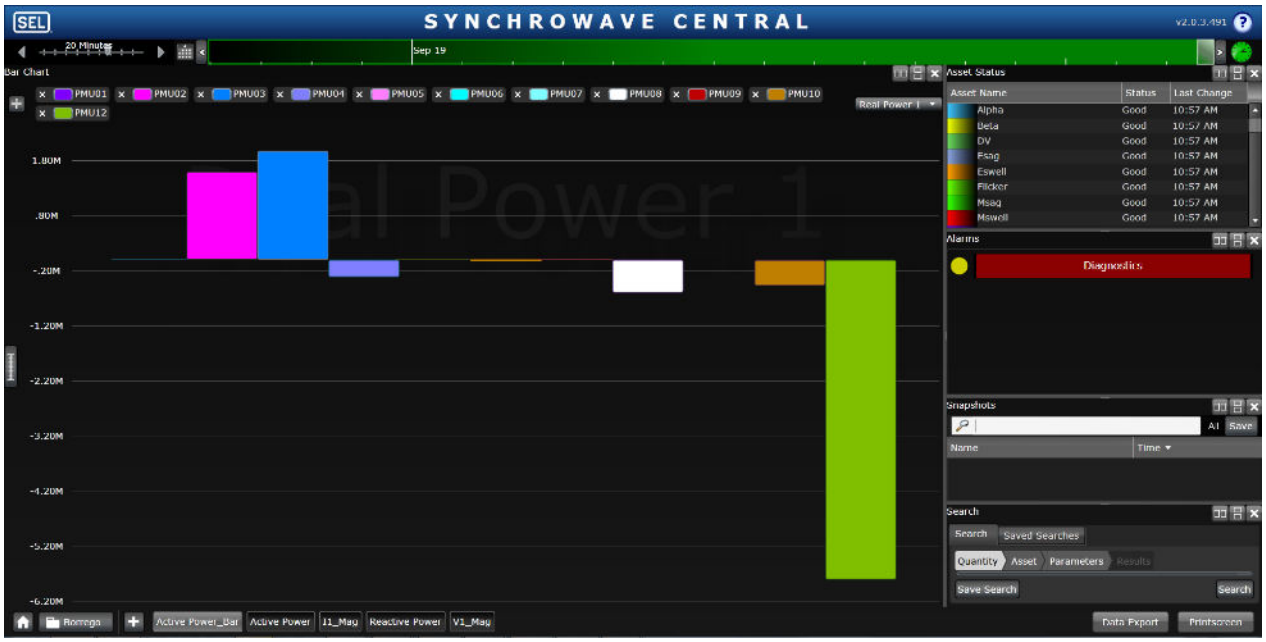


Figure 4-54. Active Powers of Different PMUs Subsequent to the Load Shedding

The following figures show the voltages, currents, real powers, and reactive powers of different PMUs during the load transfer test case. For transferring the load, the tie switch was closed first to establish the power

flow. In the next step, the upstream recloser (on the second branch) was opened to reach a redial system configuration as expected by the operator.

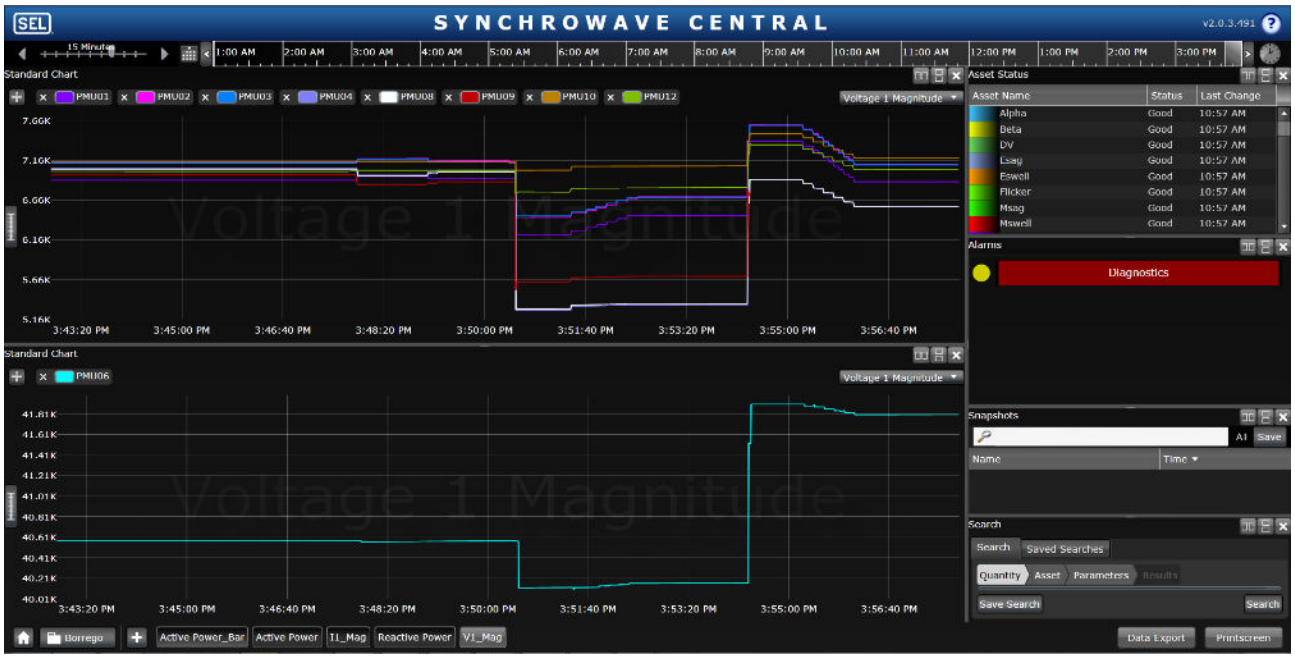


Figure 4-55. Magnitude of Positive Sequence Voltages, Capturing Exact Time of Load Transfer

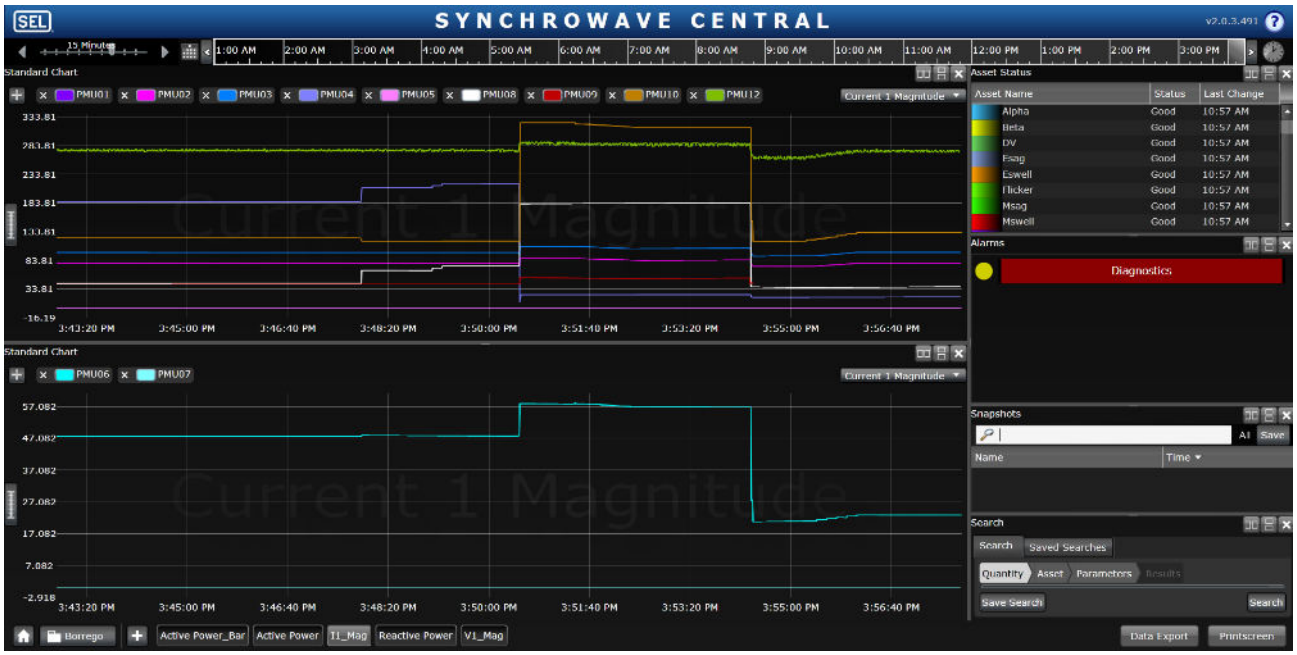


Figure 4-56. Magnitude of Positive Sequence Currents

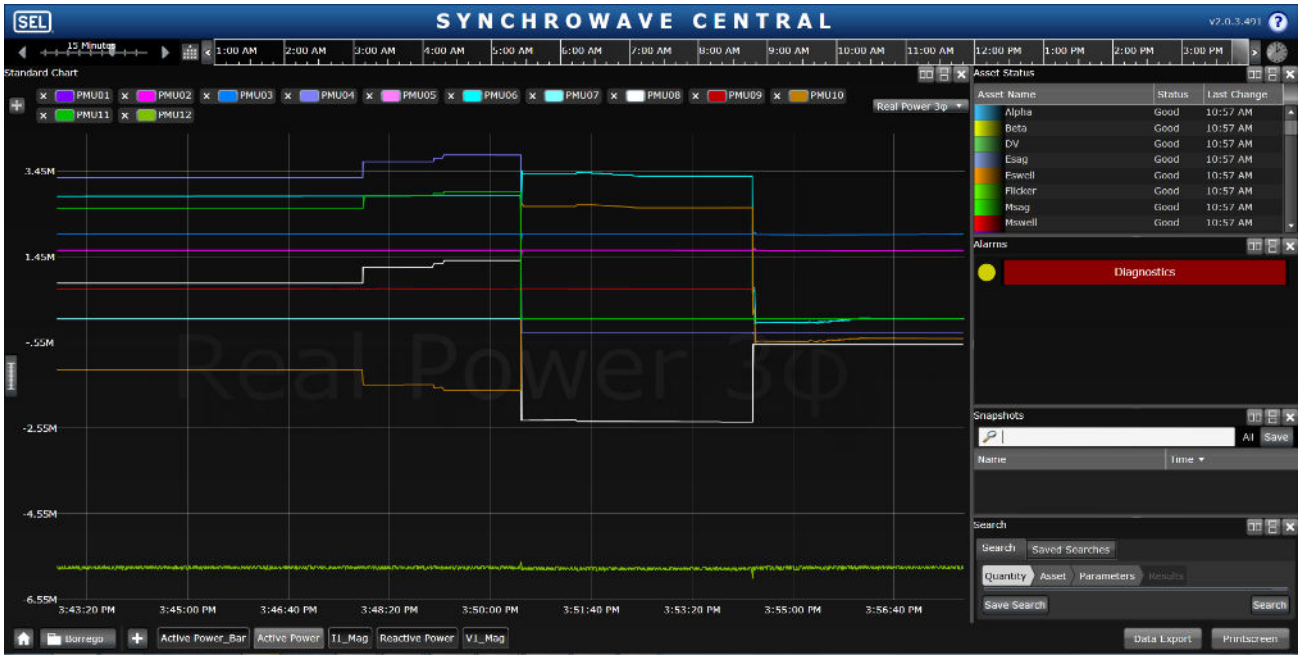


Figure 4-57. Active Powers

Change in both active and reactive power flow of the circuit that were captured by various PMUs across the circuit also demonstrated the disturbance caused by transferring load. In general, depending on the nature of a disturbance or an event, the impact can be observed by visualizing multiple system parameters.

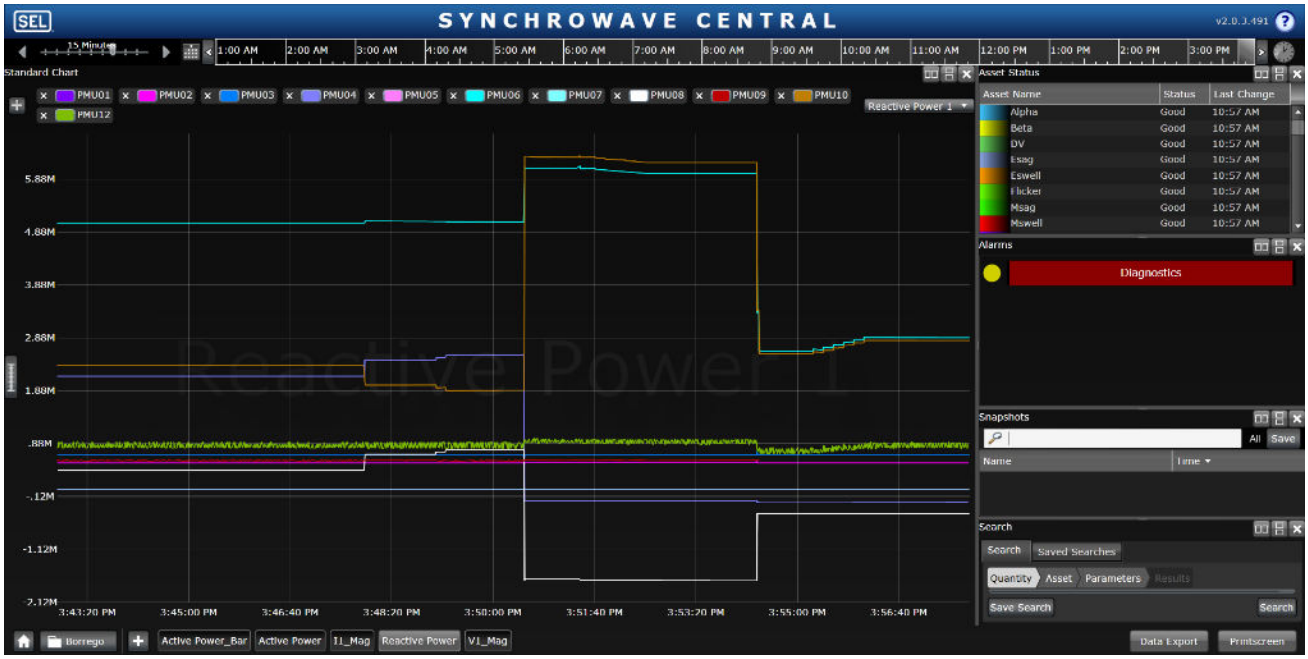


Figure 4-58. Reactive Powers

4.2.2.2 Intentional Islanding with 0.75 pu Loading Condition

In this case study, the loads were set at 0.75 pu and the PV was set at its maximum. The following figure shows the active power flow at different PMUs.

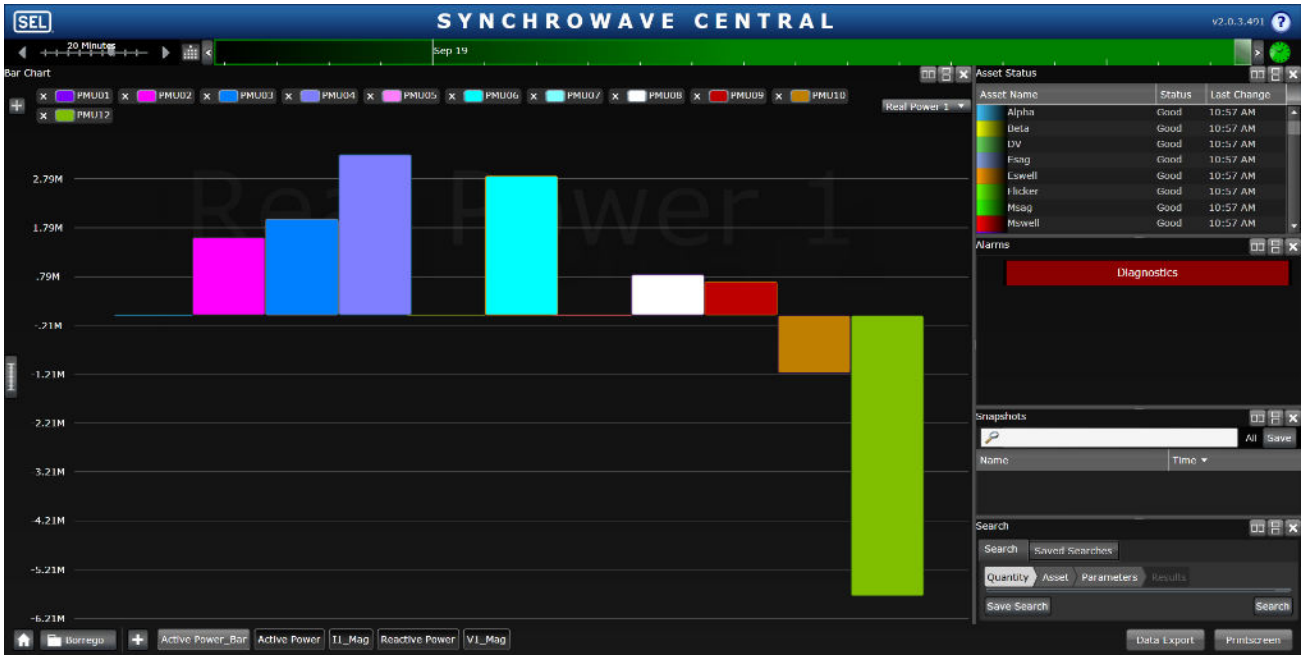


Figure 4-59. Active Powers of Different PMUs

Turning on the generators created reverse power flow in circuit 2 as shown in the following figure.

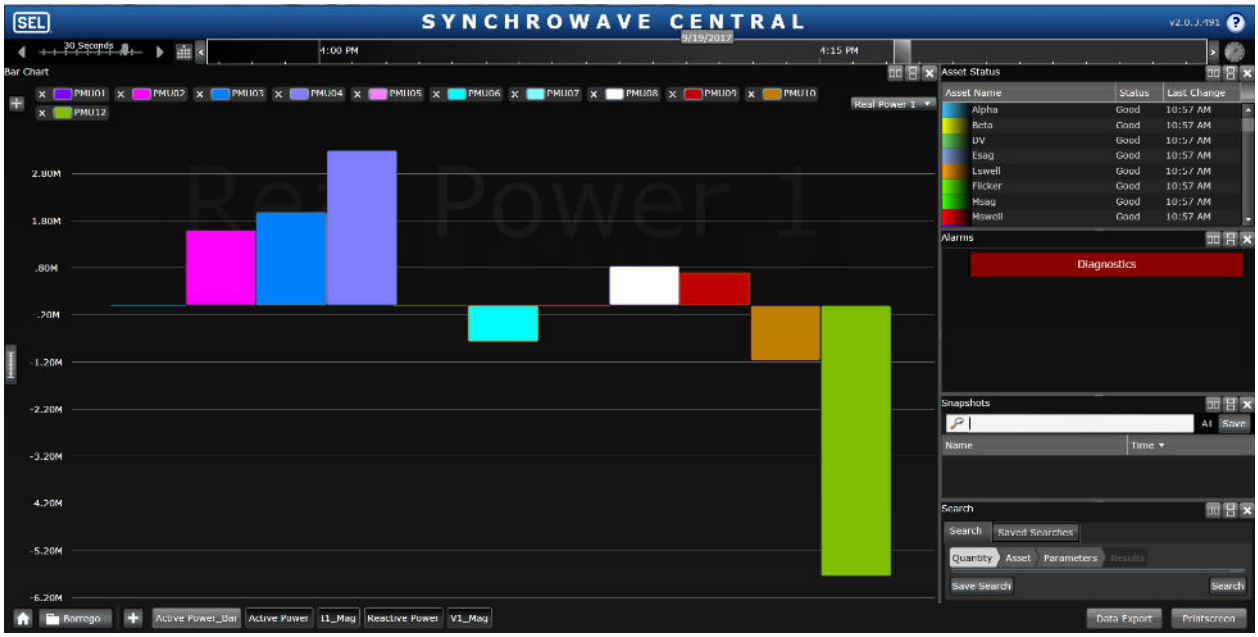


Figure 4-60. Active Powers of Different PMUs Subsequent to Turning on the Generators

Then, circuit 2 was islanded by opening CBC2. It can be observed that the system became unstable as shown in the following figure.

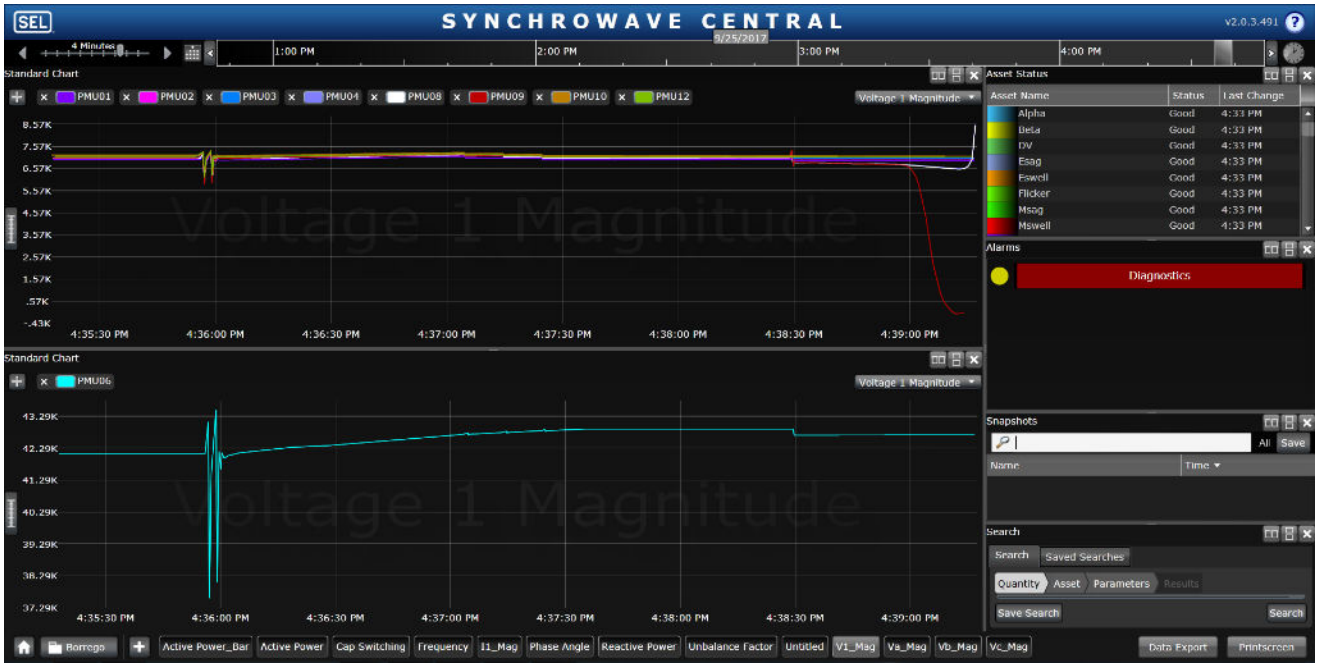


Figure 4-61. Magnitude of Positive Sequence Voltages during Islanding Process

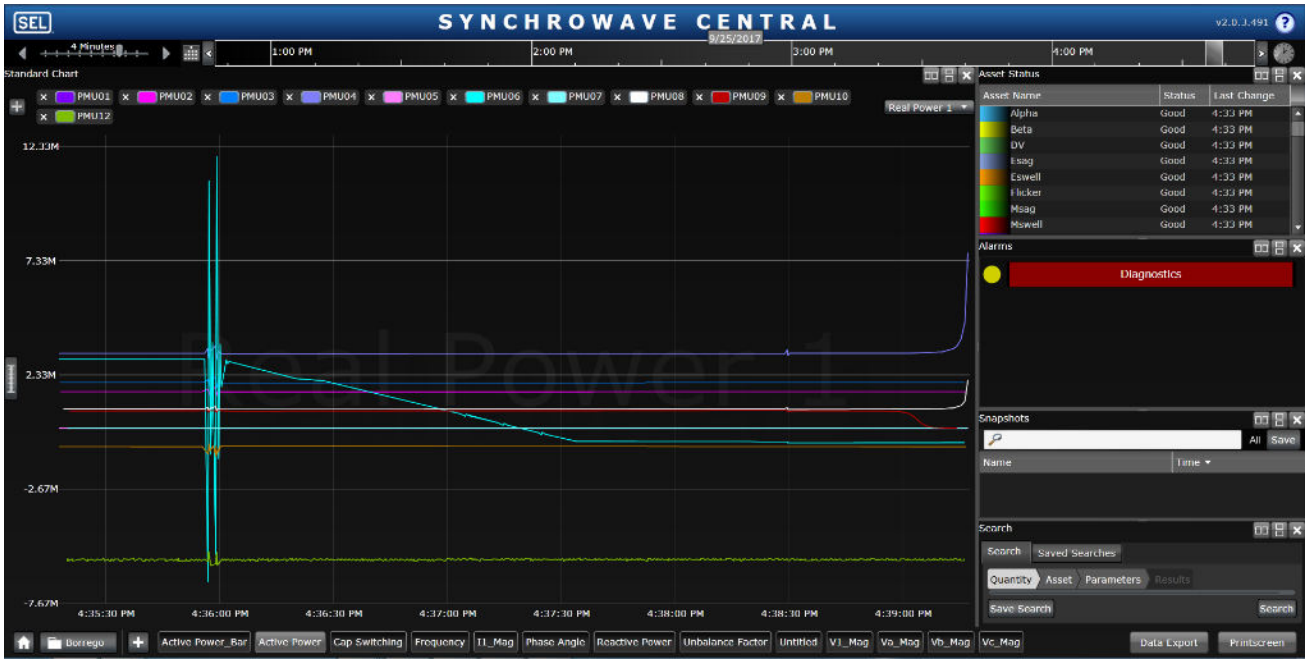


Figure 4-62. Active Powers during Islanding Process

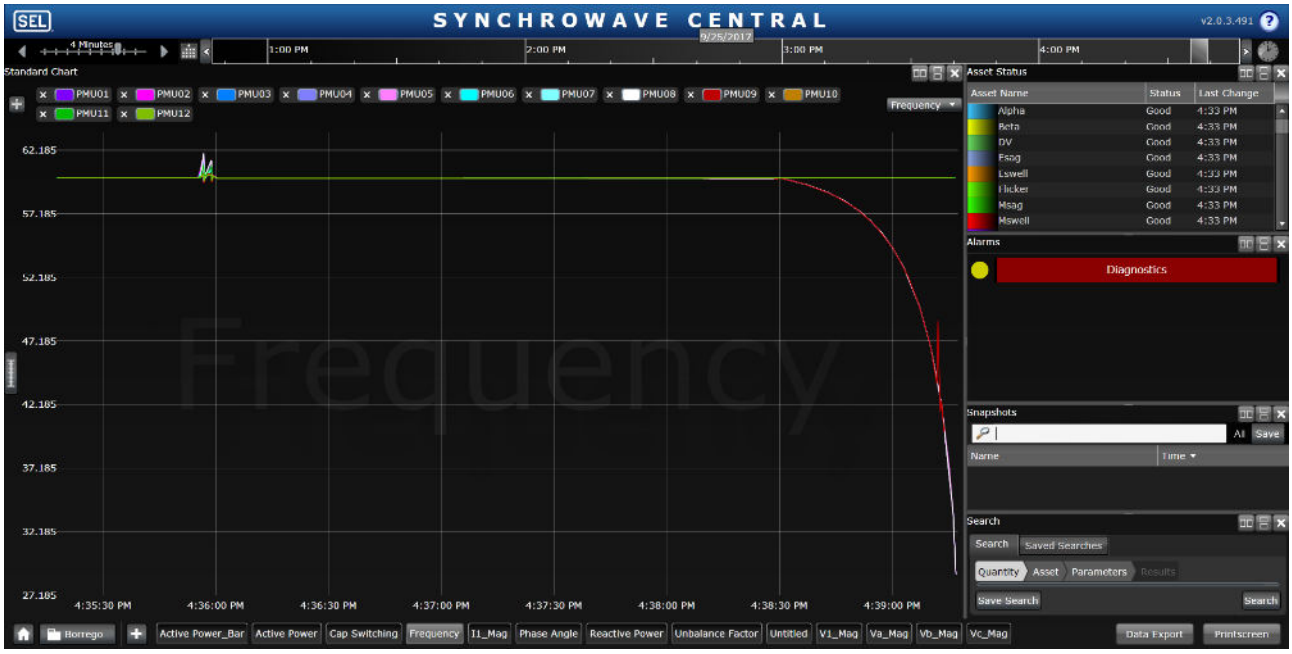


Figure 4-63. Frequency Changes during Islanding Process

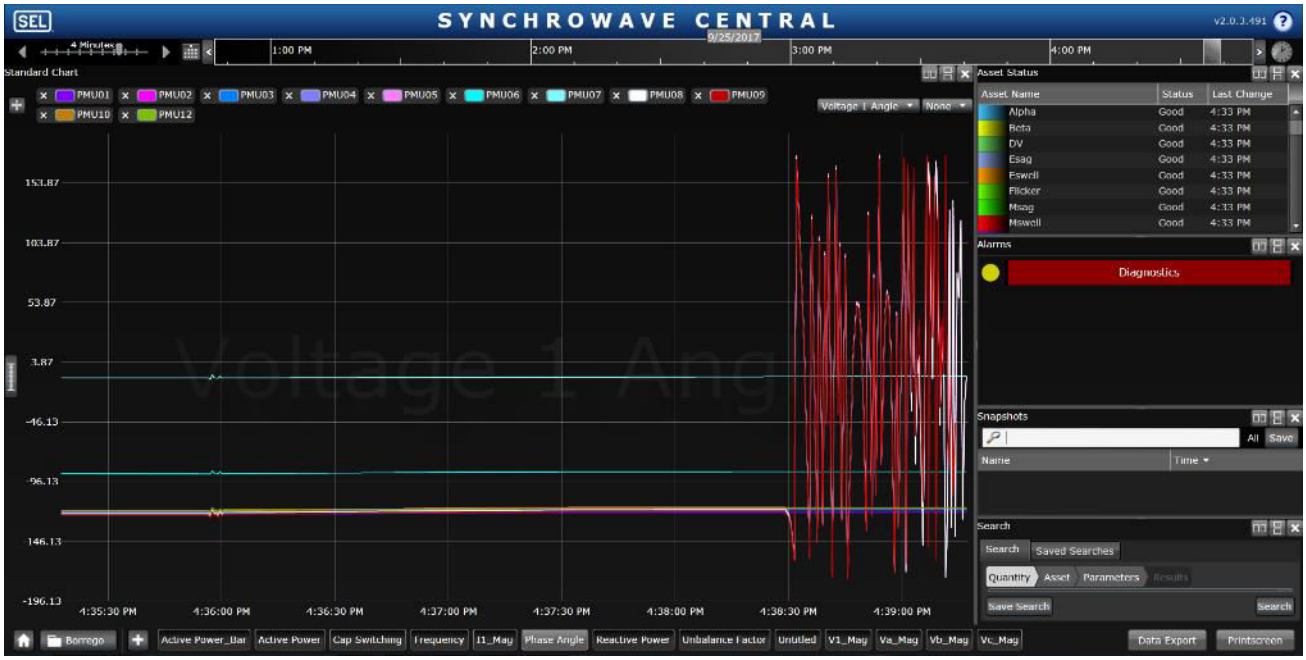


Figure 4-64. Phase Angle Changes during Islanding Process

4.2.2.3 Intentional Islanding with 0.7 Loading Condition

In this case study, the loads were reduced to 0.7 pu. In this condition, the generation of the two generators are sufficient for the loads of the microgrid. The following figure shows the active power of different PMUs after turning on the generators.

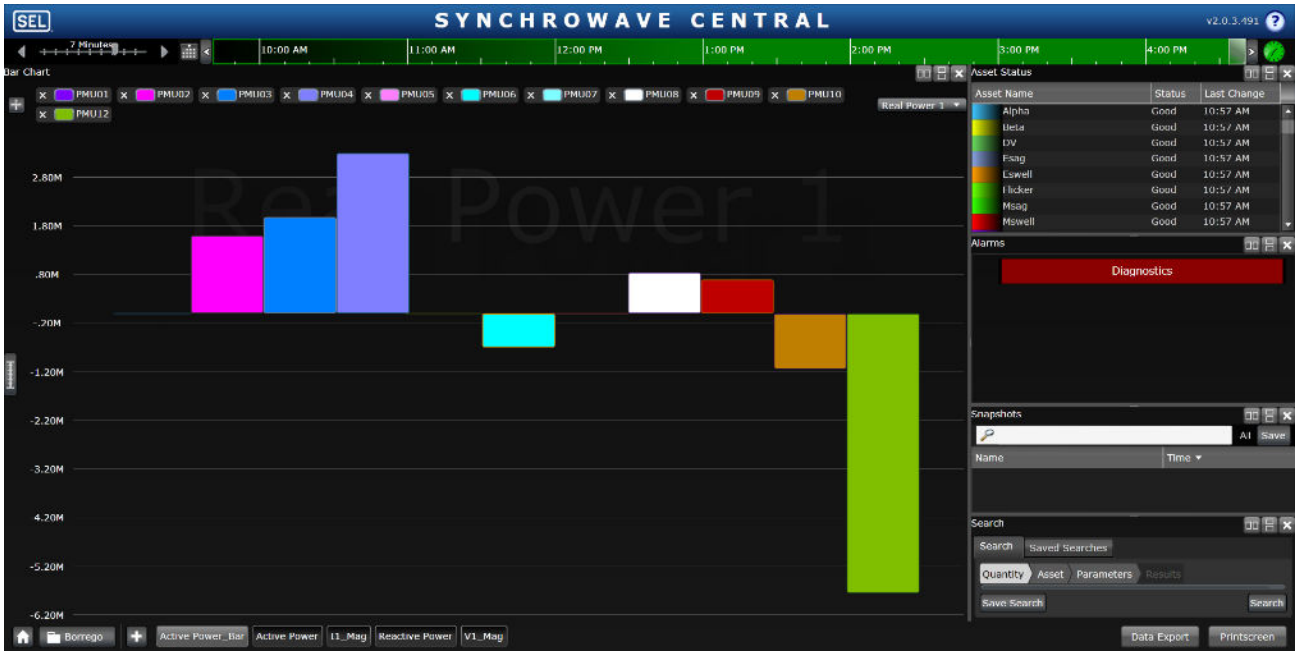


Figure 4-65. Active Powers of Different PMUs Subsequent to Turning on the Generators

In this case study, load shedding was performed before the islanding of circuits 3. Hence, the islanded circuit was stabilized based on available reserve capacity of the generation units under a reduced load condition.

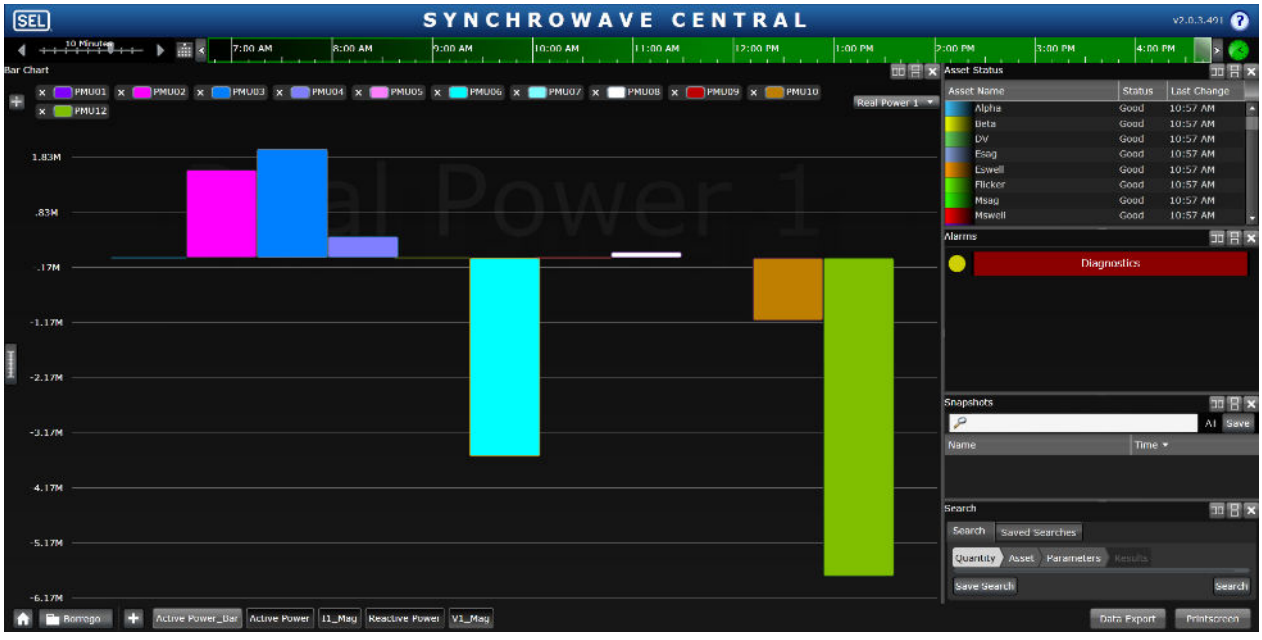


Figure 4-66. Active Powers of Different PMUs after Load Shedding

It can be observed that in this case study (unlike the case study with 0.75 loading condition), the islanded circuit was able to preserve its stability. The following figures show voltages, currents, active powers, and reactive powers of different PMUs during the islanding process.



Figure 4-67. Magnitude of the Positive Sequence Voltages

Voltage and power across the circuit were restored after a short period of transients.

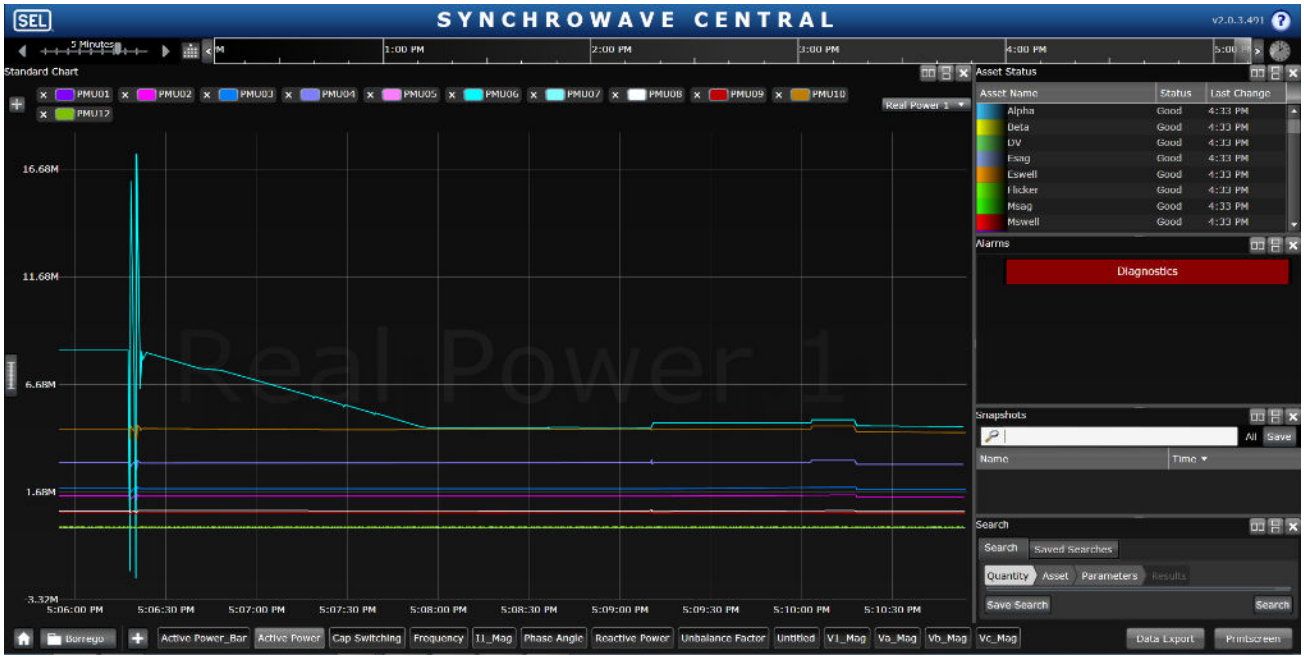


Figure 4-68. Active Powers

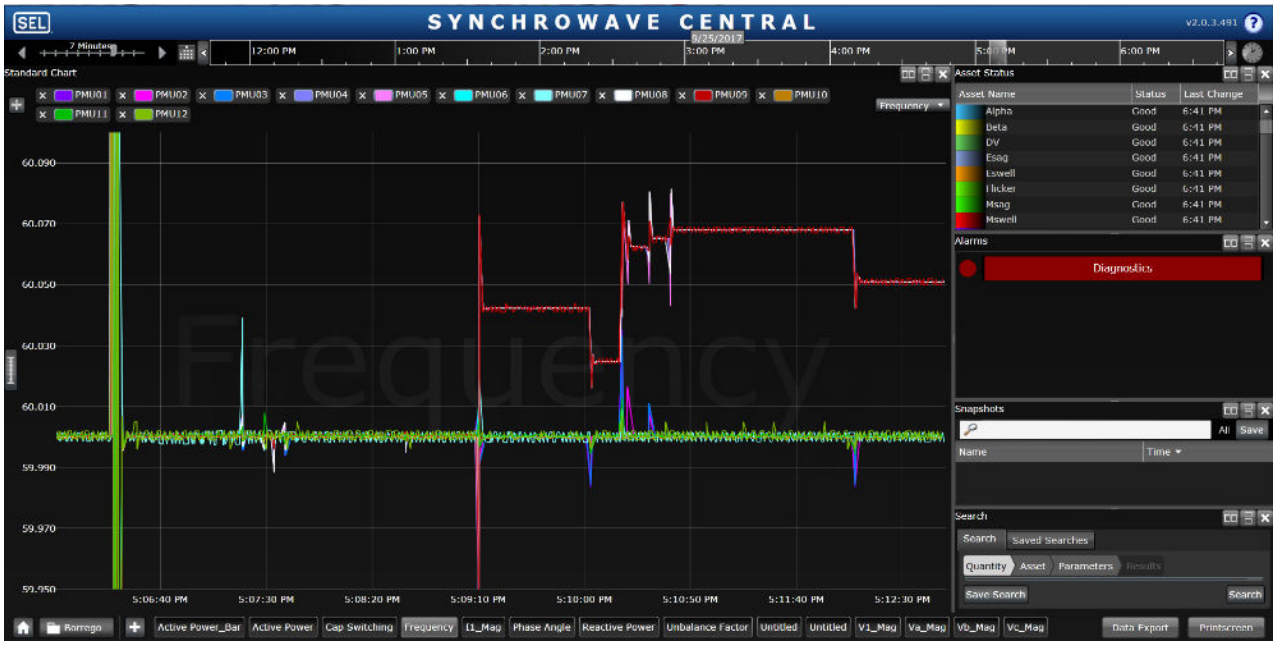


Figure 4-69. Reactive Powers

Because the frequency during island operation is not 60 Hz, the phase angle of the phasor measurement shows an oscillatory behavior. Most PMU devices are very sensitive to frequency changes (such as the case of islanding) can only tolerate a small deviation in power frequency from 60 Hz.

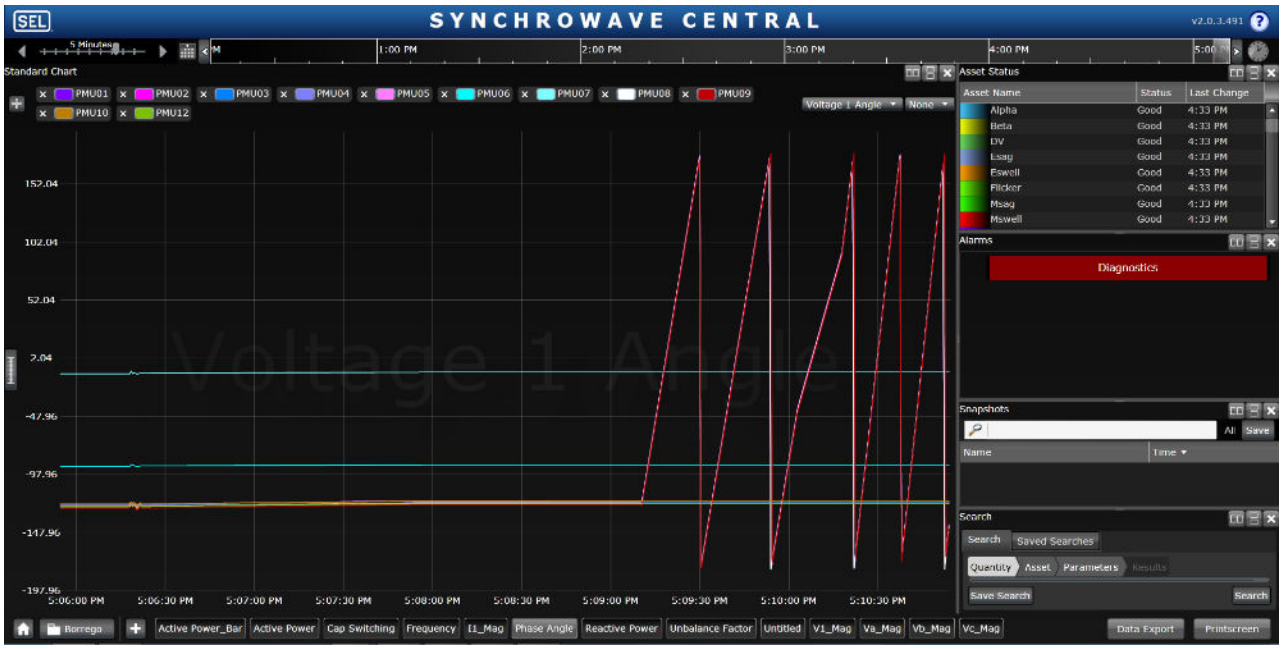


Figure 4-70. Phase Angle Changes during Islanding Process

4.2.2.4 Unbalance Factor

Loads were set to 0.75 pu and PV was set to its maximum value (6MW). In this case study, severe unbalanced condition caused by the malfunction of a circuit breaker was applied to the circuit to investigate its effect across the circuit. For this purpose in the first case study, phase A of the CB171 was opened. Figure 4-71 shows that this action caused a huge voltage variation in the downstream PMUs (PMU 12, PMU 1, PMU 2, and PMU3), while it did not creat a tangible positive voltage change in the upstream PMUs.

This malfunction can be identified more easily (even in the upstream PMUs or even Circuit 2 PMUs) by monitoring the unbalanced factor as shown in Figure 4-72. It can be seen that all PMUs have higher unbalanced factor than the threshold (0.3%).

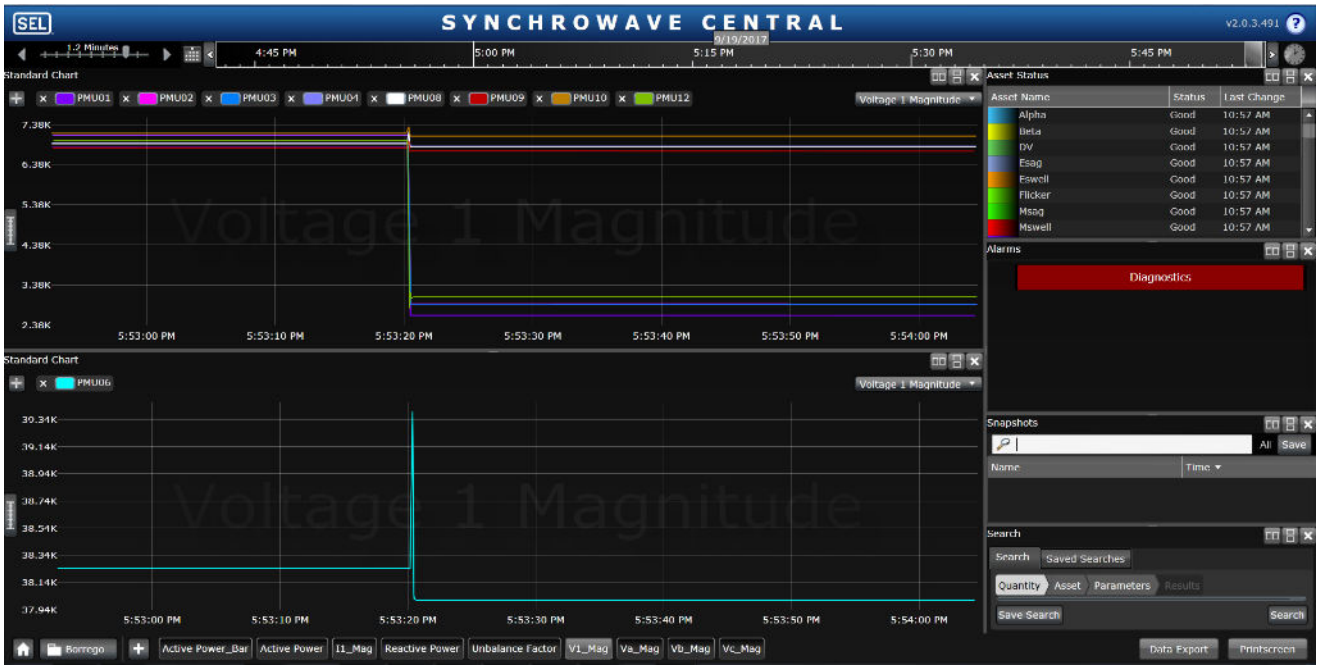


Figure 4-71. Magnitude of the Positive Sequence Voltages



Figure 4-72. Unbalanced Factors

The similar malfunction was applied to recloser CB171567. The magnitude of the positive sequence voltage is shown in Figure 4-73. It can be seen that, except PMU 2 in the downstream of CB171567, this malfunction cannot be detected by observing positive sequence voltage. However, it can be detected from the unbalanced factor of all PMUs as shown in Figure 4-74.



Figure 4-73. Magnitude of Positive Sequence Voltages



Figure 4-74. Unbalance Factors

4.2.2.5 Fault

In this case study, a single line to ground fault was applied for 20 ms to the downstream of the VR2. Voltage, current, real power, and reactive power of different PMUs are shown in the following figures.

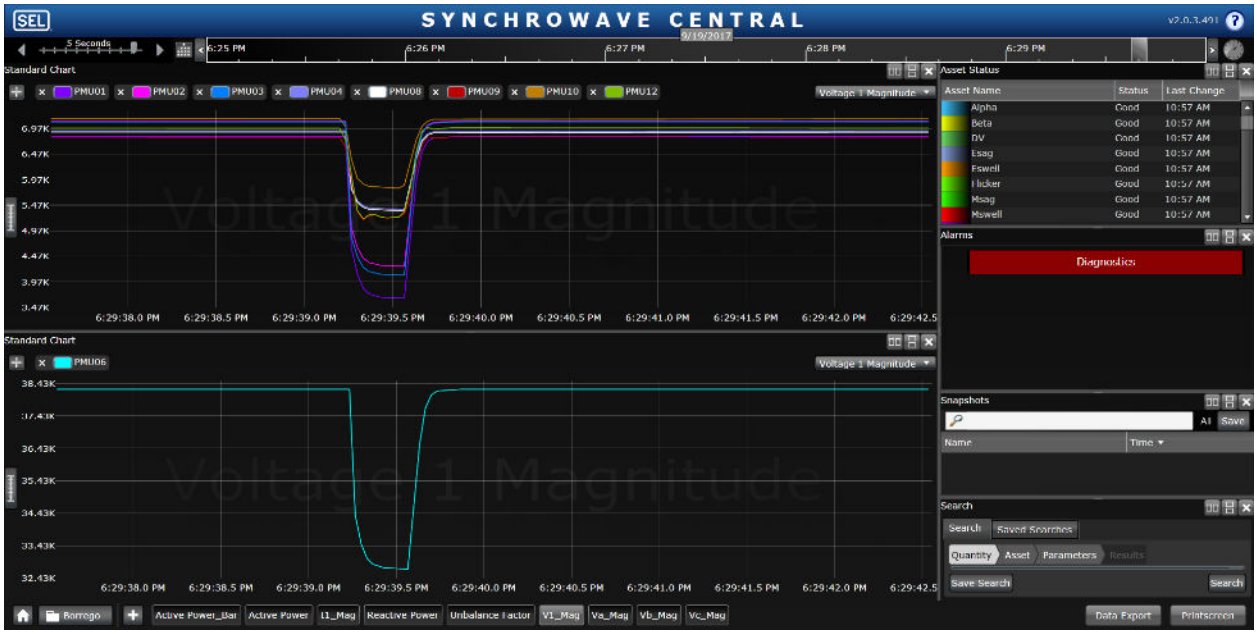


Figure 4-75. Magnitude of Positive Sequence Voltages

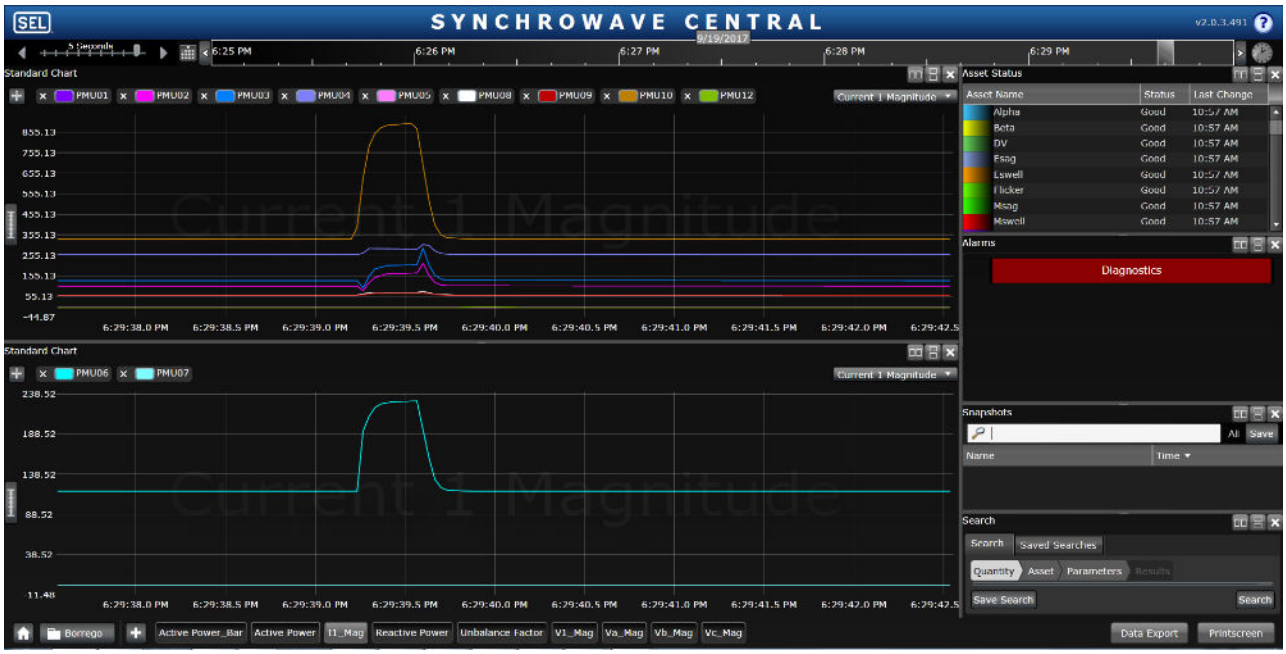


Figure 4-76. Magnitude of Positive Sequence Currents

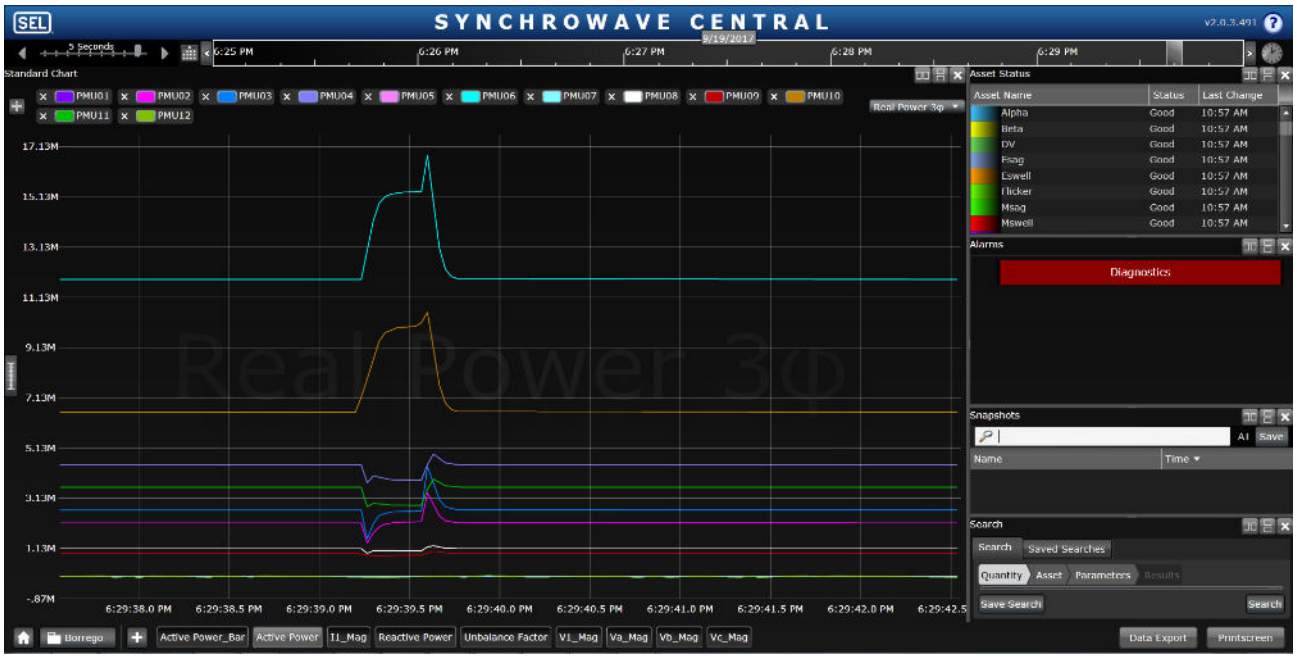


Figure 4-77. Active Powers

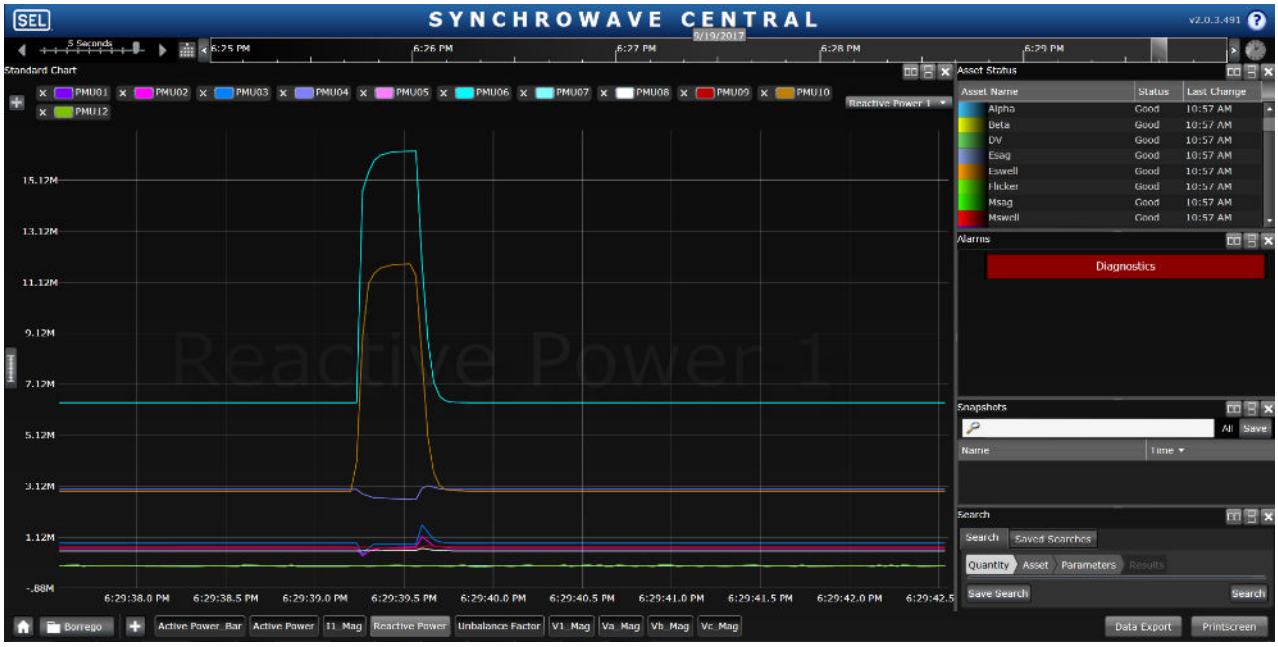


Figure 4-78. Reactive Powers

4.2.2.6 Capacitor Switching

In this section, the capacitor switching in Circuit 2 and Circuit 3 is investigated in two separate test cases.

