Company:	San Diego Gas & Electric Company (U 902 M)
Proceeding:	2028 General Rate Case
Application:	A.26-06-___
Exhibit:	SDGE-09

PREPARED DIRECT TESTIMONY OF SNEHA R. PARMAR

(ELECTRIC DISTRIBUTION O&M)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

June 2026

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APPENDICES:

SUMMARY

ELECTRIC DISTRIBUTION (in 2025$)			
O&M	2025 Adjusted-Recorded ($000)	Estimated TY 2028 ($000)	Change ($000)
Non-Shared	130,242	138,409	8,167
Shared	0	0	0
Total O&M	130,242	138,409	8,167

Summary of Requests

San Diego Gas & Electric (SDG&E or Company) is requesting the Commission adopt its Test Year 2028 (TY 2028) forecast of $138,409,000 for Electric Distribution Operations and Maintenance (O&M). This request is reasonable and represents amounts necessary for SDG&E to:

- Maintain the safety, integrity and effective operations of the electric distribution grid;
- Provide safe, reliable, and affordable delivery of electricity to Company customers;
- Achieve compliance with applicable laws and regulations; and
- Protect public safety, employee safety, and contractor safety while effectively operating and maintaining the electric grid. SDG&E has a safety-first culture that is embedded in the way the Company carries out its work, designs and builds its system, and operates and maintains its system.

To better understand the forecasted costs, the following factors should be considered:

- SDG&E's electric distribution system includes 132 distribution substations, 1,065 distribution circuits, 214,967 poles, 15,602 miles of underground systems, 8,732 miles of overhead systems, approximately 47,000 streetlights, and various other components of distribution equipment. It is a large, complex and interconnected system that requires regular operations and maintenance resources and support to operate effectively and efficiently and in compliance with all applicable laws and regulations.
- Maintaining a safe and reliable electric distribution system in compliance with all laws and regulations supports overall customer affordability. Maintenance of distribution assets not only reduces customer outages, but it reduces long-term costs by extending the useful life of assets and avoiding the need for unplanned large-scale system upgrades due to equipment failure.

- For much of the requests herein, SDG&E uses a base year forecast. This reflects SDG&E's efforts to maintain the safety and reliability of its electric distribution system while also constraining costs in its efforts to improve customer affordability. Most incremental costs above the base year are for purposes of backfilling necessary, skilled workforce not accounted for in the 2025 base year. Addressing shortages in skilled workforce will reduce reliance on less skilled and/or more expensive temporary support.

- Also of note, SDG&E has continued to seek operational efficiencies through technologies that improve process automation, such as automation of certain system outages and restoration of service, reduction in manual workloads, including remote operation of certain devices, and enhancements to real-time system data, improving operational decision-making.

PREPARED DIRECT TESTIMONY OF SNEHA R. PARMAR
(ELECTRIC DISTRIBUTION O&M)

I. INTRODUCTION

A. Summary of Electric Distribution O&M Costs and Activities

This testimony supports the TY 2028 forecasts for O&M non-shared service costs for the forecast years 2026, 2027, and 2028, associated with the Electric Distribution O&M area for SDG&E. Table SP-1 below summarizes these forecast costs which total $138.409 million for TY 2028.

TABLE SP-1
Test Year 2028 Summary of Total Costs

ELECTRIC DISTRIBUTION (In 2025$)			
Categories of Management	**2025 Adjusted Recorded ($000)**	**TY2028 Estimated ($000)**	**Change ($000)**
A. Distribution Design & Project Management	1,225	1,231	6
B. Construction Management	2,136	2,136	0
C. Electric Engineering	1,547	1,585	38
D. Electric System Operations	5,166	6,689	1,523
E. Electric Regional Operations	37,676	39,002	1,326
F. Materials and Inventory	37,715	37,715	0
G. Electric Regional Operations Troubleshooters	12,369	12,772	403
H. Service Order Team	7,197	7,959	762
I. Electric Assets and Compliance Management	3,213	5,385	2,172
J. ET&D: Operations Services	3,759	4,055	296
K. ET&D: Substation C&O[1]	12,248	13,060	812
L. Portfolio & Project Management	581	582	1
M. System Planning, Reliability and Data Management	2,760	3,570	810
N. Officer	974	988	14
O. Climate Adaptation Vulnerability Assessment	1,676	1,680	4
Total Non-Shared Services	**130,242**	**138,409**	**8,167**

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[1] Forecast activities and estimated costs contained within the "ET&D: Substation C&O" cost category listed in Table SP-1 were presented previously in SDG&E's 2025 RAMP Application (A.) 25-05-010/013 (consolidated) filed on May 15, 2025. Those activities and any changes that have occurred since the RAMP filing are detailed in Section IV below.

Electric Distribution O&M includes the costs required to operate and maintain SDG&E's electric distribution system. Expenses presented herein, which fund a wide range of activities including but not limited to engineering, project management, system operations, inspections, repairs, and employee training, are reasonable and should be adopted by the California Public Utilities Commission (CPUC or Commission). These expenses support SDG&E's fundamental philosophy to achieve operational excellence by providing customers with the cleanest, safest, and most reliable electricity in North America. SDG&E continues to operate in compliance with all regulatory requirements and maintains a high level of customer service.

SDG&E prioritizes its work to comply with applicable laws and regulations and to provide system integrity and reliability in accordance with its commitment to safety. SDG&E's longstanding commitment to safety focuses on three primary areas: (1) public safety, (2) employee safety, and (3) contractor safety. SDG&E has a safety-first culture that is embedded in the way the Company carries out its work, designs and builds its system, and operates and maintains its system. This safety-first culture is imparted on SDG&E employees from initial training, through project design, prioritization of work, operation of the system, inspection and maintenance, and construction.

Over this last General Rate Case (GRC) cycle, SDG&E has continued to pursue its goal of driving safety risks to zero and has seen steady improvement in key safety performance indices as a result. Notably, SDG&E safety rates for employee Days Away, Restricted and Transferred (DART), employee Lost Time Incidents (LTI), and employee Total Recordable Incident Rate (TRIR) or Cal/OSHA Recordable Incident Rate have improved as referenced in our 2025 Safety Performance Metrics Report.[2] These Safety Trends are also highlighted in attached Appendix D. Safety and risk reduction for employees, contractors, and the public remain core values at the Company. SDG&E became the first California electric utility to achieve Voluntary Protection Program (VPP) Certification at our Electric Transmission and Distribution (ET&D): Substation Construction & Operations (C&O) and Operations Services facilities.[3] This is a first-of-its-kind certification for an ET&D substation organization which

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[2] Rulemaking (R.) 20-07-013, 2025 Safety Performance Metrics Report of SDG&E (April 1, 2026).

[3] Sempra, *SDG&E Becomes First California Utility to Achieve Top Safety Honors with CAL/OSHA VPP Certification* (February 12, 2025), *available at:* https://www.sempra.com/newsroom/press-releases/sdge-becomes-first-california-utility-achieve-top-safety-honors-calosha-vpp.

will soon be expanded to SDG&E's Electric Regional Operations (ERO) workforce, as detailed below.

In addition to achieving excellent performance in safety in recent years, the reliability of SDG&E's electric service has also been an area of consistent superior performance. SDG&E's best-in-class reliability performance has resulted in recognition and awards from third parties. SDG&E has received "Best in the West" and/or "Outstanding Reliability Performance Pacific Region" reliability awards by the PA Consulting, earning their regional ReliabilityOne® award for twenty consecutive years.[4] In addition, SDG&E has also received the PA Consulting Group's national ReliabilityOne award in 2014, 2018, and 2021,[5] was recently recognized by the PA Consulting Group in 2021 and 2022[6] for Outstanding Grid Sustainability, and in 2023[7] for National System Resiliency.

SDG&E operates and maintains an electric distribution system that serves approximately 3.7 million people through approximately 1.55 million meters. SDG&E's service territory spans more than 4,100 square miles from the California-Mexico border north to Southern Orange County and Riverside County, and from the San Diego County Coastline east to Imperial County. SDG&E's system includes 132 distribution substations, 1,065 distribution circuits, 214,967 poles, 15,602 miles of underground systems, 8,732 miles of overhead systems, and various other components of distribution equipment. Additionally, SDG&E owns and maintains approximately 47,000 streetlights. SDG&E's distribution system (as of January 2026) is further

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[4] PA Consulting, *Florida Power & Light Company wins the National Reliability Award at PA Consulting's 25th annual ReliabilityOne® Awards* (November 13, 2025), *available at*: https://www.paconsulting.com/newsroom/florida-power-light-company-wins-the-national-reliability-award-at-pa-consultings-25th-annual-reliabilityone-awards-november-13-2025.

[5] PA Consulting, *In a tie, Florida Power & Light Company and San Diego Gas & Electric both win a National Reliability Award at PA Consulting's 25th annual ReliabilityOne® Awards* (November 18, 2021), *available at*: https://www.paconsulting.com/newsroom/florida-power-light-company-and-san-diego-gas-electric-both-win-a-reliabilityone-national-reliability-award-18-november-2021.

[6] PA Consulting, *Commonwealth Edison win the National Reliability Award at PA Consulting's 23rd annual ReliabilityOne® Awards* (November 2, 2023), *available at*: https://www.paconsulting.com/newsroom/commonwealth-edison-win-the-national-reliability-award-at-pa-consultings-23rd-annual-reliabilityone-awards-2-november-2023.

[7] PA Consulting, *Consolidated Edison Company of New York wins the National Reliability Award at PA Consulting's 23rd annual ReliabilityOne® Awards* (November 13, 2024), *available at*: https://www.paconsulting.com/newsroom/consolidated-edison-company-of-new-york-wins-the-national-reliability-award-at-pa-consultings-24th-annual-reliabilityone-awards-13-november-2024.

characterized by a customer mix of approximately 1.39 million residential and 158,000 commercial and industrial customers. There is an average of approximately 1,450 customers per circuit. The electric distribution system consists of predominantly underground facilities (approximately 64%). This percentage is much larger than that of other large California Investor-Owned Utilities (IOUs) where the CPUC estimates that only approximately 33%[8] of distribution lines in California are underground. In urban areas, the underground system can lead to higher inspection and maintenance costs given the potential for traffic control, hazardous waste services and dewatering needed to perform manhole inspections. In addition, labor resources require a higher level of training (i.e., Qualified Electrical Workers) to perform inspections of underground surface and subsurface electrical facilities. The primary distribution voltage is predominantly 12 kilovolts (kV), with some large areas of 4kV. SDG&E's 4kV systems are being converted to 12kV over time through a combination of attrition, maintenance upgrades, and programmatic efforts.[9] The 4kV system can lead to higher maintenance and inspection costs due to the age of the overall system, which is now considered obsolete.

Costs within this testimony are driven by several major trends both within the utility industry and in SDG&E's operating environment. The top trends affecting this testimony include costs that scale with increased capital construction, shortages of skilled electric distribution labor, regulations such as General Orders (GO) 95, 128, 165 and 174, and Senate Bill (SB) 410, along with increased maintenance costs associated with the growth in electric distribution system automated equipment. This testimony addresses each of these top trends in the sections below. For matters related to SDG&E's Electric Distribution Capital requests, please see Exhibit (Ex.) SDGE-08.

In preparing forecasts for TY 2028 Electric Distribution O&M requirements, historical 2021 to 2025 spending levels were analyzed, underlying cost drivers were considered, and future requirements were assessed. Forecast methodologies were selected based on future expectations for the cost category and considering the underlying cost drivers. The forecast methodologies used include:

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[8] *See* CPUC, *CPUC Undergrounding Programs Description, available at*: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/electric-reliability/undergrounding-program-description.

[9] *See* Ex. SDG&E-08: Electric Distribution Capital, 4kV Reliability Program.

- Forecasts based on historical averages; and
- Forecasts based on the base year (2025)

The majority of workpapers in this testimony utilize the base year methodology for forecasting as this method provides an appropriate baseline for the Electric Distribution O&M expenditures, as further detailed below. In addition, this testimony identifies work requirements incremental to levels of historical spending necessary to maintain the safe and reliable operation of the electric distribution system. Finally, attached to this testimony as Appendix E is SDG&E's Grid Modernization Plan pursuant to Decision (D.) 18-03-023.

B. Support To and From Other Witnesses

My testimony also references the testimony and workpapers of several other witnesses, either in support of their testimony or as support for mine. A reference list is detailed below:

- Ex. SDGE-08: Electric Distribution Capital
  - Reference to 4kV Reliability Program, Budget Code 172690 (Section 1.A)
- Ex. SCG-10/SDGE-14: Information Technology
  - Electric System Operations (Section III.D)
- Ex. SCG-16/SDGE-20: Compensation and Benefits
  - Various cost categories within this testimony reference forecast changes in connection with the compensation modernization initiative.

C. Grid Modernization Plan

D.18-03-023 requires the California IOUs to present their respective Grid Modernization Plan (GMP) for review and evaluation in the GRC.[10] Accordingly, SDG&E's GMP is attached hereto at Appendix E. SDG&E's GMP includes a 10-year grid modernization vision that integrates Distributed Energy Resources (DERs) into distribution system planning and operations, allowing markets and customers to more fully realize the value of DER. SDG&E's GMP was finalized following a public workshop hosted by the CPUC on March 12, 2026.

D. Organization of Testimony

This testimony is organized as follows:

- Introduction

[10] D.18-03-023, Ordering Paragraph (OP) 4 at 34-35.

- Affordability & Efficiency
- Non-Shared Cost Categories
  - Description of Costs & Underlying Activities
  - Forecast Methodology
  - Cost Drivers
- Risk Assessment Mitigation Phase (RAMP) Integration
- Reasonableness Review
- Conclusion

II. AFFORDABILITY & EFFICIENCY

SDG&E remains committed to delivering safe and reliable electric service while managing costs responsibly for customers and has incorporated measures which promote affordability, operational efficiency, and cost-effective results. For the purposes of Electric Distribution O&M, and as described further herein, these efforts focus on leveraging technology, optimizing the workforce, standardizing processes, and engaging in efforts to avoid higher long-term costs by maintaining core inspection and maintenance activities.

A. Use of Base Year Forecast Methodology

Most Electric Distribution O&M cost categories represented within this testimony employ a base year 2025 forecast methodology, holding staffing and non-labor costs flat unless specific, demonstrated incremental needs are identified. SDG&E uses base year forecasts for a number of reasons, including the expectation that work activities within the relevant cost category will not vary significantly throughout the forecast years when compared to the base year, and expenses for base year forecasts can be more readily estimated for both labor and non-labor based on resource requirements for workgroups which are not expected to see expenses vary significantly year to year. Other cost categories use three-year averages, typically where work volumes vary from year to year, making a forecast based solely on one specific year unreliable and potentially unrealistic. The methodology chosen for each cost category is based on forecasting accuracy, but also for purposes of constraining cost escalation while still reflecting reasonable, representative activity levels.

B. Workforce Optimization And Targeted Staffing

The TY 2028 Electric Distribution O&M forecast mostly includes attrition-based staffing backfills rather than incremental Full Time Equivalents (FTEs) additions. Across Electric

System Operations, Electric Regional Operations (ERO), Electric Engineering, Troubleshooters, and several supporting groups, hiring is limited to essential backfills and targeted skilled areas required to maintain safety and reliability for our customers. This approach seeks to maintain steady labor costs while maintaining a skilled workforce such that reliance on expensive emergency staffing or overtime is limited.

As an example, within the Electric Assets and Compliance Management workpaper 1ED009, and Section III.I below, a notable workforce efficiency measure is an expanded use of Electric Distribution Line Inspectors within the Electric Distribution Inspections (EDI) group. Using Line Inspectors in place of higher-cost Qualified Electric Workers for appropriate inspection tasks reduces O&M expense and frees Qualified Electric Workers for specialized field construction work, improving overall resource deployment.

C. Technology And Automation Supporting Operational Efficiency

SDG&E continues to integrate technologies that automate processes, reduce manual workloads, and minimize customer outage durations. Such technologies include, but are not limited to, the following:

- Advanced Distribution Management System (ADMS) and Distributed Energy Resource Management System (DERMS), which improve situational awareness, automate portions of fault isolation and service restoration, support DER integration, and reduce labor-intensive troubleshooting.
- Supervisory Control and Data Acquisition (SCADA) system expansions, which increase the ability to remotely operate devices and minimize the need for manual switching in the field where personnel must be dispatched to physically operate switches in the field.
- Geographic Information System (GIS) enhancements and accurate real-time system data, which improve planning, asset management, and operational decision-making.

These tools support safe, reliable, and efficient system operation and reduce long-term costs by minimizing outage duration, enhancing system visibility, and avoiding reactive or duplicative work. These technologies and others are further described in the Electric System Operations workpaper 1ED004 and Section III.D below.

D. Standardized Business Processes

Several organizations have implemented or expanded standardized processes to reduce cycle times, eliminate variation, and increase transparency. For example:

- The Service Order Team (SOT) continues to streamline customer-driven service work and standardize project workflows, reducing rework and improving efficiency in secondary-voltage service modifications. Some examples of this enhancement are listed below:
    - The Express Team was created to handle lower complexity jobs. For example, customers can now receive quicker turnaround times on Service Orders by submitting pictures to SDG&E for remote assessment and escalation.
    - The Over Pressure Shut Off Program was created to simplify panel upgrade projects by allowing customers the ability to have a gas regulator installed, instead of asking them to move their gas or electric services to be in compliance. This new process helps our customers save time and money when working with SDG&E to upgrade their electrical panel to accommodate solar, EV, new appliances, etc.
- Portfolio & Project Management has focused on enterprise standardization, consistent project controls, and improved QA/QC review processes, which reduce project delays and prevent costly post-construction corrections.
- Materials Management has improved inventory visibility, coordination, and reconciliation to reduce waste, prevent over-ordering, and support efficient capital and O&M project execution.

These improvements enhance affordability by reducing the amount of labor, material, and time required to complete customer and system work.

E. Avoided Costs and Consequences of Not Performing Work

SDG&E's testimony highlights several areas in which sustained O&M activity prevents significantly higher long-term costs:

- Regulatory Inspection and Maintenance Compliance: Failing to maintain required inspection cycles under GO 95, 128, 165, and 174 could result in safety defects accumulating into damage to life and property, costly corrective actions, higher outage durations, or regulatory penalties.
- Aging Asset Maintenance: Timely corrective work reduces the risk of equipment failure, which would otherwise necessitate emergency response—typically higher in cost and greater in customer impact.
- Joint Asset Management (JAM): A risk-based approach to Quality Assurance/Quality Control (QA/QC) of joint pole attachment applications and post-construction will reduce field work and overall need for labor resources.

These avoided cost areas demonstrate that maintaining reasonable O&M funding levels promotes affordability by reducing the likelihood of more expensive emergency work and long-term infrastructure degradation.

F. Use Of Lower-Cost Resources Where Appropriate

In addition to the expanded use of Line Inspectors described above, several groups have effectively applied lower cost resources or optimized task assignments to minimize O&M expenses:

- Work management systems in JAM streamline tracking of third-party attachment data and reduce manual administrative effort.
- The Electric Assets & Compliance group transitioned work performed by external personnel related to QA/QC of wood pole intrusive inspections to lower cost internal resources.
- Training programs in both Electric System Operations (ESO) and Electric Regional Operations (ERO) develop internal talent pipelines, reducing reliance on external labor and improving retention of specialized skill sets.

SDG&E has incorporated affordability and efficiency considerations throughout its test year 2028 forecast. By holding costs to base year levels wherever feasible, optimizing its workforce, leveraging technology, standardizing processes, and preventing higher future costs through timely inspection and maintenance, SDG&E promotes responsible spending while while also supporting compliance, safety, and reliability. These efficiency measures collectively support SDG&E's mission to operate a safe, reliable, and affordable electric system for its customers.

III. NON-SHARED O&M COSTS

"Non-Shared Services" are activities that are performed by a utility solely for the benefit of its customers.[11] Corporate Center provides certain services to the utilities and to other subsidiaries. For purposes of this GRC, SDG&E treats costs for services received from Corporate Center as Non-Shared Services costs. Table SP-2 summarizes the total non-shared O&M forecasts for the listed cost categories.

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[11] As opposed to "shared costs" which are borne in support of both Sempra owned CPUC regulated utilities.

TABLE SP-2
Non-Shared O&M Summary of Costs

ELECTRIC DISTRIBUTION (In 2025$)			
Categories of Management	**2025 Adjusted Recorded**	**TY2028 Estimated ($000)**	**Change ($000)**
A. Distribution Design & Project	1,225	1,231	6
B. Construction Management	2,136	2,136	0
C. Electric Engineering	1,547	1,585	38
D. Electric System Operations	5,166	6,689	1,523
E. Electric Regional Operations	37,676	39,002	1,326
F. Materials and Inventory	37,715	37,715	0
G. Electric Regional Operations	12,369	12,772	403
H. Service Order Team	7,197	7,959	762
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K. ET&D: Substation C&O	12,248	13,060	812
L. Portfolio & Project Management	581	582	1
M. System Planning, Reliability and Data	2,760	3,570	810
N. Officer	974	988	14
O. Climate Adaptation Vulnerability	1,676	1,680	4
Total Non-Shared Services	**130,242**	**138,409**	**8,167**

The following subsections describe each workpaper activity (also referred to throughout as cost categories) and forecast in more detail. For each workpaper, I describe the costs and activities associated with that workpaper, the forecast methodology, and cost drivers. For workpapers with significant cost drivers and incremental cost pressures, additional support for the forecast is provided.

A. Distribution Design & Project Management (1ED001)

TABLE SP-3
Summary of Workpaper Costs

ELECTRIC DISTRIBUTION (In 2025 $)			
A. Distribution Design & Project Management	**2025 Adjusted-Recorded (000s)**	**TY2028 Estimated (000s)**	**Change (000s)**
1. Distribution Design & Project Management	1,225	1,231	6
Total	1,225	1,231	6

1. Description of Costs and Underlying Activities

This section justifies funding of $1,231,000 for the Distribution Design & Project Management cost category. Of this total amount, $1,225,000 is attributed to base year 2025 forecasting and $6,000 reflects changes in connection with the compensation modernization initiative. Details pertaining to the forecast methodology and cost drivers for this section are further discussed below in sections III.A.2 and III.A.3. For details related to the compensation modernization initiative, please refer to the Compensation & Benefits testimony, Ex. SCG-16/SDGE-20.

Distribution Design & Project Management's responsibilities primarily relate to the preparation of construction orders. Department personnel perform the design, engineering, and permitting activities necessary to develop comprehensive construction orders, from which additions and modifications to electric distribution systems are constructed. Such construction orders range from simple services for individual customers to new installations and modifications to large complex distribution systems that serve subdivisions, capacity, commercial centers, and high-rise towers.

Also included in the Distribution Design & Project Management category are construction orders for (1) converting electric overhead lines to underground through various government programs and (2) relocating existing facilities to accommodate both private party requestors and government agencies. The construction order development process includes meeting with customers, government agencies, and other utilities in planning and coordinating additions and modifications to SDG&E's electric distribution system. Department personnel perform a variety of tasks including engineering calculations, analytical assessments, securing and executing contracts and supporting customer interconnection requests. In addition, workgroup personnel prepare and assemble the construction order job packages for distribution to customers, contractors, other utilities, and all participating departments within SDG&E.

All new project managers, planners, and designers go through a series of training courses to learn the roles, tools and responsibilities to efficiently complete these tasks. And while the development of construction orders is O&M and the project itself is typically capital work, many capital projects include a small component of O&M. Additionally, there are some small construction orders with limited scope for which the work is considered O&M, which includes, but is not limited to, temporary service disconnections and reconnections; minor adjustments, replacements, and/or repairs to equipment in lieu of full replacements; and pole bracing activities, such as service disconnects and reconnects.

2. Forecast Method

The forecast method for the Distribution Design & Project Management cost category is base year 2025. This methodology was selected as current staffing and activity levels are expected to be representative of the costs moving forward. These costs represent the support design, project management, and execution of customer facing and capital projects. Historical averages would not capture the changes in the distribution of O&M between labor and non-labor costs.

3. Cost Drivers

The cost drivers behind this forecast are a direct result of customer requests and needs. Those requests can be for new services, upgraded services, new distribution systems for commercial and residential developments, system modifications to accommodate new customer load, customer requested relocations, rearrangements, removals and the conversion of existing overhead lines to underground. All work and cost responsibilities are governed by applicable tariffs,[12] which typically place the bulk of the cost on the utility. See workpapers Ex. SDGE-09 WP 1ED001 for a more detailed cost breakdown.

B. Construction Management (1ED002)

TABLE SP-4
Summary of Workpaper Costs

ELECTRIC DISTRIBUTION (In 2025 $)			
B. Construction Management	**2025 Adjusted-Recorded (000s)**	**TY2028 Estimated (000s)**	**Change (000s)**
1. Construction Management	2,136	2,136	0
Total	2,136	2,136	0

1. Description of Costs and Underlying Activities

This section justifies funding of $2,136,000 for the Construction Management cost category. The total amount is attributed to a base year 2025 forecast. Details pertaining to the

[12] *See* SDG&E Electric Rules 2, 13, 15,16, 20, 45 and 46.

forecast methodology and cost drivers for this section are further discussed below in sections III.B.2 and III.B.3.

The primary role of the Construction Management group is to provide comprehensive construction management and field oversight for contractor-performed construction on electric distribution, and substation projects. This oversight confirms that work is performed in alignment with general safety and compliance guidelines and meets applicable local, state, and federal requirements. This includes GO 95, GO 128, and SDG&E Engineering, Design, and Safety Standards. All work activities are managed to support alignment with the executed scope and contractual requirements.

The O&M portion of construction work conducted by the Construction Management group includes, but is not limited to, temporary service disconnections and reconnections; minor adjustments, replacements, and/or repairs to equipment in lieu of full replacements; and pole bracing activities.

The Construction Management group is also responsible for administrative activities associated with contractor-performed construction work. Activities in this capacity span from pre-construction to post-construction and project closeout. Additionally, Construction Management oversees the preparation of job packages issued for construction and performs activities such as constructability review, verification of jurisdictional permits and environmental releases, and issuance and tracking of material purchase orders. For construction projects that require bidding by contractors, the group coordinates with Supply Management to prepare and issue requests for proposals, followed thereafter by a comprehensive evaluation of bids received and awarding of construction contracts. Construction Management partners with project managers, designers and engineers, and the construction contractor to monitor the successful construction of projects in accordance with project timelines and cost constraints. The group also performs detailed invoice reviews, manages the construction closeout process, including contractor completion of all punch-list items, and oversees the "as-built" documentation process for accurate recordkeeping of SDG&E facilities.

Additionally, Construction Management frequently engages with members of the public through activities such as educational outreach and responding to inquiries. These interactions help promote transparency, strengthen community understanding, and build trust throughout the construction process.

Construction Management also supports the Electric Regional Operations Corrective Maintenance Program (Compliance Management Program (CMP), a GO 165 compliance program) by monitoring and tracking contractor projects, such as pole and transformer replacements, quality control follow-up services, and fire risk mitigation services.

2. Forecast Method

The forecast method developed for the Construction Management cost category is base year 2025. Throughout the base year, SDG&E operated efficiently, prioritizing critical needs of the workgroup, which supports the safe accomplishment of contractor-performed work, in a manner aligned with compliance guidelines and SDG&E design standards, as well as applicable local, state, and federal requirements. The base year methodology is the most reflective of how SDG&E expects to operate for this GRC cycle.

3. Cost Drivers

The key cost driver behind this forecast is both labor and non-labor resources needed to oversee contractor-performed construction work on SDG&E's electric system, supporting continued adherence to applicable local, state, and federal requirements, as well as SDG&E-specific Engineering, Design and Safety Standards. This oversight promotes continued adherence to municipal requirements and compliance with new regulatory mandates that impose more stringent energization timelines, including those established under SB 410. Additional cost drivers include non-labor expenditures such as materials and equipment necessary to support the safe, compliant, and successful completion of these O&M projects. See workpapers Ex. SDGE-09 WP 1ED002 for a more detailed cost breakdown.

C. Electric Engineering (1ED003)

TABLE SP-5
Summary of Workpaper Costs

ELECTRIC DISTRIBUTION (In 2025 $)			
C. Electric Engineering	**2025 Adjusted-Recorded (000s)**	**TY2028 Estimated (000s)**	**Change (000s)**
1. Electric Engineering	1,547	1,585	38
Total	1,547	1,585	38

1. Description of Costs and Underlying Activities

This section justifies funding of $1,585,000 for the Electric Engineering cost category. Of this total amount, $1,547,000 is attributed to base year 2025 forecasting, $21,000 is attributed to backfilling vacancies not accounted for in the base year adjusted-recorded amount, and $17,000 reflects changes in connection with the compensation modernization initiative. Details pertaining to the forecast methodology and cost drivers for this section are further discussed below. For details related to the compensation modernization initiative, please refer to the Compensation & Benefits testimony, Ex. SCG-16/SDGE-20.

