

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

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SOUTHERN CALIFORNIA GAS COMPANY

AND

SAN DIEGO GAS & ELECTRIC COMPANY

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

November 19, 2015

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1 of providing a further breakdown of each customer class' costs into rate tiers and customer
2 charges.

3 The cost allocation testimony for SDG&E is sponsored by Ms. Schmidt-Pines, while the
4 SoCalGas testimony is provided herein. Both of the cost allocation testimonies rely on Ms.
5 Fung's revised direct testimony for the functional costs of the Transmission and Storage
6 functions¹ and the testimony of Dr. Wetzel for the consolidated demand forecast. The testimony
7 of Mr. Bonnett discusses the rate design process for SoCalGas and SDG&E and the resulting
8 proposed transportation rates.

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

- 11 (i) Customer-related (provisions for service lines, regulators, meters, call
12 centers, service representatives);
- 13 (ii) Medium Pressure Distribution System;
- 14 (iii) High Pressure Distribution System;
- 15 (iv) Local Transmission System;
- 16 (v) Backbone Transmission System; and
- 17 (vi) Storage (injection, inventory, and withdrawal).

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

- 20 (i) Core (residential, commercial/industrial, natural gas vehicle, gas air
21 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.

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

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

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

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

14 **B. Cost Allocation Principles**

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

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

19 The fundamental principle applicable to these cost studies, for purposes of allocating
20 costs to customer groups, is the concept of cost causation. Cost causation seeks to determine
21 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.

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

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

10 **C. The History of Cost Allocation Methodology**

11 To fully understand the current practice in California regarding the application of LRMC
12 concepts in cost allocation, a brief review of the chronological summary of the costing principles
13 adopted by the California Public Utilities Commission (Commission) is useful. In Decision (D.)
14 86-12-009, the Commission discussed its intent to examine various gas cost allocation
15 approaches. In that decision, the Commission indicated its preference for using marginal cost
16 principle. The Commission stated that it preferred a pricing methodology that was consistent
17 with the new gas industry structure it had adopted and that it wanted transportation services to be
18 priced in a way that would enhance economic efficiency, meet the service needs of utility
19 customers, and provide the Utilities with a fair opportunity to earn their allowed rate of return.

20 In D.86-12-009, however, the Commission adopted a “hybrid” form of embedded cost
21 methodology on an interim basis even though it stated that it had a preference for marginal cost
22 principle. The hybrid nature of embedded costs was created by the Commission, “by choosing
23 ‘flatter,’ less extreme allocation factors, which tend to spread costs more equally across the board

1 to all market segments.”³ The reliance on this form of embedded cost method recognized the
2 fact that adequate marginal cost studies and demand elasticity studies had not yet been developed
3 as a basis for setting LRMC-based rates.

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

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

16 In the 1996 BCAP (A.96-03-031), SoCalGas proposed the use of Rental method⁵ for
17 calculating LRMC for the customer-related function. TURN proposed that the customer-related
18 cost should be based on the New Customer Only method (NCO).⁶ The Commission approved
19 the NCO method in D.97-04-082. However, in D.97-08-062, the Commission modified its
20 earlier decision and adopted the Rental method. In the 1998 BCAP (A.98-10-012), SoCalGas

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.

1 again proposed the Rental method, but the Commission adopted the NCO method in D.00-04-
2 060.

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

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

13 The 2009 BCAP settlement based its “compromise cost allocation adjustments” on a mix
14 of allocation methods; LRMC was used for the Customer and Distribution functions, and
15 embedded cost was used for the Transmission and Storage functions.⁹

16 In the 2013 Triennial Cost Allocation Proceeding (TCAP), SoCalGas and SDG&E
17 proposed the Rental method for estimating customer-related LRMC in its application.¹⁰ D.14-
18 06-007 adopted a rate design settlement between SoCalGas, SDG&E, and all active parties and
19 rejected all proposed modifications to the existing cost allocation methodology proposed by
20 SoCalGas and SDG&E for Safety Enhancement costs.¹¹

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

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

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.

1 distribution—and to continue to use the embedded cost method for the transmission function.

2 The derivation of transmission embedded costs is described in the direct testimony of Ms. Fung.

3 The cost and allocation of storage assets was the subject of the direct testimony of Ms. Fung and

4 Mr. Watson in the TCAP Phase 1 Application, A.14-12-017.

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

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

14 In this TCAP, SoCalGas and SDG&E updates the LRMC and embedded cost studies to
15 reflect 2013 actual costs¹² and allocations based on 2013 underlying activities. The processes for
16 updating the studies are consistent with existing practices. These costs are then escalated to 2017
17 dollars to reflect SoCalGas and SDG&E's estimated Test Year costs for this TCAP.¹³ For the
18 customer-related and distribution functions, the marginal unit costs are then multiplied by the
19 forecasted MDMs presented in the Demand Forecast testimony of Dr. Wetzel to determine the
20 respective marginal cost revenues.