In the first test case, the capacitor switching in circuit 3 is studied. Initially, CBC372 and CBC198 were open. The sequence of actions and the real/reactive power of the circuit breaker CB171 are summarized in the following table.

Switch Status	Real Power (MW)	Reactive Power (MVAr)
Open CBC372 / Open CBC198	6.758	2.210
Close CBC372 / Close CBC198	6.773	-0.050
Open CBC372 / Closed CBC198	6.750	1.050
Closed CBC372 / Open CBC198	6.763	1.101
Open CBC372 / Open CBC198	6.756	2.210

The following figures show voltage and real power of different PMUs. It can be seen in Figure 4-80 that when both of the capacitors were switched on, the losses in the circuit 3 was maximum.

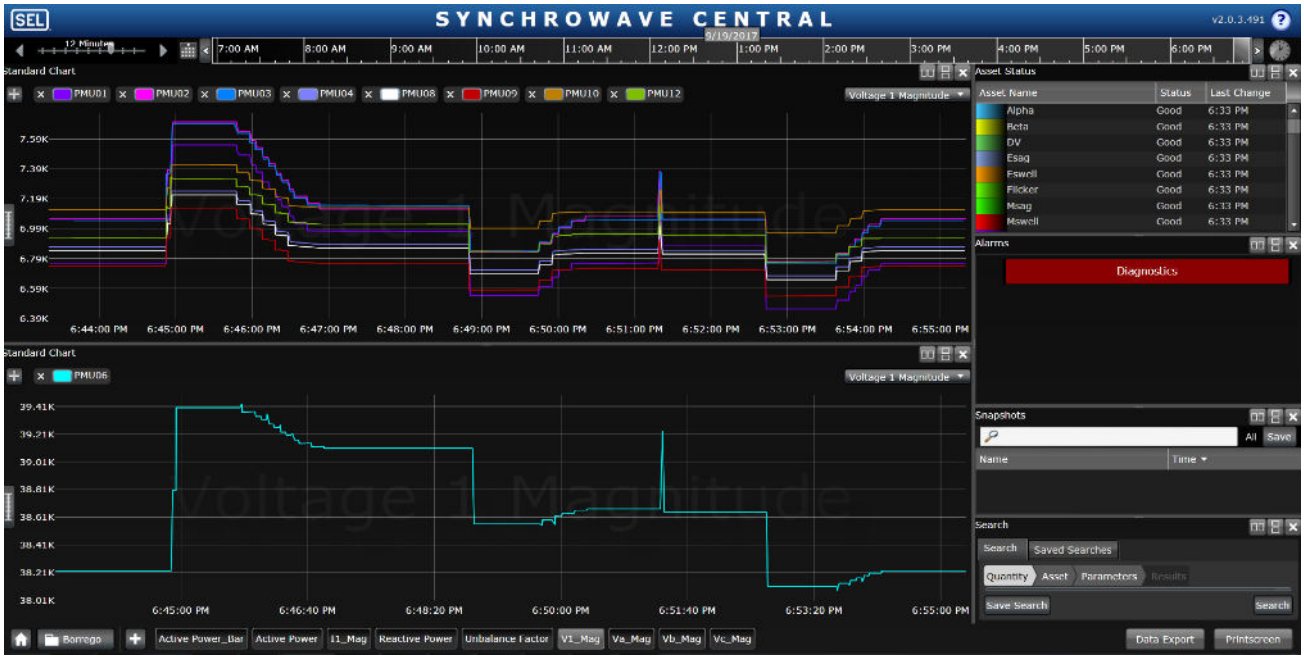


Figure 4-79. Magnitude of Positive Sequence Voltages

The step changes in voltages caused by variations in tap positions are clearly observable from the results.

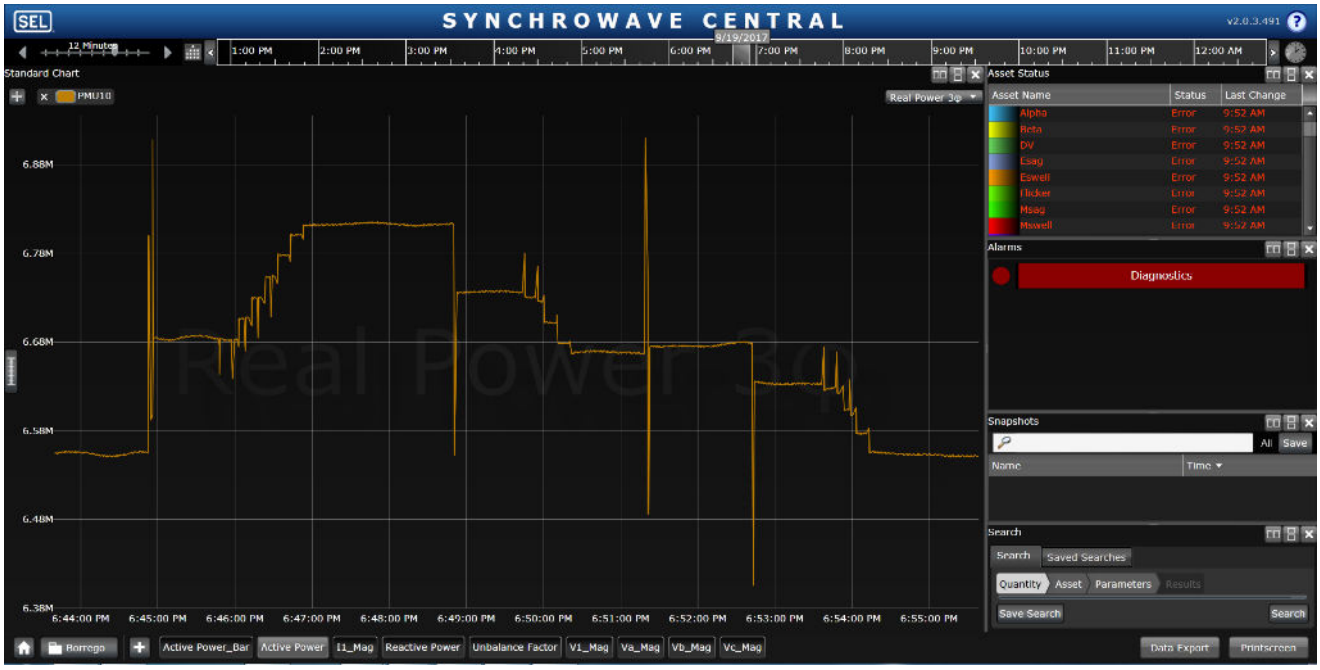


Figure 4-80. Real Power of PMU 10

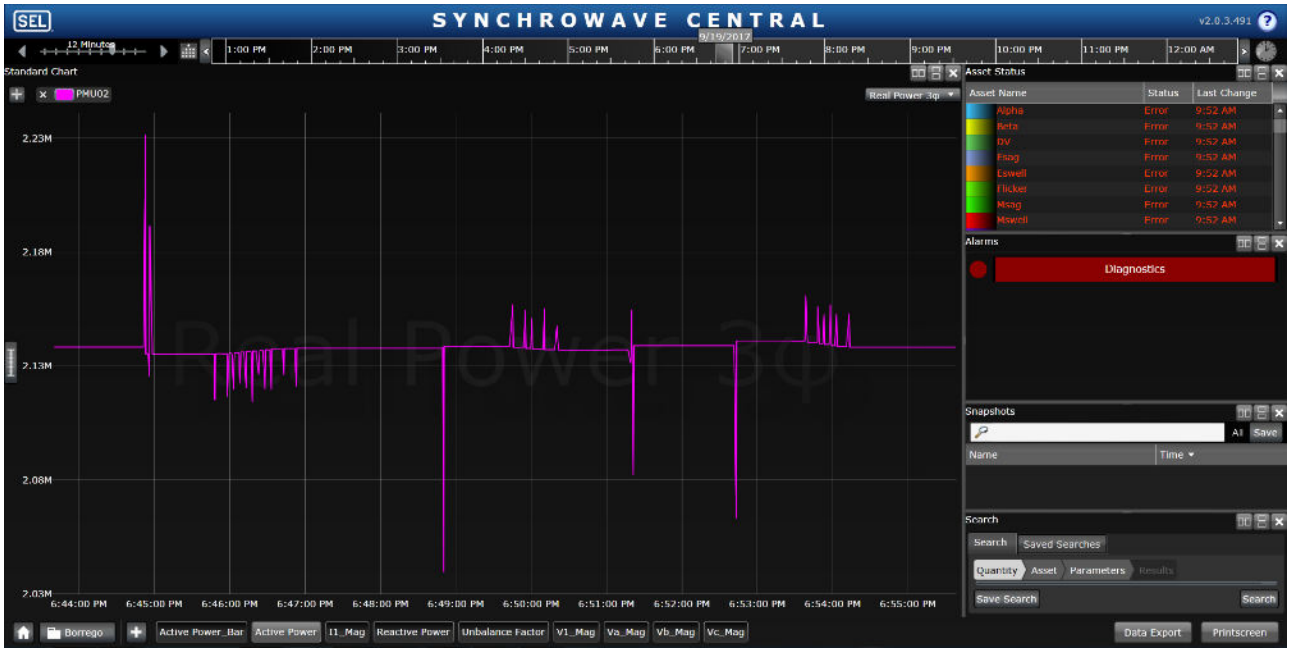


Figure 4-81. Real Power of PMU 2

Although the tap position changes are observable in the real power screen, power flow screens are not generally the best visualization screen for detecting and analyzing these events, since the impact is on voltages.

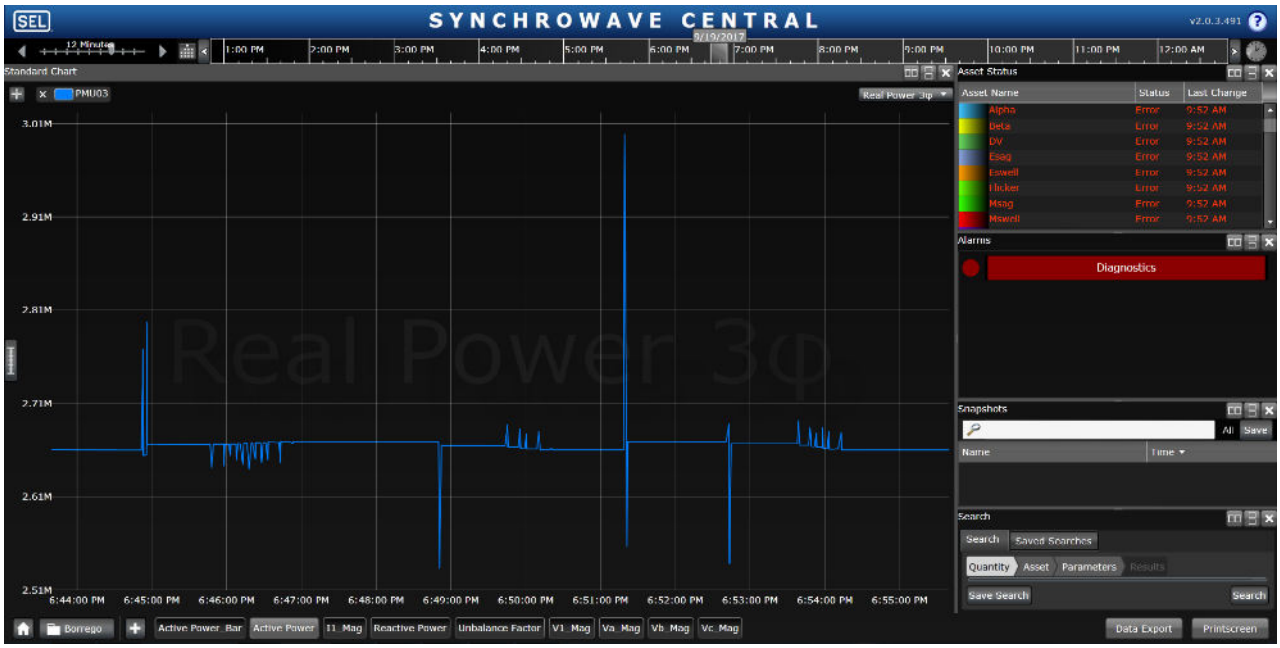


Figure 4-82. Real Power of PMU 3

A similar case study was performed for circuit 2. Initially, CBC393 and CBC17016 were open. The sequence of actions and the real/reactive power of the circuit breaker are summarized in the following table.

Switch Status	Real Power (MW)	Reactive Power (MVAr)
Open CBC393 / Open CBC17016	4.974	3.392
Open CBC393 / Close CBC17016	4.827	2.215
Close CBC393 / Close CBC 17016	4.806	1.004
Close CBC393 / Open CBC 17016	4.856	2.135
Open CBC393 / Open CBC17016	4.984	3.405

The following figures show voltages and real powers of different PMUs. It can be seen in Figure 4-84 that when both of the capacitors were switched on, the losses in the circuit 3 was minimum.

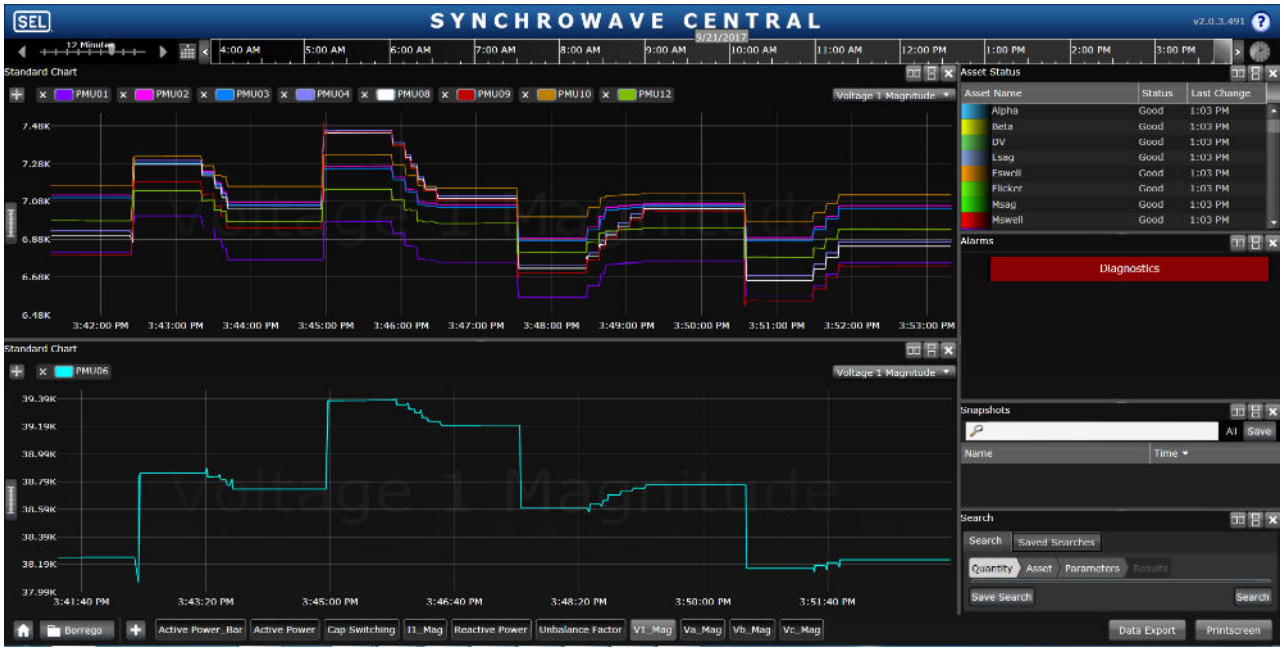


Figure 4-83. Magnitude of the Positive Sequence Voltages

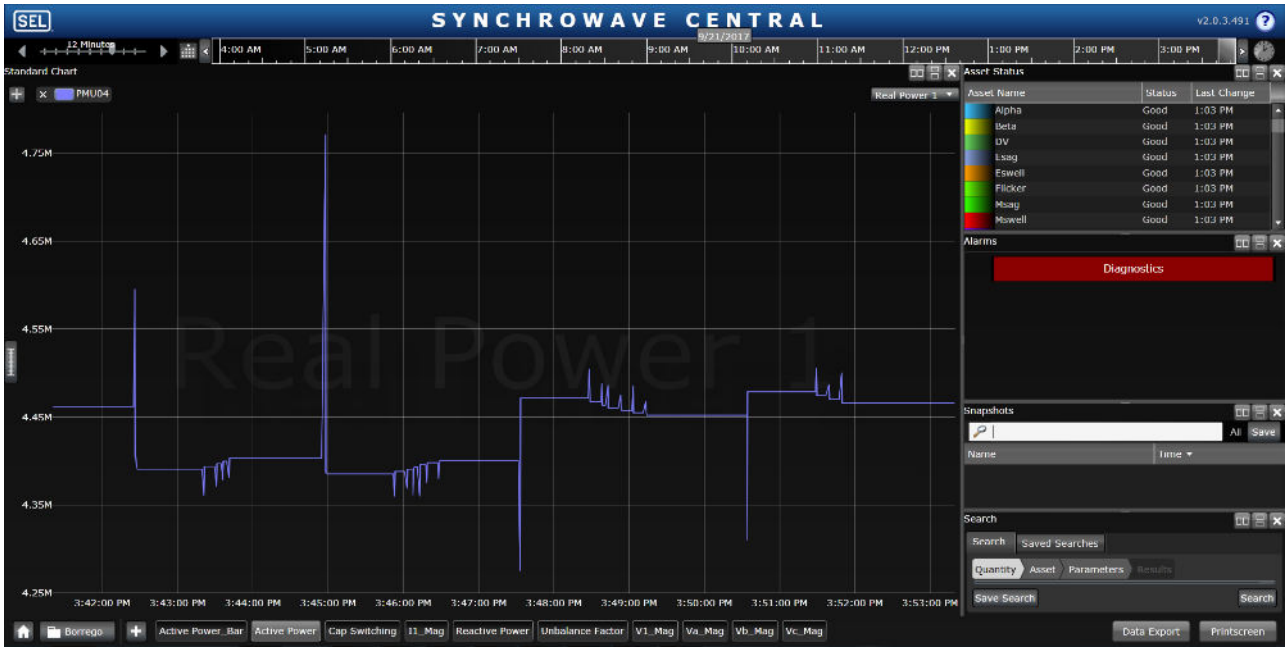


Figure 4-84. Real Powers of PMU 4

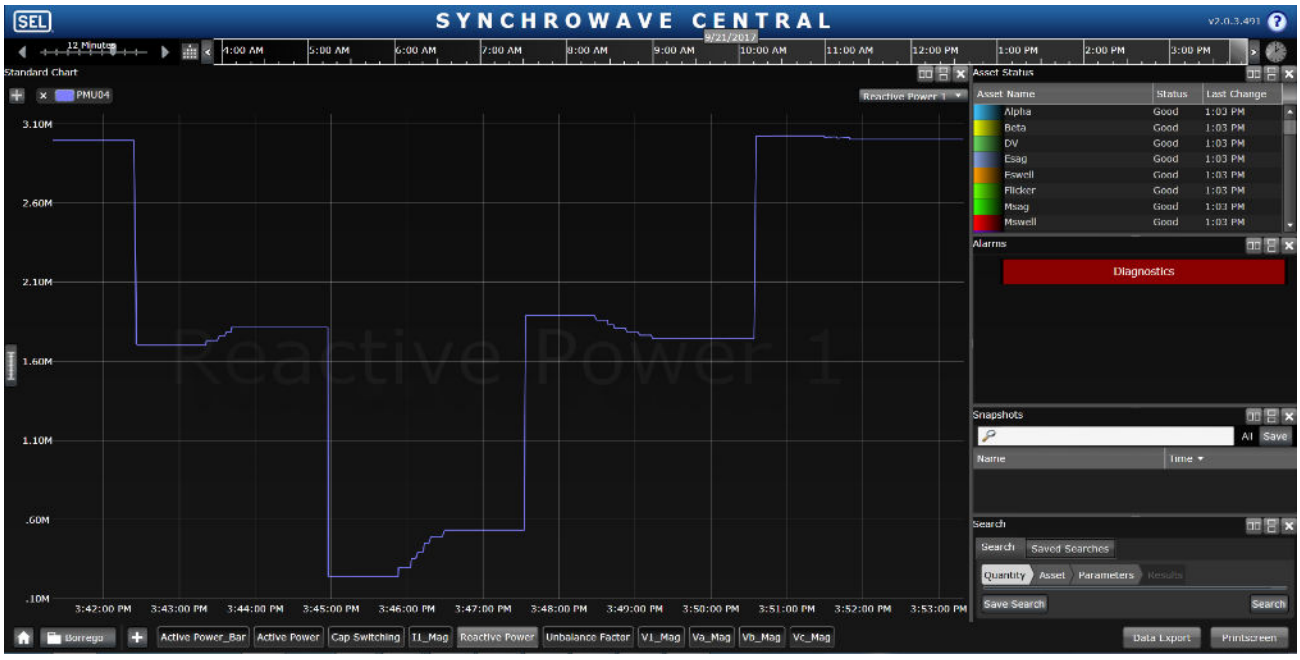


Figure 4-85. Reactive Powers of PMU 4

4.3 Use Case 6 (Circuit 4) – Water Treatment Facility Monitoring and Reactive Power Management

Following figure shows circuit 4 topology and location of the Water treatment plants (WTPs), line monitors (LMs) and switched capacitors. Due to the unavailability of the data for this circuit, one of the branches of the circuit 1 with PV is modified such that have similar behavior to the circuit 4 west branch.

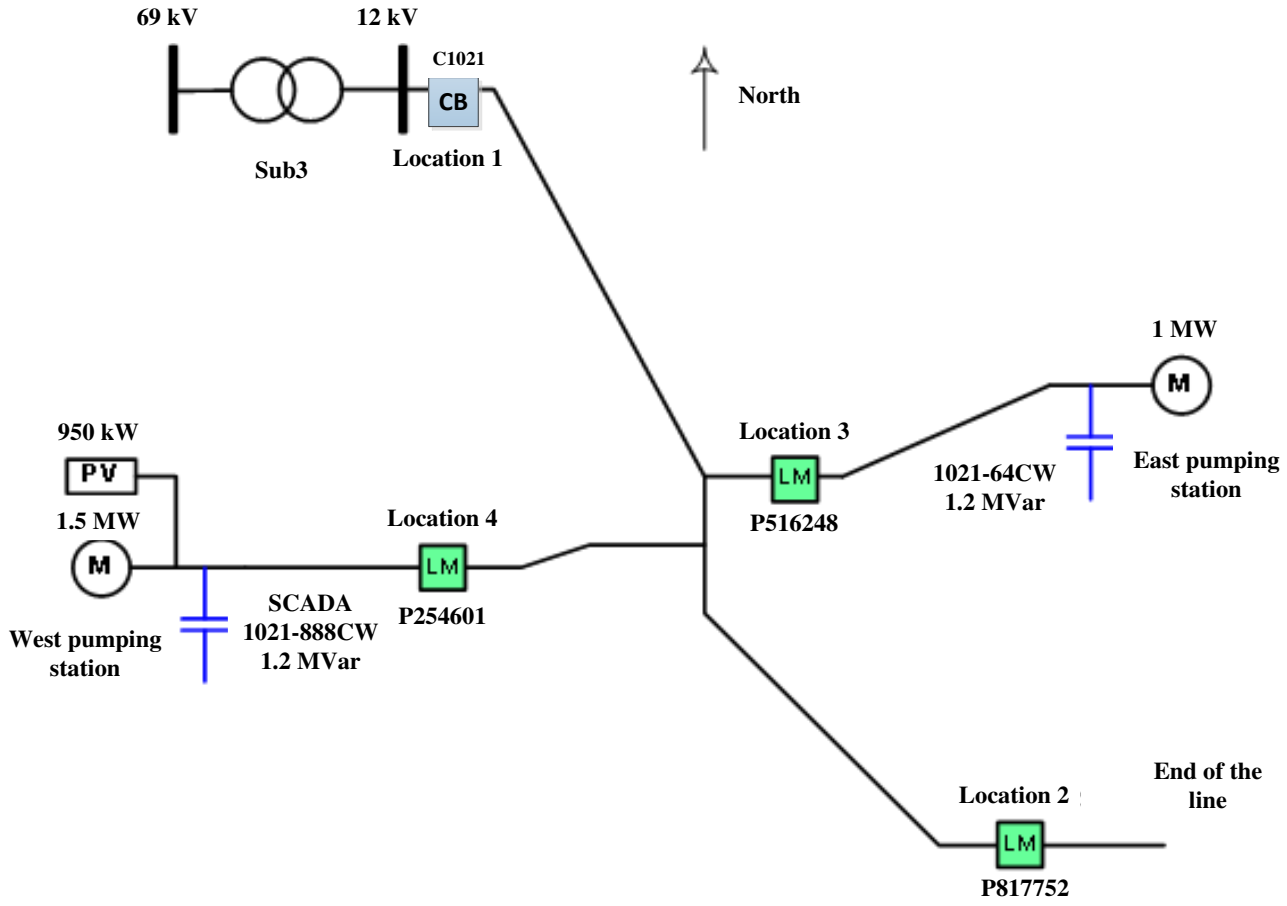


Figure 4-86. Circuit 4 Topology and Location of Line Monitoring (LM) Devices

The main objective of this use case is to coordinate and mange operation of large/critical industrial facilities such as Water Treatment Plants with the grid. The key operation aspects from the grid point of view are Real and Reactive power consumption. Specifically, for the reactive power management, the main value-added feature and advantage offered by the use case will be coordination of reactive power requirements from the plant with operation of shunt capacitors on the associated circuit feeding the plant.

The high-level sequence diagram for reactive power management application has been depicted Figure 4-87. The main approach is to observe the reactive power flow of the line through the PMU and switch in/out the capacitor banks (with a 15-second delay).

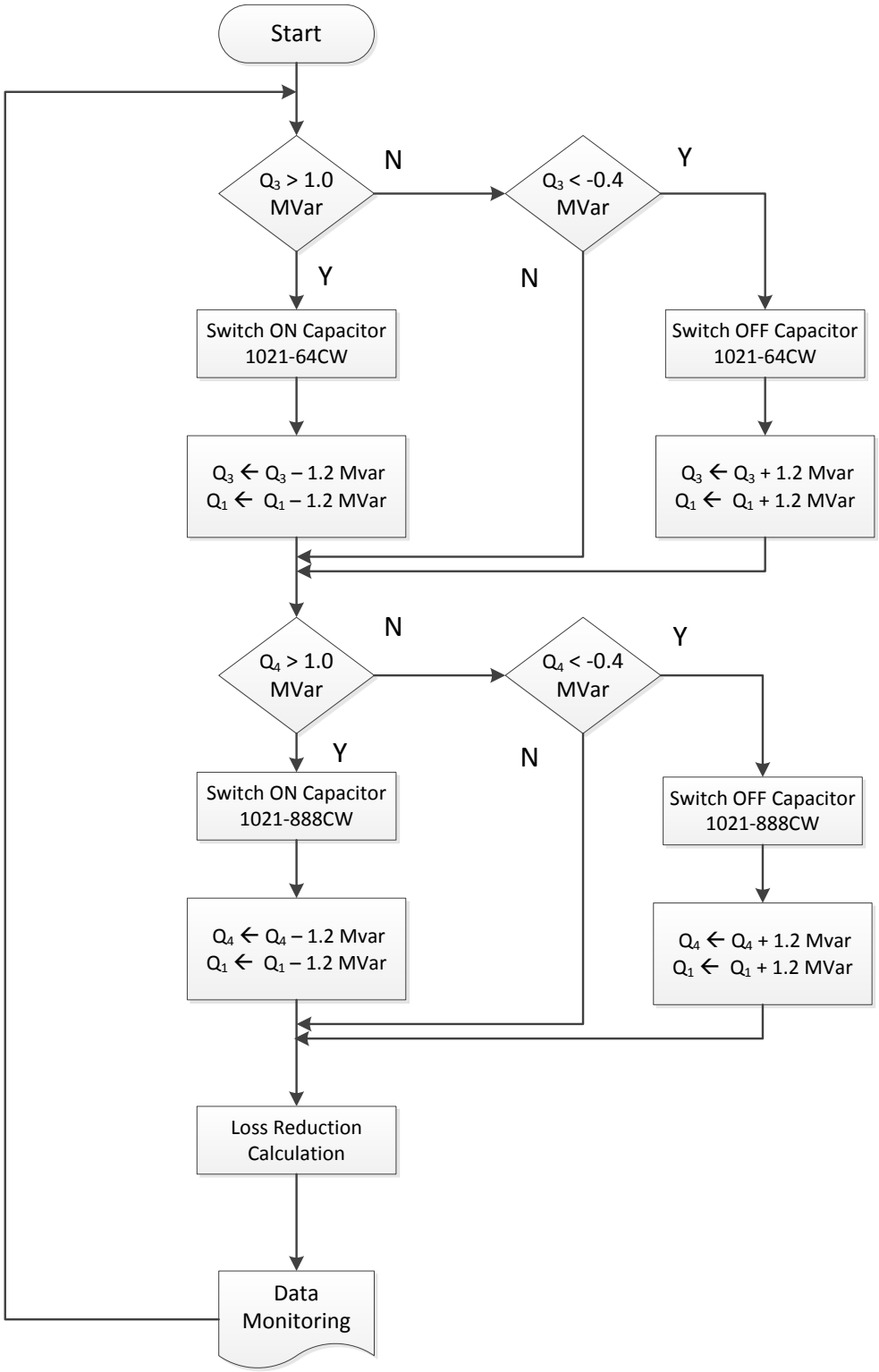

Start
Q_3 > 1.0 MVar
N
Q_3 < -0.4 MVar
Y
Y
N
Switch ON Capacitor 1021-64CW
Switch OFF Capacitor 1021-64CW
$Q_3 \leftarrow Q_3 - 1.2$ Mvar
$Q_1 \leftarrow Q_1 - 1.2$ MVar
$Q_3 \leftarrow Q_3 + 1.2$ Mvar
$Q_1 \leftarrow Q_1 + 1.2$ MVar
Q_4 > 1.0 MVar
N
Q_4 < -0.4 MVar
Y
Y
N
Switch ON Capacitor 1021-888CW
Switch OFF Capacitor 1021-888CW
$Q_4 \leftarrow Q_4 - 1.2$ Mvar
$Q_1 \leftarrow Q_1 - 1.2$ MVar
$Q_4 \leftarrow Q_4 + 1.2$ Mvar
$Q_1 \leftarrow Q_1 + 1.2$ MVar
Loss Reduction Calculation
Data Monitoring

Figure 4-87. A High-level Sequence Diagram for Reactive Power Management

4.3.2.1 Reactive Power Management without PV

For this test, initially, the load was 0.3 MW with the power factor of 0.8. Load was increased to 1.5 MW for 2 minutes and decreased back to 0.3 MW. The following figure shows voltage, active power, reactive power, and the loss of the line. It can be seen that when the load is increased, the reactive power observed by the PMU increased to 1.14 MW which is higher than the threshold; therefore, due to the defined logic, the capacitor turned on automatically after 15 seconds. Switching on the capacitor decreased the line loss by locally compensating the reactive power requirements.

Similarly, reactive power decreased to -1.3 MW after the load decreased to 0.3 MW. Because of the defined logic, the capacitor turned off automatically after 15 seconds. In this case, switching off the capacitor decreased the line loss to avoid overcompensation of the circuit.

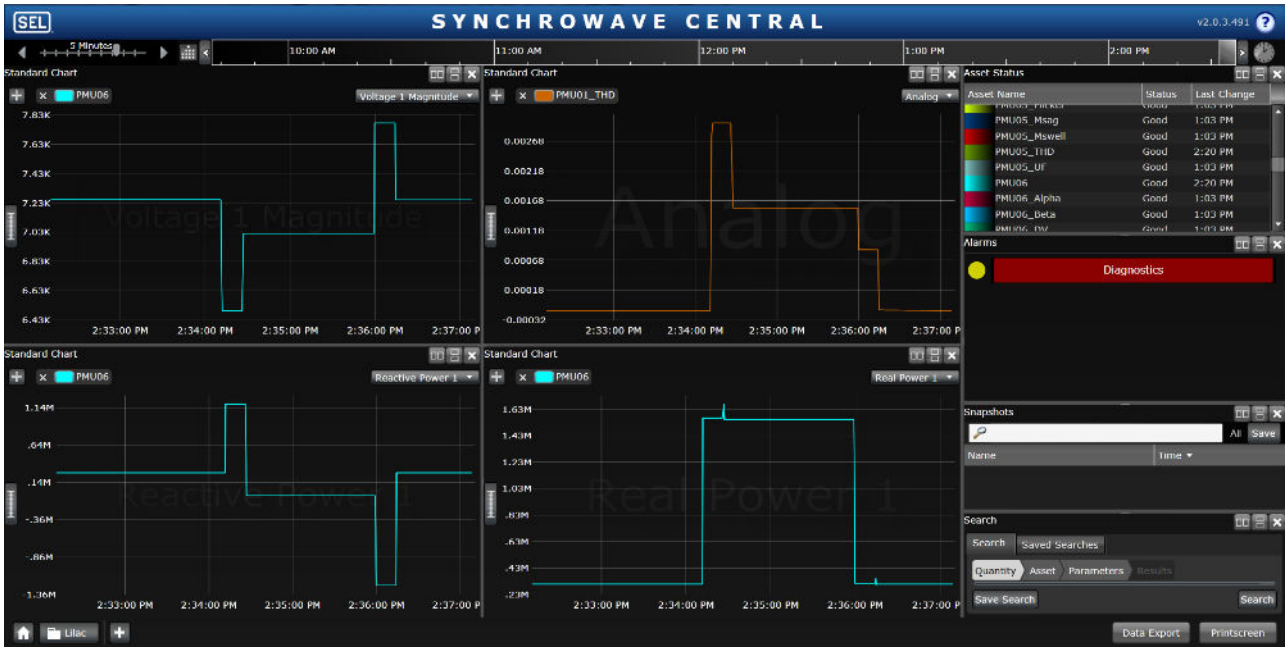


Figure 4-88. Voltage, Line Loss, Reactive Power, and Real Power

4.3.2.2 Reactive Power Management with PV

A similar test case was repeated with injecting 1 MW PV. It was observed from the following figure that the reactive power management along with local generation (PV) minimizes the line loss and improve the voltage profile. The test case confirms the effectiveness of the hybrid approach by utilizing both active and reactive power management of the customer load locally.

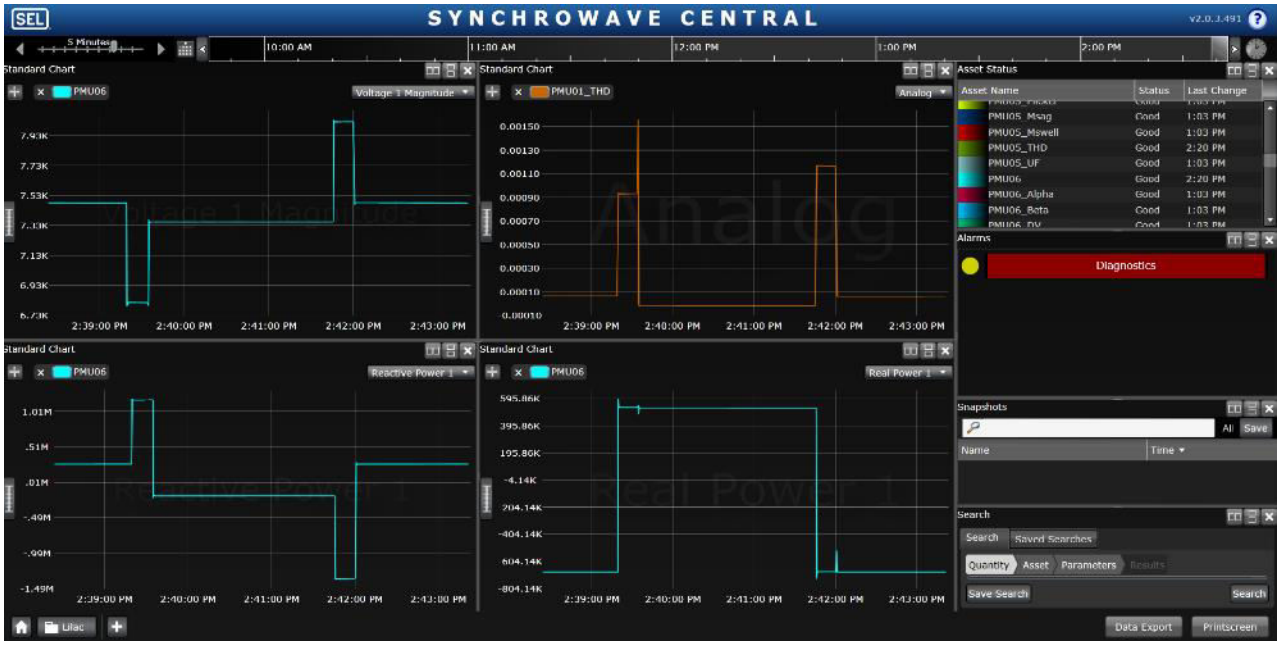


Figure 4-89. Voltage, Line Loss, Reactive Power, and Real Power

In general, the visualization screens were effective in detecting and analyzing various system disturbances. As observed, each screen and measured parameters or indices are primarily tailored for specific event detections and analysis. The combination of the proposed visualization screens and associated KPIs are needed to properly perform root-cause analysis.

5 Conclusions and Findings

This section provides a summary of key observations and conclusions from performing the pre-commercial demonstration of the monitoring and visualization technology, as well as analysis of the results and findings about the technology implementation and opportunities for system operation improvements.

5.1 Conclusions and Findings Related to Assessment of Integration and Monitoring Tools

5.1.1 Monitoring approaches

This project demonstrated new technologies and analysis methods for monitoring, visualization, and root-cause analysis of distribution systems by using various measurement techniques, data sources and integrating them in one platform to provide a unique monitoring and visualization user experience. In the advent of new customer technologies integrating with the utility systems, the proposed platform provides unique set of tools for distribution system operators and engineering analysis groups to monitor dynamic events, especially ones caused by varying characteristics of DER productions, loading effect of electric vehicle charging stations, and power electronic apparatus.

The novel concept of proposed visualization system is the ability of integration and utilization of multiple measurement platforms in one operation screen to achieve interoperability among various measurement tools and data format already exist for monitoring of customer systems and distribution systems. The key capabilities demonstrated included:

- Being able to monitor distribution assets in real-time, based on measurements received from PMUs, AMI system, Power Quality measurement devices, and SCADA system.
- Being able to tap onto historical data collected to playback and investigate events over extended period of time as selected and required by an operator or an engineer,
- Being able to view and analyze past events and to derive a range of parameters, key performance indicators, and more complex calculations or applications with the data to assist operators with analyzing behavior and health of distribution systems to make informed decisions.
- Providing a set of tools for pre/post event analysis based on various data types and sources; this can be used for root cause analysis, operator and engineers training, and assessment of operation and design procedures for new technologies and approaches.
- Demonstrating that the proposed monitoring, analysis and visualization system can be used as a base platform for further development of data analytics and real-time monitoring systems, as become required for monitoring and evaluation of newly introduced applications and integration of customer equipment.

It was also concluded that the laboratory setup prepared for integration and demonstration of use cases has clearly facilitated the troubleshooting and analysis of use cases and in performing what-if scenarios, and that would not be possible to accomplish using just data from the actual distribution systems.

5.1.2 Standards, tools and analysis approach applied

The approach for the pre-commercial system demonstration was to use the standard features and functions of the available, off-the-shelf products and to integrate them with existing tools to enhance and achieve the functional requirements for the proposed visualization system that was demonstrated. To achieve that goal, commercially available software and hardware products were used for the test setup. It was concluded that any measurements are available within the capabilities of existing feeder control and monitoring devices that can be used to define new indices and visualize performance aspects of the customer interconnections as parts of use cases. The simulations and test procedures provided successful demonstration of proposed visualization technologies in support of enhanced visibility in distribution circuits and defining greater analytical tools.

5.1.3 Technologies and performances of existing approaches

In the process of demonstration of the monitoring and visualization of measurement data extracted from actual selected distribution circuits, all available technologies present on the distribution circuits were used (e.g. PMUs, SCADA, historian, power quality monitoring). In the process of the circuit selection, in the system design phase (Phase 1 of the project) the objective was to select the circuits with rich set of measurement and control devices, with proper communication infrastructure, and presence of DER.

In cases where the selected circuit did not have sufficient number and type of devices needed to demonstrate some of the developed use cases, RTDS models were used to complement field data. For instance, for demonstration of the visualization capability for a Large Industrial Customer Facility (such as Water Treatment Facility) monitoring use case (Use Case 6), the focus was on reactive power management and flexible local generation use. However, the selected circuit (the Circuit 4) that served such a facility did not have proper communication and data measurement and streaming infrastructure completed at this time, so this use case was successfully demonstrated at ITF lab.

Based on the simulation results, it was concluded that additional values can be provided both to the customer and in enhancing of the circuit operation by closely monitoring and compensating reactive power during load fluctuations.

From the technology survey performed, it was concluded that several promising devices with promising technologies are offered by vendors in the present market that can be used for distribution systems. Selected set

of devices was exposed to a rigorous set of the tests (as part of type tests) and the results were quite extensively presented in this report.

From the type tests, it was concluded that although all devices meet the common requirements, defined by the standards (for instance, IEC 37-118 standard for synchrophasor technology), there were differences in their accuracy and available features in measurement quantities that are not commonly used in transmission systems. This finding suggested that there are further opportunities to improve measurement functions for the specific purpose of distribution systems.

5.1.4 Gap analysis and needs

Below is a list of key findings and conclusions related to the gap analysis and areas requiring technology enhancements by vendors:

- During project implementation, it was realized that one of the main barriers associated with PMU utilization is the insufficient communication infrastructure to stream data to control center at high bandwidth and resolution. In todays' utility environment, transmission PMUs don't have problems with communication systems; however, data streaming from distribution PMUs come across challenges such as packets loss and communication data quality. To achieve the full benefit of the system, it is essential to ensure that a reliable communication infrastructure is available. To some extent, data buffering and data interpolation/extrapolation techniques can be applied to mitigate data loss; yet, the fast changing phenomena in new environments are unpredictable and hard to reproduce if actual data does not exist. In addition, enhancing the data processing of the devices can also support localized (device base) data analysis to avoid transferring large amount of raw data to the control centers.
- Dealing with a new technology such as PMUs in distribution systems, it was noted that several commercial products and their features still require significant development and enhancement to meet certain characteristics of distribution systems. In addition, improper pairing and calibration issues of PMU IED along with the voltage/current sensors are more critical and difficult in distribution systems as compared to transmission systems, which adversely affect data quality.
- From the analysis, it was concluded that the phase angle differences across distribution circuits are usually less than 10 degrees; while typically the phase angle error of a physical PMU is around 1 degree to 4 degrees which is considerable (compared with 10 degrees); therefore, it is important to: 1) choose PMUs with proper calibration capability, and 2) calibrate PMUs along with other sensors in the field as part of periodical inspections.
- In one of the selected circuits for the demonstration of use cases (Circuit 4), there were several PMUs installed in the field whose data could not be accessed due to the unavailability of a PDC at the substation. This issue emphasizes the fact that for this technology to be utilized many components are re-

quired to work together in various environments, inside and outside of substations and/or control center. Possible solutions were identified and discussed including standardization of the PMU infrastructure installation and possible data sharing among adjacent substations to facilitate the data concentration and transfer to control center.

- During the project, an event viewer for capturing and analyzing voltage sag and swell of various durations and nature was introduced. This event viewer was proven to be very helpful in identifying and resolving issues with malfunctioning field devices as well as visualizing many events that would not be readily reported by typical SCADA systems and power quality devices. The root-cause analysis was performed by analyzing the data from PMUs in the vicinity and comparing the measurements versus expected outcome. In the absence of a field-base device calibration process, it was concluded that the viewer has the potential to be used as a common tool and component of monitoring platforms for distribution systems.
- During this project, a tap position counter and operation tracker was proposed and demonstrated to monitor performance of voltage regulators in the field. It was concluded that this approach can be utilized as part of field device performance monitoring process to identify the potential wear and tear of the voltage regulators due to frequent tap changes. The approach was proposed as a practical method for identifying and analyzing root causes of the frequent tap changes to manage maintenance aspects and to achieve expected asset life.

5.1.5 Deployment and operational challenges

The main findings were:

- To achieve full benefits of deployment of advanced monitoring and visualization technologies such as the ones proposed and demonstrated during this project, it is necessary to have a measurement, control and communication infrastructure that can reliably handle and support streaming of large amount of data at high resolution with minimum downtime.
- It was concluded that, due to the fact that most PMU technologies are primarily targeted for transmission applications, available PMU devices have limitations for distribution system use. They do not provide a complete set of measurement parameters and indices desirable for distribution system monitoring and analysis. Custom design codes and schemes at PDC level or the post processing of data will be required to calculate and provide indices and statistical data that are readily useable by the engineers.

5.2 Findings Related to the Demonstrated Technology

This section provides findings and conclusions related to prospective adoption of the demonstrated system.

5.2.1 Scaling and large-scale deployment

The main findings were:

- At present, the pre-commercial system was demonstrated with data and measurements from two circuits and a handful of PMU devices. However, based on the amount of data processed and the capability of the visualization tool to incorporate large number of measurement devices, it was determined that system can be scaled up and various data sources can be incorporated.
- The scaling-up can be tested in the simulated environment with the test setup at the laboratory; however, most likely additional enhancement of the lab setup will be needed to also incorporate representation of large scale communication systems with mixed media in a meshed network architecture, to reflect the data traffics and possible latency that can be expected in large scale deployment.

5.2.2 Business considerations

- The proposed monitoring and visualization system was developed with two groups of users in mind, namely, a) distribution system operators, and b) engineers and technicians involved in the event analysis and root-cause assessment of system issues.
- The new monitoring and evaluation schemes could be used for enhancement of the operations by providing additional means of awareness about the system behavior. To bring the technology in the control room and to put it in operational use, a production version needs to be developed; additionally, the GUI needs to be customized to meet operators' needs; operation procedures and training are necessary.

6 Recommendations and Next Steps

The project recommended and demonstrated an advanced monitoring and visualization platform for increasing the visibility into distribution systems to facilitate integration of customer equipment in a safe and reliable environment. The combined utilization of field data monitoring and visualization, and using the simulation environment (in this case the test setup developed at SDG&E Integrated Test Facility) were introduced to model, test and demonstrate some of the features and applications that cannot be demonstrated by using actual field data, due to the limited field data availability and/or limited ability to run into events or create phenomena such as faults, transient changes, circuit reconfigurations, and equipment failure.

Below is a list of key recommendations to further enhance the demonstrated monitoring and visualization technologies in support of enabling distribution system monitoring and visualization beyond substations and to get the monitoring technology ready for utilization by operators and engineers:

- Develop a strategy and technology roadmap to bring the technology into control center to be used by operator as a production level tool. This roadmap should address improvement of existing platform and application and development of new applications, infrastructure and procedures to bring it to operations and the control room and to streamline its use by engineering and planning groups.
- Specify the requirements for new measurement devices, such as distribution PMUs that can provide power quality measurements, in addition to existing standard features.
- Conduct business case analysis to justify cost benefits for various implementation scenarios. PMU in distribution system is an emerging technologies and require involvement from various utility groups and stakeholders to properly define and assign values on the use cases. The business case should consider combination of use cases that provide most value to a larger group of stakeholders. Many root-cause analysis aspects of the proposed technologies may not be readily understood by operators and engineers.
- The project team interacted with many stakeholders, engineers and potential users of the proposed monitoring and visualization system. The application and visualization matrix proposed in the project was shared and discussed to ensure capturing the needs of various groups and common daily operators and engineering activities. It is recommended to further enhance the functional requirement matrix by getting feedback from other departments and by surveying similar approaches used by other utilities. This survey can be later used for developing PI Coresight screens based on the needs of those groups.

6.1 Recommended next steps

To further enhance the demonstrated technology and to resolve some of the accuracy and calibration issues of the commercial PMU devices, it is recommended to share the PMU functional requirements for distribution

systems monitoring, and results of the type tests from the project, with vendors interested to enhance the technology. The lack of understanding related to the use cases and measurement approaches for distribution system were associated with some of the accuracy problems observed, which provides areas for future industry collaborations.

It is recommended to work with qualified vendors to develop a portable PMU calibration test equipment for use in the field. The pre-commercial demonstration of the monitoring and visualization technologies showed that periodical testing and calibration of the PMU based devices are essential to avoid large inaccuracy and erroneous measurements. However, for performing the calibrations in the field proper test equipment and testing procedures will be required to safely and accurately test and calibrate devices.

It is recommended to work with standard development agencies and working groups to publish and incorporate some of the findings of and measurement approaches proposed in the project in the distribution PMU guidelines and industry standards. From the type tests, it was concluded that although all devices meet the common requirements, defined by the standards (for instance, IEC 37-118 standard for PMU technology), there were differences in their accuracy and available features in measurement quantities that are not commonly used in transmission systems. This finding suggested that there are further opportunities to improve measurement functions for the specific purpose of distribution systems.

6.2 Adaptability to other utilities and/or the broader industry

It is anticipated that the visualization technology and advanced monitoring demonstrated in this project will be highly appealing to other utilities and beyond. Use of PMU in distribution systems is relatively new, and not many utilities have started to explore advantages and value offering of this technology. The widespread deployment of PV systems and exposing the system to new technologies installed by customers will change the dynamics of the distribution system to the extent that the SCADA system alone would not be able to provide all the information and data required for analyzing the system issues and for operating the system.

7 Metrics and Value Proposition

7.1. Metrics

The main focus of this project was on demonstrating new applications and methods for analyzing the impact of new customer systems on the utility distribution system. The project demonstrated an advanced monitoring and visualization platform that can support operators and engineering in managing the requirement of future complex systems.

The following metrics were identified for this project as potential metrics to consider project benefits at full scale. Given the proof of concept nature of this EPIC project, these metrics are forward looking. Sections 5 and 7 of this report outline the benefits that could potentially be gained from full deployment of this technology.

Table 7-1: Metrics for EPIC 2- Project 5
(Integration of Customer Systems into Electric Utility Infrastructure)

D.13-11-025, Attachment 4. List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area in applied research, technology demonstration, and market facilitation)	See Section
1. Potential energy and cost savings	
a. Number and total nameplate capacity of distributed generation facilities	See Sections 5 & 7
c. Avoided procurement and generation costs	See Sections 5 & 7
i. Nameplate capacity (MW) of grid-connected energy storage	See Sections 5 & 7
3. Economic benefits	See Sections 5 & 7
a. Maintain / Reduce operations and maintenance costs	See Sections 5 & 7
5. Safety, Power Quality, and Reliability (Equipment, Electricity System)	See Sections 5 & 7
b. Electric system power flow congestion reduction	See Sections 5 & 7
c. Forecast accuracy improvement.	See Sections 5 & 7
e. Utility worker safety improvement and hazard exposure reduction	See Sections 5 & 7
i. Increase in the number of nodes in the power system at monitoring points	See Sections 5 & 7
7. Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy	

b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)	See Sections 5 & 7
d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360)	See Sections 5 & 7
f. Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices for metering, communications concerning grid operations and status, and distribution automation (PU Code § 8360)	See Sections 5 & 7
j. Provide consumers with timely information and control options (PU Code § 8360)	See Sections 5 & 7

7.2. Value Proposition

Several value propositions of the demonstrated technology and methods introduced in this project are explained below.

7.2.1 Greater awareness about the system

A higher level of awareness and greater values for monitoring and analysis of the system is expected from a system that can utilize and process high resolution of measurement data, along with traditional SCADA type data and AMI data. Traditionally, there has been limitation on providing observability across the circuits (beyond substations). The proposed platform can combine data from various sources to report on power quality and operation of the devices.

7.2.2 Greater reliability

The proposed advanced monitoring and data processing platform utilizes various sources of data at the same time to calculate a series of performance indices for the operation and analysis of the system. Redundant data and combining data from various sources, not only increase the observability and deterministic aspects of the system, it also ensures that events can be analyzed and conclusions can be reached faster to make informed decision on various events, to either prevent a failure, or determine the root-cause in much faster fashion and resolve the stations.

7.2.3 Lower Costs in monitoring and control of the network

In the first glance, the proposed system may not look cost-effective, due to the emerging nature of the technology and the fact that a reliable communication system infrastructure is required to bring the high resolution data back to control center. However, the demonstrated technology enables many fast monitoring and control applications feasible that collectively the portfolio of projects can offer a very high benefit to cost ra-

tio. Several projects and applications should be analyzed and deployed together to ensure the best value propositions can be achieved from the projects.

7.2.4 Increased safety and/or enhanced environmental sustainability

Because the main focus on the proposed advanced monitoring and analysis system is on improving the system visibility and providing fasters and reliable methods for operating the system, safety and integrity enhancement of the system will be the main target. Fast actions are becoming possible based on processing and visualizing high resolution of field data. In addition, because the system becomes more observable, more customer system installation requests and interconnection applications can be processed to expedite the integration and increase the penetration levels.

8 References

[1] IEEE 1564-2014: IEEE Guide for Voltage Sag Indices.

[2] ITI (CBEMA) CURVE APPLICATION NOTE (http://.www.itic.org/technical/iticurv.pdf).

[3] IEEE 519-2014: IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems.

[4] IEEE 1100-1992: IEEE Recommended Practice for Powering and Grounding Sensitive Electronic Equipment.

[5] IEEE 1159-2009: IEEE Recommended Practice for Monitoring Electric Power Quality.

[6] IEEE 1453-2015: IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems.

[7] C. Trueblood, S. Coley, T. Key, L. Rogers, A. Ellis, C. Hansen, and E. Philpot, "PV Measures Up for Fleet Duty: Data from a Tennessee Plant Are Used to Illustrate Metrics That Characterize Plant Performance", IEEE Power and Energy Magazine, 11, 2013.

[8] IEEE 1366-2012: IEEE Guide for Electric Power Distribution Reliability Indices.

[9] https://cdn.selinc.com/assets/Literature/Publications/Technical%20Papers/6706_CatchingFalling_KG_20160215_Web3.pdf?v=20170706-140455

Appendix 14

EPIC-2, Project 6: Collaborative Programs in RD&D Consortia – Demonstration of Methodology and Tools for Estimating Propensity for Customer Adoption of Photovoltaics



EPIC Final Report

Program	**Electric Program Investment Charge (EPIC)**
Administrator	**San Diego Gas & Electric Company**
Project Number	**EPIC-2, Project 6**
Project Name	**Collaborative Programs in RD&D Consortia**
Module Name	**Demonstration of Methodology and Tools for Estimating Propensity for Customer Adoption of Photovoltaics**
Date	**December 31, 2017**

Project Attributions

This comprehensive final report documents the work done in one module of EPIC-2, Project 6.

The project team that contributed to the project definition, execution, and reporting included the following individuals, listed alphabetically by last name.

SDG&E

Bui, Nancy

Goodman, Frank

Katmale, Hilal

Mazhari, Iman

Salmani, Amin

Wilson, Dan

Navigant Consulting/Trove

Corfee, Karin

Gifford, Will (Trove)

Goffri, Shalom

Romano, Andrea

Seiden, Ken

Welch, Cory

Executive Summary

Overview

The objective of Electric Program Investment Charge 2 (EPIC-2), Project 6 (Collaborative Programs in RD&D Consortia) is to accomplish highly leveraged demonstration work through industry collaborative R&D organizations. The focus of this project module was to identify methodologies and tools for determining the primary drivers for residential photovoltaic (PV) adoption, predict residential PV adoption over time, and to demonstrate selected methods on a use case (e.g., propensity to adopt PV on the ZIP code level). The effort also developed recommendations about whether to adopt all or some of the methods and tools on a commercial basis. The project team focused specifically on residential sector PV market adoption. Additionally, the project team conducted machine learning (ML) analytics on disadvantaged communities (DAC) ZIP codes and evaluated the difference in propensity to adopt solar PV between DAC and other ZIP codes.

The scope of this project demonstrated methodologies and tools for forecasting the propensity for residential customer solar PV adoption in California and SDG&E ZIP Codes. The project included the following major tasks.

- Literature Review and Methodology Justification
- Methodology Framework Development
- Demonstration Plan
- Disadvantaged Communities Analysis

Using ML, the project team identified the most important attributes driving adoption at the non-DAC and DAC ZIP code level as detailed in **Error! Reference source not found.**.

