Application No: A.15-07-014
Exhibit No.:
Witness: Sharim Chaudhury

Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) for Authority to Revise their Natural Gas Rates Effective January 1, 2017 in this Triennial Cost Allocation Proceeding Phase 2	A.15-07-014 (Filed July 8, 2015)

REVISED PREPARED DIRECT TESTIMONY OF

SHARIM CHAUDHURY

SOUTHERN CALIFORNIA GAS COMPANY

AND

SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

~~July 8,~~ November 19, 2015

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REVISED PREPARED DIRECT TESTIMONY OF SHARIM CHAUDHURY

I. PURPOSE AND OVERVIEW OF COST ALLOCATION

The purpose of my revised direct testimony on behalf of Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) is to present the allocation of the authorized revenue requirement to customer classes. My testimony covers the following cost allocation topics:

(1) Allocation of Customer-related function costs using Long Run Marginal Cost (LRMC) method;

(2) Allocation of Medium Pressure Distribution-related function costs using LRMC;

(3) Allocation of High Pressure Distribution-related function costs using LRMC;

(4) Allocation of all functional costs to rate classes; and

(5) Application of Scalar to allocated costs to ensure recovery of the authorized revenue requirement.

A. The Cost Allocation Process and its Relationship to Rate Design

The cost allocation and rate design processes are defined in the direct testimony of Ms. Schmidt-Pines, Ms. Fung, Mr. Bonnett, and my revised direct testimony offered herein. Cost allocation refers to the process of determining the cost of each utility function and allocating these functional costs to the customer classes. It promotes the allocation of base margin and non-base margin revenue requirements across customer classes. Rate design refers to the process of providing a further breakdown of each customer class' costs into rate tiers and customer charges.

The cost allocation testimony for SDG&E is sponsored by Ms. Schmidt-Pines, while the SoCalGas testimony is provided herein. Both of the cost allocation testimonies rely on Ms. Fung's revised direct testimony for the functional costs of the Transmission and Storage functions[1] and the testimony of Dr. Wetzel for the consolidated demand forecast. The testimony of Mr. Bonnett discusses the rate design process for SoCalGas and SDG&E and the resulting proposed transportation rates.

This cost allocation is conducted by first allocating the authorized revenue requirement to the functions performed by SoCalGas in order to transport natural gas. These functions are:

(i) Customer-related (provisions for service lines, regulators, meters, call centers, service representatives);

(ii) Medium Pressure Distribution System;

(iii) High Pressure Distribution System;

(iv) Local Transmission System;

(v) Backbone Transmission System; and

(vi) Storage (injection, inventory, and withdrawal).

Once the functional allocation is complete, the cost of each function is then allocated to each customer class. The customer classes are:

(i) Core (residential, commercial/industrial, natural gas vehicle, gas air conditioning, gas engine);

[1] The cost of the storage function was the subject of Ms. Fung's direct testimony in the TCAP Phase 1 Application, A.14-12-017.

(ii) Noncore (commercial/industrial, electric generation, wholesale, enhanced oil recovery); and

(iii) Other (backbone transportation service, unbundled storage program).

After the costs of each function are allocated to the customer classes, the allocated cost is scaled to the base margin,[2] so that the exact authorized amount is being used to determine customer rates. Transmission costs, which are part of the base margin, are integrated between SoCalGas and SDG&E.

Next, non-base margin costs are allocated to customer classes. Such non-base margin costs consist of authorized costs that are not included in the base margin (such as unaccounted-for gas and costs for automated meter installation) and amounts in regulatory and balancing accounts that are to be collected in transportation rates. The rate design process consists of providing a further breakdown of the costs, both base and non-base margin, that are allocated to each customer class into individual rate tiers and customer charges.

B. Cost Allocation Principles

In conducting this cost allocation, the following principles are followed:

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.

The fundamental principle applicable to these cost studies, for purposes of allocating costs to customer groups, is the concept of cost causation. Cost causation seeks to determine which customer or group of customers causes the utility to incur particular types of costs. It is

[2] Base Margin is the amount of the authorized revenue requirement that is to be recovered through transportation rates.

therefore necessary to establish causal links between a utility's customers and the particular costs incurred by the utility in serving those customers. The essential element in the selection and development of a reasonable cost allocation methodology is the establishment of relationships between customer requirements, load profiles, and usage characteristics, and the costs incurred by the utility in serving those requirements.

Avoiding rate shocks for customers and maintaining consistent cost allocation practices are also key principles followed. While fully cost-based rates are the preferred goal, SoCalGas and SDG&E realize that the rate impact on customers is an important metric to heed when allocating costs and setting rates.

C. The History of Cost Allocation Methodology

To fully understand the current practice in California regarding the application of LRMC concepts in cost allocation, a brief review of the chronological summary of the costing principles adopted by the California Public Utilities Commission (Commission) is useful. In Decision (D.) 86-12-009, the Commission discussed its intent to examine various gas cost allocation approaches. In that decision, the Commission indicated its preference for using marginal cost principle. The Commission stated that it preferred a pricing methodology that was consistent with the new gas industry structure it had adopted and that it wanted transportation services to be priced in a way that would enhance economic efficiency, meet the service needs of utility customers, and provide the Utilities with a fair opportunity to earn their allowed rate of return.

In D.86-12-009, however, the Commission adopted a "hybrid" form of embedded cost methodology on an interim basis even though it stated that it had a preference for marginal cost principle. The hybrid nature of embedded costs was created by the Commission, "by choosing 'flatter,' less extreme allocation factors, which tend to spread costs more equally across the board to all market segments."[3] The reliance on this form of embedded cost method recognized the fact that adequate marginal cost studies and demand elasticity studies had not yet been developed as a basis for setting LRMC-based rates.

Much debate occurred over the next six years before the Commission on the methodological and computational details of LRMC. In D.90-01-021, the Commission stated its intention to consider cost allocation and rate design issues in three phases: (1) determination of LRMC, (2) cost allocation, and (3) rate design policy issues. In D.90-07-055, the Commission set final guidelines for estimating LRMC with the intention of implementing the methodology in Test Year 1992 cost allocation proceedings.

