SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA DR 26)

Date Requested: August 3, 2016
Date Responded: August 17, 2016

PRELIMINARY STATEMENT

1. These responses and objections are made without prejudice to, and are not a waiver of, SDG&E and SoCalGas' right to rely on other facts or documents in these proceedings.
2. By making the accompanying responses and objections to these requests for data, SDG&E and SoCalGas does not waive, and hereby expressly reserves, its right to assert any and all objections as to the admissibility of such responses into evidence in this action, or in any other proceedings, on any and all grounds including, but not limited to, competency, relevancy, materiality, and privilege. Further, SDG&E and SoCalGas makes the responses and objections herein without in any way implying that it considers the requests, and responses to the requests, to be relevant or material to the subject matter of this action.
3. SDG&E and SoCalGas will produce responses only to the extent that such response is based upon personal knowledge or documents in the possession, custody, or control of SDG&E and SoCalGas. SDG&E and SoCalGas possession, custody, or control does not include any constructive possession that may be conferred by SDG&E or SoCalGas' right or power to compel the production of documents or information from third parties or to request their production from other divisions of the Commission.
4. A response stating an objection shall not be deemed or construed that there are, in fact, responsive information or documents which may be applicable to the data request, or that SDG&E and SoCalGas acquiesces in the characterization of the premise, conduct or activities contained in the data request, or definitions and/or instructions applicable to the data request.
5. SDG&E and SoCalGas objects to the production of documents or information protected by the attorney-client communication privilege or the attorney work product doctrine.
6. SDG&E and SoCalGas expressly reserve the right to supplement, clarify, revise, or correct any or all of the responses and objections herein, and to assert additional objections or privileges, in one or more subsequent supplemental response(s).
7. SDG&E and SoCalGas will make available for inspection at their offices any responsive documents. Alternatively, SDG&E and SoCalGas will produce copies of the documents. SDG&E and SoCalGas will Bates-number such documents only if SDG&E and SoCalGas deem it necessary to ensure proper identification of the source of such documents.
8. Publicly available information and documents including, but not limited to, newspaper clippings, court papers, and materials available on the Internet, will not be produced.

9. SDG&E and SoCalGas object to any assertion that the data requests are continuing in nature and will respond only upon the information and documents available after a reasonably diligent search on the date of its responses. However, SDG&E and SoCalGas will supplement its answers to include information acquired after serving its responses to the Data Requests if it obtains information upon the basis of which it learns that its response was incorrect or incomplete when made.
10. In accordance with the CPUC's Discovery: Custom And Practice Guidelines, SDG&E and SoCalGas will endeavor to respond to ORA's data requests by the identified response date or within 10 business days. If it cannot do so, it will so inform ORA.
11. SDG&E and SoCalGas object to any ORA contact of SDG&E and SoCalGas officers or employees, who are represented by counsel. ORA may seek to contact such persons only through counsel.
12. SDG&E and SoCalGas objects to ORA's instruction to send copies of responses to entities other than ORA.

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Subject: Cost Effectiveness Analysis for the Pipeline Safety & Reliability Project by PWC and Neil Navin Prepared Testimony Attachment A PSRP Report

<u>QUESTION 1:</u>

Table 2 of Mr. Navin's testimony provides the estimated direct cost of the Proposed Project for Line 3602 and Line 1600 De-rate in the amount of $426.8 million and $15.1 million, respectively. Mr. Navin's testimony states on p.21 that "The estimate to de-rate Line 1600 was applied to each Alternative identified in the Ruling, except for the Hydrotest Alternative and the Replace Line 1600 in Place…where the de-rate was not applicable."

Attachment XI of Mr. Navin's testimony describes the analysis of Line 1600 de-rating impacts and states:
"The anticipated impacts of de-rating Line 1600 are:

- Insufficient regulator station capacity
- Non-uniform distribution of pressure along Line 1600."

Attachment XI describes the impacts further:

- Abandonment of ten 640 psig to 400 psig regulator stations which would no longer be needed between Line 1600 and the distribution systems downstream. These regulator stations "to abandon" were listed in a table and identified by a number designation.
- Installation of closed valves/check valves in two of the regulator station identified for abandonment from the list
- Creation of three new regulator stations required to feed the distribution system from the Proposed Line 3602.
- Replacement of an under-capacity regulator station with a new station designed to operate at the new Line 1600 MAOP of 320 psig. This is identified as Regulator Station 939 and this station is not listed among the stations identified for abandonment.
- Installation of a new 1.08 mile long, 8" distribution supply pipeline (Pre-lay Segment Replacement)
- Installation of a new 0.88 mile long, 8" high pressure connection between the west end of Line 49-31B and Line 49-125 in Mira Mesa Blvd.
- Upgrading of a 0.7 mile section of Line 49-31B in Pomerado Rd to 6" inch diameter
- Installation of a new regulator station (Regulator Station C – Pomerado and Willow Creek Regulator) from the proposed Line 3602 to Line 49-31B.

