Docket:	:	A.14-12-016
Exhibit Number	:	
Reference Number	:	ORA-03
Commissioner	:	C. Peterman
ALJ	:	R. Mason
Witness	:	N. Stannik

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Prepared Testimony on Southern California Gas Company and San Diego Gas & Electric Company Application for Pipeline Safety and Reliability Memorandum Account (PSRMA) Cost Recovery

ORA Supporting Attachments
Volume 1

San Francisco, California
August 7, 2015

Index of Sempra Data Responses				
Testimony Page(s)	**Attachment Page(s)**	**DR #**	**Question #**	**Attachment(s)**
6, 7	4 – 5, 32 – 38	03	04d	"ORA DR3 Q4d Cost Summary.xlsx"
7	17, 39	03	12	"ORA DR3 Q12 Project Comparison.xlsx"
8	47 – 48, 59	14	06a	"Q6a Line 2000 West Stage 3 Estimate.pdf"
8	54 - 55	14	11	
8	50	14	08	
8, 11	51 – 52	14	09	
9	77, 82 - 100	16	15	ORA-DR-16 Q15 Attachments 1 & 2
9, 20	70 – 71	16	09	
9	74	16	12	
9, 10, 18	106	13	05	
9, 15, 17, 18, 19	114, 119 – 126, 219 - 224	13	12	"Line 2000 Original Filing Estimate_77980300.xls" "Change Notice 083_12728000_Redacted.pdf" "Change Notice 273_20250000.pdf" "WOA 25428180.pdf" "WOA 28008484.pdf"
9, 10	17	16	14	
10	103	13	02	
10	104	13	03	
11	14	03	10	
11	31, 127 – 136	03	20	"2000-A_071_EC_Lessons Learned.pdf"
12	137	12	01	
14	7	03	06	
18	149, 151	11	04	"ORA-PSRMA-SCG-11 Q4.xlsx"

18	69	16	08	
18	80 – 81	16	18	
18	67	16	06	
23	142 – 143	12	05	
24	155	04	04	

ORA is including the cited excerpts of the following document for parties' reference.

Other Documents Index			
Testimony Page #(s)	**Attachment Page #(s)**	**Document**	**Excerpt Page(s)**
5, 8, 12, 25	166 – 187	Decision D. 14-06-007	1 - iii, 13 - 14, 23 - 26, 36 - 39, 55 - 62
12	188 – 190	A. 11-11-002 Opening Brief of SoCalGas	55 - 57
23	191 – 202	Decision D. 12-12-030	56 - 67
23	203 – 204	Sempra Amended Application in R. 11-02-019	57 – 58
23	205 – 206	49 Code of Federal Regulations	§ 192.727, Abandonment or Deactivation of Facilities
24	207 - 218	Applicants Presentation to ORA "PSEP Cost Estimating Workshop" June 24, 2015.	-

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-03)
Date Requested March 17, 2015
Date Responded April 8, 2015

QUESTION ORA-PSRMA-SCG-03-01:

How does Sempra propose to demonstrate that the requested cost recovery is reasonable?

RESPONSE ORA-PSRMA-SCG-03-01:

The instant application is unlike other reasonableness review applications previously considered by the Commission. In general, previous reasonable reviews have either focused primarily on energy procurement decisions, the reasonableness of replacement power costs for utility-owned generation assets or a specific, individual capital project with a clearly-defined scope. In contrast, recovery of PSEP costs will require the review and approval of many unique, individual projects that are designed and scoped as part of the execution process. In order to establish an appropriate reasonableness review process under these unique circumstances, SoCalGas and SDG&E propose to work with the Commission and interested parties to balance the need for a robust initial showing that is sufficient to demonstrate that the actions of SoCalGas and SDG&E are consistent with that of a reasonable manager, against the potential burden of reviewing overly-voluminous initial applications that cannot feasibly be reviewed in a timely manner. SoCalGas and SDG&E propose to achieve this balance by providing additional project-specific information and supporting documentation to illustrate processes and explain decisions in the supplemental testimony due April 17, 2015 and to further collaborate with interested parties going forward to provide additional information on specific costs, decisions, or events, as appropriate. In this way, SoCalGas and SDG&E will provide an initial showing of reasonableness and then, through discovery and further collaborative efforts, provide additional information to facilitate a thorough review of the reasonableness of PSEP costs by interested parties and the Commission. SoCalGas and SDG&E further view this as an iterative process that may be refined and improved over time as the Commission and interested parties gain experience with this unique type of reasonableness review.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-03)
Date Requested March 17, 2015
Date Responded April 8, 2015

QUESTION ORA-PSRMA-SCG-03-02:

How are recorded costs assigned to each project? If each "project number" provided in the workpapers is not used in Sempra's cost accounting system, provide all project codes, e.g. "Job Numbers," that were used for each project.

RESPONSE ORA-PSRMA-SCG-03-02

Projects have a unique internal order number that is used to track costs associated with that project. Please refer to the excel attachment *ORA DR 3 Q2 IOs.*xlsx to find the project number and account used to track costs.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-03)
Date Requested March 17, 2015
Date Responded April 8, 2015

QUESTION ORA-PSRMA-SCG-03-03:

For projects with more than one test or replace section, does Sempra have the means to distinguish costs incurred in each test or replace section?

RESPONSE ORA-PSRMA-SCG-03-03:

Work Order Authorizations (WOA's) are first initiated for projects at Stage 1 to capture project costs associated with planning and preliminary design efforts. At Stage 3, a more detailed cost estimate is developed for projects based on information obtained during preliminary design efforts. If projects are required to be separated into different sections due to constructability, pipeline attribute, or other reasons, separate work orders may be (but are not necessarily) opened up to capture costs of the separate sections (see also Response ORA-PSRMA-SCG-03-06). If a separate work order is not created to capture costs associated with different sections, actual costs for each section cannot be accurately isolated and apportioned.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-03)
Date Requested March 17, 2015
Date Responded April 8, 2015

QUESTION ORA-PSRMA-SCG-03-04:

Sempra workpapers divide the overall project cost into 16 cost categories (e.g. Labor, Material – Gas, Material – Other, etc.). Please:

a. Provide a definition of “SRV”, as used in the Cost Summary tab line items for each project.

b. Provide the standards which are used to assign recorded costs to a specific cost category, e.g. list all the types of costs that are assigned to the “Labor” cost category.

c. Describe the process used to assign recorded costs to a specific cost category, what Sempra group makes these assignments, and when the assignments are made relative to the work being performed and the costs recorded.

d. For each completed project, provide cost accounting data with the line item costs that sum to each cost category, e.g. Labor, and that sum to the overall project cost

RESPONSE ORA-PSRMA-SCG-03-04:

4a) “SRV” stands for Service. It includes third-party supporting service costs and may include costs from construction, engineering, environmental, survey and other services, such as training.

4b) Costs are categorized based on internal accounting cost categories:

- Labor: SCG and SDG&E (company) employee labor costs
- Employee expenses: company employee costs for travel, lodging, meals, training, etc.
- Material: costs for purchased pipes, fittings, valves and other miscellaneous materials
- Permits and Right-of-Way: costs associated with acquiring permits
- Service: See response 4a
- Property Tax: portion of property taxes on construction work in progress (CWIP)

- AFUDC - (Allowance for Funds Used During Construction): interest utilities are allowed to earn for funds used during construction
- Overheads: represents certain indirect costs that are associated with direct charges (i.e., payroll taxes).

4c) PSEP assigns each cost to the categories, as defined in response to 4b, based on Company guidelines. Company labor is incurred and assigned bi-weekly. Other costs, such as third party labor, are assigned as they are incurred and invoiced.

4d) Please refer to attachment *ORA DR3 Q4d Cost Summary.xlsx* for a summary of costs for each completed project.

5

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-03)
Date Requested March 17, 2015
Date Responded April 8, 2015

QUESTION ORA-PSRMA-SCG-03-05:

Please provide workpapers or documentation that explain why and how each project was split into different test/replace sections (where applicable).

RESPONSE ORA-PSRMA-SCG-03-05:

Please refer to Attachment *ORA DR3 Q5 project testvreplace.docx.*

QUESTION ORA-PSRMA-SCG-03-06:

Please provide workpapers or documentation clarifying which project costs correspond to which test/replacement segments.

RESPONSE ORA-PSRMA-SCG-03-06:

As described in response to ORA-PSRMA-SCG-03-03, Work Order Authorization Forms (WOAs) are initiated at Stage 1 to capture all project costs for pipeline projects that require test or replacement. WOAs may include one or more segments, but it is not a general practice to initiate separate WOAs for each individual section for the same pipeline unless circumstances, such as construction schedule or design approach, warrant separate tracking mechanisms for sections within the same asset.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-03)
Date Requested March 17, 2015
Date Responded April 8, 2015

QUESTION ORA-PSRMA-SCG-03-07:

Please provide workpapers or documentation that define the bidding and bid-selection process for contracted work.

RESPONSE ORA-PSRMA-SCG-03-07:

Generally, construction contractors are required to perform contract requirements to SoCalGas and SDG&E standards, and comply with applicable Federal, State, and Local laws, ordinances, and regulations. In addition to these threshold requirements, SoCalGas and SDG&E utilize specific processes to evaluate and retain skilled construction contractors. For early PSEP projects, the PSEP organization conducted traditional project-specific competitive bids to acquire contractors. As the volume of PSEP work increased, the PSEP organizations determined that a less traditional approach could be employed to mitigate costs for customers, create efficiencies and balance operational and customer impacts and constraints across the SoCalGas and SDG&E service territories. To implement this new approach, referred to as the “Performance Partnership Program”, the PSEP organization divided the two service territories into construction regions. Performance partners were selected and assigned regions to promote the timely and cost-efficient execution of PSEP work in that region. The PSEP organization continues to utilize a project-specific competitive solicitation process to obtain fixed-price bids for projects located in the region that has not been assigned a performance partner. In addition, within all regions, including those assigned a specific performance partner, the PSEP organization retains the discretion to conduct competitive solicitations to acquire contractors for any PSEP projects where it is determined that it may beneficial to conduct a traditional competitive solicitation.

As noted above, the Performance Partner Program is described in Section VIII of Chapter 1 Testimony (Rick Phillips). The solicitation process described in testimony to acquire the Performance Partners was conducted as follows:

Performance Partners were selected based on two evaluations. The first evaluation was of written proposals that were received by qualified contractors and the second evaluation was of formal presentations to SoCalGas and SDG&E by a short-list of the initial competing contractors. In each of these evaluations, core SoCalGas and SDG&E members (selected from supply management, construction, project execution, and legal) were asked to score the contractors based on the following five-point scale:

1. Fails Expectations
2. Does not Meet Expectations
3. Meets Expectations
4. Strongly Meets Expectations
5. Exceeds Expectations

Further definitions of the scoring criteria are provided in the tab labeled: 'Overview and Instructions' in attachment *ORA DR3 Q7 Perf Partner RFP Eval Scorecard 03 26 14.xlsx.*

Using this scoring system, the SoCalGas and SDG&E evaluation team individually evaluated and scored each contractors proposal with regard to three criteria:

1. Commercial Terms
2. Technical Competency
3. Overall Pricing

Each of these areas included several sub-criteria that were weighted. The scoring for each of the main criteria, sub-criteria, and weighting (both for that criteria and the total evaluation) are provided in *ORA DR3 Q7 Perf Partner RFP Eval Scorecard 03 26 14.pdf*.

After the written proposal evaluations were completed and scored, SoCalGas and SDG&E narrowed the field of construction companies considered from nine to six. These six construction contractors were invited to present their capabilities to SoCalGas and SDG&E. These presentations were scored by SoCalGas and SDG&E core staff. The scoring excel spreadsheet used is provided in attachment *ORA DR3 Q7 Bidder Presentation Scoring_4-15-14.pdf.*

Based on the presentation scoring, a total of five performance partners were selected to move to contract negotiations. The contract negotiation efforts included a comparison of contractors' overhead, profit, equipment and subcontractor mark-ups to enable an "apples to apples" evaluation. Negotiations resulted in further cost reductions in some cases. Negotiations also focused on the experience of the personnel for the type of work in the geographic area for which they were being considered. Also of consideration was the capacity of the contractor to perform the volume of work for which they were being considered. Cost, ability and capacity all figured into the final awards by

9

geographic area. The selected performance partners were then assigned work regions based on their capabilities and capacities.

As discussed above, in addition to the Performance Partnership Program, the PSEP Organization continues to utilize a more traditional competitive solicitation process in one region and also may conduct a traditional solicitation for a specific project within a Performance Partner's region, where deemed appropriate. This more traditional competitive solicitation process is summarized as follows:

1. A bid package consisting of a scope of work, construction drawings, and technical specifications is issued, in the form of a request for proposal (RFP), to a list of construction contractors that have previously been vetted and approved by the Company for this kind of work.
2. A bid meeting is held, typically onsite, to describe the work to be completed and to answer any questions that the bidding contractors might have.
3. Sealed bids from the contractors who choose to compete are opened and the technical proposals (construction approach, construction key team members, overall schedule, and areas of potential cost savings), as well as the overall lump sum prices, are evaluated by Company PSEP-designated staff, using a pre-determined set of criteria and scoring method. Please refer to *ORA DR3 Q7 Construction Bid_eval Sheet.TEMPLATE.xlsx.*
4. A meeting to discuss the scores posted by each evaluator is conducted and a winning contractor is selected that SoCalGas/SDG&E determines provides the best value.
5. Upon agreement, the successful bidder is notified of an award and the non-selected bidders are notified.
6. Once selected, contracting documents are executed and a construction start date is set. A construction kickoff meeting is then planned and conducted. At this meeting the functional team members are brought together to discuss the construction scope and special requirements (permit restrictions, material status, environmental compliance issues, landowner/city/county agreements, construction management/inspection expectations, etc…).
7. Once construction starts, the construction contractor uses the Request for Information (RFI) process to ask questions for clarification from the Construction Management (CM) team. RFIs that impact cost or schedule may require the issuance of a change order (CO) that is estimated and adjudicated as soon as practicable so that an adjustment to the lump sum price can be completed. Should agreement on price for the CO not be possible, for various reasons, then the Construction Manager can authorize the construction contractor to complete

10

the work under Time and Material (T&M) rates with daily signoffs by the CM team. Contractors are monitored by project management, construction management and safety management personnel during each job and the contractor is evaluated for each job once that job is complete via a quarterly scorecard review exercise. This evaluation includes measurement against many different key performance indicators, including the contractor's change order activity.

8. During the work there are milestone invoices and payments made to the construction contractor. SoCalGas and SDG&E retain 10% of each of these milestone payments. The retained payment is paid in full when all the milestones are met, all liens are released, all subcontractors are paid, all material is accounted for, all restoration work is completed with landowner/City/County signoffs, and all documentation (*e.g.* As-Built Drawings) are completed and accepted.

11

QUESTION ORA-PSRMA-SCG-03-08:

Please provide the decision-making process used to determine incidental and accelerated miles. Provide the specific criteria used, the process used to apply them consistently, and the quality control steps taken to ensure each decision and the data informing it was accurate and complete.

RESPONSE ORA-PSRMA-SCG-03-08:

During Stage 1, a pipeline is evaluated to identify and confirm the segments that require testing or replacement to comply with CPUC directives. These results are presented at a Stage Gate review meeting with PSEP leadership to obtain approval of the "required scope" to proceed to Stage 2.

During Stage 2, project teams evaluate options for testing or replacement of the required segments approved in Stage 1. This evaluation includes the review of potential accelerated or incidental mileage in order to mitigate customer costs, reduce customer and/or operational impacts and/or to address other constructability issues, such as permitting challenges. The options to test or replace, including relevant accelerated and incidental mileage options, are presented to PSEP leadership at a Stage Gate review meeting to seek approval to proceed to Stage 3. PSEP leadership evaluates any additional mileage presented and based on anticipated future cost avoidance, customer/operational impact and/or constructability/permitting needs will approve a proposal to include accelerated or incidental mileage within the scope of a project.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-03)
Date Requested March 17, 2015
Date Responded April 8, 2015

QUESTION ORA-PSRMA-SCG-03-09:

Does Sempra have the means to determine which recorded costs are “variable” costs that are a function of project length, and those “fixed” costs that are independent of project length? If so, please provide. If not, explain why.

RESPONSE ORA-PSRMA-SCG-03-09:

As discussed during the March 25, 2015 meeting with ORA and other intervenors, the concepts of fixed and variable costs were used in developing the PSEP estimates. Actual PSEP costs are not normally fixed, and are not tracked within Company accounting systems in a manner that would identify costs as either fixed or variable. Actual costs are inherently variable because there are many project-specific factors that impact actual costs.

13

QUESTION ORA-PSRMA-SCG-03-10:

Does Sempra have the means to determine the recorded costs incurred for the following:

a. Pipe cleaning prior to filling the test section for a hydro test?

b. Disposal of water drained from the test section following a hydro test?

c. If the answer to questions 10 (a) or (b) are yes, please provide all such recorded costs for every hydro test provided in workpapers. If the answer to questions 10 (a) or (b) are no, please explain why not.

RESPONSE ORA-PSRMA-SCG-03-10:

a. No, SoCalGas and SDG&E do not have the means to determine the recorded costs incurred specifically for pipe cleaning prior to filling a test section for a hydrotest. The costs of pipe cleaning prior to filling a test section for a hydrotest are not separately itemized by construction contractors in their bids or invoices.

b. SoCalGas and SDG&E may be able to determine the recorded costs for water disposal for most projects by going through each of the relevant invoices and attempting to identify those costs that pertain specifically to water disposal.

c. As note in response a) above, the costs of pipe cleaning prior to filling a test section for a hydrotest are not separately itemized by contractors in their bids or invoices, so SoCalGas and SDG&E do not have a means to determine those specific costs in isolation. With respect to recorded costs for water disposal, SoCalGas and SDG&E are in the process of reviewing each of the relevant invoices and will supplement this response to add those costs once that detailed review is complete.

14

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-03)
Date Requested March 17, 2015
Date Responded April 8, 2015

QUESTION ORA-PSRMA-SCG-03-11:

For each category listed in the workbook of each project summary file provided (Labor, Employee Expenses, Material – Gas, Material – Other, etc.), please state whether that category would be contracted out: never; sometimes; or always, and why. If ‘sometimes’ or ‘always’, please describe how the decision to contract out (vs. keeping the work in-house) would be made. In each case where a category was contracted out ‘sometimes’, please provide the percent of the time that category was contracted out.

RESPONSE ORA-PSRMA-SCG-03-11:

The categories provided in the work papers that are “never” contracted include:

- Labor
- Employee Expenses
- Property Tax
- AFUDC and
- Overheads

The categories contracted out “always” include:

- Material-Gas
- Material-Other
- Material-Pipe & Fittings
- Material-Valves
- Material-Water
- SRV-Construction
- SRV-Environmental
- SRV-Survey and
- SRV-Other

In general, SoCalGas and SDG&E do not fabricate or manufacture materials within the Company. Thus, the Materials category will usually be fulfilled through a contract with a third party. By definition, the “SRV” or “Service” category refers to third-party contractor services, so these categories would never be fulfilled by Company personnel. Work performed by Company personnel would be categorized as “Labor.”

The category contracted out “sometimes” include:

- Permits & Right of Way.

This category was contracted out for land negotiations, acquisition of easements and some permitting resources. Additionally, costs in this area reflect payments to various external permitting agencies to obtain permits and/or payments to land owners to enable SoCalGas and SDG&E to perform PSEP related activities. SoCalGas and SDG&E do not have a mechanism for calculating “the percentage of time” that Permits & Right of Way activities are performed by third party contractors. Indeed, it is not clear how such a calculation could be derived.

QUESTION ORA-PSRMA-SCG-03-12:

Please provide costs for similar hydro test and pipe replacement projects on natural gas transmission lines to those provided in workpapers. Please include similar past work completed by Sempra, similar past work in the same geographic region/environment, or similar work for water or wastewater pipelines, or similar work by other utilities. Describe any differences between the similar projects provided and the projects in this application, and quantify those differences that impact costs.

RESPONSE ORA-PSRMA-SCG-03-12:

SoCalGas and SDG&E do not have access to documentation that would allow for meaningful comparison of costs for similar work done by water or wastewater pipeline operators, or similar work done by other utilities.

In attempting to compare internal non-PSEP projects to PSEP projects, SoCalGas and SDG&E were unable to identify projects that are sufficiently similar to facilitate a meaningful comparison. For purposes of this response, SoCalGas and SDG&E provide the three most similar non-PSEP projects. These projects involve varying pipeline specifications and unique project-specific factors. As additional PSEP projects are completed, there may be projects that are more comparable. The attached document provides the requested information along with a project description. See *ORA DR3 Q12 Project comparison.xlsx*.

17

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-03)
Date Requested March 17, 2015
Date Responded April 8, 2015

QUESTION ORA-PSRMA-SCG-03-13:

For all de-scoped projects, provide the scope of work to be performed and revised schedule and budget for each project.

RESPONSE ORA-PSRMA-SCG-03-13:

Descoped projects are projects that no longer require hydrotesting or replacement as part of PSEP. As such, there is no scope of work or revised schedule or budget for descoped projects.

QUESTION ORA-PSRMA-SCG-03-14:

Is it possible that any in-progress projects will be de-scoped (for example, if records are found or material specifications are different than previously thought)? If so, which projects?

RESPONSE ORA-PSRMA-SCG-03-14:

Once a project has progressed passed Stage 1, it is very unlikely for a project to be descoped. The in-progress projects presented in the PSRMA reasonableness review application have progressed beyond Stage 1. Therefore, while not impossible, it is highly unlikely they could be descoped.

QUESTION ORA-PSRMA-SCG-03-15:

Has Sempra concluded its search for records of pipelines for which it seeks hydrotest cost recovery in this proceeding? If not, when will Sempra complete its search for transmission pipeline records?

RESPONSE ORA-PSRMA-SCG-03-15:

As previously explained in Response ORA-PSRMA-SCG-02-3.b, SoCalGas and SDG&E have completed their active review of transmission pipeline records to determine whether there is documentation of a strength test to at least 125% of MAOP. That said, as part of the design and engineering phase of any PSEP pipeline project, or through routine pipeline assessment or other pipeline operations-related work, SoCalGas and SDG&E may occasionally identify pipelines or segments for further review and analysis, which may potentially result in a re-categorization of a particular pipeline or segment.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-03)
Date Requested March 17, 2015
Date Responded April 8, 2015

QUESTION ORA-PSRMA-SCG-03-16:

Please provide documentation showing the process Sempra used to find its records.

RESPONSE ORA-PSRMA-SCG-03-16:

SoCalGas and SDG&E had two phases of data collection, which included: Data Research and Quality Review. As part of the Data Research phase the following steps were taken:

1. Visit the Transmission District office responsible for the facility under review to obtain relevant pipeline records located in archive files. The archive files are organized by work order numbers, which vary in content but may include a project description, as-built drawings, material information, invoices, test pressure information and other miscellaneous items.
2. Conduct additional review and research of drawings, work order files and data in Company data systems to determine if the drawings, files and data provide relevant history of the facility, from initial construction to current operation.
3. Engage in field verification of the facility, if needed, to verify current operating pipe and component configuration, review available pressure ratings and photographs of the facility.
4. Conduct additional work order, data and/or drawing research, as needed, based on the findings of the site visit.

After the collection of the data is complete, a Quality Review is undertaken to confirm the aggregated data was recorded accurately from the source documents. This is done by re-reviewing the information collected with the source documentation and verifying the source documentation is traceable to the pipeline being reviewed.

QUESTION ORA-PSRMA-SCG-03-17:

Many in-progress projects reference stages to indicate project progress (for example 'Stage 4 – Detailed Design of the Project Lifecycle'). Please describe the framework, system, or tracking method referenced by these notes. Please describe what activities fall under each stage. Please state whether or not all Sempra PSEP projects fall under this framework; if not, please list and describe the exceptions.

RESPONSE ORA-PSRMA-SCG-03-17:

Both SoCalGas and SDG&E utilize a Seven Stage process developed for PSEP projects to maintain project planning and execution consistency. The Seven Stage Work Process, with activities, is described as follows:

Stage 1

Stage 1 is where the Work Order Authorization (WOA) is initiated. The initial WOA is used to track costs for the early stage investigation and validation of Category 4 criteria mileage and presenting project recommendation and package for approval to Stage 2. Notable Stage 1 activities include

- Issue initial WOA to evaluate and define project objectives.
- Begin process to develop project scope and initial Feature Study Map.
- Gather data from Initial Filing / NTSB / Big 8 / HPPD extract.
- Document changes between initial Filing, valve list and current data.
- Identify Criteria miles.
- Develop Preliminary Test vs. Replace Decision Tree and Segment Explanation Form.
- Research pipe segment history
- Perform high level environmental review.
- Conduct Stage 1 Gate review.

Stage 2

Stage 2 is where SoCalGas and SDG&E analyze data for selection of testing or replacement and confirm the Stage 1 Decision Tree outcome. Next, options are presented and considered prior proceeding to the next stage. Notable Stage 2 activities include:

- Confirm project objectives – scope, cost, schedule to support the update WOA.

- Define construction strategy, sequence and package plan.
- Conduct field investigations by multidiscipline team for scoping and constructability.
- Coordinate with District Ops for property access.
- Send out utility request letter for as-builts.
- Validate tap information with Operations.
- Complete Test vs. Replace Study.
- Preliminary test pressure evaluation.
- Meet with PSEP valve team to coordinate work, if applicable.
- Identify customer / system impacts with Region.
- Identify environmental & permitting requirements.
- Prepare (or submit if complete) materials for detailed Environmental Review Form.
- Initiate Project Execution Plan for Stage 3.
- Identify long lead critical materials.
- Initiate Risk Register (include Region Engineering).
- Engage with Capacity Planning, Environmental, Gas Control, Marketing, Region teams, Pipeline Integrity Group and Land Services.
- Engage with Community Outreach and conduct site visit with Community Outreach and Regional Public Affairs Manager(s).
- Initiate design basis.
- Identify potholing requirements.
- Conduct Stage 2 Gate Review.

<u>Stage 3</u>

Stage 3 is where the project execution plan is finalized and funding estimates and baseline schedules are developed. Notable Stage 3 activities include:

- Finalize project objectives – scope, cost, schedule to support the WOA.
- Update construction strategy, sequence and package plan.
- Continue field investigations by multi-discipline team for scoping and constructability.
- Identify municipal ministerial permit (technical and construction) requirements from city, county, state, and regulatory agencies.
- Prepare preliminary design drawings and overview sketch.
- Define long lead material and pricing.
- Complete design reviews for constructability, safety, maintainability, operability and environmental constraints.

23

- Understand customer interruption requirements.
- Update Risk Register with an assessment and identification session (with stakeholders).
- Submit detailed environmental review.
- Prepare applications for long lead and environmental permits / licenses and identify any required mitigation plans.
- Finalize project foot-print (disturbance area).
- Complete and issue Project Execution Plan.
- Complete budget estimate and integrated project schedule.
- Prepare and submit an updated WOA, if appropriate.
- Notify and update internal stakeholders – Region Directors, Energy Markets, AEs, etc.
- Initiate LNG/CNG Plan, if applicable.
- Conduct Stage 3 Gate Review.

Stage 4

For Stage 4, design and construction documents and necessary permits and authorizations are completed; pipeline materials are purchased, received, and prepared to turnover to Contractors. Notable Stage 4 activities include:

- Implement management of change procedures.
- Complete procurement of pipeline materials.
- Retain certifications and proofs.
- Conduct design reviews, operating, maintenance, constructability, and environmental constraints; incorporate into the design.
- Finalize design based on input from Region, Gas Control, Operations, Marketing, etc.
- Issue construction documents (IFC) and work packages (95% engineering completion) at scheduled milestones.
- Confirm construction scopes of work, control estimates, schedules, and environmental compliance management plan and requirements.
- Submit long lead and environmental permit applications.
- Obtain applicable regulatory and municipal authority approvals (*e.g.*, CPUC, environmental, resource agencies, cities, etc.).
- Engaging site inspectors and providing necessary information.
- Implement any mitigation plans required to achieve permits.
- Prepare project procedures and specifications to include permit requirements to mitigate environmental impacts during site activities.
- Coordinate work with District Operations.

24

- Negotiate temporary easements.
- Confirm Communication Plan.
- Develop gas handling / tie-in procedures, Lock-Out-Tag-Out (LOTO).
- Conduct Construction Readiness Review (CRR). (Pre-RFP & Pre Contract Award)
- Conduct Stage 4 Pre-Contract Award Construction Readiness Review.

Stage 5

During Stage 5, construction contractors are mobilized and monitored to document progress; compliance; better enable SoCalGas and SDG&E to react to issues and non-conformances; conduct testing; and maintain project scope quality, budget and schedule as funded. Notable Stage 5 activities include:

- Mobilize to Sites.
- Receive environmental clearances and agency permits prior to starting any field work.
- Acquire construction equipment, materials and support services.
- Review and approve construction contractor's schedules and plans.
- Manage site activities including safety, QA, security, and environmental compliance.
- Conduct pre-construction / construction site inspections and monitoring; fulfill applicable environmental / permitting compliance requirements.
- Ensure outage dates are met, customer impacts are managed and tie-in outage coordination is conducted.
- Review submittals, NDE, material certifications, completion sheets, red-lines, etc.
- Continue risk / change management.
- Manage ready for commission process and turnover as systems are completed.
- Achieve construction completion.
- Complete site restoration.
- Reconcile field documentation.
- Conduct as-built surveying.

Stage 6

During Stage 6, commissioning and operating activities are performed to achieve completion certification for the project. Notable Stage 6 activities include:

- Select and align team to project objectives.
- Coordinate inspections by regulatory authorities.
- Plan sequential testing and start-up of completed systems.

- Assist with operator training.
- Record changes to construction documents.
- Continue change management.
- Complete pre-startup Safety Review.
- Provide technical support.
- Inspect and document that site restoration is complete.
- Continue to conduct environmental inspections / monitoring / reporting per environmental permit requirements, if applicable.
- Coordinate and prepare environmental closeout documentation.

Stage 7

During Stage 7, regulatory, contractual, archival activities are performed to close the project in an orderly manner and issue acceptance certificates. Notable Stage 7 activities include:

- Conduct Lessons Learned sessions for total project.
- Close all purchase orders.
- Submit Notices of Termination for environmental permits.
- Assemble and archive project documentation.
- Return SoCalGas/SDG&E assets to service.
- Resolve claims or disputes.
- Resolve warranty issues.
- Obtain acceptance from Operations.
- Prepare project benchmarking data and feed back into system.
- Verify final invoices paid.
- Prepare final cost accounting.
- Reconcile close-out documents
- Verify required documentation is transferred to system of record.

The Seven Stage Review Process began being implemented by the PSEP Organization in second quarter 2013. Thus, PSEP projects that were initiated prior to that time did not follow this formalized process. A similar, but less formal, project execution methodology was employed in those instances.

26

QUESTION ORA-PSRMA-SCG-03-18:

For each in-progress project, provide the project schedule as of the same date that the cost requests in this application were made. If Sempra's program mangers do not use Gantt charts that show the status of individual project activities (e.g. permit acquisition, install test heads, tie-in, etc.) explain how project progress is tracked and reported to management.

RESPONSE ORA-PSRMA-SCG-03-18:

Please refer to attachment *ORA DR3 Q18 Schedule Graphics Stage.pdf.*

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-03)
Date Requested March 17, 2015
Date Responded April 8, 2015

QUESTION ORA-PSRMA-SCG-03-19:

Please provide the anticipated or forecasted costs to complete each in-progress project, and the workpapers or documentation on which these forecasts are based.

RESPONSE ORA-PSRMA-SCG-03-19:

Below is the list of estimate at completion (EAC) for each in-progress project as of June of 2014. Loaded costs include labor and non-labor expenses.

PSEP | Pipeline Safety Enhancement Plan

Project Forecast Cost Report

Type	Status	Projects	Loaded EAC
Test	In Progress	2000-West	$18,816,225
Test	In Progress	404	$21,676,828
Test	In Progress	407	$5,977,566
Test	In Progress	1015	$3,300,492
Test	In Progress	406	$12,596,209
Test	In Progress	Playa Del Rey Phase 4-6 (Phase 5)	$288,628
Test	In Progress	1004	$9,977,402
Test	In Progress	37-18-F	$5,118,091
Test	In Progress	2001 West	$10,110,298
Test / Replacement*	In Progress	32-21	$34,524,323
Test / Replacement*	In Progress	2003	$6,795,735
Test / Replacement*	In Progress	41-116BP1	$253,130

*Project include both hydrotest and replacement aspects of PSEP work

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-03)
Date Requested March 17, 2015
Date Responded April 8, 2015

QUESTION ORA-PSRMA-SCG-03-20:

Please provide all internal performance metrics or reports for in-progress and completed projects.

RESPONSE ORA-PSRMA-SCG-03-20:

Per discussion with ORA, SoCalGas/SDG&E will provide a response at a later date.

29

**(DATA REQUEST ORA-PSRMA-SCG-03)
Date Requested March 17, 2015
Date Responded April 8, 2015**

QUESTION ORA-PSRMA-SCG-03-21:

Did Sempra track project cost performance against the estimates provided in the PSEP application? If not, provide the project budgets used, and all documents supporting them.

RESPONSE ORA-PSRMA-SCG-03-21:

Please refer to attachment *ORA DR3 Q21 Budget cost comparison.xlsx* and supporting documents in the zip file *ORA DR3 Q21 WOAs CONFIDENTIAL.zip.* **The attached WOA documents include confidential information that is submitted under GO 66-C and PUC Section 583.**

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-03)
Date Requested: March 17, 2015
Date Responded: May 10, 2015
Date Revised: June 19, 2015

QUESTION ORA-PSRMA-SCG-03-20:

Please provide all internal performance metrics or reports for in-progress and completed projects.

RESPONSE ORA-PSRMA-SCG-03-20 Part 2:

On May 10, 2015, in response to ORA's Data Request 3 Q20, SoCalGas and SDG&E provided internal reports and metrics related to PSEP program performance and progress through June 2014. Per discussions with ORA, SoCalGas and SDG&E is also providing additional project-specific documents for the four completed projects along with an accompanying sample inventory list. Because of the broad nature of this request, SoCalGas/SDG&E may update this response if additional responsive documents are found at a later date.

Certain reports contain confidential information pursuant to GO 66-C and PUC Section 583. The confidential reports have been marked confidential.