The Electric Engineering cost category comprises several workgroups that are responsible for the engineering and design of all components of the 4kV and 12kV substation and distribution network including equipment, standards, drafting, civil support structures, system protection and controls, and project management support. Costs for Electric Engineering support the following workgroups: Electric Distribution Engineering, System Protection Automation and Control Engineering, Substation Engineering and Design, Transmission Engineering and Design, Civil Structural Engineering, Electric Engineering Project Management and Organization, and the Associate Engineer Program. Each is addressed separately below.

a. Electric Distribution Engineering

The Electric Distribution Engineering workgroup is responsible for the development and maintenance of overhead and underground equipment specifications, standards, and work methods, risk analysis and mitigation, service standards for customer facilities, design manuals for project management design workgroups, and electric standard practices for uniform and safe work methods and procedures. New and revised construction standards and material specifications are designed to provide community safety and system reliability while keeping pace with technological advancements in areas such as fire-preparedness, communication technology improvements, and renewable integration. The workgroup works closely with manufacturers to specify and procure distribution equipment (i.e. poles, cable, switches, transformers, etc.) for our system with respect to functionality, reliability, affordability, and safety. As new distribution equipment and technology are introduced, the workgroup provides technical scoping and justification for new projects or programs, alongside the Electric Engineering Project Management Organization, that will proactively pilot or install new distribution equipment. The workgroup is also responsible for real-time engineering support for construction and operation workgroups, field equipment investigations to determine distribution equipment failure root causes, failure trend analysis, as well as equipment and material quality deficiency reporting and finding resolutions with manufacturers as needed.

b. System Protection Automation and Control Engineering

The System Protection Automation and Control Engineering workgroup (System Protection) is responsible for the full lifecycle management of protection, automation, and control systems. The workgroup supports the timely and accurate development, implementation, and periodic review of relay settings for thousands of protective devices, supporting the safe and reliable operation of the electric grid. System Protection collaborates with manufacturers to select relays, monitoring devices, and other system protection equipment that meets the organization's standards for functionality, reliability, affordability, and safety. The workgroup provides technical support and design reviews for substation and distribution projects, works closely with distribution operations, and partners with maintenance and field workgroups to address control and protection issues. Additionally, System Protection supports the development and enforcement of engineering standards and best practices, leads unplanned outage event analysis (i.e. high-SAIDI[13] and substation-level outages, relay miscoordination, etc.) and asset management planning, and helps facilitate the interconnection of large customers. The workgroup also assists customers experiencing power quality issues, so that all equipment operates safely and reliably.

c. Substation Engineering and Design

The Substation Engineering and Design workgroup is responsible for equipment specifications, design standards development and maintenance, engineering, and design for all transmission and distribution substations. For distribution substations, the workgroup provides support for design and engineering to repair and replace existing distribution substation equipment and install new substation equipment (i.e. transformers, breakers, disconnect switches, etc.) that enable the addition of new distribution circuits. This workgroup also partners with the other Electric Engineering distribution organizations to align standards, equipment, system protection, and work methods between the distribution-level substation equipment and distribution field equipment.

[13] System Average Interruption Duration Index (SAIDI).

d. Transmission Engineering and Design

The Transmission Engineering and Design workgroup is responsible for equipment review, standard development and maintenance, engineering, and design for all transmission structures with voltages 69kV and above. For transmission structures that contain fiber, communication, or distribution underbuild, the workgroup provides support for design and engineering discussions to support the safety and reliability of the transmission structures. This includes partnerships with the distribution organizations to coordinate distribution underbuild compliance work within planned transmission work to reduce rework and optimize cost-savings. These are distribution costs associated with transmission-driven work.

e. Civil Structural Engineering

The Civil Structural Engineering workgroup is responsible for site development and civil structural engineering and analysis for all SDG&E substation, transmission, and distribution projects and initiatives. The workgroup provides support for the creation of distribution standards, manuals, and designs, and structural equipment specifications, such as for poles and crossarms.

f. Electric Engineering Project Management Organization

The Electric Engineering Project Management Organization is responsible for the oversight and execution of distribution, substation, and transmission capital projects within the electric engineering portfolio that enable reliability, capacity, compliance, and safety. The workgroup provides end-to-end project management services so that projects are delivered safely, on time, and within budget. Core functions include comprehensive project planning/project management, financial analysis, scheduling, and document control to maintain regulatory compliance and operational excellence. By coordinating resources and managing risks, the workgroup executes infrastructure improvements that support system reliability and safety.

g. Associate Engineer Program

Within Electric Engineering, there is an Associate Engineer program, which is an ongoing rotational training program for entry level engineers that is a key component of SDG&E's effort to develop, integrate, and maintain engineers in SDG&E's workforce.

2. Forecast Method

The forecast method developed for the Electric Engineering cost category is base year 2025, including adjustments for backfill positions not reflected in the base year due to vacancies in the various engineering, project management, and drafting support positions. Throughout the base year, the Electric Engineering workgroup has operated efficiently to prioritize critical needs that support a safe and reliable electric distribution system. Based on this, the base year methodology is most reflective of how the Electric Engineering workgroup expects to operate for this GRC cycle.

3. Cost Drivers

The cost drivers for the Electric Engineering category are the O&M activities for various engineering and project management workgroups necessary to maintain the safety and reliability of the electric distribution system.

a. Labor Costs Associated with Resources Critical to Engineering Support

The key cost driver for the Electric Engineering category is labor. The Electric Engineering workgroup is staffed with critical resources needed to provide engineering, design, and project management support to construct, operate, and maintain SDG&E's electric distribution infrastructure to support the safe and reliable delivery of power to our customers. Electric Engineering resources, such as engineers, designers, drafters, standard administrators, office support personnel, project managers, supervisors, and management are all critical for engineering and designing a safe and reliable electric distribution system while maintaining regulatory and other compliance requirements.

b. Backfilling Resources Critical to Engineering Support

The key cost driver contributing to adjustments is to backfill positions for both engineering and project management and drafting support. The resources needed to backfill vacant positions as part of the base year 2025 forecast are back-office employees with job classifications including Engineers, Project Coordinators, Drafters, and Project Managers. The total estimated backfill is 0.2 FTEs. See workpapers Ex. SDGE-09 WP 1ED003 for a more detailed cost breakdown.

D. Electric System Operations (1ED004)

TABLE SP-6
Summary of Workpaper Costs

ELECTRIC DISTRIBUTION (In 2025 $)			
D. Electric System Operations	**2025 Adjusted-Recorded (000s)**	**TY2028 Estimated (000s)**	**Change (000s)**
1. Electric System Operations	5,166	6,689	1,523
Total	5,166	6,689	1,523

1. Description of Costs and Underlying Activities

This section justifies funding of $6,689,000 for the Electric System Operations cost category. Of this total amount, $5,166,000 is attributed to base year 2025 forecasting, $665,000 is attributed to backfilling vacancies not accounted for in the base year adjusted-recorded amount, $774,000 is attributed to incremental non-labor costs, and $84,000 reflects changes in connection with the compensation modernization initiative. Details pertaining to the forecast methodology and cost drivers for this section are further discussed below in sections III.D.2 and III.D.3. For details related to the compensation modernization initiative, please refer to the Compensation & Benefits testimony, Ex. SCG-16/SDGE-20.

The forecast for this cost category supports SDG&E's Electric System Operations organization, which performs 24/7/365 supervision and control of the electric system, both during normal operating conditions and emergency conditions (system stress, red flag warnings, elevated fire weather conditions, storms, etc.), including management of situational awareness tools, control systems, and workflow technologies that support compliance with safety regulations, protect field personnel, and maintain accurate documentation. Electric System Operations primary functions include Control Centers, Operator Training, and Technology, all of which are summarized below:

a. Control Centers

The Mission Control Center is SDG&E's dedicated facility for real-time grid oversight, housing advanced monitoring systems, control technologies, and essential operational workforce. The facility is shared by Electric Grid Operations and Electric Distribution Operations. Both departments staff highly trained operators on shifts 24/7/365 who are vital for safe monitoring, dispatch, and operation of automated control systems. The operators have the responsibility and authority to implement real-time actions to promote the safe and reliable operation of SDG&E's electric distribution system, following all SDG&E policies, standards, and procedures, supporting the safe and reliable operation of SDG&E's electric distribution system for both planned and unplanned events.

b. Operator Training

A key resource within the control center is the team of Distribution System Operators (DSOs) who provide 24/7 operational oversight and management of the electric distribution system. Their role includes authorizing field workers to safely perform system changes to the electric distribution system and directing unplanned outage restoration activities. Their actions have a direct impact on the reliability of the system and impact SDG&E's customer experience. The DSOs also play a critical role in implementing wildfire mitigation measures during periods of heightened fire risk. These measures include enabling sensitive relay profiles, disabling automatic reclosing functions, enforcing visual patrol requirements prior to re-energizing overhead lines, and safely executing PSPS events.

The SDG&E Mission Control Training Center was established in 2016 and provides initial and ongoing training for DSOs. The Mission Control Training Center contains instructor-based classrooms and a simulation room which allows for training on real-time operations tools. The purpose of SDG&E's Misson Control Training Center is to develop and maintain highly trained, qualified, and competent operating personnel using a systematic approach to training.

As part of this program, Distribution trainers administer an 18-month operator qualification process which develops and delivers periodic skills refresher courses. The training program incorporates a continuous feedback loop, using operator observations and performance assessments to refine and update training materials. These efforts improve the knowledge and expertise of DSOs to allow for better coordination of field activities and to have the skills and knowledge needed to safely provide coordination of field worker activities on the system while maintaining reliable system operations.

Industry-wide demand for DSOs remains high. There has been close to a 40% attrition over the last four years, and further DSO attrition is expected as the position feeds several other critical job positions, including SDG&E's Transmission System Operators (TSO). Additionally, the position combines high technical proficiency with the ability to perform under intense operational demands, which contributes to the program's rigorous qualification standards and lower completion rates, typically around 25%.

Backfill costs to address vacant positions are forecasted to hire DSO trainees, which will accelerate the output of qualified DSOs through the program. The increase in the DSO and trainee workforce also places an upward pressure on the training program required to build and maintain the skills of the DSO workforce. These skills are required to safely operate SDG&E's electric distribution system.

c. O&M Technology Support

The data systems within the Mission Control facility operate 24/7/365. Cost and forecasts associated with the core operational tools are included in the Information Technology testimony (Ex. SCG-10/SDGE-14). This testimony, however, includes the O&M costs associated with those tools and attributable to this cost center.

i. Geographical Information Systems

Enterprise GIS Services (EGISS) is the section of Electric Distribution Operations that creates and maintains all electric distribution, transmission, telecommunications, and substation data in SDG&E's enterprise GIS system. EGISS digitizes the data in a preliminary state, energizes the data in real-time, reconciles and converts design work orders into construction order as-builts, scans them to a central repository, records details in the GIS system, and identifies these assets for tax and franchise fee calculations and reports. SDG&E's enterprise GIS is a direct input of information into many operational and planning tools used by engineering and operations; thus, accurate and timely data is essential for safety and reliability.

Backfill costs to address vacant positions are forecasted due to the need for additional EGISS trainee classes to address growing demand and mitigate workforce attrition, as well as the planned enterprise GIS system redesign, which will require a learning curve period for users and the development of new training materials. SDG&E anticipates a two-week training period in 2028, with approximately 12 participants per class (including the trainer), with recurring sessions until all required staff complete training. In addition, EGISS will need to dedicate resources to develop new training materials and rewrite existing standards documents to reflect updated workflows, symbology, and terminology and to translate these requirements into the redesigned system. This standards and training material development effort is expected to require approximately three resources over a six-month period (non-consecutive).

ii. Supervisory Control and Data Acquisition (SCADA)

Integration of SCADA telemetry and controls into the operational data systems is also performed within Electric System Operations. SCADA devices provide remote telemetry to the control centers for situational awareness, allow for automated remote switching, and automatically isolate system issues. SCADA allows the monitoring, control, and protection of distribution assets. The aggregation and processing of this critical operational data from field devices, SCADA systems, and other grid assets also enables analytics, reporting, and compliance monitoring.

In recent years, SDG&E has seen high growth in the application and proliferation of these devices, which are used to minimize impacts of unplanned outages to customers, provide increased visibility of impacts of DERs on the electric distribution system at a local level, and minimize the impacts of Public Safety Power Shutoff (PSPS) events. The number of installed SCADA field sites is forecast to increase by an average eight percent per year, which places a continued need for skilled labor to build and maintain the SCADA system.

iii. Advanced Distribution Management System (ADMS) Support

ADMS is an advanced applications platform that supports enhanced monitoring, analysis, and optimization of SDG&E's electric distribution system. The Outage Management System in conjunction with the Distribution Management System functions as SDG&E's ADMS, internally referred to as the Network Management System, utilized by DSOs to execute outage restoration and switching activities. While the Outage Management System and Distribution Management System functions are used for day-to-day outage execution, ADMS provides analytical and automation capabilities that improve restoration performance, system optimization, and operational decision making.

SDG&E implemented ADMS in 2012 and has since made continuous investments to expand functionality and maintain vendor support. Over time, ADMS capabilities have evolved to include advanced tools such as Fault Location, Isolation, and Service Restoration; feeder load management; volt/VAR optimization; and enhanced system modeling. These applications improve outage restoration times, support safer and more effective switching operations, and help manage increasing system complexity as DERs, sensors, and forecasting inputs are added to the distribution system. Ongoing O&M investment is required to sustain and enhance ADMS capabilities that support electric system safety, reliability, and customer service. Maintaining these capabilities requires continuous configuration, validation, and support of the underlying distribution system model, which serves as the analytical foundation for ADMS applications. As DER penetration increases and bidirectional power flows become more common, maintaining model accuracy and completeness becomes more challenging and resource intensive.

Planned ADMS enhancements will further improve situational awareness during high-risk operating conditions, including wildfire events, enhance daily operator workflows, expand outage and reliability analytics, and support improved customer communication for both planned and unplanned outages. Achieving these outcomes requires ongoing O&M to support software configuration, integration of new data sources, and user support for an increasingly complex operational platform. Implementation of these enhancements provide desktop and operational support for users, manage ongoing data accuracy, and ensure ADMS functionality scales effectively with increasing system complexity.

ADMS also supports emerging operational use cases involving microgrids and Local Area Distribution Controllers. Continued investment enables coordination between ADMS, SCADA, and microgrid controllers to support semi-autonomous control scenarios such as islanding, peak shaving, and black start. These capabilities require sustained O&M support to manage integration, maintain setpoints, and continue safe operation as microgrid deployments expand. Many of these functions are complementary to, and enhanced by, DERMS capabilities described below.

iv. Distributed Energy Resource Management System (DERMS)

DERMS is an operational platform designed to monitor, coordinate, and signal distributed energy resources such as battery storage, and aggregated flexible loads. DERMS implementation was authorized in a prior General Rate Case, and ongoing O&M support will be required beginning in 2028 and beyond to safely integrate increasing levels of DERs onto SDG&E’s distribution system.

DERMS operates as a coordination and control layer that works in close alignment with the Outage Management System, the Distribution Management System, and ADMS functions, while remaining a separate operational platform. DERMS enables advanced operational capabilities including two-way communication with DER devices and aggregators, dynamic operating envelope management, enhanced volt/VAR optimization, and real time constraint management. These functions are critical for preventing overloads, managing voltage impacts, and maintaining safe operating conditions as DER penetration continues to grow.

Safe and effective DERMS operation depends on timely and accurate distribution power flow solutions produced by ADMS and the Distribution Management System, as these calculations define the operating limits and network constraints enforced through DERMS controls. As a result, DERMS and ADMS are operationally interdependent, with ADMS providing validated system models and constraints, and DERMS providing increased visibility into DER behavior, telemetry, and performance that improves system modeling and forecasting accuracy.

To function safely and at scale, DERMS requires several foundational O&M supported capabilities. These include accurate DER registries, reliable telemetry and communications pathways, performance verification and feedback mechanisms, and scalable backend infrastructure capable of integrating heterogeneous data sources such as Advanced Metering Infrastructure, ADMS telemetry, inverter data, weather inputs, and aggregator signals. Sustaining these components requires continuous monitoring, configuration, validation, and operational support as DER participation expands.

Failure to sustain DERMS and its supporting operational infrastructure would increase the risk of unexpected bidirectional flows, voltage violations, localized overloads, and reduced situational awareness during high stress system conditions. Continued O&M investment enables SDG&E to meet CPUC safety, reliability, wildfire mitigation, and grid modernization objectives while supporting California's clean energy transition.

2. Forecast Methodology

The forecast method developed for the ESO cost category is base year 2025, including adjustments for backfill positions and incremental positions associated with new technology deployments. Throughout the base year, SDG&E has operated efficiently to prioritize critical needs of the electric distribution system and support the safe and reliable delivery of power to our customers. Based on this, the base year methodology is the most reflective of how SDG&E expects to operate for this GRC cycle.

3. Cost Drivers

The key cost drivers for this work paper are the labor and non-labor O&M activities associated with EDO personnel and contracted support services necessary to maintain the safety and reliability of the electric system.

a. Backfilling Resources Critical to Operations

Trained and skilled utility personnel such as electric distribution operators, technologists, technicians, and management are in high demand throughout the industry, making recruitment and retention challenging.

As a result, ongoing attritional hiring is necessary to support core operational functions. Adjustments to the 2025 Base Year are included to address attrition-related needs associated with DSO training, SCADA Workforce Development, and EGISS Workforce Development. The resources needed to backfill vacant positions as a part of the Base Year 2025 forecast are back-office employees with job classifications including Electric GIS Technicians, Operations Technical Analysts, Electric Operations Technologists, Principal Systems Analysts, Business System Analysts, DSO Trainees, Engineering Team Lead, Senior Energy Management System Program Analysts and NERC System Operations Trainers. The total estimated backfill is 5.0 FTEs. See workpapers Ex. SDGE-09 WP 1ED004 for a more detailed cost breakdown.

b. Incremental Costs Critical to Technology Upgrades

Incremental O&M costs are required for Network Management System enhancements in 2028-2031 to address operational needs in the Control Center associated with the Network Management Upgrades. These incremental costs are needed because of the impact on switching accuracy, system support with increasing DER penetration, and improvements are anticipated to include initiatives such as, but not limited to, Flex Ops and Operations Mobile Applications, adding ADMS functionality like Volt/Var Optimization, digitization of key emergency response processes, and implementing further capabilities to enhance customer experience. The total estimated incremental O&M cost is $150,000. See workpapers Ex. SDGE-09 WP 1ED004 for a more detailed cost breakdown. For details on IT project costs, refer to the Information Technology testimony (Ex. SCG-10/SDGE-14).

c. Incremental Costs Critical to Technology Integration and Training

Incremental O&M costs are required to support the change management and training efforts associated with the GIS Utility Network project. These efforts will involve training employees who must become proficient in new processes and updated tools resulting from the transition to the GIS Utility Network platform. Because these activities directly support organizational readiness and user adoption, and do not create or enhance a capital asset, the related costs are not eligible for capitalization. Instead, they represent necessary operational expenditures to enable a smooth and effective transition. These incremental costs are temporary in nature, extending through 2030 (assuming the capital asset is placed into service on the currently expected timeline), and are not indicative of a permanent increase in ongoing operational needs once the transition and associated training are completed. The total estimated incremental O&M cost is $624,000. See workpapers Ex. SDGE-09 WP 1ED004 for a more detailed cost breakdown. For details on IT project costs, refer to the Information Technology testimony (Ex. SCG-10/SDGE-14).

E. Electric Regional Operations (1ED005)

TABLE SP-7
Summary of Workpaper Costs

ELECTRIC DISTRIBUTION (In 2025 $)			
E. Electric Regional Operations	**2025 Adjusted-Recorded (000s)**	**TY2028 Estimated (000s)**	**Change (000s)**
1. Electric Regional Operations	37,676	39,002	1,326
Total	37,676	39,002	1,326

1. Description of Costs and Underlying Activities

This section justifies funding of $39,002,000 for the Electric Regional Operations (ERO) cost category. Of this total amount, $37,676,000 is attributed to base year 2025 forecasting, $810,000 is attributed to backfilling vacancies not accounted for in the base year adjusted-recorded amount, $97,000 is attributed to incremental labor costs, and $419,000 reflects changes in connection with the compensation modernization initiative. Details pertaining to the forecast methodology and cost drivers for this section are further discussed below. For details related to the compensation modernization initiative, please refer to the Compensation & Benefits testimony, Ex. SCG-16/SDGE-20.

ERO is responsible for the ongoing functioning and maintenance of the electric transmission and distribution system and includes all electric distribution and transmission crews, planners, scheduling and dispatch, and support staff located in six districts (Beach Cities, Construction Metro, Eastern, Northeast, North Coast and Orange County), two satellite operating centers (Ramona and Mountain Empire), Transmission Construction & Maintenance,[14] Electric Regional Operations Construction, and Skills Training Center.

ERO is comprised of electric linemen, apprentices, line assistants, construction equipment operators, scheduling and dispatch, inspectors, planners, office support personnel, project managers, supervisors, and management personnel. The ERO workforce conducts training required by various Company organizational units including Safety, Compliance, Electric Distribution/Transmission Engineering, Fleet, Environmental, as well as various governmental agencies (*e.g.*, the CPUC, Occupational Safety and Health Administration (OSHA), State of California). The ERO workforce also reviews and updates standards and practices to address operational incident patterns. The primary job functions include:

a. Inspection and Maintenance of the Electric Distribution System

In compliance with CPUC General Orders (GOs) 95, 128, and 165, and SDG&E standards, the ERO workforce proactively completes annual patrols and detailed inspections based on reoccurring intervals of all facilities within the service territory. Work orders are created based on discovered findings and jobs are designed, scheduled, and completed in accordance with the CPUC GOs.

b. Restoration of Service After Outages

ERO crews, made up of a working foreman, lineman, apprentices, fault finding specialists, equipment operators, and line assistants respond to, repair, and restore electric outages in both the underground and overhead systems to optimize safety and reliability. Crews

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[14] The Transmission Construction & Maintenance group reports to ERO and has small amounts of distribution O&M costs due to the associated electric distribution underbuild on transmission infrastructure which must be maintained. These are distribution costs associated with transmission-driven work.

leverage the safety training that they have received to implement public and employee safety protocols while conducting all restoration activities.

c. Repairs, Service Problems, and Other Customer Issues

Service crews (typically made up of a lineman and apprentice) respond to, repair, and restore overhead and underground service problems. Service crews also address miscellaneous customer issues in accordance with OSHA and Company safety standards.

d. Constructing New Electric Infrastructure

The ERO workforce proactively analyzes infrastructure assets to help maintain a safe and reliable system. This is done through equipment inspections, reviewing outage history, equipment performance, project proposals, design, scheduling, and construction that aligns with the Company's work plan from beginning to end.

e. Scheduling and Dispatch

The ERO's scheduling and forecasting team analyzes availability of resources versus projected work to proactively forecast the long-term electric construction portfolio for the ERO workforce. The scheduling team implements an effective resource allocation philosophy when developing work plans for the electric crews, on both a strategic and real-time basis. The team is responsible for the daily scheduling and dispatch of electric crews for planned and unplanned work.

f. Operations Support

ERO has operational support personnel at each district location to assist field crews, Skills Training Center employees to monitor and administer training programs, and a project management office and safety center to support all ERO districts. Operations support includes activities such as timekeeping, project and operations coordination, and reporting for management and external stakeholders.

g. Skills Training Center Voluntary Protection Program

Skills Training Center (STC) is developing programmatic changes to achieve California Voluntary Protection Program (Cal/VPP) certification for ERO. As the primary training facility for both electric and gas field personnel, STC plays a vital role in preparing our workforce to operate safely, reliably, and in full accordance with company and regulatory standards. The STC implements robust safety and health programs designed to proactively prevent and control occupational hazards for the highest level of protection for employees, trainees, and instructors.

Safety and training are the top priorities for STC, and this commitment is reflected in every course curriculum, hands-on exercise, and operational practice across the facility. The Cal/VPP team remains highly engaged, with each representative serving as a subject matter expert for specific VPP program elements. Through these efforts, Skills Training fosters a culture where safety is a shared responsibility, empowering all personnel to take an active role in maintaining a safe and effective learning environment.

2. Forecast Method

The forecast method developed for the ERO cost category is base year 2025, including adjustments for backfill positions and incremental positions associated with new regulatory requirements, such as those reflected in SB 410. Throughout the base year, SDG&E has operated efficiently to prioritize critical needs of the electric distribution system in support of the safe and reliable delivery of power to our customers. Based on this, the base year methodology is the most reflective of how SDG&E expects to operate for this GRC cycle.

3. Cost Drivers

The cost drivers for the ERO category are the O&M activities for ERO personnel and contracted support services necessary to maintain the safety and reliability of the electric distribution system while meeting both existing and new regulatory requirements.

a. Labor Costs Associated with Resources Critical to Operations

The key cost driver for the ERO category is labor. ERO is staffed with critical resources needed to operate, maintain, and repair SDG&E's electric distribution infrastructure to deliver safe and reliable power to our customers. ERO resources such as electric linemen, apprentices, line assistants, construction equipment operators, inspectors, planners, office support personnel, project managers, supervisors, and management are all critical for maintaining a safe and reliable electric distribution system and for meeting regulatory requirements.

b. Backfilling Resources Critical to Operations

Trained and skilled utility personnel such as electric linemen, apprentices, line assistants, construction equipment operators, planners, office support personnel, project managers, supervisors, and management are in high demand throughout the industry and attritional hiring is necessary to support core operational activities. These personnel are also critical to meeting new regulatory requirements such as those reflected in SB 410. The resources needed to backfill vacant positions as a part of the Base Year 2025 forecast are a combination of both back-office and field employees with job classifications including Linemen, Planners, Compliance Coordinators, Principal Financial Analysts and ERO Response Planning Advisors, and administrative coordinators. The total estimated backfill is 5.0 FTEs. See workpapers Ex. SDGE-09 WP 1ED005 for a more detailed cost breakdown.

c. Senate Bill (SB) 410 – Powering up Californians Act

Additionally, incremental positions reporting to the organization have been included in the forecast for ERO as a part of meeting SB 410 mandates[15] to analyze current and future qualified staffing levels tied to operational goals and energization timelines. These positions are both field and administrative employees and operate to support customer project intake, project coordination, quality assurance, construction readiness and field inspections needed to support safety and compliance with SDG&E standards. The resources needed to meet the mandates set by SB 410 are a combination of both back office and field employees with job classifications including Project Coordinators and Inspector A's. The total estimated incremental is 0.8 FTEs. See workpapers Ex. SDGE-09 WP 1ED005 for a more detailed cost breakdown.

F. Materials and Inventory (1ED006)

TABLE SP-8
Summary of Workpaper Costs

ELECTRIC DISTRIBUTION (In 2025 $)			
F. Materials and Inventory	**2025 Adjusted-Recorded (000s)**	**TY2028 Estimated (000s)**	**Change (000s)**
1. Materials and Inventory	37,715	37,715	0
Total	37,715	37,715	0

1. Description of Costs and Underlying Activities

This section justifies funding of $37,715,000 for the Materials and Inventory cost category. The total amount is attributed to a base year 2025 forecast. Details pertaining to the forecast methodology and cost drivers for this section are further discussed below in sections III.F.2 and III.F.3.

15 SB 410 (Becker, 2023), *available at*: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202320240SB410.

The Materials and Inventory category encompasses the non-labor storeroom costs required to perform daily construction, both during normal and emergency operations. SDG&E manages 12 storerooms and 17 laydown yard locations across SDG&E's service territory which supports current infrastructure construction projects, corrective maintenance, and emergency inventory. Moreover, managing the financial data accuracy of inventory or fixed asset allocation to construction work is a key component performed by the storeroom. The storeroom enables material to be physically accounted for and the inventory value to be correct and accurately represented within the accounting system. The Materials and Inventory category accounts for the purchasing of low-cost minor material types, such as nuts, bolts, secondary wire, ground rods, etc., which are allocated to construction jobs as an overhead cost since direct charging these small items to each construction job would be financially infeasible. The category also reflects the cost for all storeroom freight transport charges of construction materials.

2. Forecast Method

The forecast method developed for this cost category is base year 2025. SDG&E expects base year to reasonably reflect how SDG&E expects to operate for this GRC cycle.

3. Cost Drivers

The cost drivers behind this forecast are storeroom management of bulk materials, freight transportation, and contract labor associated with staging and storage yard management.

a. Management of Bulk Materials

Low-value material items that are replenished as "truck stock" consist of bulk type materials that are not individually inventoried or managed by the district warehouses. These materials include items like nuts, bolts, washers, connectors, electrical tape, and some daily consumption items. Because inventory tracking and accounting to individual jobs is cost prohibitive, these items are not directly charged to the individual O&M account or capital budgets for which they are used.

b. Freight Transportation Costs

Freight charges consist of linehaul charges, mileage-based rates, fuel surcharges, dedicated trucks, expedited movement of materials, and loading and offloading labor. This includes liftgate and craning services, brief storage of materials, after-hours/emergency delivery costs, palletizing, wrapping, and securing loads, material handling activities, freight planning and optimization, shipment tracking, dispatch and routing, and Transportation Management System fees. These costs are settled to this category and not directly charged to the O&M account or capital budget for which the materials may be used. Due to increases in labor rates, vehicle costs, and a tightening of the transportation market, base year 2025 provides the most up to date costs for these services.

c. Staging and Storage Yard Management

Material Staging and Storage Yards are facilities utilized by SDG&E to support the safe, reliable, and efficient execution of electric and gas operations, including capital construction, system maintenance, and emergency response activities. These yards provide controlled locations for the receipt, storage, handling, and staging of utility materials and equipment required to meet operational needs. Material Staging and Storage Yards serve as an integral component of the Company's material management and logistics framework by, among other things, securing Company property, supporting construction readiness, and reducing operational risk and inefficiencies associated with direct-to-site deliveries and unplanned material movements. Services performed at Material Staging and Storage Yards may include, but are not limited to 1) receiving, inspection, and verification of inbound materials, 2) secure storage and inventory control, including tracking and accountability, 3) material staging, packaging, and preparation for specific work orders or projects, 4) coordination of material pickups, deliveries, transfers, and returns, and 5) yard operations management, including safety oversight, security, and environmental compliance.

