Application No: A.16-09-XXX
Exhibit No.: ____________
Witness: M. Bermel

Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) to Recover Costs Recorded in the Pipeline Safety and Reliability Memorandum Accounts, the Safety Enhancement Expense Balancing Accounts, and the Safety Enhancement Capital Cost Balancing Accounts	Application 16-09-XXX

CHAPTER IV

DIRECT TESTIMONY OF

MICHAEL BERMEL

ON BEHALF OF

SOUTHERN CALIFORNIA GAS COMPANY

AND

SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

September 2, 2016

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I. PURPOSE AND OVERVIEW OF TESTIMONY

As part of the Pipeline Safety Enhancement Plans (PSEP) ordered by Decision (D.) 11-06-017, the Commission required PSEP to also address the installation of "automated or remote controlled shut-off valves."[1] SoCalGas and SDG&E's Valve Enhancement Plan (Valve Plan) was created in response to that directive. The Valve Plan works in concert with PSEP to enhance system safety by installing and upgrading valve infrastructure to support the automatic and remote isolation and depressurization of the transmission pipeline system in 30 minutes or less in the event of a pipeline rupture. This 30-minute or less isolation objective is the fundamental objective of the Valve Plan. The purpose my testimony is to:

- Explain the safety enhancement benefits of SoCalGas and SDG&E's Valve Plan;
- Describe the detailed methodology for determining the scope of work required to accomplish the Valve Plan isolation objective;
- Explain how the Valve Plan implementation work-to-date has been executed prudently, reasonably, and in alignment with the Valve Plan's isolation objective; and
- Provide information on technical revisions and other factors that influence valve project costs.

Through implementation of the Valve Plan, SoCalGas and SDG&E have further enhanced the safety of their natural gas transmission system. As discussed below, the Valve Plan, as filed in 2011,[2] has been and will continue to be refined during implementation in order to effectively achieve the 30-minute isolation objective.[3]

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[1] D.11-06-017, mimeo., at 21, 30 (Conclusion of Law 9), and 32 (Ordering Paragraph 80).
[2] Originally filed in R.11-02-019 and subsequently transferred to A.11-11-002.
[3] In addition to the discussion of the Valve Plan contained in my testimony, specific valve projects are presented Chapter V (Mejia).

II. SOCALGAS AND SDG&E'S VALVE PLAN

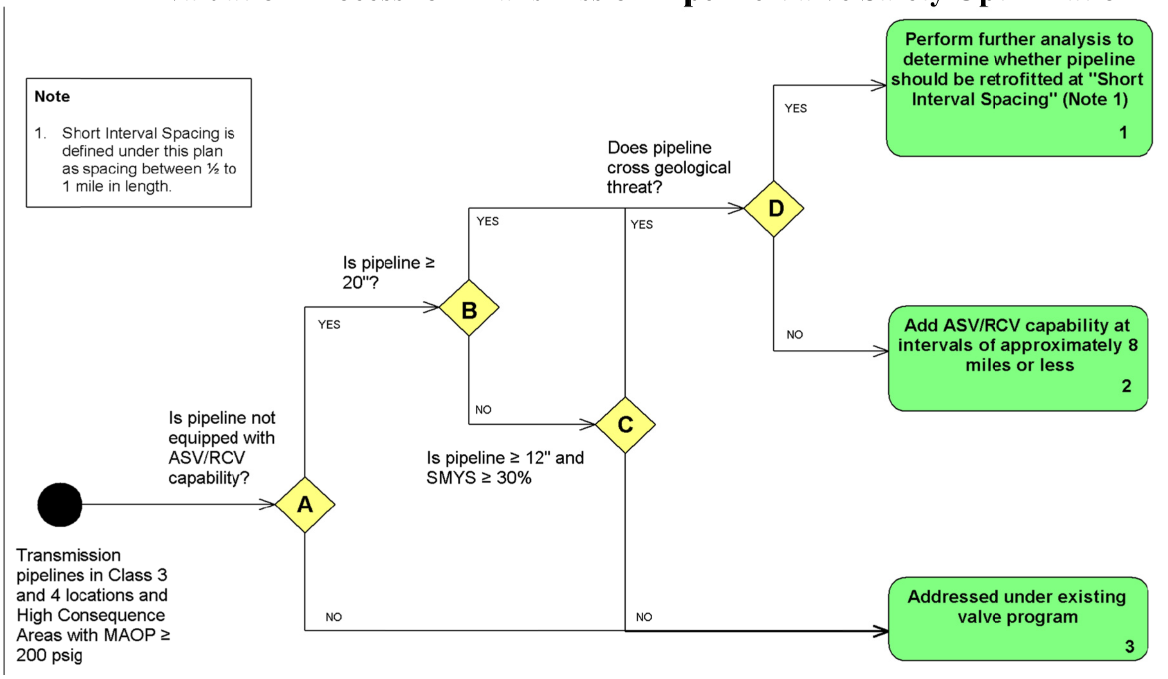
In R.11-02-019, SoCalGas and SDG&E proposed to enhance their pipeline valve infrastructure to support the automatic and remote isolation and depressurization of specific sections of its transmission pipeline system in 30 minutes or less. This isolation objective enhances public safety by promoting a consistent swiftness-in-response for large pipelines in the event of a rupture or other unplanned gas release. This improved swiftness-of-response reduces the time the public and first responders are confronted with a large volume of natural gas exiting a ruptured pipeline. The automation and/or remote control of large transmission valves also provides for the ability to isolate and manage multiple pipeline sections simultaneously in the event of wide-scale natural disaster or complex terrorist/sabotage event, or any other situation where a mobile workforce may be limited in effectiveness in providing for timely valve operation.