ORA-PSMRA-SCG-03 Q4D
Southern California Gas Company
ORA-PSMRA-SCG-03 Q4D
Line 42-66-1/42-66-2

Cost element	Cost element name[2]	Total
6110020	SAL-MGMT S/T	77,497
6110030	SAL-MGMT T&1/2	4,800
6110110	SAL-UNION S/T	32,876
6110120	SAL-UNION T&1/2	5,649
6110130	SAL-UNION D/T	2,015
6110335	SAL-DEL LUNCH PREM	377
6130010	EMP TRVL-MEALS&TIP	518
6130012	EMP TRVL-MILEAGE	53
6213070	MATL-PARTS	244
6213090	MATL-FREIGHT	650
6213260	MATL-FITTINGS	4,816
6213335	MATL-INSULATING MATL	585
6213435	MATL-PIPE WRAPPING	214
6213525	MATL-METAL PIPE&FITG	6,990
6213535	MATL-VALVES	475
6215567	MI-PIPE	746
6215568	MI-NON PIPE	18,676
6220002	SRV-CONSULTING	4,751 [1.]
6220005	SRV-CONTR-MAJOR PROJ	369,039
6220007	SRV-CONTR-TIME&EQUIP	5,650
6220530	SRV-CONSTRUCTN OTHER	8,188
6220600	SRV-CONSULTING-OTHER	25,418
6220640	SRV-TRNG & SEM IN-H	887
6220910	SRV-HAZ WASTE DISPOS	6,867
6221110	SRV-PSEP ENG & CONST	67,804
6340000	Cash Discounts on Pu	(5)
6405012	A&G-GOVT PMTS-PERMIT	24,300
	Total Directs	670,079
	Overheads	234,771
	Property Taxes	1,182
	AFUDC	8146.13
	Total Costs	914,179

[1.] GTS records resarch costs of $512 excluded from SRV-Consulting.
[2] S/T = straight time, T&1/2 = time and a half, D/T = double time

ORA-PSMRA-SCG-03 Q4D
Southern California Gas Company
ORA-PSMRA-SCG-03 Q4D
Line 45-120XO1

Cost element	Cost element name[2]	Total	
6110020	SAL-MGMT S/T	64,010	
6110030	SAL-MGMT T&1/2	6,487	
6110110	SAL-UNION S/T	5,206	
6110120	SAL-UNION T&1/2	3,917	
6110130	SAL-UNION D/T	4,498	
6130010	EMP TRVL-MEALS&TIP	619	
6130012	EMP TRVL-MILEAGE	244	
6213085	MATL-MISCELLANEOUS	3,921	
6213155	MATL-CATHODIC EQUIPM	304	
6213305	MATL-GASKETS	261	
6213325	MATL-HARDWARE	1,362	
6213335	MATL-INSULATING MATL	2,661	
6213435	MATL-PIPE WRAPPING	3,148	
6213525	MATL-METAL PIPE&FITG	41,272	
6215567	MI-PIPE	182	
6215568	MI-NON PIPE	2,029	
6220002	SRV-CONSULTING	8,257	1.
6220005	SRV-CONTR-MAJOR PROJ	522,178	
6220480	SRV-ENGINEERING	396	
6220590	SRV-MISCELLANEOUS	150	
6220600	SRV-CONSULTING-OTHER	7,557	
6221110	SRV-PSEP ENG & CONST	78,837	
6340000	Cash Discounts on Pu	(374)	
6405012	A&G-GOVT PMTS-PERMIT	18,801	
	Total Direct Costs	775,921	
	Overheads	105,247	
	Property Taxes	407	
	AFUDC	4,573	
	Total Costs	886,148	

[1.] EDM Services Inc. records research costs of $592 excluded from SRV-Consulting.
[2] S/T = straight time, T&1/2 = time and a half, D/T = double time

ORA-PSMRA-SCG-03 Q4D

Southern California Gas Company

ORA-PSMRA-SCG-03 Q4D

Line 2000-A Replacement

Cost element	Cost element name[1]	Total
6110020	SAL-MGMT S/T	231,118
6110030	SAL-MGMT T&1/2	25,699
6130001	EMP TRVL-AIR	718
6130015	EMP TRVL-MEALS/ENT	501
6130017	EMP TRVL-TAXI/SHUTTL	107
6130020	EMP TRVL-HOTEL/LODG	1,885
6211380	MATL-ELECTRIC PARTS	14
6213005	MATL-OFFICE SUPPLIES	417
6213035	MATL-GAS&DIESEL FUEL	2,178
6213455	MATL-TOOLS	59,269
6213525	MATL-METAL PIPE&FITG	130,245
6213535	MATL-VALVES	255,479
6215567	MI-PIPE	48,263
6215568	MI-NON PIPE	124
6220002	SRV-CONSULTING	216,373
6220380	SRV-TEMP AGNCY LABOR	(0)
6220530	SRV-CONSTRUCTN OTHER	1,758
6220535	SRV-GOVT PERMITS	533
6220590	SRV-MISCELLANEOUS	17
6220600	SRV-CONSULTING-OTHER	470,981
6220640	SRV-TRNG & SEM IN-H	730
6220880	SRV-CONSTR-GAS PIPE	-
6221110	SRV-PSEP ENG & CONST	2,873,699
6405012	A&G-GOVT PMTS-PERMIT	1,123
	Total Direct Costs	4,321,232
	Overheads	686,152
	Property Taxes	4,167
	AFUDC	47,443
	Total Costs	5,058,995

[1] S/T = straight time, T&1/2 = time and a half, D/T = double time

ORA-PSMRA-SCG-03 Q4D
Southern California Gas Company
ORA-PSMRA-SCG-03 Q4D
Playa Del Rey

Cost element	Cost element name[1]	Total
6110020	SAL-MGMT S/T	100,293
6110110	SAL-UNION S/T	233
6130012	EMP TRVL-MILEAGE	284
6130015	EMP TRVL-MEALS/ENT	130
6130020	EMP TRVL-HOTEL/LODG	4
6213035	MATL-GAS&DIESEL FUEL	16
6213305	MATL-GASKETS	2,213
6213535	MATL-VALVES	797
6215568	MI-NON PIPE	6,345
6220002	SRV-CONSULTING	43,636
6220008	SRV-CONTRACTORS	3,071
6220009	SRV-CONTR-SPECFC JBS	24,454
6220380	SRV-TEMP AGNCY LABOR	42,642
6220422	SRV-COPY-SERVICE CTR	9
6220530	SRV-CONSTRUCTN OTHER	3,329
6220880	SRV-CONSTR-GAS PIPE	302,263
6220910	SRV-HAZ WASTE DISPOS	46,253
6221110	SRV-PSEP ENG & CONST	9,307
6340000	Cash Discounts on Pu	(27)
	Total Direct Costs	585,252
	Overheads	97,785
	Property Taxes	
	AFUDC	
	Total Costs	683,036

[1] S/T = straight time, T&1/2 = time and a half, D/T = double time

ORA-PSMRA-SCG-03 Q4D
Southern California Gas Company
ORA-PSMRA-SCG-03 Q4D
Line 2000-A Hydrotest

Cost element	Cost element name	Total
6110020	SAL-MGMT S/T	1,182,542
6110030	SAL-MGMT T&1/2	48,850
6110110	SAL-UNION S/T	248,240
6110120	SAL-UNION T&1/2	92,674
6110130	SAL-UNION D/T	92,891
6110141	SAL-EMP CNTR MGT S/T	1,079
6110172	SAL-PT TIME C&T S/T	2,010
6110182	SAL-PT TIME C&T T&H	-
6110335	SAL-DEL LUNCH PREM	8,472
6130001	EMP TRVL-AIR	5,336
6130010	EMP TRVL-MEALS&TIP	509
6130011	EMP TRVL-INCIDENTALS	117
6130012	EMP TRVL-MILEAGE	13,664
6130014	EMP TRVL-PARKING	87
6130015	EMP TRVL-MEALS/ENT	450
6130016	EMP TRVL-CAR RENTAL	1,311
6130020	EMP TRVL-HOTEL/LODG	7,136
6211470	MATL-PRINTED MATERLS	15
6211635	MATL-COMPNY GAS USED	124,990
6213005	MATL-OFFICE SUPPLIES	4,476
6213010	MATL-PCARD/FIELD CD	244
6213025	MATL-COMPUTER EQUIP	327
6213030	MATL-SOFTWARE	683
6213035	MATL-GAS&DIESEL FUEL	3,256
6213060	MATL-VEHICLE PARTS	12
6213085	MATL-MISCELLANEOUS	4,959
6213090	MATL-FREIGHT	835
6213095	MATL-SUBSCR&PUBLICN	10
6213140	MATL-BUILDING MATERI	43
6213155	MATL-CATHODIC EQUIPM	1,352
6213180	MATL-COMPUTR HARDWAR	8,110
6213181	MATL-CONSUMABLES	890
6213225	MATL-ELECTRIC EQUIP	116
6213260	MATL-FITTINGS	1,482
6213300	MATL-GASES-INDSTRIAL	121
6213310	MATL-GAUGES	2,044
6213325	MATL-HARDWARE	34,062
6213385	MATL-ELEC MISC	3,710
6213430	MATL-PIPE COATG&STRG	2,522
6213445	MATL-PLANNING EQUIPM	345
6213455	MATL-TOOLS	1,135

6213470 MATL-PRESS CNTRL FTG	3,660

Cost element	Cost element name	Total
6213525	MATL-METAL PIPE&FITG	81,154
6213535	MATL-VALVES	84,256
6215567	MI-PIPE	12,146
6215568	MI-NON PIPE	7,501
6220002	SRV-CONSULTING	549,404 [1.]
6220005	SRV-CONTR-MAJOR PROJ	1,400
6220007	SRV-CONTR-TIME&EQUIP	103,742
6220050	SRV-ADVRTSNG&MKTG	(685)
6220060	SRV-CATERING	14,512
6220270	SRV-IT-CONSULTING	7,860
6220380	SRV-TEMP AGNCY LABOR	87,734
6220420	SRV-COPY CENTER	8,795
6220422	SRV-COPY-SERVICE CTR	56,101
6220450	SRV-MAIL-POSTAGE	50
6220480	SRV-ENGINEERING	107,142
6220530	SRV-CONSTRUCTN OTHER	10,094
6220535	SRV-GOVT PERMITS	33,595
6220590	SRV-MISCELLANEOUS	15,816
6220600	SRV-CONSULTING-OTHER	1,517,027
6220640	SRV-TRNG & SEM IN-H	2
6220840	SRV-VEH&EQUIP RENTAL	23,517
6220850	SRV-VEH&EQUIP W/OPER	919
6220880	SRV-CONSTR-GAS PIPE	136,961
6220910	SRV-HAZ WASTE DISPOS	159,046
6221085	SRV-SITE ASSESS&MIT	4,096
6221110	SRV-PSEP ENG & CONST	13,144,178
6230680	SRV-EVENT & TICKETS	4
6280001	GOV PYMNTS-PERMITS	8,917
6310020	PMT FOR EASEMENT / R	29,400
6320002	TELE-CELLULAR PHONES	7,214
6340000	Cash Discounts on Pu	(1,381)
6405012	A&G-GOVT PMTS-PERMIT	11,296
	Total Direct Costs	18,126,580
	Overheads	3,189,303
	Property Taxes	-
	AFUDC	-
	Total Costs	21,315,883

[1.] EDM and GTS records research costs of $26,868 excluded from SRV-CONSULTING

[2] S/T = straight time, T&1/2 = time and a half, D/T = double time

42-66-1/2 Workpaper Comparison (Replacement)						
Project	Project Type	Diameter (inch)	Length	Location	Cost	Comments
SL 42-66-1/2	Replacement	8,12	185	Rural (Railroad Right of Way)	$ 914,179	While the diameter comparison is similar, the type of job is different. 42-66-1/2 involved the abandonment of approximately 160 feet of pipe and the replacement of approximately 170 feet, resulting in a single line connecting a major Transmission line with a regulation station. The work was performed primarily in a railroad right-of-way. 30-15 was a replacement of approximately 2160 feet of pipe in a primary roadway.
SL 30-15	Replacement	12	2160	Primary Roadway	$ 1,575,035	

45-120 X 01 Workpaper Comparison (Replacement)						
Project	Project Type	Diameter (inch)	Length	Location	Cost	Comments
SL 45-120X01	Replacement	24	53	Primary Roadway	$ 886,148	45-120X01 consisted of the replacment of 47 feet of 22 inch pipe with 24 inch pipe on a line that serves as a connection between a Tranmssion line and Distribution supply line. 45-15 was a replacement of 2268 feet of 8" pipe on a primary roadway.
SL 45-15	Replacement	8	2268	Primary Roadway	$ 1,633,466	

2000A Workpaper Comparison (Hydro-Test)						
Project	Project Type	Diameter (inch)	Length	Location	Cost	Comments
2000A	Hydrotest	30	80232	Secondary Roadway	$ 21,315,883	The hydrotesting of existing lines are primarily driven by the requirements of PSEP and there are limited comparable Company projects, particularly given the length of Line 2000-A. Line 2000-A consisted of the hydrotesting of over 15 miles encompassing ten separate test sections over a span of 50 miles, requiring separate staging and mobilization areas for most of the sections as well as excavations at each tie point of the individual sections. 41-34 consisted of a single hydrotest of 3715 feet requiring only two excavations at either end of the test and a single mobilzation/staging area.
SL 41-34	Hydrotest	8	3715	Primary Roadway	$ 529,534	

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-14)
Date Requested: July 1, 2015
Date Responded: July 15, 2015

For all of the following Data Requests, by “Sempra,” we interpret ORA to mean “SoCalGas and SDG&E” and not our parent company.

QUESTION 1:

Please provide the “crossover table” (or similar) correlating Work Order Numbers to Internal Order Numbers for the all completed and de-scoped PSRMA projects. Please indicate the project line number (2000A, 4000, 38-528, etc.) that each entry in the table corresponds to.

RESPONSE 1:

Regarding completed and descoped PSRMA projects presented in this application, please refer to the Attachment Q1 folder for a “crossover table” correlating Work Order Numbers to Internal Order Numbers.

QUESTION 2:

At the June 24, 2015 PSEP Cost-Estimating Workshop, Sempra indicated that "actual costs captured in SAP are currently grouped differently than in the estimates."

a. How are costs grouped in Sempra's Stage 3 estimating tool?
b. How are costs grouped in Sempra's SAP system?
c. How are "cost elements" used in Sempra's SAP system?
d. ORA understood from the Cost-Estimating Workshop that "cost elements" are defined by GAAP (Generally Accepted Accounting Principles). Is this understanding correct? If so, please provide a citation to current the appropriate GAAP document(s) outlining cost element definitions and usage.

RESPONSE 2:

a. The costs in the Stage 3 estimating tool are grouped by the Work Breakdown Structure (WBS) and cost activities. WBS defines and groups a project's work elements/activities to help organize and define the total work scope of the project.

b. Costs in the SAP system are directly charged costs tracked by Cost Center or Internal Order, and are required in the accounting code block. The accounting code block are required data fields for journal entries in SAP, and consists of a Cost Center, Internal Order, and Cost Element. This allows the costs to be grouped and tracked in different ways, depending on the need. Most projects are grouped by Internal Order.

c. Cost elements are numbers in the Chart of Accounts. Primary Cost Elements are for direct costs and are one of the required items in the accounting code block where an Internal Order or Cost Center are needed for tracking cost responsibility. Secondary cost elements are used for allocating overhead costs.

d. No. Cost Elements are not defined by GAAP.

QUESTION 3:

At the June 24, 2015 PSEP Cost-Estimating Workshop, Sempra indicated that "The next iteration of the estimating tool will align [cost estimates] with the Company's [SAP accounting] system" and "PSEP is working to better align cost categories to line items in the estimating template in order to more readily utilize actual cost experience to update the cost estimating template."

a. Will the "next iteration of the estimating tool" be based on the current Stage 3 estimating tool? If so, please describe upgrades/changes/modifications that the new tool will make to the current Stage 3 tool. If not, please describe the new tool that will replace the Stage 3 estimating tool.
b. Will Sempra's efforts to align cost categories require the modification of the estimating tool, Sempra's accounting system, both, or neither? Please explain.
c. Please describe the changes that the alignment will make to the estimating tool and/or Sempra's accounting system as described in part (b). For example, "The changes will assign a cost element number to each invoice when recorded" or "The new cost estimating tool will use SAP's cost categories."
d. Will procedures be developed to guide Sempra and contractor staff in using the revised system(s)? If so, provide a list of these procedures and any procedures that currently exist with revision number and date. Provide the estimated date of release for procedures under development.
e. Please describe the roll-out, testing, and full-implementation timeline for the changes described above.

RESPONSE 3:

a. Yes. An update to the new tool will be aligned to the new approved Work Breakdown Structure (WBS) for PSEP described above in question 2a. The construction contractor's cost will also be reflected in the WBS that is currently estimated during Target Price Estimates. The tool will also incorporate updates to material pricing, labor pricing, and allowances.

b. Yes, there will be modification of the tool to work with the cost reporting system. The accounting system will not require modification for these changes.

---

c. The tool will utilize the new WBS structure. Estimating of costs will be at a cost element activity and function level. The alignment changes enable the comparison of estimates to actuals as reported in the cost reporting system (TM1) for PSEP.

d. No. There is an existing procedure in place. The update of the Stage 3 tool will not affect our existing estimating procedure. The tools revision will only affect the end users input.

e. We are currently reviewing and testing the Stage 3 tool before implementation. We plan to distribute the new version of the Stage 3 tool in August 2015. The release will coincide with training on the changes described in the response to Question 3a above.

QUESTION 4:

It is ORA's understanding that Sempra contracts out all or nearly all pipeline construction and testing work, with the exception of pipeline tie-ins, which are done by in-house SCG crews.

a. Is this understanding correct? If not, please explain.
b. Southwest Contractors bid proposal for hydrotesting of Line 2000A (provided as confidential attachment "2000-A_Southwest_Contractor_Bid_Proposal_ CONFIDENTIAL.pdf" to Sempra's response to ORA-DR-13 Q6) includes multiple provisions to tie in pipe sections. If Sempra crews always or almost always perform pipeline tie-ins, why was Southwest Contractors contracted to perform this work on Line 2000A?
c. Was the cost of using in-house crews to perform tie-ins compared to the cost of contracting out tie-ins for line 2000A? If so, please provide cost analyses, reports, etc. If not, please explain why

RESPONSE 4:

a. SoCalGas and SDG&E do primarily use contractors for pipeline construction and test work; with oversight by SoCalGas and SDG&E personnel. However, the contractors also generally perform the pipeline tie-ins, again with oversight by SoCalGas and SDG&E personnel, while the in-house SoCalGas Crews provide gas handling support during the operation. Gas handling support entails SoCalGas crews performing isolation of the line by closing valves, purging the line from gas while also establishing a safe working environment in order for contract crews could perform the pipeline tie-ins. The gas handling support also includes re-energizing the isolated pipeline upon completion of the tie-in operation.

b. The provided attachments contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583. As described in response to ORA DR14 Question 4a and provided in the attached, refer to Section 28 Tie-ins and Isolation in "*Q4b 2000 HT Special Specification_Confidential.pdf*," the SoCalGas crews provide gas handling support while the execution of the tie-in is executed by the pipeline contractor (with oversight by SoCalGas and SDG&E personnel).

c. No cost analysis was performed to compare in-house crews to contracting out tie-ins for Line 2000-A. As explained in response above in Question 4a, pipeline contractors and company personnel perform different aspects of the tie-in process. SoCalGas and SDG&E are not resourced to perform all aspects of a tie-in, although they may perform certain aspects on an as-needed basis.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-14)
Date Requested: July 1, 2015
Date Responded: July 15, 2015

QUESTION 5:

Please provide the final report and any other documentation from Sempra's PSEP Project Management Office (PMO) on cost and schedule performance of Line 2000A. If no such report or documentation exists, please describe how management was informed of the final status and performance of the Line 2000A project, and include any presentations or reports that were provided to management.

RESPONSE 5:

The provided attachments contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583.

Cost Performance – Senior management was made aware of updated cost estimates via reauthorization of the Work Order Authorization (WOA). Please refer to attachment "*Q5 WOA 28008484 CONFIDENTIAL.pdf*" for cost details. There are also monthly cost reports that notify PSEP management of costs-to date. Please refer to attachments in response to ORA DR 3 Question 20 (*05 14 WOCS PSEP.pdf, 06 14 WOCS PSEP.pdf, and 04 14 WOCS PSEP.pdf*) for a sample of cost reports.

Performance Reporting on Line 2000A

- Notification of Successful Hydrotest – Senior management was kept informed of each completed hydrotest via email. Furthermore, an email was sent on 10/31/2013 notifying a broad range of company employees that the 10th and final segment for Line 2000-A will begin hydrotesting. Please refer to the Q5 Attachment folder for a sample of PSEP Executive Steering Committee Email Notifications and "*Q5 PSEP Project Update Line 2000 Hydrotest 10312013_Redacted.pdf*" for the employee notification.

- Monthly Reporting – Senior management was informed of the progress of Line 2000A work as part of monthly meetings on the PSEP program. The attached October report shows the progress of work towards the end of construction on Line 2000A. A final status indicating the completion of the hydrotests was included in the December report, also attached. Please see "*Q5 ESC 102313 final CONFIDENTIAL.pdf" and "Q5 ESC 2013-12 final CONFIDENTIAL.pdf*".

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-14)
Date Requested: July 1, 2015
Date Responded: July 15, 2015

QUESTION 6:

Please provide the following documents for a sample PSEP project that meets the criteria below:

a. Stage 3 Cost Estimate,
b. Initial Work Order Authorization and any subsequent changes,
c. Adopted contractor bid and Target Price Agreement (if separate),
d. Current or most recent status report (including schedule, EAC, and ETC),

The sample PSEP project should meet the following criteria:

a. At least 50% of mileage is (or will be) hydrotested (vs. replaced, abandoned, etc.),
b. Completed or nearing completion,
c. Has a budget of over $10MM,

If no such project is available, please contact the originator for revised criteria.

RESPONSE 6:

The provided attachments contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583.

Line 2000W has been identified as a sample PSEP project meeting the listed criteria.

a. For the Stage 3 Cost Estimate please see attachment, *Q6a Line 2000 West Stage 3 Estimate.pdf.*

b. For Initial Work Order Authorizations and subsequent changes, please refer to Q6b attachments.
    - *Q6b 2000-W Phase 1 WOA CONFIDENTIAL.pdf*
    - *Q6b 2000-W Phase 1 WOA Revised_CONFIDENTIAL.pdf*
    - *Q6b 2000-W Phase 2 WOA CONFIDENTIAL.pdf*

c. For Line 2000W, the contractor was selected under the Performance Partner Program, which includes a scope of work for multiple projects. For contract information, please refer to the Q6c attachments.

The Line 2000W project is comprised of multiple sections, resulting in the multiple attached work authorizations and amendments. Pre-construction work, as defined in the scope of work within the applicable attachments, was performed by ARB and Southwest Contractors on Line 2000W. Pre-construction work occurs prior to the establishment of the Target Price, so the work is issued as a separate contract. The Line 2000W construction work was performed under the Performance Partnership concept and was assigned to ARB. Target Prices were established for each section and are detailed within the compensation schedule of each work authorization. This is consistent with the Performance Partner concept and consistent with other projects performed under the Performance Partner concept.

d. For current and most recent status reports for Line 2000 West providing schedule, Estimate at Completion (EAC), and Estimate to Complete (ETC), please refer to the Q6d Attachments. Please note that the costs presented reflect the schedule and fully loaded costs as of June 2015.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-14)
Date Requested: July 1, 2015
Date Responded: July 15, 2015

QUESTION 7:

a. For PSEP hydrotest projects, is Sempra, the construction contractor, or another party responsible for 1) procuring water to fill the pipeline and 2) disposing of water after the test?
b. If the answer above does not apply to all or nearly all PSEP hydrotest projects, please describe how the determination is/will be made for each project.
c. For the Line 2000A hydrotest project, was Sempra, the construction contractor, or another party responsible for procuring water to fill the pipeline and disposing of water after the test? Provide the names of all contractors that performed these activities.

RESPONSE 7:

a. The pipeline contractor is generally responsible for procuring water for use in hydrostatic testing on PSEP projects. Where alternative water sources are used (e.g. recycled water) and/or where water is reused on a project, the Environmental team, which includes utility employees and environmental contractors, leads the effort with support from the Project Execution Team and Construction. The Environmental team, which includes utility employees and environmental contractors manages water disposal for PSEP.

b. The response provided above applies to nearly all PSEP projects.

c. The pipeline contractor was responsible for supplying the hydrostatic test water for the L2000A project. Sections 14/15, 16, and 19 used hydrostatic test water from previous tests on L2000A. In addition, the contractors listed below assisted with water disposal on L2000A. Please note: The contractor names and roles/responsibilities are confidential pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583.
    1. Southwest Contractors – Water Procurement
    2. Rain for Rent – Water Storage and Disposal
    3. Ecology Control Industries – Water transportation and water storage tank cleaning
    4. KVAC Environmental – Water disposal facility
    5. CH2M Hill – Environmental monitors assisted with sampling events and monitoring during water discharge activities.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-14)
Date Requested: July 1, 2015
Date Responded: July 15, 2015

QUESTION 8:

For the Stage 3 Cost estimating tool provided by Sempra in response to ORA-DR-13 Q14 (confidential attachment "Stage 3 SCG Pipeline Estimate Template Rev 2.0 CONFIDENTIAL.xlsm"):

a. What data or analysis did Sempra use to develop the unit costs in the tab 'Material Reference'?
b. What data or analysis did Sempra use to develop the unit costs in the tab 'Replacement Reference'?
c. What data or analysis did Sempra use to develop the unit costs in the tab 'Hydrotest Reference'?
d. What data or analysis is Sempra using on an ongoing basis to improve the accuracy of the unit costs in the tabs mentioned in parts (a) through (c) above?

RESPONSE 8:

a. SoCalGas and SDG&E used historical data to update pipe material pricing.

b. The Replacement Reference unit costs were updated based on historical crew compositions for rural pipeline installation. The cost difference from "Rural Pipeline Replacement" to "Type 2: Secondary Roadway," "Type 3: Primary Roadway," "Type 4: Night Work on Primary Roadway," "Type 5: Jack & Bore," and "Type 6: HDD" were then added to the updated Rural Pipeline cost. Each type was then updated in the stage 3 tool to represent the most current project estimated costs.

c. The Hydrotest Reference worksheet was indexed using the February 2015 Chemical Engineering's Plant Cost Index (CEPCI), to adjust construction labor costs from one period to another.

d. SoCalGas and SDG&E are doing the following on an ongoing basis to update the units costs:
    a. Updating costs based on CEPCI.
    b. Updating materials based on recent purchase orders.
    c. Updating the unit cost basis per activity based on historical cost from similar project types.

QUESTION 9:

Please provide:

a. A spreadsheet of all recorded costs for Line 2000A with columns for each SAP data field, including but not limited to the following:
   - Work Order Number,
   - Internal Order Number,
   - Date cost was recorded,
   - Cost Element Number,
   - Cost description and notes,
   - Vendor name.
b. In the case that the sum of the above costs does not equal the total project recorded costs of $26.37 million provided in the application workpapers,[1] provide an explanation why not.
c. A table that shows the description or name of each cost element number used to date on project 2000A
d. A table that shows the description or name of each cost element number used to date on ALL PSEP projects.

RESPONSE 9:

The provided attachments contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583.

a. Please refer to spreadsheet: *Q9 Line 2000A Recorded Costs Final_Confidential.xlsx*, Tab: ORA DR-14 *Q9a*.

b. $26.37 million comprised project costs up to June 30, 2014. The total project costs of $26.47 million as provided for Q9a include trailing costs and accounting adjustments up to May 31, 2015.

---

[1] Sempra Workpaper “12-12-14 SCG PSEP WP 2000-A _FINAL EDITS.xlsx”, “Cost Summary” tab, cells C29 and D29.

---

c. Please refer to spreadsheet: *Q9 Line 2000A Recorded Costs Final_Confidential.xlsx*, Tab: ORA DR-14 *Q9c* for a cost element name for each cost element number used to date on project 2000A.

d. Please refer to spreadsheet: *Q9 Line 2000A Recorded Costs Final_Confidential.xlsx*, Tab: ORA DR-14 *Q9d* for a cost element name for each cost element number used to date on all PSEP projects.

QUESTION 10:

From the June 24 PSEP Cost-Estimating Workshop, it is ORA's understanding that a cost controller or Project Manager assigns a cost element number to each cost recorded to a project.

a. Is this understanding correct? If not, please explain.
b. How does the responsible party know what cost element number to assign to each recorded cost? To what degree is this assignment discretionary?
c. Please provide any company rules, policies, guidelines, or other documentation providing guidance on this process to the responsible party. If none exists, please state as such.
d. How many cost element numbers exist in Sempra's accounting system?
e. How many cost element numbers in Sempra's accounting system are actively used?

RESPONSE 10:

a. Yes.

b. The project specialist and/or project manager, who reviews and approves the cost element number, receives training on the most commonly used cost elements. Please refer to the attachment in question 10c below for frequently used cost elements. Depending on the department, some cost elements are tailored to the organization. Depending on the cost reviewer/approver's level of expertise and needs, there is some level of discretion on what cost element to use.

c. For company frequently used cost elements, please see attachment "*Q10c Frequently Used Cost Elements.xls.*"

d. Total active cost elements = 5,549

e. For calendar year 2014, SDG&E had charges in 851 cost elements and SoCalGas had charges in 780 cost elements.

QUESTION 11:

In response to ORA-DR-13 Q10, Sempra provided confidential attachment "ORA DR-13 Q10 Final CONFIDENTIAL.xlsx," which shows total costs recorded by SCG and by each contractor for the three completed projects (2000A, Playa del Rey, 42-66-1/2).

a. For each vendor/category with a total recorded cost of great than $100,000, please provide a scope of work and related contracts for the given project.
b. In addition to the vendors listed in part (a), please provide the scope of work and related contracts for the following vendors/categories used for project Line 2000A:
   - Farwest Corrosion Control Co.
   - American Environmental Testing
   - Regional Water Quality
   - State Water Resources
   - U.S. Army Corps of Engineers
   - State of California – Department of *(note: description truncated; please provide full name as well)*
   - Riverside County Flood Control
c. In addition to the vendors listed in part (a), please provide the scope of work and contracts for the following vendors/categories used for project Line 42-66-1/2:
   - Ecology Control Industries
   - Farwest Corrosion Control Co.
   - Westland Group Inc.
d. In addition to the vendors listed in part (a), please provide the scope of work and related contracts for the following vendors/categories used for project Playa del Rey Phase I:
   - Agile 1

RESPONSE 11:

The provided attachments contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583.

a-d. Please refer to Q11 Attachment folder for contract information and scope of work for the vendors listed. The following vendors have permits, not contracts:

- Regional Water Quality Control Board[2]: water discharge permit.
- State Water Resources Control Board: Stormwater Pollution Prevention Plan waiver fee and water discharge permit fee.
- U.S. Army Corps of Engineers – administrative fees to issue a right of entry permit.
- State of California – Department of Transportation: Right of Way encroachment permit
- Riverside County Flood Control – to obtain an encroachment permit to discharge water to the flood control channel.

[2] Two charges from the Regional Water Quality Control Board, totaling $9,651, were booked to Line 2000-A. Upon review, these Regional Water Quality Control Board charges were actually incurred for Line 2000 West. The charges are pending accounting adjustment.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-14)
Date Requested: July 1, 2015
Date Responded: July 15, 2015

QUESTION 12:

a. Does Sempra's PSEP Project Management Office or the PSEP management team report PSEP program status to Sempra management on a routine basis?
b. If the answer to part (a) is yes, to whom, how frequently, and in what format are these reports issued?
c. If the answer to part (a) is yes, please provide the PSEP-level reports described in parts (a) and (b) since PSEP inception.

RESPONSE 12:

The provided attachments contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583.

a. Yes.

b. PSEP Management reports to the PSEP Executive Steering Committee (ESC) via Power Point presentations monthly, and PSEP Working Committee (WC) via email agendas. Please refer to attachment "*Q12a PSEP ESC & WC MEMBERS.pdf*" for a list of the current Executive Steering Committee members and Working Committee members.

c. For copies of the PSEP ESC and WC reports, please refer to Q12c attachments.

QUESTION 13:

a. Do Project Managers report project status of individual PSEP projects to their managers on a routine basis?
b. If the answer to part (a) is yes, to whom, how frequently, and in what format are these reports issued?
c. If the answer to part (a) is yes, please provide the project-level reports described in parts (a) and (b) since the inception of the three completed projects in this application.
d. Is the status of each ongoing PSEP project discussed at regular status meetings? If so, how frequently are these meetings held?
e. If the answer to part (d) is yes, are ETC, EAC, and any changes to these estimates discussed at these meetings?

RESPONSE 13:

a. Yes, Project Managers report the status of individual projects on a routine basis.

b. Project Managers report to the PSEP leadership team, which is comprised of the following individuals:
   - SoCalGas and SDG&E Senior Director,
   - SoCalGas and SDG&E PSEP Project Execution Manager,
   - SoCalGas and SDG&E PSEP Construction Manager,
   - Jacobs PSEP Director, and
   - Jacobs PSEP Execution Project Execution Manager.

   These meetings are generally held every two weeks and a Project Status Report is issued. Meetings are also held on a monthly basis, and a Master PSEP Project Schedule is issued with EAC's.

c. Project Status Reports have been issued every two weeks since August 2014, monthly PSEP Master Schedules have been issued since the second quarter of 2013, and 30-day look-ahead schedules have been provided since January 2015. Please refer to the attachments to Question 13c.

---

d. Yes, project status is discussed at the PSEP Bi-Weekly Project Manager meetings.

e. Yes, significant project changes, such as scope, cost, and schedule, which may impact the EAC or estimated costs are discussed at these meetings.

Line 2000 West Hydrotest

PROJECT SUMMARY

			% of Total Cost	Basis of Cost
SCG Mgmt LABOR	$	265,564.20	1%	Template - General Reference
SCG Union Labor	$	120,000.00	1%	Template - General Reference
ENGINEERING/DESIGN	$	622,110.58	3%	Template - General Reference
PM/Project Services	$	817,227.00	4%	PSE - JWA
PERMITS	$	11,000.00	0%	Template - General Reference
ROW ACQUISITION	$	1,965,178.00	10%	PSE - Land Services
Other Non-Labor Costs	$	103,278.21	1%	Template - General Reference
MATERIAL- Pipe & Fittings	$	526,126.36	3%	Template - Material Reference and N. Gniadek 06.18.2014 Spreadsheet
MATERIAL-Valves	$	77,725.35	0%	Actuals from SM and N. Gniadek
MATERIAL- Other	$	761,823.63	4%	Template - Material Reference, N. Gniadek 06.18.2014 Spreadsheet, and Vendor Quote
CONSTRUCTION CONTRACTOR	$	6,099,302.40	31%	Template - Hydrotest and Replacement Reference
MOBILE EQUIPMENT	$	-	0%	-
PAVING	$	29,600.00	0%	Template - General Reference
WATER ACQUISITION	$	312,404.46	2%	Template - Hydrotest Reference
WATER STORAGE/DISPOSAL	$	1,629,100.00	8%	PSE - Environmental
CNG/LNG	$	-	0%	-
XRAY/NDE	$	101,866.50	1%	Factored Estimate from 2000-A
SURVEYING/ASBUILTS	$	581,255.00	3%	Template - General Reference and PSE - Surveying
CONSTRUCTION MANAGEMENT	$	3,226,190.00	17%	PSE - JWA
ENVIRONMENTAL	$	240,000.00	1%	PSE - Environmental
CONTAMINATION MITIGATION	$	113,000.00	1%	Template - General Reference
CONTINGENCY 10%	$	1,760,275.17		
Sub-total Cost (w/o OHAP)	$	19,363,026.85		
OHAP	$	2,301,435.40		
Total	$	21,664,462.25		

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-16)
Date Requested: July 6, 2015
Date Responded: July 20, 2015

QUESTION 1:

Please provide the following for the Line 2000-West, Line 2000C, and Line 2000-Bridge projects:

a. Work Order Number

b. Work Order Authorization

c. Any revisions to the Work Order Authorization

d. Current project status

e. Most recent presentation, document, or report listing and explaining Estimate to Completion (ETC)

RESPONSE 1:

a. Work Order Numbers

Line	External order no.
Line 2000-B	B91011.000
Line 2000-C	B91110.000
Line 2000-C	B26094.000
Line 2000-D[1]	B91119.000
Line 2000-D	B26155.000
Line 2000-West	B91035.000
Line 2000-West	B25736.000

[1] Since SoCalGas and SDG&E's Supplemental filing, Line 2000-C has been separated into two projects for operational and implementation reasons. These projects are now identified as Line 2000-C and Line 2000-D. Line 2000-D will address the sections of Line 2000 between Whitewater and Moreno Valley.

b. The provided attachments contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583. For a copy of the Work Order Authorizations (WOAs) please refer to the Q1 Attachments folder.

c. The provided attachments contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583. For a copy of revisions to the WOAs please refer to the Q1 Attachments folder.

d. Current project status is provided in the monthly PSEP reports published on the SoCalGas/SDG&E's websites. The most recent status report was published in June for May 2015 activity.
http://www.socalgas.com/regulatory/R11-02-019.shtml

http://www.sdge.com/regulatory-filing/469/gas-pipeline-safety-order-instituting-rulemaking-2011

e. Please refer to the Q1 Attachments folder for a current list of Estimate to Completion (ETC) documents for Line 2000-West, Line 2000C, and Line 2000-Bridge projects. Please note the documents presented reflect the schedule and fully loaded costs as of June 2015.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-16)
Date Requested: July 6, 2015
Date Responded: July 20, 2015

QUESTION 2:

Please provide a list of all change orders for the Line 2000-West, Line 2000C, and Line 2000-Bridge projects. The list should include change order number, date, and a brief summary/description.

