COST-EFFECTIVENESS ANALYSIS

for the

PIPELINE SAFETY & RELIABILITY PROJECT

San Diego Gas & Electric Company

and

Southern California Gas Company

Application A.15-09-013

Volume III

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PREPARED BY PWC

WITH INPUT AND DATA FROM APPLICANTS AND CONTENT FROM APPLICANTS' CONSULTANTS

COST-EFFECTIVENESS ANALYSIS FOR THE AMENDED APPLICATION OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 G) AND SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE PIPELINE SAFETY & RELIABILITY PROJECT

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I. EXECUTIVE SUMMARY

On September 30, 2015 San Diego Gas and Electric Company (SDG&E) and Southern California Gas Company (collectively the Applicants) filed Application 15-09-013[1] (Application) with the California Public Utilities Commission (CPUC or Commission) in support of their Pipeline Safety & Reliability Project (PSRP or Proposed Project).

The Proposed Project consists of constructing a new 47 mile long, 36-inch natural gas transmission line, (Line 3602), and de-rating the existing Line 1600.

On January 22, 2016 the Assigned Commissioner and Administrative Law Judge issued a joint ruling[2] (Ruling) directing the Applicants to file and serve an Amended Application by March 21, 2016 that includes, among other things, a cost analysis that compares the relative costs and benefits of the Proposed Project and various project alternatives (Alternatives).[3] Specifically, the Ruling requires that the analysis: 1) quantify seven categories of benefits, and 2) apply quantifiable data to define the relative costs and benefits of the Proposed Project and the Alternatives identified in the Ruling.[4] The seven categories of benefits that must be quantified are (1) increased safety; (2) increased reliability; (3) increased operational flexibility; (4) increased system capacity; (5) increased ability for gas storage by line packing; (6) reduction in the price of gas for ratepayers; and (7) other benefits identified by the Applicant.[5]

This analysis has been prepared by PricewaterhouseCoopers Advisory Services, LLC (PwC), with input and data from the Applicants, in response to the Ruling (Cost-Effectiveness Analysis). Consistent with the Ruling, the analysis applies quantifiable data to define the relative costs and benefits of the Proposed Project and Alternatives. The costs analysis includes the estimated fixed costs, the on-going operating costs, and the avoided costs (*i.e.*, costs that will not be incurred when the Proposed Project or a particular Alternative is implemented). The benefits analysis evaluates each of the seven types of benefits specifically identified in the Ruling.

[1] Certificate of Public Convenience and Necessity for the Pipeline Safety and Reliability Project, Application (A.) 15-09-013.
[2] Joint Assigned Commissioner and Administrative Law Judge's Ruling Requiring an Amended Application and Seeking Protests, Responses and Replies (Ruling).
[3] Ruling, pages 11-14.
[4] Ruling, page 12.
[5] Ruling, page 12.

Table 1 below highlights the requirements in the Ruling that are addressed by this Cost-Effectiveness Analysis.

Table 1 - Ruling Requirements

Ruling Requirement[6]	Method for Complying with the Ruling	Reference in Cost-Effectiveness Report
The analysis will ***quantify specific benefits*** *including: (1) increased safety; (2) increased reliability; (3) increased operational flexibility; (4) increased system capacity; (5) increased ability for gas storage by line packing; (6) reduction in the price of gas for ratepayers; and (7) other benefits identified by the Applicant. All benefits must be quantified.*	A benefits scoring model was developed based on quantifiable data for each of the seven benefit types.	• Section V: Benefits Analysis • Table 11 - Increased Safety Benefits Score • Table 14 - Increased Reliability Benefits Score • • Table 17 - Increased Operational Flexibility Benefits Score • Table 20 - Increased System Capacity Benefits Score • Increased Gas Storage through Line Pack – included under Increased System Capacity • Table 23 - Reduction in Gas Prices to Ratepayers Benefit Scores • Table 24 - Summary of Other Benefits Scores
The analysis will apply quantifiable data to define the relative ***costs*** *of the proposed project and, at a minimum, the range of alternatives identified in this Ruling.*[7]	First, preliminary cost estimates were developed for the Proposed Project and the Alternatives, then an "avoided cost" was calculated for the Proposed Project and each Alternative so that a "net cost" could be derived for each.	• Section IV: Cost Analysis • Table 6 - Estimated Fixed and Operating Costs • Section IV, C: Avoided Costs Associated with the Proposed Project and Alternatives • • Table 8 Avoided Costs
The analysis will apply quantifiable data to define the relative ***benefits*** *of the proposed project and, at a minimum, the range of alternatives.*	A benefit score was developed for the Proposed Project and each Alternative.	• Table 2 - Proposed Project and Alternatives Relative Benefit Ranking and Net Costs
Include an estimate of costs, both fixed and operating, as required by Rule 3.1(f).	Preliminary estimates were developed for both the fixed and operating costs for the Proposed Project and the Alternatives using standard estimating methods based on the known project scope.	• Section IV: Cost Estimating • Table 6 - Estimated Fixed and Operating Costs

[6] Ruling, page 12.
[7] The range of alternatives refers to the 10 alternative projects labeled A-K in the Ruling, pages 12-13.

The relative costs and benefits of the Proposed Project and Alternatives are summarized in Table 2 below.

Table 2 - Proposed Project and Alternatives Relative Benefit Ranking[8] and Net Costs[9]

	Project Alternatives	Benefit Rank	Net Cost ($M)
A	Proposed Project (36" pipeline Rainbow to Line 2010 Route)	1	$256.2
B	Hydrotest Alternative[10]	15	$118.7
C1	Alt Diameter Pipeline, Proposed Route (10")	18	$302.7
C2	Alt Diameter Pipeline, Proposed Route (12")	18	$291.6
C3	Alt Diameter Pipeline, Proposed Route (16")	11	$241.4
C4	Alt Diameter Pipeline, Proposed Route (20")	10	$239.2
C5	Alt Diameter Pipeline, Proposed Route (24")	9	$229.6
C6	Alt Diameter Pipeline, Proposed Route (30")	8	$233.5
C7	Alt Diameter Pipeline, Proposed Route (42")	1	$341.9
D	Replace Line 1600 in Place with a 16" Transmission Pipeline Alternative	12	$560.4
E/F	Otay Mesa Alternatives[11]	13	$876.8
G	LNG Storage (Peak-Shaver) Alternative	14	$2,584.7
H1	Alternate Energy Alternative: Grid-Scale Batteries	16	$8,330.1
H2	Alternate Energy Alternative: Smaller-Scale Batteries	16	$10,010.1
I	Offshore Route	7	$1,295.5
J1	Blythe to Santee Alternative 1	3	$1,219.3
J2	Blythe to Santee Alternative 2	3	$1,157.3
J3	Cactus City to San Diego Alternative	3	$981.1
K	Second Pipeline Along Line 3010 Alternative	3	$427.1

After evaluating the net costs and benefits of the Proposed Project and Alternatives, this Cost-Effectiveness Analysis concludes that the Proposed Project is the most cost-effective, prudent alternative. This conclusion is based on the following:

[8] Ranked from 1 through 19 with 1 being the highest rank.
[9] Net costs are calculated as: Fixed Costs + Operations & Maintenance Costs + Avoided Costs. Net costs are discussed in Section IV, C.
[10] In the Ruling, Alternative B is referred to as the "No Project Alternative" and defined as hydrotesting Line 1600 in sections and repairing or replacing pipeline segments as needed. The Applicants refer to Alternative B herein as the "Hydrotest Alternative."
[11] The Ruling identifies two alternative projects utilizing the Otay Mesa receipt point: Non-Physical (Contractual) or Minimal Footprint Solutions (Alternative E); and the Northern Baja Alternative (Alternative F). Both of these rely upon the use of Otay Mesa receipt point (Otay Mesa) capacity in place of the Proposed Project. Accordingly, the Applicants will refer to the two alternatives as a single project titled "Otay Mesa Alternatives." See Prepared Direct Testimony of Gwen Marelli (March 21, 2016).

- The lowest net cost project, the Hydrotest Alternative, was ranked among the lowest in terms of project benefits;

- The Proposed Project and the Alternate Diameter Pipeline (42-inch) are ranked highest in terms of benefits and also among the highest in terms of having the least net costs;

- The difference in net costs between the least-cost, Hydrotest Alternative, and the Proposed Project is approximately $138 million, which is outweighed by significant, quantifiable benefits that are not offered by the Hydrotest Alternative;

- After the least-cost alternative (Hydrotest Alternative), five projects are clustered in the net cost range of $225 million to $260 million and include alternate pipeline diameters of 16-, 20-, 24-, 30- and 36-inches (the Proposed Project);

- In terms of benefits, the Proposed Project scored higher than the four other Alternatives that also ranked in the net cost range of $225 million to $260 million (Alternative Diameters Pipelines 16-, 20-, 24- and 30-inch);

- After the cluster that includes the Proposed Project, the next group of projects grouped by least net cost ranges from $290 million to $430 million and includes Alternate Diameters of 10-, 12- and 42-inches as well as the Second Pipeline Along Line 3010 Alternative;

- The two highest net cost categories include Alternatives with net costs ranging from $500 million to $1 billion (Replace Line 1600 In-Place with a New 16-inch Transmission Pipeline Alternative, Otay Mesa Alternatives, Cactus City to San Diego) and more than $1 billion (Blythe to Santee Pipeline Route Alternatives 1 and 2, Off-Shore, Liquefied Natural Gas (LNG) Storage, and Alternate Energy Alternatives);

- Four Alternatives rank second highest in terms of benefits: the Cross-Country Pipeline Route Alternatives (Blythe to Santee Pipeline Routes, Alternatives 1 and 2; Cactus City to San Diego Alternative) and the Second Pipeline Along Line 3010 Alternative;

- The 10- and 12-inch Alternative Diameter Pipelines rank lowest in terms of benefits;

- New, larger diameter pipelines, including the Proposed Project, outperform the "least-cost" (Hydrotest Alternative) in six out of the seven benefits categories (safety, reliability, operational flexibility, system capacity, gas storage through line pack, and other benefits) and receive the same score for the category of reduction in gas price for ratepayers;

- As compared to the 16-, 20-, 24- and 30-inch Alternate Diameter Pipelines, the Proposed Project provides additional reliability, operational flexibility, system capacity, gas storage through line pack, and other benefits;

- The 42-inch Alternate Diameter Pipeline offers the same benefits as the Proposed Project but costs approximately $86 million more.

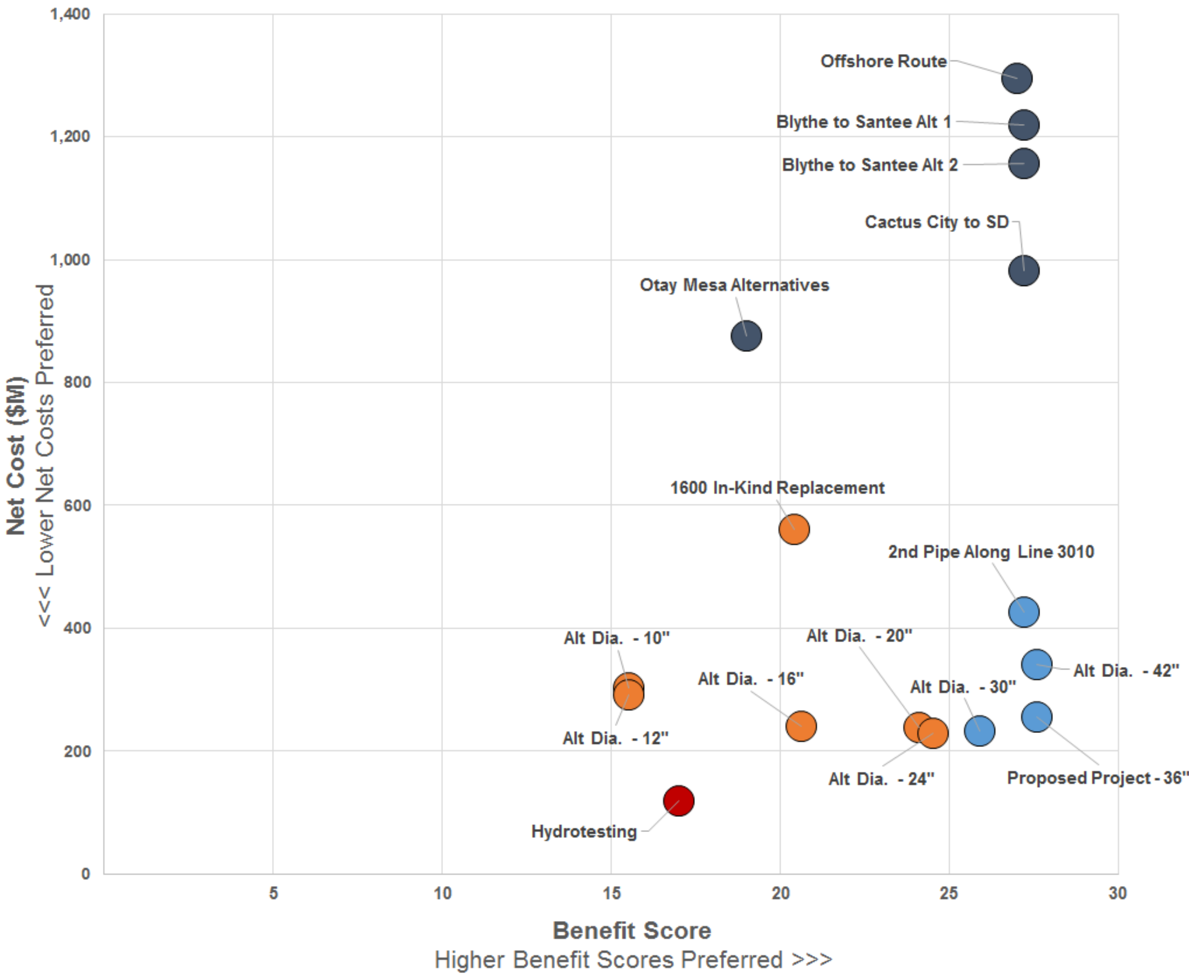
For these reasons, the Proposed Project is identified as the overall most cost-effective alternative.

The results of this Cost-Effectiveness Analysis – the net costs and benefits - are shown in Figure 1 below.[12]

[12] The following Alternatives have been excluded from the chart in order to manage axis scale:

- LNG Storage - Benefit Score 18.6, net cost $2.6B
- Alt Energy (Grid Scale) - Benefit Score 16.2, net cost $8.3B
- Alt Energy (Smaller Scale) - Benefit Score 16.2, net cost $10B

Figure 1 - Net Costs and Benefits Score for Proposed Project and Alternative Projects



II. INTRODUCTION AND APPROACH

A. Background and Summary

On September 30, 2015 San Diego Gas and Electric Company (SDG&E) and Southern California Gas Company (collectively, the Applicants) submitted an application to the California Public Utilities Commission (CPUC or Commission) for a Certificate of Public Convenience and Necessity (CPCN) for the Pipeline Safety & Reliability Project, Application 15-09-013 (Application). The Proposed Project consists of constructing a new 47 mile long, 36-inch natural gas transmission line (Line 3602), along with the de-rating of existing Line 1600 (Proposed Project).

On January 22, 2016 the Assigned Commissioner and Administrative Law Judge issued the Joint Assigned Commissioner and Administrative Law Judge's Ruling Requiring an Amended Application and Seeking Protests, Responses and Replies. The Ruling directs the Applicants to file and serve an Amended Application by March 21, 2016 that includes, among other things, a cost analysis that compares the relative costs and benefits of the Proposed Project and various Alternatives.[13] Specifically, the Ruling states:

- [Applicants] shall include a needs analysis in compliance with Rule 3.1(e) and cost analysis comparing the project with any feasible alternative sources of power, in compliance with Section 1003(d) and Rule 3.1(f).[14]
- The analysis will quantify specific benefits including: 1) increased safety; 2) increased reliability; 3) increased operational flexibility; 4) increased system capacity; 5) increased ability for gas storage by line packing; 6) reduction in the price of gas for ratepayers; and 7) other benefits identified by Applicant.[15]
- The analysis will apply quantifiable data to define the relative costs and benefits of the Proposed Project and, at a minimum, the range of alternatives identified in the Ruling. (For purposes of analysis, the cost analysis shall assume that each of the [identified] alternatives are feasible and include an estimate of costs, both fixed and operating, as required by Rule 3.1(f).)[16]

The "range of alternatives" briefly identified in the Ruling[17] is described in Section III of this Cost-Effectiveness Analysis, together with the assumptions made by the Applicants regarding the Alternatives.

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[13] Ruling, pages 11-14.
[14] Ruling, page 11.
[15] Ruling, page 12.
[16] Ruling, page 12.
[17] Ruling, pages 12-13.

This Cost-Effectiveness Analysis has been prepared by PwC, with data and input from the Applicants, to address the requirement that Applicants prepare a cost analysis comparing the Proposed Project with the Alternatives; quantify specific benefit categories; and apply quantifiable data to define the relative costs and benefits of the Proposed Project and Alternatives. Per the Ruling, this Cost-Effectiveness Analysis assumes that each of the Alternatives is feasible.[18]

B. Overview of Methodology

Consistent with industry practice and Commission and Federal Energy Regulatory Commission (FERC) precedent,[19] PwC, with input and data from the Applicants, undertook this Cost-Effectiveness Analysis to quantify and compare the relative costs and benefits of the Proposed Project and Alternatives described in the Ruling.

A cost-effectiveness analysis compares the cost of a project to different measures of program benefits.[12] A cost-effectiveness analysis evaluates not only the monetary benefits of a project but also considers benefits that are difficult or impractical to express in monetary terms. These benefits can be expressed in monetary or non-monetary (yet quantitative) units. Cost-effectiveness analyses have been applied to projects with both monetary and non-monetary benefits.

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[18] Ruling, page 12.

[19] The CPUC has utilized cost-effectiveness analysis for evaluating the costs and benefits of a project or program. For example, the CPUC requirements for evaluating demand-side management program include:

> "All demand-side resources (energy efficiency, demand response, and distributed generation) undergo a cost-effectiveness analysis. While the specific tests and the applications of those tests varies among the resources, the foundation of cost-effectiveness analysis for all demand-side resources is based in the Standard Practice Manual. The Standard Practice Manual contains the Commission's method of evaluating energy saving investments using various cost-effectiveness tests. The four tests described in the Standard Practice Manual assess the costs and benefits of demand-side resource programs from different stakeholder perspectives, including participants and non-participants."
> (http://www.cpuc.ca.gov/General.aspx?id=5267)

FERC has also approved the use of a cost-effectiveness analysis to evaluate transmission planning projects.

> "Here, the cost-effectiveness evaluation applies to projects considered not only to provide economic benefits but also to provide reliability benefits and to meet public policy requirements. While the benefits of projects considered purely for economics (e.g. adjusted production cost savings) may be quantified readily and included in a formula, reliability benefits and benefits derived from meeting public policy requirements may not be so readily quantifiable and detailed, and thus cannot easily be included in a formula."
> (https://ferc.gov/whats-new/comm-meet/2011/072111/e-3.pdf)

This Cost-Effectiveness Analysis, undertaken to comply with the Ruling, is based on two forms of benefits analysis: quantitative financial analysis and quantitative non-cost, unit-based analysis (unit benefits). The different types of analysis and the mechanisms used to score and compare the benefits are discussed in the following sections of this Cost-Effectiveness Analysis.

The Ruling requires the Applicants to conduct an analysis that will apply quantifiable data to define the relative costs and benefits of the Proposed Project and a range of Alternatives.[20] To comply with the requirement to apply quantifiable data to define the relative costs of the projects, PwC reviewed the Applicants' estimates of both the fixed cost for constructing the Proposed Project and the Alternatives and the on-going estimated costs for operating and maintaining them. Additionally, PwC and the Applicants identified certain avoided costs applicable to the Proposed Project and the Alternatives. PwC and the Applicants then quantified the impact of those avoided costs on the Proposed Project and the Alternatives over time to derive the "net cost" associated with the Proposed Project and each Alternative.

