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Exhibit Number	:	
Reference Number	:	ORA-03
Commissioner	:	L. Randolph
ALJ	:	T. Kenney
Witness	:	P. Sabino

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Triennial Cost Allocation (TCAP) Proceeding, Phase 2

Southern California Gas Company (U 9042G) and
San Diego Gas & Electric Company (U 902 G)

ORA Testimony on Cost Allocation and Rate Design

San Francisco, California
March 11, 2016

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I. INTRODUCTION

This exhibit presents the analyses and recommendations of the Office of Ratepayer Advocates ("ORA") regarding Phase 2 of Southern California Gas Company's ("SoCalGas") and San Diego Gas & Electric Company's ("SDG&E's") 2017 Triennial Cost Allocation Proceeding ("TCAP") Application. On June 8, 2015, SoCalGas and SDG&E, sometimes collectively referred to as "SoCalGas and SDG&E", "Applicants", or "Sempra" filed a joint Application ("A.") for authority to revise their natural gas rates effective January 1, 2017 and for approval of related cost allocation and rate design proposals in A.15-07-014.[1] The original filed Application was subsequently revised on November 19, 2015. Specifically, this exhibit addresses Sempra's proposals regarding:

- Gas distribution cost allocation
- Gas transmission and storage cost allocation
- Gas distribution rate design
- Gas transmission and storage rate design

On October 2, 2015, the Assigned Commissioner's Scoping Memo and Ruling ruled that ORA and Intervenors testimony be served on March 11, 2016.[2] The Scoping Memo and Ruling identified a number of issues as within the scope of the proceeding, which include, among others, the cost allocation and rate design issues this exhibit will address. This exhibit reviews the revised testimony and workpapers of the Applicants, including all discovery responses, to address the relevant portions of the Scoping Ruling pertaining to the identified issues below:[3]

1. Should the Commission authorize the allocation of costs by customer classes as proposed in the application, effective January 1, 2017?

2. Should the Commission authorize SoCalGas and SDG&E transportation rates as proposed in the application, effective January 1, 2017?

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[1] SoCalGas and SDG&E 2017 TCAP Application (A.15-07-014), p. 14.

[2] Assigned Commissioner's Scoping Memo and Ruling in A.15-07-014 dated October 2, 2015, p. 5.

[3] Id., p. 3.

3. Should the Commission authorize the proposed residential customer charges at SoCalGas and SDG&E and the revised tier differential calculation requesting to revise rates for gas services on their respective systems effective January 1, 2017?

In cost allocation proceedings such as the TCAP, the Commission determines how the authorized revenue requirements are allocated among the different customer classes of the gas utilities over a 3-year cycle. Once allocated (and scaled as needed in the case of marginal costs to reconcile with revenue requirements), the rate design process to collect the authorized revenue requirements follows.

II. SUMMARY OF RECOMMENDATIONS

- ORA recommends the Commission, consistent with past decisions, apply the New Customer Only ("NCO")[4] method to develop and calculate the Applicants' marginal customer costs and deny the Rental method as proposed by SoCalGas and SDG&E for the gas distribution services;[5]
- ORA does not oppose the Long Run Marginal Cost ("LRMC") methodology and calculation of the Applicants' medium pressure distribution marginal costs as proposed for the gas distribution services ;[6]
- ORA does not oppose the LRMC methodology and calculation of the Applicants' high pressure distribution marginal costs as proposed for the gas distribution services;[7]
- ORA recommends that clarifications be made to the definition of the term "historical investments" for purposes of the regression analysis

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[4] See for example, D.10-06-035, Ordering Paragraph #1, p. 37, adopting a settlement that used the NCO method in A.09-05-026.

[5] See Section III.C.5.

[6] See Section III.C.2.

[7] See Section III.C.2.

performed under the adopted LRMC methodology as discussed herein;[8]

- ORA agrees with using the embedded cost method for the calculation of the Applicants' gas transmission services and rates as proposed by SoCalGas and SDG&E;[9]
- ORA recommends the Commission adopt the scaled marginal cost revenues based on the LRMC NCO method for gas distribution and the resulting base margin allocation combined with the Applicants' transmission and gas storage embedded costs;[10]
- ORA recommends the Commission adopt the gas transportation rates based on ORA recommendations on cost allocation as discussed herein;[11]
- ORA recommends retaining the current SoCalGas residential customer charge at $5.00 per month;[12]
- ORA opposes the proposal of SDG&E to implement a new residential customer charge of $10.00 per month. ORA recommends that the Commission adopt a minimum bill for SDG&E's residential customers in the amount of $3.00 per month as discussed herein;[13] and
- ORA recommends keeping the current SoCalGas residential rate tier differential calculation.[14]

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[8] See Section III.C.2.

[9] See Section IV.C.

[10] See Section III.C.6.

[11] See Section V.D.3.

[12] See Section V.D.1.

[13] See Section V.D.1.

[14] See Section V.D.2.

III. Cost Allocation for Gas Distribution Service

A. Background on Cost Allocation and Marginal Cost Concepts

There are generally two broad types of cost allocation methodologies which have been used in California. One method uses embedded cost studies while the other uses marginal cost studies.[15] SoCalGas and SDG&E's Gas Transmission and Storage ("GT&S") services are allocated based on the Embedded Cost ("EC") method while the Gas Distribution service is based on the Long Run Marginal Cost ("LRMC") method.[16]

In D.92749, the Commission first established the marginal cost framework for electric service where marginal costs were defined to represent the cost of providing an additional unit of electric service over and above any currently being produced or served.[17] In D.92749, the Commission distinguished between marginal costs in the short run and long run given that the production costs to meet a change in output are different based on the ability of the producer to adjust the factors of production.[18] In the short run, plant is considered fixed and the producer can only run existing plant more or less, or buy or sell more or less electricity.[19] The short run marginal cost is the change in the variable operating cost with respect to changes in output.[20] In the long run the plant capacity can be

[15] Embedded cost studies use the utility's audited books from the Uniform System of Accounts while marginal cost studies make use of reasonable estimates of the utility's marginal cost of its primary functions required to continue providing service to its customers. In marginal cost studies, embedded costs are irrelevant to the decision to invest because those costs are considered spent.

[16] D.09-11-006.

[17] See D.92749 in OII 67 on the Commission's Investigation into the methodology for the calculation of marginal costs of electric service. This is the 1981 decision where the Commission first adopted a marginal cost framework. The adopted methodology is found in Appendix B of the decision.

[18] Appendix B, D.92749.

[19] Id.

[20] Id.

adjusted to minimize the total costs of producing the new output requirement.[21] This is the underlying marginal cost framework behind the LRMC.

The Commission first adopted the LRMC methodology for California natural gas transportation service in D.92-12-058.[22] For natural gas transportation service of the California gas utilities, the Commission states that "marginal costs are forward-looking costs: they reflect the costs a utility will incur to meet new demand for its services."[23] According to the Commission definition, "LRMC captures the cost of new facilities as well as the short-term marginal costs of daily operating requirements."[24]

In terms of the criterion that causes a utility to need more new capacity (and thus cause the need to incur more cost), the Commission adopted marginal demand measures ("MDMs") for demand-related costs.[25] And since the Commission recognized the distinction between SoCalGas' medium pressure distribution ("MPD") and high pressure distribution ("HPD") facilities,[26] the Commission adopted the following MDMs for SoCalGas for purposes of computing and allocating the marginal cost revenues for cost allocation: cold year throughput for backbone transmission, cold year coincident peak month for high pressure distribution, and peak day for medium pressure.[27] Similarly, for SDG&E, cold year peak day was adopted by the Commission.[28]

The Applicants' gas distribution marginal costs have two major functional cost categories: distribution demand-related and customer-related marginal costs. Each of these functional cost categories have two components: a capital-related cost component and an operation and maintenance ("O&M") cost component. The discussion in this section is divided into four sub-parts: the

[21] Id.

[22] D.92-12-058, Finding of Fact # 1.

[23] D.92-12-058, p. 7.

[24] D.92-12-058, p. 7.

[25] D.92-12-058, p. 21.

[26] D.92-12-058, p. 24.

[27] D.92-12-058, Conclusion of Law # 2.

[28] Id.

customer-related marginal costs, the derivation of the Applicants' distribution demand-related marginal costs, the direct O&M and other marginal cost loaders and the derivation of marginal cost revenues.

1. Customer-related Marginal Costs

The customer-related marginal capital costs consists of the new customers' one-time hook-up costs to gain access to the utilities' gas system, which are for service lines, regulators, and meters ("SRM").[29] The SRM are identified as customer costs since they are completely dedicated to providing gas service to a single customer or cluster of customers for access to the system. The Commission stated:[30]

> DRA's Service / Regulator, and Meter (SRM) method draws the - brightest line between customer and demand related costs, thereby providing a simple, but accurate basis for calculating marginal customer costs.

The marginal direct O&M costs associated with the SRM, Customer Services, and Customer Accounts, and the O&M loaders are the direct and indirect expenses associated with the capital-related cost of investment. Marginal customer-related costs vary with the number of customers in a given customer class and not with peak demand or usage.

The Rental method reflects the annualized capital cost of new hook-ups, and together with direct O&M and O&M loader costs per customer per year, that value determines the marginal customer costs when multiplied by the total number of customers for each class.[31] In other words, the Rental method treats every customer as a new customer and all customers pay an annual rental fee based on the marginal unit cost of a new customer to gain access to the system.

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[29] D.92-12-058, Finding of Fact # 46.

[30] D.92-12-058, Finding of Fact # 41.

[31] See Revised Workpapers of S. Chaudhury in A.15-07-014 Ph. 2 on LRMC Customer Costs indicating the use of Real Economic Carrying Cost (RECC) factors to annualize SRM capital costs under the Rental method, adds direct O&M and O&M loaders per customer per year to arrive at the marginal unit customer-related cost. The resulting marginal unit value is multiplied with the number of all customers for each respective class to arrive at the marginal customer costs for each class under the Rental method.

On the other hand, the NCO method reflects the full cost of the customer hook-up (i.e., not annualized) multiplied by the weighted Present Value Revenue Requirement ("PVRR") for the SRM to determine the PVRR on a per customer basis, which PVRR value is in turn multiplied with the number of new customers only to determine the total PVRR of the hook-up cost for each class as illustrated below in Table PZS1.

Table PZS1

Marginal Customer Cost Calculation Method Comparison

Line	Rental		NCO	
1	Marginal Investment Cost 2013 $/Customer:		Marginal Investment Cost 2013 $/Customer	
2	Meter & House Regulator (Line 2)	$379.23	Meter & House Regulator (Line 2)	$379.23
3	Service Line (Line 3)	$1,015.04	Service Line (Line 3)	$1,015.04
4	Marginal Inv Cost Total/Cust Line 4 = Line 2 + Line 3	$1,394.27	Marginal Inv Cost Total/Cust Line 4 = Line 2 + Line 3	$1,394.27
5				
6	Weighted RECC Factors:		Weighted PVRR Factors:	
7	Meter & House Regulator (Line 7)	9.25%	Meter & House Regulator (Line 7)	129.09%
8	Service Line (Line 8)	8.57%	Service Line (Line 8)	129.08%
9	Annualized Marginal Inv Cost		PVRR of Hook-Up Cost:	
10	Meter & House Regulator (Line 10) = Line7 x Line 2	$35.06	Meter & House Regulator (Line 10) = Line 7 X Line 2	$489.56
11	Service Line (Line 11) = Line 8 x Line 3	$86.94	Service Line (Line 11) = Line 8 x Line 3	$1,310.17
12	Total Annualized Inv Cost (Line 12) = Line 10 + Line 11	$122	PVRR of Hook Up (Line 12) = Line 10 + Line 11	$1,799.73
13				
14			No. of New Cust Hook up/Yr (Line 14)	25,224
15			Total PVRR of New Hook Up (Line 15) = Line 12 x Line 14	$45,395,841
16			Current No. of Customer (Line 16)	5,422,975
17			PVRR of Hook Up/Customer (Line 17) = Line 15 / Line 16	$8.37
18				
19	Total O&M Cost:		Total O&M Cost:	
20	Direct O&M (Line 20)	$58.95	Direct O&M (Line 20)	$58.95
21	O&M Loaders (Line 21)	$42.65	O&M Loaders (Line 21)	$42.65
22				
23	Unit Customer Cost Line 23 = Sum (Lines 12, 20,21)	**$223.60**	Unit Customer Cost Line 23 = Sum (Lines 17, 20, 21)	**$109.97**

The NCO method assumes that SRM facilities for existing customers once invested and installed are sunk, and therefore irrelevant under the marginal cost framework. Under the NCO, only the investment on SRM for new customers is considered part of marginal customer capital cost.[32]

The equipment upstream of the SRM is reflected in the appropriate transportation function, in this case, the Applicants' gas distribution system as described below.

2. Distribution Demand-Related Marginal Costs

Since marginal cost is the additional cost a utility will incur to meet new demand for its services, one can say that new demand (i.e., load growth) could arise either from throughput changes or changes in the number of customers. The distribution facilities are considered distribution demand-related while the customer facilities that provide customer access to the utilities' gas system are considered customer-related.[33] The distribution-related marginal costs consists of the Applicants' gas distribution marginal cost of investment capital, the marginal direct O&M, and the O&M-related loader costs that are incurred for each unit of the marginal demand measure. As mentioned earlier, for purposes of the Applicants' gas distribution, the marginal demand measures are expressed in terms of the HPD coincident peak month demand and MPD peak day demand.[34] In the LRMC cost allocation model, 15 years of cumulative investment is regressed against cumulative incremental load for each of the HPD and MPD. The coefficients derived from the medium pressure and high pressure

[32] See Revised Workpapers of S. Chaudhury in A.15-07-014 Ph. 2 on LRMC Customer Costs indicating the use of the SRM capital costs under the NCO method multiplied by the PVF, and multiplying the resulting value with the number of new customers only to arrive at the present value of hook-up costs for the class. This result for the class is then divided by the number of all customers to arrive at the present value of the hook-up cost on a per customer basis. This latter amount is then added to direct O&M and O&M loader costs per customer per year (which are the same under the NCO and Rental method) to arrive at the marginal unit customer-related costs for each customer class under the NCO method. The marginal unit value is multiplied with the number of all customers for each respective class to arrive at the marginal customer-related costs for each class under the NCO method.

[33] D.92-12-058, Findings of Fact # 41 and # 46.

[34] See D.92-12-058 where the term Marginal Demand Measure (MDM) was first adopted to refer to the criterion that causes a utility to need more capacity.

regressions represent the capital-related portion of medium and high pressure marginal costs.

To arrive at fully loaded medium and high pressure marginal distribution costs, the coefficients from the regressions are coupled with O&M, Administrative and General ("A&G"), Materials and Services ("M&S"), and General Plant ("GP") costs. This is because load-growth related capital additions require additional direct O&M as well as O&M loaders as discussed below in other marginal costs associated with the capital investment.

The Real Economic Carrying Cost ("RECC") is used to convert capital investments into annualized capital costs. It represents a series of level annual revenue requirement for depreciation, property taxes, state and federal taxes and returns in constant dollars over the service life of an investment, adjusted for inflation and discounted at the Applicants' cost of capital.[35]

The use of the RECC to annualize capital costs for plant investments could cause some to say that the LRMC methodology already takes care of plant replacement. The RECC contains depreciation charges for the plant investment that could be considered "used up," and could in that sense cause some to say that the RECC has already accounted for the need for replacement.[36] Based on this reasoning, adding in a separate and explicit adjustment for distribution replacement costs could double-count these costs. The Commission previously adopted the inclusion of a replacement cost adder[37] but reversed its policy when it agreed with PG&E on this point in its 2005 BCAP decision in D.05-06-029.[38] This is reflected in the Commission's statement in the 2005 decision in the Pacific Gas & Electric Company's ("PG&E's") Biennial Cost Allocation Proceeding ("BCAP") in D.05-06-029:[39]

[35] D.92-12-058, p. 32.

[36] Parties such as PG&E argued along this line in its 2005 BCAP in A.04-07-044 and so did SoCalGas/SDG&E in its 2009 BCAP in A.08-02-001 (See Allison Smith Prepared Testimony in A.08-02-001, p. 4).

[37] D.95-12-053, p. 22 and D.97-04-082, p. 48.

[38] D.05-06-029, Finding of Fact # 15.

[39] D.05-06-029, Finding of Fact # 14.

> Economic literature does not resolve whether replacement costs are appropriately included in long run marginal cost calculations.

In the text of the decision, the Commission explains:[40]

> Moreover, although the economic literature may not explicitly address this point, including replacement costs as an element of marginal costs is conceptually inconsistent with economic theory. Once a utility makes an investment in new facilities to serve increasing customer demand, the utility will repair or replace those facilities without regard for incremental increases in demand. For these reasons, we eliminate the replacement cost adder from the equation used to calculate marginal customer costs.

In D.09-11-006, the succeeding SoCalGas/SDG&E BCAP, a settlement agreement among the parties was adopted where the replacement issue was not a specific item in that settlement.[41]

With respect to the derivation of marginal distribution-related cost based on regression, the analysis regresses the combined SoCalGas 9-year historical investments for gas distribution plant additions and 6-year forecast gas distribution investment plant additions against SoCalGas' combined 9-years historical gas distribution demand and 6-years of forecast demand.[42] The analysis for this 15-year period generates the resulting relationship between investment and load growth that determines the dollars of incremental investment per decatherm of cold peak day or coincident peak month demand. The Commission described this methodology to develop the marginal unit cost for distribution:[43]

> a model developed by NERA to obtain a marginal unit capital cost by regressing the cumulative changes in investment with cumulative changes in load. Parties used a combination of historical and forecast period data.

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[40] D.05-06-029, p. 20.

[41] D.09-11-006, Ordering Paragraph # 1.

[42] D.92-12-058, Conclusion of Law # 3, where the National Economic Research Associates ("NERA') regression method was adopted to calculate the marginal capital costs for distribution.

[43] D.92-12-058, p. 32.

3. Direct O&M and Other O&M Marginal Costs Associated with the Capital Investment

As demand and the number of customers grow, capital investments and operations-related expenses are incurred to meet that growth and are the major components of the utilities' gas distribution marginal costs. However, as the costs of capital investment and direct O&M expenses are incurred, they also cause other cost components to increase. Marginal O&M expenses could be fixed costs in nature, variable in nature, or be a mix of both since costs may occur on a regular basis or be unpredictable and vary with output-related and/or customer-related service activities. The other O&M cost components are A&G, general plant, materials and supplies, also sometimes referred to as marginal cost O&M loaders. The estimates of the direct O&M and other O&M components could be different from those provided by the Applicants. However, in this case, ORA did not change the Applicants' estimates after finding them lower compared with those used by the Applicants in the previous TCAP A.11-11-002 Phase 2.

4. Scaling Marginal Cost Revenues and Cost Allocation

To obtain the marginal cost revenues, the high and medium pressure distribution marginal cost estimates are multiplied by the allocators, in this case the MDMs, to yield the marginal cost revenues for medium and high pressure distribution. Until an EPMC scaling factor is applied, these marginal cost revenues are considered "unscaled" marginal cost revenues and will need to be scaled to reconcile with the revenue requirement.[44]

To calculate the EPMC scalar, the ratio of target scaled marginal cost revenues to the base margin revenue requirement for both SoCalGas and SDG&E is determined. ORA's recommendation to use the NCO method to develop the marginal customer costs results in an EPMC scalar different from that of the Applicants. ORA's marginal cost revenue results reflect the use of a

[44] EPMC by totals was found appropriate for natural gas ratemaking in Finding of Fact # 58 and Conclusion of Law # 19, D.92-12-058.

throughput forecast or customer forecast that is not different from those used by the Applicants.

Once the scaled LRMC marginal cost revenues for gas distribution are obtained, these are then combined with the transmission and gas storage components which were allocated based on EC method. The combined total of the scaled LRMC costs and the EC-based components determines the proposed allocation of the authorized gas base margin.

B. Description of SoCalGas/SDG&E Proposal

In this proceeding, SoCalGas and SDG&E (also collectively referred to as the Applicants in A.15-07-014) propose to use the Long Run Marginal Cost ("LRMC") approach for the cost allocation of the base margin of its natural gas distribution service and the embedded cost ("EC") approach for allocation its gas transmission and storage ("GT&S") service base margin.[45] The testimony on EC study for the storage function of GT&S is separately presented by the Applicants' witness Ms. Fung in A.14-12-017.[46] The use of the LRMC approach for gas distribution and the embedded cost approach for gas transmission and storage was approved by the Commission in D.09-11-006 following the settlement in the Applicants' 2009 rate case in what was then known as the Biennial Cost Allocation Proceeding ("BCAP"). The Base Margin ("BM") refers to the amount of Commission-authorized revenue requirement that is to be recovered through the gas transportation rates.[47] The Applicants state:[48]

> SoCalGas and SDG&E propose to continue the LRMC method for the three major functional categories—customer-related, medium pressure distribution, and high pressure distribution—and to continue to use the embedded cost method for the transmission function. The derivation of transmission embedded costs is described in the direct testimony of Ms. Fung. The cost and allocation of storage assets was the subject of the direct testimony of Ms. Fung and Mr. Watson in the TCAP Phase 1 Application, A.14-12-017.

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[45] Chaudhury Revised Testimony, pp. 6-9.

[46] Chaudhury Revised Testimony, p. 2 cited at footnote 1.

[47] Chaudhury Revised Testimony, p. 3.

[48] Chaudhury Revised Testimony, pp. 6-7.