RESPONSE 2:

Line 2000C and Line 2000-Bridge have not entered construction and therefore do not have any construction change orders.

Line 2000-West does not have any approved construction change orders. Construction change orders are currently being negotiated.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-16)
Date Requested: July 6, 2015
Date Responded: July 20, 2015

QUESTION 3:

Please provide:

a. The CV or resume of the internal estimator (Ron Bott) who created the confidential September 2012 Line 2000A estimate.[2]

b. A description of Mr. Bott's estimating experience.

RESPONSE 3:

a. The provided attachment contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583. For a copy of Ron Bott's resume please refer to the Q3 Attachments folder.

b. Mr. Bott has prepared cost estimates for numerous projects as a Project Manager and has overseen the preparation of cost estimates for other Project Managers and Company Planners. Mr. Bott's estimating experience is a compilation of over 40 years experience in transmission operation and maintenance, transmission pipeline construction, construction inspection, design and lead project manager of many large new transmission pipeline installations, pipeline replacements and hydro testing of new and existing pipeline and components. Mr. Bott has prepared the cost estimates for these projects as well as the detail design drawings and material requirements, prepared bid documents and solicited bids from contractors and managed the overall project and project budget. Mr. Bott has experience working in most of SoCalGas' territory and has worked with most of the Cities, Counties and State agencies to acquire project permitting, including overseeing the preparation of California Environmental Quality Act (CEQA)/National Environmental Policy Act (NEPA) documents for environmental permitting, construction management and startup operations.

[2] "2000 Blythe to Hwy 71Cost Est Worksheet.xls"; provided in response to ORA-DR-13 Q12.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-16)
Date Requested: July 6, 2015
Date Responded: July 20, 2015

QUESTION 4:

Please describe the design status of the Line 2000A project at the time the confidential September 2012 Line 2000 estimate was completed (September 7, 2012). At a minimum, please include the status of:

a. Project design status, including the status and percentage complete of the engineering drawing package

b. Development of contractor bidding/bid-selection process

c. Contracting for work on or related to Line 2000A

d. Acquisition of permits and rights-of-way for Line 2000A

e. Hiring directly related to Line 2000A

f. Charges to all work orders associated with the Line 2000A project, including but not limited to WO# 25325

RESPONSE 4:

a. At the time of the 2012 estimate, (1) a preliminary survey had been completed to identify the location of the proposed test and replacement sections; and (2) profile information for elevation data and general base maps had been developed to identify pipe segment locations. Because detailed engineering design had not yet been conducted, the engineering drawing package had not yet been started.

b. In September 2012, the status of contracting for Line 2000-A is as follows:
   - Contract for Line 2000 survey work was executed in July 2012.
   - Contract for pipeline design work executed with engineering design contractor in September 2012.

c. No construction contractor had been selected for Line 2000-A in June 2012. At the time of the September 2012 estimate, no permits or right of way had been acquired. The estimates for permits and right of way were based on preliminary field review of locations (e.g., determination if in SCG ROW, public roadway, private property or state or federal lands). The estimates for permits and ROW were based on the project manager's past experience.

d. At the time of the September 2012 estimate, there were no additional hires directly related to Line 2000-A.

e. The provided attachments contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583. For a copy of all charges associated with Line 2000A as of September 2012, please refer to the Q4 Attachments folder.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-16)
Date Requested: July 6, 2015
Date Responded: July 20, 2015

QUESTION 5:

Confidential Change Notice 083 (provided in response to ORA-DR-13 Q12) stated "Line 2000 has been broken into 4 individual projects: 2000-A, 2000-Bridge, 2000-C, 2000-West." The Change Notice also stated "New Cost: $12,728,000 (This cost is for one of the 4 projects which make up Line 2000 cost $37,989,000."

a. Do similar change notices (relating to the described division of Line 2000) that provide revised costs for Lines 2000-Bridge, 2000-C, and 2000-West exist? If so, please provide.

b. If the answer to part (a) is no, how did the author and approver of Change Notice 083 arrive at the $37,989,000 cost? Please provide any supporting documentation.

c. If not readily discernable from the document(s) provided in parts (a) and (b) above, please provide the total "New Cost" or similar cost metric for lines 2000-Bridge, 2000-C, and 2000-West with any supporting documents.

d. If the sum of $12,728,000 and the three "New Costs" of the three lines mentioned in part (c) above does not total $37,989,000, please explain why.

RESPONSE 5:

The provided attachments contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583.

a. Yes, similar change notices do exist. Please refer to the Q5 Attachments folder for change notices.

b. Not Applicable.

c. The "New Cost" is readily discernable based on the documents provided in part a above.

d. The summation of $12,728,000 and the three "New Costs" is equal to $37,989,000. These costs are from the 2011 estimate prorated by mileage for each of the projects.

QUESTION 6:

Please provide the scope of work included in the confidential 2012 Line 2000 estimate. Specifically:

a. Does the scope of the confidential 2012 Line 2000 estimate include any of the scope of Line 2000-West? If so, please explain.

b. Does the scope of the confidential 2012 Line 2000 estimate include any of the scope of Line 2000-Bridge? If so, please explain.

c. Does the scope of the confidential 2012 Line 2000 estimate include all or nearly all of the scope of Line 2000A? Please explain.

d. Does the scope of the confidential 2012 Line 2000 estimate include all or nearly all of the scope of Line 2000C? Please explain.

RESPONSE 6:

a. No, the 2012 estimate did not contain costs for Line 2000 beyond the west end of Chino 19 in Prado Dam north of Hwy 71.

b. The 2012 estimate did not contain costs for the 2000-Bridge. The estimate for B-1 was at River Station, west of the bridge to Blythe Station.

c. Yes, the September 2012 estimate included nearly all of the scope for 2000A. In the September 2012 estimate, SoCalGas had identified 19 test sections and approximately 1,000 feet of replacement.

d. Yes, the September 2012 estimate includes nearly all of the scope for Line 2000-C (2000 at the time) (east of Line 2000-A), including Cabazon, Palm Springs, Thousand Palms and Blythe. Line 2000-C current scope includes Cabazon, Palm Springs, and Thousand Palms.

QUESTION 7:

It is ORA's understanding that the confidential September 2012 cost estimate document[3] for the Line 2000 project encompasses the entire estimate and that no supporting or supplemental documents exist. Is this understanding correct? If not, please explain and provide any such documents.

RESPONSE 7:

ORA's understanding is partially correct. The September 2012 estimate document contains all of the 2012 estimate data.[4] However, in developing the September 2012 estimate, SoCalGas did utilize other supporting documents containing pipeline data. Specifically, SoCalGas used High Consequence Area (HCA) drawings to identify the proposed segments in HCA areas and a Line 2000 test segment length spreadsheet (developed using the HCA drawings and a Feature Study) to determine appropriate test segmentation. The HCA drawings were previously provided in ORA Data Response 15-9. The provided attachments contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583. Please refer to the Q7 Attachments Folder for the test segment length spreadsheet.

Note: There are no 30-inch pressure control fittings or temporary or permanent by-pass lines in the cost estimate. Engineering review of the taps had not yet been completed.

---

[3] "2000 Blythe to Hwy 71Cost Est Worksheet.xls"; as provided in response to ORA-DR-13 Q12.
[4] As discussed in Response 18 below, however, there were subsequent estimates.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-16)
Date Requested: July 6, 2015
Date Responded: July 20, 2015

QUESTION 8:

It is ORA's understanding that the confidential September 2012 cost estimate document contains no explicit overall pipeline or project length information. Is this understanding correct? If not, please explain and provide a cell reference to an explicit total length.

RESPONSE 8:

ORA's understanding is correct. The estimate identifies 19 test sections. The verbal cost/pricing obtained from contractors was per test and replacement section, not based on length.

(DATA REQUEST ORA-PSRMA-SCG-16)
Date Requested: July 6, 2015
Date Responded: July 20, 2015

QUESTION 9:

It is ORA's understanding of the confidential September 2012 cost estimate document that one must "back-calculate" project length using water volume provided in row 248 and the pipe diameter of 30".

a. Is this understanding correct?

b. Is the unit of measurement in Cell E248 "dollars per one hundred cubic feet"?

c. What is the unit of measurement of the quantity in Cell C248?

d. Does Sempra agree that using 1) the formula for the volume of a cylinder, 2) a pipe diameter of 30", and 3) the volume of water of 5,000,000 **100-ft^3**, one arrives at a project length of 19,291.508 miles? If not, please explain and show calculations.

e. Does Sempra agree that using 1) the formula for the volume of a cylinder, 2) a pipe diameter of 30", and 3) the volume of water of 5,000,000 **ft^3**, one arrives at a project length of 192.915 miles? If not, please explain and show calculations.

f. Does Sempra agree that using 1) the formula for the volume of a cylinder, 2) a pipe diameter of 30", and 3) the volume of water of 5,000,000 **gallons**, one arrives at a project length of 25.789 miles? If not, please explain and show calculations.

g. Which of the above three calculations (parts (d), (e), and (f)) accurately calculates the length of pipe in the 2012 estimating tool? If Sempra does not agree that any of the calculations in parts (d), (e), and (f) provide this length, please provide the mathematical calculation showing the pipeline length that the September 2012. Please include units, state any assumptions, and explain any corrections.

RESPONSE 9:

a. Yes. Back-calculating using water volume does provide the approximate length. The water volume in row 248 is calculated based upon the estimated length of 30-inch pipe to be replaced or hydro tested in the original scope of work, Blythe to Chino. The estimated length of 30-inch pipe to be hydro tested including replacement sections at the time of the estimate was approximately 26 miles.

b. Yes, dollars per 100 cubic feet, however that formula was not used. The water cost quote was obtained from contractors (.05 and .06 per gallon was used). *See* Cell D248XC248.

c. The unit of measurement is gallons.

d. The unit of measure of 100ft^3 is incorrect. The unit of measure should have been changed to gallons.

e. The unit of measure of ft^3 is incorrect. The unit of measure should have been changed to gallons.

f. SoCalGas calculates 25.755 miles. Diameter^2 x pi, divided by 144 x length x 7.48 = gallons per foot. (15X15) = (225 x 3.1459)/144= 4.915 x1x7.48= 36.76.

   5,000,000/36.76 = 136,017/5,280 = 25.755 miles

g. Of the three methods (parts (d), (e), and (f)), the calculation method used in response (f) is the most accurate method to calculate the length of 30-inch pipe segments used in the cost estimate. In the supporting document provided in Q7 attachments “Line 2000 test segment length spreadsheet”, an estimated mileage of 28.74 miles was further adjusted downward to 25.484 miles to remove portions of B1, Chino 19, and all of Chino 20. The actual length used in the estimate is the footage calculated to be water-filled and tested, which totaled 25.484 miles equating to 4,701,369 gallons of water, rounded to 5,000,000 gallons.

QUESTION 10:

Sempra's response to Question 9 (above) will clarify the length of pipe included in confidential September 2012 cost estimate document for Line 2000. Please explain how this length compares to the scope of work for Project 2000A and all other projects on Line 2000, and provide supporting documentation.

RESPONSE 10:

The final length of 2000A was approximately 15 miles. The remaining mileage for line 2000 is outlined in the table provided in the response to question 17 below.

QUESTION 11:

Does the September 2012 cost estimate for Line 2000 include both capital and O&M expenses (specific to Line 2000)? If not, please explain and provide all documents showing estimates for any expenses or capital expenditures not included.

RESPONSE 11:

Yes. The September 2012 cost estimate includes both O&M costs and Capital costs.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-16)
Date Requested: July 6, 2015
Date Responded: July 20, 2015

QUESTION 12:

It is ORA's understanding that the authority to issue Change Orders lies with Project Managers and is discretionary.

a. Is this understanding correct? If not, please explain.

b. Please provide any rules, formal procedures, and other guidance that Sempra provides to Project Managers (and other responsible parties) to determine when a Change Order should be issued.

RESPONSE 12:

a. No. The Contractor initiates the construction change order process and then the Project Management Team is responsible for reviewing the change(s) with the Contractor.

b. The provided attachments contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583. Please refer to the Q12 Attachments folder for "*Q12b CONFIDENTIAL SP 0306 Change Order Management.pdf*" for a copy the procedure in effect prior to June 12, 2014. The current Change Order Management procedure was revised and last approved in June of 2015.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-16)
Date Requested: July 6, 2015
Date Responded: July 20, 2015

QUESTION 13:

In developing the 2012 estimate for the Line 2000 project, what data or analysis did Sempra use to develop unit costs?

RESPONSE 13:

The construction contract pricing was obtained by verbal quotes from contractors for hydrotesting and replacement costs for typical sections. The Project Manager (PM) used past experience to price labor, third party services, and non-labor costs. Verbal quotes were obtained from contractors for line pipe. Other materials were estimated based on PM's past pricing experience**.**

QUESTION 14:

What value does Sempra derive from estimating tools if individual costs or costs categories cannot be compared to final/actual spending?

RESPONSE 14:

The estimating tools are used to enhance project decision-making, enable funding authorizations, and improve consistency across projects.

Also, to clarify, SoCalGas' estimating tools are based on actual cost experience. PSEP will be implementing methods to better capture cost items by taking into consideration final/actual spending to align with the cost elements of the estimating tool with the intent of increasing the accuracy of the tool.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-16)
Date Requested: July 6, 2015
Date Responded: July 20, 2015

<u>QUESTION 15:</u>

Please review Attachment 1[5] and Attachment 2[6] to ORA-DR-16 Q15 (this DR question). As noted in Attachment 1 (data request response), PG&E notes that Attachment 2 was erroneously marked confidential. Pages 3 and 4 of Attachment 2 show PG&E's analysis of selected hydrotest projects broken down by cost category and amount.

Attachment01-
GTS-RateCase2015_I

Attachment02 -
GTS-RateCase2015_I

a. Does Sempra have any similar analysis or benchmarking studies for any of its PSEP projects? If so, please provide.

b. Does Sempra have any similar analysis or benchmarking studies for any the completed projects in its Application? If so, please provide.

c. If the answer to part (a) is no, does Sempra have plans to develop any similar analysis for future PSEP projects?

<u>RESPONSE 15:</u>

a. No.

b. No.

c. Yes. No specific timeline has been established.

---

[5] PG&E Response to ORA-DR-59 Q23 in A. 13-12-012 (Gas Transmission and Storage Case).
[6] Attachment 1 to PG&E Response to ORA-DR-59 Q23 in A. 13-12-012 (Gas Transmission and Storage Case).

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-16)
Date Requested: July 6, 2015
Date Responded: July 20, 2015

QUESTION 16:

It is ORA's understanding that, of the Line 2000 project, the Line 2000A project, the Line 2000-Bridge project, the Line 2000C project, and the Line 2000-West project, 1) only the Line 2000 project existed at the time of Sempra's original 2011 PSEP filing and 2) that the Line 2000 project no longer exists. Is this understanding correct? If not, please explain.

RESPONSE 16:

Yes, ORA's understanding is correct.

QUESTION 17:

Please provide an active spreadsheet with the following information:

a. In column A, the names of all projects (current and past) on Line 2000 (e.g. “Line 2000”, “Line 2000A”, “Line 2000-West”, “Line 2000C”, and “Line 2000-Bridge”).

b. In column B, each corresponding project’s mileage in Sempra’s original 2011 PSEP filing.

c. In column C, each project’s mileage at the time it was split from Line 2000.

d. In column D, the date that the split described in part (c) occurred.

e. In column E, each project’s most recent mileage.

f. In column F, the date that the data in column E reflects. If the information in any cells is incomplete, unavailable, or otherwise absent (excepting as reflects the understanding described in Question 17, if correct), please explain.

RESPONSE 17:

a-f Please refer to the Q17 Attachments folder for Line 2000 Project Information. Note: Since SCG/SDG&E’s supplemental filing, the project initially identified as Line 2000-C has been separated in Line 2000-C and Line 2000-D for operational and implementation reasons. Line 2000-D will address the sections of line 2000 between Whitewater and Moreno Valley.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-16)
Date Requested: July 6, 2015
Date Responded: July 20, 2015

QUESTION 18:

It is ORA's understanding that the confidential September 2012 estimate for Line 2000 is the most recent estimate for (or closely related to) Line 2000A.

a. Is this understanding correct? If not, please explain and provide any more recent estimates.

b. If the answer to part (a) is yes, please explain why Sempra's cost submitted in this application ($26,374,877)[7] exceeds Sempra's most recent estimate ($21,317,255.50[8]).

RESPONSE 18:

a. No. The 2012 September estimate is the estimate prepared for the Phase 2 Work Order Authorization. There were subsequent change notices, estimates, and a later Work Order Authorization (issued in November 2013 towards the end of construction for $28,008,484). The provided attachment contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583. See attached documents for the WOA details. For additional information on the project budget and associated estimates, please refer to Hugo Mejia's Amended Revised Supplemental testimony pages 24-27.

b. Although the answer to part (a) is "no," this request may benefit from some clarification.

   First, the $26,374,877 submitted in this application includes indirect costs. The $21,317,255.50 estimate referenced by ORA is a direct cost estimate that does not include indirect costs or a contingency. The fully loaded Phase 2 Work Order Authorization totals $25,428,180.

   Second, the WOA was later updated in November 2013, increasing the WOA to $28,008,484. Please refer to Hugo Mejia's Revised Amended Supplemental

---

[7] Sempra Workpaper "12-12-14 SCG PSEP WP 2000-A _FINAL EDITS.xlsx," "Cost Summary" tab, cells C29 and D29)
[8] Confidential attachment "2000 Blythe to Hwy 71Cost Est Worksheet.xls" provided in response to ORA-DR-13 Q12.

Testimony pages 24 through 28 for a discussion of the budget and estimate changes for Line 2000A. Briefly, after Line 2000A construction began, there were additional unanticipated costs resulting from changes to the project's scope; individual construction change orders; and increased project management oversight costs, easement costs, water management costs, engineering costs, and PSEP GMA costs.

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	ORA_059-23		
PG&E File Name:	GTS-RateCase2015_DR_ORA_059-Q23		
Request Date:	June 3, 2014	Requester DR No.:	ORA-GT&S-59
Date Sent:	June 24, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Bennie Barnes	Requester:	Tom Roberts

SUBJECT: HYDROTEST EXPENSE COST ESTIMATE

Note for all questions: In many of the following requests, a basis question is asked which is followed by more detailed questions in sub questions labeled a, b, c, etc. All parts of the question must be addressed, including the basic question, for the response to be considered complete. All references to pages, figures, and tables are to the application and workpapers filed December 19, 2013 in this proceeding unless otherwise noted. Provide all files in their native format. Where files are linked, provide files grouped such that links can remain active. If links cannot be maintained, explain why and provide versions of the files that provide the maximum degree of functionality, e.g. active formulas, macros, and links within files.

QUESTION 23

Describe the steps PG&E undertook to review cost drivers for PSEP hydrotesting in an effort to reduce GT&S costs and provide supporting documentation.

ANSWER 23

The attachments included herewith were erroneously marked privileged/confidential.

PG&E has incorporated cost savings drivers from Pipeline Safety Enhancement Plan (PSEP) hydrostatic testing in its Gas Transmission and Storage (GT&S) hydrostatic testing costs through incorporation of use of the PSEP actual unit costs for the development of its GT&S Rate Case cost forecasts.

In 2012 and 2013, the hydrotest program developed a number of initiative ideas on process improvements that could reduce the costs for hydrostatic testing. These initiatives were explored and in some cases implemented. These initiatives were tracked and rough estimates as to their cost savings were developed when possible, although PG&E has found it difficult to forecast for each individual initiative in most cases. Attached are the tracking sheets for cost initiatives developed by the hydrotest program as GTS-RateCase2015_DR_ORA_059-Q23Atch01 and GTS-RateCase2015_DR_ORA_059-Q23Atch02. Implementation of these initiatives has partially enabled a reduction in recorded unit costs for hydrostatic testing during the PSEP years.

PG&E Hydrostatic Test Program Cost Reduction Update

October 26, 2012

Update on Cost Reduction Plan

Accomplishments

- Continued to refine bid management process and tools to drive operational efficiencies
  - Standardized bid evaluation form to drive consistent evaluation methods
- Continued to drive cost savings opportunities through operational process improvements
  - Refined water sampling process by collecting filtered water samples in parallel with leak test samples
  - Acquired and deployed higher capacity filtration systems
  - Reduced cycle time for water sample analysis
- Piloted and continued to refine 4 cost reduction activities:
  - Completed Training on improved STPR (P15)
  - Piloting of Rail Cars for Water Management (E1)
  - Procurement of PG&E Baker Tanks (E19)

Challenges

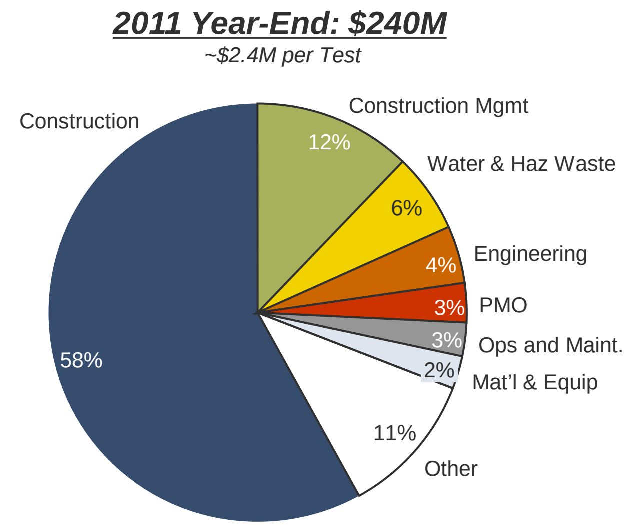
- Realization of cost savings requires ongoing change management, process refinements, and frequent check-ins

Next Steps

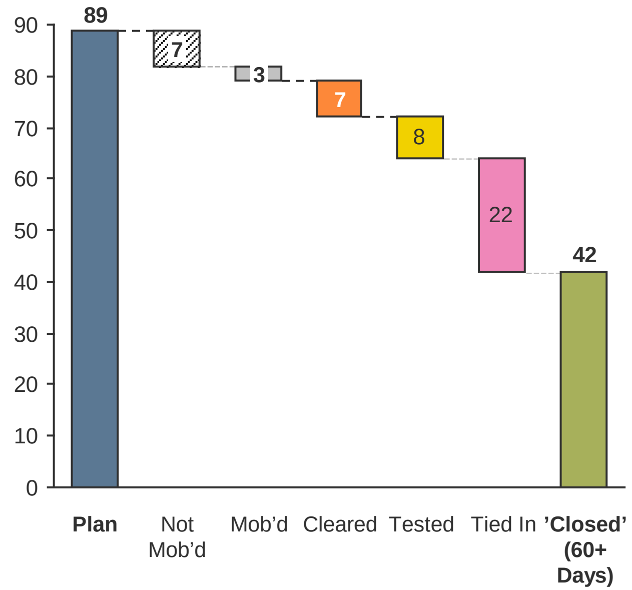
- Incorporate 2012 actual cost data for Replacement and RIM Data into decision-tree
- Complete engineering to IFB-level for 2013 projects to enable planning for next-year work
- Drive completion of remaining cost reduction initiatives, including strength tests records review, Implementation of improved STPR, and water management processes

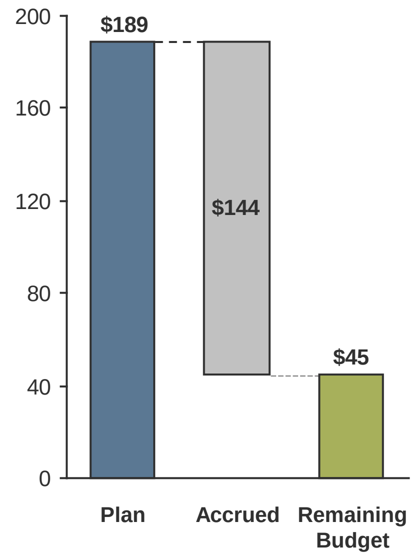
Comparison of 2011 and 2012 Hydrotest Costs

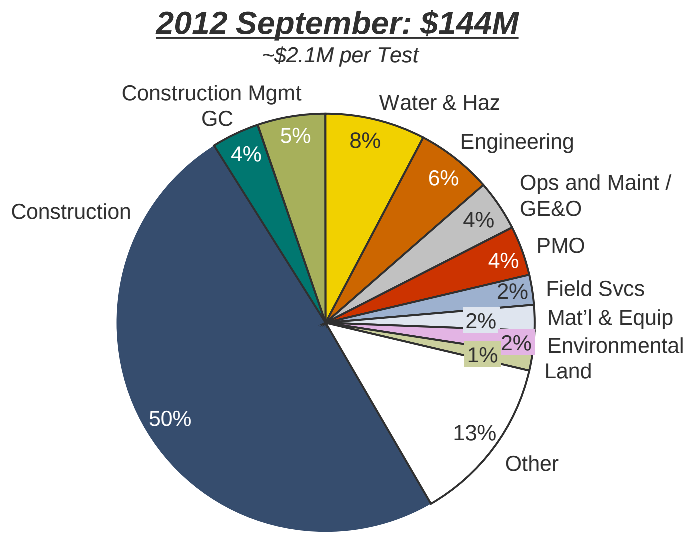
- **Construction Costs and Construction Management accounted for 70% of total spend in 2011 – Compared to ~60% of 2012 Spend by end of September**
- **Land and Environmental, and Clearance costs have significantly increased as noticeable categories of spend, whereas they had previously been in the bottom 1`% of "Other" Spend**



STATUS OF JOBS RELATIVE TO 'BURN' RATE



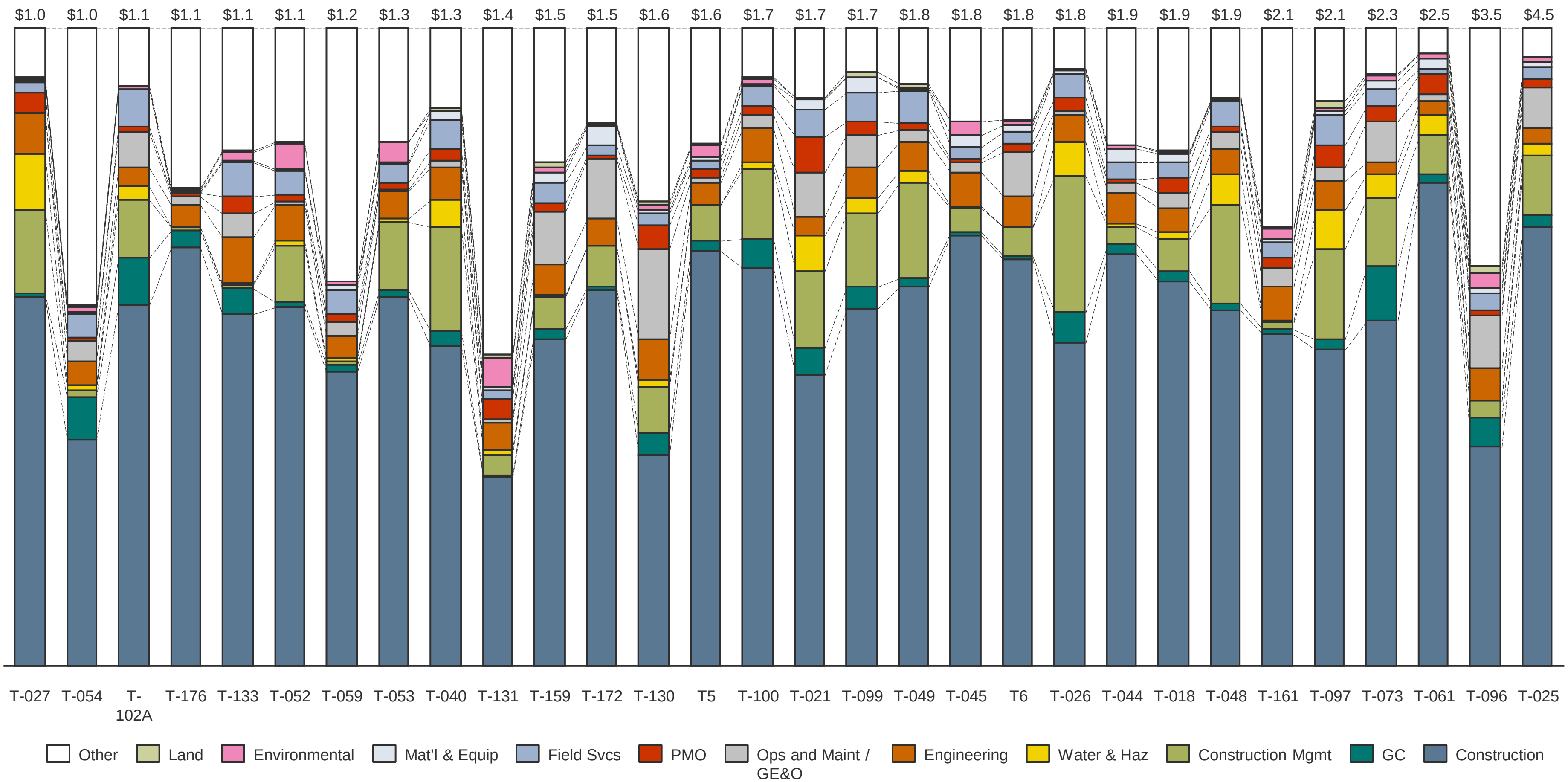




Breakdown of Costs for 'Closed' Hydrotests:
GTS-RateCase2015_DR_ORA_059-Q23Atch01
Total Cost Still Driven by Construction / CM Costs

- **Construction and CM costs are principal driver on most-expensive tests**
- **Individual categories of overhead tend to stay proportional to total overhead**

COST BREAKDOWN OF TOP-30 'CLOSED' TESTS FROM 2012



<u>Note</u>: Benchmark of 60 days past Tie-In used for general Financial Close, though no jobs are strictly closed.