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

¹¹ D.14-06-007.

¹² See, *e.g.*, SoCalGas and SDG&E's FERC Form 2, December 31, 2013.

1 The capital-related cost component reflects the capital investment required to serve an
2 additional unit. For customer-related costs,¹⁴ this is the cost of serving an additional customer.
3 Marginal customer-related capital costs have been developed using the Rental method, which
4 reflects the annualized capital cost of hooking up an additional customer. SoCalGas and
5 SDG&E have used the Rental method because the Rental method captures the concept of LRMC
6 accurately by estimating the cost of providing an additional customer with the access to gas
7 service. In the 2013 TCAP, SoCalGas and SDG&E also proposed the Rental method. The 2013
8 TCAP Settlement, approved by D.14-06-007, adopted the marginal unit customer-related cost
9 estimates presented in Appendix B to the Settlement.

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

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

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

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

3 **B. Embedded Cost for Transmission and Storage Functions**

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

7 **III. CUSTOMER-RELATED MARGINAL UNIT COST AND MARGINAL COST**
8 **REVENUE**

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

14 **A. Marginal Capital Cost**

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

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

¹⁴ Customer-related capital costs include service lines, regulators, and meters.

¹⁵ See D.92-12-058, *mimeo*, at 38.

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

3 **1. Meter Set Assembly (MSA) Costs**

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

- 8 a) Extracted meter size, type, and service pressure level information, at the customer
9 level, from SoCalGas' Customer Information System;
- 10 b) Applied updated unit cost data for the various meter sizes, types, and service
11 pressure levels to MSA configurations at the customer level; and
- 12 c) Derived customer-class-specific marginal MSA costs as the weighted average MSA
13 costs for all customers in each customer class.

14 **2. Service Line Costs**

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

- 17 a) Extracted service line lengths, pipe types, and pipe diameter data, at the customer
18 level, from SoCalGas' Service History File;
- 19 b) Applied updated unit cost data by pipe type and diameter to the average length of
20 service lines for each customer in the various customer classes; and
- 21 c) Derived customer-class-specific marginal service line costs as the average service
22 line costs for all customers in each customer class.

1 **B. Marginal Direct O&M Costs**

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

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

9 **1. Customer Services O&M Costs**

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

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

22 Customer Services O&M costs are recorded in Federal Energy Regulatory Commission
23 (FERC) Functional Accounts 870, 878, and 879. These costs are allocated across customer
24 classes at each functional account level based on either the total time to complete the orders or

1 the total order volume. Functional Account 879.010 (Customer Services Field) is the largest
2 customer services account. These costs are allocated across customer classes based on the field
3 time recorded for each customer class.

4 **2. Customer Accounts O&M Costs**

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

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

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

22 Bill distribution and remittance, which are recorded in FERC Accounts 903.330 and
23 903.700, are another large component of Customer Accounts O&M. These accounts reflect

1 postage costs and the cost for remittance processing. The allocation of these costs across
2 customer classes is performed based on the number of active customer accounts.

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

8 **3. Meters and Regulators O&M Costs**

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

15 **4. Service Lines O&M Costs**

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

20 **5. Customer Services and Information Costs**

21 Customer Services and Information (CS&I) costs are booked to FERC Accounts 907
22 through 910. The costs associated with the Energy Efficiency and Low Income Energy
23 Efficiency programs are not part of SoCalGas' transportation rates and have been removed from

1 the total CS&I cost to derive the residual portion of the CS&I costs that are authorized in base
 2 margin.¹⁶ This residual portion of CS&I costs is included in the customer-related costs.

3 **C. Calculation of Customer-Related Marginal Cost Revenue**

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

5
$$\text{MUC_C (\$/customer)} = [\text{CAPEX}^{17} \text{ per customer} * \text{RECC}^{18}\%] + [\text{O\&M \& Loaders}]$$

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

7
$$\text{Customer-Related MCR (\$)} = \text{MUC_C} * \# \text{ of Customers}$$

8 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.