Material Staging and Storage Yards enable SDG&E to improve operational efficiency, enhance safety and compliance, and support timely execution of capital and operating programs while managing costs and system reliability. Due to upward pressures, including lease costs, service provider labor rates, and a need to properly store and secure equipment, base year 2025 provides the most up to date costs for these services. See workpapers Ex. SDG&E-09 WP 1ED006 for a more detailed cost breakdown.

G. Electric Regional Operations Troubleshooters (1ED007)

TABLE SP-9
Summary of Workpaper Costs

ELECTRIC DISTRIBUTION (In 2025 $)			
G. Electric Regional Operations Troubleshooters	**2025 Adjusted-Recorded (000s)**	**TY2028 Estimated (000s)**	**Change (000s)**
1. Electric Regional Operations Troubleshooters	12,369	12,772	403
Total	12,369	12,772	403

1. Description of Costs and Underlying Activities

This section justifies funding of $12,772,000 for the ERO Troubleshooters cost category. Of this total amount, $12,369,000 is attributed to base year 2025 forecasting, $213,000 is attributed to backfilling vacancies not accounted for in the base year adjusted-recorded amount, and $190,000 reflects changes in connection with the compensation modernization initiative. Details pertaining to the forecast methodology and cost drivers for this section are further discussed below in sections III.G.2 and III.G.3. For details related to the compensation modernization initiative, please refer to the Compensation & Benefits testimony, Ex. SCG-16/SDGE-20.

The ERO Troubleshooters workgroup covers six districts (Beach Cities, Construction Metro, Eastern, Northeast, North Coast and Orange County), and two satellite operating centers (Ramona and Mountain Empire). Each district consists of Electric Troubleshooters (ETS), engineers, technical assistants, and management. The workgroup is responsible for engineering and system troubleshooting to deliver reliable and safe electric service to SDG&E customers. ETS are a key resource, acting as SDG&E's first responders for events impacting the electric system. ETS have the specific skills necessary to timely restore electric service during emergencies and unplanned interruptions while protecting public and employee safety. During service interruptions, ETS are tasked with isolating affected areas of SDG&E's distribution system and implementing restoration efforts that will minimize the impact of any service interruptions to SDG&E customers. During emergencies, ETS work closely with emergency response agencies to protect the public and SDG&E's employees from potentially hazardous conditions. ETS act as the primary interface with customers who are experiencing service problems. ETS will attempt to rectify customer issues individually and engage support from electric service crews for more complex restoration efforts. Should the issue reside with customer equipment, the ETS will recommend the customer coordinate with an electrician. ETS perform a variety of additional tasks including substation and field switching, substation security checks, and routine safety patrols related to compliance requirements. The remainder of the workgroup supports the ETS while also providing necessary customer, engineering, compliance administration, and supervisory support—all essential to providing safe and reliable electric service.

2. Forecast Method

The forecast method developed for the ERO Troubleshooters cost category is Base Year 2025, including adjustments for backfilling vacancies. Within the base year, SDG&E has worked to prioritize operational efficiencies within the ERO Troubleshooting department and therefore the base year methodology, along with including backfill adjustments as discussed in the Cost Driver section below, provides the most appropriate baseline in comparison to future targets for the organization within this GRC cycle.

3. Cost Drivers

The cost drivers for the ERO Troubleshooters category are primarily labor activities for troubleshooting personnel necessary to maintain the safety and reliability of the electric distribution system.

a. Backfilling Resources Critical to Operations

Trained and skilled utility personnel such as electric troubleshooters, engineers, technical assistants, and management are in high demand throughout the industry and attritional hiring is necessary to support core operational activities. The resources needed to backfill vacant positions as a part of the Base Year 2025 forecast are back-office employees with engineering job classifications. The total estimated backfill is 1.3 FTEs. See workpapers Ex. SDGE-09 WP 1ED007 for a more detailed cost breakdown.

H. Service Order Team (1ED008)

TABLE SP-10
Summary of Workpaper Costs

ELECTRIC DISTRIBUTION (In 2025 $)			
H. Service Order Team	**2025 Adjusted-Recorded (000s)**	**TY2028 Estimated (000s)**	**Change (000s)**
1. Service Order Team	7,197	7,959	762
Total	7,197	7,959	762

1. Description of Costs and Underlying Activities

This section justifies funding of $7,959,000 for the Service Order Team (SOT) cost category. Of this total amount, $7,923,000 is attributed to a three-year average forecast and $36,000 reflects changes in connection with the compensation modernization initiative. Details pertaining to the forecast methodology and cost drivers for this section are further discussed below in sections III.H.2 and III.H.3. For details related to the compensation modernization initiative, please refer to the Compensation & Benefits testimony, Ex. SCG-16/SDGE-20.

The SOT is responsible for planning, coordinating, and executing customer-driven additions and modifications to commercial and residential electric distribution systems, with primary responsibility for secondary voltage service work such as panel capacity upgrades and service relocations. The team oversees adherence to standardized construction and service design practices to deliver efficient, uniform, and customer focused processes. The O&M expenses for the SOT include disconnect/reconnect activities associated with residential solar installations, as well as operational support for distribution construction crews during storm and outage recovery efforts. Additional O&M responsibilities include coordination of Communication Infrastructure Provider network attachment requests on utility infrastructure, support for customer load serving upgrades related to home remodeling, participation in employee training programs, and replacement of noncapital electrical equipment. The unit of measure for this cost category is completed service order projects.

2. Forecast Method

The forecast method for the SOT cost category is a three-year historical average of recorded expenditures, applying a normalized dataset to smooth year over year volatility. For both labor and nonlabor components, this methodology incorporates variability in workforce utilization, material cost escalation, and supply chain fluctuations to develop a representative baseline of expected operating costs.

3. Cost Drivers

The primary driver of SOT costs is customer initiated electric service upgrade activity, including increased volumes of secondary service modifications and panel capacity upgrades. Recent years have shown higher workloads associated with Communication Infrastructure Provider attachments, DER interconnection requests such as residential solar PV, electric vehicle supply equipment and stationary storage system installations, as well as service relocations and load serving upgrades prompted by residential electrification trends, home remodels, and the addition of accessory dwelling units.

I. Electric Assets and Compliance Management (1ED009)

TABLE SP-11
Summary of Workpaper Costs

ELECTRIC DISTRIBUTION (In 2025 $)			
I. Electric Assets and Compliance Management	**2025 Adjusted-Recorded (000s)**	**TY2028 Estimated (000s)**	**Change (000s)**
1. Electric Assets and Compliance Management	3,213	5,385	2,172
Total	3,213	5,385	2,172

1. Description of Costs and Underlying Activities

This section justifies funding of 5,385,000 for the Electric Assets and Compliance Management cost category. Of this total amount, $3,213,000 is attributed to base year 2025 forecasting, $500,000 is attributed to backfilling vacancies not accounted for in the base year adjusted-recorded amount, $1,632,000 is attributed to incremental labor and non-labor costs, and $40,000 reflects changes in connection with the compensation modernization initiative. Details pertaining to the forecast methodology and cost drivers for this section are further discussed below in sections III.I.2 and III.I.3. For details related to the compensation modernization initiative, please refer to the Compensation & Benefits testimony, Ex. SCG-16/SDGE-20.

The Electric Assets and Compliance Management workgroups consist of three areas: Program Management, Electric Distribution Inspections, and Joint Asset Management.

a. Program Management Group (PMG)

The PMG is responsible for providing oversight and governance of SDG&E's Electric Distribution Corrective Maintenance Program (CMP) with regard to (1) performance of electric distribution inspections required by GO 165, GO 95, GO 128 and SDG&E standards, as well as enhanced inspections described in SDG&E's Wildfire Mitigation Plan (WMP) and (2) completion of repair work identified through inspection efforts described in item (1) and within the compliance timeframes required by GO 95, GO 128 and SDG&E standards.

The PMG team is also responsible for supporting the development of compliance training for employees responsible for performing inspections and completing repair work. The team also develops policies and procedures that both support compliance with the CMP and WMP requirements, including QA/QC work, and supports compliance across the Company with GO 95 (overhead) and GO 128 (underground) for overhead and underground electric distribution maintenance and repair work. Additional responsibilities include managing and supporting CPUC electric system audits for electric distribution, transmission, and substation, and supporting CPUC incident reporting and investigations for all electric distribution, transmission, substation and generation safety events. In addition to the above responsibilities, PMG also supports CPUC investigations and resolution of CPUC customer complaints related to electric safety issues, oversees internal QA/QC of CMP inspections and repair work, and supports any data requests, program enhancements, or changes related to SDG&E's CMP and electric distribution asset inspections and repairs described in the WMP.

b. Electric Distribution Inspections (EDI)

The EDI workgroup is responsible for overseeing and executing electric distribution inspections performed by Electric Distribution Line Inspectors (Line Inspectors) in compliance with GO 95, GO 165 and GO 128 and SDG&E's CMP and WMP requirements.[16] This includes the development and training of the Line Inspectors.

[16] SDG&E notes that its reference to WMP here is for clarity in describing the activity, but notes that any costs related to WMP activities, including line inspection costs, are included in the Wildfire Mitigation and Vegetation Management testimony and forecasted costs. *See* Ex. SDGE-07.

Inspections performed by Line Inspectors include detailed overhead electric distribution inspections (both ground and aerial) and patrol inspections of overhead and underground electric distribution facilities. Patrol inspections are visual inspections performed annually on all overhead and underground distribution facilities, streetlights, and all primary underground facilities (often from the ground or by vehicle), and are designed to identify visible structural problems and safety hazards. Patrols in the non-High Fire Threat Districts (HFTD) include over 58,000 electric distribution poles, over 47,000 streetlights, and over 180,000 underground structures (surface and subsurface).

Ground-based detailed inspections are thorough examinations of individual components, where conditions observed are recorded and documented. These inspections are performed every 5-years for overhead facilities and every 3, 5 or 10-years for underground facilities, depending on the type of facilities. These inspections performed by the EDI team include approximately 20,000 overhead electric distribution poles in the non-HFTD.

The EDI team also oversees the implementation and completion of the aerial/risk-informed inspections for electric distribution overhead facilities and Wood Pole Intrusive Inspection (WPI) program for electric distribution and transmission wood poles. Aerial inspections are typically performed on overhead distribution electric facilities in the HFTD and Wildfire Urban Interface areas.[17] Oversight includes management of contracted drone pilots in support of aerial inspections and the contractor that performs WPI inspections. Aerial/risk-informed inspections are required by SDG&E's CMP and WMP and target high-risk areas or asset types, and include infrared (IR), aerial, and drone-based inspections. WPI inspections are invasive inspections (*e.g.*, excavations below ground line, borings into the pole with measurements, and application of chemical treatments) used to assess internal degradation and extend the life of the asset through chemical treatment. WPI routine inspections are performed every 10 years with the exception of new poles or poles with a recent inspection. Additional inspections may be performed above and beyond to support engineering requirements under GO 95, Rule 44.

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[17] Similarly, references to work in the HFTD are also for purposes of describing the activity this workgroup performs, but related costs are included in the Wildfire Mitigation and Vegetation Management testimony and forecasted costs. *See* Ex. SDGE-07.

Additionally, the team coordinates support for inspections, such as access protocol, environmental, safety and security, permitting, traffic control and other matters needed to facilitate the performance of inspection work in a safe and compliant manner. Finally, the team performs enhanced inspections as needed to assess asset health and safety.

c. Joint Asset Management (JAM)

The JAM group manages and maintains the license agreements for more than 25 communications companies that utilize SDG&E infrastructure to support their communications equipment. Responsibilities include data governance and maintenance of all joint-use documentation, record keeping, and issuance of billing for over 285,000 attachments to approximately 151,000 SDG&E-owned poles. The JAM group processes an average of 8,000 attachment applications annually (i.e., third party requests for additions, modifications, and removals), issues over 10,000 notifications related to third-party nonconformances (including safety hazards) in compliance with GO 95, GO 128 and SDG&E standards, and processes transfer requests of third-party owned communication equipment associated with pole replacements or underground conversion projects. This involves office support and field work.

Additionally, the team is responsible for monitoring, implementing, and maintaining compliance with applicable regulations related to third party attachments, such as CPUC Right-of-Way Rules (which incorporate One-Touch Make Ready Rules) under D.22-10-025, and the Pole Attachment Database under D.20-07-004 and D.21-10-019. This requires management of and necessary enhancements to our pole database known as the Telecommunication Attachment Management System. The JAM team also provides project support for all departments across the Company related to the joint use of our facilities by third parties, such as Communication Infrastructure Provider equipment identification, joint meetings and special projects. Finally, the performance of QA/QC audits, including sampling of completed field work related to inspections, is also the responsibility of the JAM team.

2. Forecast Method

The forecast method developed for the Electric Asset and Compliance Management cost category is 2025 base year recorded, with adjustments. The 2025 base year provides an appropriate baseline of costs needed for routine and compliance-driven electric distribution activities, including inspections, corrective maintenance, asset management, and program oversight required to meet General Orders and internal safety standards. Adjustments have been made to forecasted year dollars for the EDI team based on anticipated growth in the inspection team workforce. This forecast intentionally excludes incremental activities, targets, or initiatives that are uniquely associated with SDG&E's Wildfire Mitigation Plan (WMP). Costs associated with WMP-specific mitigation measures are addressed separately in SDG&E's Wildfire Mitigation and Vegetation Management testimony (Ex. SDGE-07).

3. Cost Drivers

a. Program Management Group (PMG)

The PMG group costs are primarily driven by internal labor. This team relies heavily on work management systems to maintain visibility on inspection cycles, findings, and asset data necessary to perform the functions described above. Only O&M costs related to electric distribution assets in the non-HFTD are included in this workpaper.

b. Electric Distribution Inspections (EDI)

The EDI group labor costs are driven by internal employees, including union Line Inspectors, supervisors, and inspection support personnel. The use of Line Inspectors to perform overhead detailed inspections (including aerial inspections) and overhead and underground patrols, instead of Qualified Electric Workers, is expected to decrease overall costs associated with inspections and increase resource availability for Qualified Electric Workers to perform construction and maintenance work of electric distribution assets. Only labor costs associated with electric distribution inspections performed in the non-HFTD are included in this workpaper (1ED009).

Nonlabor costs forecasted are associated with vehicles, tools, equipment and training for the Line Inspectors and employees and for external contractors to perform the wood pole intrusive inspections on electric distribution facilities in the non-HFTD, as required by GO 165 and SDG&E's CMP. Because wood pole intrusive inspections are performed on a 10-year cycle, the inspections rotate across SDG&E's service territory by area to improve cost efficiency. This results in fluctuations in the number of wood pole intrusive inspections performed each year. The forecast is based on the average number of inspections required over the GRC cycle. Moreover, while the utilization of wood poles is being reduced in our HFTD areas, the use of wood poles and the requirement for wood pole inspections in the non-HFTD are not anticipated to decrease within this GRC cycle.

Only O&M labor and nonlabor costs related to electric distribution assets in the non-HFTD are included in this workpaper. Labor and nonlabor O&M costs associated with electric distribution asset inspections in the HFTD and higher risk Wildfire Urban Interface areas are included in Ex SDGE-07 (Wildfire Mitigation and Vegetation Management) and WPs for C526, C530, C534, C534, C536)),

c. Joint Asset Management (JAM)

The JAM group labor costs are driven by internal employees performing the work described above that supports the safe and compliant use of our electric facilities by third-parties, primarily communications companies, but also includes municipalities, local police, federal agencies, airports, and others on both a temporary and permanent basis. The JAM group's nonlabor costs include external contractor support related to management of applications for attachment under D.22-10-025, field checks of communications equipment transfers, and verification of repair of GO 95 nonconformances by third party attachers that promotes the safe operation of our electric assets. Only O&M labor and nonlabor costs related to electric distribution assets in the non-HFTD are included in this workpaper (1ED009).

The JAM group also relies on work management systems to maintain attachment records, process transfer and nonconformance notifications to attachers, and manage billing records and data required to be made available in the Pole Database required by D.20-07-004 and D.21-10-019, as amended by D.26-05-007.[18] The work management systems are supported by SDG&E's Information Technology agile support teams.

Revenues associated with joint pole attachment fees, application fees and other charges to third-party attachers are recorded in Miscellaneous Revenues. The Miscellaneous Revenues are forecasted in Other Account Revenues Account 456 described in more detail in SDG&E's GRC Exhibit SDGE-31. Since Miscellaneous Revenues are subtracted from the overall revenue requirement, the impact of such revenues is a reduction of what is collected from ratepayers. The costs provided in this workpaper are separate from the revenue generated and are necessary for record-keeping, billing, management, and to support work associated with third-party use of our distribution electric facilities.

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[18] SDG&E notes that this decision was issued May 15, 2026. Accordingly, SDG&E has not fully analyzed need for potential additional costs and or potential additional revenues related to implementation to the decision, including changes to GO 178.

Since the last GRC, SDG&E has continued to work diligently to increase revenues from third party attachments by investing in improved attachment records (e.g., field visits to identify unauthorized attachments) and recouping costs related to attachment application processing through implementation of an application fee in 2024. 2028 pole attachment revenues are estimated at approximately $4.8M, a ~40% increase since 2021.[19] These revenues are not included in the cost forecasts for Electric Distribution O&M, but are discussed and accounted for in SDG&E's Miscellaneous Revenues testimony (Ex. SDGE-31).

In summary, adjustments made to the forecast for this cost category that are labor-driven are a combination of both backfill and incremental resources. Resources needed to backfill vacant positions as a part of the Base Year 2025 forecast are field employees with the Line Inspector classification. The total estimated backfill is 5.3 FTEs. Incremental labor resources consist of back-office and field employees with the Line Inspector Supervisor and Line Inspector job classification. The total estimated incremental increase is 7.2 FTEs. See workpapers Ex. SDGE-09 WP 1ED009 for a more detailed cost breakdown.

J. Electric Transmission and Distribution: Operations Services (1ED010)

TABLE SP-12
Summary of Workpaper Costs

ELECTRIC DISTRIBUTION (In 2025 $)			
J. Electric Transmission & Distribution: Operations Services	**2025 Adjusted-Recorded (000s)**	**TY2028 Estimated (000s)**	**Change (000s)**
1. Electric Transmission & Distribution: Operations Services	3,759	4,055	296
Total	3,759	4,055	296

1. Description of Costs and Underlying Activities

This section justifies funding of $4,055,000 for the Electric Transmission and Distribution: Operations Services (Operations Services) cost category. Of this total amount, $3,759,000 is attributed to base year 2025 forecasting, $247,000 is attributed to backfilling vacancies not accounted for in the base year adjusted-recorded amount, and $49,000 reflects changes in connection with the compensation modernization initiative. Details pertaining to the

[19] *Id.*

forecast methodology and cost drivers for this section are further discussed below in sections III.J.2 and III.J.3. For details related to the compensation modernization initiative, please refer to the Compensation & Benefits testimony, Ex. SCG-16/SDGE-20.

Operations Services performs a variety of support functions centered around safety and service including tool procurement, testing, calibration, tracking for compliance, equipment salvage, material management, and training. These functions are performed across several workgroups in Operations Services and are described below.

a. Maintenance Shop - Live Line Tools, Grounds & Jumpers and Protective Equipment Testing Lab

The Maintenance Shop workgroup supports SDG&E Electric Operations by maintaining, testing, repairing, and certifying the protective equipment and tools essential to electrical worker safety and system reliability. Live line tools, also known as hot sticks, are insulated equipment specifically designed for qualified utility workers to perform work on or near energized electrical equipment and are subject to rigorous testing and inspection processes to promote the highest level of field safety. Each tool is assigned a unique barcode and logged into our tracking system, enabling precise monitoring of its location and lifecycle. This system promotes proper maintenance and timely replacement, safeguarding both personnel and equipment reliability.

The workgroup also constructs grounds and jumpers that form the foundation of the protective grounding system. These components are critical for mitigating electrical hazards and protecting personnel. Routine inspections are essential to confirm their integrity and promptly address any damage or deterioration that could compromise performance or create a potential hazard. Through the Protective Equipment Testing (PET) Lab, the workgroup verifies that all rubber protective equipment meets the stringent safety standards established by OSHA, the Institute of Electrical and Electronics Engineers, and the American Society for Testimony Materials. From insulating gloves to field-deployed rubber mats, the PET Lab rigorously tests and certifies each item for safe and reliable protection for technicians in the field.

In addition, the Maintenance Shop includes tool repair, which includes maintenance, repair, fabrication, and procurement of tooling and equipment to support the operational needs of electric operations groups, including Electrical Regional Operations, ET&D Substation Construction & Operations (C&O), Troubleshooting, Skills and Compliance Training, and other related departments.

The workgroup also manages equipment salvage, refurbishment, and high-voltage testing. This includes the disposal and refurbishment of electric distribution equipment such as overhead and underground transformers, capacitors, SF6 switches, oil switches, and the associated gas and oil reclamation and recycling services. The Maintenance Shop operates a high-voltage test station to evaluate the electrical condition of transformers, regulators, mechanical jumpers, grounds, hot sticks and other live line tools and equipment. Their responsibilities also include transformer, regulator, and streetlight controller repair, as well as field testing new equipment received for quality control.

b. Materials Management

The Materials Management workgroup is responsible for the full lifecycle of project and program equipment, including distribution substation materials, promoting industry-standard practices that support and standardize project delivery. The workgroup manages every stage of material handling: orders, receiving, validation, goods receipts, tracking, packaging, delivery coordination, and reconciliation, from the time materials are ordered through project closeout. By using centralized systems such as SAP, Smartsheet, and PowerBI, Materials Management maintains visibility and control by tracking purchase orders, vendor agreements, and storage yard inventory. The workgroup supports timely availability and delivery of materials and works closely with project workgroups to meet stakeholder expectations and compliance dates. It also oversees the return, usage, and reconciliation of excess materials, applying systematic processes for accuracy and efficiency. In addition, Materials Management provides yard support for Portfolio & Project Management, in addition to other stakeholders, including staging yard mobilization, equipment coordination, and staging yard demobilization.

c. Business Controls

The Business Controls workgroup is responsible for the oversight of Operations Services and Substation C&O financial and accounting control policies and procedures to promote compliance and develop process improvements.

d. Training and Development

The Training and Development workgroup facilitates compliance and job skill training for Operations Services and Substation C&O employees through instructor-led and modular curricula, including the development and administration of the state-accredited Substation Electrician Apprenticeship program. This workgroup also supports compliance with current labor regulations by tracking employee training history, curating training materials, and developing new content to meet changes in standards, equipment, and procedures.

e. Voluntary Protection Program

All employees within Operations Services and Substation C&O are responsible for the California Voluntary Protection Program (Cal/VPP), which implements exemplary safety and health programs that effectively prevent and control occupational hazards, exceeding minimal Cal/OSHA standards to provide the best feasible protection at the site. The Cal/VPP demonstrates that commitment to safety excellence is ongoing and continues to foster a culture where safety is a shared responsibility. VPP is an ongoing program with designated personnel serving as subject matter experts for specific elements, supporting continued achievement of VPP Star status and continuing to effectively protect the workforce.

2. Forecast Method

The forecast method developed for the Operations Services cost category is base year 2025 recorded data, with adjustments for Operations Services backfill positions that are not accounted for in the base year 2025 recorded data. Throughout the base year, SDG&E has operated efficiently to prioritize critical needs, including the tools and testing required for the operations and maintenance of the electric distribution system and the safe and reliable delivery of power to our customers. Based on this, the base year methodology is the most reflective of how SDG&E expects to operate for this GRC cycle.

3. Cost Drivers

a. Labor Costs Associated with Resources Critical to Maintenance Support

The key cost driver for the Operations Services category is labor. The Operations Services department relies on skilled personnel who maintain, repair, and fabricate protective equipment and tools utilized by the electric operations groups. Trained and skilled personnel such as PET Lab and Maintenance Shop electricians, maintenance working foremen, shop mechanics, shop assistants, material management advisors, safety trainers, office support, supervisors, and management are all essential to meeting ongoing workload demands so that the electric distribution system is supported with the tools and equipment necessary for safe operations.

b. Backfilling Resources Critical to Engineering Support

The key cost driver contributing to adjustments is to backfill key positions in the Maintenance Shop and PET Lab. To maintain operational readiness and continuity, the resources needed to backfill vacant positions as part of the Base Year 2025 forecast includes the back-office and field employee classifications of Shop Assistant and Shop/PET Lab Electrician. The total estimated backfill is 2.0 FTEs. See workpapers Ex. SDGE-09 WP 1ED010 for a more detailed cost breakdown.

K. Electric Transmission and Distribution: Substation Construction & Operations (1ED011)

TABLE SP-13
Summary of Workpaper Costs

ELECTRIC DISTRIBUTION (In 2025 $)			
K. Substation Construction & Operations	**2025 Adjusted-Recorded (000s)**	**TY2028 Estimated (000s)**	**Change (000s)**
1. Substation Construction & Operations	12,248	13,060	812
Total	12,248	13,060	812

1. Description of Costs and Underlying Activities

This section justifies funding of $13,060,000 for the Electric Transmission and Distribution: Substation Construction & Operations (Substation C&O) cost category. Of this total amount, $12,921,000 is attributed to a three-year average forecast and $139,000 reflects changes in connection with the compensation modernization initiative. Details pertaining to the forecast methodology and cost drivers for this section are further discussed below in sections III.K.2 and III.K.3. For details related to the compensation modernization initiative, please refer to the Compensation & Benefits testimony, Ex. SCG-16/SDGE-20.

Substation C&O and associated support organizations are responsible for the installation, troubleshooting, inspection, and maintenance of equipment within the approximately 132 distribution substations on the SDG&E system. Maintained substation equipment includes approximately 300 distribution power transformers and their associated load tap changers or voltage regulators, and approximately 1,670 circuit breakers including oil, air, and vacuum classifications, and their associated line and bus disconnect switches.

Inspection and maintenance activities are also performed on all substation equipment including batteries, buses, support structures, capacitor banks, reactors, grounding systems, fire suppression systems, security infrastructure and perimeter fences and gates. The substation inspection and resulting Corrective Maintenance Program (CMP) managed by this workgroup is established in compliance with GO 174, CAISO maintenance requirements, and SDG&E's substation maintenance standards. This program is critical to the safe operation and reliability of all electric distribution substation facilities.

The Substation C&O workgroup also performs maintenance of protective relays, control systems, and other SCADA devices installed in both substations and electric distribution field devices. Relay systems are critical to the safe operation of the electric system because they identify system disturbances and quickly isolate them. Fast relay action prevents further damage from system faults and minimizes potential injury to the public and field personnel. Additionally, SDG&E employs both sensitive relay functions and removing reclosing as wildfire mitigation protocols. The workgroup performs routine preventive maintenance at fixed time-based intervals to maintain reliable operation of protective relays and relay controls. They also perform timely corrective maintenance, which is troubleshooting and repairing systems that alarm or fail to function properly, to enable reliable operation of these devices. Lastly, the workgroup downloads events captured during system outages and system emergencies to investigate the cause of failures.

a. Description of RAMP Mitigations

Within this cost category there are non-shared O&M costs for risk controls that were presented in the 2025 RAMP Report and are listed in the table below. RAMP-related costs for Substation C&O include costs for the Substation Inspection and Maintenance Program needed to meet GO 174. The Substation C&O workgroup adheres to GO 174 by providing a safe and reliable operating environment within the substation boundary. Goals for this program include meeting all requirements of GO 174, achieving a level of equipment availability satisfactory to SDG&E's health and safety programs and maintenance standards, and assuring compliance with all sections of the CAISO Transmission Control Agreement. The program involves routine inspections at re-occurring cycles depending on the type of equipment. A substation security check is also performed once per week, and a more detailed inspection is performed monthly or bimonthly, which involves visually inspecting equipment to identify any problems, such as environmental hazards caused by equipment oil leaks.

The Substation Inspection and Maintenance Program is a compliance activity mandated by the CPUC and is required to meet the requirements of CPUC GO 174.