a) Please identify the specific cost implications of the impacts of Line 1600 de-rate to distribution as described above in Attachment XI.
b) Please explain whether the above described impacts already considers the costs to reconfigure the supply points for Line 1600, and if so, please cite reference to the information that verifies its inclusion.

c) Please explain whether the specific cost implications of the impacts of Line 1600 de-rate identified in item (a) are fully accounted for in the estimated direct costs shown in Table 2 of Mr. Navin's testimony. Please respond first with a yes or no, and then please explain your answer.
d) Please clarify whether "to abandon" the ten regulator stations identified in the list essentially means these regulator stations will be deactivated and left in place as is. As such, would it be accurate to state that neither O&M costs nor cost of removal of assets are expected to be incurred with respect to these ten regulator stations which will be abandoned in place. If not, please explain.
e) Please clarify whether the plan to replace Regulator Station 939 with a new station means that the old Regulator Station 939 will be removed (instead of abandoned in place) and therefore one would expect to incur costs of removal of assets in connection with the plan to replace Regulator Station 939.
f) Please explain whether the above described cost implications of the impacts of Line 1600 de-rate already includes the costs associated with getting the customers on Line 1600 transferred or converted from transmission to distribution. Please respond first with a yes or no, and then please explain your answer.
g) Please clarify whether the cost implications of the impacts of Line 1600 de-rate identified in item (a) have similarly been applied to each Alternative identified in the Ruling except as noted in Question 1 above. Please respond first with a yes or no, and then please explain your answer.

RESPONSE 1:

a. The specific cost implications of the impacts of Line 1600 derate to distribution as described in Attachment XI of the Prepared Direct Testimony of Neil Navin are summarized in the table below:

Category	Direct Cost ($M)
Abandonment of 10 Regulator Stations, Installation of valves in two regulator stations	$2.3
Creation of three new regulator stations to feed the distribution system from Line 3602 Installation of a new regulator station (Reg Station C – Pomerado and Willow Creek Regulator) from the proposed Line 3602 to Line 49-31B	Not included in derating Line 1600 estimate, included in Line 3602 estimate
Regulator Station 939	Not included
Installation of a new 1.08 mile long, 8" distribution supply line	$5.9
Installation of a new 0.88 mile long, 8" high pressure connection between west end of Line 49-31B and Line 49-125 in Mira Mesa Blvd. Upgrading of a 0.7 mile section of Line 49-31B to 6" diameter	$6.8

b. The supply points for Line 1600 will be reconfigured with the addition of pressure limiting stations. The cost of these pressure limiting stations were included in the Proposed Project cost estimates. See Attachment VI of Mr. Navin's testimony.

c. No. The estimated cost for replacing Regulator Station 939 is not included in the Proposed Project cost estimate.

d. The ten regulator stations will be abandoned/removed or replaced with valves. There is $2.3 million in abandonment costs to be incurred; however, these costs have been excluded from the revenue requirement requested for the Proposed Project. *See* Mr. Navin's testimony at page 21, footnote 16. *See also* the Prepared Direct Testimony of Michael Woodruff at page 1, footnote 2.

e. The replacement of Regulator Station 939 will consist of installing a replacement regulator station and then removing the existing regulator station. Costs will be incurred for both the installation and removal for the replacement work.

f. This response contains confidential information (*e.g.*, customer specific information, which is denoted by gray highlighting below) and is provided pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583.

   Yes, the costs described above are those associated with the scope of work described in the Application related to derating Line 1600 to distribution service and making the system changes necessary to provide sufficient connections and capacity to serve existing customers. While these improvements will provide for capacity to serve existing customers, it should be noted that there could be some serving pressure impacts to a few large customers, and no costs were included for any improvements related to their specific situations.

   To further explain, for a scenario involving derating the entire length of Line 1600 to 320 psig MAOP, the pipeline is anticipated to continue to be able to provide sufficient capacity to supply customers including large customers such as the [redacted] and [redacted] peakers and other large industrial customers with volumes of gas to meet their current demands. However for customers that are directly connected to Line 1600 and were being served at line pressure, even if volumes would be met, supply pressure would be reduced, which may impact those customers who desire and have historically experienced higher pressures. In particular, large gas turbines used for electric generation or industrial processes may be impacted. The pressures needed vary based on the specific requirements of the equipment.