In December 1992, the Commission adopted the LRMC methodology in D.92-12-058 for the three gas utilities—Pacific Gas and Electric Company (PG&E), SoCalGas, and SDG&E. All gas utilities were required to implement the LRMC methodology by early 1993. In light of this expedited schedule, the Commission stated, "The next 1993 and 1994 Biennial Cost Allocation Proceedings (BCAPs) (following implementation) is the forum that best provides the three respondents an opportunity to update LRMC methodology."[4]

In the 1996 BCAP (A.96-03-031), SoCalGas proposed the use of Rental method[5] for calculating LRMC for the customer-related function. TURN proposed that the customer-related cost should be based on the New Customer Only method (NCO).[6] The Commission approved the NCO method in D.97-04-082. However, in D.97-08-062, the Commission modified its earlier decision and adopted the Rental method. In the 1998 BCAP (A.98-10-012), SoCalGas

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[3] See D.86-12-009, *mimeo*, at 24.
[4] See D.92-12-058, *mimeo*, at 63.
[5] Rental method implies that the customer-related LRMC is the cost of hooking up an additional customer to the system. This LRMC is applicable to all customers belonging to the same customer class.

again proposed the Rental method, but the Commission adopted the NCO method in D.00-04-060.

In their 2009 BCAP application, SoCalGas and SDG&E proposed the embedded cost method, along with the LRMC method, for the Compliance Case.[7] A settlement was reached in that proceeding to:

> Adopt embedded cost allocation for transmission and storage facilities and long-run marginal cost ("LRMC") allocation for distribution facilities for both SDG&E and SoCalGas, and adopt the "compromise" cost allocation adjustments to base margin that are implied by the rates set forth in Attachment 3. SDG&E and SoCalGas shall not be required to propose LRMC cost allocation for transmission or storage costs in their next cost allocation proceeding.[8]

The 2009 BCAP settlement based its "compromise cost allocation adjustments" on a mix of allocation methods; LRMC was used for the Customer and Distribution functions, and embedded cost was used for the Transmission and Storage functions.[9]

In the 2013 Triennial Cost Allocation Proceeding (TCAP), SoCalGas and SDG&E proposed the Rental method for estimating customer-related LRMC in its application.[10] D.14-06-007 adopted a rate design settlement between SoCalGas, SDG&E, and all active parties and rejected all proposed modifications to the existing cost allocation methodology proposed by SoCalGas and SDG&E for Safety Enhancement costs.[11]

II. COST ALLOCATION METHOD PROPOSED FOR SOCALGAS AND SDG&E

SoCalGas and SDG&E propose to continue the LRMC method for the three major functional categories—customer-related, medium pressure distribution, and high pressure

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[6] Under the NCO method, for a given year, the cost of hooking up all new customers in a customer class is spread over all customers in the same customer class.
[7] A.08-02-001.
[8] D.09-11-006.
[9] D.09-11-006.
[10] A.11-11-002.

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.

A. LRMC Method for Customer-Related and Distribution-Related Functional Costs

LRMC of a service refers to incremental cost to serve one additional unit in the long run; such unit cost is called marginal unit cost. The cost causation unit (*i.e.*, the cost driver) is called marginal demand measure (MDM). The LRMC-based functional cost (marginal cost revenue) is derived by multiplying the LRMC by the number of MDMs. For customer-related costs, the MDM is the number of customers. For medium and high pressure distribution-related costs, the MDM is peak day demand and peak month demand, respectively. Embedded functional costs, on the other hand, are based on the historic costs of that function.

In this TCAP, SoCalGas and SDG&E updates the LRMC and embedded cost studies to reflect 2013 actual costs[12] and allocations based on 2013 underlying activities. The processes for updating the studies are consistent with existing practices. These costs are then escalated to 2017 dollars to reflect SoCalGas and SDG&E's estimated Test Year costs for this TCAP.[13] For the customer-related and distribution functions, the marginal unit costs are then multiplied by the forecasted MDMs presented in the Demand Forecast testimony of Dr. Wetzel to determine the respective marginal cost revenues.

Each functional marginal unit cost consists of two components: a capital-related cost component and an operation and maintenance (O&M) cost component.

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[11] D.14-06-007.
[12] *See, e.g.*, SoCalGas and SDG&E's FERC Form 2, December 31, 2013.

The capital-related cost component reflects the capital investment required to serve an additional unit. For customer-related costs,[14] this is the cost of serving an additional customer. Marginal customer-related capital costs have been developed using the Rental method, which reflects the annualized capital cost of hooking up an additional customer. 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 the access to gas service. In the 2013 TCAP, SoCalGas and SDG&E also proposed the Rental method. The 2013 TCAP Settlement, approved by D.14-06-007, adopted the marginal unit customer-related cost estimates presented in Appendix B to the Settlement.

For distribution-related costs, LRMC is the cost of providing an additional increment of throughput through the distribution system. Marginal distribution capital costs have been developed using linear regression models to determine the relationship between demand growth and investments over a 15-year period spanning historical and forecast periods.

In addition to capital-related costs, this testimony presents the O&M costs for customer-related and distribution functional categories. First, the total direct O&M costs for these functions are determined. These costs reflect the activities of field personnel and support services associated with field activities. Next, a series of O&M loaders is applied to the direct O&M costs to reflect the associated indirect costs. Indirect costs include pension and benefits, general plant, and other costs that are supportive in nature. The O&M loading factors are applied to the direct O&M costs to develop the "fully-loaded" O&M costs for each customer class. These fully-loaded O&M costs are then added to the capital-related marginal costs to develop the unit marginal cost for each functional category.

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[13] Escalation factors updated to reflect Global Insight's forecast as of fourth quarter of 2014.

Sections III and IV below present further detailed discussions on marginal cost calculations.

B. Embedded Cost for Transmission and Storage Functions

SoCalGas proposes to use the embedded cost of the transmission function, as developed in the direct testimony of Ms. Fung. The direct testimony of Ms. Fung and Mr. Watson in the TCAP Phase 1 Application, A.14-12-017, described the cost and allocation of storage assets.

III. CUSTOMER-RELATED MARGINAL UNIT COST AND MARGINAL COST REVENUE

Customer-related marginal unit cost reflects "the cost of a customer's access to the gas utility's supply system"[15] and is comprised of: (1) the marginal capital cost of service lines, regulators, and meters (SRM); (2) the marginal direct O&M costs associated with SRM, Customer Services, and Customer Accounts; and (3) O&M loaders. Section V below describes the derivation of O&M loaders.

A. Marginal Capital Cost

Consistent with D.92-12-058, the marginal capital cost reflects the facilities and equipment for (1) meters, regulators, and other Meter Set Assembly (MSA) facilities and (2) service lines.