To comply with the requirement to apply quantifiable data to define the relative benefits of the projects, PwC and the Applicants first identified quantifiable characteristics and desirable outcomes associated with the seven benefits categories identified in the Ruling. Next, a scoring mechanism was developed and applied as an objective means to evaluate the Proposed Project and the Alternatives against each of the seven benefit types. The Applicants identified and defined a number of individual benefits within each of the seven benefit categories and applied non-monetary, quantifiable measures (*e.g.*, percent reduction in pipeline failures, percent increase in capacity) as the basis for scoring the Proposed Project and the Alternatives against each benefit. Care was taken to treat each benefit as unique and not count them more than one time in the scoring model. Once each of the projects was scored, PwC ranked them from highest to lowest based on the overall benefit score.

[20] Ruling, page 12.

Table 3 lists the costs and benefits evaluated and scored consistent with the requirements of the Ruling.

Table 3 - Costs and Benefits Evaluated and Scored

	Type of Assessment		
Description	**Quantitative Monetary**	**Quantitative Non-Monetary**	**Metric/Measure**
Project Costs - Fixed costs	✓		Dollars
Project Costs - Operating costs	✓		Dollars
Avoided Costs - Replacement of Line 1600	✓		Dollars
Avoided Costs - Reduced operation of Moreno Compressor Station	✓		Dollars
Safety – Increased safety margin to prevent pipeline rupture through the de-rating of Line 1600		✓	Defined benefit score
Safety - Long-term safety benefit of transmission pipeline		✓	Defined benefit score
Safety - Reduction in incidents per HCA mile of pipeline		✓	Defined benefit score
Safety - Increased real-time awareness of excavation damage		✓	Defined benefit score
Safety - Achievement of "as soon as practicable" safety objective		✓	Duration by year
Increased Reliability - Redundancy to natural gas transmission system		✓	Defined benefit score
Increased Reliability - Curtailment impact to core gas customers		✓	Percentile of average severity of curtailment scores
Increased Reliability - Curtailment impact to electric generation (EG) gas customers		✓	Percentile of average severity of curtailment scores
Increased Operational Flexibility - Meeting current and future natural gas peak demand		✓	Defined benefit score
Increased Operational Flexibility - Utility operational control of asset		✓	Defined benefit score
Increased System Capacity - Impact to system capacity		✓	Percentage increase in MMcfd of capacity
Increased gas storage through line pack		✓	Proportional to capacity
Reduction in gas prices to ratepayers		✓	Defined benefit score
Other Benefits - Emissions reductions due to reduced operating hours at compressor stations		✓	Percent reduction in net Moreno operating hours

All of the underlying estimates and technical data used to develop the cost estimates, avoided cost estimates and quantifiable benefits analysis were provided by the Applicants.

III. DESCRIPTION OF THE PROPOSED PROJECT AND THE PROJECT ALTERNATIVES

This section briefly summarizes the Proposed Project and the Alternatives identified in the Ruling.

For all of the Alternatives except the Hydrotest Alternative and the Replace Line 1600 in Place with a New 16-inch Transmission Pipeline Alternative, Line 1600 would be de-rated and operated as a distribution asset.

A. Proposed Project (Pipeline Safety & Reliability Project - PSRP)

Line 3602 is the proposed new 36-inch diameter, 47-mile long natural gas transmission pipeline connecting the existing Rainbow Metering Station to Marine Corps Air Station (MCAS) Miramar. Additionally, the Proposed Project includes the de-rating of the existing Line 1600, a 16-inch natural gas transmission pipeline that also runs from Rainbow Station to Miramar.

For additional information regarding the Proposed Project, please reference Applicants' PEA.[21]

B. Hydrotest Alternative

In the Ruling, the No Project Alternative includes hydrotesting Line 1600 in sections and only repairing or replacing pipeline segments as needed.[22]

The Hydrotest Alternative involves a complex four year project to test the northern 45-miles of Line 1600, from Rainbow Metering Station to Kearny Villa Station. Line 1600 is an approximately 50-mile, 16-inch diameter, high pressure natural gas transmission pipeline that begins at the Rainbow Metering Station and terminates at Mission Station in San Diego.[23] The Hydrotest Alternative will involve testing 19 different pipeline segments during the shoulder months.[24] The Applicants would hydrotest Line 1600 in sections and only repair or replace pipeline segments as needed.

Testing will require installing bypasses and arranging for alternative distribution requirements and could include environmental mitigation and community impacts. It will also require gas to be imported from the gas transmission system receipt point located at Otay Mesa.

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[21] A.15-09-013, Volume II, Proponent's Environmental Assessment (PEA), Chapter 3.0, Project Description and Chapter 5.2.3, pages 5-16.
[22] Ruling, page 12.
[23] Line 1600 Hydrotest Study and Cost Estimate. *See* Prepared Direct Testimony of Neil Navin (March 21, 2016), Attachment A, Appendix 12.
[24] The shoulder months are from April 1 through June 15, and October 1 through December 15.

For additional information regarding this Alternative, please refer to the Line 1600 Hydrotest Study and Cost Estimate.[25]

C. Alternative Diameter Pipeline, Various Sizes, Proposed Route

This Alternative requires the Applicants to evaluate the installation of different sized pipelines of alternate diameters. This analysis assumed the same proposed route as the 47-mile Proposed Project from Rainbow Metering Station to MCAS Miramar. The seven alternate diameters addressed in this Cost-Effectiveness Analysis are:

Table 4 - Pipeline Material Thickness by Alternative Proposed Diameter of Line[26]

No.:	Alternate Diameter[27]	Pipeline Specification
C1	Alt. Dia. 10"	Pipe, 10", X-52, 0.365" WT, FBE
C2	Alt. Dia. 12"	Pipe, 12", X-52, 0.375" WT, FBE
C3	Alt. Dia. 16"	Pipe, 16", X-52, 0.375" WT, FBE
C4	Alt. Dia. 20"	Pipe, 20", X-52, 0.375" WT, FBE
C5	Alt. Dia. 24"	Pipe, 24", X-65, 0.375" WT, FBE
C6	Alt. Dia. 30"	Pipe, 30", X-65, 0.50" WT, FBE
C7	Alt. Dia. 42"	Pipe, 42", X-60, 0.750" WT, FBE

Alternative C was included in the Ruling[28] but was not included in the PEA.

D. Replace Line 1600 in Place with a New 16-inch Transmission Pipeline

This Alternative requires the removal of the existing Line 1600 and replacing it with a new 16-inch diameter pipeline within existing easements.

Nineteen pipeline segments covering approximately 45 miles would be removed and replaced. Removal and replacement would be conducted in phases.

For additional information regarding Alternative D, please refer to the PEA.[29]

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[25] *See* Prepared Direct Testimony of Neil Navin (March 21, 2016), Attachment B.
[26] Provided by the Applicants.
[27] The Ruling calls for "an evaluation of pipeline sizes that range in diameter from 10 inches to 40 inches." On February 9, 2016, the Applicants confirmed with Energy Division staff that standard-sized pipeline diameters within this range should be evaluated and that a 42-inch diameter alternative can be included because 40 inches is not a standard size diameter.
[28] Ruling, page 13.
[29] PEA, Chapter 5.2.2, Page 5-9.

E. Otay Mesa Alternatives

The Ruling identifies two alternative projects utilizing the Otay Mesa receipt point: Non-Physical (Contractual) or Minimal Footprint Solutions (Alternative E); and the Northern Baja Alternative (Alternative F).[30] Both of these rely upon the use of Otay Mesa receipt point (Otay Mesa) capacity in place of the Proposed Project. Accordingly, the Applicants will refer to the two alternatives as a single project titled "Otay Mesa Alternatives."

In order to deliver 400 million cubic feet per day (MMcfd) on a firm basis, the Otay Mesa Alternatives requires the physical construction of new pipeline facilities[31] via an expansion on the North Baja pipeline systems. These Alternatives would also require the Applicants to secure a multi-year capacity contract for the transportation of gas supplies.[32]

Several variations for Alternative E were described in the Ruling[33] that would also rely upon the use of Otay Mesa capacity; therefore, the Applicants assumed the same costs based on the Otay Mesa Alternatives assumptions above for purposes of this Cost-Effectiveness Analysis, even though these variations would potentially have incremental costs.

Alternative E was not included in the PEA, but was included in the Ruling.[34]

F. See Alternative E: Otay Mesa Alternatives

Alternative F is discussed in conjunction with Alternative E above. Alternative F was included in the PEA and in the Ruling.[35]

G. LNG Storage (Peak Shaver) Alternative

This LNG Alternative entails the construction of four independent LNG storage and regasification facilities, each located adjacent to an existing electric generating plant. This alternative is similar to the PEA's "United States – LNG Alternative," but at a smaller scale with LNG storage sited at or near natural gas peaker generation sites."

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[30] Ruling, page 13.
[31] The Applicants were ordered in the Ruling to consider other specific options in Alternative E. These options included: 1) use of the Southern System Minimum Flow Requirement; 2) operational flow orders (OFO); 3) system balancing; and 4) tariff discounts.
[32] *See* Prepared Direct Testimony of Gwen Marelli (March 21, 2016).
[33] *See* Amended Application.
[34] Ruling, page 13.
[35] Ruling, page 13.

LNG storage would serve three existing gas-fired generation sites in the SDG&E system, which is comprised of combustion turbines, steam turbines at Encina Power Plant (located in Carlsbad), the combined cycle plants at Palomar Energy Center (located in Escondido) and the Otay Mesa Energy Center (located in Otay Mesa), with LNG storage to serve one (1) planned (future) generation site in Pio Pico.

Each LNG facility would require rail or truck deliveries of LNG to support peak capacity shaving requirements or ability for each electric generating plant to operate for at least 5 days from LNG storage.

Alternative G was not included in the PEA but was included in the Ruling.[36]

H. Alternate Energy Alternatives

1. Alternative H1: Grid-Scale Battery / Energy Storage

The Applicants assume that Alternative H1 – Grid Scale Battery/Energy Storage - envisions the installation of a system of grid-scale batteries and associated equipment that would be sufficient to supply customers with energy equivalent to the Proposed Project.

The Applicants' evaluation of Alternative H1 is based on a scenario under which: the gas supply is lost to all local electric generation during a peak load period; gas supply is unavailable for a four-hour period; and that no customer outages would occur. The Applicants are unaware of a battery storage project of this magnitude being undertaken and, as a result, battery production on this scale would be very difficult, very expensive, very large (requiring approximately 100 acres of land) and would take a very long time to produce.

A system of grid-scale batteries might provide four hours of electric supply under the circumstances that electric generation was unavailable due to the loss of the natural gas supply; however, grid-scale batteries would not provide any energy replacement for the residential and business needs that are currently supplied by natural gas. For example, during the four hour period, customers might still receive electricity service from the grid-scale batteries, but would not have any natural gas service to operate their gas water heaters, gas heating units, gas appliances or any other gas supplied equipment.

In order for the four hours of grid-scale storage to be ready and available if a system wide natural gas outage occurred, the system of batteries would need to be fully charged at all times. It is likely that grid-scale batteries would be charged and discharged on a regular basis and operated by the California Independent System Operator (CAISO) as an ongoing resource it could count

[36] Ruling, page 13.

on for grid reliability purposes. Therefore, depending on the timing of a natural gas outage, there is no certainty that the system of batteries would be fully charged when needed.[37]

2. Alternative H2: Smaller-Scale Battery Storage

The Applicants assume that a smaller-scale, alternative energy battery storage involves the installation of smaller-scale batteries and associated equipment to supplement the gas supply system at times when additional capacity is needed (e.g. unplanned outages, maintenance, peak demand). Similar to the grid-scale battery storage project, the Applicants assume that smaller-scale battery storage would supply four hours of electric supply, including approximately 11,200 MWh of energy storage capacity.

Similar to the issue with the grid-scale battery storage, smaller-scale battery storage would not provide any energy replacement for the residential and business needs that are currently supplied by natural gas. Customers might still receive electricity service from the batteries, but would not have any natural gas service. Likewise, the same issues exist in that the system of batteries would need to be fully charged at all times, but would be charged and discharged on a regular basis and operated by the CAISO as an ongoing resource it could count on for grid reliability purposes. Therefore, depending on the timing of a natural gas outage, there is no certainty that the system of batteries would be fully charged when needed.[38]

The Applicants could not identify any other reliable alternate energy options that do not require the installation of a new gas transmission pipeline.[39]

Alternative H was included in the Ruling[40] but was not included within the PEA.

Henceforth, Alternatives H1 and H2 will be referred to as “Alternative Energy.”

I. Offshore Route Alternative

The Offshore Route Alternative assumes construction of a 36-inch diameter underwater pipeline off of the shore of Southern California, transitioning from offshore to onshore at Line 3010/3011 intersection (receiving point for supply gas to other pipelines in San Diego region). Figure 2 below shows a potential route for this Alternative.

For additional information regarding Alternative I, please refer to the PEA.[41]

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[37] *See* Prepared Direct Testimony of S. Ali Yari (March 21, 2016).
[38] *See* Prepared Direct Testimony of S. Ali Yari (March 21, 2016).
[39] *See* Prepared Direct Testimony of S. Ali Yari (March 21, 2016).
[40] Ruling, page 13.
[41] PEA, Chapter 5.2.2, Page 5-6.

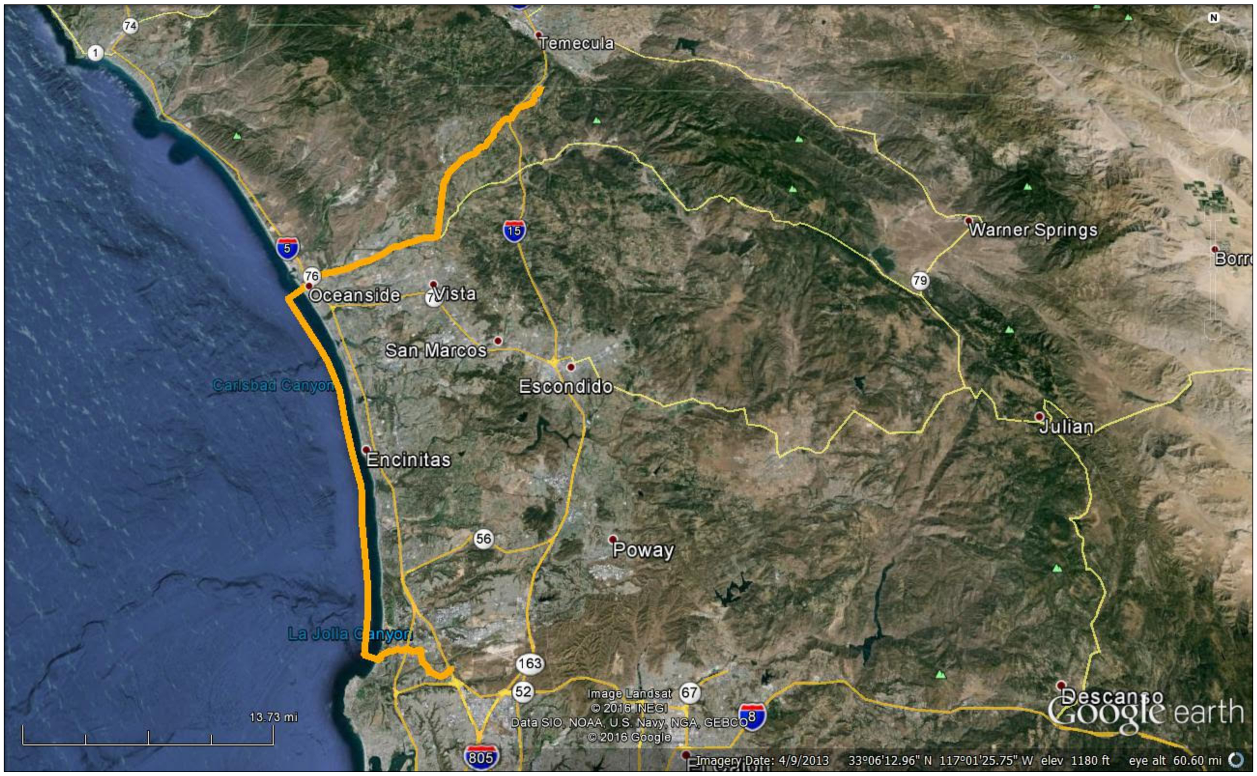

Figure 2 - Offshore Route Alternative (Conceptual - illustrative purposes only)

J. Cross-County Pipeline Route Alternatives

The Cross-County Pipeline Route Alternatives comprise three distinguishable routes from Riverside and Imperial counties to the San Diego area. The alternative routes are shown in Figure 3 and discussed below.

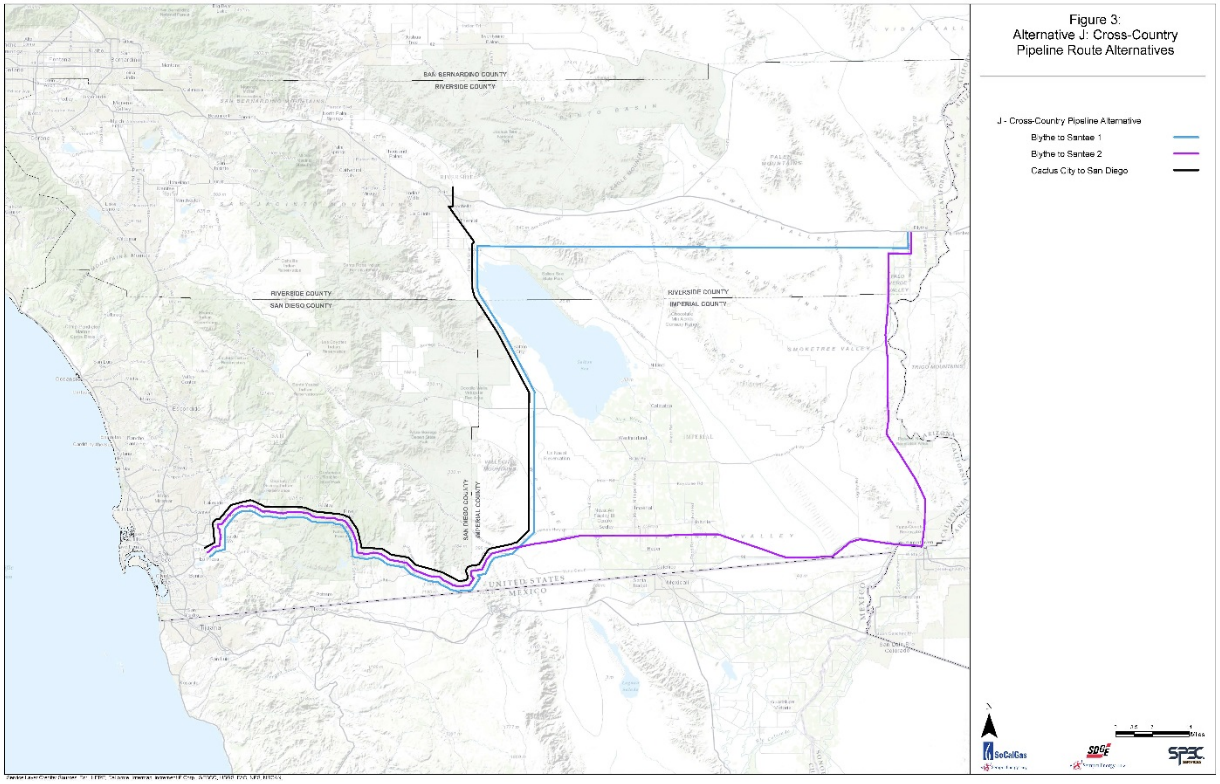

Figure 3 - Cross County Pipeline Route Alternatives (Conceptual - illustrative purposes only)

1. Blythe to Santee Alternative 1

This 222 mile cross-county pipeline initiates in the City of Blythe and traverses directly west, veering south near the northwestern corner of the Salton Sea in Riverside County. The route would then shift southwardly through Imperial County until just north of Ocotillo, at which point the route would run in a general westerly direction until its terminus within the community of Spring Valley. Approximately 202 miles of pipeline would be sited cross-county on undeveloped land, including land that is managed by eight different state and federal agencies.[42]

2. Blythe to Santee Alternative 2

This 223 mile cross-county pipeline initiates in the City of Blythe and travels south until nearly reaching the City of Yuma, Arizona. At the City of Yuma, the route would veer west, following I-8 until its terminus within the community of Spring Valley. This Alternative would run through Riverside, Imperial, and San Diego counties. Approximately 199 miles of pipeline would be sited cross-county on undeveloped land, including land that is managed by eight different state and federal agencies.[43]

[42] PEA, Chapter 5.0, page 5-28.
[43] PEA, Chapter 5.0, page 5-30.