Table E- 1 Machine Learning Key Customer Attributes

Non- DAC Key Customer Attributes	DAC Key Customer Attributes
• Average number of credit mortgage type inquiries in the last 12 months	• Average number of credit mortgage type inquiries in the last 12 months
• Climate zone	• % Owner Occupied Households
• Percentage of households that are married families	• Climate zone
• Average balance on an open auto loan and lease trades reported in the last 6 months	• % Manufactured Housing Units
• Average household size	
• Percentage of owner-occupied housing units	

Comparing adoption in DAC and non-DAC ZIP codes, owner occupancy emerged as a key attribute explaining the difference in PV market share. The percentage of owner occupied homes is 63% for non-DAC ZIP codes, compared to 50% for DAC ZIP codes.

Key Findings and Conclusions

The strength of aggregate and ZIP code-level back-casts suggest that causal models can be used to forecast residential rooftop PV adoption moving forward with a reasonable degree of accuracy, even when

the analysis is spatially disaggregated. Such methods could support integrated resource planning and a better understanding of likely solar PV installation location. As demonstrated by the results, the key findings of this project can be summarized as follows:

- Causal models, when appropriately calibrated, can explain historical adoption patterns well.
- Preliminary results suggest that the adoption of residential solar PV in California and in the SDG&E service territory is past the inflection point in the characteristic S-curve of adoption.
- ML techniques can help to explain historical adoption patterns and can reduce the variance between simulated and actual adoption when analyzed at a granular level.
- The rate of diffusion (i.e., the shape of the S-curve) is reasonably consistent spatially; the long-run market share appears to differ more substantially when analyzed at a granular level (e.g., at the ZIP code level).
- ZIP code-level forecasts seem possible with reasonable accuracy.
- Market share solar PV as a percent of total homes is about 50% higher in non-DAC ZIP codes (6% vs. 4% market share).
- Owner occupancy is a key attribute in explaining the differences between DAC and non-DAC solar PV market adoption.
- Statewide analysis of Non-DAC and DAC ZIP codes generates close fit between simulated and actual.

Recommendations

The project team recommends that SDG&E not commercially adopt these methods and tools at this juncture, without more foundational work being done first. Based on the pre-commercial demonstration results and findings in this project, the following actions by SDG&E or other stakeholders are recommended as steps toward commercial adoption of the demonstrated methods and tools.

- Improve SDG&E's existing zip-code based Bass diffusion technique with refinements for the long-run market share parameters based on significant customer attributes.
- Improve certain model inputs (e.g., historical PPA prices, kilowatt-hour production, technical suitability due to shading and orientation, price sensitivity, and correlation between homeownership and credit scores).
- Leverage the same or equivalent methodology to evaluate solar PV adoption for other specific segments of interest and potentially individual customer analysis, including but not limited to: commercial and industrial customers, low-income customers, and customers on distribution feeders that are capacity constrained or at risk for reverse power flow.
- Adapt the methodology for use in forecasting adoption of other DER types.
- Consider utilizing a customer discrete choice survey approach to facilitate independent estimation of both the long-run market share parameters and the Bass diffusion coefficients.

Table of Contents

Executive Summary ..... **iii**

Overview iii

Key Findings and Conclusions iii

Recommendations iv

1. Introduction **1**

1.1 Project Objective 1

1.2 Project Approach 1

1.2.1 Task 1: Formation of the internal SDG&E project team 1

1.2.2 Task 2: Development of a project plan and contractor selection 1

1.2.1 Task 3: Demonstration Activities 2

1.2.2 Subtask 3.1: Literature Review and Methodology Justification 2

1.2.3 Subtask 3.2: Methodology Framework Development 9

1.2.4 Subtask 3.3: Demonstration 11

1.2.5 Subtask 3.4: Disadvantaged Communities Analysis 17

1.2.6 Task 4 – Conduct Data Analysis and Develop Findings and Recommendations 18

1.2.7 Task 5 – Final Report 18

2. Results and Analysis **19**

2.1 Demonstration Activity Results and Analysis 19

2.1.1 Customer Attributes Driving Adoption 19

2.1.2 Data Compilation 19

2.1.3 Random Forest Model 21

2.1.4 Granular Adoption Analysis 23

2.2 Disadvantaged Communities Results and Analysis 32

2.2.1 Customer Attributes Driving Adoption 32

2.2.2 Data Compilation 32

2.2.3 Machine Learning Models 33

2.2.4 Statistical Analysis Results 35

2.2.5 DAC vs. Non-DAC Adoption Analysis 37

2.3 Assumptions 38
3. Key Findings 39
4. Recommendations and Next Steps 41
5. Metrics and Value Proposition 42
5.1 Metrics 42
5.2 Value Proposition 42
6. Technology Transfer Plan 43
6.1 SDG&E Technology Transfer Plans 43
6.2 Adaptability to Other Utilities and Industry 43
7. References 44

Figures

Figure 1. Task 3 Demonstration Activities Summary 2
Figure 2. Adoption Forecasting Methodology for SDG&E 10
Figure 3. Ensemble Model: Example for Regression 13
Figure 4. Illustrating Difference Between Rate of Diffusion and Long-Run Market Share 14
Figure 5. Illustration of a Calibration of Bass Diffusion Coefficients – Comparison of Actual Historical vs. Model Simulated Adoption 15
Figure 6. Logit Market Share Model 16
Figure 7. NEM Installation Percentage by ZIP Code 20
Figure 8. Incremental and Cumulative MW Installed in Modeled ZIP Codes – Demo Results 21
Figure 9. Random Forest Estimation Error Distribution for Percentage of Households with NEM Installations 22
Figure 10. Variable Importance Plot – Estimating Percentage of NEM Installation Households 23
Figure 11. Model Simulated vs. Actual PV Installed – Statewide Coefficients Only 24
Figure 12. Simulated Cumulative Adoption (2009-2017) for all 118 SDG&E ZIP Codes – Statewide Coefficients Only (Held Constant Across All ZIP Codes) 25
Figure 13. Model Simulated vs. Actual PV Installed – Adding Customer Attribute Coefficients 27
Figure 14. Simulated Actual Cumulative Adoption (March 2017) for all 118 SDG&E ZIP Codes – Adding Customer Attribute Coefficients 27
Figure 15. Model Simulated vs. Actual PV Installed 29
Figure 16. Simulated vs. Actual Cumulative Adoption (in March 2017) for all 118 SDG&E ZIP Codes – Adding ZIP Code-Specific Coefficients 29
Figure 17. Monthly Simulated vs. Actual Cumulative Adoption (January 2009 – March 2017) for all 118 SDG&E ZIP Codes – Adding ZIP Code-Specific Coefficients 30
Figure 18. Simulated vs. Actual Cumulative Adoption over Time – ZIP Codes 92020, 91977, 91910, and 91906 31
Figure 19. Simulated vs. Actual Monthly Incremental Adoption over Time – ZIP Codes 92020, 91977, 91910, and 91906 32
Figure 20. NEM Installation Percentage, by DAC ZIP Codes 33
Figure 21. Random Forest Attribute Variable Importance – DAC ZIP Codes 34
Figure 22. Random Forest Estimation Error Distribution for Percentage of Households with NEM Installations 35
Figure 23. Percentage of Owner Occupied Homes and Market Share Attributes 36
Figure 24. Remaining Four Attributes 37
Figure 25. Comparison of DAC and non-DAC Adoption: Simulated vs. Actual 38

Tables

Table 1. BDCM Key Inputs and Outputs 10
Table 2. Public Data Sources Used for this Demonstration 12
Table 3 Additional Public Data Sources Used for DAC Demonstration 17
Table 4. Random Forest Estimation Error Quartiles and Mean Percentage of Households with NEM Installs 22
Table 5. Key Customer Attributes 23
Table 6. Random Forest Estimation Error Quartiles and Mean Percentage of Households with NEM Installs 35

List of Acronyms

BDCM	Bass Diffusion System Dynamics Causal Model
CART	Classification and Regression Tree
CTree	Conditional Tree Inference
DAC	Disadvantaged Communities
DER	Distributed Energy Resources
DG	Distributed Generation
DGStats	Distributed Generation Statistics
DR	Demand Response
EE	Energy Efficiency
EPIC	Electric Program Investment Charge
EV	Electric Vehicle
IOU	Investor-Owned Utility
kWh	Kilowatt-Hour
LCOE	Levelized Cost of Electricity
MASH	Multi-Family Affordable Solar Housing
ML	Machine Learning
MW	Megawatt
NEM	Net Energy Metering
NREL	National Renewable Energy Laboratory
PG&E	Pacific Gas & Electric
PPA	Power Purchase Agreement
PV	Photovoltaic
SASH	Single Family Affordable Solar Housing
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
T&D	Transmission and Distribution
TPO	Third-Party Owner
ZIP	Zone Improvement Plan

1. Introduction

1.1 Project Objective

The objective of EPIC-2, Project 6 (Collaborative Programs in RD&D Consortia) is to accomplish highly leveraged demonstration work through industry collaborative R&D organizations. The leveraging includes both prospective financial leveraging via co-sponsorship by other members of the collaborative, and intelligence leveraging by better informing the project content in EPIC activities with the knowledge of relevant activities occurring in a worldwide sense. The focus of this project module was to identify methodologies and tools for determining the primary drivers for residential photovoltaic (PV) adoption, predict residential PV adoption over time, and to demonstrate selected methods on a use case (e.g., propensity to adopt PV on the ZIP code [1] level). The effort also developed recommendations about whether or not to adopt all or some of the methods and tools on a commercial basis. The project team focused specifically on residential sector PV market adoption, envisioning that—depending on the degree of success in the demonstration—the methods and tools might someday be applicable to other areas, such as energy efficiency (EE), demand response (DR), non-PV distributed generation (DG), storage, electric vehicles (EVs), and microgrids. Additionally, the project team conducted machine learning analytics on Disadvantaged Communities (DAC) ZIP codes and evaluated the difference in propensity to adopt solar PV between DAC and other ZIP codes.

1.2 Project Approach

The project demonstrated tools and methodology for forecasting the propensity for customer adoption of DER in various parts of the SDG&E service territory. The major tasks were:

- Task 1: Formation of an internal SDG&E project team
- Task 2: Development of a project plan and contractor selection
- Task 3: Perform demonstration activities
- Task 4: Prepare comprehensive final report (draft for review and final version)
- Task 5: Final Report

1.2.1 Task 1: Formation of the internal SDG&E project team

Objective: Engage expertise needed to provide technical support.

Approach: An internal team consisting of engineers from the project's stakeholder groups within SDG&E was formed.

Output: A project team with structure and assignments.

1.2.2 Task 2: Development of a project plan and contractor selection

Objective – Prepare a detailed work plan, competitively procure a qualified contractor, and conduct a kickoff meeting with the selected contractor.

Approach – The internal team met with stakeholders within SDG&E and incorporated their inputs into the project plan. The project team carefully selected the data provided to the contractor, without disclosing proprietary and sensitive customer information. The team collaborated on finalization of the project plan.

Output – Procurement of contractor and completed project plan.

1.2.1 Task 3: Demonstration Activities

Figure 1 below describes the sub-tasks undertaken in Task 3 to demonstrate Methodology and Tools for Estimating Propensity for Customer Adoption of Photovoltaics.

Figure 1. Task 3 Demonstration Activities Summary



Based on the results of the demonstration, the project team identified challenges, recommendations, and next steps for future research.

1.2.2 Subtask 3.1: Literature Review and Methodology Justification

1.2.2.1 Objective

Conduct a literature review designed to provide a broad perspective on the methods, tools, and data necessary for distributed energy resource (DER) predictive analytics and adoption, with a specific focus on solar PV adoption by residential customers. The goal of this literature review was to provide both a theoretical and practical foundation to select a methodology, highlighting the benefits of machine learning-based enhancements to causal models.

1.2.2.2 Approach

The project team's literature review considered both academic and industry sources and focused on the following components:

- **Causal models**. Causal models are defined as the class of methods with closed functional forms/algebraic equations defining customer propensities and adoption forecasts. The project team has observed that the energy industry uses these types of models extensively for both EE and DER adoption. Examples include discrete choice models that provide a long-run probability of customer adoption (e.g., an equilibrium) and diffusion of innovation/bass models that explain the time dynamics and adoption path to that equilibrium.
- **Machine learning models**. Machine learning models are defined as a class of methods by which the functional form equations defining the relationships between input and output variables may not be known a priori and are instead learned through a training process. Multiple industries use these types of models to discover correlations between data and observed product adoption behaviors that might otherwise be missed.
- **Combined methods**. Both academic and industry researchers are working on techniques to combine causal and machine learning methods. Although this research remains in its infancy, early results suggest that causal models can be enhanced by data-driven, machine learning techniques.

1.2.2.2.1 Causal Models

The most common causal modeling paradigm for developing new technology adoption forecasts combines seminal theoretical constructs from the fields of economics and marketing science:

- **Consumer utility theory and discrete choice analysis.** Nobel Economics Laureate Daniel McFadden and others developed a class of consumer preference models fully consistent with rational consumers maximizing utility behavior over a discrete set of alternatives, and where the analysis outcome represents each alternative as probability of selection. Discrete choice analysis has been employed over the last 40 years to a variety of problems including transportation mode choice, energy forecasting and the choice of end-use systems and fuels, and existing and new product forecasting across a range of industries. As discussed further below, the key common feature of these models is that probabilities of selections are easily translated into market shares and product sales.

- **Diffusion of innovations and the Bass diffusion model.** Although discrete choice analysis provides a powerful theoretical and practical backbone for estimating long-run or equilibrium market shares of products and services, the modeling outcomes are largely time-invariant. Fortunately, Frank Bass and his colleagues in the marketing science field developed the Bass diffusion model to simulate the S-shaped approach to equilibrium that is commonly seen for technology adoption. In this model, market potential adopters flow to adopters through two primary mechanisms: adoption from external influences such as marketing and advertising, and adoption from internal influences, or word of mouth. The Bass diffusion model was first used to model the adoption of color TVs in the 1960s and has been used to forecast a broad variety of new technologies including computers, wireless telephones, smartphones, and now solar PV and other DER.

1.2.2.2.2 Consumer Utility Theory and Discrete Choice Analysis

Central to robust causal models is characterizing market share through established methodologies. This section summarizes key literature related to random utility theory and methods (such as discrete choice analysis) that can be used for market share parameter estimation.

- **D. McFadden. "Economic Choices," presented at the Prize Lecture, Stockholm, Sweden, Dec. 8, 2000. [2]**

  In his acceptance of the Nobel Prize in Economic Science, McFadden gave a lecture that discussed the "microeconomic analysis of choice behavior of consumers who face discrete economic alternatives." The theoretical basis for discrete choice analysis, McFadden describes the history, development, and application of the multinomial logit model, a means by which to determine the probability of choosing one alternative over others given their utility as characterized by their measurable attributes.

  The project team modeling approach employs the logit formulation developed and described by McFadden in its calculation of the long-run market share of solar PV. The construct is particularly suitable for this application, where the study endeavors to obtain more granular forecasts by identifying key customer attributes, which are readily incorporated into a logit market share formula.

- **M.E. Ben-Akiva, S.R. Lerman. Discrete Choice Analysis: Theory and Application to Travel Demand. Cambridge, MA: The MIT Press, 2006. [3]**

  In this work, the authors bring together the research of many to provide a comprehensive overview of discrete choice analysis, which they define as "the modeling of choice from a set of mutually exclusive and collectively exhaustive alternatives." Using transportation demand forecasting as their case study, the authors detail the theories of individual choice behavior, aggregate forecasting techniques, the nested-logit model, and multinomial choice models (among others) with an emphasis on their application to real-world policy planning.

  Past studies conducted by the project team have utilized the discrete choice analysis techniques described in this seminal textbook to estimate the coefficients of its logit market share model. Though this study does not involve a discrete choice analysis component, the project team adapted some of the techniques described in this work are adapted to estimate the coefficients of each customer attribute within its logit model.

- **L. O'Keeffe. "A Choice Experiment Survey Analysis of Public Preferences for Renewable Energy in the United States," Journal of Environmental and Resource Economics at Colby, vol. 01, 2014. [4]**

  In this paper, the author utilizes choice experiment surveys to analyze public preferences for the features of various renewable energy projects. Conditional and mixed multinomial logit models were used to determine the estimates for the important attributes of a project, such as price. The results of the study indicate that while consumers are sensitive to increases in the price of electricity, they also are willing to pay more for projects that are associated with reducing environmental costs.

1.2.2.2.3 Diffusion of Innovations and the Bass Diffusion Model

This section provides the more relevant and seminal papers related to diffusion modeling, with a focus on the Bass diffusion model, which is the method used in this study.

- **F.M. Bass. "A New Product Growth for Model Consumer Durables." Management Science, vol. 15, pp. 215-227, Jan. 1969. [5]**

  Dr. Bass describes the development of his model, which is used to estimate the sales of a product over time. The model assumes that the probability of adoption at any point in time is related to the number of previous adopters. More specifically, Dr. Bass describes the population of potential adopters as either innovators or imitators: innovators being those who will be the first to adopt, and imitators those who adopt based on the signal that those around them are adopting the product.

  The Bass diffusion construct has been applied in scores of studies since its publication in 1969 and was reprinted in 2004 after being identified by *Management Science* as among the Top 10 Most Influential Papers published in the 50-year history of *Management Science*. [6]

- **J.D. Sterman. "The Bass Diffusion Model," in Business Dynamics: Systems Thinking and Modeling for a Complex World, S. Isenberg, New York: McGraw-Hill, 2000, pp. 332. [7]**

In this chapter of the world's leading textbook on system dynamics, Dr. Sterman, the Director of the System Dynamics Group at the Massachusetts Institute of Technology (MIT), takes the Bass diffusion model and describes a few key concepts that improve upon the original model. One such concept is market growth—Bass assumed the market size remained constant, while Sterman describes incorporating market growth. In addition, Sterman details that the entire population will not be interested in purchasing the product given their sensitivity to price, and thus a fraction willing to adopt multiplier is required to adjust the population to a more accurate market size. Finally, Sterman describes integrating a learning curve that informs how the price of a product changes over time as associated with the number of products produced.

The approach utilized in this demonstration study applies the Bass diffusion model using the system dynamics construct described by Sterman. A key advantage of this construct is that it permits any model input to vary over time, including product attributes such as cost, efficiency, or efficacy as well as exogenous factors such as tax credits or incentives, which can change the calculated long-run market share over time. This feature is particularly relevant in the forecasting of solar PV adoption, whose characteristics, especially cost, are rapidly declining as the technology evolves and whose tax environment is also changing over time.

- **V. Mahajan, E. Muller, and Y. Wind. "Diffusion Models, Managerial Applications and Software," in New-Product Diffusion Models. New York: Springer, 2000, pp. 295-310. [8]**

  This book covers several constructs for new product diffusion models, including the Bass diffusion model. A key aspect of this reference is that the authors have estimated the *p* and *q* coefficients of the Bass diffusion model for dozens of technologies using historical product adoption data. While one must be cautious in extrapolating the data from this analysis, it does give practitioners a reasonable range of estimates as a starting point in any analysis, and the values can be used to bound nonlinear optimization routines used to estimate diffusion parameters in other studies, such as this one.

- **B. Sigrin, M. Gleason, R. Preus, I. Baring-Gould, and R. Margolis. "The Distributed Generation Market Demand Model (dGen): Documentation." Internet: https://www.nrel.gov/docs/fy16osti/65231.pdf. Feb. 2016. [9]**

  The National Renewable Energy Laboratory's (NREL's) Distributed Generation Market Demand model provides an example of how Bass diffusion can be utilized to model technology adoption and diffusion. Specifically, the dSolar module simulates the adoption of solar over time as driven by the economic attractiveness of adopting.

- **A. Agarwal. "A Model for Residential Adoption of Photovoltaic Systems." M.S. thesis, California Institute of Technology, California, 2015. [10]**

  Mr. Agarwal's thesis details the application of Frank Bass' diffusion model to the case of solar PV adoption. The model described in the thesis has the flexibility to allow users to input various rate structures, subsidies, and customer demographics to conform to the service region of interest. In addition, this model was trained on Southern California Edison's residential customer data, which included details such as size and date of PV installations, socioeconomic background of the customer, location, and monthly energy consumption.

1.2.2.2.4 Machine Learning Models

This section provides foundational references to support the project team's specification of machine learning (ML) models in this project. Researchers in statistics, computer science, and other fields have published a significant number of works on ML, especially in the past 25 years. The team selected the three references in this section to offer context for the classification and regression tree (CART[1]) and random forest[2] models that were applied in this EPIC project. The third reference, "Classification and Regression by Random Forest," is the reference that most directly relates to the methodology used in this project. The first reference discusses the theoretical foundation and algorithms from which the project methodology can be traced. The second reference compares several of the algorithms spawned from the development in the first reference and that are used in practice today, including the random forest model used for this project.

- **L. Breiman. Classification and Regression Trees. California: Wadsworth & Brooks/Cole Advanced Books & Software, 1984. [11]**

  The methodology used to construct tree structured rules is the focus of this monograph. Unlike many other statistical procedures, which moved from pencil and paper to calculators, this text's use of trees was unthinkable before computers. Both the practical and theoretical sides have been developed in the authors' study of tree methods. CARTs reflect these two sides, covering the use of trees as a data analysis method and in a more mathematical framework, proving some of their fundamental properties. [12]

- **W.L. Loh. "Fifty Years of Classification and Regression Trees." International Statistical Review, vol. 84, pp. 329-348, 2014. [13]**

  The first publication of a regression tree algorithm was in 1963. This paper highlights many of the popular variants on the original algorithm, which are accessible to researchers today through statistical computing platforms like R. Brief summaries of several of the most used algorithms are provided. The paper provides example modeling applications using each of the algorithms presented, with a comparison of the results. Conclusions are provided that offer guidance on pitfalls and algorithm recommendations under different scenarios.

- **A Liaw and M. Wiener. "Classification and Regression by Random Forest." R News, vol. 2/3, pp. 18-22, Dec. 2002. [14]**

  This paper provides an application-focused overview of random forest methodology and its implementation accessible in R through the random forest package. The paper is concise, at just over four pages, and provides short summaries of the algorithm, its usage in the R package, and recommendations for practical usage. Examples are provided for regression, classification, and unsupervised learning.

[1] A classification and regression tree (CART) is a ML algorithm for estimating a numerical or categorical outcome using explanatory variables, with no specification of the assumed structure of the relationship between the outcome and explanatory variables.
[2] Random forest is a ML algorithm that uses reconciliation from estimates from a large number of CART models on sub-samples of historical outcomes and explanatory variables to improve model fit.

The project team's ensemble modeling approach combines CART and random forests where each tree in the forest is an instance of a CART. These trees are trained from historical adoption data. They discover correlations between adoption and a pool of input features derived from a fusion of company and project team data such as measurements derived from utility billing date (e.g., average peak load, baseline load, total daily load, etc.), and different consumer attributes packaged in the project team solution (e.g., demographics, psychographics, premise, and financials). These trees produce adoption profiles that are subsets of key attributes and values that drive varying levels of adoption propensity at the individual customer level.

1.2.2.2.5 Combined Models

The combination of causal methods and ML is a relatively new field of study. The approach employed by the project team in this demonstration project expands upon the approaches previously employed and documented in literature, and appears to be novel in its application of integrating ML with a Bass diffusion and logit modeling construct in forecasting solar PV adoption. This section describes key papers where both causal modeling and ML methods have been applied together.

- **S. Athey and I. Guido. "Machine Learning Methods for Causal Effects." Internet: www.nasonline.org/programs/sackler-colloquia/documents/athey.pdf. 2015. [15]**

  This presentation details the development of a combined causal and ML model as part of a paper that is still a work in progress. The authors present their foundation for developing a new means of estimation that combines a causal approach with machine learning for the prediction component of models, with an emphasis on distinguishing between the causal and predictive parts of the model.

- **P. Bajari, D. Nekipelov, S. Ryan, and M. Yang. "Demand Estimation with Machine Learning and Model Combination." National Bureau of Economic Research, 2015. [16]**

  To develop a tool that would assist econometricians in estimating demand based on large observational datasets, the authors compare statistical analysis methods commonly used to model consumer behavior with the causal methods used in econometric models. They propose a model combining the ML and econometric methods via a weighted linear regression, which was shown to improve the accuracy of a sample prediction of sales data pertaining to salty snacks.

A key element of the modeling approach is the rigor with which the project team assesses the economics of solar PV. The approach selected employs a discounted cash flow optimization model that can evaluate the economics of a solar PV system from the perspective of both the customer and a third-party owner (TPO).[3] [17] A key factor in the rapid uptake of solar PV in the recent past has been the removal of the upfront cost purchase barrier through TPO in combination with a lease, or power purchase agreement (PPA), contract structure. Though the pendulum of system ownership appears to be swinging back toward

[3] "Third-party financing is a well-established financing solution in the United States, having emerged in the solar industry as one of the most popular methods of solar financing. Third-party solar financing predominantly occurs in two forms: solar leases and power purchase agreements (PPAs) In the lease model, a customer signs a contract with an installer/developer and pays for the use of a solar system over a specified period of time, rather than paying for the power generated. In the PPA model, the solar energy system offsets the customer's electric utility bill, and the developer sells the power generated to the customer at a fixed rate, typically lower than the local utility." www.epa.gov/repowertoolbox/understanding-third-party-ownership-financing-structures-renewable-energy.

customer ownership, TPO is expected to continue to play a large role in the adoption of distributed solar PV and thus, must be accounted for in a rigorous adoption model; however, any ownership construct (cash purchase, financed, TPO) could be calculated in this model. Discounted cash flow techniques are not new, though their application to forecasting solar PV and their ability to help explain pricing strategies of TPO system providers is particularly relevant in the solar PV technology space.

- **F. Stermole and J. Stermole. Economic Evaluation and Investment Decision Methods. Investment Evaluation Corporation, 2012. [18]**

  This textbook provides a comprehensive overview of how to perform economic evaluation under many different scenarios. Using examples with respect to industries such as oil & gas, mining, and energy, this textbook provides the fundamentals of computing discounted cash flows.

- **Navigant Consulting, Inc. *Solar Project Return Analysis for Third Party Owned Solar Systems.* 2016. [19]**

  As part of the analysis performed to evaluate the TPO solar PV leasing business model in Arizona, Navigant utilized its RE-SIM™ model to conduct discounted cash flow analysis and to compare the economics of TPO systems in different service territories. The cash flow streams accounted for in this analysis included initial capital outlay, debt-financing cash inflow and interest payments, incentives, accelerated depreciation for tax purposes, Federal Investment Tax Credit benefits, and much more. The RE-SIM model is a nonlinear optimization model with the objective to minimize the lease or PPA rate within the bounds of the constraints. The analysis conducted in this study helped to shed light on pricing strategies of TPO PV providers, which is critical to understanding the impact of forecast cost declines or tax credit changes and to forecast product adoption. This study was submitted as part of formal written and oral testimony in the 2016 UniSource Electric rate case (Docket Number E-04204A-15-0142).

- **U. Benzion and J. Yagil. "Decisions in Financial Economics: An Experimental Study of Discount Rates," Advances in Financial Economics, M. Hirschey, J. Kose, A.K. Makhija, Eds. United Kingdom: Emerald Group Publishing, 2002, pp. 19-40. [20]**

  The authors perform an experimental study involving individuals of varying economic understanding, finding that implicit discount rates decrease as the time horizon or monetary sum decrease. In addition, they find that implicit discount rates approach market interest rates as the economic understanding or formal education of the subjects increases.

  Their results also indicate that across all combinations of the subject's education, monetary sum, and time horizon, people tend to have inherently high implied discount rates. These high implied discount rates are captured in the approach used for this demonstration project, which allows for sensitivity analyses to be performed around variables such as customer discount rate, incentive levels, and payback period as well as the resulting adoption of solar PV.

1.2.2.3 Outcome

After careful review of the literature cited above, the project team identified the methodological framework to be demonstrated in this project using combined methods. The project team chose to use a Bass diffusion system dynamics causal model (BDCM) to demonstrate the methodological framework.[4] While multiple options exist for forecasting adoption of any product over time, this approach combines several well-established techniques, including Bass diffusion, random utility theory, and system dynamics causal modeling, and provides a robustness and flexibility not present in more simplistic approaches (e.g., regression of a logistic curve). When combined with more recently developed ML algorithms, which can identify those attributes that are most salient, the methodology offers even greater potential to provide comparatively accurate granular adoption forecasts (e.g., at the ZIP code level or possibly lower if more granular data is provided).

1.2.3 Subtask 3.2: Methodology Framework Development

1.2.3.1 Objective

Leveraging the literature review, develop a methodological framework to model customer propensity to adopt PV systems.

1.2.3.2 Approach

This section provides a high-level overview of the methodology selection process for this demonstration study. The BDCM model uses a discrete choice market share approach in conjunction with a calibrated Bass diffusion model to forecast the adoption of PV or other DER technologies. The approach considers situations in which a consumer selects one option from a finite set of alternatives (e.g., the TPO solar PV business model presents a choice between two rates of electricity to consumers). In the discrete choice portion of the framework, the decision maker chooses the solution that maximizes a utility function that depends on several economic and non-economic attributes.

The BDCM model components simulate the S-shaped approach to equilibrium that is commonly seen for technology adoption. In this classic application of the Bass model, market potential adopters flow to adopters through two primary mechanisms: adoption from external influences such as marketing and advertising, and adoption from internal influences or word of mouth. Table 1 provides a high level summary of the key inputs and outputs of BDCM. Table 1 provides a stock/flow diagram illustrating the causal influences underlying the BDCM model, along with typical examples of adoption S-curves.

[4] Navigant Consulting, Inc.'s proprietary RE-SIM™ model that uses a discrete choice market share approach in conjunction with a calibrated Bass diffusion model to forecast the adoption of PV or other DER technologies.

Table 1. BDCM Key Inputs and Outputs

Key Inputs	Key Outputs
• Technology cost and performance forecast • Electricity prices and utility offset rates • Utility incentives, state and federal tax credits • Historical installed capacity, building stocks, consumption • Market diffusion parameters and consumer sensitivity • Eligibility constraints (homeownership rates, PV access factors, etc.)	• Levelized cost of energy • Levelized value of electricity • Price response curves • System-level technical and market potential forecast • Potential as a percentage of sales • Calibrated (through back-casting) market diffusion parameters

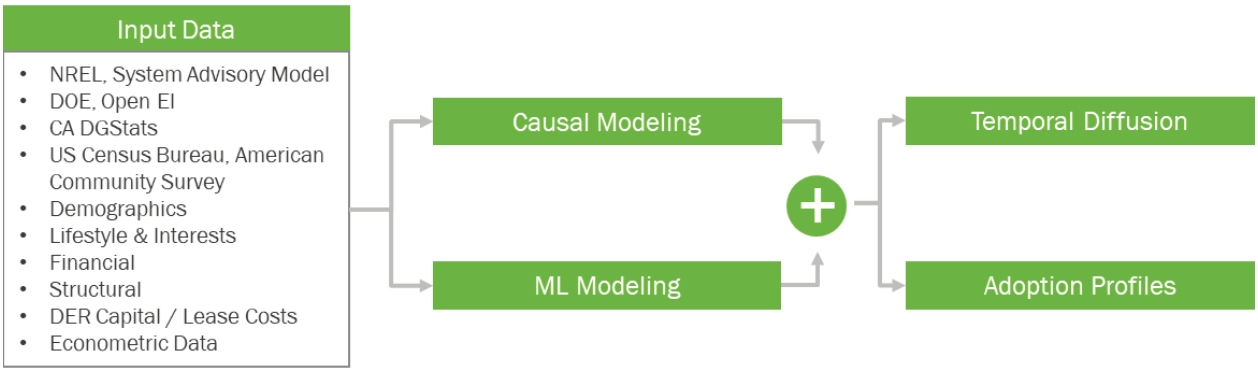
1.2.3.2.1 Adoption Forecasting Model

The adoption forecast model combines the BDCM model and the ML method to create additional value for customer analytics. This joint modeling approach augments the well-established discrete choice causal models that are largely driven by subject matter expertise, with additional adoption information that is automatically discovered through a data-driven and ML process. The net effect of this approach, depicted in Figure 2, provides a more accurate market potential estimate, along with additional insights gained from customer-specific adoption propensities. The synthesis of ML and BDCM occurs through fine-tuning the long-run market share calculations in BDCM with ZIP code-level customer characteristics from ML. More specifically, the non-economic attributes are further delineated by the important attributes identified by ML.

1.2.3.3 Outcome

The results of this framework identification solidified the approach used for the demonstration and identified key inputs and outputs of the model.

Figure 2. Adoption Forecasting Methodology for SDG&E



1.2.4 Subtask 3.3: Demonstration

1.2.4.1 Objective

The goal of this task was to demonstrate the methodology framework developed using San Diego Gas & Electric (SDG&E) data.

1.2.4.2 Approach

1.2.4.2.1 Demonstration Use Case

As a use case, the project team forecasted solar PV adoption at a ZIP code level, for all ZIP codes specific to SDG&E (118 ZIP codes). Specifically, the project team utilized the California Distributed Generation Statistics Currently Interconnected Data Set [21], with *App Received Date* serving as the proxy for the installation date of the net energy metered (NEM) systems. The project team modeled solar PV adoption for the residential sector in each of the applicable ZIP codes over a 20-year time horizon (1998-2017). The ML analysis identified the key customer attributes that factor most prominently into PV adoption, accounting for all NEM installations across the investor-owned utility (IOU) territories in California. Using the larger dataset for the ML component of the analysis, as opposed to only the SDG&E ZIP codes, facilitated a better understanding of which customer attributes factor most prominently into adoption of solar PV. This is because it provides additional variation in the candidate model covariates for the ML models to train on from the more than 1,000 additional ZIP codes in the Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) service territories.

1.2.4.2.2 Data Sources

The demonstration use case does not rely on any granular or customer-level data from SDG&E. Rather, the project team utilized publicly available data in concert with data from other studies conducted by the project team in other jurisdictions, which, in some cases, may be proprietary. Any proprietary data utilized demonstrated the methodology and output but was not provided in raw form to SDG&E as part of any deliverable. Table 2 provides a list of the public data used for this demonstration.

Table 2. Public Data Sources Used for this Demonstration

Data	Source	Usage in Model
Solar PV Net Metering Interconnection	California Distributed Generation Statistics, http://www.californiadgstats.ca.gov/downloads/	To calibrate diffusion and market share parameters and to compare historical adoption[5] with simulated adoption
Residential Load Profiles	US Department of Energy, Open EI, https://openei.org/doe-opendata/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states	Not used in the model—used to calculate residential offset rate in SDG&E territory
Solar PV System Production	NREL, System Advisory Model, https://sam.nrel.gov/	Not used in the model—used to calculate residential offset rate in SDG&E territory
American Community Survey	US Census Bureau, https://factfinder.census.gov/	To compile ZIP code-level demographic attributes, which served as candidate covariates in the ML models
2010 Decennial Census	US Census Bureau, https://factfinder.census.gov/	To estimate households by ZIP code
California Energy Commission	Building Climate Zone by ZIP Code, http://www.energy.ca.gov/maps/renewable/BuildingClimateZonesByZIPCode.pdf	To map climate zones to ZIP code
State of California Dept. of Finance	P1: State Population Projections (2010-2060), http://www.dof.ca.gov/Forecasting/Demographics/projections/	To forecast 2010 Census Data through the 2017 calibration period

1.2.4.2.3 Parameter Development

The project team determined which model parameters/coefficients were assumed to be fixed versus which parameters were solved for using available data to calibrate the model (e.g., using nonlinear optimization techniques). The project team estimated key model parameters by leveraging information from other analyses, publicly available data, and proprietary datasets regarding customer attributes in each ZIP code. The project team approach for estimating key model parameters is detailed in the following sections.

Key Customer Attributes

In this project, the primary purpose of ML was to discover the most important attributes that drive PV adoption at the ZIP code aggregate level. The project team tuned the model settings to distill the attributes that were most important for defining PV adoption propensity, along with the structural relationship between those attributes. ML models in the CART family are well-suited for this project because it is not well known which consumer attributes are associated most with PV adoption. ML

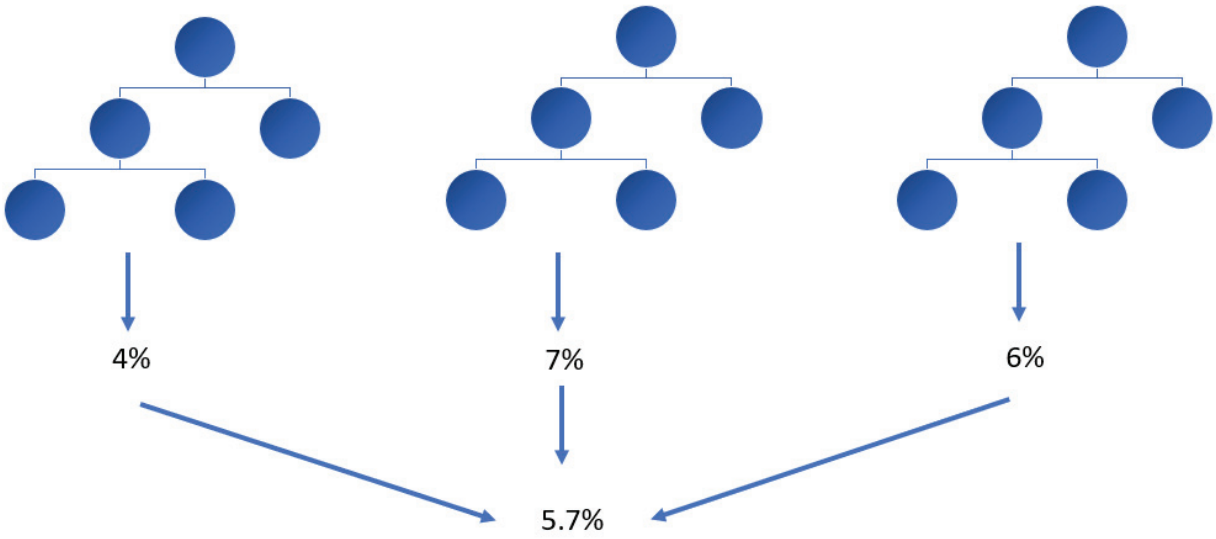
[5] The team used the *Application Received* date for the time field, though future analysis should use the *Application Complete* date, which is time lagged by about a month relative to the *Application Received* date.

algorithms are an efficient means for discovering those attributes, especially when missing values are not prevalent in the analysis of the ZIP code-level data. Random forest ensemble modeling offers robust identification of the most important attribute drivers compared with single models that risk overfitting to the data. The suitably large number of ZIP codes in California IOU territories makes the subsampling aspect of the random forest algorithm appropriate.

The project team used random forest ML models in this demonstration, where each tree in the forest is an instance of a regression tree for predicting the proportion of customers in a ZIP code that have net meters installed for PV systems, a continuous variable. These trees are trained from historical adoption data, discovering correlations between adoption and a pool of input features derived from a fusion of Census Bureau and project team customer attribute data (e.g., demographics, psychographics, premise physical characteristics, and financials).

Figure 3 illustrates the prediction from multiple trees in an ensemble being aggregated and reconciled into a single estimate.

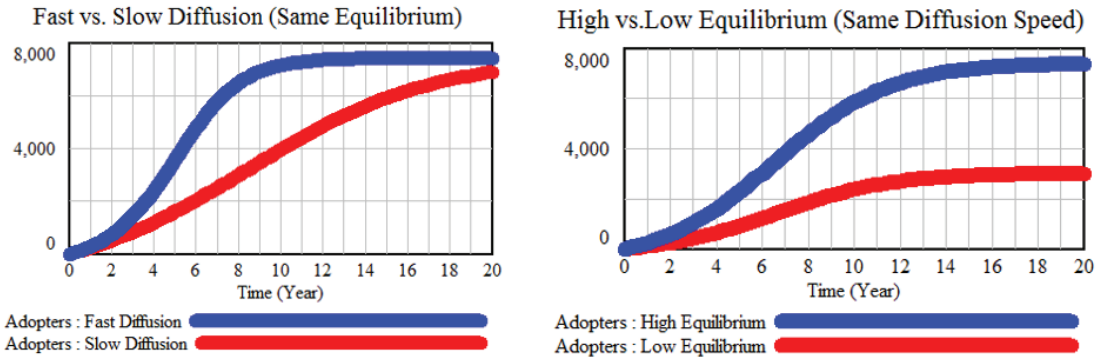
Figure 3. Ensemble Model: Example for Regression



Adoption Parameters

Estimating PV adoption using the enhanced Bass diffusion model can be broken into two parts: calculating long-run market share and the rate at which the long-run market share is achieved over time. The left graph in Figure 4 illustrates two adoption profiles approaching the same long-run market share but at different rates of diffusion, which are governed by the *p* and *q* parameters of the Bass diffusion model (there are also referred to as marketing effectiveness and work of mouth strength in the BDCM adoption model). In contrast, the right graph in Figure 4 illustrates two adoption profiles with different long-run market share but constant rates of diffusion (i.e., constant Bass diffusion coefficients).

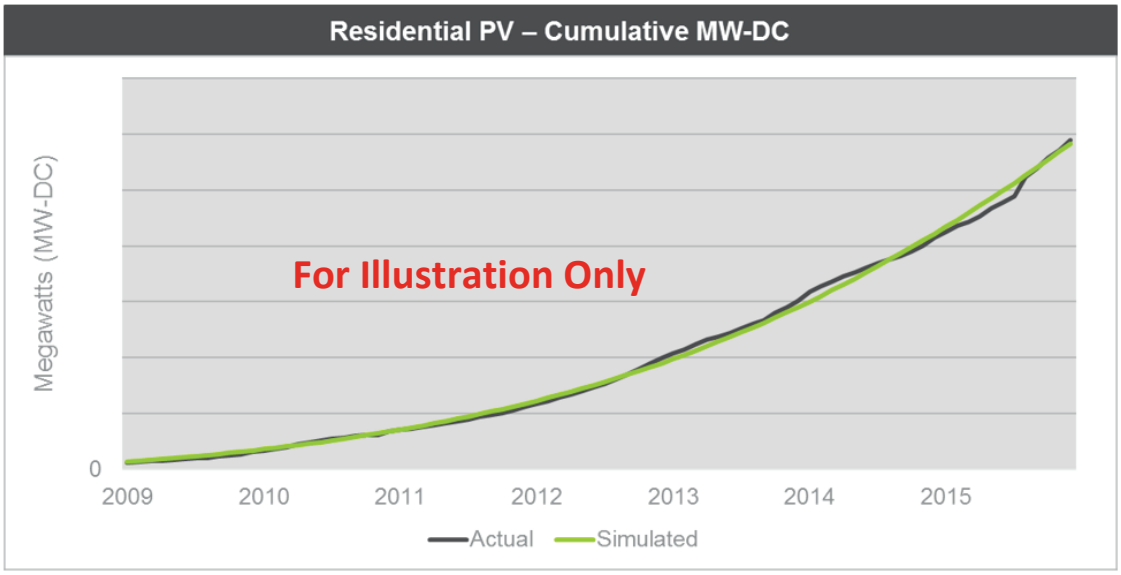
Figure 4. Illustrating Difference Between Rate of Diffusion and Long-Run Market Share



Unless the population is sufficiently far along in the adoption S-curve (e.g., past the inflection point of adoption), it is typically impossible to simultaneously estimate both the long-run market share and the Bass diffusion coefficients using historical data alone. This is because an infinite combination of coefficients tends to yield equally good data fits. As such, one must typically fix one set of parameters while calibrating the coefficients of the other.

The literature review revealed multiple cases that utilized a fixed functional format for calculating long-run market share (informed through a combination of means, including but not limited to discrete choice analysis), typically using a logit market share model. The project team calibrated the Bass diffusion coefficients of marketing effectiveness and word of mouth strength (the *p* and *q* in the Bass model) through nonlinear optimization techniques to achieve the best possible fit for simulated and historical adoption. Figure 5 is for demonstration purposes only and illustrates a diffusion coefficient calibration, showing a close fit between historical adoption and simulated adoption in the residential sector of a utility service territory. This calibration process entailed adjusting Bass diffusion coefficients through nonlinear optimization to minimize the absolute value of the difference between simulated and actual adoption totaled over each month of the simulation forecast.

Figure 5. Illustration of a Calibration of Bass Diffusion Coefficients – Comparison of Actual Historical vs. Model Simulated Adoption



In this demonstration, the project team was primarily interested in fine-tuning the long-run market share calculations to facilitate obtaining a more granular forecast of spatial adoption, in this case by ZIP code. The project team sought to maximally leverage information obtained through similar studies conducted by the project team in California and Arizona and to calibrate coefficients of the logit long-run market share model and the diffusion model. The approach seeks to marry the granular data and ML methods with causal Bass diffusion modeling without having to resort to more costly analysis approaches such as executing customer discrete choice analysis surveys. The survey approach could be used in future analyses to facilitate independent estimation of both the long-run market share parameters and the Bass diffusion coefficients; however, it was outside the scope of this demonstration.

Logit Long-Run Market Share Coefficients

The functional format of the binary logit model used to estimate long-run adoption of solar PV in a utility service territory is illustrated in Equation 1.

Equation 1. Binary Logit Market Share Model

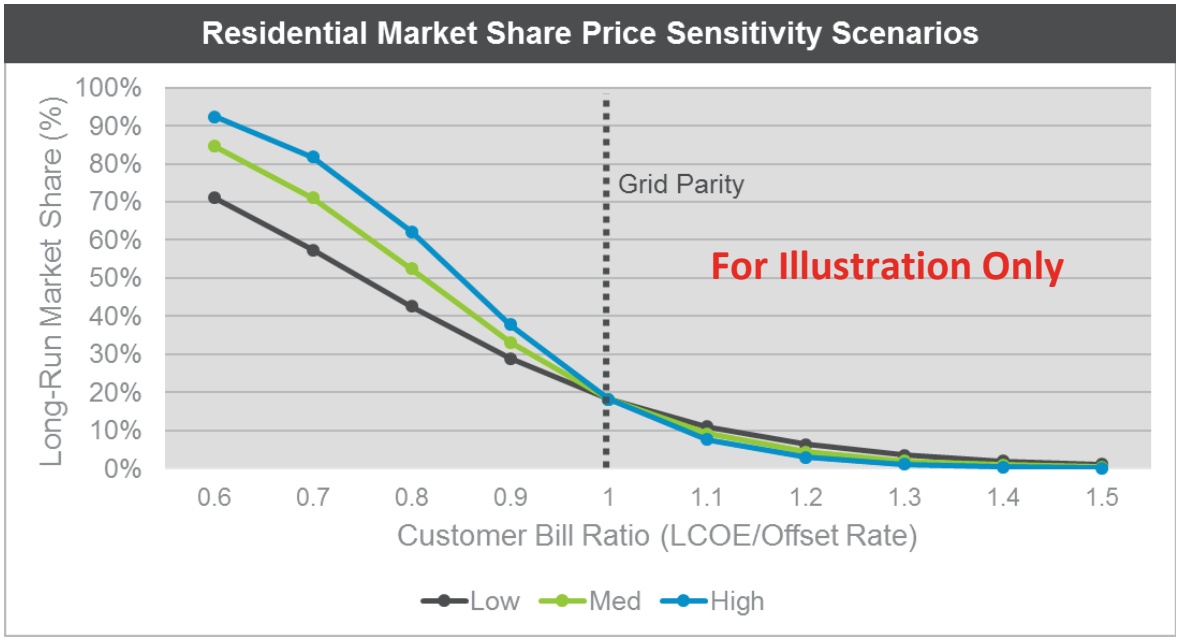
$$Long\ Run\ Solar\ PV\ Market\ Share = \frac{1}{1 + e^{(\alpha + \beta \cdot Price\ Ratio)}}$$

Where, the price ratio was calculated to be the ratio between the lease rate, or PPA rate—typically calculated as a levelized cost of electricity (LCOE)—that could be offered by a TPO of a PV system and the utility's electricity offset rate for a customer with a PV system installed.[6]

[6] Utility offset rates ($/kWh) are defined as the dollar value of a customer's bill reduction for each kilowatt-hour generated by the customer's solar system. It is the amount of their bill that is offset for each kilowatt-hour generated (hence the term). In other words, it is the amount a customer saves on their utility bill.

The shape of the above logit market share model was like the illustrative graphic, demonstrating three separate β coefficients.

Figure 6. Logit Market Share Model



In this demonstration, the project team utilized a logit market share model by expanding the α coefficient, sometimes referred to as an alternative specific coefficient, to include the top four to six customer attributes identified by the project team's ML analysis.

Thus, the project team further disaggregated the α coefficient (sometimes referred to as an intercept term) as follows in Equation 2, holding the price coefficient constant.

Equation 2. Disaggregation of the Intercept Term

$$\propto = \propto_0 + \propto_1 \cdot \boldsymbol{Attribute_1} + \propto_2 \cdot \boldsymbol{Attribute_2} + \propto_3 \cdot \boldsymbol{Attribute_3} + \cdots$$

The project team applied statistical methods to calculate the best fit for each of the disaggregated α coefficients using the combination of the following by ZIP code: historical adoption, number of households, aggregate customer attributes (e.g., median income), and a scaling factor (calculable using the fixed Bass diffusion parameters). The team used these to account for how far along on the adoption S-curve each ZIP code should theoretically be as a percentage of maximum adoption.

1.2.4.3 Outcome

The outcome of the demonstration is detailed in Section 2.

1.2.5 Subtask 3.4: Disadvantaged Communities Analysis

1.2.5.1 Objective

The goal of the DAC demonstration was to conduct ML analytics on DAC ZIP codes, model DAC ZIP code solar propensity to adopt and compare the results to non-DAC ZIP codes in California.

1.2.5.2 Approach

1.2.5.2.1 Disadvantaged Community Definition

Disadvantaged Communities (DAC) are communities designated by CalEPA, pursuant to Senate Bill 535, using the California Communities Environmental Health Screening Tool (CalEnviroScreen). DAC are identified by census tract and include the tracts that scored at or above 75% in the 3.0 version of the CalEnviroScreen that is available at the time of the EPIC application. [22] For the purposes of this analysis, the project team defined a DAC ZIP code as a ZIP code where >50% of the population lives in census tracts with a CalEnviroScreen 3.0 score > 75%. Using the SB 535 Disadvantaged Communities List, 255 ZIP codes in California meet this criterion; however, only two of these ZIP codes were in SDG&E territory, requiring this analysis to be conducted at the state level.

1.2.5.2.2 Data Sources

The DAC demonstration use case used the same data that was used in the prior subtask, with the additions provided in Table 3.

Table 3 Additional Public Data Sources Used for DAC Demonstration

Data	Source	Usage in Model
List of Disadvantaged Communities	http://www.energy.ca.gov/commission/diversity/definition.html	Used to determine DAC and non-DAC ZIP codes for ML, statistical and propensity to adopt analysis.

1.2.5.2.3 Parameter Development

For the DAC analysis, the project team determined which model parameters/coefficients were assumed to be fixed versus which parameters were derived using available data to calibrate the model (e.g., using nonlinear optimization techniques). Key model parameters were estimated by leveraging information from other analyses, publicly available data, and proprietary datasets regarding customer attributes in each ZIP code. The approach for estimating key model parameters is detailed in the following sections.

Key Customer Attributes

In the DAC analysis, the primary purpose of ML was to discover the most important attributes that drive solar PV adoption at the ZIP code aggregate level, specifically within DAC-designated ZIP codes. Since there were only two ZIP codes in SDG&E territory with a DAC population >50%, the project team applied its ML models to the 171 DAC ZIP codes in the IOU service territories with Census Bureau demographics data were available. As with the primary analysis unrestricted to DAC ZIP codes, CART and random forest ensemble models were used to distill the attributes most strongly linked to PV adoption percentage at the ZIP code level.

Statistical Analysis

The project team ran statistical analyses on the key customer attributes to gain insight into the differences in these attributes in DAC versus non-DAC ZIP codes. Specifically, the team tested the mean difference of the attribute value for statistical significance, and compared the distribution of the attributes across the DAC and non-DAC ZIP codes. In addition, the team also analyzed the percentage of owner occupied homes, and solar PV market share.

Adoption Parameters

The project team employed the same diffusion modeling methodology for the DAC analysis as described in Sections 1.2.3 and 1.2.4. While the construct was the same, the region analyzed differed in that it included all California ZIP codes for which data were available, as opposed to limiting the analysis to the SDG&E service territory. The primary reason for expanding the analysis region was to provide an adequate sample size for both DAC and Non-DAC ZIP Codes (SDG&E's service territory only has twos ZIP codes that met the DAC definition outlined in Section 1.2.5.2.1.). Additionally, the optimization of diffusion parameters aggregated applicable ZIP code adoption data to provide two sets of parameter estimates – one for the aggregation of all DAC ZIP codes and one for the aggregation of all non-DAC ZIP codes.

1.2.5.3 Outcome

The outcome of the DAC demonstration is detailed in Section 2.

1.2.6 Task 4 – Conduct Data Analysis and Develop Findings and Recommendations

1.2.6.1 Objective:

Conduct data analysis and develop findings and recommendations.

1.2.6.2 Approach

The project team performed data analysis and developed results and recommendations on next steps as outlined in Section 4 of this report.

1.2.6.3 Output

Data analysis, findings and recommendations, as provided in Section 3 and Section 4 of this report.

1.2.7 Task 5 – Final Report

1.2.7.1 Objective

Aggregate all findings and compile it into a comprehensive report.

1.2.7.2 Approach

Develop a comprehensive final report based on an agreed-upon outline developed by the team. The project team used results from the demonstration and data analysis to develop the final report. The report was prepared as a draft for review by project stakeholders and then revised into final form, based on the review comments.

1.2.7.3 Output

Comprehensive final report as presented in this document.

2. Results and Analysis

2.1 Demonstration Activity Results and Analysis

The following sections detail the results of each stage of the demonstration activity. As noted in Section 1.2.3, the demonstration plan included the analysis of PV adoption in all ZIP codes across the three California IOU service territories to provide approximately 10 times the ZIP codes of data to train the models that would then be applied to the 118 ZIP codes in the SDG&E service territory.

2.1.1 Customer Attributes Driving Adoption

The project team conducted ML modeling to identify the most important attributes driving adoption at the ZIP code level. This analysis included compiling the analysis data and fitting it to a random forest ML model.

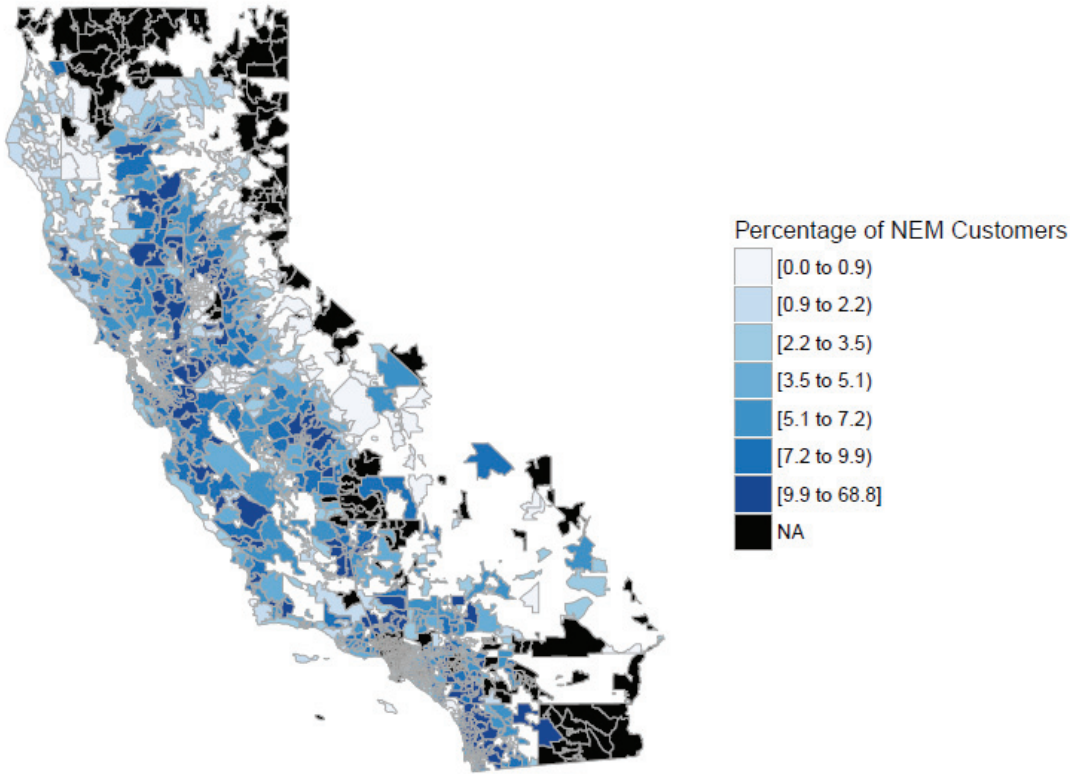
2.1.2 Data Compilation

The project team imported solar PV interconnection data using the California Distributed Generation Statistics (DGStats) NEM interconnections database. [23] This dataset contains a record for each individual NEM solar PV install for customers in all IOU territories (e.g., SDG&E, SCE, and PG&E), using the ZIP code as the most granular customer identifier. The project team filtered the dataset to include only residential customers. The team then aggregated the data to the ZIP code level by month and year for the granular adoption analysis and cumulatively over all the years for the customer attribute analysis.

The project team leveraged demographics and physical attributes available from the US Census Bureau at the ZIP code level, incorporating climate zone identifiers at the ZIP code level from the California Energy Commission to account for weather differences. In total, the team assembled approximately 100 covariates for use in the ML modeling process.