1 **IV. DISTRIBUTION-RELATED MARGINAL UNIT COST AND MARGINAL COST**
2 **REVENUE**

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

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

13 **A. MPD Marginal Unit Cost and Marginal Cost Revenue**

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

17 **1. Marginal Capital Cost**

18 Consistent with D.92-12-058 and subsequent cost allocation proceeding filings, the
19 capital-related marginal MPD cost is developed using a linear regression model, recognizing that
20 peak day demand is the cost driver for the MPD system. The regression analysis establishes the
21 relationship between cumulative load-growth-related capital investment in the MPD system (the
22 dependent variable) and cumulative peak day demand growth (the independent variable). Load-
23 growth-related investments include new business, pressure betterment, and meter and regulating
24 station investments. The period for the regression analysis is 15 years: nine years of historical

1 data (2005 – 2013) and six years of forecast data (2014 – 2019). The resulting estimated
2 coefficient of the independent variable represents the capital-related MPD marginal capital cost.

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

8 **2. Marginal Direct O&M Costs**

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

13 **3. Calculation of MPD Marginal Cost Revenue**

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

$$15 \text{ MUC_MPD (\$/MCFD}^{19}\text{)} = [\text{CAPEX per MCFD} * \text{RECC}\%] + [\text{O\&M \& Loaders}].$$

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

$$18 \text{ MPD_MCR (\$)} = \text{MUC_MPD} * \text{MCFD}$$

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

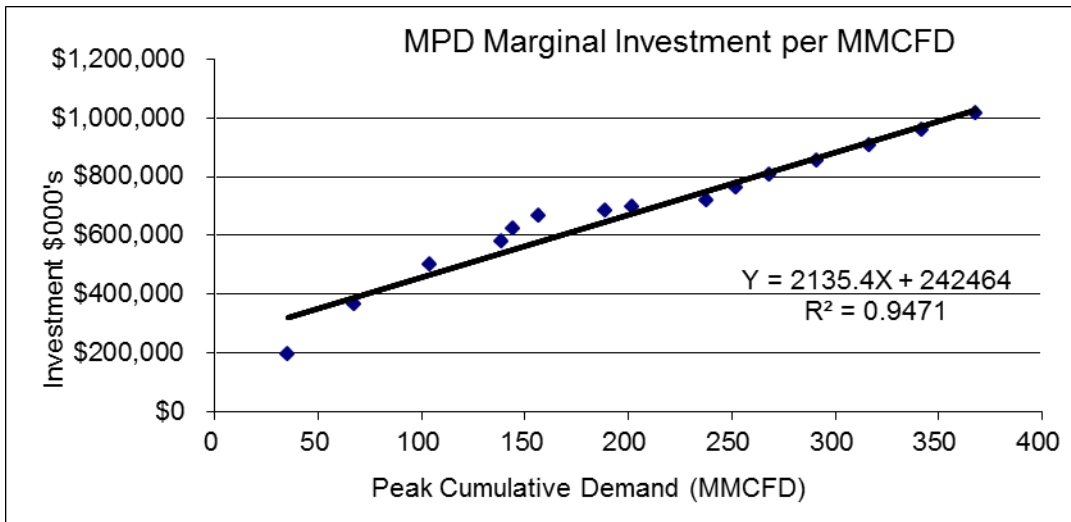
22 ¹⁹ MCFD refers to thousand cubic feet per day.

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

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Table 3



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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

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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_HPDP) cost is as follows:

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

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

$$\text{HPD_MCR } (\$) = \text{MUC_MPD} * \text{MCF/month}$$

1 Tables 5 and 6 present the derivation of marginal capital cost for HPD. Table 7 shows
 2 the HPD marginal cost, capital, and O&M combined. See Section V discusses O&M Loaders
 3 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

