Application No: A.11-11-002
Exhibit No.: ______________________
Witness: Gary Lenart

In the Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for Authority to Revise Their Rates Effective January 1, 2013, in Their Triennial Cost Allocation Proceeding	)))))))	A.11-11-002 (Filed November 1, 2011)

REVISED UPDATED PREPARED DIRECT TESTIMONY

OF GARY LENART

SAN DIEGO GAS & ELECTRIC COMPANY

AND

SOUTHERN CALIFORNIA GAS COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

February 22, 2013

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REVISED UPDATED PREPARED DIRECT TESTIMONY

OF GARY LENART

I. QUALIFICATIONS

My name is Gary G. Lenart. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011. I am employed by the Southern California Gas Company (SoCalGas) as Natural Gas Rate Manager for SoCalGas and San Diego Gas and Electric Company (SDG&E).

I hold a Bachelor of Science degree in Business Finance and Computer Science from Bradley University in Peoria, Illinois and a Master of Business Administration from California State University at Northridge, California. I have been employed by SoCalGas since 1988, and have held positions of responsibilities as a General Ledger Accountant for Pacific Interstate Company (an interstate pipeline affiliate), a Financial Analyst for Pacific Enterprises Oil & Gas Company (an oil exploration and production affiliate), as an analyst in the Strategic Planning & Economic Analysis department, as the Financial Analyst for the New Product Development department, as a Market Advisor for the Customer Service & Information department, and as Principle Economic Analyst for the Regulatory Affairs department. I have been in my current position as Natural Gas Transportation Rates Manager since June, 2010.

As Manager of Gas Transportation Rates, I am responsible for managing the gas transportation rates for both SoCalGas and for SDG&E. This includes allocating authorized revenue requirements to customer rate classes; and, developing the design of the rate for each class; and, managing the impact on customers' monthly bills.

I have previously testified before the California Public Utilities Commission (Commission).

II. PURPOSE & OVERVIEW OF COST ALLOCATION

The purpose of my direct testimony on behalf of SoCalGas is to present the allocation of the authorized revenue requirement to customer classes. Following an overview of cost allocation, the subjects of my testimony are:

1) Customer related costs allocated at Long Run Marginal Cost (LRMC) method
2) Medium Pressure Distribution Related at LRMC
3) High Pressure Distribution Related at LRMC
4) Allocate all functional costs to rate classes
5) Scale allocated costs to the authorized revenue requirement
6) Present the Transition Adjustment and Phase-Out of adjustment

A. How This Cost Allocation Was Conducted and Relationship to Rate Design Testimony

The cost allocation and rate design process is defined in the testimony of Mr. Mock, Ms. Fung, Mr. Bonnett and my testimony offered herein. Cost allocation refers to the process of determining the cost of each utility function and allocating these functions to the customer classes. Rate design refers to the process of integrating transmission function costs between the utilities, incorporating authorized costs which are not included in the authorized revenue requirement (such as unaccounted for gas and costs for automatic meter reading), including amounts in regulatory and balancing accounts which are to be collected in transportation rates, and, providing a further break down of each class into rate tiers and customer charges.

The cost allocation testimony for SDG&E is provided by Mr. Mock, while the SoCalGas testimony is provided herein. Both of the cost allocation testimonies rely on the testimony of Ms. Fung for the functional costs of the Transmission and Storage functions; and the testimony of Mr. Wetzel for the Demand Forecast. The two testimonies of Mr. Bonnett then provide the rate design process for SoCalGas and SDG&E, respectively; and is where the proposed transportation rates may be found.

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

(i) Customer Cost (Service lines, regulators, meters, call centers, service representatives);

(ii) Medium Pressure Distribution;

(iii) High Pressure Distribution;

(iv) Local Transmission System;

(v) Backbone Transmission System; and

(vi) Storage Functions (core reliability, load balancing, unbundled storage program).

Once that was complete, the cost of each function was then allocated to each customer class. The customer classes are:

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

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

(ix) Other (backbone transmission service, unbundled storage program).

After the costs of each function have been allocated to the customer classes, the allocation was scaled to the base margin.[1] This ensures that only the authorized amount is being used to determine the rates.

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

Once the cost allocation process of functionalizing costs, allocating them to classes, and scaling to the base margin amount have been completed, the rate design process begins. The rate design process consists of integrating transmission function costs between the utilities, incorporating authorized costs which are not included in the base margin (such as unaccounted for gas and costs for automatic meter reading), including amounts in regulatory and balancing accounts which are to be collected in transportation rates, and providing a further break down of the costs 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 were followed:

1. Costs are to be allocated to customer classes based on cost causality;
2. Avoid rate shock and keep a customer perspective; and
3. Maintain consistency with current practice whenever possible.

The fundamental and underlying principle applicable to this cost study, for purposes of allocating costs to customer groups, is based on 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 therefore necessary to establish a linkage 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 shock, keeping a customer perspective and consistent practice are also principles that were followed. While fully cost-based rates are preferred, SoCalGas and SDG&E realize that the impact on customers is an important principle to follow when allocating costs and setting rates. Even though our cost allocation method is sound, SDG&E and SoCalGas recognize that it can be difficult for an end-use customer to understand why the same transportation service they received one day costs more the next day. Especially, in these economic conditions SoCalGas and SDG&E want to do everything possible to mitigate significant rate shock in utility service.

C. The History of Cost Allocation

To fully understand the current situation in California surrounding LRMC concepts, it is necessary to first provide a brief chronological summary of the costing principles adopted by the Commission in conducting cost allocation studies for gas utilities. The desire on the part of the Commission to examine various gas cost allocation approaches was discussed in Decision (D.) 86-12-009. In that decision, the Commission indicated its theoretical preference for marginal cost. 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.

However, in D.86-12-009 the Commission adopted a "hybrid" form of embedded cost on an interim basis even though it had a theoretical preference for marginal cost. 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."[2] The reliance on this form of embedded costs 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 in various venues before the Commission on the methodological and computational details of LRMC. In D.90-01-021, the Commission stated its intentions 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,

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[2] See D.86-12-009, mimeo at 24.

the Commission set final guidelines for estimating LRMC, with the intention of implementing the methodology in test year 1992 cost allocation proceedings.