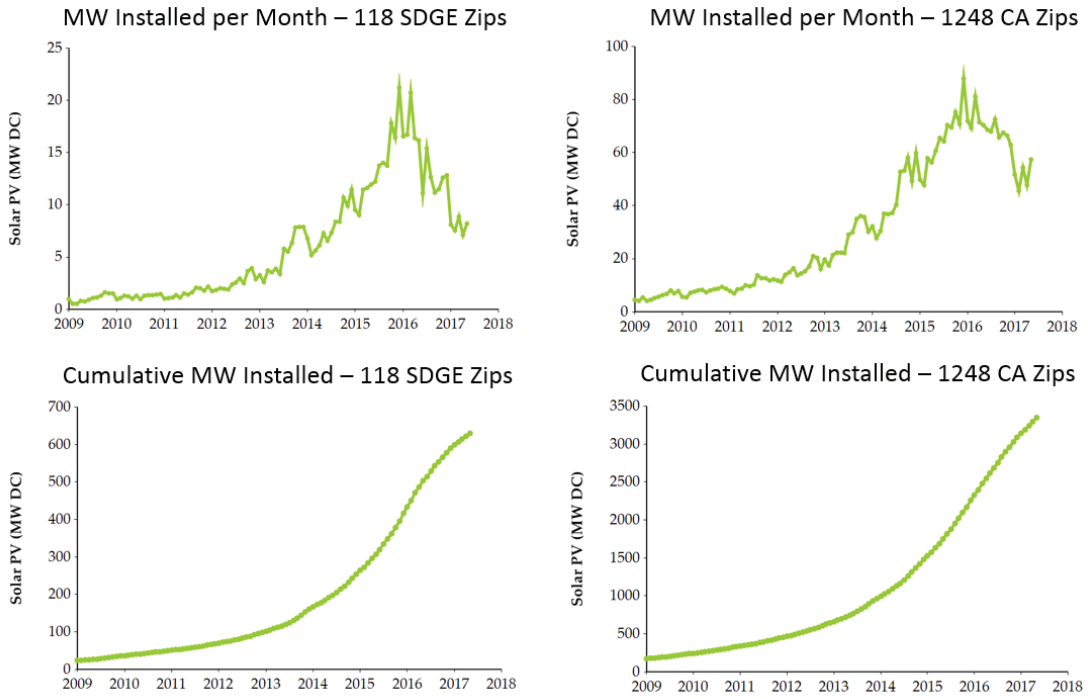
The team converted total NEM installs by ZIP code into the proportion of households to establish a common analysis basis across the ZIP codes, which vary by size. This necessitated identifying ZIP codes that make up the three IOUs in the state to account for ZIP codes without any NEM installs in the DGStats database. The final data preparation step involved filtering the data to include customer demographic data in only those ZIP codes where data is readily available across all fields. The resulting dataset covered 1,248 out of 1,659 ZIP codes represented in the DGStats database and 116 of 118 ZIP codes specific to SDG&E's service territory, as presented in Figure 7. These data represented roughly 12 million homes in California and 1.4 million homes in SDG&E's service territory. The two ZIP codes in the SDG&E territory without an estimate did not have any residential households, according to Census data.

Figure 7. NEM Installation Percentage by ZIP Code



Next, the project team aggregated system installation data by month of install to enable modeling over time rather than for the current snapshot through 2017, as was done for the ML modeling. Figure 8 shows the aggregate adoption data for the 1,248 ZIP codes modeled in California and the 118 ZIP codes modeled in SDG&E's service territory, both on an incremental (i.e., new installations per month) and cumulative megawatt installed basis, including data through the first quarter of 2017.

Figure 8. Incremental and Cumulative MW Installed in Modeled ZIP Codes – Demo Results[7]



2.1.3 Random Forest Model

The project team fit a random forest model consisting of individual CART models applied to each of 500 random subsets of the analysis dataset of California ZIP code NEM installation data and corresponding covariates. The project team chose to use 500 random subsets, which was determined to be sufficient because additional subsamples showed diminishing value to the explanatory power of the model. The resulting model accounted for 48% of the variation in the ZIP code-level proportion of NEM installations across the IOUs and 76% of the variation for the SDG&E ZIP codes.

Figure 9 depicts the random forest error distribution for estimating the proportion of households with NEMs for PV system installations—i.e., the error of the ML model to the actual DGStats data. The green curve shows the distribution of the estimation error for the SDG&E ZIP codes, and the black curve shows the estimation error distribution for other IOUs in California. For both the SDG&E and other IOU ZIP codes, the error distribution is tightly centered around zero.

[7] Historical installation data aggregated from DGStats.com, filtered to include only residential installations.

Figure 9. Random Forest Estimation Error Distribution for Percentage of Households with NEM Installations

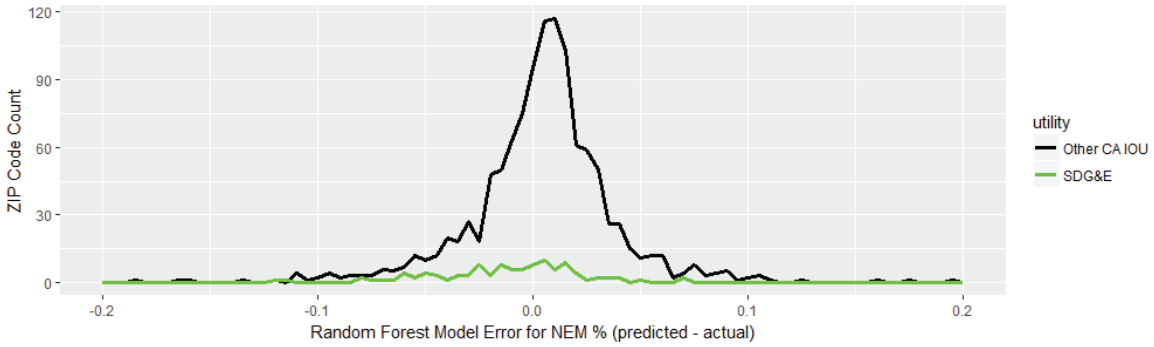


Table 4 details the numerical summary of the error distribution shown in Figure 9. For SDG&E, a slight skew toward underestimating NEM installation proportions occurs, as both the mean and median were less than zero. Of SDG&E ZIP codes, 50% had NEM installation percentage estimates between -2.8% and 0.8% of the true installation percentage.

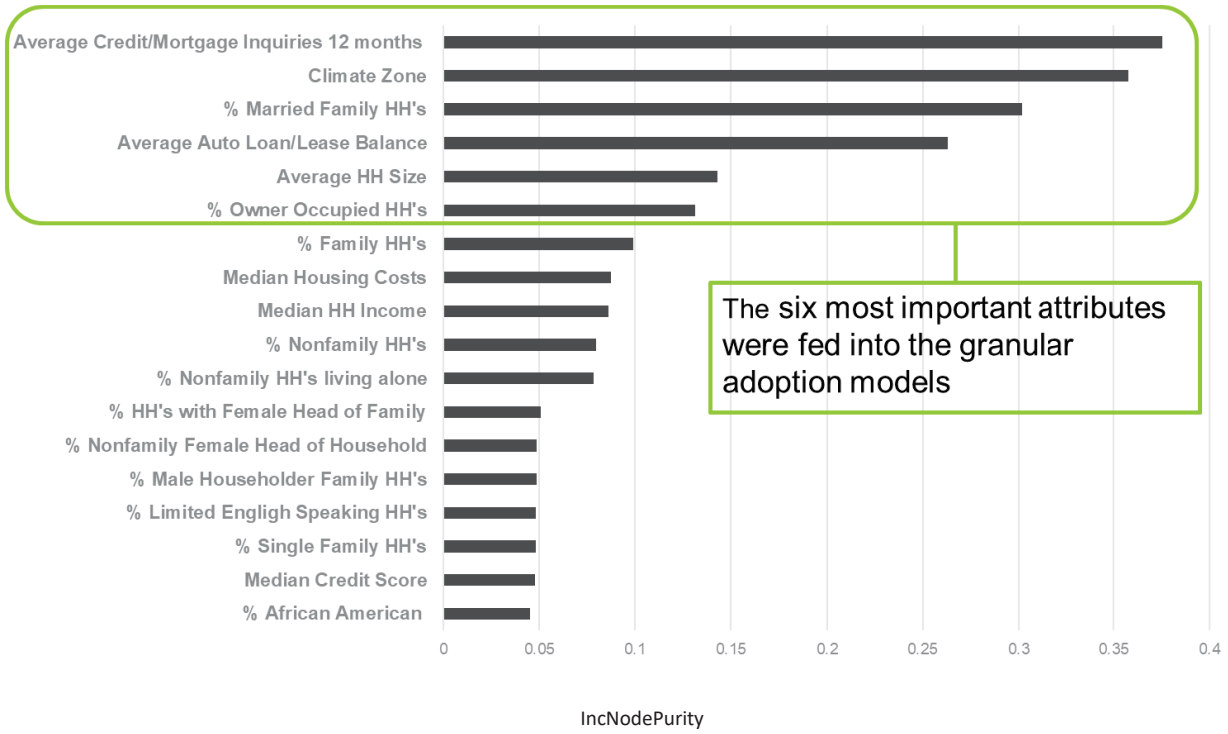
Table 4. Random Forest Estimation Error Quartiles and Mean Percentage of Households with NEM Installs

Utility ZIP Codes	Min	1st Quartile	Median	Mean	3rd Quartile	Max
SDG&E	-12.0%	-2.8%	-0.6%	-1.1%	0.8%	6.8%
Non-SDG&E	-57.6%	-1.0%	0.5%	0.2%	1.9%	19.5%

While the 76% reduction in the NEM percentage variance in SDG&E ZIP codes was an important validation for the random forest model goodness of fit, the primary purpose for the random forest model in this project was to isolate the most significant ZIP code-level drivers for estimating NEM adoption percentage.

The project team examined the variable importance measure from the random forest model, shown in Figure 10. The variable importance in the x-axis of the plot, labeled IncNodePurity, is the relative degradation in model precision associated with the removal of the listed model covariate. Figure 10 shows six attributes, enclosed by the green box, that stick out significantly to the right; as a result, these were determined to be the most important attributes estimating ZIP code-level PV NEM adoption.

Figure 10. Variable Importance Plot – Estimating Percentage of NEM Installation Households



These attributes correlate to varying degrees with the approximately 100 candidate covariates, of which the top 30 in terms of importance are shown in Figure 10. The six attributes in the green box in Figure 10 and listed in Table 5 in order of most to least important were the most predictive for estimating NEM percentage.

Table 5. Key Customer Attributes

Key Customer Attributes
Average number of credit mortgage type inquiries in the last 12 months
Climate zone
Percentage of households that are married families
Average balance on an open auto loan and lease trades reported in the last 6 months
Average household size
Percentage of owner-occupied housing units

2.1.4 Granular Adoption Analysis

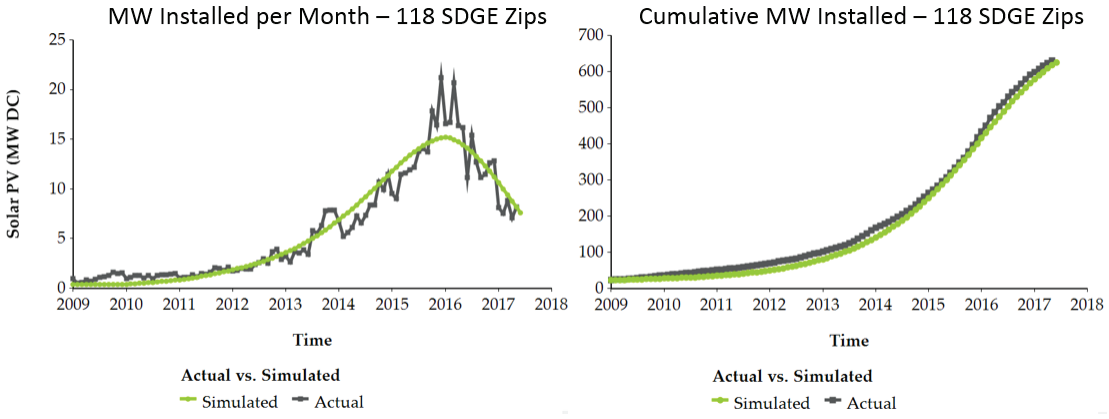
This section presents the results of analysis that explores the ability of the project team's causal model to replicate historical adoption profiles, which provide a greater level of confidence that such a model may provide reasonable forecasts moving forward. This section provides a description of a three-step analysis process, each of which improves the ability of the causal model to replicate historical adoption at a granular level (e.g., ZIP code level).

2.1.4.1 Aggregate Adoption Analysis – Statewide Coefficients

The project team began the adoption analysis by first running a nonlinear optimization to solve for the best fit of its model parameters for adopting data in SDG&E's service territory. The project team estimated the two parameters (marketing effectiveness and word of mouth, or the *p* and *q* in the Bass model) that would drive long-run (equilibrium) adoption in the logit market share model (discussed in Section 1.2.3), assuming a historical price ratio of 0.8 over the historical period simulated. While this is a somewhat simplified assumption, evidence suggests that TPOs tend to price leases and PPAs based on prevailing electricity rates, and that they have been able to historically price below utility electricity rates since introducing the TPO business model. [24] Initially, the plan was to hold the Bass diffusion parameters constant in accordance with values the team has estimated from other studies. However, the adoption data suggests that the market may be past the inflection point of the typical S-curve adoption profile, which means that more information is available to estimate diffusion parameters than originally anticipated. Through a calibration process, the project team independently estimated the two Bass diffusion parameters (*p* and *q* in the classical model, or advertising effectiveness and word of mouth parameters in the team's BDCM model), in addition to the parameters governing the long-run market share. All parameters in this step of the analysis were held constant across all ZIP codes modeled, though the team did back-cast historical adoption for each ZIP code.

The project team obtained an excellent fit of the data when aggregated across all ZIP codes, both on a cumulative megawatt installed basis and on an incremental monthly installation basis. Figure 11 provides a graphical view of the model simulated adoption compared with the actual adoption data gathered from the DGStats database. This result suggests that the Bass diffusion modeling approach is well-suited for analyzing the adoption of solar PV in the residential market, whose dynamics of market growth and saturation appear to be consistent with those observed with numerous other successful product deployments.

Figure 11. Model Simulated vs. Actual PV Installed – Statewide Coefficients Only

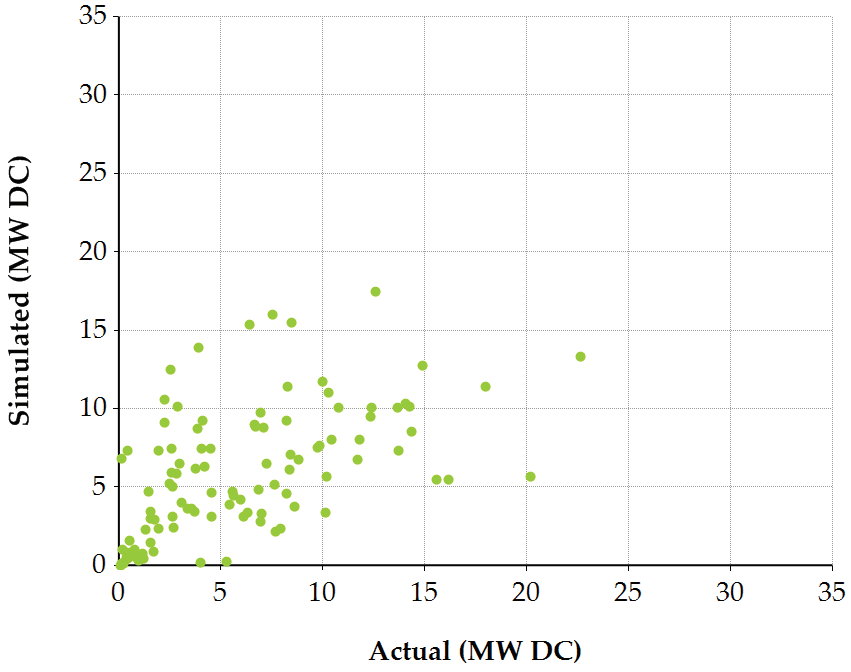


The project team noted that to obtain the strong fit seen above, it added an additional dynamic into the Bass model. Specifically, the team permitted the word of mouth parameter to grow over time, which results in a somewhat steeper (or super-exponential) growth profile. Using only a single, constant value for this parameter resulted in a flatter bell curve of incremental adoption and did not fit the data as well. The implications of this model modification are that the positive feedbacks that tend to generate the exponential growth early in the adoption cycle have been accelerating over time. Such positive feedbacks

include the word of mouth effect but are not limited to that feedback since the model fit will effectively load onto this single parameter any other positive, or reinforcing, feedback that exists in the actual market dynamics. With the growth of social media over the last decade, it is reasonable to believe that this social networking parameter has indeed grown over time. Considering the limited scope and timeframe of the project, the team does not assert that this is the only mechanism by which a super-exponential type of growth dynamic could be caused.

Because forecasting adoption at a more granular level than the entire residential sector was a focus of this project, the model included a back-cast of adoption for each of the 118 ZIP codes the team modeled in SDG&E's service territory. However, without introducing additional model parameters to explain observed variance in adoption across ZIP codes, the project team did not anticipate getting a tight back-cast fit when disaggregating to the ZIP code level. Figure 12 shows the model simulated versus actual cumulative megawatts of adoption from January 2009 through March 2017 for each of the 118 ZIP codes modeled. As seen in this figure, where each data point represents a different ZIP code, substantial noise exists in the adoption back-cast at the ZIP code level. A better data fit would show each data point falling along the diagonal of the graph, if simulated and actual adoption were closely correlated.

Figure 12. Simulated Cumulative Adoption (2009-2017) for all 118 SDG&E ZIP Codes – Statewide Coefficients Only (Held Constant Across All ZIP Codes)



The above results warrant the addition of model parameters to better explain the variance from ZIP code to ZIP code.

2.1.4.2 Granular Adoption Analysis – Incorporating Customer Attributes

The next step of the team's analysis entailed incorporating the customer attributes calculated in the ML analysis described in Section 2.1.1. Observation of ZIP code-level adoption data suggested that long-run market share across ZIP codes varied more substantially than the rate of diffusion that would be governed by the Bass diffusion parameters (advertising effectiveness and word of mouth). As a result, the project

team held these diffusion parameters constant across all ZIP codes and incorporated customer attribute coefficients into its logit market share model, which effects the calculation of long-run market share.

As discussed in Section 1.2.3, the team expanded the two-parameter logit market share calculation into Equation 3

Equation 3. Adding Customer Attribute Coefficients to the Long-Run Market Share

$$LongRun\_MarketShare_{ZipCode} = \frac{1}{1 + e^{\alpha_{ZipCode} + \beta \, \mathrm{Price}Ratio}}$$

Where,

$$\alpha_{ZipCode} = a1_{ClimateZone} + a2 * attribute2_{ZipCode} + a3 * attribute3_{ZipCode} + a4 * attribute4_{ZipCode} + a5 * attribute5_{ZipCode}$$

The above function effectively resulted in a logit market share calculation having the following number of coefficients:

- Price coefficient (β): One global price coefficient
- Climate zone-specific coefficients (a1): 16 coefficients, one for each climate zone in California
- Customer attribute coefficients (a1-a5): Five coefficients, one for each of the five key customer attributes, the value of which varies by ZIP code:
    - $attribute2_{ZIPCode}$ = Average number of mortgage-type credit inquiries in the last 12 months
    - $attribute3_{ZIPCode}$ = Percentage of households that are married families
    - $attribute4_{ZIPCode}$ = Average balance on open auto loan and lease trades reported in the last 6 months
    - attribute $5_{ZIPCode}$ = Average household size

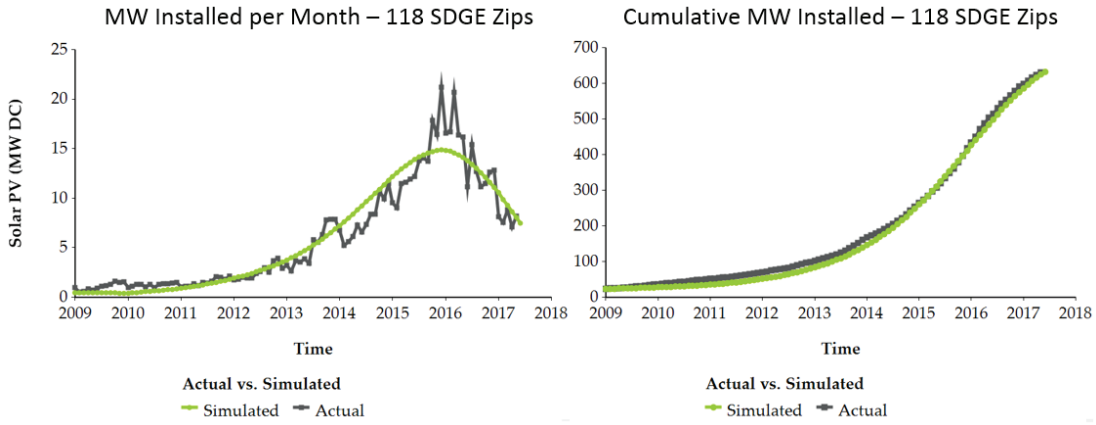
The last key customer attribute identified in the ML analysis was the percentage of owner-occupied housing units. The project team accounted for this parameter more directly by calculating an eligible homes value, which only included owner-occupied homes and the calculated fraction of customers (by ZIP code) whose credit score exceeded 680, a typical value assumed to qualify for a solar PV lease or PPA.

To estimate the values of the above coefficients, the project team conducted a logit regression analysis by transforming the long-run market share equation into a linear function, permitting linear regression of each of the coefficients. The team calculated the market share input for the regression by applying a scaling factor against the actual market share that was a function of the best-fit diffusion parameters from the prior step in the analysis.

After calculating the coefficients of the logit market share equation, the project team employed a nonlinear optimization to re-calculate the global (i.e., constant across ZIP codes) diffusion coefficients, which the team expected to be different from the prior analysis because the calculation of long-run market share has changed with the additional coefficients in the calculation.

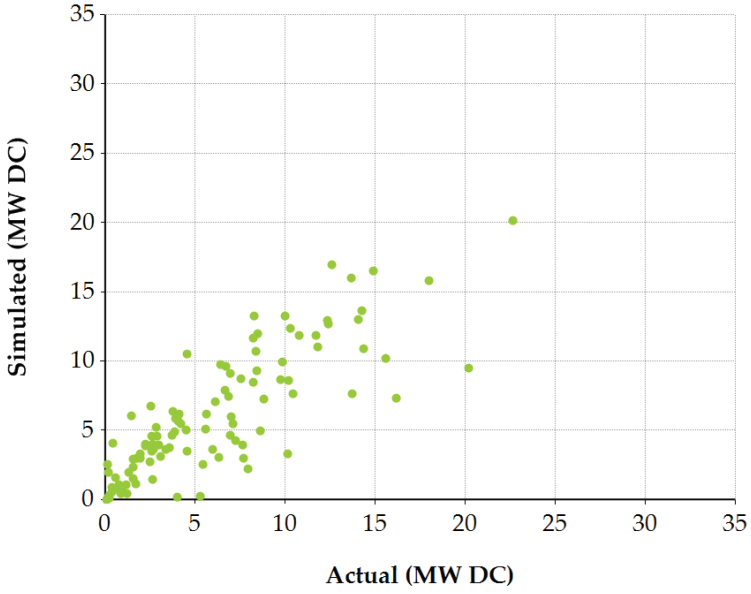
The analysis results again show a strong fit of incremental and cumulative adoption from 2009 through the first quarter of 2017, as illustrated below in Figure 13.

Figure 13. Model Simulated vs. Actual PV Installed – Adding Customer Attribute Coefficients



The project team again plotted the simulated versus actual cumulative adoption from January 2009 through March 2017, as seen in Figure 14. Comparing this figure with Figure 13, a better correlation emerged between the simulated and actual adoption forecasted at the ZIP code level, yet considerable variance between simulated and actual still exists. Adding the customer attribute coefficients reduces the value of the objective function[8] for the parameter fitting optimization by roughly 33%.

Figure 14. Simulated Actual Cumulative Adoption (March 2017) for all 118 SDG&E ZIP Codes – Adding Customer Attribute Coefficients



[8] The objective function in the parameter fit is the sum of the absolute value of the difference between simulated and actual cumulative adoption of each ZIP code summed over every month of the simulation and over all ZIP codes.

2.1.4.3 Granular Adoption Analysis with ZIP Code-Specific Parameters

While adding customer attributes to the long-run market share calculation somewhat improved the fit at the ZIP code level, sufficient variance still exists to warrant further exploration of model parameters. When almost every ZIP code analyzed appears to be past the inflection point of adoption, adding another parameter to the market share calculation specific to each ZIP code should provide an even better fit at the ZIP code level. Addition of such granular parameters can be risky when little information is known about the S-curve adoption profile and can result in poor long-run market share forecasts when early in the adoption curve. In these cases, a danger of overfitting the model exists, resulting in a false sense of security regarding the forecasting accuracy based on past data fits. However, once past the inflection point of adoption, this risk diminishes greatly, as the shape of the S-curve and of the incremental adoption data indicates the ultimate market saturation value.

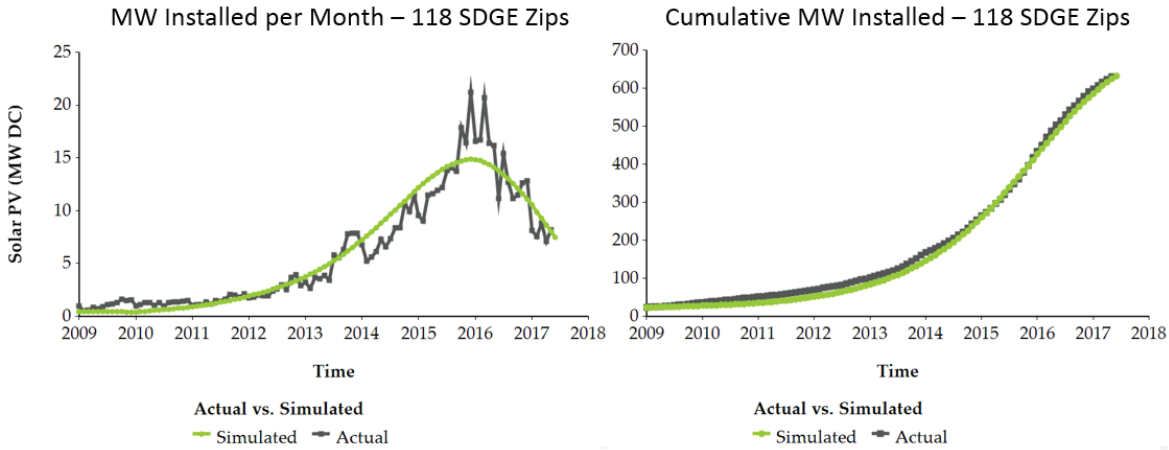
In theory, with sufficient historical data for each ZIP code, one could fit all the parameters of the model to the data, resulting in ZIP code-specific parameters for both the long-run market share calculations and for the coefficients governing the rate of diffusion (the shape of the S-curve). However, these optimizations take time to perform, especially when conducting them across 118 ZIP codes in SDG&E's service territory. Additionally, ensuring a good fit of the data is sometimes an iterative process, involving the addition of constraints or tightening the upper and lower bounds of the parameter estimates to ensure good parameter estimates. The reason for this is the inherent limitations of a nonlinear optimization, which uses gradient hill climbing techniques, which are prone to finding local optima as opposed to global optima. Considering the scope limitations of this project, the project team chose only to fit a single ZIP code-specific parameter, adding an a0 term to the calculation of long-run market (refer to Equation 2 for the original formula). For simplicity of code modification and to facilitate comparison of results, the project team added an a0 term to the original expression for the α term in lieu of replacing the entire α term with only a ZIP code-specific parameter. The results of the fit are the same in either case since the optimization of an alternate a0 term would effectively roll into it all the other terms in the α expression in a single, modified coefficient. In other words, the customer-specific attributes calculated in the prior step become redundant when one adds a ZIP code-specific parameter to the calculation of long-run market share.

Equation 4. Disaggregation of Logit Coefficient

$$\alpha_{ZipCode} = a0_{ZipCode} + a1_{ClimateZone} + a2 * attribute2_{ZipCode} + a3 * attribute3_{ZipCode} + a4 * attribute4_{ZipCode} + a5 * attribute5_{ZipCode}$$

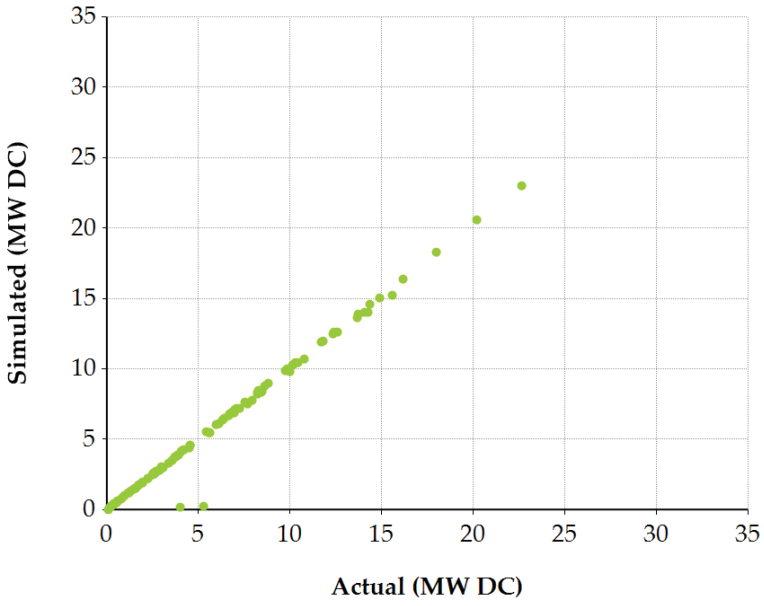
Again, the results demonstrated an excellent fit of both incremental adoption and cumulative adoption when compared with the historical data, as shown in Figure 15.

Figure 15. Model Simulated vs. Actual PV Installed



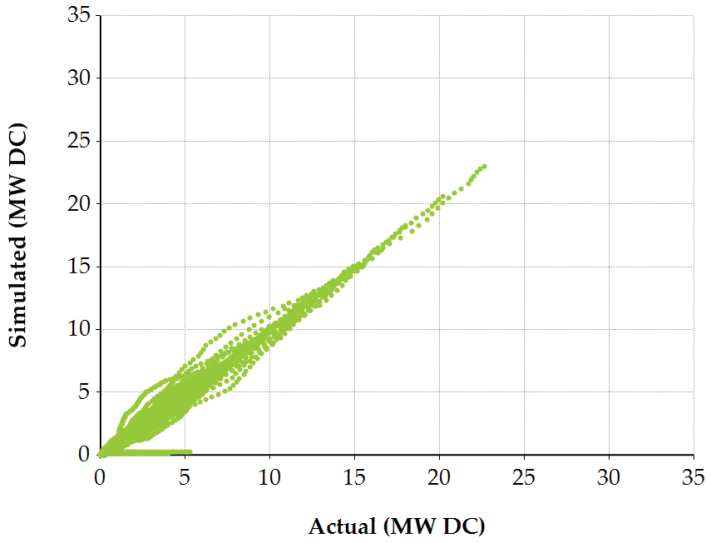
Looking at the results at the ZIP code level, however, there is a much better fit. Simulated cumulative adoption from 2009 through March 2017 aligns closely with actual historical adoption for nearly every ZIP code analyzed. These results can be compared with those presented in Figure 11 and Figure 13.

Figure 16. Simulated vs. Actual Cumulative Adoption (in March 2017) for all 118 SDG&E ZIP Codes – Adding ZIP Code-Specific Coefficients



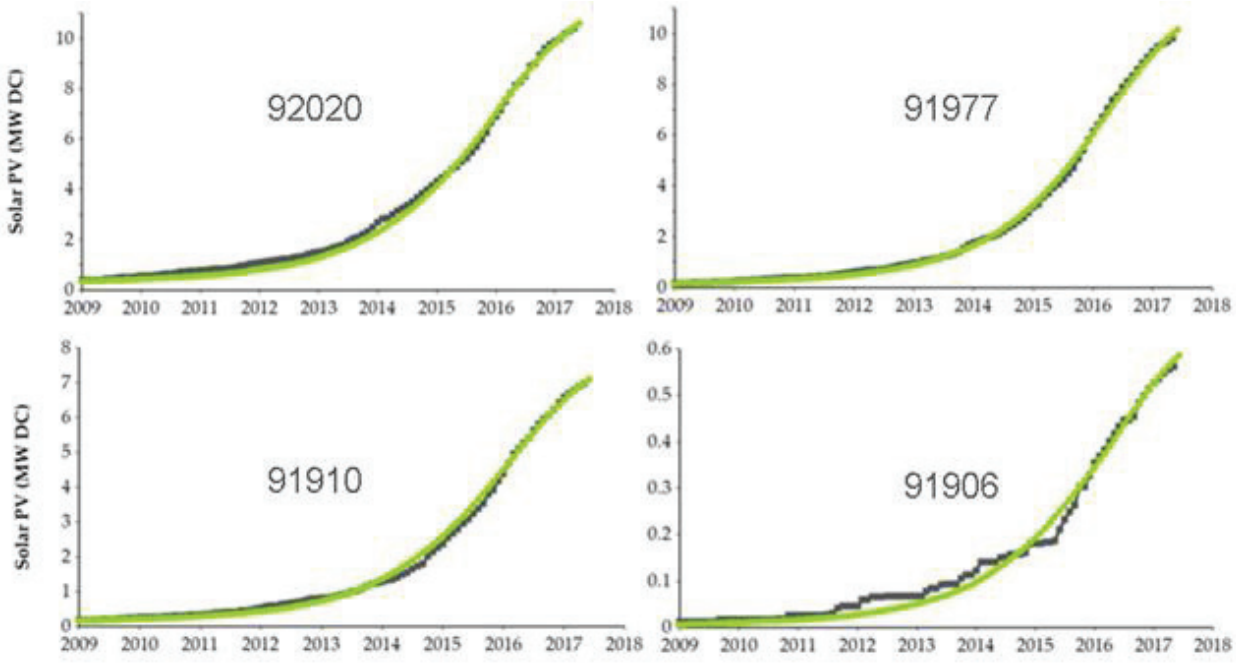
Due to the construct of the optimization and the constraints imposed, the fit is best at the final timestep of the simulation. Greater variance exists between simulated and actual cumulative adoption at each timestep in the simulation. In Figure 17, where each data point represents an individual ZIP code in each month of the simulation from 2009 through 2017, additional variance is observed when inspecting the curve fits at all time periods of the simulation; however, in general, the simulated cumulative adoption fits the actual cumulative adoption very well.

Figure 17. Monthly Simulated vs. Actual Cumulative Adoption (January 2009 – March 2017) for all 118 SDG&E ZIP Codes – Adding ZIP Code-Specific Coefficients



Another way to inspect the data is to look at the simulated versus actual adoption over time for individual ZIP codes. Though showing this result for all 118 ZIP codes would be cumbersome, Figure 18 shows the goodness of fit of the simulated adoption with actual cumulative adoption for four typical ZIP codes. As shown in the figure, the simulated adoption aligns quite well with actual adoption over time even at the ZIP code level, though actual adoption data tends to be a bit less smooth when viewing at the individual ZIP code level (particularly for ZIP codes with smaller installation quantities) as opposed to summed over many ZIP codes. Though not all ZIP codes align as well as those illustrated below, these results are typical and reasonably consistent at the ZIP code level, though outliers do exist.

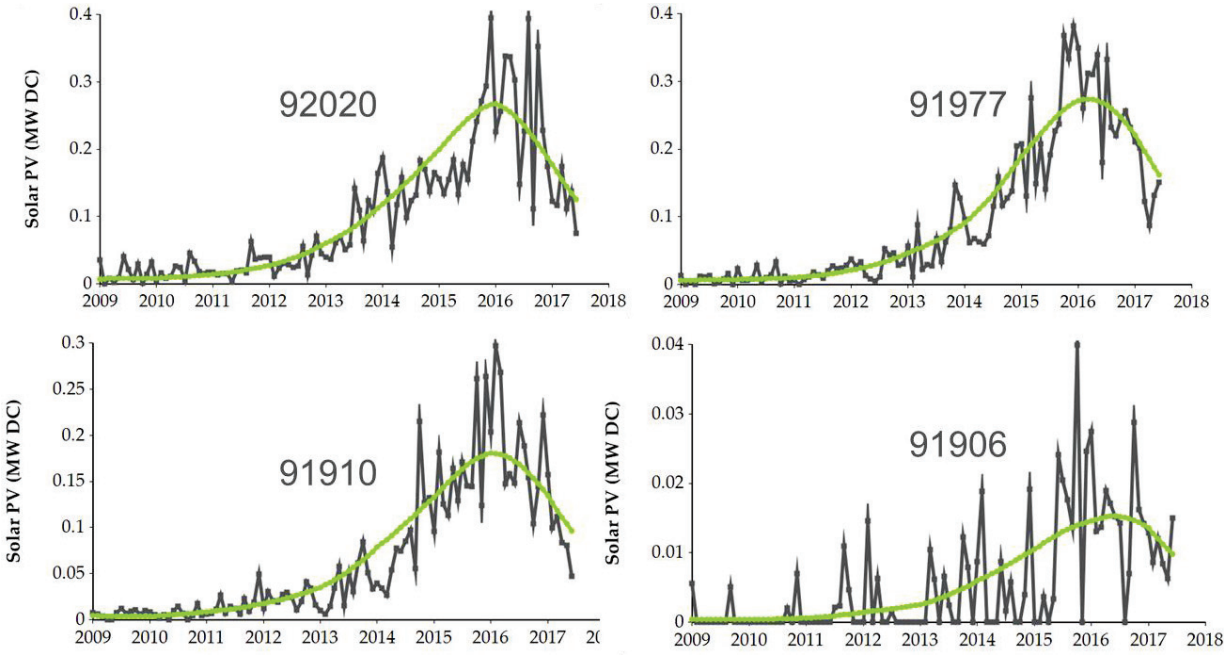
Figure 18. Simulated vs. Actual Cumulative Adoption over Time – ZIP Codes 92020, 91977, 91910, and 91906



Though each of the above adoption profiles results in a different long-run market share, the shape of the adoption (i.e., the shape of the S-curve, or the rate at which the long-run market share is approached) is reasonably consistent across ZIP codes. Again, outliers do exist, but for the most part, assuming a constant set of diffusion coefficients (i.e., *p* and *q* in the classical Bass model) across the service territory is a reasonable approximation.

Figure 19 shows the incremental adoption per month for each of the above four ZIP codes. Whenever one views incremental data as opposed to cumulative data, the results are noisier, owing to the smoothing effect of integrating—or cumulating—data over time. That said, the project team still observes a strong correlation between simulated and actual adoption at the ZIP code level, even when comparing incremental adoption data. It should also be apparent that the characteristic rise and fall of incremental adoption, manifested as a somewhat bell-shaped incremental adoption curve, is visible at the ZIP code level, not just in aggregate across ZIP codes.

Figure 19. Simulated vs. Actual Monthly Incremental Adoption over Time – ZIP Codes 92020, 91977, 91910, and 91906



2.2 Disadvantaged Communities Results and Analysis

The following sections detail the results the DAC demonstration activity.

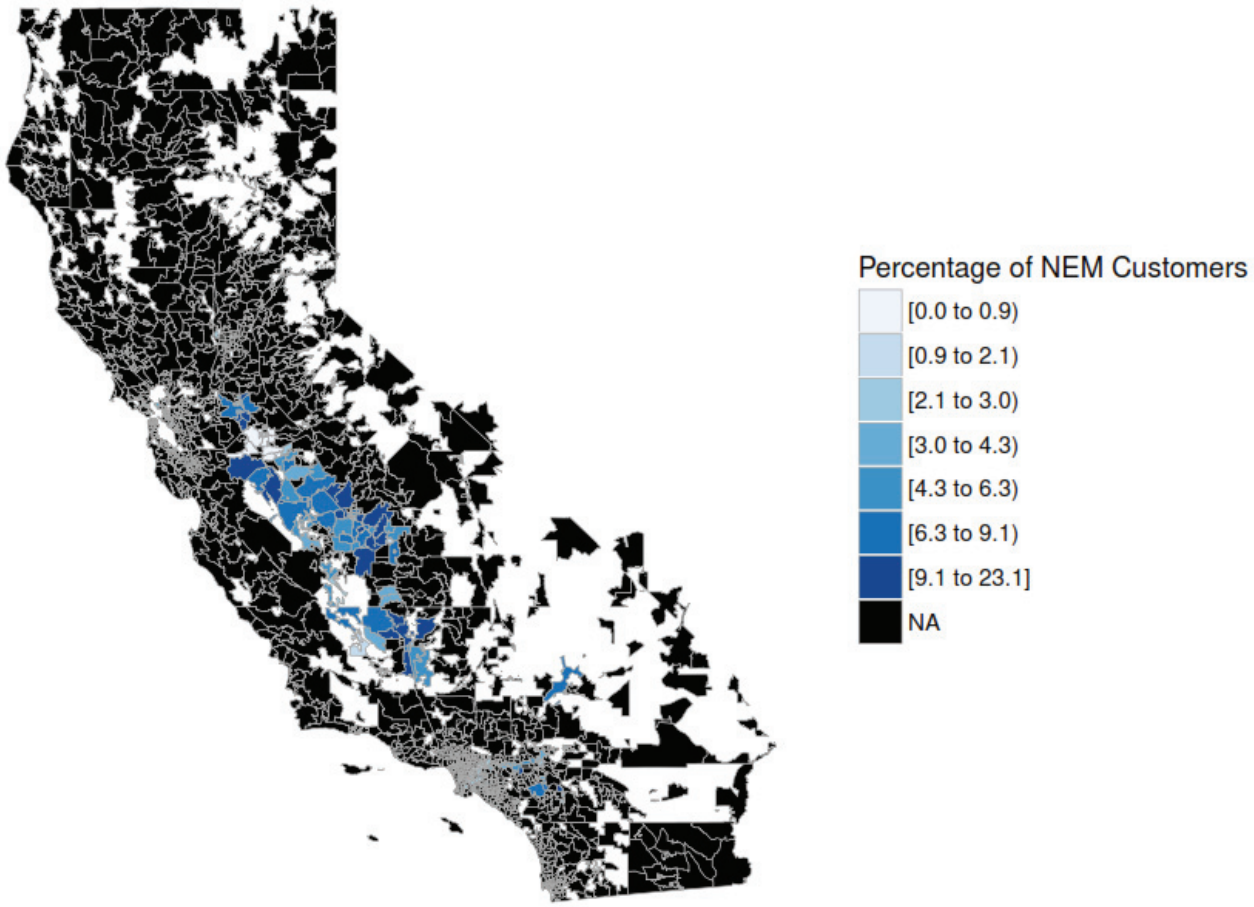
2.2.1 Customer Attributes Driving Adoption

The project team conducted ML modeling to identify the most important attributes driving adoption at the ZIP code level, for DAC-designated ZIP codes. This analysis included filtering the compiled analysis data as described in Section 2.1.2 to only include those with DAC indicators and available attributes from the American Community Survey at the ZIP code level, and fitting the ML models.

2.2.2 Data Compilation

After filtering the California IOU territory ZIP code data, the resulting dataset included 171 out of 255 ZIP codes designated as DAC ZIP codes due to NEM data only being available in IOU territories and American Community Survey census data limitations. The NEM installation penetration for the DAC ZIP codes is shown in Figure 20 in shades of blue from light (lowest percentage) to dark (highest percentage), with black signifying non-DAC ZIP codes or outside of the IOU service territories, and white signifying Census Bureau ZIP Code level attribute data were not available.

Figure 20. NEM Installation Percentage, by DAC ZIP Codes



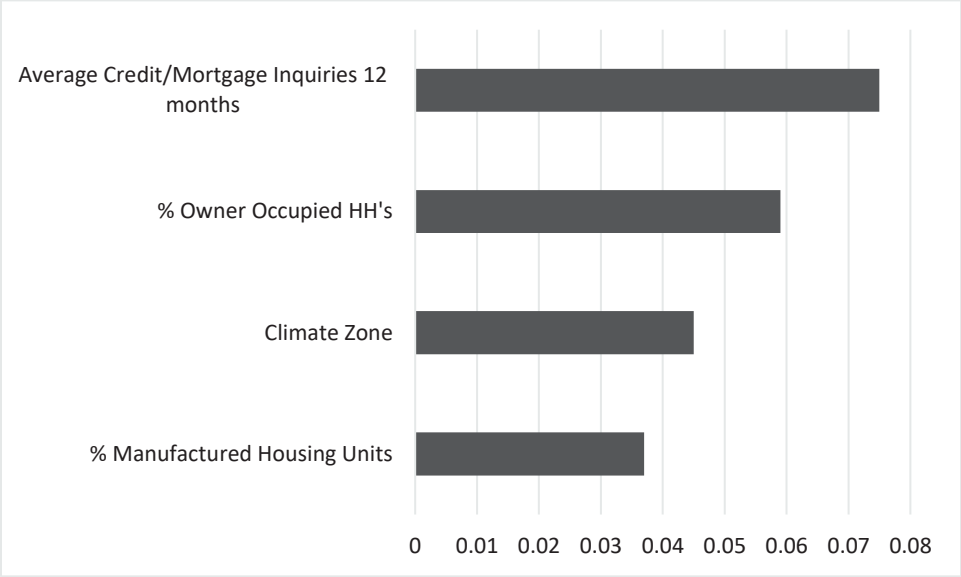
2.2.3 Machine Learning Models

The project team fit a Conditional Inference Tree (CTree) model to the DAC-filtered set of California ZIP codes for estimating the NEM percentage, and found that it outperformed the random forest model in terms of variance explained, when fit on the full set of DAC ZIP codes and the full set of candidate predictor variables. CTree models account for statistical distributional properties of candidate predictor variables when considering non-parametric splits, as opposed to recursive univariate splits used for the individual CART trees in a random forest. [25]

The CTree model isolated four attributes most strongly linked to the NEM percentage in DAC ZIP codes, as shown below in Figure 21.

The project team fed the attributes from the CTree model into a random forest ensemble model to quantify the variable importance and to test whether the importance order observed was consistent. Overall, the random forest model explained 53 percent of the variance in NEM installation percentage for the DAC ZIP codes. The attribute importance order from the CTree was also observed in the random forest model, shown below.

Figure 21. Random Forest Attribute Variable Importance – DAC ZIP Codes



Three of these four key explanatory attributes were also significant for the overall NEM Installation ML analysis, with only the percentage of manufactured housing units found to be significantly linked to predicting NEM installation within the DAC filtered list of ZIP codes.

The figure below depicts the random forest error distribution for estimating the proportion of households with NEM installs for solar PV system installations—i.e., the error of the ML model to the actual DG Stats data, in the DAC ZIP codes. The black curve shows the estimation error distribution, centered on zero, and slightly left skewed, implying the random forest models had a slight tendency to under-state the NEM installation percentage.

Figure 22. Random Forest Estimation Error Distribution for Percentage of Households with NEM Installations

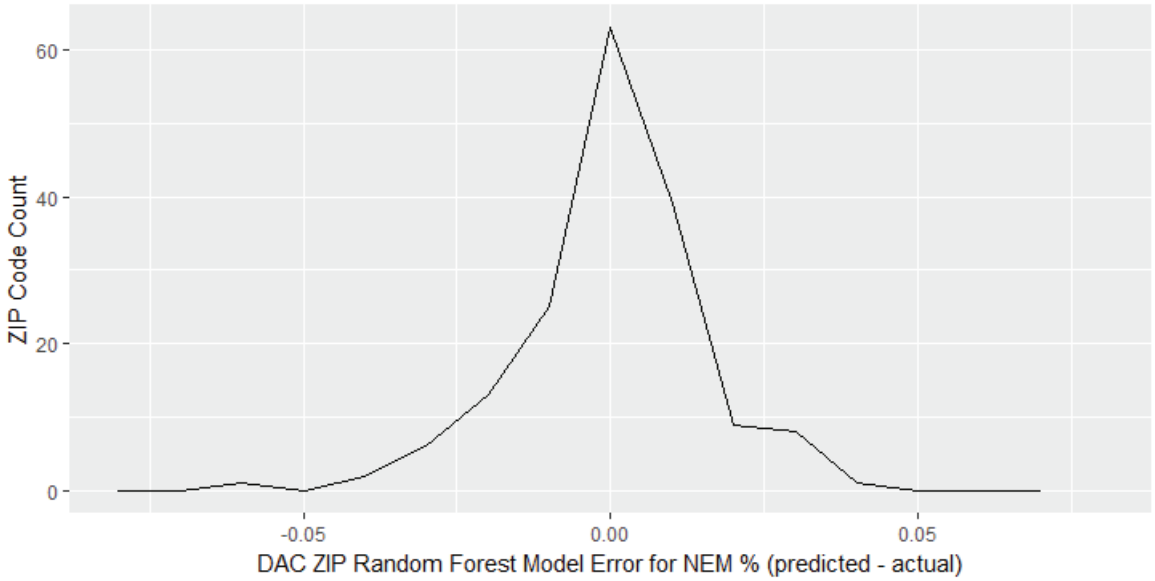


Table 6 details the numerical summary of the error distribution shown in Figure 22. Approximately 50 percent of the DAC ZIP codes were predicted within 0.1% of their true NEM installation percentage.

Table 6. Random Forest Estimation Error Quartiles and Mean Percentage of Households with NEM Installs

DAC ZIP Codes	Min	1st Quartile	Median	Mean	3rd Quartile	Max
SDG&E	-5.7%	-0.1%	0.0%	0.0%	0.1%	4.4%

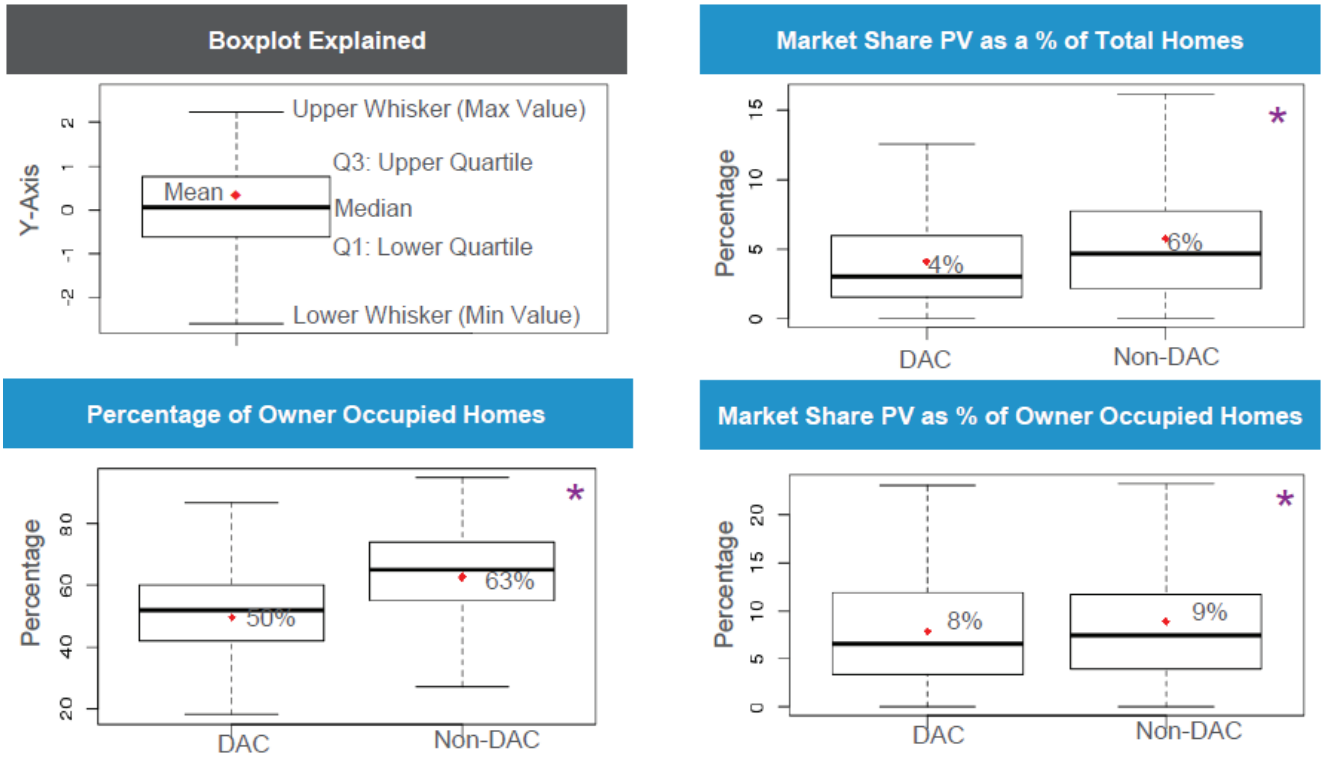
2.2.4 Statistical Analysis Results

Figure 23 and Figure 24 depict the statistical analysis results as box and whisker plots. As illustrated below, owner occupancy is a key attribute explaining the difference in solar PV market share between DAC and non-DAC ZIP codes. The percentage of owner occupied homes is 63% for non-DAC ZIP codes. This is statistically different from the average home ownership in DAC ZIP codes of 50%.[9] The solar PV market share as a percentage of total homes is 6% for non-DAC ZIP codes, versus DAC ZIP codes where solar PV market share is 4%, signifying a statistically different mean value.

When analyzing the solar PV market share as a percent of owner occupied homes (the bottom right graph in Figure 23), the difference in average market share across DAC and non-DAC ZIP codes is still statistically significant; however, the distributions are more similar when only evaluating owner occupied homes.

[9] Statistical significance is measured at the 90% confidence interval.

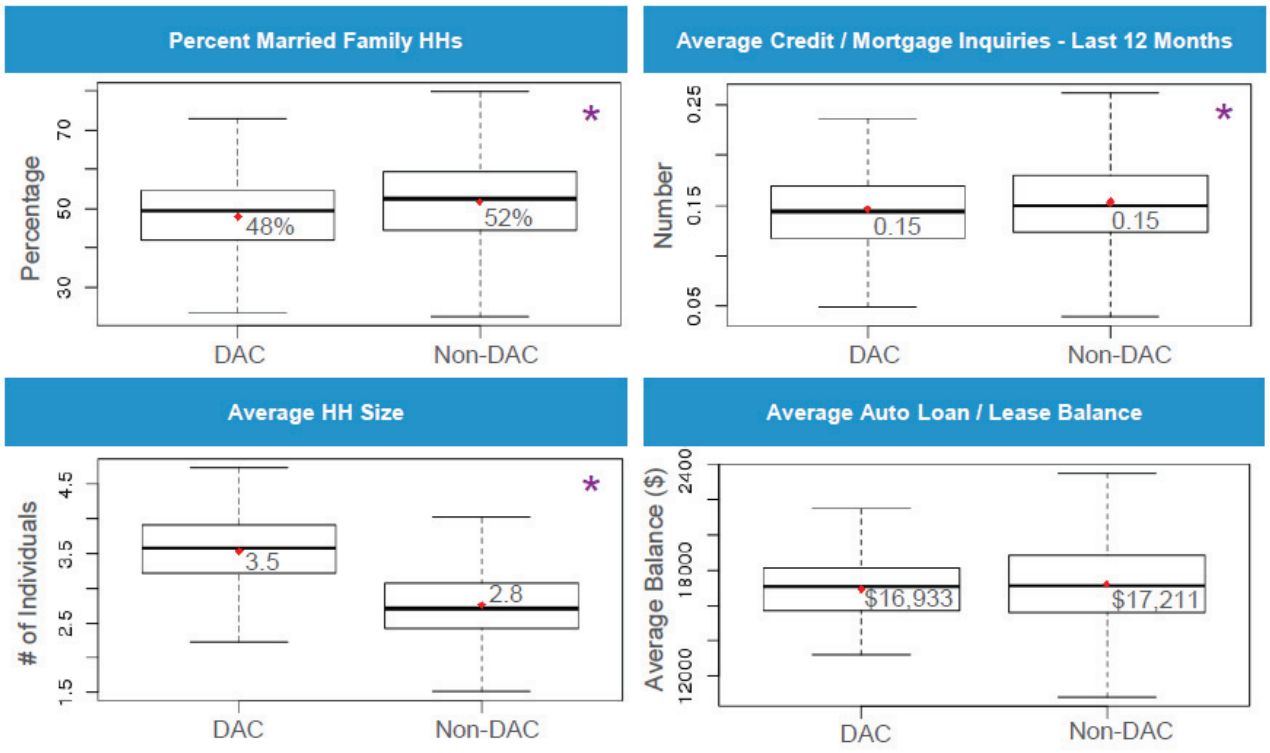
Figure 23. Percentage of Owner Occupied Homes and Market Share Attributes



**Indicates that the means of the attribute between DAC and Non-DAC ZIPs are statistically different at the 90% confidence interval.*

As illustrated in Figure 24, the remaining four attributes are more similarly distributed between DAC and non-DAC and although statistically significant do not practically explain differences in adoption. For these parameters, a higher value correlates with higher adoption levels for all attributes other than household size. Yet the positive correlation of the other parameters, particularly homeownership, overwhelms the solar PV adoption results.

Figure 24. Remaining Four Attributes

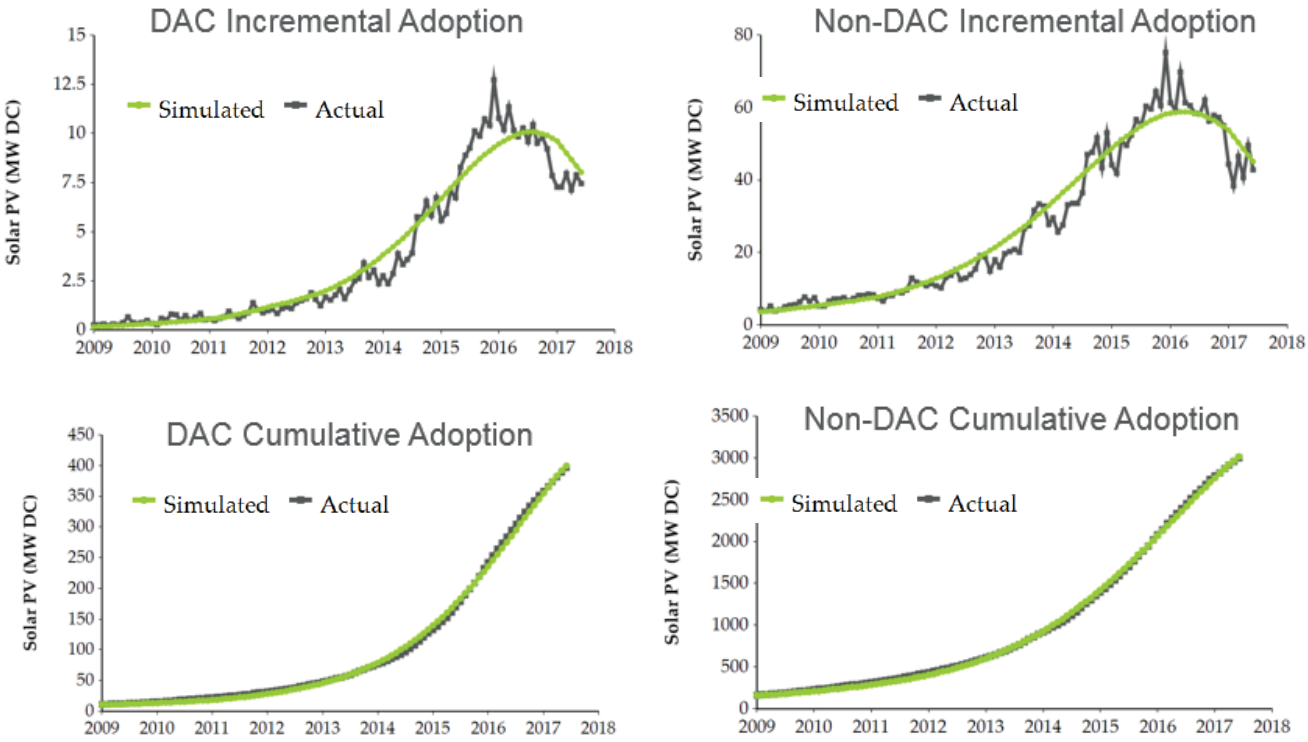


**Indicates that the means of the attribute between DAC and Non-DAC ZIPs are statistically different at the 90% confidence interval; however, this does not signify that these attributes are drivers of differences between DAC and non-DAC.*

2.2.5 DAC vs. Non-DAC Adoption Analysis

Comparing the model simulated with actual adoption data for DAC Zip codes and non-DAC Zip codes, one finds that both DAC and non-DAC data fit simulated results quite well, as illustrated below in Figure 25. Both categories again show the characteristic rise and fall of incremental adoption, resulting in S-shaped cumulative adoption that is similarly shaped across both categories. Differences in the rates of adoption or shape of the S-curve appear minor; however, one may notice a somewhat greater curvature in DAC incremental adoption in the 2015-2016 timeframe, possibly a result of the timing of the extension of the California Single Family Affordable Solar Housing (SASH) and Multi-Family Affordable Solar Housing (MASH) incentives. [26] As such, the non-DAC simulated results tend to fit the data somewhat more closely, though both sets of simulated results compare well with actual historical adoption.