TABLE SP-14
RAMP and GRC Risk Control Activities – O&M

Electric Distribution – O&M				
ID	**Control/Mitigation Name**	**2025 RAMP 2028 Estimate In 2024 $ (000s)**	**2028 GRC 2028 Forecast In 2025 $ (000s)**	**Change (000s)**
C268	**Substation Inspection and Maintenance Program**	2,180	2,180	0

b. Description of Selection and Prioritization of RAMP Risk Mitigations

The RAMP risk mitigation efforts are associated with specific actions, such as programs, projects, processes, and utilization of technology and are designed to address a specific safety and/or reliability risk. The Company's selection and prioritization of these RAMP mitigation activities considered many factors when determining if these risk mitigation activities are an effective and worthwhile investment. The Enterprise Risk Management (ERM) process for identifying and assessing system risk is described in the RDF Integration testimony (Ex. SCG-02B/SDGE-02B).

In accordance with GO 174, conditions identified through SDG&E's Substation Inspection and Maintenance Program which require mitigations are evaluated and prioritized to focus on safety and reliability. Mitigation selection considers safety risks to personnel, the public, and equipment; regulatory or industry compliance requirements; customer and reliability impacts; and system operational constraints. Cost effectiveness is also evaluated using engineering judgments. Mitigations are selected when they meaningfully reduce risk, correct conditions, and prevent further asset deterioration, while options providing limited risk reduction, excessive operational disruption, or insufficient feasibility may be deferred or discarded. From a customer perspective, projects are prioritized where they can improve customer safety, reduce unplanned outage likelihood or severity, protect critical loads, and improve long-term system resiliency. In prioritizing these proactive activities, SDG&E seeks to reduce the likelihood of future risk events, and avoid significantly higher operational, customer and recovery impacts associated with responding to realized incidents.

2. Forecast Method

The forecast method developed for the Substation C&O cost category is a three-year average. Distribution substation maintenance activities are determined by time-based cycles with the amount of scheduled maintenance varying from year to year. In addition, the amount of unscheduled maintenance, including results from the substation inspection program or troubleshooting from unplanned equipment outages, is also variable from year to year. Based on the variability of these key maintenance activities, which can differ by each type of substation equipment, a three-year average methodology is most reflective, as it provides an average forecast for the typical annual O&M costs and how SDG&E expects to operate for this GRC cycle.

3. Cost Drivers

The cost drivers for the Substation C&O are the O&M activities for personnel to perform substation inspection and maintenance, time-based interval maintenance of major and minor substation equipment, troubleshooting for unplanned equipment outages and failures, and emergency response staffing during major events. To support the planned and unplanned labor activities, the Substation C&O workgroup relies on non-labor funding such as tools, substation material and spare parts, office equipment, land maintenance activities and security activities that allow for the safe and reliable operation of its substations and all associated equipment and land.

a. Labor Costs Associated with Resources Critical to Substation C&O

The key cost driver for the Substation C&O category is labor. Substation C&O is staffed with critical resources needed to construct, operate, and maintain SDG&E's substation and field SCADA distribution infrastructure to support safe and reliable delivery of power to our customers. Substation C&O resources such as substation electricians, apprentices, electrician assistants, equipment operators, SCADA and relay technicians, engineers, compliance coordinators, office support personnel, supervisors, and management are all critical for maintaining SDG&E's substations and field distribution SCADA infrastructure to a safe and reliable standard.

Additionally, as SDG&E's electric distribution field devices, relays and SCADA infrastructure has expanded over the years, the scope and scale of maintenance and installation required has also expanded, which includes distribution voltage regulators, capacitors, distribution reclosers, weather stations, other distribution SCADA-controlled equipment and switchgear, and aircraft warning lights. Labor costs are also driven by staffing additional resources around the clock during major events and system emergencies (i.e. unscheduled load shedding, extreme weather, earthquakes, etc.).

L. Portfolio & Project Management (1ED012)

TABLE SP-15
Summary of Workpaper Costs

ELECTRIC DISTRIBUTION (In 2025 $)			
L. Portfolio and Project Management	**2025 Adjusted-Recorded (000s)**	**TY2028 Estimated (000s)**	**Change (000s)**
1. Portfolio and Project Management	581	582	1
Total	581	582	1

1. Description of Costs and Underlying Activities

This section justifies funding of $582,000 for the Portfolio and Project Management cost category. Of this total amount, $581,000 is attributed to base year 2025 forecasting and $1,000 reflects changes in connection with the compensation modernization initiative. Details pertaining to the forecast methodology and cost drivers for this section are further discussed below in sections III.L.2 and III.L.3. For details related to the compensation modernization initiative, please refer to the Compensation & Benefits testimony, Ex. SCG-16/SDGE-20.

Portfolio & Project Management is responsible for effectively managing transmission, distribution, and substation projects as well as energy storage, system hardening, and system interconnection projects by focusing on clearly defined project scope, schedule, and budget. This group manages projects from preliminary design through energization, supporting consistent project management responsibility throughout the life of the project.

In addition, Portfolio & Project Management is responsible for managing large projects within the electric portfolio and providing project services, including capital project accounting support, and quality assurance/quality control. Furthermore, the Portfolio Management & Project Controls team is responsible for aligning all capital projects to the Company vision, strategy, and priorities. They set the governance standards and report KPI's to drive standardization and quality performance across the business units. They work to unify business units across SDG&E by focusing on resource utilization while promoting accountability and efficiency. These roles support efficient processing of work to enable greater, more streamlined capacity and reduce cycle times for all electric system projects and validate quality in design, construction, and manufacturer fabrication.

Project accounting supports the Company in compliance with internal and external financial policies and requirements through contract invoice review, audit support, monthly accruals, and SOX compliance. QA/QC support is provided to validate quality in design, construction, and manufacturer fabrication. This is accomplished through design reviews, post construction checks, manufacturer audits, special inspections, pole inspections, and vendor reviews. This verifies that all work is built to SDG&E Design and Safety Standards and is in accordance with GO 95 and GO 128 design and construction specifications.

2. Forecast Method

The forecast method developed for the Portfolio & Project Management cost category is base year methodology. This methodology was selected as current staffing and activity levels are expected to be representative of the costs moving forward. These roles support efficient processing of work to enable greater, more streamlined capacity and reduce cycle times for all electric system projects and validate quality in design, construction, and manufacturer fabrication.

3. Cost Drivers

Portfolio and Project Management supports project management, QA/QC activities, security support during construction, financial accounting and support for capital projects, and portfolio level governance for project management and project controls. These activities are combined to drive an efficient, effective and standardized approach to capital project management across the electric division. Heightened focus on governance, predictability and construction ready work packages is helping align upstream planning with downstream execution. The O&M activities are performed primarily by external service providers. This is driven by purchased services, mainly consulting, engineers and contract labor.

M. System Planning, Reliability and Data Governance (1ED013)

TABLE SP-16
Summary of Workpaper Costs

ELECTRIC DISTRIBUTION (In 2025 $)			
M. System Planning, Reliability and Data Management	**2025 Adjusted-Recorded (000s)**	**TY2028 Estimated (000s)**	**Change (000s)**
1. System Planning, Reliability and Data Management	2,760	3,570	810
Total	2,760	3,570	810

1. Description of Costs and Underlying Activities

This section justifies funding of $3,570,000 for the System Planning, Reliability and Data Governance cost category. Of this total amount, $2,760,000 is attributed to base year 2025 forecasting, $136,000 is attributed to backfilling vacancies not accounted for in the base year adjusted-recorded amount, $637,000 is attributed to incremental labor and non-labor costs, and $37,000 reflects changes in connection with the compensation modernization initiative. Details pertaining to the forecast methodology and cost drivers for this section are further discussed below in sections III.M.2 and III.M.3. For details related to the compensation modernization initiative, please refer to the Compensation &Benefits testimony, Ex. SCG-16/SDGE-20.

This cost category supports activities related to the following workgroups: Electric Reliability, Distributed Energy Resources (DER) Engineering, Asset Data Systems & Records Management, Electric Distribution Planning, Electric Transmission Planning, and Customer Generation.

a. Electric Reliability

The Electric Reliability workgroup is responsible for reviewing, coding, auditing, and recording the classification, duration, and customer counts for outage information, as well as calculating performance indices based on this information. The workgroup also maintains the official data repository for outage data, known as the Reliability Database, which is the foundation for data reporting to internal and external entities. This data includes System

Average Interruption Duration Index, System Average Interruption Frequency Index, and Customer Average Interruption Duration Index. Other responsibilities include responding to customer inquiries related to outage information for their account(s) and supporting CPUC reporting requirements.

b. DER Engineering

The DER Engineering workgroup consists of engineers, project managers, and project specialists that evaluate and deploy advanced technologies to integrate distributed energy resources while maintaining grid reliability, flexibility, and safety. The DER Engineering workgroup also leverages solutions like inverters, advanced controls, and intelligent devices to enable DER growth and deliver benefits such as voltage support, load management, and islanding capability. The DER Engineering workgroup supports the operations and maintenance of utility-initiated microgrids and utility-owned DER assets including energy storage, and mobile battery programs. The workgroup also conducts system studies for DER-related projects and manages SDG&E's testing facility. This facility tests and refines technology before placing DER equipment in service. This advanced testing reduces the field deployment and commissioning (quality control) timeline.

c. Asset Data Systems & Records Management

The Asset Data Systems & Records Management workgroup manages the development, implementation and integration of enterprise asset data systems and tools that support the objectives of asset management, including measuring asset performance and enabling data driven, risk-informed decision making to support capital investment priorities and advance asset data intelligence, integration, and analytics. The workgroup is also responsible for establishing and maintaining best practices in the areas of data governance and management to align with industry standards. These data enablement initiatives play a crucial role in improving operational efficiencies, accessing critical data to support risk-informed decisions, and improving customer satisfaction by leveraging data needed to enhance reliability.

d. Electric Distribution Planning

The Electric Distribution Planning workgroup is responsible for circuit- and substation-level electric load forecasting and the planning of electric distribution system upgrades that support safe and reliable service for customers. The process of forecasting loads, studying system needs and constraints, and identifying required upgrades is generally referred to as the

Distribution Planning Process. The core responsibilities of the Electric Distribution Planning workgroup include performing power flow and other technical analyses, developing reports and new analytical tools, supporting regulatory processes including compliance submittals and providing subject matter expertise in CPUC proceedings, leading or collaborating in stakeholder-driven planning processes, and evaluating distribution system impacts associated with Wholesale Distribution Access Tariff and Electric Rule 21 interconnection requests, which are processed through the Customer Generation workgroup. Additional responsibilities include supporting emergency operations, reviewing fusing requests, integrating advanced technologies, managing projects, and providing engineering support for internal and external stakeholders. The Electric Distribution Planning workgroup also coordinates with the Electric Transmission Planning workgroup by providing the distribution substation load profiles for the transmission system models.

e. Customer Generation

The Customer Generation workgroup is responsible for managing generation interconnection requests for all DERs and wholesale generation facilities under SDG&E's Electric Rule 21 and the Wholesale Distribution Access Tariff. Through the Distribution Interconnection Information System (DIIS), the workgroup as part of application intake, assesses the project scope and identifies other workgroups for purposes of engineering review, inspections, and the issuance of Permission to Operate. Core responsibilities include application processing, field inspections, engineering design, project management, and supporting compliance with regulatory standards within the required timelines. As part of engineering design and project management, the workgroup oversees the design and execution of distribution system upgrades driven by new generation interconnection requests. This includes coordination with Electric Distribution Planning or other engineering workgroups to address distribution system impacts identified in their analyses.

The workgroup also leads and supports regulatory filings with the CPUC and FERC, while actively participating in stakeholder forums, workshops, and regulatory proceedings. The workgroup manages regulatory compliance by tracking tariff updates, implementing procedural changes, and maintaining audit-ready documentation for mandated reporting and data requests. Key ongoing regulatory proceedings that are supported by this group, include but are not limited to the Electric Rule 21 Order Instituting Rulemaking (OIR),[20] Microgrid OIR,[21] Building Decarbonization OIR,[22] and Energization OIR,[23] and contribute to the associated Advice Letters and other regulatory compliance requirements.

2. Forecast Method

The forecast method developed for the System Planning, Reliability and Data Governance cost category is base year 2025 with adjustments for backfill positions, software needs, and other associated maintenance costs. Throughout the base year, SDG&E has operated efficiently to prioritize critical needs of the electric distribution system to support safe and reliable delivery of power to our customers, and the base year is the most reflective of how SDG&E expects to operate for this GRC cycle.

3. Cost Drivers

The cost drivers for the System Planning, Reliability and Data Governance category are the O&M activities for personnel and contracted support services necessary to perform system planning, reliability, customer generation interconnection, and data governance to support the safety and reliability of the electric distribution system. The cost drivers for specific workgroups are described below. See workpaper Ex. SDGE-09 WP 1ED013 for a more detailed cost breakdown. Incremental O&M adjustments are driven by the deployment of new DER equipment and testing capabilities, increased maintenance needs associated with aging assets, expanded training and resource requirements to support advanced technologies, and a shift of mature asset management systems and data products from capital development to ongoing O&M support.

a. Electric Reliability

The key cost drivers for the Electric Reliability workgroup forecast are mandated CPUC reporting requirements, customer outage requests, and software costs.

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[20] *See* R.25-08-004, Order Instituting Rulemaking to Update Distribution Level Interconnection Rules and Regulations (August 14, 2025).

[21] *See* R.19-09-009, Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 (September 12, 2019).

[22] *See* R.19-01-011, Order Instituting Rulemaking Regarding Building Decarbonization (January 31, 2019).

[23] *See* R.24-01-018, Order Instituting Rulemaking to Establish Energization Timelines (January 25, 2024).

i. CPUC Reporting Requirements

Pursuant to D.16-01-008, SDG&E provides an annual Electric Reliability Report to the CPUC. Though generally focused on a system level, this annual report also provides results at an operating district level while also identifying worst-performing circuits. SDG&E is also required to communicate with the public about the annual report, with at least one public in-person presentation per year.

Additionally, SDG&E expects additional reporting requirements as a result of R.24-05-023. Pursuant to this proceeding, the IOUs have jointly developed a Proposed Customer Reliability Report template, including a proposed narrative structure and supporting data schema, to standardize how reliability information is reported across geographic, demographic and customer segments.[24] SDG&E anticipates that a final decision in the rulemaking will establish compliance obligations that may include development of processes to compile, validate, and report customer-level reliability data, integrate information from existing reporting frameworks (e.g., WMDR and annual reliability reports), and produce a periodic Customer Reliability Report (potentially on an annual basis). Implementation of these requirements would require coordination across multiple data systems, as well as ongoing analytical preparation, quality assurance, and review prior to periodic submission.

ii. Customer Outage Requests

D.16-01-008 also sets forth a requirement for SDG&E to respond to customer inquiries about their electric reliability within 15 business days of the request. SDG&E maintains a website through which customers can request detailed outage information for their service address. The preparation and delivery of these outage letters require review by a dedicated team of analysts.

iii. Reliability Software Costs

Electric Reliability shares software costs with Electric Distribution Operations, Electric Regional Operations, and Office of Customer Success. This software is required to report on reliability metrics, and continued investment is essential to drive safe operation of the electric system, minimize customer outage times, and improve customer outage notification.

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[24] *See* R.24-05-023, Joint IOU Proposed Customer Reliability Report Template Pursuant to Administrative Law Judge's Ruling (December 15, 2025), at OP 12 at 33.

b. DER Engineering

The cost drivers behind the DER Engineering forecast are driven primarily by non-labor adjustments such as microgrid operating requirements, increasing numbers of DERs, and their associated technologies. Over the past several years, the DER Engineering workgroup has measurably expanded the number of utility-owned DERs. This includes the addition of new generators and a battery at the Borrego Springs microgrid, the deployment of five new microgrids (Cameron Corners, Boulevard, Clairemont, Elliott, and Paradise), the integration of new mobile batteries, a Nanogrid, and other distributed resources. Collectively, these deployments demonstrate a clear increase in both the scale and diversity of DERs on the system.

The workgroup continues to support critical activities such as testing of new technologies, performing microgrid islanding studies, integration of microgrids into SDG&E's Local Area Distribution Controller, generator deployments for PSPS activities and long duration outages, and performing other engineering studies related to DERs. The workgroup also supports the growing portfolio of energy storage and clean technology capital projects including the Advanced Energy Storage program and the Mobile Battery Energy Storage Program. This adjustment includes labor true-up of approximately 0.1 FTEs to account for vacancies in the base year. Backfilling vacant positions is essential to maintain these capabilities. See workpapers Ex. SDGE-09 WP 1ED013 for a more detailed cost breakdown.

i. DER Software Costs

Investment in software and tools is critical to support the adoption of new and evolving technologies. This incremental adjustment includes licenses for Power Hardware-in-the-Loop (PHIL) testing. Due to the low-inertia nature of microgrids (few or no rotating generators when in island mode compared to many thousands of rotating generators on the larger electric system), dynamic simulation using PHIL (which combines real electrical equipment such as inverters and relays with a real-time simulated power system) is essential to evaluate system interactions under realistic conditions. This approach reduces uncertainty and enables safe validation of protection, communications, and load response in a lab environment without impacting customers. The total incremental non-labor cost for DER Software is estimated at $66,000. See workpapers Ex. SDGE-09 WP 1ED013 for a more detailed cost breakdown.

ii. Relay and Controller Training and Conferences

As DER technologies advance, the need for continuous training becomes imperative to stay proficient in emerging technologies and associated skills, including programming, relay configuration, and RTAC systems. These incremental adjustments will also support hands-on experience with PHIL testing and participation in industry conferences and workshops. These investments are important to maintain technical excellence and support readiness for future challenges. The DER Engineering workgroup's training costs are not accounted for in an overhead pool, but are fully funded within the workgroup's O&M cost center. These trainings and conferences are not accounted for in the base year and are reflected in incremental adjustments starting in 2026. The total incremental non-labor cost for DER Training is estimated at $20,000. See workpapers Ex. SDGE-09 WP 1ED013 for a more detailed cost breakdown.

iii. Integrated Testing Facility

The DER workgroup also operates SDG&E's Integrated Testing Facility, where new technologies are evaluated in a controlled environment before being deployed in the field. This cost driver includes an incremental adjustment for the Integrated Testing Facility, specifically to enhance its hardware and software capabilities. The facility's equipment is currently used to support microgrid testing at Borrego Springs, Cameron Corners, and other sites, and will be further leveraged for modeling and testing upcoming projects under the Microgrid Incentive Program once contracts are executed. Additionally, the DER Engineering workgroup seeks specialized software to enable communication protocols, protocol translators, and integration with intelligent electronic devices. These incremental investments are critical for supporting interoperability and maintaining system reliability. Although most projects tested at the Integrated Testing Facility cover their own expenses, the shared laboratory equipment requires periodic calibration and upkeep. Incremental funding is needed to implement a regular calibration schedule and stagger equipment maintenance, supporting high-quality testing and development activities for new technologies before field deployment. The total incremental non-labor cost for the Integrated Testing Facility is estimated at $70,000. See workpapers Ex. SDGE-09 WP 1ED013 for a more detailed cost breakdown.

iv. Maintenance

The DER Engineering workgroup's energy storage fleet plays a key role in supporting distribution system needs and enhancing operational flexibility. Because these assets are generally not involved in market operations, they are fully managed and tracked within the DER Engineering workgroup's cost center.

Additionally, the DER workgroup successfully commissioned new generators in 2025 to support the utility-initiated Borrego microgrid which replaced the previously retired units with new Tier 4 units. Because O&M costs for these units were not included in the 2025 base year O&M costs, the forecast was adjusted for TY 2028 to account for the additional funding the DER Team is requesting for fuel and associated maintenance to support the fulltime operational capabilities of the generators, enabling their use when necessary.

v. Borrego Generator Preventative Maintenance

Adjustments to base year within the DER Engineering workgroup include preventative maintenance specific to the Borrego Springs microgrid generator with a microgrid generator servicer per a contract agreement. This maintenance is essential to support ongoing microgrid operations and prevent unexpected failures that could disrupt service. The total incremental non-labor cost for Borrego Springs microgrid generator maintenance is estimated at $60,000. See workpapers Ex. SDGE-09 WP 1ED013 for a more detailed cost breakdown.

vi. Inverter, Battery, HVAC, & Fire Protection Maintenance

Many energy storage systems and related devices within the DER Engineering workgroup's fleet are nearing end of useful life, resulting in increased service demands and more frequent maintenance. Incremental adjustments are forecasted for scheduled service and maintenance of batteries, inverters, HVAC units, and fire protection systems to support accuracy, reliability, compliance, operational readiness, and to avoid costly downtime. The total incremental non-labor cost for the service and maintenance of batteries, inverters, HVAC, and fire protection systems is estimated at $100,000. See workpapers Ex. SDGE-09 WP 1ED013 for a more detailed cost breakdown.

vii. Fuel for Generators

Additional incremental adjustments are anticipated for fuel costs for newly commissioned generators supporting utility-initiated microgrids. These incremental costs are not included in the 2025 base year but are necessary to support these generators are operational and available when needed. The total incremental non-labor cost for generator fuel is estimated at $100,000. These targeted incremental adjustments will enable the DER Engineering workgroup to maintain system performance, promote operational readiness, and support reliable testing and deployment of advanced technologies across the distribution system. See workpapers Ex. SDGE-09 WP 1ED013 for a more detailed cost breakdown.

c. Asset Data Systems & Records Management

Cost drivers for Asset Data Systems & Records Management reflect the resources needed to support asset management objectives; specifically, data enablement needs such as measuring asset performance, advancing asset data intelligence, and enhancing data driven, risk-informed metrics. As asset management solutions mature from a development state to a deployed production state, costs associated with labor and tool maintenance will gradually shift from Capital to O&M. The costs account for current team members and time needed to maintain tools and technology that have been fully developed. This also accounts for the costs associated with the tools themselves, such as cloud consumption costs (costs incurred for using technology systems that are housed on the cloud and is based on how much is used) for tools that are in full use.

i. Maintaining Resources Critical to Asset Management

Asset Data Systems & Records Management is responsible for developing and maintaining systems that support data-driven decisions related to asset management. The workgroup follows a standard Development-Operations deployment process; tools are created in a development environment, then pushed to a production environment once fully developed. The allocation of costs follows this methodology. For instance, as assets go into service, costs associated with team members are increasingly attributed to O&M. Accordingly, a greater percentage of costs are recorded in O&M. An increase of 1.0 FTE from the 2025 base year is accounted for to maintain and implement asset data aggregation, integration, data visualization, reporting, and asset health and risk models for Electric Engineering and ERO. This incremental adjustment is expected to start in 2027. The development of these data products supports the overall objectives of the broader Asset Management Program and addresses the focus directed by the Commission on advancing asset data accessibility, including wildfire risk proceedings, implementation of the Risk Framework OIR requirements,[25] system reliability, and climate adaptation. See workpapers Ex. SDGE-09 WP 1ED013 for a more detailed cost breakdown.

ii. Asset Data Systems & Records Management Software

Asset Data Systems & Records Management forecasted costs include O&M related to in-service cloud computing data products. These costs directly support the ongoing technology needs for proper data management and governance processes. Additionally, these data products and the associated O&M contribute to the reporting and analytics requirements related to CPUC regulatory proceedings, implementation of the Risk Framework OIR requirements, system reliability, and climate adaptation. The total incremental non-labor cost for cloud computing costs is estimated at $91,000. See workpapers Ex. SDGE-09 WP 1ED013 for a more detailed cost breakdown.

d. Electric Distribution Planning

The Electric Distribution Planning workgroup forecast is based on continuation of base year staffing and workload assumptions, with no incremental costs requested. The O&M forecast represents a proportional allocation associated with the group's ongoing engineering and planning support for capital distribution capacity projects.

e. Customer Generation

Key cost drivers include labor for application processing, engineering, regulatory compliance, and project management. An adjustment of 0.8 FTE for backfilled vacancies is accounted for to support these efforts. Additional costs stem from software platforms such as DIIS and Integration Capacity Analysis tools, consulting services for planning and design, regulatory support, and ongoing staff training to stay current with evolving interconnection standards and technologies. Funding for these activities is critical to support California's clean energy goals, support regulatory compliance, and enable efficient interconnection of DERs, including wholesale generators, to SDG&E's distribution system, ultimately maintaining grid reliability and delivering timely service to interconnection customers. See workpapers Ex. SDGE-09 WP 1ED013 for a more detailed cost breakdown.

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[25] *See generally* R.20-07-013, Order Instituting Rulemaking to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities (July 16, 2020).

N. Officer (1ED014)

TABLE SP-17
Summary of Workpaper Costs

ELECTRIC DISTRIBUTION (In 2025 $)			
N. Officer	**2025 Adjusted-Recorded (000s)**	**TY2028 Estimated (000s)**	**Change (000s)**
1. Officer	974	988	14
Total	974	988	14

1. Description of Costs and Underlying Activities

This section justifies funding of $988,000 for the Officer cost category. Of this total amount, $974,000 is attributed to base year 2025 forecasting and $14,000 reflects changes in connection with the compensation modernization initiative. Details pertaining to the forecast methodology and cost drivers for this section are further discussed below in sections III.N.2 and III.N.3. F or details related to the compensation modernization initiative, please refer to the Compensation & Benefits testimony, Ex. SCG-16/SDGE-20.

This work group includes the electric distribution O&M allocation of costs for officers and administrative assistants who directly support the Electric Distribution organization. The total salaries are a direct labor charge and any cross-over amounts allocated to electric transmission are excluded from the recorded costs and not included in the requested expenses. Typical activities included in this account include officer activities in support of electric distribution.

2. Forecast Method

The forecast method developed for the Officer cost category is base year recorded. For labor, the base year provides an appropriate baseline in comparison to future targets and how SDG&E expects to operate for this GRC cycle. Base year recorded is also the best method to forecast non-labor costs related to this work group since it is a lower calculated forecast than historical average cost calculations and reflects how SDG&E expects to operate for this GRC cycle.

3. Cost Drivers

The primary cost driver of this forecast is the allocation of officer labor and officer administrative support staff for managing and supporting Electric Operations departments.

O. Climate Adaptation Vulnerability Assessment (CAVA) (1ED015)

TABLE SP-18
Summary of Workpaper Costs

ELECTRIC DISTRIBUTION (In 2025 $)			
O. Climate Adaptation Vulnerability Assessment (CAVA)	**2025 Adjusted-Recorded (000s)**	**TY2028 Estimated (000s)**	**Change (000s)**
1. Climate Adaptation Vulnerability Assessment (CAVA)	1,676[26]	1,680	4
Total	1,676	1,680	4

1. Description of Costs and Underlying Activities

This section justifies funding of $1,680,000 for the Climate Adaptation Vulnerability Assessment (CAVA) cost category. Of this total amount, $1,676,000 is attributed to base year 2025 forecasting and $4,000 reflects changes in connection with the compensation modernization initiative. Details pertaining to the forecast methodology and cost drivers for this section are further discussed below in sections III.O.2 and III.O.3. For details related to the compensation modernization initiative, please refer to the Compensation & Benefits testimony, Ex. SCG-16/SDGE-20.

This cost category supports the need for labor and non-labor costs associated with meeting the requirements of the Climate Adaptation OIR,[27] which requires extensive community equity and engagement efforts, including facilitating workshops and coordinating with community-based organizations to support adaptation strategies that reflect local priorities and address equity concerns. Deliverables include stakeholder engagement reports, outreach materials, and recommendations to enhance equitable climate resilience. This work also involves quantifying infrastructure and operational vulnerabilities to climate hazards through

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[26] 2025 Adjusted Recorded costs are for illustrative purposes only. SDG&E is seeking recovery for amounts in the CAVAMA through December 31, 2027.

[27] R.18-04-019, Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation (April 26, 2018).

sensitivity analyses of heat-wave definitions and assessments of projected changes to low-level marine layer clouds, which influence temperature and wildfire risk. These analyses generate scientific datasets and reports that support grid reliability and adaptation planning.

Additional responsibilities include modeling and quantifying heatwave and wildfire exposure across the service territory by using advanced climate modeling to produce high-resolution projections and exposure maps that inform grid planning efforts. The work also encompasses analyses of SDG&E assets to identify exposure to climate hazards and to produce vulnerability reports and resilience recommendations aligned with scientific best practices and regulatory requirements. Finally, it includes the design of the Community Vulnerability Index and the development of the Climate Intelligence Tool, with deliverables such as the Community Vulnerability Index methodology and processed climate datasets for integration into broader data models to strengthen climate-informed decision-making.

2. Forecast Method

The forecast method developed for this cost category is base year. This method is most appropriate because base year 2025 provides an appropriate estimate of future needs for the organization as opposed to average or trend methodologies.

3. Cost Drivers

The cost drivers behind this forecast are SDG&E employee labor and contracted resources related to studies and assessments. These costs are necessary to identify long-term climate impacts, facilitate climate considerations into business practices, and deliver filings that meet CPUC directives and industry best practices. Future year forecasts reflect the scope and complexity of regulatory obligations. Labor and non-labor resources are required to manage cross-functional coordination, regulatory filings, and integration of climate resilience across business units.