To accomplish this, the Valve Plan focuses on the installation of valves routed in Class 3/4 or High Consequence Area (HCA) locations with the following characteristics:

- 12" or greater in diameter, operating at a Maximum Allowable Operating Pressure (MAOP) which produces pipeline stresses in excess of 30% of Specified Minimum Yield Stress (SMYS); or
- 20" or greater in diameter, operating at a MAOP which produces pipeline stress in excess of 20% of SMYS.

In addition, valves will be installed on pipelines 12" and greater in diameter subject to special geologic risks, including pipelines traversing active earthquake faults where engineering analysis suggests a shortened Automatic Shut-Off Valve (ASV)/Remote Control Valve (RCV) spacing interval provides added system reliability and/or public safety. The Valve Plan process and scope is illustrated in Figure 1 below in decision tree form:

Figure 1
Evaluation Process for Transmission Pipeline Valve Safety Optimization



To accomplish the isolation objective and optimize valve asset deployment and utilization, SoCalGas and SDG&E analyzed various pipeline rupture and depressurization transient modeling data sets, and concluded that providing for an isolation spacing of approximately 8 miles (the Location Class 3 maximum distance for valve spacing, as interpreted under Code of Federal Regulations (CFR) 49, Section 192.179) would enable SoCalGas and SDG&E to meet a 30-minute depressurization objective under an automated or remote closure control scheme. SoCalGas and SDG&E also determined that employing this spacing, taking advantage of the valves previously installed pursuant to CFR 49, would leverage existing assets and minimize cost in securing Valve Plan isolation and depressurization objectives.

Notably, in 2012, the Consumer Protection and Safety Division's (CPSD) (now Safety and Enforcement Division) issued a technical report which included review and analysis of the Valve Plan. Therein, CPSD made the following findings:

> CPSD believes the Companies' have used a sound approach towards determining where automated valves should be installed, in order to reduce the consequences of a major pipeline breach. This approach appropriately considers pipeline diameter, the operating stress of the line, and geological threats as part of the determination process. Under their approach, the Companies intend to limit the spacing of valves in order to be able to isolate a segment in a Class 3, 4, or HCA location to no more than eight miles in length.[4]

And:

> The additional enhancement measures related to automated valves, as proposed by the Companies, would improve current performance and CPSD recommends that the CPUC allow the Companies to proceed with their proposal to install telemetry facilities and backflow prevention devices at all locations as planned. CPSD believes these readings are crucial because they allow for pin-pointing failure locations and will assist in first response efforts to any failure events.[5]

Furthermore, in D.14-06-007, the Commission acknowledged the scope of the Valve Plan and authorized the Valve Plan work to proceed subject to after-the-fact reasonableness reviews:

> In addition to the testing or replacing pipeline, Safety Enhancement includes modifications of 541 valves, and the addition of 20 valves, to provide for automated shut-off capability in order to isolate, limit the flow of gas to no more than 30 minutes, and thereby facilitate timely access of "first responders" into the area surrounding a substantial section of ruptured pipe. Safety Enhancement also includes: 1) improvements to communications and data gathering to ascertain pipeline conditions; 2) installing backflow valves to prevent gas from flowing into sections intended to be isolated from other connected lines; 3) expand the coverage of SDG&E and SoCalGas' private radio networks to serve as back-up to other available means of communications with the newly installed valves to improve system reliability….[6]

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[4] R.11-02-019, January 17, 2012 Technical Report of CPSD Regarding the SoCalGas and SDG&E PSEP at 14; see *also* D.14-06-007, mimeo., at 15-16.

[5] R.11-02-019, January 17, 2012 Technical Report of CPSD Regarding the SoCalGas and SDG&E PSEP at 16.

[6] D.14-06-007, mimeo., at 8; *see also* D.14-06-007, mimeo., at 59 (Ordering Paragraph 2).

Pursuant to the above authority, and consistent with the Valve Plan isolation objective, SoCalGas and SDG&E have proceeded with efforts to enhance safety through execution of the Valve Plan. This activity has included valve installations and enhancements, communication equipment installations, backflow prevention valve installations, and expansion of our private radio network coverage.

A. Valve Plan Scope As-Filed in 2011

Preliminary application of the Valve Plan isolation criteria to SoCalGas and SDG&E pipelines was performed in 2011 in order to produce an initial list of mainline valves to be targeted for modification. These valves were generally identified as the two principal valves which would define the isolation boundary on the main transmission pipeline. Specific transmission system valve locations were identified by number and included in the filing based on a survey of existing pipeline databases, maps, Geographic Information System (GIS) info, and maintenance records. Similar review work conducted on the SDG&E distribution pipeline system yielded additional preliminary mainline valve sites to be targeted for upgrades. Additionally, SoCalGas identified existing ASV sites residing in pipeline areas outside of Class 3/HCA areas to be upfitted with communication assets to enable operating personnel to monitor pressure excursions and/or valve closure incidents by exception.