Figure 25. Comparison of DAC and non-DAC Adoption: Simulated vs. Actual



2.3 Assumptions

The team made some specific assumptions:

- Considered only credit score eligibility and homeownership in calculating suitability for installation, as opposed to further refining technical suitability of homes for solar PV (e.g., fraction of homes in each ZIP code with acceptable orientation, shading, etc.).
- Utilized constant pricing undercut of leases/PPAs relative to prevailing electricity rates, as opposed to calculating or estimating pricing undercut differences over time.
- Aggregated analysis to the ZIP code level rather than the customer unit level.
- Defined a DAC ZIP code as a ZIP code where >50% of the population lives in census tracts with a CalEnviroScreen 3.0 score > 75%.
- Did not use ZIP Codes without a direct 1:1 map with ZIP Code Tabulation Areas (ZCTAs) in the DAC analysis. The excluded ZIP codes were found in small population density areas within the IOU service territories, or had very few residential customers. The Census Bureau does not publish demographics data for these ZIP codes to protect confidentiality.

3. Key Findings

The following section presents the key project findings that were identified by the project team. The strength of aggregate and ZIP-code-level back-casts suggest that causal models can be used to forecast residential rooftop PV adoption moving forward with a reasonable degree of accuracy, even when the analysis is spatially disaggregated. Such methods could support integrated resource planning and a better understanding of likely solar PV installation location, facilitating transmission and distribution-level planning and analysis.

As indicated by the demonstration results, the key findings of this project can be summarized as follows:

- Causal models, when appropriately calibrated, can explain historical adoption patterns well.
- The Bass diffusion construct employed in the project team's BDCM can replicate historical adoption patterns for both cumulative and incremental solar PV adoption.
- Preliminary results suggest that the adoption of residential solar PV in California and in the SDG&E service territory is past the inflection point in the characteristic S-curve of adoption.
- ML techniques can help to explain historical adoption patterns and can reduce the variance between simulated and actual adoption when analyzed at a granular level. Importantly, these techniques confirmed existing assumptions (e.g. climate zone) and introduced new considerations (e.g. married family households).
- The parameterization of the most important attributes through discrete choice modeling— are best suited to understanding drivers of individual customer adoption, which was beyond the scope of this demonstration
- The rate of diffusion (i.e., the shape of the S-curve) is reasonably consistent spatially; the long-run market share appears to differ more substantially when analyzed at a granular level (e.g., at the ZIP code level).
- ZIP code-level forecasts seem possible with reasonable accuracy, particularly when ZIP code-level adoption appears to be past the inflection point of S-curve adoption.
- Market share solar PV as a percent of total homes is about 50% higher in non-DAC ZIP codes (6% vs. 4% market share).
- Owner occupancy is a key attribute in explaining the differences between DAC and non-DAC solar PV market adoption.
    - When comparing PV adoption in only owner-occupied homes, market share solar PV is very similar between non-DAC and DAC ZIP codes (9% vs. 8%).
    - Differences in other attributes do not drive strong variance in solar PV market share across non-DAC and DAC ZIP codes.
- Statewide analysis of Non-DAC and DAC ZIP codes generates close fit between simulated and actual. Although DAC ZIP codes have a lower penetration as a percentage of total homes, market share is closer as a percentage of owner occupied homes.

The project team views the outcome of this pre-commercial demonstration as a success because the demonstration activity results verify the capabilities of the methodology that was demonstrated. The ability of the methodology to forecast spatially was even more certain than expected at the outset of the project due to the DGStats installation data suggesting the market may be past the inflection point of the S-curve. As DER penetration continues to grow, this project outlines how SDG&E and other utilities can leverage the methodology framework to help forecast the adoption of other DER in their jurisdictions.

4. Recommendations and Next Steps

The project has demonstrated a set of methods and tools that could be used to estimate the propensity for customer adoption of a DER technology such as photovoltaics. The project team recommends that SDG&E not commercially adopt these methods and tools at this juncture, without more foundational work being done first. Based on the pre-commercial demonstration results and findings of this project, the following actions by SDG&E or other stakeholders are recommended as steps toward prospective commercial adoption of the demonstrated methods and tools.

- Improve SDG&E's existing zip-code based Bass diffusion technique with refinements for the long-run market share parameters based on significant customer attributes.
- Improve certain model inputs (e.g., historical PPA prices, kilowatt-hour production, technical suitability due to shading and orientation, price sensitivity, and correlation between homeownership and credit scores) and conduct additional research to determine whether the residential solar PV market in SDG&E territory is approaching saturation.
    - Refine estimate of suitable buildings in the SDG&E service territory
    - Refine price sensitivity to forecast future adoption under different price/policy scenarios
    - Add parameters at the ZIP code level (e.g., one or two of the diffusion parameters) to provide greater forecast accuracy at that level of granularity
- Leverage the same or equivalent methodology to evaluate solar PV adoption for other specific segments of interest and potentially individual customer analysis, including but not limited to the following groups:
    - Commercial and industrial customers
    - Low-income customers building on the analysis done on DAC
    - Customers on distribution feeders that are capacity constrained or at risk for reverse power flow during peak PV generation hours
- Adapt the methodology for use in forecasting adoption of other DER (e.g., solar + storage, storage, EVs) and conduct demonstrations in these areas.
- Consider utilizing a customer discrete choice survey approach to facilitate independent estimation of both the long-run market share parameters and the Bass diffusion coefficients.

5. Metrics and Value Proposition

5.1 Metrics

The commercial adoption methodologies and tools for estimating propensity for customer adoption of photovoltaics will be impacted by the following metrics.

- Potential energy and cost savings
    - Avoided customer energy use (kWh saved) – The use of tools to estimate customer adoption of PV would lead to understanding the contribution of electric load from PV systems, which in turn will provide the customers with reduced energy usage and economic savings.
    - Avoided procurement and generation costs – Accurate estimation of customer PV adoption rates would enable utilities to estimate the avoided cost to procure energy from sources that might be inefficient or contribute to environmental pollution.
- Environmental benefits
    - GHG emissions reductions – Adoption of PV would lead to reduced emissions from fossil fuel based sources which would have to be used in absence of renewable resources like PV.

5.2 Value Proposition

The purpose of EPIC funding is to support investments in R&D projects that benefit the electricity customers of SDG&E, PG&E, and SCE. The primary principles of EPIC are to invest in technologies and approaches that provide benefits to electric ratepayers by promoting greater reliability, lower costs, and increased safety. This EPIC project contributes to these primary principles in the following ways:

- Greater Reliability: More accurate DER forecasting techniques will be required as these technologies have a greater impact on SDG&E's distribution system. It has become evident through circuit load data that residential PV is now playing a role in daily load shapes. To ensure the system is properly designed for future needs, PV adoption forecasts must be carefully analyzed to anticipate future electric system requirements and reduce the risk of outages.
- Lower costs: PV adoption will likely have a direct impact on the type and location of distribution system, and possibly, transmission system upgrades. Applying the most appropriate resources at the most beneficial locations will inherently keep costs lower than the alternatives. Improved forecasting methods should enable the allocation of those resources to be applied in the most appropriate way.
- Higher consumer satisfaction: More accurate DER forecasting can improve consumers' contribution through demand response management in the operation of a utility power system by reducing or shifting their electricity usage during peak periods in response to time-based rates or other forms of financial incentives.

6. Technology Transfer Plan

6.1 SDG&E Technology Transfer Plans

A primary benefit of the EPIC program is the technology and knowledge sharing that occurs both internally within SDG&E and across the industry. To facilitate this knowledge sharing, SDG&E will share the results of this project by announcing the availability of this report to industry stakeholders on its EPIC website, by submitting papers to technical journals and conferences, and by presentations in EPIC and other industry workshops and forums. The results will also be shared internally through presentations to internal stakeholders.

6.2 Adaptability to Other Utilities and Industry

All successful product rollouts tend to follow an S-shaped adoption curve, and solar PV is no exception. The further a technology progresses along the S-curve, the more accurate adoption forecasts become. The project approach is readily adaptable to all other IOUs in California, with adoption patterns holding across most ZIP codes in the state. This approach to forecasting adoption can be utilized by other utilities for integrated resource planning and forecasting transmission and distribution needs. While this demonstration project leveraged public information, if the project team had customer-specific data, the granularity of the analysis could have been refined, possibly to the feeder and substation level under various scenarios and rate structures.

7. References

[1] Wikipedia. “ZIP Code.” Internet: https://en.wikipedia.org/wiki/ZIP_Code, Dec. 5, 2017.

[2] D. McFadden. “Economic Choices,” presented at the Prize Lecture, Stockholm, Sweden, 2000.

[3] M.E. Ben-Akiva, S.R. Lerman. Discrete Choice Analysis: Theory and Application to Travel Demand. Cambridge, MA: The MIT Press, 2006.

[4] L. O'Keeffe. “A Choice Experiment Survey Analysis of Public Preferences for Renewable Energy in the United States,” Journal of Environmental and Resource Economics at Colby, vol. 01, 2014.

[5] F.M. Bass. “A New Product Growth for Model Consumer Durables.” Management Science, vol. 15, pp. 215-227, Jan. 1969.

[6] F.M. Bass. “Comments on ‘A New Product Growth for Model Consumer Durables: The Bass Model.’” Management Science, vol. 50, pp. 1833–1840, Dec. 2004.

[7] J.D. Sterman. “The Bass Diffusion Model,” in Business Dynamics: Systems Thinking and Modeling for a Complex World, S. Isenberg, New York: McGraw-Hill, 2000, pp. 332.

[8] V. Mahajan, E. Muller, and Y. Wind. “Diffusion Models, Managerial Applications and Software,” in New-Product Diffusion Models. New York: Springer, 2000, pp. 295-310.

[9] B. Sigrin, M. Gleason, R. Preus, I. Baring-Gould, and R. Margolis. “The Distributed Generation Market Demand Model (dGen): Documentation.” Internet: https://www.nrel.gov/docs/fy16osti/65231.pdf. Feb. 2016.

[10] A. Agarwal. “A Model for Residential Adoption of Photovoltaic Systems.” M.S. thesis, California Institute of Technology, California, 2015.

[11] L. Breiman. Classification and Regression Trees. California: Wadsworth & Brooks/Cole Advanced Books & Software, 1984.

[12] L. Breiman. Classification and Regression Trees. California: Wadsworth & Brooks/Cole Advanced Books & Software, 1984.

[13] W.L. Loh. “Fifty Years of Classification and Regression Trees.” International Statistical Review, vol. 84, pp. 329-348, 2014.

[14] A Liaw and M. Wiener. “Classification and Regression by Random Forest.” R News, vol. 2/3, pp. 18-22, Dec. 2002.

[15] S. Athey and I. Guido. “Machine Learning Methods for Causal Effects.” Internet: www.nasonline.org/programs/sackler-colloquia/documents/athey.pdf. 2015.

[16] P. Bajari, D. Nekipelov, S. Ryan, and M. Yang. “Demand Estimation with Machine Learning and Model Combination.” National Bureau of Economic Research, 2015.

[17] US Environmental Protection Agency. “Understanding Third-Party Ownership Financing Structures for Renewable Energy.” Internet: www.epa.gov/repowertoolbox/understanding-third-party-ownership-financing-structures-renewable-energy.

[18] F. Stermole and J. Stermole. Economic Evaluation and Investment Decision Methods. Investment Evaluation Corporation, 2012.

[19] Navigant Consulting, Inc., Solar Project Return Analysis for Third Party Owned Solar Systems. 2016.

[20] U. Benzion and J. Yagil. “Decisions in Financial Economics: An Experimental Study of Discount Rates,” Advances in Financial Economics, M. Hirschey, J. Kose, A.K. Makhija, Eds. United Kingdom: Emerald Group Publishing, 2002, pp. 19-40.

[21] California Distributed Generation Statistics. “NEM Currently Interconnected Data Set.” Internet: http://www.californiadgstats.ca.gov/downloads/, Sept. 30, 2017.

[22] California Energy Commission. “Electric Program Investment Charge 2016 Annual Report.” Internet: http://www.energy.ca.gov/2017publications/CEC-500-2017-015/CEC-500-2017-015-CMF.pdf, April 2017.

[23] California Distributed Generation Statistics. “Currently Interconnected Data Set.” Internet: http://www.californiadgstats.ca.gov, 2017.

[24] Navigant Consulting, Inc., “Solar Project Return Analysis for Third Party Owned Solar Systems.” Proc. UniSource Electric Rate Case, 2016.

[25] T. Hothorn, K. Hornik, and A. Zeileis. “ctree: Conditional Inference Trees.” Internet: https://cran.r-project.org/web/packages/partykit/vignettes/ctree.pdf, 2015.

[26] “Decision Extending the Multifamily Affordable Solar Housing and Single Family Affordable Solar Homes Programs within the California Solar Initiative.” Internet: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M145/K938/145938475.PDF, Jan. 29, 2015.

Appendix 15

EPIC-2, Project 6, Module 2: Collaborative Programs in RD&D Consortia – Unmanned Aerial Systems Data Lifecycle Management and Deep Learning Demonstration

SDGE connected

A Sempra Energy utility℠

EPIC Final Report

Program	**Electric Program Investment Charge (EPIC)**
Administrator	**San Diego Gas & Electric Company**
Project Number	**EPIC-2, Project 6**
Project Name	**Collaborative Programs in RD&D Consortia**
Module Name	**Unmanned Aerial Systems Data Lifecycle Management and Deep Learning Demonstration**
Date	**December 31, 2017**

Attribution

This comprehensive final report documents the work done in this EPIC project. The project team for this work included the following individuals from SDG&E, listed alphabetically by last name.

Akau, Don
Alapati, Gayatri
Asaro, Christine
Bui, Ngoc
Edalia, Olivo-Gomez
Goodman, Frank
Hobbib, Tom
Katmale, Hilal
Mazhari, Iman
Murphy, Lisa
Myott, Sean
Shiffman, Nadav
Smith, Drew
Surbey, Chris
Thiemsuwan, Jade
Ubinas, Hector
Webb, Jimmie
Willie, Thomas

The project team also included representatives of the following organizations:

Gis Surveyors Inc
GE/Avitas
Harris Corporation
Network Mapping
PricewaterhouseCoopers

Executive Summary

The objective of EPIC-2, Project 6 (Collaborative Programs in RD&D Consortia) is to accomplish highly leveraged demonstration work through industry collaborative R&D organizations. The focus of this project module was to demonstrate tools that ingested and analyzed data collected by means of Unmanned Aircraft Systems (UAS), existing Red, Green & Blue (RGB) imagery, Geographic Information Systems (GIS), Power Line Systems – Computer Aided Design and Drafting (PLS-CADD) and other various inspection data types. The project team demonstrated the tools' ability to automatically identify and tag assets shown in RGB imagery, specifically avian covers, in real-world locations through machine learning. Additional identification of vegetation modeled using Light Imaging Detection and Ranging (LiDAR) data that encroached into vendor determined zone(s) around electrical wires which provided a road map for future proactive vegetation maintenance efforts. The project's findings suggested potential Imagery Data Management Platforms (IDMP) which would improve current asset management and data lifecycle management processes, producing a roadmap that would enable integration of the technology used by each vendor.

Unmanned Aerial Systems (UAS) have provided a unique opportunity for SDG&E to obtain, disseminate and use aerial sensor data that provides benefits such as cost savings to its ratepayers and lower physical risks to SDG&E personnel while increasing public safety. The primary project objective was to demonstrate platforms that could integrate with existing and future SDG&E infrastructure, software applications and legacy data sets with the ability to ingest, store, analyze and report on SDG&E assets derived from GIS, PLS-CADD, UAS collected data and other various sources.

The project scope included identification of the vendors' proposed IDMP and demonstration of their tool's Data Lifecycle Management (DLM) workflow process and how it integrates with existing and future SDG&E platforms. The vendors approach was based on stakeholders' current workflows and data requirements. The test segment consisted of a SDG&E 1.25-mile segment of a distribution circuit that included 30 electrical distribution poles. The test segment was selected due to previous LiDAR data collection as part of the Fire Risk Management (FiRM) program and provided an accurate representation of minimally accessible terrain.

The three test cases identified for the project addressed Proof of Concept (POC) on the following:

1. *Avian Cover Identification* – Test case to evaluate the identification of assets (avian cover) through advanced analytics on RGB images and demonstrate value for continual maintenance and visual inspection.

2. *Vegetation Encroachment Identification* – Test case to evaluate identification of vegetation encroachment within a buffer zone around power lines, thereby assisting in identification of trees for maintenance and trimming.
3. *Cataloging and Remote Asset Management* – Test case to demonstrate ingestion of data from various data sources and cataloging metadata information of existing assets that enables remote visualization and management of assets.

The results of the three test cases were presented and demonstrated to SDG&E stakeholders to give them the ability to examine and compare the vendors' tools for usability and functionality. None of the vendor tools were developed to a point where they could be integrated without modification to current SDG&E systems, but the POC's were clearly demonstrated by all vendors.

The EPIC project was successful in demonstrating the ability of vendors to utilize tools that ingested existing, new operational, and inspection data sets to perform analysis on spatial data and metadata to be viewed by users on a cloud-based platform. Assets were viewed remotely with attached metadata for analysis and measurement in a 3-dimensional environment. Machine learning was used to analyze LiDAR and imagery data for automated identification of encroaching vegetation and avian covers. It was also clearly identified there would be an immediate increase in efficiencies and utilization by providing access to data sets currently collected and analyzed by individual stakeholders. Efficiency would also increase by providing LiDAR, imagery and other UAS data collected during design and as-built phases of engineering to other stakeholders or a data management tool for analysis and inspection.

It is recommended that SDG&E pursue additional evaluation of UAS technology for stakeholder groups within the company that will benefit from the aggregation of various sources of data into a data management platform that also provides advanced analytical capabilities. The evaluation should also focus on developing requirements for integration of this data management platform into the SDG&E information technology environment. While the project successfully demonstrated the value of advanced analytics using UAS data, additional evaluation is required before operational deployment of the data management platform.

Table of Contents

1.0 Introduction 1
1.1 Project Objective 1
1.2 Issue/Problem Being Addressed 1
1.3 Project Task Summary 2
1.3.1 Phase 1 – SDG&E Internal Project Work Prior to Contractor Procurement 2
1.3.2 Phase 2 – Project Development Activities 3
1.3.3 Phase 3 – SDG&E Internal Project Work prior to project conclusion 5
2.0 ASD Operations Assessment 7
2.1 ASD Operations Summary 7
2.1.1 ASD UAS Data Collection 11
2.1.2 Contractor UAS Data Collection 11
2.2 Stakeholder Summaries 13
2.2.1 Vegetation Management 13
2.2.2 Electric System Planning, Engineering and Construction 15
2.2.3 Environmental Planning 16
2.2.4 Land Management 19
2.2.5 GIS Group 21
2.3 Use Case Summary 22
2.4 Project Baseline Data Set 22
2.5 Test Case Summary 23
2.5.1 Avian Cover Identification 23
2.5.2 Vegetation Encroachment Identification 24
2.5.3 Cataloging and Remote Asset Management 24
3.0 Vendor Tools and Test/Use Case Results 25
3.1 Vendor Tool Overview 25
3.1.1 Vendor A 25
3.1.2 Vendor B 25
3.1.3 Vendor C 26
3.1.4 Vendor D 26
3.2 Test/Use Case Results 27
3.2.1 Avian Cover Identification 27
3.2.2 Vegetation Encroachment Identification 46

3.2.3 Cataloging and Remote Asset Management 63
3.2.4 System Setup and Integration with PLS-CADD and GIS 75
3.2.5 Demonstrate Data Lifecycle Management 81
4.0 Project Outcome 94
4.1 Key Findings 94
4.2 Recommendations and Next Steps 94
5.0 Technology Transfer Plan 96
5.1 SDG&E Technology Transfer Plan for Project Results 96
5.2 Adaptability to Other Utilities and Industry 96
6.0 Metrics and Value Proposition 97
6.1 Metrics 97
6.2 Value Proposition 97
7.0 Appendices 99
7.1 Appendix A: Aviation Services Department UAS Workflow 99
7.2 Appendix B: Vendor-Stakeholder Use Case Matrix. 101
7.3 Appendix C: Proposed DMP 103
7.3.1 Proposed DMP Architecture Diagram 103
7.3.2 Proposed DMP Architecture Diagram Reference Chart 105

List of Tables

Table 1. ASD Services 8
Table 2. Data Utilization by Stakeholders 9
Table 3. Sensors from ASD and SDG&E UAS Contractors 10
Table 4. Potential Applications for UAS Data 12
Table 5. Potential Stakeholder Participants 13
Table 6. Accuracy Measurements for the Detection of Avian Covers 30
Table 7. Pole Count 38
Table 8. Results of precision 44
Table 9. Ability of vendors to identify the avian covers 45
Table 10. Vendor Results Comparison 63
Table 11. Additional Applications of UAS Data For Asset Management 72

List of Figures

Figure 1. Example of Avian Cover Detection 28
Figure 2. Example of Pole Detection with No Avian Cover Detection 29
Figure 3. Advanced Search 31
Figure 4. Visual Map of the Avian Cover Detection 31
Figure 5. Example of Closest Pole Image 32
Figure 6. Example of Avian Cover Detected 32
Figure 7. Image Containing an Avian Cover 35
Figure 8. A selection of Avian Covers From the UAV imagery 35
Figure 9. A selection of Avian Covers from the UAV imagery Continued 36
Figure 10. Image Segmentation Via Machine Learning Platform 37
Figure 11. The Display of Avian Covers Alongside Contextual LIDAR & Image data 38
Figure 12. The Display of Avian Cover Symbols To Enable Rapid Review Of The Line Status 39
Figure 13. Target Parameters 40
Figure 14. Example of Pylon Head With Avian Cover Label 41
Figure 15. Example of Pylon head Without Avian Cover Label 42
Figure 16. Bounding Boxes Based on Trained Model 43

Figure 17. Vegetation Encroachment Zone Definitions 46
Figure 18. Link 3 Closest Vegetation Assets 47
Figure 19. Encroachment Workflow Diagram 48
Figure. 20 Advanced Search 49
Figure 21. Visual Map of Detected Vegetation Encroachments 49
Figure 22. Sample LiDAR Views of Encroachments 50
Figure 23. Classified Vegetation Encroachments. 52
Figure 24. Comparison of Tree Detection Results from Algorithm A 56
Figure 25. Comparison of Algorithm A and B Results 57
Figure 26. Comparison of Tree Detection Results (red) and SDG&E Dataset (yellow). 57
Figure 27. Calculation of the Three-Dimensional Distance between Vegetation and Wire 58
Figure 28. LiDAR Point Cloud Colored by Class 59
Figure 29. Dangerous Vegetation Detection in LiDAR Point Cloud (shown in red) 60
Figure 30. Buffers showing trees within them 61
Figure 31. Buffers Around Pylons and Vectored Pylons 61
Figure 32. Example of Vendor A Home Screen 64
Figure 33. Feature Coded LiDAR Derived From UAS 66
Figure 34. The supplied vectors from the PLS-CADD model. 66
Figure 35. UAS LIDAR Alongside Extracted CAD Model. 67
Figure 36. Oblique UAS Image 67
Figure 37. The UAV-Derived Structure Images 68
Figure 38. Example of Vendor D Home Screen 71
Figure 39. Example of File Attachment Screen 71
Figure 41. Example of File Attachment Screen 85
Figure 42. Role Based Access Control Component Diagram 87

Abbreviations & Acronyms

Acronym	*Definition*
AI	Artificial Intelligence
AOM	Aviation Operations Manual
API	Application Programming Interface
APM	Asset Performance Monitoring
ASD	Aviation Services Department
BAK	Backup File
BOM	Bill of Material
CAD	Computer Aided Design
CAPP	Computer Aided Process Planning
CIP	Critical Infrastructure Protection
CR	Change Request
DLM	Data Lifecycle Management
DMP	Data Management Platform
DSM	Digital Surface Model
DTM	Digital Terrain Model
DXF	Drawing Exchange Format
EAM	Enterprise Asset Management
EPIC	Electric Program Investment Charge
ERP	Enterprise Resource Planning
Esri	Environmental Systems Research Institute
FAA	Federal Aviation Administration
FiRM	Fire Risk Management
FMV	Full Motion Video
FTP	File Transfer Protocol
GIS	Geographic Information System
GPS	Global Positioning System
IDMP	Image Data Management Platform
IR	Infrared
IT	Information Technology
KML	Keyhole Markup Language
KMZ	Keyhole Markup language Zipped
LAS	Log ASCII Standard

LDAP	Lightweight Directory Access Protocol
LiDAR	Light Imaging Detection and Ranging
NCR	Non-Conformance Report
NERC	North American Electric Reliability Corporation
OGC	Open Geospatial Consortium
PLM	Product Life Cycle Management
PLS-CADD	Power Line Systems - Computer Aided Design and Drafting
POC	Proof of Concept
PPK	Post Processed Kinematic
PS	Part Shortage
PSEP	Pipeline Safety Enhancement Plan
QR	Quality Report
RACI	Responsible, Accountable, Consulted, Informed
RBAC	Role Based Access Control
RD&D	Research, Demonstration and Deployment
RGB	Red, Green, Blue
RoW	Right-of-Way
RTK	Radio To Kinetic
SDG&E	San Diego Gas & Electric
SHP	Shape file
SMS	Safety Management System
SN	Serial Number
SOP	Standard Operating Procedures
SPARC	SDG&E Portal for Awareness and Real-time Collaboration
SRTM	Shuttle Radar Topography Mission
SQL	Sequential Query Language
TIFF	Tag Image File Format
TL	Transmission Line
T&D	Transmission and Distribution
UAS	Unmanned Aerial Systems
UAV	Unmanned Aerial Vehicle
UV	Ultraviolet
WCS	Web Coverage Service
WFS	Web Feature Service
WMS	Web Map Service

1.0 Introduction

1.1 Project Objective

The objective of EPIC-2, Project 6 (Collaborative Programs in RD&D Consortia) is to accomplish highly leveraged demonstration work through industry collaborative R&D organizations. The focus of this project module on Unmanned Aerial Systems (UAS) Data Lifecycle Management and Deep Learning Demonstration was to demonstrate cloud-based platforms that could integrate with existing and future San Diego Gas and Electric (SDG&E) infrastructure, software applications and legacy data sets with the ability to ingest, store, analyze and report on SDG&E assets derived from Geographic Information System (GIS), Power Line Systems - Computer Aided Design and Drafting (PLS-CADD), UAS-collected data, and various other sources. The purpose for the research was to assist in identifying potential uses for the data among stakeholders. The goal was to determine an appropriate data lifecycle management plan that benefits most stakeholders and incorporates planning, design, construction and maintenance.

Other goals included process improvements in UAS data collection and insight into standardized requirements based on usage and tool criteria. SDG&E also desired a plan for integration with Environmental Systems Research Institute (Esri) GIS and PLS-CADD programs, along with legacy stakeholder platforms such as PowerWorkz and the SDG&E Portal for Awareness and Real-time Collaboration (SPARC) used by Vegetation Management and GIS. In this project module, SDG&E aimed to provide the Proof of Concept (POC) that machine learning tools have the ability to ingest various data sets and perform tasks such as asset identification through image analysis and spatial proximity determined by analysis of Light Imaging Detection and Ranging (LiDAR), and imagery or full motion video.

The end goal was to identify process improvements creating a more reliable network with increased safety and lower risk, while lowering overall operational costs and passing these savings on to customers.

1.2 Issue/Problem Being Addressed

SDG&E currently collects LiDAR, Red, Green, Blue (RGB) video and imagery, Infrared (IR) and Ultraviolet (UV) data for the company's electrical system each year, for a multitude of business cases. All aerial data collection is coordinated through the Aviation Services Department (ASD) group. Data is collected for distribution and transmission line design, as-built, line/assets inspection, marketing, sales and operational efforts. The UAS imagery data is subsequently provided directly back to the requesting stakeholder without the capabilities for dissemination to other potential end users.

The current workflow has resulted in large collections of useable data being stored on individual department's storage drive, not accessible by other stakeholders within SDG&E. Storage drives are managed by permission only to individual personnel within each department thus preventing

other groups from accessing data and duplicating the information in storage. There is currently no IDMP in place to link all the storage drives, enrich data with other attribute information, manage the lifecycle of data or become accessible by others within the company. Resulting silos of data sources and the high-level assessment of ASD operations are described and diagramed in more detail in Section 2.0 below.

The standardized collection and dissemination of data sets have the potential to provide substantial increases in productivity and efficiency throughout SDG&E, resulting in an overall decrease in total cost to ratepayers. Increased sharing of data through an Image Data Management Platform (IDMP) available to all company groups would mitigate safety concerns for personnel accessing remote assets or difficult access issues where SDG&E is unsuccessful in gaining entrance. It would also allow stakeholders with limited staff resources to focus their efforts through automated identification and reporting of an assets' status or location based on specified criteria or thresholds.

1.3 Project Task Summary

The project was implemented in three phases:

- Phase 1 – SDG&E Internal Project Work Prior to contractor procurement that includes
    - Task 1: Development of Project Plan
    - Task 2: Contractor Procurement
- Phase 2 – Project Development Activities
    - Task 3: Baseline Analysis (Evaluate existing infrastructure)
    - Task 4: Requirements Elicitation and Design
    - Task 5: Test System Setup and Integration
    - Task 6: Demonstrate Data Lifecycle Management
    - Task 7: Display Vendor Tools with GIS and PLS-CADD
    - Task 8: Advanced Analytics Demonstration
- Phase 3 – SDG&E Internal Project Work prior to project conclusion
    - Task 9: Finalize Project Report for External Release
    - Task 10: Technology Transfer Plan

A summary of each of the tasks performed during the execution of the project follows. Each of the tasks were performed with direction and input from representatives of each of the participating stakeholder groups described in Section 2.2 below. SDG&E engaged four vendors to utilize their data management platforms to undertake pre-commercial demonstration of the test cases. Due to time constraints, not all the tasks were performed by all vendors, though the POC for the test cases described in Section 3.2 below were demonstrated by each vendor.

1.3.1 Phase 1 – SDG&E Internal Project Work Prior to Contractor Procurement

Task 1 – Development of Project Plan

Objective – Develop detailed work plan for the project.

Approach – The project team met with SDG&E stakeholders to conduct a review of existing processes of data capture from UAS and other applications of data capture. The project team identified conceptual vision for the proposed test platform that could demonstrate multiple use cases leveraging UAS data analytics. The project plan identified staffing requirements for the project, both internal and contracted, with definition of needed skills. Required equipment and other resources were also identified,

Output - Project work plan including technical scope definition, schedule, budget, and staffing requirements was developed

Task 2 – Contractor Procurement
Objective – Procurement of contractor services under contract with Supply Management.

Approach – The project team engaged with a set of contractors. The selected contractors had data management platforms that were uniquely qualified to demonstrate the test cases that were envisioned in the conceptual vision for the proposed test platform. The objective was to leverage multiple vendor platforms in a collaborative manner that would help SDG&E determine the requirements for a UAS data management platform under various operational and business scenarios. The following documents were developed and finalized as part of the contracts package for the four vendors that were selected.

- Detailed scope of work
- Detailed project schedule
- Detailed Project Budget
- Professional services agreement

Output – Contract agreements were finalized with SDG&E supply management and four UAS platform providers that are referenced in the attribution page upfront in the document. A fifth contractor was selected to perform engineering services for the project team to achieve the desired project objectives.

1.3.2 Phase 2 – Project Development Activities

Task 3: Baseline Analysis (Evaluate existing infrastructure)
Objective –Identify existing infrastructure for data collection, storage and dissemination.

Approach – The project team met with SDG&E stakeholders to identify existing and potential UAS workflows and data requirements. Current practices related to flight planning, contractor vetting, quality control, data management and other aviation services functional operations were assessed to make recommendations for areas of improvement.

Output - A 1.25-mile segment of circuit containing 30 poles was selected for analysis on this project and the baseline data set was developed for testing purposes.

Task 4: Requirements Elicitation and Design

Objective – The objective of this task was to develop requirements and design the ingestion of the data provided in the baseline data set or collected independently into a data management platform.

Approach – The project team met with SDG&E stakeholders to assess the requirements for data usage and ingestion for the use cases. These use cases are described in detail, by applicable stakeholder, in Section 2.2 below. Through various meetings, various processes were identified in collection requirements, technological limitations and data overlap between stakeholders.

Output – Test cases were developed from the previously identified use cases using the respondent stakeholders input regarding the possibilities of substantial impact to SDG&E stakeholders, potential benefit to ratepayers and the feasibility of completion within the short duration of the project. A test plan was developed independently by vendors for each test case. The results for test cases are described in further detail in Section 3.2 below.

Task 5: Test System Setup and Integration

Objective – The project team ingested new and existing data sources including still imagery, full motion video, LiDAR, along with other design and inspection data to a replicated IDMP for analysis by various tools.

Approach – Data sources were organized, cataloged and data reported from various data sources such as (but not limited to) LiDAR, RGB imagery with Global Positioning System (GPS) metadata and SDG&E GIS records to organize and catalog assets with minimal human interaction. They were also asked to demonstrate the ability to reconcile records from different data sources on the same asset and report any discrepancies back to SDG&E's GIS group to allow for database corrections. This task also included installing, configuring and testing tools after the ingestion and analysis of the provided data sets.

Output – The project team setup the various tools and integrated the dataset into the test system.

Task 6: Demonstrate Data Lifecycle Management

Objective –Demonstrate the lifecycle of the data within the tools using automated data lifecycle workflow to manage/purge/archive data according to stakeholder defined policies and SDG&E Information Technology (IT) Security protocols.

Approach – The test system was demonstrated with functionality using a web browser or thin user client for SDG&E stakeholders and the EPIC 2 Project #6 Team. A live session

demonstration was provided by vendors to stakeholders for end users to gain experience with the vendor tool and proposed test cases. Lightweight documentation specific to test/use cases, functionalities, workflows and datatypes were created by vendors and delivered to SDG&E.

Output – The results for data lifecycle management are described in further detail in Section 3.2.5 below.

Task 7: Display Vendor Tools with GIS and PLS-CADD
Objective – Develop a plan to integrate vendor tools with GIS and PLS-CADD..

Approach – The vendors were requested to provide a plan for integration of their tools with GIS that captures the technology, business practices, and configurations required for future integration. Vendors were also requested to provide a workflow or show the ability to display LiDAR data and other PLS-CADD design components in their respective tools, and provide a method for query and/or download if possible. All vendors cataloged and ingested various GIS data sets and display them within their tools. Vendor B, Vendor C and Vendor D ingested PLS-CADD exports for visualization in their respective tools. Vendor C demonstrated the ability to export PLS-CADD specifications and 3D models for visualization and analysis in Vendor C Tool.

Output – The results for GIS and PLS-CADD integration are described in further detail in Section 3.2.4 below.

Task 8: Advanced Analytics Demonstration
Objective – Demonstrate deep learning analytics using UAS collected imagery and LiDAR data sets.

Approach – The project team demonstrated avian cover identification and the level of confidence for each identification. Demonstrated the ability to automatically detect vegetation within a specified encroachment zone to facilitate focused and proactive vegetation management.

Output – The results of avian cover detection are described in further detail in Section 3.2.1 below and the results of vegetation encroachment identification are described in further detail in Section 3.2.2 below

1.3.3 Phase 3 – SDG&E Internal Project Work prior to project conclusion

Task 9: Comprehensive Final Report
Objective – Develop comprehensive final report

Approach - A final report will be written to align with a final report outline developed by the project team at the start of the project. The outline should not conflict with the guidelines for final reports developed by the utility administrators of EPIC, but it should be more complete and

follow a storyline of what occurs sequentially in the project. It should be prepared as a draft in MS Word for review and comments and a revision into final form, based on comments received on the draft. The final report is the crucial documentation of the project work, needed to assure that the information developed in the project does not get lost and is available to prospective users.

Output - Comprehensive final report as presented in this document

Task 10: Technology Transfer Plan

Objective – Develop technology transfer plan to share results with all stakeholders

Approach - A technology transfer plan was developed to share the results with SDG&E stakeholders and with other stakeholders in the industry that would benefit from this pre-commercial demonstration

Output - Technology transfer plan as documented in Section 5 of this report

2.0 ASD Operations Assessment

The ASD within SDG&E manages all aviation operations. They are responsible for coordination of flights for manned aircraft, UAS operations, updating SDG&E's Aviation Operations Manual (AOM), and vetting contractors using Unmanned Aerial Vehicles (UAVs) for data collection efforts. ASD is continually looking for process improvements to increase efficiencies and safety. Vendors were requested to evaluate current ASD operations and provide input to guide aerial data governance as well as overall processes and procedures.[1]

2.1 ASD Operations Summary

SDG&E's ASD currently handles all requests for UAS data from the stakeholders. ASD currently staffs 7 people that handle UAS operations. ASD informs stakeholders that UAS services are available through an internal bi-monthly newsletter that is distributed to all stakeholders. Stakeholders request data from ASD through request via SDG&E web portal or the "Aviation In-Box", which is an e-mail address that ASD has set up specifically for incoming requests. The current ASD workflow is summarized in *Appendix A: Aviation Services Department.*

[1] Portions of Section 2 were developed and/or quoted directly from vendor presentation or reports given to the EPIC-2 Project #6 team.

ASD provides support to all SDG&E stakeholders and performs UAS and helicopter aerial data collection for the specific needs of a project. Table 1 contains a sample of services that ASD has provided via UAS, manned aircraft and contractors:

Table 1. ASD Services

ASD Services		
Contractor Vetting	Line Inspection	QC Inspection of Pole Tension
Dam Inspection	Overhead Patrols	Structure Assessment
Demo Flights	Photo/Video for Marketing	UAS Training Flights
Flight Demos for Public Affairs	Photo/Video of Security Gates	Video of Gas Valve Restoration for Pipeline Safety Enhancement Plan (PSEP)
Imagery for Preconstruction	Photos of High Voltage Signs	Video of Mission Control Fence Lines
Inspection of High Pressure Gas Line	Photos/Videos	Video of TL on CNF
Landscape Projects	Pole Assessment	Yard Inspection

The services ASD provides to stakeholders and their use of the data varies greatly. Table 2 depicts the different types of data utilized by stakeholders that requested data from the ASD at the time of this project.

Table 2. Data Utilization by Stakeholders

Stakeholder	RGB Imagery	RGB Video	LiDAR	Infrared	Ultraviolet	PLS-CADD
Transmission/Distribution Maintenance	X	X		X		
Transmission/Distribution Engineering	X	X	X			X
Electric Standards	X	X				
Environmental	X	X				
Emergency Services	X	X				
Facilities	X	X		X		
Legal	X	X				
Construction Supervisors	X	X				
Media & Public Relations	X	X		X		
Vegetation Management	X	X				

After the review of incoming requests from stakeholders, the decision is made whether data acquisition would be better handled by ASD or a contractor primarily based on scope, schedule, data type, equipment and available personnel requirements. If it is determined that the data acquisition should be executed by ASD further review is initiated to determine the appropriate method for data collection, UAS or helicopter. If the data is being acquired by a contractor, the appropriate vendor is selected based on sensor requirements and availability. The following table shows the types of sensors available from ASD and SDG&E UAS contractors:

Table 3. Sensors from ASD and SDG&E UAS Contractors

	RGB Imagery	RGB Video	LiDAR	Infrared	Ultraviolet
SDG&E Aviation Services Department	X	X	X	X	
AES	X	X			
Burns & McDonnell	X	X			
Flight Evolved	X	X	X	X	
Skyscene	X	X	X	X	
Unmanned Aerial	X	X		X	
WH Pacific	X	X			
Birdseye Aerial	X	X		X	

UAS data collected with these types of sensors has many potential uses for various stakeholders. Some of the additional applications identified by the ASD group and vendors which were not tested during this project are described as follows:

- 3D pole modeling for structural alignment providing the added benefit of pole integrity risk management.
- Thermal Scanning would be beneficial for component and line assessments. Thermal scanning can provide identification of hot spots and this process has the potential of being automated utilizing machine learning.
- Corona Scanning can provide condition assessments on SDG&E facility components for early identification of failing components to provide proactive mitigation of risks.
- Emergency Planning & Response, UAS has the unique ability to access areas that would be hazardous for personnel to enter. UAS can give a “bird’s eye” view of terrain

enabling enhanced planning, management and decision making.

2.1.1 ASD UAS Data Collection

If UAS is found to be best suited for the stakeholder data acquisition, ASD begins a risk assessment by accessing available data on the internet using resources like "Google Earth". While performing the risk assessment ASD looks for things like schools, livestock, homes, etc. ASD also checks to ensure that the flight will be compliant with current Federal Aviation Administration (FAA) regulations for the area where they are anticipating data collection via UAS. ASD has waivers in place through the FAA to remain in compliance with Part 107 of Federal Regulations when flying in controlled airspaces. Homeowners that have property that fall within the flight path of the UAS are given notice using the existing SDG&E Public Outreach phone system. If these factors cannot be safely mitigated, the flight will be postponed, and the request is declined. Mobilization from the ASD is achieved within hours of receipt of stakeholder request. On-site the ASD UAS team goes through pre-flight checklists to ensure safety, review scope, perform hazard analysis, etc. The UAV is flown by an FAA Part 107 Certified Remote Pilot and the data is collected. ASD has provided RGB photos and videos to stakeholders using this process.

Data is collected and processed by ASD. Once processed the data is delivered via thumb drive or email directly to the stakeholder. The data is also stored on an ASD laptop computer which is currently not accessible to other SDG&E stakeholders.

2.1.2 Contractor UAS Data Collection

Contractors provide various data sets including RGB imagery, LiDAR, IR, UV and PLS-CADD files as needed by requests from stakeholders via ASD request process. Contractors are also required to be vetted by ASD which is executed in three phases:

2.1.2.1 Phase 1 - Documentation:

ASD personnel distributes to potential contractors a packet indicating the necessary documentation to proceed in the vetting process. This information is to be completed and sent back to the ASD via email as the first step in becoming a ASD approved vendor for SDG&E.

Contractors must provide the following documentation to ASD:

- FAA Part 107 Certificate (or Part 61 if operating under a Section 333 exemption)
- Certificate of Insurance for $10M
- Type of UAS to be flown
- Logbook/Pilot Resume/Experience flying for utilities
- Proof of FAA registration

<u>If available, provide the following documents</u>

- Checklists
- Safety Management System manual

- Maintenance practices
- Risk assessment worksheet

2.1.2.2 Phase 2 – In-person Interview:

Meet with vendor to introduce/review the following:

- SDG&E AOM
- SDG&E Safety Policy
- Risk Assessment
- TracPlus and flight following procedures
- Contractor notification form

2.1.2.3 Phase 3 – Flight Operations:

Vetting Flight - After a vendor is approved to provide UAS services for ASD, they must submit their flight plan to ASD before executing any UAS mission. Upon approval the vendor mobilizes, follows pre-flight procedures for safety and accuracy, acquires and processes the data. Data is delivered directly to the stakeholder in this workflow as well.

SDG&E solicited its stakeholders to gauge interest in UAS data collection services and they were informed that the focus of this project would be on UAS and field data collection in the areas shown in table 4 below:

Table 4. Potential Applications for UAS Data

Potential Applications for UAS Data		
Construction and Maintenance	Fire Risk Mitigation	Design Vegetation Management
GIS	Environmental	Transmission & Distribution Operations
Grid Operations	Land Management	Transmission & Distribution Design

The SDG&E stakeholders identified for potential participation and solicitation on this project are included below in table 5:

Table 5. Potential Stakeholder Participants

Potential Stakeholder Participants		
Electric Transmission and Distribution Engineering	Vegetation Management	Operating Districts
Electric System Operations	Land Management	Fire and First Responder Coordination
Distributions Planning	Fire Risk Mitigation	Environmental Resources
Transmission Planning	Project Management	Asset and Data Analytics

2.2 Stakeholder Summaries

SDG&E stakeholders were identified by project leadership with the intent to review and document each group's workflow processes and specific requirements for data usage and ingestion. The stakeholders that were identified for participation based on project interest staffing resources were Vegetation Management, Electric Distribution Planning, Environmental Planning, Land Management and the GIS group. Each participating stakeholder was interviewed and/or contacted through questionnaire to identify their data usage and ingestion, required file types and software platforms used during daily processes. Use cases developed from this information were later refined to specific cases tested during the EPIC 2 Project #6. Specific test cases and POCs were designed to meet the requirements for the identified stakeholders. Additionally, use cases and future applications of the data and software were documented to help guide future test cases. Select file formats were identified based on stakeholder needs to ensure the data collection efforts and resulting products met those requirements.

Like the vendors, stakeholders were asked to provide existing and potential use cases for the project. Stakeholders responding to the initial request for participation in the project included Vegetation Management, Electric Distribution Planning, Environmental Planning, Land Management and GIS groups. The results of the inquiry are diagrammed in Appendix B: Vendor-Stakeholder Use Case Matrix.

2.2.1 Vegetation Management

The Vegetation Management team is directly responsible for ensuring that vegetation growth within SDG&E territory is identified and documented for yearly maintenance. It is critical for Vegetation Management to perform routine maintenance for public safety and to be in compliance with regulations set forth by the CPUC. The maintenance prevents vegetation encroachment near power lines. SDG&E has a mission to prevent and reduce power outages for their customers. Power outages are commonly caused by vegetation encroachment as overgrown

and diseased vegetation and trees near power lines contact SDG&E structures and energized conductors.

Vegetation Management department currently uses handheld measuring devices to identify vegetation growth, often times in treacherous conditions. From a safety perspective, vegetation encroachment not only causes power outages, but can also spark wildfires. SDG&E employs certified arborists and tree pruning crews year-round to inspect and maintain vegetation clearance standards by ensuring trees and vegetation are cut back to the appropriate distance from distribution power lines. SDG&E currently utilizes a work management application, PowerWorkz, to track the inspection and maintenance schedule of all surrounding trees and their conditions. The implementation of the system has significantly reduced power outages. Leveraging UAS capabilities to gather data regarding vegetation and plant conditions will further enhance work management applications to benefit ratepayers, improve safety, and improve SDG&E's core business.

Use cases for UAS data within Vegetation Management include:

1. **Vegetation Encroachment Identification.** See Test Case in Section 2.5.2 below.

2. **Corrected Locations of Current GIS Assets.** Within SDG&E GIS database there are geographic locations for assets including vegetation. These locations can be erroneous up to a couple hundred feet for certain SDG&E assets. Through data collection using UAS technology these locations could be corrected in the GIS database.

3. **Change Detection on Subsequent Data Sets.** Vegetation Management has a database cataloging species and growth rates vegetation within regulatory limits of SDG&E transmission and distribution assets. Vegetation classification and measurements are observed and recorded by SDG&E field employees on the ground. Vegetation Management is interested in utilizing UAS captured data couple with analysis tools to determine vegetation location, species and separation from SDG&E above ground electrical assets. Additionally, UAS captured data integration into this process would alleviate the necessity of manned field observations to monitor vegetation encroachments and growth rates.

   Currently Vegetation Management does not use nor has access to the imagery and LiDAR data captured through the siloed stakeholder based ASD process. Vegetation management has expressed an interest in having access to collected data along with gaining notification for future UAS capture missions. The group could provide input on collection parameters prior to UAS missions which would allow for vegetation observations and analytics. Additionally, a centralized database for all captured imagery products and LiDAR would allow the vegetation management team to view conditions and plan future projects. Vegetation Management would also like an automated

notification process for changes to assets that require monitoring and maintenance by the group.

4. **Sag and Sway Calculations for Encroachments.** Electrical load, ambient temperatures and wind speed create sag and sway in overhead electrical lines and facilities. There are minimum distances between wires, poles, the ground and buildings. These distances are codified in state electrical codes. Sag and sway potential must be calculated as part of considerations for Vegetation Management.

   PLS-CADD currently provides calculations based on existing components to determine sag and sway potential. In a future state, the Vegetation Management group would like to see a platform that can identify encroachments into the sag and sway encroachment area. These areas can vary based on type of line and what equipment is being used.

5. **Identification of Protected Vegetation and Wildlife Species.** The Vegetation Management group is responsible for ensuring that protected species of wildlife and vegetation is not impacted by the operations within their group. Protected vegetation and wildlife species are cataloged in an internal database within the Vegetation Management group.

   Data collected by UAS could positively impact the way Vegetation Management catalogs and assesses potential impact of its operations on these protected species of wildlife and vegetation.

6. **Use Asset Metadata to Predict Growth Rates.** Vegetation Management identified a potential opportunity for leveraging metadata that currently exists within SDG&E databases to predict growth rates of vegetation. The stakeholder group would like to see a future state development of technology to automatically identify potential growth in areas that may come into contact with SDG&E lines.

7. **Use Repetitive Data Sets to Predict Growth Rates.** By collecting repetitive datasets Vegetation Management foresees an opportunity to better predict growth rates of vegetation that has potential to come into contact with SDG&E lines.

2.2.2 Electric System Planning, Engineering and Construction

Executes preliminary planning of electrical distribution lines, prior to engineering. This stakeholder used PLS-CADD format files for distribution pole planning in areas that are often inaccessible to regular ground inspection. Potential uses and impacting transmission and distribution engineering, design, construction standards, materials and project management.

Use Cases Identified for Electric Distribution Planning:

1. **Cataloging and Remote Asset Management.** See Test Case Section 2.5.3 below.

2. **Remote access.** SDG&E has transmission and distribution lines that can be found in treacherous terrain that is difficult for field crews to access. These environments can present many safety concerns that could be mitigated with UAS technology.

   By utilizing UAS technology some of these risks can be alleviated. Field crews will not have to travel by foot as far into unfavorable terrain if the data can be collected by UAS. Pole inspections would require less hiking as a UAS could be launched from a nearby access road and flown to inspect SDG&E assets and collect imagery data on the assets

3. **PLS-CADD integration.** PLS-CADD is a sophisticated three-dimensional engineering model. This model includes the terrain, the structures and all the wires. The model can be viewed in a number of different ways: profile views, plan views, plan & profile sheets, 3-D views, staking lists. PLS-CADD is software used to draft and model SDG&E powerlines. Integration of PLS-CADD was identified from the onset of this project as something each vendor would be required to exhibit within their respective platform.

2.2.3 Environmental Planning

The Environmental Planning group at SDG&E is responsible for the stewardship of the Earth's natural resources and conserving plant and animal species along with their natural habitats. It is their responsibility to protect the wellbeing of SDG&E employees, the public, and the environment and promotes sustainable energy production to meet the needs of the present without impacting the ability of future generations to meet their needs.

The Environmental Planning Group identified the benefit of collecting LiDAR and image data via UAS platform to provide current geospatially accurate electrical equipment and terrain data. The data would be an enhancement to the existing process where the team is using imagery and assets within the Esri GIS environment. Electrical assets within Esri GIS database are based amalgamation of source data derived from records and field measurements. The source data ranges from digitizing facilities from historical paper maps to survey grade geodetic positions. For this reason, and the inclusion of errors due to manual digitizing, projection transformations, some pole and wire locations derived from the GIS database can be off the actual location by a hundred feet or so. The Enterprise GIS Solutions team will correct and re-digitize GIS data, and push the updates to GIS databases, that can be accessed by other departments through GIS applications. With access to current data, the environmental team can complete effective desktop reviews by aligning accurate electrical equipment positions with current photography, cultural resources, water features, vegetation and land ownership. The enhanced desktop reviews will decrease project turnaround time to schedule, approve and execute projects.

Additional benefits would be to limit vehicle and personnel incursions into environmentally sensitive areas.

Use cases identified for Environmental Planning:

1. **Asset cataloging.** See Test Case Section 3.2.3 below

2. **Avian covers.** See Test Case Section 3.2.1 below

3. **Corrected locations of current GIS assets.** The Environmental Planning group for SDG&E would benefit from accurate locations of assets that are mapped and databased within the enterprise GIS environment. When the UAS derived LiDAR and photography data for transmission and distribution circuits is coupled with positional constraints, the assets can be verified via an office review with a high level of confidence. The asset information currently available lacks overall positional confidence to allow for effective environmental planning. If the information available to the Environmental Planning group was accurate, it would create an ability to conduct effective internal desktop reviews of projects. Increasing data accuracy would also increase stakeholder confidence that the pole and associated data locations are accurate in relation to surrounding features. There are several types of features that would be of interest to the Environmental group including vegetation, cultural resources, water features, land ownership, etc.

   Having the ability to quickly access data through the desktop review process would allow the Environmental group to more efficiently review and release projects. Increased data accuracy would reduce the need for site inspections and surveys. These procedures would save time, reduce costs, limit impacts on the environment and improve system reliability.

4. **Access to recent imagery via GIS** – In a similar vein to the use case described above, the Environmental group would benefit greatly from having access to recent imagery in GIS. One potential use for this would be to examine the surroundings of a pole that might need service work performed to minimize impact on the environment in that area.

   Recent imagery provided by GIS would also assist the Environmental group with enhanced ability to provide a desktop review of an area that might have land use conflicts with sensitive locations. Enabling review of hard to access locations like flooded access roads or no access roads.

5. **Annual or Bi-Annual update of assets.** The Environmental Planning group currently relies on existing imagery data as it exists in the GIS database. As UAS practices grow and develop the Environmental Planning group would see an immediate benefit to collecting asset data via UAS on a regular basis, annually or bi-annually. Having recent

imagery can help the group determine what the environmental status of any asset locations that may require a field visit by SDG&E field crews.

6. **Accurate GIS parcel layer.** Parcel layers currently being utilized by the Environmental group can have positional inaccuracies. For projects that deal with sensitive boundary lines, UAS data can be combined with a field survey to provide an accurate parcel lines and existing conditions imagery.

7. **Identifying physical encroachments.** SDG&E GIS has location data on field assets. However, this data can be inaccurate (sometimes up to hundreds of feet). Having the ability to view recent, accurate orthorectified imagery will help the Environmental group identify physical encroachments into environmentally sensitive areas or other SDG&E assets.

8. **Best practices for Data Management.** Data management is an important component necessary for successful implementation of UAS collected data. SDG&E has "silos" of data when it comes these types of datasets. When a group asks for imagery to be collected it is delivered only to the group requesting these services.

   SDG&E would benefit greatly from a unified data management platform. The UAS data collected from the various internal groups and vendors could be ingested into a single platform. The platform could serve as the repository for the UAS data and the source for access to the many stakeholder groups within the company. There would be a standard for data storage and dissemination companywide that would better serve the stakeholders.

9. **Identification of protected vegetation and wildlife species.** SDG&E is committed to protecting the natural resources of California including protected vegetation and wildlife species. Identifying vegetation is currently done manually by field crews on the ground. Identified species are cataloged and put into a database where they can be monitored and viewed via GIS. Wildlife species and nests are identified in a similar manner and stakeholders can view areas that have wildlife concerns.

   In a future state the Environmental group would see a benefit in having a platform that can natively locate and identify wildlife and vegetation through deep learning classification. This would provide a cost benefit by deterring the use of field crews for certain applications. By utilizing machine deep learning a future state platform could potentially locate vegetation and wildlife a field visit might miss. By reducing the amount of field crew utilization this would also prevent exposure to possible safety hazards in environments that can be difficult to access on foot or by vehicle.

10. **Standardization of collection requirements.** Data collection via UAS or fixed wing methods can often produce similar results. Sometimes the data collected is in the correct location for the Environmental group to utilize but the imagery is not captured from a compatible altitude, angle, orientation, etc. Another problem indicated by the Environmental group is that the data being viewed is too old to be used for the group's purposes.

    By establishing standards for the collection of UAS data there would be guidance for how the data is collected, when it is collected and with a standard orientation that would work for the environmental group. Some vendors associated with this project have addressed the issue of too low a pixel count associated with this use case. Having a standard camera setting or distance while capturing data based on the abilities of the UAS and safety factors would be a benefit to SDG&E.

If these use cases were pursued and implemented the Environmental group has indicated the following applications that are pertinent to their group: high resolution aerial photography and 360-degree video of proposed projects (i.e., transmission lines, distribution lines, re-conductor, fiber line, access road, staging yard, etc.). This would be similar to an airborne version of Google Street View for a proposed project. This photography and video could assist Environmental in the following ways:

- Desktop review for land use conflicts and sensitive locations.
- Desktop review of hard-to-access locations such as flooded access roads and overgrown access roads or no access roads.
- Preliminary environmental habitat evaluations. Photography/video of entire pole/facility would capture conditions of the surrounding pole and provide a baseline for desktop review.
- Pre-construction condition of the land and surrounding areas that could be compared to post-construction conditions to avoid disputes from land owners (staging yard land owners, county/city roads, etc.). Updated data could also assist in identifying vacant land for potential laydown/staging yards.
- Emergency Assessment Video/photography after a fire to see conditions of electric transmission/distribution facilities and surrounding vegetation.

2.2.4 Land Management

Land Management handles all land issues related to SDG&E, such as easement encroachment enforcement, conflict detection for development proposals, resolving customer disputes, securing SDG&E project staging yards and land rights interpretation. No test cases were put in place for this group.

Use cases identified for Land Management:

1. **Right-of-way/property encroachments** Land Management is charged with identifying Right-of-Way and property encroachments as related to SDG&E assets. Types of encroachments include: buildings, vehicles, storage of materials, etc. Currently they are relying on outdated and often excessively inaccurate GIS data to view SDG&E assets.