IV. RISK ASSESSMENT AND MITIGATION PHASE (RAMP) INTEGRATION

A. GRC Risk Controls/Mitigations and Benefit Cost Ratios

As previously discussed, certain costs supported in this testimony are for Control/Mitigation activities described in SDG&E's May 15, 2025 RAMP Report[28] for activities

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[28] A.25-05-013, Application of SDG&E to Submit Its 2025 Risk Assessment and Mitigation Phase Report (May 15, 2025), at Attachment 1.

designed to reduce risk. Specifically, the control and mitigation in this testimony was included in SDG&E-Risk-5 Electric Infrastructure Integrity. As further reference, a roadmap matching controls and mitigations to both the 2025 RAMP and the TY 2028 GRC testimony is appended to Ex. SCG-02B/SDGE-02B. Table SP-19 below summarizes the Control/Mitigation BCRs based on the costs[29] in this testimony and estimated in the 2025 RAMP with the associated BCRs. Controls/Mitigations that are mandated by CPUC or other agencies are listed in bold in the table below and are listed in Appendix B, attached to this testimony, providing the details regarding the respective mandates for each Control/Mitigation. Appendix C provides a GRC workpaper breakdown for the RAMP controls and mitigations sponsored in this testimony.

TABLE SP-19
Comparison of RAMP and GRC Risk Control Benefit Cost Ratios

SDG&E Electric Distribution – O&M							
ID	**Control/ Mitigation Name**	**2025 RAMP Direct, in 2024$ 2028-2031**			**2028 GRC Direct, in 2025$ 2028-2031**		
		BCR Societal	**BCR Hybrid**	**BCR WACC**	**BCR Societal**	**BCR Hybrid**	**BCR WACC**
C268	**Substation Inspection and Maintenance Program**	2.27	1.93	2.16	4.58	4.64	4.35

B. Changes From 2025 RAMP Report

Since the filing of the 2025 RAMP Report in May 2025, there have been no significant changes to the control/mitigation activities identified in this testimony. Currently, the target units and costs are in line with the expectations summarized in the 2025 RAMP Report.

C. Feedback from Safety Policy Division and Parties

The Commission's Safety Policy Division (SPD) issued their assessment report on October 10, 2025 regarding the Companies' 2025 RAMP Reports. Parties subsequently served opening and reply comments on November 17, 2025 and December 1, 2025 respectively. Appendix B in the RDF Integration testimony (Ex. SCG-02B/SDG&E-02B) appends a summary of the feedback and recommendations received and the Companies' responses.

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[29] Post-test year forecasts can be found in the detailed workpapers Ex. SDGE-09-WP.

V. REASONABLENESS REVIEW

A. High DER Memorandum Account (HDERMA)

The HDERMA is a memorandum account that was renamed from the former Integration Capacity Analysis and Locational Net Benefit Analysis Memorandum Account (ICLNBMA).[30] The original ICLNBMA was established to capture incremental costs associated with mandated processes and Distribution Resource Planning tools, including the Integration Capacity Analysis (ICA) and Locational Net Benefit Analysis (LNBA).

On October 23, 2024, the Commission issued D.24-10-030 in the High DER proceeding, which adopts changes to the Distribution Planning Process that the Commission determined will improve planning outcomes and introduces updates to the Integration Capacity Analysis (ICA) data portal.[31] The decision authorizes SDG&E to track costs for implementing these changes and record them in memorandum accounts previously authorized under D.18-02-004.[32] Pursuant to OP 41 of D.24-10-030, SDG&E submitted Advice Letter 4584-E in December 2024 to rename the ICLNBMA to HDERMA and update its purpose to include tracking costs related to the improvements adopted in D.24-10-030. Accordingly, HDERMA now tracks costs associated with ICA data portal and other enhancements directed by the Commission in the High DER proceeding.

The recorded balance for this memorandum account from January 1, 2024 through December 31, 2025 is $0.502 million. This amount consists of expenses recorded in the ICA subaccount and the Grid subaccount, as broken down by Table SP-20 below. The ICA subaccount captures activities related to implementing changes to the ICA portal, such as integrating the Limited Generation Profile so customers interested in this interconnection option can download the Limited Generation Profile templates to use for their Rule 21 applications. The Grid subaccount reflects costs associated with necessary tool enhancements and studies

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30 The ICLNBMA was opened for ICA and LNBA through Advice Letter 3143-E (effective November 6, 2017), and later updated to include incremental costs associated with the with Grid Needs Assessment (GNA) and Distribution Deferral Opportunity Report (DDOR) and Data Access Portal in March 2018.

31 *See* D.24-10-030 at 2-5.

32 *Id.* at OP 40.

required under D.24-10-030, such as forecasting tool upgrades for scenario planning and costs associated with completing the Electrification Impact Study Part 2.

TABLE SP-20
Summary of HDERMA Costs

HDERMA	2024-2025 Expenses ($000)
ICA Subaccount	73
Grid Subaccount	429
Total	502

For additional details regarding regulatory accounting treatment, please refer to the SDG&E Regulatory Accounts testimony (Ex. SDGE-26).

B. Climate Adaptation Vulnerability Assessment Memorandum Account (CAVAMA)

The Climate Adaptation & Vulnerability Assessment Memorandum Account (CAVAMA) records costs incurred to enhance climate resilience and comply with expanding obligations established through regulatory proceedings. These obligations include the analysis, engagement, and reporting required under the Climate Adaptation OIR (R.18-04-019), as well as support for other regulatory proceedings with climate adaptation components, such as RAMP, IEPR, and WMP. Activities tracked under CAVAMA include conducting data-driven analyses of climate impacts on SDG&E's system and communities, developing adaptation strategies, and integrating resilience measures into long-term planning. These efforts are critical to safeguarding system reliability, protecting public safety, and alignment with regulatory requirements.

Capital costs recorded under CAVAMA are associated only with the Resilience Zone component of the Wildfire and Climate Resilience Center (WCRC). As part of the Climate Adaptation OIR (R.18-04-019) and D.20-08-046, issued in September 2020, the CPUC requires investor-owned utilities to conduct community outreach and engagement to inform and support climate adaptation planning efforts. The Resilience Zone is designed to support this requirement through dedicated facilities for community outreach, education, and engagement, as further described in SDG&E's 2025 Climate Adaptation and Vulnerability Assessment (CAVA),[33] 2024 Community Engagement Plan (CEP),[34] and 2026 Annual Advice Letter.[35] The Resilience Zone project encompasses the buildout of a dedicated, multi-use space within an existing SDG&E facility to support community-facing education, outreach, and engagement on climate resilience. This includes areas designed for public workshops, stakeholder convenings, and hands-on training focused on community safety, all-hazards emergency preparedness, and climate adaptation planning. The space serves as a key resilience measure that enables SDG&E SMEs to translate evolving climate science into actionable information for customers and communities to be better informed, better prepared, and more resilient to extreme weather events, while fostering partnerships and supporting SDG&E's long-term grid resilience objectives.

The recorded O&M balance for this memorandum account from January 1, 2021 through December 31, 2025 is $6.4 million. Non-recurring capital expenditures recorded from January 1, 2021 through December 31, 2025 are $2.76 million. Additional details can be found in workpaper Ex. SDGE-09-RRWP. Additional details regarding regulatory accounting treatment of CAVAMA costs are addressed in the SDG&E's Regulatory Accounts testimony (Ex. SDGE-26).

VI. CONCLUSION

The costs represented in this testimony are a reasonable and necessary forecast of the requirements to manage SDG&E's electric distribution system safely, efficiently, and in alignment with supporting SDG&E's mission to provide customers with the safest and most reliable power in North America. This testimony supports programs and activities that further these goals. Forecasts were developed by using both historical expenditures and O&M estimates, assessing upward pressures, and using available information to develop reasonable

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[33] SDG&E 2025 Climate Adaptation Vulnerability Assessment, Section 7.7 Appendix VII, available at https://www.sdge.com/sites/default/files/documents/2025-05/SDGE%20CAVA%20-%20Supplemented%20250519.pdf?nid=28966

[34] SDG&E 2024 Community Engagement Plan, Section 5.3, available at https://www.sdge.com/sites/default/files/regulatory/R1804019_SDGE%20CEP.pdf

[35] Update on the Climate Change Adaptation Team Initiatives in Compliance with Decision (D.) 20-08-046, 2026 advice letter available at https://tariffsprd.sdge.com/sdge/filings/?utilId=SDGE&bookId=ELEC&flngStatusCd=Effective

forecasts. As described herein, many of the core business activities remain the same as described in previous rate cases with incremental cost drivers identified in my introduction section, which include: costs that scale with capital construction, shortages of skilled electric distribution labor, compliance initiatives such as SB 410, and increased reliance on electric distribution system automation. The values of public, employee, and contractor safety continue to drive activities within this testimony. The compilation of O&M costs and support for costs included in memorandum accounts, will allow SDG&E to operate its system in a way that continues to prioritize public and employee safety, system maintenance and reliability, meet environmental and regulatory compliance, develop the workforce, introduce new systems, address mature and aging equipment, and mitigate risk. SDG&E respectfully requests the Commission approve the cost forecasts described in this testimony and associated workpapers.

This concludes my prepared direct testimony.

VII. WITNESS QUALIFICATIONS

My name is Sneha Parmar. My business address is 9060 Friars Rd. San Diego, Ca 92123. I am employed by SDG&E as the Director of Electric Regional Operations. I have been employed by SDG&E since 2007. I have over 18 years of experience in the utility industry. While with SDG&E, I have held various positions in the functional areas of Reliability, the Sunrise Powerlink Project, System Protection Maintenance, Transmission Engineering, Substation Engineering, and Transmission and Substation Operations.

My present responsibilities include Electric Regional Operations, which include electric distribution and transmission operations and distribution assets and compliance. Before starting my current position, I was the Director of Transmission and Substation Operations. Before that, I was the Manager of the Substation Engineering group, responsible for the design and project management of SDG&E's substation projects. Prior to that, I worked as the team lead at SDG&E's System Protection Maintenance group responsible for construction, maintenance, and operations of system protection equipment.

I earned a Bachelor of Science in Electrical Engineering from California Polytechnic State University. I am a registered Professional Engineer in California.

I have not previously testified before this Commission.

APPENDIX A – Glossary of Terms

ACRONYM	DEFINITION
A	Application
ADMS	Advanced Distribution Management System
BCR	Benefit Cost Ratio
C&O	Construction & Operations
CAIDI	Customer Average Interruption Duration Index
CAISO	California Independent System Operator
CMP	Compliance Management Program
CPUC	California Public Utility Commission
D	Decision
DART	Days Away, Restricted and Transferred
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DIIS	Distribution Interconnection Information System
DSO	Distribution System Operator
EDI	Electric Distribution Inspections
EGISS	Enterprise GIS Services
ERO	Electric Regional Operations
ESO	Electric System Operations
ET&D	Electric Transmission & Distribution
ETS	Electric Troubleshooters
FERC	Federal Energy Regulatory Commission
FTE	Full Time Equivalent
GIS	Geographical Information System
GMP	Grid Modernization Plan
GO	General Order
GRC	General Rate Case
HFTD	High Fire Threat District
ICA	Integration Capacity Analysis
ILNBMA	Integration Capacity Analysis and Locational Net Benefit Analysis Memorandum Account
IOU	Investor-Owned Utility

IT	Information Technology
JAM	Joint Asset Management
LTI	Lost Time Incidents
kV	Kilovolt
OIR	Order Instituting Rulemaking
O&M	Operations and Maintenance
OSHA	Occupational Safety and Health Administration
PMG	Program Management Group
PSPS	Public Safety Power Shutoff
QA	Quality Assurance
QC	Quality Control
QEW	Qualified Electric Worker
RAMP	Risk Assessment Mitigation Phase
SAIDI	System Average Interruption Duration Index
SB	Senate Bill
SCADA	Supervisory Control And Data Acquisition
SDG&E	San Diego Gas & Electric
SOT	Service Order Team
STC	Skills Training Center
TRIR	Total Recordable Incident Rate
TSO	Transmission System Operator
TY	Test Year
VPP	Voluntary Protection Program
WMP	Wildfire Mitigation Plan
WP	Work Paper
WPI	Wood Pole Intrusive Inspection

APPENDIX B – CONTROLS AND MITIGATIONS COMPLIANCE DRIVER ROADMAP

The table below indicates the compliance drivers that underpin Risk Controls/Mitigations identified in testimony.

Control/ Mitigation ID	Control/Mitigation Name	Compliance Driver
C268	Substation Inspection and Maintenance Program	GO-174

APPENDIX C - RAMP ACTIVITIES SORTED BY WORKPAPER

GRC - RAMP Integration

GRC Workpaper	GRC Wkp Description	RAMP WKP	RAMP Wkp Description	RAMP Unit Measure	TOTAL (in 000s)							UNITS						
					2025	2026	2027	2028	2029	2030	2031	2025	2026	2027	2028	2029	2030	2031
1ED011.000	Electric Transmission & Distribution: Substation Construction & Operations	1OR05 C268	SDG&E-Risk-5 Electric Infrastructure Integrity Substation Inspection and Maintenance Program	Inspections & Repairs	1,563	2,180	2,180	2,180	2,180	2,180	2,180	2,288	2,286	2,286	2,286	2,286	2,286	2,286

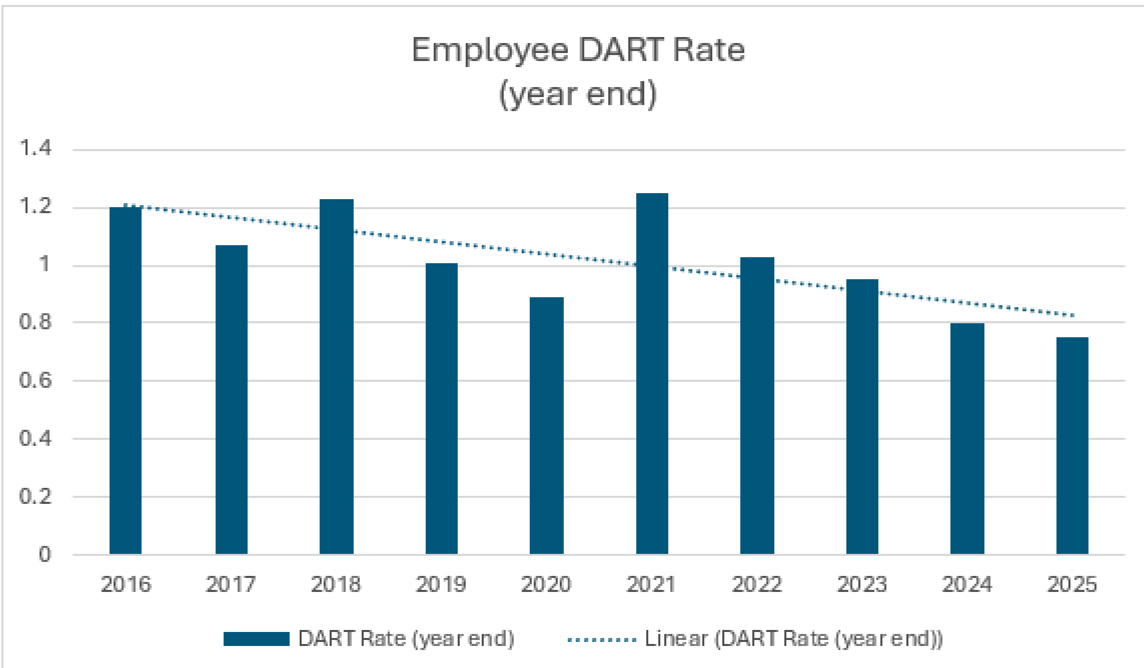
Note: Totals may include rounding differences. Total amounts preceded by a double asterisk (**) are in millions ($MM). Unit values preceded by a single asterisk (*) are displayed in thousands (000s).

APPENDIX D – SAFETY TRENDS

Metric: Employee Days Away, Restricted and Transfer (DART) Rate

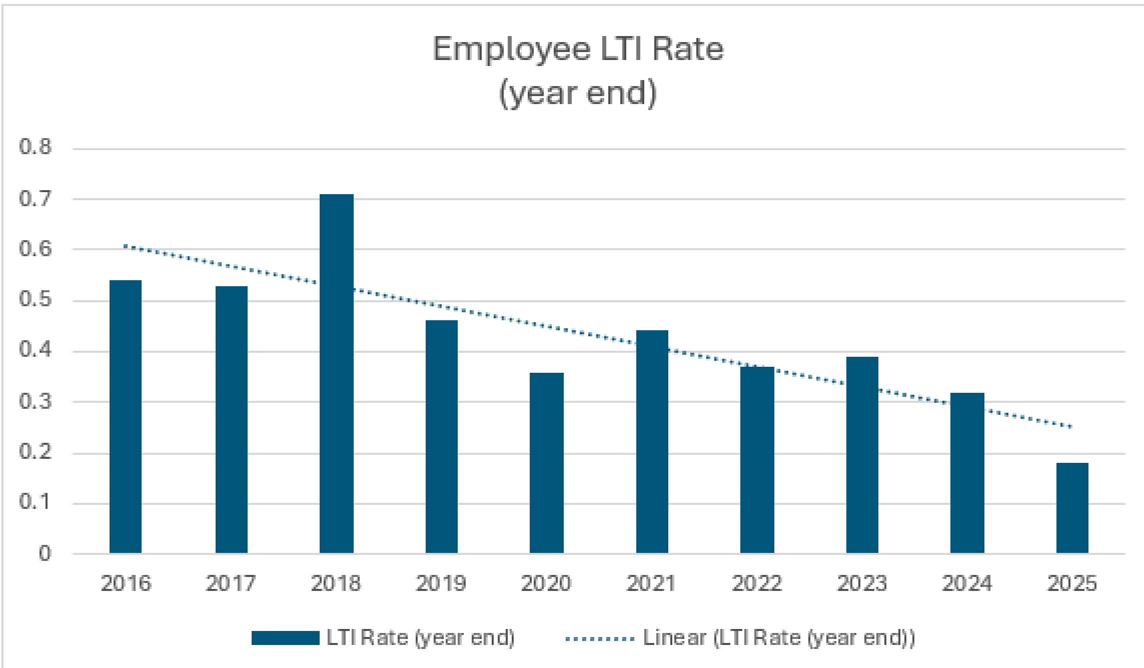
Calculation: Number of DART Cases times 200,000 divided by employee hours worked

SDG&E's DART Rate performance has generally declined over the past ten years. In 2025, SDG&E experienced a 6% decrease in its DART case rate compared with year-end 2024. Improvement in SDG&E's DART rate demonstrates reduced incident severity as DART captures the subset of incidents that materially affect an employee's ability to work.



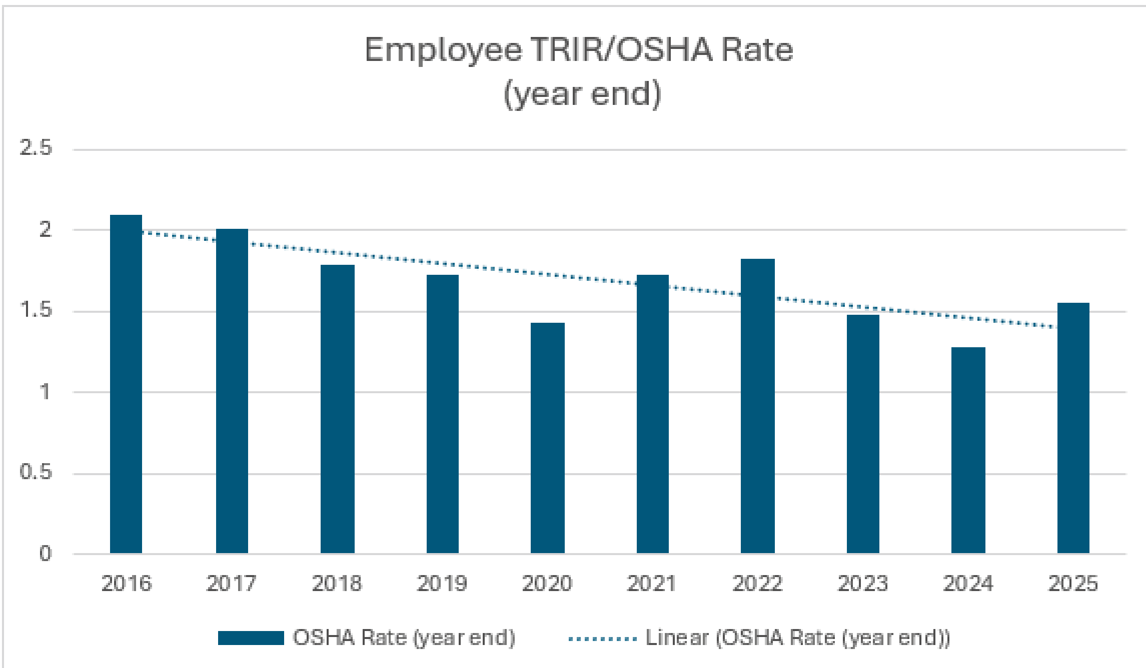
Metric: Employee Lost Time Incident (LTI) Rate
Calculation: Number of LTI Cases times 200,000 divided by employee hours worked

SDG&E's LTI Rate performance has generally declined over the past ten years. SDG&E continues to focus on Serious Injury and Fatality (SIF) prevention and achieved its best-ever LTI rate in 2025. 2025 LTIs decreased by 58% when compared to 2024, achieving a Company record-low LTI rate of 0.18. SDG&E's 2025 LTI rate illustrates that incidents were generally less severe.



Metric: Employee Total Recordable Incident Rate (TRIR) or Cal/OSHA Recordable Incident Rate
Calculation: Number of Cal/OSHA Recordable Cases times 200,000 divided by employee hours worked

SDG&E's Total Recordable Incident Rate/OSHA Rate has generally declined over the past ten years. It is calculated using all injuries and illnesses that meet Cal/OSHA recordability criteria. As indicated above, the severity of SDG&E incidents has generally declined, as demonstrated by SDG&E's DART and LTI performance.



APPENDIX E – GRID MODERNIZATION PLAN

Grid Modernization Plan

GRID MODERNIZATION PLAN OVERVIEW

Over the past decades, San Diego Gas and Electric Company (SDG&E or Company) has invested in innovative, cutting-edge technologies and programs that have established the utility as a leader in wildfire safety and grid resiliency. These advancements, from automation and advanced control technologies, to implementing efficient work practices and community microgrids, form the foundation for the grid of the future. SDG&E recognizes that affordability is top of mind for our customers. Modernizing the grid is critical for maintaining reliability, supporting decarbonization, meeting statewide clean energy mandates, and the Company is committed to pursuing these objectives through prudent grid investments.

The California Public Utilities Commission (Commission or CPUC) has defined the modern grid:

> A modern grid allows for the integration of distributed energy resources (DERs) while maintaining and improving safety and reliability. A modern grid facilitates the efficient integration of DERs into all stages of distribution system planning and operations to fully utilize the capabilities that the resources offer, without undue cost or delay, allowing markets and customers to more fully realize the value of the resources, to the extent cost-effective to ratepayers, while ensuring equitable access to the benefits of DERs. A modern grid achieves safety and reliability of the grid through technology innovation to the extent that is cost-effective to ratepayers relative to other legacy investments of a less modern character.[1]

Consistent with this definition, the future grid needs to be dynamic, robust, and resilient, and it must evolve to maintain safe and reliable grid operations with increasing numbers of DERs and DER technologies. The future grid needs to empower customers, increase renewable generation, integrate Electric Vehicles (EV) and reduce Greenhouse Gas (GHG) emissions while providing operational efficiency and security, and maintaining customer privacy.

[1] Decision (D.) 18-03-023 at 7.

Building on this foundation, SDG&E's Grid Modernization vision is to develop a flexible, customer-centered grid that accommodates choice while maintaining affordability and reliability. By strengthening the core capabilities needed to safely and reliably operate an increasingly dynamic distribution system, the Company enables customers to adopt new technologies at their own pace. This strategy prioritizes near-term operational needs while preserving the flexibility to incorporate evolving technologies, market developments, and regulatory direction—helping avoid unnecessary or premature investments as future requirements continue to take shape.

To realize this vision, SDG&E has developed a framework for expanding its technical capabilities. The framework has four key themes that ground the investments needed to advance the grid. These themes are shown in below.

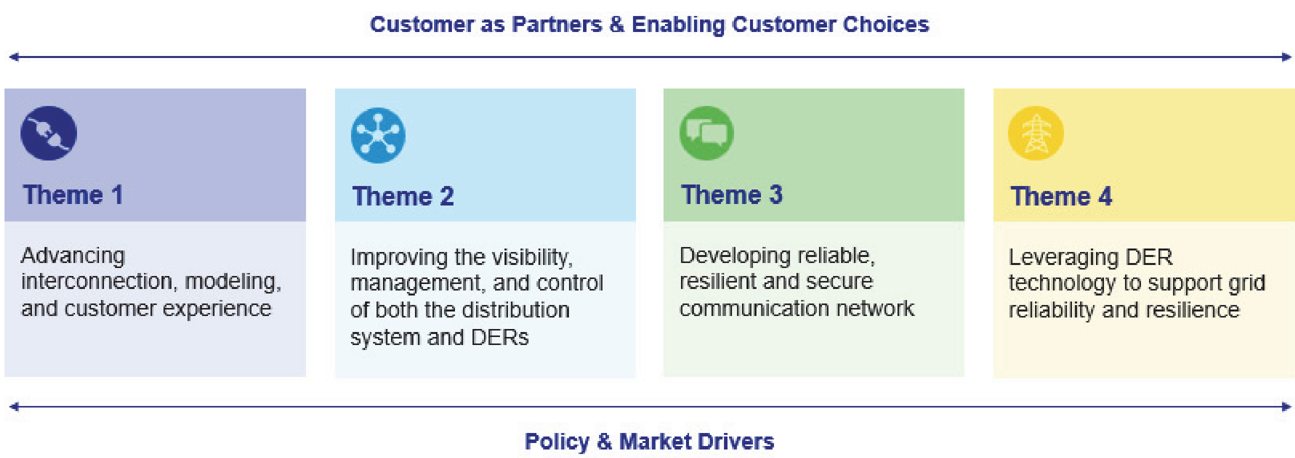


Figure 1 – Grid Modernization Plan Key Themes

In addition, SDG&E continues carrying out its customer-centric vision and places a high priority on implementing technologies that empower customers in ways they personally value. This overarching vision is embedded and expands across all technological investments. Investments made in upgrading the infrastructure, enhancing visibility, management, and control of the distribution system, along with building resilient, robust, and secure networks are all aimed at delivering best-in-class electrical service to SDG&E's customers. In 2025, for the 20th consecutive year, SDG&E received the ReliabilityOne® Award for "Outstanding Reliability Performance" among utilities in the West.

With more and more customer energy solutions available, SDG&E strives to continue supporting customers' energy choices and is equipped to enable customer participation in wholesale markets. Customer facing programs like Demand Response (DR) programs and transportation electrification programs may require specific grid management enhancements for them to be more effective. Customer facing tools like Distribution Interconnection Information System (DIIS), Customer Energization Portal, and Distribution Resource Portals have provided greater ease and flexibility to customers adopting DER technologies and will continue to be enhanced to further support DER integration into the distribution system. SDG&E believes next generation Advanced Metering Infrastructure (AMI) is a key foundational technology that aligns with all four grid modernization themes while providing an enhanced customer experience. In December 2025, SDG&E filed its Smart Meter 2.0 Application (A.) 25-12-012. Once approved, SDG&E will commence implementing the new infrastructure.

Similarly, SDG&E aligns its grid modernization plan with key regulatory drivers and state policies and is continuously updating components of its planned roadmap (Figure 3- Grid Modernization Investment Phased Roadmap) as needed. SDG&E fully expects market drivers and technological evolution to impact the planned roadmap.

Examples of ongoing regulatory proceeding and state governed activities that have influenced technology investments that foster DER integration include the High DER Future Grid Rulemaking (R.) 21-06-017, Rule 21 Interconnection R.17-07-007, Interconnection R.25-08-004, Energization R.24-01-018, Customer Distributed Energy Resources R.22-11-013, Demand Response R.25-09-004, Demand Flexibility R.22-07-005, and other rulemaking proceedings within the umbrella of the Commission's DER Action Plan 2.0.

Regardless of the investments and across any technological theme, cybersecurity must be carefully evaluated, designed, and implemented as part of the technology deployment. Relying on highly decentralized resources and distributed power supply infrastructure for real-time operation represents a fundamentally new operating environment with new risks and challenges for grid operators and system reliability.

GRID MODERNIZATION-RELATED UPGRADES PLANNED, INITIATED AND/OR COMPLETED TO DATE

As mentioned previously, SDG&E utilizes the four themes as guiding principles in making its investments and upgrades, including grid modernization-related upgrades. Grid modernization-related upgrades are discussed below under each theme, with description of its scope, DER integration relevance, current status, and any relevant Work Papers (WP) in the 2028 GRC.

Theme 1: Advancing Interconnection, Modeling, & Customer Experience

California's decarbonization goals will result in customers adopting an increasing number of electric end-uses and resources, such as EVs, over the next 20 years. This time frame includes the period covered by SDG&E's 2028 General Rate Case (GRC) cycle. Ongoing improvements to the generator interconnection process, including SDG&E's public-facing DIIS, customer energization and Integration Capacity Analysis (ICA) portals, support SDG&E's ability to timely interconnect and energize customers' energy technology choices. Collaborative customer engagement efforts enhance forecasting through early identification of load and resource addition trends, including locations, amounts, and technologies. Identification of loads through modeling, and the incorporation of these loads through forecast scenarios, will allow the distribution capacity plan to identify infrastructure upgrade needs in advance of when material commitments for these upgrades must be made. This will ensure SDG&E's electric system is prepared for a high electrification future. Collectively, these measures provide a positive and value-added customer experience, both now and over the long-term.