Hydrostatic Test Program

Planning

	Cost Driver	Lever	Proposed Change for 2012	Expected Benefits	Implementation Timing/Owner	Status	Estimated Savings
P1	Strength Test Records Review*	P	Perform a thorough records search and engineering review for each test during the initial planning phase	Cost avoidance	3Q2012 / Campbell	Records for 24.5 miles have been verified and removed from scope. Records verification for 2-4 miles are ongoing.	$ 11,500,000
P2	Destructive Testing*	P	Only conduct destructive testing on pipe based on linear indication or anomaly or when pipe data characteristics are unknown	Cost savings from ATS	3Q2012 / Campbell	Closed. Program will continue to perform destructive testing. No cost savings expected.	$ -
P3	H-Form*	P	Collect full H-form for any leaks, ruptures, or anomalies	Cost savings from GE	1Q2012 / Campbell	Complete. Program will collect full H-forms for all test segments	$ -
P4	Test Procedure Certification*	P	Expand RCP's roles to certify execution of hydrostatic test plan for every test; Do not engage Bureau Veritas for 2012 work	Cost savings from BV	January 2012 / Campbell	Complete. Secured RCP concurrence to perform certification going forward; Defining specific scope of work	$ 1,183,000
P5	Automated Ball Indentation (ABI) Test*	R	Only use ATC's ABI test when the pipe data (i.e., grade or mechanical properties destructive testing) is needed	Cost savings from ATC:	1Q2012 / Campbell	Complete. Program will not implement ABI testing on hydrostatic test segments	$ 587,000
P6	Test Pressure Verification*	P	Engage Kiefner and Associates for subject matter expertise input in unique test situations	Cost savings from Kiefner and Associates	1Q2012 / Campbell	Complete. Program will limite test pressure verification by Kiefner and Associates	$ 42,000
P7	Work Hours*	P	Plan construction to be 5 ten-hour periods on weekdays. Use overtime and weekend work sparingly.	Cost savings	February 2012 / Mannie	Complete. Both clearance schedule and technical specification incorporate 5 ten-hour periods; Base schedule assumes no weekends nor holidays	$ 6,000,000
P8	Engineering and Permitting Duration*	P	Rank each test project as H/M/L based on engineering and permitting durations from 2011; Build timelines in the 2012 schedule	Increased schedule attainment; Cost savings from reduced downtime	Complete	Complete for the initial 2012 PSEP work scope, including Integrity Management work	$ 3,000,000

** High-priority activities with near-term cost reduction opportunities*

	Cost Driver	Lever	Proposed Change for 2012	Expected Benefits	Implementation Timing/Owner	Status	Estimated Savings
P9	Test Execution Planning	P R	Plan multiple tests on a single pipeline route consecutively for more effective utilization of water and construction resources	Better utilization of crew and resources; Cost savings through reduced set-up costs	2Q2012 / Campbell	Complete for the initial 2012 PSEP work scope, including Integrity Management work; Work ongoing	$ 300,000
P10	Test Length Optimization	P	Optimize test lengths by including additional untested pipeline planned for Phase 2	Reduces overall program costs without increasing 2012 costs	2Q2012 / Campbell	Complete for the initial 2012 PSEP work scope, including Integrity Management work	
P11	Short-Length Tests	CP	Re-evaluate decision tree's cost assumptions for hydrostatic testing, and develop revised criteria for deciding between testing or replacing segments	Cost savings	3Q2012 / Campbell	Detailed cost analysis ongoing pending collection of replacement and RIM Project data	
P12	Pigging Technology	P T	Leverage industry experts to identify pigs and cleaning solutions to minimize cleaning runs	Time and cost savings	3Q2012 / Campbell	Complete. Mercury Assessment & Cleaning (MAC) team continues to provide cleaning guidance	
P14	Unclear Procedures	T	Standardize processes documented in procedure manual	Standardized processes; Clearly defined roles	1Q2012 / Magallones	Complete	$ -
P15	Unclear STPR	T	Revise STPR and hydrostatic test standards to include ramp test pressures	Reduce QA/QC and re-work time	2Q2012 / Campbell	Engineers have been trained, but form has not yet been fully implemented.	
P16	Unclear Roles & Responsibilities	T	Establish clear roles and responsibilities for Construction organization; Communicate expectations to organization	Clarity of organizational structure and functional responsibilities	February 2012 / Mannie / Moreland	Complete. Preliminary organizational structure distributed; Defining roles & responsibilities	$ -

* *High-priority activities with near-term cost reduction opportunities*

	Cost Driver	Lever	Proposed Change for 2012	Expected Benefits	Implementation Timing/Owner	Status	Estimated Savings
P17	Lack of Training	T	Develop program-wide onboarding process for PG&E and contractor resources	Clear roles and responsibilities	1Q2012 / Moreland	Contractor training delivered to construction contractors in May; Program orientation delivered in 1Q2012	$ -
P18	Repair Costs	P T	Evaluate newer technologies (i.e., freezer plugs); Evaluate cost reduction process changes (i.e., tracer gas)	Reduces repair costs (Not a reduction from 2011 costs but could reduce expected 2012 repair costs if the frequency of ruptures or leaks increases)	2Q2012 / Campbell	Engineering team continues to evaluate freezer plugs; Completed contract with Praxair to provide tracer gas support	

* *High-priority activities with near-term cost reduction opportunities*

Hydrostatic Test Program

GTS-RateCase2015_DR_ORA_059-Q23Atch01

Resource Management

	Cost Driver	Lever	Proposed Change for 2012	Expected Benefits	Implementation Timing/Owner	Status	Estimated Savings
R1	Allocation of Functional Team Members	R	Divide tests into four regions and appoint Regional Leads to coordinate and manage work in each of these regions	Better utilization of resources within each of the four regions and better coordination	Complete	Complete. Engineering, Customer, Land, Environmental, and Project Managers have all been assigned to specific regions	$ -
R2	Construction Coordination Resources*	R	Consolidate construction coordinator supervisor roles; Define roles and responsibilities	Cost savings through productivity gain	February 2012 / Bigras	Complete. Preliminary structure defined; Job descriptions for CCS, Inspectors and PCs completed	$ -
R3	Inspection Resources*	R	Expand inspection staff assignments to span multiple test segments; Define expectations for responsibilities	Cost savings through productivity gain	February 2012 / Bigras / Moreland	Completed organization charts and process maps	$ -

** High-priority activities with near-term cost reduction opportunities*

	Cost Driver	Lever	Proposed Change for 2012	Expected Benefits	Implementation Timing/Owner	Status	Estimated Savings
D1	Timeliness of Engineering Package for Construction for 2012 Work*	R	Complete Issued-for-Bid drawings for 2012 work by April 2012; Complete issued-for Construction drawings for 2012 work by June 2012	More complete bid packages for more accurate bids and less change orders	January 2012 / Campbell	Complete. Completion of 2012 drawings on track for 3Q2012; Developed preliminary scope for 2013 work	
D2	Incomplete Job Packages*	R	Release near-complete job packages to contractors for estimated pricing	Improved bid accuracy; Reduced change orders; Cost savings	March 2012 / Campbell	Complete. Provided IFB drawings, test procedures, and detailed water management plan for preliminary bids	$ 3,000,000
D3	Lack of Test Segment Estimates	P R	Prepare a job estimate for each individual hydrostatic test; Refine estimate model throughout hydrostatic test cycle	Improved cost estimate data to support proactive cost management	January 2012 / Campbell	Complete. Developed job estimate model from 2011 bid data; Continuing to refine estimate model as bid packages and actual data are received	$ -
D4	Timeliness of Engineering Package for Construction for 2013 Work	P R	Complete the scope and engineering of 2013 work in 2012	More efficient planning and preparation for construction in 2013	4Q2012 / Campbell	Developed preliminary scope for 2013 work; Engineering still expected to complete 30-40% of 2013 IFB drawings by end of year.	

* *High-priority activities with near-term cost reduction opportunities*

	Cost Driver	Lever	Proposed Change for 2012	Expected Benefits	Implementation Timing/Owner	Status	Estimated Savings
S1	Time & Materials Contracts*	P R	Leverage fixed cost contracts for all test segments; Bundle test segments to gain cost efficiencies; Deploy standardized processes for bid management; Align with PSEP bid package timelines and scope when appropriate	Cost savings	January 2012 / Moreland	Complete. Defined plan for competitive bids for all 2012 tests; Released 18 packages for competitive bidding	
S2	Contractor Resource Constraints*	R	Expand bidding group to 5-8 qualified construction contractors to increase competition	More competitive construction bids; Reduced overtime spend	1Q2012 / Villar	Complete. Expanded set of qualified construction contractors to 5; Additional qualifications underway	$ -
S3	Change Order Management*	C P	Deploy change order management process to provide efficient resolution to change orders for scope or funding	Improved cost management; Cost savings	February 2012 / Moreland	Complete. Deployed change order management process; CM tool under development	

* *High-priority activities with near-term cost reduction opportunities*

GTS-RateCase2015_DR_ORA_059-Q23Atch01

Joint Scheduling/Planning

	Cost Driver	Lever	Proposed Change for 2012	Expected Benefits	Implementation Timing/Owner	Status	Estimated Savings
J1	Bundling of PSEP Work*	P	Maximize crew resources across PSEP programs by bundling work in similar geographies	Cost savings	Complete	Work ongoing; Structuring bids to include hydrotest, replacement, and valve automation work	

* *High-priority activities with near-term cost reduction opportunities*

Hydrostatic Test Program Execution

	Cost Driver	Lever	Proposed Change for 2012	Expected Benefits	Implementation Timing/Owner	Status	Estimated Savings
E1	Cleaning Solution Management*	P R	Deploy poly tanks to minimize cost of cleaning solution storage; Accelerate approval process to minimize storage durations; Consolidate cleaning solution from multiple locations for disposal by railcar	Cost savings	4Q2012 / Sanchez	Work ongoing. Deploying double-walled tanks for water storage; deployed our first two railcar loads in October – developing a process to streamline this new transportation option	
E2	Water Cleaning Requirements*	P R	Empower contractor to be responsible for cleaning lines to specified Mercury concentration; Include cleaning cost breakdown in bid	Reduced standby time from waiting for instructions to continue cleaning	Complete	Complete. Included in the newly developed bid spec	$ 300,000
E3	Water Analysis*	P	Propose process improvement to reduce lag time by collecting the filtered water sample in parallel with the leak test sample; Evaluate options to install Save-a-valves prior to construction work	Reduce standby time up to 3 days	Complete	Complete. New sampling process has been developed and will be implemented on 2012 tests. Paper analysis of possible mercury locations on initial 2012 work scope complete; Process in now part of the test procedure and is being followed	$ 1,500,000
E4	Water Specialists*	R	Reduce 2 water specialist positions and leverage contractors for peak periods	Cost savings	Complete	Complete	
E5	Water Filtration	R	Acquire filtrations systems; Extend use of filtration bed systems (up to 10/system) and implement use of regenerated carbon.	Increased availability of higher capacity filtration systems; Cost savings	Complete	Complete. PG&E has purchased filtration systems, which have been received and deployed	$ 600,000
E6	Waste Characterization Samples	P	Reduce sample collection requirements to 4 per test based analytical result evaluation	Reduced cycle time for sample analysis = reduce on site time and reduced sample costs	Complete	Complete. New sampling process has been developed and will be implemented on 2012 tests; Process is now part of the test procedure and is being followed	$ 1,500,000

** High-priority activities with near-term cost reduction opportunities*

C – Cost Controls
P – Process Improvement
R – Resource Management
T – Tools or Training

Recently Completed Initiatives
Completed Initiatives Reported Previously

Hydrostatic Test Program Execution

	Cost Driver	Lever	Proposed Change for 2012	Expected Benefits	Implementation Timing/Owner	Status	Estimated Savings
E7	Contract Administration*	CP R T	Build Contract Administration group; Define processes for timely contract administration; Deploy tight contract controls	Improved billing accuracy and supplier performance management	1Q2012 / Moreland	Complete. Team hired and trained; Transition to Construction Management organization on track for May 18th	$ -
E8	Water Transport	P	Focus only on the movement of contaminated wastewater; Delegate remaining responsibility to contractor	Cost savings	Complete	Complete. Bid specification requires contractor to put liquids in a tank for PG&E to pick up. PG&E no longer manages vacuum trucks	$ 500,000
E9	Baker Tanks	P R	Evaluate options to purchase or rent baker tanks to ensure availability for tests; Identify alternative options for water management/storage	Increased availability of water storage and transport; Cost savings	2Q2012 Villar / Bigras	10 tanks will be picked up next week for delivery to Los Banos and 10 tanks will be delivery thereafter per week. Savings expected in 2013	
E10	Pipeline Drying Duration	P	Evaluate drying techniques, tools, and processes to reduce drying durations	Reduced drying cycle times	1Q2012 / Campbell	Complete. Evaluation of benchmarking data underway; Best process appears to be one that we are already using.	$ -
E11	Hydrostatic Test Operator	R	Allow PG&E crews to conduct some hydrostatic tests with certification provided by RCP; Use State Fire Marshall certified hydrostatic test operators when using a contractor	Cost savings	2Q2012 / Campbell	Complete. PG&E conducted hydrostatic tests on PR001, PR002, and PR003	
E12	Limited and Reactive Cost Tracking	CP R T	Assign accountability to test segment costs to project coordinators; Define clear change order process	Proactive cost management	1Q2012 / Moreland	Complete. Test segment cost accountability assigned to PCs. Ongoing cost reporting and forecasting in place	$ -

** High-priority activities with near-term cost reduction opportunities*

	Cost Driver	Lever	Proposed Change for 2012	Expected Benefits	Implementation Timing/Owner	Status	Estimated Savings
B1	Cost Controls*	Billing	Require weekly invoice submittals; Drive detailed reporting of program actuals and forecasts	Improved cost controls and awareness; Avoidance of cost overruns	1Q2012 / Moreland	Complete. Weekly invoice submittals included in the bid specification and also agreed to by GC when they conduct hydrostatic tests.	$ -

** High-priority activities with near-term cost reduction opportunities*

Appendix

TIMELINE OF COST REDUCTION EFFORTS

2012 Cost Reduction Efforts

Hydrostatic Test program will implement program-wide process improvements activities to decrease costs on a per-test segment and per-mile basis

Multiple Operational Levers are Required to Drive Down Contractor/Construction Costs

Program Planning
- Proposed requirements for direct exams
- Incorporate additional contractor time to reduce unexpected OT/DT requirements

Resource Management
- Regionalization of program resources
- Streamline Construction Management resources
- Consolidation of vendors for 3rd party verification

Project Design
- Increased accuracy of job packages resulting in fewer change orders
- Improved delivery of job packages resulting in less downtime

Sourcing
- Competitively bid prices for all test segments
- Expanded contractor base for fixed -price contracts
- Deploy change order process to manage scope and funding

Joint Scheduling / Planning
- Bundle work spanning multiple PSEP projects
- Assign contractors to projects along the same pipeline or geography to minimize standby and mobilization periods

Execution
- Leverage resources within and across test segments to minimize standby time
- Proactive cost management driven by new Contract Administration team
- Improve water management processes and utilize advanced equipment to reduce water management cycle time

Billing
- Improved billing accuracy through invoice audits and suppler performance management
- Ongoing and more timely reporting of program forecast vs. actual spend

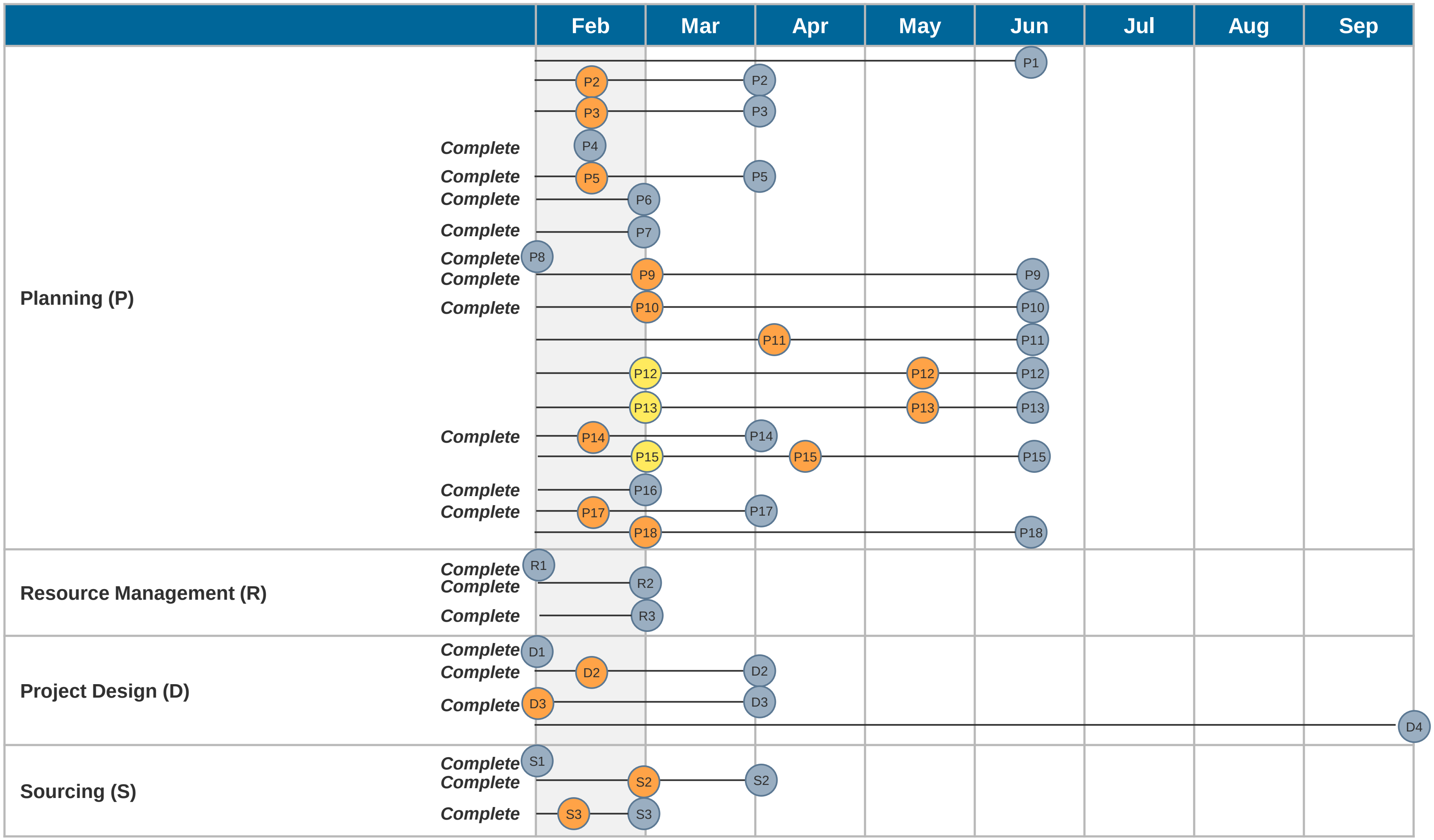
Cost Controls

Coordination & Planning

Process Improvements

X# Development Complete
X# Pilot Complete
X# Deployment Complete

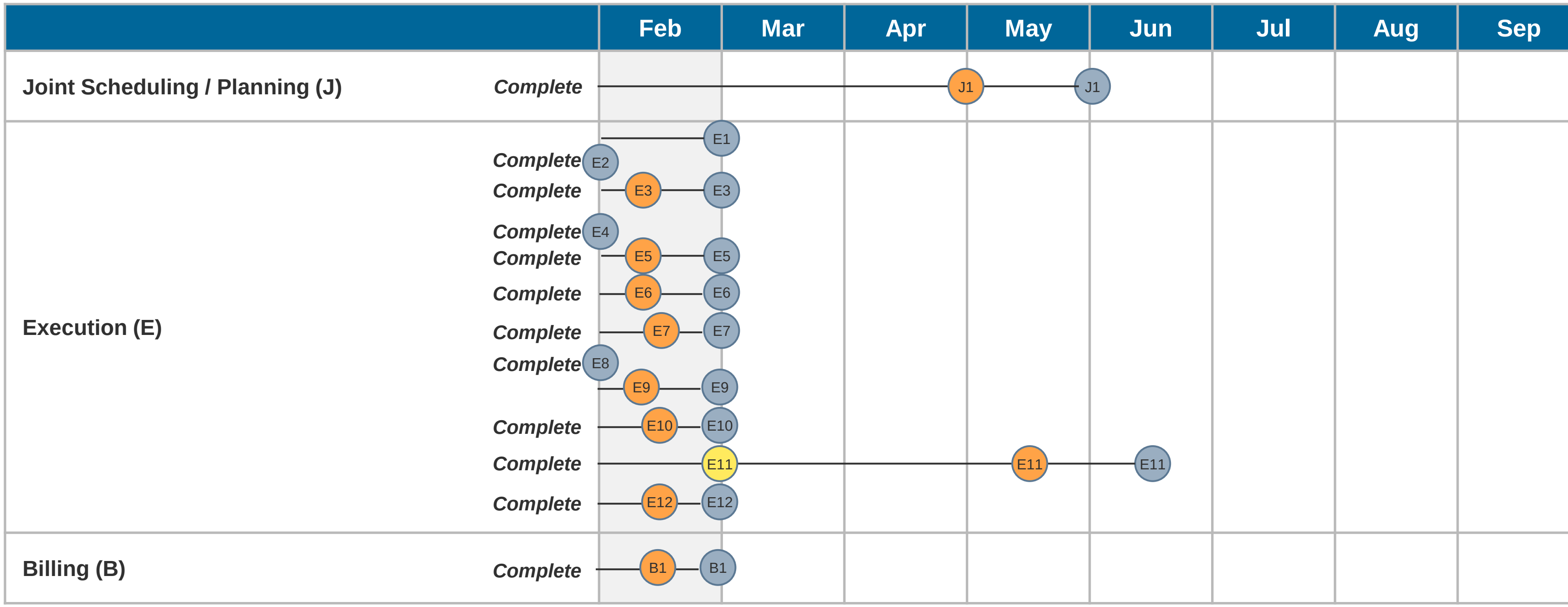
Timeline of 2012 Cost Reduction Efforts



GTS-RateCase2015_DR_ORA_059-Q23Atch01

Timeline of 2012 Cost Reduction Efforts

X# Development Complete
X# Pilot Complete
X# Deployment Complete



SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-13)
Date Requested: June 11, 2015
Date Responded: June 25, 2015

SoCalGas and SDG&E object to each question to the extent that it seeks information protected by the attorney-client privilege, the attorney work product doctrine, or any other applicable privilege or evidentiary doctrine. No information protected by such privileges or evidentiary doctrines will be knowingly disclosed.

QUESTION 1:

It is ORA's understanding that costs for Projects Line 2000-A, Playa Del Rey Phases 1 & 2, and Line 42-66-1/2 were recorded in a single Work Order Authorization and that costs were not recorded separately for each test/replacement segment/section.

Is this understanding correct? If not, please explain.

RESPONSE 1:

Yes, ORA's understanding is correct. Even though Line 2000-A rolled up to a single Work Order Authorization, costs were recorded for test and replacement work separately by the internal orders.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-13)
Date Requested: June 11, 2015
Date Responded: June 25, 2015

QUESTION 2:

It is ORA's understanding that for some PSEP work, Sempra developed internal cost estimates for each contracted segment or project before soliciting cost estimates from contractors.

a. Is this understanding correct? If not, please explain.

b. Please describe the process through which an agreed-upon price was reached if Sempra's estimate and the contractor's estimate did not agree.

c. Was each "agreed-upon price" (generated through the process described in part (b)) the same as the "Target Price" "Agreed upon price before construction" shown in Sempra's description of cost/profit-sharing bands as described in response to ORA-DR-04?[1] In cases where these two prices were not the same, please explain.

d. Is each project's initial budget the same as the "Target Price" (as described above)? If not, please explain.

[1] Sempra Response to ORA-DR-04, Q6. Figure "PSEP Target Pricing Risk/Reward Mechanics"

RESPONSE 2:

a. Yes, SoCalGas developed internal total project cost estimates for each contracted project before soliciting cost estimates from contractors, with the exception of Playa Del Rey.

   For the Playa Del Rey storage facility work, it was determined that it would be appropriate to sole-source the work on a Time-and-Material basis. This was because the selected contractor had 12 years of experience performing repair and maintenance work at Playa Del Rey and was familiar with the existing soil conditions, pipe and substructure locations and requirements for water/soil remediation. In addition, the contractor was already authorized and certified to perform this type of work at Playa Del Rey and was scheduled to be onsite to perform similar pressure test work on other pipes. While the coordination of work between two different contractors would create issues because of the limited working space and limited time allotted for completion of the projects, the use of the one experienced contractor allowed SoCalGas to combine the work, which saved projects costs and eliminated recurring mobilization fees, scheduling problems, and work location conflicts. As such, sole-sourcing to this contractor on a Time-and-Material basis was deemed efficient and prudent.

b. Not applicable as Lines 2000A and 42-66-1 & 2 were competitively bid.

c. For Lines 2000A and 42-66-1 & 2, the “agreed-upon price” was not the same as the “Target Price” because, at the time SoCalGas and SDG&E constructed these projects, our current target price negotiation process was not yet in place. The projects were awarded through our standard bidding process in which we developed a high-level estimate to competitively bid the project.

d. The initial budget for each project was not the same as the “Target Price.” At the time these completed projects were constructed, the target price process was not yet in place.

QUESTION 3:

It is ORA's understanding that the methodology discussed in Question 2 above was used for the test/replace project for Line 2000-A.

a. Is this understanding correct? If not, please explain.

b. If the answer to part (a) is yes, please provide Sempra's cost estimate, including the cost estimate documentation, and all assumptions, calculations, and supporting data.

c. If it is not clear from the cost estimate, clearly explain if and how estimates were provided for each test/replace segment/section.

d. If this estimate did not provide a cost estimate for each test/replace segment/section, explain how SCG was able to evaluate whether the contractor cost estimates (see Question 4 below) were reasonable.

RESPONSE 3:

a. ORA's understanding of the methodology discussed in Question 2 for Line 2000A is not correct. The project was awarded through our standard bidding process.

b. Not applicable.

c. All segments/sections were bid as a whole package, and the request required contractors to provide costs for each of the segments/sections. Please note that some of the costs shown are for multiple segments. The provided attachments contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583. For cost estimate bid details, please refer to the Q6 Attachment folder.

d. Bids were evaluated based on predetermined criteria, and the winning bidder could provide the best value for the company, customers, and meet the schedule requirements. In certain circumstances, however, the top ranked bidder was not selected. For Line 2000A, PSEP awarded the contract to the second-lowest bidding contractor because the lowest bidding contractor had submitted a bid that did not meet the time completion requirements.

QUESTION 4:

It is ORA's understanding that individual segments of Line 2000-A were bid separately by at least one contractor.

a. Is this understanding correct? If not, explain.

b. If the answer to part (a) is yes, please provide the contractor bids for each segment of Line 2000-A, and the project overall, including all assumptions, calculations, and supporting data.

c. Indicate which of the bids provided in response to Part (b) were by the contractor who actually performed the work on each segment.

d. If this project was not subjected to a competitive solicitation such that only one bid was obtained by SCG, explain why there was no competitive solicitation, and explain the process SCG used to determine the sole-source contractor bid was reasonable. Provide all data supporting SCGs determination that this bid from the sole-source contractor reasonable.

e. How did SCG resolve any differences between its own internal cost estimate, discussed in Question 2 above, and the contractor bid above, to establish a budget for the project?

RESPONSE 4:

a. No, individual segments of Line 2000-A were not bid separately. All segments for Line 2000-A were bid together to the contractors.

b. Not applicable.

c. Not applicable.

d. Line 2000A was subject to a competitive solicitation to select a qualified construction contractor to complete Line 2000-A under a fixed-price contract. SoCalGas and SDG&E received six bids.

e. At the time the contractor bid was received, the bid amount was in line with our internal cost estimate. Therefore, no adjustment to the Work Order Authorization (WOA) budget was required at that time.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-13)
Date Requested: June 11, 2015
Date Responded: June 25, 2015

QUESTION 5:

It is ORA's understanding that Sempra primarily used the following cost-estimation tools for PSEP work, including the Complete Projects in this PSRMA proceeding:

- An initial PSEP estimator tool developed by an outside contractor in 2011
- An internal PSEP estimator tool developed by SoCalGas around 2013
- Internal estimates for individual projects developed by an experienced SoCalGas team between 2011 and 2013, once project design was near completion.

a. Do the descriptions, timeframes, and developers listed above correctly and completely describe Sempra's primary cost-estimation tools? If not, please explain.

b. If Sempra has used any other major cost-estimation tools, please describe their developer, the implementation timeframe, and a description of how and when they were/are used.

c. What percentage of project costs estimates (by count) do the tools in the list above (including any additions described in part (b)) cover?

d. If Sempra has used any other cost-estimation tools or methods, please list them and describe their scope.

RESPONSE 5:

a. Yes.

b. For projects that have test vs. replace options, a Test vs. Replace Estimating Tool was developed for comparison purposes.

c. After receiving clarification from ORA, SoCalGas is compiling the information requested and estimates providing no later than July 6, 2015.

d. Other cost Estimating tools or methods SoCalGas PSEP has used:

   Stage 2 Cost Estimating tool was used for Test vs. Replace calculations. Primary purpose is to compare relative costs for projects under consideration for replacement.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-13)
Date Requested: June 11, 2015
Date Responded: June 25, 2015

QUESTION 6:

For each pipeline segment in Completed Project 2000-A, please provide an active spreadsheet (see note at end of this DR) with the following information:

a. Segment name / number

b. Contractor name

c. Contractor bid price

d. Scope of work

e. Date and description of changes to scope of work (if any)

RESPONSE 6:

As mentioned in the response to Question 4a, all segments were bid together to the contractors. One contractor was awarded the winning bid per project.

a-e. The provided attachments contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583. For responses and supporting documentation to Question 6, please refer to the Q6 Attachments folder.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-13)
Date Requested: June 11, 2015
Date Responded: June 25, 2015

QUESTION 7:

It is ORA's understanding that Sempra paid contractors via "milestone payments" for the PSEP work completed on Line 2000-A and Line 42-66-1/2. For each pipeline segment in Completed Projects Line 2000-A and Line 42-66-1/2, please provide an active spreadsheet (see note at end of this DR) with the following information:

a. Segment name / number
b. Contractor name
c. Milestone description(s)
d. Milestone completion date(s)
e. Milestone payment amount(s)
f. Milestone payment date(s)

RESPONSE 7:

As mentioned in the response to question 4a, all segments were bid together to the contractors. One contractor was awarded the winning bid per project.

The provided attachments contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583. For Question 7 responses please refer to the Q7 Attachment folder. Additional supporting documentation for Line 2000A can be found in the Q6 Attachment folder.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-13)
Date Requested: June 11, 2015
Date Responded: June 25, 2015

QUESTION 8:

Please describe how Sempra distinguishes transmission from distribution pipe in its system. Does the classification of a given pipe section as distribution vs. transmission have any impact on the planning, design, cost estimating, and construction efforts to hydrotest or replace a pipe segment? Please explain.

RESPONSE 8:

Attached please find a Motion filed by SoCalGas and SDG&E in R.11-02-019 to clarify the application of 49 CFR 192.3, which relates to the above definitions.

SoCalGas and SDG&E distinguish high pressure distribution supply lines from transmissions pipelines in the following manner.

Transmission Line: a pipeline, other than a gathering line, that (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field.

Distribution Supply Line: a pipeline operated at a pressure greater than 60 psig and (1) supplies one or more distribution regulator stations, or (2) supplies three or more customers.

The response and Gas Standard attachment provided in Question 8 contains confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583. Please refer to Q8 Attachment folder.

The classification of a pipeline may impact the planning, design, costing estimating and construction efforts of hydrotest or a pipeline replacement project. Distribution supply line projects are typically planned by the Distribution Region - Technical Services planners are provided with tools that allow for design, planning and others project activities. Transmission projects are planned by employees who use different systems for project planning. Furthermore, a PSEP short segments distribution projects and replacements less than 300 feet are typically planned by the Distribution Region. PSEP projects and hydrotests and replacements greater than 300 feet are typically planned by the PSEP PMO.

QUESTION 9:

Please provide all reports, memos, communications and other documentation within Sempra, including from Sempra's Project Management Office (PMO) to Sempra management regarding the status, progress, and changes in scope to PSEP hydrotesting and replacement work, including Line 2000-A, Line 42-66-1/2, and Playa Del Rey Phases 1 & 2. If no such documentation exists, please state as such and explain how SCG prudently managed these projects and the subcontractors performing the work.

RESPONSE 9:

SoCalGas and SDG&E object to this request on the grounds that it is unduly burdensome and not reasonably calculated to lead to the discovery of relevant evidence. This request would require SoCalGas and SDG&E to search through years of communications between many people. Subject to and without waiving these objections, SoCalGas and SDG&E respond as follows:

As explained in the Supplemental Testimony of Rick Phillips, PSEP governance and management is primarily the responsibility of the PSEP Program Management Office (PMO), which is comprised of a combination of SoCalGas, SDG&E, and contractor Project Management personnel. The PSEP PMO collaborates, coordinates, and provides functional guidance on the various aspects of project design and construction so as to meet or exceed compliance requirements and industry best practices. The PMO and the governance and management structure are designed to promote safety and efficiency by providing structure, guidance, and oversight. In addition to its safety focus, the PMO oversees implementation, provides checks and balances during the project life cycle, and allows SoCalGas and SDG&E to assess whether projects are within budget, on schedule, and meet cost, quality, customer impact, and compliance goals.

The PSEP PMO contains elements for review, analysis, approval and governance to oversee and manage projects to best achieve the safety goals of the program and balance between cost, customer impact, quality, compliance with regulations and company policies, and an expeditious schedule. In addition, the requirements built into the seven-stage process help realize the program goals. PMO leadership reviews projects as the projects pass from one stage to the next. Schedules are reviewed each month, with notable changes evaluated for action or cause. Key PMO management meets twice each month to review overall schedule progress, changes, and other topics, as well as progress toward safety goals. Quality review of key documents and a robust material supply process promote accuracy in installation and documentation of each line tested or replaced and each valve modified. These key reviews, approvals, and oversight compose the essence of PSEP governance. The PSEP PMO approach strives for the best balance of enhancing public safety, cost efficiency, and schedule, while moving toward higher goals each year.

Although Line 2000-A, Lines 42-66-1/2, and Playa Del Rey Phases 1 and 2 were initiated prior to the full implementation of the PMO and Seven Stage Review Process, they were subject to similar oversight that involved PMO management and project managers from the region or department executing the work. Decisions related to the scope of these projects were subject to review and approval by PMO leadership, and PMO leadership was appraised of costs, schedule, and status through regular meetings with the region or department executing the work.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-13)
Date Requested: June 11, 2015
Date Responded: June 25, 2015

QUESTION 10:

Provide the total costs recorded by SCG and by each contractor for the following projects:

a. Line 2000-A

b. Line 42-66-1/2

c. Playa Del Rey Phases 1 & 2

RESPONSE 10:

The provided attachments contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583. For the total costs recorded by SoCalGas and by contractor per project, please refer to the Q10 Attachment folder.

QUESTION 11:

It is ORA's understanding that Sempra's internal estimator tool developed in 2013 was developed after the start of the Completed Projects in its PSRMA application and was therefore not used to estimate costs for those projects.

a) Is this understanding correct? If not, please explain.

b) Does the estimator tool developed in 2013 have estimates for any of the In-progress Projects in Sempra's PSRMA Application?

c) If the answer to Part (b) is yes, please provide all outputs of the estimator tool for the In-Progress Projects included in Sempra's PSRMA application.[2]

RESPONSE 11:

a) ORA's understanding is correct.

b) Yes, the estimator tool developed in 2013 has estimates for in-progress Projects in Sempra's PSRMA Application.

c) The provided attachments contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583. For estimator outputs for the In-progress projects listed below, please refer to Q11 Attachment folder.

32-21
37-18-F
404
406
407
1004
1015
2000-W
2001-W
2003

---

[2] As listed in Sempra Application (Chapter III, Phillips) page 11, line 1 (Table "In Progress Projects with an O&M Component").

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-13)
Date Requested: June 11, 2015
Date Responded: June 25, 2015

QUESTION 12:

Please provide all cost estimates generated for Project Line 2000-A since 2010. For cost-estimates generated by estimator tools (or similar), please provide all related output of the tools.

RESPONSE 12:

The provided attachments contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583. For cost estimates generated for Project Line 2000-A, please refer to the Q12 Attachment folder.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-13)
Date Requested: June 11, 2015
Date Responded: June 25, 2015

QUESTION 13:

Please provide the output of the 2011 PSEP estimator tool for each of the three Completed Projects (Line 2000-A, Playa Del Rey Phases 1 & 2, and 42-66-1/2). If such output does not exist, please explain why.

RESPONSE 13:

For a copy of the 2011 PSEP estimator tool for Line 2000A and Line 42-6-1/2, please refer to the Q13 Attachment folder.

The Playa Del Rey Phases 1 and 2 project was assumed at $100,000 for labor and $500,000 for non-labor.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-13)
Date Requested: June 11, 2015
Date Responded: June 25, 2015

QUESTION 14:

Please provide Sempra's 2011 and 2013 PSEP estimator tools in native format, e.g. MS Excel. If this is not practicable, please contact the originator to explain why and to discuss alternatives.

RESPONSE 14:

The provided attachments contain confidential information pursuant to G.O. 66-C and Cal. Pub. Util. Code § 583. For a copy of the 2011 and updated 2013 PSEP estimator tool please refer to the Q14 Attachment folder.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-13)
Date Requested: June 11, 2015
Date Responded: June 25, 2015
Date Amended: July 6, 2015

QUESTION 5:

It is ORA's understanding that Sempra primarily used the following cost-estimation tools for PSEP work, including the Complete Projects in this PSRMA proceeding:

- An initial PSEP estimator tool developed by an outside contractor in 2011
- An internal PSEP estimator tool developed by SoCalGas around 2013
- Internal estimates for individual projects developed by an experienced SoCalGas team between 2011 and 2013, once project design was near completion.

a. Do the descriptions, timeframes, and developers listed above correctly and completely describe Sempra's primary cost-estimation tools? If not, please explain.

b. If Sempra has used any other major cost-estimation tools, please describe their developer, the implementation timeframe, and a description of how and when they were/are used.

c. What percentage of project costs estimates (by count) do the tools in the list above (including any additions described in part (b)) cover?

d. If Sempra has used any other cost-estimation tools or methods, please list them and describe their scope.

RESPONSE 5:

a. Yes.

b. For projects that have test vs. replace options, a Test vs. Replace Estimating Tool was developed for comparison purposes. For Stage 3 level (or equivalent) estimates, there were additional tools as listed in the table in part (c).

c. Per clarification with ORA, see below for the percentage estimates that the specified tools are used by currently active or completed PSEP projects to determine stage 3 (or stage 3-equivalent) cost estimates.[1]

[1] It is possible that certain projects used multiple tools. For purposes of this response, SoCalGas and SDG&E are providing the most recent tool used on file to develop stage 3 (or stage 3 equivalent) estimates.