For residential and small core commercial and industrial customers, marginal unit capital costs are calculated using the actual costs of new customer hookups in SoCalGas' service territory for the years 2009 through 2013. For other customer classes, the costs of all customers, not just new customers, belonging to a specific customer class are used to estimate marginal

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[14] Customer-related capital costs include service lines, regulators, and meters.
[15] See D.92-12-058, *mimeo*, at 38.

MSA and service line costs because of low customer growth rates and the large variations in meter costs for these customers.

1. Meter Set Assembly (MSA) Costs

MSA costs include the cost of the meter, regulator, and other equipment required in hooking up a new customer and the direct labor cost for installing the equipment. Consistent with prior cost allocation proceedings, the marginal costs of MSAs have been updated in the following manner:

a) Extracted meter size, type, and service pressure level information, at the customer level, from SoCalGas' Customer Information System;

b) Applied updated unit cost data for the various meter sizes, types, and service pressure levels to MSA configurations at the customer level; and

c) Derived customer-class-specific marginal MSA costs as the weighted average MSA costs for all customers in each customer class.

2. Service Line Costs

Consistent with D.92-12-058 and the subsequent cost allocation proceeding applications, the marginal costs of service lines have been updated as follows:

a) Extracted service line lengths, pipe types, and pipe diameter data, at the customer level, from SoCalGas' Service History File;

b) Applied updated unit cost data by pipe type and diameter to the average length of service lines for each customer in the various customer classes; and

c) Derived customer-class-specific marginal service line costs as the average service line costs for all customers in each customer class.

B. Marginal Direct O&M Costs

Customer-related marginal O&M costs are broken into five components: (1) Customer Services, (2) Customer Accounts, (3) Meters and Regulators, (4) Service Lines, and (5) O&M Loaders. The first four components comprise the total direct O&M costs. O&M loaders, as discussed in Section V below, are applied to direct O&M costs to derive fully-loaded O&M costs.

The updated customer-class-specific O&M costs are based on 2013 recorded O&M expenses.

1. Customer Services O&M Costs

Customer Services O&M costs include the field services' recorded expenses associated with the maintenance and safe and reliable operation of SoCalGas-owned equipment (*e.g.*, meters and regulators), as well as customer-owned appliances. Customer service activities, and the associated costs, result from responses to customer service requests and internal work requirements. Requests are categorized into general order types for which both frequency and duration are recorded. Customer Services O&M costs also include support costs associated with related field activities, such as field order dispatch costs, staff and supervision costs, communication costs, as well as an allocation of vehicle, tools, and uniform costs.

Orders are apportioned to customers and customer classes using data from SoCalGas' customer services dispatching system, the Portable Automated Centralized Electronic Retrieval (PACER) system. The Data Analysis Reporting Tools (DART) system tracks orders by time to complete each activity by customer class.

Customer Services O&M costs are recorded in Federal Energy Regulatory Commission (FERC) Functional Accounts 870, 878, and 879. These costs are allocated across customer classes at each functional account level based on either the total time to complete the orders or the total order volume. Functional Account 879.010 (Customer Services Field) is the largest customer services account. These costs are allocated across customer classes based on the field time recorded for each customer class.

2. Customer Accounts O&M Costs

Customer records and collection expenses, meter reading costs, and supervision costs are the primary costs reflected in these O&M accounts. Specifically, these accounts include the recorded expenses incurred to receive calls from customers requesting service, obtain monthly-metered gas consumption data from non-automated meters, calculate and reconcile billing information, print and mail gas bills and collection notices to customers, respond to inquiries related to billing and collections, perform collection activities, and process customer payments.

Customer Accounts O&M costs are booked to FERC Accounts 901-905. Customer Resource Center activity, which is recorded in FERC Accounts 903.101 and 903.107, is one of the largest components of Customer Accounts O&M. This includes field service calls, customer account inquiries, and general customer inquiries. The associated costs are allocated among customer classes based on the number of accounts and the weighted call volumes. Field orders are further tracked by type of activity (*e.g.*, turn-on requests) and customer class.

Meter reading, which is recorded in FERC Account 902, is another significant component of Customer Accounts O&M. The costs associated with manually reading core meters are allocated based on the weighted read times for core customer classes. The costs associated with the daily collection of electronic measurement for noncore customers are allocated by the number of noncore active meters.

Bill distribution and remittance, which are recorded in FERC Accounts 903.330 and 903.700, are another large component of Customer Accounts O&M. These accounts reflect postage costs and the cost for remittance processing. The allocation of these costs across customer classes is performed based on the number of active customer accounts.

Supervision and staff support costs, FERC Accounts 903.1, and 905, are allocated based on the activities supported. For example, Account 903.100 is allocated based on the allocation of all related line and staff functions, including billing, meter reading, Customer Resource Center, and branch services. The total allocation for these various functions is summed to develop the allocator for supervision of these functions.

3. Meters and Regulators O&M Costs

Consistent with the methodology adopted in D.92-12-058, Meters and Regulators O&M costs are allocated based on two allocation methods. Costs that are common to all customer segments are allocated according to each customer segment's share of total connected meters in service. Costs specifically identifiable as meter repair and replacement are allocated based on each customer segment's share of the total number of meter repairs and replacements during the year.

4. Service Lines O&M Costs

Service line O&M costs are allocated to each customer class based on each class' share of total service line footage at year end 2013. Because there is a direct relationship between service line footage and costs associated with the operation and maintenance of service lines, service line footage is the appropriate basis for allocating service line O&M costs.

5. Customer Services and Information Costs

Customer Services and Information (CS&I) costs are booked to FERC Accounts 907 through 910. The costs associated with the Energy Efficiency and Low Income Energy Efficiency programs are not part of SoCalGas' transportation rates and have been removed from the total CS&I cost to derive the residual portion of the CS&I costs that are authorized in base margin.[16] This residual portion of CS&I costs is included in the customer-related costs.

C. Calculation of Customer-Related Marginal Cost Revenue

The Marginal unit customer cost (MUC_C) is calculated as follows:

MUC_C ($/customer) = [CAPEX[17] per customer * RECC[18]%] + [O&M & Loaders]

For each customer class, the marginal cost revenue (MCR) is then derived as follows:

Customer-Related MCR ($) = MUC_C * # of Customers

The following table shows the calculations for MUC_C.