SDG&E and SoCalGas do not have specific and complete information on the [redacted] peaker units, but based on information provided by the developer at the time the plant was built, believe that on-site fuel gas compression to boost gas pressures exists at the facility. If not, potential impacts may include that the compressors may need to be reconfigured, or replaced to operate with lower suction pressure and the compressor operation may increase compared to historical operations, increasing auxiliary load, thus decreasing net electrical output.

The [redacted] facility is also a gas turbine peaker plant which is believed to be approaching the point in its life cycle where it will be phased out of service in the next year or two. This gas turbine equipment is an older vintage and smaller in size than [redacted]. Fuel gas pressures requirements are significantly lower and based on a current general understanding of the units, it is believed that derating Line 1600 to 320 psig will have no material impacts.

In addition to the electric generator peaker plants, SDG&E and SoCalGas have identified another large industrial customer that is served directly from a segment of Line 1600 that is not currently within the scope of the Pipeline Safety & Reliability Project (Application (A.)15-09-013). The customer is a large manufacturer of gas turbines and in the process of manufacturing and testing the gas turbines has a desire to have higher fuel gas pressures. Derating this segment of Line 1600 to 320 psig would impact the customer in a similar way as [redacted] is impacted and steps such as on-site fuel gas compression would be needed to reach desired pressures.

An alternative to providing on site fuel gas compressors for impacted customers would be to extend a new high pressure pipeline from the closest high pressure source. In the case of [redacted], this would include building a pipeline connection from the proposed new Line 3602 and interconnecting to the current lateral feeding the peaker. For SDG&E's large industrial customer, a line would need to be extended from Line 3602, Line 3011 or Line 2010 to the facility. Neither of these conceptual pipeline extensions is currently being pursued, and they are currently not included in the proposed Pipeline Safety & Reliability Project scope.

SDG&E's and SoCalGas' goal is to implement pipeline safety requirements in a manner that protects community values and avoids any unnecessary customer impacts, whether due to hydrotesting Line 1600 or derating it. SDG&E and SoCalGas welcomes the opportunity as part of the Pipeline Safety & Reliability Project proceeding (A.15-09-013) to explore the potential customer impacts associated with either hydrotesting or derating Line 1600 and to identify appropriate measures that can be taken to protect community values by avoiding those impacts. Any costs associated with these efforts are not included in in this response or the subject Application.

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g. Yes. The capital costs to derate Line 1600 have been applied to all the alternatives excluding Alternatives B and D in the CEA analysis.

QUESTION 2:

ORA notes that the SoCalGas/SDG&E Pipeline Safety Enhancement Plan (PSEP) proposal in A.11-11-002 was submitted based on a Level 5 budget estimate where a Level 5 is extremely preliminary (p.25, D.14-06-007). Line 1600 was included in the PSEP submission.

Response to ORA-15 Question 1a) and 1b) state "As of April 2016, approximately 74 miles of pipe have been successfully hydro tested as part of SoCalGas and SDG&E's PSEP. SoCalGas and SDG&E anticipate hydro testing approximately 90 miles in Phase 1 of PSEP."

Response to ORA-15 Question 1h) indicate that SoCalGas had previously done hydro testing on Line 6916. Footnote 4 to that response notes that Line 6916 is not a PSEP-related project and the hydro test occurred between 2007-2008.

Page 23 of the CEA states with respect to Alternative B: Hydro test: "Cost estimates were developed based on historic information and experience with similar type 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."

a) Please explain whether the cost estimates for Alternative B: Hydro test in the CEA were developed based on historic information and experience obtained as part of SoCalGas and SDG&E's PSEP described in Response to ORA-15 Q.1a) and 1b). If not, please identify the basic source of the "historic information and experience with similar type projects" which served as basis to develop cost estimates for purposes of the Alternative B:Hydrotest cost estimates and explain the reason for rejecting use of the PSEP data on hydro testing for purposes of Alternative B.
b) Please provide the cost per mile assumed in the CEA for hydro testing Alternative B.
c) Please provide the cost per mile based on actual cost spent to date on hydro testing the approximately 74 miles of pipe as of April 2016 under the PSEP.
d) Please provide the length (in mile)s and pipe diameter (in inches) of Line 6916 referenced in the response above and state whether the hydro testing done in 2007-2008 was for the entire length of Line 6916.
e) Given the SoCalGas and SDG&E recent experience on hydro testing of 74 miles in the PSEP stated in Response to ORA-15 Q.1 (a) (plus previous non-PSEP hydro testing experience for Line 6916), please explain why a Level 4 class estimate would still be an appropriate designation for Alternative B hydro testing.