In late 1992, in D.92-12-058, the Commission adopted an LRMC methodology for the three gas utilities – Pacific Gas and Electric Company (PG&E), SoCalGas, and SDG&E. All gas utilities were required to adopt the LRMC methodology for implementation by early 1993. In light of this expedited time schedule, the Commission stated that, "The next 1993 and 1994 Biennial Cost Allocation Proceedings (BCAP)s (following implementation) is the forum that best provides the three respondents an opportunity to update LRMC methodology."[3] The dynamic nature of LRMC is noticed by the updating and fine-tuning of the gas utilities' LRMC methodologies that has continued in every SoCalGas and SDG&E cost allocation proceeding since implementation of LRMC in 1993.

The next BCAP was in 1996. This BCAP (A.96-03-031) proposed LRMC-Rental and LRMC-NCO (New Customer Only method) was approved in D.97-04-082. However, in D.97-08-062 the Commission modified its decision and retained the rental method.

In the 1998 BCAP (A.98-10-012) LRMC-Rental was proposed and LRMC-NCO was adopted in D.00-04-060.

In the 2009 BCAP, SoCalGas proposed the Embedded Cost method in its application, along with the LRMC for the Compliance Case.[4] 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."[5]

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[3] See D.92-12-058, mimeo at 63.
[4] A.08-02-001.
[5] D.09-11-006.

While the 2009 BCAP ended with a "compromise cost allocation adjustments" settlement, it was based on a mix of allocation methods in that LRMC was used for Customer and Distribution functions and Embedded Cost was used for the Transmission and Storage functions.[6]

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

SDG&E and SoCalGas are proposing to continue the LRMC method for the three major functional categories: customer-related, medium pressure distribution, and high pressure distribution; and embedded cost method for Transmission and Storage functions. The Transmission and Storage cost are found in the testimony of Ms. Fung.

A. LRMC Method for Customer Related and Distribution Related Functions

The theory of LRMC allocation is to allocate costs based on the marginal cost required to serve one more unit, as opposed to embedded cost which bases the functional cost on the historic costs of that function. For customer-related costs, the units are the number of customers. For distribution-related costs, the units are cubic feet per day or cubic feet per month.

In this Triennial Cost Allocation Proceeding (TCAP), SDG&E and SoCalGas updated its LRMC study to reflect 2010 actual costs and allocations based on 2010 activities. The process was consistent with current practice and follows the 1992 LRMC D.92-12-058 in developing the appropriate marginal unit costs for each functional category.[7] These costs are then escalated to 2013 dollars to reflect SDG&E and SoCalGas' estimated marginal unit cost for the TCAP period.[8] These marginal unit costs are then multiplied by the proposed Marginal Demand Measures (MDMs) presented in the Demand Forecast testimony of Mr. Wetzel to determine the Total System Marginal Cost Revenue.

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[6] D.09-11-006.

[7] Functional categories are Customer-related and Distribution-related functions, transmission and storage functions provided via embedded cost method in testimony of Ms. Sim-Cheng Fung.

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

The capital-related cost component reflects the capital investment required to serve an additional unit. In the case of customer-related costs,[9] this is the cost of serving an additional customer. For demand-related costs, this is the cost of serving an additional increment of throughput.[10] Marginal customer-related capital costs have been developed using the rental method, which reflects the annualized capital cost of new hookups. Marginal distribution capital costs have been developed using a linear regression model to determine the relationship between demand growth and investment over a 10-year historical and 5-year forecast period.

The marginal customer-related capital costs are developed using the Rental method because it reflects the annualized cost of a new customer. This method reflects the "rent" that a customer pays. Another method which has been proposed in the past uses a present value cost of a new customer instead of the annualized cost. This represents the "ownership" of customer costs. The problem with this "ownership" method is that it does not include the true economic cost of ownership, like the Rental method does, because it does not include the opportunity cost that is incurred by having money spent on owning an asset rather than renting it.

Also, using the present value cost, as opposed to the annualized cost, is more suited to ranking alternative investments that have differing costs and differing time horizons (including both differences in start dates and end dates). However, since this TCAP proposal is for a specific time period of 3 years starting in 2013 and ending in 2015, and it is not being used to rank investments options, the proposed method using the annualized cost during TCAP period is a better indication of the cost of the function.

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[8] Escalation factors updated to reflect Global Insights data for first quarter of 2011.
[9] Customer-related capital costs are service lines, regulators and meters.
[10] Demand related capital costs are the medium and high pressure distribution systems.

In addition to capital-related costs, this study presents the O&M cost for each functional category. First, the total direct O&M costs for customer-related and demand-related 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 indirect costs associated with providing natural gas service. 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 cost for each class. These "fully-loaded" O&M costs are added to the capital-related marginal costs to develop the unit marginal cost for each functional category.

Further discussion on marginal cost calculations are presented in Sections IV and V below.

B. Embedded Cost for Transmission & Storage Functions

SoCalGas is proposing to use the embedded cost of the transmission and storage functions as proposed in the testimony of Ms. Fung.

IV. MARGINAL UNIT CUSTOMER-RELATED COST (for service lines, regulators, meters, billing, call centers, service reps, etc. $/customer)

Customer-related marginal cost reflects "the cost of a customer's access to the gas utility's supply system."[11] The marginal customer cost is comprised of: (1) the marginal capital cost of service lines, regulators and meters (SRM); and (2) the marginal O&M costs associated with SRM, Customer Services, and Customer Accounts.

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.

[11] See D.92-12-058, mimeo, p. 38.

For residential and small core commercial and industrial customers, marginal per unit capital costs are calculated using the actual costs of new customer hookups in SoCalGas' service territory for the year 2010. For other customer classes, the cost of all customers (not just new customers) belonging to a specific customer class are used to estimate marginal MSA and service line costs because of low customer growth rates and the large meter cost diversity.

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 to receive gas and the direct labor cost for installing the equipment. Consistent with prior BCAPs, the marginal costs of MSAs have been updated in the following manner:

a) Meter size, type, and service pressure level information, at the customer level, were extracted from the Customer Information System (CIS).

b) Updated unit cost data for the various meter sizes, types, and service pressure levels are applied to MSA configurations at the customer level.

c) Customer-class-specific marginal MSA costs are the average MSA costs for all customers in each customer class.