3. Cactus City to San Diego

This 160 mile cross-county pipeline initiates in Cactus City and travel south until just north of Ocotillo, at which point the route would shift west and travel generally in a western direction until its terminus within the community of Spring Valley. Approximately 120 miles of pipeline would be sited cross-county on undeveloped land that is managed by eight different state and federal agencies.[44]

Alternatives J1-J3 were included in the Ruling as "Cross-County Pipeline Route Alternatives."[45] For additional information regarding Alternatives J1-J3, please refer to the PEA.[46]

K. Second Pipeline along Line 3010 Alternative

The Second Pipeline along Line 3010 Alternative would consist of constructing a new 36-inch pipeline approximately 45 miles in length, running adjacent to the existing 30-inch Line 3010. The second pipeline would originate at the existing Rainbow Metering Station and terminate at Line 3010's interconnect with Line 2010.

For additional information regarding Alternative K, please refer to the PEA.[47]

[44] PEA, Chapter 5.0, page 5-32.
[45] Ruling, page 13.
[46] PEA, Chapter 5.2.3, Pages 5-28, 5-30, 5-32.
[47] PEA, Chapter 5.2.3, Page 5-33.

IV. COSTS ANALYSIS

A. Methodology

The Ruling[48] directs Applicants to file an Amended Application that includes a cost analysis comparing the Proposed Project with any feasible alternative sources of power, in compliance with Section 1003(d) and Rule 3.1(f). Section 1003(d) requires *"Every electrical and every gas corporation submitting an application to the commission for a certificate authorizing the new construction of any electrical plant, line, or extension or gas plant, line or extension… shall include all of the following information… (d) a cost analysis comparing the project with any feasible alternative sources of power."* Rule 3.1(f) requires "*a statement detailing the estimated cost of proposed construction or extension and the estimated annual costs, both fixed and operating associate therewith. In the case of a utility which has not yet commenced service or which has been rendering service for less than 12 months, the applicant shall file as part of the application supporting statements or exhibits showing that the proposed construction is in the public interest, and whether it is economically feasible.*"

In most cases, implementing the Proposed Project or one of the Alternatives will avoid certain costs that would arise if another alternative were implemented. To illustrate, constructing a new pipeline to replace the transmission function of Line 1600 would reduce or avoid certain costs associated with operating the Moreno Valley Compressor Station. The methodology used to account for these "avoided costs" (or savings), and develop a "net cost" for the Proposed Project and each of the Alternatives is expressed in simple terms as follows:

Fixed Costs + O&M Costs + Avoided Costs = Net Costs

For the purposes of this Cost-Effectiveness Analysis, the Applicants' do not distinguish between capital and expense costs.

The Applicants developed the fixed cost estimate for the Proposed Project and Alternatives using common, industry standard estimating practices, aligned with Association for the Advancement of Cost Engineering Recommended Practices.[49] The estimates are based on a combination of market research, historical data, parametric modeling, semi-detailed unit costs and order-of-magnitude estimating based on experience and engineering judgment. The level of scope definition and estimating accuracy has been defined by references to the Association for the Advancement of Cost Engineering (AACE) RP 56R-08 Classification system, described below.

For the Proposed Project and all the Alternatives except the Hydrotest Alternative (Alternative B) and Replace Line 1600 in Place with a New 16-inch Transmission Pipeline Alternative

[48] Ruling, pages 11-12.
[49] AACE® International Recommended Practice No. 56R-08.

(Alternative D), Line 1600 would be de-rated and operate as a distribution asset. The costs for de-rating Line 1600 are included in the fixed cost estimate for all the Alternatives except Alternatives B and D. The costs for de-rating Line 1600 were developed based on a combination of historical data, semi-detailed unit costs, and engineering experience and judgment. Under the Hydrotest Alternative, it is anticipated that Line 1600 will be replaced within approximately 20 years.

Applicants also estimated the on-going, annual operating costs for the Proposed Project and the Alternatives. The operating costs for the pipeline alternatives also include amounts for complying with Transmission Integrity Management Program (TIMP) requirements. The operating cost estimates were developed using a combination of historical operations and maintenance costs and other estimates based on Applicants' engineering judgment. This analysis assumes that operating costs for the Otay Mesa Alternatives are included in Applicants' contract pricing.

B. Estimated Costs of the Proposed Project and Alternatives

Cost Estimate Classification

In support of the Application filing in September 2015, Applicants developed a cost estimate for the Proposed Project based on a defined route, semi-detailed design and engineering, and a robust environmental assessment. By contrast, the maturity of the estimates for each Alternative is lower, due to the lack of detailed definition for key project cost drivers – such as scope definition, level of completed design and engineering, material and labor requirements, permitting needs, environmental requirements, and schedule/sequence assumptions.

For those Alternatives that were not carried forward by Applicants in the PEA[50] – the Off-Shore Route Alternative, Existing Alignment Alternatives (Replace Line 1600 In-Place with a New 16-inch Transmission Pipeline Alternative, New 16" or 36" Pipe Parallel to Line 1600), LNG Alternatives, Infrastructure Corridor Alternative, and the Northern Baja Alternative – detailed cost estimates were not prepared. Only high-level cost estimates are available for those Alternatives, which were previously determined by the Applicants to be imprudent as compared to the Proposed Project.

The Applicants' estimating team evaluated each of the project estimates against the AACE International[51] Recommended Practices, specifically, the cost estimate classification system, to classify the level of maturity of each estimate. The AACE classification is based on the

[50] PEA, Chapter 5.0, pages 5-6 through 5-15.
[51] AACE International developed a guideline for cost estimate classification in the late 1960s to early 1970s. Those guidelines and standards are generally accepted in the engineering and construction communities as a means for evaluating the maturity of a project cost estimate.

relationship between scope definition and estimate accuracy. The estimate accuracy range is based on known scope, but excludes unforeseen risks that could alter that scope.[52]

The AACE matrix maturity levels are defined on a scale from 1 through 5 based on Primary Characteristics and Secondary Characteristics, as shown below:

Table 5 - Cost Estimate Classification Matrix for Building and General Construction Industries

	Primary Characteristic	***Secondary Characteristic***		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges[53]
Class 5	0% to 2%	Functional area, or concept screening	SF or m^2 factoring, parametric models, judgment, or analogy	L: -20% to -30% H: +30% to +50%
Class 4	1% to 15%	Schematic design or concept study	Parametric models, assembly driven models	L: -10% to -20% H: +20% to +30%
Class 3	10% to 40%	Design development, budget authorization, feasibility	Semi-detailed unit costs with assembly level line items	L: -5% to -15% H: +10% to +20%
Class 2	30% to 75%	Control or bid/tender, semi-detailed	Detailed unit costs with forced detailed take-off	L: -5% to -10% H: +5% to +15%
Class 1	65% to 100%	Check estimate or pre bid/tender, change order	Detailed unit costs with detailed take-off	L: -3% to -5% H: +3% to +10%

The cost estimates prepared by the Applicants were developed based on the known and anticipated project scope at the time of the filing (September 2015), along with additional estimating information that was collected or developed for the Proposed Project and certain alternative projects that were subsequently identified in the Ruling. Table 6 below shows the estimated fixed cost and annual operating costs for the Proposed Projects and each of the Alternatives.

[52] AACE Recommended Practice, No. 56R-08, Cost Estimate Classification System – As Applied for the Building and General Construction Industries, TCM Framework: 7.3 – Cost Estimating and Budgeting, Rev. December 5, 2012. 7 AACE International Recommended Practice, No. 34-R-05, TCM Framework: 7.3 - Cost Estimating and Budgeting, 2007, p. 4.

[53] The state of construction complexity and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual cost form the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

The estimated costs for the Proposed Project and the Alternatives include contingency. Per the AACE, contingency is defined as "a cost element of the estimate used to cover the uncertainty and variability associated with a cost estimate, and unforeseeable elements of cost within the defined project scope."[54] Including a contingency allows for uncertain cost elements to be included in the project budget, even though the exact contingency-related expenditures and unforeseen events are currently unknown.

Table 6 - Estimated Fixed and Operating Costs[55]

Alt. No.	Project Name	(Millions of 2015 Dollars)	
		Fixed Cost	Annual Operating Cost [56]
A	Proposed Project (Rainbow to Line 2010 Route)	$441.9	$0.3
B	Hydrotest Alternative	$112.9	$0.5
C1	Alt Diameter Pipeline, Proposed Route (10")	$297.6	$0.3[57]
C2	Alt Diameter Pipeline, Proposed Route (12")	$320.1	$0.3[58]
C3	Alt Diameter Pipeline, Proposed Route (16")	$337.1	$0.3
C4	Alt Diameter Pipeline, Proposed Route (20")	$352.9	$0.3
C5	Alt Diameter Pipeline, Proposed Route (24")	$361.2	$0.3
C6	Alt Diameter Pipeline, Proposed Route (30")	$392.2	$0.3
C7	Alt Diameter Pipeline, Proposed Route (42")	$527.5	$0.3
D	Replace Line 1600 in-Place with a New 16-inch Transmission Pipeline Alternative	$556.1	$0.4
E/F	Otay Mesa Alternatives	$977.1	$45[59]
G	LNG Storage (Peak-Shaver) Alternative AKA (United States – LNG Alternative)	$2,669.7	$1.2
H1	Alternate Energy (Battery) Alternative – Grid Scale	$8,415.1	$1.2
H2	Alternate Energy (Battery) Alternative – Smaller Scale	$10,095.1	$1.2
I	Offshore Route Alternative	$1,449.9	$0.5

[54] AACE International Recommended Practice No. 34R-05, TCM Framework: 7.3 – Cost Estimating and Budgeting, 2007, p. 4.
[55] Prepared Direct Testimony of Neil Navin (March 21, 2016), page 31, workpaper Estimated Fixed and Operating Costs for Proposed Project and Alternatives
[56] Annual Operating Costs includes the costs for complying with TIMP. The Applicants incur TIMP costs once every seven years. TIMP costs were divided by 7 to determine the "annual" TIMP costs. That portion – 1/7 – were added to the annual O&M costs to determine total operating costs.
[57] The 10-inch and 12-inch alternate diameter pipelines do not meet regulatory requirements for natural gas demand on a 1-in-10 year winter day. It is assumed that these alternatives will require the import of gas via the Otay Mesa receipt point. These additional import costs have been accounted for by including them as O&M costs in order to calculate net costs. This analysis can be seen in Section V, Avoided Cost.
[58] *Id.*
[59] Estimated costs to transport natural gas. *See* Prepared Direct Testimony of Gwen Marelli (March 21, 2016), page 7.

Alt. No.	Project Name	(Millions of 2015 Dollars)	
		Fixed Cost	Annual Operating Cost [56]
J1	Blythe to Santee Alternative 1	$1,377.5	$1.4
J2	Blythe to Santee Alternative 2	$1,315.5	$1.4
J3	Cactus City to San Diego Alternative	$1,143.4	$1.0
K	Second Pipeline Along Line 3010 Alternative	$595.2	$0.3

Cost Estimate Assumptions

Described below are the respective assumptions and inclusion/exclusion considered for the Proposed Project and Alternatives.

Alternative A: Proposed Project (Rainbow to Line 2010 Route)

Applicants developed direct cost estimates for the Proposed Project based on the known and anticipated project scope at the time of the Application's filing (September 2015). The cost estimates have been updated to include the de-rating of Line 1600 to distribution pressure. The direct cost estimates include costs for material and equipment procurement, construction, engineering and design, environmental permitting and mitigation, other project execution-related activities, and company labor. The cost estimate is within a Class 3 range of accuracy as defined by AACE.[60]

Alternative B: Hydrotest

Cost estimates were developed for this project based on historic information and experience with similar types of projects. The level of contingency was decided using expert judgment, based on the accuracy of the estimate which reflects a Level 4 class estimated as defined by AACE classification system.

Alternative C1: Alternative Diameter Pipeline, Proposed Route (10")

High-level cost estimates have been developed for this Alternative. Costs for this Alternative were scaled from the Proposed Project on a cost per mile basis. This project involves the same proposed route and similar components as the Proposed Project though in different quantities. Other costs for activities such as engineering, survey, and right-of-way acquisition, should be comparable, on a unit cost basis, to the estimates developed for the Proposed Project. A 10-inch alternate diameter pipeline does not meet regulatory requirements for natural gas demand on a 1-in-10 year winter day. It is therefore assumed that this Alternative will require the import of gas via the Otay Mesa receipt point.

[60] See Prepared Direct Testimony of Neil Navin (March 21, 2016), page 16

Alternative C2: Alternative Diameter Pipeline, Proposed Route (12")

High-level cost estimates have been developed for this Alternative. Costs for this Alternative were scaled from the Proposed Project on a cost per mile basis. This project involves the same proposed route and similar components as the Proposed Project though in different quantities. The pipeline material specifications for each alternative would be similar to the Proposed Project. Other costs for activities such as engineering, survey, and right-of-way acquisition, should be comparable, on a unit cost basis, to the estimates developed for the Proposed Project. A 12-inch alternate diameter pipeline does not meet regulatory requirements for natural gas demand on a 1-in-10 year winter day. It is therefore assumed that this Alternative will require the import of gas via the Otay Mesa receipt point.

Alternative C3: Alternative Diameter Pipeline, Proposed Route (16")

High-level cost estimates have been developed for this Alternative. Costs for this Alternative were scaled from the Proposed Project on a cost per mile basis. This project involves the same proposed route and similar components as the Proposed Project though in different quantities. The costs for activities such as engineering, survey, and right-of-way acquisition, should be comparable, on a unit cost basis, to the estimates developed for the Proposed Project.

Alternative C4: Alternative Diameter Pipeline, Proposed Route (20")

High-level cost estimates have been developed for this Alternative. Costs for this Alternative were scaled from the Proposed Project on a cost per mile basis. This project involves the same proposed route and similar components as the Proposed Project though in different quantities. Other costs for activities such as engineering, survey, and right-of-way acquisition, should be comparable, on a unit cost basis, to the estimates developed for the Proposed Project.

Alternative C5: Alternative Diameter Pipeline, Proposed Route (24")

High-level cost estimates have been developed for this Alternative. Costs for this Alternative were scaled from the Proposed Project on a cost per mile basis. This project involves the same proposed route and similar components as the Proposed Project though in different quantities. Other costs for activities such as engineering, survey, and right-of-way acquisition, should be comparable, on a unit cost basis, to the estimates developed for the Proposed Project.

Alternative C6: Alternative Diameter Pipeline, Proposed Route (30")

High-level cost estimates have been developed for this Alternative. Costs for this Alternative were scaled from the Proposed Project on a cost per mile basis. This project involves the same proposed route and similar components as the Proposed Project though in different quantities. Other costs for activities such as engineering, survey, and right-of-way acquisition, should be comparable, on a unit cost basis, to the estimates developed for the Proposed Project.

Alternative C7: Alternative Diameter Pipeline, Proposed Route (42")

High-level cost estimates have been developed for this Alternative. Costs for this Alternative were scaled from the Proposed Project on a cost per mile basis. This project involves the same proposed route and similar components as the Proposed Project though in different quantities. Other costs for activities such as engineering, survey, and right-of-way acquisition, should be comparable, on a unit cost basis, to the estimates developed for the Proposed Project.

Alternative D: Replace Line 1600 in Place with a New 16" Transmission Pipeline Alternative (In-Kind Replacement)

High-level cost estimates have been developed for this Alternative. Costs for this Alternative were scaled from the Proposed Project on a cost per mile basis. This project involves similar components as the Proposed Project though in different quantities. Other costs for activities such as engineering and survey should be comparable, on a unit cost basis, to the estimates developed for the Proposed Project. Right-of-way acquisition costs for this Alternative are significantly greater than those for the Proposed Project.[61]

Alternative E/F: Otay Mesa Alternatives

In evaluating the Otay Mesa Alternatives, the Applicants identified both a low end cost and a high end cost for building out capacity to provide service under these Alternatives. The low end cost is based on existing rates for the pipelines and rates for facilities in service since 2002.[62] The high end cost is based on recently published pipeline costs for projects proposed or awarded for construction in Arizona and Northern Mexico. The high end cost assumes the North Baja Pipeline System and Gasoducto Rosarito System are looped from Ehrenberg to TGN.

Alternative G: LNG Storage (Peak-Shaver) Alternative AKA (United States – LNG Alternative)

The estimate for this Alternative was based on evaluating the costs for a similar LNG storage facility project, and developing factored estimates for the supply and construction of four LNG storage facilities based on each facility's operational requirements. These estimates were developed for each LNG storage facility by comparing them to available, actual costs for an existing LNG storage facility. Liquefaction costs were excluded – LNG plant costs have been factored based on re-gasification and storage only.

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[61] A feasibility study was conducted to evaluate the feasibility of acquiring the necessary Right of Ways.
[62] See Prepared Direct Testimony of Gwen Marelli (March 21, 2016), page 7.

Alternative H: Alternate Energy (Battery) and Alternative (Alternative H1 - Grid Scale and Alternative H2 - Smaller Scale)

Costs for both the grid scale and smaller scale alternatives were developed based on a rough order of magnitude estimate. The estimate considered energy storage capacity, amount of land required, number of sites and project complexity.

The Grid Scale Alternative assumes installation of lithium-ion batteries at $500/kWh (kilowatt hours). For approximately 2,802 MW (megawatts) of power and four hours of energy, approximately 11,200 MWh (megawatt hours) of capacity is required. Between 100 and 125 acres of land is needed for this installation.

The Smaller Scale Alternative assumes approximately 11,200 MWh of energy storage capacity for four hours of electric supply, projected at an installed cost of $600/ kWh. The difference in cost per kWh accounts for the number of sites required to host the smaller scale battery locations.

Alternative I: Off-Shore Alternative

A high level cost estimate for this Alternative was prepared based on considering broad project assumptions. There is a lack of scope definition. The estimate is based on a productivity efficiency factor for marine project conditions. Permitting costs and costs arising as a result of environmental considerations were assumed to be very high.

Alternative J1: Blythe to Santee Alternative 1

High-level cost estimates have been developed for this Alternative. This project involves similar components as the Proposed Project though in significantly different quantities. Costs for this Alternative were scaled from the Proposed Project on a cost per mile basis and adjusted for population density and terrain type. The pipeline material specifications for each alternative would be similar to the Proposed Project. Class estimate for this Alternative is very high level based on the lack of scope definition and that broad assumptions are considered.

Alternative J2: Blythe to Santee Alternative 2

High-level cost estimates have been developed for this Alternative. This project involves similar components as the Proposed Project though in significantly different quantities. Costs for this Alternative were scaled from the Proposed Project on a cost per mile basis and adjusted for population density and terrain type. The pipeline material specifications for each alternative would be similar to the Proposed Project. Class estimate for this Alternative is very high level based on the lack of scope definition and that broad assumptions are considered.

Alternative J3: Cactus City to San Diego Alternative

High-level cost estimates have been developed for this Alternative. This project involves similar components as the Proposed Project though in significantly different quantities. Costs for this Alternative were scaled from the Proposed Project on a cost per mile basis and adjusted for population density and terrain type. The pipeline material specifications for each alternative would be similar to the Proposed Project. Class estimate for this Alternative is very high level based on the lack of scope definition and that broad assumptions are considered.