RESPONSE 2:

a. Yes.

b. Alternative B: Hydrotest Line 1600 cost estimate was not based on a cost per mile; it was based on a cost per hydrotest segment. A calculated cost per mile is approximately $1.8 million direct cost per mile excluding the transportation cost of delivering gas supplies to the Otay Mesa receipt point during testing.

c. The calculated cost per mile based on actual direct cost spent to date on hydrotesting the approximately 74 miles of pipe as of April 2016 under the PSEP is $2.3 million.

d. Line 6916 referenced in the response is a 16-inch pipeline and the section the project addressed was approximately 45 miles.

e. Line 1600 hydrotest estimate is considered a Class 4 estimate because it is a factored estimate, engineering is less than 15% complete, layout and proposed site plans are still preliminary, and the remainder of the project definition deliverables are preliminary.

QUESTION 3:

Page 5 of the CEA concludes "the Proposed Project is identified as the overall most cost effective alternative."

a) Please provide the assumptions on the economic useful life of the Proposed Project and each of the Alternatives under the CEA, including cite references to the CEA regarding those assumptions.
b) In the case of Alternative B: Hydro testing, please provide the number of hydro tests the CEA assumed were necessary on Line 1600. If the CEA assumed more than one round of hydro testing was necessary, please explain the reasons for this assumption. If the CEA only assumed one round of hydro testing for the entire Line 1600, then please explain why it is appropriate to not repeat hydro testing on Line 1600 after a certain number of years.
c) Please provide how many years of useful life the CEA assumes remain on Line 1600 if under the de-rate alternative in the CEA.
d) Please state whether the assumption on the useful life of the assets in the CEA is similar to those used for purposes of depreciation (i.e., the book life) in developing the revenue requirements of the Proposed Project. Please state all of the ways in which these CEA and depreciation assumptions differ.

RESPONSE 3:

a. As stated in the CEA on page 29, this analysis assumes that the Proposed Project and Alternatives will have a service life of 100 years.

b. The CEA assumed one round of hydrotesting for Line 1600 (note: this could encompass multiple actual hydrotests over the length of the line). Subsequently, the line would be operated and maintained consistent with applicable laws and regulations; including ongoing assessment of the line's integrity, which could include additional hydrotesting. If the Commission were to require additional hydrotesting of Line 1600, or Applicants deemed such additional hydrotesting to be prudent, Alternative B would be even less cost-effective.

c. CEA assumes an indefinite life for derated Line 1600.

d. No. The useful life of the assets presented in the CEA is not similar to the book life used for purposes of depreciation used to calculate the illustrative revenue requirement. Please see 3a above regarding the assumed useful life for purposes of the CEA. Regarding the book life, for purposes of depreciation SDG&E and SoCalGas follow the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts. The book life for the transmission pipeline asset is 45 years. The CEA evaluated the benefits of the Proposed Project and alternatives to customers, which would exist through the actual useful life of the project.

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QUESTION 4:

Page 20 of the CEA states “The operating costs for the pipeline alternatives also include amounts for complying with Transmission Integrity Management Program (TIMP) requirements.”

Page 11 of the CEA states “For all of the Alternatives except the Hydro test 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) Please provide the annual expense cost of the TIMP requirements assumed for purposes of the pipeline alternatives in the CEA.
b) Please clarify whether the operating costs for the pipeline alternatives also include amounts for complying with the Distribution Integrity Management Program (DIMP) requirements with respect to the Line 1600 De-rate to distribution given the statement above from page 11 of the CEA. If not, please explain.
c) Based on your response to item (b) above, please provide the annual expense cost of the DIMP requirements assumed for purposes of the pipeline alternatives in the CEA.

RESPONSE 4:

a. The annual TIMP expense costs assumed for purposes of the pipeline alternatives in the CEA are provided in the workpapers supporting the Prepared Direct Testimony of Neil Navin. *See* PSRP Alt Workpapers, page 2.

b. The O&M cost estimate for the Line 1600 derate does not include costs for TIMP or DIMP. Once de-rated to 320 psig, Line 1600 will no longer be managed under TIMP and will be managed under DIMP. The expectation is that SDG&E will continue with integrity inspections of Line 1600 in DIMP.

c. No annual costs were assumed for DIMP.

QUESTION 5:

Page 20 of the CEA states "For those Alternatives that were not carried forward by Applicants in the PEA 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."

Please explain the above reference that "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."

RESPONSE 5:

For those Alternatives that Applicants determined to be imprudent as compared to the Proposed Project, Applicants developed cost estimates based on broad, project level assumptions (a "high-level" cost estimate) as opposed to the more detailed cost estimates developed for the other Alternatives. The more detailed estimates, in contrast, include costs broken down by project element (e.g. construction, environmental, engineering and design) and were scaled from the Proposed Project on a per mile basis.