2. Service Line Costs

Consistent with D.92-12-058 and subsequent BCAP applications, the marginal costs of service lines have been updated in the following manner:

a) Service line lengths, pipe types, and pipe diameter data, at the customer level, were extracted from SoCalGas' service history file.

b) Updated unit cost data by pipe type and diameter are applied to the average length of service lines for each customer in the various customer classes.

c) Customer-class-specific marginal service lines costs are the average service line costs for all customers in each customer class.

B. Marginal 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 VI, are applied to direct O&M costs to derive fully-loaded O&M costs.

The updated customer-class-specific O&M costs use year 2010 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 generalized 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' Portable Automated Centralized Electronic Retrieval (PACER) system which is SoCalGas' customer services dispatching system. The PACER system tracks orders by time to complete for each activity and 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. For activities where all orders are processed at approximately the same cost, the order volume is used to allocate costs across customer classes. Functional Account 880.302 (Customer Services Dispatch) is an example of costs allocated by order volume.

2. Customer Accounts O&M Costs

Customer Accounts O&M costs are booked to FERC Accounts 901-905. Customer Contact Center, meter reading, and bill distribution are the primary activities reflected in these accounts. Specifically, these accounts include the recorded expenses incurred to receive calls from customers requesting service, obtain monthly-metered gas consumption data of over 5 million 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 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. Customer Contact Center costs are allocated among customer classes based on the number of accounts and the weighted call volume. 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 901, 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 2010[12]. Since 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 & 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 transportation rates and have been removed from the

[12] For the 2009 BCAP, service line O&M costs were allocated to each customer class based on each class' share of the combined total of the other three direct O&M costs: Customer Services, Customer Accounts, and Meters and

allocation of CS&I costs.[13] The CS&I costs that are to be recovered through transportation rates are initially included in the customer-related costs. These costs are then removed from the customer-related function and are allocated separately as discussed in Section VIII.4.

C. Calculation of Marginal Unit Customer Costs

The calculation of Marginal Unit Customer cost is as follows:

$/customer = [CAPEX per customer * RECC%] + [O&M & Loaders]

Customer-Related costs are then allocated to classes based on:

$/customer class = $/customer * # Customers/class

The following table demonstrates the calculations for Marginal Customer Costs.[14]

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	$1,308.85	9.13%	$119.46	$96.74	$216.19
Core C/I	$5,702.08	9.22%	$525.75	$232.50	$758.25
Gas A/C	$19,070.98	9.35%	$1,783.87	$2,620.18	$4,404.06
Gas Engine	$44,609.02	9.06%	$4,043.18	$1,055.57	$5,098.75
NGV	$38,013.84	9.53%	$3,624.54	$937.61	$4,562.15
Noncore C/I	$201,320.50	9.46%	$19,052.77	$14,685.05	$33,737.82
Small EG	$201,599.97	9.50%	$19,149.88	$13,485.11	$32,635.00
Large EG	$1,087,772.05	9.69%	$105,416.39	$13,050.97	$118,467.35
EOR	$394,879.66	9.60%	$37,900.80	$11,795.62	$49,696.43
Long Beach	$5,599,024.93	9.82%	$549,895.42	$62,764.16	$612,659.58
SDG&E	$13,198,289.20	9.82%	$1,296,239.77	$50,670.69	$1,346,910.45
Southwest Gas	$4,110,851.76	9.82%	$403,737.90	$106,243.38	$509,981.28
Vernon	$2,784,119.95	9.82%	$273,435.97	$5,630.44	$279,066.41
DGN	$669,749.44	9.82%	$65,777.91	$14,347.22	$80,125.13
UBS	n/a	n/a	n/a	n/a	n/a
BTS	n/a	n/a	n/a	n/a	n/a

Regulators O&M costs because service line footage information by class was not available at the time. This information is available for this TCAP.

[13/] The EE and LIEE costs are recovered through a separate surcharge.

[14] See Section VI for O&M Loaders and RECC Factors.

V. MARGINAL UNIT DISTRIBUTION-RELATED COST

Consistent with D.92-12-058, distribution costs have been classified as customer-related or demand-related. Customer-related costs were addressed in Section IV. This section addresses the marginal cost of demand-related distribution costs. The marginal cost for distribution consists of three types of costs: capital-related, direct O&M, and indirect O&M. The demand-related distribution capital costs are reflected in the plant accounts for mains (Account 376) and measuring & regulating station equipment (Account 378). Distribution O&M costs are reflected in Accounts 874, 875, 887, and 889 for mains and measuring & regulating (M&R) stations. The indirect costs are included by applying the O&M loaders discussed in Section VI.

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). This segmentation is appropriate because a significant portion of SoCalGas' total load is served directly off the high-pressure distribution system.

A. Medium-Pressure Distribution (MPD) Marginal Cost

The MPD marginal cost consists of an annualized capital-related cost and the fully-loaded marginal O&M cost. The derivation of each is described below.

1. Marginal Capital Cost

Consistent with D.92-12-058, and subsequent BCAP filings, the capital-related marginal MPD cost is developed using a linear regression model. The regression analysis establishes the relationship between cumulative peak-day demand growth (the independent variable) and cumulative load-growth-related capital investment in the MPD system (the dependent variable). Load-growth-related investment includes new business, pressure betterment and meter and regulating station investment. The period for the regression analysis is 15 years: 10 years of historical data (2001 – 2010) and 5 years of forecast data (2011 – 2015). The resulting estimated coefficient of the independent variable represents the capital-related MPD marginal 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 O&M Costs

The marginal O&M costs for the MPD system include direct O&M costs and O&M loaders. The year 2010 recorded direct distribution O&M costs are allocated between medium-pressure and high-pressure systems based on the split in total distribution investment between the medium and high-pressure distribution systems. Table 2 shows the direct and indirect marginal O&M costs.

3. Calculation of Marginal MPD Costs

The resulting marginal capital cost and marginal O&M costs for MPD are presented in Tables 2 thru 4. The MPD marginal cost, capital and O&M combined, is shown on Table 4. See Section VI for O&M Loaders and RECC Factors.

The calculation of Marginal Unit MPD cost is as follows:

$/mmcfd = [CAPEX per mmcfd * RECC%] + [O&M & Loaders]

The following table demonstrates the calculations for Marginal Unit Investment per mmcfd (or CAPEX per mmcfd).