Alternative K: Second Pipeline along Line 3010 Alternative

High-level cost estimates have been developed for this Alternative. This project involves similar components as the Proposed Project though in different quantities. The pipeline material specifications for each alternative would be similar to the Proposed Project. Other costs for activities such as engineering and surveying, should be comparable, on a unit cost basis, to the estimates developed for the Proposed Project. Right of way acquisition costs for this Alternative are significantly greater than those for the Proposed Project.[63]

C. Avoided Costs Associated with the Proposed Project and Alternatives

The Applicants analyzed the total avoided costs that would accrue over an assumed 100 year useful life[64] for the Proposed Project and Alternatives involving construction of a new pipeline (all Alternatives except the Hydrotest Alternative and the Replace Line 1600 In Place with a 16" Pipeline Alternative). This analysis allowed for the evaluation of:

- The anticipated avoided costs over set periods of time;
- Both one-time and recurring avoided costs; and
- The net cost that incorporates both the total cost for installing the project and the avoided costs.

The Applicants' methodology[65] for calculating the avoided costs is as follows:

- Determine the various cost elements that make up the two types of avoided costs (described in the following section);

[63] A feasibility study was conducted to evaluate the feasibility of acquiring the necessary Right of Ways.
[64] The Role of Pipeline Age in Pipeline Safety, Kiefner and Rosenfield states that "…a well-maintained and periodically assessed pipeline can safely transport natural gas indefinitely." A 100 year lifetime period has been assumed for calculation purposes.
[65] The Applicants use a conservative methodology for conducting the avoided cost analysis. The Applicants' method is based on conservative assumptions and is commonly used in evaluating the costs of projects over time. Other methods could be used to analyze avoided costs over time.

- Tabulate the avoided costs on a time line for the Proposed Project and for those Alternatives to which they apply;
- Escalate the avoided costs over time by applying an inflation rate of 2.9%;[66]
- Discount the avoided costs back to 2015 at 7.79%,[67] resulting in avoided costs presented in 2015 values; and

Calculate the net cost by adding the estimated fixed cost plus the present value of operating expenses and avoided costs over 100 years shown in

- Table 8.

It is assumed that avoided costs will begin to accrue from the year that the Proposed Project and Alternatives become operational.[68]

Two avoided costs are associated with not having to hydrotest Line 1600, and are accounted for in this analysis, as follows:

Avoided Cost 1: Future Replacement of Line 1600
Even if Line 1600 is hydrotested, it is prudent to assume that it will need to be replaced eventually. Thus, this set of avoided costs include the cost associated with replacing Line 1600 at some point in the future. The Applicants have established a 20-year interval as a reasonable expectation for the expiration of the benefits from pressure testing. This interval is based upon engineering judgment, and Line 1600 would likely either need to be replaced or re-evaluated depending upon a number of factors that would ultimately include coating degradation, cathodic protection performance, time-dependent threat growth, leakage maintenance program demands, and time-independent threat rates.[69]

The avoided costs analysis assumes Line 1600 operating as a transmission asset will be replaced in 20 years. These avoided costs are realized by the Proposed Project and the Alternatives that contemplate derating Line 1600.

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[66] Inflation rate based on IHS Fourth Quarter 2015 Construction Cost Index Forecasts for Gas Utility Construction: Pacific Region for Transmission Plant averaged from 2017 through 2025.
[67] SDG&E discount rate. *See* Prepared Direct Testimony of Michael Woodruff (March 21, 2016).
[68] *See* Prepared Direct Testimony of Neil Navin (March 21, 2016), page 31: Workpaper – Estimated Fixed and Operating Costs for Proposed Project and Alternatives.
[69] *See* Prepared Direct Testimony of Travis Sera (March 21, 2016), page 24.

Avoided Cost 2: Moreno Compressor Station Operations

For the Proposed Project, or certain Alternatives (C4, C5, C6, C7, I, J1, J2, J3, K)[70] there can be a potential impact on the costs associated with the annual operations and maintenance of the Moreno Compressor Station[71,72] as well as the amounts expended for emissions.

The following sections describe these avoided cost elements in more detail.

1. Future Replacement of Line 1600

Overview of Current Costs

Line 1600, if hydrotested and maintained at transmission level service (the Hydrotest Alternative), will be abandoned and/or replaced earlier than the Proposed Project or any of the Alternatives that would allow Line 1600 to be de-rated because Line 1600 will have a shorter usable asset lifespan. The estimated cost of installing a new 16-inch diameter pipeline along the same route as the Proposed Project, which is the most efficient replacement option from a cost perspective, is $337.1M. The estimated remaining life of Line 1600 is assumed to be 20 years or less.

Source of Avoided Cost

The Proposed Project and Alternatives except the Hydrotest Alternative will have a useful life in excess of Line 1600 if it is maintained as a transmission asset. This analysis assumes that the Proposed Project and the Alternatives will have a service life of 100 years. Over the life of the Proposed Project and the Alternatives, the costs related to the eventual replacement of Line 1600 will be avoided.

Assumptions

For the purpose of this avoided costs analysis, it is assumed that Line 1600 will be replaced with a 16–inch diameter transmission pipeline along the same route as the Proposed Project. It is assumed that the physical replacement work will take two years.

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[70] The cross county lines (J1, J2 and J3) are not directly connected to the Moreno Compressor Station, but are assumed to provide similar benefits with regards to avoided costs as the Proposed Project, due to the additional capacity inherent to a 36” pipeline. Due to the length of these lines, it is possible that additional compression may be needed to balance the gas flow in the system. However, at this stage in the design, it is not known whether this additional compression will be required.

[71] *See* Prepared Direct Testimony of Neil Navin (March 21, 2016), Attachment A – PSRP Report at Attachment XII - Moreno Compressor Station PSRP Report.

[72] For the Proposed Project, it is assumed that the Moreno Compressor Station would only require reduced operations to function minimally as a safeguard during extreme or unplanned capacity interruption scenarios. *See* Prepared Direct Testimony of Neil Navin (March 21, 2016), Attachment A – PSRP Report at Attachment XII - Moreno Compressor Station PSRP Report.

The costs for replacing Line 1600 in the future make up the avoided costs for future Line 1600 Replacement in the cost avoidance analysis.

2. Moreno Compressor Station Operations

Overview of Current Costs[73]

The Proposed Project and certain Alternatives would reduce the need for compression at Moreno Compressor Station. Although compression at Moreno would likely still be needed at certain times, many of the operating costs could potentially be avoided or reduced. The associated avoided costs include the following:

Emission Fees and Permitting: Based on average annual costs for emissions, emissions subjected to fee, and applied fee rates. Average cost from 2011 to 2014 is $44,748.

Operations and Maintenance: Based on average annual costs for labor and non-labor costs. Average annual costs for 2010 to 2015 is $2,613,907.

Fuel: Based on the average cost of fuel used, with the average price per dekatherm for the California border in 2021 assumed to be $3.23.[74] Average annual costs based on usage for 2011 to 2013 is $1,400,000.

NOx Sales and Purchases: Each year, the Applicants are allocated a fixed number of credits for NOx RECLAIM emissions.[75] When emissions are exceeded, additional credits have to be purchased. Similarly, unused credits can be sold at spot market prices. Average annual emissions at Moreno Compressor Station from 2012 to 2015 were 139,338 lbs. The average cost for emission credits is approximately $14 per lb.

GHG Costs: Applicants pay for greenhouse gas (GHG) emissions arising from Moreno Compressor Station operations.[76] The average annual GHG emissions from 2012 to 2014 were 25,159 metric tons. Projected annual GHG costs are $1,320,830 per annum based on a levelized price per ton of $52 per metric ton.

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[73] Based on the figures provided within the Prepared Direct Testimony of Neil Navin (March 21, 2016), Attachment A – PSRP Report at Attachment XII - Moreno Compressor Station PSRP Report.
[74] Based on CMEGroup Globex Futures.
[75] *See* Assembly Bill (AB) 32 (California Global Warming Solutions Act of 2006) - http://www.arb.ca.gov/cc/ab32/ab32.htm
[76] Pursuant to AB 32 and the Governor's Executive Order S-01-07.

Source of Avoided Cost

The estimated annual cost savings resulting from assuming reduced operations at Moreno Compressor Station for the Proposed Project and certain Alternatives is approximately $5.87 million, calculated as:[77]

Table 7 - Savings associated with the installation of a 36" or larger pipeline

Cost Element	Annual Savings
O&M Non-Labor	($295,077)
Fuel	($1,363,626)
NOx Purchases	($1,162,000)
NOx Sales	($691,125)
GHG Cap & Trade Cost	($1,254,789)
Capital Spending	($1,100,000)
Annual Sum	**($5,866,617)**

Assumptions

Avoided costs relating to the Moreno Compressor Station will be incurred for the Proposed Project and Alternatives C4, C5, C6, C7, I, J1, J2, J3 and K, as follows:

- Alternative C7 (42" pipeline) and Alternatives I (Off-shore), J1, J2, and J3 (Cross-County Alternatives)[78] and K (Second Pipeline along Line 3010) will provide the same reduction in operational requirements to the Moreno Compressor Station as the Proposed Project.

[77] The Moreno Compressor Station PSRP Report (Prepared Direct Testimony of Neil Navin (March 21, 2016), Attachment A – PSRP Report at Attachment XII) makes the following assumptions with regards to cost saving should the Proposed Project be implemented:

- The Moreno Compressor Station operations will be reduced by 95% to function minimally as a safe guard during extreme or unplanned capacity interruption scenarios for a 36" line.
- Fuel, NOx credit purchases and sales, and GHG costs are reduced in direct proportion (*i.e.*, 1:1) as the reduction in operation;
- Emission fees and permitting costs will remain unchanged due to the need of maintaining permitting for the compressor the station;
- Labor costs will remain unchanged, and Non-labor costs will be reduced by $300,000 (or 20% of annual cost average); and
- $1.1M in capital spending will be avoided (based on historical capital spending).

[78] The cross county lines (J1, J2 and J3) are not directly connected to the Moreno Compressor Station, but are assumed to provide similar benefits with regards to avoided costs as the Proposed Project, due to the additional capacity inherent to a 36" pipeline. Due to the length of these lines, it is possible that additional compression may be needed to balance the gas flow in the system. However, at this stage in the design, it is not known whether this additional compression will be required.

- Alternatives C4, C5 and C6 (20”, 24” and 30” pipelines, respectively) will provide some reduction in operational requirements to the Moreno Compressor Station, assumed to be in direct proportion to the reduction in pipeline diameter.[79]

The analysis assumes that the remaining Alternatives will not have any effect on the current state operational output of the Moreno Compressor Station and, therefore, do not accrue avoided costs.

D. Net Costs of the Proposed Project and Alternatives

The table below shows the avoided costs associated the Proposed Project and the Alternatives:

Table 8 - Avoided Costs (Millions of 2015 Dollars)

Alt No.	Project Name	Fixed Cost	Total O&M Cost[80]	Avoided Cost	Net Cost
A	Proposed Project (36” pipeline Rainbow to Line 2010 Route)	$441.9	$4.6	($190.3)	$256.2
B	Hydrotest Alternative	$112.9	$5.8	$0.0	$118.7
C1	Alt Diameter Pipeline, Proposed Route (10")	$297.6	$105.3	($100.3)	$302.7
C2	Alt Diameter Pipeline, Proposed Route (12")	$320.1	$71.8	($100.3)	$291.6
C3	Alt Diameter Pipeline, Proposed Route (16")	$337.1	$4.6	($100.3)	$241.4
C4	Alt Diameter Pipeline, Proposed Route (20")	$352.9	$4.6	($118.3)	$239.2
C5	Alt Diameter Pipeline, Proposed Route (24")	$361.2	$4.6	($136.3)	$229.6
C6	Alt Diameter Pipeline, Proposed Route (30")	$392.2	$4.6	($163.3)	$233.5
C7	Alt Diameter Pipeline, Proposed Route (42")	$527.5	$4.6	($190.3)	$341.9
D	Replace Line 1600 in Place with a New 16" Transmission Pipeline	$556.1	$4.4	$0.0	$560.4
E/F	Otay Mesa Alternatives	$977.1	$0.0	($100.3)	$876.8
G	LNG Storage (Peak-Shaver) Alternative	$2,669.7	$15.3	($100.3)	$2,584.7
H1	Alternate Energy Alternative: Grid-Scale Batteries	$8,415.1	$15.3	($100.3)	$8,330.1
H2	Alternate Energy Alternative: Smaller-Scale Batteries	$10,095.1	$15.3	($100.3)	$10,010.1
I	Offshore Route	$1,449.9	$5.1	($159.5)	$1,295.5
J1	Blythe to Santee Alternative 1	$1,377.5	$16.7	($175.0)	$1,219.3
J2	Blythe to Santee Alternative 2	$1,315.5	$16.8	($175.0)	$1,157.3
J3	Cactus City to San Diego Alternative	$1,143.4	$12.7	($175.0)	$981.1
K	Second Pipeline Along Line 3010 Alternative	$595.2	$3.5	($171.6)	$427.1

[79] The Moreno Compressor Station PSRP Report (Prepared Direct Testimony of Neil Navin (March 21, 2016), Attachment A – PSRP Report at Attachment XII) shows a straight line reduction in operations in proportion to pipeline diameter between 36” and 16” diameters.
[80] Present value of O&M and TIMP costs over 100 years. Also includes present value of gas transportation costs via Otay Mesa for Alternatives C1 and C2.

The results of the costs analysis show that the “least-cost” alternative is the Hydrotest Alternative, which has an estimated net cost of $118.7 million. Table 9 shows the Proposed Project and remaining Alternatives grouped together by range of net costs. After the Hydrotest Alternative, the next group of least-cost alternatives are clustered together in the $225 million to $260 million range. This second least-cost category includes alternate diameter sizes ranging from 16- to 36-inches (*i.e.*, the Proposed Project). The third least-cost category has a larger range, from $290 million to $430 million, and includes Alternative Diameters of 10-, 12- and 42-inches as well as the Second Pipeline Along Line 3010 Alternative.

The remaining two categories of Alternatives far exceed the net costs of the Proposed Project. These last two “greatest cost” categories include Alternatives whose net costs range from $500 million to $1 billion (Replace Line 1600 in Place with a New 16-inch Pipeline, Otay Mesa Alternatives and Cactus City to San Diego Alternative) and over $1 billion (Blythe to Santee Pipeline Routes, Alternatives 1 and 2, Off-Shore, LNG Storage, and Alternative Energy Alternatives).

Table 9 - Relative Costs of Proposed Project and Alternatives from Least to Greatest Net Cost

Net Cost Range	Alt No.	Project Name	Net Cost
$100 M to $200 M	B	Hydrotest	$118.7 M
$225 M to $260 M	C5	Alt Diameter Pipeline 24"	$229.6 M
	C6	Alt Diameter Pipeline 30"	$233.5 M
	C4	Alt Diameter Pipeline 20"	$239.2 M
	C3	Alt Diameter Pipeline 16”	$241.4M
	A	Proposed Project (36” Diameter)	$256.2 M
$290 M to $430 M	C2	Alt Diameter Pipeline 12”	$291.6 M
	C1	Alt Diameter Pipeline 10"	$302.7 M
	C7	Alt Diameter Pipeline 42"	$341.9 M
	K	Second Pipeline Along Line 3010 Alternative	$427.1 M
$500 M to $1Billion	D	Replace Line 1600 In Place with a New 16-inch Transmission Pipeline	$560.4 M
	E/F	Otay Mesa Alternatives	$876.8 M
	J3	Cactus City to San Diego Alternative	$981.1 M
Over $1 Billion	J2	Blythe to Santee Alternative 2	$1,157.3 M
	J1	Blythe to Santee Alternative 1	$1,219.3 M
	I	Offshore Route Alternative	$1,295.5 M
	G	LNG Storage Alternative	$2,584.7 M
	H2	Alternate Energy Alternative: Smaller Scale Batteries	$10,010.1 M
	H1	Alternative Energy Alternative: Grid Scale Battery	$8,330.1 M

V. BENEFITS ANALYSIS[81]

This Cost-Effectiveness Analysis included an evaluation of the different types of benefits across the seven benefit types set forth in the Ruling. The benefits were quantified and scored using a benefits evaluation model that was developed by PwC, with input and data from the Applicants. This evaluation complies with the requirement in the Ruling to apply quantifiable data to define the relative benefits of the Proposed Project and the Alternatives.[82] In addition to the quantifiable benefits, the Applicants identified a few project benefits that could not be readily quantified.

Approach and Methodology

To comply with the requirement to apply quantifiable data to define the relative benefits of the projects, PwC and the Applicants developed a model (referred to herein as the "benefits evaluation model") to quantitatively evaluate and score the relative benefits of the Proposed Project and each of the Alternatives. PwC and the Applicants first considered desirable outcomes (*e.g.*, enhanced safety) and quantifiable characteristics (*e.g.*, percent reduction in incidents per High Consequence Area (HCA) mile) associated with the seven benefits categories identified in the Ruling. The model was then created to evaluate 16 specific benefits, each of which falls within one of the seven categories identified in the Ruling. Care was taken to treat each benefit as unique and not counted more than one time in the scoring model.

After the benefits were defined, PwC and the Applicants developed quantifiable scoring criteria so that benefits could be objectively evaluated and scored. The types of quantifiable metrics used in the scoring criteria include the percentage or measurable increase/reduction in a known quantity or unit of measure/metric that is used to define a benefit. For instance, a quantitative threshold expressed in terms of MMcfd is used to quantify the increases expected in system capacity for the Proposed Project and each of the Alternatives. Similarly, the number of incidents per HCA mile is one metric relied on to quantify and score safety performance.

The complete list of benefits included in the scoring model and the metric or measure used to quantify and score each one, is listed in Table 10 of this Cost-Effectiveness Analysis.

The scoring criteria are generally applied on a 1 to 5 scale. In the scoring benefits model, 1 is the lowest (worst) score and 5 is the highest (best) score. The scores were averaged within each of the seven benefit categories and then those seven average scores were summed to determine the final benefit score for the Proposed Project and the Alternatives.

[81] The avoided costs associated with the Proposed Project and each Alternative may also be viewed as a benefit. In order to avoid double-counting, however, avoided costs are not discussed in this section.
[82] Ruling, page 12.

For certain benefits, there is no obvious measure or metric against which the benefit is generally compared. For those benefits, the scoring scale was defined to allow for an objective evaluation of the Proposed Project and the Alternatives against the scale and a quantitative measure of the benefit defined. For instance, measuring long-term safety benefits of a transmission pipeline is an important benefit and must be included in the overall analysis. Because there is no standard measure or metric for evaluating this benefit, the Applicants defined this benefit on an objective scale, defined by technical insight. This benefit type can then be scored and that score included in the overall quantitative benefits evaluation.

Once the scoring was complete for the Proposed Project and the Alternatives across each benefit category, the total benefit score was determined and a relative quantifiable benefit ranking was prepared.

Table 10 - Benefits Evaluation Scoring Summary

Benefits Criteria	Proposed Project - 36"	Hydrotest	Alt Diameter Pipelines - 10"	Alt Diameter Pipelines - 12"	Alt Diameter Pipelines - 16"	Alt Diameter Pipelines - 20"	Alt Diameter Pipelines - 24"	Alt Diameter Pipelines - 30"	Alt Diameter Pipelines - 42"	Replace Line 1600 In-Place	Otay Mesa Alternatives	LNG Storage	Alt Energy - Grid Scale	Alt Energy - Smaller Scale	Offshore Route	Blythe to Santee Alt 1	Blythe to Santee Alt 2	Cactus City to SD	2nd Pipeline Along Line 3010
1. Safety	5	3	5	5	5	5	5	5	5	4	4	3	3	3	4	4	4	4	4
2. Reliability	5	1	1	1	3	4	4	5	5	3	1	2	2	2	5	5	5	5	5
3. Operational Flexibility	5	4	4	4	4	5	5	5	5	4	3	4	4	4	5	5	5	5	5
4. System Capacity	5	3	2	2	3	4	4	5	5	3	5	3	3	3	5	5	5	5	5
5. Gas Storage thru Line Pack	5	3	2	2	3	4	4	5	5	3	5	3	3	3	5	5	5	5	5
6. Reduction in Gas Price for Ratepayers	3	3	3	3	3	3	3	3	3	3	1	1	3	3	3	3	3	3	3
7. Other Benefits	5	3	1	1	3	4	4	4	5	3	5	5	1	1	5	5	5	5	5
Total of Average Scores	27.6	17.0	15.5	15.5	20.6	24.1	24.5	25.9	27.6	20.4	19.0	18.6	16.2	16.2	27.0	27.2	27.2	27.2	27.2
Overall Relative Rank	1	15	18	18	11	10	9	8	1	12	13	14	16	16	7	3	3	3	3

(1 is the lowest (worst) score and 5 is the highest (best) score; Overall Relative Rank – 1 is the highest and 18 is the lowest)

A. Increased Safety

Increased safety benefits were scored against the criteria in the benefits evaluation model. For the purposes of this evaluation it is assumed that the Proposed Project and all of the Alternatives will comply with State laws to pressure test or replace Line 1600.