The Applicants propose to derive the LRMC customer-related unit cost of gas distribution using the "Rental Method" and to use "linear regression models to determine the relationship between demand growth and investments over a 15-year period spanning historical and forecast periods" and to use these regression results to derive the marginal distribution-related unit cost of capital.[49]

In this TCAP, the SoCalGas Base Margin (BM) which will be subject to the cost allocation process is shown in the total amount of $2.002 billion and that base margin amount is for gas distribution, transmission, and storage.[50] The SDG&E BM subject to the cost allocation process is shown in the total amount of approximately $306 million.[51] It is only the gas distribution portion of the BM that will be subject to the LRMC method while the transmission and storage portion of the base margin will be allocated using the embedded cost method. SoCalGas explains that after the allocated costs of gas distribution are scaled to the base margin, the transmission costs are then integrated between SoCalGas and SDG&E.[52] The system integration of the SoCalGas and SDG&E transmission costs was approved by the Commission in D.06-04-033.[53]

To ensure the utilities have the opportunity to recover their authorized base margin, the need for scaling of marginal cost revenues using the Equal Percent of Marginal Cost ("EPMC") has been recognized by the Commission as appropriate.[54] The calculated EPMC for SoCalGas in this case is shown as 77 percent while it is 81 percent for SDG&E.[55]

According to the Applicants, SoCalGas and SDG&E updated the LRMC and embedded cost studies to reflect 2013 actual costs and allocations based on

[49] Chaudhury Revised Testimony, pp. 6-9.

[50] Table 14, Chaudhury Revised Testimony, p. 29.

[51] Table 13, Ms. Schmidt-Pines Revised Testimony, p. 17.

[52] Chaudhury Revised Testimony, p. 3.

[53] D.06-04-033, Ordering Paragraph # 1.

[54] D.92-12-058, Conclusion of Law # 11.

[55] Revised Workpapers on SoCalGas 2017 LRMC Cost Allocation model and SDG&E 2017 LRMC Cost Allocation model.

2013 underlying activities and that the processes for updating the studies are consistent with existing practices.[56] Applicants explain that these 2013 costs are then escalated to 2017 dollars to reflect SoCalGas and SDG&E's estimated Test Year costs in this TCAP.

With respect to the allocation of the non-base margin revenues, Applicants state that "the methods employed to develop and allocate non-margin costs are consistent with the methods employed to develop the SoCalGas and SDG&E's transportation rates adopted in California Public Utilities Commission (Commission) D.14-06-007, the most recent cost allocation proceeding decision."[57] The non-base margin costs consists of authorized costs that are outside of the base margin (the automated meter installation and unaccounted for gas were cited as examples) and the amounts in regulatory and balancing accounts that are authorized to be collected in transportation rates.[58]

1. The Applicants' Customer-Related Costs

Based on the Rental method, the calculated residential customer LRMC marginal customer unit cost for SoCalGas is approximately $224/customer (in 2017$) while SDG&E's is slightly higher at approximately $240/customer (in 2017$).[59] In the previous most recent TCAP filing in A.11-11-002, the corresponding residential customer cost numbers were $216.19/customer for SoCalGas while SDG&E's was $263/customer, both costs stated in 2013$ and based on the Rental method.[60] In this proceeding, the calculated LRMC marginal customer costs for all the SoCalGas customer classes are shown in Table 11 of Mr. Chaudhury's Testimony while those for SDG&E's customer classes are shown in Table 10a of Ms. Schmidt-Pines Testimony, which are reproduced below in Table PZS2.

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[56] Chaudhury Revised Testimony, p. 7.

[57] Bonnett Revised Testimony, p. 1.

[58] Chaudhury Revised Testimony, p. 3.

[59] Table 11, Chaudhury Revised Testimony and Table 10a, Schmidt-Pines Revised Testimony.

[60] Table 11, SoCalGas TCAP Workpapers and Table 10a, SDG&E TCAP Workpapers in A.11-11-002.

Although the NCO method is not being proposed, the Applicants nevertheless developed the numbers for the NCO method. ORA appreciates the efforts by the Applicants to include a NCO calculation of customer access costs in its workpapers despite its support for the Rental method. For SoCalGas, the calculated residential customer LRMC marginal customer unit cost is $109.97/customer (2017$) based on the NCO method while the NCO with replacement adder is $215.84/customer (2017$).[61] For SDG&E, the calculated residential customer LRMC marginal customer units cost is $102.88/customer (2017$) based on the NCO method without the replacement adder, while the NCO with a replacement adder is $488.07/customer (2017$).[62]

In response to ORA discovery on whether the Applicants' methodologies capture any replacement costs for the customer-related and/or the distribution-related portions, and if so, to explain how these replacement costs are reflected in the marginal cost calculations, the Applicants responded:[63]

> The LRMC methods for customer-related and distribution-related functional capital costs do not capture any replacement costs.

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[61] Chaudhury Revised Workpapers, 2017 TCAP LRMC Customer Cost for SoCalGas and SDG&E.

[62] Chaudhury Revised Workpapers.

[63] Response to data request ORA-08 Q.4(a).

Table PZS2
Applicants' Proposed Unscaled LRMC Revenues
Customer Cost Under the Rental Method
(in 2017$)

Line #	Customer Class	SoCalGas Customer LRMC $/customer	SoCalGas Customer Cost $ 000	SDG&E Customer LRMC $/customer	SDG&E Customer Cost $ 000
		(A)	(B)	(C)	(D)
1	Residential	$224	$1,256,152	$240	$212,544
2	Core C/I	$711	$147,464	$462	$13,980
3	Gas A/C	$5,865	$53	Na	na
4	Gas Engine	$5,085	$3,788	Na	na
5	NGV	$22,281	$7,993	$4,450	$171
6	**Total Core**		$1,415,451		$226,694
7					
8	Noncore C/I	$30,179	$18,758	$10,168	$529
9	Small EG	$25,258	$5,463	$6,941	$355
10	Large EG	$128,644	$8,806	$8,485	$168
11	EOR	$83,029	$2,408	Na	na
12	**Total Retail Noncore**		$35,435		$1,051
13					
14	Long Beach	$886,337	$886	na	na
15	SDG&E	$1,513,039	$1,513	na	na
16	Southwest Gas	$797,252	$797	na	na
17	Vernon	$539,223	$539	na	na
18	DGN	$216,430	$216	na	na
19	**Total Wholesale**		$3,952		
20	UBS	$0	$0	na	na
21	BTS	$0	$0	na	na
22	**Total Noncore**		$39,387		$1,051
23	**Total SoCalGas(col B) Total SDG&E (col D)**		**$1,454,838**		**$227,746**

Source: Table 11 Revised Workpapers Chaudhury in A.15-07-014 SoCalGas Cost Allocation Model and Table 10a Revised Workpapers Chaudhury SDG&E Cost Allocation Model.

Note: na – not applicable.

2. The Applicants' Distribution-Related Marginal Costs

To calculate the LRMC distribution-related marginal unit cost and marginal cost revenue, the Applicants state: "The period for the regression analysis is 15 years: nine years of historical data (2005-2013) and six years of forecast data (2014-2019)."[64]

[64] Chaudhury Revised Testimony, pp. 15-16.

In calculating the components of its distribution marginal costs, SoCalGas derives the annualized marginal capital-related cost by multiplying the Real Economic Carrying Charge (RECC) of 8.57 percent (for MP) and 8.56 percent (for HP) against the corresponding marginal investment cost of $2,135.42 per MCFD and $20.391 per MCF/month, for MP and HP, respectively.[65] The latter coefficient amounts of $2,135.42 and $20.39 are the result of SoCalGas' 15-year regression analysis. The results of the SoCalGas' calculation of LRMC Distribution-related marginal costs for MP and HP are $200.38/MCFD and $1.92/MCF/month, respectively.

The regression coefficients for SDG&E are $2,478.15/MCFD and $275.05 MCFD for MPD and HPD, respectively as shown in Tables 3 and 4 of Ms. Schmidt-Pines' workpapers. The results of SDG&E's calculation of LRMC Distribution-related marginal costs for MP and HP are shown as $243.90/MCFD and $24.46/MCFD, respectively.

ORA performed additional review since 2014 actual recorded numbers were available. The distribution regression was performed using 10 years of historical data (2005-2014) instead of 9 years, and five years of forecast data (2015-2019) instead of 6 years, which indicated no material difference from the Applicants' proposed results.[66] The regression coefficients for SoCalGas' MP and HPD are shown as $2,170.83/MCFD and $19.797/MCF/month, respectively.[67] The results of the SoCalGas calculation of LRMC Distribution-related marginal costs are shown as $203.65/MCFD and $1.86/MCF/month, for MP and HP, respectively.[68]

In addition, the regression coefficients for SDG&E are $2,478.15/MCFD and $275.05/MCFD, for MP and HP, respectively.[69] The results of the SDG&E calculation of LRMC Distribution-related marginal costs are shown as

[65] See Tables 4 and 7, Chaudhury Revised Testimony, pp.18-20.

[66] Response to data request ORA-08 Q.3.

[67] Workpapers provided in Response to data request ORA-08 Q.3.

[68] Workpapers provided in Response to data request ORA-08 Q.3.

[69] Workpapers provided in Response to data request ORA-08 Q.3.

$243.90/MCFD and $24.46/MCFD, for MP and HP, respectively.[70] Table PZS3 summarizes the Applicants' Unscaled LRMC Revenues for distribution costs.

Table PZS3
Applicants' Unscaled LRMC Revenues
Distribution Costs

Line No.	Customer Class	MPD LRMC $/mcfd	MPD Costs $000	HPD LRMC $/mcfd	HPD Costs $000
		(A)	(B)	(C)	(D)
1	Residential	$200.38	$469,949	$1.92	$75,171
2	Core C/I	$200.38	$106,015	$1.92	$21,981
3	Gas A/C	$200.38	$12	$1.92	$7
4	Gas Engine	$200.38	$717	$1.92	$257
5	NGV	$200.38	$2,546	$1.92	$1,801
6	**Total Core**		**$579,240**		**$99,217**
7	Noncore C/I	$200.38	$17,273	$1.92	$12,779
8	Small EG	$200.38	$2,816	$1.92	$1,148
9	Large EG	$200.38	$1,863	$1.92	$3,152
10	EOR	$200.38	$60	$1.92	$2,183
11	**Total Retail Noncore**		**$22,012**		**$19,263**
12	Long Beach	$200.38	$0	$1.92	$0
13	SDG&E	$200.38	$0	$1.92	$0
14	Southwest Gas	$200.38	$0	$1.92	$0
15	Vernon	$200.38	$0	$1.92	$0
16	DGN	$200.38	$0	$1.92	$0
17	**Total Wholesale**		$0		$0
18	UBS	$200.38	$0	$1.92	$0
19	BTS	$0	$0	$0	$0
20	**Total Noncore**		**$22,012**		**$19,263**
21	**Total SoCalGas**		**$601,252**		**$118,480**
22					
23	Residential	$244	$68,588	$24	$6,881
24	Core C/I	$244	$20,705	$24	$2,116
25	NGV	$244	$472	$24	$122
26	**Total Core**		$89,765		$9,120
27	Noncore C/I	$244	$1,354	$24	$187
28	Small EG	$244	$914	$24	$143
29	Large EG	$244	$532	$24	$491
30	**Total Noncore**		$2,800		$822
31	**Total SDG&E**		**$92,565**		**$9,941**

Source: Table 12 Revised Workpapers Chaudhury in A.15-07-014 SoCalGas Cost Allocation Model and Table 10b Revised Workpapers Chaudhury SDG&E Cost Allocation Model.

[70] Workpapers provided in Response to data request ORA-08, Q.3.

3. Applicants' Other Marginal Costs Associated with Investment

Once the annualized capital-related cost is calculated, SoCalGas adds the corresponding direct O&M costs and the O&M-related loader costs for A&G, General Plant (GP), and Materials and Supplies (M&S) to derive either the marginal distribution marginal unit cost each for MP and for HP or the customer-related marginal unit cost.

According to SoCalGas, the 2013 recorded distribution-related direct O&M costs are allocated between MP and HP on the basis of the split in total distribution investment between MP and HP.[71] The SoCalGas calculated direct O&M on distribution is $9.98/MCFD for MP shown in Table 4 and $0.08/MCF/month for HP shown in Table 7.[72] The SDG&E calculated direct O&M on distribution is $26.15/MCFD for MP shown in Table 3 and $1.06/MCFD for HP shown in Table 4.[73]

The direct O&M costs for customer-related investment are different for each customer class. For SoCalGas' residential customers, the direct O&M cost is estimated at $58.95 per customer per year while the average for non-residential Core Commercial/Industrial will be $201.17 per customer per year.[74] For SDG&E residential customers, the direct O&M costs are estimated to be $41.77 per customer per year while the two other non-residential classes, which are part of Core, have direct O&M costs at $671.20/customer per year and $105.98/customer per year, for NGV and GN-3 class, respectively.[75] The calculated direct O&M costs are assumed to be the same whether under the Rental or NCO method.

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[71] Chaudhury Revised Testimony, p. 16.

[72] Tables 4 and 7 Chaudhury Revised Testimony, pp. 18-20.

[73] Tables 3 and 4, Schmidt-Pines Revised Testimony, p. 7.

[74] See Chaudhury Revised Workpapers on SoCalGas LRMC Customer Costs for the direct O&M costs of other SoCalGas customer classes.

[75] See Chaudhury Revised Workpapers on SDG&E LRMC Customer Costs for the direct O&M costs of other SDG&E classes.

The O&M loaders reflect indirect costs and are likewise assumed to be the same whether under the Rental or NCO method.[76] The Applicants explain that the A&G and GP loading factors are percentages that are applied to the direct O&M costs for each functional category while the M&S costs are assigned to each functional category based on plant investment.[77] These marginal O&M loaders are shown in Tables 8 through 10 of Mr. Chaudhury's Testimony for SoCalGas while those for SDG&E are shown in Tables 7 through 9 of Ms. Schmidt-Pines Testimony.

Table PZS4

Applicants' Proposed Marginal O&M Loaders

Line No.	SoCalGas A&G LF	SoCalGas GP LF	SDG&E A&G LF	SDG&E GP LF
1	41.79%	30.21%	28.43%	13.22%

Source: Tables 8 & 9 Revised Prepared Testimony Chaudhury in A.15-07-014 and Tables 7 & 8 Revised Prepared Testimony Schmidt-Pines in A.15-07-014. The SoCalGas M&S costs are shown in Table 10 of Mr. Chaudhury's Testimony while SDG&E's M&S costs are shown in Table 9 of Ms. Schmidt-Pines Testimony.

4. The Applicants' Marginal Cost Revenues and Cost Allocation

Reproduced in this exhibit's Table PZS5 below are the results of Mr. Chaudhury's Table 15 of Revised Testimony which provides the cost allocation comparison of the Applicants' proposal for SoCalGas against the current allocation of the base margin.[78] In addition, Table PZS5 also reproduces the results of Ms.Schmidt-Pines' Table 13 of Prepared Testimony which provides the same information for SDG&E.[79] For purposes of comparing the result of cost allocation calculated on the basis of the NCO method, Table PZS5 also shows the results of using the NCO-based marginal customer capital-related cost allocation in columns (E) and (F) which are ORA's recommendations.

[76] Chaudhury Revised Testimony, p. 21.

[77] Chaudhury Revised Testimony, p. 21. See also Schmidt-Pines Revised Testimony, p. 12.

[78] As shown under columns A thru D from Line 1 thru 21 of Table PZS5.

[79] As shown under columns A thru D from Line 23 thru 31 of Table PZS5.

Under SoCalGas' proposal, Table PZS5 shows that the Residential customer class will have cost responsibility for 73.1% of the SoCalGas BM. This is slightly higher by 0.8% than the Residential customer class cost responsibility under the current allocation of the BM which is shown as 72.3%. The current allocation of the BM is based on the Settlement Agreement adopted in D.14-06-007 which was the most recent TCAP for SoCalGas.

Table PZS5
Cost Allocation of Base Margin Comparison ($000)

Line No.	Customer Class	Applicants' Proposed (A)	Applicants' % Total (B)	Current (C)	Current % Total (D)	ORA Recommended (E)	ORA % Total (F)
1	Residential	$1,464,529	73.1%	$1,435,087	72.3%	$1,419,902	70.9%
2	Core C/I	$232,638	11.6%	$277,662	14.0%	$261,201	13.0%
3	Gas A/C	$64	0.0%	$74	0.0%	$78	0.0%
4	Gas Engine	$3,933	0.2%	$2,071	0.1%	$3,079	0.2%
5	NGV	$13,943	0.7%	$9,940	0.5%	$17,252	0.9%
6	**Total Core**	$1,715,107	85.7%	$1,724,834	86.9%	$1,701,513	85.0%
7	Noncore C/I	$49,471	2.5%	$57,226	2.9%	$57,034	2.8%
8	Small EG	$8,001	0.4%	$4,577	0.2%	$14,424	0.7%
9	Large EG	$31,667	1.6%	$31,375	1.6%	$31,570	1.6%
10	EOR	$5,403	0.3%	$5,004	0.3%	$6,148	0.3%
11	**Total Retail Noncore**	$94,542	4.7%	$98,182	4.9%	$109,176	5.5%
12	Long Beach	$1,486	0.1%	$1,357	0.1%	$1,269	0.1%
13	SDG&E	$20,610	1.0%	$14,782	0.7%	$19,882	1.0%
14	Southwest Gas	$1,429	0.1%	$1,294	0.1%	$1,379	0.1%
15	Vernon	$1,173	0.1%	$974	0.0%	$1,102	0.1%
16	DGN	$885	0.0%	$611	0.0%	$910	0.0%
17	**Total Wholesale**	$25,583	1.3%	$19,017	1.0%	$24,543	1.2%
18	UBS	$17,020	0.8%	$26,476	1.3%	$17,020	0.8%
19	BTS	$150,206	7.5%	$116,052	5.8%	$150,206	7.5%
20	**Total Noncore**	$287,351	14.3%	$259,727	13.1%	$300,945	15.0%
21	**Total SoCalGas**	$2,002,458	100.0%	$1,984,561	100.0%	$2,002,458	100.0%
22							
23	Residential	$232,998	76.2%	$233,081	76.2%	$221,857	72.5%
24	Core C/I	$29,771	9.7%	$35,290	11.5%	$38,680	12.6%
25	NGV	$1,114	0.4%	$1,220	0.4%	$1,370	0.4%
26	**Total Core**	$263,883	86.3%	$269,591	88.1%	$261,908	85.6%
27	Noncore C/I D	$1,674	0.5%	$2,174	0.7%	$2,495	0.8%
28	EG – D	$1,142	0.4%	$1,061	0.3%	$1,743	0.6%
29	TLS	$964	0.3%	$1,593	0.5%	$1,519	0.5%
30	**Total Noncore**	$3,781	1.2%	$4,828	1.6%	$5,756	1.9%
31	**Backbone Trans**	$38,229	12.5%	$31,473	10.3%	$38,229	12.5%
32	**Total SDG&E**	$305,893		$305,893		$305,893	100.0%

Source: Table 15 Mr. Chaudhury's Revised Testimony and Table 13 Ms. Schmidt-Pines Prepared Testimony. Response to data request ORA-18 Q.1(ai).

Neither the Rental Method nor the NCO Method was adopted in D.14-06-007, and instead, the adopted marginal unit customer-related cost estimates in Appendix B to the Settlement was based on a settlement number.[80]

Table PZS5 shows in column B line 6 that overall, total Core will have cost responsibility for 85.7% of the SoCalGas BM under the SoCalGas Rental method proposal compared to 86.9% under the current allocation shown in column D, or a slightly lower cost responsibility by 1.2% under the SoCalGas proposal. The Core Commercial/Industrial (C/I) class will benefit from the lower cost responsibility of the SoCalGas proposal since the Residential customer class has a slightly increased burden on cost responsibility for the BM as noted above. Table PZS5 shows that the Core C/I class will have cost responsibility for 11.6% of the SoCalGas BM under the SoCalGas proposal compared to the higher 14.0% under the current allocation, which is 2.4% lower than the current allocation.

As shown in Table PZS5, the total Noncore customer class will have cost responsibility for 14.3% of the BM under the SoCalGas proposal which is 1.2% higher as compared to the 13.1% under the current allocation. Based on the foregoing Table PZS5, ORA recommends using the NCO method which results in Core customers having 0.7% less in cost responsibility compared to the Applicants' Rental method, which is approximately $13.5 million less cost burden on the SoCalGas Core customers and $2.0 million less on the SDG&E Core customers. ORA's recommendation is discussed in the next section.

C. ORA Review and Analysis

1. Marginal Customer Cost

ORA's review examined the inputs to the marginal cost calculation and asked the Applicants to show how the average numbers were derived, including a description of the specific calculation details and all the elements included in the calculation for each of the average labor, average meter, and average

[80] Response to data request ORA-06 Q.1(f).

regulator costs shown in the Excel workpapers for meter cost detail and service line detail.[81] The Applicants explained:[82]

> The average labor cost by meter size was calculated by multiplying total labor cost by the percent of total hours spent installing meters of that particular meter size and then dividing by the number of meters of that size… The average costs of meters and regulators by size were calculated by the total costs of meters (regulators) divided by the associated number of meters (regulators).

ORA likewise asked the Applicants to fully explain how the sample size data used to determine the weighted average meter and regulator CAPEX per customer represents a reasonable and valid sample size for the population of the number of residential customers and to provide any study or test done by the Applicants that show the statistical validity of the sample sizes used in the case.[83]

The Applicants respond that they have not done any such study for the statistical validity of the sample sizes or any test. However, they clarified that the data on cost to hook-up a new customer is from the recent five year period for all new customers for the residential and core commercial and industrial classes as shown below:[84]

> Since the implementation of the LRMC method, for residential and core commercial and industrial segments, it has been SoCalGas/SDG&E's practice to include <u>all</u> new customers from the recent five-year historical period. For LRMC calculation, the relevant point is not whether the number of new customers represents a reasonable and valid sample size for the existing/total customers. Rather, the relevant point is whether the inclusion of data for <u>all</u> new customers for the recent five years would result in a reasonable cost of hooking up a new customer.

ORA found that the average service length by rate class, line diameter, and pipe type was derived by dividing the total service line footage for all customers in the rate class, line diameter, and pipe type category by the number

[81] Data request ORA-07 Q.1.

[82] Response to data request ORA-07 Q.1.(a).

[83] Data Request in ORA-14 Q.1(a) and (b).

