Docket No.: A.11-11-002

Exhibit No.: ____________________

Date: November 16, 2012

Witness: Mark E. Fulmer

TESTIMONY OF MARK FULMER
ON BEHALF OF THE CITY OF LONG BEACH

I. INTRODUCTION AND BACKGROUND

Q: Please state your name and business address.

A: My name is Mark Fulmer. I am a Principal at MRW & Associates, LLC ("MRW"). My business address is 1814 Franklin Street, Suite 720, Oakland, California. My professional and educational background is provided in Attachment A.

Q: Have you previously testified before the California Public Utilities Commission?

A: Yes. I have previously testified before the California Public Utilities Commission ("Commission") on behalf of a variety of parties on cost allocation and rate design issues. I have also submitted testimony in proceedings before the Federal Energy Regulatory Commission and state utility commissions in Arizona, Hawaii, Pennsylvania and Rhode Island.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the City of Long Beach, Gas & Oil Department ("Long Beach").

Q: What are Long Beach's interests in this proceeding?

A: Long Beach owns and operates a municipal natural gas utility that provides service to approximately 500,000 residents and businesses in the cities of Long Beach, Signal Hill and portions of Los Alamitos and Paramount. Long Beach is a wholesale customer of Southern California Gas Company ("SoCalGas") and purchases natural gas transportation and storage services from SoCalGas.

Q: Please summarize your conclusions and recommendations.

A: My conclusions and recommendations regarding the Triennial Cost Allocation Proceeding ("TCAP") for SoCalGas and San Diego Gas and Electric Company ("SDG&E," jointly the "Sempra Utilities") are as follows:

- Given the Commission's precedent and clear historical preference for the New Customer Only ("NCO") method for calculating marginal customer costs and absent any compelling evidence to support the competing Rental method, the Commission should again adopt the NCO method.
- The Sempra Utilities have proposed an increase to the marginal customer costs for wholesale customers that is orders of magnitude greater than the costs approved in the last Biennial Cost Allocation Proceeding ("BCAP"). The Sempra Utilities have failed to justify such a large escalation and, as a result, the Commission should reject the proposed increases in marginal customer costs for wholesale customers.
- In support of the Commission's goal of cost-based rate making, the proposed Transition Adjustment should be accelerated in order to ensure a transition to fully cost-based rates prior to the next TCAP.
- Costs associated with the Pipeline Safety Enhancement Program ("PSEP") are most appropriately allocated according to the Equal Percent Authorized Margin ("EPAM") methodology.

II. THE COMMISSION SHOULD ADOPT THE HISTORICALLY PREFERRED NCO METHODOLOGY FOR CALCULATION OF CUSTOMER COSTS

Q: What are customer costs?

A: Customer costs are for service lines (from pipe to the meter), meters, regulators, billing/collection apparatus, call centers, and service representatives. For SoCalGas, the total customer cost-related revenue requirement is about $997 million in 2013.[1] This represents over half of the total $1.770 billion total SoCalGas revenue requirement being allocated in this proceeding (excluding PSEP costs).

Q: How are these costs typically allocated in California?

A: Since the late 1980s the Commission's policy has been to require utilities to allocate most costs, to the extent possible, based on an assessment of long-run marginal costs. This goal of cost-based allocation also applies to customer-related costs.

Q: How do the Sempra Utilities propose allocating the customer cost revenue requirement?

A: The Sempra Utilities propose using what is known as the "Rental method" to determine customer class-based marginal costs for the purposes of allocating customer costs.

[1] Workpaper "2013TCAP SCG RD Model."

Q: Please describe the Rental method.

A: Sempra Utilities' witness Lenart explains that:

> [t]he Rental method calculates the capital component of the unit marginal cost by annualizing the cost of hooking up a new customer, or marginal investment, using the Real Economic Carrying Charge (RECC).[2]

Specifically, the marginal investment for lines, meters, and regulators for a new customer is first estimated. A "RECC factor" is applied to that estimate that "annualizes" the cost over the expected lifetime of the investment. In the residential class example provided by Witness Lenart the RECC factor is 9.1%.[3] RECC factors create a real (i.e., no impact of inflation) levelizing factor that converts capital investment into annualized capital-related marginal costs[4] and are "a function of authorized rate of return, inflation, salvage value, book life, and tax rates.[5]

Operation and maintenance ("O&M") loaders are added to that assessment of annual capital-related marginal cost. These O&M loaders reflect the indirect costs for administrative and general expenses, general plant, and materials and supplies.[6] This total annualized unit marginal cost is multiplied by the number of customers in that particular class to arrive at the total marginal costs for that class.

This exercise is performed with each class. The total customer cost revenue requirement is allocated to the different customer classes proportional to the total marginal cost for each class.

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[2] Supplemental Direct Testimony of Gary Lenart on behalf of San Diego Gas & Electric Company and Southern California Gas Company ("March 16 Lenart Supplemental Testimony") at 6 (March 16, 2012).
[3] March 16 Lenart Supplemental Testimony at 7.
[4] Updated Prepared Direct Testimony of Gary Lenart on behalf of San Diego Gas & Electric Company and Southern California Gas Company (" June 1 Lenart Updated Testimony") at 20 (June 1, 2012).
[5] June 1 Lenart Updated Testimony at 21.
[6] June 1 Lenart Updated Testimony at 21.

Q: Please describe the NCO method traditionally used by the Commission.