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 5 **Table 6**

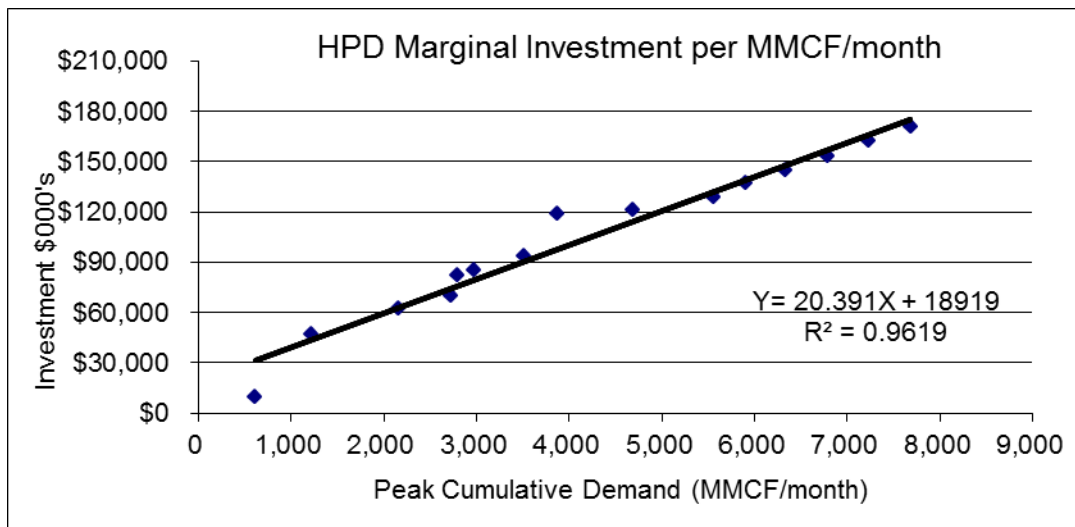


Table 7	
Marginal HP Distribution Cost	
Capital-related Charge:	
HPD Regression Coefficient \$/MCF/month	\$20.391
x RECC Factor	8.56%
= Annualized Capital-related Charge (\$/MCF/month)	\$1.75
+ Direct O&M	\$0.08
+ A&G	\$0.03
+ GP	\$0.02
+ M&S	\$0.04
= Marginal HP Distribution Cost(\$/MCF/month)	\$1.92

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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.

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

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

13 **B. O&M Loaders**

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

20 **1. A&G Loading Factor**

21 Marginal A&G expenses and payroll taxes are combined into a single loading factor.
22 This loading factor is calculated consistent with the methodology established by D.92-12-058,
23 with an adjustment to reflect the exclusion of storage and transmission-related costs. The
24 loading factor derived in Table 8 reflects the ratio of marginal A&G expenses plus payroll taxes

1 to net O&M expenses. Net O&M expenses are calculated as total O&M expenses minus the sum
2 of fuel-related expenses, total production expenses, and total A&G expenses.

3 Recorded 2013 A&G expenses have been classified as either marginal or non-marginal
4 on an account-by-account basis. Consistent with D.92-12-058, any costs that vary with either the
5 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	<u>\$49,006</u>
= 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%

6 7 **2. General Plant Loading Factor**

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

Table 9 General Plant Factor	
Total General Plant \$000	\$1,146,811
* Weighted Average RECC for General Plant	<u>15.22%</u>
= 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

1 **VI. OTHER UPDATES TO THE COST ALLOCATION OF BASE MARGIN**

2 **A. Transmission Function Costs**

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

5 **B. Storage Function Costs**

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

9 **C. NGV Compressor Costs**

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

12 **VII. RESULTS OF THE COST ALLOCATION STUDY**

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

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

19

TABLE 11 UNSCALED LONG RUN MARGINAL COST REVENUES CUSTOMER COST			
Customer Class	Customer LRMC	Customer	Customer
	\$/customer	Count	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

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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	MPD	MPD	HPD	HPD Peak	HPD
	LRMC \$/mcf	Peak Day (mcf)	Costs \$000	LRMC \$/mcf	Month Demand (mcf)	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

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

²¹ D.92-12-058, page 50.

1 functions. In this TCAP, marginal costs are scaled at a rate of 77% in order to reconcile to the
 2 base margin of \$1,668,970. 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 LRM Revenues D=A+B+C	Scalar E	Scaled LRM Revenues F=D*E
Residential	\$1,256,152	\$469,949	\$75,171	\$1,801,273	77%	\$1,382,466
Core C/I	\$147,464	\$106,015	\$21,981	\$275,461	77%	\$211,415
Gas A/C	\$53	\$12	\$7	\$72	77%	\$55
Gas Engine	\$3,788	\$717	\$257	\$4,763	77%	\$3,655
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
Noncore C/I	\$18,758	\$17,273	\$12,779	\$48,810	77%	\$37,462
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
Total Retail Noncore	\$35,435	\$22,012	\$19,263	\$76,710	77%	\$58,874
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
Total SoCalGas	\$1,454,838	\$601,252	\$118,480	\$2,174,570	77%	\$1,668,970
Calculation of Scalar: Scalar = [Base Margin - Transmission – Storage] / [Unscaled Customer + Distribution] Scalar = \$1,668,970 divided by \$2,174,570						

3
 4 After the allocation of customer and distribution functional costs across customer classes,
 5 the remaining base margin items for transmission, storage, NGV, and uncollectible costs are

1 allocated to customer classes, as shown in Table 14. Local Transmission costs²² are allocated to
2 customer classes using cold year peak month throughput, and Backbone Transmission costs²³ are
3 allocated to the Backbone Transportation Service (BTS) rate.²⁴ Storage costs²⁵ are allocated to
4 customer classes using the storage rates²⁶ (for inventory, injection, and withdrawal) applied to
5 the capacities for Core Storage, Load Balancing, and Unbundled Storage Program proposed in
6 Phase 1 of this TCAP. Uncollectible and NGV Public Access Station cost are also included.
7 The system average uncollectible rate is 0.278%. NGV Public Access Station cost is allocated to
8 the NGV class for recovery through the NGV Compressor Adder.