Table 2		
Year	Cumulative MMCFD	Cumulative CAPEX $000's
2001	33	$48,407
2002	71	$106,860
2003	106	$202,223
2004	141	$276,032
2005	174	$393,377
2006	216	$495,752
2007	251	$577,099
2008	256	$621,791
2009	269	$649,536
2010	289	$677,478
2011	345	$710,430
2012	373	$744,132
2013	405	$778,599
2014	440	$813,845
2015	478	$849,885

Table 3

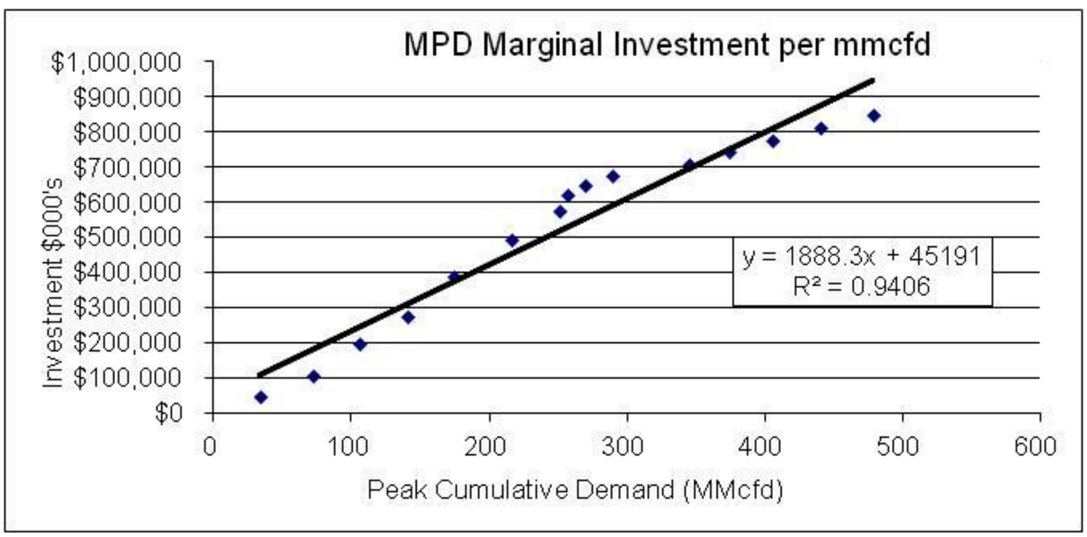

Table 4	
Marginal MP Distribution Cost	
Capital-related Charge:	
MPD Regression Coefficient $/mcfd	$1,888.28
x RECC Factor	8.88%
= Annualized Capital-related Charge ($/Mcfd)	$167.72
+ Direct O&M	$6.94
+ A&G	$3.38
+ GP	$1.70
+ M&S	$0.25
= Marginal MP Distribution Cost($/Mcfd)	**$179.99**

B. High-Pressure Distribution (HPD) Marginal Cost

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 investments in the HPD system are regressed against cumulative load growth. Consistent with the methodology adopted in D.92-12-058, and used in subsequent BCAPs, the coincident peak-month demand served off the HPD system is used as the measure of customer load for the HPD system.

The resulting marginal capital cost and marginal O&M costs for HPD are presented in Tables 5 thru 7. The HPD marginal cost, capital and O&M combined, is shown on Table 7. See Section VI for O&M Loaders and RECC Factors.

The calculation of Marginal Unit HPD cost is as follows:

$/mmcf/month = [CAPEX per mmcf/month * RECC%] + [O&M & Loaders]

The following table demonstrates the calculations for Marginal Unit Investment per mmcf/month (or CAPEX per mmcf/month).

Table 5		
Year	**Cumulative MMCF/ month**	**Cumulative CAPEX $000's**
2001	573	$28,032
2002	1,270	$45,535
2003	1,939	$62,318
2004	2,558	$76,520
2005	3,153	$85,178
2006	4,109	$117,701
2007	4,663	$130,837
2008	4,732	$137,135
2009	4,922	$148,122
2010	5,252	$150,770
2011	6,900	$159,745
2012	7,376	$168,902
2013	7,914	$178,244
2014	8,505	$187,773
2015	9,129	$197,491

Table 6

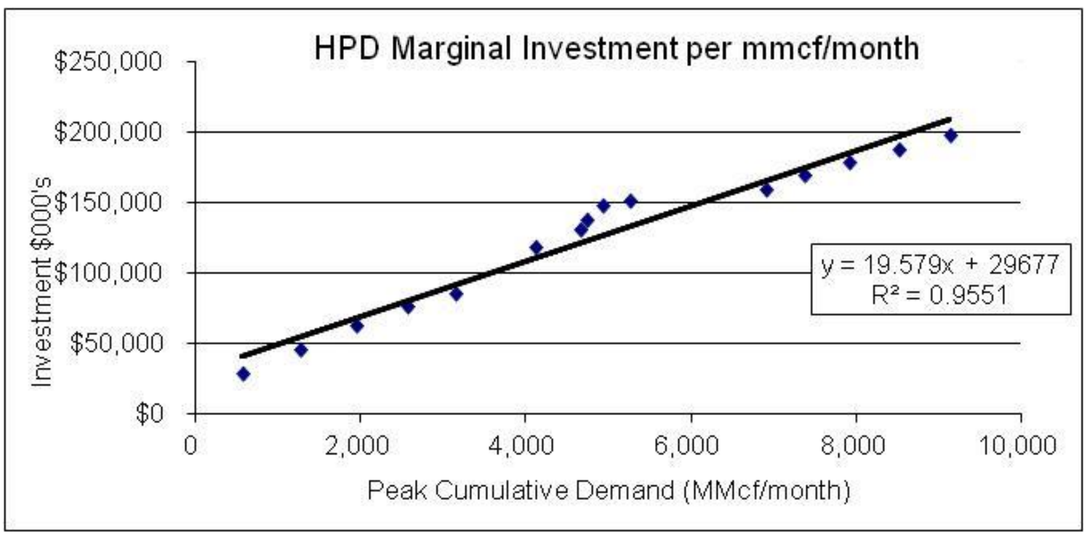

Table 7	
Table Marginal HP Distribution Cost	
Capital-related Charge:	
HPD Regression Coefficient $/mcf/month	$19.58
x RECC Factor	8.87%
= Annualized Capital-related Charge ($/Mcf/month)	$1.74
+ Direct O&M	$0.08
+ A&G	$0.04
+ GP	$0.02
+ M&S	$0.00
= Marginal MP Distribution Cost($/Mcf/month)	**$1.87**

VI. INDIRECT COST LOADING FACTORS DEVELOPED FOR LRMC STUDY

A. Real Economic Carry 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."[15]

The RECC factors used Tables 1, 4 and 7 are the weighted average for the function; 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, distribution, and transmission capital investments.