A: The NCO method also begins with an estimation of the marginal investment for lines, meters, and regulators for a new customer. This estimation is multiplied by a Present Value of Revenue Requirements (PVRR) factor. The PVRR factor reflects the revenue requirement costs over the life of the assets above the raw equipment cost, such as property taxes and income taxes. For the residential class example provided by Sempra Utilities witness Lenart, the PVRR factor is 1.242.[7] This value is then multiplied by the estimated number of new customers and divided by the total number of customers.

The remaining steps in the NCO method are the same as the Rental method. O&M loaders are added to the capital-related per-customer marginal cost. The sum is then multiplied by the forecast number of customers to arrive at the total marginal costs for that class. For each class, the total customer cost revenue requirement is then proportionally allocated to the different customer classes based on the total marginal cost of each class.

Q: Has the Commission heard parties debate the merits of the Rental method versus the NCO method before?

A: Yes. Debates over the Rental method versus the NCO method have occurred in nearly every cost allocation proceeding at the Commission, be it electric or gas, over the past 20 years. As has been argued in these proceedings, both methods have their appeals and drawbacks. For example, The Utility Reform Network ("TURN") witness in the last BCAP in 2008, William Marcus, argued that the NCO method "achieves many of the

[7] March 16 Lenart Supplemental Testimony at 7.

Commission's goals for using margin cost pricing to achieve economic efficiency."[8] Mr. Marcus explained his position that:

> [f]rom the point of view of marginal cost theory, customer access is best considered a one-time event, with the costs of that event best recovered through a hookup charge. The hookup [or NCO] method improves economic efficiency because it reflects as marginal only those cost that are avoidable.[9]

Mr. Marcus also argued in the last BCAP that the Rental method is predicated upon flawed assumptions concerning the applicability and accuracy of "rental" prices appropriately representing marginal or incremental costs.[10]

On the other hand, in the cost allocation phase of its last General Rate Case, Southern California Edison witness Robert Thomas argued that the NCO method ignores the economic values of existing interconnections facilitates and hence "systematically understates marginal costs."[11] He goes on to note that the NCO method can inappropriately assign zero marginal costs when a customer class is experiencing a net decrease in customers.[12]

In this proceeding, Sempra Utilities witness Lenart echoes these sentiments when he argues that the Rental method better determines customer-related costs for the whole class, while the NCO method is "skewed by variations in growth rates [and] does not fully account for replacement costs."[13]

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[8] A.08-02-001, Prepared Testimony of William B. Marcus on Behalf of TURN ("Marcus Testimony") at 15 (December 23, 2008).
[9] Marcus Testimony at 15.
[10] Marcus Testimony at 17-18.
[11] A.11-06-007, Southern California Edison Phase 2 of 2013 General Rate Case, Exhibit SCE-2 ("SCE-2") at 14 (October 7, 2011).
[12] SCE-2 at 15.
[13] March 16 Lenart Supplemental Testimony at 7-9.

Q: How has the Commission previously ruled on the Rental method versus the NCO method debate?

A: For the most part, cost allocation cases such as BCAPs for gas utilities and Phase 2 General Rate Cases for electric utilities are settled and the Commission often does not explicitly state which method is preferable. When the Commission has weighed in, or the settlement explicitly adopted a position, the NCO method has prevailed. Mr. Marcus has noted in a previous proceeding that since the 1990s the Commission had generally adopted the NCO method:

> The [NCO] method has been adopted in four PG&E BCAPs, (the last one in 2005) and two PG&E electric cases, the last rate design case for Edison, and the 1996 SDG&E gas BCAP, and the 1999 consolidated SoCal Gas and SDG&E BCAP.[14]

Since that testimony, the Commission has not weighed in on this issue, as the four cost allocation proceedings have all settled without specifying a method for allocating customer costs.[15]

Q: What allocation method do you recommend?

A: I am not convinced on a theoretical or practical level that either the Rental method or the NCO method is clearly superior for allocating costs in this TCAP and should be adopted here on its merits alone. As such, given the Commission's precedent and clear historical preference for the NCO method, the NCO method should continue to be used.

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[14] Marcus Testimony at 19.
[15] D.09-11-006 (Sempra Utilities BCAP); D.07-09-004 (PG&E GRC Phase 2); D.09-08-028 (SCE GRC Phase 2); D.11-12-053 (PG&E GRC Phase 2).

III. THE ORDERS OF MAGNITUDE INCREASE IN MARGINAL CUSTOMER COSTS FOR WHOLESALE CUSTOMERS HAS NOT BEEN JUSTIFIED AND SHOULD BE REDUCED.

Q: How do the Sempra Utilities set the marginal customer costs associated with wholesale customers like Long Beach?

A: The general process used by the Sempra Utilities for setting the marginal customer cost for wholesale customers like Long Beach is consistent with the descriptions I provided earlier for the Rental method and the NCO method. However, because there are no new "incremental" wholesale shippers, there can be no marginal investment values for meters, regulators or service lines for this customer class. Instead, the "marginal investment" for this customer class is set at the value of the "Exclusive Use Facilities." As the name implies, these are facilities and equipment used solely to serve the wholesale shipper, and generally represent the meter that measures the gas delivered from the SoCalGas system into the wholesale shippers' system.

Q: The Sempra Utilities used this same process in its 2009 BCAP. How have the marginal customer costs for wholesale customers changed from the 2009 BCAP to the current TCAP?

A: As shown in Table 1 below, the Exclusive Use Facilities costs in the TCAP are dramatically higher – by orders of magnitude – than those used in the 2009 BCAP.

Table 1: Comparison of Wholesale Customer Exclusive Use Facilities Costs[16]

	2009 BCAP (2009$)	2013 BCAP (2010$)	% Change
Long Beach	243,392	5,165,165	2,022%
SDG&E	189,380	12,175,338	6,329%
Southwest Gas	76,184	3,792,235	4,878%
Vernon	16,484	2,568,333	15,481%
DGN	152,367	617,840	305%

Q: What accounts for these extremely large increases in the exclusive use facilities costs for wholesale customers?