   Accurate and up-to-date UAS imagery that is easily accessible would be a benefit to the Land Management group. The group could view the imagery and compare it with the existing base maps to identify potential right-of-way and property encroachments. This type of data would enable the Land Management group to view recent data remotely from a desktop station. The remote evaluation would reduce mobilization and onsite investigations associated with project planning.

2. **Erosion detection.** Land Management is interested in utilizing UAS collected data to identify potential erosion problems that might impact assets. Currently, erosion issues are primarily brought up by customer complaints and field crews. Utilizing accurate, recent imagery, Land Management will be able to assess areas that might be prone to erosion problems. By contrasting imagery observed over an interval of time, Land Management could detect erosion from the overlaid images.

3. **Locating homeless encampments.** The Land Management Group is interested in deploying UAS technology to identify and map homeless encampments within or adjacent to facilities and easements. Imagery and other multi-spectral sensor technology can detect and identify both people and structures from the remote UAS platform without incursion into the encampments. The technology will provide an increased level of safety for SDG&E and consultant evaluation teams. Newer data could be compared with historic data to compare the changes in the camps over time.

4. **Temporal data storage to identify changes over time.** The Land Management group is interested in the development of a historical UAS image and data repository. Temporal imagery is a useful tool to identify changes over time. Some applications include right of way encroachment management, erosion detection and asset management. Currently there is no infrastructure in place to identify changes in assets, environment or facilities within SDG&E.

   By using UAS data and a central data management platform for temporal data storage Land Management could leverage historic data to report any changes to SDG&E assets over time.

5. **Accurate GIS parcel layer.** SDG&E GIS currently contains raster data obtained through contractors and vendors data. SDGE is currently pursuing the options to add this raster data as reference to advanced analytics and GIS feature location accuracy. Land

Management can view GIS data to give them an idea of where the parcels and facilities are located in a general area, but it is often not accurate enough to utilize for any kind of meaningful decision making.

By incorporating UAS data into Land Management's parcel data it would give the group a clearer picture of what the conditions are like on the ground and how they compare to the parcel lines. This application would also be useful in identifying encroachments.

6. **Corrective Maintenance Program**. Although Land Management is not responsible for managing the Corrective Maintenance Program, they are often heavily involved. A common example is when maintenance needs to be performed on a SDG&E pole, but the landowner has placed fences or structures around the pole preventing access to the pole. LM will get involved, research easements, utilize current and historical aerial photography and resolve the access issue with the landowner.

   By utilizing UAS data, Land would be able to better track what the encroachment looks like and when it may have started happening. Historical information and photographs of facilities are always useful for these types of issues.

2.2.5 GIS Group

The **GIS Group** interacts and support many stakeholders in their business processes. The groups included but are not limited to the Analysis Group, Enterprise GIS Solutions, GIS Business Solutions, Transmission Engineering, Electrical Distribution Operations, Planning, Engineering, Emergency Operations Center, Vegetation Management and Environmental/Cultural. Much of their GIS data is available through the SPARC interface (SDG&E's proprietary GIS portal application relating to Transmission, Distribution, Emergency Operations Center, etc.).

SDG&E's GIS team receives monthly GIS base data updates via contract surveyors and GIS vendors. Additionally, the group has a very active data editing and management effort, performing daily reconciling and posting of edits. On any given week, nearly all circuits have some sort of edit work performed on them. Knowing of updated and current imagery for a given area would assist in both accurate visualization and editing.

The GIS group does not currently request UAS support from the ASD group, though they are aware that the option is available. The GIS team would like to incorporate data generated by UAVs across the board, they have specific interest in the vegetation management use case as well as asset tagging. The group would like to be able to have an automated process to determine images that relate to field assets and tag them or link them to the GIS feature class.
To keep the online GIS portals running at acceptable speeds, the GIS group would like to have a feature layer that could be queried that shows the extent of UAV data without returning the

imagery until it is specifically requested. The feature layer would be updated as needed as field data is collected and made available to the portal(s). Also, the GIS team would like to get the Ortho-rectified imagery added to the GIS applications as base maps, to provide accurate location, and elevation reference to the Editor group for digitizing the assets.

2.3 Use Case Summary

Interviews with stakeholders and assessments of workflows, user platforms, and data management platforms many use cases were identified. Those use cases also helped to identify potential benefits common to multiple stakeholders and their need to catalog and manage assets remotely, such as the ingestion of meta-data tagged RGB imagery or shape files, and the ability to be able to query by asset or geographic location. The used cases identified have impacts to staff and public safety, data lifecycle management, file storage and end user access.
These use cases were reviewed by the EPIC 2 Project #6 Team and test cases described in Section 3.2 below were developed to showcase vendors ability ingest, analyze and report on UAS data and SDG&E assets. See Appendix B: Vendor-Stakeholder Use Case Matrix. for a matrix of use cases identified per stakeholder.

2.4 Project Baseline Data Set

To perform the test cases a data set including the necessary files to complete the tests was developed. This test segment consisted of a SDG&E 1.25-mile segment of a distribution circuit including 30 poles. The test segment was selected due to previous LiDAR data collection as part of the FiRM program. To improve the test segment data supplementation of oblique and grid RGB photos was performed which increased the analysis performed by vendors. The baseline data set of LiDAR flight data, RGB photos, GIS data, PLS-CADD data, design and construction documents along with other various reports and exports was provided to each vendor allowing them to perform analysis, develop tools, and generate necessary reports for the EPIC 2 Project #6 Team. From the given data set vendor were also able to evaluate SDG&E's existing IDMP, collection methods, standards and procedures for design, construction, as-built and maintenance efforts. Vendors that were not able to collect their own RGB imagery due to various project constraints were provided with additional oblique and grid photos for analysis. The project baseline data set included the following:

- PLS-CADD models of design and as-built conditions, including Drawing Exchange Format (DXF) exports of the line and pole facilities, LiDAR cloud and stringing charts.
- GIS electric distribution poles and vegetation data in database and shape file formats.
- Log ASCII Standard (LAS) file of LiDAR point cloud.
- Documentation including SDG&E standards, pole identification lists, construction plans, Keyhole Markup language Zipped files (KMZs) and various reports.
- RGB imagery collected during flight mission for PLS-CADD design.
- Additional RGB imagery from other circuits for avian cover analysis totaling approximately 3000 photos.

- Additional RGB oblique and nadir imagery collected at project start was provided to Vendor B, Vendor C and Vendor D only as Vendor A utilized their self-acquired imagery.

2.5 Test Case Summary

UAV, LiDAR and RGB data collection technology has advanced sufficiently so that it may be applied to address specific applications that currently are being implemented through costly field visits and manned aviation assets. By using machine learning and other processing algorithms many of these tasks can be accomplished for less overall expense and on a regularly scheduled basis. By having assets automatically cataloged from high resolution imagery, a more accurate inventory of both assets and asset condition can be maintained. Future applications can then focus on predicting failure based on asset condition as detected by UAS in the normal course of flying SDG&E facilities. In the same manner, vegetation growth and health can be more effectively cataloged, monitored and predictive algorithms can be used to target areas where the growth will soon encroach on the safe zone around the facilities.

A review and assessment of SDG&E's existing UAS operational technologies and practices as applied to their electrical distribution and transmission business was conducted. From the review and assessment, three test cases were developed to collect data via UAVs and apply it to software solutions to satisfy the needs of the use case. All vendors were provided with the SDG&E baseline dataset described in Section 2.4 above. Vendor A chose to utilize their own UAV to collect data for the test cases. Vendor B, Vendor C, and Vendor D were provided with additional oblique and nadir RGB imagery collected by an SDG&E contractor not involved with this EPIC 2 Project #6.

A portion of SDG&E line circuit containing 30 poles was selected for the purposes of testing three use cases.

2.5.1 Avian Cover Identification

Vendors were tasked with ingesting existing RGB data into the vendor proposed platform and demonstrate the platform's capability to identify avian covers, specifically the existence or absence of avian covers where they are required. The long-term goal of this test case is to be able to capture significantly more detailed asset management data and condition assessment with automated machine learning analytics.

This test case was established to evaluate each vendors ability to develop and train machine models that can continuously learn to automatically identify avian covers as new imagery data is introduced to the platform. The model can then be applied to drone captured data to assess whether avian covers are present or need repair/replacement in potential future state.

2.5.2 Vegetation Encroachment Identification

The Vegetation Management Group is responsible for the maintenance and trimming of approximately 4,500 trees and the validation of trimming work performed by contractors on these assets. These services are currently done through physical inspection with hand held measuring devices, often in remote locations and treacherous conditions. This test case was developed to test the ability of vendors to accurately identify vegetation encroaching within a buffer zone around power lines.

2.5.3 Cataloging and Remote Asset Management

SDG&E leadership expressed a desire to use LiDAR and imagery to catalog assets in remote areas and demonstrate change management for those assets. Vendors were also asked to demonstrate extra metadata tagging for relevant data as they relate to assets identified by UAS. This test case was developed to evaluate each vendors ability to ingest SDG&E distribution pole GIS asset metadata into the vendor tool; associate and assign imagery collected via the UAS platform to the GIS asset then demonstrate the ability view, edit and analyze imagery and metadata within the vendors tool.

3.0 Vendor Tools and Test/Use Case Results

The test cases described in Section 2.5 above and baseline data set described in Section 2.4 above were provided to each vendor in order to develop a standardized assessment of each vendor tool. The results for each test case are described in this section.[2]

3.1 Vendor Tool Overview

3.1.1 Vendor A

The Vendor A visualization tool used for this project was Vendor A Tool. This tool demonstrated the ability to ingest and display all files provided in the baseline data set except for the PLS-CADD model file. The demonstration was performed using Chrome web browser.
The tool provides a 2D home page with a map displaying symbols for assets and machine learning analysis results with an option for downloading assets. The tool is also equipped with a 3D reviewer workstation for performing spatial analysis, reviewing asset associated imagery and downloading 3D data sets.

The system allowed control of data sets such as filtered LiDAR point cloud, imagery, video, and annotations in 2D and 3D views. There were also measurement functions such as angle, height, distance, area and volume with different methods for selection. The Vendor A Tool can be installed behind SDG&E's security firewall.

3.1.2 Vendor B

The Vendor B visualization tool used for this project was Vendor B Tool. This tool demonstrated the ability to ingest and display all files provided in the baseline data set including the ability to ingest PLS-CADD model file exports. The demonstration was performed using Google Chrome web browser. Vendor B identified compatibility with Chrome 55 or higher and Firefox 50.1.0 or higher (tested using Windows 8.1 or higher).

The tool provides a 3D home page with color coded symbols representing tree assets ingested from GIS data and avian covers missing or detected. Vegetation encroachments are identified as polygons for the limits of encroachment.
The system allowed specific data sets to be turned on and off through an asset dropdown tree along with discover, search and upload functionality.

[2] Portions of Section 3 were developed and/or quoted directly from vendor presentation or reports given to the EPIC-2 Project #6 team.

3.1.3 Vendor C

The Vendor C visualization tool used for this project was Vendor C Tool. This tool demonstrated the ability to ingest and display all files provided in the baseline data set including the ability to ingest PLS-CADD model file exports. The demonstration was performed using Internet Explorer web browser.

Inside the portal a 3D representation of the network is displayed, from terrain and base imagery through to high resolution LiDAR and asset images. These can all be layered up to provide a rich, detailed view of the as built, as surveyed conductors, structures, vegetation and condition. Vendor C Tool operates using pre-optimized datasets generated following any processing to, allow fast loading, and reduced data volumes to be distributed across the internet whilst maintain the visual quality required for review and condition assessment in the portal. This method was chosen as opposed to the alternative on the fly compression or distributing uncompressed data, as this leads to reduced server load – meaning more users can access the data concurrently, and the amount of data that needs to be handled at any given point, resulting in a smoother user experience.

Vendor C Tool revolves around a central store that then feeds data into the web viewer, this central store can provide feeds into other systems and vice versa. 2D data layers can be fed into other software like Esri ArcMap, ArcGIS Online, QGIS, PLS-CADD as standard Web Feature Service (WFS) / Web Map Service (WMS) feeds that are fully Open Geospatial Consortium (OGC) compliant. Conversely, existing feeds can be fed into Vendor C Tool, allowing data to be integrated into the system, bringing everything into one place, maximizing the amount of information available to inform intelligent business decisions. Once again, this includes standard WFS / WMS feeds and a range of tabular database connections.

3.1.4 Vendor D

The Vendor D visualization tool used for this project was Vendor D Tool. This tool demonstrated the ability to ingest and display all files provided in the baseline data set except for the PLS-CADD model file. The demonstration was performed using Chrome web browser, the Vendor D Tool and CloudCompare software.

The tool provides features including:

- 2D cartometric representation of terrain in the vicinity of power lines using orthophotomap,
- Representation of altitudes of the terrain and objects above ground level by Digital Surface Model (DSM) and Digital Terrain Model (DTM),
- Distance, altitude, area, and volume measurements based on orthophotomap and DTM/DSM (e.g., conducting measurements of distances between the power lines and objects close to them or distances between poles or other devices),

- Ability to attach files like high resolution images and movies showing details of devices installed on the poles (e.g., avian covers), PDF files with documents (e.g., work orders), and notes generated directly in the Vendor D Tool with additional information,
- Establishment of vector data layers for performing analysis by comparison with raster maps layers (e.g., orthophotomap, DTM, DSM) and presentation of the results of GIS analysis performed in external software,
- Generation of vector objects by drawing directly in the Vendor D Tool,
- 3D view for presentation of 3D model of the terrain with or without objects above ground level, based on DTM or DSM with textures made from orthophotomaps and other raster and vector layers with the ability to perform measurements,
- 3D point cloud view for presentation and analysis of 3D point clouds acquired using LiDAR or generated during photogrammetric image processing.

The Vendor D Tool is a cloud based platform which does not require any investments in advance or installation processes due to the fact that it is operated via web browser or mobile app on mobile devices. The platform's dedication to store, analyze, and share image data combined with its personalized functionalities, configuration, and analytics, make the platform a robust solution for supporting daily tasks related to asset management across SDG&E.

3.2 Test/Use Case Results

3.2.1 Avian Cover Identification

This section describes in detail the results for the test case defined in Section 2.5.1 above. The remainder of this section will discuss the approach, accuracy, recommendations for a future state presented by each vendor and a comparison of vendor results and the EPIC 2 Project #6 Team recommendations.

3.2.1.1 Vendor A Results

3.2.1.1.1 Approach

For this test case Vendor A analyzed their RGB nadir and oblique imagery collected during their two UAS flight missions flown by the vendor under supervision by SDG&E personnel. These images provided a much higher resolution than those provided as part of the baseline data set. The images were ingested into a IDMP where work orders were created for annotators to review the images and visually identify avian covers. The vector outlines of the annotations were ingested back to the IDMP and pushed to the Vendor A deep learning tool. In the deep learning tool, a model was trained to identify the objects inside the vector outlines and create a catalog of the objects.

3.2.1.1.2 Results

The Artificial Intelligence (AI) Workbench identified the avian covers with an accuracy of 85% at a confidence level of 80%. As seen in the vendor demonstration, images containing an avian

cover were flagged with a positive indicator in the interface so they could then be reviewed in detail by the software user. The user can also then generate a report on number of avian covers detected in the section tested. Avian cover locations were not represented in the Vendor A Tool with a symbol but were identified with a flag on the RGB images that were successfully analyzed. The flags could also potentially be exported to an Esri platform in the future. Additional RGB images were provided for additional training in the machine learning tool with minimal increase in identification accuracy. Avian Cover detection is shown in Figure 1 below.



Figure 1. Example of Avian Cover Detection

3.2.1.1.3 Additional Features Demonstrated

- The machine learning tool showed the ability import and apply additional models trained previously to automatically identify specific features on steel towers such as bolts, as well as material defects such as corrosion on steel frames.

3.2.1.1.4 Vendor Recommendations for Future State

- Provide as-is vs as-design comparisons for assets such as avian guards, pole caps, insulators, transformers and other features
- Detection of other objects, e.g. bird nests
- Advance from image-level to object-level detection by fusing LiDAR & design data with image-level detections to achieve >95% precision with >95% recall
    - Enables unique object identification and tracking

3.2.1.2 Vendor B Results

3.2.1.2.1 Approach

At the start of the POC, several data sets were provided that were comprised of near NADIR and oblique imagery. After an initial review of the two datasets, deep learning models were developed using the near nadir dataset because it contained the most images (~1500), which was important for building up a large training base.

After manually eliminating any images that did not contain poles from training, an analysis was conducted to determine if avian covers could be detected in an image when the avian cover was ~150 pixels or less. In these cases, while the pole was visible, the resolution was insufficient to recognize the avian cover with the human eye or through deep learning as shown in Figure 2.



Figure 2. Example of Pole Detection with No Avian Cover Detection

To achieve a span of ~150 pixels or greater, it was calculated the horizontal distance from the UAS to pole needed to be 80 feet or less. To remove images that didn't meet this criterion, a pre-processing step was developed that opened each image and calculated the horizontal distance from the UAS to the pole. Images that were taken at a distance greater than 80 feet were removed from consideration.

3.2.1.2.2 Results

With 444 images remaining that met the criteria for training and testing, a final review was made to identify the images that had the closest view of the pole. These 37 images were reserved to use for testing and presenting results.

With a limited training set of 407 images, the initial results of the model produced too many false positives, in many cases identifying objects that resembled avian covers that were not associated with a pole. As a result, an additional processing step was added that evaluated whether the detection of an avian cover was within a small distance of a pole. If the detection of the avian cover was not near a pole, the algorithm would discard the result, which greatly improved the model results.

Using ground truth data, the accuracy of the avian cover deep learning model was validated as follows in Table 6.

Table 6. Accuracy Measurements for the Detection of Avian Covers

	Avian Covers
Actual	36
Detected	32
Missed	4
False positives	8
Precision	80%
Recall	89%

In deep learning methodologies, there are two primary ways of measuring the accuracy of a model: Recall measures the percentage of avian covers that were successfully detected; Precision is a measure of the number of false positives, e.g. 80% precision would mean that a 1/5 of the detections were not of avian covers.

Even with the extremely small training set, the results were excellent - **89% of the avian covers were detected**. With more training data both the recall and precision values would be improved.

3.2.1.2.2.1 Discovering and Reviewing Results

Once the deep learning models were created, they were applied to the reserved data set as a pre-processing step. The images and results were ingested into the Vendor B asset management platform which provides users across the organization the ability to quickly identify poles with missing avian covers.

Search and Discovery of Results

There are two methods to quickly locate assets and the results of the analytics in the asset management platform:

1. "Discover" – Users are presented a map and icon indicating the location of assets as shown in Figure 3 below. Upon clicking on the icon the interface will zoom into the circuit and display the poles on a map. Red  indicates no avian covers were detected on the pole. Yellow  indicates a single avian cover was located. Green  indicates that two or more covers were found.

2. “Search” – The search menu can be used to locate assets by type, e.g., poles, encroachment, or images. Additionally, much like the original data management platform, users can also apply filters to refine results.

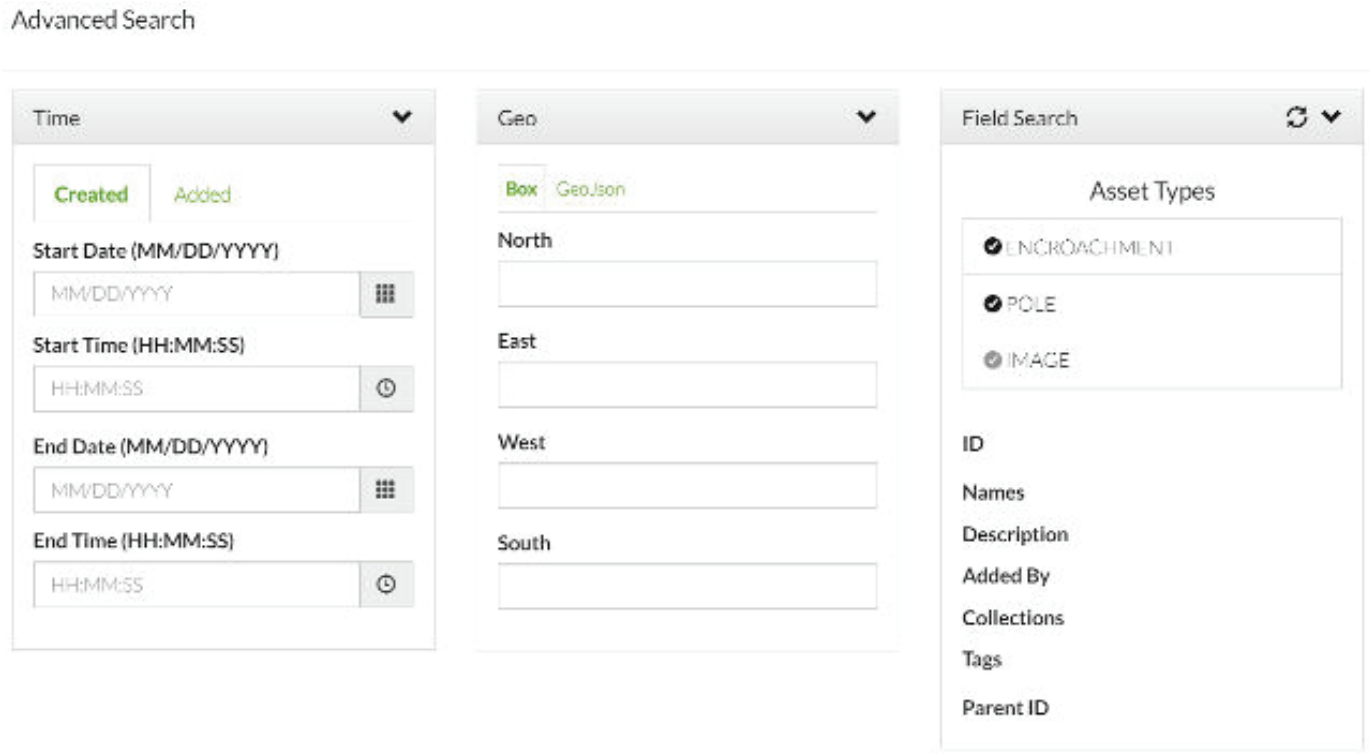


Figure 3. Advanced Search

Viewing Results

Within the map view, the user can easily navigate around the map with the mouse and zoom in to get a closer look. Users can control what assets (poles, encroachments, or both) are displayed on the map by clicking on the  icon as show in figure 4:



Figure 4. Visual Map of the Avian Cover Detection

While the icon provides a quick indicator of the present or absence of an avian cover, users can view the results by right clicking on any icon. The closest image to the pole that was reserved for testing is displayed in figure 5.

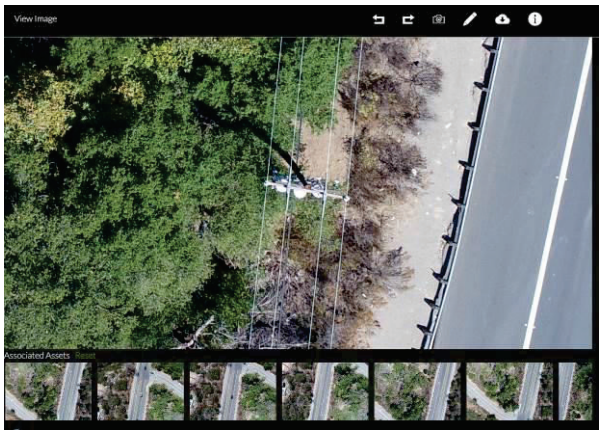


Figure 5. Example of Closest Pole Image

A Pole Report provides key pole information such as the pole identification, GPS coordinates, facility identification, and an inventory list of items detected on the pole such as avian covers and insulators without covers. When the mouse is placed over one of the inventory items in the list, the item is highlighted on the image of the pole as shown in figure 6.

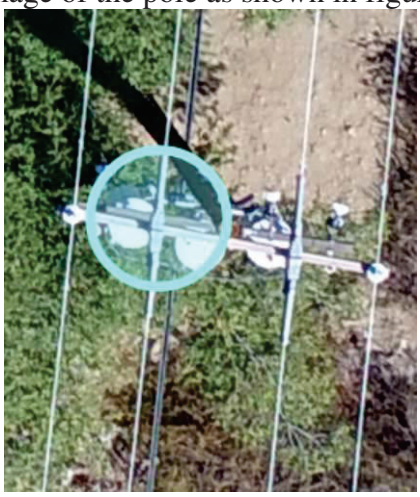


Figure 6. Example of Avian Cover Detected

The thumbnails along the bottom of the screen are other images associated with this pole and can be clicked on to view. These images were used to train the model for deep learning and therefore weren't used to display results.

3.2.1.2.3 Additional Features Demonstrated

None

3.2.1.2.4 Vendor Recommendations for Future State

Vendor B's deep learning technology is a viable and dependable solution for T&D asset management workflows including the detection of anomalies on assets such as the avian cover example. To maximize results in an operational environment, the following recommendations should be considered:

3.2.1.2.4.1 Camera and Sensor Settings

Most image collection platforms offer multiple settings which can affect the quality and accuracy of the analytics run downstream. The following guidelines will help improve results.

1. Capture imagery using the camera's full resolution.
    a. Avoid cropping images or modifying the aspect ratio of the image.
2. Turn the camera orientation metadata settings on.
    a. When using oblique imagery, the camera's orientation metadata (roll/pitch/yaw) is useful in determining if the collected imagery meets collection requirements.
3. When looking for damage types such as a linear fracture (thin line), using the camera's RAW uncompressed format is recommended, which will prevent thin lines from blurring.

3.2.1.2.4.2 Flight/Capture Techniques

The technique used to capture data can greatly affect the probability of success for locating poles and assets as well as identifying anomalies. To maximize results, consider the following when developing a standardized flight plan:

1. Maintain a consistent distance to the pole.
2. Maintain a persistent look angle upon the pole.
    a. Deep learning analytics operate on the original images without considering the look angle or where the image fits in the larger mosaic. For this reason, it helps to have a consistent view of the pole in all the images so that the algorithm can more effectively "learn".
    b. The camera used during the proof of concept had excellent resolution. At that resolution, the UAVs could fly 30-50 feet away from the pole and identify objects or damages with a size greater than 4mm. This distance should be sufficient to detect most damage types.
    c. Before embarking on a major collection, it is recommended that test flights be performed at varying altitudes to determine if the desired object or damage can be identified at that height.
3. Utilize a data validation tool when collecting data.

    a. A data validation tool will help reduce costs and ensure the data collected in the field meets downstream analytic requirements. Data validation tools provide pilots feedback in the field to ensure:
        i. The resolution required for analysis is met.
        ii. Proper focus is maintained throughout the capture.
        iii. All required metadata is present and within specified criterial for the capture.
        iv. Proper overlap and coverage for stitching and analysis purposes.
4. Provide the orientation metadata such as roll/pitch/yaw with the imagery.
    a. The orientation metadata is useful when capturing oblique imagery. The camera orientation can quickly determine if the data meets the analysis requirements.
5. Wait for GPS uncertainty to be reduced before starting image capture
    a. FLT log files from the GPS can take a minute to obtain low error bounds. To ensure accurate GPS coordinates, it is recommended that a few minutes be given between when the GPS is turned on and data capture begins.
6. Avoid capturing imagery in poor weather conditions (low light or wet objects change color and can reduce detection results).
7. Avoid capturing imagery in poor lighting conditions (excessive shadows or low sun angles can reduce the pixel range over objects thus affecting detection results).

3.2.1.3 Vendor C Results

3.2.1.3.1 Approach

3.2.1.3.1.1 Manual Identification

Vendor C did not perform automated asset identification using machine learning. For this test case, a range of manual assessment methods were tested and evaluated. This was focused on understanding the consistency and limitations in the asset photos and using human assessment to identify presence on a selection of lines. This was expected to be highly accurate and thus serve as both a verification and training set for later method testing. It would also be used to demonstrate the display of avian cover locations in the online system. See figure 7 below:

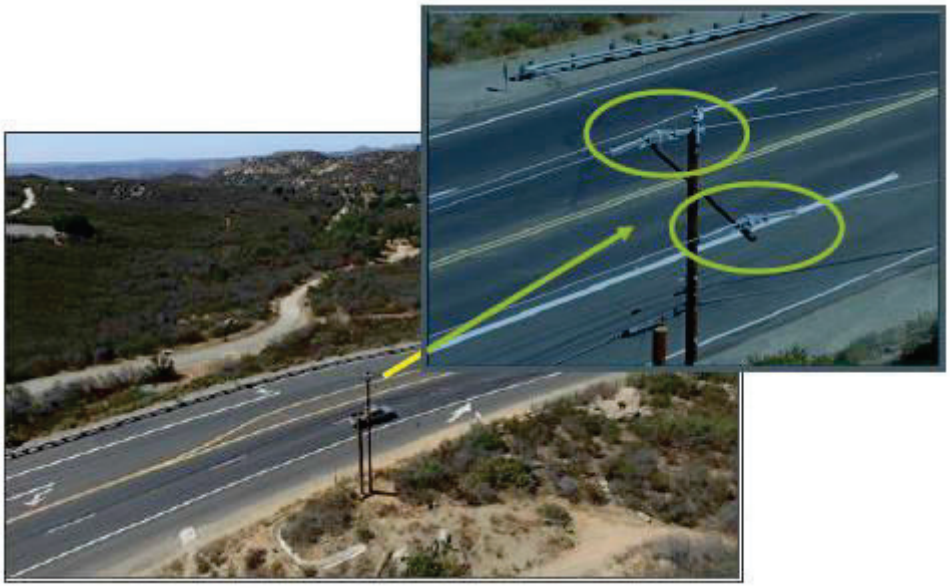


Figure 7. Image Containing an Avian Cover

A review of the available images saw significant variability in the quality that was available, which made identification difficult in some instances but always possible. Initial indications were that the imagery was not going to be suitable for automated analysis without significant work or error rates. Figure 8 and 9 below shows the imagery of the Avian covers.



Figure 8. A selection of Avian Covers From the UAV imagery



Figure 9. A selection of Avian Covers from the UAV imagery Continued

3.2.1.3.1.2 Automated Identification

Having reviewed the supplied data and considered the manual methods available for identifying the avian covers, the next stage is to explore a way of automatically detecting their presence. The most appropriate methodology in this case, given the variability of the data inputs, is a machine learning approach. The principle is to create a machine learning system that will accurately identify the presence of the covers and collate this information in a way that it can be used. A prerequisite of this approach is the automated matching of photography to the asset and a degree of consistency in the way in which photographs are taken – considering resolution, perspective and color balance.

The online 3D system used to show the results is not optimized for data analysis – it acts as a portal to link and explore the data and the results, not the analysis itself. As a result, were further time available in this trial, the chosen method would have been the detailed use of the internal machine learning group. Following engagement with the relevant technical specialists from this group, it appears to have the right mechanisms to rapidly train a machine-learning derived system (using object-based recognition) which can be used to identify a desired set of survey objects fast and effectively. In order to achieve this, we must prepare the system through the provision of an extensive library of target images - these images must include visual representations of the target object in a multitude of different conditions as depicted in figure 10.



Figure 10. Image Segmentation Via Machine Learning Platform

In the case of SDG&E's avian covers, the first hurdle would be to manually filter the full set of existing poles present in the supplied imagery which included avian covers and then to apply a range of image manipulation techniques to generate an appropriate training set. These could include the use of cropping and contrast adjustment to highlight the appropriate section of the tower – the avian cover.

3.2.1.3.2 Results

Vendor C did not perform automated asset identification using machine learning. For the trial, based on some simple business rules, technicians reviewed the set of images that had been georeferenced and stored in the online system. The presence of a cover was noted along with the number of phases that included.

Table 7 shows the sample area:

Table 7. Pole Count

Pole Count	
Number of poles	28
Photographed poles	21
Uncovered	11
1 Cover	1
2 Covers	7
3 Covers	2
Unknown	7

3.2.1.3.2.1 Display in the online system

The asset images themselves were displayed for the trial by using two elements:

1. Figure 11 is displaying based on the image capture location and using a 'hovering thumbnail' to enable the user to intuitively relate the photo to the nearest asset.



Figure 11. The Display of Avian Covers Alongside Contextual LIDAR & Image data

2. Creating a colored coded symbol for each image (that related to a single pole) which represented the cover status – that is 0-3 phases covered (white being no cover and dark blue being all three phases) as shown in figure 12 below.



Figure 12. The Display of Avian Cover Symbols To Enable Rapid Review Of The Line Status

Where a photo was not present for a pole, no status was created. This approach enabled a fairly rapid and intuitive assessment of a given line as to the cover status. With further effort on the automated matching of photos to the assets, this display mode could be made more intuitive in use – for example by symbolizing the poles themselves, including those which have no photo (meaning no cover status).

3.2.1.3.2.2 Considerations for further testing

Due to the scope of the provided dataset and the scale of each image provided we believe that the existing Machine-Learning System will be unable to efficiently identify the target objects due to a sheer volume of noise/false positives in the supplied raw dataset, by applying the image manipulation techniques and provisioning further training data, we believe that we will be able to produce a meaningful test output.

This step can be achieved by further utilizing the metadata that is included with imagery and in future imagery, seeking improved metadata (in terms of accuracy and precision). This includes information such as the direction of the photograph, the angle in which the imagery was taken and the pole heights. This will allow us to mathematically identify the top of pole in the image and so target the object recognition more effectively. This method is only realistically viable when using a stabilized and orientation recording mount, due to the unreliability in terms of stability when the data is collected via a human operator.

In terms of the calculations needed to determine the area in the image, see figure 13 diagram detailing the information need and how it is utilized.

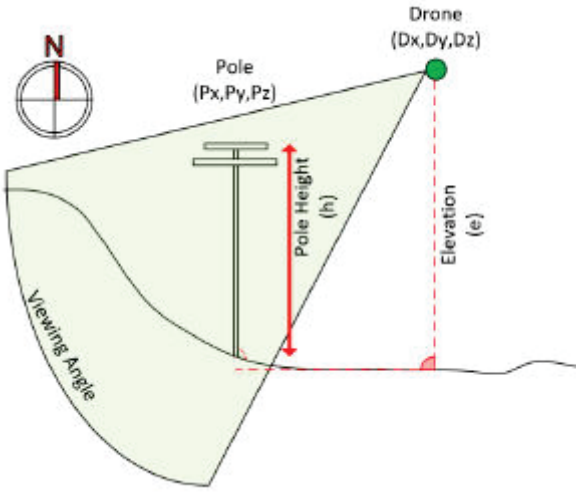


Figure 13. Target Parameters

A secondary method of identifying these covers would be to utilize the LAS data that was collected during the capture phase of the project, using this data we can generate buffers to limit down the target area to help aid the identification process.

Once this data is filtered we will be able to generate a las based image of the pole from a certain angle, and once again utilize the machine learning system to identify the cover. This method would require more effort in the training stage, however this would minimize imaging issues such as weather conditions, image resolution, image quality. But by working with LAS will allow the detection of the top of the pole to be done at higher speed and with more accuracy.

3.2.1.3.2.3 Stage 3 – automated condition assessment

The premise on this item was to make use of the same machine learning platform and explore in a limited way the ability to find defects on the covers. However, the limited training dataset available and the time for this project meant that progressing to this stage was not feasible. However, there are some automated methods that should be relatively feasible as a follow-on initiative:

- Automatically validating installation records on poles via the asset photography to validate the presence of covers and alert to discrepancies (cover in place but not recorded and cover not in place but recorded)
- Categorizing cover types where different methods are used, based on color or construction methods
- Identifying gross damage to covers (for example, if two phases are covered but one is not)

In the short time available, it was possible to explore the way in which the avian cover data could be intuitively displayed to enable an asset manager's assessment, make some initial observations on the data extent and quality and collect some initial statistics for the presence and nature of the covers on the line of interest. It is clear that to reliably use machine learning techniques to carry

out a simple presence identification, then the imagery would need to be more consistent in terms of angle and resolution. The use of LiDAR-derived geometries and capture angle/position information for the photos would help to target the machine learning approach by focusing on certain aspects of the image to reduce noise. Further work could test these ideas and also identify the minimum resolution needed to identify the different types of damage that occur. It could also explore the use of 'geopointing' UAV cameras based on LiDAR/model derived targets to enable pole top photography from the UAV platform that was of very high resolution and quality.

3.2.1.4 Vendor D Results

3.2.1.4.1 Approach

For this test case Vendor D analyzed the RGB nadir and oblique imagery collected during the two UAS flight missions that were flown as part of the project. Acquired data was used for deep learning models training. The analysis team utilized images taken during drones' free flights, oblique imagery of poles, and image data gathered in single and double grid autonomous flights. Additionally, the team gathered images of avian covers from handheld cameras for training.
All image data were labeled with an open-source graphical image annotation tool called **LabelImg**. Labels were stored in .xml files, and were applied to objects representing the following classes:

- Pylon head with avian cover - Heads of energy (distribution) poles with minimum one avian cover on the energy lines shown in figure 14 below

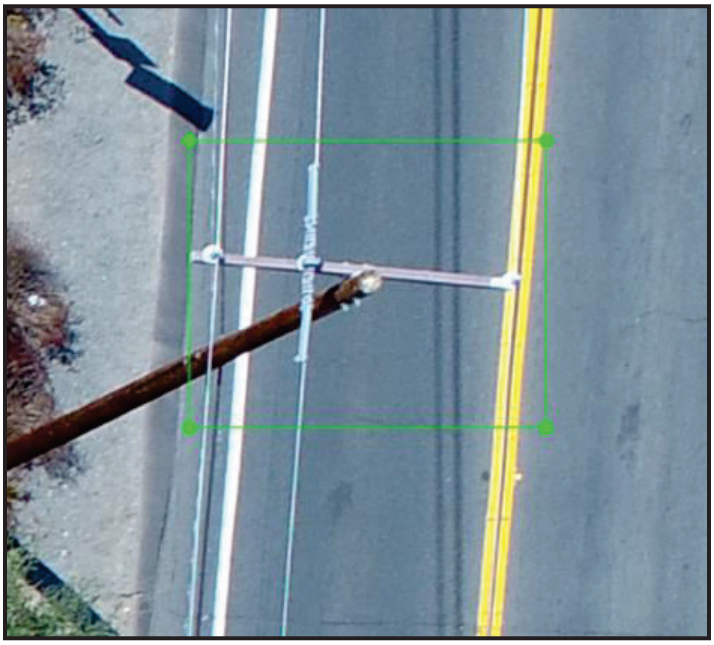


Figure 14. Example of Pylon Head With Avian Cover Label

- Pylon head without avian - Heads of energy (distribution) poles without any avian covers as shown in figure 15 below

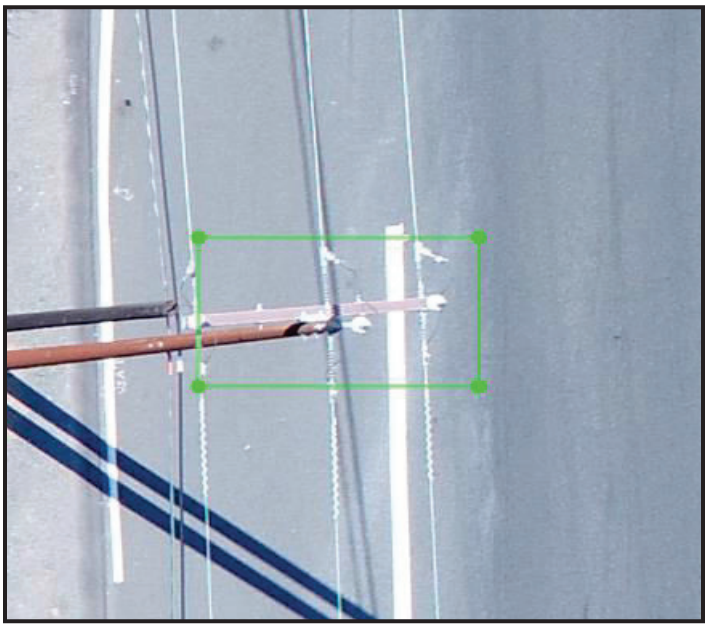


Figure 15. Example of Pylon head Without Avian Cover Label

3.2.1.4.2 Results

After 800,000 steps of training, all of the models gave results of almost 100% accuracy. The model was tested on the additional test dataset provided (one that has not been involved in any phase of training) and proved its high accuracy as shown in figure 16



Figure 16. Bounding Boxes Based on Trained Model

Accuracy checks were made both analytically and visually and detailed results of precision are shown below:

Table 8. Results of precision

Model	Overall Precision	Pylon head with avian Precision	Pylon head without avian Precision	Avian cover Precision
All data	0.9908	0.9961	0.9993	0.9769
Handheld	0.9948	0.9992	0.9999	0.9856
Free flight	0.9973	0.9995	0.9999	0.9924
Single grid	0.9990	0.9999	0.9999	0.9971
Double grid	0.9958	0.9978	0.9999	0.9898

3.2.1.4.3 Additional Features Demonstrated

- Detected 2 assets essentially, avian cover and distribution poles.

3.2.1.4.4 Vendor Recommendations for Future State

The chosen methodology to evaluate avian cover inventory added accuracy and efficiency, and demonstrated a potential for cost reduction when auditing grid elements. The machine learning techniques used for computer vision were an effective way for detecting and inventorying not only avian covers, but a host of additional grid elements. SDG&E should consider the following recommendations for additional machine learning benefits:

- Expand upon systems developed during use case.
    - Systems may be expanded to utilize additional features which can contribute to automation of detection processes, therefore increasing its effectiveness and decreasing SDG&E's costs regarding fines for absence of avian covers on the power lines.
- Review all field work processes.
    - SDG&E should review all of its processes concerning field work connected with power lines inventory, maintenance, monitoring, and vegetation management to assess which processes can be improved with deep learning and computer vision algorithms carried out on a low altitude aerial image data.
    - It would also be beneficial for SDG&E to check how trained models perform on image data acquired with the use of different platform.

***Note:** Several tasks concerning the developed deep learning system extension must be completed before the system is complete and usable:

1. Testing of cropping images with different dimension and stride:
    - Changing the parameters of the imagery used for model training may affect the training time and accuracy.

- Lower width, height and stride of cropped images can extend dataset elements number, which may improve computing time and algorithm efficiency.

2. Extracting localization information from images:
   - All images taken with a drone are geotagged, which means that coordinates of the drone were measured at the moment of taking a photo.
   - Depending on the hardware, GPS receiver accuracy may differ.
   - More advanced drones have GPS Radio to Kinetic (RTK) or Post Processed Kinematic (PPK) receivers (horizontal and vertical accuracy < 5 cm), which are also equipped with the IMU system for measuring camera angles at the moment of photo acquisition.
   - Localization information may be extracted for each image and can be used to identify the pole on which detected objects are present. It may be used for reporting or preparing GIS or CAD files containing geospatial and descriptive information about the examined grid.

3.2.1.5 Comparison of vendor results

The test section was examined visually by the project team via desktop using images taken by private contractor in conjunction with the pole and structure data provided by the GIS group. This manual examination determined that there were 15 poles in the test section that had one or more avian covers. The total number of covers spread out over these 15 poles totaled 32. The table below shows the results of the vendors ability to identify the avian covers.

Table 9. Ability of vendors to identify the avian covers

Vendor	Recall	Precision	Confidence	Minimum Pixels Required
Vendor A	85%	70%	80%	300
Vendor B	89%	80%	95%??	150
Vendor C[3]				
Vendor D	>99%	>99%	>99%	<100

3.2.2 Vegetation Encroachment Identification

This section describes in detail the results for the test case defined in Section 2.5.2 above. The remainder of this section will discuss the approach, results, recommendations for a future state presented by each vendor and a comparison of vendor results.

3.2.2.1 Vendor A Results

3.2.2.1.1 Approach

For this test case Vendor A analyzed the LiDAR data set collected during their UAS flight missions. The LAS point classifications were mapped to PLS-CADD point codes per the SDG&E TE-0135 LiDAR & Imagery Standard. A rectangular 3D encroachment zone utilizing adjustable height and width parameters relative to top of structure, bottom of structure and conductor point of attachment was used for this POC as shown below.

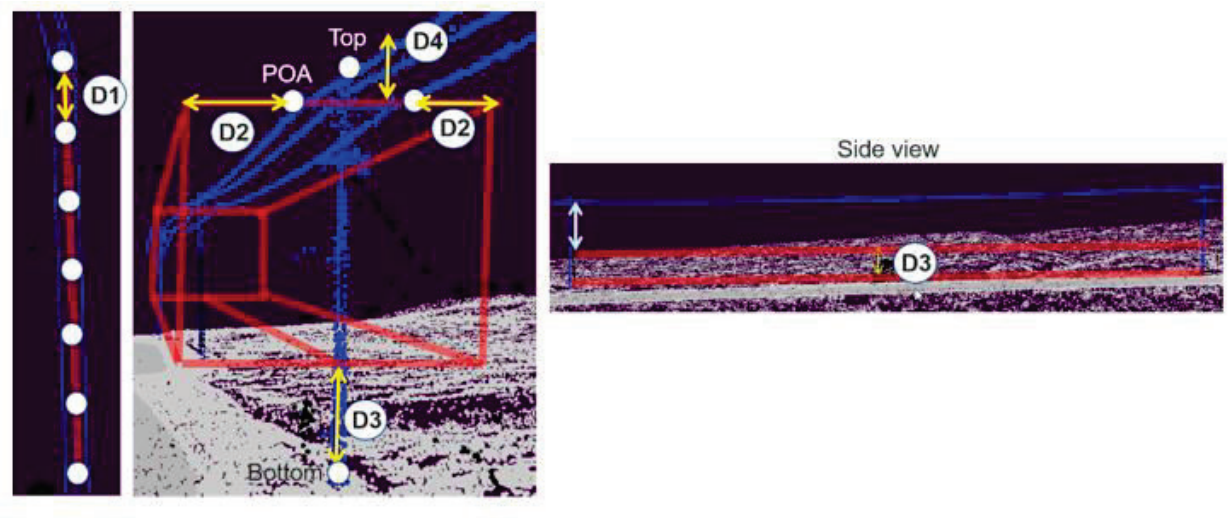


Figure 17. Vegetation Encroachment Zone Definitions

The analysis for vegetation encroachment was performed using vertical cross sections perpendicular to the span alignment and sampling three meters worth of data at a time. Advanced analytics were then performed to identify vegetation within the said 3D encroachment zone for each three-meter segment. Three sets of height and width parameters were visualized for the user by red, yellow and green markers.

3.2.2.1.2 Results

The vegetation encroachment analytic tool could identify encroachments in multiple three meter segments between pole assets with respect to existing vegetation classification of the input LiDAR data. Vendor A also expressed the ability to change the shape of the encroachment zone and incorporate sag and sway parameters in the future. The PLS-CADD model and DXF exports were not used as part of the advanced analytics or demonstration.

3.2.2.1.3 Additional Features Demonstrated

- Ability to link three closest tree assets to vegetation encroachment notifications to show potential increase in efficiencies identifying corrected asset locations.

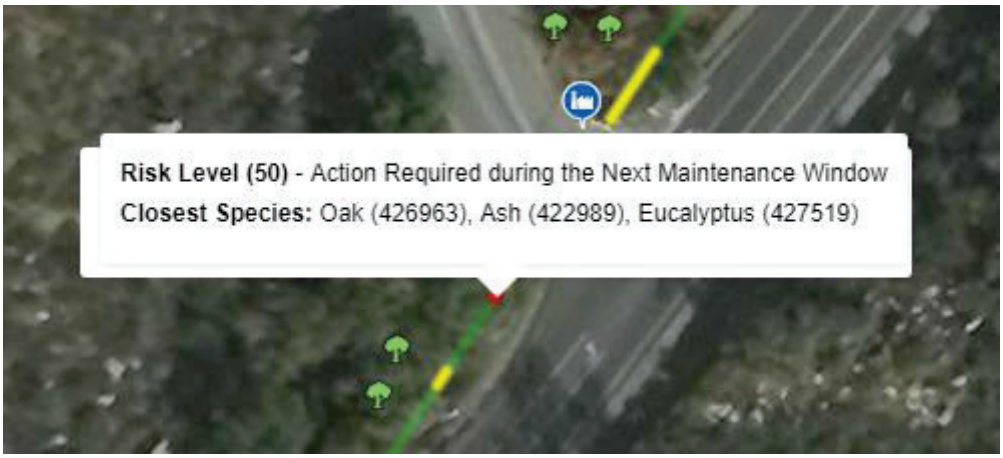


Figure 18. Link 3 Closest Vegetation Assets

- Demonstrated ability to select a point in the LiDAR cloud and query images showing the location using geotagging and orientation of photos.
- Vendor expressed the ability to use tubular encroachment zones along the wires with multiple zones of analysis.

3.2.2.1.4 Vendor Recommendations for Future State:

- Full integration with PowerWorkz and nightly syncs to track asset characteristics: species, growth rate, up to date height.
    - Click & comment to update/track historical data & status for the asset.
- Point and Click image display functionality to include vegetation assets.
- Work order based image ingestion for trimming documentation & verification.
- Customized encroachment zones based on regulatory and SDG&E practices to integrate with worst-case sag and sway analysis.
- 3D encroaching vegetation volume assessment and RGB image verification for costing analysis.
- Rule-based risk score computation based on volume, species growth rates, conductor type and sag/sway analysis.

3.2.2.2 Vendor B Results

3.2.2.2.1 Approach

For this test case Vendor B used two datasets provided that included a classified LiDAR point cloud (in LAS or LAZ format) and a PLS-CADD model of the conductor lines that were exported as a DXF file. The datasets single LAS file contained approximately 20 million points. The points were classified into a number of feature classes.

An ‘as-built’ PLS-CADD model, which was derived from the same LiDAR point cloud, provided geometric alignment between the two sources. With the focus on conductor lines, the DXF file was ingested and the conductor lines were separated into their own shapefiles. The remaining structures, such as telecom lines and pole structures were defined as outside of scope for this test case.

Next, the point clouds were ingested to build spatial indices that would allow for fast geometric queries. Algorithms were developed to evaluate the 3D positions of every conductor line in the PLS-CADD model and identify the LiDAR points that were both classified as vegetation and were within a specified distance to the conductor line. The vegetation points that were identified as potential encroachments were clustered into groups and a bounding polygon was created around them as shown below.

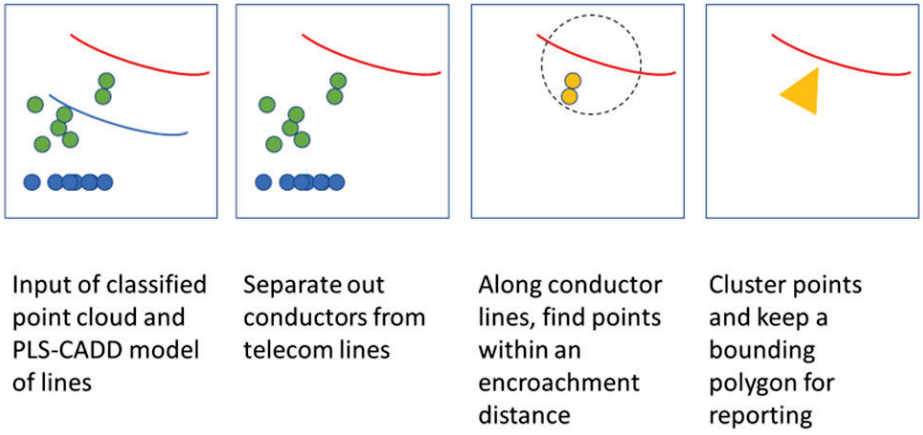


Figure 19. Encroachment Workflow Diagram

The polygons and supporting metadata, including the closest encroachment distances for the cluster, were then ingested into Vendor B’s asset management platform.

3.2.2.2.2 Results

The algorithms to identify encroachments were calculated during a pre-processing step. The images and results were ingested into the asset management platform, which provides several interfaces to quickly identify vegetation encroachments for conductor lines.

3.2.2.2.2.1 Search and Discovery of Results

There are two methods to quickly locate assets and view the analytic results in the asset management platform:

1. “Discover” – Users are presented a map and icon indicating the location of assets. Upon clicking on the icon, the interface will zoom into the circuit and display the poles and encroachments on a map. Encroachments are identified with a tree pushpin that is color coded based on how close the vegetation is to the conductor. Red indicates vegetation

was detected within 10 feet. Yellow indicates within 10- 12 feet, and green indicates within 12 - 15 feet.

2. "Search" -- The Search menu can be used locate assets by type, e.g., encroachment, poles, or both. Additionally, much like the original data management platform, users can also apply filters to refine results.

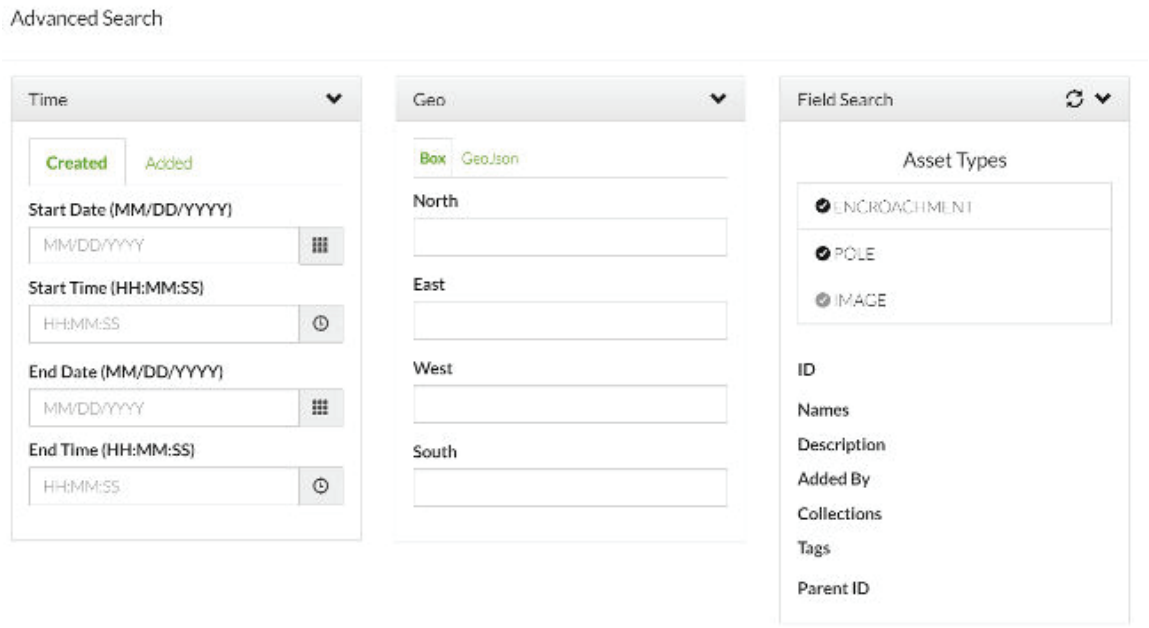


Figure. 20 Advanced Search

3.2.2.2.2.2 Viewing Results

Using the mouse, users can easily navigate and zoom into assets on the map. Using the icon, users can control what assets (poles, encroachments, or both) are displayed on the map. Along with the location of the encroachments, a 2D polygon is also shown that highlights the footprint of the encroachment area as shown in figure 21.



Figure 21. Visual Map of Detected Vegetation Encroachments

Users can view the encroachment results by right-clicking the vegetation encroachment pushpin. A 3D point cloud viewer is opened with the camera pointed at the selected encroachment. By pressing the "x" key, users are taken on an automated orbital flight of the encroachment. During the flight, users can pause and resume the flight by pressing the "x" key. Users can also

manually view the results using the mouse to navigate the point cloud (hold down shift to slow the speed at which the camera moves) as shown below.

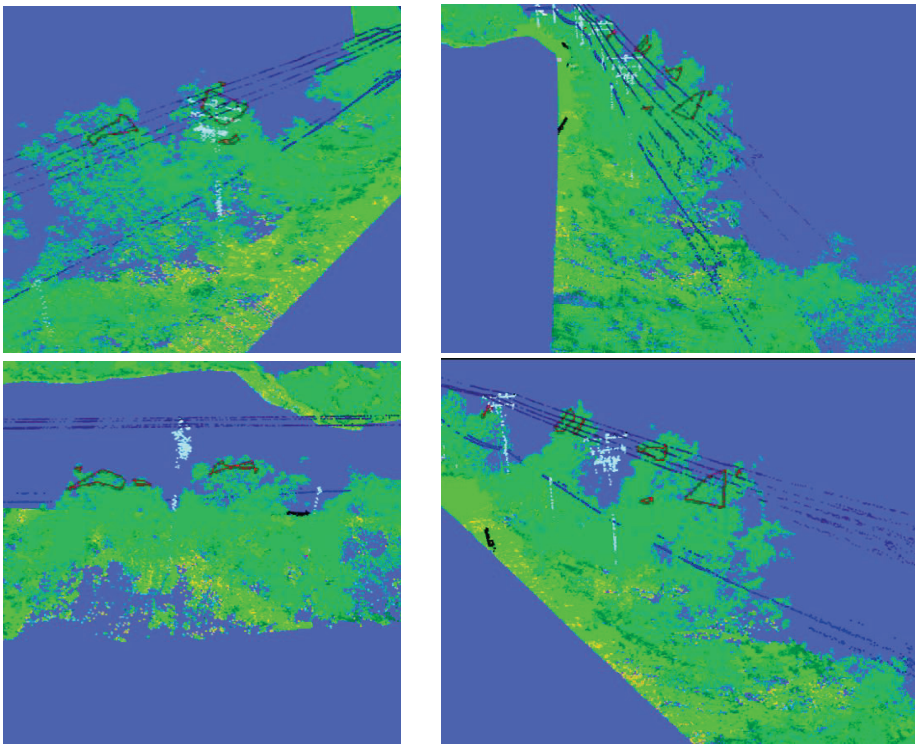


Figure 22. Sample LiDAR Views of Encroachments

3.2.2.2.2.3 Findings

Using LiDAR point cloud data and PLS-CADD models, algorithms were successfully developed to locate and categorize vegetation encroachments that were of potential risks to conductor lines. During this effort, the following observations were made:

- Encroachment detection can be accomplished reliably. Furthermore, given the computational efficiency, processing of large areas can be scaled up using distributed computations.
- The resulting encroachment areas can be made searchable and accessible across a large geographic area.
- The LiDAR collection, point classification, and derived PLS-CADD models resulted in inputs of high enough resolution to support vegetation encroachment detection. The LiDAR was of good quality and density.
- Encroachments can be associated to individual spans and physical assets.
- While not within scope of this test case, stakeholders indicated there was a desire to enable tracing of encroachments back to specific and known trees. Unfortunately, it was determined that the locations of known trees in the GIS were not sufficiently aligned with the LiDAR data to support tracing encroachments back to specific trees. Further data collection and analysis could lead to a solution to address this need.
- LiDAR and PLS-CADD based solutions offer opportunities for automated solutions to detect vegetation encroachments as well as potential clearance violations.