Table 1
Calculation of Marginal Customer Costs
$/Customer

Customer Class	CAPEX $/customer	RECC %	Annualized CAPEX $/customer	O&M and Loaders $/customer/year	Marginal Unit Cost $/customer/year
Residential	$1,394.27	8.75%	$122.00	$101.60	$223.60
Core C/I	$4,099.28	8.89%	$364.60	$346.70	$711.30
Gas A/C	$13,734.35	9.06%	$1,244.77	$4,620.40	$5,865.16
Gas Engine	$48,323.24	8.64%	$4,176.78	$907.74	$5,084.52
NGV	$62,935.38	9.21%	$5,794.55	$16,486.83	$22,281.38
Noncore C/I	$179,258.46	9.12%	$16,350.27	$13,828.55	$30,178.82
Small EG	$121,936.26	9.12%	$11,114.75	$14,143.52	$25,258.28
Large EG	$906,717.62	9.43%	$85,513.35	$43,130.52	$128,643.87
EOR	$333,328.79	9.32%	$31,056.11	$51,972.43	$83,028.54
Long Beach	$5,071,825.51	9.54%	$483,937.00	$402,400.06	$886,337.07
SDG&E	$11,907,864.24	9.54%	$1,136,209.46	$376,829.08	$1,513,038.54
Southwest Gas	$3,233,019.45	9.54%	$308,484.14	$488,768.27	$797,252.41
Vernon	$2,529,362.03	9.54%	$241,343.45	$297,880.00	$539,223.46
DGN	$525,735.12	9.54%	$50,163.93	$166,266.45	$216,430.37

[16] The costs associated with the Energy Efficiency and Low Income Energy Efficiency program costs are not part of the base margin and are recovered through a Public Purpose Program Surcharge rate.
[17] Marginal MSA and Service line capital costs.
[18] RECC refers to real economic carrying charge described in Section V below. RECC is applied to annualize marginal capital costs.

IV. DISTRIBUTION-RELATED MARGINAL UNIT COST AND MARGINAL COST REVENUE

This section addresses the marginal cost of distribution function. The marginal cost for distribution consists of three types of costs: capital-related, direct O&M, and O&M loaders. The distribution capital costs are recorded in the plant accounts for mains (Account 376) and measuring & regulating station equipment (Account 378). Distribution direct O&M costs are reflected in Accounts 874, 875, 887, and 889 for mains and measuring & regulating (M&R) stations.

The Commission acknowledged in D.92-12-058 that it is appropriate for SoCalGas to develop separate marginal costs for medium pressure distribution (MPD) and high pressure distribution (HPD) functions. This segmentation is appropriate because the cost driver for the HPD system is different from that of the MPD system.

A. MPD Marginal Unit Cost and Marginal Cost Revenue

The MPD marginal cost consists of an annualized capital-related cost and the fully-loaded marginal O&M cost. The following sections describe the derivation of marginal capital and direct O&M costs. Section V below discusses the O&M loaders.

1. Marginal Capital Cost

Consistent with D.92-12-058 and subsequent cost allocation proceeding filings, the capital-related marginal MPD cost is developed using a linear regression model, recognizing that peak day demand is the cost driver for the MPD system. The regression analysis establishes the relationship between cumulative load-growth-related capital investment in the MPD system (the dependent variable) and cumulative peak day demand growth (the independent variable). Load-growth-related investments include new business, pressure betterment, and meter and regulating station investments. The period for the regression analysis is 15 years: nine years of historical data (2005 – 2013) and six years of forecast data (2014 – 2019). The resulting estimated coefficient of the independent variable represents the capital-related MPD marginal capital cost.

The cumulative peak day demand growth is calculated based on the net positive change in the number of customers per year multiplied by the average peak day demand per customer for each class. The total annual footage for new business and pressure betterment by distribution pipe size and type is multiplied by the associated unit costs to obtain total annual investment costs.

2. Marginal Direct O&M Costs

The 2013 recorded distribution-related direct O&M costs are allocated between medium pressure and high pressure distribution systems based on the split in total distribution investment between the medium and high pressure distribution systems. Distribution-related direct O&M costs are booked to FERC Accounts 874, 875, 887, and 889.

3. Calculation of MPD Marginal Cost Revenue

The calculation of marginal unit MPD cost (MUC_MPD) is as follows:

MUC_MPD ($/MCFD[19]) = [CAPEX per MCFD * RECC%] + [O&M & Loaders].

For each customer class, the marginal cost revenue (MPD_MCR) is then derived as follows:

MPD_MCR ($) = MUC_MPD * MCFD

Tables 2 and 3 present the derivation of marginal capital cost for MPD. Table 4 shows the MPD marginal cost, capital, and O&M combined. Section V discusses O&M Loaders and RECC Factors.

[19] MCFD refers to thousand cubic feet per day.

Table 2		
Year	Cumulative MMCFD	Cumulative CAPEX $000's
2005	35	$189,849
2006	68	$362,478
2007	104	$498,062
2008	139	$574,536
2009	144	$617,770
2010	156	$663,994
2011	189	$681,505
2012	202	$691,239
2013	238	$715,182
2014	252	$757,600
2015	268	$802,970
2016	291	$851,292
2017	316	$902,565
2018	342	$956,789
2019	368	$1,013,966