A: According to the Sempra Utilities, the cost increases were attributable to increased meter costs and updated listing of the meters serving wholesale customers showing significantly more meters serving wholesale customers.[17]

Q: What drives the increase in wholesale meter costs?

A: When asked this question in discovery, the Sempra Utilities only response was to state the obvious: "[i]ncreases were due to Labor, Contract Costs, and Materials."[18] This unhelpful response is self-evident and does not provide any rationale or evidence as to why the labor, contract and material costs increased by roughly a factor of ten in three years.

Q: What types of wholesale meters does Sempra Utilities use to serve wholesale shippers?

A: The Sempra Utilities use three types of meters to serve wholesale shippers: turbine meters, rotary meters, and ultrasonic meters.

[16] Data from the 2009 BCAP and 2013 TCAP workpapers.
[17] Response to Long Beach Data Request No.5, Question 5-1d.
[18] Response to Long Beach Data Request No. 5, Question 5-1c (included as Attachment B).

Q: How big an increase was there in the estimated costs of turbine meters?

A: Table 2 below shows the Sempra Utilities' estimated costs of wholesale customer turbine meters from the 2009 BCAP and in this proceeding. There are huge increases in the labor (+1129%), contract (+900%) and materials (+711%) costs for turbine meters.

Table 2: Turbine Meter Costs[19]

	2009 BCAP	2013 TCAP	$ change	% change
Avg. Meter Cost	$11,274	$17,118	$5,844	52%
Avg. Labor Cost	$9,848	$121,021	$111,173	1129%
Avg. Contract Cost	$24,190	$242,000	$217,810	900%
Materials	$28,016	$227,203	$199,187	711%
Regulator Cost	$3,938	$2,303	($1,635)	-42%
GEMS Device Cost	$11,350	$8,195	($3,155)	-28%
TOTAL	**$88,616**	**$617,840**	**$529,224**	597%

Q: How big an increase was there in the estimated costs of ultrasonic meters?

A: Since the last BCAP, the Sempra Utilities have switched from orifice meters to ultrasonic meters. Thus, some cost difference should be expected. However, as shown in Table 3, the Sempra Utilities again show large increases in labor, contract and materials costs from 2009 (orifice) to 2013 (ultrasonic). While orifice and ultrasonic meters use different technologies and some cost difference should be expected, the Sempra Utilities provide no rationale why these costs increased so dramatically.

[19] Response to Long Beach Data Request No. 5, Question 5-1c.

Table 3: Orifice and Ultrasonic Meter Costs[20]

	(Orifice Meters) 2009 BCAP	(Ultrasonic Meters) 2013 TCAP	$ change	% change
Avg. Meter Cost	$32,400	$119,284	$86,884	268%
Avg. Labor Cost	$18,625	$204,372	$185,747	997%
Avg. Contract Cost	$35,000	$379,500	$344,500	984%
Materials	$72,817	$561,130	$488,313	671%
Regulator Cost	$5,150	$0	($5,150)	-100%
GEMS Device Cost	$9,683	$19,881	$10,198	105%
TOTAL	**$173,675**	**$1,284,167**	**$1,110,492**	639%

Q: Did the costs related to rotary meters also drive the large increases in wholesale meter costs?

A: No. The 2013 TCAP Workpapers show rotary meters to be orders of magnitude less costly than turbine or ultrasonic meters and were not identified as drivers behind the increase in wholesale shipper marginal costs.

Q: What impact on the cost allocated to the TLS Customer class do these increased wholesale customer meter costs have?

A: To estimate the impact of these unexplained increases in labor, contract and materials, costs, I replaced the 2013 TCAP values with the 2009 BCAP values in the customer long-run marginal cost workpapers. TLS Customer class rates decreased by 1.5%.[21]

Q: Does the increase in the number of meters serving Wholesale customers cited by Sempra Utilities necessarily mean that there has been a corresponding increase in the marginal cost of serving Wholesale customers since the last BCAP?

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[20] Response to Long Beach Data Request No. 5, Question 5-1c.
[21] Using SCE's default Rental cost allocation method.

A: No. Since meters are the key drivers affecting the cost of "Exclusive Use Facilities" and "Exclusive Use Facilities" effectively serve as a proxy for marginal cost under the methodology that Sempra Utilities has used for developing the marginal cost of serving Wholesale customers, an increase in the number of meters does increase the indicative marginal cost of serving Wholesale customers under the methodology Sempra has used. No evidence has been presented in this proceeding, however, that the actual marginal cost of serving Wholesale customers has increased by any amount corresponding to the increase in the number of meters or remotely approaching such amount. In the absence of such justification, the order of magnitude increase in meter costs cited by Sempra Utilities casts significant doubt on the validity of the methodology it has used to develop marginal costs for Wholesale customers.

Q: What is your recommendation based on the unexplained and unjustified increase in wholesale meter costs?

A: I recommend that for calculating wholesale customer marginal costs that the 2009 BCAP values be used for labor, contract and material costs with regard to wholesale meters.

IV. THE TRANSITION ADJUSTMENT SHOULD BE ACCELERATED IN ORDER TO ENSURE COST-BASED RATES PRIOR TO THE NEXT TCAP.

Q: Do the Sempra Utilities propose adoption of fully cost-based rates?