1. Evaluating Benefits using the Benefits Evaluation Model

The increased safety benefits and the respective scoring criteria are described below.

- 1.1 Increased safety margin to prevent pipeline rupture through the de-rating of Line 1600:[83]

  Evaluating the increased safety margins in terms of the percentage of specified minimum yield strength (SMYS) on Line 1600.

  1. N/A
  2. Line 1600 operating at 800 psi (49% of SMYS) - Transmission Function
  3. Line 1600 operating at 640 psi (39% of SMYS) - Transmission Function
  4. Line 1600 operating at 320 psi (<20% of SMYS) - Distribution Function
  5. Removal of Line 1600

- 1.2 Long-term Safety Benefit of Transmission Pipeline Project: Ability to sustain safety over the life of the transmission pipeline due to aspects such as:
    - Presence of known significant anomalies,
    - Presence of known anomalies, and
    - Future resiliency or strength of design:
        - Thickness of material
        - Corrosion protection
        - Protective coating
        - Installation techniques that prevent damage to the pipe

  The scale for scoring the projects against this benefit is:

  1. Anomalies persist in transmission pipeline
  2. N/A
  3. No transmission pipeline is part of the project
  4. N/A
  5. Meets or exceeds modern design standards

- 1.3 Reduction in incidents per HCA mile of pipeline:[84] Using the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) data, age, type of pipeline material, wall thickness, and other parameters, a percentage reduction or increase in the number of incidents per HCA mile was able to be quantified.

  The scale for scoring the projects against this benefit is:
  1. > 25% increase in potential incidents/ HCA mile
  2. 0-25% increase in potential incidents/HCA mile
  3. No change in potential incidents/HCA mile likelihood
  4. 0-25% reduction in incidents/ HCA mile
  5. > 25% reduction in incidents/ HCA mile

[83] See Prepared Direct Testimony of Travis Sera (March 21, 2016).
[84] *See* Section V.H, Pipeline Failure Analysis

- 1.4 Increased real-time awareness of excavation damage: Ability to detect excavation damage in real-time to prevent or mitigate larger incidents from occurring.

  The scale for scoring the projects against this benefit is:

  1. Reduced capabilities for real-time awareness of excavation damage
  2. N/A
  3. No change in capabilities for real-time awareness of excavation damage
  4. N/A
  5. Increased capabilities for real-time awareness of excavation damage

- 1.5 Achievement of "as soon as practicable" safety objective:[85] Based on estimated completion or in-service year.

  The scale for scoring the projects against this benefit is:

  1. Beyond 2026
  2. Complete by 2026
  3. Complete by 2024
  4. Complete by 2022
  5. Complete by 2020

[85] In Decision (D.) 11-06-017, Ordering Paragraph 5, the Commission directed pipeline operators to develop a plan to test or replace all transmission pipelines that do not have documentation of a pressure test "as soon as practicable."

The results of the safety benefits scoring are shown in Table 11 below.

Table 11 - Increased Safety Benefits Score

Safety Benefits	Proposed Project - 36"	Hydrotest	Alt Diameter - 10"	Alt Diameter - 12"	Alt Diameter - 16"	Alt Diameter – 20”	Alt Diameter - 24"	Alt Diameter - 30"	Alt Diameter - 42"	Replace Line 1600 In-Place	Otay Mesa Alternatives	LNG Storage	Alt Energy – Grid Scale	Alt Energy – Smaller Scale	Offshore Route	Blythe to Santee Alt 1	Blythe to Santee Alt 2	Cactus City to SD	2nd Pipeline Along Line 3010
1.1 Increased safety margin to prevent pipeline rupture through the de-rating of Line 1600[86]	4	3	4	4	4	4	4	4	4	5	4	4	4	4	4	4	4	4	4
1.2 Long-term Safety Benefit of Transmission Pipeline	5	1	5	5	5	5	5	5	5	5	3	3	3	3	5	5	5	5	5
1.3 Reduction in incidents per HCA mile of pipeline	5	3	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
1.4 Increased real-time awareness of excavation damage	5	3	5	5	5	5	5	5	5	5	3	3	3	3	5	5	5	5	5
1.5 Achievement of “as soon as practicable” safety objective	4	4	4	4	4	4	4	4	4	2	3	2	2	2	1	2	2	2	2
Average Score	**5**	**3**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**4**	**4**	**3**	**3**	**3**	**4**	**4**	**4**	**4**	**4**

*(*1 is the lowest (worst) score and 5 is the highest (best) score)

[86] Line 1600 will be de-rated for all Alternatives except the Hydrotest Alternative and the Line 1600 Replace in Place with a New 16-inch Pipeline.

Results of the increased safety benefits evaluation are discussed below.

a) Proposed Project

The Proposed Project eliminates the need to operate Line 1600 at a higher pressure and instead allows for its de-rating at a lower and safer pressure that will improve overall system safety margins.

The Proposed Project will feature a new 36” pipeline (in addition to the de-rated Line 1600) that meets or exceeds design standards and ensures the longer term safety benefit of the transmission system.

The Proposed Project will also reduce the number of incidents per HCA mile in the system.[87,88]

Ability to achieve “as soon as practicable” safety objective based on completion or in-service year.

b) Hydrotest

If Line 1600 remains a transmission asset, the risks of long seam weld hook crack failures, exposure to time dependent threats (such as corrosion), and other material and design related factors that can interact with non-state-of-the-art vulnerabilities to create increased risk remain as well, and therefore do not support the long term safety benefit of transmission pipeline.

Additionally, there are no significant changes in incidents per HCA mile if Line 1600 is hydrotested and remains in transmission level service.

No improvements in real-time awareness of excavation damages.

Ability to achieve “as soon as practicable” safety objective based on completion or in-service year.

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[87] *See* Section V.H, Pipeline Failure Analysis.
[88] *See* Section V.H, Pipeline Failure Analysis.

c) *Alternative Diameter Pipelines*

Table 12 - Safety Benefits of Alternative Diameter Pipelines

Project	Safety Benefits
Alternative Diameter Pipelines 10" through 42" (with a de-rated Line 1600 at distribution pressure)	De-rating of Line 1600 to distribution service will improve overall system safety margin. The new transmission pipeline meets or exceeds modern design standards for longer term safety benefit of transmission pipeline safety. Fewer incidents per HCA mile due to the use of state-of-the-art materials and fabrication techniques. Increased capability for real-time awareness of excavation damages. Ability to achieve "as soon as practicable" safety objective based on completion or in-service year.

d) *Other Alternative Projects*

Table 13 - Safety Benefits of Other Alternatives

Project	Safety Benefits
Replace Line 1600 In-Place with a New 16-inch Transmission Pipeline (with removal of Line 1600)	The removal and replacement of Line 1600 will improve overall system safety margin. The new transmission pipeline meets or exceeds modern design standards for longer-term safety benefit of transmission pipeline safety. Fewer incidents per HCA mile due to the use of state-of-the-art materials and fabrication techniques. Increased capability for real-time awareness of excavation damages. Unable to achieve "as soon as practicable" safety objective based on completion or in-service year.
De-rated Line 1600 is assumed for each of the below options (but no transmission pipeline is part of the project): • Otay Mesa Alternatives • LNG Storage • Alternate Energy – Grid Scale • Alternate Energy – Smaller Scale	De-rating of Line 1600 to distribution service will improve overall system safety margin. There is no new transmission pipeline to meet or exceed modern design standards for longer-term safety benefit of transmission pipeline safety. Fewer incidents per HCA mile due a de-rated distribution Line 1600. No improvements in real-time awareness of excavation damages. Low ability to achieve "as soon as practicable" safety objective based on completion or in-service year for the Otay Mesa, the

Project	Safety Benefits
	LNG and Alternate Energy Alternatives.
Alternative Pipelines – 36" (with a de-rated Line 1600) • Blythe to Santee Alt 1 • Blythe to Santee Alt 2 • Cactus City to SD • 2nd Pipeline Along Line 3010 • Offshore Route	De-rating of Line 1600 to distribution service will improve overall system safety margin. The new transmission pipeline meets or exceeds modern design standards for longer term safety benefit of transmission pipeline safety. Fewer incidents per HCA mile due to the use of state-of-the-art materials and fabrication techniques. Increased capability for real-time awareness of excavation damages (for the Offshore Alternative this applies to segments that are on land). Low ability to achieve "as soon as practicable" safety objective based on completion or in-service year varies with these projects, with the Offshore Pipeline scoring the worst at 1, and the Cross County lines and the 2nd Pipeline Along 3010 scoring 2s.

B. Increased Reliability

System reliability refers to the ability to maintain safe, consistent, and continuous service to customers. System reliability is insured by maintaining safe operating pressures, which in turn result from having sufficient supply to meet demand and sufficient pipeline and storage capacity.

Using modern design standards and state-of-the-art materials and technology can increase the reliability of the physical gas transmission asset. Additionally, extra capacity as a result of a larger pipe diameter and the ability to operate safely at a higher pressure, can help improve the inherent reliability of a system during events when (a) projected daily demand exceeds forecast levels or (b) intra-day demands fluctuate in a manner that exceeds current operating parameters.

The Proposed Project and Alternatives were evaluated and scored in terms of their impact on increasing the current reliability/redundancy of the Applicants' gas transmission system. The three main distinctions in assessing the impacts to reliability/redundancy are as follows:

- No change to system reliability/redundancy;
- Increased system reliability/redundancy, and
- Decreased system reliability/redundancy.

1. Evaluating Benefits using the Benefits Evaluation Model

Please note, system capacity-related reliability benefits are implicit in the evaluation of increased reliability. These benefits are included in the "Increased System Capacity" section below in order to avoid double-counting the benefits.

Increased reliability benefits have been assessed by evaluating and scoring the reliability aspects of the Proposed Project and Alternatives using the benefits evaluation model described above.

The increased reliability benefits of the respective scoring criteria are described below.

- <u>2.1 Redundancy to natural gas transmission system:</u>

  Ability for a project to provide redundancy to the natural gas system should an unplanned event occur and place any of the two primary gas transmission assets (Line 3010 and Moreno Compression Station) out of service. The scale for scoring the projects against this benefit is:

  1. Reduced Level of System Redundancy
  2. Existing Level of System Redundancy
  3. Increased System Redundancy
  4. Complete Redundancy for Line 3010
  5. Complete Redundancy for Line 3010 or Moreno Compressor Station

- <u>2.2 Curtailment impact to core gas customers:</u> An outage scenario analysis[89] has been performed to model the impact of the Alternatives on overall system reliability. The analysis evaluates curtailments to gas customers in the case of an outage or reduction in pressure of Line 3010 under current conditions, given the hypothetical availability of the Proposed Project or Alternates. A range of scenarios were modeled across variabilities in gas supply from Otay Mesa and seasonal variations in gas demand. SDG&E Gas Rule 14[90] was used to segregate impact to the key customer classes in order of their curtailment priority. The scenario analysis methodology and approach is discussed in detail in Section H, Supporting Analysis.

  The scale for scoring the Alternatives against this benefit is based on a normalization of the average curtailment measured across all scenarios modeled for each Project Alternative. The average percentage of gas curtailment identified under each Project Alternative was normalized from 0% to 100%, and the following scores (1 through 5) were applied accordingly.

  1. Normalized curtailment impacts are above 81% of the maximum in all Project Alternatives[91]

[89] See Section H for a detailed description of the scenario analysis performed.
[90] See Prepared Direct Testimony of Gwen Marelli (March 21, 2016), page 2.
[91] Scores are based on a normalization of the average curtailment impacts under each Project Alternate, compared to the maximum impact for all Project Alternates. The maximum curtailment impact to the

2. Normalized curtailment impacts are between 61% and 80% of the maximum in all Project Alternatives
3. Normalized curtailment impacts are between 41% and 60% of the maximum in all Project Alternatives
4. Normalized curtailment impacts are between 21% and 40% of the maximum in all Project Alternatives
5. Normalized curtailment impacts are between 0% and 20% of the maximum in all Project Alternatives

- 2.3 Curtailment impact to electric generation (EG) gas customers: An outage scenario analysis[92] has been performed to model the impact of the Alternatives on overall system reliability. The analysis evaluates curtailments to customers in the case of an outage or reduction in pressure of Line 3010 under current conditions, given the hypothetical availability of the Proposed Project or Alternatives. A range of scenarios were modeled across variabilities in gas supply from Otay Mesa and seasonal variations in gas demand. SDG&E Gas Rule 14[93] was used to segregate impact to the key customer classes in order of their curtailment priority. The scenario analysis methodology and approach is discussed in detail in Section H, Supporting Analysis.

  The scale for scoring the Alternatives against this benefit is based on a normalization of the average curtailment measured across all scenarios modeled for each Project Alternative. The average percentage of gas curtailment identified under each Project Alternative was normalized from 0% to 100%, and the following scores (1 through 5) were applied accordingly.

  1. Normalized curtailment impacts are above 81% of the maximum in all Project Alternatives[94]
  2. Normalized curtailment impacts are between 61% and 80% of the maximum in all Project Alternatives
  3. Normalized curtailment impacts are between 41% and 60% of the maximum in all Project Alternatives
  4. Normalized curtailment impacts are between 21% and 40% of the maximum in all Project Alternatives
  5. Normalized curtailment impacts are between 0% and 20% of the maximum in all Project Alternatives

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core gas customer class, as an average across the 48 unique scenarios modeled per Project Alternate, was a 20.8% curtailment of gas services.

[92] See Section H for a detailed description of the scenario analysis performed.

[93] See Prepared Direct Testimony (March 21, 2016) of Gwen Marelli, page 2.

[94] Scores are based on a normalization of the average curtailment impacts under each Project Alternate, compared to the maximum impact for all Project Alternates. The maximum curtailment impact to the electric generation (EG) gas customer class, as an average across the 48 unique scenarios modeled per Project Alternative, was a 46.6% curtailment of gas services.

- 2.4 Curtailment impact to non-core, non-EG gas customers: An outage scenario analysis[95] has been performed to model the impact of the Alternatives on overall system reliability. The analysis evaluates gas curtailments to customers in the case of an outage or reduction in pressure of Line 3010 under current conditions, given the hypothetical availability of the Proposed Project or Alternatives. A range of scenarios were modeled across variabilities in gas supply from Otay Mesa and seasonal variations in gas demand. SDG&E Gas Rule 14[96] was used to segregate impact to the key customer classes in order of their curtailment priority. The scenario analysis methodology and approach is discussed in detail in Section H, Supporting Analysis.

  The scale for scoring the Alternatives against this benefit is based on a normalization of the average curtailment measured across all scenarios modeled for each Project Alternative. The average percentage of gas curtailment identified under each Project Alternative was normalized from 0 to 100%, and the following scores (1 through 5) were applied accordingly.

  1. Normalized curtailment impacts are above 81% of the maximum in all Project Alternatives[97]
  2. Normalized curtailment impacts are between 61% and 80% of the maximum in all Project Alternatives
  3. Normalized curtailment impacts are between 41% and 60% of the maximum in all Project Alternatives
  4. Normalized curtailment impacts are between 21% and 40% of the maximum in all Project Alternatives
  5. Normalized curtailment impacts are between 0% and 20% of the maximum in all Project Alternatives

- 2.5 Curtailment impact to electric customers: An outage scenario analysis[98] has been performed to model the impact of the Alternatives on overall system reliability. The analysis evaluates electric curtailments to customers in the case of an outage or reduction in pressure of Line 3010 under current conditions, given the hypothetical availability of the Proposed Project or Alternatives. A range of scenarios were modeled across variabilities in gas supply from Otay Mesa and seasonal variations in gas and electric demand. SDG&E Gas Rule 14[99] was used to segregate impact to the key customer classes in order of their curtailment priority. The scenario analysis methodology and approach is discussed in detail in Section H, Supporting Analyses.

[95] See Section H for a detailed description of the scenario analysis performed.
[96] See Prepared Direct Testimony of Gwen Marelli, (March 21, 2016), page 2.
[97] Scores are based on a normalization of the average curtailment impacts under each Project Alternate, compared to the maximum impact for all Project Alternates. The maximum curtailment impact to the non-core, non-EG gas customer class, as an average across the 48 unique scenarios modeled per Project Alternative, was a 63.2% curtailment of gas services.
[98] See Section H for a detailed description of the scenario analysis performed.
[99] See Prepared Direct Testimony of Gwen Marelli, (March 21, 2016), page 2.

The scale for scoring the Alternatives against this benefit is based on a normalization of the average curtailment measured across all scenarios modeled for each Project Alternative. The average percentage of curtailment required under each Project Alternative was normalized from 0 to 100%, and the following scores (1 through 5) were applied accordingly.

1. Normalized curtailment impacts are above 81% of the maximum in all Project Alternatives[100]
2. Normalized curtailment impacts are between 61% and 80% of the maximum in all Project Alternatives
3. Normalized curtailment impacts are between 41% and 60% of the maximum in all Project Alternatives
4. Normalized curtailment impacts are between 21% and 40% of the maximum in all Project Alternatives
5. Normalized curtailment impacts are between 0% and 20% of the maximum in all Project Alternatives

The results of the increased reliability benefits scoring are shown in Table below.

Table 14 - Increased Reliability Benefits Score

Reliability Benefits	Proposed Project - 36"	Hydrotest	Alt Diameter - 10"	Alt Diameter - 12"	Alt Diameter - 16"	Alt Diameter - 20"	Alt Diameter - 24"	Alt Diameter - 30"	Alt Diameter - 42"	Replace Line 1600 In-Place	Otay Mesa Alternatives	LNG Storage	Alt Energy – Grid Scale	Alt Energy – Smaller Scale	Offshore Route	Blythe to Santee Alt 1	Blythe to Santee Alt 2	Cactus City to SD	2nd Pipeline Along Line 3010
2.1 Redundancy to natural gas transmission system	5	2	1	1	2	3	3	4	5	2	3	3	1	1	5	5	5	5	5
2.2 Curtailment impact to core gas customers	5	1	3	3	5	5	5	5	5	5	1	1	1	1	5	5	5	5	5
2.3 Curtailment impact to electric generation (EG) gas customers	5	1	1	1	3	4	5	5	5	3	1	1	1	1	5	5	5	5	5

[100] Scores are based on a normalization of the average curtailment impacts under each Project Alternative, compared to the maximum impact for all Project Alternatives. The maximum curtailment impact to the electric customer class, as an average across the 48 unique scenarios modeled per Project Alternative, was a 4.2% curtailment of electric services.

Reliability Benefits	Proposed Project - 36"	Hydrotest	Alt Diameter - 10"	Alt Diameter - 12"	Alt Diameter - 16"	Alt Diameter - 20"	Alt Diameter - 24"	Alt Diameter - 30"	Alt Diameter - 42"	Replace Line 1600 In-Place	Otay Mesa Alternatives	LNG Storage	Alt Energy – Grid Scale	Alt Energy – Smaller Scale	Offshore Route	Blythe to Santee Alt 1	Blythe to Santee Alt 2	Cactus City to SD	2nd Pipeline Along Line 3010
2.4 Curtailment impact to non-core, non-EG gas customers	5	1	1	1	2	3	4	5	5	2	1	1	1	1	5	5	5	5	5
2.5 Curtailment impact to electric customers	5	1	1	1	3	5	5	5	5	3	1	5	5	5	5	5	5	5	5
Average Score	**5**	**1**	**1**	**1**	**3**	**4**	**4**	**5**	**5**	**3**	**1**	**2**	**2**	**2**	**5**	**5**	**5**	**5**	**5**

*(*1 is the lowest (worst) score and 5 is the highest (best) score)

Results of the increased reliability benefits evaluation are discussed below.

a) Proposed Project

The Proposed Project will provide significant benefits in system reliability and resiliency.