SoCalGas has updated its RECC factors using inflation assumptions from the Global Insight forecast report, updated tax rates, and SoCalGas' discount rate of 8.68%, revised per AL 3199-A. 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 costs 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 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.

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

Recorded year 2010 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	$209,854
+ Total Payroll Taxes $000	$39,358
= Marginal A&G and Payroll Taxes $000	$249,212
/ Net O&M Costs $000	$511,809
= Marginal A&G Loading Factor as a % of O&M	**48.69%**

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 2010 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 2010 are used to calculate a weighted average RECC factor. This factor is then applied to gross general plant in service as of December 31, 2010 to derive an annualized cost for general plant. This annualized general plant cost is divided by year 2010 net O&M expenses to derive the general plant loading factor. Like the A&G loading factor, the general plant loading factor reflects the exclusion of storage and transmission-related costs.

Table 9 General Plant Factor	
Total General Plant $000	$719,315
* Weighted Average RECC for General Plant	17.41%
= Annualized General Plant Costs	$125,199
/ Net Recorded O&M Costs $000	$511,809
= General Plant Loading Factor as a % of O&M	**24.46%**

3. 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 year 2010 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 2010 M&S costs and the derivation of annual M&S costs for each function.

Table 10
M&S Annual Costs

Function	2013$
Customer Related $000	$1,142
Load Related $000	$1,332
Total	**$2,474**

VII. OTHER UPDATES TO THE COST ALLOCATION OF BASE MARGIN

A. Transmission Function Costs

Transmission Costs have been updated to the amount proposed in the 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 testimony of Ms. Fung.

C. NGV Compressor Costs

NGV Compressor Costs have been updated to the amount set forth in the SoCalGas testimony of Mr. Bonnett.

D. Allocation of Core Storage Costs between SoCalGas and SDG&E

SoCalGas is proposing to allocate costs of core storage between SoCalGas and SDG&E as proposed in the testimony of Mr. Emmrich.

VIII. RESULTS OF THE COST ALLOCATION STUDY

Upon completing the cost functionalization studies, SoCalGas allocates each function to customer classes using the appropriate Marginal Demand Measure (MDM). Each MDM reflects the forecast annual average for the 2013 – 2015 TCAP period. These are shown in Tables 11, 12 and 13 and the results of the cost allocation study are shown in Table 14.

Customer-related costs are allocated using the number of customer per class (as shown in Table 11).

TABLE 11 UNSCALED LONG RUN MARGINAL COSTS CUSTOMER COST			
Customer Class	Customer LRMC $/customer A	Customer Count B	Customer Costs $000 C
Residential	$216	5,548,854	$1,199,620
Core C/I	$758	210,450	$159,574
Gas A/C	$4,404	9	$38
Gas Engine	$5,099	700	$3,567
NGV	$4,562	296	$1,350
Total Core			$1,364,150
Noncore C/I	$33,738	682	$22,998
Small EG	$32,635	142	$4,649
Large EG	$118,467	66	$7,860
EOR	$49,696	32	$1,590
Total Retail Noncore			$37,097
Long Beach	$612,660	1	$613
SDG&E	$1,346,910	1	$1,347
Southwest Gas	$509,981	1	$510
Vernon	$279,066	1	$279
DGN	$80,125	1	$80
Total Wholesale			$2,829
UBS	$0	0	$0
BTS	$0	0	$0
Total Noncore			$39,926
Total SoCalGas			**$1,404,076**

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 (as shown in Table 12).

TABLE 12
UNSCALED LONG RUN MARGINAL COSTS
DISTRIBUTION COSTS

Customer Class	MPD LRMC $/mcfd	MPD Peak Day (mcfd)	MPD Costs $000	HPD LRMC $/mcfd	HPD Peak Month Demand (mcf)	HPD Costs $000
	A	B	C	D	E	F
Residential	$179.99	2,423,466	$436,191	$1.87	40,249,793	$75,305
Core C/I	$179.99	559,914	$100,777	$1.87	11,666,205	$21,827
Gas A/C	$179.99	69	$12	$1.87	3,518	$7
Gas Engine	$179.99	1,770	$319	$1.87	67,159	$126
NGV	$179.99	15,045	$2,708	$1.87	1,001,304	$1,873
Total Core			$540,007			$99,137
Noncore C/I	$179.99	88,180	$15,871	$1.87	6,700,189	$12,536
Small EG	$179.99	6,116	$1,101	$1.87	302,056	$565
Large EG	$179.99	7,012	$1,262	$1.87	3,544,230	$6,631
EOR	$179.99	28	$5	$1.87	667,888	$1,250
Total Retail Noncore			$18,239			$20,981
Long Beach	$179.99	0	$0	$1.87	0	$0
SDG&E	$179.99	0	$0	$1.87	0	$0
Southwest Gas	$179.99	0	$0	$1.87	0	$0
Vernon	$179.99	0	$0	$1.87	0	$0
DGN	$179.99	0	$0	$1.87	0	$0
Total Wholesale			$0			$0
UBS	$179.99	0	$0	$1.87	0	$0
BTS	$0.00	0	$0	$0.00	0	$0
Total Noncore			$18,239			$20,981
Total SoCalGas			**$558,247**			**$120,119**

Total Customer-Related, Distribution-Related and Customer Service & Information related costs allocated at the "CSI Allocator" are shown in Column E of Table 13. This is the un-scaled costs which are scaled to the base margin amount in Column G. 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." The scalar is employed to adjust the proposed marginal cost revenues to the base margin, excluding cost directly allocated to the Transmission, Storage, Uncollectibles and NGV Public Access functions. In this TCAP, marginal costs are scaled at a rate of 71% in order to reconcile to the base margin of $1,515,736. This process is shown on Table 13.