[84] Response to data request ORA-14 Q.1(a) and (b).

of customers in the category.[85] Similar to meters, the historical data used for purposes of the calculation for residential, small commercial and industrial customers reflect service established in 2009-2013, the most recent five years.[86] For other rate classes, the historical data covers whenever service was established.[87]

ORA asked the Applicants whether there were any changes in practice standards relative to the meter set assembly location and service installation that could have some effect on the length of the services and found no recent change based on discovery responses.[88]

ORA compared the proposed marginal customer-related cost numbers in this TCAP against those presented in the previous TCAP filing. One way to compare these numbers with the current TCAP filing on an apples-to-apples basis is to express both of these numbers in 2017 dollars using the Applicants' escalation factors from 2013 to 2017. Therefore, when stated in 2017 dollars, the SoCalGas and SDG&E LRMC marginal customer unit costs from the previous TCAP filing in A.11-11-002 appear to be higher than the numbers proposed in the 2017 TCAP, also based on the Rental method.[89]

2. Marginal Distribution-Related Cost

ORA's review included verifying the inputs to the calculation of the Applicants' marginal distribution-related cost. ORA asked about the Applicants' "historical investment" information shown in Table 4 of Mr. Chaudhury's workpapers and whether these numbers represent the actual recorded historical investment for the period 2005-2013.[90] ORA learned that the "historical

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[85] Response to data request ORA-07 Q.2.

[86] Response to data request ORA-08 Q.5(a).

[87] Id.

[88] Response to data request ORA-08 Q.5(b) thru (d).

[89] In the A.11-11-002 filing the SoCalGas TCAP marginal residential customer cost translates to $234/customer (2017$) compared to the $224/customer proposed in this TCAP. For SDG&E, the Applicants' TCAP marginal customer cost for SoCalGas translates to $285/customer (2017$) compared to the $240/customer in this case.

[90] Data Request in ORA-15 Q.1(a).

investment" information shown in Table 4 represents only the historical total annual footage for new business and pressure betterment but these are valued at 2017 unit costs, and in that sense, the "historical investment" dollars represent only "hypothetical costs" as shown in the Applicants' response below:[91]

> The information on historical investment in the above described columns and rows in Table 4 of Mr. Chaudhury's workpapers (SCG 2017 TCAP LRMC Distribution Costs excel spreadsheet) do not represent SoCalGas' actual historical investment costs for the period 2005-2013. Rather, Table 4 represents historical total annual footage for new business and pressure betterment by distribution pipe size and type valued at 2017 unit costs. These costs represent hypothetical costs if the historical new business and pressure betterment footage investments were to take place in 2017. This methodology has been used in previous BCAPs and TCAPs.

The marginal distribution-related capital investments were thus calculated using the "hypothetical costs" during the period 2005-2013, rather than actual historical investment costs. The Applicants' response indicates that only the annual footage data were based on historical data on new business and pressure betterment. To the extent that cumulative incremental investments which were regressed against the cumulative incremental load were "hypothetical cost-based," these higher valued "hypothetical costs" based on 2017 unit costs in investment capital could in theory yield inaccurate regression coefficients.

These streams of incremental capital investment at higher dollar values could have no basis in reality since these dollar investments were never really actually made. The Commission should provide clarity by defining the term "historical," for purposes of the regression method that has been adopted previously. In the absence of clarity as to what constitutes "historical investments," or even "historical loads," the ratepayers could be faced with inaccurate marginal cost estimates for cost allocation. Clarification from the Commission would help avoid any other ways the term "historical investments" could be creatively interpreted. For example, Commission clarification could prevent "historical planned investments" where the regression analysis would be

[91] Response to data request ORA-15 Q.1(a).

performed based on historical planned investments of the Applicants that may never have materialized. The regression analysis is an adopted methodology that should have a standard common meaning and understanding to avoid introducing elements that could distort the marginal cost price signals the Commission seeks to accomplish. We want to avoid the use of investment plan costs that never materialized. As the Commission states:[92]

> It is our belief that accurate marginal cost methods will lead to clearer signals when marginal cost-based prices are implemented, thereby providing the opportunity for customers to purchase economically efficient levels of service.

ORA's review included comparing the Applicants' recorded capital expenditures for the period 2009-2014 on gas distribution as reported in the recent 2016 GRC, against the data shown at Table 4 of Mr. Chaudhury's workpapers. ORA found that this comparison was not an apples-to-apples one, as explained by the Applicants response to an ORA data request to explain the reasons for an ORA observed material difference when it compared a portion of the historical investment for the period 2009-2013 for "New Business" and "Pressure Betterment" shown at Table 4 of Mr. Chaudhury's workpapers against those shown in the 2016 GRC workpapers for Exhibit SCG-04-CWP-R.[93] The Applicants explain below:[94]

> The two sets of data on historical gas distribution investment on "New Business" and "Pressure Betterment" as described above are not comparable. Mr. Ayala's definition of distribution capital investment is different from that in Mr. Chaudhury's TCAP testimony. For example, Mr. Ayala defines distribution-related capital investment to include installation of gas mains and services (service lines), meter set assemblies (MSAs) and the associated regulator stations necessary to provide service to customers (see page FBA-89, Exhibit SCG-04-R). In Mr. Chaudhury's testimony, service lines and MSAs are part of the customer-related function.

[92] D.92-12-058, p. 20.

[93] Data Request in ORA-15 Q.1(b).

[94] Response to data request ORA-15 Q.1(b).

ORA agrees with Mr. Chaudhury's classification that treats service lines and MSAs as part of the customer-related function rather than distribution capital investments.[95]

3. Other Marginal Costs Associated with the Capital Investment

ORA's review indicates that in deriving the O&M loaders for marginal A&G costs, SoCalGas removed the costs for production (including purchased gas cost), transmission expenses (including gas used for transmission compressor stations), storage expenses, A&G expenses, and various exclusions from the total O&M costs (as reported on its FERC Form 2, Line No. 271 at page 325) so that only the relevant Net O&M portion for gas distribution is left remaining for the calculation of the loading factor.[96] It is appropriate for SoCalGas to remove each of those irrelevant expenses, as they do not pertain to gas distribution.

The marginal A&G factor reflects the increase in labor-related A&G expenses and payroll taxes. The A&G accounts from Account 920 through 932 were shown separated between marginal and non-marginal costs by SoCalGas.[97] A further adjustment of 6.24% was made to the marginal A&G cost for the transmission and storage adjustment.[98] Therefore, Applicants have appropriately included only those Accounts that had marginal costs for the calculation of the A&G loader.

With respect to the calculation of the GP loader, SoCalGas' workpapers show that a transmission and storage adjustment of 6.24 percent was made to the total General Plant.[99] The annualized General Plant was derived by multiplying the weighted RECC against the net General Plant amount after the

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[95] D.92-12-058, Finding of Fact # 46.

[96] Exclusions are shown in Mr. Chaudhury's Revised Workpapers to include Hazardous Substance costs (dist acct 880), Uncollectible Acct (acct 904), Self Generation (acct 908), Energy Efficiency (acct 908, Low Income Energy Efficiency (acct 908), CARE (acct 901), and AMI (acct 903100.

[97] Chaudhury Revised Workpapers on the LRMC O&M loaders.

[98] Chaudhury Revised Workpapers on the LRMC O&M loaders.

[99] The Transmission and Storage adjustment of 6.24% is from the Embedded Cost study data.

adjustment for transmission and storage of 6.24 percent. The ratio of the annualized General Plant amount and the Net O&M portion for gas distribution were used in the calculation for the GP loader.

ORA's review also examined the nature of the O&M costs, that is, whether these are considered fixed costs or variable costs or both. If the O&M costs were considered fixed, variable or both, the Applicants were asked to describe whether each of the cost elements varies with a change in the number of customers or with a change in the amount of gas usage, or both. In this regard, the Applicants' customer–related marginal O&M costs consist of five components: (1) Customer Services, (2) Customer Accounts, (3) Meters and Regulators, (4) Service Lines, and (5) the O&M Loaders described earlier.[100] Regarding marginal O&M costs consisting of these five components, the Applicants explain in response to an ORA data request:[101]

> The Customer Services O&M costs are estimated marginal costs. From a cost allocation perspective, these costs are variable costs with respect to the number of customer services activities (e.g., visits to customer premises by customer service representatives) or the average length of time required to complete different types of customer services activities. The number of customer services activities varies with the number of customers.
> From a rate design perspective, these costs are considered fixed costs as they simply represent the cost of access to the SoCalGas' gas delivery system and do not vary with the level of gas consumption.

A similar response was received from the Applicants with respect to the nature of the Customer Accounts O&M, the O&M for "Meters, Reg & MSA," and the O&M for Service lines.[102] Based on the workpapers provided, this information indicates that the calculated SoCalGas annual residential customer marginal customer-related unit cost based on the Rental method of approximately $224 per customer (shown in Table PZS2 col (A) at line 1) consists of approximately

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[100] Chaudhury Revised Testimony, p. 11.

[101] Response to data request ORA-08 Q.1(b).

[102] Response to data request ORA-08 Q.1(c) through (e).

54.6 percent in fixed costs and approximately 45.4 percent in variable costs.[103] For SDG&E, the calculated annual residential customer marginal customer-related unit cost, based on the Rental method of approximately $240 per customer, (shown in Table PZS2 column (C) at line 1) consists of approximately 75.3 percent in fixed costs and approximately 24.7 percent in variable costs.[104]

ORA's analysis did not make changes to any of the Applicants' estimates of the SRM customer costs under the NCO method nor did ORA change any of the O&M and A&G cost numbers. ORA's analysis also made use of the Applicants' numbers of customer and demand forecasts.

4. Cost Allocation Using A Marginal Customer Cost Alternative Methodology

In Table PZS5 of this exhibit, ORA first presented the comparison of the cost allocation results based on ORA's alternative scenarios that make use of the NCO method for marginal customer cost against the Applicants' proposals. The cost allocation results from ORA's recommendation shown in Table PZS5 differ from the Applicants' proposal because of the underlying customer cost method used to develop the marginal customer capital-related unit cost. Table PZS5 shows that the difference in cost allocation results between the Rental and NCO is about 0.7 percent, where the Core class could be allocated costs to the extent of 0.7 percent more under Rental method compared to the NCO-based while the Noncore could be allocated costs to the extent of 0.7 percent less under the Rental method. Cost allocation is a zero-sum process.[105] Translated into dollars, Table PZS5 shows that approximately $13.6 million more of cost responsibility could be allocated to the Core under Applicants' proposed Rental-based allocation method while the Noncore has that same amount of lower cost responsibility.

The main driver for the difference in cost allocation was the method used to derive the marginal customer-related capital unit cost. In responses to data

[103] Revised Workpapers for SoCalGas on 2017 LRMC Customer Costs at Tab "cust MUC."

[104] Revised Workpapers for SDG&E on 2017 LRMC Customer Costs at Tab "cust LRMC."

[105] D.00-04-060, p. 13.

request ORA-18, ORA was able to obtain the marginal customer-related capital costs based on NCO numbers developed by the Applicants themselves, with and without a replacement cost adder. The scenarios described in response to data request ORA-18 were all based on the NCO method for the marginal customer-related capital costs. The succeeding Tables PZS6 through PZS9 show the unscaled LRMC revenues from marginal customer costs in response to data request ORA-18. These numbers should be compared against those presented earlier in Table PZS2 of this exhibit for the Applicant's unscaled LRMC revenues based on proposed marginal customer-related costs developed via the Rental method shown again below:

Table PZS2
Applicants' Proposed Unscaled LRMC Revenues
Customer Cost Under the Rental Method
(in 2017$)

Line #	Customer Class	SoCalGas Customer LRMC $/customer	SoCalGas Customer Cost $ 000	SDG&E Customer LRMC $/customer	SDG&E Customer Cost $ 000
		(A)	(B)	(C)	(D)
1	Residential	$224	$1,256,152	$240	$212,544
2	Core C/I	$711	$147,464	$462	$13,980
3	Gas A/C	$5,865	$53	Na	na
4	Gas Engine	$5,085	$3,788	Na	na
5	NGV	$22,281	$7,993	$4,450	$171
6	**Total Core**		$1,415,451		$226,694
7					
8	Noncore C/I	$30,179	$18,758	$10,168	$529
9	Small EG	$25,258	$5,463	$6,941	$355
10	Large EG	$128,644	$8,806	$8,485	$168
11	EOR	$83,029	$2,408	Na	na
12	**Total Retail Noncore**		$35,435		$1,051
13					
14	Long Beach	$886,337	$886	na	na
15	SDG&E	$1,513,039	$1,513	na	na
16	Southwest Gas	$797,252	$797	na	na
17	Vernon	$539,223	$539	na	na
18	DGN	$216,430	$216	na	na
19	**Total Wholesale**		$3,952		
20	UBS	$0	$0	na	na
21	BTS	$0	$0	na	na
22	**Total Noncore**		$39,387		$1,051
23	**Total SoCalGas(col B) Total SDG&E (col D)**		**$1,454,838**		**$227,746**

Source: Table 11 Revised Workpapers Chaudhury in A.15-07-014 SoCalGas Cost Allocation Model and Table 10a Revised Workpapers Chaudhury SDG&E Cost Allocation Model.

Note: na – not applicable.

The direct O&M and O&M loaders are assumed to be the same under both the Rental and NCO methods (without a replacement adder).

The LRMC distribution-related cost estimates should be the same also whether calculated based on the Rental and NCO methods (without the explicit replacement cost adder).

TABLE PZS6
UNSCALED LONG RUN MARGINAL COST REVENUES
SoCalGas CUSTOMER COST NCO
No Replacement Cost Adder

Customer Class	Customer LRMC $/customer A	Customer Count B	Customer Cost $000 C
Residential	$110	5,617,809	$617,787
Core C/I	$388	207,317	$80,511
Gas A/C	$4,620	9	$42
Gas Engine	$1,963	745	$1,463
NGV	$18,823	359	$6,752
Total Core			$706,554
Noncore C/I	$14,580	622	$9,063
Small EG	$36,487	216	$7,891
Large EG	$60,188	68	$4,120
EOR	$51,972	29	$1,507
Total Retail Noncore			$22,581
Long Beach	$402,400	1	$402
SDG&E	$376,829	1	$377
Southwest Gas	$488,768	1	$489
Vernon	$297,880	1	$298
DGN	$166,266	1	$166
Total Wholesale			$1,732
UBS	$0	0	$0
BTS	$0	0	$0
Total Noncore			$24,314
Total SoCalGas			**$730,868**

Source: Response to data request ORA-18 Q.1.a(i) Table 11 for SoCalGas.

TABLE PZS7 UNSCALED LONG RUN MARGINAL COST SDG&E CUSTOMER COST NCO No Replacement Cost Adder			
Customer Class	Customer LRMC $/customer	Customer Count	Customer Cost $000
Residential	$103	884,624	$91,010
Core C/I	$205	30,265	$6,204
NGV	$1,630	38	$62
Total Core			$97,277
Noncore C/I	$6,366	52	$331
Small EG	$4,897	51	$250
Large EG	$5,871	20	$116
Total Noncore			$697
Total SDG&E			**$97,974**

Source: Response to data request ORA-18 Q.1 a(i) Table 10a for SDG&E.

The above Tables PZS6 and PZS7 show substantially lower marginal customer cost estimates based on the NCO method (with no explicit replacement cost adders) compared to those based on the Rental method. The Applicants stated in their response that the proposed Rental method has no replacement cost, and hence, ORA compares the Applicants' numbers against the NCO without the explicit replacement adder. The difference in the calculated unscaled LRMC customer cost between the two methodologies is significant such that the resulting EPMC scalar is 115% for SoCalGas and 133% for SDG&E to scale these marginal costs up to meet the target BM. Based on the Applicants' proposal, the EPMC scalar is 77% for SoCalGas and 81% for SDG&E.[106]

Based on the scenario using the NCO method with a replacement cost adder, the Tables below show numbers that are closer to those obtained under

[106] Revised Workpapers of Chaudhury on 2017 LRMC SoCalGas and SDG&E Cost Allocation models.

the Rental method. The EPMC scalar is 79% for SoCalGas and 48% for SDG&E.[107]

TABLE PZS8

UNSCALED LONG RUN MARGINAL COST REVENUES
SoCalGas CUSTOMER COST NCO
With Replacement Cost Adder

Customer Class	Customer LRMC $/customer	Customer Count	Customer Cost $000
	A	B	C
Residential	$216	5,617,809	$1,212,554
Core C/I	$632	207,317	$130,980
Gas A/C	$5,290	9	$48
Gas Engine	$4,834	745	$3,602
NGV	$21,515	359	$7,718
Total Core			$1,354,901
Noncore C/I	$22,121	622	$13,750
Small EG	$41,583	216	$8,994
Large EG	$96,336	68	$6,595
EOR	$65,573	29	$1,902
Total Retail Noncore			$31,240
Long Beach	$606,697	1	$607
SDG&E	$856,488	1	$856
Southwest Gas	$618,997	1	$619
Vernon	$399,765	1	$400
DGN	$187,443	1	$187
Total Wholesale			$2,669
UBS	$0	0	$0
BTS	$0	0	$0
Total Noncore			$33,909
Total SoCalGas			**$1,388,810**

Source: Response to data request ORA-18 Q.1 b(i) Table 11 for SoCalGas.

[107] Workpapers in Response to data request ORA-18 Q.1.(bi).

TABLE PZS9 UNSCALED LONG RUN MARGINAL COST SDG&E CUSTOMER COST NCO With Replacement Cost Adder			
Customer Class	Customer LRMC $/customer	Customer Count	Customer Cost $000
Residential	$488	884,624	$431,756
Core C/I	$762	30,265	$23,051
NGV	$3,802	38	$146
Total Core			$454,953
Noncore C/I	$8,935	52	$465
Small EG	$6,618	51	$338
Large EG	$7,418	20	$147
Total Noncore			$950
Total SDG&E			**$455,902**

Source: Response to data request ORA-18 Q 1 b(i) Table 10a for SDG&E.

5. The Significance of Marginal Customer Costs in the Base Margin

The focus of ORA's analysis on cost allocation is on the LRMC for gas distribution service. ORA notes that the gas distribution service comprises the major portion of the Applicants' total base margin, accounting for approximately $1.67 billion, or a little over 83 percent, of the total base margin of $2.002 billion.[108] Further, ORA notes that of the $1.67 billion in scaled LRMC revenues, it is the customer costs that comprise the most significant portion of the scaled LRMC revenues for gas distribution, accounting for approximately $1.12 billion of the $1.67 billion in scaled LRMC revenues, or approximately 67 percent.[109]

Given the significance of both the gas distribution component in the SoCalGas total base margin, and the major portion accounted for by customer costs in the scaled LRMC revenues in this proceeding, ORA is concerned with how the Applicants propose to derive the LRMC customer capital-related unit

[108] See Table 14, Chaudhury Revised Testimony in A.15-07-014, p. 29.

[109] See Table 13, Chaudhury Revised Testimony, p. 27.

cost of gas distribution, which is a key component of the marginal customer costs. In particular, ORA is concerned with the Applicants' proposal that the marginal customer capital-related costs be developed using the Rental method.[110]

Applicants state "SoCalGas and SDG&E have used the Rental Method because the Rental Method captures the concept of LRMC accurately by estimating the cost of providing an additional customer with access to gas service."[111] The Applicants explain:[112]

> The Rental method is based on the allocation to all customers of the annualized carrying costs associated with new capital investment in service lines, meters, and regulators. The NCO approach, on the other hand, allocates only to new customers (and replacement customers in the case of NCO with replacement adder) the entire capital investment as if it were an expense. This total capital cost is then divided into all customers to derive customer-related unit capital cost. NCO-based customer-related capital cost is heavily dependent on the capital investment on the number of new and replacement customers.
>
> Under the hypothetical scenario of no new customer, the NCO method without replacement adder will lead to zero customer-related capital cost! Clearly, LRMC should be able to produce reasonable customer-related capital cost during period of no customer growth, a result that the Rental method is capable of producing.

ORA disagrees with the Applicants' assertions regarding the Rental method and the NCO method. Under the LRMC concept, as explained earlier in the exhibit, "marginal costs are forward-looking costs: they reflect the costs a utility will incur to meet new demand for its services."[113] A hypothetical scenario of "no new customer" means zero new demand for access to the utility services, and under the LRMC concept, the absence of new demand from new customers means that no marginal customer-related capital costs are supposed to be incurred. Hence, the Applicants incorrectly assert that "LRMC should be able to produce

[110] Chaudhury Revised Testimony in A.15-07-014, p. 8.

[111] Chaudhury Revised Testimony, p. 8.

[112] Response to data request ORA-09 Q.5(c).

[113] D.92-12-058.

reasonable customer-related capital cost during period of no customer growth." In addition, the Applicants readily admit that the Rental method *is capable* of producing customer-related capital cost during periods of no customer growth, which should not be the case under the LRMC concept in the absence of new demand from additional customers. In this regard, therefore, the Rental method goes against the very essence of the LRMC concept because the Rental method *is capable* of producing customer-related capital cost when there should be none associated with zero new demand.

The Rental method also effectively results in excessive marginal customer-related costs. As Applicants state "The Rental Method is based on the allocation to **all** customers of the annualized carrying costs associated with new capital investment in service lines, meters, and regulators."[114] The Rental method uses the RECC to annualize the SRM capital cost and allocates the annualized costs to all customers, whether new or existing.

Therefore, contrary to the claims of the Applicants, the NCO method is superior to the Rental method in terms of capturing the concept of LRMC accurately. As such, the NCO method is the more appropriate method to derive the marginal customer-related capital costs. ORA recommends using the NCO method to develop the Applicants' marginal customer-related capital costs.

6. Results of the Cost Allocation of the Base Margin

As mentioned earlier, the unscaled LRMC revenues are translated to scaled LRMC revenues with the use of an EPMC scalar to ensure recovery of the authorized BM. The scaled LRMC revenues for gas distribution are combined with the embedded costs of the transmission and storage services to arrive at the allocation of the BM.[115] The embedded costs of gas transmission is separately presented by witness Ms. Fung and the cost allocation of the BM incorporates the transmission cost numbers as recommended by Ms. Fung.[116] A comparison

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[114] Response to data request ORA-09 Q.5(c) (emphasis added).