Table 3

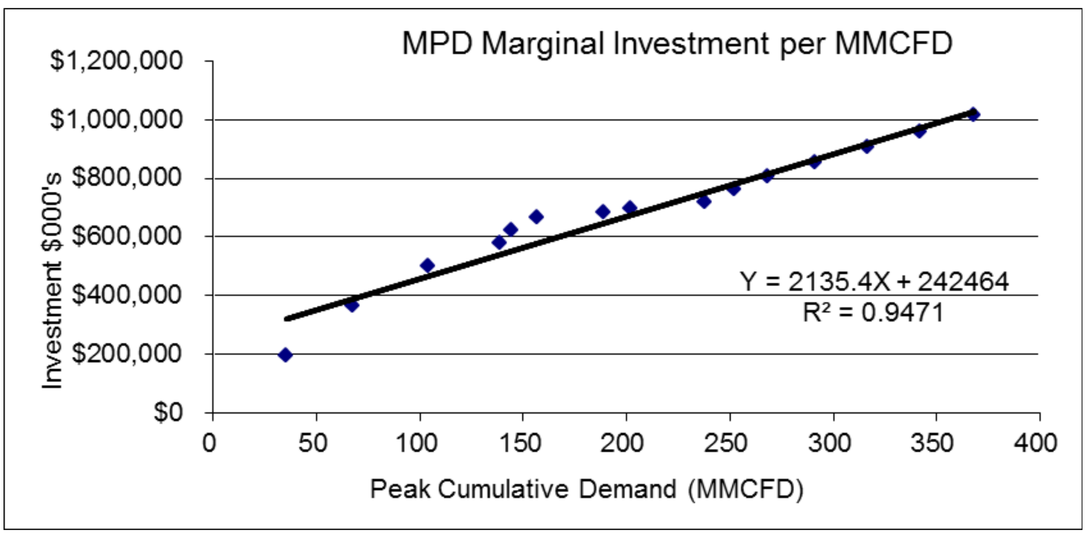

Table 4	
Marginal MP Distribution Cost	
Capital-related Charge:	
MPD Regression Coefficient $/MCFD	$2,135.42
x RECC Factor	8.57%
= Annualized Capital-related Charge ($/MCFD)	$183.00
+ Direct O&M	$9.98
+ A&G	$4.17
+ GP	$3.01
+ M&S	$0.21
= Marginal MP Distribution Cost($/MCFD)	**$200.38**

B. HPD Marginal Unit Cost and Marginal Cost Revenue

The methodology for calculating the marginal capital-related cost for the HPD system is analogous to the methodology used for the MPD system. Cumulative load-growth-related investment costs in the HPD system are regressed against cumulative load growth. Consistent with the methodology adopted in D.92-12-058 and used in subsequent cost allocation proceedings, the coincident peak month demand served off the HPD system is used as the measure of cost driver for the HPD system.

The calculation of marginal unit HPD (MUC_HPD) cost is as follows:

MUC_HPD ($/MCF/month) = [CAPEX per MCF/month * RECC%] + [O&M & Loaders].

For each customer class, the marginal cost revenue (HPD_MCR) is then derived as follows:

HPD_MCR ($) = MUC_MPD * MCF/month

Tables 5 and 6 present the derivation of marginal capital cost for HPD. Table 7 shows the HPD marginal cost, capital, and O&M combined. See Section V discusses O&M Loaders and RECC Factors.

Table 5		
Year	Cumulative MMCF/ month	Cumulative CAPEX $000's
2005	613	$10,034
2006	1,212	$47,295
2007	2,158	$62,374
2008	2,718	$69,741
2009	2,789	$82,299
2010	2,974	$85,437
2011	3,511	$93,475
2012	3,870	$119,019
2013	4,680	$121,184
2014	5,555	$129,027
2015	5,908	$137,055
2016	6,333	$145,269
2017	6,783	$153,667
2018	7,233	$162,251
2019	7,679	$171,020

Table 6

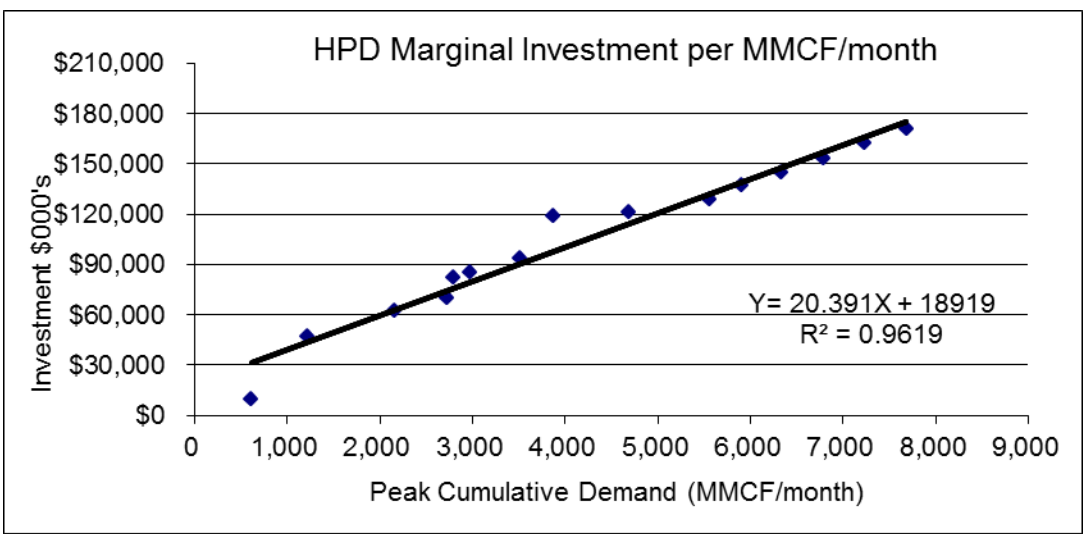

Table 7	
Marginal HP Distribution Cost	
Capital-related Charge:	
HPD Regression Coefficient $/MCF/month	$20.391
x RECC Factor	8.56%
= Annualized Capital-related Charge ($/MCF/month)	$1.75
+ Direct O&M	$0.08
+ A&G	$0.03
+ GP	$0.02
+ M&S	$0.04
= Marginal HP Distribution Cost($/MCF/month)	**$1.92**

V. REAL ECONOMIC CARRYING CHARGE AND INDIRECT O&M COST LOADING FACTORS DEVELOPED FOR THE LRMC STUDIES

A. Real Economic Carrying Charge (RECC) Factors

RECC factors are used to convert capital investment into annualized capital costs. As stated in the LRMC Proceeding:

> In a regulated utility, additions to rate-base cause a series of future revenue requirements that are greater in the early years and lower in the later years of the rate-based asset's life. To compute marginal cost the series of revenue requirements need to be stated on an annual basis, and in a way that best represents the economic cost to the customer. A common way is to use the "levelized cost of service." This is computed by taking the present value of the series of payments and computing the constant annual charge that would have the same present value. This is similar to calculating mortgage payments.
>
> In the presence of inflation, the levelized cost of service has the disadvantage of producing an annual flow that is constant in nominal terms, but declines in real value. A more appropriate annual value is one that rises with inflation, staying constant in real terms, and again generates the same present value. The "Real Economic Carrying Charge" RECC is the first year's value of this series.[20]

[20] Long Run Marginal Cost Proceeding, I.86-06-005, Testimony of Dr. Van Lierop, February 1992, Section IV.A, page 23 and 24.

The RECC factors used in Tables 1, 4, and 7 above are the weighted averages for the respective customer-related, medium pressure distribution, and high pressure distribution functional categories, and, when applied to a capital investment, produce the first year charge of a series of annualized capital charges that remains constant in real terms over the life of the asset. The RECC factor is a function of authorized rate of return, inflation, salvage value, book life, and tax rates. Based on the differing book lives and salvage values of utility assets, separate RECC factors have been developed for service lines, pressure regulators, meters, and distribution capital investments.