For the identified transmission system valve locations, which were to constitute the main transmission pipeline isolation sections, a preliminary assessment was developed prescribing the type of installation or upgrade needed at the individual valve sites based on information gathered through the data systems noted above. The initial analysis was a high-level estimate of the scope of work to be conducted at mainline valve locations and a projection of how many isolation sections would be required to support Valve Plan isolation objectives. Due to time constraints associated with the filing schedules, this assessment work did not include walk down and site surveys of each valve site for verification, site condition analysis, site constructability, and customer impacts, among other factors. Moreover, the original Valve Plan did not include details on each smaller tap valve, crossover valve, and lesser operational valve, which would have to be reviewed and possibly modified to support full pipeline section isolation.

The SoCalGas and SDG&E Valve Plan included a generalized forecast of pipeline sites where additional work was anticipated in order to control back-flow and to minimize the number of customers subject to service loss in the event of a pipeline rupture and large pipeline section isolation. These valve and flow control locations were planned to be refined and finalized during more detailed engineering planning, which involves, among other tasks, building and running computerized pipeline flow models for each prospective pipeline section to be closed. These more detailed analyses aid in determining two primary pieces of information, namely (1) customers, including major customers (like electric generating facilities), that could lose service with specific valve closure sequences under different flow/load conditions, and (2) the suite of smaller valves and regulator stations that should be modified to minimize back flow into a ruptured pipeline section from smaller and/or cross-connected pipeline sections.

These analyses are necessary to provide 30-minute isolation of over 360 different pipeline sections. Rapid shut-in of SoCalGas and SDG&E's pipeline system in highly-populated areas requires careful consideration of customer impacts and related gas flow consequences. Historically, isolation and depressurization of a single section of a large transmission pipeline would typically require a month or more of detailed operational and engineering planning. Further, due to the dynamic nature of SoCalGas and SDG&E's system, the work may no longer be applicable or relevant to an implementation schedule performed 5-10 years after the analyses is conducted. Instead, detailed flow analysis work is required throughout implementation so that the implementation schedule is based on the most current system configuration and operating objectives.[7] As such, field refinement, as necessary, promotes accomplishment of our 30-minute isolation objective.

In a similar manner, in order to better manage post-event operations, flow meter installations on the transmission and distribution systems were planned to provide operators at the SoCalGas and SDG&E Gas Control center a more comprehensive view of system status and gas flows associated with any rupture/isolation or errant valve closure. Exact metering locations were to be specified during the Valve Plan implementation.

In summary, the SoCalGas and SDG&E Valve Plan was a forecast of general requirements and estimated costs to modify its system to support the stated isolation objective, with some specificity for larger valves based on point-in-time analyses and reviews. SoCalGas and SDG&E remain committed to the original isolation and depressurization criteria and objectives, but have refined implementation to accomplish those objectives.

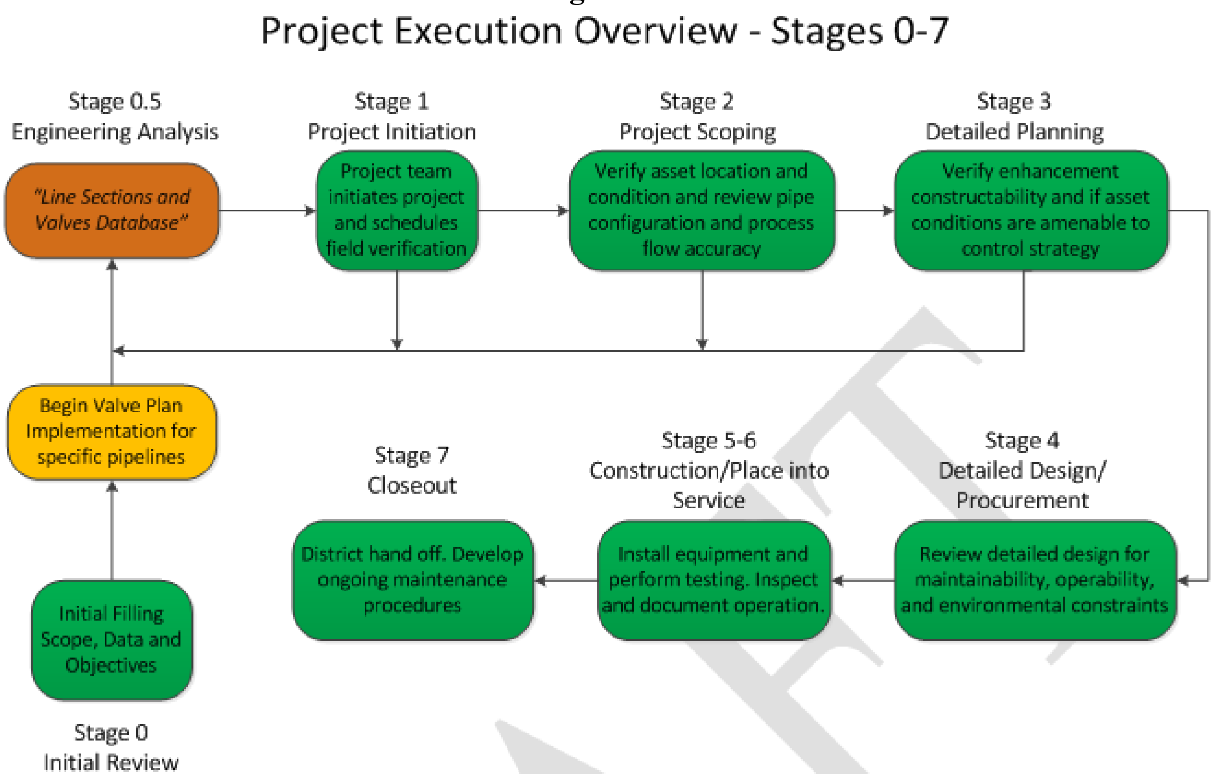
III. PROCESS TO REFINE VALVE PLAN IMPLEMENTATION SCOPE