[115] Shown in Table 14, Revised Workpapers of Chaudhury in A.15-07-014 for SoCalGas and in Table 12, Workpapers of Schmidt-Pines in A.15-07-014 for SDG&E.

[116] Chaudhury Revised Testimony, p. 24.

of the Applicants' results of cost allocation against ORA's recommendation was previously shown in Table PZS5 of this exhibit.

The Tables PZS10 and PZS11 show the results of cost allocation based on the NCO method compared to the current allocation. The results show that SoCalGas residential customers will be allocated 70.9 percent of the BM, which means a slightly lower cost responsibility compared to the current allocation to the extent of 1.4 percent lower allocation, or approximately $15 million less cost burden. SoCalGas Core C/I customers shows a cost allocation that is lower by one percent compared to the current allocation, or approximately $16 million less cost burden. Overall, Table PZS10 shows that SoCalGas Total Core customers will have a lower allocation of 1.9 percent compared to the current, or approximately $23 million less cost burden. On the other hand, the Noncore customers will be allocated 15 percent of the BM, which is higher compared to the current allocation of 13.1 percent, or a difference of 1.9 percent, or approximately $41 million more.

For SDG&E, the results of the cost allocation with NCO are shown below in Table PZS11.

TABLE PZS10 **SoCalGas COST ALLOCATION COMPARISON** **Based on the NCO Method** $ 000				
Customer Class	ORA Recommended Allocation of Base Margin A	% Total B	Current Allocation of Base Margin C	% Total D
Residential	$1,419,902	70.9%	$1,435,087	72.3%
Core C/I	$261,201	13.0%	$277,662	14.0%
Gas A/C	$78	0.0%	$74	0.0%
Gas Engine	$3,079	0.2%	$2,071	0.1%
NGV	$17,252	0.9%	$9,940	0.5%
Total Core		85.0%		86.9%
Noncore C/I	$57,034	2.8%	$57,226	2.9%
Small EG	$14,424	0.7%	$4,577	0.2%
Large EG	$31,570	1.6%	$31,375	1.6%
EOR	$6,148	0.3%	$5,004	0.3%
Total Retail Noncore	$109,176	5.5%	$98,182	4.9%
Long Beach	$1,269	0.1%		0.1%
SDG&E	$19,882	1.0%		0.7%
Southwest Gas	$1,379	0.1%		0.1%
Vernon	$1,102	0.1%		0.0%
DGN	$910	0.0%		0.0%
Total Wholesale		1.2%		1.0%
UBS	$17,020	0.8%		1.3%
BTS	$150,206	7.5%		5.8%
Total Noncore		15.0%		13.1%
Total SoCalGas	**$2,002,458**	**100.0%**	**$1,984,561**	**100.0%**

Source: Response to data request ORA-18 Q1.ai and shown as Table 15 in the workpapers of the SoCalGas cost allocation model provided in the response.

TABLE PZS11 SDG&E COST ALLOCATION COMPARISON Based on the NCO Method $ 000				
Customer Class	ORA Recommended Allocation of Base Margin	% Total	Current Allocation of Base Margin	% Total
Residential	$221,857	72.5%	$233,081	76.2%
Core C/I	$38,680	12.6%	$35,290	11.5%
NGV	$1,370	0.4%	$1,220	0.4%
Total Core	$261,908	85.6%	$269,591	88.1%
Noncore C/I – D	$2,495	0.8%	$2,174	0.7%
EG – D	$1,743	0.6%	$1,061	0.3%
TLS	$1,519	0.5%	$1,593	0.5%
Total Noncore	$5,756	1.9%	$4,828	1.6%
Backbone Transmission	$38,229	12.5%	$31,473	10.3%
Total SDG&E	**$305,893**		**$305,893**	

Source: Response to data request ORA-18 Q1.ai and shown as Table 13 in the Schmidt-Pines Workpapers for the SDG&E cost allocation model.

For SDG&E, the foregoing Table PZS11 shows that SDG&E residential customers will be allocated 72.5 percent of the BM based on the NCO, which also means a slightly lower cost responsibility compared to the current allocation of 76.2 percent, or a difference of 3.7 percent in cost burden which translates to approximately $11 million less cost. SDG&E Core C/I customers will have a cost allocation that is slightly higher at 12.6 percent compared to the current allocation of 11.5 percent, or a difference of 1.1 percent which is approximately $3.4 million more in cost burden. Overall, SDG&E Total Core customers will have a lower cost allocation of 85.6 percent compared to the current allocation of 88.1 percent, or a difference of 2.5 percent, or approximately $7.6 million less in cost burden. On the other hand, Noncore customers will have a slightly higher cost allocation of 1.9 percent compared to the current allocation of 1.6 percent, or a difference of 0.3 percent, or approximately $928,000 more in cost burden. SDG&E backbone transmission will have higher cost allocation of 12.5 percent compared to 10.3 percent under the current, or a difference of 2.2 percent more cost allocation which translates to approximately $6.8 million more cost burden.

ORA included the above-described results of NCO cost allocation in Table PZS5 (see page 25) in a side by side comparison of the results of cost allocation against those based on the Applicants' proposed Rental method.

7. Commission Expressed Preference for the LRMC NCO Method Over the Rental Method

The Commission originally adopted the Rental method in its LRMC policy decision. That method has subsequently been replaced by the NCO method for every major gas and electric utility except SoCalGas prior to the Commission decision in the year 2000.[117] With the adoption of the Joint Recommendation in D.00-04-060, the NCO was also adopted for SoCalGas.[118] Throughout the years, the Commission has repeatedly expressed preference for the LRMC NCO method in previous decisions as described below.

In D.95-12-053, the Commission adopted the NCO method for PG&E's marginal customer cost based on a one-time hook-up cost as reasonable.[119] The Commission also found that "the Rental method overstates the price that would prevail in a competitive market by assuming that none would be allowed to purchase their hook-up."[120]

In D.96-04-050, Southern California Edison's (SCE's) GRC case, the Commission found that "The rental method does not produce a competitive price for customer hookups and, in fact, significantly overstates the price that would prevail in a competitive market."[121] The same decision adopted the NCO method as the Commission states: "The NCO method for calculating marginal customer

[117] In D.92-12-057, D.95-12-053, D.96-04-050, and D.98-06-073.

[118] D.00-04-060, Findings of Fact # 8 and 9.

[119] D.95-12-053, Finding of Fact # 18.

[120] D.95-12-053, Finding of Fact # 17,

[121] D.96-04-050, Finding of Fact # 37.

costs and allocating those costs is fully consistent with marginal cost principles and should be adopted."[122]

In D.97-08-062,[123] the Commission retained the adoption of the rental method for cost allocation within SoCalGas' core class, but still preferred the NCO method:[124]

> D.97-04-082 is modified to replace the last paragraph of Section III.E. on page 59 with the following text:, "Therefore, based on the language contained in the Global Settlement, we retain the use of the rental method for interclass cost allocation for this BCAP period. We find however, that the NCO method is the preferred methodology and we, therefore, should use it in this proceeding for evaluating core rate design proposals. We would prefer to use the NCO method for LRMC allocation within the core class. However, the record here does not provide us with a reasonable NCO cost allocation for gas engine and gas air conditioning customers. Therefore, we will retain the use of the rental method for cost allocation within the core class for this BCAP period."

In D.00-04-060, the Commission subsequently adopted the LRMC (NCO) for SoCalGas and SDG&E by approving the Joint Recommendation (JR) which would adopt the NCO.[125] D.00-04-060 states that "the JR would adopt the LRMC/NCO method, which is the current method adopted for PG&E, SDG&E, and SCE, while rejecting the replacement cost adder."[126]

In D.05-06-029 for the 2005 PG&E BCAP, the Commission provided:[127]

> The Commission has traditionally calculated the marginal cost of customer interconnection or "hook up" by using a method PG&E calls "new customer only." This method assumes a one-time charge for new facilities in the marginal cost calculation.

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[122] D.96-04-050, Conclusion of Law # 21.

[123] D.97-04-082 modified SoCalGas' and SDG&E's Biennial Cost Allocation Program in D.97-04-082.

[124] D.97-08-062, Ordering Paragraph # 2.

[125] Finding of Fact # 8 and # 9, D.00-04-060.

[126] D.00-04-060, p. 8.

[127] D.05-06-029, p. 20.

In D.10-06-035 for the 2009 PG&E BCAP, the Commission adopted a Partial Settlement among PG&E, TURN, ORA (then DRA), and other parties, which among others, based the revenue cost allocation on the midpoint of combined TURN/DRA scenario and PG&E's proposal, and where the positions of these aforementioned settlement parties were all notably based on the NCO method.[128]

Based on the foregoing, ORA recommends the Commission continue to adopt the NCO method for the Applicants' gas distribution service cost allocation because it is based on sound economic theory consistent with the Commission's adopted LRMC marginal cost policy and Commission precedent.

IV. Cost Allocation and Rates for Gas Transmission Service

This section discusses ORA's analysis of Applicant's proposal to allocate gas transmission based on historical embedded costs ("EC"). As discussed in greater detail, the Applicants' methodology and results follows the guidelines set forth by the Commission in D.14-06-007.

- ORA agrees with the Applicants' embedded transmission costs and the allocation of embedded transmission costs between local and backbone transmission;
- ORA does not oppose the Applicants' calculation of the Backbone Transmission (BTS) service rate; and
- ORA does not oppose the Applicants' request for continuation of the SFV and MFV rate design structures as discussed herein.

A. Background

As explained in Section III of this exhibit, GT&S costs are based on historical embedded costs unlike those for gas distribution customer costs, medium pressure distribution costs, and high pressure distribution costs, which are based on LRMC. Transmission costs are then further disaggregated

[128] Appendix 1, D.10-06-035 in A.09-05-026, pp. 1-2.

between the local transmission and backbone transmission functions. The Applicants first presented the use of the EC methodology for GT&S costs in the Applicant's previous BCAP filing which resulted in D.09-11-006 and the adoption of a Settlement Agreement. In the Settlement Agreement, the settling parties agreed that "SDG&E and SoCalGas shall not be required to propose an LRMC cost allocation for transmission and storage costs in their next cost allocation proceeding."[129] The embedded cost-based cost allocation methodology uses the utility's recorded expenditures and allocates them to customer classes based on cost causality.

Pursuant to D.09-11-006 in the SoCalGas/SDG&E BCAP Phase 2 adopted settlement agreement, the split between backbone and local transmission costs was specifically reserved in the review of the Firm Access Rights (FAR) proceeding.[130] In the subsequent review of the FAR, also known as the FAR Update, the Commission in D.11-04-032 ordered the Applicants to, among other things, prepare a new backbone embedded cost study to be filed with their 2011 TCAP application.[131] The FAR tariff also was subsequently renamed as the Backbone Transmission Service ("BTS").[132]

Further, the decision adopted the rate design for BTS and related proposals jointly recommended by parties representing core customers, noncore customers, and SDG&E/SoCalGas.[133] As a result of the FAR Update decision, the firm reservation charge increased 163 percent from the then current rate, and other end-use transportation rates were reduced.[134] The decision also includes the BTS revenue requirement, rate design issues, and proposals for future changes to the FAR system in the scope of the 2011 TCAP.[135] The 2011 TCAP

[129] D.09-11-006, Appendix A, Settlement Agreement, June 2, 2009, p. 9.

[130] Appendix A, D.09-11-006.

[131] D.11-04-032, p. 3 and Conclusion of Law # 7 and Ordering Paragraph # 4.

[132] D.11-04-032, Ordering Paragraph # 1.

[133] D.11-04-032, Ordering Paragraphs # 6, 7, 10, and 11.

[134] D.11-04-032, p. 33.

[135] D.11-04-032, p. 58.

(filed in A.11-11-002) resulted in the Commission's decision in D.14-06-007 which, among other things, adopts a plan for pipeline safety enhancement, adopts a settlement agreement on cost allocation and rate design for the TCAP (GRC Phase 2), and rejects a specific cost allocation for the safety enhancement plan that was based on human exposure to risk rather than the cost of providing service to all customer classes.[136]

Subsequently, in the TCAP decision, D.14-06-007, the Commission retained the existing cost allocation and rate design and adopted a number of provisions that pertain to GT&S, as shown in Attachment III and IV of that decision, which are reproduced below:

Attachment III Provisions in D.14-06-007 Section II B.4.:

4. Backbone

a. BTS reservation charges shall use a 2,978 Mdth/d denominator, to be adjusted annually in SoCalGas' Annual Regulatory Account Update filings.

b. All BTS rates shall be subject to BTBA rate adjustments.

c. SoCalGas' volumetric interruptible BTS rate shall equal its reservation charge SFV rate.

d. SDG&E transmission shall continue to be classified as backbone.

e. SoCalGas shall withdraw its proposal for backbone-only rates from this proceeding. If SoCalGas chooses to resubmit a proposal for backbone only rates prior to the next TCAP, it will do so in its upcoming application relating to Southern System issues (see Section 6 below). If the Southern System application does not propose a backbone-only rate, the application will address why SoCalGas chose not to re-propose it in the application. Nothing in this Settlement is intended to predetermine the potential availability of a backbone-only rate as a result of the upcoming application.

f. SoCalGas' MFV Rate Option shall be maintained for this TCAP period, with the MFV Volumetric rate designed such that 100% load factor MFV rate equals the SFV "100% Reservation" rate for BTS service.[137]

5. Storage

a. SoCalGas shall receive full rate recovery by SoCalGas of its Honor Rancho Expansion Project costs.

[136] D.14-06-007, pp. 2-3.

[137] MFV stands for Modified Fixed Variable and SFV stands for Straight Fixed Variable.

b. The 2009 BCAP Phase 1 Settlement Agreement shall be extended through the end of 2015.

Attachment IV Provisions in D.14-06-007:

17) Adopt SoCalGas/SDG&E's calculation that the embedded cost of the total integrated transmission system is $198 million.
18) Adopt SoCalGas/SDG&E's calculation that the total embedded cost of the backbone transmission system is $147.5 million.
19) Adopt SoCalGas/SDG&E's proposal to allocate $89.6 million of embedded storage costs among the storage functions.

B. Description of the Applicants' Proposal

The Applicants' witness Ms. Sim-Cheng Fung provides her data sources and describes the results of the EC study on Gas Transmission for each of SoCalGas and SDG&E. In TCAP Phase 1 in A.14-12-017, the same witness Ms. Fung presented the results of the EC study on Storage for SoCalGas and SDG&E. The stated SoCalGas total storage cost of $110.585 million is expected to be decided in A.14-12-017 Phase 1.[138] In each case, the methodology is presented as consistent with the EC methodology approved by D.14-06-007. ORA's discussion and review relied on the embedded costs presented in the testimony and workpapers of Ms. Fung in this TCAP.

According to the Applicants, the basis of the cost allocation of the total storage costs to the core customer classes was presented in the Revised TCAP Phase 1 Direct Testimony of Mr. Chaudhury.[139] Except for load balancing inventory which is still pending in the 2016 TCAP Phase 1 proceeding, the cost allocation of the total storage costs to the various customer classes was authorized in D.14-06-007 (see Attachment IV Provisions, item 19).[140]

Similar to Storage, the proposed costs for Gas Transmission are for four years (2017-2019) and the starting point for the EC study is the total recorded

[138] Response to data request ORA-19 Q.1(d).

[139] Response to data request ORA-19 Q.1(a) makes reference to page 3 Table 2 of Mr. Chaudhury's Revised Testimony.

[140] Response to data request ORA-19 Q.1(a).

costs for calendar year 2013, as presented in the 2013 Annual Report to the Commission (FERC Form 2).[141]

The data presented in the Applicants' Testimony tables provide details of costs that enables one to follow the determination of plant-in-service (which is the capital-related portion), Operation and Maintenance ("O&M"), and Administrative and General ("A&G") expenses that constitute base margin costs.[142] Embedded costs for depreciation, return on rate base, and federal and state income taxes and property taxes in the total amount of approximately $89.1 million comprise the 2013 SoCalGas Transmission capital-related portion as shown in Table 3.[143]

Embedded costs for O&M, A&G, and Miscellaneous Revenue in the total amount of approximately $125.8 million comprise the 2013 SoCalGas Transmission O&M/A&G Expense-related portion as shown in Table 7.[144] The combined total amount of $89.1 million in transmission capital-related cost and $125.8 million in transmission O&M/A&G expense-related cost, which adds up to $214.9 million, comprises the 2013 embedded transmission costs for SoCalGas as shown in Table 8.[145]

Similarly, for SDG&E, embedded costs for the 2013 SDG&E capital-related costs in the amount of approximately $19.9 million are presented in Table 12, while the 2013 SDG&E O&M/A&G and miscellaneous revenue related expenses in the total amount of approximately $18.3 million are presented in Table 15.[146] The combined total amount of $19.9 million and $18.3 million, which adds up to $38.2 million, comprises the 2013 embedded transmission costs for SDG&E as shown in Table 16.[147]

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[141] Prepared Direct Testimony of Sim-Cheng Fung for SoCalGas and SDG&E in A.14-12-017 dated December 18, 2014, p. 1 and Revised Prepared Direct Testimony of Sim-Cheng Fung for SoCalGas and SDG&E in A.15-07-014 dated November 19, 2015, p. 1

[142] All references to Tables are to Ms. Fung's Revised Testimony.

[143] Fung Revised Testimony, p. 4.

[144] Fung Revised Testimony, p. 5.

[145] Fung Revised Testimony, p. 6.

[146] Fung Revised Testimony, pp. 8-9.

[147] Fung, p. 10.

The above results of the SoCalGas and SDG&E EC study are summarized in Table 17 which shows the combined total 2013 transmission costs in the amount of $253.1 million.[148] The Applicants propose to maintain the total transmission cost at this level until another EC study is performed for the next TCAP.[149]

According to the Applicants, transmission pipelines are examined individually and categorized based on functional definitions.[150] Based on these functional definitions that serve as the bases of categorization, the Applicants report that "All of SoCalGas' and SDG&E's compressor stations are classified as backbone transmission facilities."[151] In addition, "All of SDG&E's gas transmission pipelines are classified as backbone pipelines, but a significant number of SoCalGas' transmission pipelines perform a local transmission function."[152]

SoCalGas proposes to allocate the SoCalGas transmission embedded costs between backbone and local transmission on the basis of certain allocators for the capital-related and the expense-related portions of the total SoCalGas transmission presented in the testimony.[153]

With respect to rates for the Backbone Transmission Service ("BTS") rate design, SoCalGas and SDG&E propose to continue "a straight fixed-variable ("SFV") rate by dividing total backbone costs by a proposed denominator of 2,818 thousand decatherms per day (MDth/d), resulting in a proposed firm BTS rate of $0.183/decatherm as shown in Table 19."[154]

ORA reviews the proposed gas transmission cost allocation and rates in the next section.

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148 Fung Revised Testimony, p. 10.

149 Fung Revised Testimony, p. 10.

150 Fung Revised Testimony, p. 11.

151 Fung Revised Testimony, p. 11.

152 Fung Revised Testimony, p. 11.

153 Fung Revised Testimony, p. 11.

154 Fung Revised Testimony, p. 12.

C. ORA Review and Analysis

Based on ORA's review of the embedded costs presented in the tables and appendices of Ms. Fung's testimony, ORA agrees with the determination of those transmission embedded costs. ORA focuses next on the proposed allocation of the SoCalGas gas transmission costs between backbone and local transmission. The gas transmission cost is made up of both capital-related and O&M expense-related components.

ORA's review shows that to allocate the SoCalGas transmission costs between backbone and local transmission, each of the elements of the SoCalGas 2013 capital-related costs (Depreciation, Return, and Taxes) is multiplied by an allocator.

The Depreciation element of the SoCalGas total 2013 transmission is multiplied by 68.9%, which is the percentage of the SoCalGas Depreciation expense on backbone transmission as a ratio of total SoCalGas 2013 Transmission Depreciation.[155]

The Return element of the SoCalGas total 2013 transmission is multiplied by 67.9%, which is the percentage of the Net Book Value of the backbone transmission as a ratio of the total 2013 SoCalGas Net Book Value for transmission.[156]

Lastly, the Tax element of the SoCalGas total 2013 transmission is multiplied by the same 67.9%. The sum of the three elements as multiplied by the allocators' results in the capital-related portion of the SoCalGas backbone transmission in the amount of approximately $60.9 million shown in Table 18.[157]

In a similar manner, each of the elements of the SoCalGas 2013 O&M/A&G expense and Miscellaneous Revenues is multiplied by an allocator based on pipeline mileage. For backbone transmission, the pipeline mileage is

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[155] As shown in Tab "BBT_LT margin" of excel worksheet included in response to data request ORA-13 Q.1.

[156] Id.

[157] Fung Revised Testimony, p. 12.

based on 71%.[158] The sum of these expense elements multiplied by the allocators' based on pipeline mileage results in the O&M/A&G expense-related portion of the SoCalGas backbone transmission in the amount of approximately $89.3 million.

The sum of $60.9 million from the capital-related portion and $89.3 million from the expense-related portion results in the combined amount of $150.2 million for SoCalGas backbone transmission. Based on the SoCalGas transmission cost of $214.9 million shown in Table 8 and the amount of $150.2 million for SoCalGas backbone transmission, then the difference between these two numbers represents the SoCalGas local transmission cost in the amount of $64.7 million.

When the SoCalGas backbone transmission is combined with the SDG&E 2013 embedded transmission cost of $38.2 million shown in Table 16, the result is an amount of approximately $188.4 million in total backbone transmission for the Applicants combined together as presented in Table 18.[159]

Based on the foregoing, ORA does not oppose the Applicants' proposed allocation of the transmission costs between backbone and local transmission.