SoCalGas has updated its RECC factors using inflation assumptions from Global Insight's forecast, updated tax rates, and SoCalGas' discount rate of 8.02% revised per Advice Letter 4442. The authorized book lives and salvage values for the different investments have also been updated to reflect current factors.

B. O&M Loaders

SoCalGas develops three distinct O&M loaders that are applied to direct marginal O&M cost to develop the fully-loaded O&M cost for each functional category. These loading factors reflect indirect costs for: (1) administrative and general (A&G) expenses, (2) general plant, and (3) materials and supplies (M&S). The A&G and general plant loading factors are percentages that are applied to the direct O&M costs for each functional category. M&S costs are assigned to each functional category based on plant investment.

1. A&G Loading Factor

Marginal A&G expenses and payroll taxes are combined into a single loading factor. This loading factor is calculated consistent with the methodology established by D.92-12-058, with an adjustment to reflect the exclusion of storage and transmission-related costs. The loading factor derived in Table 8 reflects the ratio of marginal A&G expenses plus payroll taxes to net O&M expenses. Net O&M expenses are calculated as total O&M expenses minus the sum of fuel-related expenses, total production expenses, and total A&G expenses.

Recorded 2013 A&G expenses have been classified as either marginal or non-marginal on an account-by-account basis. Consistent with D.92-12-058, any costs that vary with either the size of labor force or the size of plant are deemed marginal costs for this study.

Table 8
A&G Factor

Total Marginal A&G Costs $000's	$192,408
+ Total Payroll Taxes $000	$49,006
= Marginal A&G and Payroll Taxes $000	$241,413
/ Net O&M Costs $000	$577,625
= Marginal A&G Loading Factor as a percentage of O&M	**41.79%**

2. General Plant Loading Factor

Gross general plant, as reflected in FERC Accounts 390 through 398, includes general plant in service as of year-end 2013 for structures and improvements, office furniture and equipment, computer applications and equipment, shop and garage equipment, and communication equipment. RECC factors associated with each capital category and the amounts of gross plant in service at year-end 2013 are used to calculate a weighted average RECC factor. This factor is then applied to gross general plant in service as of December 31, 2013, to derive an annualized cost for general plant. This annualized general plant cost is divided by year 2013 net O&M expenses to derive the general plant loading factor, as shown in Table 9. Like the A&G loading factor, the general plant loading factor excludes of storage and transmission-related costs.

Table 9 General Plant Factor	
Total General Plant $000	$1,146,811
* Weighted Average RECC for General Plant	15.22%
= Annualized General Plant Costs	$174,518
/ Net Recorded O&M Costs $000	$577,625
= General Plant Loading Factor as a percentage of O&M	**30.21%**

3. Materials and Supplies (M&S) Loading Factor

M&S is comprised of materials and supplies kept in stock for use in daily field operations and in capital projects. Examples of M&S items include pipe, valves, fittings, and safety equipment. Recorded 2013 M&S costs are allocated based on gross gas plant in each functional category. Distribution M&S is further categorized as customer-related and demand-related distribution plant investment. As with the other O&M loaders, storage and transmission-related M&S costs have been removed from this analysis.

The functionally allocated M&S costs are annualized using the RECC factor developed for M&S investments. The annualized M&S costs are then added to the marginal O&M costs for each function as part of the fully-allocated O&M costs.

Table 10 shows the functionalization of the year 2013 M&S costs and the derivation of annual M&S costs for each function.

Table 10 M&S Annual Costs	
Function	
Customer Related $000	$1,252
Load Related $000	$1,443
Total	**$2,695**

VI. OTHER UPDATES TO THE COST ALLOCATION OF BASE MARGIN

A. Transmission Function Costs

Transmission Costs have been updated to the amounts proposed in the revised direct testimony of Ms. Fung.

B. Storage Function Costs

Storage Costs and Storage Rates for Inventory, Injection, and Withdrawal have been updated to the amounts set forth in the TCAP Phase 1 direct testimony of Ms. Fung and Mr. Watson.

C. NGV Compressor Costs

NGV Compressor Costs have been updated to the amounts set forth in the rate design testimony and workpapers of Mr. Bonnett.

VII. RESULTS OF THE COST ALLOCATION STUDY

Upon completing the cost studies to allocate costs to functional categories, SoCalGas allocates each functional cost to customer classes using the appropriate MDM (cost driver). Each MDM reflects the forecast annual average for the years 2017 – 2019, reflecting the duration of the 2016 TCAP Phase 2 period.

For the customer-related functional category, Table 11 shows the marginal unit costs, the customer counts, and the marginal cost revenues by customer classes.

TABLE 11 UNSCALED LONG RUN MARGINAL COST REVENUES CUSTOMER COST			
Customer Class	Customer LRMC $/customer	Customer Count	Customer Cost $000
	A	B	C
Residential	$224	5,617,809	$1,256,152
Core C/I	$711	207,317	$147,464
Gas A/C	$5,865	9	$53
Gas Engine	$5,085	745	$3,788
NGV	$22,281	359	$7,993
Total Core			$1,415,451
Noncore C/I	$30,179	622	$18,758
Small EG	$25,258	216	$5,463
Large EG	$128,644	68	$8,806
EOR	$83,029	29	$2,408
Total Retail Noncore			$35,435
Long Beach	$886,337	1	$886
SDG&E	$1,513,039	1	$1,513
Southwest Gas	$797,252	1	$797
Vernon	$539,223	1	$539
DGN	$216,430	1	$216
Total Wholesale			$3,952
UBS	$0	0	$0
BTS	$0	0	$0
Total Noncore			$39,387
Total SoCalGas			**$1,454,838**

Table 12 shows the allocation of MPD and HPD marginal cost revenues by customer classes. Medium pressure distribution costs are allocated using 1-in-35 peak day core/1-in-10 cold day noncore MPD service level peak day demand; and High pressure distribution costs are allocated using 1-in-35 peak month core/1-in-10 cold month noncore HPD service level peak month demand.