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Date Requested: August 3, 2016
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<u>QUESTION 6:</u>

Response to ORA-17 Question 2a) state “Alternatives E/F: were scaled off of actual projects/project estimates: Gasoducto Sonora Project, TransCanada’s North-South alternative, and Samalayuca-Sasabe project.” In addition, the response states “Alternative G was scaled off of actual projects: Energeia Costa Azul. It was compared to KBR, Fortis Mount Hayes, and GNA Wyoming LNG facilities.”

a) Please explain how “Alternatives E/F were scaled off of actual projects/project estimates” as described in the above statements. Please provide all available specific data to support your response.
b) Please explain how “Alternative G was scaled off of actual projects” as described in the above statements. Please provide all available specific data to support your response.

<u>RESPONSE 6:</u>

a. Alternatives E/F were scaled off of TransCanada’s North-South Alternative and Gasoducto Sonora Project as follows:

Project	Total Cost (Million 2012$)	Project Length (miles)	Cost (Million 2012$ per mile)	Alternative E/F Length (miles)	Resultant cost (Million 2012$)
TransCanada’s North-South Alternative	$503.3	105	$4.8	86 miles (Ehrenberg Gasoducto Rosarito)	$413
Gasoducto Sonora Project	$1,000.0	521	$1.9	140 miles (looping Gasoducto Rosarito pipeline)	$269
Total				226 miles	$682

b. Alternative G cost estimate was based on a similar project, Energía Costa Azul (ECA). Each plant was compared to the ECA project and factored based on the 6/10th rule. Liquefaction costs were excluded and not used.

   Plant costs were factored based on Inside Battery Limits (ISBL), which included regasification and storage only, and did not include Outside Battery Limits (OSBL). The ECA project cost breaks down as follows: LNG Storage Facility Size: 6.78 BCF, Feed Gas: 1,000 MMscfd, Cost: $731MM.

Project		Storage (BCF)	Plant Cost (Scaled Based on 6/10th rule)	Other Direct Costs (Million 2015$)*	Total Cost
Scaled Project	ECA	6.78			$731
Proposed LNG site	Pio Pico	0.27	$125	$278	$403
	Carlsbad	0.44	$168	$349	$517
	Otay Mesa	0.54	$188	$382	$ 570
	Palomar	0.50	$181	$552	$552
	Subtotal				$2,042
	Contingency (30%)				$613
	Total				**$2,655**

6/10th rule is:

$$Plant\ Cost = \left(\frac{ProposedStorage}{ECAStorage}\right)^{0.6}$$

Other Direct Cost, include: Offsite (Storage, flare & liquid blow-down, fire protection, drainage, waste treatment, etc.), site infrastructure, roads & fences, substation, telecom, underground pipeline, site preparation, engineering & procurement, permitting, land/ROW acquisition, environmental, and direct labor costs.

Note: these are Class 5 estimates with an expected accuracy range of -50% to + 100%.

<u>QUESTION 7:</u>

Page 13 of the CEA refers to the Otay Mesa Alternatives for two alternative projects utilizing the Otay Mesa receipt point: Non-Physical (Contractual) or Minimal Footprint Solutions (Alternative E) and the Norther Baja Alternative (Alternative F). Footnote 31 on page 13 of the CEA states "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."

Page 27 of CEA states "The Applicants analyzed the total avoided costs that would accrue over an assumed 100 year useful life for the Proposed Project and Alternatives involving construction of a new pipeline (all Alternatives except the Hydro test Alternative and the Replace Line 1600 In Place with a 16" Pipeline Alternative)."

a) Please identify all the options included in the CEA for purposes of Alternative E's cost effectiveness analysis, and provide the corresponding capital and O&M expense and avoided costs.
b) Please identify all the costs included in the CEA for purposes of Alternative F's cost effectiveness analysis. (i.e., capital, O&M, and avoided costs) and provide the corresponding capital and O&M expense and avoided costs.
c) Is it accurate to assume that avoided costs likewise accrue to the Otay Mesa Alternatives E and F, and if so, please explain the avoided costs associated with each.

<u>RESPONSE 7:</u>

a. The avoided costs for the future replacement of Line 1600 are considered for the Otay Mesa Alternatives (Alternative E/F).
    a. The CEA, pages 28-30, describes the avoided costs associated with the future replacement of Line 1600.
    b. The CEA, page 32, Table 8, shows the capital costs, O&M expenses and avoided costs for Alternative E/F.

b. In the CEA, Alternative F is discussed in conjunction with Alternative E (*see* CEA, page 13). The capital costs, O&M expenses and avoided costs for Alternatives E/F are shown in the CEA on page 32, Table 8.

c. The CEA assumes that the avoided cost that accrues to Alternative E/F is the cost for the future replacement of Line 1600.