A: The Sempra Utilities have stated that their goal is to have rates that are fully cost based[22] and their proposed rates show progress in that direction. However, they have proposed to adjust allocated costs in order to avoid "rate shock" on some customers that would

[22] Updated Prepared Direct Testimony of Gary Lenart on behalf of San Diego Gas & Electric Company and Southern California Gas Company ("September 18 Lenart Updated Direct Testimony") at 32 (September 18, 2012).

receive larger increases with a full transition to cost-based rates. They refer to this reallocation as a “Transition Adjustment.”

Q: What is the benefit of moving towards cost-based rates?

A: Cost-based rates create clear signals to consumers and are a mainstay of Commission policy goals. For example, the recently-issued Order Instituting Rulemaking on residential electric rate design issues, the Commission again emphasized that “[d]eveloping equitable rates based on the principle of cost causation is one of the underlying goals of the Commission’s rate making process” and noted that “avoiding cross-subsidies and supporting cost-causation principles ‘achieves equity in rates by relating the costs imposed on the utility system to the customer responsible for those costs.”[23]

Q: Why did the Sempra Utilities include a Transition Adjustment?

A: The Sempra Utilities have included a Transition Adjustment in this TCAP to limit any rate increase resulting from the cost-based rates coming out of their marginal and embedded cost studies.[24] With full cost-based allocation a number of customer classes would experience large increases to their transportation rates. These customer classes include SoCalGas Air Conditioning (“Gas A/C”), SoCalGas Gas Engine, Electric Generation Tiers 1 and 2 (“EG-D”), and SDG&E Residential.[25] In this context, the

[23] R.12-06-013, Order Instituting Rulemaking On The Commission’s Own Motion To Conduct A Comprehensive Examination Of Investor Owned Electric Utilities’ Residential Rate Structures, The Transition To Time Varying And Dynamic Rates, And Other Statutory Obligations at 13 (fn 19) (June 21, 2012).
[24] September 18 Lenart Updated Direct Testimony at 31, 33.
[25] September 18 Lenart Updated Direct Testimony at 34 (Table 16).

Sempra Utilities define a large increase as anything above 10% relative to current transportation rates.[26]

Q: How do the Sempra Utilities propose to re-allocate costs under the Transition Adjustment?

A: The Sempra Utilities propose to limit transportation rate increases for individual customer classes to 10% annually until cost-based rates are achieved.[27] The Sempra Utilities propose keeping cost-shifting resulting from re-allocation within each utility (SoCalGas and SDG&E) and within the core and non-core customer designations.[28] As a result, the Sempra Utilities propose to re-allocate costs between specific rate classes. The Sempra Utilities' proposed re-allocations for the SoCalGas customer classes are summarized in Table 4 below.

Table 4: Sempra Utilities Proposed Transition Adjustment[29]

	2013 Rate Increase Relative to prior year with Cost-Based rate	Proposed Transition Adjustment ($000)
SoCalGas – Core		
Residential	4%	$0
Core C/I	(19%)	$1,263
Gas A/C	18%	($3)
Gas Engine	37%	($1,260)
Natural Gas Vehicles	4%	$0
SoCalGas – Non-core		
Non-core C/I	(22%)	$0
EG-D Tier 1	104%	($1,900)
EG-D Tier 2	37%	($1,100)
TLS	(36%)	$3,000
BTS	21%	$0

[26] September 18 Lenart Updated Direct Testimony at 34.
[27] September 18 Lenart Updated Direct Testimony at 35.
[28] September 18 Lenart Updated Direct Testimony at 34-35.
[29] September 18 Lenart Updated Direct Testimony, Appendix 1 at A-1, A-2.

The Sempra Utilities have chosen the 10% benchmark, according to witness Lenart, "because any smaller increase would put off the move to cost-based rates for too long."[30] For Gas A/C, core Gas Engine, EG-D Tier 2, and SDG&E Residential rate classes, the rate increase as a result of movement to cost-based rates is relatively small and using the 10% benchmark allows for fully cost-based rates prior to the next TCAP cycle in 2016.[31]

For EG-D Tier 1 customers, however, a 10% benchmark does not allow for timely transition to cost-based rates. In fact, under the Sempra Utilities' own rate illustration, annual increases would need to be up to 14% for cost-based rates to be achieved by 2019.[32] As shown in Table 4, the Sempra Utilities propose to finance the cost shifting from EG-D Tier 1 customer by re-allocating $1.9 million from TLS customers. The Sempra Utilities additionally propose re-allocation of $1.1 million from EG-D Tier 2 customer to TLS customers. The rates resulting from the Sempra Utilities' proposed Transition Adjustment for EG-D Tier 1 customers is illustrated in Table 5 below.

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[30] September 18 Lenart Updated Direct Testimony at 35.
[31] September 18 Lenart Updated Direct Testimony, Appendix 1at A-1, A-2.
[32] For 2016-2019 these rates are illustrative. The Sempra Utilities explain that a specific proposal would need to be included in the next TCAP. September 18 Lenart Updated Direct Testimony at 35, Appendix 1 at A-1, A-2.

Table 5: Sempra Utilities Proposed Transition Adjustment Rates for EG-D Tier 1[33]

	EG-D Tier 1 Rate $/therm	% Change from Prior Year
Current Rates	$0.06	--
2013 Cost-Based Rates	$0.11	104%
2013 Adjusted	$0.06	10%
2014 Adjusted	$0.07	10%
2015 Adjusted	$0.07	10%
2016 Adjusted	$0.08	10%
2017 Adjusted	$0.09	10%
2018 Adjusted	$0.10	11%
2019 Adjusted	$0.11	14%

Q: Do you agree with the Sempra Utilities' proposed Transition Adjustment?