The Applicants propose to continue an SFV rate for the BTS by using a proposed denominator of 2,818 thousand decatherms per day ("MDth/d") which results in a proposed firm BTS rate of $0.183/decatherm (dth).[160] As proposed, the estimated BTS denominator of 2,818 MDth/d would include BTS firm SFV contracts, scheduled MFV, and interruptible throughput from October 1, 2014 through May 31, 2015 and extrapolated for the remaining four months to September 30, 2015.[161] The BTS denominator is adjusted annually in SoCalGas' Annual Regulatory Update filings. (see Attachment III Provisions, item 4a).

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[158] As shown in Tab "BBT_LT NBV" of excel worksheet included in response data request ORA-13 Q.1.

[159] Fung Revised Testimony, p. 12.

[160] Fung Revised Testimony, p. 12 and also shown in Table 19 on the same page.

[161] Fung Revised Testimony, pp. 12-13.

The Applicants clarified that the "minor change" proposed in this case is to replace MFV contracted volumes with MFV scheduled volumes in the BTS denominator.[162] Applicants explain the current use of the higher contracted volume results in an under-collection of BTS revenues and the proposal mitigates this issue.[163]

Data supporting the Applicants' assertions regarding the scheduled volumes versus the contracted volumes were presented in Table 20, described in Ms. Fung's testimony.[164] The Applicants anticipate that the proposed throughput denominator will be updated to reflect the average BTS utilization for the 12 months of the prior October through September, prior to implementation of the BTS rates in 2017.[165] The Commission previously found both SFV and MFV as reasonable tariff options.[166] The BTS under-collections are accumulated and amortized in balancing accounts for the BTS revenues.[167] Further, the Commission also found it reasonable to amortize the MFV rate balance in the BTBA.[168] Although the current balancing account method would allow the Applicants to ultimately recover any under-collection of BTS revenues, ORA does not oppose the proposal.

[162] Response to data request ORA-13 Q.3.(a).

[163] Response to data request ORA-13 Q.3(a).

[164] Fung Revised Testimony, pp. 13-14.

[165] Fung Revised Testimony, p. 14.

[166] D.11-04-032, Conclusions of Law # 8 and 10.

[167] Fung Revised Testimony, p. 14. Refer also to the Backbone Transmission Balancing Account (BTBA) created to record the difference between authorized BTS revenue requirements and actual BTS revenues.

[168] D.11-04-032, Conclusion of Law # 12.

V. Rate Design

A. Summary of ORA Recommendations

- Keep the current SoCalGas residential customer charge of $5.00 per month and reject the proposed increase of the SoCalGas residential customer charge to $10.00 per month;
- Reject the proposed implementation of a new SDG&E residential customer charge of $10.00 per month and instead authorize a Residential minimum bill for SDG&E in the amount of $3.00 per month as discussed herein;
- Deny the request for simplified tier differential calculation for SoCalGas to the extent the Commission determines the simplification would violate the Public Utilities Code section 739.7 regarding the residential rate inverted structure mandated in the statute as discussed herein;
- Adopt the natural gas transportation rates based on ORA's recommendations on cost allocation and rate design as discussed herein;
- Adopt the NCO method for purposes of the customer cost update to the submeter credit as discussed herein; and
- Deny the Applicants' request to update the NGV Compression Adder as discussed herein.

B. Background

The section on Rate Design presents the rate outcome of the Applicants' cost allocation proposals and ORA's recommendation. Consistent with ORA's statutory mission, the overall goal here is to obtain the lowest possible rate for service consistent with reliable and safe service levels.[169]

In addition, while obtaining the lowest possible rate, another goal is to have just and reasonable rates.[170] There are other important goals of ratemaking

[169] Public Utilities Code section 309.5.

[170] Public Utilities Code section 451.

such as rates based on cost-causation principles where customer cost responsibility is aligned with the proposed rate structure. Rates should encourage economically efficient decision-making by reflecting the marginal cost pricing signals. There are also several attributes of a sound rate structure. Professor James Bonbright, one of the foremost experts in public utility ratemaking, identified at least ten attributes of a sound rate structure.[171] Among these attributes are that rates should be sufficient to provide for the utilities' authorized revenue requirements.[172] Rates should be stable, predictable, be easily understandable, be non-controversial and avoid rate shock to customers.[173] Rates should encourage conservation and energy efficiency.[174] The rates should maintain consistency with existing practices to the extent that is possible.[175]

Applicants state that the conduct of their cost allocation follow the principles described below:[176]

1. Allocate costs to customer classes based on cost causality;
2. Avoid rate shocks for customers; and
3. Maintain consistency with the existing practices whenever possible.

These principles are consistent with the Commission's cost allocation general guidelines which focus on the principles of cost causation, economic efficiency, and equity as important considerations in selecting the appropriate allocation factors that are both just and reasonable.[177]

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[171] Bonbright, J., Danielsen, A., and Kamerschen, D., 2nd Ed. 1988. Principles of Public Utility Rates, Public Utilities Reports, Inc.

[172] Id., pp. 383-384.

[173] Id.

[174] Id.

[175] Id.

[176] Chaudhury Revised Testimony, p. 3.

[177] In D.92-12-058, the Commission states that one of the central principles of marginal cost pricing is cost causation and that the rates charged should reflect the change in the utility's costs that would actually occur if there were an increase in demand. Prior to this in D.86-12-009, the Commission states as part of guiding principles in ratemaking that "economic efficiency dictates that rates be based on marginal cost." But, as the Commission explained in that decision, economic efficiency is not the sole consideration. The Commission states that equity considerations remain important.

C. Description of the Applicants' Proposals

The Applicants' rate design proposals are:[178]

1. Revise the tier differential calculation for SoCalGas and SDG&E;
2. Increase the residential customer charge for SoCalGas;
3. Implement a residential customer charge for SDG&E;
4. Update the submeter credit;
5. Update Natural Gas Vehicle (NGV) compression costs;
6. Provide allocation method for the System Operator Gas Account; and
7. Provide TLS Reservation Revenue Report.

The Applicants explain that of the seven rate design proposals listed above, only two of these are new proposals, namely the third proposed item to "implement a residential customer charge for SDG&E" and the sixth proposed item to "provide allocation method for the System Operator Gas Account."[179] According to the Applicants, except for these two, the rest of the proposals are requests to update the current rates or calculations which were previously approved.[180] The Applicants cite the following Commission decisions in support:[181]

Item 1 – D.09-11-006 specifically section II.B.2.1 regarding the approval of the current tier differential calculation for SoCalGas;

Item 2 – D.94-12-052, which approved the current residential customer charge for SoCalGas;

Item 4 – D.14-06-007, Ordering Paragraph #7, which adopted the comprehensive rate design settlement where the current submeter credit for both SoCalGas and SDG&E were approved; and

Item 5 – D.14-06-007, Ordering Paragraph #8, where the current NGV compression rate adder was approved.

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[178] Bonnett Revised Testimony, p. 2.

[179] Response to data request ORA-10 Q. 4.

[180] Response to data request ORA-10 Q. 4.

[181] Response to data request ORA-10 Q. 4.

Item 7 – D.14-06-007, Ordering Paragraph #7 and Attachment III, Section III.B.3.c. which required that the TLS Reservation Revenue Report be included in this TCAP.

In addition, Tables 1 and 2 of Mr. Bonnett's testimony show the Applicants' illustrative proposed class average rates in this rate case. The last column of Tables 1 and 2 indicate negative rates of change between the proposed rates in this rate case and the rates on 1/1/2015. In response to ORA discovery, SoCalGas and SDG&E state that the class average rate reduction shown in Table 1 and Table 2 of Mr. Bonnett's testimony is solely attributable to the regulatory account balances as discussed in the testimonies of Mr. Ahmed and Ms. Niederle, respectively.[182] ORA obtained further clarification regarding the negative rates of change reflected in the last column of these tables which will be discussed in the ORA review portion.[183]

According to the Applicants, the proposed rates rely upon the cost allocation of authorized base margin costs among customer classes, as shown in the prepared direct testimony of Dr. Chaudhury and Ms. Schmidt-Pines.[184] In addition, the result of the allocation of the non-base margin costs are incorporated to complete the transportation rate revenue requirement, where the latter becomes the starting point for rate design calculations.[185]

The Applicants justify the proposed increase to the SoCalGas residential customer charge from $5 per month (approximately $0.16438 per meter per day) to $10 per month (approximately $0.32876 per meter per day) [186]and the implementation of an SDG&E residential customer charge stating that these proposals are consistent with Commission policy.[187] The Applicants state that the

[182] Response to data request ORA-10 Q.5(d) and 5(f).

[183] Response to data request ORA-20 Q.1.

[184] Revised Prepared Direct Testimony of Jason Bonnett in A.15-07-014 Phase 2 dated November 19, 2015, p. 1.

[185] Bonnett Revised Testimony, pp. 2-3.

[186] Bonnett Revised Testimony, p. 4.

[187] Bonnett Revised Testimony, pp. 5-11 citing to Commission decisions in D.93-06-087, D.94-12-052 and D.99-06-058.

fully allocated residential marginal customer costs that are $224 per year and $240 per year for SoCalGas and SDG&E, respectively, cover costs that do not vary with usage.[188] Applicants argue that the current residential customer charge partially covers the fixed costs of services provided every month.[189]

Applicants argue the following points: First, it is appropriate to recover the customer costs, which are largely fixed, in a rate set on a fixed basis to reflect cost causation. [190] Second, a fixed customer charge is appropriate because it would also reduce intra-class subsidies which occurs to the extent fixed customer charges are set below fixed costs.[191] In this proceeding, the Applicants assert that a residential intra-class subsidy exists.[192] Third, setting the residential customer charge closer to costs would mitigate bill volatility between seasons by enabling the recovery of some fixed costs during the low-usage summer months.[193] Fourth, the proposed residential fixed customer charges do not inhibit conservation efforts and energy efficiency price signals.[194] According to Applicants, the foregoing shows that the proposed residential customer charges are consistent with Commission policy. Finally, the bill increases resulting from the SoCalGas and SDG&E proposals on the residential customer charge are not inequitable.[195]

In addition to the proposals regarding the residential customer charge, SoCalGas and SDG&E propose to "revise the tier differential calculation" for purposes of simplification.[196] Applicants explain that the current composite tier differential between the SoCalGas Baseline (BL) and NonBaseline (NBL) transportation rate is 1.15, where the NBL rate is 15 percent higher than the

[188] Bonnett Revised Testimony, p. 4.

[189] Bonnett Revised Testimony, pp. 4-5.

[190] Bonnett Revised Testimony, p. 5.

[191] Bonnett Revised Testimony, p. 8.

[192] Response to data request ORA-11 Q.7(f).

[193] Bonnett Revised Testimony, p. 8.

[194] Bonnett Revised Testimony, pp. 9-11.

[195] Bonnett Revised Testimony, pp. 11-12 and as shown in Table 5.

[196] Bonnett Revised Testimony, p. 4.

composite BL rate.[197] According to the Applicants, the composite BL rate is equal to the sum of the customer charge revenues and BL volumetric rate revenues divided by the BL volumes and the rate difference between the BL and NBL is currently capped at $0.26 per therm.[198] The Applicants propose to set the tier differential between BL and NBL bundled rates (this refers to the transportation plus commodity) at $0.26 per therm throughout the TCAP term.[199] As a result of this proposal, Applicants propose that the bundled NBL rate for SoCalGas would become 36 percent higher than the resulting bundled BL rate.[200] Similarly, for SDG&E where the current tier differential between SDG&E's BL and NBL bundled rates is a factor of 1.14 (the NBL rate is 14 percent higher than the BL rate), the proposal would yield a resulting bundled NBL rate that is 35% higher than the resulting bundled BL rate.[201]

D. ORA Review and Analysis

1. Residential Customer Charge

ORA focuses first on the issue of the proposed residential customer charge increase for SoCalGas and the implementation of one for SDG&E, where there is currently no residential customer charge.

Commission policy on cost causation go hand in hand with the adopted marginal cost pricing approach and the goal of sending accurate pricing signals to promote economic efficiency. As shown in the discussion in the section on cost allocation of gas distribution services, there is a fundamental difference in the calculation of the marginal customer unit costs, where the Applicants made use of the Rental method, and ORA used the NCO method. In the cost allocation discussion, ORA explained why the Commission should adopt the

[197] Bonnett Revised Testimony, p. 4.

[198] Bonnett Revised Testimony, p. 4.

[199] Bonnett Revised Testimony, p. 4.

[200] Bonnett Revised Testimony, p. 4.

[201] Bonnett Revised Testimony, p. 4.

NCO method instead of the Rental method. ORA does not repeat those arguments here.[202]

The Applicants rely on the Rental method to support the assertions regarding the existence of a residential intra-class subsidy as shown in the response below:[203]

> SoCalGas and SDG&E identified the above-described intra-class subsidy by comparing the current monthly residential fixed customer charge at each utility ($5 at SoCalGas and $0 at SDG&E) to the fully allocated annual LRMC customer cost ($224 at SoCalGas and $240 at SDG&E, as shown in the prepared direct testimony of Dr. Chaudhury and Ms. Schmidt-Pines, respectively) divided by 12 months, or $18.67 at SoCalGas and $20.00 at SDG&E. Since the current residential fixed customer charge is less than the fully allocated LRMC customer cost, an intra-class subsidy exists.

The Applicants agree that compared to the Rental method, the use of the NCO method results in lower marginal customer-related capital cost estimate.[204] The fully allocated annual LRMC customer cost based on the NCO method (without replacement cost adder) is $110 at SoCalGas and $103 at SDG&E as shown in Tables PZS6 and PZS7 of this exhibit, respectively. Taking these numbers and dividing by 12 months, or $9.16 for SoCalGas and $8.58 for SDG&E and comparing to the current monthly residential fixed customer charge at each utility ($5 at SoCalGas and $0 at SDG&E), the alleged intra-class subsidies are not as high as Applicants assert, particularly when one considers the presence of variable O&M costs as further explained below.

ORA has already explained that the fully allocated annual LRMC customer cost, whether based on the Rental or NCO method, contain certain O&M cost elements that are considered variable costs, rather than fixed, from a cost allocation perspective.[205] In response to discovery, the Applicants indicated that

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[202] See Section III.C.

[203] Response to data request ORA-11 Q.7(f).

[204] Response to data request ORA-09 Q.5(b).

[205] Response to data request ORA-08 Q.1(b) through (e).

Customer Services O&M costs are variable costs with respect to the number of customer services activities.[206] Visits to customer premises by customer service representatives were provided as an example of this variability of customer service activities. Another example of the variable nature of the cost is with respect to the average length of time required to complete different types of customer service activities. Applicants also identified the variable cost nature of Customer Accounts O&M, O&M costs associated with Meter Set Assemblies, and O&M costs associated with Service Lines.[207]

The SoCalGas fully allocated annual customer cost of $224 or $18.67 per month is not purely fixed costs. SoCalGas annual residential customer marginal customer-related unit cost based on the Rental method of approximately $224 per customer (shown in Table PZS2 col (A) at line 1) consists of approximately 54.6 percent fixed costs and approximately 45.4 percent variable costs.[208] This is based on the assumption that the capital-related cost for the SRM are all unavoidable fixed costs associated with a new customer and the O&M costs are all variable costs. On the basis of the Rental method, there are $10 per month in fixed costs (i.e., $223.6 x 54.6%, then divide by 12 months). But as previously explained, the Rental method should be rejected.

Based on the NCO method, the fully allocated annual customer cost of $110 or $9.16 per month for SoCalGas, does not represent pure fixed costs. On the basis of the NCO method, there are approximately $5 per month in fixed costs (i.e., $110 x 54.6%, then divide by 12 months). Therefore, SoCalGas has not provided sufficient evidence to warrant the proposed increase from the current $5 per month residential customer charge to $10 per month.

In the case of SDG&E, where currently there is $0 residential customer charge, the calculated annual residential customer marginal customer-related unit cost based on SDG&E's Rental method of approximately $240 per customer (shown in Table PZS2 col (C) at line 1) consists of approximately 75.3 percent

[206] Response to data request ORA-08 Q.1(b) through (e).

[207] Response to data request ORA-08 Q.1(b) through (e).

[208] Revised Workpapers for SoCalGas on 2017 LRMC Customer Costs at Tab "cust MUC."

fixed costs and approximately 24.7 percent variable costs.[209] This is again based on the assumption that the capital-related cost for the SRM are all unavoidable fixed costs associated with a new customer and the O&M costs are all variable costs. This comes to approximately $15 per month in fixed costs calculated on the basis of the Rental method (i.e., $240 x 75.3%, then divide by 12 months).

Based on the NCO method, the SDG&E fully allocated annual customer cost is $103 or $8.58 per month (without replacement adder). Even based upon the NCO method, the $8.58 per month does not represent pure fixed costs. Rather, approximately $6.50 per month in fixed costs are calculated on the basis of the NCO method (i.e., $103 x 75.3%, then divide by 12 months). SDG&E has not provided sufficient evidence to warrant the implementation of the proposed residential customer charge of $10 per month.

There are various reasons that support adoption of a minimum bill of $3 for SDG&E rather than a fixed customer charge of $6.50 per month. At a policy level, a fixed monthly customer charge serves as a disincentive to energy efficiency and conservation. The Commission recognizes this in recent Commission decisions. In PG&E's A.10-03-014, where PG&E proposed a fixed customer charge, the Commission stated in D.11-05-047 that "[s]hifting revenue recovery from a volumetric rate to a fixed customer charge produces a bill impact that cannot be avoided by changing usage patterns or being more energy efficient. A customer charge thus offers no price signal to be more energy efficient."[210] PG&E's request for a fixed residential customer charge was subsequently denied in that case.[211] Similarly, in A.11-11-002 (filed jointly with SoCalGas), where SDG&E proposed a residential customer charge for the recovery of fixed costs, the Commission found in D.14-06-007 that "[a] customer charge dilutes the price signals for conservation and energy efficiency."[212]

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209 Revised Workpapers for SDG&E on 2017 LRMC Customer Costs at Tab "cust LRMC."

210 D.11-05-047, Finding of Fact # 13.

211 D.11-05-047, Ordering Paragraph # 4,.

212 D.14-06-007, Findings of Fact # 21 and # 22.

SDG&E's request for a fixed residential customer charge was made in the last TCAP rate case (A.11-11-002).[213]

SoCalGas is correct that over 20 years ago the Commission approved the current residential customer charge of $5 per month for SoCalGas in D.94-12-052.[214] This fixed charge has not been increased since that time. ORA recommends keeping the SoCalGas residential customer charge at the current $5 per month. The current amount of the SoCalGas residential customer charge at $5 per month remains sufficient to cover its fixed costs.

In D.15-07-001, the Commission rejected the request of investor-owned electric utilities for a fixed monthly charge and directed them instead to implement a minimum bill in 2015.[215] The Commission further states "[a]s an alternative to the fixed charge, the minimum bill charge is a mechanism that is designed to recover a minimum level of revenue, recognizing that some costs are still incurred to maintain service even in the event that a customer does not use energy."[216] In Finding of Fact #6 of that decision, the Commission finds that SCE currently has a fixed charge of less than $1 for residential customers while SDG&E and PG&E currently do not charge residential customers a fixed monthly charge, but assess a minimum bill instead.[217] Also as provided for in PU Code Section 739.9(h), "the commission may consider whether minimum bills are appropriate as a substitute for any fixed charges."[218] The ORA proposals to implement a minimum bill of $3 for SDG&E residential customers and to not increase SoCalGas' residential customer charge is consistent with the Commission's recent policy pertaining to the electric investor-owned utilities.

[213] D.14-06-007, Ordering Paragraph # 11.

[214] D.94-12-052, Finding of Fact # 39.

[215] D.15-07-001, p. 5.

[216] D.15-07-001, p. 217.

[217] D.15-07-001, Finding of Fact # 6.

[218] Public Utilities Code section 739.9(h), repealed and added by Stats.2013, Ch.611, Sec.5 (AB 327) (Effective January 1,2014).

In addition, while the Commission uses marginal cost principles to design rates, it is important to point out that in D.93-06-087, the Commission highlighted other ratemaking principles that it also relies upon:[219]

> The Commission continues to use marginal cost principles to design rates, while it also relies on other ratemaking principles such as rate stability, avoidance of large bill impacts, and customer acceptance.

In D.93-06-087, the Commission recounted how SDG&E customers have in the past shown displeasure to a residential customer charge. The 1993 decision recounted what is called "The SDG&E Experience" regarding the residential customer charge, reproduced below:[220]

> By D.87-12-069 the Commission adopted a $4.80 customer charge for San Diego Gas & Electric Company's (SDG&E) residential electric customers. (27 CPUC 2d 201, 215-16.) Seven months later, by D.88-07-023, the Commission repealed the $4.80 charge and re-established the $5.00 minimum charge which existed prior to January 1, 1988. (28 CPUC 2d 503.) During the intervening months residential customers had voiced considerable displeasure over the payment of a customer charge. The Commission received many telephone calls, letters, and petitions from customers in opposition to customer charge. An estimated 700 customers attended public participation hearings in San Diego. Nearly all of the 85 customers who spoke at those hearings were vehemently opposed to the customer charge.
>
> In repealing the customer charge, the Commission reaffirmed its commitment to cost-based unbundled rates, and stated that customer charges are an accurate way to identify fixed costs. It then stated:
>
> "However, unbundling is not our only objective in rate design. Customer acceptance and understandability are also important. Obviously, if both are not achieved, it [*36] is unlikely that the price signals intended through rate design will be received." (Id., 504.)
>
> The Commission went on to state:
>
> "D.87-12-069 was premised upon DRA's arguments for establishing a residential customer charge and today we support those same arguments which DRA uses to justify maintaining the charge.

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[219] D.93-06-087, p. 1.

[220] D.93-06-087, pp. 9-10.

However, we must look at more than just economic principles. In practice, we continuously strive to balance the sometimes competing, always complex goals of sound rate design. We set the priorities, weigh the facts, and select the best features to meet our objectives. We note that residential customers generally do not employ the sophisticated analytical techniques other customer classes use when reviewing their utility bills." (Id., 505.)
The Commission noted that understandability can be difficult to achieve where a "climate of distrust or perceived unfairness" has been allowed to develop; under these conditions almost any rate changes are likely to be viewed with suspicion. It also noted that the skill and care with which rate design changes are implemented affects understandability. It noted further that in the move toward cost-based rates, to which it remained [*37] fully committed because it is based on sound economic principles, it must remain sensitive to the practical impacts of theory.