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

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.

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TABLE 14 ALLOCATION OF BASE MARGIN							
\$ 000							
Customer Class	Scaled LRMC Revenues	Uncollectible	BTS	Local Transmission	NGV Public Access	Storage	Allocated Base Margin
	A	B	C	D	E	F	G
Residential	\$1,382,466	\$4,354	\$0	\$23,855	\$0	\$53,855	\$1,464,529
Core C/I	\$211,415	\$720	\$0	\$7,026	\$0	\$13,478	\$232,638
Gas A/C	\$55	\$0	\$0	\$2	\$0	\$6	\$64
Gas Engine	\$3,655	\$12	\$0	\$85	\$0	\$180	\$3,933
NGV	\$9,471	\$40	\$0	\$769	\$2,440	\$1,222	\$13,943
Total Core	\$1,607,062	\$5,126	\$0	\$31,737	\$2,440	\$68,742	\$1,715,107
Noncore C/I	\$37,462	\$210	\$0	\$7,399	\$0	\$4,400	\$49,471
Small EG	\$7,236	\$27	\$0	\$457	\$0	\$280	\$8,001
Large EG	\$10,608	\$204	\$0	\$13,411	\$0	\$7,444	\$31,667
EOR	\$3,569	\$0	\$0	\$1,166	\$0	\$668	\$5,403
Retail Noncore	\$58,874	\$441	\$0	\$22,434	\$0	\$12,793	\$94,542
Long Beach	\$680	\$0	\$0	\$594	\$0	\$212	\$1,486
SDG&E	\$1,161	\$0	\$0	\$8,357	\$0	\$11,092	\$20,610
Southwest Gas	\$612	\$0	\$0	\$628	\$0	\$189	\$1,429
Vernon	\$414	\$0	\$0	\$485	\$0	\$274	\$1,173
DGN	\$166	\$0	\$0	\$455	\$0	\$264	\$885
Total Wholesale	\$3,033	\$0	\$0	\$10,520	\$0	\$12,030	\$25,583
UBS	\$0	\$0	\$0	\$0	\$0	\$17,020	\$17,020
BTS			\$150,206				\$150,206
Total Noncore	\$61,908	\$441	\$150,206	\$32,953	\$0	\$41,843	\$287,351
Total SoCalGas	\$1,668,970	\$5,567	\$150,206	\$64,690	\$2,440	\$110,585	\$2,002,458

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1 **VIII. COMPARISON OF PROPOSED COST ALLOCATION TO CURRENT COST**
2 **ALLOCATION**

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

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

TABLE 15				
COST ALLOCATION COMPARISON				
\$ 000				
Customer Class	Proposed	% Total	Current	% Total
	Allocation of		Allocation of	
	Base Margin		Base Margin	
	A	B	C	D
Residential	\$1,464,529	73.1%	\$1,435,087	72.3%
Core C/I	\$232,638	11.6%	\$277,662	14.0%
Gas A/C	\$64	0.0%	\$74	0.0%
Gas Engine	\$3,933	0.2%	\$2,071	0.1%
NGV	\$13,943	0.7%	\$9,940	0.5%
Total Core	\$1,715,107	85.7%	\$1,724,834	86.9%
Noncore C/I	\$49,471	2.5%	\$57,226	2.9%
Small EG	\$8,001	0.4%	\$4,577	0.2%
Large EG	\$31,667	1.6%	\$31,375	1.6%
EOR	\$5,403	0.3%	\$5,004	0.3%
Total Retail Noncore	\$94,542	4.7%	\$98,182	4.9%
Long Beach	\$1,486	0.1%	\$1,357	0.1%
SDG&E	\$20,610	1.0%	\$14,782	0.7%
Southwest Gas	\$1,429	0.1%	\$1,294	0.1%
Vernon	\$1,173	0.1%	\$974	0.0%
DGN	\$885	0.0%	\$611	0.0%
Total Wholesale	\$25,583	1.3%	\$19,017	1.0%
UBS	\$17,020	0.8%	\$26,476	1.3%
BTS	\$150,206	7.5%	\$116,052	5.8%
Total Noncore	\$287,351	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.

1 **IX. QUALIFICATIONS**

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

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

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

18 I have previously testified before the Commission.