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

Customer Class	Customer Cost	MPD	HPD	Customer Service & Info	Unscaled LRMC Revenues	Scalar	Scaled LRMC Revenues
	A	B	C	D	E=A+B+C+D	F	G=E*F
Residential	$1,199,620	$436,191	$75,305	$30,156	$1,741,272	71%	$1,236,552
Core C/I	$159,574	$100,777	$21,827	$15,341	$297,519	71%	$211,281
Gas A/C	$38	$12	$7	$0	$57	71%	$41
Gas Engine	$3,567	$319	$126	$4	$4,016	71%	$2,852
NGV	$1,350	$2,708	$1,873	$3,026	$8,958	71%	$6,362
Total Core	$1,364,150	$540,007	$99,137	$48,527	$2,051,822	71%	$1,457,087
Noncore C/I	$22,998	$15,871	$12,536	$299	$51,703	71%	$36,717
Small EG	$4,649	$1,101	$565	$85	$6,400	71%	$4,545
Large EG	$7,860	$1,262	$6,631	$1,264	$17,016	71%	$12,084
EOR	$1,590	$5	$1,250	$820	$3,665	71%	$2,603
Total Retail Noncore	$37,097	$18,239	$20,981	$2,467	$78,785	71%	$55,949
Long Beach	$613	$0	$0	$227	$840	71%	$596
SDG&E	$1,347	$0	$0	$215	$1,562	71%	$1,109
Southwest Gas	$510	$0	$0	$249	$759	71%	$539
Vernon	$279	$0	$0	$184	$463	71%	$329
DGN	$80	$0	$0	$100	$180	71%	$128
Total Wholesale	$2,829	$0	$0	$975	$3,803	71%	$2,701
UBS	$0	$0	$0	$0	$0	71%	$0
BTS	$0	$0	$0	$0	$0	71%	$0
Total Noncore	$39,926	$18,239	$20,981	$3,442	$82,588	71%	$58,649
Total SoCalGas	**$1,404,076**	**$558,247**	**$120,119**	**$51,969**	**$2,134,410**	**71%**	**$1,515,736**

Calculation of Scalar:
Scalar = [Base Margin - Transmission – Storage] / [Unscaled Customer + Distribution]
Scalar = $1,515,736 / $2,134,410 = 71%

Now that the customer, distribution and customer service & information costs have been allocated, the remaining base margin items for transmission, storage, NGV and un-collectible costs need to be allocated. This is shown in Table 14. Local Transmission costs[16] are allocated to customer classes using cold year peak month throughput and Backbone Transmission costs[17] are allocated to the Backbone Transmission Service (BTS) rate.[18] Storage costs[19] are allocated to customer classes using the storage rates[20] (for inventory, injection and withdrawal) applied to the capacities of Core Storage, Load Balancing and Unbundled Storage Program that are authorized in 2009 BCAP Phase 1 Decision. Un-collectibles and NGV Public Access Station costs are included. The system average uncollectible rate is 0.238% and NGV Public Access is allocated to NGV class for recovery through the NGV Compressor Adder.

Finally, scaled LRMC costs are combined with the Transmission, Storage, Uncollectibles 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 (expressed in thousands of dollars) and represents a completely cost based allocation without any adjustments for core averaging or the adjustments agreed to in the 2009 BCAP settlement agreement.

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[16] As presented in the testimony of Ms. Fung.
[17] As presented in the testimony of Ms. Fung.
[18] Backbone Transmission Service (BTS) is service from a receipt point to the city-gate and is recovered from core customers through the procurement rate (Schedule G-CP); and, non-core customers purchase directly from SoCalGas or purchase supplies at the city-gate from a marketer who has purchased BTS.
[19] As presented in the testimony of Ms. Fung.
[20] As presented in the testimony of Ms. Fung.

TABLE 14
ALLOCATION OF BASE MARGIN

$ 000

Customer Class	Scaled LRMC Revenues	Uncollect	BTS	Local Trans	NGV Public Access	Storage	Allocated Base Margin
	A	B	C	D	E	F	G
Residential	$1,236,552	$3,289	$0	$19,052	$0	$38,558	$1,297,450
Core C/I	$211,281	$596	$0	$5,569	$0	$11,314	$228,760
Gas A/C	$41	$0	$0	$2	$0	$1	$43
Gas Engine	$2,852	$8	$0	$33	$0	$17	$2,909
NGV	$6,362	$22	$0	$619	$1,150	$498	$8,651
Total Core	$1,457,087	$3,915	$0	$25,275	$1,150	$50,387	$1,537,814
Noncore C/I	$36,717	$152	$0	$5,716	$0	$1,662	$44,247
Small EG	$4,545	$14	$0	$193	$0	$68	$4,819
Large EG	$12,084	$149	$0	$10,538	$0	$3,314	$26,085
EOR	$2,603	$0	$0	$588	$0	$165	$3,356
Retail Noncore	$55,949	$315	$0	$17,036	$0	$5,208	$78,507
Long Beach	$596	$0	$0	$476	$0	$93	$1,165
SDG&E	$1,109	$0	$0	$6,449	$0	$7,171	$14,730
Southwest Gas	$539	$0	$0	$517	$0	$74	$1,130
Vernon	$329	$0	$0	$421	$0	$89	$838
DGN	$128	$0	$0	$246	$0	$73	$447
Total Wholesale	$2,701	$0	$0	$8,109	$0	$7,500	$18,309
UBS	$0	$0	$0	$0	$0	$26,476	$26,476
BTS			$116,052				$116,052
Total Noncore	$58,649	$315	$116,052	$25,145	$0	$39,184	$239,345
Total SoCalGas	**$1,515,736**	**$4,230**	**$116,052**	**$50,420**	**$1,150**	**$89,571**	**$1,777,159**

IX. SOCALGAS AND SDG&E COST ALLOCATION ADJUSTMENTS AND PHASE-OUT PERIOD

A. Rate Impact of Fully Cost Based Allocation

The rates which would result from the cost allocation in Table 14, as well as in Table 12 in Section VII of the testimony of Mr. Mock, are shown in Table 15:[21] These rate changes are due to: (i) updating the marginal unit costs and the embedded cost studies; (ii) updating the demand forecast; (iii) removing compromise cost adjustments from the 2009 BCAP Settlement and core averaging;[22] and (iv) any other proposals described in the testimony of Mr. Bonnett. They do not include the impacts of updating regulatory account amortizations, which will be included in the final rates presented in Mr. Bonnett's testimony.