Sempra Stage 3 Tool Naming Convention Key				
Description	**Date Range**	**Named**	**Count**	**Percentage**
Other methods	All	Other	8	6%
Construction Management Software (CMS) used in districts	All	CMS	4	3%
Subject Matter Expert (SME) estimated	All	SME	2	2%
SPEC tool from 2011	Anything using SPEC format from pre-2013	2011	7	5%
SCG 2013 tool from GTS/SPEC/Jacobs	Anything in SCG format up to 8-7-14	2013	55	43%
SCG 2014 tool from GTS	8-7-14 to 2-26-15	2014	9	7%
SCG Tool updated by Matinee Masoomian	2-26-15 to present	2015	6	5%
SCG Valve Stage 3 2014 (Excluding SDGE)	5-8-14 to present	2014 Valve	38	29%
			129	100%
			* This count does not include descoped jobs*	

d. Other cost Estimating tools or methods SoCalGas PSEP has used:

Stage 2 Cost Estimating tool was used for Test vs. Replace calculations. Primary purpose is to compare relative costs for projects under consideration for replacement.

Company	SCG
Plant Category	Trans
Line Number	2000
Diameter (in.)	18, 26, 30

Hydrotest Mileage

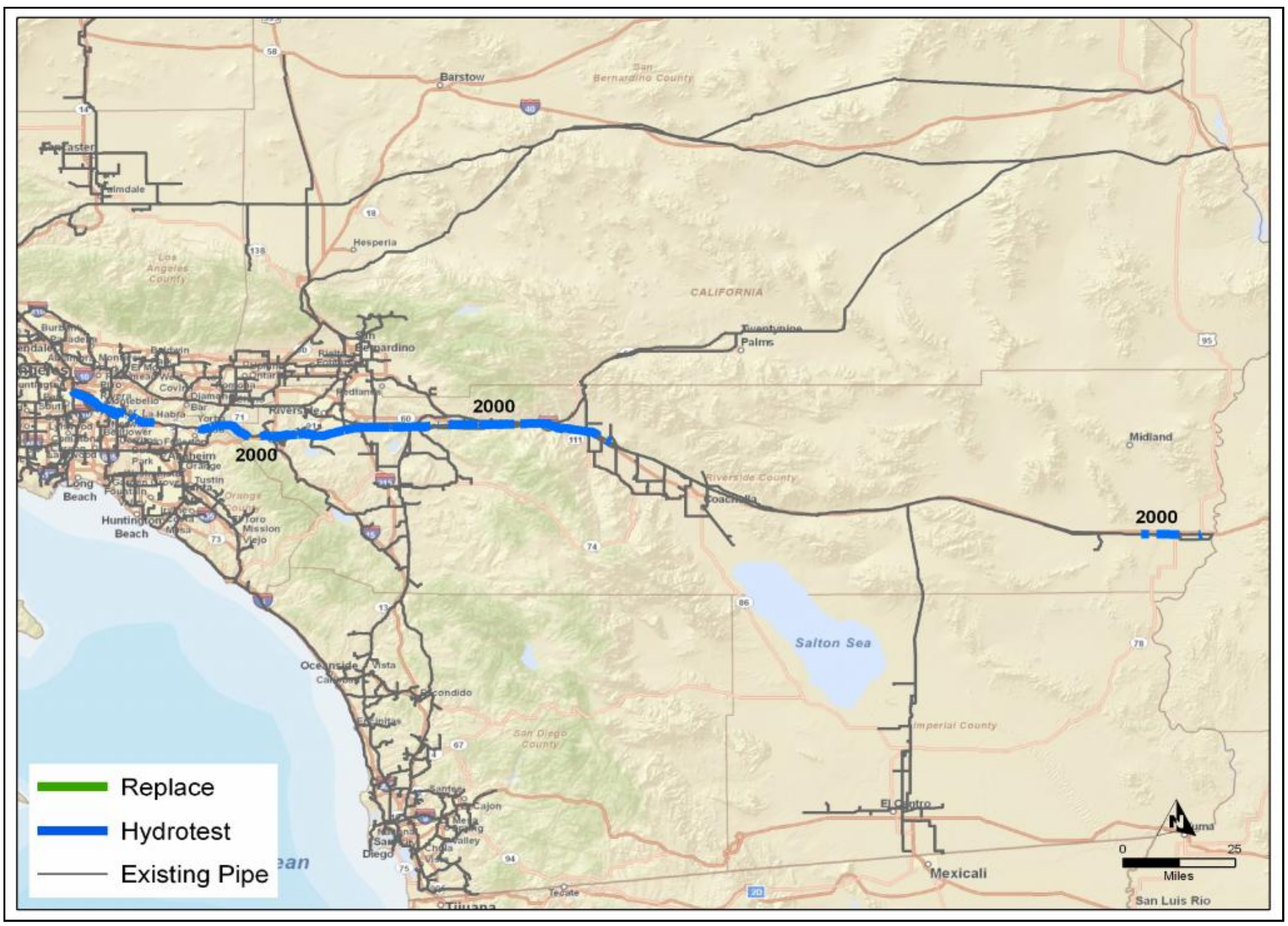
Category 4 Criteria	Accelerated	Total
55.027	62.574	117.600

Cost Detail

O&M

Hydrotest		
Direct Labor	$	1,263,700
Direct Non Labor	$	63,940,600
Total Hydrotest	$	65,204,300
Hydrotest Repairs		
Direct Labor	$	185,000
Direct Non Labor	$	1,665,000
Total Repairs	$	1,850,000

In Line Inspection		
Direct Labor	$	120,000
Direct Non Labor	$	1,080,000
Total ILI	$	1,200,000
In Line Inspection Repairs		
Direct Labor	$	972,600
Direct Non Labor	$	8,753,400
Total Repairs	$	9,726,000



Existing Segments

Category	Station Start	Station Stop	Criteria Miles	Diameter	Action	Decision Tree Box	Comments
Cat 1	-650.39	50	0.1326	30			
Cat 1	50	278.1	0.0432	30			
Cat 1	278.1	328.22	0.0095	30			
Cat 4	328.22	372	0.0083	30	Hydrotest	5	possible RV lot
Cat 4	372	7368	0.2587	30	Hydrotest	5	possible RV lot, channel crossing
Cat 4	7368	7392	-	30			
Cat 1	7392	11754	0.5100	30			
Cat 4	11754	11784	-	30			
Cat 4	11784	14574	0.5000	30	Hydrotest	5	street work
Cat 4	14574	14594	0.0038	30	Hydrotest	5	street work
Cat 1	14594	19080	0.8496	30			
Cat 1	19080	19728	0.1227	30			
Cat 1	19120	33001	2.2000	30			
Cat 4	33001	33200	0.0377	30	Hydrotest	5	none
Cat 4	33200	33314.5	0.0217	30	Hydrotest	5	none
Cat 1	33314.5	33341.9	0.0052	30	Hydrotest		none
Cat 4	33341.9	33607	0.0502	30	Hydrotest	5	none
Cat 4	33607	33798.9	0.0363	30	Hydrotest	5	none
Cat 4	33798.9	55450	0.2000	30	Hydrotest	5	residential crossings
Cat 1	55450	62341	1.3051	30			
Cat 4	62341	70198	0.2424	30	Hydrotest	5	none
Cat 1	70198	70415.8	-	30			
Cat 4	70338	112489.25	-	30			
Cat 1	112489.25	113592.1	-	30			
Cat 4	113593.20	130487.4	-	30			
Cat 1	130487.4	131948.6	-	30			
Cat 1	131948.6	132675	-	30			
Cat 4	132675	133020.6	-	30			
Cat 1	133020.6	134469.2	-	30			

Cat 4	134469.2	275881.92	-	30			
Cat 1	275881.92	277060.78	-	30			
Cat 4	277060.78	392802	-	30			
Cat 1	392802	393778	-	30			
Cat 4	393778	426905.63	-	30			
Cat 1	426905.63	426930.9	-	30			
Cat 4	426930.9	427076.4	-	30			
Cat 1	427076.4	427103.9	-	30			
Cat 4	427103.9	451283	-	30			
Cat 4	451283	451694	-	30			
Cat 4	451694	451927	-	30			
Cat 4	451927	452595	-	30			
Cat 4	452554.00	539611.96	-	30			
Cat 1	473964.3	473991.86	-	30			
Cat 4	473991.86	476904	-	30			
Cat 1	476904	476930.63	-	30			
Cat 4	476930.63	493931	-	30			
Cat 4	493931	527812.4	-	30			
Cat 1	527812.4	527857.5	-	30			
Cat 4	527857.5	532674.3	-	30			
Cat 1	532674.3	532694.8	-	30			
Cat 4	532694.8	539612	-	30			
Cat 1	539611.96	539629	-	30			
Cat 4	539629	556091	-	30			
Cat 4	556091	559882.4	0.6800	30	Hydrotest	5	none
Cat 4	559859.35	571031.3	-	30			
Cat 1	571031.3	571054.8	-	30			
Cat 4	571054.8	618583.6	0.2100	30	Hydrotest	5	none, remote area
Cat 1	618583.6	618624.1	-	30	Hydrotest		none, remote area
Cat 4	618624.1	649146	0.4400	30	Hydrotest	5	none, remote area
Cat 1	649146	649154	-	30			
Cat 4	649154	655113	-	30			
Cat 1	655113	655149	-	30			
Cat 4	655149	666033.33	0.3300	30	Hydrotest	5	none, remote area
Cat 1	666033.33	666116.83	-	30			
Cat 4	666116.83	689891	0.5600	30	Hydrotest	5	none
Cat 1	689891	691384.5	0.2800	30			

Cat 4	691281.00	719723.96	0.2000	30	Hydrotest	5	none
Cat 1	719723.96	719747.55	-	30			
Cat 4	719747.55	723936.06	-	30			
Cat 1	723936.06	726755	0.5339	30			
Cat 1	726755	727513.55	0.1438	30			
Cat 1	727513.55	728503.63	0.1875	30			
Cat 4	728297.55	729714	0.2683	30	Hydrotest		railroad crossing
Cat 1	729714	730849.5	-	30			
Cat 4	730838.00	737752.21	-	30			
Cat 1	737752.21	737762.71	-	30			
Cat 4	737762.71	759019.5	4.0259	30	Hydrotest	5	street work
Cat 1	759019.5	759044.5	0.0047	30	Hydrotest		none
Cat 4	759044.5	771882.74	1.6915	30	Hydrotest	5	street work, residential crossing, parking lot
Cat 4	771882.74	772549.45	0.1263	30	Hydrotest	5	street work
Cat 4	772548.95	773093.26	0.1031	30	Hydrotest	5	street work
Cat 4	773093.26	773195.01	0.0193	30	Hydrotest	5	street work
Cat 4	773178.43	773541.29	0.0687	30	Hydrotest	5	street work
Cat 4	773541.29	773628.71	0.0166	30	Hydrotest	5	street work
Cat 4	773625.69	774724.15	0.2080	30	Hydrotest	5	street work
Cat 1	774724.15	774749.15	0.0047	30	Hydrotest		street work
Cat 4	774749.15	774982.4	0.0442	30	Hydrotest	5	street work
Cat 4	774982.4	775375.94	0.0745	30	Hydrotest	5	street work
Cat 4	775371.28	776077	0.1337	30	Hydrotest	5	street work
Cat 1	775610.1	776226.83	0.1168	30			
Cat 4	776215.66	777122.75	0.1718	30	Hydrotest	5	street work
Cat 1	777122.75	777860.76	0.1398	30			
Cat 4	777849.08	779062.34	0.2298	30	Hydrotest	5	street work
Cat 1	779529.2	779552.7	0.0045	30	Hydrotest		street work
Cat 4	779552.7	822527.26	0.7932	30	Hydrotest	5	street work
Cat 1	822527.26	822552.76	-	30			
Cat 4	822552.76	822920.67	-	30			
Cat 1	822920.67	822929	-	30			
Cat 4	822867	836328	2.5494	30	Hydrotest	5	street & dirt work
Cat 1	836328	836410	0.0155	30	Hydrotest		dirt work
Cat 4	836410	849478.35	2.4751	30	Hydrotest	5	street & dirt work
Cat 1	849478.35	849678.04	0.0378	30			
Cat 4	849654.87	860083	1.7150	30	Hydrotest	5	street work

Cat 1	860083	860364	0.0532	30			
Cat 4	860364	871633	2.1343	30	Hydrotest	5	street work, commerical property crossings
Cat 1	871633	871733	0.0189	30			
Cat 4	871733	872142	0.0775	30	Hydrotest	5	dirt work
Cat 1	872142	872252	0.0208	30			
Cat 4	872252	873024	0.1462	30	Hydrotest	5	Hwy 215 crossing, RR crossing
Cat 1	873024	873329	0.0578	30			
Cat 4	873329	873910	0.1100	30	Hydrotest	5	commercial parking
Cat 1	873910	874108	0.0375	30			
Cat 4	874108	886226	2.2936	30	Hydrotest	5	commercial parking, some street work, dirt
Cat 1	886226	886241	0.0028	30	Hydrotest		street work
Cat 4	886241	896398	1.2437	30	Hydrotest	5	residential crossings, dirt work
Cat 1	896398	896423	0.0047	30	Hydrotest		dirt work
Cat 4	896423	897195	0.1462	30	Hydrotest	5	dirt work
Cat 1	897195	897565	0.0701	30			
Cat 4	897565	909248	1.2261	30	Hydrotest	5	street work, residential crossing
Cat 1	909248	909260	-	30			
Cat 4	909260	918731	-	30			
Cat 1	918731	922435	-	30			
Cat 4	922435	932703	1.4161	30	Hydrotest	5	street work, residential crossings
Cat 1	931922	932044	0.0231	30			
Cat 4	932044	932703	0.1248	30	Hydrotest	5	street work, residential crossings
Cat 1	932703	932809	0.0201	30			
Cat 4	932809	941105	1.5712	30	Hydrotest	5	street work, residential crossings, railroad crossing, commercial property
Cat 1	941105	941197	0.0174	30			
Cat 4	941197	943385	0.4144	30	Hydrotest	5	commercial property, parking lots
Cat 1	943385	944143	0.1436	30			
Cat 4	944143	956351	2.3121	30	Hydrotest	5	street work, residential crossings, golf course crossing
Cat 1	956351	956618	0.0506	30			
Cat 4	956618	957420	0.1519	30	Hydrotest	5	residential crossing
Cat 4	957420	957983	0.1066	30	Hydrotest	5	Hwy 15 crossing
Cat 4	957983	959986	0.3676	30	Hydrotest	5	residential crossing, street work
Cat 1	959986	960294	0.0110	30			
Cat 4	960294	963485	0.6044	30	Hydrotest	5	commercial parking,
Cat 1	963485	963615	0.0246	30			
Cat 4	963615	965462	0.3498	30	Hydrotest	5	street work, commercial parking

Cat 1	965462	965617	0.0294	30			
Cat 4	965617	966210	0.1123	30	Hydrotest	5	dirt work
Cat 4	966210	966251	0.0078	30	Hydrotest	5	dirt work
Cat 4	966251	968095	0.3492	30	Hydrotest	5	bridge crossing, aligned next to RR
Cat 4	968095	968099	0.0008	30	Hydrotest	5	aligned next to RR tracks
Cat 4	968099	968143	0.0083	30	Hydrotest	5	aligned next to RR tracks
Cat 1	968143	968156	0.0025	30	Hydrotest		aligned next to RR tracks
Cat 4	968156	969667	0.2862	30	Hydrotest	5	aligned next to RR tracks
Cat 1	969667	969683	0.0030	30	Hydrotest		aligned next to RR tracks
Cat 4	969683	976708	1.3305	30	Hydrotest	5	commercial property crossings, street work
Cat 1	976708	976865	0.0297	30			
Cat 4	976865	977562	0.1320	30	Hydrotest	5	dirt work
Cat 4	977562	983010.78	-	30			
Cat 1	983010.78	984909.05	-	30			
Cat 4	984909.05	986696	-	30			
Cat 1	986696	986777	-	30			
Cat 1	986777	986946	-	30			
Cat 4	986946	987046	-	30			
Cat 1	987046	988786	-	30			
Cat 4	988786	1019990	-	30			
Cat 4	1019990	1020020	-	30			
Cat 4	1020020	1023581	-	30			
Cat 1	1023581	1023593	-	30			
Cat 4	1023593	1042666	0.3600	30	Hydrotest	5	none
Cat 4	1042666	1042694	-	30			
Cat 1	1042694	1044348	-	30			
Cat 4	1044348	1048356	0.0068	30	Hydrotest	5	none
Cat 4	1048356	1048923.8	0.1075	30	Hydrotest	5	none
Cat 1	1048923.8	1050555.4	0.3090	30			
Cat 4	1050612.05	1051255	0.1218	30	Hydrotest	5	none
Cat 2	1051255	1053914	0.5036	30			
Cat 4	1053914	1054363.2	0.0851	30	Hydrotest	5	none
Cat 1	1054363.2	1055472	0.2100	30			
Cat 4	1055472	1065133	1.5397	30	Hydrotest	5	commercial property crossings, street work, adjacent to residential homes
Cat 1	1065133	1065540	0.0771	30			
Cat 4	1065540	1071946	1.2133	30	Hydrotest	5	aligned between RR tracks & commercial property

Cat 2	1071946	1072070	0.0235	30	Hydrotest		
Cat 4	1072070	1090112	3.4170	30	Hydrotest	5	aligned between RR tracks, commercial property and residential homes. Two RR crossings
Cat 1	1090112	1090191	0.0150	30	Hydrotest		aligned between RR tracks and residential homes
Cat 4	1090191	1104725	2.7527	30	Hydrotest	5	aligned between RR tracks and residential homes, culvert crossing, street work
Cat 4	1104725	1104802	0.0146	30	Hydrotest	5	aligned between RR tracks and residential homes
Cat 4	1104802	1119539	2.7911	30	Hydrotest	5	aligned between RR tracks and residential homes, street work
Cat 4	1119539	1120486	0.1794	30	Hydrotest	5	aligned between RR tracks & commercial property
Cat 4	1120486	1126545	1.1475	30	Hydrotest	5	aligned between RR tracks & commercial property, multiple RR crossings, aligned near train hub
Cat 4	1126545	1200000	0.0053	26	Hydrotest	5	None, stationing chage
Cat 4	1200000	1200068.73	0.0130	26	Hydrotest	5	commercial property
Cat 1	1200068.73	1200134.93	0.0125	26			
Cat 1	1200138.42	1201086.5	0.1796	26			
Cat 4	1201697.83	1202780	0.2050	26	Hydrotest	5	commercial property next to RR tracks
Cat 4	1202780	1203675	0.1695	26	Hydrotest	5	aligned inbetween RR tracks and commercial property, train hub
Cat 4	1203675	1205799	0.4023	26	Hydrotest	5	aligned inbetween RR tracks and commercial property, train hub. RR crossings
Cat 1	1205799	1209419	0.6856	26			
Cat 1	1209419	1209960	0.1025	26			
Cat 4	1209960	1219576.1	1.8212	26	Hydrotest	5	aligned between RR tracks, commercial property and residential homes
Cat 1	1219576	1220618	0.1973	18			
Cat 4	1220618	1225918	1.0038	26	Hydrotest	5	aligned next to commercial property. Near Hwy 5. street work
Cat 4	1225918	1227503	0.3002	26	Hydrotest	5	aligned next to commercial property. Near Hwy 5. street work, parking lot
Cat 2	1227503	1228993	0.2822	30			
Cat 4	1228993	1234940	1.1263	26	Hydrotest	5	aligned next to RR tracks. RR crossing
Cat 2	1234940	1235944	0.1902	26			
Cat 4	1235944	1241122	0.9807	26	Hydrotest	5	street work, hwy 710 crossing
Cat 4	1241122	1241203	0.0153	26	Hydrotest	5	street work
Cat 4	1241203	1252765	2.1898	26	Hydrotest	5	multiple RR crossings, commercial crossings, critical primary train hub, street work

ACTIVITY AND LOCATION: Line 2000	SPECIFICATION NO.	A-E FIRM NAME	SHEET Sheet 1 of 1
PROJECT TITLE AND CLIENT: **SOUTHERN CALIFORNIA GAS COMPANY** **PIPE HYDROTEST COST ESTIMATE**	ESTIMATED BY: SPEC Services, Inc.		DATE: July 26, 2011
	STATUS OF DESIGN Conceptual		SPEC Project Number 5057

DESCRIPTION	QUANTITY		MATERIAL COST		LABOR COST		TOTAL COST	Comments
	NUMBER	UNIT	UNIT COST	TOTAL	UNIT COST	TOTAL	TOTAL	
INPUT IN ALL BLUE CELLS								
1 **MATERIALS**								
Pipe 30 Actual OD (in) Water Volume:	424,213	bbl / OD						
0.281 Wall Thickness (in) Baker Tank Volume:	14,140	bbl / Segment						
503950 Length (Ft)								
Hydrotest Test Segment 30 QTY								
Pipe 26 Actual OD (in) Water Volume:	73,671	bbl / OD						
0.264 Wall Thickness (in) Baker Tank Volume:	10,524	bbl / Segment						
116894 Length (Ft)								
Hydrotest Test Segment 7 QTY								
Pipe n/a Actual OD (in) Water Volume:	0	bbl / OD						
0.000 Wall Thickness (in) Baker Tank Volume:	0	bbl / Segment						
0 Length (Ft)								
Hydrotest Test Segment 0 QTY								
Total Hydrotest Length 117.6 Miles								
Total Hydrotest Segment(s) 37 QTY								
Purging Volume of Nitrogen [to obtain 3 atm (44 psig) on line], minimum 4 miles per test segment	10,553,740	SCF	$ 0.19	$ 2,005,211			$ 2,005,211	
Temporary Pig Launcher/Receiver (one/ OD change)	2	LS	$ 25,000	$ 50,000			$ 50,000	
Water Injection Pump & Filter (capacity 1200 gpm)	37	day(s)	$ 486	$ 17,982			$ 17,982	
On-Site Vacuum Truck(s) (minimum one per/ test segment)	37	each	$ 5,000	$ 185,000			$ 185,000	
Baker Tank(s) =X	10	each						
Total Baker Tank(s) Rental days ($/day per tank) =Y=X*Z	2,640	day(s)	$ 1,600	$ 4,224,000			$ 4,224,000	
Total Hydrotest Water ($19/bbl)	497,884	bbl	$ 19.00	$ 9,459,796			$ 9,459,796	
Water Disposal Vacuum Truck(s) =A	10	each						
Vacuum Truck Water Disposal loads (capacity 120 bbl) =B	4,150	loads						
Disposal Time =C=B/(A*10)	42	day(s)						
Total Vacuum Truck(s) Rental days ($/day per truck) =D=C*A	420	day(s)	$ 5,000	$ 2,100,000			$ 2,100,000	
Treated Water Disposal ($55/bbl)	497,884	bbl	$ 55	$ 27,383,621			$ 27,383,621	
Miscellaneous Materials	5	%		$ 2,271,281			$ 2,271,281	
SCG Post Estimate Changes								
Additional Baker Tanks: 0 QTY								
Additional Test Segments: (due to elevation changes) 0 QTY								
Total Material Cost							**$ 47,696,900**	
2 **CONSTRUCTION**								
Construction Labor (25K/ test segment)	37	LS			$ 25,000	$ 925,000	$ 925,000	
Hydrotest Labor (10K/ test segment)	37	day(s)			$ 10,000	$ 370,000	$ 370,000	
Dewater/ Dry Pipeline ($15,000/ test segment)	37	LS			$ 15,000	$ 555,000	$ 555,000	
Tie-ins Crew Rates ($25,000/ test segment)	37	Each			$ 25,000	$ 925,000	$ 925,000	
3rd Party Witness ($2,000/ test segment)	37	Each			$ 2,000	$ 74,000	$ 74,000	
Test/Construction period (5 days per test segment+ Hydrotest Labor+ Disposal Time) =Z	**264**	**day(s)**						
Total Construction Cost							**$ 2,849,000**	
3 **SCG LABOR / INSPECTION** Projects < $1 million - company labor is 10%	10	%				$ -	$ -	
$1million < Projects < $10 million - company labor is 5%	5	%				$ -	$ -	
Projects >$10 million - company labor is 2.5%	2.5	%				$ 1,263,648	$ 1,263,648	
Total SCG Labor / Inspection Cost							**$ 1,263,700**	
4 **DESIGN / ENG. / CONST./ ENVIRON.**								
Planning / Design / Eng / Coord / Procurement	5	%				$ 2,527,295	$ 2,527,295	
ROW Acquisition	0	LS				$ -	$ -	
Construction Permits	0	LS				$ -	$ -	
Environmental Permits	0	LS				$ -	$ -	
Environmental Monitoring	0	LS				$ -	$ -	
Total Design / Engineering / Construction Cost							**$ 2,527,300**	
5 **CONTINGENCY**								
Projects < $2 million - Contingency is 30%	30	%				$ -	$ -	
Projects >$2 million - Contingency is 20%	20	%				$ 10,867,380	$ 10,867,380	
TOTAL PROJECT COST (See Appendix for assumptions/clarifications)							**$ 65,204,300**	

LESSONS LEARNED
PSEP Line 2000A Hydrotest Project

Summary

The Line 2000A Hydrotest Project was the first hydrotest project executed under SoCal Gas (SCG) PSEP. The project was initiated and progressed into early Stage 5 by SCG's PCM organization then transitioned to and managed by PSEP. This approach enabled the project to be started prior to full PSEP implementation, completed in 2013 and serve as a prototype to provide input to the design of the PSEP work process.

Scope

The scope of the project included hydrotesting of ten pipeline segments totaling 14.9 miles in length located over a 40 mile section of Line 2000 running from Banning, CA to Corona, CA. Field execution began in early July 2013 and was completed in November 2013. In addition to mainline segment testing, the project scope also included isolation & reinstatement of supply line taps and replacement of ~175 feet of pipeline and eight wrinkle bends.

Lessons Learned

As a prototype, L2000A provided an early opportunity, before a large number of PSEP projects were substantially defined and designed, to capture Lessons Learned and identify possible work process improvements. Two assessments were conducted in order to take advantage of these learnings and incorporate them into PSEP procedures, practices work process; the first shortly after the start of construction, the second following completion of field construction.

In-Progress Lessons Learned (Attachment A) were identified by a small number of team members and presented to the PSEP team in August 2013. Final Lessons Learned (Attachment B) were identified by a group of project team members representing all functions in a workshop utilizing a brainstorming format; voting was used to prioritize the identified learnings into a Lessons Learned Summary. Both the complete list of learnings or raw data (which the Summary is based on) and the Summary are included in Attachment B.

2000-A Lessons Learned Summary

#	Category	Issue/Topic	Description	Recommendation(s)	Potential Impact
1	Construction/Project/Inspection	Material Documentation	Approved MTRs not available for some materials; MTRs for some installed materials are on file but were not approved by SCG prior to installation.	Establish material management procedures that document materials chain of custody & assure piece-marking; train inspectors. Key responsibilities for Inspectors include not allowing delivery of undocumented materials on job site/installation.	Potential Safety/Compliance violation
1a	Construction/Project/Inspection	Material Documentation	No MTRs available for some materials	Establish material management procedures that document materials chain of custody & assure piece-marking; train inspectors. Key responsibilities for Inspectors include not allowing delivery of undocumented materials on job site/installation.	Potential Safety/Compliance violation
2	Project/Quality/Construction	Field Documentation	Field documents require review before being uploaded to PMCS: incomplete & inadequate field documents were uploaded as a result (by the wrong people, wrong pages uploaded, illegible, etc.)	Incorporate QA/QC or Squad Check team to review documents and quality before uploading onto PMCS	Potential Compliance issues
3	Construction/Project/Inspection	Closeout Documentation	Closeout packages needs to be completed by segments, instead of the entire project after construction phase. Also quicker turnaround time in approvals and uploading the packages to PMCS	Complete closeout packagers on a per segment basis. Set hard deadlines for turn around time from end of hydrotest and de-watering	Compliance; impacts closeout schedule
4	Construction/Project/Inspection	Communication	Communication between CM, PM, Inspection Team, and QA/QC needs to be improved throughout the lifecycle of the project. Project progressed to late Stage 4 prior to establishment of PSEP procedures & practices. Team responsibilities handed off form PCM to PSEP Stage 4/5.	Establish core team at start of Stage 2. Minimize turnover of core team members. Limit turnover to key activity end-points when possible (ie, end of Stage)	Overall project efficiency; cost & schedule
5	Construction/Inspectors	Field Documentation	Pipe joints & weld numbering system should be consistent and mapped out in advance (e.g. duplicate #s; not same numbers but adding an X at the end), different numbering convention was given by X-ray vs. Inspection (Test heads)	Establish a standard joint and weld numbering system prior to construction, and adhere to one convention throughout project	Potential Compliance
6	Construction	Roles & Responsibilities	Inspection Roles & Responsibilities need to be better defined (e.g. inspectors need to adhere to R&R of PSEP instead of past knowledge)	Assign personnel in Stage 4. Address Inspection/Construction Management Roles in Stage 4 construction planning meetings & pre-construction kickoff meetings.	R&R for all discipline
7	Quality	Work Process Documentation	Closer look at document control/quality process needed: identify & get concurrence from leadership.	Establish work process in order to review/approve documentation properly (e.g. Squad Check)	Impacts closeout schedule
8	Document Management	Document Management	Establish document management tools, eg, document distribution/communication matrix & external approval/notification matrix to track all permits, TREs & notifications	Establish documents in early Stage 2; utilize and update throughout project	Implemented during project; establish in Stage 2
9	Construction/Environmental	Water Management	Dedicated resource should manage all aspects of water management	Assign responsible party for water management	
10	Stage 5 Roles & Responsibilities	Pre-Construction Meeting	Incomplete review of roles and responsibilities, and insufficient discussion at pre-construction/kick-off meeting; discussion inhibited by CPUC presence, planned transfer of responsibilities from PCM to PSEP created uncertainites reagrding some R&Rs	Conduct initial pre-construction kickoff meeting prior to CPUC involvement followed by kickoff meeting w/ CPUC; avoid reassignment of projects at this stage if possible.	
11	Construction/Quality	Quality	Communication & teamwork (relations need to be addressed): construction management blocked quality involvement (NCR generation AFTER construction was complete instead of during the project)	Establish team & R&Rs in Stage 4 prior to construction. Review & align during kickoff meeting.	Potential Compliance
12	Construction	Documentation	Ensure proper OP Qual documentation established at beginning of job	Establish checklist of required on-site documentation & assign responsibility to maintain throughout construction.	Compliance
13	Construction	Contractors	Manage contractor and work activities to ensure adequate planning (lack of 3-day look ahead)	Provide 1-2 week look-ahead to manage construction schedule more effectively	
14	Construction/Environmental	Water Management	Utilized 'double' wash water train	Continue practice on future projects	L - Cost, reduces treatment cost
15	Quality/Survey	Survey	Survey As-Built Quality Review process was effective; produced outstanding product	Continue practice on future projects	
16	General	Program Development	Executing a prototype project (early) was an effective means to identify PSEP requirements & issues & make work process adjustments to address	n/a	H - Cost
17	Construction/Environmental	Water Management	Reuse water for Hydrotesting instead of discharging after every test	Continue practice on future projects when applicable	Less discharge, implement to future projects (M - Cost & Schedule)
18	Inspectors	Communication	Open discussion about DIRs allowed inspectors to teach others who were less experienced in the field	Continue practice on future projects when applicable	Sharing DIRs amongst inspectors

In Progress Lessons Learned Line 2000A

- Common LL Approach vs In Progress
  - End of stage or end of project vs mid-stage 5
  - Cross-functional, facilitated session vs one-off observations
  - Possible in-depth analysis vs observations/limited analysis
- Purpose
  - Leveraging information across PSEP early
  - Provide foundation/'food for thought' for complete assessment & identification of efficient improvements
- Format – Interaction encouraged

In Progress Lessons Learned
Line 2000A

Background

- Business Objective of 2013 completion imposed demanding schedule
- Schedule required initiation by PCM resulting in mid-execution transition
- Ten segments -11/11A/12/13/14&15/16/17/18/18A/19

Engineering/Design

Item/Observation	Detail/Impact	Comment
Issued DDS did not include all taps	Mid-construction revisions & procedure rework	
Initial water treatment ineffective	Water treatment based on non-representative sample/potential schedule delay	Contributed to reevaluation & revision of execution plan; revised fill plan to include wash water segregation & disposal
No master MTO	Assumption construction contractor would perform MTO from individual drawings/potential schedule delay	Have engineering subcontractor generate from CADD data base

In Progress Lessons Learned
Line 2000A

Planning

Item/Observation	Detail/Impact	Comment
50+ External Approvals (permits easements)/notifications	Requirements (pulling permits & notifications) not entirely clear/opportunity for error, i.e., missed notification, non-adherence & schedule delay	Developed consolidated external approval/notification matrix w/ target notification dates keyed by planned field activity dates
Procedures developed during construction	Risk Mitigation Plan & Hydrotest Procedures developed during construction; discrepancies identified between DDS, procedure, specification & addenda /potential schedule delay	Develop drafts in Stage 4
Construction staking	Staking performed for engineering assumed adequate/activity conducted on short notice-potential schedule delay	
Budgeting-final documentation started in Stage 5	Due to multiple segments final documentation in-progress prior to completion of all construction	Include in Stage 5 budget

In Progress Lessons Learned Line 2000A

Scope Definition

Item/Observation	Detail/Impact	Comment
Wrinkle bends	Scope added late Stage 4-Permits & easements not obtained at award of construction contract (CC)	Ideally, full scope definition e/o Stage 3 & basis for S3 TIC estimate; if not possible finalize during Stage 4 & include in construction RFP; **Develop schematic early Stage 2 to communicate key information to all internal stakeholders, review face to face.**
Relocated tap alternate supply	Initial scope added late Stage 4, revised mid Stage 5/Drawings, permits, easements not available at award of CC; TRE not obtainable, causing mid-construction redesign, addition of test segment (18A) & hot tap/stopple	**Early & frequent face to face interface w/ Operations & all key stakeholders (operations/construction sequence review, PEP development, IAP, operations & construction reviews)**
Reg station fed by line 2001 not 2000	Purchased PCF not required/potential added cost	PCF used due to addition of 18A

In Progress Lessons Learned Line 2000A

Scope Definition & Field Execution/Coordination

Item/Observation	Detail/Impact	Comment
R&Rs not fully understood at construction start	Project & Construction Management transition from PCM to PSEP; not all field positions filled	PSEP startup; ensure positions staffed earlier
Delayed field incident reporting	Water spill & first aid	
	CPUC presence inhibited full discussion of planning topics	Conduct pre-construction meeting prior to CPUC pre-construction meeting
Revised water management plan after start of construction	Initial water treatment ineffective potential schedule impact concern/Additional cost (storage & treatment)	Storage capacity increased to provide flexibility & reuse of water
Water spill	Tank overflowed during dewater/potential schedule impact-discharge to storm drain would have required revision of SWPP	Item of high emphasis during pre-construction planning with construction contractor

In Progress Lessons Learned
Line 2000A

External Stakeholders

Item/Observation	Detail/Impact	Comment
CPUC involvement	Higher than anticipated level of CPUC involvement/dedicated resource required to	
Notification of property owner	Wrinkle Bend excavation eliminated homeowner access to driveway; notification shorter than planned/potential public relations impact	
City of Riverside curtailed work hours	Change in permit requirements/potential schedule impact	PA & Construction responded on short notice w/ alternate plan to work nights
Rescheduled test to avoid 1st day of school	Test planned for first day of school/traffic could inhibit patrolling, response & exposure if failure occurred	Consider external stakeholder activities during schedule development
Clear understanding of notification vs authorization	Riverside-considers authorization required to take water	

In Progress Lessons Learned
Line 2000A

Program & Contractor Performance

Item/Observation	Detail/Impact	Comment
Limited PMCS functionality initially	Work arounds required initially to issue documents & manage RFIs	Documents currently issued via PMCS; enable contractor access on future projects
Surveying-short response time	Supported changes to plan as needed/potential schedule impact	
Engineering-short response time	Supported changes to plan as needed/potential schedule impact	
Construction-progress per schedule	Supported changes to plan as needed/potential schedule impact	

In Progress Lessons Learned
Line 2000A

Summary

- Preliminary Assessment – Follow-up with identification of common root causes & associated fixes end of Stage 5
- Conclusions & Recommendations
  - Not complex
  - Timing-perform activity earlier in project

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-12)
Date Received: June 4, 2015
Date Responded: June 18, 2015

QUESTION 1:

It appears that all of the replacement segments in completed project Line 2000-A are replacements of hydro test tie-in locations.[1] Is this accurate? If not, please explain.