QUESTION 8:

Page 13 of the CEA states, "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). [Footnote omitted] 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 fact, in A.15-09-013, the Joint Assigned Commissioner and Administrative Law Judge's Ruling Requiring an Amended Application and Seeking Protests, Responses, and Replies, dated 1/22/2016 (Ruling), on page 12 requires that, The [Cost Effectiveness] 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 this Ruling. (For purposes of analysis, the cost analysis shall assume that *each* of the following alternatives are feasible and include an estimate of costs, both fixed and operating, as required by Rule 3.1(f).) (Emphasis added.)

Among the alternatives that the Ruling requires Sempra to assume to be feasible and to include an estimate of costs, both fixed and operating, on page 13, the Northern Baja Alternative is explicitly called out as defined in the PEA. Separately on page 13, the Non- Physical (Contractual) or Minimal-Footprint Solutions are called out, and the instructions for defining that alternative state, "Not included in PEA. Address multi-year contracting for capacity and supplies; Southern system minimum flow requirement; operational flow order/system balancing; and tariff discounts."

As required by the Ruling, the definition of the Northern Baja Alternative provided on page 5-15 of the PEA states as follows:
The Northern Baja Alternative offers a possible limited construction alternative to the Proposed Project. The existing North Baja pipeline includes an existing capacity for natural gas transmission to the Baja Norte/Gasoducto Rosarito/TGN pipelines, which can in turn transport and deliver natural gas to the Otay Mesa receipt point. No customers or suppliers on the SoCalGas/SDG&E system have delivered gas via this path due to higher delivery costs unless required by maintenance outage or in support of maintenance activities. The existing North Baja pipeline includes an available daily capacity of 185 MMcfd, which is approximately the same net quantity of additional capacity that the Proposed Project would provide. However, all of the existing capacity on the Gasoducto Rosarito pipeline appears to be under contract until at least 2022. Because the Northern Baja Alternative would rely on the Baja Norte/Gasoducto Rosarito/TGN pipelines that are outside of the Applicant's system, and because most of these lines are fully subscribed and the available capacity on the North Baja pipeline does not necessarily ensure that a contract would be granted to the Applicant or its customers, the

capacity needed to meet the Proposed Project objectives without the construction of an expansion to another pipeline is unknown.

Should capacity become available to the Applicant, the Northern Baja Alternative may be able to utilize existing infrastructure without requiring the construction of additional facilities and pipeline, and consequently without the associated environmental and social impacts and site suitability issue. While the Northern Baja Alternative could allow for the implementation of PSEP, it would be based on speculation of available capacity and infrastructure, and would not present a long-term solution to increasing system capacity unless capacity on all three pipeline systems could be contracted on a long-term basis by SDG&E or its customers. Therefore, this alternative is likely infeasible for economic, social, and technological reasons and it does not meet the Proposed Project objectives of system reliability and resiliency or operational flexibility. As a result, the Northern Baja Alternative was eliminated from further consideration.

With all of this in mind, please answer the following.

a) As of the date of this data request, is Sempra Utilities' Mexican affiliate, Ienova LNG, currently shown on its public website as having 400,000 MMbtu/day of subscribed capacity on the Gasoducto Rosarito line?[1]
b) If the answer to question a is yes, as of the date of this data request, is the subscribed capacity that Ienova LNG has on Gasoducto Rosarito not scheduled to expire until 2022?
c) As of the date of this data request, is Sempra Utilities' Mexican affiliate, Ienova LNG, currently shown on its public website as having 540,000 MMbtu/day of subscribed capacity on the Transportadora de Gas Natural line?[2]
d) Is the Transportadora de Gas Natural line asked about in question (c) the same line that is referred to as the "TGN" pipeline on page 5-15 of the PEA in A.15-09-013?
e) If the answer to question c is yes, as of the date of this data request, is the subscribed capacity that Ienova LNG has on the TGN line not scheduled to expire until 2022?

RESPONSE 8:

a.– e. Yes.

[1] If there are questions about the source of this information, please see the following website: http://www.gasoductorosarito.com/english/information.aspx
[2] If there are questions about the source of this information, please see the following website: http://www.gasoductorosarito.com/english/information.aspx

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QUESTION 9:

If the answer to questions 8 a, b, c, d, and e are affirmatively answered, then please do as follows.

a) Have the same analysts who prepared the Cost Effectiveness Analysis in A.15-09-013 analyze the cost-effectiveness of the Northern Baja Alternative as defined on page 5-15 of the PEA. This time, please ensure that the Northern Baja Alternative is analyzed separately from the Non-Physical (Contractual) or Minimal-Footprint Solutions. Please provide the following modifications to the definition in the PEA:
    1. Assume that the Gasoducto Rosarito line has 400,000 MMbtu/day of capacity.
    2. Assume that the TGN pipeline has 540,000 MMbtu/day of subscribed capacity.
    3. When analyzing the cost-effectiveness of the Northern Baja Alternative, apply quantifiable data to define relative costs, and quantify specific benefits consistent with those required on page 12 of the Ruling, 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 consistent with those already shown in the PEA.

b) Please update the CEA to include this Northern Baja Alternative throughout, including in all existing tables.
c) Please provide the updated CEA so that all changes are shown in tracked changes.
d) Please also provide a clean version of the updated CEA.