The test case was successful in identifying a number of regions with potential vegetation encroachments. One small area of vegetation was found within 10 feet of the conductor lines, and several other areas were identified where vegetation was within 12- 15 feet of conductor lines.

3.2.2.2.3 Vendor Recommendations for Future State

This test case was successful and proved the technical risk to a LiDAR-based vegetation encroachment solution is small. It is recommended further study be conducted to determine how this technical capability can be deployed into an existing vegetation management workflow. Recommendations include:

- Identifying workflows for updating existing GIS data with accurate LiDAR geolocation information that will support tracing encroachments back to a known existing tree or identifying a new tree.
- Exploring techniques for automating the process of performing point cloud classification and PLS-CADD model generation. Potentially performing the vegetation encroachment without PLS-CADD models.
- Identifying workflows for customizing encroachment parameters and PLS-CADD models to be used for vegetation encroachment.
- Investigating how to quantify the volume of vegetation in an encroachment and mapping the volume, heights, and tree species into a cost model to estimate remediation costs.
- Distinguishing between encroachments likely to 'fall in' to the path of the conductors from those that grow up and into conductors.
- Fusing drone or other aerial imagery with the LiDAR point clouds to enhance the visualization of encroachments.
- Developing interfaces between the demonstrated vegetation encroachment analytics and existing work order management systems.
- Identifying trends by comparing results from year to year.
- Exploring predictive analytics to anticipate areas most likely to have rapid vegetation growth.

3.2.2.3 Vendor C Results

3.2.2.3.1 Approach

For this test case, Vendor C ingested PLS-CADD outputs described in Section 3.2.3.3.1.1 below for comparative analysis. The outputs included models of wires including sag/sway at max load and 80MPH winds. Encroachment buffer zones were projected along the wires to identify encroachments in each zone with a different color.

3.2.2.3.2 Results

The datasets provided had been subject to a simple radial clearance vegetation analysis process based on the PLS-CADD modelling. The purpose of this is to identify against policy or

regulatory requirements, vegetation that infringes the minimum clearance distance or is within a cut-back requirement as seen below.

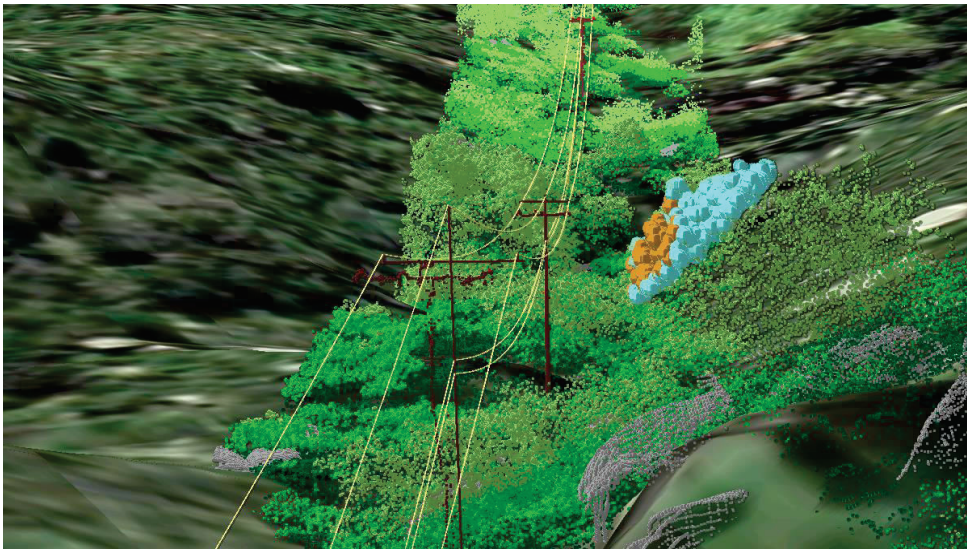


Figure 23. Classified Vegetation Encroachments.

3.2.2.3.3 Additional Features Demonstrated

- Vendor C Tool demonstrated the ability to identify encroachments using customized outputs from PLS-CADD.
- Multiple outputs of PLS-CADD could be ingested during the standard workflow to represent different load and weather conditions.
- LAS files ingested contain PLS-CADD feature coding per SDG&E standards
- Vendor C expressed the ability to automate work orders with specific requirements and integrate attributes collected in the field such as updated geographic locations.

3.2.2.3.4 Vendor Recommendations for Future State

3.2.2.3.4.1 Data Integration and Management

The Vendor C Tool environment provides the opportunity to integrate many different data sources from internal departments with external datasets:

- Integrating vegetation management intelligence with asset condition or engineering information through a platform widely available to personnel throughout a company can facilitate communication and cooperation. With this in mind Vendor C Tool could help identify situations where resources for inspection activities (by different departments) could be shared, potentially helping to cut costs associated for multiple departments.

- We can also split the LiDAR vegetation canopy into more manageable units of single or small groups of trees. Work could be completed to transform these canopy objects into 3D object within Vendor C Tool. This would allow the synergy of existing valuable

vegetation records, such as tree species or date of last cut, recorded in the field, to be integrated and made accessible through these objects. These records could then be augmented and updated as required, to ensure the information stored in the Vendor C Tool system remains current.

- Integration of spectrally rich airborne or satellite based imagery into Vendor C Tool could be used to provide the capability to aid identification of stressed vegetation, at a greater risk of fall or catching fire.

- The integration of external datasets, such as spatial representations of high fire-risk areas, or the location of high traffic transport routes or high value assets could also be attributed and visualized. These could be used to gain a deeper understanding of the consequence should a vegetation hazard occur, allowing managers to make more risk based management decisions.

- There is capability to develop interactive interrogation of the databases behind Vendor C Tool, allowing for fully configurable queries. This could provide flexibility to be utilized business-wide, tailoring queries to different management goals in the different aspects of the business, ensuring full utilization of the data.

Holding multiple datasets in one platform with spatial relations and joins, ensures datasets are current, removes issues of data duplication and makes viewing and generating vegetation related reports more efficient, saving costs in time and duplicated data entry effort.

3.2.2.4 Vendor D Results

3.2.2.4.1 Approach

The purpose of developing the proof of concept on vegetation management with UAS was to identify potential applications of LiDAR point cloud, aerial images, and derivative photogrammetry products to form an approach for most effectively utilizing each type of data. By creating a synergistic approach to using different types of data, data will be thoroughly utilized and reusable, resulting in cost savings for SDG&E.

The major considerations during use case development were:

- Most effective algorithm for locating vegetation to be cut down.
- Possibility of performing fully autonomous detection of powerlines and trees on LiDAR point clouds and drone images, and quality of detection.
- Data type that is best suited for the use case (LiDAR vs. aerial image, or combination)
- Combination of data types to obtain best results from the technical and economical point of view.

The data used to develop the Vegetation Management proof of concept are as follows:

- Classified LiDAR point cloud acquired from drone on September 24, 2016, provided by SDG&E and products based on LiDAR:
    - Digital Surface Model
    - Digital Terrain Model
    - Canopy Height Model
- Photogrammetric products based on a dataset of 3133 images in natural colors acquired during photogrammetric drone flight mission on September 19, 2017 as a part of EPIC initiative:
    - Dense point cloud
    - Orthophotomap
    - Digital Surface Model
    - Digital Terrain Model
- GIS and CAD data provided by SDG&E
    - Geospatial database containing geometric and descriptive information on high vegetation (trees) occurring on the analyzed area.
    - 3D CAD data presenting analyzed powerline.

The rationale for using both aerial images and LiDAR data is that the two types of data express different characteristics.

- Aerial images:
    - Contain visual information for generating high quality/high resolution orthophotomaps.
    - Generate colored dense point clouds.
    - Algorithms used to generate products are not suited for representing thin objects like wires.
- LiDAR data:
    - Contain information on the intensity of laser beam reflections (no information on colors).
    - Has a lower horizontal resolution.
    - Represents thin objects like wires and poles clearly on LiDAR point cloud.
    - LiDAR technology penetrates vegetation and contains information on the terrain and other objects covered by plants that are hidden from aerial images.
    - More easily recognizes types of objects (terrain, buildings, vegetation, etc.).

It is important to note that LiDAR sensors for UAS are relatively new and the technology is expensive. LiDAR solutions run at a higher cost than solutions using photogrammetric sensors.

3.2.2.4.2 Results

The analysis broke down into the following steps:

- Tree detection.

- Calculation of the distance between detected trees and wires.
- Direct calculation of the distances in the point cloud.
- Identification of the trees which are either too close to the wire or higher than the distance to the wire.
- Recording of the trees to be taken out due to creation of potential firebreaks.

Tree detection

The first step of point cloud processing was automatic detection of trees. The accuracy of the results mainly depends on the type of the landscape and the quality of the data acquired. Two different algorithms were deployed in order to define the best approach in this particular case. Algorithm A is a modification of the approach proposed by Eysn et al. (2012) developed in ArcMap while algorithm B is implemented in Global Mapper.

The workflow in Algorithm A consisted of the following steps:

- Digital Terrain Model calculation from Ground LiDAR class.
- Digital Surface Model calculation from High vegetation class.
- Canopy Height Model calculation from DTM and DSM.
- Local maximum height calculation.
- Detection of tree tips.
- Selection of trees higher than the defined threshold.
- Conversion of raster to shapefile.

A leading practice for successfully detecting trees is to adjust the parameters that describe the spread and height of trees. Since these values vary for different landscapes and locations, it is crucial to perform tests on real data. In algorithm A, two parameters were altered:

- Search radius for calculation of local maximum height (can be identified as the maximum spread of the tree).
- Minimum height of the tree.

Six sets of parameters were tested on LiDAR point cloud for the purpose of this report. The results were then assessed visually in comparison to the point cloud and orthophotomap for a chosen test area. Comparison to the orthophoto was also performed because it is challenging to identify singular trees in LiDAR cloud manually. There are noticeable difference because the

LiDAR point cloud and images were not simultaneously acquired and are not perfectly aligned. The best results in terms of properly detected trees were achieved in the 5th set of parameters as shown in figure 24 below.

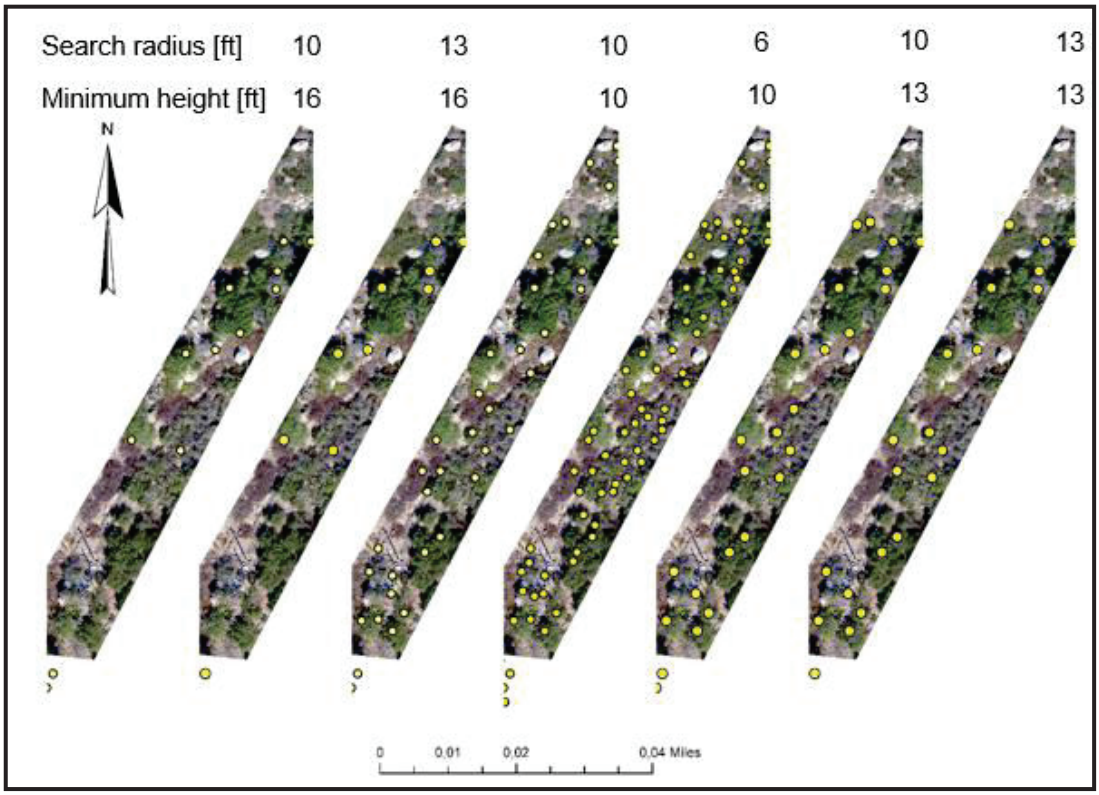


Figure 24. Comparison of Tree Detection Results from Algorithm A

When testing algorithm B, LiDAR point cloud was also used to detect trees. However, Algorithm B missed a significant amount of trees in big clusters, which was not an issue in the case of algorithm A. It is important to stress that within clusters, it is extremely challenging to find single trees manually. While comparing results of both algorithms, it was noticeable that algorithm A was more successful in tree detection. More trees were accurately detected especially in the case of big clusters of trees as seen in figure 25.

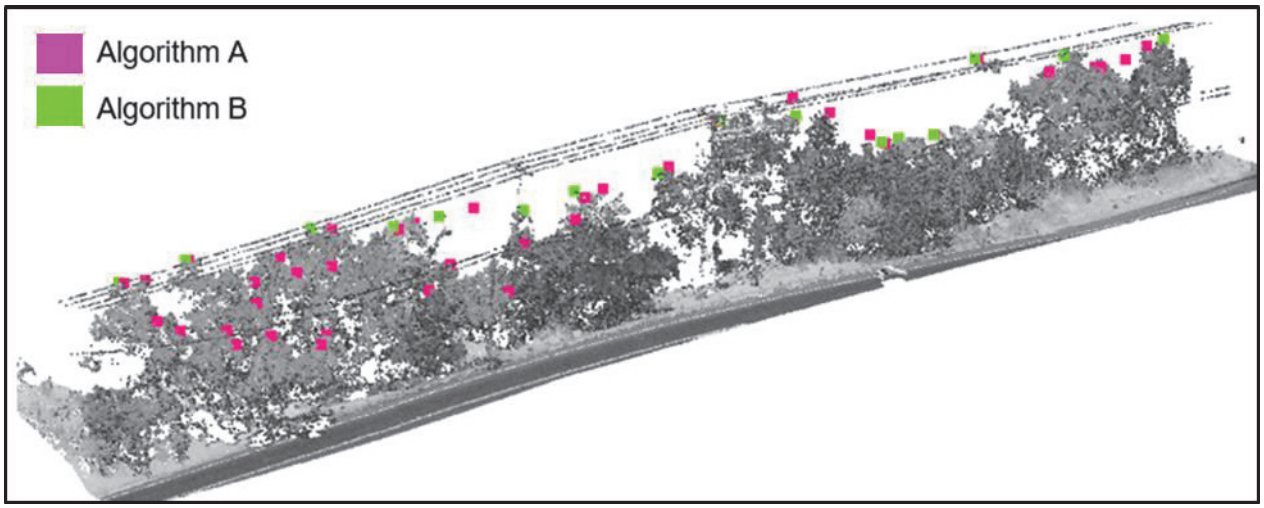


Figure 25. Comparison of Algorithm A and B Results

The analysis team then compared algorithm A to the SDG&E vegetation dataset. Since the SDG&E vegetation data mostly contained trees higher than 20 feet, the same threshold was applied on the algorithm A's dataset. Results of the comparison are shown below:

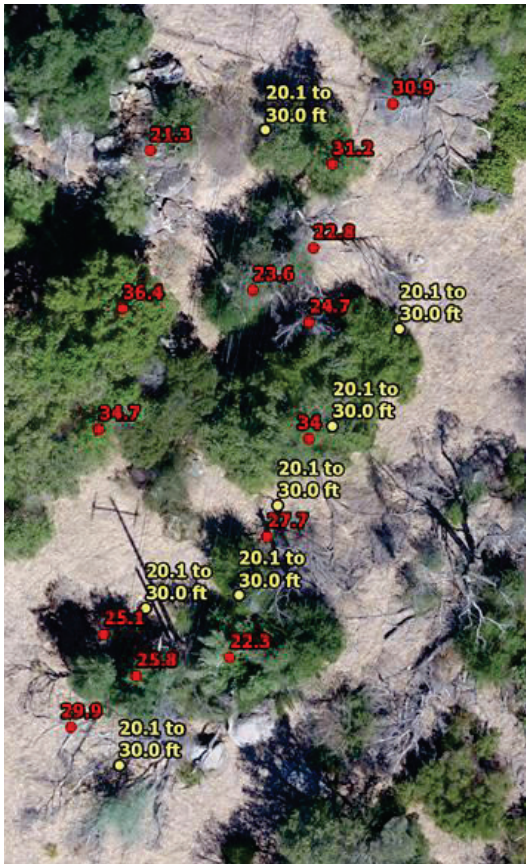


Figure 26. Comparison of Tree Detection Results (red) and SDG&E Dataset (yellow).

It is clear from the above analysis that trees can be detected in a point cloud and provide accurate results. Algorithm A was quite successful in this case, but it is important to keep in mind that deploying it requires performing multiple comparative analyses to find the best parameters for certain types of vegetation and landscape. However, it can be seen as worth the investment as it enables wire sag and growth modeling in the process of hazard detection.

Distance between detected trees and wires

Once the trees are detected, it becomes possible to calculate the distance between trees and wires. PLS-CADD has a built-in layer which contains not only X and Y coordinates of the line but also its height as weather and loading conditions allow.

The analysis team first established the planar distance between points representing trees and lines representing wires. In addition to calculation of the distance, height difference between trees and wires can also be determined by the coordinates. Once the planar distance and height differences are known it is possible to calculate three-dimensional distance in the design as shown in Figure 27 below

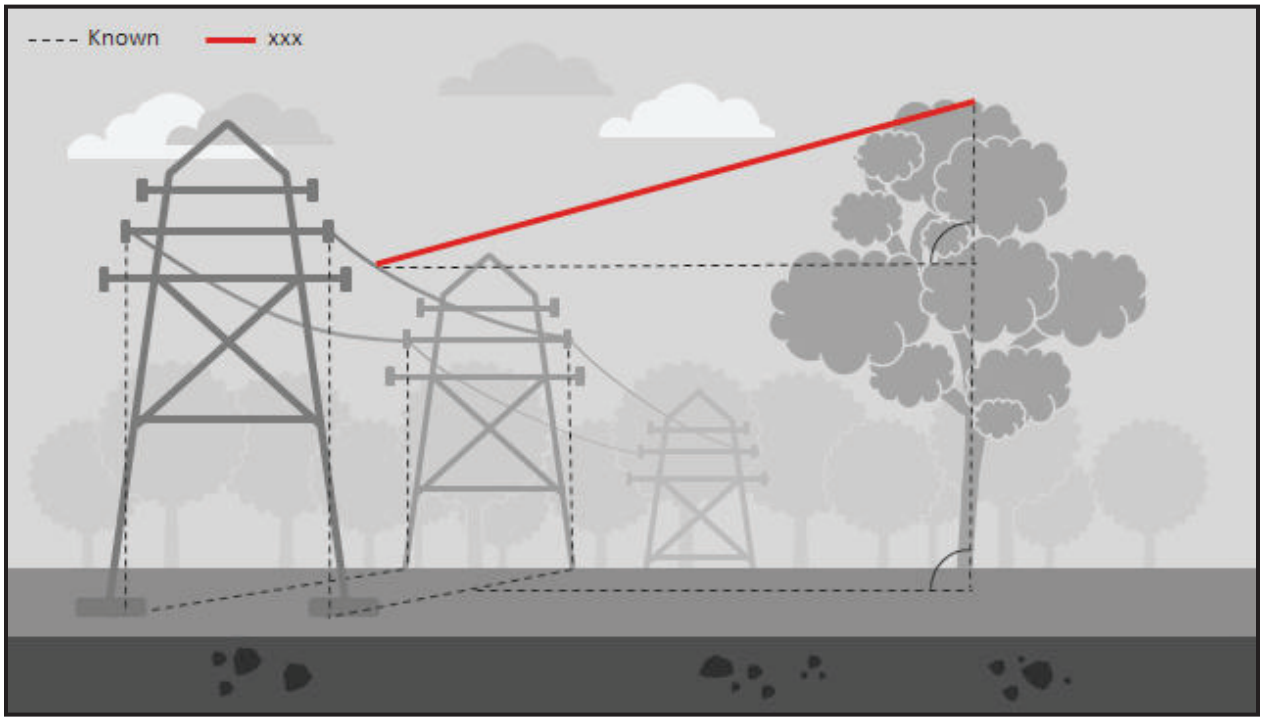


Figure 27. Calculation of the Three-Dimensional Distance between Vegetation and Wire

LiDAR point cloud is classified into categories representing different objects and elements of a landscape. Layered data can be used to measure distance between objects in varying classes. It is possible to measure distance from points located on a tree and points on a wire or a pylon by using point cloud acquired by laser scanner or created from images. Taking into account all of this information and measurements, it is possible to identify the trees that are too close to the

infrastructure based on a defined threshold in a colored by class point Cloud LiDAR image as seen in Figure 28 below.

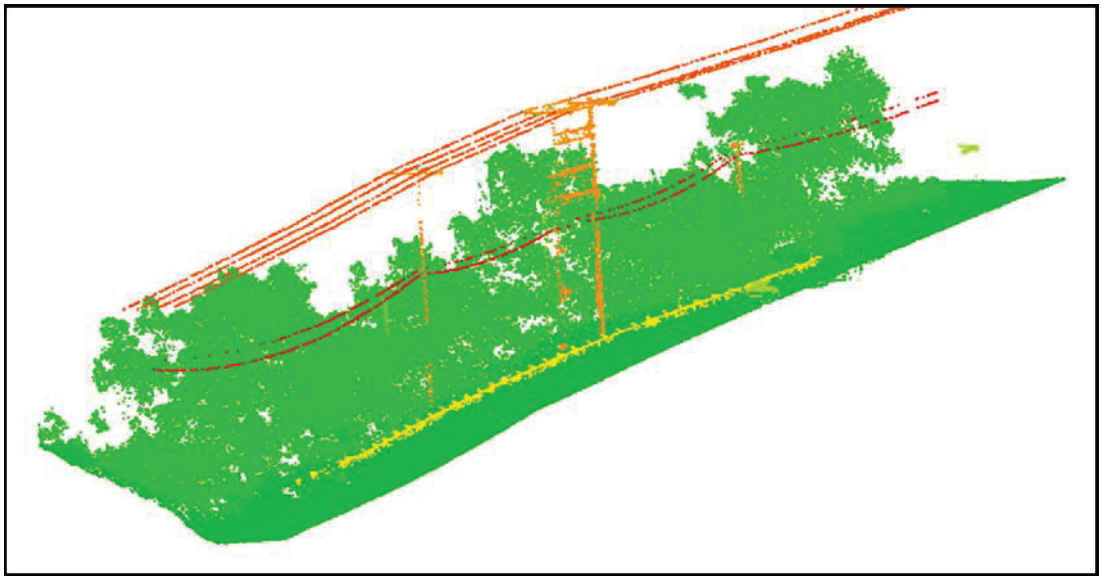


Figure 28. LiDAR Point Cloud Colored by Class

Distance measurements only describe the situation at the time of the measurement (for specific value of the wire sag). Since the sag value is influenced by multiple variables such as tension, loading, or temperature, there is a need to take these changes into consideration. Knowing the situation at the time of the measurement, tension, loading, and temperature maximum change in the wire sag can be defined based on a stringing chart report.

Thin objects like wires may not be well represented in a point cloud derived from images, since the thickness of the wire is relatively small when compared to the Ground Sampling Distance of images. As it often results in gaps in the 3D representation of the wire, LiDAR survey is recommended to collect the data. Since the route of power lines does not vary over time and the only variable that is changing is the sag of the wire, it is possible to use the same point cloud for a few years.

The 3D model of vegetation is reconstructed well on both types of point cloud data, therefore photogrammetric point cloud can also be used for this purpose. Since the structure of vegetation changes often, data gathering should be more frequent. It is possible to merge part of the LiDAR point cloud that represents the wire, with vegetation information from either LiDAR or image point cloud to identify unwanted vegetation. The red in Figure 29 shows the dangerous vegetation that was detected.

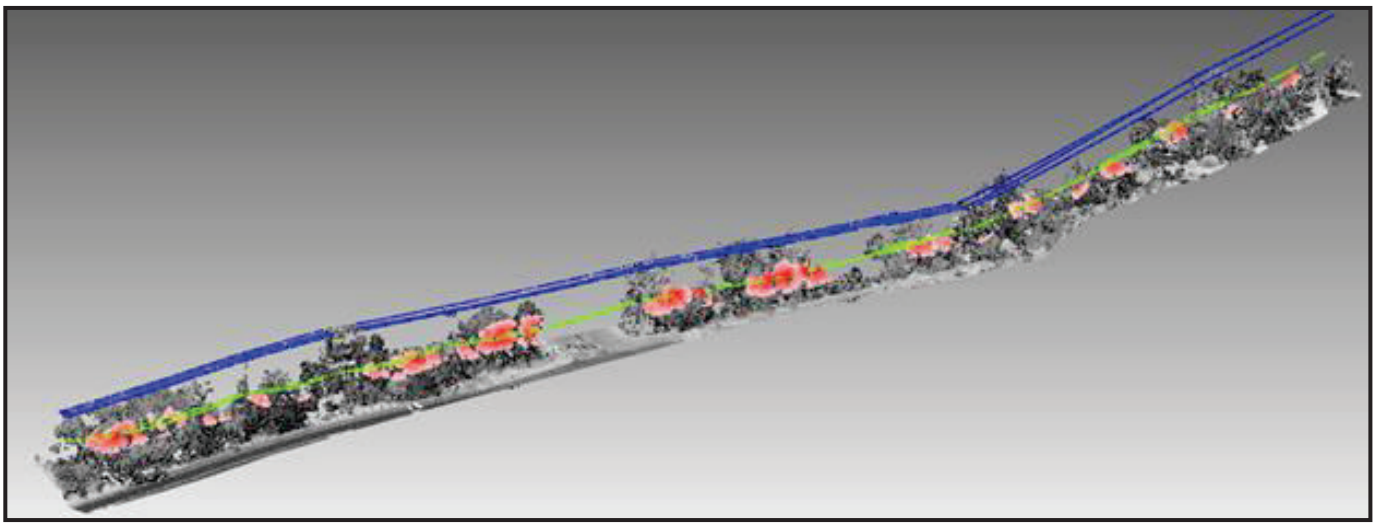


Figure 29. Dangerous Vegetation Detection in LiDAR Point Cloud (shown in red)

Detection of the trees that may affect the infrastructure falling down - Coordinates of detected trees along with calculated planar distance to wires can be used to identify the trees that may be dangerous to the infrastructure. The threshold for identifying hazards is looking for trees whose height is greater than the distance to the wire, and inspecting them for risk and health.

3.2.2.4.3 Additional Features Demonstrated

- Could incorporate species data if it was labeled.
- Fire breaks creation.

Accurate location of wires and poles is critical to identifying areas where trees should be cut in order to prevent fires. The two most suitable approaches are as follows:

1. Usage of point cloud
    - Calculation of the distance between poles and vegetation class is necessary. Once calculated, the distance threshold can be applied to identify the trees that are too close to the poles and should be removed to mitigate hazard.
2. Usage of detected trees and location of the wires represented in a form of vector layer
    - GIS tools can be used to create buffers around poles within a chosen distance. It is possible to count the trees that are within these buffers and export coordinates of these trees to be able to locate them in the field.
3. Numbers represent in figure 28, represent the number of trees to be taken out.

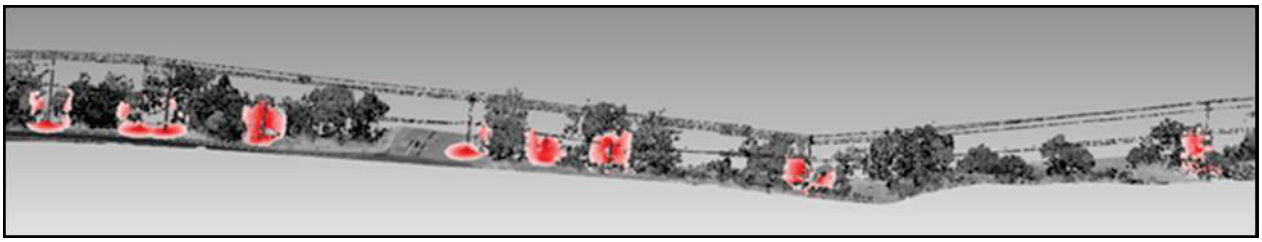


Figure 30. Buffers showing trees within them

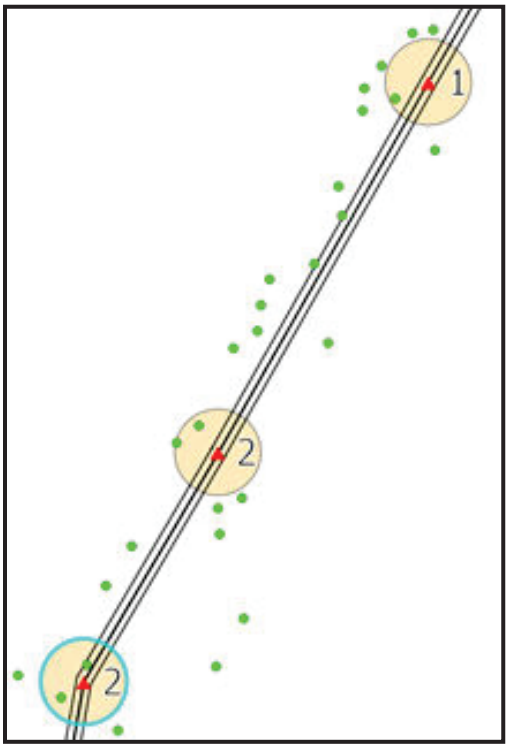


Figure 31. Buffers Around Pylons and Vectored Pylons

3.2.2.4.4 Vendor Recommendations for Future State

Analysis results have shown definite potential for aerial data application in vegetation management. LiDAR point cloud is suitable to perform most tasks. The use case demonstrated that usage of singular classes in the point cloud successfully enabled a direct detection of hazardous areas. As for image point cloud, developing a methodology requires more time due to the complexity of the classification and minimal information about the ground structure. However, once the point cloud is successfully classified and artificial objects (pylons and parts of the wires) are removed, the same algorithm can be used to directly identify hazardous vegetation. Point cloud can identify the trees currently past the threshold, and also identify the trees which may destroy the infrastructure when falling down in the future. In order to utilize point cloud, it is recommended to use DTM obtained from LiDAR and filter out any artificial objects. If using LiDAR DTM, it is important to note that both point clouds must be perfectly

aligned. Below are two potential opportunities for UAS data application at SDG&E that were identified by this vendor:

- Investigate value in combined vegetation images with predictive modeling based on tree species growth rates to enable strategic management work-planning; algorithm development can be explored as an option for automated tree species classification.
    - Utilizing an algorithm for tree detection from a point cloud will build an accurate and complete database.
    - An automatic method for distance calculation will enable instant and accurate identification of the trees to be trimmed or removed.
- Investigate the use of near IR imaging to identify trees in poor health that are at risk of falling into infrastructure
    - Aerial data can inform and enhance SDG&E's current data on trees' locations and GIS layers of infrastructure.
    - Photogrammetric point cloud is particularly useful in detecting trees, and can be used to not only accurately detect the location but also the number of trees in SDG&E's vegetation dataset.
    - Photogrammetric point cloud can also provide additional information on attributes of objects (e.g., height of the trees).
- Investigate integration with PowerWorkz system.
    - Integration can drive efficient work-planning while leveraging existing platforms.

The following proposed UAS application will improve the workload on the Vegetation Management teams and minimize the field work that has to be performed. Distances calculated based on the point cloud will be more accurate and can be utilized to measure trees at any height of choice. Long term, the calculations and measurements can be repeated or improved without conducting field trips.

3.2.2.5 Comparison of vendor results

Table 10. Vendor Results Comparison

Vendor	Encroachment Identification	Buffer Zone Shape Utilized	PLS-CADD Sag/Sway Ability
Vendor A	Positive	Rectangular	Negative
Vendor B	Positive	Tubular	Positive
Vendor C	Positive	Tubular	Positive
Vendor D	Positive	Distance Parameters	Negative

3.2.3 Cataloging and Remote Asset Management

This section describes in detail the results for the test case defined in Section 2.5.3 above. The remainder of this section will discuss the approach, results, recommendations for a future state presented by each vendor and a comparison of vendor results.

3.2.3.1 Vendor A Results

3.2.3.1.1 Approach

For this test case Vendor A ingested from the baseline data set and vendor collected UAS data various forms of data including Esri GIS, Shapefile (SHP), LAS, imagery and more. The data sets were organized in an enterprise IDMP and loaded to the vendor tool to allow users the ability to access, visualize and analyze the data. The Vendor A Tool demonstrated the following product features:

- Asset on-boarding through shapefiles and as-built DXF.
- Data ingestion of as-built LiDAR, RGB/IR/video archives and orthoimages.
- Data sorting and association based on metadata.
- 2D/3D visualization with 3D click and display.
- Collaboration tools for comments, annotations, uploads and downloads.

3.2.3.1.2 Results

The Vendor A Tool successfully ingested data from different sources and associated imagery and metadata to SDG&E assets for remote viewing and analysis.

The platform features 2D home, 3D review workstation, reports and data ingestion pages for users to perform various forms of analysis, measurements, annotations and data transfer functions. It includes navigation and controls for here location, zoom and full screen display.

The home page displays a low-resolution background with symbols for various assets and advanced analytics notifications. Selected assets display any desired attribute information and a link to review the asset in the 3D workstation if applicable. This page also provides a summary for inspection notifications that can be tied to the appropriate work orders and allows specific layers of data to be toggled off and on as shown below.



Figure 32. Example of Vendor A Home Screen

The review workstation provides 3D workspace for analysis of metadata, LiDAR and imagery. It includes a hierarchy structure for client, site, asset and date for filtering and selection purposes. There are tools for navigating views, selection of objects and measurement tools such as distance, height, area, volume and more. Users that select a point in the LiDAR cloud or a specific asset will be shown all images displaying that specific point in 3D space. Users have the ability to toggle on and off annotations and specific LAS point cloud classifications, adjust camera position and change other view settings.

3.2.3.1.3 Additional Features Demonstrated

Vendor A also demonstrated addition features such as those identified below:

- The baseline data set was added to the Vendor A Tool as an additional project for visualization and analysis but was not integrated with UAS data collected by the vendor for change management or comparison purposes.
- Images contained in an analytics query result were identified with a flag in the corner, i.e. avian cover detection.

3.2.3.2 Vendor B Results

Results for Vendor B included in Section 3.2.5 below

3.2.3.3 Vendor C Results

3.2.3.3.1 Approach

3.2.3.3.1.1 Upload and configuration processes

Data supplied from the various sources required review, post-processing and transformation before upload to the online system was possible. The following lists each data type and the work undertaken to create suitable outputs for ingestion into the system.

Ortho-rectified imagery (stock, where available) - No further work required. Conversion of 622 ECW (≈700 MB) into a proprietary format optimized for internet streaming (especially important over variable connections).
Time to convert: 60 minutes (automated process).

LiDAR Point Cloud: Required exploration in order to make robust assumptions on the classification schema, the accuracy and suitability of the classification and any filtering that may have been undertaken. Required conversion to a format that was optimized for streaming over an internet connection.
Conversion of LAS into Compressed Point Format – 12 GB.
Time to convert: 30 minutes

Digital Terrain Model (DTM): There is a need to convert and smooth the high-Resolution corridor DTM derived from the LiDAR with low resolution terrain data derived from a third party. This is to enable the fusing of the contextual terrain outside of the narrow powerline corridor. In this case, the ground points from the point cloud were used to create a DTM which was then fused with terrain from the Shuttle Radar Topography Mission (SRTM) elevation dataset.
Time to convert: 30 minutes

PLS-CADD Exports - PLS-CADD can produce an extensive collection of reports and network analytics. Certain features, such as conductors at a given loading and weather condition, can be extracted on demand and then formatted such that it enables display on the online system. For this dataset we were instructed to assess the following factors:

- Vector information - Extract wires from PLS-CADD at different conditions.
- Max Op. (167 °F)
- Blowout (85 mph)
- Vegetation reports
    - Grow in @ Max Op.
    - Grow in @ Blowout
    - Fall in @ Max Op.

Time to extract: 45 minutes
Time to convert: 20 minutes
All data was compiled then uploaded directly to the system database and data store in a batch process. A quality assurance process was then carried out to ensure data had translated correctly and was suitable for display in the system.

3.2.3.3.2 Results

The figures 33, 34, 35, 36 and 37 show a virtual tour of the available data in the online viewing system to provide context as to the extent, detail and cartographic methods of representation.

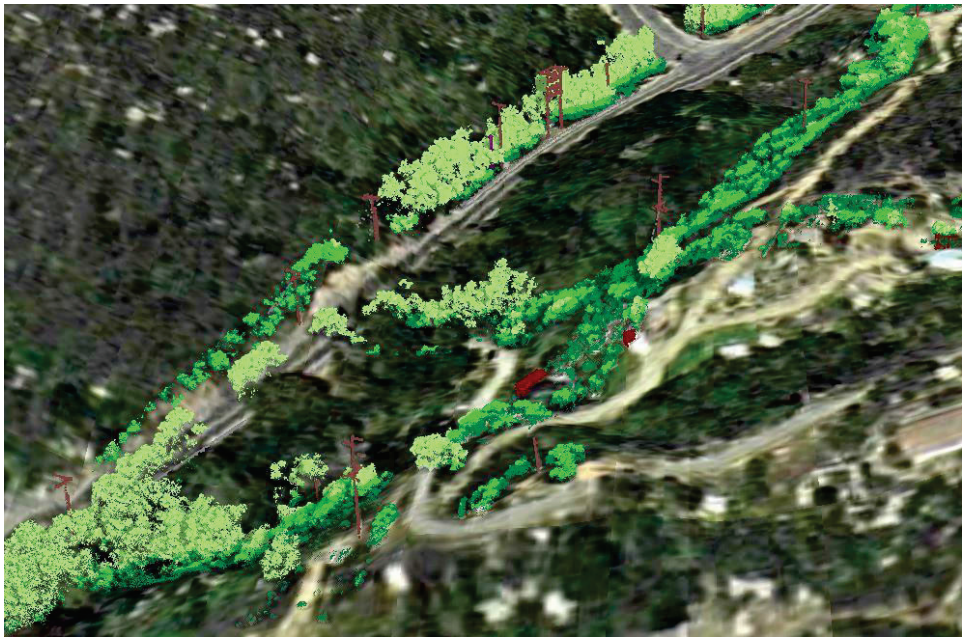


Figure 33. Feature Coded LiDAR Derived From UAS

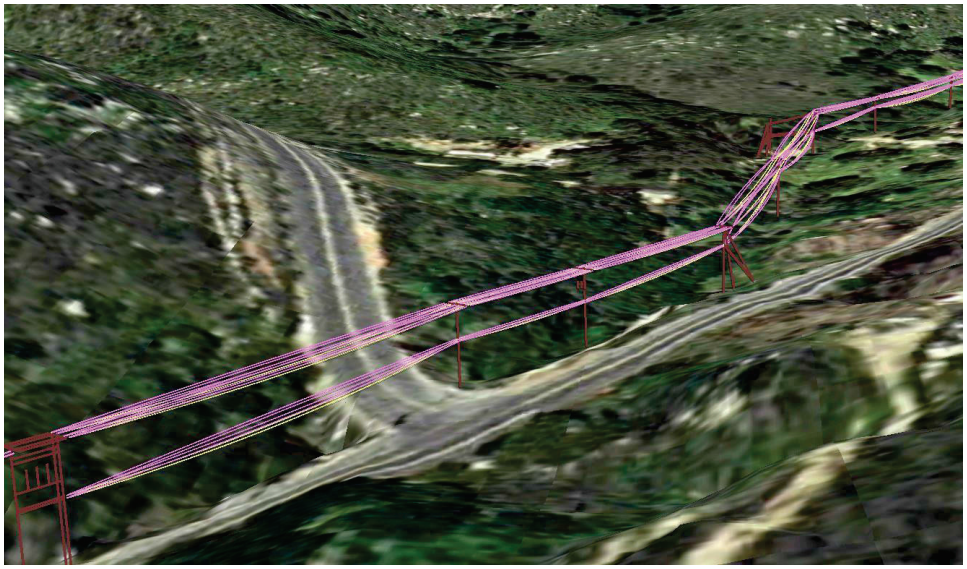


Figure 34. The supplied vectors from the PLS-CADD model.

Note the display of both ‘plumb’ and ‘blown’ conductors, i.e. still air and sagged/swayed conductors under the engineering criteria described earlier

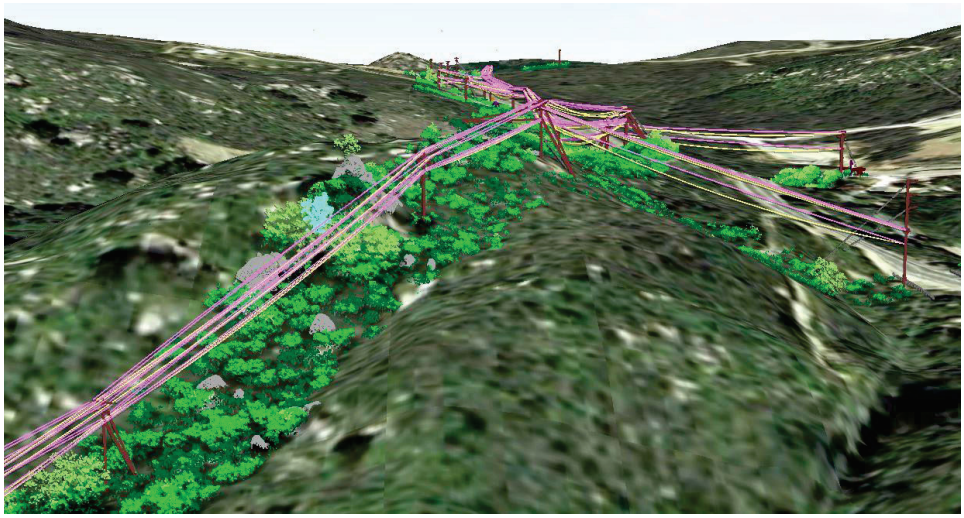


Figure 35. UAS LIDAR Alongside Extracted CAD Model.

Note the contextual terrain data integrated to the more detailed LiDAR-derived terrain.



Figure 36. Oblique UAS Image

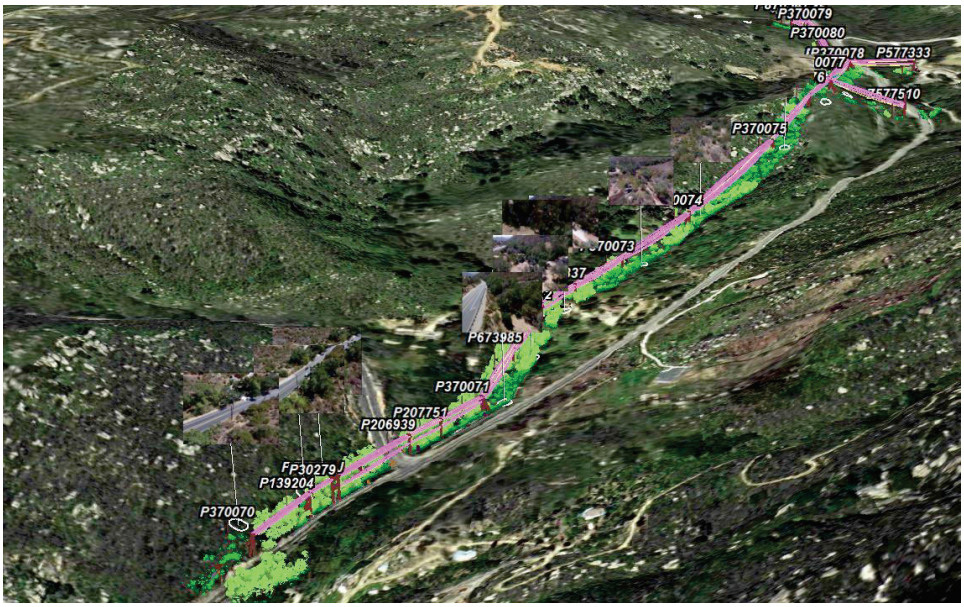


Figure 37. The UAV-Derived Structure Images

3.2.3.3.3 Vendor Recommendations for Future State

- Standardization of data structures and formats to enable more efficient sorting and loading
- A greater consistency in the UAV imagery in particular
- Metadata files giving an overview of the available data and its spatial extents (including areas such as the point classification schema)

Vendor C also provided recommendations for future use cases including:

3.2.3.3.3.1 Data & system integration

The work undertaken showed how the ability to display disparate sources of data (being LiDAR, models and images) can add value in terms of improving access to information for planning and other benefits. Further benefit could be realized by:

- Exploring the options for live-linking GIS and asset data on a read-only basis to ensure that those using the 3D platform could have access to more detailed attribution and up-to-date information.
- Looking at the ways in which users can interact with the 3D environment and start to feed changes and updates back to the connected asset and work management systems, using the virtual environment as the user interface for work recording.
- The expansion to start taking on a greater range of external data sources – taking in new line designs, models from other Computer Aided Design (CAD) systems, GIS data from state and other open sources and a greater depth within the existing corporate GIS.
- The exposure of the online system to external work contractors and other authorized parties such that they have access to more relevant information to enable them to better carry out maintenance and construction tasks.

The benefits in this case stem from the removal of a requirement to access multiple systems to get information or complete a task and the improvement of information provided to those working on the physical network. The means by which this could be tested and validated is through a series of pilot tests which focus on specific user cases (such as integrating the internal vegetation work management system to the online viewer using UAS-derived LiDAR infringements).

3.2.3.3.3.2 Exploring future asset management opportunities

The data used in the trial and the capabilities provided by the online access platform provide significant future potential for asset management. In no specific order are a range of areas that could be explored in future work:

- Dynamic visualization of status per span via cartographic methods (i.e. color according to category) – including last inspection, ground clearance, vegetation status, asset type, risk rating, etc. Enabling reviews of lines and areas to criteria of interest to form an intuitive assessment or enable work planning.
- Virtual line patrols on images and LiDAR for features of interest – then targeting ground patrols directly to areas of interest/concern. Could include vegetation management (including fall-in trees), areas with a greater risk of public safety or assets with certain attributes, enabling the access to all key datasets and records.
- Ground and building change detection to identify potential network risks or change to safety status based on hard object encroachment – showing the location and then enabling assessment from the desktop.
- Connection to investment and asset maintenance optimization platforms based on access to the results of analysis, third party data, internal data and a range of criteria.

3.2.3.4 Vendor D Results

3.2.3.4.1 Approach

Traditionally, geospatial products have been seen as supplementary tools that aid asset inspections on an ad-hoc basis. However, technological advancements have enabled the incorporation of aerial data (e.g., images, photogrammetry, LiDAR), turning geospatial products into a source of reliable and accessible information for companies' comprehensive asset management platforms. Drone based solutions accelerate the processes of inventorying and creating digital asset registers, improves situational awareness of power grid assets, and enhances prediction and reaction capabilities to events that may interfere with the network performance. Asset management typically requires RGB cameras to produce raw photos, point cloud, and 3D models.

The analysis team used aerial data collected during drone inspections over energy lines located in California. The data received from SDG&E consisted of raw images, LiDAR data, and additional vector GIS and CAD data. These were used to develop:

- DSMs and DTMs (from both image and LiDAR data).
- RGB orthophotomap.
- LiDAR reflection intensity orthophotomap.
- PDF files with additional information related to examine assets (attached in Vendor D Tool to relevant dataset).

Due to its features and characteristics, the Vendor D Tool was chosen as a proprietary aerial data platform for the study.

The Vendor D analysis team reviewed utility company leading practices and analyzed ways in which geospatial products enhanced asset management processes. The team concluded that utilizing digital maps of a company's operational radius is the best way to aggregate and visualize multiple sources of data concerning linear utility assets. Adding aerial data to digital representations of governed assets enables companies to retrieve information related to the assets more accurately and efficiently. This not only improves inventory processes but also facilitates asset maintenance in terms of necessary repairs and restorations.

3.2.3.4.2 Results

The Vendor D Tool successfully ingested data from different sources and associated imagery and metadata to SDG&E assets for remote viewing and analysis. The platform features 2D home page, with buttons to switch to 3D navigation and select projects, analysis tools for users and navigation controls.

The home page displays an overall low-resolution background with high-resolution orthophotomap along the test segment corridor. There are dots representing different assets with labels for identification, e.g. trees are labeled with a green dot and the type. The navigation controls include north orientation of screen, split screen view, zoom and navigation history. The tools for analysis include layer controls for all the types of data ingested from the baseline data set. Tools for measurement include distance, area, height, height difference, volume and coordinates. Different icons represent different file attachments and the associated data is displayed when the icon is selected. Figure 38 is an example of Vendor D's home screen.



Figure 38. Example of Vendor D Home Screen

There are also tools to add a note or attach a new file as shown in figure 39 below:

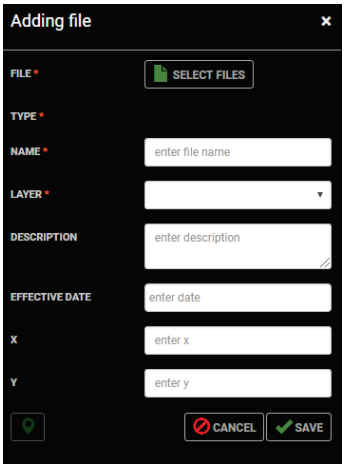


Figure 39. Example of File Attachment Screen

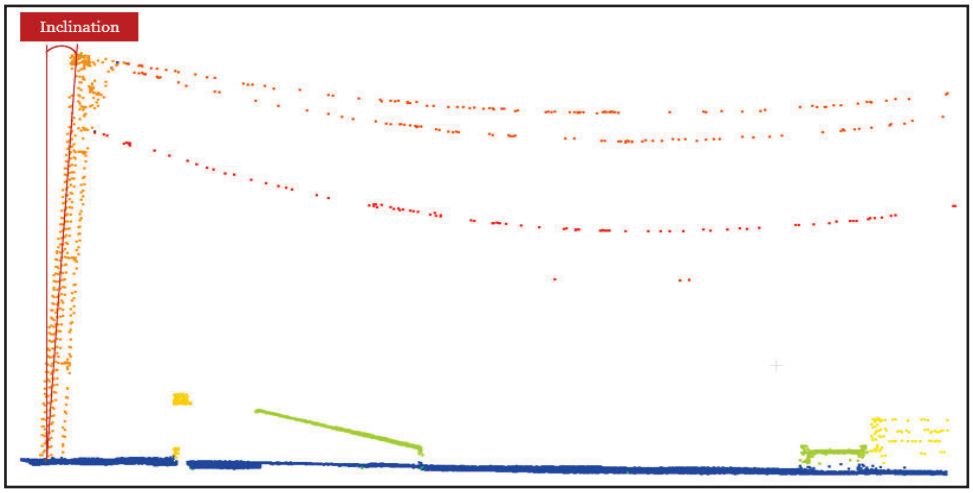
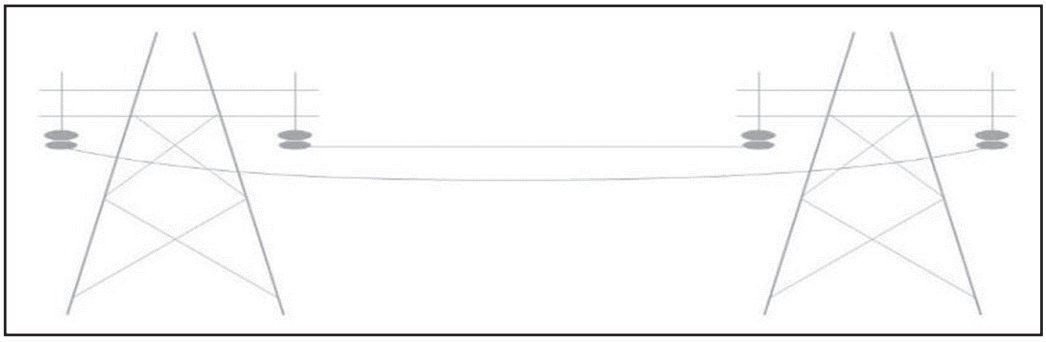
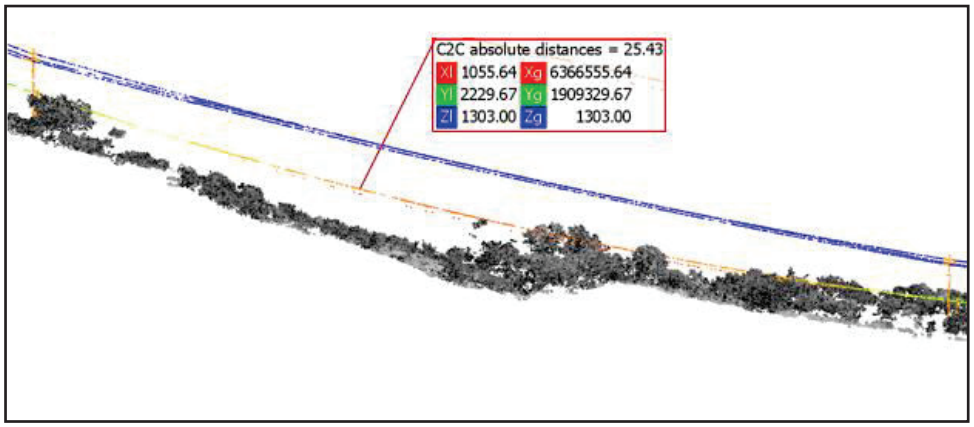
3.2.3.4.3 Additional Features Demonstrated

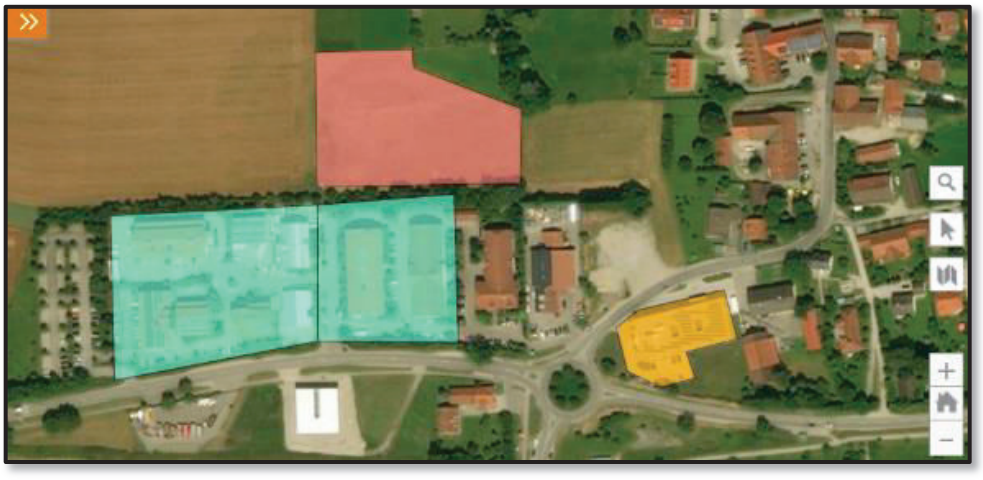
- Orthophotomap created from RGB nadir imagery for high resolution background.
- PLS-CADD model represented from DXF export included in baseline data set.
- Displayed oblique images taken for pole documentation purposes during baseline data set acquisition.

Additional applications of UAS data in terms of asset management and related maintenance proposed by the vendor are as follows:

Table 11. Additional Applications of UAS Data For Asset Management

Application	Suitable Geospatial Product
Cataloging assets, verifying quantity and location of inventor or mounted elements Examples: • Analyzing vectored paths of wires to detect areas where avian covers are needed • Combining buffer and intersect tools to automatically detect areas where problems may appear • Manually measuring problem areas on oblique images or LiDAR point cloud	• Raw photos • Point cloud • 3D model
Performing visual assessments to evaluate condition of: • Pole structures (e.g., concrete losses, condition of welds, rivets, coating) • Support structures  • Insulators and wires (e.g., wire fixings on the poles) ***Oblique image presenting top of the distribution pole including elements such as avian cover, wire fixings, and insulators***	• RGB/IR photos and videos

Controlling the position of a pole relative to the ground by measuring deviation from the vertical position and identifying abnormalities in construction to prevent poles from falling over.  **LiDAR point cloud presenting position of a distribution pole relative to the ground**	• Point cloud • 3D model
Performing wire sag analysis to enable efficient wire transfer of energy.  **Visual representation of wire sag**	• LiDAR
Automatically calculating the distance between SDG&E 2nd level and 3rd level wires or/and third party wires.  **LiDAR point cloud presenting two types of SDG&E wires and one third-party wire**	• Classified LiDAR

Gathering data on the condition of energy power lines in case of natural disasters. Helpful in identifying damages, planning repair services, and mapping current state of natural environment  **Image representing conditions on the ground**	• Orthophotomaps
Creating and enhancing information database for asset data. If the location of a particular pole can be determined by the user on the digital map in the asset management platform, related PDF files with additional information on such asset will be available in the same place for users from different departments to utilize.  **Example of asset information represented from a database**	• PDF files (as a non geospatial product)

3.2.3.4.4 Vendor Recommendations for Future State

Broad use of geospatial products based on aerial data can provide SDG&E with objective and reliable information related to governed infrastructure. Below are recommendations that will enable streamlined daily operations and crucial business processes connected with asset inventory and maintenance:

- Adopt aerial data lifecycle governance framework.
    - Adopting the framework can:
        - reduce duplicates among documentation and databases related to the same asset,
        - fill the gaps in the system related to certain assets or areas of interest,
        - enhance work orders for maintenance purposes with actual images of particular devices to be replaced or inspected manually, and
        - support asset history with objective aerial data evidence to track faults and outages for service restoration and reporting purposes, which ultimately increases overall energy network reliability and responsiveness of maintenance teams.
    - Elevated level of internal situational awareness can drive improved Key Performance Indicators, savings (e.g., prevention of costly breakdowns) and translate into higher customer satisfaction.
- Adopt Vendor D Tool.
    - In order to streamline internal processes connected with asset management and governance over critical energy infrastructure, SDG&E needs a technically robust and universal platform to effectively fulfill their daily tasks.
    - Vendor D Tool integrates functionalities tailored to requirements of a given industry or developed in collaboration with a particular client – In SDG&E's case, it can analyze and present 3D point clouds from LiDAR or photogrammetric images.