Below, SDG&E describes what has been initiated and completed in support of generator interconnection, load energization and distribution planning, and what SDG&E envisions for the future.

Distribution Interconnection Information System

To date, SDG&E has authorized over 340,000 Net Energy Metering (NEM)/Net Billing Tariff (NBT) interconnection requests advancing an aggregate capacity of over 2,400 Megawatts (MW) of generation behind the load meter. To support the significant adoption of NEM/NBT, SDG&E has been adapting and further developing the DIIS. The automated application process and online tool was launched in 2013, allowing customers and contractors to apply for interconnection of their generating resources and for authorization to commence parallel operation of those generators with the utility's electric grid. DIIS allows fast track applications to be processed on an average of 3 days for residential applications.

The system allows users to create and submit project applications, receive real-time status updates and notifications, and is available 24/7. As mentioned in the overview, SDG&E's DIIS has greatly facilitated its customers embracing technology adoption quickly and easily. The automated interconnection application review, engineering study, payment, and authorization workflow and the Permission to Operate release process within DIIS reinforces SDG&E's key goals of implementing a transparent and efficient interconnection process.

SDG&E has integrated DIIS with systems such as the Geographic Information System (GIS); Systems, Applications, Products in Data Processing (Systems, Applications, and Products (SAP)); and Pi-Vision to streamline the interconnection process and to enable the tracking and visibility of DER's under Rule 21 and the Wholesale Distribution Access Tariff (WDAT). Generators receiving authorization to operate in parallel with the utility system are visible in GIS which communicates to SDG&E's Network Management System (NMS). Additionally, interconnection process improvements support SDG&E's modeling of the distribution system for long-term planning purposes. Through GRC Test Year (TY) 2028, further description is provided in the Information Technology (IT) testimony (Exhibit (Ex.) SCG-10/SDGE-14-CWP G09090).

Customer Energization Portal

In compliance with Senate Bill (SB) 410 (Energization Timelines and Transparency), Assembly Bill (AB) 50 (Standardized and Streamlined Interconnection Rules), and Energization R.24-01-018, which establish standardized energization timelines and transparency requirements, the Customer Energization Portal is being further developed and utilized to provide customers with an enhanced customer experience, including two-way messaging, customer scheduling, enhanced payment tools, and document management, cloud modernization, and virtual assistant. New requirements from the above compliance requirements are being integrated into the Customer Energization Portal, including the provision of a single point of contact (SPOC), required customer notifications, and timely, consistent job status visibility and updates throughout the energization lifecycle. A further description is provided in the IT testimony (Ex. SCG-10/SDGE-14 – Information Technology Capital (A09090 - Customer Energization)).

Integration Capacity Analysis

SDG&E has implemented several enhancements and updates to the ICA online portal to enhance usability and customer experience. Efforts to refine the accuracy and representation of circuit segments that display zero hosting capacity have continued. SDG&E's technical teams review and validate each zero instance through Quality Assurance/Quality Control processes.

Details of limiting criteria for the circuits have been added to the ICA results portal for Steady State Voltage, Voltage Fluctuation, Thermal, Protection, and Operational Flexibility. SDG&E's circuit models include distribution upgrades recently completed or planned. Limited Generation Profiles (LGP) have been added into the ICA portal, enabling interconnecting generators electing the LGP option to download the LGP template and have it submitted with their Rule 21 application. The ICA methodology was updated to incorporate LGP application information.

SDG&E has executed additional ICA enhancements to improve customers' experience under R.21-06-017 and beyond, including:

- Unique legend symbols and color-coding in the map
- Standardized acronyms and terminology within pop-ups and data files
- Addition of ICA analysis date in data files
- Ability to perform expanded data downloads
- Updates to make the User Guide easier to find and interpret, and to use the ICA portal functions
- Descriptive axis labels added to the Load Profile charts

Electrification & Customer Engagement/Focus

As electrification accelerates across the region, early engagement with customers has become essential to ensuring both a positive customer experience and a grid that is strategically prepared for future demand. SDG&E has incorporated a comprehensive, forward-looking outreach effort designed to better understand customer needs and anticipate electrification-driven load growth. To meet these emerging needs, SDG&E has developed a cross-departmental outreach initiative that engages customers far earlier than traditional utility processes. Using a combination of in-person and virtual meetings, questionnaires, and research of publicly available information, SDG&E collaborates directly with developers, trade groups, large commercial customers, and EV fleet operators as their projects begin to take shape. This early-stage engagement provides visibility into the various stages of emerging new electrical loads and allows SDG&E to further clarify future electrification loads, customer priorities, and potential infrastructure requirements. This approach has already yielded meaningful insights. Through proactive outreach, SDG&E has engaged with numerous large-scale projects anticipated to add significant load over the next ten years. Customers consistently report that electrification is a core business and operational priority, motivated primarily by cost considerations and evolving regulatory requirements. Many customers already have clean transportation or building electrification plans underway, and a majority of regional jurisdictions have adopted climate action or sustainability plans that will influence local load growth. This feedback can inform SDG&E's planning. This engagement framework strengthens the customer experience by providing clearer expectations, earlier collaboration, and improved transparency throughout the service request and load development process. At the same time, it supports the region's electrification goals by ensuring that SDG&E's grid modernization efforts are grounded in current customer information. Together, these initiatives position SDG&E to serve as a responsive partner in the transition to cleaner energy while maintaining the reliability, safety, and resiliency of the grid.

Medium-Duty/Heavy-Duty (MD/HD) Forecasting

SDG&E has undertaken a more comprehensive and granular forecasting effort for the MD/HD transportation sector to accurately quantify the long-term grid impacts of fleet electrification. This work represents a significant advancement in SDG&E's forecasting capabilities and supports modernizing the grid by enhancing visibility into localized load growth, informing infrastructure needs, and ensuring grid readiness.

To build a complete picture of fleet activity, SDG&E integrated multiple complementary datasets. This multi-source data integration allows SDG&E to locate where commercial vehicles operate. This is critical due to cases where vehicle registration addresses differ from domiciled locations. For each identified facility, SDG&E evaluated the number and types of vehicles, annual mileage, vehicle efficiency and battery characteristics, expected electrification timing under California's Zero-Emission Vehicle regulations and economic adoption, and facility-specific charging windows determined by business operations. These inputs were used to generate detailed forecasts, and then aggregated into circuit- and bus-level load profiles. In summary, this MD/HD forecast provides SDG&E with a more robust foundation for distribution capacity planning, refined infrastructure needs, and strengthened customer collaboration. The insights gained through this forecast will support the safe, reliable, and efficient transition of the transportation sector to zero emission technologies and SDG&E's efforts to modernize the grid for a decarbonized future.

Microgrid Portal (Tribal/Local Government Portal)

SDG&E completed development, in November 2023, of a separate, access-restricted data portal for local and tribal governments. The development and activation of the portal complies with requirements specified in the D.20-06-017.[2] This portal supports transparency for local governments and tribes.

The portal includes a map application that displays GIS data. The GIS data depicts (a) planned grid hardening investments, (b) high fire threat districts (HFTD), (c) electrical infrastructure and (d) weather-related factors that led to the decision to de-energize from each prior Public Safety Power Shutoff (PSPS) events and the resulting distribution and transmission line outages.

Theme 2: Improving the visibility, management, and control of both the Distribution System and DERs

To maintain safe and reliable operation of the electric distribution system under high levels of DER penetration outlined in the section above, SDG&E must be able to accurately model, monitor, and manage the distribution system in its as-switched state. This includes real-time visibility into switching configuration, protection settings, voltage and loading conditions, outage restoration status, and bidirectional power flows. Advanced grid monitoring, data acquisition, visualization, and situational awareness systems are therefore required to assess system conditions and account for both forecast and real-time operation of interconnected DERs including Behind-the-Meter (BTM) and Front-of-the-Meter (FTM) resources. These systems must integrate expected and measured operating profiles and enable appropriate signaling, control actions, and enforcement of operating limits necessary to support safe and reliable distribution operations.

SDG&E plans to expand grid management capabilities to monitor, and pursuant to applicable DER programs, manage and control DERs. Within its existing control systems architecture, these capabilities will be assessed, designed, and deployed in a progressive manner at carefully designed integration points to ensure practical and efficient implementations.

As shown in Figure 2, over two decades of evolution, SDG&E's control system architecture has developed into a set of complementary systems operating across multiple layers.

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[2] D.20-06-017, Ordering Paragraph (OP) 11. *See* SDG&E Advice Letter (AL) 3610-E (effective April 8, 2021).

At the foundation, field devices, such as Remote Terminal Units (RTUs), sensors, and other smart grid devices, collect data and execute control actions on the physical system. These devices interface with the Supervisory Control and Data Acquisition (SCADA) headend system, which provides real-time data acquisition and supervisory control. Building on this foundation, the Advanced Distribution Management System (ADMS) integrates SCADA data with an as-switched network model to enable system visualization, analytics, outage management, and operational decision-making. Looking ahead, as ADMS capabilities continue to advance through enhanced analytics and more robust modeling, the Distributed Energy Resource Management System (DERMS) will further extend this architecture by enabling coordinated monitoring and control of DERs in alignment with programmatic and operational needs.

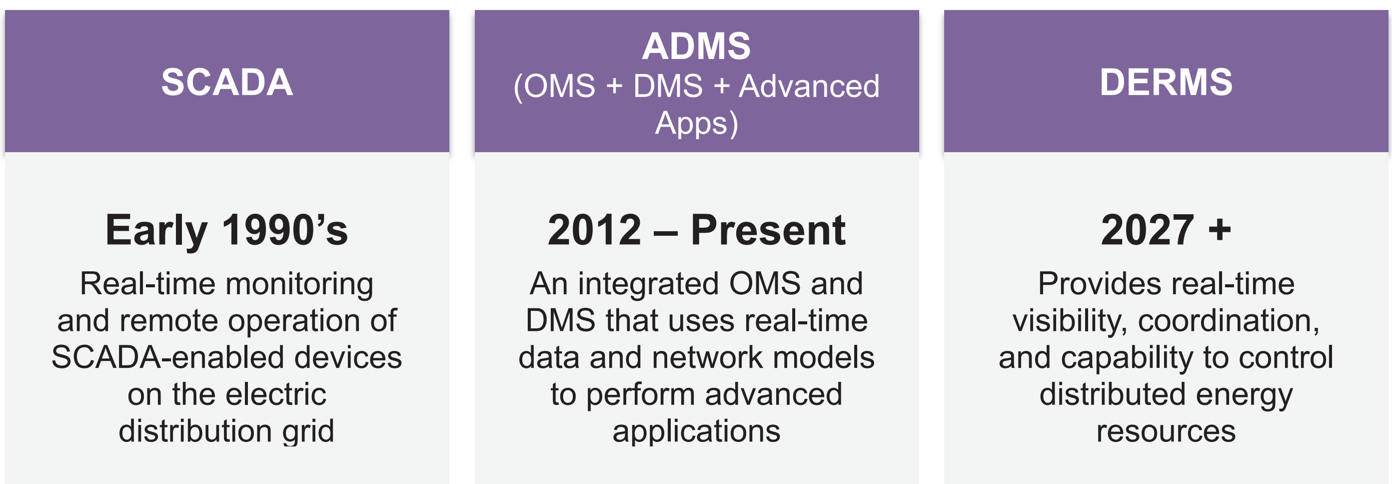

Figure 2 – Control System Evolution at SDG&E

In the following section, SDG&E provides additional detail on each grid modernization related project under Theme 2 supporting the continued modernization of its control systems and the deployment of distribution automation devices. For each project, SDG&E outlines progress achieved to date, as well as the additional scope proposed in this GRC to address emerging needs and support safe and reliable operations in an increasingly complex, DER-integrated grid environment.

Supervisory Control and Data Acquisition (SCADA) Headend Replacement

SDG&E has long been using the SCADA system to monitor, control, and protect distribution assets in conjunction with other platforms (i.e. ADMS). As the cornerstone of its operational platform, the implementation of the Distribution SCADA (DSCADA) system more than two decades ago initiated SDG&E's roadmap (Figure 3- Grid Modernization Investment Phased Roadmap) establishing system management capabilities within the distribution control center, as shown above in Figure 2. Over time, this legacy DSCADA system faced increasing challenges as more and more communication-enabled edge devices were deployed in the field.

In 2017, SDG&E engaged a consulting firm to perform a full evaluation of the DSCADA system. Upon evaluation, it was identified that the legacy DSCADA system did not meet SDG&E's technical roadmap requirements for grid modernization. Key issues included a lack of support for Internet Protocol (IP) communications protocols as well as a limited capacity to send/receive DSCADA points associated with newer devices and general system scalability concerns. Moreover, given the DSCADA system had antiquated user interfaces, the development, maintenance and updates of DSCADA screens was very inefficient and time consuming. The system did not have a reliable backup process and was heavily dependent on an aging hardware configuration, which created many challenges for operational support of the system.

Consistent with the final recommendation by the consulting firm, SDG&E decided to replace the legacy system with a new DSCADA Head-end system. As such, in 2023 SDG&E completed Phase 2 of SCADA Head-end upgrade project. This improved our communications to field devices by moving to a more robust IP communication path. The IP communication now allows for more visibility across the network sensors and improved communications to field devices by 5% on average per channel with 98% of all RTUs completing a poll within 90 seconds. Phase 2 also scaled the system to utilize Private Long Term Evolution (PLTE) as it becomes available. In addition, the Inter-Control Center Communications Protocol (ICCP) connections with the SDG&E Transmission system was established which allowed for better visibility for distribution system operators.

As part of an audit assessment, new Operational Technology Standards were implemented in 2021 that now require SDG&E to maintain the DSCADA software and hardware in compliance with those standards. The Operational Technology Vulnerability Assessment standard requires regular review of supported vendor software and no End of Life /End of Support systems or applications as part of cyber security controls and validation. This puts Electric Distribution Operations - Technology (EDOT) on a regular schedule of upgrades for the DSCADA system for both hardware and software applications. In 2026, SDG&E is looking to replace the current hardware, operating systems, and vendor software to stay in compliance. Our current hardware was purchased in 2018 as part of the original replacement project and is starting to experience hardware failures and operating systems are on a limited Extended Life Cycle Support (ELS).

Advanced Distribution Management System (ADMS)

In September 2012, SDG&E deployed its initial ADMS which included an Outage Management System (OMS) integrated with a Distribution Management System (DMS). To achieve SDG&E's desired operational vision, the ADMS was tightly integrated with other ancillary operational systems including GIS, SCADA, Customer Notification System (CNS), and AMI systems. This initial ADMS deployment included a fully as-switched model of the distribution system which provides granular system visibility and management capabilities for the distribution system operators. The OMS also enabled the full suite of digital switch plan management, including documentation, tagging, and authorization capabilities across emergency and planned work, with all SCADA field switching executed remotely from the control center. The full ADMS platform also enables timely customer outage communications, integrated workflow management, and the ability to open and close FTM distribution resources in real-time. The ADMS platform integrates data from AMI and SCADA with the internal as-switched grid model. ADMS has been a core enabling factor when it comes to SDG&E's superior safety and reliability metrics.

Moreover, ADMS is a key foundational system that anchors SDG&E's ability to operate and manage the distribution system in a high DER future. Its DER-aware modeling, integrated network analysis, and system reconfiguration applications pave the way for SDG&E to develop its growing capabilities around program-enabled DER management and is a first step towards the fully integrated ADMS and DERMS platform, as depicted in Figure 2 above. In its TY 2028 GRC, SDG&E proposes the Outage and Distribution Management and Foundational Technology – IT CAPITAL project (*see* Ex. SCG-10/SDGE-14-CWP H09200 – Grid Operations), which supports the enhancement of ADMS to address safety and reliability driven needs. These enhancements also provide a foundation for implementation of broader DER management capabilities, as proposed in the new Enterprise DERMS project. Additionally, SDG&E intends to improve its electric modeling, including DER modeling, which is the foundation for all optimization applications within the ADMS. Accurate modeling improves switching accuracy, operating efficiency, as well as providing an accurate baseline for planning and operations given the increasing number of DERs and DER technologies operating in parallel with the distribution system.[3] The projects will also build upon existing architecture and platforms and further implement and refine advanced applications such as Volt/Var Optimization (VVO), Fault Location Isolation and Service Restoration (FLISR), Fault Location (FL), and day ahead forecasting. This project is driven by the need for safety and reliability, which is particularly important with increasing numbers of DERs and evolving DER technologies.

<u>Fault Location Isolation and Service Restoration Implementation</u>

Given that FLISR is an existing module within ADMS, SDG&E plans to continue enabling FLISR technology gradually with improvements in power flow capabilities as more upgraded SCADA line devices and updated substation relays become available. FLISR allows layered reliability benefits to be reached beyond the RTU modernization and the Distribution Protection & Control Modernization efforts, as it automatically isolates the fault and restores electrical service to customers outside of the faulted area during outages. This reduces the necessity of field personnel response prior to confirming fault location and isolation. For customers on FLISR capable circuits, they are provided with a more reliable and responsive electric service by minimizing outage duration.

<u>Distribution Protection & Control Modernization Program</u>

SDG&E modernizes its distribution protection and control by replacing aging protective relays and SCADA equipment that have reached end of life. In addition, SDG&E installs new relays and SCADA systems at legacy substations that currently lack this technology, advancing the overall transition toward fully SCADA-equipped substations. The benefits of installing and upgrading SCADA equipment include faster faulted circuit identification, faster isolation of faulted electric distribution circuits, faster load restoration after system disturbances, and

[3] Evolving DER technologies include Vehicle-To-Grid (V2G), standalone energy storage, and a variety of appliance controls. DR programs may be able to cost-effectively tap these technologies to provide commercially viable wholesale and retail services.

improved visibility via telemetry points that can identify potential grid issues such as load imbalance, power factor, load factor, overloads, or voltage issues. In addition to the significant reliability benefits that SCADA substation control provides, the additional data, improved visibility and controllable equipment accommodates an increasing number of DERs, as well as new DER technologies, without jeopardizing distribution system performance.

As of February 2026, SDG&E has SCADA fully enabled at over 94% of distribution substations and expects to have SCADA at all 12-kilovolt (KV) substations within the next decade. The Distribution Protection & Control Modernization Program (see Ex. SDGE-08-CWP 152430) is ongoing and expected to continue through TY 2028. This project is reliability driven, but it is also expected to provide ancillary benefits to DER integration.

Remote Terminal Unit Modernization

SDG&E initiated field RTU modernization projects to transition legacy communication systems (increasingly unsupported by carriers) to IP-based communication, replacing legacy systems with technologically advanced and compatible RTU's for enhanced situational awareness, command, and control. RTU's leveraging IP based communication are faster, more reliable, and address the end-of-life legacy RTU's which are largely unsupported by vendors, some of whom may no longer exist. Modernizing existing field devices while coupled with a SCADA Headend replacement allows for increased operational speed and more reliable sectionalizing inclusive of establishing circuit tie connections in the field. This program when combined with the SCADA expansion initiatives, provide the transformation of status quo into operational flexibility coupled with increased situational awareness for system operators to remotely observe and operate the distribution system. The penetration of DERs is anticipated to grow in the future and this operational improvement will transform the company's capabilities to observe and operate the dynamic, complex, and changing landscape of the future electric system. SDG&E plans to complete the effort of replacing legacy field RTUs in 2026.

Wireless Fault Indicators

SDG&E has installed over 3,000 Wireless Fault Indicator (WFI) sensors and necessary network communication systems throughout the electrical system. These integrated sensors improve reliability by allowing SDG&E field personnel to more efficiently identify fault location for faster sectionalizing of the faulted area, faster restoration for those customers outside the faulted areas, and faster identification of the outage cause and subsequent grid repair.

Deployment of WFI has been prioritized in the HFTD areas, with the goal of mitigating some of the reliability impacts of SDG&E's operational protocols designed to improve public safety by reducing the risk of wildfire. WFI installations enable faults to be identified quicker and more efficiently, contributing to reducing restoration times by 30%-50% according to industry data. Safety and reliability drive deployment of WFIs, as the HFTD WFI project has been completed and the RAMP WFIs project (*see* Ex. SDGE-08-CWP 202880) is to be proposed to modernize the WFI fleet in the SDG&E service territory providing more detailed telemetry, higher accuracy, and improved security by leveraging SDG&E's PLTE network. SDG&E's current fleet of WFI devices have been discontinued by the manufacturer, in addition to the third-party remote monitoring system will be sunsetting as of 2028, prompting a need to replace and modernize the fleet to maintain situational awareness of the distribution system. The ability to quickly locate and address faults is beneficial for all customers, including those choosing to add DERs. Modern smart WFIs represent a more cost-effective alternative to other outage mitigation solutions that require large infrastructure replacements and long-duration, planned outages to implement. In addition to being a cost-effective technology, WFIs are minimally invasive, quick to deploy, and adaptable to many system configurations providing immediate impact and operational benefit in locating faults, identifying fault magnitude and mitigating prolonged outages and associated costs. A new program allows SDG&E to replace aging technology with higher quality hardware and expanded data acquisition to modernize troubleshooting procedures and improve safety and reliability.

The new wave of WFIs brings seamless integration into existing SCADA systems, removing the need for third party software and services thus reducing additional software costs and providing system operators with real-time actionable data that can reduce troubleshooting time. Smart WFIs can be utilized as a risk management tool by providing historical voltage, load, and power quality data that can be used by SDG&E to preemptively address costly infrastructure deterioration and can be leveraged as a low-cost solution to monitor temporary circuit configurations. This program will be included in the 2028 GRC cycle to continue to provide important situational awareness in the coming landscape of electrification, leveraging the visibility, and operability provided by smart WFI devices to monitor and support DERMS and growing load pockets.

SCADA Capacitors

SDG&E has been installing and upgrading line capacitors to SCADA-controlled to increase capacitor bank reliability, minimize downtime, and cut down the travel time needed for repair work. SCADA-controlled line capacitors will provide local and remote control and failure protection while reducing operating costs. Like the WFI program, SDG&E prioritized installing and replacing capacitors in HFTD before expanding to wildlife-urban interface and locations outside the HFTD. SCADA-controlled capacitors reduce the risk of catastrophic failures that could create ignitions by leveraging sensors and relays to quicky detect and isolate faulted or damaged capacitors, much faster than SDG&E's current fused protection system. In addition to this critical safety benefit, SCADA-controlled capacitors provide increased capacity and reliability, and also provide additional data and switchable points on the distribution system. In a high DER future, voltage management requires more data sensors and advanced control algorithms to coordinate voltage regulating equipment owned by the Utility. These algorithms account for DERs' voltage impacts and for dynamic load changes. Installation of SCADA-controlled capacitors enables SDG&E to dynamically adjust reactive power flow throughout the entirety of a distribution circuit efficiently and cost-effectively. SCADA-controlled capacitors play a key role in the Company's voltage management strategy.

Under General Order (GO) 165, utilities are required to inspect distribution facilities to ensure safe and reliable operation. Capacitor banks and associated equipment (e.g., switches, controllers, fuses, arresters, and potential transformers) are explicitly included as applicable distribution equipment subject to patrol and detailed inspections. During detailed overhead and underground inspections, inspectors perform a visual and operational assessment to confirm that capacitor equipment is present, intact, and functioning as intended. This includes verifying observable conditions such as whether the capacitor is online and switching properly, whether controllers are powered and operating, and whether there are visible signs of damage, corrosion, overheating, or abnormal conditions. When a GO 165 inspection identifies a capacitor that is damaged, malfunctioning, offline, or otherwise not operating properly, the condition is entered into SDG&E's work management system, where depending on the risk and severity posed by the issue, a work order would be created to repair, adjust, or replace the defective capacitor units.

When capacitor-related issues are discovered during GO 165 inspections, repairs or replacements are completed within the timeframes required by GO 95 Rule 18, based on the severity and risk classification of the condition. Accordingly, any repairs or replacements of existing capacitors would be performed through the Corrective Maintenance Program and budgets, while proactive upgrades or modifications to an existing capacitor would be performed through this Grid Modernization initiative. As of April 2026, SDG&E has installed and replaced 380 SCADA-controlled capacitors. Both the HFTD SCADA-controlled capacitor replacement project and the non-HFTD SCADA-controlled capacitor projects are completed. Installation and replacement of SCADA-controlled line capacitors is safety and reliability driven. Reliable distribution operations is beneficial for all customers including those choosing to add DERs.

Power Quality Program

SDG&E continues to deploy and expand substation Power Quality (PQ) monitoring systems and field PQ monitoring devices to gather high resolution system data and intelligence supporting key initiatives including early fault detection and advanced fault locating. These programs directly improve system reliability by reducing forced outages, shorten outage duration by way of advanced fault locating, increase public & worker safety by reducing fire risk and eliminating unplanned crew response, and reduce costs associated with unplanned outages and wildfire events. Additional system monitoring also brings valuable asset health data to engineers, eliminating the need to perform site visits to such information. With additional visibility provided by the PQ meters installed in the field, SDG&E has increased situational awareness on the distribution and transmission systems. Additional benefits include data to support DER (generation and storage) development providing data to analyze system impacts of DER on system voltage and equipment, EV expansion impacts, voltage compliance, Voltage Ampere-Reactive (VAR) optimization, and system harmonics impact and mitigation. As of first quarter 2026, SDG&E has deployed 295 distribution substation PQ meters (bank/bus/circuit), 243 distribution field PQ monitors, and 25 transmission level monitors. The Distribution Power Quality Program (*see* Ex. SDGE-08-CWP 942410) is ongoing and expected to continue through 2028 GRC cycle. This program is primarily driven by safety and reliability. Good PQ benefits all customers including those choosing to add DERs.

Local Area Distribution Controller (LADC)

To support the controls associated with microgrids, SDG&E has developed and deployed a microgrid controller, known as an LADC. The LADC is designed as a fast local controller capable of rapidly controlling Inverter-Based Resources (IBR) using high-speed synchrophasor data as its primary control input. This fast control capability is necessary due to the low-inertia environment in which microgrids operate, where data sampled at roughly one-second intervals has proven too slow and has led to unforeseen consequences, including microgrid instability and customer outages. To ensure safe and stable operation under transient microgrid conditions, control decisions must be based on significantly higher-resolution data. This requirement is especially critical in systems with uncontrolled customer-owned DER employing legacy inverters without strong ride-through capabilities, where voltage or frequency excursions during transients can cause large numbers of devices to trip offline simultaneously. LADC was first deployed at SDG&E's Ramona Air Attack Base Microgrid in December 2022, with the goal that the LADC would be the standard controller for utility operation of microgrids. Since then, SDG&E deployed LADC at the commissioned Borrego Springs Phase 1 in December 2023 and commissioned the Cameron Corners microgrid in December 2025. Borrego Springs Phase 2 is expected to be commissioned in 2026. Four new sites will have been deployed in late 2026 and 2027.

LADC projects are necessary for the operation of sufficient controllable DER capacity within the microgrids to provide acceptable frequency and voltage control when in Island Mode.

Distributed Energy Resource Management System

In the 2024 GRC, SDG&E proposed an enterprise DERMS solution where the selection and implementation are anticipated to begin in 2027. Enterprise DERMS is intended to provide overarching operational functions to monitor, manage, and control DERs in alignment with program provisions, while supporting ongoing system lifecycle updates and technology upgrades. Building on prior investments in SCADA headend replacement, ADMS, and grid infrastructure, SDG&E is evaluating and designing operational frameworks to ensure safe and reliable operation of a distribution system with rapidly increasing DER penetration and diverse technologies. These functions are expected to enable DER participation in retail programs where customers or aggregators modify load or generation to provide grid services, such as reducing imports to defer infrastructure or supporting operations during abnormal conditions. Rather than deploying a single comprehensive platform upfront, SDG&E plans to incrementally enhance existing tools and develop scenario-driven functionality as use cases are validated and proven cost-effective. While DERMS remains an evolving technology dependent in part on regulatory direction, SDG&E has prioritized initiating targeted pilots and phased implementation in this

GRC cycle. This approach ensures flexibility while maintaining reliability as DER adoption accelerates.

Although SDG&E has not yet deployed a full enterprise DERMS, it has been an early adopter in advancing grid capabilities through collaboration with national labs, vendors, and research institutions, including work funded through the Electric Program Investment Charge (EPIC). These efforts have evaluated foundational elements such as Institute of Electrical and Electronics Engineers (IEEE) 2030.5 integration, expanded aggregator communication, dynamic charging and discharging controls, and near real-time forecasting. Enterprise DERMS is expected to operate in conjunction with ADMS to enable two-way communication between SDG&E and DER operators, including customers and aggregators, allowing DERs to provide grid services as needs arise. Initial use cases include aggregator integration, dynamic operating limits for energy storage, and enhanced forecasting to support efficient interconnection and distribution operations. SDG&E's focus includes developing dispatch capabilities for utility-scale storage, collaborating with stakeholders to define cost-effective smart inverter use cases, and working with vendors to pilot and implement required functionalities. Core functions under evaluation include dynamic limit management, DER and aggregator communications, DER control and monitoring, and data exchange with ADMS. Together, these efforts are expected to establish a scalable, flexible DERMS foundation that supports reliability, enables customer flexibility, and optimizes DER value to the grid.