RESPONSE 9:

a. Applicants object to Question 9 on the grounds that it is vague and ambiguous, poses an incomplete hypothetical, calls for speculation, and asks Applicants to perform analyses which ORA may perform for itself. Subject to and without waiving their objections, Applicants respond as follows.

   Applicants do not own or operate the gas transmission lines serving the Otay Mesa receipt point from outside SDG&E's service territory. In the CEA, Applicants estimated the cost of delivering 400 MMcfd to Otay Mesa based on an estimated cost of constructing new pipeline facilities to expand the Mexico pipeline system, as it did not appear that 400 MMcfd of capacity would exist without expansion of the existing pipelines. However, Applicants do not know if the owners, operators, or other contracted users of such pipelines might be able to provide firm delivery of gas in smaller quantities for a period of time. Sempra affiliates own certain of the relevant pipelines[3] and, given the Commission's rules on affiliate transactions, Applicants do not believe it is appropriate to contact such affiliates without specific Commission direction to do so.

In order to respond to this question, Applicants require information to be provided by either: 1) existing pipeline shippers willing to release their firm capacity rights on the North Baja pipeline system (comprised of three pipelines, North Baja Pipeline, Gasoducto Rosarito and Transportadora de Gas Natural de Baja California (TGN)) for the quantity specified, or 2) a request to North Baja Pipeline, Gasoducto Rosarito and TGN for the cost of expansion capacity in excess of the quantities available to meet the specified amounts that is not available to the Applicants. Applicants do not have sufficient knowledge of the North Baja pipeline system's design and operation to determine what improvements may be required to expand capacity and prepare cost estimates for those improvements and associated transportation rates.

As stated in the PEA, which was filed in September 2015, 185 MMcfd of firm pipeline capacity was available on the North Baja Pipeline and 25 MMcfd on Gasoducto Rosarito. Currently, approximately 185 MMcfd is available on North Baja Pipeline, but only 20 MMcfd on Gasoducto Rosarito and 0 MMcfd on TGN. The current combined cost of firm transportation on these three pipelines (North Baja Pipeline, Gasoducto and TGN) for available capacity is a $.2476 per decatherm per day demand charge, $.0075 per decatherm volumetric charge, and $.0304 per decatherm in fuel charges assuming a $2.25 per decatherm purchase gas cost on the El Paso South Mainline. Applicants lack sufficient information to respond regarding future firm capacity or the cost of gas delivered to Otay Mesa.

b. Applicants submitted their CEA in response to the Joint Assigned Commissioner and Administrative Law Judge's Ruling issued on January 22, 2016 in Application (A.) 15-09-013 (Joint Ruling). The Joint Ruling at 11 states: "Sempra 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)." P.U. Code § 1003(d) provides for submission of: "A cost analysis comparing the project with any feasible alternative sources of power."

   In accordance with the Joint Ruling, the CEA evaluates the Otay Mesa Alternatives and described the basis for addressing the two alternatives under a single name in the CEA. (See CEA at page 13). As further stated in the CEA, the Northern Baja Alternative is

[3] The North Baja pipeline system is comprised of three pipelines: North Baja Pipeline, Gasoducto Rosarito and Transportadora de Gas Natural de Baja California (TGN). Both Gasoducto Rosarito and TGN are owned by IEnova, Applicants' affiliate.

indistinguishable in terms of costs and benefits to the Non-Physical or Minimal Footprint Solution identified in the Joint Ruling.

Applicants further object to this request on the ground that ORA's directions to Applicants to "assume that the Gasoducto Rosarito line has 400,000 MMbtu/day of capacity" and "assume that the TGN pipeline has 540,000 MMbtu/day of subscribed capacity" is inconsistent with P.U. Code Section 1003(d), which directs Applicants to compare the Proposed Project to "feasible alternative sources of power." Forcing Applicants to utilize false assumptions would render Applicants' P.U. Code Section 1003(d) comparison inaccurate.

Applicants further object to this request on the ground that P.U. Code Section 1003(d) and Commission Rule 3.1 address information to be submitted by Applicants, and do not provide authority for ORA to direct Applicants to alter information submitted by Applicants to establish that the public convenience and necessity are served by the proposed project. The CEA is part of Applicants' evidence in support of their Application, and ORA has no authority to dictate the substance of Applicants' evidence.