RESPONSE 1:

Yes, all of the replacement segments in project Line 2000-A are replacements of hydrotest tie-in locations.

[1] Sempra Workpaper, "12-12-14 SCG PSEP WP 2000-A _FINAL EDITS".

QUESTION 2:

The Chino, Corona, and Riverside segments of project Line 2000-A are at least 24 miles[2] from the Beaumont and Banning sections of the same project.

a) Why were these two regions included in the same project?

b) Has Sempra established a maximum distance between two segments on the same pipeline above which the segments would be split into separate projects?

RESPONSE 2:

a) The project was planned to be done with one Contractor under one contract. Construction on the 10 segments on 2000-A were planned to be worked sequentially. The distance between sections did not cause the project to be split.

b) SoCalGas and SDG&E have not established a maximum distance between two segments on the same pipeline causing it to split into separate projects.

[2] Sempra Workpaper, "12-12-14 SCG PSEP WP 2000-A _FINAL EDITS", sheet 'Table'.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-12)
Date Received: June 4, 2015
Date Responded: June 18, 2015

QUESTION 3:

Complete project Line 42-66-1 / 42-66-2 involves both replacement (segment 42-66-1) and abandonment (segment 42-66-2) of pipeline. However, only line 42-66-1 is labeled on the workpaper map[3] provided by Sempra.

Please provide a map similar to that in the provided workpapers showing where the abandoned line is (or was) located. If this is not possible, please explain why and describe in words where the abandoned segment runs (or ran) relative to segment 42-66-1 and local landmarks (railroad tracks, S. Beach Boulevard, private property fences, etc.)

RESPONSE 3:

The attached document contains confidential information pursuant to Provisions of Public Utilities Code Section 583 and General Order 66-C.

For Line 42-66-2 abandonment details, please refer to the "42-66-1 and 2_Map2 CONFIDENTIAL.pdf" file in the Q3 Attachments folder.

[3] Sempra Workpaper, "12-12-14 SCG PSEP WP 42-66-1_FINAL EDITS", sheet 'WP Summary Overview'.

QUESTION 4:

Sempra's workpaper for completed project Line 42-66-1 / 42-66-2 states: "Upon further inspection and analysis of the Line, it was determined that only 42-66-1 needed to be replaced and 42-66-2 could be abandoned."[4] Please provide further explanation as to how and why segment 42-66-2 was determined to be able to be abandoned.

RESPONSE 4:

Background: Existing SL 42-66-1 and SL 42-66-2 ran from different sides of a mainline valve on SoCalGas' Transmission Line 2000 that runs east and west on the north side of the UPRR in La Habra. These two supply lines connected Line 2000 to SoCalGas' Distribution Regulator Station (ID 2020-OC) located on the south side of the railroad tracks just west of Harbor Blvd in La Habra. Both supply lines had been installed in casing pipe under the railroad tracks.

The hydraulic analysis completed by the Orange Coast Region engineering group for the replacement of these two supply lines indicated that a single connecting line was all that was required between the Line 2000 and the Regulator Station. This eliminated one cased crossing under the railroad tracks, reducing the overall project costs. By installing a bridle assembly around the mainline valve, service to the Regulator Station could still be provided from either or both the upstream and the downstream section of Line 2000. A bridle assembly involves piping around the mainline valve with reduced sized piping and two reduced sized valves, one near Line 2000 on either side of the mainline valve. Please refer to illustration below:

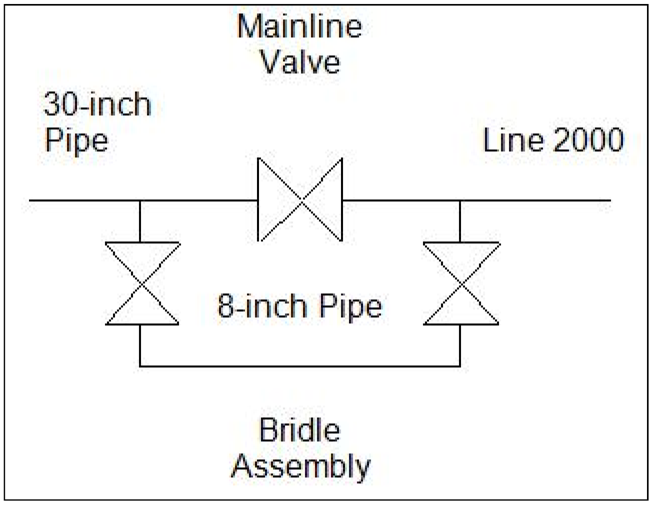
[4] Sempra Workpaper, "12-12-14 SCG PSEP WP 42-66-1_FINAL EDITS", sheet 'WP Summary Overview'.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-12)
Date Received: June 4, 2015
Date Responded: June 18, 2015



Approximately 0.026 miles of 8-inch pipe was installed as the replacement of SL 42-66-1 connecting Line 2000 with the Regulator Station. Because of the reconfigured piping (one line connecting Line 2000 to the Regulator Station vs the existing configuration utilizing two lines) only approximately 0.002 miles of 8-inch pipe was installed as the replacement of SL 42-66-2. The replacement section of SL 42-66-2 is only part of the bridle around the mainline valve on Line 2000.

Because of limited work space, portions of the two existing supply lines were removed in order to install the new piping. The sections of the existing piping that were left in-place were abandoned.

RESPONSE: In the past SoCalGas' practice was to install two lines for connections between Transmission lines and Distribution regulator stations – one from each side of the Transmission mainline valve. SoCalGas' current practice includes a bridle assembly around the Transmission mainline valve, and only one line connecting to the Distribution regulator station. The Request for Engineering Review (RER) supports the use of one line by recommending that 42-66-1 and 42-66-2 be replaced with a single 8" inlet to ID 2020-OC. For RER details please refer to the "SL 42-66-1 and 2_RER 12506b CONFIDENTIAL.pdf" file in the Q4 Attachments folder.

The attached documents include confidential information pursuant to Provisions of Public Utilities Code Section 583 and General Order 66-C.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-12)
Date Received: June 4, 2015
Date Responded: June 18, 2015

QUESTION 5:

Was the abandonment of segment 42-66-2 carried out according to 49 Code of Federal Regulations § 192.727, Abandonment or Deactivation of Facilities?[5] If so, please explain for each of the items in § 192.727 what steps Sempra took to comply with the abandonment of segment 42-66-2.

RESPONSE 5:

Yes, the abandonment of segment 42-66-2 was carried out according to 49 Code of Federal Regulations § 192.727, Abandonment or Deactivation of Facilities. CFR - Subpart 192.727 “Abandonment or deactivation of facilities” has the following major sections:

(a) Each operator shall conduct abandonment or deactivation of pipelines in accordance with the requirements of this section.

Yes – the abandonment was completed in compliance with Subpart 192.727.

(b) Each pipeline abandoned in place must be disconnected from all sources and supplies of natural gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

Yes - the abandoned sections were disconnected from all sources and supplies of natural gas and purged on any natural gas, and metal plates were welded to the open ends of the abandoned sections. The lines were not offshore.

(c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of natural gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

Not Applicable – the lines are not inactive, they were abandoned in place.

---

[5] http://www.ecfr.gov/cgibin/text-idx?SID=871181d97e8334deea0a0034ce1492e1&mc=true&node=se49.3.192_1727

(d) Whenever service to a customer is discontinued, one of the following must be complied with:

Not Applicable – no service to a customer was disconnected.

(e) If air is used to purging, the operator shall insure that a combustible mixture is not present after purging.

Not Applicable – nitrogen was used for purging.

(f) Each abandoned vault must be filled with suitable compacted material.

Yes - one vault was abandoned – the concrete walls and floor were removed and the hole was backfilled with native soil and compacted.

(g) For each abandoned offshore facility or each abandoned onshore pipeline that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility.

Not applicable – the lines do not impact any waterway.

<u>QUESTION 6:</u>

In a document titled "ORA DR3 Q5 project testvreplace.docx" provided in response to data request DR-ORA-03, Question 5, Sempra states:
"COR-18, COR-18A: COR-18 and COR-18A are adjacent. The test had to be split because Tap 183.15 was placed into service while planning the hydrotest. The change was made to the design once it became known that the tap was becoming active. A pressure control fitting and bridle arrangement was installed to keep the tap active while COR-18 and COR-18A were tested."[6]

a) Would it have been technically possible to delay placing Tap 183.15 into service until after the hydrotest had been completed? If not, why?

b) If the answer to part (a) is yes, what would such a delay have cost? Please provide calculations and/or workpapers as appropriate.

c) Please provide the additional costs that were incurred as a result of the change to the project resulting from Tap 183.15 being brought into service?

<u>RESPONSE 6:</u>

a) No, it was not possible to delay placing Tap 183.15 into service. Tap 183.15 was replacing another tap off Line 2000 that was abandoned because of construction work driven by others. Without the installation of Tap 183.15, a pressure district would not have adequate feed to maintain minimum pressure.

b) Not Applicable

c) The following document contains confidential information pursuant to Provisions of Public Utilities Code Section 583 and General Order 66-C.

   An estimate cost of $296,782 was incurred as a result from Tap 183.15 being brought into service. For estimate please refer to the "2000-A_014_PC_Change Notice No 408 CONFIDENTIAL.pdf" file in the Q6 Attachments folder.

[6] Sempra Response to ORA-DR-03, Q5, Attachment "ORA DR3 Q5 project testvreplace.docx".

QUESTION 7:

Were the segments listed as replaced in completed project Line 2000-A replaced at the time of hydrotesting? If not, did the replacements require a second dig at the same site in order to perform the replacement? Please explain.

RESPONSE 7:

Yes, the segments listed as replaced for Line 2000-A were replaced at the time of hydrotesting.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-11)
Date Requested: May 28, 2015
Date Responded: June 11, 2015

The following questions will refer to the four projects submitted in Sempra's application as complete (Line 2000-A, Line 42-66-1/42-66-2, Line 45-120X01, Playa del Rey Phases 1-3) as "the projects" or "the four completed projects". The questions below do not refer to any of the other projects in the Application. ORA understands that post-June 12, 2014 costs are not being assessed for reasonableness in this application. The following questions are intended to learn more about the magnitude of potential "trailing costs" and understand their relevance to PSEP projects.

QUESTION 1:

It is ORA's understanding that the four completed projects were, as of June 12, 2014, in Stage Seven of the Seven-Stage Review Process, but were not completely closed out. Is this understanding correct? If not, please explain.

RESPONSE 1:

ORA's understanding is generally correct. As mentioned in Supplemental testimony,[1] the four completed projects[2] were not subject to the formal Seven Stage Review Process. The four completed projects were, however, as of June 12, 2014, at a Stage Seven equivalent level of project completion and not completely closed out.

---

[1] Hugo Mejia's Revised Supplemental Testimony, dated May 28, 2015 pages 18, 28, 33, 36.

[2] As stated in Hugo Mejia's Revised Supplemental Testimony, dated May 28, 2015, for purposes of this application, a project is considered complete six months after SoCalGas or SDG&E return the pipeline or valve to service.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-11)
Date Requested: May 28, 2015
Date Responded: June 11, 2015

QUESTION 2:

As of May 1, 2015, has Stage Seven of the Seven-Stage Review Process been completed for any of the projects since June 12, 2014? If so, which ones and on what date?

RESPONSE 2:

As mentioned in Supplemental testimony,[3] the four completed projects were not subject to the formal Seven Stage Review Process. At this time, no projects have been completely closed out.

[3] Hugo Mejia's Revised Supplemental Testimony, dated May 28, 2015 pages 18, 28, 33, 36.

QUESTION 3:

Have any of the four completed projects accrued "trailing costs" since June 12, 2014? If so, which ones?

RESPONSE 3:

Yes, all four completed projects have accrued trailing costs since June 12, 2014.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-11)
Date Requested: May 28, 2015
Date Responded: June 11, 2015

QUESTION 4:

For any of the four completed projects for which the answer to Question 3 is yes and all costs are accounted for, please provide:

a) The total dollar amounts of the received trailing costs; and
b) The percentage of total project costs that the received costs represent.

RESPONSE 4:

a) Per discussion with ORA, SoCalGas and SDG&E understand "accounted for" to refer to costs already booked. Trailing costs are still being incurred and trailing costs currently included for these projects are still in the process of being reconciled. As such, the trailing costs are subject to change. Please refer to the attached file ORA-PSMRA-SCG-11Q4; Label C for trailing costs as of May 2015.
b) Please refer to Label F for the percentage of total project costs.

ORA-PSMRA-SCG-11
Q4

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(DATA REQUEST ORA-PSRMA-SCG-11)
Date Requested: May 28, 2015
Date Responded: June 11, 2015

QUESTION 5:

For any of the four completed projects for which the answer to Question 3 is yes and all costs are not yet accounted for, please provide:

a) The total dollar amounts of the received trailing costs; and
b) The percentage of total project costs that the received costs represent; and
c) An estimate, if available, of when the trailing costs will be accounted for; and
d) An estimate, if available, of how much the trailing costs will be; and
e) The percentage of the total project costs the estimated costs represent.

RESPONSE 5:

a) – e) Per discussion with ORA, SoCalGas and SDG&E understand “not yet accounted for” to refer to costs not already booked. SoCalGas and SDG&E anticipate there will be trailing costs not yet booked to the four completed projects. SoCalGas and SDG&E are unable to determine with a level of certainty the amount of trailing costs that remain outstanding at this time, but do not expect additional trailing costs to be significant.

ORA-PSRMA-SCG-11Q4

Pipeline Safety Enhancement Plan

SoCalGas and SDG&E

	(a)	(b)	(c =a+b)	(d)	(e =c+d)	(f =c/e)
	Trailing Costs (July 2014 to May 2015)					
Projects	**Labor and Non-labor Costs**	**Overheads**	**Trailing Total**	**PSRMA**	**Total**	**Percentage of Trailing Costs**
45-120X01[1]	(31)	(1,628)	(1,659)	886,148	884,489	-0.2%
42-66-1/42-66-2[2]	9,204	7,602	16,805	813,327	830,133	2.0%
2000-A[3]	70,145	20,460	90,604	26,374,877	26,465,481	0.3%
Playa del Rey Ph. 1 & 2[3]	92,460	5,485	97,945	683,036	780,981	12.5%
Total	171,777	31,919	203,696	28,757,389	28,961,085	

[1]SoCalGas/SDG&E filed a Motion on May 28, 2015 to remove Line 45-120X01 from consideration in this proceeding.

[2]Reduced PSRMA total for 42-66-1/42-66-2 per SoCalGas/SDG&E's Motion to amend the application A.14-12-016 filed on May 28, 2015.

[3]Currently still researching trailing costs. Additional adjustments will be made as needed.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(ORA-PSRMA-SCG-04)

Date Received: March 27, 2015
Date Responded: April 10, 2015 (Partial)

QUESTION ORA-PSRMA-SCG-04-01:

It is ORA’s understanding that Sempra’s system-wide search for records concerning natural gas transmission pipeline specifications, installations, and hydro tests is complete, although at the commencement of specific projects Sempra may conduct further, more narrow searches specific to a certain pipeline segment or set of segments. Is ORA’s understanding correct? If not, please explain.

RESPONSE ORA-PSRMA-SCG-04-01:

ORA’s understanding is correct. As previously explained in response ORA-PSRMA-SCG-03, question 15, as part of the design and engineering phase of PSEP pipeline projects, through routine pipeline assessments, or other pipeline operations-related work, SoCalGas and SDG&E may occasionally identify pipelines or segments for further review and analysis, which may potentially result in a re-categorization of a particular pipeline or segment.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(ORA-PSRMA-SCG-04)

Date Received: March 27, 2015
Date Responded: April 10, 2015 (Partial)

QUESTION ORA-PSRMA-SCG-04-02

Please provide:

a) the total number of miles of transmission pipeline in Sempra's natural gas system;

b) the conclusion date of Sempra's overall record search; and

c) the number of miles of transmission pipe without traceable, verifiable, and complete (TVC) records at the following dates:

i. Immediately before the start of the PSEP program
ii. At the conclusion Sempra's record search
iii. Quarterly since the conclusion date of Sempra's record search.

RESPONSE ORA-PSRMA-SCG-04-02:

Per discussion with ORA, SoCalGas/SDG&E will provide a response at a later date.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(ORA-PSRMA-SCG-04)

Date Received: March 27, 2015
Date Responded: April 10, 2015 (Partial)

QUESTION ORA-PSRMA-SCG-04-03:

In Sempra's PSRMA application overview presentation on March 25th, Sempra noted (slide 13) of the Performance Partner Program: "contracts are limited to one year terms with extensions based on safe, cost-conscious, and efficient performance"

a) Please provide sample evaluation document(s) (rubric(s), report card(s), etc.) that Sempra uses to evaluate contractors as described above. This sample need not be from an actual Partner or contract, but is meant to be illustrative.

b) How many contract re-evaluations have been performed in the PSEP program as described above? What percent of these evaluations have resulted in a renewal of the contract? What percent of these evaluations have resulted in termination (or lapsing) of the contact?

RESPONSE ORA-PSRMA-SCG-04-03:

a) For evaluation documents that PSEP uses to track, monitor and evaluate the performance of our Performance Partner contractors, please refer to the two attachments in the following zip file:

   ORA DR4 Q3 – Rubrics_Scorecards.zip

b) There has not been any completed contract re-evaluations performed in the PSEP program to-date. The contracts for Performance Partnerships started in May 2014. SoCalGas/SDG&E are currently in the process of performing the first re-evaluation(s).

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(ORA-PSRMA-SCG-04)

Date Received: March 27, 2015
Date Responded: April 10, 2015 (Partial)

QUESTION ORA-PSRMA-SCG-04-04:

Please state which projects in the current Application (completed, in-progress, and de-scoped) were executed with fixed-bid contracts and which projects were executed using the incentive mechanism discussed at the March 25th meeting (additional question below). If any projects were executed with both, please explain. If any projects changed from one type to the other, please explain.

RESPONSE ORA-PSRMA-SCG-04-04:

The tables below depict which projects were executed using the fixed-bid contracts or the performance partner incentive mechanism. In addition, one project, Playa Del Rey, used a Time and Material (T&M) contract. No contracts were executed for the descoped projects, as they were descoped prior to contracts execution.

COMPLETED PROJECTS	
2000-A	Fixed Bid
42-66-1/42-66-2	Fixed Bid
45-120X01	Fixed Bid
Playa Del Rey Storage Phases 1-2	Time and Material (T&M)

IN PROGRESS PROJECTS	
404	Incentive Mechanism
406	Incentive Mechanism
407	Fixed Bid/Incentive Mechanism*
1004	Incentive Mechanism
1015	Incentive Mechanism
2003	Incentive Mechanism
2000 West	Incentive Mechanism
2001 West	Incentive Mechanism
32-21	Incentive Mechanism
37-18F	Incentive Mechanism
41-116BP1	Fixed Bid
Playa del Rey Storage Phase 5	Incentive Mechanism

*Line 407 was divided into two sections. The North Section went into construction prior to the implementation of the Incentive Mechanism and thus was executed under a fixed-bid contract.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(ORA-PSRMA-SCG-04)

Date Received: March 27, 2015
Date Responded: April 10, 2015 (Partial)

QUESTION ORA-PSRMA-SCG-04-05:

It is ORA's understanding that current and future contracts in the PSEP program will largely be executed through a system that includes cost-sharing for cost overruns and profit-sharing for cost savings. ORA understood these contracts to include mechanisms called "cost/profit-sharing bands" at the March 25th meeting and will refer to them as such below. Is this understanding correct? If not, please explain.

RESPONSE ORA-PSRMA-SCG-04-05:

Per discussion with ORA, SoCalGas/SDG&E will provide a response at a later date.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(ORA-PSRMA-SCG-04)

Date Received: March 27, 2015
Date Responded: April 10, 2015 (Partial)

<u>QUESTION ORA-PSRMA-SCG-04-06:</u>

Please provide the structure of contracts and "cost/profit-sharing bands" described in Question 5, including what delineates each "band" (e.g. cost overrun/savings percentage) and the percentage sharing mechanism in each "band".

Please provide an example of a project with a cost overrun and a different project with a cost savings, and how these difference would be shared (for example: "A project with an estimated value of $5M saved $250k. Since this is a savings of 5% of the contract price, the contractor keeps $A (X%) and Sempra keeps $B (Y%)") These examples need not be from actual projects, but are meant to be illustrative.

<u>RESPONSE ORA-PSRMA-SCG-04-06:</u>

Per discussion with ORA, SoCalGas/SDG&E will provide a response at a later date.

Date Received: March 27, 2015
Date Responded: April 10, 2015 (Partial)

QUESTION ORA-PSRMA-SCG-04-07:

Other than the cost/profit-sharing bands, are there any other incentive mechanisms that have been used in the contracts for the projects that are within the scope of the application? If so, please describe each of them.

RESPONSE ORA-PSRMA-SCG-04-07:

Per discussion with ORA, SoCalGas/SDG&E will provide a response at a later date.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(ORA-PSRMA-SCG-04)

Date Received: March 27, 2015
Date Responded: April 10, 2015 (Partial)

QUESTION ORA-PSRMA-SCG-04-08:

It is ORA's understanding that Sempra's PSEP work is divided into a number of geographic regions that collectively cover Sempra's entire service territory. Is this understanding correct? If not, please explain. If so, please list these regions and state what percentage of PSEP projects are covered by each region. Please provide one percentage breakdown for number of projects and one percentage breakdown for estimated value of projects.

RESPONSE ORA-PSRMA-SCG-04-08:

Per discussion with ORA, SoCalGas/SDG&E will provide a response at a later date.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(ORA-PSRMA-SCG-04)

Date Received: March 27, 2015
Date Responded: April 10, 2015 (Partial)

QUESTION ORA-PSRMA-SCG-04-09:

It is ORA's understanding from the March 25th meeting that one of the regions does not use cost/profit sharing bands as an incentive mechanism.

a. Is this understanding accurate?

b. If ORA's understanding is accurate, which region does not use the cost/profit sharing bands? Please explain in detail.

RESPONSE ORA-PSRMA-SCG-04-09:

Per discussion with ORA, SoCalGas/SDG&E will provide a response at a later date.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(ORA-PSRMA-SCG-04)

Date Received: March 27, 2015
Date Responded: April 10, 2015 (Partial)

QUESTION ORA-PSRMA-SCG-04-10:

Please provide the contracts for each of the completed projects within the application.

RESPONSE ORA-PSRMA-SCG-04-10:

Per discussion with ORA, SoCalGas/SDG&E will provide a response at a later date.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(ORA-PSRMA-SCG-04)

Date Received: March 27, 2015
Date Responded: April 10, 2015 (Partial)

QUESTION ORA-PSRMA-SCG-04-11:

Please provide the contract(s) for two of the in-progress projects within the Application. Please ensure that the contract(s) for one project are fixed price contract(s), and that the contract(s) for the other project include the cost-profit sharing bands mentioned in Questions 5 and 6.

RESPONSE ORA-PSRMA-SCG-04-11:

Per discussion with ORA, SoCalGas/SDG&E will provide a response at a later date.

SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY

APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS

(A.14-12-016)

(ORA-PSRMA-SCG-04)

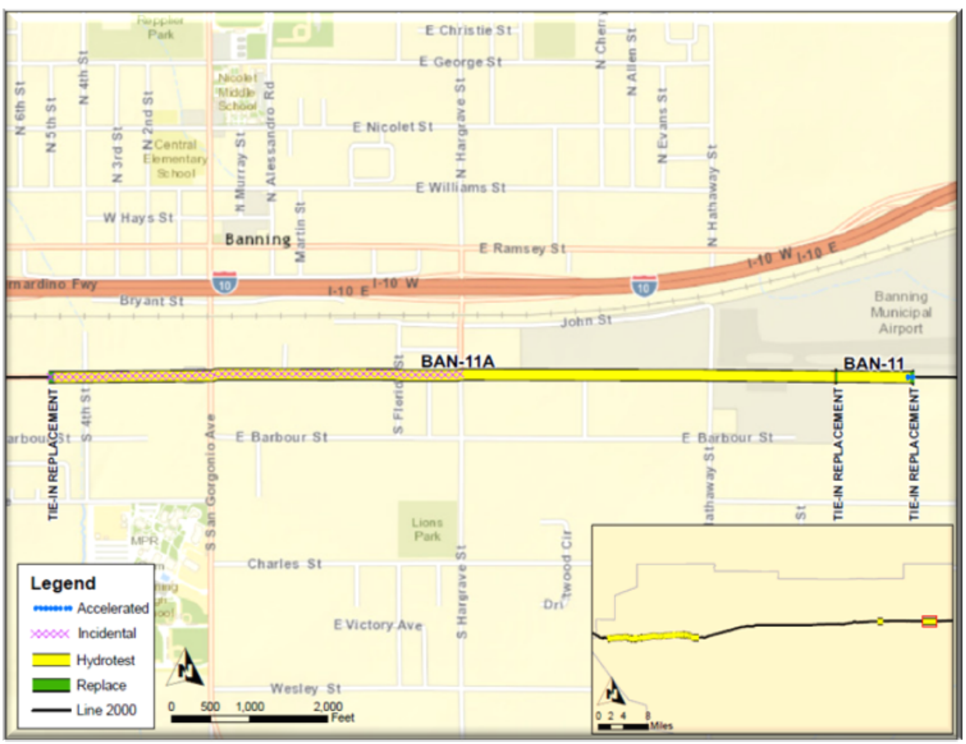
Date Received: March 27, 2015
Date Responded: April 10, 2015 (Partial)

QUESTION ORA-PSRMA-SCG-04-12:

The examples of projects that were accelerated and incidental miles provided at the March 25 meeting were helpful. Please provide brief written explanations for each of the examples discussed at that meeting, including which example is an "accelerated" project and which is an "incidental" one.

RESPONSE ORA-PSRMA-SCG-04-12:

Example of Incidental Miles:
Line 2000-A: Banning 11A (Slide 16 of the 3/25 Presentation)



Total miles tested – 1.580 miles
Category Four miles - 0.755 miles
Incidental miles - 0.825 miles

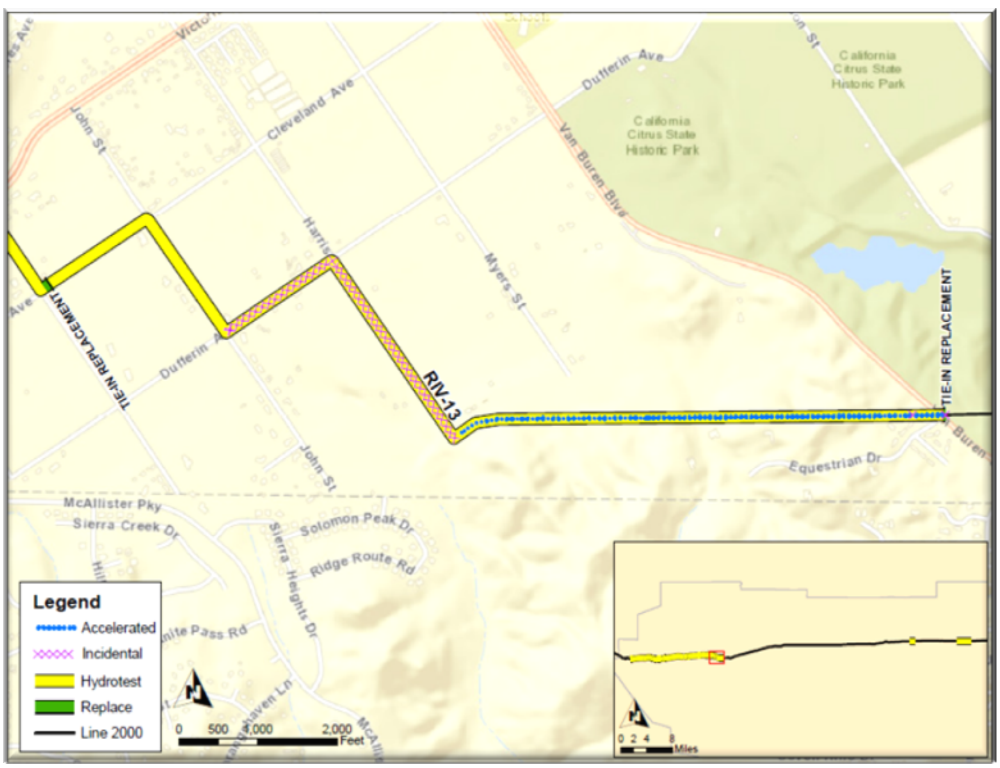
SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
APPLICATION TO
RECOVER COSTS RECORDED IN THEIR PIPELINE SAFETY AND RELIABILITY MEMORANDUM ACCOUNTS
(A.14-12-016)

(ORA-PSRMA-SCG-04)

Date Received: March 27, 2015
Date Responded: April 10, 2015 (Partial)

The Banning 11A section of the Line 2000-A project is an example of the inclusion of incidental miles into the overall length tested. The western terminus of the Category Four section was at a major thoroughfare (Hargrave St on map) that did not have sufficient space available for the staging and other construction activity (e.g. storage of water tanks, installation of test heads). For this project, a minimum staging area of 44,000 square feet was required. The closest space to meet these requirements was 0.825 miles west of the western terminus of the Category Four miles. The location was also chosen because there was access to a flood control channel that enabled the efficient disposal of treated water after the hydrotest.

Example of Accelerated and Incidental Miles:
Line 2000-A: Riverside 13 (Slide 17 of the 3/25 Presentation)



Total miles tested – 2.177 miles
Category Four miles - 0.499 miles
Accelerated Miles - 0.971 miles

Incidental miles - 0.707 miles. The Riverside 13 section of the Line 2000-A project is an example of accelerated and incidental miles included in the overall test length to realize operating and cost efficiencies by including segments that would have otherwise been addressed in subsequent phases of PSEP. The accelerated portion of 0.971 miles, if treated as a separate project in Phase 2, would have required the pipeline to be taken out of service a second time, as well as incurring duplicative costs for test heads, water, permits, construction, etc. Also, two additional tie-in points would have been required. The 0.707 incidental miles were necessary to bridge the Category Four and Accelerated sections.

Decision 14-06-007 June 12, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U902G) and Southern California Gas Company (U904G) for Authority To Revise Their Rates Effective January 1, 2013, in Their Triennial Cost Allocation Proceeding	Application 11-11-002 (Filed November 1, 2011)

DECISION IMPLEMENTING A SAFETY ENHANCEMENT PLAN AND APPROVAL PROCESS FOR SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY; DENYING THE PROPOSED COST ALLOCATION FOR SAFETY ENHANCEMENT COSTS; AND ADOPTING A RATEMAKING SETTLEMENT

Table of Contents (Cont.)

Title **Page**

Table of Contents (Cont.)

Title **Page**

Table of Contents (Cont.)

Title **Page**

With the burden of proof placed on SDG&E and SoCalGas, the Commission has held that the standard of proof SDG&E and SoCalGas must meet is that of a preponderance of evidence.[12] Preponderance of the evidence usually is defined "in terms of probability of truth, e.g., 'such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth'"[13] In short; SDG&E and SoCalGas must present more evidence that supports the requested result than would support an alternative outcome.

We have analyzed the record in this proceeding within these parameters. These are the same parameter used for Pacific Gas & Electric Company (PG&E). (D.12-12-030 at 41.)

3.2. Application of Standard

It is thus quite clear that SDG&E and SoCalGas bear the burden of proof for the reasonableness of its past practices in building, maintaining, and operating the pipeline systems and for its ratesetting proposals in this proceeding. Parties have debated what standard to apply: clear and convincing or preponderance, a lower standard. The Commission's standard for reasonableness issues is the preponderance standard, and we find that at even the lower standard of preponderance of evidence, SDG&E and SoCalGas failed

---

And to Reflect That Increase In Rates (D.09-03-025, *mimeo*. at 8) (March 12, 2009) and Decisions cited therein.

[12] *See* D. 12-12-030, at 44. "Decision Mandating Pipeline Safety Implementation Plan, Disallowing Costs, Allocating Risk of Inefficient Construction Management to Shareholders, and Requiring Ongoing Improvement in Safety Engineering."

[13] In the Matter of the Application of San Diego Gas & Electric Company for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project, D.08-12-058, *citing* Witkin, Calif. Evidence, 4th Edition, Vol. 1, 184.

to have adequate and reliable records for significant segments of their system and must therefore bear some of the consequences that result from those inadequate records. We further find that SDG&E and SoCalGas's showing was inadequate in detail and thoroughness to approve Safety Enhancement as proposed thus failing the usual preponderance test. This has been one of the main challenges in this proceeding. Therefore, as discussed below, we will require further showing before approving any final cost recovery from the balancing accounts.

3.3. Record

The record for this proceeding consists of the documents filed and served and the testimony and exhibits admitted during the evidentiary hearings. This record is the sole basis for this decision.

4. SDG&E & SoCalGas' Safety Enhancement

4.1. Decision Tree

SDG&E and SoCalGas produced two exhibits, the first of which is a "Decision Tree" included here as Attachment I,[14] and a more complicated table that reconciled all the natural gas pipeline system into various classifications or risk factors, age, documentation, etc., referred to as a "Reconciliation" included here as Attachment II.[15]

The Decision Tree results in a first cut allocation of SDG&E and SoCalGas's pipelines into the proposed phases 1A, 1B, and Phase 2. It is the heart of SDG&E and SoCalGas's Safety Enhancement process.

[14] Ex. SCG-33-R.

[15] Ex. SCG-34-R.

embodied in the Decision Tree we address all pipelines to ensure the system as a whole can be relied upon to be safe, and not just complying with the safety rules of a bygone era.