TABLE 12 UNSCALED LONG RUN MARGINAL COST REVENUES DISTRIBUTION COSTS						
Customer Class	MPD LRMC $/mcfd	MPD Peak Day (mcfd)	MPD Costs $000	HPD LRMC $/mcf	HPD Peak Month Demand (mcf)	HPD Costs $000
	A	B	C	D	E	F
Residential	$200.38	2,345,287	$469,949	$1.92	39,076,037	$75,171
Core C/I	$200.38	529,071	$106,015	$1.92	11,426,499	$21,981
Gas A/C	$200.38	59	$12	$1.92	3,630	$7
Gas Engine	$200.38	3,578	$717	$1.92	133,820	$257
NGV	$200.38	12,707	$2,546	$1.92	935,981	$1,801
Total Core			$579,240			$99,217
Noncore C/I	$200.38	86,202	$17,273	$1.92	6,643,003	$12,779
Small EG	$200.38	14,054	$2,816	$1.92	596,963	$1,148
Large EG	$200.38	9,296	$1,863	$1.92	1,638,566	$3,152
EOR	$200.38	299	$60	$1.92	1,134,788	$2,183
Total Retail Noncore			$22,012			$19,263
Long Beach	$200.38	0	$0	$1.92	0	$0
SDG&E	$200.38	0	$0	$1.92	0	$0
Southwest Gas	$200.38	0	$0	$1.92	0	$0
Vernon	$200.38	0	$0	$1.92	0	$0
DGN	$200.38	0	$0	$1.92	0	$0
Total Wholesale			$0			$0
UBS	$200.38	0	$0	$1.92	0	$0
BTS	$0.00	0	$0	$0.00	0	$0
Total Noncore			$22,012			$19,263
Total SoCalGas			**$601,252**			**$118,480**

In D.92-12-058, the Commission stated that "marginal cost revenues need to be scaled to the embedded-based authorized revenue requirement under our ratemaking procedures."[21] The scalar is employed to adjust the proposed marginal cost revenues to the base margin, excluding cost directly allocated to the Transmission, Storage, Uncollectible, and NGV Public Access

[21] D.92-12-058, page 50.

functions. In this TCAP, marginal costs are scaled at a rate of 77% in order to reconcile to the base margin of $1,668,970~~1,669,045~~. Table 13 shows this process.

TABLE 13
LONG RUN MARGINAL COST SCALED REVENUES
SCALED CUSTOMER & DISTRIBUTION COSTS
$ 000

Customer Class	Customer Cost A	MPD B	HPD C	Unscaled LRMC Revenues D=A+B+C	Scalar E	Scaled LRMC Revenues F=D*E
Residential	$1,256,152	$469,949	$75,171	$1,801,273	77%	$1,382,466~~1,382,528~~
Core C/I	$147,464	$106,015	$21,981	$275,461	77%	$211,415~~211,424~~
Gas A/C	$53	$12	$7	$72	77%	$55
Gas Engine	$3,788	$717	$257	$4,763	77%	$3,655~~6~~
NGV	$7,993	$2,546	$1,801	$12,340	77%	$9,471
Total Core	$1,415,451	$579,240	$99,217	$2,093,908	77%	$1,607,062 ~~1,607,134~~
Noncore C/I	$18,758	$17,273	$12,779	$48,810	77%	$37,462~~3~~
Small EG	$5,463	$2,816	$1,148	$9,427	77%	$7,236
Large EG	$8,806	$1,863	$3,152	$13,821	77%	$10,608
EOR	$2,408	$60	$2,183	$4,651	77%	$3,569~~3,570~~
Total Retail Noncore	$35,435	$22,012	$19,263	$76,710	77%	$58,874~~7~~
Long Beach	$886	$0	$0	$886	77%	$680
SDG&E	$1,513	$0	$0	$1,513	77%	$1,161
Southwest Gas	$797	$0	$0	$797	77%	$612
Vernon	$539	$0	$0	$539	77%	$414
DGN	$216	$0	$0	$216	77%	$166
Total Wholesale	$3,952	$0	$0	$3,952	77%	$3,033
UBS	$0	$0	$0	$0	77%	$0
BTS	$0	$0	$0	$0	77%	$0
Total Noncore	$39,387	$22,012	$19,263	$80,662	77%	$61,908~~61,910~~
Total SoCalGas	**$1,454,838**	**$601,252**	**$118,480**	**$2,174,570**	**77%**	**$1,668,970 ~~1,669,045~~**

Calculation of Scalar:
Scalar = [Base Margin - Transmission – Storage] / [Unscaled Customer + Distribution]
Scalar = $1,668,970~~1,669,045~~ divided by $2,174,570

After the allocation of customer and distribution functional costs across customer classes, the remaining base margin items for transmission, storage, NGV, and uncollectible costs are allocated to customer classes, as shown in Table 14. Local Transmission costs[22] are allocated to customer classes using cold year peak month throughput, and Backbone Transmission costs[23] are allocated to the Backbone Transportation Service (BTS) rate.[24] Storage costs[25] are allocated to customer classes using the storage rates[26] (for inventory, injection, and withdrawal) applied to the capacities for Core Storage, Load Balancing, and Unbundled Storage Program proposed in Phase 1 of this TCAP. Uncollectible and NGV Public Access Station cost are also included. The system average uncollectible rate is 0.278%. NGV Public Access Station cost is allocated to the NGV class for recovery through the NGV Compressor Adder.

Finally, scaled LRMC costs are combined with the Transmission, Storage, Uncollectible, and NGV Public Access costs to determine the proposed cost allocation of authorized gas base margin. This is presented in column G of Table 14 and represents a completely cost-based allocation.

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[22] Presented in the revised direct testimony of Ms. Fung.
[23] Presented in the revised direct testimony of Ms. Fung.
[24] BTS is service from a receipt point to the city-gate and is recovered from core customers through the procurement rate (Schedule G-CP at SoCalGas, Schedule GPC at SDG&E); non-core customers purchase directly from SoCalGas or purchase supplies at the city-gate from a marketer who has purchased BTS.
[25] Presented in the testimony of Ms. Fung in the TCAP Phase 1, A.14-12-017.
[26] Presented in the testimony of Mr. Watson in the TCAP Phase 1, A.14-12-017.