The Proposed Project will provide complete redundancy to Line 3010 or Moreno Compressor Station in the event of a loss of either facility.

Based on a detailed outage and curtailment scenario analysis, the Proposed Project is expected to be amongst the projects that are estimated to result in the least amount of potential curtailment of customers across curtailment priorities defined by SDG&E Gas Rule 14.[101]

b) Hydrotest

Hydrotesting Line 1600 does not provide any significant additional benefits to system reliability to what is currently available to the gas system.

Based on a detailed outage and curtailment scenario analysis, the Proposed Project is expected to be amongst the projects that are estimated to result in the greatest amount of potential curtailment of customers across curtailment priorities defined by SDG&E Gas Rule 14.

[101] See Prepared Direct Testimony of Gwen Marelli (March 21, 2016), page 2.

c) Alternative Diameter Pipelines

Table 15 - Reliability Benefits of Alternative Diameter Pipelines and the Replace Line 1600 In-Place with a New 16-inch Transmission Pipeline

Project	Reliability/Redundancy Benefits
Alternative diameter 10" through 12" (with a de-rated Line 1600 at distribution pressure)	Reduced level of system redundancy. See scoring Table for average curtailment percentages as defined by SDG&E's customer groups by order of service interruption priority.
Alternative diameter 16" (with a de-rated Line 1600 at distribution pressure) and the Replace Line 1600 In-Place with a New 16-inch Transmission Pipeline Alternative (no Line 1600)	Existing level of system redundancy. See scoring Table for average curtailment percentages as defined by SDG&E's customer groups by order of service interruption priority.
Alternative diameter pipelines 20" and 24" (with a de-rated Line 1600 at distribution pressure)	Increased System Redundancy. See scoring Table for average curtailment percentages as defined by SDG&E's customer groups by order of service interruption priority.
Alternative diameter pipeline 30" (with a de-rated Line 1600 at distribution pressure)	Complete Redundancy for Line 3010. See scoring Table for average curtailment percentages as defined by SDG&E's customer groups by order of service interruption priority.
Alternative diameter pipeline 42" (with a de-rated Line 1600 at distribution pressure)	Complete Redundancy for Line 3010 or Moreno Compressor Station. See scoring Table for average curtailment percentages as defined by SDG&E's customer groups by order of service interruption priority.

d) Other Alternatives

Table 16 - Reliability Benefits of Other Alternatives

Project	Reliability/Resiliency Benefits
Otay Mesa Alternatives (with a de-rated Line 1600 at distribution pressure)	Increased System Redundancy. See scoring Table for average curtailment percentages as defined by SDG&E's customer groups by order of service interruption priority.
Alternative pipelines: • Blythe-Santee Alt 1 • Blythe-Santee Alt 2 • Cactus City to SD • 2nd Pipeline Along Line 3010 • Offshore Route (with a de-rated Line 1600 at distribution pressure)	Complete Redundancy for Line 3010 or Moreno Compressor Station. See scoring Table for average curtailment percentages as defined by SDG&E's customer groups by order of service interruption priority.
• LNG Storage • Alternate Energy – Grid	Increased System Redundancy for the LNG Storage option with Reduced System Redundancy for the Alternate Energy Alternatives.

Project	Reliability/Resiliency Benefits
Scale • Alternate Energy – Smaller Scale (Includes a de-rated Line 1600 at distribution pressure for all three above)	See scoring Table for average curtailment percentages as defined by SDG&E's customer groups by order of service interruption priority.

C. Increased Operational Flexibility

Increased operational flexibility is defined as the ability of the system to respond to operational (supply or demand) uncertainty in a manner that sustains normal operations with minimal impact to customers. Incremental pipeline capacity can provide flexibility to operate the Applicants' system by expanding the options available to handle stress conditions on a daily and hourly basis that put system integrity and customer service at risk.

Operational flexibility[102] can be improved through the following means:

1. Increased capacity to handle intra-day or peak demand fluctuations; and
2. The ability to control day-to-day operations of the system without reliance on external systems or entities (complete asset control)

2. Evaluating Benefits using the Benefits Evaluation Model

Increased operational flexibility benefits have been assessed by evaluating and scoring the operational flexibility aspects of the Proposed Project and Alternatives using the benefits evaluation model described above.

The increased operational flexibility benefits of the respective scoring criteria are described below.

- 3.1 Meeting current and future natural gas peak demand: Ability to meet increasingly volatile daily and hourly peak demand due to: increased reliance on gas-fired EG to supplement closure of the San Onofre Nuclear Generating Station (SONGS) and dependence on intermittent renewable power; need to meet future peak demand due to increases in the use of renewable energy sources (up to 50% renewable generation by 2030); forecasted growth in the population of the San Diego greater metropolitan area (up by 1 million people by 2035).

  The scale for scoring the projects against this benefit is:
  1. No ability to meet current peak or future peak demand.
  2. Decrease in the ability to meet current peak or future peak demand.
  3. No increase in the ability to meet current peak or future peak demand.
  4. Improved ability to meet current peak demand, but unlikely to meet future forecast peak demand.

[102] *See* Prepared Direct Testimony of Davis Bisi (March 21, 2016).

5. Ability to meet and/or exceed the demands of current and all predicted future peak demand through 2035.

- <u>3.2 Utility Operational Control of Asset:</u> Ability to control the physical asset by SDG&E.

  The scale for scoring the projects against this benefit is binary:
  1. Utility does not have operational control over asset
  2. N/A
  3. N/A
  4. N/A
  5. Utility has operational control over asset

The results of the increased operational flexibility scoring are shown in Table 17 below.

Table 17 - Increased Operational Flexibility Benefits Score

Operational Flexibility Benefits	Proposed Project - 36"	Hydrotest	Alt Diameter - 10"	Alt Diameter - 12"	Alt Diameter - 16"	Alt Diameter - 20"	Alt Diameter - 24"	Alt Diameter - 30"	Alt Diameter - 42"	Replace Line 1600 In-Place	Otay Mesa Alternatives		Alt Energy – Grid Scale	Alt Energy – Smaller Scale	Offshore Route	Blythe to Santee Alt 1	Blythe to Santee Alt 2	Cactus City to SD	2nd Pipeline Along Line 3010
3.1 Meeting current and future natural gas peak demand	5	3	2	2	3	4	4	4	5	3	5	3	3	3	5	5	5	5	5
3.2 Utility Operational Control of Asset	5	5	5	5	5	5	5	5	5	5	1	5	5	5	5	5	5	5	5
Average Score	**5**	**4**	**4**	**4**	**4**	**5**	**5**	**5**	**5**	**4**	**3**	**4**	**4**	**4**	**5**	**5**	**5**	**5**	**5**

(1 is the lowest (worst) score and 5 is the highest (best) score)

Results of the increased operational flexibility benefits evaluation are discussed below.

a) Proposed Project

The Proposed Project will replace an existing 16-inch diameter pipeline with a 36-inch diameter pipeline, which will increase the transmission capacity of the gas system in San Diego County by approximately 200 MMcfd. This increase in capacity will enhance the Applicants' ability to reliably manage the fluctuating peak demand of core and noncore customers, including electric generation (EG) and clean transportation. The new line would provide incremental system capacity and increase operational flexibility by expanding the options available to handle stress conditions on a daily and hourly basis that put customer service at risk.

The Proposed Project is able to meet and/or exceed the demands of current and all predicted future peak demand through 2035.

Under the Proposed Project, the Applicants retain operational control of the asset.

b) Hydrotest

There will be no increase in system capacity after the hydrotesting on Line 1600 is complete, and a potential short-term decrease in system capacity during the hydrotesting of Line 1600. In order to backfill the loss of supply from Line 1600 (~100 MMcfd), natural gas would have to be imported from Otay Mesa.

The lack of any increase in system capacity results in no change to the current operational flexibility and therefore no increase in the ability to meet current peak or future peak demand. Under this option the Applicants retain operational control of the asset.

c) Alternative Diameter Pipelines

Table 18 - Operational Flexibility Benefits of Alternative Diameter Pipelines

Project	Operational Flexibility Benefits
Alternative diameter 10" through 12"" (with a de-rated Line 1600 at distribution pressure)	Decrease in the ability to meet current peak or future peak demand. Under this option the Applicants retain operational control of the asset.
Alternative diameter 16" (with a de-rated Line 1600 at distribution pressure)	No increase in the ability to meet current peak or future peak demand. Under this option the Applicants retain operational control of the asset.
Alternative diameter 20" through 30" (with a de-rated Line 1600 at distribution pressure)	Improved ability to meet current peak demand, but unlikely to meet future forecast peak demand through 2035. Under this option the Applicants retain operational control of the asset.
Alternative diameter 42" (with a de-rated Line 1600 at distribution pressure)	Ability to meet and/or exceed the demands of current and all predicted future peak demand through 2035. Under this option the Applicants retain operational control of the asset.

d) Other Alternative Projects

Table 19 - Operational Flexibility Benefits of Other Alternatives

Project	Operational Flexibility Benefits
Replace Line 1600 In-Place with a New 16-inch Transmission Pipeline Replacement (no Line 1600)	No increase in the ability to meet current peak or future peak demand. Under this option the Applicants retain operational control of the asset.

Project	Operational Flexibility Benefits
Otay Mesa Alternatives (with a de-rated Line 1600 at distribution pressure)	Ability to meet and/or exceed the demands of current and all predicted future peak demand through 2035. Under this option the Applicants do not retain operational control of the asset as the lines are owned and operated by third-party entities.
Alternative pipelines: • Blythe to Santee Alt 1 • Blythe to Santee Alt 2 • Cactus City to SD • 2nd Pipeline Along Line 3010 • Offshore Route (with a de-rated Line 1600 at distribution pressure for all cases above)	Ability to meet and/or exceed the demands of current and all predicted future peak demand through 2035. Under this option the Applicants retain operational control of the asset.
• LNG Storage • Alternative Energy (with a de-rated Line 1600 at distribution pressure for both cases above)	No increase in the ability to meet current peak or future peak demand. Under this option the Applicants retain operational control of the asset.

D. Increased System Capacity

The Proposed Project and Alternatives were evaluated in terms of increased system capacity. The three elements of operational flexibility are:

- No change to system capacity
- Increased system capacity
- Decreased system capacity

1. Evaluating Benefits using the Benefits Evaluation Model

Increased system capacity benefits have been assessed by evaluating and scoring the capacity aspects of the Proposed Project and Alternatives using the benefits evaluation model described above.

The increased system capacity benefits of the respective scoring criteria are described below.

- 4.1 Impact to system capacity:[103] Ability of the project option to increase current system capacity. This impact is based on the diameter of the pipe and other critical design features. Increased system capacity can also help improve the system's ability to meet additional load demands if the need arises. During intra-day, peak or extreme weather demand fluctuations, extra capacity can help bridge the gap between design and higher load scenarios.

  The scale for scoring the projects against this benefit is:
  1. Reduces system capacity by more than 20%
  2. Reduces system capacity by up to 20%
  3. No change to system capacity
  4. Increases system capacity by up to 20%
  5. Increases system capacity by more than 20%

The results of the increased capacity scoring are shown in Table 20 below.

Table 20 - Increased System Capacity Benefits Score

System Capacity Benefits	Proposed Project - 36"	Hydrotest	Alt Diameter - 10"	Alt Diameter - 12"	Alt Diameter - 16"	Alt Diameter - 20"	Alt Diameter - 24"	Alt Diameter - 30"	Alt Diameter - 42"	Replace Line 1600 In-Place	Otay Mesa Alternatives	LNG Storage	Alt Energy – Grid Scale	Alt Energy – Smaller Scale	Offshore Route	Blythe to Santee Alt 1	Blythe to Santee Alt 2	Cactus City to SD	2nd Pipeline Along Line 3010
4.1 Impact to system capacity	5	3	2	2	3	4	4	5	5	3	5	3	3	3	5	5	5	5	5

*(*1 is the lowest (worst) score and 5 is the highest (best) score)

Results of the increased capacity benefits evaluation are discussed below.

a) Proposed Project

The Proposed Project will increase overall gas system capacity. This increase in capacity will improve the ability to manage intra-day and peak load. To this end, the installation of a new 36" pipeline[104] is projected to add an additional 200 MMcfd (30%)[105] of system capacity.

[103] *See* Prepared Direct Testimony of David Bisi (March 21, 2016).
[104] In this scenario, Line 1600 will be consequentially de-rated to distribution operating pressures and no longer be considered a transmission asset.
[105] Current system capacity = 630 MMcfd in the winter operating season.

b) Hydrotest

A hydrotested Line 1600 will not add any incremental capacity to the system and will therefore not provide any of the benefits applicable to the Proposed Project above or the Alternatives.

c) Alternate Diameter Pipelines

Table 21 - System Capacity Benefits of Alternative Diameter Pipelines

Project	System Capacity Benefits
Alternate diameter 10” through 12” (with a de-rated Line 1600 at distribution pressure)	Reduces system capacity by up to 20%.
Alternate diameter 16” (with a de-rated Line 1600 at distribution pressure)	No change to system capacity.
Alternate diameter 20” and 24” (with a de-rated Line 1600 at distribution pressure)	Increases system capacity by up to 20%.
Alternate diameter 30” through 42”	Increases system capacity by more than 20%.

d) Other Alternatives

Table 22 - System Capacity Benefits of Other Alternatives

Project	System Capacity Benefits
Replace Line1600 In-Place with a New 16-inch Transmission Pipeline Alternative (with no Line 1600)	No change to system capacity.
Otay Mesa Alternatives (with a de-rated Line 1600 at distribution pressure)	Increases system capacity by more than 20%.
Alternative pipelines: • Blythe to Santee Alt 1 • Blythe to Santee Alt 2 • Cactus City to SD • 2nd Pipeline Along Line 3010 • Offshore Route (with a de-rated Line 1600 at distribution pressure for cases above)	Increases system capacity by more than 20%.
• LNG Storage • Alternate Energy – Grid Scale • Alternate Energy – Smaller Scale (with a de-rated Line 1600 at distribution pressure for cases above)	No change to system capacity.

E. Increased Gas Storage through Line Pack

All additional pipelines on the SDG&E system incrementally increase the system line pack to greater or lesser extents. Line pack simply provides an operational buffer to changes in customer demand, and any incremental benefit that line pack provides is implicitly captured by the potential increases in system capacity provided in Section D above.

F. Reductions in Gas Price for Ratepayers

Reduction in gas prices to ratepayers is not expected for any of the project options and under two projects there is a potential for increases to ratepayer gas prices as discussed below.

- <u>6.1 Reduction in gas prices to ratepayers</u>: Reduction in gas prices to ratepayers is not expected for any of the options being discussed presently and for two of the Alternatives (Otay Mesa and LNG Storage) there is a potential for an increase in gas prices to ratepayers owing to transportation costs to fill LNG tanks and the incremental transportation costs for supply from Otay Mesa.

This benefit was scored as follows:[106]

1. Increase in gas prices to ratepayers expected
2. N/A
3. No change in gas prices to ratepayers expected
4. N/A
5. Potential reduction in gas prices to ratepayers

Table 23 - Reduction in Gas Prices to Ratepayers Benefit Scores

Gas Prices to Ratepayers	Proposed Project - 36"	Hydrotest	Alt Diameter - 10"	Alt Diameter - 12"	Alt Diameter - 16"	Alt Diameter - 20"	Alt Diameter - 24"	Alt Diameter - 30"	Alt Diameter - 42"	Replace Line 1600 In-Place	Otay Mesa Alternatives	LNG Storage	Alt Energy – Grid Scale	Alt Energy – Smaller Scale	Offshore Route	Blythe to Santee Alt 1	Blythe to Santee Alt 2	Cactus City to SD	2nd Pipeline Along Line 3010
6.1 Reduction in gas prices to ratepayers	3	3	3	3	3	3	3	3	3	3	1	1	3	3	3	3	3	3	3

(1 is the lowest (worst) score and 5 is the highest (best) score)

[106] *See* Prepared Direct Testimony of Gwen Marelli (March 21, 2016) for further details.

G. Other Benefits

Other benefits assessed in this study include environmental and other external or societal impacts as a result of any of the project options. The primary topics evaluate emissions reductions, air quality improvements, and the environmental and jurisdictional zoning impacts of route or site selection. Of these, net emissions reductions as a benefit is scored below.

1. Evaluating Benefits using the Benefits Evaluation Model

Other benefits have been assessed by evaluating and scoring the different aspects of benefits generated by the Proposed Project and Alternatives using the benefits evaluation model described above.

The other benefits and their respective scoring criteria are described below.

- 7.1 Emissions reductions due to reduced operating hours at Moreno Compressor Station:[107] The ability to manage excess capacity or load demand with minimal compression can lead to significant reductions in emissions at Moreno Compressor Station and a consequential reduction in combustion emissions of GHGs such as carbon dioxide, as well as a reduction in emissions of other pollutants such as nitrous oxides.

  The scale for scoring the projects against this benefit is:
  1. Potential increase in net emissions at Moreno Compressor Station
  2. N/A
  3. 0% reduction in net emissions at Moreno Compressor Station
  4. 0% to 75% reduction in net emissions at Moreno Compressor Station
  5. 75% or greater reduction in net emissions at Moreno Compressor Station

[107] Based on the figures provided within the Moreno Compressor Station – PSRP Report. *See* Prepared Direct Testimony of Neil Navin (March 21, 2016), Attachment A – PSRP Report at Attachment XII.

2. Results of Analyses

Table 24 - Summary of Other Benefits Scores

Other benefits	Proposed Project - 36"	Hydrotest	Alt Diameter - 10"	Alt Diameter - 12"	Alt Diameter - 16"	Alt Diameter - 20"	Alt Diameter - 24"	Alt Diameter - 30"	Alt Diameter - 42"	Replace Line 1600 In-Place	Otay Mesa Alternatives	LNG Storage	Alt Energy – Grid Scale	Alt Energy – Smaller Scale	Offshore Route	Blythe to Santee Alt 1	Blythe to Santee Alt 2	Cactus City to SD	2nd Pipeline Along Line 3010
7.1 Emissions reductions due to reduced operating hours at compressor stations	5	3	1	1	3	4	4	4	5	3	5	5	1	1	5	5	5	5	5

*(*1 is the lowest (worst) score and 5 is the highest (best) score)

Results of the other benefits evaluation are discussed below.

a) Proposed Project

The Proposed Project will reduce net emissions at the Moreno Compressor Station by 75% or greater.[108] The reduced operating hours at Moreno Compressor Station will result in a net reduction in emissions of GHGs such as carbon dioxide and methane, as well as a reduction in emissions of other pollutants such as nitrous oxides.

b) Hydrotest

A hydrotested Line 1600 is not expected to change the current level of emissions at Moreno Compressor Station as a result of no incremental redundancy or capacity offered by this option.

[108] It is assumed that the Moreno Compressor Station would only require reduced operations to function minimally as a safeguard during extreme or unplanned capacity interruption scenarios. The Moreno Compressor Station PSRP Report uses a high case of reduced operations by 95%. *See* Prepared Direct Testimony of Neil Navin (March 21, 2016), Attachment A – PSRP Report at Attachment XII.

c) *Alternative Diameter Pipelines*

Table 25 - Other Benefits of Alternative Diameter Pipelines

Project	Net Emissions at Moreno Compressor Station
Alternative diameter 10” through 12” (with a de-rated Line 1600 at distribution pressure)	Potential increase in net emissions at Moreno Compressor Station.
Alternative diameter 16” (with a de-rated Line 1600 at distribution pressure)	0% reduction in net emissions at Moreno Compressor Station.
Alternative diameter 20” through 30” (with a de-rated Line 1600 at distribution pressure)	0% to 75% reduction in net emissions at Moreno Compressor Station.
Alternative diameter 42” (with a de-rated Line 1600 at distribution pressure)	75% or greater reduction in net emissions at Moreno Compressor Station.

d) *Other Alternatives*

Table 26 - Other Benefits of Other Alternatives

Project	Net Emissions at Moreno Compressor Station
Replace Line 1600 In-Place with a New 16-ince Transmission Pipeline Alternative (no Line 1600)	0% reduction in net emissions at Moreno Compressor Station.
Otay Mesa Alternatives (with a de-rated Line 1600 at distribution pressure)	75% or greater reduction in net emissions at Moreno Compressor Station.
Alternative pipelines[109]: • Blythe to Santee Alt 1 • Blythe to Santee Alt 2 • Cactus City to SD • 2nd Pipeline Along Line 3010 • Offshore Route (with a de-rated Line 1600 at distribution pressure for cases above)	75% or greater reduction in net emissions at Moreno Compressor Station.
• LNG Storage • Alternate Energy (with a de-rated Line 1600 at distribution pressure for cases above)	75% or greater reduction in net emissions at Moreno Compressor Station for the LNG Storage Alternative. Potential increase in net emissions at Moreno Compressor Station for the Alternate Energy solutions owing to the de-rating of Line 1600 and no addition of new transmission pipeline under this Alternative.