A: While I agree with the need for some degree of re-allocation to avoid significant rate increases for a subset of customers, I find that the Sempra Utilities' proposal does not properly balance the competing interests of movement towards cost-based rates and avoidance of rate shock. Namely, the Transition Adjustment should be accelerated such that cost-based rates are achieved for all customer classes coincident with the next TCAP proceeding in 2016.

Q: How would an acceleration of the Transition Adjustment affect the proposed rates?

A: In the Sempra Utilities' proposal, the only rate class requiring a Transition Adjustment after 2016 is EG-D Tier 1. If the Transition Adjustment were to be accelerated such that cost-based rates were achieved in 2016, EG-D Tier 1 customers would see annual rate increases of 19% over the TCAP period. EG-D Tier 1 rates under the accelerated Transition Adjustment are summarized in Table 6 below.

[33] September 18 Lenart Updated Direct Testimony, Appendix 1 at A-1, A-2.

Table 6: Accelerated Transition Adjustment for EG-D Tier 1 Customers

	EG-D Tier 1 Rate $/therm	% Change from Prior Year
Current Rates	$0.055	--
2013 Cost-Based Rates	$0.111	104%
2013 Adjusted	$0.065	19%
2014 Adjusted	$0.078	19%
2015 Adjusted	$0.093	19%
2016 Adjusted	$0.111	19%

Q: Is a 19% annual rate increase appropriate for EG-D Tier 1 customers?

A: Yes. A 19% annual increase for EG-D Tier 1 customers would incur only to the transportation portion of a customer's rate, and not to the customer's entire gas bill. In past decisions, the Commission has approved modified allocation measures in cases where a cost-based allocation would be unduly detrimental to a particular customer class with the caveat that such actions do "not subjugate [the Commission's] primary ratemaking goal [of use of marginal costs for ratemaking] in order to address these issues."[34] Thus, it is reasonable to require that all customers transition to cost-based rates prior to the beginning of the next TCAP period.

V. PSEP COSTS SHOULD BE ALLOCATED BASED ON THE EPAM METHODOLOGY

Q: Please summarize the PSEP costs that are being allocated in this proceeding.

A: First, we cannot know at this point in time what exactly those costs will be, as the Commission has yet to issue a decision in Phase 1. Nonetheless, the Sempra Utilities' testimony in Application 11-02-018, which has been submitted into the record of this proceeding, presented two cases: a Base Case and a Preferred Case. The Base Case

[34] D.96-04-050, 1996 Cal. PUC LEXIS 270 at *29 (1996).

includes only the work required under Decision 11-06-017.[35] The Preferred Case includes Base Case costs plus costs associated with additional projects that Sempra recommends be included in the PSEP. These include:

> the replacement of pipeline segments to mitigate construction "threats;" (b) proposed technology enhancements (e.g., fiber-optic cabling, methane detection monitors and remote monitoring system); and (c) development of a "comprehensive Enterprise Asset Management system.[36]

The Sempra Utilities also present the plan in two phases: Phase 1A for activities through 2015, and Phase 1B for activities from 2016 through 2021.[37]

Q: What is the magnitude of these costs?

A: They are quite significant. The Proposed Case Phase 1A costs total approximately $1.4 billion of capital investment plus $262 million in non-capital O&M costs for both utilities.[38] Phase 1B would add another $1.4 billion of capital investment plus $30 million in additional O&M costs.[39] The Base Case capital costs for Phase 1A is about 20% less than the Proposed Case while the Phase 1A Base Case O&M cost is 5% less. However for Phase IB, the Base Case costs are even lower: only $533 million in capital costs (versus over $1.4 billion) and $24 million for additional O&M costs.[40]

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[35] R.11-02-019, Amended Testimony of Southern California Gas Company and San Diego Gas & Electric Company In Support of Proposed Natural Gas Pipeline Safety Enhancement Plan ("December 2 Amended Testimony") at 13 (December 2, 2011).
[36] R.11-02-019, Amended Pipeline Safety Enhancement Plan of Southern California Gas Company and San Diego Gas & Electric Company Pursuant to D.11-06-017 (December 2 Amended PSEP") at 44 (December 2, 2011).
[37] Timing per the December 2 Amended PSEP. Given that the proceeding's schedule did not meet Amended Plan's expectations, there will be inevitable delay from the dates cited here. Nonetheless, the timing of the costs here reflects the utilities' application rather than speculation concerning what the actual timing might be.
[38] December 2 Amended PSEP at 45-46 (Table C, Table D).
[39] December 2 Amended PSEP at 45-46 (Table C, Table D).
[40] December 2 Amended PSEP at 47-48 (Table E, Table F).

These requested costs translate into significant increases to the Sempra Utilities' revenue requirements. For example, by 2015, the revenue requirement associated with the PCAP would be approximately $277 million (Proposed Case).[41] By 2020, this would increase to over $450 million.[42] For comparison, the base margin revenue requirement being allocated in this TCAP proceeding is approximately $2 billion.[43]

Q: What cost allocation proposals have been presented so far by the Sempra Utilities?

A: In their December 2, 2011 Amended Pipeline Safety Enhancement Plan and supporting testimony, the Sempra Utilities proposed to allocate the PSEP costs using the EPAM method. The utilities' supporting testimony justifies using the EPAM allocation methodology for these costs on grounds that the PSEP safety enhancements benefit all customers and that increasing rates on a percentage basis is relatively equitable across different customer classes.[44]

Tables presented by the Sempra Utilities in its December 2011 testimony in Rulemaking 11-02-019 showed rate increases in 2015 on the order of 9-11% for the non-residential class and 7.7% and 6.5% increase for the SoCalGas and SDG&E residential classes, respectively.[45] The Sempra Utilities later presented an alternative cost allocation method in response to an Assigned Commissioner Ruling.