TABLE 14
ALLOCATION OF BASE MARGIN

$ 000

Customer Class	Scaled LRMC Revenues A	Uncollectible B	BTS C	Local Transmission D	NGV Public Access E	Storage F	Allocated Base Margin G
Residential	$1,382,466 ~~1,382,528~~	$4,354~~4,296~~	$0	$23,855~~24,613~~	$0	$53,855	$1,464,529 ~~1,465,292~~
Core C/I	$211,415 ~~211,424~~	$720~~710~~	$0	$7,026~~7,249~~	$0	$13,478	$232,638~~232,862~~
Gas A/C	$55	$0	$0	$2	$0	$6	$64
Gas Engine	$3,655~~6~~	$12	$0	$85~~88~~	$0	$180	$3,933~~6~~
NGV	$9,471	$40	$0	$769~~794~~	$2,440	$1,222	$13,943~~13,967~~
Total Core	$1,607,062 ~~1,607,134~~	$5,126~~5,058~~	$0	$31,737~~32,747~~	$2,440	$68,742	$1,715,107 ~~1,716,121~~
Noncore C/I	$37,462~~3~~	$210~~207~~	$0	$7,399~~7,635~~	$0	$4,400	$49,471~~49,705~~
Small EG	$7,236	$27	$0	$457~~472~~	$0	$280	$8,001~~8,015~~
Large EG	$10,608	$204~~201~~	$0	$13,411~~13,838~~	$0	$7,444	$31,667~~32,092~~
EOR	$3,569 ~~3,570~~	$0	$0	$1,166~~1,203~~	$0	$668	$5,403~~5,440~~
Retail Noncore	$58,874~~7~~	$441~~434~~	$0	$22,434~~23,147~~	$0	$12,793	$94,542~~95,252~~
Long Beach	$680	$0	$0	$594~~613~~	$0	$212	$1,486~~1,505~~
SDG&E	$1,161	$0	$0	$8,357~~8,623~~	$0	$11,092	$20,610~~20,876~~
Southwest Gas	$612	$0	$0	$628~~648~~	$0	$189	$1,429~~1,449~~
Vernon	$414	$0	$0	$485~~500~~	$0	$274	$1,173~~1,189~~
DGN	$166	$0	$0	$455~~470~~	$0	$264	$885~~900~~
Total Wholesale	$3,033	$0	$0	$10,520~~10,854~~	$0	$12,030	$25,583~~25,918~~
UBS	$0	$0	$0	$0	$0	$17,020	$17,020
BTS			$150,206~~148,148~~				$150,206~~148,148~~
Total Noncore	$61,908 ~~61,910~~	$441~~434~~	$150,206~~148,148~~	$32,953~~34,002~~	$0	$41,843	$287,351~~286,338~~
Total SoCalGas	**$1,668,970 ~~1,669,045~~**	**$5,567~~5,492~~**	**$150,206~~148,148~~**	**$64,690~~66,748~~**	**$2,440**	**$110,585**	**$2,002,458**

VIII. COMPARISON OF PROPOSED COST ALLOCATION TO CURRENT COST ALLOCATION

The following is a comparison of the proposed 2017 cost allocation to the current allocation effective January 1, 2015. This comparison is pre-System Integration and pre-BTS unbundling, discussed in the testimony of Mr. Bonnett.

The proposed allocation of base margin across customer classes is comparable to the current allocation. The Proposed and Current base margins in Table 15 differ by $18 million because of the net effect of the inclusion of Aliso Canyon storage turbine replacement revenue requirement of $27 million and the exclusion of Honor Rancho storage expansion revenue requirement of $9 million in the base margin for 2017, as discussed in the direct testimony of Ms. Fung in A.14-12-017 and in an update to the SoCalGas brokerage fee study described in the direct testimony of Ms. Payan.

TABLE 15 COST ALLOCATION COMPARISON $ 000				
Customer Class	Proposed Allocation of Base Margin A	% Total B	Current Allocation of Base Margin C	% Total D
Residential	$1,464,529 ~~1,465,292~~	73.~~2~~1%	$1,435,087	72.3%
Core C/I	$232,638~~232,862~~	11.6%	$277,662	14.0%
Gas A/C	$64	0.0%	$74	0.0%
Gas Engine	$3,933~~6~~	0.2%	$2,071	0.1%
NGV	$13,943~~13,967~~	0.7%	$9,940	0.5%
Total Core	$1,715,107 ~~1,716,121~~	85.7%	$1,724,834	86.9%
Noncore C/I	$49,471~~49,705~~	2.5%	$57,226	2.9%
Small EG	$8,001~~8,015~~	0.4%	$4,577	0.2%
Large EG	$31,667~~32,092~~	1.6%	$31,375	1.6%
EOR	$5,403~~5,440~~	0.3%	$5,004	0.3%
Total Retail Noncore	$94,542~~95,252~~	4.~~8~~7%	$98,182	4.9%
Long Beach	$1,486~~1,505~~	0.1%	$1,357	0.1%
SDG&E	$20,610~~20,876~~	1.0%	$14,782	0.7%
Southwest Gas	$1,429~~1,449~~	0.1%	$1,294	0.1%
Vernon	$1,173~~1,189~~	0.1%	$974	0.0%
DGN	$885~~900~~	0.0%	$611	0.0%
Total Wholesale	$25,583~~25,918~~	1.3%	$19,017	1.0%
UBS	$17,020	0.8%	$26,476	1.3%
BTS	$150,206~~148,148~~	7.5~~4~~%	$116,052	5.8%
Total Noncore	$287,351~~286,338~~	14.3%	$259,727	13.1%
Total SoCalGas	**$2,002,458**	**100.0%**	**$1,984,561**	**100.0%**

This concludes my revised prepared direct testimony.

IX. QUALIFICATIONS

My name is Iftekharul (Sharim) Bar Chaudhury. I am employed by SoCalGas and SDG&E as the Rate Design and Demand Forecasting Manager within the CPUC/FERC Gas Regulatory Affairs Department, which supports gas regulatory activities of both SoCalGas and SDG&E. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011.

I hold a Bachelor of Arts degree in Economics from Illinois State University. I received my Masters and Ph.D. degrees in Economics from the University of California, San Diego.

I have held my current position managing the rates group since August 2014, and have been managing the demand forecasting group since April 2013. Prior to joining SoCalGas, I worked at Southern California Edison Company from June 1999 to March 2013, holding several positions of increasing responsibility, from Senior Analyst to Manager of Price Forecasting to Manager of Long-Term Demand Forecasting. From October 1998 to May 1999, I worked at the National Economic Research Associates (NERA) as a Senior Consultant. Prior to joining NERA, I worked at SoCalGas from 1991 to 1998, holding several positions of increasing responsibility, starting as Marketing Analyst to Senior Economist in the Rate Design group to Manager of Rate Design. I also worked for about a year at the California Energy Commission in the Demand Analysis Office.

I have previously testified before the Commission.