Based on its review in the case of SDG&E, ORA recommends the implementation of a minimum bill instead of a residential customer charge. ORA recommends the amount of the SDG&E minimum bill (also called a minimum transportation charge in PG&E's tariffs) be initiated at $3 per month.[221] ORA also recommends to include in the record of this proceeding any discussion in the Public Participation Hearings ("PPH") regarding the proposed residential customer charge in this TCAP and the feedback received from both SoCalGas and SDG&E customers during the PPHs.[222]

2. Tier Differential Calculation

Mr. Bonnett states:[223]

"[c]urrent SoCalGas residential rates consist of a $0.16438 per-meter per-day customer charge and a two-tiered usage structure: baseline (BL) and non-baseline (NBL) volumetric rates. The current targeted composite tier differential between SoCalGas' BL and NBL transportation rates is 1.15 (*i.e.*, the NBL rate is 15 percent higher than the composite BL rate). The composite BL rate is equal to the sum of the customer charge revenues and BL volumetric rate revenues divided by the BL volumes; however, the rate difference between the BL and

[221] D.05-06-029, Finding of Fact # 2 which states that a $3 minimum monthly transportation bill for residential customers of PG&E would not create a hardship for customers and recognizes that PG&E incurs costs even when a customer does not use any gas commodity.
[222] See PPH Transcripts in A.15-07-014, Volume 1 dated February 9, 2016, and Volume 2 dated February 10, 2016.

[223] Bonnett Revised Testimony, pp. 3-4.

NBL is currently capped at $0.26/therm. SoCalGas proposes to simplify the calculation by setting the tier differential between BL and NBL bundled rates (*i.e.*, transportation plus commodity) at $0.26/ therm throughout this Triennial Cost Allocation Proceeding (TCAP) term, which is equal to the current tier differential limit. Using this methodology, the resulting bundled NBL rate is 36% higher than the resulting bundled BL rate."

In discovery, SoCalGas states that the Settlement in A.08-02-001 adopted in D.09-11-006 established a cap on the difference between the baseline and non-baseline volumetric rates, currently at $0.26 per therm.[224] The adopted Settlement in D.09-11-006 states:[225]

> Adopt TURN's proposal for developing the residential tier differential. Residential rates for SoCalGas customers will be set to achieve a composite tier differential of 15% between the non-baseline rate and the baseline rate, where the baseline and non-baseline rates include the commodity rate adopted in this proceeding. However, the rate difference between the baseline and non-baseline rates, excluding commodity rate, shall be capped at 24¢/therm for 2010, 25¢/therm for 2011, and 26¢/therm for 2012.

SoCalGas refers to Table 2 in Mr. Bonnett's revised workpapers to explain the current calculation for the composite baseline rate below:[226]

(((The sum of customer charge revenues + Baseline revenues) / Baseline volumes) + gas commodity rate)

or;

((($314,904,293 + $788,460,987) / 1,583,823,111 therms) + $0.42840) = **$1.12505**

The current calculation for the composite non-baseline rate is as follows:

((non-Baseline revenue / non-Baseline volumes) + gas commodity rate)

or;

(($563,228,638 / 743,220,847 therms) + $0.42840) = **$1.18623**

Therefore, the calculated Tier differential is: $1.18623 / $1.12505 = **1.05.**

[224] Response to data request ORA-11 Q.2(a).

[225] Appendix A, Section II.B.2. item I, D.09-11-006

[226] Response to data request ORA-11 Q.2(a).

In the same response, the SoCalGas explains why the calculated tier differential of 1.05 is lower than the target of 1.15:[227]

> This figure is lower than the target tier differential of 1.15 because 1.15 represents an upper limit such that the BL and NBL rate differential is no more than $0.26 per therm. At the current tier differential of 1.05, we reached the $0.26 per therm rate difference cap.

SoCalGas explains that the proposed tier differential calculation is an attempt to simplify the understanding of what the tier differential represents, which should measure the difference between residential baseline and non-baseline rates.[228] The response to ORA explicitly states that the proposal **does not make any changes to the currently approved rate methodology**, that refers to the 1.15 target ratio and the difference cap of $0.26 per therm, will not be changed.[229] SoCalGas states that its proposal continues the current methodology that already includes the commodity rate in the calculation.[230] SoCalGas states the actual rates are unaffected by the proposal.[231] When asked to confirm whether it is SoCalGas' proposal to keep the target ratio at 1.15, SoCalGas answered in the affirmative but states that the effective ratio will be lower than the target ratio when the rate differential of $0.26 per therm becomes the binding constraint.[232] SoCalGas also explains that the proposed simplification of the tier differential calculation will avoid the "unnecessary step" of calculating a composite baseline rate.[233]

ORA understands from the above responses that the following specific elements are not proposed to be changed: (1) the approved methodology for the

[227] Id.

[228] Id.

[229] Id.

[230] Response to data request ORA-11 Q.3 (g).

[231] Response to data request ORA-11 Q.3(f).

[232] Response to data request ORA-11 Q.3(e).

[233] Id.

SoCalGas residential rate tier differential; (2) the tier differential ratio of 1.15; and (3) the difference cap of $0.26 per therm.

Notwithstanding the above and SoCalGas' response that the actual rates are unaffected by the proposal, ORA remains concerned about the exclusion of the customer charge from the baseline rate calculation for purposes of the composite tier differential, given that a composite rate would no longer be needed to be calculated.[234] By avoiding the allegedly "unnecessary step" of the composite baseline rate calculation, the proposed methodology would minimize, if not entirely eliminate, the relevance of the composite baseline rate in the tier differential which "simply determines the percentage difference between the baseline and non-baseline rates."[235] While taking the simple percentage difference between the baseline and non-baseline rates may provide a simple, more direct and straightforward calculation, this proposed change does not satisfy the requirements of Public Utilities Code section 739.7 which states:[236]

> In establishing residential rates, the commission shall retain an appropriate inverted rate structure. If the commission increases baseline rates pursuant to Section 739, revenues resulting from those increases shall be used exclusively to reduce nonbaseline residential rates.

SoCalGas mentioned section 739.7 in a footnote but did not provide sufficient explanation regarding compliance beyond the mention of the required inverted rate structure.[237] Inverted rates mean that the first tier or the baseline tier rate should be lower than the second tier rate. When a customer charge exists, the Commission has in the past typically included the customer charge as part of the first tier in determining whether there is an appropriate inverted rate structure.

The Applicants did not demonstrate how the proposed change would result in an inverted rate structure even when the customer charge is included as part of the tier differential calculation. ORA's calculation follows the current

[234] Response to data request ORA-11 Q.3(f).

[235] Id.

[236] Public Utilities Code section 739.7 (*Repealed and added by Stats. 1992, Ch. 1040, Sec. 4. Effective January 1, 1993.)*

[237] Bonnett Revised Testimony, p. 4.

calculation for the composite baseline rate as explained by SoCalGas in response to data request ORA-11 Q.2(a). SoCalGas' proposed numbers from this data response result in a calculated tier differential of approximately 0.90.[238] Based on this result, the first tier rate is greater than the second tier rate, which is contrary to the inverted rate structure required in Public Utilities Code section 739.7.

It would be appropriate to include the customer charges in the calculation of baseline rates as the Commission explains in its discussion of these issues in D.87-12-039:[239]

> Among the utilities in this proceeding, only SoCal presently imposes a residential customer charge. The issues raised during this proceeding concern the imposition of new customer charges, the increase of present customer charges, and the question of whether to include customer charges in the calculation of baseline rates. The issue of whether customer charges must be considered in the calculation of the baseline rate is so well settled that it requires no further discussion. Our current policy will continue.

The Commission states in D.93-06-087 that the 15% tier differential strikes a reasonable balance between ratemaking goals and the mandated inverted rates:[240]

> A 15% tier differential strikes a reasonable balance between our ratemaking goals and the legislative mandate for an inverted residential rate structure.

If ORA's recommendation regarding the minimum bill for SDG&E is adopted, and a simple tier ratio is likewise adopted, then the minimum bill revenues should be excluded in the calculation of the ratio. This is consistent with how the Commission adopted a proposal in D.93-06-087 to use a simple tier ratio calculation which excludes the minimum bill revenues:[241]

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[238] ORA's calculation uses the SoCalGas numbers for the gas commodity rate of $0.40277, the baseline rate of $0.31211, the non-baseline rate of $0.57211, the baseline volumes of 1,839,570 mth/yr, non-baseline volumes of 584,298 mth/yr, the proposed SoCalGas residential customer charge of $10/month, and SoCalGas customer numbers.

[239] D.87-12-039, p. 66.

[240] D.93-06-087, Finding of Fact # 34.

[241] D.93-06-087, Conclusion of Law # 7.

> We should [*245] adopt PG&E's proposal to use a simple tier ratio calculation which excludes minimum bill revenues.

In the past, there was a SoCalGas proposal to reduce the Tier I/Tier II rate differential from 41% to 35%. The Commission provided guidance on the important issue to consider in tier differential analysis as stated in D.94-12-052:[242]

> The important consideration in the tier differential analysis is the price signal that is sent to the customer when usage exceeds the Tier I level. Under SoCalGas' proposal, for a SoCalGas residential customer, the cost of the first therm in Tier II is 35% greater than the cost of the last therm in Tier I, the fact that the customer pays a customer charge notwithstanding. Such [*57] a price signal is exactly the same as the one received by residential customers served by PG&E and SDG&E, even though customers served by those utilities do not pay a customer charge. We agree with SoCalGas and DRA.

In the 1997 SoCalGas BCAP, the Commission explained why a composite tier differential calculation is more meaningful than a simple differential as it further states in D.97-04-082:[243]

> Therefore, we should retain the existing tier differential calculated on a composite basis. The composite tier differential is more meaningful than the simple differential because it gives the price for access and purchase of a quantity of gas that covers basic needs.

Based on the foregoing, ORA recommends the Commission keep the currently adopted residential rate tier differential calculation for SoCalGas.

3. ORA's Recommended Gas Transportation Rates

ORA's rate recommendations are based on the NCO method for marginal customer costs and reflect the SoCalGas' and SDG&E's proposed customer and throughput forecast which ORA does not oppose.[244] In addition, ORA's rate recommendations would keep the current SoCalGas residential customer charge at $5.00 per month and would provide for a minimum bill to SDG&E residential customers in the amount of $3.00 per month. In contrast, the Applicants' rate

[242] D.94-12-052 (1994 Cal. PUC LEXIS 1059, *; 58 CPUC2d 306).

[243] D.97-04-082, p. 118.

[244] See ORA Exhibit 2 on ORA's testimony on Applicants' customer and demand forecast.

proposals are based on the Rental method and include a proposed doubling from $5 to $10 per month in the residential customer charge for SoCalGas and the proposed implementation of a new residential customer charge of $10 per month for SDG&E, which is currently $0.

Before showing ORA's recommended gas transportation rates, it should be explained that Tables 1 and 2 of Mr. Bonnett's testimony show the Applicants' illustrative proposed class average rates in this rate case. The last column of Tables 1 and 2 indicate negative rates of change between the Applicants' proposed rates and the rates in effect on 1/1/2015. In response to ORA discovery, SoCalGas and SDG&E explain that the class average rate reduction shown in Tables 1 and 2 of said testimony is solely attributable to the regulatory account balances as discussed in the testimonies of Mr. Ahmed and Ms. Niederle, respectively.[245] The review of the regulatory account balances are not part of this ORA exhibit. In order to obtain further clarification regarding the negative rates of change reflected in the last column of these tables, ORA requested additional information.[246]

Since the non-base margin with the regulatory accounts is allocated differently from the base margin, ORA is concerned that the impact of the regulatory account balances on rates could prevent viewing the real impact of the cost allocation on base margin rates that were fully based on the LRMC pricing. ORA found no caps or floors were applied in the Applicants' rate models. ORA understands that the rate model in this TCAP did not include any mechanisms to mitigate cost increases because of the projected rate decreases shown in Tables 1 and 2. Most of the rate decreases could be attributed to the regulatory account balances and to the proposed increased throughput to some extent.

ORA asked the Applicants to explain whether the percentage change to the class average shown in the last column of SoCalGas' Table 1 and SDG&E's Table 2 presented in Mr. Bonnet's Revised Testimony would still show negative rates of percentage change to the class average had the regulatory account

[245] Response to data request ORA-10 Q.5(d) and 5(f).

[246] Response to data request ORA-20 Q.1.

balances been hypothetically with zero or close to zero account balances. ORA also requested the Applicants provide in their rate model additional scenarios, including the regulatory account balances with zero or close to zero balances. In response to the ORA request, the Applicants state:[247]

> In response to ORA's request, SoCalGas and SDG&E kept the regulatory account balances unchanged from 1/1/15 rates. Thus, there is zero impact on proposed rates from the regulatory account balances. SoCalGas and SDG&E believe this was the intent behind the "with zero or close to zero account balances" portion of the question.

Based on this response, the regulatory account balances included in the additional scenario runs of the model were as of the date 1/1/15 to achieve a zero impact on the proposed rates from the regulatory account balances. All the additional scenarios in Response to ORA-20 had regulatory account balances as of the date 1/1/15 and were designated with numbers 12 through 15 in the model based on the assumptions described below:

> Scenario 12: Based on the Applicants' Proposal with Rental and increases to residential customer charges to $10/month for SoCalGas and $10 for SDG&E;
>
> Scenario 13: Based on the NCO, no RCA, but with the Applicants' proposed increases to residential customer charges;
>
> Scenario 14: Based on NCO with RCA and with the Applicants' increases to residential customer charges; and
>
> Scenario 15: Based on the Applicants' Proposal with Rental but no increases to residential customer charges.

The scenarios created in the model allow the Commission to see the impact of the cost allocation on rates without the impact of the regulatory account balances coming into play. Scenario 12 represents the Applicants' primary proposal based on the Rental method. The results for Scenario 12, which served

[247] Response to data request ORA-20 Q.1(a).

as the basis for Table 1 in Mr. Bonnett's Testimony, indicate that a number of rates would continue to experience a rate decrease, including those for the residential class shown with -2% change.[248] Scenario 12 indicates that rate decreases could range from -2% to -36%. As shown in the results for the Scenario 12 run of the model for SoCalGas, there are now 4 rate classifications that could see rate increases instead of decreases previously shown in Table 1 of Mr. Bonnett's testimony. These include the EG-D Tier 2 post SW with 2%, the TLS-CI CA Rate (w/ csitma & carb adders) with 10%, and the TLS-EG CA Rate (w/ carb adder) with 13%, and the BTS w/ BTBA with a 19% change compared to the class average rates on 1/1/15.[249] The only rate classification with neither a positive nor negative percent change compared to 1/1/15 class average rates is the Gas Engine class, with 0% change indicated in Table 1.

Based on Scenario 12, the results for SDG&E in Table 2 of Mr. Bonnett's testimony indicate that there are five (5) rate classifications that could continue to see rate decreases ranging from -3% through -25%. Scenario 12 also shows there are now four (4) rate classifications that could see rate increases instead of decreases previously shown in Table 2. The rate classifications that could experience rate increases include: the Residential with 1%, EG-D Tier 2 post-SW with 2%, TLS-CI CA Rate (w/ csitma & carb adders) with 9%, and TLS-EG CA Rate (w/ carb adder) with 13%.[250] The "SW" is an acronym to denote the term, "Sempra-wide". ORA provides a brief background below to explain the term Sempra-wide.

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[248] Id.

[249] Response to data request ORA-20 Q.1(a). Response to data request ORA-10 explained the rate classifications: An EG-D Tier 2 customer is an electric generation customer who receives gas from the distribution system and who uses less than 3 million therms per year whereas an EG-D tier 2 customer is an electric generation customer connected to the distribution system who uses greater than 3 million therms per year. TLS-CI CA Rate and TLS_EG CA Rate refers to Transmission Level Service customers, either commercial/industrial or electric generation, who utilize the class average rate schedule. The rate adders are the California Solar Initiative Thermal Program Memorandum Account (CSITPMA) and California Air Resources Board (CARB) fees. EG customers are exempt from paying the CSITMA adder pursuant to ordering paragraph 16 of D.10-01-022.

[250] Response to data request ORA-20 Q.1(a).

Electric generator ("EG") customers of both SoCalGas and SDG&E have a single Sempra-wide EG rate. The Sempra-wide EG rate was adopted by the Commission in D.00-04-060 to address what was perceived to be a mismatch between the pricing of gas transportation service and the pricing of electricity in then emerging competitive markets.[251] In that decision, the Commission expressed concern that higher rates for EG service in the SDG&E territory compared to those in SoCalGas create a disincentive to build new generation in SDG&E territory. The Sempra-wide EG rate approach reduces gas and electric costs to SDG&E's customers. These rates include transmission, distribution, customer-related, and non-margin costs for both utilities.

The Applicants describe EG rate tiers as follows: "an EG-D tier 1 customer is an electric generation customer who receives gas from the distribution system and who uses less than 3 million therms per year whereas an EG-D tier 2 customer is an electric generation customer connected to the distribution system who uses greater than 3 million therms per year."[252]

In addition, Applicants explain the TLS-CI CSITMA and CARB category:[253]

> These customers are Transmission Level Service customers, either commercial/industrial or electric generation, who utilize the class average rate schedule. The rate adders are the California Solar Initiative Thermal Program Memorandum Account (CSITPMA) and California Air Resources Board (CARB) fees. EG customers are exempt from paying the CSITMA adder pursuant to ordering paragraph 16 of D.10-01-022.

The Applicants explain the reason behind the no rate increase observation the Gas Engine rate class:[254]

> The Gas Engine rate currently contains a rate cap which was established in D.00-04-060. Thus, the proposed rates will continue to exceed the rate cap and the class average rate for these customers will remain unchanged. The non-negative rate for the EG-D Tier 2 post SW customer was addressed in the revised

[251] D.00-04-060, Findings of Fact # 34, 38, and 39.

[252] Response to data request ORA-10 Q.5 (a).

[253] Response to data request ORA-10 Q.5 (b).

[254] Response to data request ORA-10 Q5 (e).

testimony of SoCalGas and SDG&E on November 19th and the current class average rate is similar to the rates of the other customer classes. The BTS rate increase is due to increased demand and transmission costs discussed in the testimony of Ms. Fung.

To see the impact of the NCO method on rates versus the Rental method with zero impact from the regulatory account balances, the Commission should compare Scenario 12 and Scenario 13, a comparison which is provided in Response 20.[255] Both Scenario 12 and Scenario 13 include the Applicants' proposed increases to residential customer charges. To see the impact of the Rental method without the proposed increases to residential customer charges, and with zero impact from the regulatory account balances, the Commission should compare Scenario 12 and Scenario 15. Both Scenarios 12 and 13 for SoCalGas and SDG&E are provided in the succeeding tables while Scenario 15 is available in the workpapers for Response 20.

The foregoing discussion explains the impact of the regulatory account balances on the percentage decreases shown in Tables 1 and 2 of Mr. Bonnett's testimony. The scenarios described in the foregoing allow one to see the real impact of the cost allocation on the BM.

In addition to the regulatory account balances, the forecast throughput volumes are also expected to increase for certain classes such as the residential class. The proposed increase in throughput for the residential class compared to those under the present rates also contributes to the rate decreases projected for the residential class under Scenario 12 shown in Table PZS12.

[255] See ORA Attachments and Workpapers to this ORA-03 Exhibit included in the submission.