[109] The Cross County lines (J1, J2 and J3) are not directly connected to the Moreno Compressor Station, but are assumed to provide similar benefits with regards to avoided costs as the Proposed Project, due to the additional capacity inherent to a 36” pipeline. Due to the length of these lines, it is possible that additional compression may be needed to balance the gas flow in the system. However, at this stage in the design, it is not known whether this additional compression will be required.

H. Supporting Analysis

This section describes the approach and methodology used to estimate the impact of the various project options on overall system reliability introduced in Section VI.B above.

1. Pipeline Failure Analysis

Davies Consulting, LLC, with input and data from the Applicants, analyzed the potential failure rates for the existing Line 1600, the Proposed Project, and two proposed Alternatives: the 30" diameter pipeline (Alternative C5) and the 42" diameter pipeline (Alternative C6).

The Applicants' method for comparing alternatives is by calculating the likelihood of an incident in an HCA mile as represented by the risk score in the equation below:

$$Risk = Likelihood\ of\ Incident \times HCA\ Miles$$

Where in accordance with Title 49 of the Code of Federal Regulations (49 CFR) Part 191.3, an "incident" is currently defined as any of the following events:

1. An event that involves a release of gas from a pipeline and
    a) A death, or personal injury necessitating in-patient hospitalization; or
    b) Estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more.
2. An event that is significant, in the judgment of the operator, even though it did not meet the criteria of paragraph.

a) Likelihood of Pipeline Incidents

To calculate the likelihood of pipeline incidents, the Applicants used historical pipeline incident and mileage data from PHMSA.[110] The Applicants downloaded PHMSA's Gas Transmission and Gathering Incident Data from 1970-1984, 1984-2001, 2002-2009, and 2010-present (filtering 2010 to present to only show incidents up to 2014, as all 2015 incidents may not yet be included). For each data set, the Applicants filtered the data to exclude gathering pipelines, offshore incidents,[111] and incidents attributable to a compressor or compressor station, all of which were not relevant to this analysis.

To analyze the risk of an incident on a pipeline like Line 1600, the Applicants filtered the data to remove any pipelines constructed after 1960 or having a diameter other than 16 inches. The year

[110] http://www.phmsa.dot.gov/pipeline/library/data-stats/raw-data
[111] Prior to 1984, the incident data did not include a flag by which to identify offshore versus onshore incidents so the filtering of offshore incidents was only applicable to 1984 and beyond.

1960 was chosen based on "Integrity Characteristics of Vintage Pipelines," which identifies 1960 as approximately the cutoff date for "historic" versus "modern" pipeline manufacturing.[112] More specifically, the report indicates that between 1950 and 1970, modern manufacturing techniques for pipelines were introduced, and "historic" practices were phased out. The report indicates that the use of flash welding, which was used in constructing Line 1600, peaked in 1950 and was phased out by 1970. To calculate the number of incidents on historic pipelines similar to Line 1600, the Applicants used all of the remaining unfiltered records for each dataset. The total remaining incidents, for the period 1970 to 2014, on onshore transmission pipelines constructed prior to 1960, is 125.

The PHMSA annual mileage report provides the total miles of pipeline by decade of installation and, separately, by diameter. The incident rate for pre-1960 16-inch pipelines was determined using the PHMSA reported information.[113] Eight percent of all installed pipe has a diameter of 16 inches. The Applicants multiplied the total number of pre-1960 vintage pipeline miles by 8% to determine the number of mile-years needed to calculate the incident rate. The incident rate was then calculated to be **35.4E-05, or about 0.354 per thousand mile-years**.

To determine the incident rate on a new/modern pipeline, similar to the Proposed Project, the Applicants relied on a similar methodology to that described above. The team selected an incident and installation mileage date range of 2000 to 2014. Applying this filter to 36-inch pipe resulted in the identification of one incident. In order to increase the sample size to provide a more meaningful result, the Applicants expanded the diameter filter to include pipelines between 30-inches and 42-inches. The PHMSA incident data, reported 6 incidents that occurred on pipelines with diameters between 30-inch to 42-inch installed between 2000 and 2014. It should be noted, however, that one of these incidents was attributable to stripped threads, and the Proposed Project will not be subject to such failures by design. Thus, the comparable number of incidents of pipelines similar to the Proposed Project would be 5.

To determine the mile-years needed in the calculation of incident rate, the team collected the miles of 30-inch to 42-inch pipeline constructed between 2000 and 2009 and the miles constructed between 2010 and 2014. The share of 30-inch to 42-inch pipeline in the system is approximately 25%. Thus, the incident rate for onshore transmission 30-inch to 42-inch pipelines installed between 2000 and 2014 is **6.4 E-05, or 0.064 per thousand mile-years**.

Between the historic period in which Line 1600 was installed and the current modern period in which the proposed pipeline (Line 3602) will be installed, many improvements have been made in terms of testing, maintenance, and operations. These improvements, in addition to the new material and design, may have further reduced the likelihood of an incident on newly installed pipelines. Thus, to be conservative, it may be better to compare the incident rate over the same time period of 2000 to 2014.

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[112] Clark, E. B., B. N. Leis, and R. J. Eiber. "Integrity Characteristics of Vintage Pipelines." 2010. P7.
[113] The PHMSA definition of incident was used for the Applicants' analysis.

Once again, when identifying onshore transmission line incidents during the period between 2000 and 2014, there was insufficient data to use pipelines exactly 16 inches in diameter. Thus, the Applicants expanded the consideration to include pipelines with diameters between 12 and 20 inches. The share of pipelines between 12 and 20 inches is approximately 28%. Thus, the incident rate for onshore transmission 12-inch to 20-inch pipelines installed between 2000 and 2014 is **9.15E-05, or 0.0915 per thousand mile-years**.

As illustrated in Table 27, pipelines similar to Line 1600 have higher incident rates as compared to lines similar to the Proposed Project (Line 3602).

Table 27 - Incident Rates

Line	Incident Period	Incident Rate per Thousand Mile Years
Line similar to 1600	1970 – 2014	0.354
Line similar to 1600	2000 – 2014	0.0915
Line similar to 3602[114]	2000 - 2014	0.064

b) Consideration of Cause-Specific Incidents

In addition to a decrease in the probability of an incident based on year of installation, the Proposed Project will also have a reduced likelihood of an incident compared to Line 1600 because it will be less susceptible to corrosion, will be installed with features that reduce the likelihood of third-party damage (*e.g.*, mesh and intrusion detection monitoring), and thicker pipe wall necessarily implies much greater puncture resistance.[115] The European Gas Pipeline Incident Data Group (EGIG)[116] has collected data on 1,060 incidents on over 100,000 kilometers of natural gas pipeline. This data shows that "[f]or pipelines having a wall thickness of 15 millimeters or thicker, there have been no corrosion or third-party damage incidents reported."[117] Because the Proposed Project will have a minimum thickness of 0.625 inches (15.875 millimeter), the EGIG data suggests that the likelihood of corrosion and third party damage is negligible.[118]

[114] The Proposed Project, because of its modern construction and safety practices, is likely to have a lower incident rate.
[115] For a detailed list of additional safety-enhancing features of the Proposed Project, *see* Prepared Direct Testimony of Deanna Haines (March 21, 2016).
[116] Horalek V., Bolt R, EGIG Pipeline Incident Database: Safety Performances Determines the Acceptability of Cross Country Gas Transmission Systems
[117] Horalek V., Bolt R, EGIG Pipeline Incident Database: Safety Performances Determines the Acceptability of Cross Country Gas Transmission Systems
[118] *See* Prepared Direct Testimony of Neil Navin (March 21, 2016), for the physical specifications of the Proposed Project.

As shown in Figure 4 below, nationwide 39% (and in California, 43%) of all incidents are a result of corrosion or third party damage.[119] According to EGIG data, no incidents caused by corrosion or third parties have been reported on a pipeline with a wall thickness greater than 15 millimeters. Assuming that this data is accurate for future incidents in California, the incident rate for pipelines with a wall thickness greater than 15 millimeters should be 43% lower.

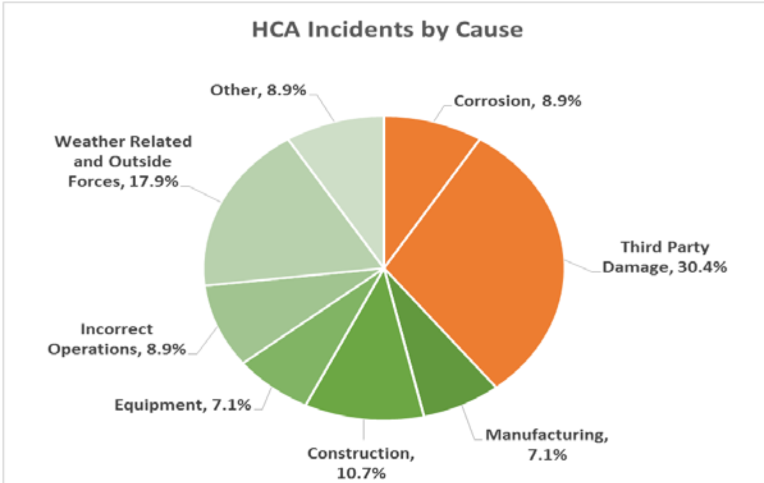

Figure 4 - HCA Incidents by Cause

A 43% reduction, however, is larger than the difference in incident rates calculated for Lines 1600 and the Proposed Project from the PHMSA database. The calculated incident rates of 9.15E-05 for thinner pipelines like Line 1600 and 6.4 E-05 for thicker pipelines like the Proposed Project results in a decrease of 29%. The Applicants' analysis uses the more conservative 29% decrease rate.

c) Additional Considerations

There are several other factors that support the finding that the Proposed Project will have a reduced likelihood of incident than a pipeline like Line 1600. They are presented here for consideration, but are not used in the risk score calculation as they are not quantifiable due to data limitations.

Modern steels have greatly improved fracture toughness which also diminishes the likelihood of puncture and the tendency for burst.[120] In other words, modern pipes are much more likely to leak than to rupture.

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[119] Information compiled at the federal level by PHMSA and published at location http://primis.phmsa.dot.gov/gasimp/performancemeasures.htm

[120] See B.N. Leis, O.C. Chang, T.A. Bubenik. "Leak versus Rupture Considerations for Steel Low-Stress Pipelines, GRI Report-00/0232." 2001. P11. See B.N. Leis and X.K. Zhu. "Leak vs. Rupture Boundary for Pipes with a Focus on Low Toughness and/or Ductility, PRCI Report PR-003-063526." 2012. A-3, A-8.

Modern manufacturing techniques may also further reduce the likelihood of an incident. The EGIG report finds that "the observed failure frequencies for pipelines constructed before 1964 are significantly higher than pipelines constructed after 1964."[121] According to Figure 4, better manufacturing of the new pipe would potentially eliminate the likelihood by an additional 7.1% of incidents, as the incidents attributable to non-state-of-the-art manufacturing and construction would be eliminated.

In addition, A.O. Smith, the company that manufactured the pipe for Line 1600, was the manufacturer for pipe involved in 415 incidents due to manufacturing, according to the PHMSA incident records. Most of the causes of these incidents are attributed to either corrosion or to manufacturing defects.

d) HCA Miles of Proposed Alternatives

The impact of an incident depends on whether the incident occurs in a high consequence area (HCA). Comparing potential impacts of an incident on each of the Alternatives requires a calculation of number of HCA miles affected by the incident. The HCA for a pipeline is a function of the proximity of structures to the pipeline, the size of the pipeline, and the pressure at which the pipeline is operating. For Line 1600, which operates at a transmission pressure of 640 psi, the HCA is 32.7 miles. Operating at distribution pressure of 320 psi, the HCA for Line 1600 is 2.3 miles.[122] The Proposed Project, operating at 800 psi, has an HCA of 32.1 miles.[123]

Table 28 - HCA Miles

Pipeline Option	HCA Miles
Line 1600 Transmission Pressure	32.7
Line 1600 De-rated at 320 psi.	2.3
Proposed Line 3602	32.1

e) Risk Score of Proposed Alternatives

The risk score of the Alternatives is calculated as the product of the likelihood of an incident (incident rate) on the pipeline and the HCA mileage of the pipeline. Table presents the risk scores for each component of the Alternatives analyzed.

[121] Horalek V., Bolt R, EGIG Pipeline Incident Database: Safety Performances Determines the Acceptability of Cross Country Gas Transmission Systems, p.8.
[122] Line 1600, once de-rated, will be a distribution line and will therefore not be subject to Subpart O and TIMP regulations. Using HCA comparison for a de-rated Line 1600 is shown for comparability purposes only.
[123] Calculated pursuant to 49 CFR 192.903.

Table 29 - Risk Scores

Pipeline Option	Likelihood of Incident	HCA Miles	Risk Score
Line 1600 Transmission Pressure	0.0915	32.7	2.99
Line 1600 De-rated	0.0915	2.3	0.21
Proposed Project 3602	0.064	32.1	2.05

Note that even without accounting for the potential incident rate reduction of derating Line 1600, the risk score of the de-rated line is only 7% of the line at transmission pressure. Combining the risk scores of the Proposed Project and the de-rated Line 1600 results in:

$$Risk\ Score\ of\ Proposed\ Alternative = \sqrt{0.21^2 + 2.05^2} = 2.06$$

The risk score for the Hydrotest Alternative is:

$$Risk\ Score\ of\ (Hydrotest)\ Alternative\ =\ 2.99$$

The Proposed Project – a new 36-inch pipeline plus a de-rated Line 1600 operating at distribution-level operating pressure – has a total risk score of 2.06. Line 1600, operating at transmission-level operating pressure, has a risk score of 2.99. Therefore, the Proposed Project has a reduced incident rate of 31% in HCA miles, while increasing the capacity of the transmission pipeline serving SDG&E's service territory.

2. Scenario Analysis

a) Analysis Overview

One of the primary drivers for the Proposed Project is to alleviate the current reliance on Line 3010 for transmission duties on the SDG&E gas system. To more clearly delineate the implications of this current reliance and the value of the proposed system redundancy, an analysis has been performed on scenarios where Line 3010 is operational in combination with the Proposed Project and each of the Alternatives. The objectives of the analysis are to assess the gas and electric curtailment impacts associated with an outage or reduction in pressure of Line 3010 if each of the Alternatives is also in place.

The analysis identifies impacts under various demand conditions and for a variety of available supply combinations. The basis of the analysis is explained in more detail below, and the results are discussed at the close of this section.

It is important to note, the Applicants' gas transmission system is designed to meet a 1 in 10 design criterion. The Ruling, however, requires the Applicants to "apply quantifiable data to define the relative [reliability benefits]" of the Proposed Project. For purposes of identifying and quantifying the potential reliability benefits of the Proposed Project, PwC, with input from Applicants, generated a series of plausible scenarios in addition to the 1-in-10 design criterion. The assumptions used to generate these scenarios reflect engineering judgment and historical experience operating the gas transmission system. These scenarios were generated for the limited purpose of complying with the Ruling within a short timeframe and do not constitute the basis of new design criteria.

b) Assumptions, Parameters, and Variables

The scenario analysis is performed for a variety of cases, but the following assumptions apply universally.

Table 30 - Base Assumptions for Scenario Analysis

Base Assumptions
The impact is based on a 1-day outage or reduction in pressure of Line 3010, which can be extrapolated as needed
Moreno Compressor Station is functioning
An impact to Line 3010 has occurred in the northern section of the pipeline

The scenario analysis is performed across 3 main parameter sets as indicated in the table below.

Table 31 - Parameter Sets for Scenario Analysis

Project Alternatives Parameter Set	Line 3010 Parameter Set	Otay Mesa Supply Parameter Set
Line 1600 (Pre/Post Hydrotesting) Line 1600 (During Hydrotesting) Line 3602 (Proposed Project) Alternate Diameter Pipeline 10" Alternate Diameter Pipeline 12" Alternate Diameter Pipeline 16" Alternate Diameter Pipeline 20" Alternate Diameter Pipeline 24" Alternate Diameter Pipeline 30" Alternate Diameter Pipeline 42" Replace L1600 In-Place Alternative Otay Mesa Alternatives LNG Storage Alternative Alt Energy Alternative (Grid-Scale) Alt Energy Alternative (Smaller-Scale) Offshore Route Blythe to Santee Alternative 1 Blythe to Santee Alternative 2 Cactus City to San Diego Alternative Second Pipeline Along L3010 Alternative	Line 3010 Complete Outage Line 3010 at 80%	Otay Mesa Full Supply Otay Mesa Medium Supply Otay Mesa Low Supply Otay Mesa No Supply

Each scenario has variables applied related to the time of year under which the scenario occurs and the supply available from Otay Mesa.

Table 32 - Seasonal Demand Variables for Scenario Analysis

Seasonal Demand Variables		
	Natural Gas Demand	**Electric Demand**
Example Summer Day With Low Electrical Generation	Example Summer day for Core, Electric Generation and Non-Core, Non-EG customers with low Natural Gas demand for Electrical Generation.	Example Summer day with low electric demand.
Example Summer Day With High Electrical Generation	Example Summer day for Core, Electric Generation and Non-Core, Non-EG customers with high Natural Gas demand for Electrical Generation.	Example Summer day with high electric demand.
Example Winter Day	Example Winter day for Core, Electric Generation and Non-Core, Non-EG customers.	Example Winter day for electric demand.
Winter 1 in 10 Year Day	Example Winter 1 in 10 Year day for Core, Electric Generation and Non-Core, Non-EG customers.	Example Winter 1 in 10 Year day for electric demand.
Example Spring Day	Example Spring day for Core, Electric Generation and Non-Core, Non-EG customers.	Example Spring day for electric demand.
Example Fall Day	Example Fall day for Core, Electric Generation and Non-Core, Non-EG customers.	Example Fall day for electric demand.

The base assumptions and variables result in 48 unique scenarios for each of the 20 identified situations: Line 1600 Pre or Post Hydrotesting, Line 1600 During Hydrotesting, the Proposed Project (Line 3602), and the 17 Project Alternatives. This results in a total of 960 unique scenarios for analysis.

Illustrated in Table 33 below is an example of the unique 48 scenarios for one Alternative (Alternate Diameter Pipeline 12"), which is replicated against each of the Alternatives.