4.2.5. Southern California Generation Coalition - Summary

The Southern California Generation Coalition (Coalition) in its opening brief argues that the application and testimony lacked the necessary detail needed before the Commission could adequately conduct a review of the proposed expenditures and authorize rate recovery. The Coalition proposed that the Commission should "review on a case-by-case basis" utilizing an existing tool used by this Commission, the Expedited Application Docket procedure, each pipeline segment as a specific project within Safety Enhancement. (Coalition Opening Brief at 1.) As discussed below, we find merit with this concept, which we expand on in our balancing account methodology, but we do not adopt a series of mini-reviews by project or groups of projects. Preapproval would unduly delay Safety Enhancement and relieve SDG&E and SoCalGas of their obligation to exercise expert and prudent management.

4.2.6. Discussion

Safety Enhancement will take years to complete and will encompass numerous individual projects. It is only fair that ratepayers should have the benefit of detailed plans for this Commission to consider before authorizing or preapproving the expenditure of many hundreds of millions of dollars.

As set forth below, we find that SDG&E and SoCalGas have presented an adequate justification for Safety Enhancement at a conceptual level and we approve their Decision Tree (Attachment I) analytical approach. We find, however, that the budgets offered in support of this billion-dollar proposal are not sufficiently detailed to justify ratemaking pre-approval at this time. We authorize SDG&E and SoCalGas to file Tier 2 advice letters to establish balancing accounts and, in time, subsequent applications to demonstrate the reasonableness of costs and recover those costs in rates. We authorize SDG&E and SoCalGas to proceed with Safety Enhancement projects that conform to the Decision Tree logic and track the costs of the work in a series of balancing accounts described below. This decision does not preclude SoCalGas or SDG&E from submitting additional applications for specific projects for further guidance or approval. For example, SDG&E and SoCalGas may prefer to file one or more applications before undertaking specific projects, asking for pre-approval for the related revenue requirement to be included in rates which would be subject to a cap. Or, simply use the balancing accounts authorized in this decision and rely on the reasonableness reviews to authorize subsequent rate recovery.

For the Safety Enhancement Capital Cost Balancing Account SDG&E and SoCalGas may file reasonableness review applications for the recorded balances which reflect completed projects. This might be every other year or whenever there is a large balance. For the Safety Enhancement Expense Balancing Account, SDG&E and SoCalGas may file annually for a reasonableness review of the account balance beginning after December 31, 2015. They may also choose to file less often.

5. Safety Enhancement – Applying Section 454 Standard

5.1. Decision Tree

The Decision Tree is consistent with the priorities we set forth in D.11-06-017 and reflects a reasoned and orderly approach to testing or replacing natural gas pipeline in the SDG&E and SoCalGas systems. We find that SDG&E and SoCalGas have justified this approach to prioritizing the testing and replacement of natural gas pipeline systems. Therefore, we approve the Decision Tree and the analytical processes shown therein.

5.2. Ratemaking Proposal

During the evidentiary hearings SDG&E and SoCalGas produced two exhibits, Decision Tree the Reconciliation which explain and document both the review process (Decision Tree) proposed by SDG&E and SoCalGas and demonstrated in table form that the planning counted for the entire system (Reconciliation). This involved discussion and input from the parties and directions from the Judge. SDG&E and SoCalGas were eventually able to demonstrate that the Decision Tree does constitute a comprehensive plan to fully review and where necessary replace the natural gas system. The Reconciliation, and the time it took for the company to prepare it, illustrates both the complexity of the problem and that neither SDG&E nor SoCalGas, as of serving testimony or the evidentiary hearings, had sufficient management systems and personnel in place to show that they fully understand the flaws and weaknesses in the implementation plan and they do not have a complete plan in place which would result in a safe and reliable natural gas system.

The witness for the applicants clearly demonstrated that the budget preparation performed for this proceeding by SDG&E and SoCalGas is rudimentary at best. The witness contrasted the company's proposal with the budget requirements used by the federal government for major procurement projects. The witness clearly showed that SDG&E and SoCalGas at best a "level 5" budget in a system where a level 5 budget is extremely preliminary, in fact rudimentary, and then only after careful planning and design does the budget progressively improve to levels 4, 3, 2, and finally level 1which is the most complete an advanced level of budgetary planning.[17]

In testimony, SDG&E and SoCalGas admitted:

> The estimates in our workpapers represent best available cost projections considering the nature and extent of projects that needed to be estimated for the PSEP, and the short timeframe available to develop them. SoCalGas and SDG&E acknowledge that these estimates are necessarily preliminary and often somewhat conceptual in nature. (Ex. SCG-21 at 1-2.)

The budget proposals of SDG&E and SoCalGas are clearly not sufficient to justify this Commission to authorize for ratemaking purposes. There are only two clear alternatives: authorize the program but make the companies fully liable for all risk of reasonableness review in an after-the-fact review of the final cost of the project; or require the companies to more fully develop budget proposals on a segment by segment basis for project construction, and seek commission approval based upon the level 1 quality of budgeting.

We therefore find that SDG&E and SoCalGas have not justified their proposed ratemaking for the costs of Safety Enhancement with their current showing. We direct SDG&E and SoCalGas to file new applications, consistent with today's decision, with detailed project descriptions and history and adequate cost records to justify recovery in rates.

5.3. Safety Enhancement Balancing Accounts

A balancing account is an appropriate regulatory tool where the scope of work is known and accepted as is here, Safety Enhancement as described by the

---

[17] "Class 5 or slightly better" characterization is based on a "recommended practice" produced by the Association for the Advancement of Cost Engineering.

SDG&E and SoCalGas	Pipeline Miles[(i)] Phase 1A/B	Pressure Testing & Replacement Cost Responsibility
Pre-1946 Pipeline	269	Ratepayers Pay for Pressure Testing and/or New Pipeline
1946 Through June 1961	511	Ratepayers Pay for Pressure Testing and/or New Pipeline
July 1961 Through November 1970	29	When SDG&E or SoCalGas Cannot Produce Records Shareholders Pay for Pressure Testing & Absorbs Undepreciated Balances; Ratepayers Pay for New Pipeline
November 1970 to Present	74	When SDG&E or SoCalGas Cannot Produce Records Shareholders Pay for Pressure Testing & Absorbs Undepreciated Balances; Ratepayers Pay for New Pipeline

(i) Reconciliation

As we discussed elsewhere, for any pipeline abandoned or replaced that was installed after July 1, 1961, shareholders must absorb the remaining undepreciated book value. And, as also discussed, ratepayers bear the revenue requirement of the net replacement costs as they benefit from having a new safe and reliable pipeline.

6.4. Safety Enhancement Reasonableness Applications

6.4.1. Minimum Filing Requirements

When SDG&E and SoCalGas file applications to demonstrate the reasonableness of Safety Enhancement they will bear the burden of proof that the companies used industry best practices and that their actions were prudent. This is not a "perfection" standard: it is a standard of care that demonstrates all actions were well planned, properly supervised and all necessary records are retained. At a minimum we would expect that SDG&E and SoCalGas could document and demonstrate an overview of the management of Safety Enhancement which might include: ongoing management approved updates to the Decision Tree and ongoing updates similar to the Reconciliation. The companies should be able to show work plans, organization charts, position descriptions, Mission Statements, etc., used to effectively and efficiently manage Safety Enhancement. There would likely be records of contractor selection controls, project cost control systems and reports, engineering design and review controls, and of course proper retention of constructions records, retention of pressure testing records, and retention of all other construction test and inspection records, and records of all other activities mandated to be performed and documented by state or federal regulations.

6.5. Incentive Compensation

SoCalGas proposes to apply an 18.17% incentive compensation plan overhead loader to its management and associated direct labor costs, and SDG&E proposes a 17.79% incentive compensation plan overhead loader to its management and other direct labor costs. (Ex SCG-10 at 122.)

TURN argues (Opening Brief at 82) that incentive compensation plans usually are designed to reward utility management and employees for meeting specific financial goals that contribute to the shareholders' earnings. TURN goes on that regardless of whether or not it is appropriate for ratepayers fund incentive compensation plans in the normal course of business, incentives for the pipeline safety enhancement plan is clearly not in the ratepayers' best interests.

We note, however, that the usual practice for determining total compensation in the general rate case process for SDG&E and SoCalGas includes not just direct salary, but also various health benefits, retirement contributions, and incentive components. We are concerned here that Safety Enhancement is in large part remediation and we are confronted with the problem of reasonably compensating the workers, who follow the orders of the executives. But ratepayers need not reward management for this remediation. After careful consideration we believe that no employee at or above the level of vice president in any position, directly or indirectly associated with Safety Enhancement, in either SDG&E and SoCalGas, or positions allocated from their parent companies, should receive any incentive compensation for Safety Enhancement to be paid by ratepayers. Any Safety Enhancement incentive compensation for executives should be borne solely by shareholders. We do this solely because we do not want rank and file employees to avoid assignment to Safety Enhancement positions. We expect incentives to be sensibly established: e.g., an incentive for safely meeting schedules, or ensuring all work is performed to industry standards, etc.

We agree with TURN that this is a concern, that this is a remediation program; we are reluctant to include any compensation termed "incentive" and we conclude that no incentive compensation for executives, who as a body manage the companies and made decisions which led us to having to have a remediation program is warranted.

6.6. Pipeline Safety and Reliability Memorandum Accounts

Ordering Paragraph 3 in Dec. 12-04-021 in R. 11-02-019 allowed that:

> San Diego Gas and Electric Company and Southern California Gas Company must file a Tier 2 Advice Letter creating a memorandum account to record for later Commission ratemaking consideration the escalated direct and incremental overhead costs of its Pipeline Safety Enhancement Plan, as described in Attachment A to their January 13, 2012, filing, and costs of document review and interim safety measures as set forth in Attachment B to the January 13, 2012, filing.

On April 20, 2012, SDG&E and SoCalGas submitted Tier 2 Advice Letters 2106-G and 4359 to establish Pipeline Safety and Reliability Memorandum Accounts. Those Advice Letters were approved on May 18, 2012, with an effective date of May 20, 2012. As adopted, these accounts allow SDG&E and SoCalGas to record the actual incremental costs (i.e., operating and maintenance and capital-related costs such as depreciation, income taxes, and return on investment.

7. Pipeline Safety and reliability Memorandum Account Recovery

SDG&E and SoCalGas along with the other respondents to R.11-02-019 were authorized to establish a Pipeline Safety and reliability Memorandum Account Recovery (Memo Account) in D.12-04-021:

> SDG&E and SoCalGas to create a memorandum account in which to record the incremental costs of implementing the Pipeline Safety Enhancement Plan. The Commission will consider whether such properly recorded costs are reasonable and incremental as well as which costs, if any, may be recovered from ratepayers in revenue requirement at a later time in the Triennial Cost Allocation Proceeding.

We believe that there is not a sufficient record on the costs recorded in the Memo Account to authorize recovery at this time. We find that the companies should not recover any management incentive compensation or any costs associated with searching for test records of pipeline testing.

SoCalGas should file an application with testimony and work papers to demonstrate the reasonableness of the costs incurred which would justify rate recovery.

23. The proposed allocation of costs of the new pipeline, which replaces the existing pipeline, would reallocate costs between customer classes with no change in service.

24. The existing cost allocation, as settled, allocates costs to customer classes based upon the costs incurred to serve those customers.

25. Safety Enhancement does not change the service provided to customers although it does likely improve reliability by replacing existing pipelines with new pipelines that meet industry and Commission required safety standards.

26. The ratepayers will be served by a safe and reliable system with new components that will operate for decades.

Conclusions of Law

1. As required by § 451 all rates and charges collected by a public utility must be "just and reasonable," and a public utility may not change any rate "except upon a showing before the commission and a finding by the commission that the new rate is justified," as provided in § 454.

2. Pub. Util. Code § 451 requires safe operation of a natural gas system. It is a long-standing and continuing responsibility, not a one-time obligation.

3. The burden of proof is on SDG&E and SoCalGas to demonstrate that it is entitled to the relief sought in this proceeding, including affirmatively establishing the reasonableness of all aspects of the application.

4. The standard of proof that SDG&E and SoCalGas must meet is that of a preponderance of evidence, which means such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth.

5. The Decision Tree analysis used to evaluate the existing pipeline network for safety, documentation, and reliability, is a reasonable but not final process.

6. Although industry best practices had changed by January 1, 1956, the Commission only adopted those standards in 1961.

7. The record for Phase 1 of Safety Enhancement supports the application of the July 1, 1961 adoption of the Commission's General Order 112 for testing and record-retention.

8. The analytical approach for Phase 1 in the Decision Tree management process, as fully described in testimony by SDG&E and SoCalGas, should be approved.

9. The Safety Div. should oversee Safety Enhancement to ensure public safety during the design, maintenance and construction phase as well as ensure safety in the future operations of the modified pipeline systems.

10. The Commission has the authority to delegate stop work order authority to Safety Div.

11. The Commission must ensure parties have timely procedural opportunities for a review of any action or stop work orders issued by Safety Div.

12. The proposed ratemaking for Safety Enhancement should not be approved.

13. It is reasonable for SDG&E and SoCalGas' shareholders to absorb the portion of the Safety Enhancement costs that were caused by any prior imprudent management. SDG&E and SoCalGas should absorb the costs of pressure testing where the company cannot produce records that provide the minimum information to demonstrate compliance with the industry or regulatory strength testing and records keeping requirements of industry standards beginning with the adoption of General Order 112 and its revisions, as

well as the requirements of 49 CFR, Part 192 and its revisions beyond the effective date of Part 192.

14. Where Phase 1 pipelines are replaced without testing SDG&E and SoCalGas should absorb an amount equal to the average cost of pressure testing where the company cannot produce pressure test records after the adoption of General Order 112, effective July 1, 1961.

15. SDG&E and SoCalGas should absorb the un-depreciated balances of any abandoned pipelines wherever they should have Phase 1 testing records after July 1, 1961, and do not.

16. The inclusion of executive incentive compensation in the costs of Safety Enhancement recoverable from ratepayers was not justified.

17. SDG&E and SoCalGas should be authorized to file annually after December 31, 2015 to recover the reasonable costs recorded in the Safety Enhancement balancing accounts.

18. Subsequent applications to review the Safety Enhancement Capital Cost Balancing Accounts and a Safety Enhancement Expense Balancing Accounts should be filed with sufficient detail to justify the work performed pursuant to the analytical approach embodied in the Decision Tree and the reasonableness of those costs. SDG&E and SoCalGas should be allowed to file annually for the costs of completed projects.

19. It is reasonable to require the ratepayers to pay for the costs to repair or rebuild the system that SDG&E and SoCalGas demonstrate are just and reasonable costs.

20. A valid record of a pipeline pressure test must include all elements required by regulations in effect at the time the test was conducted.

21. It is reasonable to require SDG&E and SoCalGas to comply with 49 CFR Part 192, subpart J pressure test specifications when conducting pressure tests pursuant to the plan approved herein.

22. SDG&E and SoCalGas have justified the concept of a Phase 1A and Phase 1B.

23. SDG&E and SoCalGas costs incurred prior to the effective date of today's decision should be subject to approval based on a reasonableness review of the Pipeline Safety and Reliability Memorandum Accounts.

24. The reasonableness issues identified by ORA and TURN will be addressed in the reasonableness review applications for the balancing accounts.

25. There is no justification for any executive incentive compensation component to be added into the costs of Safety Enhancement recovered from ratepayers.

Rate Design Settlement

26. The Commission has the authority to adopt a settlement when it is reasonable in light of the whole record, consistent with law, and in the public interest.

27. The proposed rate design settlement is reasonable in light of the whole record, consistent with law, and in the public interest and should be adopted.

28. The uncontested issues are reasonable in light of the whole record, consistent with law, and in the public interest and should be adopted.

29. The uncontested Natural gas Vehicle compression rate adder settlement is reasonable in light of the whole record, consistent with law, and in the public interest and should be adopted.

Cost Allocation for Safety Enhancement

30. The existing cost allocation methodology is reasonable for the costs of Safety Enhancement because these costs are necessary to safely and reliably supply natural gas to existing customers in the same manner as the existing system serves customers.

31. This decision should be effective today.

32. This proceeding should be closed.

O R D E R

IT IS ORDERED that:

1. We adopt the Phase 1 analytical approach for Safety Enhancement to ensure the safety and reliability of San Diego Gas & Electric Company and Southern California Gas Company as embodied in the Decision Tree (Attachment I) and Reconciliation (Attachment 2) and related descriptive testimony.

2. We authorize San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) to begin work as described in their Safety Enhancement Plans with costs recorded in balancing accounts and subject to refund pending a subsequent reasonableness review.

3. The Director of the Commission's Consumer Protection and Safety Division, or designee, (Safety Div.) is delegated the following specific authority to act in addition to all existing general authority delegated to staff:

(a) Safety Div. may inspect, inquire, review, examine and participate in all activities of any kind related to Safety Enhancement. San Diego Gas & Electric Company (SDG&E), Southern California Gas Company (SoCalGas), all of their contractors shall immediately provide any document, analysis, test result, plan, of any kind related to

Safety Enhancement as requested by Safety Div.'s staff or its contractors. Safety Div. must subsequently confirm all requests in written form, however all responses to must be immediate.

(b) Safety Div. may issue immediate stop work orders to SDG&E and SoCalGas, and all of their contractors when necessary to protect public safety. SDG&E and SoCalGas must comply immediately.

(c) The Commission's Executive Director, and the Chief Administrative Law Judge, together shall ensure that SDG&E and SoCalGas, and all other parties to this proceeding, shall have timely procedural opportunities for a review of any action or stop work orders issued by Safety Div. as may be feasible under the specific circumstances whenever Safety exercises its delegated authority.

(d) Safety Div. must formally file a copy of any Stop Work Order in this proceeding by the close of business on the workday following its issuance to either SDG&E and SoCalGas, or any contractors.

4. Within 30 days of the effective date of this decision San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) must file Tier 2 Advice Letters to establish a Phase 1 Safety Enhancement Capital Cost Balancing Account and a Phase 1 Safety Enhancement Expense Balancing Account to record the expenditures incurred pursuing the Safety Enhancement proposals adopted in Ordering Paragraph 1. These accounts may be effective as of the date of this decision.

5. San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) may file annually after December 31, 2015 for reasonableness review of the completed projects recorded in the Phase 1 Safety Enhancement Capital Cost Balancing Account and annually for the expenses recorded in the Phase 1 Safety Enhancement Expense Balancing Account.

SDG&E and SoCalGas may alternatively file for preapproval of specific projects seeking approval of a cap or for other specific guidance.

6. Cost recovery of the Pipeline Safety and Reliability Memorandum Accounts for San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) will be reviewed for reasonableness in a new application or applications. In addition to the other requirements to demonstrate reasonableness, SDG&E and SoCalGas are limited to the recovery of only those costs that directly contribute to the implementation of Safety Enhancement.

7. The comprehensive rate design settlement (Attachment 3) between San Diego Gas & Electric Company (SDG&E) and all active parties and adopts a rate design settlement between Southern California Gas Company (SoCalGas) and all active parties is adopted. This settlement resolved all contested issues except the rate design proposals for SDG&E and SoCalGas' Safety Enhancement costs. We also adopt for implementation the 28 uncontested issues included in Attachment IV.

8. The Natural gas Vehicle compression rate adder settlement is adopted.

9. We reject all proposed modifications to the existing cost allocation methodology proposed by San Diego Gas & Electric Company and Southern California Gas Company and the parties for Safety Enhancement costs. Safety Enhancement costs will be allocated consistent with the existing cost allocation and rate design for the companies.

10. Within 30 days of the effective date of this decision San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) must file Tier 1 Advice Letters to implement the rate design settlements and uncontested issues as contained in Attachments III, IV and V.

11. This decision denies San Diego Gas & Electric Company's request for a residential customer fixed charge.

12. Application 11-11-002 is closed.

This order is effective today.

Dated June 12, 2014, at San Francisco, California.

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
MICHAEL PICKER
Commissioners

after an activity takes place, would create uncertainty about what standards will be applied by the Commission in the future across the board.[212]

Regulatory opportunism is a term used to describe a situation in which a regulator leaves open the possibility that it will not allow utilities to recover the cost of sunk capital.[213] As noted by Dr. Montgomery, regulatory opportunism can have substantial negative effects:

> [T]he lack of regulatory credibility induces myopic behavior by the firm: a strong incentive to delay cost-reducing investment, or, if the firm does invest, it will favor a series of sequential investments over a single larger, cheaper investment…The prospect of regulatory opportunism means that the firm will not fully exploit economies of scale in investment.[214]

The cost responsibility proposals presented by intervenors encourage regulatory opportunism.

3. *Ex post* reasonableness review of PSEP expenditures and investments would also create undesirable incentives

DRA proposes that the Commission review SoCalGas and SDG&E's PSEP-related expenditures for reasonableness on an *ex post* basis – i.e., after the expenditures have been made. As with intervenors' other proposals to require utility shareholders to shoulder the financial burden of PSEP-related costs, DRA's proposal for *ex post* reasonableness reviews would create undesirable incentives. In particular, conducting such reviews *ex post* would create a perception of regulatory opportunism, and would be economically inefficient.[215]

Traditionally, details over the quality of service delivered and cost recovery are resolved in GRCs. *Ex-post* reviews, sometimes called reasonableness or prudency reviews, are a mechanism designed to assess whether past expenditures were made appropriately. However, the temptation to critique past decisions with 20-20 hindsight tends to create a skewed view of

---

212 Ex. SCG-14 (Montgomery) at 8.
213 Ex. SCG-14 (Montgomery) at 14.
214 Ex. SCG-14 (Montgomery) at 14 (citing Guthrie, G., (2006) "Regulating Infrastructure: The Impact on Risk and Investment," *Journal of Economic Literature*, V. 44, December, pp. 925-972.
215 Ex. SCG-14 (Montgomery) at 14.

what constitutes "reasonable" or "appropriate."[216] In much the same way that punishing a stock trader for incorrectly predicting the peak price of a stock does not produce a better trading strategy, using *ex post* reviews to judge reasonableness sets an unfair burden of foresight on the utility.[217]

Similar to disallowance of future costs, *ex post* reviews create an incentive for inefficient expenditure on the part of the utility. Rather than devoting resources to implementing an approved plan, the utility will focus on documenting the justification for each expenditure, and when forced to invest, will choose less-efficient systems with low capital costs (but possibly higher operating costs) to hedge the risk that they will not be able to recover the full capital cost of the investment.[218] Utilities will also be less willing to take risks on new technologies, even if they offer possibilities of achieving other social objectives for technology improvement and lowered environmental impact. The phrase "nobody ever lost his job for choosing IBM" characterizes this behavior.[219]

If there were just one simple, low-cost way to design systems for the safe and reliable operation of a complicated natural gas transmission and distribution system, perhaps such a regime would be harmless. In reality, the types of investment incentivized by *ex post* reviews tend to be more expensive to operate, less innovative, and therefore more costly to ratepayers in the long run.[220] The experience of electric utilities in the 1970s provides support for this point. After having much of their sunk investment disallowed, and facing *ex post* reasonableness

[216] Ex. SCG-14 (Montgomery) at 15.
[217] Ex. SCG-14 (Montgomery) at 15.
[218] Ex. SCG-14 (Montgomery) at 15.
[219] Ex. SCG-14 (Montgomery) at 15.
[220] Ex. SCG-14 (Montgomery) at 15.

reviews going forward, many utilities became extremely risk averse and inefficient in their investments, raising the cost to ratepayers without providing an improvement in service.[221]

4. Intervenor cost responsibility proposals would increase future costs and rates

The Commission's goal in this proceeding is to improve safety through a cost-effective program of pipeline testing and replacement. The intervenors' shareholder cost responsibility proposals would work against the Commission's goal in two ways: First, the retroactive regulatory change and cost disallowance would distort incentives and result in potential unintended consequences for safety improvement, as just discussed. The second effect would be an unambiguous cost increase for SoCalGas and SDG&E customers.[222]

The intervenors' proposals amount to an arbitrary and disproportionate penalty, which would adversely affect the willingness of shareholders to invest in future infrastructure programs, ultimately increasing the cost of financing for new investment.[223] Moreover, this appearance of a new risk of regulatory opportunism would not be limited to just the SoCalGas and SDG&E PSEP. Unless the Commission could reverse the altered perception, a longer-term cost of the intervenors' proposals would be the added cost of *all* new investment by the utilities.[224] As a result, the intervenors' proposals would create a qualitative change in the regulatory regime, with potentially severe implications for future utility investment decisions in all areas.[225] As Dr. Montgomery explained, "A penalty in the form of disallowance of future costs is an example of a misguided penalty."[226]

[221] Ex. SCG-14 (Montgomery) at 15-16 (citing Lyon (1995) and Guthrie (2006)).
[222] Ex. SCG-14 (Montgomery) at 16.
[223] Ex. SCG-14 (Montgomery) at 16.
[224] Ex. SCG-14 (Montgomery) at 16.
[225] Ex. SCG-14 (Montgomery) at 16.
[226] Ex. SCG-14 (Montgomery) at 6.

5.2.2. Adopted Amounts for PG&E's Implementation Plan

In the following subsections, we address each significant component of PG&E's Implementation Plan. As explained in this section, we approve PG&E's Implementation Plan subject to the following:

- PG&E's request to include the costs for pressure testing post-1955 pipelines in revenue requirement is denied;
- PG&E's request to include the costs for the gas system records integration program in revenue requirement is denied,
- The risk of cost overruns is assigned to shareholders,
- PG&E's return on equity is reduced to the incremental cost of debt for capital costs incurred as part of the Implementation Plan for five years.

5.2.2.1. Pipeline Modernization Program

In this section we address the issues related to the Pipeline Modernization Program, which includes pressure testing, replacement, inline inspection, and valves. We find that costs to pressure test pipeline installed between 1956 and 1961 should not be included in revenue requirement, that pipeline segments located in Class 2 areas should be delayed to Phase 2, and that PG&E's proposed pressure testing program is reasonable.[44]

[44] We also note that projects approved today may displace projects planned and authorized as part of PG&E's Integrity Management Program in the Gas Accord V decision. That decision provides for a one-way balancing account for unspent Integrity Management costs, which will thereby be returned to ratepayers.

Pressure Testing

PG&E requests a total of $271.9 million in 2012, 2013, and 2014 to pressure test 783 miles of pipeline. The parties have raised three significant issues with regard to PG&E's proposed pressure testing: (1) cost responsibility for 1956 to 1961 pipeline with missing pressure test records, (2) excessive forecasted pressure testing costs, and (3) failing to test to 90% SMYS.

DRA opposes ratepayer responsibility for pressure testing transmission pipeline installed after 1935. DRA argues that industry standards in effect since 1935 required any prudent natural gas transmission system operator to pressure test pipelines before placing the lines in service and to retain records of construction, testing, and maintenance on those lines. DRA concludes that all pressure testing costs for lines installed after 1935 should be assigned to shareholders.

TURN agrees with DRA's proposition that PG&E's responsibility to pressure test and retain records begins well before PG&E's proposed date of 1961, but TURN contends that the cut-off date is 1955. TURN points to American Standards Association Code for Pressure Pipeline (ASA B31.8) as establishing in 1955 the industry standard of pre-service pressure testing for natural gas pipeline. TURN explains that PG&E's avowed practice was to follow this industry standard from 1955 on, but that PG&E now cannot find records of those tests.[45] TURN concludes that the cost of pressure testing now needed to bring PG&E pipeline installed in or after 1955 into compliance with the 1955 standard should be assigned to shareholders. TURN estimates that pressure testing approximately 90 miles of 1956 to 1961 pipeline accounts for $45 million of

[45] Hearing Exh. 31 at 75 - 77.

testing expense. TURN applies a similar rationale for pipeline of that vintage which PG&E's proposed decision tree determines should be replaced, and recommends disallowance of $81 million in costs for replacing 18 miles of 1956 to 1961 pipeline.

PG&E states that while it began to follow the industry guidelines in 1955, it did so on a voluntary basis rather than due to a legal or regulatory requirement. Because it was not required to perform pre-service pressure tests from 1955 to 1961, PG&E posits that ratepayers should fund pressure testing for any pipeline placed into service during that time for which PG&E cannot locate pressure test data. PG&E summarizes its position: even though it may have "lost, destroyed, or misplaced" some of its records, it was able to prudently operate its natural gas transmission system by relying on the historical exemption in subpart J, thus the newly required pressure testing or replacement should be at ratepayers expense.[46]

We find that where PG&E undertook or stated that it undertook to comply with industry standards but no longer possesses the records of such compliance, the costs of retesting required by the missing records is a result of an error in PG&E's operation of its natural gas transmission system. Where PG&E's record retention errors have led to re-testing pipeline installed between 1955 and 1961, the costs of such re-testing is not a just and reasonable cost of providing public utility service. Such costs, therefore, should be excluded from authorized revenue requirement to be recovered from ratepayers.

[46] PG&E Reply Brief at 8.

The evidentiary record supports the factual finding that from 1956 on, PG&E's practice was to comply with then-applicable industry standards for pre-service pressure testing, and that retaining records of such testing was part of the industry standard. As it was PG&E's practice to incur these pre-service test costs, we would expect that absent unusual circumstances such costs would be included in revenue requirement and recovered from ratepayers. No evidence has been presented to suggest that the cost of the 1956 to 1961 testing was excluded from revenue requirement. We, therefore, find that the preponderance of the evidence supports the findings that from 1956 to 1961: (1) PG&E's practice was generally to pressure test natural gas pipeline before placing the pipeline into service, with record retention being part of the practice, and (2) the costs of such pressure testing were included in revenue requirement recovered from ratepayers. We further find that if PG&E had competently retained the pressure test records for pipeline installed from 1956 to 1961, we would have evidence that such pressure tests did, in fact, occur and this pipeline would not be included in the Implementation Plan.[47]

Now, in response to D.11-06-017, PG&E is required to pressure test or replace all applicable natural gas transmission pipeline in its system. PG&E is unable to locate records of some of its previous testing for the 1956 to 1961 pipeline, and requests Commission authorization to include the cost of re-testing this pipeline in revenue requirement. PG&E argues that because it was not legally required to pressure test these pipeline segments previously, even

---

[47] See Conclusion of Law 3 in D.11-06-017 defining pre-1961 pressure test requirements. Notwithstanding compliance with historic standards, PG&E should evaluate these pipeline segments in later Phases of the Implementation Plan.

though it did so in compliance with industry practices, the directive in D.11-06-017 justifies allocating the cost of the re-testing to ratepayers.

We do not agree that the change from an industry practice to regulatory mandate somehow excuses PG&E's failure to retain the pressure test records. As noted above, the record supports the finding that PG&E stated that from 1956 on, PG&E's practice was to pressure gas system test pipeline prior to placing it in service and that the costs of such testing was passed on to ratepayers. As required by industry practice and prudent natural gas transmission system operations, PG&E should have created and maintained records of those pressure tests. The absence of the records for the 1956 to 1961 pipeline now brings these pipeline segments into the Implementation Plan for re-testing or replacement. Having paid for such testing once, the ratepayers should not be required to pay for re-testing due to PG&E's failures in document management.

For pipeline determined to be in need of replacement, ratepayers should similarly be relieved of the obligation to pay for retesting, but not for complete replacement. That is, absent PG&E's poor document management, ratepayers would not have been required to pay for retesting the 1956 to 1961 pipeline. Certain pipeline segments, for reasons unrelated to PG&E's poor document management, require replacement, rather than just re-testing.[48] PG&E shareholders should be held to their obligation for re-testing costs, but not extended to replacement costs. Shareholders should not be excused from their

[48] As discussed in more detail below, some pipeline segments have features, such as now-suspect welds, that when combined with age of the pipeline and operating pressure, support replacement rather than pressure testing based on sound safety engineering.

duty to pay the costs of re-testing, and ratepayers should not receive a new pipeline at no cost. Thus, shareholders will be allocated the costs of retesting pipeline installed in 1956 to 1961; and where such pipeline is scheduled for replacement, the estimated cost of pressure testing will be recorded as an equitable adjustment to reduce the replacement costs included in revenue requirement and recovered from ratepayers. In this way, PG&E's shareholders meet their obligation caused by management's protracted failure to retain the missing records while ratepayers fund the remaining pipeline replacement costs. We order similar treatment for pipeline installed after 1961, lacking pressure test records, and scheduled for replacement, rather than pressure testing, in Phase 1.

In conclusion, we hold that for pipeline segments installed after 1955 or for which PG&E does not know the installation date, and where PG&E cannot produce pressure testing documentation, the cost of pressure testing these segments now is not a just and reasonable cost of providing public utility service and we deny PG&E's request to include these costs in revenue requirement for recovery from ratepayers. Where such segments, and any segments installed after 1955 similarly lacking pressure test records, require replacement, rather than pressure testing, we grant PG&E's request to include in revenue requirement for recovery from ratepayers replacement costs but only to the extent the replacement costs exceed the estimated cost of pressure testing the segment.

DRA argues that PG&E's forecasted costs for pressure testing are too high.

DRA presented testimony developed by an outside expert setting forth cost estimates for fixed costs per test and variable cost per foot of pipeline tested. As shown below, DRA's cost forecasts were substantially lower than PG&E's:

Cost Item	DRA	PG&E
Variable Cost – 12" and under ($/ft)	$8	$30
Variable Cost – 14" to 20" ($/ft)	$12	$39
Variable Cost – 22" to 28" (4/ft)	$19	$45
Variable Cost – 30" to 42" ($/ft)	$37	59
Fixed Cost – Fabricate Test Header	$0	$15,000 to $40,000
Fixed Cost – Move Around/Test Section Charge	$44,700 to $76,700	$200,000 to $500,000
Fixed Cost – Mob/demob	$85,600 to $139,400	$500,000

For comparison purposes, set out below are the total costs for a 2,500 foot length pressure test for both a 12" diameter pipeline and a 36" diameter using DRA's and PG&E's costs forecasts:

Comparison of DRA and PG&E Pressure Testing Cost Forecasts		
	DRA	**PG&E**
12" pipeline, 2,500 feet	$150,300	$790,000
36" pipeline, 2,500 feet	$308,600	$1,187,500

Thus, PG&E's pressure test cost forecasts are more than triple DRA's estimates. TURN also presented pressure test cost estimates per mile of $29,700 to $40,000.[49] TURN's cost estimates are from 2001, and thus of limited evidentiary value due to the passage of time.

PG&E responded that its pressure testing cost estimates were developed based on actual cost data from pressure tests of its gas system

[49] Hearing Exh. 131 at 81 – 82.

analyzed by experienced engineers. PG&E pointed out that DRA's costs estimates do not include pre-cleaning pipeline, which DRA's expert claimed to be regular maintenance, but which PG&E claims is actually unusual for a natural gas transmission and distribution system.[50] PG&E similarly dismissed DRA's reliance on pressure testing cost estimates in sets of industry data as showing very broad cost ranges and lacking detail on the diameter of pipeline tested, test medium, and average test length.[51]

We agree that DRA's analysis is insufficient to overcome PG&E's actual cost experience of pressure testing natural gas pipeline in its natural gas system. We, therefore, authorize PG&E to include in revenue requirement the forecasted costs of its natural gas transmission pipeline pressure testing projects as requested in the Implementation Plan.