Table PZS 12

SoCalGas Natural Gas Transportation Rates Without Regulatory Account Change Rental Method

	SCENARIO 12	Present Rates			Proposed Rates			Changes		
		Jan-1-15 Volumes Mth	Average Rate $/therm	Jan-1-15 Revenues $000's	Jan-1-17 Volumes Mth	Proposed Rate $/therm	Jan-1-17 Revenues $000's	Revenue Change $000's	Rate Change $/therm	% Rate change %
		A	B	C	D	E	F	G	H	I
1	CORE									
2	Residential	2,337,534	$0.71570	$1,672,983	2,435,160	$0.69928	$1,702,865	$29,882	($0.01642)	-2.3%
3	Commercial & Industrial	984,102	$0.33979	$334,392	1,023,186	$0.28266	$289,213	($45,179)	($0.05713)	-16.8%
4										
5	NGV - Pre SempraWide	117,220	$0.13363	$15,665	157,095	$0.13560	$21,303	$5,638	$0.00197	1.5%
6	SempraWide Adjustment	117,220	$0.00867	$1,016	157,095	$0.00295	$463	($553)	($0.00572)	-66.0%
7	NGV - Post SempraWide	117,220	$0.14230	$16,681	157,095	$0.13855	$21,766	$5,085	($0.00375)	-2.6%
8										
9	Gas A/C	825	$0.14108	$116	772	$0.13219	$102	($14)	($0.00889)	-6.3%
10	Gas Engine	16,774	$0.12163	$2,040	20,699	$0.12163	$2,518	$477	$0.00000	0.0%
11	Total Core	3,456,455	$0.58621	$2,026,212	3,636,911	$0.55444	$2,016,463	($9,749)	($0.03177)	-5.4%
12										
13	NONCORE COMMERCIAL & INDUSTRIAL									
14	Distribution Level Service	893,164	$0.06968	$62,239	865,102	$0.06196	$53,605	($8,634)	($0.00772)	-11.1%
15	Transmission Level Service (2)	654,456	$0.01804	$11,806	660,238	$0.00000	$0	($11,806)	($0.01804)	-100.0%
16	Total Noncore C&I	1,547,620	$0.04784	$74,045	1,525,339	$0.04377	$66,763	($7,282)	($0.00408)	-8.5%
17										
18	NONCORE ELECTRIC GENERATION									
19	Distribution Level Service									
20	Pre Sempra Wide	333,969	$0.05403	$18,044	285,096	$0.06128	$17,472	($572)	$0.00726	13.4%
21	Sempra Wide Adjustment	333,969	($0.00910)	($3,041)	285,096	($0.01007)	($2,871)	$170	($0.00097)	10.6%
22	Distribution Post Sempra Wide	333,969	$0.04492	$15,003	285,096	$0.05121	$14,601	($402)	$0.00629	14.0%
23	Transmission Level Service (2)	2,641,080	$0.01487	$39,270	2,392,699	$0.00000	$0	($39,270)	($0.01487)	-100.0%
24	Total Electric Generation	2,975,049	$0.01824	$54,273	2,677,795	$0.02049	$54,872	$599	$0.00225	12.3%
25										
26	TOTAL RETAIL NONCORE	4,522,669	$0.02837	$128,318	4,203,134	$0.02894	$121,635	($6,683)	$0.00057	2.0%
27										
28	WHOLESALE									
29	Wholesale Long Beach (2)	92,897	$0.01453	$1,350	73,520	$0.01648	$1,212	($138)	$0.00195	13.4%
30	Wholesale SWG (2)	67,209	$0.01453	$977	65,367	$0.01648	$1,077	$101	$0.00195	13.4%
31	Wholesale Vernon (2)	87,906	$0.01453	$1,278	95,137	$0.01648	$1,568	$291	$0.00195	13.4%
32	International (2)	69,979	$0.01453	$1,017	91,378	$0.01648	$1,506	$489	$0.00195	13.4%
33	Total Wholesale & International	317,990	$0.01453	$4,622	325,403	$0.01648	$5,364	$742	$0.00195	13.4%
34	SDGE Wholesale	1,247,558	$0.01258	$15,692	1,251,556	$0.01617	$20,240	$4,549	$0.00359	28.6%
35	Total Wholesale Incl SDGE	1,565,548	$0.01298	$20,313	1,576,959	$0.01624	$25,604	$5,290	$0.00326	25.1%
36										
37	TOTAL NONCORE	6,088,217	$0.02441	$148,631	5,780,093	$0.02547	$147,239	($1,393)	$0.00106	4.3%
38										
39	Unbundled Storage (4)			$26,476			$17,020	($9,456)		
40	System Total (w/o BTS)	9,544,672	$0.23063	$2,201,319	9,417,004	$0.23157	$2,180,722	($20,597)	$0.00094	0.4%
41	Backbone Trans. Service BTS (3)	2,809	$0.15777	$161,782	0	#DIV/0!	$202,692	$40,910	#DIV/0!	#DIV/0!
42	**SYSTEM TOTALw/BTS**	**9,544,672**	**$0.24758**	**$2,363,102**	**9,417,004**	**$0.25310**	**$2,383,414**	**$20,312**	**$0.00551**	**2.2%**
43										
44	EOR Revenues	203,920	$0.03081	$6,283	231,570	$0.03712	$8,597	$2,313	$0.00631	20.5%
45	Total Throughput w/EOR Mth/yr	9,748,592			9,648,574					

1) These rates are for Natural Gas Transportation Service from "Citygate to Meter". The BTS rate is for service from Receipt Point to Citygate.
2) These Transmission Level Service "TLS" amounts represent the average transmission rate, see Table 7 or detail list of TLS rates.
3) BTS charge ($/dth/day) is proposed as a separate rate. Core will pay through procurement rate, noncore as a separate charge.
4) Unbundles Storage costs are not part of the Core Storage or Load Balancing functions (those are included in transport rates).

Table PZS13

SDG&E Natural Gas Transportation Rates Without Regulatory Account Change Rental Method

2016 TCAP Phase II Application w/o Reg. Acct. chg. Rental Method										
SCENARIO 12		Present Rates			Proposed Rates			Changes		
	Customer	Jan1-15 Volumes Mth	Average Rate $/therm	Jan1-15 Revenues $000s	Jan1-17 Volumes Mth	Proposed Rate $/therm	Jan1-17 Revenues $000s	Revenue Change $000	Rate Change $/therm	% Rate Change %
		A	B	C	D	E	F	G	H	I
1	**CORE**									
2	Residential	321,869	$0.92062	$296,319	319,982	$0.92960	$297,456	$1,138	$0.00898	1.0%
3	Com & Industrial	177,578	$0.34893	$61,962	182,660	$0.30943	$56,521	($5,442)	($0.03950)	-11.3%
4										
5	NGV Pre SWide	11,417	$0.24253	$2,769	18,501	$0.19269	$3,565	$796	($0.04983)	-20.5%
6	SWide Adj	11,417	($0.08949)	($1,022)	18,501	($0.02516)	($466)	$556	$0.06432	-71.9%
7	NGV Post SWide	11,417	$0.15304	$1,747	18,501	$0.16753	$3,100	$1,352	$0.01449	9.5%
8										
9	Total CORE	510,864	$0.70474	$360,028	521,144	$0.68518	$357,076	($2,952)	($0.01957)	-2.8%
10										
11	**NONCORE C & I**									
12	Distrib Level Serv	25,161	$0.05420	$1,364	27,807	$0.04045	$1,125	($239)	($0.01375)	-25.4%
13	Transm Level Serv (2)	13,582	$0.01901	$258	17,168	$0.02078	$357	$99	$0.00177	9.3%
14	Total Noncore C&I	38,743	$0.04186	$1,622	44,975	$0.03294	$1,481	($140)	($0.00892)	-21.3%
15										
16	**NONCORE ELECTRIC GEN**									
17	Distrib Level Serv									
18	Pre SWide	103,761	$0.01729	$1,794	95,807	$0.01771	$1,696	($98)	$0.00042	2.4%
19	SWide Adj	103,761	$0.02947	$3,058	95,807	$0.03014	$2,887	($170)	$0.00067	2.3%
20	Distrib Level post SW	103,761	$0.04676	$4,852	95,807	$0.04784	$4,584	($268)	$0.00108	2.3%
21	Transm Level Serv (2)	577,118	$0.01461	$8,431	574,075	$0.01656	$9,504	$1,073	$0.00195	13.3%
22	Total Electric Gen	680,879	$0.01951	$13,283	669,882	$0.02103	$14,087	$805	$0.00152	7.8%
23										
24	**TOTAL NONCORE**	719,622	$0.02071	$14,904	714,857	$0.02178	$15,569	$664	$0.00107	5.2%
25										
26	**SYSTEM TOTAL**	**1,230,486**	**$0.30470**	**$374,933**	**1,236,000**	**$0.30149**	**$372,645**	**($2,287)**	**($0.00321)**	**-1.1%**

1) These rates are for Natural Gas Transportation Service from "Citygate to Meter". The BTS rate is for service from Receipt Point to Citygate.
BTS is a SoCalGas tariff and service is purchased from SoCalGas.

2) Average transmission level service rate is shown here, see Rate Table 6 for detail list of TLS rates.

3) All rates include Franchise Fees & Uncollectible charges.

Table PZS 14

SoCalGas Natural Gas Transportation Rates Without Regulatory Account Change NCO No RCA

2016 TCAP Phase II Application w/o Reg. Acct. chg. w/ NCO no RCA

	SCENARIO 13	Present Rates			Proposed Rates			Changes		
	Customer	Jan1-15 Volumes Mth	Average Rate $/therm	Jan1-15 Revenues $000s	Jan1-17 Volumes Mth	Proposed Rate $/therm	Jan1-17 Revenues $000s	Revenue Change $0	Rate Change $/therm	% Rate Change %
		A	B	C	D	E	F	G	H	I
1	CORE									
2	Residential	2,337,534	$0.72	$1,672,983	2,435,160	$0.68	$1,655,375	($17,608)	($0.04)	-5.00%
3	Com & Industrial	984,102	$0.34	$334,392	1,023,186	$0.31	$317,524	($16,868)	($0.03)	-8.70%
4										
5	NGV - Pre SWide	117,220	$0.13	$15,665	157,095	$0.16	$24,605	$8,941	$0.02	17.20%
6	SWide Adj	117,220	$0.01	$1,016	157,095	$0.00	$349	($667)	($0.01)	-74.30%
7	NGV Post SWide	117,220	$0.14	$16,681	157,095	$0.16	$24,955	$8,274	$0.02	11.60%
8										
9	Gas A/C	825	$0.14	$116	772	$0.15	$117	$0	$0.01	7.00%
10	Gas Engine	16,774	$0.12	$2,040	20,699	$0.12	$2,518	$477	$0.00	0.00%
11	Total Core	3,456,455	$0.59	$2,026,212	3,636,911	$0.55	$2,000,488	($25,724)	($0.04)	-6.20%
12										
13	NONCORE C & I									
14	Distrib Level Service	893,164	$0.07	$62,239	865,102	$0.07	$61,412	($827)	$0.00	1.90%
15	Transm Level Serv (2)	654,456	$0.02	$11,806	660,238	$0.02	$12,915	$1,109	$0.00	8.40%
16	Total Noncore C&I	1,547,620	$0.05	$74,045	1,525,339	$0.05	$74,327	$282	$0.00	1.80%
17										
18	NONCORE EG									
19	Distrib Level Serv									
20	Pre SWide	333,969	$0.05	$18,044	285,096	$0.09	$24,711	$6,667	$0.03	60.40%
21	SWide Adj	333,969	($0.01)	($3,041)	285,096	($0.01)	($3,673)	($633)	($0.00)	41.50%
22	Distrib Post SWide	333,969	$0.04	$15,003	285,096	$0.07	$21,038	$6,034	$0.03	64.30%
23	Transm Level Serv (2)	2,641,080	$0.01	$39,270	2,392,699	$0.02	$39,390	$120	$0.00	10.70%
24	Total Electric Gen	2,975,049	$0.02	$54,273	2,677,795	$0.02	$60,428	$6,155	$0.00	23.70%
25										
26	TOTAL RETAIL NONCORE	4,522,669	$0.03	$128,318	4,203,134	$0.03	$134,755	$6,436	$0.00	13.00%
27										
28	WHOLESALE									
29	Whsale Long Bch (2)	92,897	$0.01	$1,350	73,520	$0.02	$1,185	($165)	$0.00	10.90%
30	Whsale SWG (2)	67,209	$0.01	$977	65,367	$0.02	$1,053	$77	$0.00	10.90%
31	Whsale Vernon (2)	87,906	$0.01	$1,278	95,137	$0.02	$1,533	$255	$0.00	10.90%
32	International (2)	69,979	$0.01	$1,017	91,378	$0.02	$1,473	$455	$0.00	10.90%
33	Total Whsale & Interntnl	317,990	$0.01	$4,622	325,403	$0.02	$5,244	$622	$0.00	10.90%
34	SDGE Whsale	1,247,558	$0.01	$15,692	1,251,556	$0.02	$19,483	$3,792	$0.00	23.80%
35	Total Whsale Incl SDGE	1,565,548	$0.01	$20,313	1,576,959	$0.02	$24,727	$4,414	$0.00	20.80%
36										
37	TOTAL NONCORE	6,088,217	$0.02	$148,631	5,780,093	$0.03	$159,482	$10,850	$0.00	13.00%
38										
39	Unbundled Storage (4)			$26,476			$17,020	($9,456)		
40	System Total (w/o BTS)	9,544,672	$0.23	$2,201,319	9,417,004	$0.23	$2,176,990	($24,330)	$0.00	0.20%
41	BTS (3)	2,809	$0.16	$161,782	2,818	$0.20	$202,692	$40,910	$0.04	24.90%
42	**SYSTEM TOTALw/BTS**	**9,544,672**	**$0.25**	**$2,363,102**	**9,417,004**	**$0.25**	**$2,379,682**	**$16,580**	**$0.01**	**2.10%**
43										
44	EOR Revenues	203,920	$0.03	$6,283	231,570	$0.05	$11,669	$5,386	$0.02	63.50%
45	Total Throughput w/EOR Mth/yr	9,748,592			9,648,574					

1) These rates are for Natural Gas Transportation Service from "Citygate to Meter". The BTS rate is for service from Receipt Point to Citygate.

2) These Transmission Level Service "TLS" amounts represent the average transmission rate, see Table 7 or detail list of TLS rates.

3) BTS charge ($/dth/day) is proposed as a separate rate. Core will pay through procurement rate, noncore as a separate charge

4) Unbundles Storage costs are not part of the Core Storage or Load Balancing functions (those are included in transport rates).

Table PZS15
SDG&E Natural Gas Transportation Rate Without Regulatory Account Change NCO NO RCA

2016 TCAP Phase II Application w/o Reg. Acct. chg. w/ NCO no RCA										
SCENARIO 13		Present Rates			Proposed Rates			Changes		
	Customer	Jan1-15 Volumes Mth	Average Rate $/therm	Jan1-15 Revenues $000s	Jan1-17 Volumes Mth	Proposed Rate $/therm	Jan1-17 Revenues $000s	Revenue Change $000	Rate Change $/therm	% Rate Change %
		A	B	C	D	E	F	G	H	I
1	**CORE**									
2	Residential	321,869	$0.92062	$296,319	319,982	$0.89158	$285,290	($11,029)	($0.02904)	-3.2%
3	Com & Industrial	177,578	$0.34893	$61,962	182,660	$0.36119	$65,975	$4,012	$0.01226	3.5%
4										
5	NGV Pre SWide	11,417	$0.24253	$2,769	18,501	$0.20697	$3,829	$1,060	($0.03555)	-14.7%
6	SWide Adj	11,417	($0.08949)	($1,022)	18,501	($0.01899)	($351)	$670	$0.07050	-78.8%
7	NGV Post SWide	11,417	$0.15304	$1,747	18,501	$0.18798	$3,478	$1,731	$0.03494	22.8%
8										
9	Total CORE	510,864	$0.70474	$360,028	521,144	$0.68070	$354,742	($5,286)	($0.02404)	-3.4%
10										
11	**NONCORE C & I**									
12	Distrib Level Serv	25,161	$0.05420	$1,364	27,807	$0.06547	$1,821	$457	$0.01127	20.8%
13	Transm Level Serv (2)	13,582	$0.01901	$258	17,168	$0.02041	$350	$92	$0.00140	7.4%
14	Total Noncore C&I	38,743	$0.04186	$1,622	44,975	$0.04827	$2,171	$549	$0.00641	15.3%
15										
16	**NONCORE EG**									
17	Distrib Level Serv									
18	Pre S Wide	103,761	$0.01729	$1,794	95,807	$0.02751	$2,636	$842	$0.01022	59.1%
19	S Wide Adj	103,761	$0.02947	$3,058	95,807	$0.03855	$3,694	$636	$0.00909	30.8%
20	Distrib Level post SW	103,761	$0.04676	$4,852	95,807	$0.06607	$6,330	$1,478	$0.01931	41.3%
21	Transm Level Serv (2)	577,118	$0.01461	$8,431	574,075	$0.01619	$9,292	$862	$0.00158	10.8%
22	Total Electric Gen	680,879	$0.01951	$13,283	669,882	$0.02332	$15,622	$2,340	$0.00381	19.5%
23										
24	**TOTAL NONCORE**	719,622	$0.02071	$14,904	714,857	$0.02489	$17,793	$2,889	$0.00418	20.2%
25										
26	**SYSTEM TOTAL**	**1,230,486**	**$0.30470**	**$374,933**	**1,236,000**	**$0.30140**	**$372,536**	**($2,397)**	**($0.00330)**	**-1.1%**

1) These rates are for Natural Gas Transportation Service from "Citygate to Meter". The BTS rate is for service from Receipt Point to Citygate. BTS is a SoCalGas tariff and service is purchased from SoCalGas.

2) Average transmission level service rate is shown here, see Rate Table 6 for detail list of TLS rates.

3) All rates include Franchise Fees & Uncollectible charges.

ORA's rate recommendations are based on the NCO method without an explicit replacement cost adder. ORA recommends keeping the current SoCalGas residential customer charge at $5 per month instead of the SoCalGas proposed increases to the residential customer charge to $10 per month. ORA recommends a new residential minimum bill of $3 per month instead of SDG&E's proposed implementation of a new residential customer charge of $10 per month.

ORA's rate recommendations are provided in the succeeding tables which were created based on responses to data request ORA-18. In response to ORA-18, the Applicants provided ORA with the cost allocation and rate design model scenario runs of the SoCalGas and SDG&E 2017 TCAP and the corresponding results and active Excel spreadsheets based on the following ORA assumptions:[256]

> The marginal customer-related capital costs are developed using the New Customer Only (NCO) approach based on the NCO numbers presented by SoCalGas and SDG&E in the application <u>without</u> a replacement cost adder. Assume customer and demand forecast and the transmission and storage embedded cost numbers are based on the Applicants' proposed numbers. In addition, continue to assume the authorized base margin used in the Applicants' Revised Workpapers in this TCAP.
>
> i. With increases in customer charges as proposed by the Applicants;
>
> ii. Without any increases in the current customer charges by the Applicants.

Applicants created seven (7) extra scenarios in addition to the original 4 scenarios in their rate model in response to ORA-18.[257] The Applicants' Proposal with the Rental method is Scenario 3 (with residential customer charge increases) while the Applicants' Proposal with the Rental method without any increases to the residential customer charge is Scenario 2. The scenario run designated as "Scenario 5" in the rate model in response to ORA-18 corresponds most closely to ORA's recommendation with the NCO method and no increases

[256] Response to data request ORA-18 Q.1(a).

[257] See ORA Attachments for Response to data request ORA-18 and Workpapers to this ORA-03 Exhibit included in the submission.

to the residential customer charge except that the $3 minimum bill amount recommended by ORA is not specifically spelled out in Scenario 5. The ORA recommended rates based on Scenario 5 runs are shown for both SoCalGas and SDG&E at the end of this exhibit in Tables PZS16 through Table PZS18.[258] The ORA rate recommendation for SDG&E is based on the original Scenario 5 (i.e., NCO, no residential customer charge change) that now should include a $3 residential minimum bill. The ORA rate recommendation in Scenario 5 is compared to a modified Scenario 5 that was modified to include a $3 residential customer charge instead of a $3 minimum bill for SDG&E. The purpose of the modified Scenario 5 is to show the impact of a $3 residential customer charge versus a $3 residential minimum bill. No changes were made to the SoCalGas residential customer charge in the modified Scenario 5.

The estimated class average residential monthly bills for SoCalGas and SDG&E are presented in Table PZS19 and Table PZS20 under four scenarios, namely: Modified Scenario 5, Original Scenario 5, Applicants' Proposed Scenario 3, and Applicants' Proposed Scenario 2. Table PZS19 shows the estimated class average residential monthly bills for SoCalGas. Table PZS20 shows the estimated class average residential monthly bills for SDG&E.

Table PZS20 shows the monthly bills for the ORA modified Scenario 5 in column A for SDG&E. For purposes of comparison, the modified Scenario 5 in column A for SDG&E includes a $3 residential customer charge, instead of a $3 residential minimum bill. In contrast, in column B of Table PZS20, the original Scenario 5 does not include any residential customer charge. Under the original Scenario 5, the residential customer would pay only the $3 minimum bill for usage anywhere from zero to a usage level below the baseline. At baseline usage, the residential customer will pay the baseline rate instead of the $3 minimum bill. At a usage level in excess of the baseline, the residential customer will pay the nonbaseline rate in addition to the baseline rate for baseline usage.

[258] The original Scenario 5 run is included in ORA's workpapers for this Exhibit and available in the Excel folder marked Response to ORA-18 Q.1 aii UnModified Scen5. The Modified Scenario 5 run is included also in the folder marked Response to ORA-18 Q.1 aii Modified Scen5.

The difference between modified Scenario 5 and the original Scenario 5 is in the treatment of the $3. Under the modified Scenario 5, the $3 is a residential customer charge which is a fixed charge that has to be paid regardless of the amount of usage. Based on this scenario, the residential customer has to pay the $3 residential customer charge in addition to any baseline usage and nonbaseline usage.

In Table PZS21 ORA provides a summary of the estimated rates under the selected scenarios 2, 3, and 5. ORA shows in Table PZS21 that Original Scenario 5 with the $3 residential minimum bill has the same amount of average rate as the Modified Scenario 5 with the $3 residential customer charge. As explained above, the $3 residential customer charge is a fixed charge regardless of use and is an add-on to the baseline and the nonbaseline rates as applicable. On the other hand, the $3 residential minimum bill would apply only to those who use anywhere from zero to a level below the baseline rate. If usage is at baseline or greater, the $3 minimum bill does not apply.

4. Other Rate Design Proposals

The Applicants cite to previous Commission decisions in support of the request for the update to the submeter credit, the NGV compression costs, and the provision of the TLS Reservation Revenue Report.

D.14-06-007, Ordering Paragraph #7, which adopted the comprehensive rate design settlement where the current submeter credit for both SoCalGas and SDG&E were approved;

D.14-06-007, Ordering Paragraph #8, where the current NGV compression rate adder was approved.

D.14-06-007, Ordering Paragraph #7 and Attachment III, Section III.B.3.c. which required that the TLS Reservation Revenue Report be included in this TCAP.

To the extent that the update to the submeter credit is impacted by the Applicants' calculation of the marginal customer capital-related cost which is based on the Rental method, ORA recommends that the update to the submeter credit instead be based on the NCO method as discussed herein.[259]

With respect to the Compression Rate Adder, the Applicants state:[260]

> A compression surcharge or Compression Rate Adder is intended to cover the cost of providing compressed natural gas (CNG) to motor vehicles fueling at public access CNG vehicle refueling stations owned and operated by the utility. The Compression Rate Adder is charged to customers on a volumetric or dollar-per-therm basis in addition to the Uncompressed Commodity Charge, which is based on the prevailing cost of the natural gas commodity and delivery charge. The Compression Rate Adder is meant to reflect the capital and operating costs of compressing the natural gas and providing public access to CNG fuel to operate NGVs. Additional state fuel tax, federal excise tax, and utility user taxes, which can vary by location, are also charged to customers….The NGV Compression Rate Adder has been updated to reflect current costs and proposed allocations of those costs. These costs are composed of a capital related revenue requirement related to public-access refueling equipment, including return on ratebase, and a "fully-loaded" revenue requirement related to operations and maintenance expenses.