The process to determine the scope of work to be performed to isolate each discrete pipeline section associated with the SoCalGas and SDG&E Valve Plan through final project

[7] Due to the added complexity and risk associated with managing pipeline isolation and depressurization in near-real time across its pipeline system, SoCalGas and SDG&E will adopt this new flow analysis process moving forward for ASV/RC-related projects.

construction, commissioning, and reconciliation includes the PSEP Seven Stage Review Process (see also Chapter II (Phillips) and Chapter V (Mejia)) and additional, preliminary scoping and analysis efforts described here. Figure XIV-2 provides an overview of the valve project implementation process:

Figure 2



For valves, two additional scoping steps that occur prior to the Seven Stage Review Process (identified as Stage 0 and Stage 0.5) are necessary to determine how to effectively achieve the isolation objective.

During Stage 0, SoCalGas and SDG&E assess the valve scope from the 2011 PSEP Filing. Next, during Stage 0.5, SoCalGas and SDG&E update and refine the valve scope analysis based on new data sets (e.g., GIS, valve data bases, operational records, and flow analyses). SoCalGas and SDG&E use this new analysis to develop an updated preliminary valve scope of work and begin initiating projects.

Stage 0.5 includes detailed paper analysis conducted when a section of pipeline and related valves are to be modified in the following year. This stage includes an updated review of all databases, maintenance systems, maps, and other information used to prepare the original Valve Plan, as well as a detailed system flow analysis on the gas distribution and transmission systems, which may result in updates to the main valves to be used to isolate a pipeline section. To illustrate the complexity of this analysis, the output from a simple flow analysis and section evaluation is shown in Figure 3.

Figure 3
Analyzing Pipeline Sections for Back-Flow Management and Customer Retention