[41] December 2 Amended PSEP at 62 (Table T).
[42] December 2 Amended PSEP at 62 (Table T).
[43] September 18 Lenart Updated Direct Testimony at 37 (Table X-1); Updated Prepared Direct Testimony of Joseph Mock at 16 (June 1, 2012).
[44] December 2 Amended Testimony at 22.
[45] December 2 Amended Testimony at 136 (Table X-13). Percent increases were relative to the rates in place (i.e., in 2011). The values were revised in the September 18 Lenart Updated Direct Testimony at 11 (Table 5). The percentage increases changed in the update, mainly due to changes in the baseline rate (from "current" 2011 rates to current "2012" rates).

Q: Please describe the alternate cost allocation proposal.

On November 2, 2011, Assigned Commissioner Florio issued a ruling in Application 11-02-019 requiring the Sempra Utilities to present a scenario that uses "the same cost allocation and rate design principles used in the most recently adopted cost allocation or gas accord decision for those companies."[46] Using this allocation method, the PSEP costs are first assigned to their function: backbone, local transmission, SoCalGas distribution, and SDG&E distribution. Backbone and local transmission costs are combined and assigned using transmission allocators. Distribution costs for each utility are assigned using distribution allocators.

For wholesale transmission customers like Long Beach, this means that the rate increase in 2015 from the PSEP would be 80% rather than 11%.[47]

Q: Given these alternative cost allocations, what methodology does Long Beach recommend for allocating PSEP costs?

A: The safety enhancements that will be implemented through the PSEP benefit all gas customers in Southern California and the public generally. Such benefits are not a function of the particular system facilities used to serve different customer classes or how they are classified as between transmission and distribution. As a result, it makes little sense to allocate such costs first to the different functional elements of the system or to use transmission and distribution allocators for allocating these costs. Allocating PSEP costs on an EPAM basis will more appropriately match costs and safety benefits to

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[46] R.11-02-019, Amended Scoping Memo and Ruling of the Assigned Commissioner at 5 (November 2, 2011).

[47] R.11-02-019, Supplemental Testimony of Southern California Gas Company and San Diego Gas & Electric Company In Support of Proposed Natural Gas Pipeline Safety Enhancement Plan at 3 (Table 1) (December 2, 2011). Percent change relative to rate in place in 2011.

different customer classes. As a result, Long Beach recommends the EPAM allocation offered by the Sempra Utilities and finds its rationale to be reasonable.

Q: Does this conclude your testimony?

A: Yes.

ATTACHMENT A

MARK E. FULMER

PROFESSIONAL EXPERIENCE

Principal
MRW & Associates, LLC
(1999 - Present)
Conduct economic and technical studies in support of clients involved in regulatory and legislative proceedings and power project development. Advise clients on the economic issues associated with taking electricity service from non-utility sources or self-generating power. Work includes expert testimony on rate matters; economic analysis of end-use energy-efficiency projects, retail rate and wholesale price forecasting, and pro forma analysis of cogeneration and distributed generation facilities.

Project Engineer
Daniel, Mann, Johnson & Mendenhall
(1996 - 1999)
Acted as project manager and technical advisor on energy efficiency projects. Work included management of PG&E program to promote innovative energy efficient technologies for large electricity users. Coordinated the implementation of an intranet-based energy efficiency library. Directed technical and market analyses of small commercial and residential emerging technologies.

Associate
Tellus Institute
(1990-1996)
Advised public utility commissions in five states on electric and gas industry deregulation issues. Submitted testimony on the rate design of a natural gas utility to the Pennsylvania Public Utilities Commission. Testified before the Hawaii PUC on behalf of a gas distribution utility concerning a competing electric utility's demand-side management plan. Analyzed national energy policies for a set of non-governmental agencies, including critiquing the DOE's national energy forecasting model. Developed model to track transportation energy use and emissions and used the model to evaluate state-level transportation policies. Developed model to track greenhouse gas emission reductions resulting from state-level carbon taxes.

Research Assistant
Center for Energy and Environmental Studies, Princeton University
(1988-1990)
Researched the technical and economic viability of gas turbine cogeneration using biomass in the cane sugar and alcohol industries. First researcher to apply "pinch" analysis and a mixed-integer linear programming model to minimize energy use in cane sugar refineries and alcohol distilleries.

EDUCATION

M.S.E., Mechanical and Aerospace Engineering, Princeton University, 1991
B.S., Mechanical Engineering, University of California, Irvine, 1986

Mark E. Fulmer
Prepared Testimony

Previous Employers

1. Rhode Island Public Utilities Commission No. 2025 Prepared Testimony on Behalf of Rhode Island Department of Public Utilites and Carriers (Commission Staff). Testimony addressed the costs, savings, and cost-effectiveness of the proposed demand-side management programs of Providence Gas Company. April 1993.

2. Pennsylvania Public Utility Commission R-943029 Prepared Testimony on Behalf of the Pennsylvania Office of Consumer Advocate. Testimony reviewed 1307(f) filing of Columbia Gas of Pennsylvania, particularly the impact of the proposed gas cost recovery mechanism on residential customers. May 1994.

3. Public Utilities Commission of the State of Hawaii No. 94-0206 Prepared Testimony on Behalf of the Gas Company of Hawaii (Gasco). Testimony identification of Gasco's concerns regarding HECO's proposed DSM programs for competitive energy end-use markets. December 1994.