The Applicants further state that the end goal of the cost allocation for the NGV Compression Adder is to reflect SoCalGas' and SDG&E's (referred to as "Companies" in the quote below) reasonable and fair cost of providing that NGV compression service to both their "Companies'" private fleet of NGVs and to "non-Company owned NGVs" (referred to as the public customers using NGV compression) so that there is no subsidy between the "Companies" and "non-Company owned NGVs":[261]

> The goal of this cost allocation methodology is to determine the volumetric based prices for the NGV Compression Rate Adder that reflect the Companies' reasonable and fair cost of providing that service to both the Companies' private fleet of NGVs, as well as to non-Company owned NGVs, *i.e.*, public customers, so that private

[259] See SCG 2017 TCAP Submeter Credit workpaper showing the calculations of avoided costs per subunit and incurred cost per master meter are derived based on SCG LRMC Customer Cost which are all based on the Rental method.

[260] Bonnett Revised Testimony, pp. 13-14.

[261] Bonnett Revised Testimony, p. 14.

NGV compression customers do not subsidize the public NGV compression users and vice versa.

It is unclear from the data presented in the Applicants' workpapers on the NGV Compression Rate Adder whether the NGV stations that primarily service SoCalGas' and SDG&E's NGV fleets were properly excluded from the calculation.[262] The data provides no breakdown by NGV stations and no clear separation between any identified NGV stations that primarily service the "Companies'" NGV fleets and those Company-owned NGV stations that provides public refueling service. The data on the NGV station rate base is presented as a total aggregate number value of "public access station" and "Total public & private access." The Applicants fail to show that only those stations identified as providing public access refueling equipment are included in the cost calculation. Without a clear showing on the absence of subsidy in the calculated numbers for the NGV compression adder, ORA is unable to verify that the update to the NGV compression rate adder is appropriate.

ORA agrees that the TLS Reservation Revenue Report is required to be included in this TCAP pursuant to D.14-06-007.

The Applicant proposes an Equal Cents Per Therm ("ECPT") allocation for the proposed System Operator Gas Account ("SOGA").[263] The proposed SOGA was presented in the testimony of Mr. Ahmed.[264] In Mr. Ahmed's testimony, he states that the proposed SOGA is based on another proposal which was presented by Mr. Borkovich for the Applicants in relation to a proposed modification of Rule 41.[265] ORA does not take a position on the proposed allocation method for the SOGA since it would be premature to assume the approval of the underlying request for modification of Rule 41 at this time.

[262] SCG and SDG&E 2017 TCAP NGV Compression Rate Adder Excel file.

[263] Bonnett Revised Testimony, pp. 15-16.

[264] Mr. Ahmed Testimony for SoCalGas and SDG&E in A.15-07-014, p. 19.

[265] Ahmed Testimony, p. 19.

VI. CONCLUSION

Based on the foregoing, ORA respectfully recommends the Commission adopt the conclusions and recommendations as discussed herein.

Table PZS 16

SoCalGas Natural Gas Transportation Rates

ORA Recommendation on SoCalGas

2016 TCAP Phase II Application w/NCO Method No RCA, No Change in Res Customer Charge

SCENARIO 5		**Present Rates**			**Proposed Rates**			**Changes**		
	Customer	Jan1-15 Volumes Mth	Average Rate $/therm	Jan1-15 Revenues $000s	Jan1-17 Volumes Mth	Proposed Rate $/therm	Jan1-17 Revenues $000s	Revenue Change $0	Rate Change $/therm	% Rate Change %
		A	B	C	D	E	F	G	H	I
1	CORE									
2	Residential	2,337,534	$0.72	$1,672,983	2,435,160	$0.63	$1,527,365	($145,618)	($0.09)	-12.40%
3	Com & Industrl	984,102	$0.34	$334,392	1,023,186	$0.27	$274,377	($60,015)	($0.07)	-21.10%
4										
5	NGV - Pre SWide	117,220	$0.13	$15,665	157,095	$0.12	$18,714	$3,049	($0.01)	-10.90%
6	SWide Adj	117,220	$0.01	$1,016	157,095	($0.01)	($1,244)	($2,260)	($0.02)	-191.40%
7	NGV Post SWide	117,220	$0.14	$16,681	157,095	$0.11	$17,469	$789	($0.03)	-21.90%
8										
9	Gas A/C	825	$0.14	$116	772	$0.11	$87	($29)	($0.03)	-19.80%
10	Gas Engine	16,774	$0.12	$2,040	20,699	$0.12	$2,518	$477	$0.00	0.00%
11	Total Core	3,456,455	$0.59	$2,026,212	3,636,911	$0.50	$1,821,816	($204,396)	($0.09)	-14.50%
12										
13	NONCORE C & I									
14	Distrib Level Servi	893,164	$0.07	$62,239	865,102	$0.07	$58,454	($3,786)	($0.00)	-3.00%
15	TransmLevel Serv (2)	654,456	$0.02	$11,806	660,238	$0.02	$10,330	($1,476)	($0.00)	-13.30%
16	Total Noncore C&I	1,547,620	$0.05	$74,045	1,525,339	$0.05	$68,784	($5,261)	($0.00)	-5.70%
17										
18	NONCORE EG									
19	Distrib Level Serv									
20	Pre SWide	333,969	$0.05	$18,044	285,096	$0.08	$23,827	$5,784	$0.03	54.70%
21	SWide Adj	333,969	($0.01)	($3,041)	285,096	($0.02)	($4,603)	($1,563)	($0.01)	77.40%
22	DistribPost SWide	333,969	$0.04	$15,003	285,096	$0.07	$19,224	$4,221	$0.02	50.10%
23	TransmLevel Serv (2)	2,641,080	$0.01	$39,270	2,392,699	$0.01	$31,018	($8,252)	($0.00)	-12.80%
24	Total Electric Gen	2,975,049	$0.02	$54,273	2,677,795	$0.02	$50,242	($4,031)	$0.00	2.80%
25										
26	TOTAL RETAIL NONCORE	4,522,669	$0.03	$128,318	4,203,134	$0.03	$119,025	($9,293)	($0.00)	-0.20%
27										
28	WHOLESALE									
29	Whsale Long Bch(2)	92,897	$0.01	$1,350	73,520	$0.01	$937	($413)	($0.00)	-12.30%
30	Whsale SWG (2)	67,209	$0.01	$977	65,367	$0.01	$833	($144)	($0.00)	-12.30%
31	Whsale Vernon (2)	87,906	$0.01	$1,278	95,137	$0.01	$1,213	($65)	($0.00)	-12.30%
32	International (2)	69,979	$0.01	$1,017	91,378	$0.01	$1,165	$148	($0.00)	-12.30%
33	Total Whsale & Interntnl	317,990	$0.01	$4,622	325,403	$0.01	$4,147	($474)	($0.00)	-12.30%
34	SDGE Whsale	1,247,558	$0.01	$15,692	1,251,556	$0.01	$16,703	$1,012	$0.00	6.10%
35	Total Whsale Incl SDGE	1,565,548	$0.01	$20,313	1,576,959	$0.01	$20,851	$537	$0.00	1.90%
36										
37	TOTAL NONCORE	6,088,217	$0.02	$148,631	5,780,093	$0.02	$139,876	($8,755)	($0.00)	-0.90%
38										
39	Unbundled Storage (4)			$26,476			$17,020	($9,456)		
40	System Total (w/o BTS)	9,544,672	$0.23	$2,201,319	9,417,004	$0.21	$1,978,712	($222,607)	($0.02)	-8.90%
41	BTS (3)	2,809	$0.16	$161,782	2,818	$0.19	$192,350	$30,567	$0.03	18.50%
42	**SYSTEM TOTALw/BTS**	**9,544,672**	**$0.25**	**$2,363,102**	**9,417,004**	**$0.23**	**$2,171,062**	**($192,040)**	**($0.02)**	**-6.90%**
43										
44	EOR Revenues	203,920	$0.03	$6,283	231,570	$0.05	$10,477	$4,194	$0.01	46.80%
45	Total Throughput w/EOR Mth/yr	9,748,592			9,648,574					

1) These rates are for Natural Gas Transportation Service from "Citygate to Meter". The BTS rate is for service from Receipt Point to Citygate.

2) These Transmission Level Service "TLS" amounts represent the average transmission rate, see Table 7 or detail list of TLS rates.

3) BTS charge ($/dth/day) is proposed as a separate rate. Core will pay through procurement rate, noncore as a separate charge

4) Unbundles Storage costs are not part of the Core Storage or Load Balancing functions (those are included in transport rates).

Table PZS17
SDG&E Natural Gas Transportation Rates
ORA Recommendation on SDG&E

2016 TCAP Phase II Application w/NCO Method NO RCA, No Change in Res Customer Charge										
	SCENARIO 5	Present Rates			Proposed Rates			Changes		
	Customer	Jan1-15 Volumes Mth	Average Rate $/therm	Jan1-15 Revenues $000s	Jan1-17 Volumes Mth	Proposed Rate $/therm	Jan1-17 Revenues $000s	Revenue Change $000	Rate Change $/therm	% Rate Change %
		A	B	C	D	E	F	G	H	I
1	**CORE**									
2	Residential	321,869	$0.92062	$296,319	319,982	$0.70665	$226,114	($70,205)	($0.21397)	-23.2%
3	Com & Industrial	177,578	$0.34893	$61,962	182,660	$0.21295	$38,898	($23,064)	($0.13598)	-39.0%
4										
5	NGV Pre SWide	11,417	$0.24253	$2,769	18,501	$0.07049	$1,304	($1,465)	($0.17204)	-70.9%
6	SWide Adj	11,417	($0.08949)	($1,022)	18,501	$0.06764	$1,251	$2,273	$0.15713	-175.6%
7	NGV Post SWide	11,417	$0.15304	$1,747	18,501	$0.13813	$2,556	$808	($0.01491)	-9.7%
8										
9	Total CORE	510,864	$0.70474	$360,028	521,144	$0.51342	$267,568	($92,461)	($0.19132)	-27.1%
10										
11	**NONCORE COM & INDUSTRIAL**									
12	Distrib Level Serv	25,161	$0.05420	$1,364	27,807	$0.03840	$1,068	($296)	($0.01580)	-29.2%
13	Transm Level Serv (2)	13,582	$0.01901	$258	17,168	$0.01382	$237	($21)	($0.00519)	-27.3%
14	Total Noncore C&I	38,743	$0.04186	$1,622	44,975	$0.02901	$1,305	($317)	($0.01285)	-30.7%
15										
1	**NONCORE ELECTRIC GEN**									
17	Distrib Level Serv									
18	Pre SWide	103,761	$0.01729	$1,794	95,807	$0.01116	$1,069	($725)	($0.00613)	-35.4%
19	SWide Adj	103,761	$0.02947	$3,058	95,807	$0.04832	$4,629	$1,572	$0.01885	64.0%
20	Distrib Level post SW	103,761	$0.04676	$4,852	95,807	$0.05948	$5,699	$847	$0.01272	27.2%
21	Transm Level Serv (2)	577,118	$0.01461	$8,431	574,075	$0.01274	$7,313	($1,118)	($0.00187)	-12.8%
22	Total Electric Gen	680,879	$0.01951	$13,283	669,882	$0.01942	$13,011	($271)	($0.00008)	-0.4%
23										
24	**TOTAL NONCORE**	719,622	$0.02071	$14,904	714,857	$0.02003	$14,316	($588)	($0.00068)	-3.3%
25										
26	**SYSTEM TOTAL**	**1,230,486**	**$0.30470**	**$374,933**	**1,236,000**	**$0.22806**	**$281,884**	**($93,049)**	**($0.07664)**	**-25.2%**

1) These rates are for Natural Gas Transportation Service from "Citygate to Meter". The BTS rate is for service from Receipt Point to Citygate.
BTS is a SoCalGas tariff and service is purchased from SoCalGas.

2) Average transmission level service rate is shown here, see Rate Table 6 for detail list of TLS rates.

3) All rates include Franchise Fees & Uncollectible charges.

Table PZS18
SDG&E Natural Gas Transportation Rates
Comparison with a $3 Residential Customer Charge

2016 TCAP Phase II Application w/NCO Method NO RCA, with $3 Res Customer Charge										
Modified SCENARIO 5		Present Rates			Proposed Rates			Changes		
	Customer	Jan1-15 Volumes Mth	Average Rate $/therm	Jan1-15 Revenues $000s	Jan1-17 Volumes Mth	Proposed Rate $/therm	Jan1-17 Revenues $000s	Revenue Change $000	Rate Change $/therm	% Rate Change %
		A	B	C	D	E	F	G	H	I
1	**CORE**									
2	Residential	321,869	$0.92062	$296,319	319,982	$0.70665	$226,114	($70,205)	($0.21397)	-23.2%
3	Com & Industrial	177,578	$0.34893	$61,962	182,660	$0.21295	$38,898	($23,064)	($0.13598)	-39.0%
4										
5	NGV Pre SWide	11,417	$0.24253	$2,769	18,501	$0.07049	$1,304	($1,465)	($0.17204)	-70.9%
6	SWide Adj	11,417	($0.08949)	($1,022)	18,501	$0.06764	$1,251	$2,273	$0.15713	-175.6%
7	NGV Post SWide	11,417	$0.15304	$1,747	18,501	$0.13813	$2,556	$808	($0.01491)	-9.7%
8										
9	Total CORE	510,864	$0.70474	$360,028	521,144	$0.51342	$267,568	($92,461)	($0.19132)	-27.1%
10										
11	**NONCORE C & I**									
12	Distrib Level Serv	25,161	$0.05420	$1,364	27,807	$0.03840	$1,068	($296)	($0.01580)	-29.2%
13	Transm Level Serv (2)	13,582	$0.01901	$258	17,168	$0.01382	$237	($21)	($0.00519)	-27.3%
14	Total Noncore C&I	38,743	$0.04186	$1,622	44,975	$0.02901	$1,305	($317)	($0.01285)	-30.7%
15										
1	**NONCORE ELECTRIC GEN**									
17	Distrib Level Serv									
18	Pre SWide	103,761	$0.01729	$1,794	95,807	$0.01116	$1,069	($725)	($0.00613)	-35.4%
19	SWide Adj	103,761	$0.02947	$3,058	95,807	$0.04832	$4,629	$1,572	$0.01885	64.0%
20	Distrib Level post SW	103,761	$0.04676	$4,852	95,807	$0.05948	$5,699	$847	$0.01272	27.2%
21	Transm Level Serv (2)	577,118	$0.01461	$8,431	574,075	$0.01274	$7,313	($1,118)	($0.00187)	-12.8%
22	Total Electric Gen	680,879	$0.01951	$13,283	669,882	$0.01942	$13,011	($271)	($0.00008)	-0.4%
23										
24	**TOTAL NONCORE**	719,622	$0.02071	$14,904	714,857	$0.02003	$14,316	($588)	($0.00068)	-3.3%
25										
26	**SYSTEM TOTAL**	**1,230,486**	**$0.30470**	**$374,933**	**1,236,000**	**$0.22806**	**$281,884**	**($93,049)**	**($0.07664)**	**-25.2%**

1) These rates are for Natural Gas Transportation Service from "Citygate to Meter". The BTS rate is for service from Receipt Point to Citygate.
BTS is a SoCalGas tariff and service is purchased from SoCalGas.

2) Average transmission level service rate is shown here, see Rate Table 6 for detail list of TLS rates.

3) All rates include Franchise Fees & Uncollectible charges.

Table PZS19

SoCalGas Residential Bill Class Average Customer

Month	ORA Modified Scen 5 w/no increase in Res Cust Charge for SCG	Original Scen 5 w/no Increase in Res Cust Charge	SoCalGas Proposed Scen 3 w/increase in Res Cust Charge	SoCalGas Proposed Scen 2 w/no Increase in Res Cust Charge
	(a)	(b)	(c)	(d)
Jan-17	$73.37	$73.37	$69.52	$74.35
Feb-17	$60.14	$60.14	$57.33	$60.95
Mar-17	$49.37	$49.37	$48.19	$50.05
Apr-17	$38.71	$38.71	$38.85	$39.23
May-17	$35.07	$35.07	$36.46	$35.48
Jun-17	$30.51	$30.51	$32.25	$30.86
Jul-17	$26.39	$26.39	$28.73	$26.70
Aug-17	$24.25	$24.25	$26.82	$24.52
Sep-17	$25.11	$25.11	$27.43	$25.39
Oct-17	$25.68	$25.68	$28.09	$25.97
Nov-17	$31.85	$31.85	$32.97	$32.27
Dec-17	$52.23	$52.23	$50.69	$52.96
Monthly Ave	$39.39	$39.39	$39.78	$39.89

Source: Response to data request ORA-18.

Table PZS20

SDG&E Residential Bill Class Average Customer

Month	ORA Modified Scen 5 w/$3 Res Cust Charg instead of $3 Res Min Bill	Original Scen 5 w/no Increase in Res Customer Charge But w/$3 Res Min Bill	SDG&E Proposed Scen 3 w/increase in Res Customer Charge	SDG&E Proposed Scen 2 w/no Increase in Res Customer Charge
	(a)	(b)	(c)	(d)
Jan-17	$51.47	$54.85	$48.13	$55.87
Feb-17	$43.29	$46.12	$40.90	$46.97
Mar-17	$38.49	$40.32	$37.89	$41.06
Apr-17	$29.78	$30.52	$30.83	$31.08
May-17	$25.92	$25.07	$28.46	$25.53
Jun-17	$22.21	$21.36	$25.13	$21.76
Jul-17	$19.74	$18.73	$23.33	$19.08
Aug-17	$17.40	$16.32	$21.41	$16.62
Sep-17	$17.62	$16.66	$21.33	$16.97
Oct-17	$18.25	$17.21	$22.11	$17.53
Nov-17	$24.12	$24.08	$26.41	$24.53
Dec-17	$38.84	$40.71	$38.17	$41.47
Monthly Ave	$28.93	$29.33	$30.34	$29.87

Source: Response to data request ORA-18.

Table PZS21
Summary of Residential Rates Under Selected Scenarios

Line No	SoCalGas	ORA Modified Scen 5 w/no increase in Res Cust Charge	Original Scen 5 w/no Increase in Res Cust Charge	SocalGas Proposed Scen 3 w/increase in Res Cust Charge	SoCalGas Proposed Scen 2 w/no Increase in Res Cust Charge
		(a)	(b)	(c)	(d)
1	Res Cust Charge	$ 5.00	$ 5.00	$ 10.00	$ 5.00
2	Baseline Rate	$ 0.4391	$ 0.4391	$ 0.3143	$ 0.4527
3	NonBaseline Rate	$ 0.6991	$ 0.6991	$ 0.5743	$ 0.7127
4	Average Rate	$ 0.6272	$ 0.6272	$ 0.6461	$ 0.6461
5	SDG&E	ORA Modified Scen 5 w/$3 Res Cust Charg instead of $3 Res Min Bill	Original Scen 5 w/no Increase in Res Customer Charge But w/$3 Res Min Bill	SDG&E Proposed Scen 3 w/increase in Res Customer Charge	SDG&E Proposed Scen 2 w/no Increase in Res Customer Charge
6		(a)	(b)	(c)	(d)
7	Res Min Bill	$ -	$ 3.00	$ -	$ -
8	Res Cust Charge	$ 3.00	$ -	$ 10.00	$ -
9	Baseline Rate	$ 0.5495	$ 0.6828	$ 0.3386	$ 0.7032
10	NonBaseline Rate	$ 0.8095	$ 0.8390	$ 0.5986	$ 0.8623
11	Average Rate	$ 0.7066	$ 0.7066	$ 0.7420	$ 0.7420

Source: Response to ORA-18 and ORA-18 Q.1 aii UnModified Scen5 and Modified Scen5.

VII. WITNESS QUALIFICATIONS

Q.1 Please state your name and address.

A.1 My name is Pearlie Sabino. My business address is 505 Van Ness Avenue, San Francisco, California, 94102.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst V in the Office of Ratepayer Advocates Energy Cost of Service and Natural Gas Branch.

Q.3 Briefly describe your educational background and work experience.

A.3 I have a Bachelor of Science in Business Economics from the University of the Philippines and a Master of Arts in Economics from the Ateneo de Manila University. As a USAID scholar, I obtained Executive training on Energy Planning and Policy from the University of Pennsylvania.

Prior to joining ORA, I worked in various positions from Research Analyst to Corporate Planning Analyst to Chief Economist with the National Power Corporation (Philippines).

Since joining the ORA in 1997, I have worked on a number of electric and gas rate cases, including but not limited to: the review of SoCalGas' Gas Cost Incentive Mechanism; the review of Biennial Cost Allocation Proceeding (BCAP) applications for PG&E, SoCalGas and SDG&E; various gas transportation contracts (such as Guardian, Ruby, US Gypsum), various applications pertaining to the grant of Certificate of Public Convenience and Necessity (CPCN) for gas storage contracts, including amendments; SoCalGas/SDG&E system integration and firm access rights proceedings, including the FAR Update proceeding, the Joint

SCE/SoCalGas/SDG&E Omnibus proceeding, the Joint PG&E/SoCalGas/SDG&E Application for Public Purpose Program Cost Reallocation proceeding, the PG&E BCAP in 2005 and 2009, the SoCalGas SDG&E BCAP in 2009, the PG&E Gas Transmission & Storage rate cases in A.13-12-012 and A.09-09-013 (Gas Accord V Settlement), the PG&E Pipeline Safety Enhancement Plan Phase 1 in R.11-02-019 and San Bruno Investigation cases, the SoCalGas/SDG&E Pipeline Safety Enhancement Plan in A.11-11-002 Phase 1 &2, the Southwest Gas 2014 GRC in A.12-12-024, the SoCalGas/SDG&E North-South Project in A.13-12-013, and the Liberty GRC in A.15-05-008.

Q.4 What is your area of responsibility in this proceeding?

A.4 I am responsible for ORA’s testimony in this proceeding regarding cost allocation and rate design issues.

Q.5 Does that complete your prepared testimony?

A.5 Yes, it does.