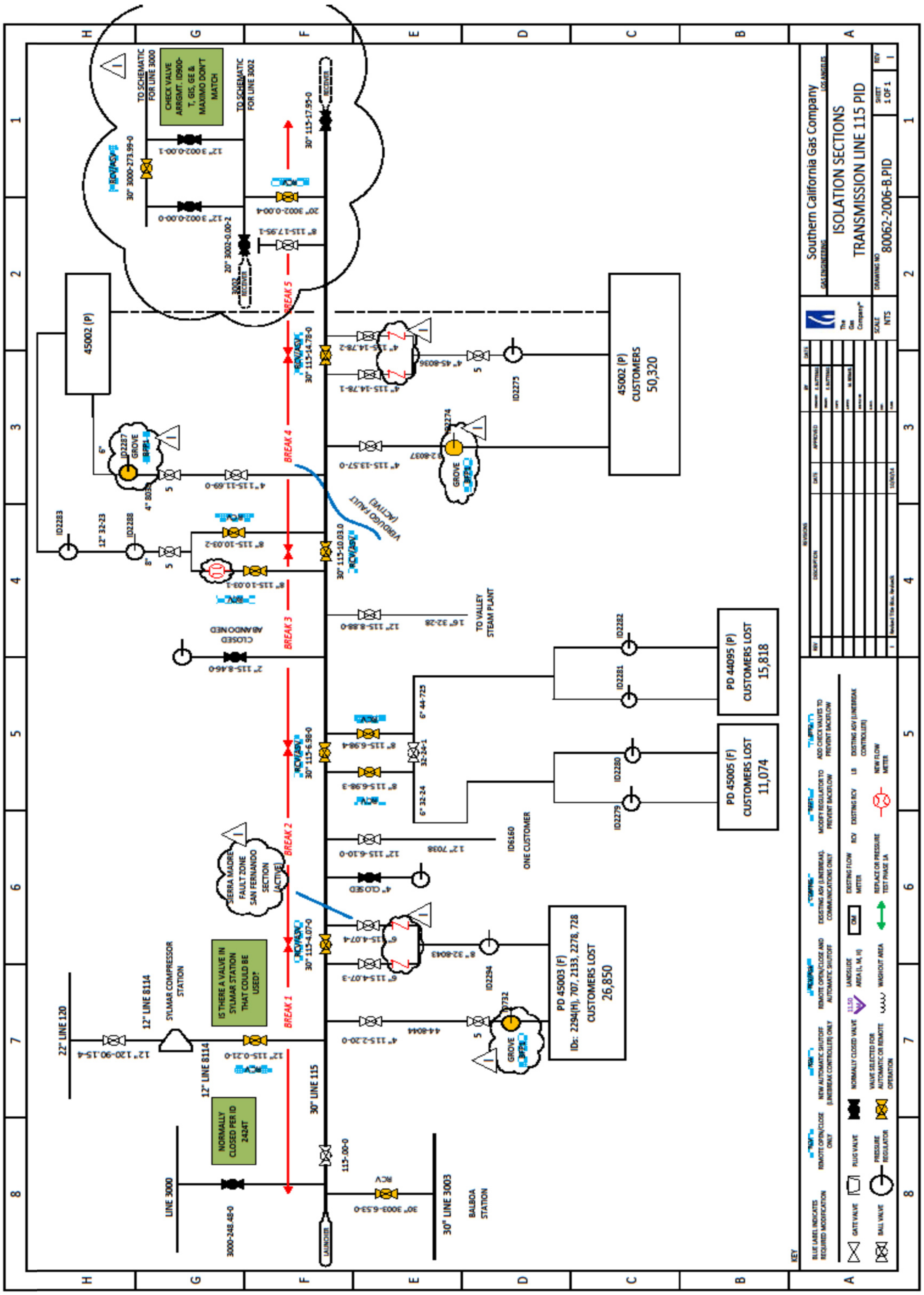


Figure 3 shows that numerous main pipeline valves are required for isolating a section of pipeline, and that mitigating the loss of service to customers in a complex piping network requires a refined control strategy and multiple assets. The detailed system flow analysis also provides first-cut assessment and recommendations for valve modifications to reduce back-flow or to prevent wide-spread customer service loss.

Stage 0.5 is also where final determination is made on how to achieve isolation objective and the assets to be employed for a sub-section of pipeline. The specific sub-tasks for Stage 0.5 includes the following:

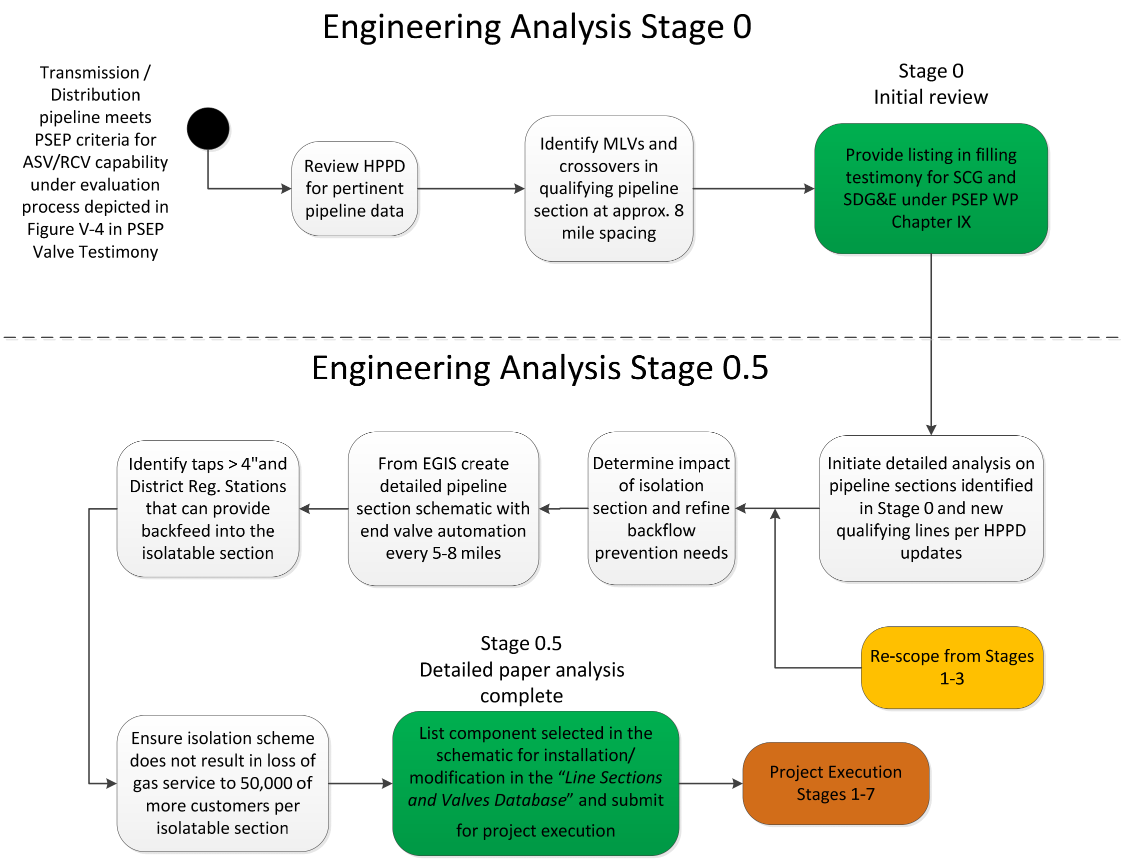
- Confirm latest piping configuration, state of crossover valves, tap locations and valve states, regulator station settings, check valves installations and feeds to distribution systems;
- Prepare an isolation plan schematic for each of the 5-8 mile sections to be removed from service within 5 minutes in the event of a pipeline.[8]
- Define which tap and regulator stations need to be removed from service (closed) to support isolation of the specific pipeline section, and specify the locations for any of the 120 back-flow control flow assets reference earlier in this testimony.
- Work with Distribution Engineering staff to flow-model the mainline valve closures and the ability of the distribution system to: (1) continue to serve customers under a medium load hour without the loss of 50,000 customers or more with each valve closure plan[9] and (2) ensure the equivalent of anything greater than a 4" open pipe or 8" reduced port valve or regulator station does not back-feed the isolated section. Shut all back-flow off, where practical.