MRW

1a. FERC Docket Nos. EL00-95-075 and EL00-98-063
Affidavit on Behalf of Duke Energy Trading and Marketing LLC. March 20, 2003.

1. CPUC Rulemaking 01-10-024 Prepared Testimony on Behalf of the Alliance for Retail Energy Markets. Testimony addressed the utility procurement plans with respect to resource adequacy. June 23, 2003

2. CPUC Rulemaking 01-10-024
Rebuttal Testimony on Behalf of the Alliance for Retail Energy Markets. July 14, 2003.

3. Arizona Corporation Commission No. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630. E01933A-02-0069, E-01933A-98-0471
Rebuttal Testimony on Behalf of Constellation NewEnergy, Inc. and Strategic Energy, L.L.C. Testimony addressed the future of the Arizona Independent System Administrator. July 28, 2003.

4. Arizona Corporation Commission No. E-00000A-02-0051
Reply Testimony on Behalf of Constellation NewEnergy, Inc. and Strategic Energy L.L.C. August 29, 2003.

5. Arizona Corporation Commission No. E-01345A-03-0437
Direct Testimony on Behalf of Constellation NewEnergy and Strategic Energy, Inc. February 3, 2004

6. Arizona Corporation Commission No. E-01345A-03-0437
Cross Rebuttal Testimony of Mark E. Fulmer on Behalf of Constellation NewEnergy and Strategic Energy, Inc. March 30, 2004

7. CPUC Rulemaking 03-10-003
Direct Testimony of Mark E. Fulmer on Behalf of The City and County of San Francisco on Community Choice Aggregation Transaction Costs. April 15, 2004

8. CPUC Rulemaking 03-10-003
Reply Testimony of Mark E. Fulmer on Behalf of The City and County of San Francisco on Cost Responsibility Surcharge for Community Choice Aggregation. May 7, 2004

9. CPUC Rulemaking 03-10-003
Rebuttal Testimony of Mark E. Fulmer on Behalf of The City and County of San Francisco on Cost Responsibility Surcharge for Community Choice Aggregation. May 20, 2004

10. CPUC Rulemaking 04-04-003
Testimony of Mark Fulmer on Behalf of Strategic Energy LLC and Constellation NewEnergy concerning the Long Term Procurement Plans of PG&E, SCE and SDG&E. August 6, 2004

11. CPUC Rulemaking 04-04-003
Rebuttal Testimony of Mark Fulmer on Behalf of Strategic Energy LLC and Constellation NewEnergy concerning the Long Term Procurement Plans of PG&E, SCE and SDG&E. August 20, 2004

12. CPUC Rulemaking 03-10-003
Opening Testimony of Mark E. Fulmer on Behalf of the City and County Of San Francisco on Allocation of Costs for Community Choice Aggregation Phase 2. April 28, 2005

13. CPUC Rulemaking 04-12-014
Testimony of Mark E. Fulmer on Behalf of the Alliance for Retail Energy Markets Concerning Southern California Edison's Test Year 2006 General Rate Case Application. May 6, 2005.

14. CPUC Rulemaking 03-10-003
Rebuttal Testimony of Mark E. Fulmer on Behalf of the City and County Of San Francisco on Allocation of Costs for Community Choice Aggregation Phase 2. May 16, 2005.

15. CPUC Rulemaking 04-12-014
Testimony of Mark E. Fulmer on Behalf of the Alliance for Retail Energy Markets Concerning Southern California Edison's Test Year 2006 General Rate Case Application. May 25, 2005.

16. CPUC Application 06-03-005
Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition Concerning Phase 2 of the Pacific Gas and Electric Co.2007 General Rate Case Marginal Cost, Revenue Allocation and Rate Design. October 27, 2006.

17. CPUC Application 07-01-045
Testimony of Mark E. Fulmer on Behalf of The Alliance for Retail Energy Markets and The California Manufacturers and Technology Association Concerning Southern California Edison's Application to Update is Direct Access and Other Service Fees. June 22, 2007.

18. CPUC Rulemaking 08-03-002
Testimony of Mark Fulmer Behalf of Debenham Energy, LLC. Concerning Tariffs Supportive of Green Distributed Generation. October 31, 2008.

19. CPUC Application 09-02-022
Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition Concerning Pacific Gas & Electric's 2009 Rate Design Window Application. July 31, 2009.

20. CPUC Application 09-02-019
Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition Concerning the Cost Recovery Proposed By PG&E in its Application to Implement a Photovoltaic Program. August 14, 2009.

21. Superior Court of San Francisco
Deposition of Mark E. Fulmer on Behalf of the City and County of San Francisco in PG&E v. CCSF. (Verbal deposition only.) September 2, 2009.

22. California Superior Court of San Francisco Court Case No. CGC-07-470086
Testimony of Mark E. Fulmer on Behalf of the City and County of San Francisco in Pacific Gas & Electric Company v. City and County of San Francisco. (Trial exhibits only in electronic file.) September 25, 2009.

23. CPUC Application 09-12-020
Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition Concerning Phase 1 of Pacific Gas & Electric Company's Test Year 2011 General Rate Case. May 19, 2010.

24. CPUC Application 10-03-014
Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition Concerning Phase 2 of Pacific Gas & Electric's Test Year 2011 General Rate Case Application. October 6, 2010.

25. CPUC Rulemaking 07-05-025
Testimony of John P. Dalessi, Mark E. Fulmer, Margaret A. Meal on Behalf of the Joint Parties on a Fair and Reasonable Methodology to Determine the Power Charge Indifference Adjustment (PCIA) and the Competition Transition Charge (CTC). January 31, 2011.