Applicants further object to this request on the ground that ORA's directions to alter information contained in Applicants' submission is contrary to Article 13 of the Commission's Rules, which creates an evidentiary hearing process to permit the Commission to resolve disputed issues of fact and determine whether a CPCN should be granted for the proposed project (or an alternative identified pursuant to CEQA). ORA's directions to Applicants to update the CEA is not consistent with the Commission's Rules regarding submission of evidence.

Applicants further object that they have no obligation to conduct analyses for ORA which ORA may perform for itself.

c. Please see response to 9(b) above.

d. Please see response to 9(b) above.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

PIPELINE SAFETY & RELIABILITY PROJECT (PSRP)

(A.15-09-013)

(DATA REQUEST ORA DR 26)

Date Requested: August 3, 2016
Date Responded: August 17, 2016

QUESTION 10:

Page 25 of the CEA states "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. 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." Table 8 at page 32 of the CEA is captioned "Avoided Costs" and shows the avoided costs associated with the Proposed Project and the Alternatives. For the Otay Mesa Alternatives E/F, the column designated "Fixed Cost" shows the amount of $977.1 million. The column designated "Total O&M Cost" shows a zero amount for the Otay Mesa Alternatives. The column designated "Avoided Cost" shows the negative amount of ($100.3) million for the Otay Mesa Alternatives. The column designated "Net Cost" shows the amount of $876.8 million for the Otay Mesa Alternatives.

a) Please provide the "low end cost" and the "high end costs" as described in the above statements on page 25 of the CEA.
b) Please provide the breakdown of numbers shown in Table 8 between the low end and the high end for each of the Otay Mesa Alternatives.

RESPONSE 10:

a. The low end cost would be approximately $45 million per year based on current rates. The high end cost would be approximately $997 million (in 2012 dollars). *See* CEA at page 22, Table 6. *See also* the Prepared Direct Testimony of Gwen Marelli at page 7.

b. The amounts shown in CEA Table 8 and Table 6 apply to the costs for Alternative E/F and include both the high end and low end amounts. The same avoided costs for replacing Line 1600 would apply to each of the Otay Mesa Alternatives.

QUESTION 11:

In describing Alternative G: LNG Storage (Peak-Shaver) Alternative AKA (United States – LNG Alternative), the CEA at page 25 states "The estimate for this Alternative was based on evaluating 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." Table 8 at page 32 of the CEA is captioned "Avoided Costs" and shows the avoided costs associated with the Proposed Project and the Alternatives. For the LNG Storage (Peak-Shaver) Alternative (G), the column designated "Fixed Cost" shows the amount of $2,669.7 million. The column designated "Total O&M Cost" shows the amount of $15.3 million for the LNG Alternatives. The column designated "Avoided Cost" shows the negative amount of ($100.3) million for the LNG Storage (Peak-Shaver) Alternatives. The column designated "Net Cost" shows the amount of $2,584.7 million for the LNG Storage (Peak Shaver) Alternatives.

a) Please provide the basis for the estimated fixed costs in the amount of $2,669.7 million shown in Table 8 for Alternative G, including all unit costs and other assumptions to arrive at this amount.
b) Please provide the basis for the estimated total O&M cost in the amount of $15.3 million shown in Table 8 for Alternative G including all unit costs and other assumptions to arrive at this amount.
c) Please identify the four LNG storage facilities described above and explain why it is reasonable to develop the estimates of Alternative G on the basis of these storage plants.
d) Please identify the existing LNG storage facility described above and explain why its actual costs would be reasonable for comparison purposes for Alternative G.

RESPONSE 11:

a. The basis for the Alternative G cost estimate is provided in the workpapers supporting the Prepared Direct Testimony of Neil Navin, *see* PSRP Alt Workpapers, p. 22.

b. Table 8 Total O&M Cost provides the present value of O&M and TIMP costs over 100 years. The Alternative G annual O&M cost was calculated by assuming a full-time employee count per storage facility.

c. The four LNG storage facilities described above refer to the four new storage facilities that Applicants would construct under Alternative G. Each new facility would be located near one of Applicants' four existing power plants. The estimates were developed based on a similar project, Energía Costa Azul (ECA). Each plant was compared to the ECA project and factored based on the 6/10th rule (*see* the workpapers supporting Mr. Navin's testimony, PSRP Alt Workpapers, p. 22.)

d. The existing storage project is ECA. It was reasonable to use this project for comparison purposes because it is generally similar (*e.g.*, size, construction requirements, location, etc.) to the four storage facilities described in Alternative G. Based on these similarities, Applicants consider ECA to be a reasonable proxy for the Alternative G facilities.