Figure 4 provides detail on the work elements associated with Stage 0.5.

[8] Due to piping inter-connections in populated areas, it is typical to have 2-4 isolation sections evaluated at one time as a distribution system may, and usually are, fed from more than one transmission tap location to support system reliability.

[9] If the flow analysis shows the loss of more than 50,000 customers with the proposed section closure scheme, SoCalGas and SDG&E will rework the section closure plan – with added valves or modified asset locations. The objective may add to the count of smaller valves and backflow assets proposed in the original SoCalGas and SDG&E Valve Plan.

Figure 4



Through these stages, valve locations and needed assets are refined. This is done in an effort to achieve the isolation objective and incorporate information learned from the detailed flow analysis. In addition to the detailed flow analysis, there may be other reasons for changing the valve specifics; these include:

1. Current satellite view shows valve location problematic; for example, encroachment or relative orientation of buildings, structure or roadway near valve site.
2. Changes have occurred in the location classification for a section of pipeline, which typically adds to the amount of pipeline miles subject to coverage and is expected to increase overall valve count during implementation.
3. Non-PSEP work (such as Transmission and Distribution Integrity Management Programs (TIMP/DIMP) or General Rate Case (GRC) related project) performed at

the location since the PSEP Filing, which may have changed (or removed) the assets in-place during original scoping.

4. Modifications to assumptions about asset condition, type, and/or location. Examples include actuators assessed to take more than 5 minutes to fully close a valve, or are not assessed to be reliable in a remote control application based on history under manned operation. In some instances, the ability and complexity associated with a valve to accept an actuator retrofit can impact the decision to seek an alternative valve.
5. Information gathered since the original PSEP filing that may suggest certain equipment is no longer compatible with our updated PSEP control system strategy. This includes, among other developments, the decision to abandon the use of gas-over-hydraulic actuators in conjunction with our ASV strategy, due to antiquity, parts availability and/or failure mode analysis considerations.
6. Pipeline work that was originally planned to occur as part of PSEP that may have not occurred as-planned.[10]

Once all of the Stage 0.5 planning elements are accounted for, a Phase 0.5 project recommended scope is completed and forwarded to the PSEP Engineering/Construction team for execution or refinement in Stages 1 through 3.

During Stage 1, SoCalGas and SDG&E place the Stage 0.5 scope of work into queue for detailed planning, and reconcile the Stage 0.5 scope of work with PSEP or other Company work. In this way, SoCalGas and SDG&E assess whether there will be work for that area on other

[10] For example, if PSEP is no longer replacing some pipelines or electing to pressure test, the assumption(s) in the original PSEP calling for new valve/controls installed on a new pipeline during construction may no longer be valid.

projects, enabling SoCalGas and SDG&E to align efforts and evaluate possible re-scope to promote efficiencies and reduce costs.

During Stage 2, SoCalGas and SDG&E conduct field verification of the locations targeted for valve installations. At this time, SoCalGas and SDG&E note where work scope may need to be changed due to local findings (e.g., actuator type/orientation is different than assumed or vault is too small for actuator).

During Stage 3, SoCalGas and SDG&E assess the worksite for general constructability and logistics considerations (e.g. traffic, environmental, customer loss, adjacent facilities), search for alternate solutions if the work is overly complex, and assess whether more economical alternatives are available. If a preferred potential option is identified, the project is sent back to Stage 0.5 for rework.

Based on the information gathered and efforts undertaken during Stages 1-3, confirmation of field assets and logistics, permitting, and constructability of assets defined in Stage 0.5 are conducted. Through this process, findings can drive a need to restart or partially modify Stage 0.5 recommendations and the project planning may return to that Planning Stage. Information that can result in reconsideration/rework from these stages includes:

1. Valve or station is in a location where work cannot be performed without extensive traffic or permitting issues;
2. Work cannot be accommodated without the addition of significant assets/bypass taps to serve customers during construction;
3. Configuration of station assets is not amenable to the addition of new control components (e.g., space for panels, actuator, etc.);
4. An alternate valve can be used for less cost or complexity in work planning;

5. Condition or type of asset, when confirmed with site visit, is assessed to be incompatible with successful modification or implementation of desired control strategy; and
6. Location is targeted for other rework or elimination in the future due to other considerations or programs (e.g., Pipeline Integrity Program requirements).

The remaining stages occur after the scope of work has been vetted and are addressed in greater detail in Chapter II (Phillips) and Chapter V (Mejia). Briefly, Stage 4 includes detailed final design, procurement, and permitting; Stage 5 is the construction stage; Stage 6 is system testing and commissioning; and Stage 7 is project closeout and related documentation.