Table 33 - Example of 48 Scenarios Analyzed for Alternate Diameter Pipeline 12"

		1. Example Summer Low-EG Day								2. Example Summer High-EG Day								3. Example Winter Day							
Scenario ID		4.1.1.1	4.2.1.1	4.1.2.1	4.2.2.1	4.1.3.1	4.2.3.1	4.1.4.1	4.2.4.1	4.1.1.2	4.2.1.2	4.1.2.2	4.2.2.2	4.1.3.2	4.2.3.2	4.1.4.2	4.2.4.2	4.1.1.3	4.2.1.3	4.1.2.3	4.2.2.3	4.1.3.3	4.2.3.3	4.1.4.3	4.2.4.3
Project Alternate	Alt. 12"	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Line 3010	80%	✓		✓		✓		✓		✓		✓		✓		✓		✓		✓		✓		✓	
	0%		✓		✓		✓		✓		✓		✓		✓		✓		✓		✓		✓		✓
Otay Mesa Supply	High	✓	✓							✓	✓							✓	✓						
	Medium			✓	✓							✓	✓							✓	✓				
	Low					✓	✓							✓	✓							✓	✓		
	None							✓	✓							✓	✓							✓	✓

		4. Winter 1-in-10 Year Day								5. Example Spring Day								6. Example Fall Day							
Scenario ID		4.1.1.4	4.2.1.4	4.1.2.4	4.2.2.4	4.1.3.4	4.2.3.4	4.1.4.4	4.2.4.4	4.1.1.5	4.2.1.5	4.1.2.5	4.2.2.5	4.1.3.5	4.2.3.5	4.1.4.5	4.2.4.5	4.1.1.6	4.2.1.6	4.1.2.6	4.2.2.6	4.1.3.6	4.2.3.6	4.1.4.6	4.2.4.6
Project Alternate	Alt. 12"	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Line 3010	80%	✓		✓		✓		✓		✓		✓		✓		✓		✓		✓		✓		✓	
	0%		✓		✓		✓		✓		✓		✓		✓		✓		✓		✓		✓		✓
Otay Mesa Supply	High	✓	✓							✓	✓							✓	✓						
	Medium			✓	✓							✓	✓							✓	✓				
	Low					✓	✓							✓	✓							✓	✓		
	None							✓	✓							✓	✓							✓	✓

c) *Summary Methodology*

A first step in the analysis involved a comparison of SDG&E's natural gas supply and customer demand under each of the six seasonal demand conditions. The table below presents SDG&E's customer natural gas demand data, as well as the various natural gas supply combinations analyzed in the study.[124]

Table 34 - Natural gas customer demand and supply combinations under each seasonal demand conditions[125]

	1. Example Summer Low-EG Day MMcfd	2. Example Summer High-EG Day MMcfd	3. Example Winter Day MMcfd	4. Winter 1-in-10 Year Day MMcfd	5. Example Spring Day MMcfd	6. Example Fall Day MMcfd
Natural Gas Demand [MMcfd]						
Core Demand	100	100	310	350	170	180
Electric Generation (EG) Demand	100	300	165	165	220	270
Non-Core, Non-EG Demand	75	75	62	62	75	75
Total Demand	**275**	**475**	**537**	**577**	**465**	**525**
Natural Gas Supply Combinations [MMcfd]						
Project Alternatives Capacity						
Line 1600 (Pre/Post Hydrotesting)	150	150	150	150	150	150
Line 1600 (During Hydrotesting)	0	0	0	0	0	0
Line 3602 (Proposed Project)	680	680	680	680	680	680
Alternate Diameter Pipeline 10"	50	50	50	50	50	50
Alternate Diameter Pipeline 12"	70	70	70	70	70	70
Alternate Diameter Pipeline 16" [126]	160	160	160	160	160	160
Alternate Diameter Pipeline 20"	250	250	250	250	250	250
Alternate Diameter Pipeline 24"	400	400	400	400	400	400

[124] Natural gas supply from Otay Mesa Receipt Point was determined through an analysis of 2014-2015 flow data from the Gasoducto Rosarito pipeline that feeds into it.

[125] The gas transmission system is designed to meet a 1 in 10 design criterion. The Ruling, however, requires the Applicants to "apply quantifiable data to define the relative [reliability benefits]" of the Proposed Project. For purposes of identifying and quantifying the potential reliability benefits of the Proposed Project, PwC, with input from the Applicants, generated a series of plausible scenarios in addition to the 1 in 10 design criterion. The assumptions used to generate these scenarios reflect engineering judgment and historical experience operating the gas transmission system. These scenarios were generated for the limited purpose of complying with the Ruling within a short timeframe and do not constitute the basis of new design criteria.

[126] This scenario analysis uses 160 MMcfd and reflects the capacity of a new 16-inch pipeline operating at 800 psi. The remainder of the Cost-Effectiveness Analysis assumes 150 MMcfd for all 16-inch pipelines. The capacity difference between a 16-inch pipeline at 640 psi and 800 psi is considered negligible and does not significantly impact the outcome of this analysis.

	1. Example Summer Low-EG Day MMcfd	2. Example Summer High-EG Day MMcfd	3. Example Winter Day MMcfd	4. Winter 1-in-10 Year Day MMcfd	5. Example Spring Day MMcfd	6. Example Fall Day MMcfd
Natural Gas Demand [MMcfd]						
Alternate Diameter Pipeline 30"	600	600	600	600	600	600
Alternate Diameter Pipeline 42"	710	710	710	710	710	710
Replace Line 1600 In-Place Alternative	160	160	160	160	160	160
Otay Mesa Alternatives	400	400	400	400	400	400
LNG Storage Alternative	0	0	0	0	0	0
Alt Energy Alternative (Grid-Scale)	0	0	0	0	0	0
Alt Energy Alternative (Smaller-Scale)	0	0	0	0	0	0
Offshore Route	680	680	680	680	680	680
Blythe to Santee Alternative 1	680	680	680	680	680	680
Blythe to Santee Alternative 2	680	680	680	680	680	680
Cactus City to San Diego Alternative	680	680	680	680	680	680
Second Pipeline Along Line 3010 Alternative	680	680	680	680	680	680
Line 3010 Parameter						
Line 3010 Complete Outage	0	0	0	0	0	0
Line 3010 at 80%	380	380	380	380	380	380
Otay Mesa Supply[127]						
Otay Mesa Full Supply	295	86	313	313	329	324
Otay Mesa Medium Supply	156	60	230	230	244	247
Otay Mesa Low Supply	33	33	148	148	130	168
Otay Mesa No Supply	0	0	0	0	0	0

Table 35 - Electric customer demand and supply combinations under each seasonal demand conditions

	1. Example Summer Low-EG Day MW	2. Example Summer High-EG Day MW	3. Example Winter Day MW	4. Winter 1-in-10 Year Day MW	5. Example Spring Day MW	6. Example Fall Day MW
Electric Demand (MW)[128]						
Peak Electric Demand	3,062	3,723	2,969	3,328	2,693	3,019
Electric Supply Combinations (MW)						
Natural Gas Fired Electric Generation	562	1,686	1,124	1,124	1,236	1,517
Renewable Electric Generation	70	70	70	70	70	70
Electric Import Capacity	2,500	2,500	2,500	2,500	2,500	2,500

Subsequently, supply combinations are established for each of the 960 scenarios, and then analyzed against the customer demand under those conditions. The following key outputs are gathered.

Table 36 - Outputs of Assessed Impacts

Outputs of Assessed Impacts	
General Impacts	• Is immediate curtailment at Electrical Generation stations required?
	• Overall capacity shortfalls in MMcfd
Curtailment to Gas Customers[129]	• Curtailment for Core Customers (% of service impacted, # of customers affected)[130] • Curtailment for Electric Generation (EG) Customers (% of service impacted) • Curtailment for Non-Core, Non-EG Customers (% of service impacted)
Curtailment to Electric Meters	• Curtailment to Electric Meters (% of service impacted, # of meters affected)

d) Summary Results

Outcomes of the 960 scenarios analyzed have been summarized in Figure 5 below. The graph presents the average percentage of curtailment for each gas customer class and outages to electric customers for the 20 situations.

[129] The Scenario Analysis applies the order of gas customer curtailments as described in the Prepared Direct Testimony of Gwen Marelli (March 21, 2016), page 2.
[130] Operational activities related to an outage are not factored in determining the number of core customers affected.

Figure 5 - Scenario Analysis Summary Results

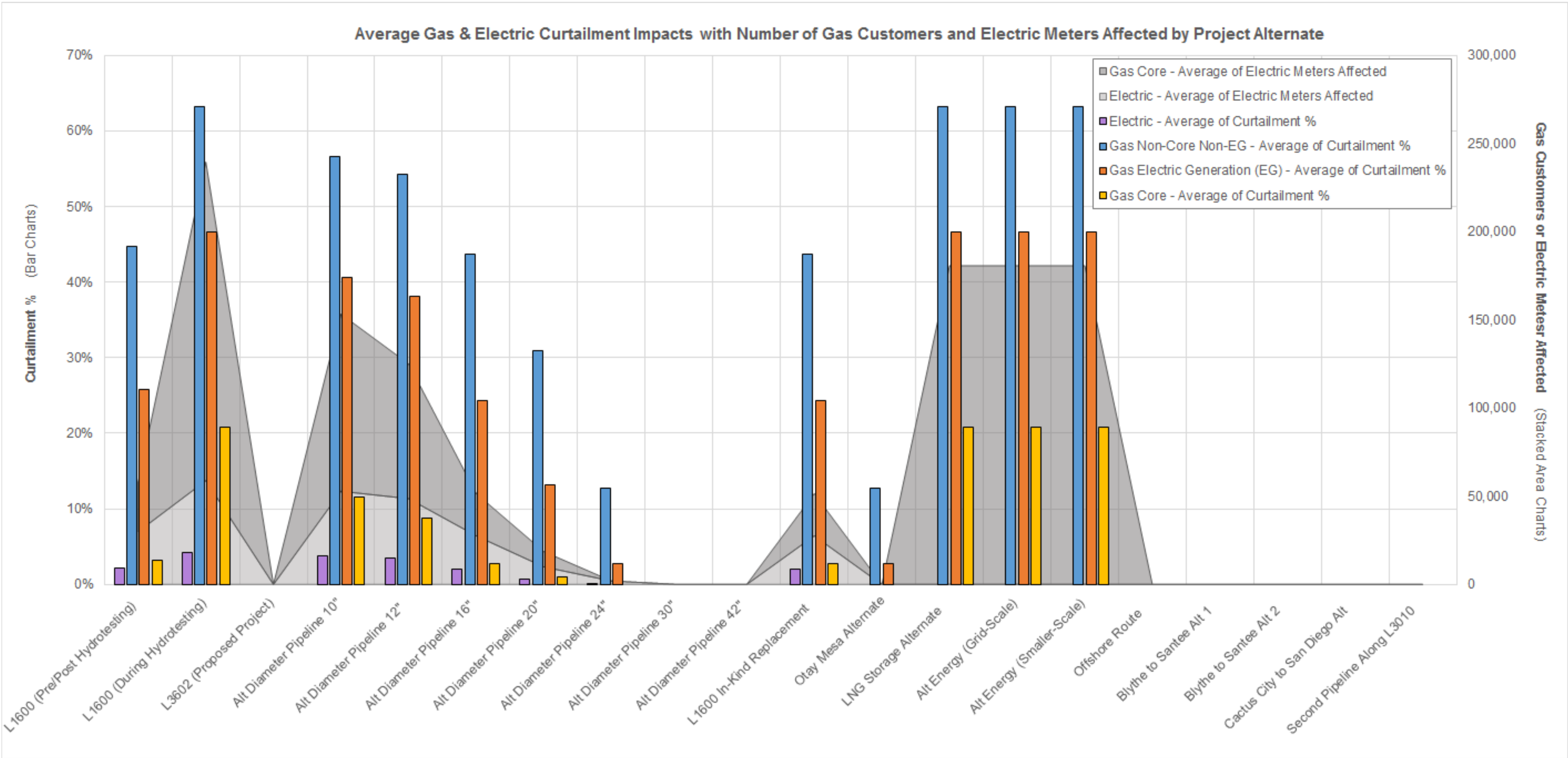

Table 37 - Ranking of Project Alternatives by Average Curtailment

	Scoring of Average Curtailment Severity (Relative to other Project Alternatives, with range 1-Worst to 5-Best)			
Project Alternative	Gas Non-Core, Non-EG Customers	Gas Electric Generation (EG) Customers	Gas Core Customers	Electric
Line 1600 (Pre/Post Hydrotesting)	2	3	5	3
Line 1600 (During Hydrotesting)	1	1	1	1
Line 3602 (Proposed Project)	5	5	5	5
Alt Diameter Pipeline 10"	1	1	3	1
Alt Diameter Pipeline 12"	1	1	3	1
Alt Diameter Pipeline 16"	2	3	5	3
Alt Diameter Pipeline 20"	3	4	5	5
Alt Diameter Pipeline 24"	4	5	5	5
Alt Diameter Pipeline 30"	5	5	5	5
Alt Diameter Pipeline 42"	5	5	5	5
Replace Line 1600 in Place with a New 16" Transmission Pipeline	2	3	5	3
Otay Mesa Alternatives	4	5	5	5
LNG Storage Alternative	1	1	1	5
Alt Energy (Grid-Scale)	1	1	1	5
Alt Energy (Smaller-Scale)	1	1	1	5
Offshore Route	5	5	5	5
Blythe to Santee Alt 1	5	5	5	5
Blythe to Santee Alt 2	5	5	5	5
Cactus City to San Diego Alt	5	5	5	5
Second Pipeline Along Line 3010	5	5	5	5

From the graph and table above, it is evident that the highest and lowest reliability impacts were observed as follows.

Table 38 - Best and Worst Performing Alternatives

Best Performing	Worst Performing
Line 3602 (Proposed Project)	Line 1600 (Pre/Post Hydrotesting)
Alternate Diameter Pipeline 24”	Line 1600 (During Hydrotesting)
Alternate Diameter Pipeline 30"	Alt Diameter Pipeline 10"
Otay Mesa Alternatives	Alt Diameter Pipeline 12"
Offshore Route	Alt Diameter Pipeline 16"
Blythe to Santee Alternative 1	Replace Line 1600 in Place with a New 16" Transmission Pipeline
Blythe to Santee Alternative 2	LNG Storage Alternative
Cactus City to San Diego Alternative	Alt Energy (Grid-Scale)
Second Pipeline Along Line 3010 Alternative	Alt Energy (Smaller-Scale)

I. Benefits Analysis Summary

The following table provides the relative rank of the Proposed Project and Alternatives.

Table 39 - Relative Benefits of Proposed Project and Alternatives from Greatest to Least Benefits

Alt No.	Project Name	Benefits Rank
A	Proposed Project (36” Diameter)	1
C7	Alt Diameter Pipeline 42"	1
J1	Blythe to Santee Alternative 1	3
J2	Blythe to Santee Alternative 2	3
J3	Cactus City to San Diego Alternative	3
K	Second Pipeline Along Line 3010 Alternative	3
I	Offshore Route Alternative	7
C6	Alt Diameter Pipeline 30"	8
C5	Alt Diameter Pipeline 24"	9
C4	Alt Diameter Pipeline 20"	10
C3	Alt Diameter Pipeline 16”	11
D	Replace Line 1600 In Place with a New 16-inch Transmission Pipeline	12
E/F	Otay Mesa Alternatives	13
G	LNG Storage Alternative	14
B	Hydrotest	15
H1	Alternative Energy Alternative: Grid Scale Battery	16
H2	Alternate Energy Alternative: Smaller Scale Batteries	16
C1	Alt Diameter Pipeline 10"	18
C2	Alt Diameter Pipeline 12”	18

The results of the benefits analysis show that the Proposed Project and 42-inch Alternative Diameter Pipeline offer the most benefits. Four Alternatives comprise the next highest-ranked group, the Cross-Country Pipeline Route Alternatives (Blythe to Santee Pipeline Routes, Alternatives 1 and 2; Cactus City to San Diego Alternative) and the Second Pipeline Along Line 3010 Alternative. The Off-Shore Route offers the third-most benefits, followed in descending order by several Alternative Diameter Pipelines (30-, 24-, 20-, and 16-inches), Replace Line 1600 In Place with a New 16-inch Alternative, the Otay Mesa Alternatives. The LNG Storage Alternative ranked 14th in terms of benefits, followed by the Hydrotest Alternative and the Alternative Energy Alternatives. The Alternative Diameter Pipelines of 10- and 12-inches offer the least benefits of all the Alternatives.

New, larger diameter pipelines outperform the “least-cost” (Hydrotest Alternative) in six out of the seven categories (safety, reliability, operational flexibility, system capacity, gas storage through line pack, and other benefits) and receive the same score for the category of reduction in gas price for ratepayers. As compared to other larger diameter pipelines, the Proposed Project provides additional reliability, operational flexibility, system capacity, gas storage through line pack, and other benefits.

VI. CONCLUSION

With data and input from the Applicants, PwC prepared this Cost-Effectiveness Analysis to comply with the Ruling. The analysis applies quantifiable data to define the relative costs and benefits of the Proposed Project and the range of Alternatives identified in the Ruling. The relative costs and benefits of the Proposed Project and Alternatives are set forth in the following table.

Table 40 - Proposed Project and Alternatives Relative Benefit Ranking and Net Costs

	Description	Benefit Rank	Net Cost ($M)
A	Proposed Project (Rainbow to Line 2010 Route)	1	$256.2
B	Hydrotest Alternative	15	$118.7
C1	Alt Diameter Pipeline, Proposed Route (10")	18	$302.7
C2	Alt Diameter Pipeline, Proposed Route (12")	18	$291.6
C3	Alt Diameter Pipeline, Proposed Route (16")	11	$241.4
C4	Alt Diameter Pipeline, Proposed Route (20”)	10	$239.2
C5	Alt Diameter Pipeline, Proposed Route (24")	9	$229.6
C6	Alt Diameter Pipeline, Proposed Route (30")	8	$233.5
C7	Alt Diameter Pipeline, Proposed Route (42")	1	$341.9
D	Replace Line 1600 in Place with a New 16" Transmission Pipeline	12	$560.4
E/F	Otay Mesa Alternatives	13	$876.8
G	LNG Storage (Peak-Shaver) Alternative AKA (United States – LNG Alternative)	14	$2,584.7
H1	Alternate Energy (Battery) Alternative – Grid Scale	16	$8,330.1
H2	Alternate Energy (Battery) Alternative – Smaller Scale	16	$10,010.1
I	Offshore Route Alternative	7	$1,295.5
J1	Blythe to Santee Alternative 1	3	$1,219.3
J2	Blythe to Santee Alternative 2	3	$1,157.3
J3	Cactus City to San Diego Alternative	3	$981.1
K	Second Pipeline Along Line 3010 Alternative	3	$427.1

When considering both net project costs and benefits, the Proposed Project is the most cost-effective, prudent Alternative, as it provides more benefits than any of the Alternatives except for the 42-inch diameter pipeline, which provides the same level of benefits but costs $86 million more (on a net cost basis) than the Proposed Project.

Although the costs analysis concludes that the “least-cost” alternative is the Hydrotest Alternative, which is estimated to cost $118.7 million on a net cost basis, the group of “second least-cost” alternatives ranges from $225 million to $260 million and includes the Proposed Project. The third least-cost group has a larger range, from $290 million to $430 million, and the remaining two groups of Alternatives far exceed the net costs of the Proposed Project. These two “greatest cost” categories include Alternatives whose net costs range from $500 million to

$1 billion (Replace Line 1600 In-Place with a New 16-inch Transmission Pipeline Alternative, Otay Mesa Alternatives, Cactus City to San Diego Alternative) and more than $1 billion (Blythe to Santee Pipeline Routes, Alternatives 1 and 2, Off-Shore, LNG Storage, and Alternative Energy Alternatives).

In terms of benefits, the Proposed Project and 42-inch diameter pipeline ranked highest. Four Alternatives comprise the next highest-ranked group, the Cross-Country Pipeline Route Alternatives (Blythe to Santee Pipeline Routes, Alternatives 1 and 2; Cactus City to San Diego Alternative) and the Second Pipeline Along Line 3010 Alternative. The remaining projects are ranked in descending order, with the 10- and 12-inch Alternative Diameter Pipelines ranking lowest in terms of benefits. The "least-cost" Hydrotest Alternative ranked 15th out of 19.

New, larger diameter pipelines outperform the "least-cost" (Hydrotest Alternative) in six out of the seven benefits categories (safety, reliability, operational flexibility, system capacity, gas storage through line pack, and other benefits) and receive the same score for the category of reduction in gas price for ratepayers. As compared to other larger diameter pipelines, the Proposed Project provides additional reliability, operational flexibility, system capacity, gas storage through line pack, and other benefits.

The Proposed Project would provide more benefits than the 16-, 20-, 24- and 30-inch Alternate Diameter Pipelines without adding significantly higher costs. By contrast, the 42-inch Alternate Diameter Pipeline offers the same benefits as the Proposed Project but costs approximately $86 million more. For these reasons, the Proposed Project is identified as the overall most cost-effective alternative.