[21] The rates in Table 15 would result from using the allocated base margin from Table 14, as well as in Table 12 in Section VII of the testimony of Mr. Mock, and processing them through the rate design calculations discussed in the testimony of Mr. Bonnett. The rates are being shown here in order to observe the impact of allocated base margin.

[22] Since this amount is a fully cost based allocation with no adjustments added in, it is by default that the 2009 BCAP compromise cost adjustments and the core averaging has been removed.

Table 15
Fully Cost Based 2013 TCAP Rates

	2012 Current	2013TCAP No Adjustments	$/th Change	% Change
SCG:				
Res $/th	$0.544	$0.568	$0.024	4%
CCI CA $/th	$0.299	$0.242	($0.057)	-19%
Gas A/C	$0.067	$0.079	$0.012	18%
Gas Engine	$0.088	$0.122	$0.033	37%
NGV Uncompressed post-SW $/th	$0.057	$0.059	$0.002	4%
Core Class Average $/th	$0.460	$0.457	($0.003)	-1%
NCCI-D CA $/th	$0.068	$0.053	($0.015)	-22%
EG-D Tier 1 post-SW $/th	$0.055	$0.099	$0.045	81%
EG-D Tier 2 post-SW $/th	$0.024	$0.033	$0.009	36%
TLS CA Rate csitma/efba exempt	$0.017	$0.011	($0.006)	-36%
TLS CA Rate csitma/efba non-exempt	$0.018	$0.012	($0.006)	-34%
UBS $1,000/yr	$27,530	$26,476	($1,055)	-4%
BTS w/BTBA $/dth/d	$0.110	$0.126	$0.016	15%
SAR w/ BTS $/th	$0.206	$0.199	($0.007)	-4%
SDGE:				
Res $/th	$0.592	$0.675	$0.082	14%
CCI CA $/th	$0.191	$0.135	($0.056)	-29%
NGV Uncompressed post-SW $/th	$0.058	$0.060	$0.002	4%
Core Class Average $/th	$0.449	$0.465	$0.016	4%
NCCI-D $/th	$0.122	$0.091	($0.030)	-25%
EG-D Tier 1 post-SW $/th	$0.055	$0.100	$0.045	81%
EG-D Tier 2 post-SW $/th	$0.024	$0.033	$0.009	36%
TLS CA Rate csitma/efba exempt	$0.017	$0.011	($0.006)	-36%
TLS CA Rate csitma/efba non-exempt	$0.019	$0.013	($0.006)	-33%
SAR $/th	$0.200	$0.203	$0.004	2%

As was stated earlier, our goal is to have rates which are fully cost based. However, as can be seen from Table 15 above, fully cost-based rates would result in rate increases of over 10% for five customer classes.[23] In addition to achieving fully cost based rates, SDG&E and SoCalGas are also following the customer focused principles of avoiding rate shock and maintaining consistent practices; and therefore, are concerned

[23] The customer classes with large increases are Gas A/C; Gas Engine; EG; BTS; Residential at SDGE.

over the impact on customers from such large increases. While our cost allocation method is sound, it can be difficult for an end-use customer to understand why the same transportation service they received one day costs more the next day. Especially, in these economic conditions we do not want to have significant rate shock in utility service.

As a result, SoCalGas and SDG&E are proposing a Transition Adjustment for cost allocation in this TCAP period. This is an adjustment to the allocated costs which will reduce the initial impact of moving towards fully cost based rates. The adjustments will then be phased out over time, at which time rates will be fully cost based.

The adjustments are being made to limit rate shock in this TCAP. The Commission has a history of approving "non-cost based allocation adjustments" as indicated in the approval of the settlement agreement in the 2009 BCAP Phase II decision (D.09-11-006) and also as far back as 1986 with the approval of Core-Averaging adjustments in D.86-12-009.

The Transition Adjustment shown in Table 16 is approximately $4 million at SoCalGas and $9 million at SDG&E. These adjustments amount to about 0.6% of authorized costs in rates. This is much lower than the approximately $57 million in current SoCalGas and SDG&E rates, which is 2.8% of authorized costs in rates today. This proposal will actually move closer to fully cost-based rates since, unlike the current adjustments from the 2009 BCAP settlement, the adjustments aren't static and provide a path to gradually move all rate classes to fully cost based rates and mitigating this issue in future cost allocation proceedings. The proposed cost allocation and resulting rates, including the Transition Adjustment but excluding forecasted regulatory account amortizations, is as follows in Table 16.

Table 16

2013 TCAP Transition Adjustment

	2012 Current	2013TCAP No Adj		Transition Adjustment $000	2013TCAP w/ Adjustment	$/th Change	% Change
SCG:							
Res $/th	$0.544	$0.568	4%	$0	$0.568	$0.024	4%
CCI CA $/th	$0.299	$0.242	-19%	$1,263	$0.243	($0.056)	-19%
Gas A/C	$0.067	$0.079	18%	($3)	$0.074	$0.007	10%
Gas Engine	$0.088	$0.122	37%	($1,260)	$0.097	$0.009	10%
NGV Uncompressed post-SW $/th	$0.057	$0.059	4%	$0	$0.059	$0.002	4%
Core Class Average $/th	$0.460	$0.457	-1%	$0	$0.457	($0.003)	-1%
NCCI-D CA $/th	$0.068	$0.053	-22%	$0	$0.053	($0.015)	-22%
EG-D Tier 1 post-SW $/th	$0.055	$0.099	81%	($1,725)	$0.060	$0.006	10%
EG-D Tier 2 post-SW $/th	$0.024	$0.033	36%	($900)	$0.027	$0.002	10%
TLS CA Rate csitma/efba exempt	$0.017	$0.011	-36%	$2,625	$0.012	($0.005)	-29%
TLS CA Rate csitma/efba non-exempt	$0.018	$0.012	-34%		$0.013	($0.005)	-28%
UBS $1,000/yr	$27,530	$26,476	-4%		$26,476	($1,055)	-4%
BTS w/BTBA $/dth/d	$0.110	$0.126	15%		$0.126	$0.016	15%
SAR w/ BTS $/th	$0.206	$0.199	-4%	$0	$0.199	($0.007)	-3%
SDGE:							
Res $/th	$0.592	$0.675	14%	($8,000)	$0.649	$0.057	10%
CCI CA $/th	$0.191	$0.135	-29%	$8,000	$0.179	($0.013)	-7%
NGV Uncompressed post-SW $/th	$0.058	$0.060	4%	$0	$0.060	$0.002	4%
Core Class Average $/th	$0.449	$0.465	4%	$0	$0.465	$0.016	4%
NCCI-D $/th	$0.122	$0.091	-25%	$0	$0.091	($0.030)	-25%
EG-D Tier 1 post-SW $/th	$0.055	$0.100	81%	($300)	$0.061	$0.006	10%
EG-D Tier 2 post-SW $/th	$0.024	$0.033	36%	($800)	$0.027	$0.002	10%
TLS CA Rate csitma/efba exempt	$0.017	$0.011	-36%	$1,100	$0.012	($0.005)	-29%
TLS CA Rate csitma/efba non-exempt	$0.019	$0.013	-33%		$0.014	($0.005)	-27%
SAR $/th	$0.200	$0.203	2%	$0	$0.203	$0.003	2%