IV. OVERVIEW OF COMPLETED TECHNICAL WORK VERSUS AS-FILED VALVE LISTINGS AND SCOPE

In this application, SoCalGas and SDG&E are requesting review and recovery of costs associated with 17 valve and meter work sites, encompassing 52 valve/flow control devices and 3 meters. Table 1 provides a detailed listing of the Valve Plan work completed and requested for recovery in this Application. The Table shows the specific asset modified/installed, how it relates to the original filing asset scope and related information. The detailed costs for the projects to install these assets are discussed in Chapter V (Mejia).

TABLE 1

Valve ID	Major Valve upgrades in WPs	Base Valve Installed	Substituted Valve	USM (FM) Installed	Back Flow Prevention Check Valve (BFP2)	Back Flow Prevent (BFP3)	Original Installation Type	Final Installation Type	Location	Substitute/ Comment
4000-85.88-0	1	1					C/P	A/VT	Arrow and Haven	Non amenable actuator
2001-179.65-0	1	1					C/P	C/P	Bain	
2001-179.65-1						1		A/AG	Bain	BFP N/O bridle
1013-0.00-0	1	1					NV/AG	NV/AG	Brea Sta.	
4000-101.67-0	1	1					NV/AG	C/P	Chino	Need further explanation on change of install type
4000-101.67-3	1								Chino	Descoped @ 0.5 listid in the filling but no cost or installation type
4002-100.37-0	1	1					C/P	C/P	Chino	
2001-191.19-0		1	1					C/P	Chino	2001-193.91-0 is a sevice valve previously RCV equiped
2001-191.19-3						1		A/AG	Chino	N/O Bridle BFP
2001-191.19-4						1		C/P	Chino	N/O Bridle BFP
2002-6.81-0	1	1					NV/NP	NV/VT	Fern & Walnut	
2002-6.81-2	1					1	NV/NP	NV/VT	Fern & Walnut	BFP N/O bridle
2002-6.81-1						1		NV/VT	Fern & Walnut	BFP N/O bridle
120-103.49-2						1		C/P	Haskell	
120-103.48-1	1						NV/NP		Haskell	Descope @ stage 1 improved constructability, improved site conditions
3001-1.01-0	1						A/VT		Haskell	Descoped @ stage 0.5. Moved to two NO bridles at the start of the line
404-55.42-0	1						NV/NP		Haskell	Descope @ stage 1 improved constructability, improved site conditions
3001-1.02-0		1						A/AG	Haskell	Baseline crossover valve for L3001 and L404 provides isolation
2000-155.06-7									Moreno Large	Descoped @ stage 1
2000-155.06-8									Moreno Large	Descoped @ stage 1
1027-0.00-0	1						NV/NP		Moreno Large	Descoped @ stage 0.5
5000-157.82-0	1						C/P		Moreno Large	Descoped @ stage 0.5
6900-0.00-0	1						A/AG		Moreno Large	Descoped @ stage 0.5
New Flow Meter	1			1			FM	FM	Moreno Large	
2001-155.95-3						1		A/AG	Moreno Small	
2001-155.95-4									Moreno Small	Descoped @ Stage 1&2
New Flow Meter	1			1			FM	FM	Moreno Small	
235-212.20-New Location	1	1					SIS	NV/AG	Palmdale East	MP 209.87 --added for geological thread mitigation
335-34.70-New Location	1	1					SIS	NV/AG	Palmdale East	MP 32.68 -added for geological thread mitigation
235-215.22-0	1	1					C/P	NV/AG	Palmdale Tap	
335-37.73-0	1	1					C/P	C/P	Palmdale Tap	
235-217.72-New Location	1	1					SIS	NV/AG	Palmdale West	MP 217.85- added for geological thread mitigation
335-40.30-New Location	1	1					SIS	NV/AG	Palmdale West	MP 40.36 -added for geological thread mitigation
1015-6.07-1						1		A/AG	Pixley	BFP N/O bridle
1015-6.07-2						1		A/AG	Pixley	BFP N/O bridle
1015-6.07-0	1	1					NV/VT	A/AG	Pixley	Valve replaced by PI in 2012
2000-193.18-0		1	1					C/P	Prado	2000-193.18-13
4000-107.25-0	1	1					C/P	A/AG	Prado	Manual gear operated
4002-106.02-0	1	1					C/P	A/AG	Prado	Manual gear operated
4002-106.02-3						1		A/AG	Prado	BFP N/O Bridle
4002-106.02-4						1		A/AG	Prado	BFP N/O Bridle
2001-207.69-17*					1			BFP2	Puente	BFP Check Valve
2001-207.69-18*					1			BFP2	Puente	BFP Check Valve
2000-212.69-1**					1			BFP2	S.F. Springs	BFP Check Valve
2000-212.69-2**					1			BFP2	S.F. Springs	BFP Check Valve
2000-212.69-0		1	1				NV/AG	A/AG	S.F. Springs	Plug valve was not replaced because pipe was already piggable. Substituded 26" PI valve 2000-212.70-0. MLV valve was better selection for isolation.
1014-27.69-0	1	1					A/AG	C/P	Victoria	Actuated valve
1202-7.60-0	1	1					A/AG	A/VT	Victoria	Location was not feasible for above ground actuator
2006-5.53-0		1	1					C/P	Victoria	Valve replaced by PI in 2006. Substituded 20" tap valve 2006-5.54-0 in filling
New Flow Meter	1			1			FM	FM	Victoria	On L1014
2000-125.13-0	1	1					NV/NP	C/P	Whitewater	New pipe removed from scope
2000-125.13-8	1						NV/NP	C/P	Whitewater	Descoped @ stage 0.5
2001-125.13-0	1	1					C/P	C/P	Whitewater	
2051-126.40-0	1	1					C/P	C/P	Whitewater	
5000-126.40-0	1						C/P		Whitewater	Descoped @ stage 0.5
5000-157.82-0	1						C/P		Whitewater	Descoped @ stage 0.5
	34	25	4	3	4	11				