Demand Response Management System (DRMS) Replacement

SDG&E has over two decades of experience in managing DR programs. At present, given cost-effectiveness requirements, SDG&E has one operational DR program. In November 2026, SDG&E will file its next DR Application with the Commission and will propose multiple new DR programs and pilots. The existing DRMS project will continue to monitor, control, and optimize electricity demand in response to grid conditions and additional DRMS functionality may need to be sources as future needs of DR customers, programs, and pilots are identified. This platform will allow SDG&E's internal DR team to track and manage the various DR programs and pilots via one single platform. The DRMS replacement system will be designed to grow and expand, allowing SDG&E to have the capacity to manage and signal smart devices in accordance with DR program provisions. The new platform will also allow SDG&E's DR team to provide better customer experience as many more customer-purchased smart devices and equipment are accessed by Commission-approved DR programs. The DRMS technology is primarily driven by anticipated DR program needs, but the replacement project is primarily driven by aging IT infrastructure.

As SDG&E advances toward implementation of an enterprise DERMS, the existing DRMS is expected to serve as a complementary and foundational component within the broader DER operational framework. While DRMS will continue supporting program administration, customer engagement, and event driven DR dispatch, these capabilities also establish a pathway toward more continuous and grid aware coordination of DERs.

In this model, flexible customer sited resources such as smart thermostats, EVs, battery storage systems, and other controllable loads may be aggregated and coordinated alongside additional DER technologies to support operational needs based on real time system conditions, localized constraints, and grid reliability objectives.

This evolution supports a transition from traditional event-based demand response toward more dynamic DER orchestration capabilities, including real time monitoring, aggregated control, forecasting, and constraint aware optimization aligned with modern DERMS frameworks such as Smart Electric Power Alliance (SEPA) 2.0. Through this integrated approach, SDG&E can better align existing DRMS investments with future DERMS functionality while supporting operational flexibility, reliability, and continued customer participation as DER adoption expands.

Besides the projects discussed above to increase visibility, management, and control of the distribution system, SDG&E has also been utilizing a combination of data, analytical method, engineering and operation knowledge, and various tools to build a data notification system, visualization dashboards to enable proactive, and targeted response to data changes and system events. Some of the use cases implemented include temperature; disconnection of microgrids from the larger system, microgrid operation, and reconnection of microgrids to the larger system; voltage monitoring and applicable business unit notification; phase balancing; and overloading circuits watchlist. With more data available, including DER performance data, SDG&E expects to continue using analytics to further fine-tune its process to make more data driven planning and operational decisions. In addition, SDG&E also has ongoing grid technology deployment through Wildfire Mitigation and Vegetation Management (*see* Ex. SDGE-07-CWP 152590) such as the Advanced Protection Program (APP) technology to further extend branch circuit protection for improved reliability.

Theme 3: Developing Reliable, Resilient, and Secure Communication Network

As the distribution network becomes increasingly affected by the growing number of DER resources and associated DER technologies, and requires more telemetry and control points to operate safely and reliably, the need for cyber security systems and standards to protect SDG&E's Operational Technology (OT) networks also increases. Grid requirements envisioned for California's planned high DER future necessitate a communications network that is highly accessible, controllable, reliable, resilient, and secure. These communication network capabilities are becoming more foundational than ever to both grid operation and planning. Moreover, the customer's interest in communicating with and controlling its DERs, presents an unprecedented cybersecurity threat to grid stability. It requires active grid monitoring, mitigation, and recovery procedures to be in place. Cybersecurity-related grid modernization-related upgrades that SDG&E has completed and/or initiated are listed below.

To maintain and grow a reliable, resilient, and secure communication network, SDG&E must upgrade or replace aging infrastructure, such as projects to replace End of Support or End of Life devices within the Wide Area Network (WAN). In the Grid Modernization Plan, only those communication-related projects aiming to enhance and extend the communication network to support grid operations in a high DER environment are discussed and listed below.

<u>Fiber Development</u>

SDG&E's current backhaul fiber optic network is comprised of approximately 958 miles of fiber connecting over 64 transmission substations. SDG&E is about 71% complete with another approximately 522 miles to build towards completing a diverse fiber optic infrastructure network to all remaining substations. The fiber optic network not only provides a direct connection to substation equipment, but it also serves as backhaul and redundant pathways for backbone communications that enable distribution automation devices and grid monitoring to be interconnected to back-end control systems. More information on continued program growth and sustained execution across multiple planned installations can be found in the Fiber Optic for Relay Protection & Telecommunications project (*see* Ex. SDGE-08-CWP 071440).

Private LTE

SDG&E has been deploying a PLTE Field Area Network (FAN) using licensed radio frequency (RF) spectrum since 2020. As of first quarter 2026, approximately 70 base stations sites have been placed into services and have allowed hundreds of end points to communicate via this PLTE network. The base station sites include retrofitting of existing wireless telecommunication sites, as well as construction of new stand-alone fire-retardant mono poles within substation properties, or within SDG&E Rights-of-Way, or existing replacement of electric transmission and distribution structures; along with implementing covered conductor as well on the transmission and distribution structures. The program is expected to continue deploying sites, as needed, with a target of eventually obtaining 100% system wide coverage of SDG&E's services territory. The PLTE network and associated upgraded communication infrastructure will enhance the overall reliability of SDG&E's communication network and provide a greater cyber security posture for SDG&E's grid and grid monitoring technologies. The project is critical for enabling fire prevention and public safety programs such as Falling Conductor Technology and Early Fault Detection and enabling communications for such programs as Weather Stations, Strategic Undergrounding, and SCADA devices. In the meantime, SDG&E envisions this network will also serve as a foundational network to support safe and reliable distribution operations with an increasing number of DERs and DER technologies operating in parallel with the SDG&E system. Similar to the Fiber development projects, PLTE is also primarily driven by safety and reliability but provides the foundation for accommodating an increasing number of DERs and evolving DER technologies.

During testing & integration at the Integrated Test Facility (ITF), SDG&E performed end-to-end PLTE infrastructure validation, including User Equipment (UE) behavior, modem performance, and SCADA integration across head ends. These tests ensure production readiness for field deployments and support ongoing SCADA modernization. Regarding PLTE Grid Enhancement Technologies, SDG&E tested new communication needs for: Field Grid Devices, End-User Devices, Industrial Internet of Things (IoT) devices, Utility Sensors, Field Laptops/Mobile Workforce. For Device, Subscriber Identity Module (SIM), and Head-End Management Controller (HMC) Router Staging the team manages staging, provisioning, and lifecycle tracking of SIMs, HMC routers, and lab devices used for PLTE field deployments. This includes maintaining lab stock, validating configurations, and preparing equipment for large scale rollouts. Utilizing an OT Faraday-style shielded room was connected to the LTE/PLTE test networks via coax for controlled RF delivery. This ensures that no unintended emission leaves the room and testing complies with RF isolation requirements when operating experimental Federal Communications Commission (FCC)-licensed testing. PLTE Dual Band Radio Access Network (RAN) testing & Drive Testing Setup was used to operate the ITF drive testing lab environment for uplink/downlink performance validation using calibrated servers, SIM profiles, and Internet Performance (IPerf) traffic generation. This ensures reliable PLTE performance under real world conditions before field activation.

Advanced Metering Infrastructure

SDG&E's existing AMI was originally deployed to support customer billing, usage information, and foundational operational needs. While interval load data from the current AMI system has provided value for engineering analysis and planning functions, the system architecture was not designed to support real-time grid management or advanced analytics - at scale. As the first-generation AMI system approaches the end of its useful life, SDG&E is evaluating the replacement of both meters and the associated communications network with a modernized AMI platform aligned with current and future grid requirements. While individual Smart Meter 1.0 devices may continue to physically operate beyond their expected useful life, the underlying systems that enable remote data collection are expected to be discontinued, rendering affected meters and modules that have not been replaced with next generation technology, non-communicating.

As reflected in A.25-12-012, the Smart Meter 2.0 deployment represents a critical component of SDG&E's broader grid modernization strategy. Next generation AMI technology enables greater data granularity and enhanced device capabilities that supports a transition from primarily passive data collection toward integrated grid management. These capabilities reduce uncertainty in a dynamic distribution grid and improve asset insights and management. This includes the ability to improve meter to transformer associations and enhance our visibility and confidence in predicting and confirming customer outages. In addition, improved remote monitoring and diagnostic capabilities of a modern communication network reduce the need for field visits, shifting operations to focus on higher priority objectives.

SDG&E envisions utilizing next generation technology capable of supporting future use cases through secure, standardized interfaces. As DER programs are designed and implemented, this platform may support coordinated management of DERs and targeted DR programs. By facilitating the ability to implement programs under which customers allow their load and generation to be modified in accordance with grid conditions, Smart Meter 2.0 has the potential to deliver long term value to all customers.

Finally, Smart Meter 2.0 incorporates modern cybersecurity capabilities that enhance system security. By embedding security capabilities into the AMI architecture, SDG&E supports compliance with evolving cybersecurity standards while protecting customer and system data in a prudent manner.

Cyber Security

SDG&E's Cybersecurity organization provides risk-based support to Grid Modernization-related projects to help ensure new OT systems align with existing cybersecurity standards and established control requirements. This support includes reviewing OT-related architectures, identifying applicable security controls, and coordinating with OT engineering to apply configuration and network requirements consistent with the Company's approved cybersecurity framework.

As Grid Modernization introduces additional distributed devices and digital interfaces, Cybersecurity evaluates these technologies for secure integration into SDG&E's operational environment, including alignment with authentication, segmentation, and monitoring practices already in place. These activities help promote consistent application of controls and support the reliable onboarding of new OT systems into existing monitoring and incident-response processes.

Additional information regarding SDG&E's cybersecurity programs and risk-based approach is provided in the Cybersecurity testimony (Ex. SCG-11/SDGE-15).

Theme 4: Leveraging DER Technology to Support Grid Reliability and Resilience

Over the past few decades, the energy landscape has undergone profound transformation, driven by changing customer needs, advancing technology, and a shared commitment to a more resilient and sustainable future. IBRs are at the heart of this transition. Theme Four highlights how SDG&E thoughtfully embraces and leverages these emerging technologies not only to strengthen the electric grid, but to better serve and protect the communities that rely on it. Through rigorous testing at our integrated testing facility, we build confidence and understanding in how these resources interact with our system. That knowledge enables SDG&E to deploy

IBRs with purpose, supporting reliability, resilience, and peace of mind by providing critical backup power through microgrids when our customers need it most.

Integrated Test Facility (ITF)

Over the past decade SDG&E has enhanced an innovative ITF to support the implementation of various grid modernization and DER technologies in a safe and controlled environment before commissioning and/or deployment in the field. Since the inception of the facility, the ITF has been integral to our fielding of systems and DERs and provides the testing hub to model, simulate, test, and perform a complete demonstration. The lab has comprehensive capabilities in terms of coverage, which includes the DER technology itself, traditional SCADA devices, systems, communications technology, and system/device security. The lab has been heavily utilized in our EPIC program, grant-funded programs, and field deployment projects. Some of the recent activities include the LADC, smart inverter testing, IEEE 2030.5[4] interoperability projects and wildfire mitigation projects. The facility currently consists of following integrated labs:

- Foundational Communication Lab
- Power Systems Lab
- DER Lab
- Smart Garage Lab
- System Protection lab
- Cyber Security Lab

The ITF has supported a wide range of projects that leveraged its full suite of capabilities. This included developing new Real-Time Digital Simulator (RTDS) models and updating several legacy models for SDG&E's Borrego Springs Microgrid, which enabled extensive testing efforts such as the Department of Energy (DOE)-funded project, "Grid Resiliency with a 100% Renewable Microgrid"[5]. As part of this funding opportunity and demonstration, both generator and battery models were updated, including transitioning the microgrid's primary islanding

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4 Institute of Electrical and Electronics Engineers (IEEE), *IEEE Standard for Smart Energy Profile Application Protocol*, in IEEE Std 2030.5-2018 (Revision of IEEE Std 2030.5-2013) (December 21, 2018), at 1-361. IEEE 2030.5 is a DER communications protocol.

5 Office of Scientific and Technical Information (OSTI), *Grid Resiliency with a 100% Renewable Microgrid* (September 30, 2025), at 1-198, *available at*: https://www.osti.gov/biblio/2589920.

resource from the original configuration to the new battery system, and a new UltraCap was introduced to the model and microgrid for synthetic inertia. The team completed hardware-in-the-loop testing of two 3rd-party site energy controllers for microgrids. SDG&E's PLTE system was tested extensively at the ITF prior to field deployments and integration of DER technologies. This testing involved collaboration between the IT Telecom and the Information Security groups and utilization of multiple labs and the Faraday cage. In addition, CPUC mandated Isolating Meter Socket Adapter evaluation and testing has been conducted at the ITF, adhering to Resolution E-5194. As of late 2025, a new EPIC-4 ITF Microgrid Testbed Project was awarded as well as project partnership with University of California San Diego on a Flexible Data Center project leveraging IEEE 2030.5. More details are below in the EPIC section of this document. The ongoing ITF projects are fully funded by the California Energy Commission, EPIC, or CPUC. As such, no additional capital funding is being requested for the ITF.

SDG&E-Owned Energy Storage Systems

SDG&E has succeeded in designing, building, and operating utility-owned energy storage and microgrid assets. In total, there are 27 SDG&E-owned energy storage facilities, seven of which support microgrid operations, representing 482 MW of capacity. Since 2022, which was the last reporting year in the previous GRC cycle, SDG&E has completed eight utility-owned energy storage projects, totaling over 340 MW.

SDG&E has a long history of working with innovative partners to test battery chemistries in a variety of use cases to support needs of the grid. Since 2012, SDG&E has been deploying utility-owned energy storage systems to address system reliability issues. In the 2019 GRC, SDG&E proposed the Advanced Energy Storage (AES) project, which is currently being implemented at the Borrego Spring Microgrid.[6]

For the current phase of AES, SDG&E has recently commissioned a new 7.3 MW / 14.6 MWh battery energy storage system (BESS). This system leverages renewable energy interconnected at both the transmission and distribution levels, some of which might otherwise have to be curtailed, and supports microgrid operations as the new island master at the Borrego Springs microgrid.

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6 D.19-09-051 at 294-295.

Resiliency-Focused Microgrids

In addition to deploying utility-owned energy storage systems, SDG&E has also leveraged energy storage as part of several distinct microgrids in its territory to improve resiliency and reliability. During grid-connected mode, the energy storage systems installed as part of these microgrids provide load support, and in some cases are bid into the California Independent System Operator (CAISO) market to maximize overall system benefits from deployed systems. All of the microgrids are planned to operate in "island mode," meaning the microgrid assets provide energy to isolated circuit(s) or pre-determined circuit segment(s) in the event that the electric service is otherwise unavailable—due to planned maintenance work, unplanned damage to the system, or in response to PSPS events.

SDG&E has been a pioneer in the development of community microgrids since 2012 with the initial development of the Borrego Springs Microgrid. For the past decade, SDG&E has continued its development of these solutions to incorporate multiple resources and controllable microgrid boundaries from a single circuit to an entire substation with dynamically configurable load pockets to manage both dynamic energy and power considerations. Most recent completions include Ramona Air Attack Base microgrid in April 2022 and Cameron Corners microgrid in December 2025. With this experience, SDG&E has undertaken the development of additional microgrids to support PSPS resiliency at a community level. As discussed in previous Wildfire Mitigation Plan (WMP) updates, SDG&E has been operating two microgrids (Butterfield Ranch and Shelter Valley) in a temporary configuration, since deployment in 2020, utilizing backup mobile energy storage or traditional generators. SDG&E proposes to make Butterfield Ranch and Shelter Valley permanent microgrid solutions rather than its current temporary configuration. The majority of microgrids are deployed and serve communities in the HFTD, although their physical location may be outside of the HFTD. The two temporary community-scale microgrids located just outside the HFTD (Butterfield Ranch and Shelter Valley) serve communities that are affected by PSPS de-energizations due to the servicing distribution lines which traverse through the HFTD.

The WMP microgrid projects within the Wildfire Mitigation and Vegetation Management workpapers (Ex.SDGE-07-CWP 212730) are primarily driven by safety, reliability, and resiliency. As part of the pre-determination process for temporary microgrids, backup mobile energy storage or traditional generators are evaluated and sized appropriately prior to deployment to provide adequate load support for impacted customers. The temporary microgrid program consists of sites strategically selected based on community needs and the availability of essential services if energized. These locations enable the use of conventional generation to supply power to designated critical facilities during PSPS events, with the option to integrate mobile battery units for additional support. Each microgrid can serve either single or multiple customers. The generating assets are leased and, when not needed for PSPS operations, can be redeployed to support customers during planned distribution outages or unexpected events such as the rapid deployment at Shelter Valley during the Scissors Fire.

A key aspect of these microgrid projects is that they are designed to be 100% renewable in nature based on available solar and battery resources. SDG&E has completed upgrading the Borrego Springs Microgrid to operate with up to 100% renewable resources (Advanced Energy Storage 2.0 and Borrego 3.0), benefiting from two local solar farms and ample customer rooftop systems. SDG&E completed the Borrego 3.0 Microgrid Project in 2025. On November 5, 2025, SDG&E successfully tested the Borrego Springs microgrid for seven hours by disconnecting the single 69 kV line serving the community and energizing the entire community for five of those hours with battery power sourced entirely with solar Photovoltaic (PV) energy. As designed, this asset provides clean peaking capacity, reduces renewable curtailment in Borrego Springs, and enhances microgrid capability during islanded operations. In addition, it reduces reliance on conventional generation resources, such as diesel generators.

In addition to the two permanent microgrids above and pursuant to SDG&E's AL 4277-E-A and Res. E-5308 (March 21, 2024) authorizing remote grids, SDG&E continues to pursue the evaluation of the fire risk of long distribution lines and the associated costs, environmental impacts, and cultural aspects related to resilience. Remote grids may be an alternative option. Remote Grids can provide qualified existing remote retail electricity customers with electric retail distribution service through facilities owned, maintained, and operated by SDG&E; where the facilities are entirely separate from the remainder of the SDG&E distribution system.

Remote Grids are standalone, decentralized energy resources and utility infrastructure for continuous, permanent energy delivery, in lieu of providing retail distribution services via the larger SDG&E electric system, to small loads, in remote locations within SDG&E's distribution service area. Remote Grids may allow for the removal or permanent de-energization of lines in high wildfire risk areas. Remote Grids provide benefits to both the customers served by Remote

Grids and to all retail distribution customers who benefit from the cost-effective elimination of wildfire risks associated with retail distribution lines that run for significant distances through HFTD and which can sometimes serve a small number of remotely located customers. The elimination or permanent de-energization of these lines will serve two key objectives: (1) reducing the likelihood of fire ignition due to damage or failure of such lines; and (2) elimination or reduction of the cost to harden these lines and to conduct enhanced vegetation management to mitigate the fire-related risks. The predominant size of each customer load is anticipated to be around 25 kilowatts (kW) per installment, with 1 MW total metered load limit for all customers connected to the Remote Grid portfolio.

OVERVIEW OF CURRENT GRC GRID MODERNIZATION REQUEST

A. Proposed Grid Modernization-Related Programs and Program Drivers for the 2028 GRC

The narratives, program drivers, ongoing activities, and proposed initiatives included in the TY 2028 GRC are addressed in the preceding section, "Grid Modernization-Related Upgrades Planned, Initiated and/or Completed to Date." Table 1 in Section B presents a summary of the grid modernization-related projects and the associated estimated funding requests necessary to support SDG&E's grid modernization objectives within the TY 2028 GRC.

B. Cost Summary of Grid Modernization Plan: List of Total Amounts Requested

Table 1: Cost Summary of Grid Modernization-Related Capital Projects in 2028 GRC (Dollars in 000)

Exhibit	WP#	Project Name	Primarily DER Integration Driven	2028 ($000)
SDGE-08 - Electric Distribution Capital	071440	Fiber Optic for Relay Protection & Telecommunications	N	1,454
SDGE-08 -Electric Distribution Capital	152430	RAMP - Distribution Protection and Control Modernization	N	2,948
SDGE-08-Electric Distribution Capital	942410	RAMP - Distribution Power Quality Program	N	730
SCG-10/SDGE-14-Information Technology Capital	G09090	Customer Generation	Y	*1,621*

Exhibit	WP#	Project Name	Primarily DER Integration Driven	2028 ($000)
SCG-10/SDGE-14-Information Technology Capital	H09200	Grid Operations	Y	*7,209*
SDGE-07 - Wildfire Mitigation and Vegetation Management	212730	Microgrids	N	*0*
SCG-10/SDGE-14-Information Technology Capital	A09090	Customer Energization Portal	N	*13,435*
SDGE-07 - Wildfire Mitigation and Vegetation Management	152590	Advanced Protection Program	N	*6,540*
SDGE-08 - Electric Distribution Capital	202880	RAMP – Wireless Fault Indicators	N	*2,123*
			Total	*36,060*

In summary, among the total approximately $36.06 million of requested dollars for grid modernization for TY2028, $8.83 million are costs primarily driven by DER integration.

C. Additional Operations and Management (O&M) Expenses

In addition to the non-labor costs within the above funding request, SDG&E also forecasts the following incremental labor needs to support grid modernization-related programs within 2028 GRC, as shown below in Table 2.

Table 2: Cost Summary of additional Grid Modernization-Related O&M Expenses in 2028 GRC (Dollars in 000)

Exhibit	Workpaper	Theme	Category	2028 ($000)
SDGE-09 - Electric Distribution O&M	1ED004	Improved visibility, management, and control of the distribution system and DERs	1, 2, 9, 10	6,689
SDGE-09 - Electric Distribution	1ED013	Support advanced technologies,	4, 6	3,570

O&M		DERs, and asset management systems		
Total				10,259

GRID MODERNIZATION 10 YEAR LOOKOUT

To implement SDG&E's grid modernization vision and capabilities in a progressive manner, the Company has carefully crafted its investments in phases to accommodate a larger number of DERs and associated DER technologies in the near-term, mid-term, and long-term, as shown in Figure 3 below. Each phase is thematic in nature, with the first phase dedicated to providing key basic infrastructure necessary to safely and reliably operate SDG&E's future electric distribution grid given the number and nature of the resources that operate in parallel with it. As with any plan and roadmap, SDG&E's approach is to be forward-looking but is responsive and supportive of the need for meeting priority grid challenges. All planned investments and activities are expected to evolve and be consistent with relevant state policies and regulatory proceedings. SDG&E believes this incremental approach is the practical and cost-effective way to achieve the Company's ultimate vision, especially when compared against the alternative of an all-encompassing, "big bang" project.

Figure 3- Grid Modernization Investment Phased Roadmap

Near-Term (2026 to 2030) – The first phase focuses on traditional and foundational technology investments SDG&E has already made in the past decades along with customer affordability and engagement; which will need to continue in this TY 2028 GRC. These projects are discussed above in detail throughout the grid modernization plan in both upgrades to date and new projects proposed in this TY 2028 GRC. SDG&E believes all projects establish key components of the Company's vision to create a reliable, safe, and resilient grid given the anticipated increase in the number of DERs and their evolving technologies. SDG&E additionally anticipates continued DER pilots that will provide information that guides future phases.

Mid-Term (2031 to 2036) – The second phase includes planned investments that support the use of DERs at scale to provide energy services defined through specific Commission-approved programs. Distribution operations enhanced programs and platforms will make customers our partners; facilitating customers' ability to take actions which are either compatible with SDG&E's distribution operations or directly contribute towards operational needs. Investments in this phase are expected to evolve based on the foundational technology investments made in the past and in the near-team phase, along with changes and needs coming out of the on-going regulatory proceedings and state initiatives. With inclusive program diversity, customer-centric goals will continue evolve into a more affordable and reliable grid. The TY 2028 GRC projects set the foundation for the technology to be further developed and enhanced.

Long-Term (Beyond 2036) – The third phase allows SDG&E to support future market structures through which DERs provide grid services via competitive processes intended to provide commercial viability and overall ratepayer benefits. With continued efforts in being the best partner for our customers, we will further our evolving methods of streamlining interconnection processes, reliability, and cost effectiveness.

GRID MODERNIZATION SUPPLEMENTAL INFORMATION

As required,[7] SDG&E includes the following supplemental information for projects driven primarily by the needs created by increasing numbers of DERs and by evolving DER technologies. This supplemental information is relevant to the technology category within the grid modernization framework. Other information, such as capital budgets, O&M expense of maintaining grid modernization-related systems, investment drivers, and status of currently funded projects, is either discussed in the main Grid Modernization Plan above or in the relevant testimony justification and work papers.

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[7] D.19-09-051 at 41.

Distribution Interconnection Info. System – Rule 21 and Net Energy Metering Enhancements IT Capital Exhibit SCG-10/SDGE-14 and Workpaper (Ex. SCG-10/SDGE-14-CWP G09090) – Customer Generation	
Related Grid Modernization Categories	6. Interconnection Processing Tool
System integration challenges the technology supports	The DIIS enables a robust process for the customers to interconnect an authorized DER per RULE 21 Tariff. DIIS maintains records of applications at premise, meter, transformer. DIIS does not directly connect with any devices such as generators or telemetry. DIIS complies with current RULE 21 and WDAT Tariff. DIIS does not currently have any system integration challenges.
Grid services the technology enables	The DIIS enables a user-friendly process for customers to get authorization to interconnect a DER. DIIS does not specifically enable any grid services. DIIS provides authorized DER data to GIS and Pi-Vision to enable DER visibility and monitoring.
Supporting Technology	
Technology Maturity	SDG&E DIIS has been implemented since 2013 and is a mature and existing technology. DIIS is becoming a legacy system, requiring significant refactoring effort. To mitigate the costs and failures, DIIS is currently being converted to the Amazon Web Services (AWS) Cloud Technology platform.
Expected Useful Life of Equipment	>5 years
Equipment capacities, ratings, and other specifications	Not applicable
Which DERs does the Technology Integrate	DERs include Inverter-Based Generators such as the Solar, AES and Non-Inverter based generators such as Fuel Cell, Fuel Cell Natural Gas, Internal Combustion Engines, and other generator technologies
Proposed method and result for assessment of cost reasonableness	DIIS is a home-grown application designed and developed by SDG&E.
Locational Investment and Deployment Plan	Not a locational investment

Enterprise Distributed Energy Resource Management System (DERMS) Ex. SDGE-09 – Electric Distribution O&M Ex. SCG-10/SDGE-14 – Information Technology Capital (CWP H09200) – Grid Operations	
Related Grid Modernization Categories	2. Grid Management System
System integration challenges the technology supports	Item 1-7 of list of challenges
Grid services the technology enables	The DERMS enables SDG&E to build the foundation for operating the distribution system in a high DER future. DERMS has the potential to enable grid services such as voltage support, capacity, reliability, and resilience if coupled with appropriate resources and policy.
Supporting Technology	SCADA, ADMS, WAN, FAN
Technology Maturity	The DERMS technology maturity has evolved in the past decade but in general is developing. SDG&E will take industry implementation and use case applicability into consideration during the process of selecting vendors.
Expected Useful Life of Equipment	The DERMS project involves integration across multiple software systems. Useful life of software ranges from 10-15 years.
Equipment capacities, ratings, and other specifications	Not applicable
Which DERs does the Technology Integrate	Potentially all DERs
Proposed method and result for assessment of cost reasonableness	SDG&E plans to utilize the "lowest cost approach" to evaluate the technologies.
Locational Investment and Deployment Plan	Not a locational investment

DER INTEGRATION RELATED EPIC PROJECT SUMMARY

The EPIC Program continues into its fifth investment cycle, with authorization extending through 2030. The sections below highlight SDG&E's portfolio of DER Integration projects supported through EPIC to date. For more than a decade, SDG&E has leveraged EPIC funding to demonstrate and validate grid modernization-related technologies, advancing capabilities in DER integration, system visibility, and operational flexibility. These projects have served as a critical testbed for innovation, generating valuable insights and demonstrated benefits that inform broader deployment strategies. Building on this foundation, SDG&E has incorporated proven solutions and key learnings from EPIC initiatives into its GRC proposals to enable scaled implementation, supporting a reliable, cost-effective, and increasingly decarbonized grid.

EPIC-1 Cycle

In the EPIC-1 cycle, an initiative consisting of five pre-commercial demonstration projects on advanced distribution system automation was funded. All five projects had content pertaining to DER integration. The following projects with DER integration relevance were funded and completed:

- **Project 1 - Smart Grid Architecture Project** investigated emerging communication architecture standards for power system modernization, with focus on the International Electrotechnical Commission (IEC) 61850.
- **Project 2 - Visualization and Situational Awareness Project** explored how data collected from sensors and devices in the distribution system can be processed, combined, and presented to system operator in a way that enhances grid monitoring and situational awareness.
- Project **3 - Distributed Control for Smart Grids Project** investigated the structure for hierarchical control of distribution systems as they become more complex with adoption DER and other emerging component types.
- **Project 4 - Demonstration of Grid Support Functions of Distributed Energy Resources Project** investigated the value proposition for grid support functions of DER. It also included a demonstration of the emerging IEEE 2030.5 standard and a demonstration of DER hosting capacity analysis tools.
- **Project 5 - Smart Grid Circuit Demonstrations Project** had two major workstreams. The first workstream investigated advanced distribution circuit designs for assimilation of new technologies. The second module demonstrated methodologies and tools integration of energy storage technologies into advanced distribution systems.