We find, however, that DRA's analysis is sufficient to demonstrate that PG&E's cost forecasts for pressure testing natural gas pipeline are much higher than industry-based estimates. As the two examples above show, PG&E's cost estimates are more than triple DRA's. Therefore, we conclude that the record shows that PG&E's cost forecast for pressure testing natural gas transmission pipeline falls in the high end of the range of reasonableness. We will use this conclusion, and our similar conclusion for PG&E pipeline replacement costs, to inform our analysis of PG&E's request for an overall 20% contingency adder.

TURN also challenged PG&E's determination that a valid hydrotest record from 1961 to 1970 must include the name of the operator.

---

50 PG&E Opening Brief at 26.

51 Id. at 27.

TURN cited to D.11-06-017 as requiring records of a valid pressure test consistent with regulations in effect at the time of the test.[52] PG&E counters that while then-effective pressure test regulations did not require an operator's name, such information is "necessary to ensure accountability" for the test.[53]

We agree with PG&E that the operator name adds value to the pressure test record and is required by current PHMSA regulations.[54] Such information, however, was not required by the regulations in effect at the time for pressure tests performed between 1961 and 1970. Thus, consistent with D.11-06-017, we find that pressure test records for tests performed between 1961 and 1970 need only contain the information required by the then-applicable regulations to be valid pressure test records for purposes of inclusion in PG&E's Implementation Plan.

TURN also proposes that all pipeline segments be pressure tested to 90% Specified Minimum Yield Strength (SMYS)(the pressure level at which the pipe would undergo permanent deformation). PG&E explains that pressure testing to this very high level is not required by federal subpart J regulations for existing pipeline, which require up to 150% of MAOP for that pipeline. PG&E states that it uses the 90% SMYS standard for new pipeline, and that this is practical because new pipeline would typically have a uniform SMYS. In contrast, PG&E contends, its existing pipeline often is comprised of pipe with a variety of characteristics with no uniform SMYS. Consequently, PG&E argues, pressure testing to 90% SMYS for each portion of an existing pipeline is

---

52 TURN Opening Brief at 25.

53 PG&E Reply Brief at 66.

54 See 49 CFR § 192.517(a)(1).

impractical and unnecessary, which is why the industry and PG&E pressure testing rules allow existing pipeline to be tested based on its actual maximum allowable operating pressure, plus a margin of safety. TURN acknowledges the practical difficulty with its proposed 90% SMYS standard in its brief.[55] PG&E contends that little safety improvement is gained by increasing the pressure level tested to 90% SMYS, which might be two or three times the maximum operating pressure. PG&E also notes that bringing each pipeline component up to 90% SMYS would greatly increase costs.

We find that federal regulations in 49 CFR subpart J pressure testing protocols provide for a margin of safety based on the MAOP of the pipeline to be tested. The 90% SMYS standard TURN advocates creates serious practical problems, which TURN admits. We find, therefore, that PG&E has established by a preponderance of the evidence that the 49 CFR subpart J pressure testing protocols are reasonable to use in its pressure tests.

TURN recommends deferring from Phase 1 to Phase 2 pressure testing or replacement of pipeline segments located in Class 2 locations.[56] TURN explains that D.11-06-017 requires PG&E to begin its work with pipeline located in densely populated places, i.e., Class 3 and 4 locations and High Consequence Areas of Class 1 and 2 locations, but that PG&E has also included significant

55 TURN Opening Brief at 41.

56 PHMSA regulations define the four class locations by number of human-occupied buildings located within 220 yards of the pipeline: Class 1, 10 or fewer buildings; Class 2, 10 to 45 buildings; Class 3, 46 or more buildings, or with a place of public assembly; and, Class 4, where buildings with four or more stories are prevalent. 49 CFR § 192.5

amounts of Class 2 locations that are not High Consequence Areas. TURN recommends that these less densely populated areas be moved to Phase 2.

PG&E responds that when it prepared its Implementation Plan, it included pipeline segments adjacent to segments within the specified scope to determine if cost and construction efficiency could be achieved by doing the adjacent Class 2 segments as part of Phase 1 of the Implementation Plan. PG&E gave particular attention to such pipeline operating at over 30% SMYS. PG&E states that to go back and pressure test or replace these pipeline segments could increase costs and delayed completion of the overall program.[57]

PG&E has presented a valid justification to evaluate Class 2 locations adjacent to Class 3 locations and determine whether including these segments in Phase 1 would be economically more efficient or decrease customer interruptions such that these segments should be included in Phase 1 and not deferred to Phase 2. In rebuttal testimony at 3-15 to 3-17, PG&E states that it looked at "adjacent pipeline segments as well" and explains that going back to pressure test or replace "adjoining pipe segments at a later time" would lead to increased costs.

In D.11-06-017, the Commission directed PG&E to "start with pipeline segments located in Class 3 and Class 4 locations and Class 1 and Class 2 high consequence areas, with pipeline segments in other locations given lower priority."[58] Accordingly, the general rule is that pipeline segments in Class 1 or 2 locations will not be included in Phase 1. We recognize exceptions to this general rule where, for sound engineering or economic reasons, pipeline

---

[57] PG&E Reply Brief at 54.

[58] D.11-06-017 at Ordering Paragraph 4.

segments not located in the priority locations should nevertheless be included in Phase 1. Pipeline segments adjacent to priority locations logically fit within such exceptions. Thus, we find that to the extent a pipeline segment is located in a Class 1 or 2 area but is adjacent to Class 3 or 4 locations, PG&E properly included the Class 1 or 2 segments in Phase 1. In this way, the priority location drives the project and the lower priority work is only included where efficiency or other engineering rationale supports extending the project beyond the priority location. Pipeline segments in Class 2 or Class 1 locations which are not high consequence areas, or adjacent to Class 3 or 4 locations or high consequence areas, must be deferred to Phase 2 of the Implementation Plan.

5.2.2.2. Pipeline Replacement, In-Line Inspection Retrofits, and Valve Automation

Pipeline Replacements

PG&E proposes to replace 185.5 miles of mostly older pipeline at a total cost of $818.7 million during 2012, 2013 and 2014. All of these costs will be capitalized.

As set forth above, the authorized revenue requirement for replacing pipeline installed after 1956 for which PG&E does not have pressure test records will be reduced by the estimated cost of pressure testing that pipeline. Similarly, pipeline replacements for some Class 2 locations may be deferred to Phase 2. This reduction and deferral will reduce the total pipeline replacement costs in the Implementation Plan Phase 1.

DRA and TURN challenge PG&E's proposed pipeline replacement costs as excessive. DRA presented a thorough analysis of PG&E's proposed estimates for pipeline replacement costs, and based on this analysis recommended a 20% disallowance. DRA's and PG&E's pipeline replacement cost estimates priced the pipeline replacement based on the project area's

Because this alternative has not yet been approved, these cost reductions are not reflected in either the Base Case or Proposed Case cost estimates shown above. If this method is approved, SoCalGas and SDG&E would study additional areas to apply this method with the potential for additional savings.

J. Phase 2 Cost Estimates.

SoCalGas and SDG&E propose that Phase 2 of their Pipeline Safety Enhancement Plan run in parallel with and extend past the completion of Phase 1(B) and address mileage not addressed in Phase 1. An assessment of these lines is underway and will not be completed until July 2012. Based on a preliminary review, SoCalGas and SDG&E anticipate that some of these pipeline segments will require pressure testing or replacement.

The cost to pressure test or replace pipelines in Phase 2 will vary based on pipeline size, location, and operational requirements. If the Phase 2 costs are similar to Phase 1, SoCalGas and SDG&E would expect the following average testing and replacement costs: (1) $3.5 to $4 million per mile (Capital) for new construction or pipe replacement; (2) $500,000 t0 $600,000 per mile (O&M) to pressure test; and (3) $86,000 per mile (O&M) to in-line inspect using the TFI tool.

SoCalGas and SDG&E are unable to provide Phase 2 cost estimates to any level of certainty because they have not yet finished their records review on Phase 2 pipeline segments. If one were to assume that 40% of Phase 2 transmission pipelines will be addressed using either pressure testing or replacement and apply the same pressure testing versus replacement ratio as Phase 1 pipeline segments, the total estimated costs would be in the range of $1.5 to $3 billion or more for SoCalGas and about $100 million for SDG&E. These speculative cost estimates – which are provide not only before the completion of the records review but also before the

Commission has clarified the scope of required testing[64] and replacement in Phase 2 – are provided for illustrative purposes only.

These Phase 2 cost estimates are also based on the assumption that approximately 200 miles of pipelines installed before 1946 that are not piggable will be replaced in Phase 1(B). If that is not the case, these pipeline segments will need to be carried over to Phase 2, increasing the Phase 2 cost estimates by approximately $700 million.

Cost estimates for Phase 2 could potentially be reduced by hundreds of millions of dollars if (1) the Commission approves the use of the TFI tool in parallel with pressure testing in Phase 1, (2) the data gathered from these TFI tool runs demonstrates that it is an equivalent means to test the strength of a pipeline when compared to pressure testing; and (3) the Commission subsequently approves the use of the TFI tool as an appropriate alternative to pressure testing. In addition, adoption of SoCalGas and SDG&E's proposal to modify General Order 112-E to eliminate reliance on the Grandfather Clause rather than precluding California pipeline operators from utilizing 49 CFR §192.619(c) would further reduce the scope and costs of Phase 2.[65]

IX. RATEMAKING AND REGULATORY ACCOUNT TREATMENT FOR PSEP

SoCalGas and SDG&E request approval and recovery of the revenue requirements resulting from the Capital and O&M forecasts of the Pipeline Safety Enhancement Plan for the years 2011 through 2015, to coincide with our anticipated General Rate Case cycles.[66] The Phase 1(A) Proposed Case interim revenue requirements for the years 2011 through 2015 totals

---

64 It is unclear in the June 9 decision whether natural gas pipeline operators are required to retest pipeline segments that were not previously tested to a standard that would satisfy current provisions of 49 CFR §192.619. *See* Footnote 70 at page 119 in the Supporting Testimony.

65 *See* starting at page 44 of Supporting Testimony.

66 References to the next rate case cycles with 2016 test years are based on a proposal in SoCalGas and SDG&E's 2012 General Rate Case applications that are pending before the Commission and are subject to Commission approval.

(2) Outside business districts, at intervals not exceeding 7½ months, but at least twice each calendar year.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–43, 47 FR 46851, Oct. 21, 1982; Amdt. 192–78, 61 FR 28786, June 6, 1996]

§ 192.723 Distribution systems: Leakage surveys.

(a) Each operator of a distribution system shall conduct periodic leakage surveys in accordance with this section.

(b) The type and scope of the leakage control program must be determined by the nature of the operations and the local conditions, but it must meet the following minimum requirements:

(1) A leakage survey with leak detector equipment must be conducted in business districts, including tests of the atmosphere in gas, electric, telephone, sewer, and water system manholes, at cracks in pavement and sidewalks, and at other locations providing an opportunity for finding gas leaks, at intervals not exceeding 15 months, but at least once each calendar year.

(2) A leakage survey with leak detector equipment must be conducted outside business districts as frequently as necessary, but at least once every 5 calendar years at intervals not exceeding 63 months. However, for cathodically unprotected distribution lines subject to § 192.465(e) on which electrical surveys for corrosion are impractical, a leakage survey must be conducted at least once every 3 calendar years at intervals not exceeding 39 months.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–43, 47 FR 46851, Oct. 21, 1982; Amdt. 192–70, 58 FR 54528, 54529, Oct. 22, 1993; Amdt. 192–71, 59 FR 6585, Feb. 11, 1994; Amdt. 192–94, 69 FR 32895, June 14, 2004; Amdt. 192–94, 69 FR 54592, Sept. 9, 2004]

§ 192.725 Test requirements for reinstating service lines.

(a) Except as provided in paragraph (b) of this section, each disconnected service line must be tested in the same manner as a new service line, before being reinstated.

(b) Each service line temporarily disconnected from the main must be tested from the point of disconnection to the service line valve in the same manner as a new service line, before reconnecting. However, if provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service need not be tested.

§ 192.727 Abandonment or deactivation of facilities.

(a) Each operator shall conduct abandonment or deactivation of pipelines in accordance with the requirements of this section.

(b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(d) Whenever service to a customer is discontinued, one of the following must be complied with:

(1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.

(2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

(3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

(e) If air is used for purging, the operator shall insure that a combustible mixture is not present after purging.

(f) Each abandoned vault must be filled with a suitable compacted material.

(g) For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility.

(1) The preferred method to submit data on pipeline facilities abandoned after October 10, 2000 is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS ''Standards for Pipeline and Liquefied Natural Gas Operator Submissions.'' To obtain a copy of the NPMS Standards, please refer to the NPMS homepage at *http://www.npms.phmsa.dot.gov* or contact the NPMS National Repository at 703–317–3073. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax or e-mail to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP–10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001; fax (202) 366–4566; e-mail *InformationResourcesManager@phmsa.dot.gov*. The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.

(2) [Reserved]

[Amdt. 192–8, 37 FR 20695, Oct. 3, 1972, as amended by Amdt. 192–27, 41 FR 34607, Aug. 16, 1976; Amdt. 192–71, 59 FR 6585, Feb. 11, 1994; Amdt. 192–89, 65 FR 54443, Sept. 8, 2000; 65 FR 57861, Sept. 26, 2000; 70 FR 11139, Mar. 8, 2005; Amdt. 192–103, 72 FR 4656, Feb. 1, 2007; 73 FR 16570, Mar. 28, 2008; 74 FR 2894, Jan. 16, 2009]

§ 192.731 Compressor stations: Inspection and testing of relief devices.

(a) Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with §§ 192.739 and 192.743, and must be operated periodically to determine that it opens at the correct set pressure.

(b) Any defective or inadequate equipment found must be promptly repaired or replaced.

(c) Each remote control shutdown device must be inspected and tested at intervals not exceeding 15 months, but at least once each calendar year, to determine that it functions properly.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–43, 47 FR 46851, Oct. 21, 1982]

§ 192.735 Compressor stations: Storage of combustible materials.

(a) Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building.

(b) Aboveground oil or gasoline storage tanks must be protected in accordance with National Fire Protection Association Standard No. 30.

§ 192.736 Compressor stations: Gas detection.

(a) Not later than September 16, 1996, each compressor building in a compressor station must have a fixed gas detection and alarm system, unless the building is—

(1) Constructed so that at least 50 percent of its upright side area is permanently open; or

(2) Located in an unattended field compressor station of 1,000 horsepower (746 kW) or less.

(b) Except when shutdown of the system is necessary for maintenance under paragraph (c) of this section,

SoCalGas /SDG&E
Pipeline Enhancement Safety Plan (PSEP)
PSEP Cost Estimating Workshop

Presentation to Office of Ratepayer Advocates (ORA)

June 24, 2015

SoCalGas
A Sempra Energy utility

PSEP | Pipeline Safety Enhancement Plan

SDGE connected
A Sempra Energy utility

Agenda

1. Welcome / Introductions
2. Company Cost Estimating Practices and Controls
3. Company Estimating Tools
4. PSEP Cost Estimating
5. PSEP Construction Contractor Estimating
6. Estimates versus Actuals
7. PSEP Completed Projects
8. PSEP Timelines – Organization and Cost Estimating
9. Summary

The goal of today's meeting is to provide background and context regarding SoCalGas/SDG&E PSEP Cost Estimating practices

Cost Estimating Practices and Controls

- There are different types of Cost Estimates during a project's life cycle:
  - To fit accuracy and individual project needs
- Work Orders are required for all large company projects
  - Establishment of Internal Order (I-O) to track and collect projects costs into company's tracking system (i.e. SAP)
  - Cost Estimate of Project
    - Provides for management control and approval
    - Higher cost projects need higher levels of approvals

Estimating Tools

» **Departmental Tools for Cost Estimating**

- **Distribution**
  - Mainframe system
  - Until recently: Construction Management System (CMS)
  - Most recently: SAP-PM and Graphic Work Design
- **Transmission and Storage**
  PCM → Project Construction Mgmt. (larger)
  → Transm. → Smaller projects
  - Spreadsheet based tools
- **PSEP**
  - Templates on Excel
    - Standardized tables with default values for individual cost items
    - Flexibility to use values other than defaults

PSEP Cost Estimating

- Three standardized estimates
  - Stage 3 Template
    - Primary purpose is to establish project cost after scope is reasonably defined
      - used for WOA → # in financial system
      - began use in Nov. 2013
  - Stage 2 Template customer impact
    - Primary purpose is to compare relative costs of test versus replace
    - Used for projects under consideration for replacement
  - 2011 Filing Template
    - Significant refinements since the filing

- Stage 2 and 3 Templates Updates
  - Based on historical costs
  - To reflect process changes/improvements

PSEP Project Cost Estimating – Non Template

» **Projects/Project Managers may update their cost estimates as needed when:**
  - Significant scope changes occur
  - Projects are split into two or more sections
  - Cost estimates for individual line items are determined to be materially different than what was used in the original template

» **Project Managers manage their Estimate At Completion(EAC) and Estimate To Completion (ETC)**
  - Monthly EAC process implemented in August 2014
  - Each Project Manager determines what data to keep as back up for the EAC and ETC

Note: PSEP phase 1A currently has ~165 individually tracked projects. Phase 1B will add ~50 more.

PSEP Construction Contractor Estimates

- **Construction Contract is typically the largest single component of a cost estimate**
  - Construction Contractor is typically ~30 -50% of a project's overall, fully-loaded cost
- **Performance Partner Program established in June 2014**
  - Pipeline Contractors estimate the construction component
    - Known as the "Target Price Estimate"
- **Fixed-Bid, Time & Material and other contracting approaches may also be used**

Comparing Cost Estimates to Actual Costs

» **PSEP's first generation cost estimating template's line items did not match the Company's SAP system**

- Prepared on an expedited basis by outside contractor to adhere to the regulatory schedule
- Actual costs captured in SAP are currently grouped differently than in the estimates

» **The next iteration of the estimating tool will align with the Company's system**

- PSEP is working to better align actual cost categories to line items in the estimating template in order to more readily utilize actual cost experience to update the cost estimating template

PSRMA Completed Projects

» **Playa Del Rey Phase 1&2**
  - No cost estimate due to accelerated test schedule → issue?

» **L# 42-66-1/2**
  - Cost estimate by Distribution region using the CMS tool

» **L# 45-120X01**
  - Cost estimate by Distribution region using the CMS tool

» **L#2000-A**
  - Cost estimate by Transmission
  - Experienced project manager used the department's cost estimating tool/spreadsheet

PSEP Organization Timeline

- **August 2011**
  - Filed response seeking approval of PSEP
- **May 2012**
  - Received approval to open a memo account to begin certain PSEP work
  - Began staffing up organization with company personnel
- **May - December 2012**
  - Jacobs
  - RFP/contracting process for PMO, engineering design, project controls, supply chain partner, environmental partner
- **December 2012 - ~ April 2013**
  - Development of majority of PSEP standards/policies
- **~ April 2013 - Present**
  - Continue to evolve metrics, reports, and processes to enhance PSEP implementation
- **Ongoing 2012-2015**
  - Hiring personnel both company and contract firms as needs arise

PSEP Cost Estimating for PSEP Project Team
Projects - Timeline

» **June - July 2011**

- SoCalGas's external contractor developed cost estimates for all PSEP pipeline projects.
- Valve program costs estimated by SoCalGas in-house personnel

» **August 2013 – October 2013**

- Development of Stage 2 and Stage 3 Cost Estimating Templates

» **November 2013** – present

- Use of Stage 2 and Stage 3 Template

Summary

1. Company only requires one cost estimate – in order to set up a WOA
2. Different departments have developed different costs estimating tools
3. PSEP Managed Projects have one standardized Cost Estimate – the Stage 3 Template
4. Other cost estimates are less formalized and may vary across projects projects
5. Actual costs are being used to update PSEP's cost estimating templates

☑ Pre-Project Activation
or
☐ Project Active (Stages 1 - 7)

Change Notice

To: Omar Rivera (Project Manager)
cc: (Project Engineering)
cc: Gary Martinez (Project Controls Specialist)
From: Gary Martinez (Originator)

Date Prepared: 04/30/2013
Project No.: 2000-A
Change Notice No.: 083
Change Notice Rev. No.: 0

Company: SCG
Project Title: 2000-A
Location: Transmission

Description of Change: Execution Plan Change

Reason for Change: Line 2000 has been broken up into 4 individual projects:
2000-A
2000-Bridge
2000-C
2000-West

References: See attached documentation for mileage breakdown of each individual project. Related to Change Notice 014 for Line 2000.

List Others Affected: NONE

	CAT 4	Accelerated	Incidental
Miles Decreased:	N/A	N/A	N/A
Miles Increased:			

Why: Execution plan change

(i.e.: Files found, drop below 30% SMYS, drop below 20% SMYS or Other)

Schedule Affect:

Original Cost: N/A
Total of Changes to date: $ 0
Total this Change: $ 12,728,000
New Cost: $ 12,728,000 (This cost is one of the 4 projects which make up the Line 2000 cost $37,989,000)

Attached additional documentation if required

Change Notice Disposition

☐ **Rejected** : Take no further Action
☑ **Approved, Proceed with Request.**
☐ **Approved as noted below:**

Change Category:
☐ Errors & Omissions
☐ Change in Condition
☐ Scope Change
☐ Contractor Rework
☐ Hydrotest/X-Ray Failure
☑ Other (explanation required)

Project Manager: [signature] Date: 5/1/13
Sempra Manager: [signature] Date: 5-6-13
Sempra Director: Date: 5-10-13

Additional Distribution:

[redacted]

From: [redacted]
Sent: Tuesday, April 30, 2013 1:00 PM
To: [redacted]
Cc: [redacted]
Subject: RE: 2000A, B, C, W mileage explanation

Hi [redacted],

The most current mileages are as follows (changes from last version are in red):

	Criteria (mi)	Accelerated (mi)	Incidental (mi)	Total (mi)
2000A:	11.372	2.375	1.185	14.932
2000B:	0.131		0.123	0.254
2000C:	1.883	4.504	0.643	7.030
2000W:	tbd	tbd	tbd	40.2

Total mileage of A,B,C = 22.22

Reason for change:

	Criteria (mi)	Accelerated & Incidental (mi)
Test info found	16.865	
No longer criteria	5.192	
Revised test limits, footage was accelerated, not required in Phase 1A		37.883
Added in (not in filing)	1.204	3.554 (Incidental 1.538, Accelerated 2.016)

Dropped off: 59.940 mi, Added in: 4.758 mi, Total change from filing: 55.182 mi

[redacted]

From: [redacted]
Sent: Tuesday, April 30, 2013 12:49 PM
To: [redacted]
Cc: [redacted]
Subject: RE: 2000A, B, C, W mileage explanation

Hi [redacted],

Can you please email me a fresh email advising of the below again with your edits and the break-up for each of the 4 lines:

2000-A:
2000-Bridge:

2000-C:
2000-West:

This will be for audit purposes as supporting documentation.

Thanks,
[redacted]

From: [redacted]
Sent: Friday, April 26, 2013 11:35 AM
To: [redacted]
Cc: [redacted]
Subject: 2000A, B, C, W mileage explanation

Hi [redacted],

This is what I came up with:

	Criteria (mi)	Accelerated (mi)	Incidental (mi)	Total (mi)
2000A:	10.779	2.968	1.185	14.932
2000B:	0.1311	0	0.1231	0.254
2000C:	1.8833	4.5036	0.6426	7.030
2000W:	tbd	tbd	tbd	40.2

Total mileage of A,B,C = 22.22

Reason for change:

	Criteria (mi)	Accelerated&Incidental (mi)
Test info found	16.865	
No longer criteria	5.192	
Revised test limits, footage was accelerated, not required in Phase 1A		37.883
Added in (not in filing)	1.204	3.554

Dropped off: 59.940 mi, Added in: 4.758 mi, Total change from filing: 55.182 mi

Let me know if you have questions,

[redacted]

Associate Engineer – PSEP
Southern California Gas Company
[redacted]

☐ Pre-Project Activation
or
☑ Project Active (Stages 1 - 7)

PSEP Change Notice

To: Rick Chiapa (Portfolio Manager)
cc: (Project Engineering)
cc: Gary Martinez (Project Controls Specialist)
From: Gary Martinez (Originator)

Date Prepared: 10/30/2013
Project No.: Line 2000A
Change Notice No.: 273
Change Notice Rev. No.: 0

Company: SCG
Project Title: Line 2000A
Location: Transmission

Description of Change: Budget Allocation

Reason for Change: Original Budget was allocated at $12,728,000 per CN 083. This CN will increase the budget by $7,522,000 to $20,250,000. The budget being requested falls within the approved WOA amount of $25,428,180.

References: Approved Phase 2 WOA Form, and email from Ron Bott dated 7/25/13

List Others Affected: None

	CAT 4	Accelerated	Incidental
Original Mileage:	11.372	2.375	1.185
Total Mileage Changes to Date:	N/A	N/A	N/A
Total Miles This Change:	N/A	N/A	N/A
New Mileage:	N/A	N/A	N/A

Why: Additional Budget request to come in line with approved Phase 2 WOA for 2000A
(i.e.: Files found, drop below 30% SMYS, drop below 20% SMYS or Other)

Original Cost: $ 12,728,000
Total of Changes to date: $ 0
Total this Change: $ 7,522,000
New Cost: $ 20,250,000

Schedule Affect:
No Impact

Attached additional documentation if required

Change Notice Disposition

☐ **Rejected** : Take no further Action
☑ **Approved, Proceed with Request.**
☐ **Approved as noted below:**

Change Category:
☐ Errors & Omissions
☐ Change in Condition
☑ Scope Change
☐ Contractor Rework
☐ Hydrotest/X-Ray Failure
☐ Other (explanation required)

Portfolio Manager: Date: 11/5/13
Sempra Manager: Date: 11-11-13
Sempra Director: Date: 11-11-13

Additional Distribution:

25325 300703750

WORK ORDER AUTHORIZATION FOR SEMPRA ENERGY UTILITIES

Field names with ALL CAPITAL letters are required.

COMPANY CODE: 2200

Work Order No: 25325.000

CAPITAL ☑ O&M ☐

TITLE: PSEP Hydro Testing Line 2000 Category 4 Criteria Locations - Phase II

Thomas Bros.

WR/DPSS Number:

BUDGET CODE: 512

DATE PREPARED: 9/18/2012 | EST. START DATE: 9/18/2012 | EST. COMPLETION DATE: 3/1/2014 | BILLING CODE: NC | 0% Billable

RESPONSIBLE COST CENTER: 2200-2419

Regulatory Prg/UDF: PSH - REF PSRMA - PSEP Hydrostatic Testing

Phase 1 ☐ Phase 2 ☑ Prelim Eng Survey (Ferc 183) ☐ Shared Asset ☐

ORGANIZATION: Transmission

OPERATING AREA/DISTRICT: Brea

OPERATING REGION: Desert Area (51)

COUNTY: San Bernardino MUNICIPALITY: Billable to: Affiliate ☐ Third Party ☐ Sending Order ☐ Receiving Order ☐

TECHNICAL/ECONOMIC PROJECT REVIEW*

		By:	Date:
☐	Legal Review		
☐	Accounting		
☐	Tax		
☐	Finance		

*Required for any and all Category 1 & Category 2 commitments over $30 million & $10 million, respectively, prior to review and approval by the utilities' CEO or COO, as appropriate. All technical reviews & contracts initially totaling $30 million or more must be evidenced by a completed Internal Review Checklist (IRC).

Comments regarding Technical/Economic Project Review:

Reference Approval and Commitment Policy:

☑ CATEGORY 1 ☐ CATEGORY 2

JOB SCOPE SUMMARY

Line 2000 hydro testing of HCA segments identified as Cat 4 criteria footage between Colorado River to Hwy. 71 in Corona. Identify pipe segment hydro test limits and prepare design drawings, specifications, material orders, permits and construction package. Perform construction of Hydro test and replacement segments.

Bill to Name & Address:

CODE	DETAILED DESCRIPTION OF WORK
o	Prepare base mapping and design drawings required for hydro test or replacement of pipe segments.
o	Obtain ministrial and environmental permits
o	Obtain Temporary Construction Easement
o	Perform Hydro Static testing on Pipeline
I	Install and Hydro Test replacement pipe segments.

FERC ACCOUNT	%	Acctg Dept Use (Enter I(Os))
863.85	100% O&M	
367	100% capital	

Charging Cost Centers to this order

Receiver	Co.	Amount	Or %

APPROVALS

Project Approved up to/on order

Name / Title	Signature	Mail Loc	Date
Ron Bolt, Preparer	R. Bolt	12 B7	10/5/2012
Ron Bolt, Project Mgr	R.Bolt	12 B7	10/5/2012
Rick Phillips, Line Director	R Phillips		10/8/12
David Buckowski, Line Director	[signature]		10/9/12
Functional Committee Chair			
Rick Morrow, Functional VP	R Morrow		10-15-12
Utility President			
Utility C. E. O.			

ESTIMATED COSTS	Capital Installation	Capital Removal	O&M	Total
Company Labor	$ 107,940	$ -	$ 611,660	$ 719,600
Contract Costs	1,063,708	-	12,733,372	13,797,080
Material	2,255,461	-	319,200	2,574,661
Other Direct Charges	529,184	-	4,762,663	5,291,847
Total Direct Cost	3,956,293	-	18,426,895	22,383,188
Affiliate Transfer In Costs	-	-	-	-
Labor Indirects	326,595	-	1,959,321	2,285,916
Material Indirects	35,326	-	-	35,326
Other Indirects	69,202	-	344,718	413,920
AFUDC	309,829			309,829
Total Indirect Cost	740,952	-	2,304,040	3,044,992
Gross Expenditures	4,697,245	-	20,730,935	25,428,180
ITCCA (Y or N) 0.00%	n			-
Less: Billing/Part Contr.				
Total Net Estimated Costs				25,428,180

Accounting Use Only

Acctg Ops: [signature] Date

Ord Type | Int Prt | Stat Map %

OH Key | Cst Sheet | Stat Map %

User Status | FERC Ind | Stat Map %

Total Commitment Accumulated | Stat Map % | Stat Map %

Gross Expenditures by year:	2012	2013	2014	2015	2016
	$ 1,779,973	$ 21,613,953	$ 2,034,254	$ -	$ -
% by Year	7%	85%	8%	0%	0%

IO_Form_503.xls 03/25/2011 INSTRUCTIONS ARE LOCATED ON THE "MANUALS & FORMS" PAGE OF THE ACCOUNTING & FINANCE INTRANET WEBSITE

CAP. WOA# 91009.000

WORK ORDER AUTHORIZATION FOR SEMPRA ENERGY UTILITIES

Field names with ALL CAPITAL letters are required

COMPANY CODE	2200
Work Order No	25325 Revision 1
CAPITAL ☐	O&M ☑
Thomas Bros	
WR/DPSS Number	
BUDGET CODE	512
BILLING CODE	NC

TITLE PSEP -Phase I Hydro Testing Line 2000 CAT 4 Criteria Locations

DATE PREPARED 11/5/2013 EST START DATE 9/10/2012 EST COMPLETION DATE 3/1/2014

Phase 1	Phase 2	Prelim Eng Survey (Ferc 183)	Shared Asset
☐	☑	☐	☐

RESPONSIBLE COST CENTER 2200-2419 Regulatory Prg/UDF PSH - REF PSRMA - PSEP Hydrostatic Testing

ORGANIZATION Transmission OPERATING AREA/DISTRICT Beaumont OPERATING REGION Desert Area (51)

COUNTY San Bernardino MUNICIPALITY Billable to Affiliate ☐ Third Party ☐ Sending Order ☐ Receiving Order ☐

TECHNICAL/ECONOMIC PROJECT REVIEW*

☐ Legal Review	By		Date
☐ Accounting	By		Date
☐ Tax	By		Date
☐ Finance	By		Date

*Required for any and all Category 1 & Category 2 commitments over $30 million & $10 million, respectively, prior to review and approval by the utilities' CEO or COO, as appropriate All technical reviews & contracts initially totaling $30 million or more must be evidenced by a completed Internal Review Checklist (IRC)

Comments regarding Technical/Economic Project Review

Reference Approval and Commitment Policy

☑ CATEGORY 1 ☐ CATEGORY 2

JOB SCOPE SUMMARY

Line 2000 Hydro testing of HCA segments identified as Category 4 criteria footage between Banning and Hwy 71, Corona Identify pipe segment hydro test limits and prepare design drawings, specifications, material orders, obtain permits and construction package Perform construction of hydro test or replacement sections

Bill to Name & Address

CODE	DETAILED DESCRIPTION OF WORK
o	Prepare Base Maps and design drawings required for hydro test or replacement
0	Obtain ministerial and environmental permits
o	Obtain Temporary Construction Easement
o	Perform Hydro testing of 10 pipeline test segments
I	Perform replacement of identifed pipe segments

Revision 1 Revised scope of work to delay testing of Line 2000 from Blythe to Banning Increased number of test segments from 9 to 10 due to new District tap Added pressure control fitting to supply new District tap during hydro test
Increased costs $2,580,305 Original estimate is $25,428,179 See attached Variance Explanation

RECEIVED DEC 05 2013 By:

FERC ACCOUNT	%	Acctg Dept Use (Enter I/Os)
863 65	100% OM	
307	100% Capital	

Charging Cost Centers to this order

Receiver	Co	Amount	Or %

APPROVALS

Project Approved up to/on order

Preparer	Ron Bott	Mail Loc / Date	11/15/2013
Project Mgr	R Bott/ R Chiapa	Mail Loc / Date	
Line Director	D Buczkowski	Mail Loc / Date	11/25/13
Functional VP	P Morrow	Mail Loc / Date	11/25/13
Functional Sr VP	B Lane	Mail Loc / Date	12/2/13
Utility President		Mail Loc / Date	
Utility C E O		Mail Loc / Date	

ESTIMATED COSTS	Capital Installation	Capital Removal	O&M	Total
Company Labor	$ 292,000	$ -	$ 1,188,766	$ 1,480,766
Contract Costs	1,644,000	-	8,153,694	9,797,694
Material	410,000	-	496,980	906,980
Other Direct Charges	1,945,705	-	10,558,134	12,503,839
Total Direct Cost	**4,291,705**	**-**	**20,397,574**	**24,689,279**
Affiliate Transfer In Costs	-	-	-	-
Labor Indirects	449,697	-	1,959,007	2,408,703
Material Indirects	-	-	8,612	8,612
Other Indirects	96,185	-	425,818	522,004
Ad Valorem Tax (per GRC decision)	63,571			63,571
AFUDC	316,315			316,315
Total Indirect Cost	**925,768**	**-**	**2,393,437**	**3,319,205**
Gross Expenditures	**5,217,473**	**-**	**22,791,011**	**28,008,484**
ITCCA (Y or N) 0 00%	N			-
Less Billing/Part Contr				
Total Net Estimated Costs				**28,008,484**

Accounting Use Only

Actg Ops			Date
Ord Type	Int Prfl	Stat Map	%
OH Key	Cst Sheet	Stat Map	%
User Status	FERC Ind	Stat Map	%
Total Commitment Accumulated		Stat Map	%
		Stat Map	%

Gross Expenditures by year	2012	2013	2014	2015	2016
	$ 1,120,339	$ 26,327,975	$ 560 170	$ -	$ -
% by Year	4%	94%	2%	0%	0%

IO_Form_503 xls 11/01/2013 INSTRUCTIONS ARE LOCATED ON THE "MANUALS & FORMS" PAGE OF THE ACCOUNTING & FINANCE INTRANET WEBSITE