TABLE 1 LEGEND

A/AG	New actuator, above ground installation
A/VT	New actuator, vault installation
C/P	Control, power, and communications only
COMM	Communications only
NV/AG	New valve installation with new actuator above ground
NV/VT	New valve installation with new actuator in vault
NV/NP	New valve installation with replaced pipe
None	Existing RCV
FM	Flow meter installation
BFP1	Backflow prevention installation - controls modification
BFP2	Backflow prevention installation - check valve
BFP3	Backflow prevention installation - RCV 40 supply valves
SIS	Short interval spacing stated in Testimony under Section E Part 3 of "*Proposed Valve Plan*"

Shaded cells = Valve listed or referenced in R.11-02-019 Valve Plan.

V. ORIGINAL VALVE PLAN COST ESTIMATE FOUNDATIONS

The original SoCalGas and SDG&E Valve Plan included preliminary forecasted costs based on a limited number of major valve projects completed in prior years. The historical project costs were used in conjunction with contractor and material estimates in 2011 to produce the Valve Plan cost estimates. The historical projects used to help develop cost estimates were of varying size and complexities. In other words, many of the historical costs relied upon to develop estimates were not as complex as the PSEP work (e.g., did not involve comparatively significant efforts in public streets or the inclusion of bypass piping for customer retention).

As SoCalGas and SDG&E have moved through implementation, the costs associated with some of the more complex valve installation sites, involving traffic and vaults, have increased relative to earlier expectations. Factors that continue to result in cost increases and work scope changes include:

- Contractor and/or material cost escalation;
- Expanded project documentation required to close out projects;

- Time and complexities related to permitting issues and work in major roadways;
- The need to conduct (sometimes multiple) analyses for limiting back-flow into isolated sections of large diameter pipelines and continuing service to customers under a rupture condition;
- Subsequent refinement of control system design and related components needed to improve reliability and reduce risks of errant valve closures in complex pipeline networks. This modification included:
  - Installation of secondary electronic controllers to provide a "voting system" for added automatic closure reliability;
  - Abandoning the (re)use of some assets originally targeted for retrofit;[11]
  - Addition of extra taps for pressure sensing and actuator power gas supply; and
  - Enhanced point-to-point commissioning and failure mode test conducted for all sites

The impact of some of the described factors by Valve Plan project, are discussed in the Chapter V (Mejia) and associated workpapers.

VI. CONCLUSION

SoCalGas and SDG&E's Valve Plan was designed to enhance its pipeline valve infrastructure to support the automatic and remote isolation and depressurization of specific sections of its transmission pipeline system in 30 minutes or less in the event of a full-diameter-equivalent pipeline rupture. This isolation objective enhances safety by promoting a consistent swiftness-in-response for large pipelines in the event of a rupture or other unplanned gas release.

[11] One such example includes the election to not repurpose antiquated valve actuators employing gas over-hydraulic fluid technology because field observations suggested they would not be effective for reliable remote and automatic closure application (without direct operator observation).

In implementing the Valve Plan, SoCalGas and SDG&E refined the valve upgrade and installation sites and engaged in additional analysis to find efficiencies and assess the need for additional devices to accomplish the isolation objective. While the actual locations of the equipment may have been refined, the criteria for pipeline sections qualifying for valve and metering enhancements under PSEP remain unchanged from our original Valve Plan. The completed work presented for review and recovery in this Application supports the Valve Plan pipeline isolation and depressurization objectives.

This concludes my prepared Direct Testimony.

VII. WITNESS QUALIFICATIONS

My name is Michael A. Bermel. My business address is 555 West 5th Street, Mail Stop 11A3, Los Angeles, CA 90013.

My current Job Title is Measurement, Regulation and Control Manager. I have been employed by SoCalGas since 1981. I possess a Bachelor-of-Science degree, in Mechanical Engineering, from Cal State University, Long Beach. I am a Registered Professional Mechanical Engineer in the State of California. I have over 20 years of experience managing the engineering, design and commissioning of valve, pressure control, gas quality management, receipt points and related automated control and monitoring sites for SEu and affiliates.

I am the principal architect and manager of SoCalGas and SDG&E system PSEP valve isolation strategy, policy, procedures and specifications for employing automatic and remote shut-off valves on our large gas pipelines.

I have not previously testified before the Commission. This concludes my Testimony.