EPIC-2 Cycle

In the EPIC-2 cycle, projects were funded in the initiative areas of renewables and distributed energy resource integration; grid modernization and optimization; customer focused products and services; and cross-cutting/foundational strategies and technologies. The following projects with DER integration relevance were funded and completed:

- **Project 1 - Modernization of Distribution System and Integration of Distributed Generation and Storage Project** focused on pre-commercial testing of an interoperable substation communication network based on the IEC 61850 communication standards.

- **Project 2 - Data Analytics in Support of Advanced Planning and System Operations Project** investigated the assimilation of several data streams into a central database to support advanced distribution system operations.
- **Project 3 - Monitoring, Communication, and Control Infrastructure for Power System and Advancement Project** investigated an open field messaging bus concept for interoperability, peer-to-peer communication, and multiple protocol conversion.
- **Project 4 - System Operations Development and Advancement Project** investigated improving distribution system operations via use of regional aggregation monitoring and circuit optimizers and local resource aggregation and monitoring.
- **Project 5 - Integration of Customer Systems into Electric Utility Infrastructure Project** examined control and monitoring concepts based on data from Phasor Measurement Units (PMUs) in the context of advanced SCADA.
- **Project 6 - EPRI and Other Collaborative Programs Project** included a workstream on use of machine learning to identify important attributes driving adoption of photovoltaic systems at the zip code level for disadvantaged communities (DAC) and other locations.

EPIC-3 Cycle

In the EPIC-3 cycle, projects were funded in the areas of grid modernization and optimization and customer services and enablement. The following projects with DER integration relevance were funded:

- **Project 3 - Application of Advanced Metering Infrastructure (AMI) Data to Advanced Utility System Operations Project** investigated two key areas: the use of AMI data as a voltage sensor network and as a means for phase identification. Accurate phasing information is essential for optimal control and effective operation of the distribution system with ADMS and a DERMS. The project is now complete.
- **Project 4 - Safety Training Simulators with Augmented Visualization Project** is divided into two workstreams. The first workstream is focused on a focused patrol simulator that uses multiple data sources to more rapidly locate faults in the distribution system. The second workstream is focused on a virtual reality simulator that can improve worker training to avoid voltage hazards, such as those that may be associated with an energized DER that has failed to cut out during a system outage. This project is now complete

- **Project 7 - Demonstration of Multiple-Purpose Mobile Battery for Port of San Diego and Other Applications Project** is determining the value proposition for stacked benefits that may be obtained by rotating a mobile battery to different locations with varying use cases. Two battery sizes are being tried in the demonstration work. Sites include a tenant of the Port of San Diego, an SDG&E microgrid, and two Community Resource Centers (CRCs). Use cases include customer load smoothing, demand response, peak shaving, and emergency power supply. Various mobile battery technologies and control systems, including implementation of the IEEE 2030.5 communication protocol, were tested at the ITF, and at remote field locations, to demonstrate operational flexibility and microgrid capabilities during extended planned outages and emergencies

EPIC-4 Cycle

In the EPIC-4 cycle, projects were funded in the areas of grid modernization and customer enablement, reflecting themes of grid visibility and resiliency. DER operational flexibility, and community resiliency through renewable and V2G resources. The following projects, which were launched in late 2024 and 2025 with DER integration relevance were funded:

- **Project 1 - PMU-based Network Analysis (PNA) Project** enhances situational awareness of SDG&E's local transmission system (69kV network only) by developing an optimal PMU placement software program and deploying a minimum number of PMUs in regions with an existing and growing number of inverter-based resources. This approach not only minimizes the number of PMUs required but also expands observability within the region, where voltage phasors for all 69kV buses in the region are determined from the measurements. The added PMUs will improve dynamic monitoring of transmission facilities in the local area, not just on facilities with PMUs but other transmission facilities that become observable. The contingency analysis performed based on PMUs also provides back-up to the contingency analysis running from the existing Energy Management System ("EMS") ensuring the local transmission is contingency secure. This project is currently in the development phase.
- **Project 2 - Vehicle-to-Everything (V2X) for Community Resilience** demonstrates the use of bidirectional Battery Electric Vehicles (BEVs), solar PV, and onsite BESS at CRCs to create an integrated "CRC Energy System." It aims to enhance resilience by using flexible mobile DERs along with predictive software to optimize charging, discharging, and renewable energy use. This

project is currently in the development phase.

- **Project 4 - Zonal Electrification** with DERs for Operational Flexibility project is a collaborative effort between the Customer Programs and Electric Distribution Operations teams. This initiative is designed to enhance customer decision-making by integrating DER flexibility and promoting electrification, particularly for underserved customers. As part of a broader roadmap, this project will establish production DERMS integration requirements. This includes ensuring the coexistence of DERMS with existing SDG&E technology components, which is crucial for optimizing the overall distribution system operator environment. By integrating these systems, SDG&E aims to enhance the efficiency and reliability of its distribution network, ultimately leading to better service for its customers. This project is currently in the development phase.

- **Project 5** - **Nanogrid HVAC Module Development and Demonstration** develops a mobile, clean-energy nanogrid by combining solar, hydrogen production/storage, batteries, and low-Global Warming Potential (GWP) Heating, Ventilation, and Air Conditioning (HVAC) to support emergencies or planned outages. Designed for rapid deployment, it supplies power, water, EV charging, and conditioned workspace while demonstrating a portable DER-integrated solution. This project is currently in the demonstration phase.

- **Project 6 - ITF Microgrid Testbed** builds a hardware-in-the-loop microgrid testbed at SDG&E's Integrated Test Facility with storage and inverter systems to replicate grid conditions. It supports testing of IEEE 2030.5 gateways, DERMS integrations, and third-party energy controllers, helping assess risks and validate new energy technologies. This project is currently in the development phase.

For the completed projects, all comprehensive final project reports throughout the EPIC cycles are posted on the EPIC public website at www.SDGE.com/epic.

DER INTEGRATION RELATED QUESTIONS

In addition to the main components of the Grid Modernization Plan above, SDG&E also includes answers to the DER integration related questions in the Decision.[8]

A. Foundational Technologies

i. Are there foundational planning and communications technologies that are critical for distribution system planning for

[8] D.18-03-023, Appendix A.

DER integration that have not been installed?

As discussed in Theme 1, SDG&E continues to enhance its planning and modeling processes utilizing data driven planning tools, customer facing portals and advanced forecasting methods. Customer-facing applications (DIIS, ICA, Customer Energization Portal) are leveraged to enable streamlined interconnection and energization requests. Advanced forecasting tools allow SDG&E to appropriately plan for multiple scenarios of varying DER penetration, including large DER related transportation loads. SDG&E will continue to build on these processes and tools to modernize its electric grid.

For short-term planning used for distribution operations, SDG&E currently does not have utility programs under which BTM assets would have day-ahead schedules. SDG&E does own WDAT assets that participate in the wholesale market and receive day-ahead schedules and real-time market instructions via the CAISO market. With the implementation of DERMS, the potential development of programs under which BTM assets would support distribution operations, and with Commission approval of utility DR programs, SDG&E anticipates developing a means of short-term scheduling for BTM assets.

SDG&E is undertaking Fiber Development, PLTE, and AMI enhancements across the service territory to further develop its communications technologies. This control and functionality will further support SDG&E's DER interconnection and export-to-grid as permitted by tariff.

ii. *And does the investment in these foundational technologies together with the capabilities they enable outweigh the "traditional" solution to provide the needed capability?*

With respect to long-term planning, see SDG&E's response to A.i above. With respect to short-term planning used for distribution operations, as referenced in SDG&E's response to A.i. above; these enhancements allow for continued network capabilities with the increasing DER and SCADA communication requirements that traditional solutions do not adequately provide for.

B. DER-Specific Integration Challenges

i. For each type of DER, what types of integration challenges are anticipated to occur?

DER integration challenges vary significantly by resource type, but several consistent themes emerge across PV, BESS, EVs, and DR assets. In the near term, one of the primary challenges is misalignment between planned and actual deployment. Projects may be delayed, partially installed, or configured differently than modeled, which introduces uncertainty into operational forecasts. From an operational perspective DER challenges include:

- **Limited visibility and observability**: BTM resources are not directly monitored via SCADA and operators rely on aggregated or inferred behavior rather than real-time telemetry.
- **Unpredicictable and externally driven behavior**: BESS' and EVs may operate based on market signals (e.g., CAISO schedules) rather than distribution system needs. This creates variability in load shapes and export conditions.
- **Phase-level and location uncertainty:**
  - Phase level and locational uncertainty is a known challenge when it comes to DER integration and is not unique to any one single utility. This largely comes from how distribution system and supporting data systems were originally built. Platforms like GIS, CIS, and NMS were not designed to maintain precise electrical connectivity down to the customer or device level, especially in real-time.
  - As DER penetration increases, these gaps become more noticeable. DER data is also introduced through multiple pathways such as interconnection records, AMI data, and third-party platforms. Because of that, a lot of the integration relies on mapping logic and intermediate processes instead of a single consistent system of record. That makes it difficult to fully standardize how DERs are represented with NMS.
  - From an operation standpoint, this creates challenges in maintaining an accurate model of where DERs are connected and how they behave on the system
  - **Key Considerations include:**
    - DERs are not always mapped to the correct feeder, phase, or service transformer
    - Differences between GIS, Customer Information System

(CIS), and NMS models can lead to inconsistencies that need to be reconciled

  - Current validation methods such as field verification are time intensive and not scalable across the entire system
  - Integrating DER data from AMI, interconnection processes, and external platforms often requires transformation before it can be used operationally
  - These limitations reduce confidence in power flow results and DER situational awareness and can lead to more conservative assumptions within the power flow solution that drive ADMS applications

- To address this, SDG&E is taking an incremental approach by improving model accuracy over time through better data integration, targeted validation in high impact areas, and the use of analytics to help fill in some of the gaps. The goal is not perfect data across the entire system, but a level of accuracy that supports reliable planning and operations as DER adoption continues to grow.

- **Interoperability and communication challenges**: DERs communicate through a mix of vendor platforms, gateways, and protocols and integration often relies on adapters and custom interfaces rather than standardized models.
- **Aggregation complexity (Virtual Power Plants (VPPs))**: Coordinating diverse assets (batteries, thermostats, load controllers) introduces variability in response time, availability, and performance.

ii. What type of distribution system upgrades are critical to mitigate each of these challenges?

Mitigating DER integration challenges requires both physical grid upgrades and digital/operational enhancements. Key Upgrades include:

- **Enhanced system visibility:** Expansion of SCADA and AMI data integration to improve situation awareness and increased telemetry at key nodes (feeders, substations, and critical DER aggregation points).
- **ADMS Capabilities**: Power flow and state estimation that account for DER injections and improved model accuracy down to the service transformer level.
- **DERMS implementation and integration**: This enables coordination and control of DERs to align with grid needs and provides a mechanism to manage variability and enforce operational constraints. DERMS will enable a structured approach to mitigating system impacts arising from

incomplete or evolving DER integrations.

- **Improved data integration architecture**: Standardized data exchange between CIS, GIS, SCADA, AMI, and external DER platforms and a reduction in reliance on point-to-point adapters and manual mapping.
- **Communications infrastructure upgrades**: Reliable, low latency communication pathways for DER dispatch and monitoring are critical for VPP participation and real-time control.
- **Protection and voltage regulation upgrades**: Devices must accommodate bidirectional power flow and dynamic DER behavior.

iii. How, and to what degree, does the Grid Modernization Plan enable two- way flows of electricity?

Grid modernization-related efforts have significantly advanced the ability to support bi-directional power flow, but the level of enablement varies across the system. Key enablers include:

- **SCADA and AMI integration**: Improves visibility into real-time and near real-time system conditions and enables operators to detect reverse power flow and DER-driven fluctuations.
- **Enhanced modeling and analysis with ADMS**: Allows evaluation of DER impacts through power flow and scenario analysis and supports both proactive (planning) and reactive (operations) decision-making.
- **Integration of DERMS platform**: Enables coordinated dispatch of DERs to support grid needs rather than independent DER operation. Facilitates aggregation and participation in grid services.
- **System Awareness and DER Near Real-Time Planning**: Enhanced ability to support DER near real-time planning (e.g., day-ahead DER dispatch schedules) and identify where penetration is approaching operational limits.

Although system integrations and enhancements continue, limitations remain. Visibility is still incomplete at edge of the grid (e.g., BTM DERs) and real-time control of distribution assets is not yet fully standardized or scalable. Additionally, many systems still rely on an incomplete picture of what's going on in the distribution system in real-time. As DER penetration continues to increase, modernization efforts must continue to evolve for customer affordability, flexibility, and reliability.

C. DERs Providing Grid Services

Track 3 of the High DER proceeding is examining how DERs could cost-effectively provide distribution services. "Bridging solutions" have been employed by Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) to facilitate partial energization of new loads pending completion of upgrades that allow full energization. Bridging solutions involve imposition of import limits that may be effectuated by control of customer's on-site generation and/or end-use load. There has been discussion of "non-bridging solutions," where customers would limit their imports to secure cost savings (e.g., avoiding the cost of an otherwise required main panel upgrade) or to obtain compensation (e.g., a payment based on the cost of the distribution upgrade that is avoided as a result of the import limit). At this point, SDG&E has not identified a need for bridging solutions. It is also unclear whether there is significant customer interest in non-bridging solutions that would not include payment from the utility. Non-bridging solutions that would include a payment from the utility (e.g., a payment based on deferred or avoided distribution infrastructure) have not yet been developed. Available evidence suggests there are challenges in designing programs that are cost-effective and that have compensation levels that are high enough to attract sufficient commercial interest.[9]

SDG&E is exploring the possibility of controlling DERs near or in real-time to support grid operations during abnormal conditions. Additional technology upgrades are planned to enable DERs to provide grid services including but not limited to following:

a. Advanced notification to WDAT customers of planned and unplanned (*i.e.*, emergency) outages to allow DER owners to better coordinate scheduled availability in CAISO marketplace

b. Day-ahead and real-time forecasting of system needs to inform dispatch of utility-owned DERs and DERs participating in utility DR programs

In addition, mass fleets of DERs reflect a new and unique cybersecurity challenge to all grid operators. Collectively, small inverters constitute the largest generator-connected technology on the SDG&E system. Specific investments needed include:

a. Systems to efficiently, provision, test and automatically connect DER to utility communications networks in a secure manner. The need for such systems are contingent on the identification of distribution

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[9] The results of the now-discontinued Distribution Investment Deferral Framework (DIDF) suggest that is difficult to provide compensation that is high enough to attract commercial interest from DER developers while providing overall ratepayer benefit.

services that DERs can feasibly and cost-effectively provide as well as specification of the associated performance requirements.

b. Capability to detect compromised inverters behaviorally without direct access

c. Ability to isolate large fleets of compromised inverters at scale via utility managed isolation solutions

d. The development of highly standardized interfaces supporting required applications such that plug-and-play interoperability is realized

e. Fielding of communication systems and DER management systems that conform to industry standards

f. Ensuring that sufficient reliability exists within the DER to perform the commands

D. Role of Existing and Customer Technologies in Achieving Objectives

Smart Inverters: To the extent smart inverters are used to effect established import and export limits, or in the provision of needed distribution services, the work of the Commission's Smart Inverter Working Group (SIWG) and Smart Inverter Operationalization Working Group (SIOWG) process, including communication standards, can be leveraged. SDG&E looks forward to continuing work to extend the IEEE 2030.5 / Common Smart Inverter Profile (CSIP) standard to achieve additional use cases such as DER providing energy resources to PSPS microgrids.

AMI Infrastructure: SDG&E's existing AMI infrastructure was designed primarily as a billing and customer support system. While load data collected by the AMI meters has also been leveraged to support engineering and planning analysis, the existing system architecture is not suitable for use at scale in real time grid management nor control. Further, SDG&E believes with the advent of more capable metering solutions (see SDG&E's Smart Meter 2.0 application, A.25-12-012), enhanced data analytics can be achieved.

Third Party Communication Network: SDG&E expects to leverage third party communication networks to certain DERs managed by aggregators. An emerging challenge exists when customers are enrolled with multiple aggregators, each of which provides differing services all located behind a common point of interconnection.

APPENDIX E1 – GRID MODERNIZATION CLASSIFICATION TABLE

The table below reflects the Grid Modernization Classification Table as submitted in Advice Letter 3366-E, with Column I updated to reflect relevant projects in the 2028 GRC.

A. Technology Category	B. Use Cases	C. Function	D. System wide or Local Deployment	E. Distribution System Management Activities and Responsibilities	F. System/ Integration Challenges Addressed	G. Relevant DERs	H. Applicable Grid Mod Technologies Related to DER Integration	I. 2028 GRC Application Exhibit and Category
1. Grid Connectivity	HDA, S&R, GDS	Circuit modeling, Data Used for Forecasting and DER Value and Solution Analysis	System wide	Distribution Planning, Grid Operations, Market Operations	Items 1 - 8 of list of challenges	EV, DG, ES, EE, DR	Base data layer for ICA, Load and DER forecasting, state estimation, ArcGIS, EDGIS	SDGE-09- Electric Distribution O&M (1ED013) SCG-10/SDGE-14-CWP H09200 – Grid Operations
2. Grid Management Systems (GMS)	HDA, GDS, S&R	All functions in the definitions, except for DER Value and Solutions Analysis	System wide	Distribution Grid Operations	All items	PEV, DG, ES, DR	Distributed Energy Resource Management System (DERMS), Advanced Distribution Management System (ADMS), Demand Response Management System (DRMS), DER Head-End, and VVO	SCG-10/SDGE-14-CWP H09200 – Grid Operations SDGE-09- Electric Distribution O&M (1ED013)
3. Long and Short-term Planning Tools	HDA, S&R, GDS	DER Forecasting, DER Valuation Solution Analysis, Circuit Modeling	System wide	Distribution Planning	Thermal, Operational Limitations	EE, DR, EV, DG, ES	Integrated Load and DER forecasting, solution analysis for capacity/reliability, LoadSEER, Power flow modeling and analysis of distribution feeders (CYME) System Modeling Toolset	SDGE-09- Electric Distribution O&M (1ED013) SCG-10/SDGE-14-CWP H09200 – Grid Operations

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							(SMT); Long- Term Planning Tools (LTPT;) Integration Capacity Analysis (ICA), Locational Net Benefit Analysis Tool (LNBA)	
4. Data Sharing Portals	HDA, S&R, GDS	DER Valuation, Solution Analysis, Circuit Modeling	System wide	Distribution Planning	Sustained voltage violations, thermal, protection	EE, DR, EV, DG, ES	Data Sharing Portal (web interface) to publish Distribution Resources Plan data; Distribution	SCG-10/SDGE-14-CWP G09090 - Information Technology Capital SDGE-09- Electric Distribution O&M (1ED013)
5. Grid Analytics Application	HDA, S&R, GDS	Circuit/System Modeling	System wide	Distribution Planning Grid Operations	Sustained voltage violations, Thermal, protection, asset management	EV, DG, ES, DR	Asset management, sensing and measurement (data), improves quality of asset data to improve distribution planning inputs and operational decisions	SDGE-09- Electric Distribution O&M (1ED013) SCG-10/SDGE-14-CWP H09200 – Grid Operations
6. Interconnection Processing Tool	HDA, S&R, GDS	Application Assessment and Processing	System wide	Service Planning and Customer Engagement	Indirect impact on sustained voltage violations, thermal, protection interconnection process	EV, DG, ES	Customer facing application to support streamlining the interconnection process, improve distribution planning, Integration Capacity Analysis (ICA)	SCG-10/SDG&E-14-CWP G09090 - Information Technology Capital SDGE-09- Electric Distribution O&M (1ED013)
7. Adaptive Protection System	S&R, HDA, GDS	Sensing & Measurement, Data & Device Communications, Control &	Local & System wide	Grid Operations	Protection	All	This is typically incorporated as part of the Common Substation Platform (CSP) at the	SDGE-07-CWP 212730 - Wildfire Mitigation and Vegetation Management

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		Feedback Systems, Reliability Management,					substation level. In the future, it may be incorporated into ADMS. (Capability in GMS for SCE)	
8. Substation Automation and Common Substation Platform (CSP)	HDA, S&R, GDS	Sensing & Measurement, Data & Device Communications, Control & Feedback Systems, Reliability Management, Cybersecurity	Local & System Wide	Distribution Planning, Grid Operations, Market Operations	Items 1 - 10 of list of challenges	EV, DG, ES	SCADA, coordinated distribution device control with DERs, protection, cybersecurity	SDGE-08-CWP 152430 - Distribution Protection & Control Modernization Program
9. Volt/Var Optimization	HDA, S&R, GDS	Sensing & Measurement, Data & Device, Communications Control & Feedback Systems	Local	Distribution Planning, Grid Operations, Market Operations	Voltage fluctuation, sustained voltage violations, Low (Secondary) Voltage Controllers, Conservation Voltage Reduction	EV, DG, ES, DR	Substation Load Tap Changers, Voltage Regulators, Automated programmable capacitor controls, integration with GMS and/or DMS and EMS, future integration with smart inverters	SDGE-09- Electric Distribution O&M (1ED013) SCG-10/SDGE-14-CWP H09200 – Grid Operations SDGE-09- Electric Distribution O&M (1ED004)
10. Fault Location, Isolation and Service Restoration (FLISR)	HDA, S&R, GDS	Sensing & Measurement, Data & Device Communications, Control & Feedback Systems, Reliability Management	Local	Distribution Planning, Grid Operations, Market Operations	Thermal, Operational Limitations, Fault Location & Service Restoration, Cybersecurity	EV, DG, ES, DR	Remote Intelligent Switches, Augmented Remote Control Switches, Automatic Reclosers, RCS retrofits	SDGE-09- Electric Distribution O&M (1ED013)
11. Remote Fault Indicators	S&R, HDA, GDS	Sensing &	Local	Distribution Planning, Grid Operations,	Thermal,	EV, DG, ES	Wireless bidirectional fault indicators, providing	SDGE-08-CWP 202880 - RAMP –

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		Measurement, Data & Device Comms.		Market Operations	Operational Limitations, Cybersecurity		real time power flow characteristics	Wireless Fault Indicators
12. Field Area Network	S&R, HDA, GDS	Sensing and Measurement, Data & Device Communications, Cybersecurity	Large Local Areas, eventually system wide	Distribution Planning, Grid Operations, Market Operations	Items 1 - 10 of list of challenges	EV, DG, ES	Wireless radios, Routers	Sub-project level inclusion across Grid Modernization
13. Wide Area Network	S&R, HDA, GDS	Sensing and Measurement, Data & Device Communications, Cybersecurity	Large Local Areas, eventually system wide	Distribution Planning, Grid Operations, Market Operations	Items 1 - 10 of list of challenges	EV, DG, ES	Fiber optic and IP connectivity	SDGE-08-CWP 071440 - Fiber Optic for Relay Protection & Telecommunications
14. Grid Sensors	HDA, S&R, GDS	Sensing & Measurement, Data & Device Comms.	Local	Distribution Planning, Grid Operations, Market Operations	Thermal, Operational Limitations, Fault Location & Service Restoration, Cybersecurity	EV, DG, ES	Typically, incorporated with other devices/systems such as SCADA reclosers, and FLISR schemes. Telemetry included with the RFIs, RCS retrofits and RISs. This could also include PMUs	SDGE-08-CWP 942410 – Distribution Power Quality Program
15. Remote Controlled Switches	HDA, S&R	Control & Feedback Systems	Local	Distribution Planning, Grid Operations,	Operational Limitations	All	Typically, incorporated with other devices/ systems such as SCADA reclosers, and FLISR schemes.	N/A
16. DER Hosting Capacity Reinforcement	HDA, GDS, S&R	Control & Feedback Systems	Local	Grid Operations	Thermal	All	Installing new manual switches, upgrading sections of cable/ conductor, extending feeder lines to create new ties	N/A

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17. Relay Replacement	HDA, S&R	Control & Feedback Systems	Local	System Planning, Grid Operations	Protection	All	Upgrading legacy protection relays on as-needed basis	SDGE-08-CWP 152430 - Distribution Protection & Control Modernization Program
18. Utility-Owned Storage	HDA, S&R	Sensing & Measurement, Control & Feedback, Reliability Management	Local	System Planning and Grid Operations	Voltage Violations, Thermal, Operational Limitations, DER Aggregation Impacts	DR, EV, DG, ES	Energy storage systems installed on the distribution systems to buffer DER output and load (PEV)	SDGE-07-CWP 212730 - Wildfire Mitigation and Vegetation Management
19. Microgrid Interfaces	HDA, S&R	Sensing & Measurement, Control & Feedback, Reliability Management	Local	System Planning and Grid Operations	Voltage Violations, Thermal, Operational Limitations, DER Aggregation Impacts	DR, EV, DG, ES	"Trayer" switches and other hardware and software which allow DER powered microgrids	Continued efforts through EPIC Program

APPENDIX E2 - ACRONYM TABLE

Acronym	Definition
AB	Assembly Bill
ADMS	Advanced Distribution Management System
AES	Advanced Energy Storage
AMI	Advanced Metering Infrastructure
AP	Advanced Protection
APP	Advanced Protection Program
AWS	Amazon Web Services
BESS	Battery Energy Storage System
BEV	Battery Electric Vehicle
BTM	Behind-the-Meter
CAISO	California Independent System Operator
CIS	Customer Information System
CNS	Customer Notification System
CPUC	California Public Utilities Commission
CRC	Community Resource Center
CSIP	Common Smart Inverter Profile
DAC	Disadvantaged Communities
DCRI	Distribution Communications Reliability Improvements
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DIDF	Distribution Investment Deferral Framework
DIIS	Distribution Interconnection Information System
DMS	Distribution Management System
DOE	Department of Energy
DR	Demand Response

DRMS	Demand Response Management System
DRP	Distributed Resource Planning
DSCADA	Distribution SCADA
EDOT	Electric Distribution Operations - Technology
EE	Energy Efficiency
ELS	Extended Life Cycle Support
EMS	Energy Management System
EPIC	Electric Program Investment Charge
ES	Energy Storage
EV	Electric Vehicles
FAN	Field Area Network
FCC	Federal Communications Commission
FL	Fault Location
FLISR	Fault Location, Isolation, and Service Restoration
FTM	Front-of-the-Meter
GDS	Grid Data Services
GHG	Greenhouse Gas
GIS	Geographic Information System
GMS	Grid Management System
GO	General Order
GRC	General Rate Case
GWP	Global Warming Potential
HD	Heavy-Duty
HDA	High Distributed Energy Resources Adoption
HFTD	High Fire Threat District
HMC	Head-End Management Controller
HVAC	Heating, Ventilation, and Air Conditioning
IBR	Inverter-Based Resource
ICA	Integration Capacity Analysis
ICCP	Inter-Control Center Communications Protocol
IEC	International Electrotechnical Commission

IEEE	Institute of Electrical and Electronics Engineers
IoT	Internet of Things
IOU	Investor-Owned Utilities
IP	Internet Protocol
iPerf	Internet Performance
IT	Information Technology
ITF	Integrated Test Facility
kW	Kilowatt
LADC	Local Area Distribution Controller
LGP	Limited Generation Profile
LTE	Long-Term Evolution
MD	Medium-Duty
MW	Megawatts
NBT	Net Billing Tariff
NEM	Net Energy Metering
NMS	Network Management System
O&M	Operations and Management
OIR	Order Instituting Rulemaking
OMS	Outage Management System
OT	Operational Technology
PEV	Plug-in Electric Vehicle
PG&E	Pacific Gas & Electric
PLTE	Private Long Term Evolution
PMU	Phasor Measurement Unit
PQ	Power Quality
PSPS	Public Safety Power Shutoff
PV	Photovoltaic
RAN	Radio Access Network
RCS	Request for Comments
RF	Radio Frequency
RFI	Request for Information

RFP	Request for Proposal
RTDS	Real-Time Digital Simulator
RTU	Remote Terminal Unit
S&R	Safety and Reliability
SAP	Systems, Applications, and Products
SB	Senate Bill
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric Company
SEPA	Smart Electric Power Alliance
SGO	Smart Grid Operation
SIM	Subscriber Identity Module
SIOWG	Smart Inverter Operationalization Working Group
SIWG	Smart Inverter Working Group
SPOC	Single Point of Contact
TLGP	Tribal/Local Government Portal
TY	Test Year
UE	User Equipment
V2X	Vehicle-to-Everything
VAR	Voltage Ampere-Reactive
VPP	Virtual Power Plants
VVO	Volt/Var Optimization
WAN	Wide Area Network
WDAT	Wholesale Distribution Access Tariff
WFI	Wireless Fault Indicator
WMP	Wildfire Mitigation Plan
WP	Work Paper

(END OF GRID MODERNIZATION PLAN)