3.2.3.5 Comparison of vendor results

All vendors demonstrated the ability to ingest UAS data including RGB imagery and LiDAR and display them in their individual platforms for user visualization and inspection. Each vendor also demonstrated the ability to ingest various types of metadata provided by SDG&E stakeholders and then catalog those assets and tie them to related imagery and LiDAR for user analysis.

3.2.4 System Setup and Integration with PLS-CADD and GIS

This section describes in detail the results for the request to provide a plan for integration with PLS-CADD and GIS. The remainder of this section will discuss the approach, results, recommendations for a future state presented by each vendor and a comparison of vendor results.

3.2.4.1 Vendor A Results

3.2.4.1.1 Approach

For this POC Vendor A approach was to ingest PLS-CADD and GIS data types from the baseline data set to a potential IDMP structure and show how it would integrate with the Vendor A Tool and user interface platforms like GIS and PLS-CADD.

3.2.4.1.2 Results

3.2.4.1.2.1 GIS Integration

Vendor A was successful in demonstrating POC that GIS data sets could be ingested to a IDMP and loaded to the Vendor A Tool for cataloging, visualization and analysis. Although there was not an attempt to integrate with SDG&E GIS, the vendor ensured the ability to provide live updates import/export with Esri GIS databases as needed in a future state.

3.2.4.1.2.2 PLS-CADD Integration

Vendor A did not have the ability at the time of this report to fully integrate with PLS-CADD. The POC covered the LiDAR data file ingestion process, mostly as it related to feature code extraction for the purposes of vegetation encroachment analysis. LiDAR data was presented in the Vendor A Tool to show that LiDAR and DXF data could be readily viewed and queried in their platform but it could not currently ingest and disseminate those files from the PLS-CADD model. Vendor A proposed the standard process for PLS-CADD data ingestion below:

3.2.4.2 Vendor B Results

3.2.4.2.1 Approach

Vendor B did not perform this task but made recommendations as stated in Section 3.2.4.2.4 below.

3.2.4.2.2 Vendor Recommendations for Future State

3.2.4.2.2.1 GIS Integration

GIS represents one of the key operational systems that must interact with the asset management system. Primary interactions between asset management system and GIS could include:

- Supporting mission planning by accessing the GIS data representing the distribution infrastructure to create/update flight plans.
- Automatically tagging assets on ingest with GIS information such as asset IDs and other basic metadata (similar to the workflow demonstrated in the data management test case except deriving the information directly from GIS).
- Inserting hyperlinks to specific images of assets in the GIS data records, allowing seamless access to current and historical images of assets from within the GIS. The platform facilitates downloading the asset data, that can be used in GIS, as the formats are OGC compatible and universally consumed by all geospatial applications.
- Creating workflows to update GIS assets with information derived from analytics.

- Integrating image analytics as tasks directly within GIS.

One or more common OGC data access standards, including WMS and WFS, can also be used to share information between systems. Specific Application Programming Interfaces (API) will need to be created to populate and maintain links between the GIS records and the asset management solution.

3.2.4.2.2.2 PLS-CADD Integration

To support the engineering design workflow, further research is required to determine how PLS-CADD and the asset management system can be integrated to manage the LiDAR data collected by UAS as well as other LiDAR systems.

The general workflow includes:

- Accessing data in the asset management system from PLS-CADD to create engineering backup (BAK) files
- Saving and managing the BAK files in the asset management system
- Generating vegetation encroachment and other analytics such as joint use studies from PLS-CADD's BAK files

3.2.4.3 Vendor C Results

3.2.4.3.1 Approach

The approach of Vendor C for this POC used the rationale that the principle in this use case is access to timely 3D information describing the network location, condition and context, via a suitable platform that may integrate effectively with existing utility systems and processes. The need for such a platform has been recognized by network operators for the following key reasons:

- The GIS platforms in place, while still relevant and crucial to business-wide operations, were designed to provide a detailed and highly controlled single source of records and were often linked to the network connectivity models. The result of this locked-down structure and strict governance is a highly inflexible structure and a slow process of data ingestion, with limitations in the 3D environment.
- Legacy systems have not kept pace with the significant increases in data volumes generated by new sensors such as LiDAR, such that the storage, management and access to this data is challenging if not impossible, using historical approaches.
- The revolution in mobile computing and data transmission via mobile data networks means new demands from the user base and new opportunities to improve the way field operations are planned and managed. There is not however a means to effectively push this data to such devices and provide the ability to view the bulk 3D data, take measurements and see the recently delivered results of analytics, such as vegetation clearances.
- The volumes of data for long term storage, given the trend towards annualized or more regular capture of LiDAR and imagery, is significant such that utility IT systems are

rapidly exceeded in capacity. This challenge is further exacerbated by the complexity in managing the millions of files and thousands of terabytes of data that are generated by utility line mapping programs.

3.2.4.3.1.1 Objectives and architecture

The objectives of this type of system are achieved by:

- Using a cloud hosted solution – to enable hosting near to the customer (minimizing lag) and in a rapidly scalable environment (generally this means Amazon Web Services, Azure or Rackspace in the closest datacenter).
- A focus on the web browser, such that the use of the system is intuitive and simple without the need for complex installations
- The implementation of high compression rates for data transfer, enabling a rich user experience (i.e. sufficient detail without data loading lag) without the need to excessively 'thin' the data.
- The use of open format databases to enable flexibility in connecting to other sources and tailoring the outputs to each customer, particularly crucial to enable the use of existing GIS information and other asset or process control databases.

3.2.4.3.2 Results

3.2.4.3.2.1 Generic system attributes

Based on user feedback, practical experience and the understanding of the network operator in this case, the following are implemented to realize the objectives:

- Inside the portal a 3D representation of the network is displayed, from terrain and base imagery through to high resolution LiDAR and asset images. These can all be layered up to provide a rich, detailed view of the as-built, as surveyed conductors, structures, vegetation and condition.
- The system is configured to use pre-optimized to allow fast loading, and reduced data volumes to be distributed across the internet whilst maintain the visual quality required for review and condition assessment in the portal. This method was chosen as opposed to the alternative on the fly compression or distributing uncompressed data, as this leads to reduced server load – meaning more users can access the data concurrently, and the amount of data that needs to be handled at any given point, resulting in a smoother user experience.
- The system revolves around a central store that then feeds data into the web viewer, this central store can provide feeds into other systems and vice versa. In a future state the platform will have 2D data layers can be fed into other software like Esri ArcMap, ArcGIS Online, QGIS, PLS-CADD as standard WFS / WMS feeds that are fully OGC compliant. Currently only asset data layers (Imagery, metadata, and GIS shapefile) are downloadable and can be used in other software like GIS etc.

- Conversely, existing feeds can be fed into the system, allowing data to be integrated into the system, bringing everything into one place, maximizing the amount of information available to inform intelligent business decisions. Once again, this includes standard WFS / WMS feeds and a range of tabular database connections.
- Variable user demand (managing peaks) is implemented by the use of a horizontal scaling approach, using automated scripts to initiate new instances and access additional computation to ensure performance does not become limited.
- The vendor also brought up an ability of the platform to create new shapefiles from analytics that can be imported into GIS. This feature was not demonstrated.

3.2.4.3.2.2 Data input requirements

The system, based on its intended purpose, is designed to be the overarching platform that collates, organizes and streams a large variety of datasets to end users within utilities. It is designed to work with a multitude of data formats that get converted into standard stream friendly formats for distribution across the internet. However, when it comes to providing an accurate and user-friendly 3D model of the powerline alongside the analytics results, experience has led Vendor C to develop some specific requirements. This includes but is not limited to the import file formats, data thinning/filtering and the types of geometrics in spatial files. These may not be specific to other industry systems however the principles are likely to be similar.
The common datasets to make a 3D Powerline model for ingestion to the system, and similar systems, are:

- Orthoimagery – georeferenced and mosaicked orthometric photos.
- Digital Terrain Model (DTM) – Generated from a classified LiDAR point cloud.
- Digital Surface Model (DSM) – Generated from a classified LiDAR point cloud.
- LiDAR point clouds – collected from an appropriate aerial or ground-based platform and filtered via point classification.
- Vector features (Wires, Towers, Poles, Cables, Transformers, Disconnectors etc.) – as generated from a PLS-CADD or other CAD format model, according to the analysis parameters required by the project aims (i.e. thermal rating, vegetation).
- Infringement Information – including but not limited to LiDAR points representing ground, vegetation and building infringements according to statutory distances.

Each of these datasets have a variety of options for import, depending on capture methods and the formats that have been used to store the data. For pre-processing, we recommend utilizing Tag Image File Format (TIFF) files for the Orthos, DTM and DSM. The TIFF format allows additional geospatial information to be captured within the file, meaning there are no additional reference files.

LAS data is stripped of most of its “meta” data when loaded into the system for streaming, inside LAS files there is a large number of additional attributes that are unnecessary for visualization

purposes, so this is removed. Attributes like scan angle, GPS Time, Flight line, Scanner specification can all be removed from the points before streaming. Instead the only information remaining is the XYZ position of the point, and the RGB value it should be displayed as. For ingestion into the system LAS 1.2 Point Type 3 is preferred, as this includes the RGB values enabling easy extraction and conversion. Other LAS specifications are accepted and can be included within the platform; however these require an additional processing step.

For vector features, a wide range of inputs can be used; it is recommended to use Esri Shapefile or SQLite/Spatialite as this ensures a trouble-free import into the database. Vector features are stored inside a PostgreSQL/PostGIS database which enables fast queries, and the ability to store vast amounts of attribution, while giving us the flexibility of a database for searching, reviewing and updating all within a geospatial aware environment. The tables within the database are then streamed into the platform via WFS, which also provides the flexibility to utilize the WFS feeds within other packages, ArcGIS, QGIS and PLS-CADD.

Vegetation infringement information is extracted from PLS-CADD models or from external analytics comparing the distances between conductor and vegetation. These calculations can then be displayed visually within the system, and styled appropriately to provide additional contextual information. It is important to note that there is a deliberate separation between the analytics and the display of results: the computational requirements, interfaces and software needs are sufficiently different that tailored analytics for multiple projects are best done separately and fed into the generic platform.

3.2.4.3.3 Vendor Recommendations for Future State

The online platform is designed to meet a range of utility objectives and the software effort is driven by the direct requirements of existing and potential commercial users. In this context, being a publicly available document and with the content being generically applicable, it would not be appropriate to share a detailed software roadmap. However, the following are objectives in the short to medium term:

- Enabling the utility user to search among the large number of asset and GIS fields available, to ensure rapid and effective navigation across large continuous datasets – via typed search, data sorting and user type profiling.
- More closely integrating the sources of spatial data and imagery with the network GIS and asset data, via loose linkages/integrations – to facilitate a seamless view across disparate sources of information.
- Align the display, configuration and user interactions more closely with the different use cases, particularly vegetation management and asset management.
- Further improving performance as relates to supported devices, operating systems and the speed of access on less robust data connections.

Longer term:

- Implementing integrations to common asset systems with live communication to SAP, Maximo and Ellipse, among others.

3.2.4.4 Vendor D Results

3.2.4.4.1 Approach

For this POC Vendor D's approach ingested various GIS data sources from the baseline data set but did not provide a plan for integration with PLS-CADD platform or files.

3.2.4.4.2 Results

3.2.4.4.2.1 GIS Integration

Vendor D was successful in demonstrating POC that GIS data sets could be ingested to a IDMP and loaded to the Vendor D Tool for cataloging, visualization and analysis. Although there was not an attempt to integrate with SDG&E GIS, the ability to import/export GIS information was demonstrated. The vendor ensured the ability to provide live updates with Esri databases as needed.

3.2.4.4.2.2 PLS-CADD Integration

Vendor D Tool did not have the ability at the time of this report to integrate with PLS-CADD.

3.2.5 Demonstrate Data Lifecycle Management

This section describes in detail the results for the request to demonstrate data lifecycle management. The remainder of this section will discuss the approach, results, recommendations for a future state presented by each vendor and a comparison of vendor results.

3.2.5.1 Vendor A Results

3.2.5.1.1 Approach

For this POC Vendor A recognized the challenges and complexities of obtaining, processing and incorporating the large dataset types proposed for this project. They proposed a robust enterprise IDMP that provides for ingestion of the data, aided in management of the data and the ability to incorporate that data in the daily business decision making processes. Key to their proposal is a system that:

- Associates the collected inspection data to current systems of record and asset hierarchies to allow analysis and business decision making at a deeper level.
- Effectively manages metadata for facilities and their components to provide advanced search and filter capabilities and rules-based analytics.
- Allows for improved and detailed visualization of data types as they relate to specific assets and provides a detailed and multi-dimensional view of the current state of the asset.
- Assists in providing and managing workflows for the various stakeholders in their varied needs.

- Allows for efficient storage of and access to the most current version of the data.

3.2.5.1.2 Results

The initial focus of the Vendor A was ingestion of large volumes of data and the associated metadata management that would be required. Large amounts of incoming data provide a unique challenge in ensuring the data is properly tagged and can be associated with the desired assets. Vendor A proposed three types of metadata to be analyzed; Embedded, User Created and System Generated:

- Embedded metadata is native from the item being processed, in this case usually EXIF data and other information related to the image.
- User created metadata is defined during ingestion via manual or automatic association to asset hierarchies or the systems of record.
- System generated metadata which is automatically added due to automated processing, for example, processing resulting from application of automated defect recognition software.

The following table shows potential types of system generated metadata:

Table 12. Potential types of system generated metadata

Data Type	Required Metadata	Additional Metadata
Imagery – RGB, IR Video – RGB, IR	EXIF Info: GPS Latitude, Longitude, Altitude, Time and Date Stamps	EXIF Info: GPS Satellite info, GPS Version, Image Direction references
LiDAR – (.las)	X, Y, Z Values, Intensity, Return info, GPS Time, Scan Angle, Scan Direction	RGB Values, Point Classification

Once the data has been properly tagged, the Vendor A system will allow the user to perform detailed search, visualization, and inspection capabilities. The inspection interface also allows for additional asset inspection, tagging and the addition of image annotation to aid in reporting and information dissemination. During the analytics phase, metadata was updated to allow for better component detection, change detection and management, and other potential use cases. The resulting knowledge gained would allow the business to streamline workflows and improve inspection, asset management and data management processes.

Ingestion of large amounts of data into this system will require development of data storage policies that maintains various levels of access to data based on business requirements. Vendor A proposed developing data retention based on “Hot, Warm, Cold” rankings. The data ranking would determine the level of data storage and ease of access; data ranked “Hot” would be readily accessible while “Cold” data would take more time to bring it up from archived location. The

following workflow image outlines how the data collection and retention workflow might look based on collection and data retention rules.

Vendor A proposed the following “typical user” workflow:

- User logs in to enterprise system and performs a query on a system asset.
- Vendor A Tool queries its database and associated other databases. This query is internal to the could-based platform.
- Query results returned to User.
- If new, unprocessed data is available, import of that data is commenced.
- Initial system-added metadata is created for the contents.
- Data approval workflow is run, in which data is ingested, tagged with additional available metadata and, upon approval by reviewing parties, is released for use by end users.
- System continues to perform analytics to process data, identify features, defects, etc.
- Image analytics are run to determine if additional GIS data/assets can be cross referenced.
- User is presented with the results of the analysis.
- User then reviews any alerts or notifications generated via analysis.
- If necessary, system will launch additional applications for user(s) to process and update relevant files.
- If available, historical imagery is related to new imagery to add to the temporal data repository.
- User performs any necessary updates to as-designed or as-built files. Approval process is launched for revisions.

In summary, Vendor A proposed a browser based platform that allows users to process and review new and previously processed imagery and LiDAR products; this system is linked in various ways back to PLS-CADD and GIS data and systems internal to SDG&E. Machine deep learning and analytics would be performed in the cloud-based Vendor A Tool, providing enhanced workflows and long-term data management solutions necessary to be able to effectively distribute and use such a large amount of imagery and LiDAR data. Better storage, access and analysis of such a data collection will allow the business stakeholders to make better and timelier decisions on time critical business processes, resulting in improved service to the customers and a safer and more cost-effective operation.

3.2.5.2 Vendor B Results

3.2.5.2.1 Approach

The approach of Vendor B for this POC recommended using the Vendor B’s scalable web-based UAS data management platform, upload imagery from the field and transform the data into information that enables users across the organization to quickly locate areas of concern, assess the situation, and make informed decisions.

3.2.5.2.2 Results

3.2.5.2.2.1 Ingesting and Cataloging Data

There are several methods available to ingest UAS data into the Vendor B IDMP, ranging from uploading files to consuming the output of a streaming service, which is most often used with Full Motion Video (FMV). With the emphasis of this POC focused on still imagery**,** two common ingest approaches were used - manually uploading data and using an automated process for an entire data collection.

1. In order to upload a file or set of files, the user must have the appropriate permissions which are managed and authenticated through the data management platform. Using any device that has a web browser, users can select a file and upload it to the system. The user will be prompted to enter details about the asset such as a description, expiration criteria, collection details, or any keyword tags they will be used to associate similar data. If the imagery's metadata contains date, time, latitude, longitude, altitude, etc., this information will be automatically catalogued upon ingest as well.

2. Using an http-based RESTful interface, an automated process can be used to ingest and associate related imagery. For example, in this POC a process was developed that determined each image's GPS coordinates and compared its location to a Keyhole Markup Language (KML) file of pole locations ingested from the GIS. Using these locations, the process identified the pole closest to the image's location, allowing the ingest process to automatically determine and assign a tag to the imagery metadata with the pole id for each image. As a result, users can easily query by pole ID to easily locate all related imagery. See figure below.

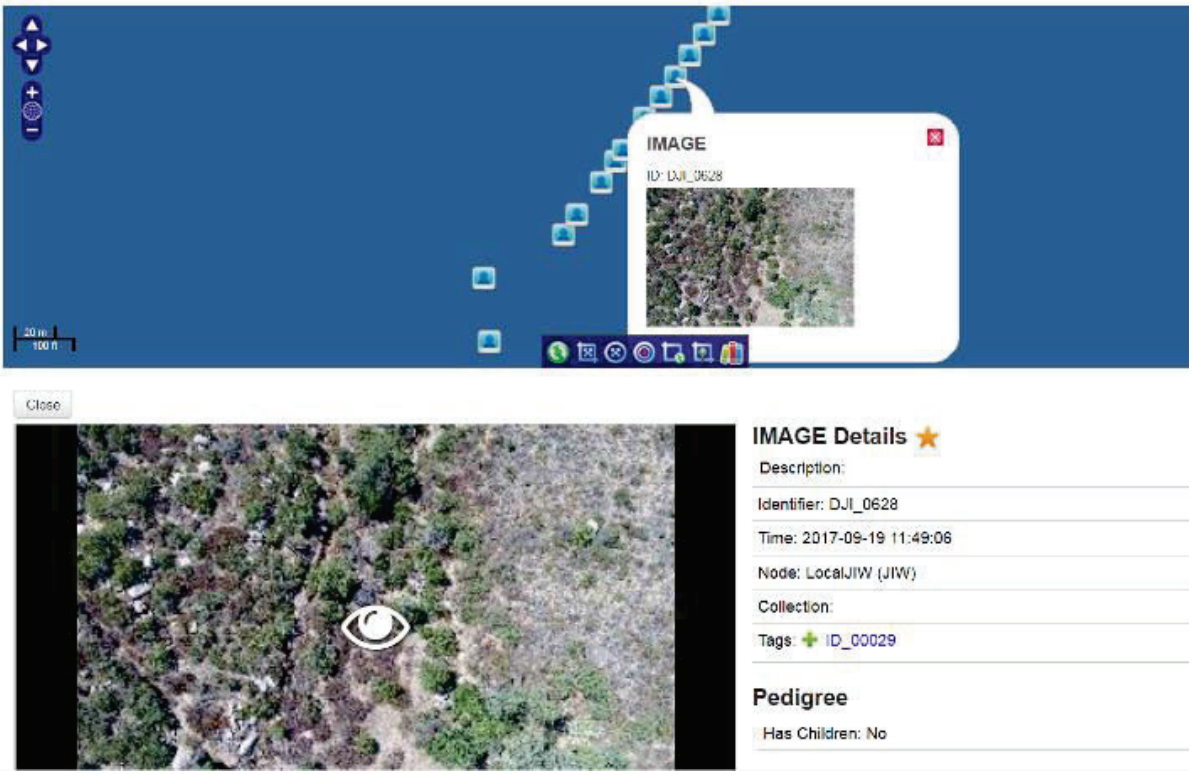


Figure 41. Example of File Attachment Screen

3.2.5.2.2.2 Discovering and Disseminating Data

As utilities capture and consume mass amounts of data, one of the keys to any system is the ability for users to locate data quickly. With Vendor B's UAS data management platform there are several options that can be used to locate assets. They range from entering specific coordinates, drawing a geo-bounding box on a map, or filtering on keywords, platform types, tags, metadata, date and time, or asset types. Additionally, users can either search for specific values or utilize wildcard searches to locate their assets.

Results are presented back to the user grouped by time/start time and ordered with the newest assets first.

A variety of actions can then be performed such as:

- Opening image(s) in image viewer
- Adding assets to a library or workbook
- Executing analytics
- Generating a Google Earth KML file that contains all selected assets
- Downloading the assets to a local machine

3.2.5.2.2.3 Archiving and Deleting Data

Data is automatically archived as part of the ingest process. If the images are processed, the original image is preserved and archived.

To aid in data management there are several techniques for archiving and deleting assets within the UAS data management platform. Three examples of how data can be removed from the system include:

1. Assets can be manually purged by users with System Administrator privileges.
2. An expiration timeframe can be assigned to the asset. For example, if a company policy is to remove data from the system once it reaches an age of five years, an expiration timeframe of 5*365 = 1825 days can be assigned to the asset. Once that expiration period has been met the asset is automatically deleted from the system.
3. The system can be configured to monitor disk space so that when a predetermined threshold of available disk space is reached, the oldest files are automatically removed. System administrators can manage what assets should be considered for deletion, which ones should not be removed, as well as how many days an asset should be retained before it is eligible for deletion.

In the event a delete activity fails, administrators have access to logs that identify the affected files and are provided the ability to flag them for deletion or save and archive the assets.

3.2.5.2.3 Additional Features Demonstrated

3.2.5.2.3.1 Managing Users and Permissions

User access to the UAS data management platform can be managed several ways. User accounts and groups can be configured to use an internal or external Authentication Server or Microsoft Active Directory (using Lightweight Directory Access Protocol (LDAP) queries).
System administrators can also control what specific users can do within the system by setting up Role Based Access Controls (RBAC). RBAC provides administrators with the ability to create roles, assign groups of users within that role, and define access privileges. This process allows administrators to control what types of actions groups of users can take within the system (e.g., restrict one group of users to viewing data while allowing others the ability to read and write data to the system). Figure 42 shows the users role based on access control.

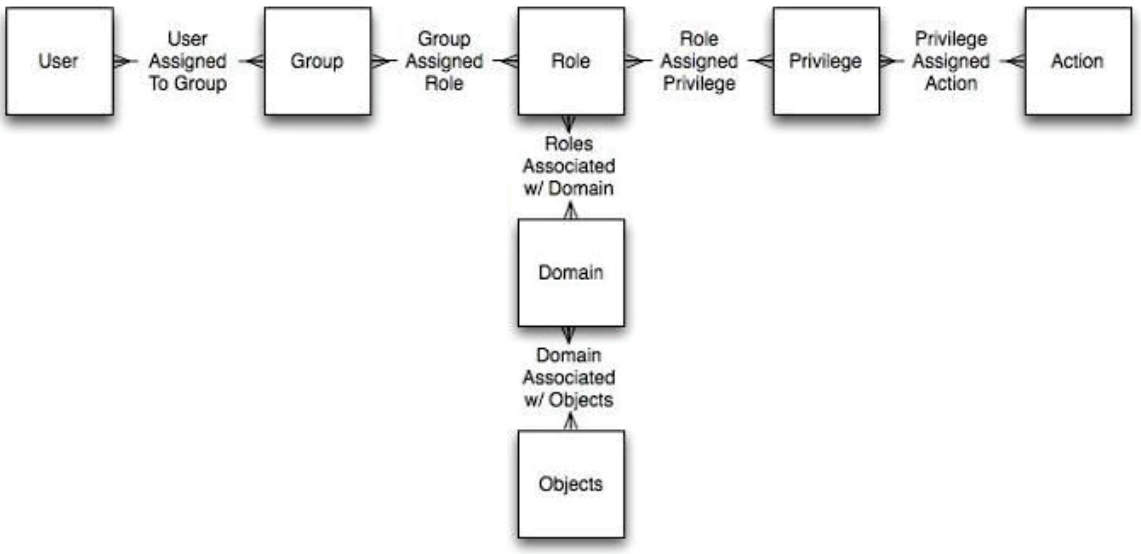


Figure 42. Role Based Access Control Component Diagram

3.2.5.2.3.2 GIS Integration

The Vendor B UAS data management platform and SDG&E's GIS both support OGC data access standards including WMS and WFS. As a result, assets from the UAS data management platform can be downloaded and viewed within the GIS.

Below is a visual representation of assets that are stored in the UAS data management platform which are downloaded and visualized within a GIS. These assets include images which are represented as green triangles and videos which are represented as red airplanes. The platform is currently only capable of integrating the core analytic tools from their remote sensing platform into Esri ArcCatalog toolbox.

3.2.5.2.4 Vendor Recommendations for Future State

While the Vendor B UAS data management platform met all expectations of this test case, the application of analytics to assets in the geospatial and temporal data catalog will require an asset-centric management approach. Vendor B proposed a plan to provide WFS feeds of asset data, that can populate SDGE GIS portal applications.

3.2.5.3 Vendor C Results

3.2.5.3.1 Approach

Vendor C did not demonstrate a data lifecycle management plan but did provide recommendations for future use cases related to data management and ingestion described in Section 3.2.5.3.4 below.

3.2.5.3.2 Vendor Recommendations for Future State

Vendor C also provided recommendations for future use cases including:

3.2.5.3.2.1 Enterprise data management

The project in this instance looked at a snapshot in time on a portion of the network. It is the experience of Vendor C that:

- Much data is collected each year by different groups within the utility.
- This data may not be easily accessible (or in some cases, not widely known that the data exists).
- The data is increasingly becoming unwieldy and difficult to manage due to file sizes and a range of standards and formats.
- There is willingness to do things like machine learning or change detection, but the 'data management infrastructure' has not been designed with this in mind.

Assuming these challenges may be overcome, there is much potential to be found in exploiting and making available a wider set of data to the organization and analytics partners in order to facilitate:

- The detection of topographical and asset changes based on geospatial datasets such as imagery and LiDAR (understanding what is happening around the assets and the Right-of-Way (RoW)).
- The creation of large multi-year training datasets for a range of machine learning applications, by making available the results of raw data, analysis and models to enable training processes to be completed in an automated fashion.
- The ability to start understanding asset degradation and change via the images of those assets, as far back as is needed.
- The ability to go back in time to understand a situation in a given location in cases of liability or understanding early asset failure.

This may be facilitated by designing a 3-tiered data management and access infrastructure, which considers:

1. Raw/bulk data storage – with the input datasets being photos, aerial images, LiDAR, meteorological observations, loading data and so on. This is structured around the topology of the datasets and the networks to enable a logical organization and is managed via automated tools.
2. An access portal to provide visibility to the data location and metadata – showing what is in the store, when and how it was collected and providing direct access. An example of this platform is the Trimble data marketplace, a general toolset based on cloud infrastructure. In particular, this tier is the enabling software toolset that extracts data for analytics process and for the final tier.
3. An access portal for the 'latest cut' of the data, enabling an understanding of the sort of data that does exist and automatically provisioning the most up to date information for the wider user base. A 3D platform, this might also provide a user interface for Tier 2, enabling a more seamless user experience.

This case, which is about enabling infrastructure for some of the more in-depth analysis and applications, is something that could be explored via processes such as detailed data audits, data standards harmonization and test and development of platforms supporting each of the three tiers.

3.2.5.4 Vendor D Results

3.2.5.4.1 Approach

The approach of Vendor D for this POC suggested that in order to manage the various types of gathered aerial data and geospatial products in an efficient manner within the structure of a large organization, it is essential to establish appropriate aerial data governance principles by providing a clear foundation and guidelines. Establishing a framework of data governance starts with defining the concept of data governance.

Data governance is the practice of defining the standard processes an organization will leverage to manage gathered aerial data in support of its operations in an efficient and organized manner. A thorough and effective data governance and lifecycle management strategy addresses regulatory requirements, enables business continuity, and enables collection of necessary data by stakeholder in a timely, cost effective manner.

Exercising aerial data governance across the organization is critical for long-term success, sustainability, and execution of the organization's mission. Such transformation requires a strong foundation in each identified component of aerial data governance.

Successful facilitation of aerial data governance requires a cross-section of people, data and technology. All three elements play a crucial role in enabling effective usage of aerial data across the organization.

3.2.5.4.2 Results

Once the data governance policy has been defined and put into place, Vendor D sets out what they feel are necessary pieces in the data lifecycle management process. The following outlines the steps they see in this process, their evaluation of the current state of the process at SDG&E, and any recommendations they see that would help improve the overall process:

- Tasking – Defining the requirements for the type of data to be collected and employing either internal or external assets as necessary to facilitate the data collection.
  Currently Vendor D feels SDG&E has limited standards and documentation on collection and dissemination of aerial data. The following steps are recommended for improvement of standards on handling data:
  - Development of guidelines based on data and operational needs
  - Establishing a list of use cases across all departments and stakeholders.
- Collecting – Imagery, video, or LiDAR is captured using the appropriate system and delivered for processing to be applied to the user's use case.

Currently SDG&E possesses a good set of risk and safety policies regarding aerial data collection, whether by internal company assets or external vendors.
Recommendations –
    - Development of an SOP defining when to use internal or external collection resources based on cost-benefit.
    - Develop SOP defining technology requirements for data collection.
- Processing – Conversion of the raw data into usable data products and stored in accordance with the data governance policies in place.
SDG&E has limited capabilities for processing data products in-house.
Recommendations –
    - Develop SOP that details the cost-benefit analysis for in-house versus external processing and includes specifications for processing data, either internally or externally.
- Exploiting – Performing analysis and extraction of value-added and relevant information required to support the use case in question or the key stakeholders in their daily work.
SDG&E currently uses PLS-CADD and Esri GIS software to display and analyze GIS, CAD and collected aerial imagery products.
Recommendations –
    - Development of web-based tools and analytics that will assist in processing collected data for use in defined business cases.
    - Development of an SOP for data analysis.
- Disseminating – Ensure the data, analysis and results are shared among the stakeholders in support of the business decision making processes.
SDG&E currently uses ineffective measures to transfer and share collected aerial data products, usually Electronic Data Transfer, File Transfer Protocol (FTP) or physical devices (thumb drives or portable hard drives). While they possess security policies and technological capabilities in terms of hardware and software that provides adequate guidance, they lack the additional policies and storage media to effectively incorporate regular use of aerial data products.
Recommendations –
    - Document current policies for working with aerial data.
    - Develop a centrally managed platform for ingestion, storage and analysis.
    - Develop a storage and maintenance SOP
    - Develop a data retention policy

Vendor D provides a robust and detailed analysis of the data governance needs and lifecycle management requirements in order for SDG&E to take their collection and analysis of data to the next level.

3.2.5.4.3 Vendor Recommendations for Future State

Transforming the aerial data governance from a reactive level to a governed level is a long-term, continuous improvement effort that requires a transformation roadmap. The following steps are recommended to build a strong foundation for successful data governance within SDG&E:

Aerial Data Governance Recommendations:

- Establish a project management structure around data governance transformation.
    - Define clear roles and provide strong backing and sponsoring from the executive level.
    - The steering committee should have a holistic view over the process.
    - Data stewards should be established in order to effectively control aerial data governance progress and usage across departments.
- Identify and quantify the opportunities and benefits that aerial data bring to the organization.
    - Consider the savings it enables, especially compared to current processes.
- These benefits must be regularly and repeatedly communicated to all stakeholders.
- Develop aerial data governance strategy.
    - Based on deep assessment of current maturity, the future state of aerial data management capabilities must be established, and a long-term roadmap developed and accepted.
- Develop consistent data definitions, architecture, standards, policies and procedures.
    - Rules and security levels for data usage must be established. All key users should be trained and accountable for the data and metadata.
- Establish metrics and reporting structure to control and gather feedback about the aerial data usage, data needs and requirements across the organization.
    - Milestones and thresholds should be identified in order to measure is the project objectives has been met.

Aerial Data Lifecycle Recommendations:

Tasking Recommendations:

- Identify appropriate organizational leadership to drive program standup.
    - Leadership will maintain momentum and provide the business case for a requirement driven approach that enhances core business activities and maintains regulatory compliance (e.g., federal and state).
- Define internal process for defining and routinely communicating UAS data collection requirements from organizational leadership to operations groups.
    - Supplement with appropriate governance and tools (e.g., PowerWorkz or equivalent) to enable access to current taking and both downward and upward sharing of leading practices and lessons learned.
- Develop guidelines for defining data requirements per operation type.
    - Data requirements will later inform the type of UAS and sensor needed.
- Establish a list of all use cases of aerial data usage across all departments.

    - Prioritize use cases according to technical feasibility (hardware and tools), as well as cost-benefit analysis.

Collecting Recommendations:

- Define and document collection process.
    - Processes that meet leadership defined requirements.
- Determine collection cadence.
    - E.g., How often to fly UAS to meet both regulatory requirements and provide preventative maintenance return on investment.
- Perform cost-benefit analysis.
    - Analysis on performing UAS collection using external sub-providers vs. standing up wholly owned program capabilities
- Define and document process for sending collected data from UAS to appropriate next step user.
    - Both who and how needs to be defined on both ends
    - The collection and receiving teams needs to identify the people in charge of sending receiving and on the method (i.e., physical passing of memory cards vs. leveraging cloud based solutions such as Esri Drone2map, which is compatible with current SDG&E GIS platforms)
- Develop a procedure for conducting collection cost-benefit analysis based on defined criteria to drive future decision making.
    - Analysis will determine which type of operations require in-house or outsourced data collection.
- Develop procedures for defining and selecting technology requirements (e.g., what UAS and sensor types create return on investment).
    - Requirements will inform the type of UAS and sensor needed.

Processing Recommending:

- Define and document process for proper processing.
    - Validate that routine processing aligns with original requirements, that right data type is being captured for inputs, and that outputs enable expected exploitation.
- Identify necessary software solutions (e.g., machine learning).
    - Assess whether these activities she be performed by sub-providers or internally.
- Develop procedure for conducting processing cost-benefit analysis (i.e., what types return value).
    - Analysis will determine the most optimal way for processing depending on the use case and resolution/accuracy requirements.
- Develop procedure for processing data.
    - Define and document the process for each type of data processing to be performed (e.g., categorizing and cataloging images)

    - Include guidelines on properly generating orthophotomaps, 3D point clouds, Digital Terrain Models (DTM), Digital Surface Models (DSM), and list technical requirements for final products.
- Define and document for transferring processed data to end users.
    - End users will receive properly transferred data.

Exploiting Recommendations:

- Define the business activities to be supported by collected data.
    - Include guidance on activities for all types of aerial data and guidelines for properly utilizing all analysis tools to drive efficiencies.
- Develop routine process to assess whether or not data is having desired impact.
    - Process will promote enhancement of data as needed.

Disseminating Recommendations:

- Document all current processes of working with aerial data.
    - Documentation will enable design of new workflow with aerial data processes embedded within.
- Develop centrally managed platform to discover, gather, analyze, and store aerial data. Setup appropriate access for key stakeholders.
    - The architecture and functionalities must be designed together with key users.
    - Provide easy access to all data linked to a certain geographic location so that all stakeholders can easily find and retrieve all relevant information.
    - Facilitate easy integration with other software solutions across the organization via web services such as Web Map Service (WMS), Web Feature Service (WFS) or Web Coverage Service (WCS), common spatial databases, or file systems.
    - Allow integration with Deep Learning models.
    - Design and choice of central data storage must be performed in parallel.
- Develop procedure for data maintenance.
    - If SDG&E chooses to use internal servers, the governing directives for its use should contain detailed instructions for their own employees as well as third-party vendors.
    - If platform will be deployed on the cloud, the governing directives for its use should only include information necessary for SDG&E employees to upload and archive data on the cloud.
- Develop data retention policy.
    - Typically propose an average of 6-24 months.
    - The above average duration of storing data on cloud or server to be between 6 to 24 months. However, period of time should be set during internal evaluation process by analyzing employees needs as well as costs of storing data.
- Perform stakeholder analysis.
    - Analysis will identify key data needs and enable definition of supporting processes.

4.0 Project Outcome

4.1 Key Findings

The tools evaluated in this project were demonstrated in use cases that would improve system reliability, safety and potentially create operational cost savings. Remotely sensed UAS technology when combined with geospatial analytics provides an effective tool for accomplishing some of the key metrics defined in the EPIC guidelines. Vendors successfully demonstrated the following POC analytics:

1. Avian Covers – The use case provided guidance on UAS imagery collection procedure and resolution along with proving machine learning is a viable option to identify and asses T&D electrical assets.
2. Vegetation Encroachment Identification – The use case provided guidance on UAS collected LiDAR data and proved that vegetation and electrical facilities can be measured and modeled with remotely sensed data.
3. Sage, cataloging and management of UAS data - The results of this use case included providing a data management platform for the data collected, applying analytics to answer specific questions, and delivering analytics results to end users.
4. Web-based asset management platform as detailed in this document will enable organization-wide UAS data management which will allow users across the organization to quickly and easily locate critical information to make informed decisions.

The project learning involved understanding the use of advanced analytics on images collected from UAS and other sources that could be used to automatically identify equipment of power lines. The identification and cataloging of assets remotely presents an opportunity to SDG&E and other utilities to undertake cost-effective remote inspections that would otherwise require personnel in the field, driving up costs. It also ensures personnel safety during inspections which could be compromised when inspections are done in treacherous terrains. Vegetation encroachment identification presents an opportunity for SDG&E and other utilities to effectively manage down power lines due to falling trees and effectively estimate the growth of trees in relation to the power lines. Through this demonstration, the project team learned of the wide array of use cases that could be developed to serve multiple stakeholder groups within utilities that are ultimately responsible to provide safe and reliable power to their customers.

4.2 Recommendations and Next Steps

It is recommended that SDG&E pursue additional evaluation of UAS technology for stakeholder groups within the company that will benefit from the aggregation of various sources of data into a data management platform that also provides advanced analytical capabilities. The evaluation should also focus on developing requirements for integration of this data management platform into the SDG&E information technology environment. While the project successfully

demonstrated the value of advanced analytics using UAS data, additional evaluation is required before operational deployment of the data management platform.

The project team recommends an IDMP architecture diagrammed in Appendix C. This architecture diagram depicts one proposed Data Management Platform (DMP) structure that would provide storage and access to stakeholder platform and data requirements. Other elements to consider include:

- Responsible, Accountable, Consulted, Informed (RACI) matrix for data governance
- A project management structure should be created that focuses on data governance transformation.
- Identify and quantify the opportunities and benefits aerial data can bring to the business.
- Develop a comprehensive data governance strategy.
- Based on the governance and user needs, develop a set of standards, policies and procedures and from that a system architecture capable of managing the data and policies.
- Ensure that metrics are gathered that allow measurement of the program success and the ability to change to meet future needs.
- Data retention policy based on use case needs.
- Develop UAS data collection standards that include image collection specifications for all types of UAS data.
- Diagram existing data management architecture and identify gaps and overlaps for all stakeholders.
- Develop use cases summaries and for all stakeholders.
- Develop user workflows and platform requirements for interaction with vendor tool.
- Develop cost benefit analysis comparing current and proposed processes along with UAS data sources and newly developed collection requirements standards.
- Develop a more accurate risk-based analysis for proactive vegetation management including species, growth rate, health and conditions like weather and wind models.
- Investigate vendor tool bandwidth and browser requirements for field and office end users.

5.0 Technology Transfer Plan

5.1 SDG&E Technology Transfer Plan for Project Results

A primary benefit of the EPIC program is the technology and knowledge sharing that occurs both internally within SDG&E and across the industry. To facilitate this knowledge sharing, SDG&E will share the results of this project by widely announcing to industry stakeholders that this report is available on the SDG&E EPIC website, by submitting papers to technical journals and conferences, and by presentations in EPIC and other industry workshops and forums. SDG&E will also conduct formal presentations of the results to internal stakeholders to encourage adoption, as per the recommendations.

5.2 Adaptability to Other Utilities and Industry

As technology evolves utilities are poised to leverage UAS and other data collection technologies to capture high resolution imagery. In some cases, these images have been stored in silos in different business units within the organizations, used by individual stakeholders for their own purposes. This EPIC project demonstrated the value of having a central repository (data management platform) to store, catalog, and sort data that could be used by multiple stakeholders concurrently. It also allows the stakeholders to perform deep learning analytics on the vast amount of data to provide actionable results to important test cases ranging from auto identification of equipment on poles to tracking vegetation encroachment on power lines. These are just a few of the use cases that the data captured from UAS will enable stakeholders to leverage. All these cases will enable the utilities to perform virtual asset inspection that enhances safety and reliability of power system equipment.

6.0 Metrics and Value Proposition

6.1 Metrics

The project metrics used to evaluate and test UAS technology and vendor machine learning tools and software as they related to three specific test cases are listed in Section 3.0 above. In addition to the use cases covered earlier, the following describes additional metrics:

Habitat area disturbance reductions - UAS technologies allow for a remotely operate vehicle to access sensitive habits without impacting the land through vehicular are personnel incursions. The use cases demonstrated a process to capture and analyze electrical facilities, surrounding vegetation and terrain features from an aerial drone. The UAS technology can reduce habitat area disturbance by replacing some required physical inspections with UAS derived inspections.

Wildlife fatality reductions (electrocutions, collisions) - This report studied the feasibility of combining UAS derived imagery with deep learning analytics to determine the location and condition of avian covers on electrical facilities. The avian covers provide a level of protection against electrocution for birds with large wing spans resting on electrical distribution and transmission poles. Currently the avian covers are assessed by physical inspection taken from ground observation on scheduled maintenance intervals. UAS data capture and associated deep learning analytics could provide increase inspections, improved evaluation of the presence and condition of avian covers resulting in reducing the risk to wildlife.

Utility work safety improvement and hazardous exposure reduction - This report studied several uses case for utilizing UAS technology and machine learning analytics to remotely observe, measure and catalog electrical facilities and surrounding terrain. The technology and process remove utility workers from making physical inspection where in many cases required access through hazardous terrain and complete inspections in close proximity to energized facilities and equipment.

6.2 Value Proposition

The purpose of EPIC funding is to support investments in R&D projects that benefit the electricity customers of SDG&E, PG&E, and SCE. The primary principles of EPIC are to invest in technologies and approaches that provide benefits to electric ratepayers by promoting greater reliability, lower costs, and increased safety. This EPIC project contributes to these primary and secondary principles in the following ways:

- Safety – The use of UAS technology enables remote asset management thereby helping utility field crew with tools that promote their safety. During emergencies such as fire or other natural disasters UAS technology can act as a first line of defense in monitoring and tracking remotely, thereby ensuring safety of personnel and limiting harm to people and property.
- Reliability – Greater reliability of systems can be achieved with using UAS and other data collected and running deep learning analytics on the data to identify issues before

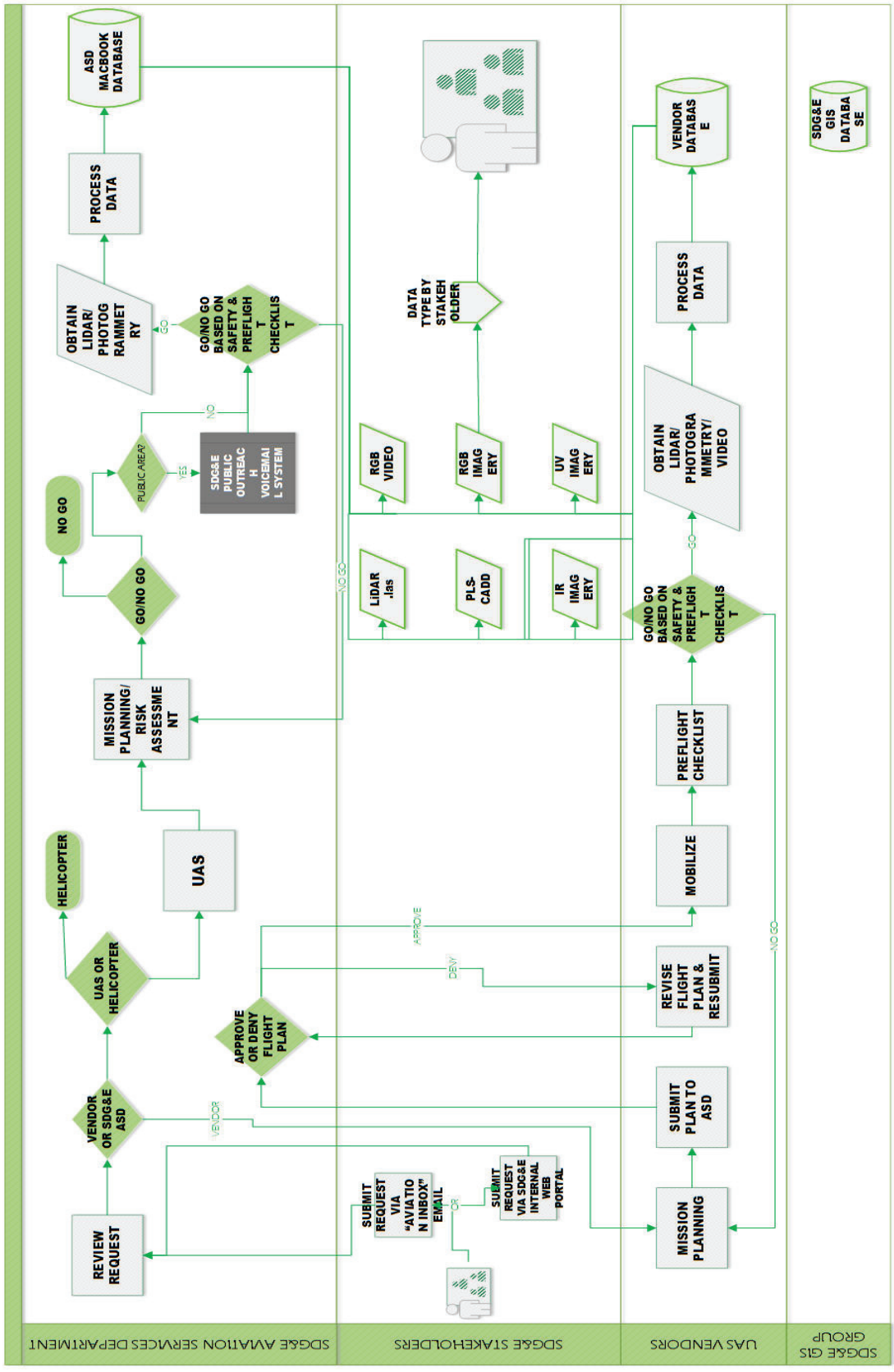
they occur. It also helps various stakeholder groups (e.g vegetation, environmental and other groups in utilities) to effectively plan asset management activities, thereby improving reliability of service.

- Efficient use of ratepayer monies – Asset inspection costs can be reduced using advanced technology such as UAS that complements on field inspections by field crew. Crews can be deployed more effectively and in a cost effective manner, thereby making efficient use of ratepayer monies.

7.0 Appendices

7.1 Appendix A: Aviation Services Department UAS Workflow

Workflow depicting the current ASD process for collection of aerial sensor data.


SDG&E AVIATION SERVICES DEPARTMENT
SDG&E STAKEHOLDERS
UAS VENDORS
SDG&E GIS GROUP
REVIEW REQUEST
VENDOR OR SDG&E ASD
UAS OR HELICOPTER
HELICOPTER
UAS
MISSION PLANNING/ RISK ASSESSMENT
GO/NO GO
NO GO
PUBLIC AREA?
YES
NO
SDG&E PUBLIC OUTREACH VOICEMAIL SYSTEM
GO/NO GO BASED ON SAFETY & PREFLIGHT CHECKLIST
GO
OBTAIN LIDAR/ PHOTOGRAMMETRY
PROCESS DATA
ASD MACBOOK DATABASE
VENDOR
APPROVE OR DENY FLIGHT PLAN
APPROVE
DENY
SUBMIT REQUEST VIA "AVIATION" INBOX" EMAIL
OR
SUBMIT REQUEST VIA SDG&E INTERNAL WEB PORTAL
SUBMIT PLAN TO ASD
REVISE FLIGHT PLAN & RESUBMIT
MISSION PLANNING
MOBILIZE
PREFLIGHT CHECKLIST
GO/NO GO BASED ON SAFETY & PREFLIGHT CHECKLIST
NO GO
NO GO
LiDAR .las
PLS-CADD
IR IMAGERY
RGB VIDEO
RGB IMAGERY
UV IMAGERY
DATA TYPE BY STAKEHOLDER
OBTAIN LIDAR/ PHOTOGRAMMETRY/ VIDEO
PROCESS DATA
VENDOR DATABASE
SDG&E GIS DATABASE

7.2 Appendix B: Vendor-Stakeholder Use Case Matrix.

This matrix depicts the used cases identified by each stakeholder in Section 2.2 above which is cross-referenced with the platforms existing capability to demonstrate the use case as part of this pre-commercial demonstration.

EPIC-2 Project #6

Vendor-Stakeholder Use Case Matrix

Prepared by:
GIS Surveyors Inc. (GSI)

Vendor	Stakeholder Use Cases																									
	VEGETATION MANAGEMENT							ELECTRIC DISTRIBUTION PLANNING			ENVIRONMENTAL										LAND MANAGEMENT					
	VEGETATION ENCROACHMENT ID	CORRECTED LOCATIONS OF CURRENT GIS ASSETS	CHANGE DETECTION ON SUBSEQUENT DATA SETS	SAG AND SWAY CALCULATIONS FOR ENCROACHMENTS	IDENTIFICATION OF PROTECTED VEGETATION AND WILDLIFE SPECIES	USE ASSET METADATA TO PREDICT GROWTH RATES	USE REPETITIVE DATA SETS TO PREDICT GROWTH RATES	ASSET CATALOGING	REMOTE ACCESS	PLS-CADD INTEGRATION	ASSET CATALOGING	AVIAN COVERS	CORRECTED LOCATIONS OF CURRENT GIS ASSETS	ACCESS TO RECENT IMAGERY VIA GIS	ANNUAL/BIANNUAL ASSET UPDATES	ACCURACTE GIS PARCEL LAYER	IDENTIFYING PHYSICAL ENCROACHMENTS	BEST PRACTICES FOR DATA MANAGEMENT	IDENTIFICATION OF PROTECTED VEGETATION AND WILDLIFE SPECIES	STANDARDS FOR DATA COLLECION	RIGHT-OF-WAY/PROPERTY ENCROACHMENTS	EROSION DETECTION	LOCATING HOMELESS ENCAMPMENTS	TEMPORAL DATA STORAGE TO IDENTIFY CHANGES OVER TIME	ACCURACTE GIS PARCEL LAYER	CORRECTIVE MAINTENANCE ISSUES
GE	X							X			X	X														
Harris	X							X			X	X														
Network Mapping	X							X			X															
PwC	X							X			X	X														

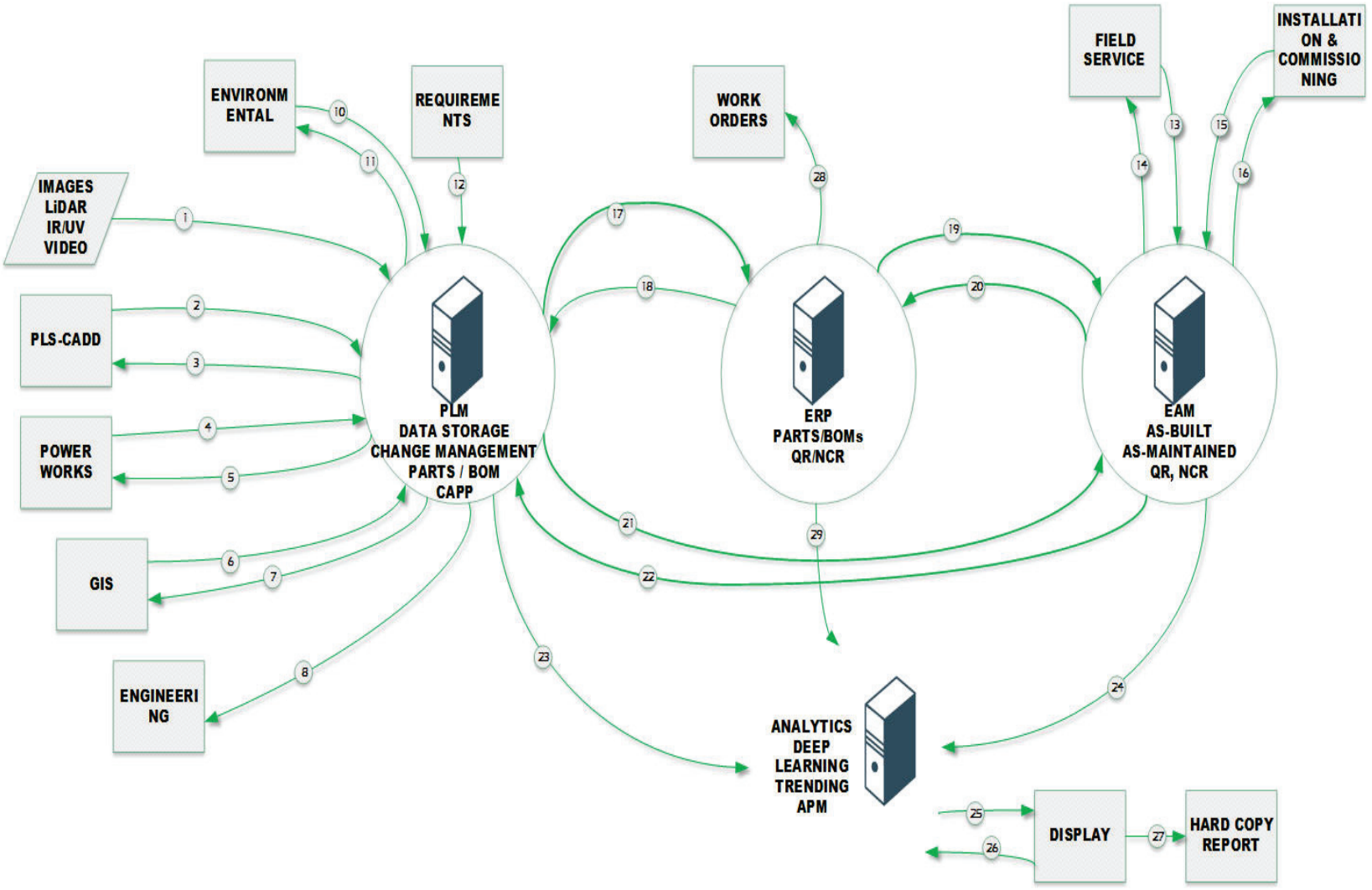
TEST CASE ARE BLUE

COMMON TEST/USE CASE BETWEEN STAKEHOLDERS

7.3 Appendix C: Proposed DMP

7.3.1 Proposed DMP Architecture Diagram

This architecture diagram depicts one proposed DMP structure that would provide storage and access to stakeholder platform and data requirements.


ENVIRONM
ENTAL
REQUIREME
NTS
WORK
ORDERS
FIELD
SERVICE
INSTALLATI
ON &
COMMISSIO
NING
IMAGES
LiDAR
IR/UV
VIDEO
PLS-CADD
POWER
WORKS
GIS
ENGINEERI
NG
PLM
DATA STORAGE
CHANGE MANAGEMENT
PARTS / BOM
CAPP
ERP
PARTS/BOMs
QR/NCR
EAM
AS-BUILT
AS-MAINTAINED
QR, NCR
ANALYTICS
DEEP
LEARNING
TRENDING
APM
DISPLAY
HARD COPY
REPORT
1
2
3
4
5
6
7
8
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29

7.3.2 Proposed DMP Architecture Diagram Reference Chart

This table identifies the potential data types, format criteria, sources and targets for many of the data sets collected by the ASD group for various stakeholders.

Data Flow Reference Number	Data Type(s)	Data Criteria	Source	Target
1	RGB, LiDAR, IR, UV, Video	RGB - 20Mp, LiDAR +/- 50 mm, IR, UV, Video HD mp4	UAV, Field Service	PLM
2	SHP, LAS		PLS-CADD Session	PLM
3	SHP, LAS		PLM	PLS-CADD Session
4				PLM
5				Power Works Session
6	GPS		GIS Session	PLM, EAM
7	GPS		PLM, EAM	GIS Session
8	Word, Excel, PPT, TXT	.docx, .pptx, .xlsx, pdf	Engineering Session	PLM
9	TXT	ASCII	PLM	Session
10	TXT	ASCII		PLM
11	TXT	ASCII	PLM	Session
12	TXT, XLS, CSV	ASCII	Requirements Mgt. Tool	PLM
13	TXT, RGB, Video, LiDAR	RGB - 20Mp, LiDAR +/- 50 mm, IR, UV, Video HD mp4, ASCII	Session	EAM
14	TXT, RGB	RGB - 20Mp	EAM	Session
15	RGB, LiDAR, IR, UV, Video	RGB - 20Mp, LiDAR +/- 50 mm, IR, UV, Video HD mp4	Session	EAM
16	RGB, LiDAR, IR, UV, Video	RGB - 20Mp, LiDAR +/- 50 mm, IR, UV, Video HD mp4	EAM	Session
17	CR, BOM, CAPP		PLM	ERP
18	BOM, QR		ERP	PLM
19	BOM, Prod. Order		ERP	EAM
20	BOM, SN, QR, PS		EAM	ERP
21	BOM, CAPP		PLM	EAM
22	SN, BOM, NCR, QR		EAM	PLM
23	GIS, SHP, TXT, PW,*		PLM	APM System
24	BOM, RGB, PS		EAM	APM System
25	<<ALL>>		APM System	Display
26	SQL, TXT	ASCII	Input	APM System
27	<<Result>>		Display	Printer
28	BOM, CAPP, Date		ERP	Printer