26. CPUC Rulemaking 07-05-025
Testimony of Mark E. Fulmer on Behalf of The Direct Access Parties Concerning the Transitional Bundled Service Rate, Direct Access Switching Rules, Minimum Stay Provisions, and Energy Service Provider Financial Security Requirements. January 31, 2011.

27. CPUC Rulemaking 07-05-025
Reply Testimony of Mark E. Fulmer on Behalf of The Direct Access Parties Concerning the Transitional Bundled Service Rate, Direct Access Switching Rules, Minimum Stay Provisions, and Energy Service Provider Financial Security Requirements. February 25, 2011.

28. CPUC Rulemaking 07-05-025
Reply Testimony of John P. Dalessi, Mark E. Fulmer, Margaret A. Meal on Behalf of The Joint Parties on a Fair And Reasonable Methodology to Determine the Power Charge Indifference Adjustment (PCIA) and the Competition Transition Charge (CTC). February 25, 2011.

29. CPUC Application A.11-03-001, 11-03-002, 11-03-003
Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition and The Alliance for Retail Energy Markets Concerning Competitive Issues in the 2012-2014 Demand Response Program Proposals. June 15, 2011.

30. CPUC Application 11-03-001, 11-03-002, 11-03-003
Rebuttal Testimony of Mark E. Fulmer on Behalf of The Direct Access Customer Coalition and The Alliance for Retail Energy Markets Concerning Competitive Issues in the 2012-2014 Demand Response Program Proposals. July 11, 2011.

31. CPUC Application 11-06-004
Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition and the Alliance for Retail Energy Markets concerning PG&E's 2012 Energy Resource Recovery Account (ERRA) and 2012 Generation Non-bypassable Charges Forecast. August 26, 2011.

32. CPUC Application 11-05-023
Testimony of Mark Fulmer on Behalf of the Direct Access Customer Coalition, the Alliance for Retail Energy Markets and the Western Power Trading Forum concerning the Application of San Diego Gas & Electric for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center, and Quail Brush Power. September 22, 2011.

33. CPUC Application 11-06-007
Testimony of Mark Fulmer on Behalf of the Direct Access Customer Coalition Concerning Phase 2 of Southern California Edison's Test Year 2012 General Rate Case Application. February 6, 2012.

34. CPUC Application 11-12-009
Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition, the Alliance for Retails Energy Markets and the City and County of San Francisco Concerning Pacific gas & Electric Company's Application to Revise Direct Access and Community choice Aggregation Service Fees. May 14, 2012.

35. CPUC Rulemaking 12-03-014
Testimony on Behalf of the Alliance for Retail Markets, Direct Access Customer Coalition, and Marin Energy Authority. With Sue Mara. June 25, 2012.

36. CPUC Rulemaking 12-03-014
Reply Testimony on Behalf of the Alliance for Retail Energy Markets, Direct Access Customer Coalition, and Marin Energy Authority. With Sue Mara. July 23, 2012.

37. CPUC Application 12-03-001
Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets Concerning PG&E Company's Application to Implement Economic Development Rates for 2013-2017. August 24, 2012.

38. CPUC Application 12-02-001
Rebuttal Testimony of Mark E. Fulmer on Behalf of the Alliance for Retail Energy Markets Concerning Pacific Gas & Electric Company's Application to Implement Economic Development Rates for 2013-2017. October 19, 2012.

39. CPUC Application 12-04-020

Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets, the Direct Access Customer Coalition and 3 Phases Renewables Regarding Pacific Gas and Electric Company's Application to Establish a Green Option Tariff. October 19, 2012.

40. CPUC Application 12-04-020
Rebuttal Testimony of Mark Fulmer on Behalf of the Alliance for Retail Energy Markets, the Direct Access Customer Coalition and 3 Phases Renewables Regarding Pacific Gas and Electric Company's Application to Establish a Green Option Tariff. November 9, 2012.

ATTACHMENT B

SAN DIEGO GAS AND ELECTRIC COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
2013 TRIENNIAL COST ALLOCATION PROCEEDING (A.11-11-002)
(5th DATA REQUEST FROM LONG BEACH OIL & GAS DEPARTMENT)

1c: The table below summarizes the difference between the amounts used in the 2009 BCAP filing and the current TCAP filling. Increases were due to Labor, Contract Costs, and Materials. SoCalGas switched from Orifice Meters to Ultrasonic meters, and the costs of those meters has increased.

	Turbine Meters 2009 BCAP	Turbine Meters 2013 TCAP	$ change	% change
Avg. Meter Cost	$11,274	$17,118	$5,844	52%
Avg. Labor Cost	$9,848	$121,021	$111,173	1129%
Avg. Contract Cost	$24,190	$242,000	$217,810	900%
Materials	$28,016	$227,203	$199,187	711%
Regulator Cost	$3,938	$2,303	($1,635)	-42%
GEMS Device Cost	$11,350	$8,195	($3,155)	-28%
TOTAL	**$88,616**	**$617,840**	**$529,224**	597%

	Orifice Meters 2009 BCAP	Ultrasonic Meters 2013 TCAP	$ change	% change
Avg. Meter Cost	$32,400	$119,284	$86,884	268%
Avg. Labor Cost	$18,625	$204,372	$185,747	997%
Avg. Contract Cost	$35,000	$379,500	$344,500	984%
Materials	$72,817	$561,130	$488,313	671%
Regulator Cost	$5,150	$0	($5,150)	-100%
GEMS Device Cost	$9,683	$19,881	$10,198	105%
TOTAL	**$173,675**	**$1,284,167**	**$1,110,492**	639%