B. The Transition Adjustments and Associated Phase-Out by Rate

Based on Table 15, only certain rates would experience significant rate-shock.[24] The following is a discussion of the rates having these large increases, the adjustment being made to avoid the potential for rate shock, and the phasing out of that adjustment.

[24] The customer classes with large increases are Gas A/C; Gas Engine; EG; BTS; Residential at SDG&E.

Table 16 illustrates the Adjustment and proposed rates for 2013 and Appendix 1 illustrates each year of the phase-out period.

The adjusted rate increase for the Sempra-wide EG-D1 rate in 2013 is 10%, which requires a $2 million adjustment ($1.7 million at SoCalGas and $300,000 at SDG&E). This level of increase was selected because any smaller increase would put off the move to cost-based rates for too long. This adjustment is then able to be phased out in a straight-line fashion over 6 years[25] until fully cost based rates are achieved.

SoCalGas and SDG&E propose to use this same 10% rate change as a benchmark for the 2013 increases in the SoCalGas core Gas A/C and core Gas Engine rates, the 2013 increase in the SDG&E core residential rate, and the 2013 increase in the Sempra-Wide EG-D2 (Tier 2) rate. These adjustments are then phased out over 3 years for the SoCalGas core Gas Engine rate and Sempra-Wide EG-D2 (Tier 2) rate, and over 1 year for the SoCalGas core Gas A/C rate and SDG&E's core residential rate.

There is no adjustment being made to the Backbone Transmission Service (BTS) rate because it is the result of a specific proposal in the testimony of Ms. Fung.

The rates for 2013 and each year of the phase-out period (excluding forecasted regulatory account amortizations) are shown in Appendix 1. Notice that the rates in year 2019 are at the same level as presented in Table 15 and are the fully cost-based rates with no adjustments.

X. COMPARISON OF PROPOSED COST ALLOCATION TO CURRENT COST ALLOCATION

The following is a comparison of the proposed cost allocation to the current allocation. This comparison is pre-System Integration and pre-BTS unbundling, which

[25] For years beyond 2015, we are only explaining an approach that may be proposed in the next TCAP to bring us to fully cost-based rates, and that the next TCAP will depend on updated cost studies, throughput forecasts and balancing account amortizations.

are discussed in the testimony of Mr. Bonnett. The results are very similar to the last BCAP. The most significant change is to the noncore C&I and the BTS rate classes. The Proposed and Current totals in Table 17 differ because of an update to the SoCalGas brokerage fee and also because of the inclusion of Honor Rancho in base margin as proposed in the testimony of Ms. Fung.

TABLE X-1 COST ALLOCATION COMPARISON $ 000				
Customer Class	Proposed Allocation of Base Margin A	% Total B	Current Allocation of Base Margin C	% Total D
Residential	$1,297,450	73.0%	$1,274,788	72.1%
Core C/I	$230,023	12.9%	$238,693	13.5%
Gas A/C	$40	0.0%	$75	0.0%
Gas Engine	$1,649	0.1%	$1,484	0.1%
NGV	$8,651	0.5%	$8,148	0.5%
Total Core	$1,537,814	86.5%	$1,523,188	86.1%
Noncore C/I	$44,247	2.5%	$63,644	3.6%
Small EG	$4,819	0.3%	$9,605	0.5%
Large EG	$26,085	1.5%	$35,258	2.0%
EOR	$3,356	0.2%	$3,684	0.2%
Total Retail Noncore	$78,507	4.4%	$112,192	6.3%
Long Beach	$1,165	0.1%	$1,636	0.1%
SDG&E	$14,730	0.8%	$8,336	0.5%
Southwest Gas	$1,130	0.1%	$1,416	0.1%
Vernon	$838	0.0%	$1,317	0.1%
DGN	$447	0.0%	$608	0.0%
Total Wholesale	$18,309	1.0%	$13,313	0.8%
UBS	$26,476	1.5%	$26,067	1.5%
BTS	$116,052	6.5%	$94,095	5.3%
Total Noncore	$239,345	13.5%	$245,667	13.9%
Total SoCalGas	**$1,777,159**	**100.0%**	**$1,768,855**	**100.0%**

This concludes my revised updated prepared direct testimony.

APPENDIX 1

Summary of Impact of Allocation on Rates

	2012 Current	2013TCAP Rates No Adj $/th	% Change from 2012	Adj $000	Proposed 2013TCAP rates w/ Adj $/th	% Change from 2012	2014 Rate $/th	% Change from prior year	2015 Rate $/th	% Change from prior year
	A	B	C	D	E	F	G	H	I	J
SCG:										
Res $/th	$0.544	$0.568	4%	$0	$0.568	4%	$0.568	0%	$0.568	0%
CCI CA $/th	$0.299	$0.242	-19%	$1,263	$0.243	-19%	$0.243	0%	$0.243	0%
Gas A/C	$0.067	$0.079	18%	($3)	$0.074	10%	$0.079	8%	$0.079	0%
Gas Engine	$0.088	$0.122	37%	($1,260)	$0.097	10%	$0.107	10%	$0.117	10%
NGV Uncompressed post-SW $/th	$0.057	$0.059	4%	$0	$0.059	4%	$0.059	0%	$0.059	0%
Core Class Average $/th	$0.460	$0.457	-1%	$0	$0.457	-1%	$0.457	0%	$0.457	0%
NCCI-D CA $/th	$0.068	$0.053	-22%	$0	$0.053	-22%	$0.053	0%	$0.053	0%
EG-D Tier 1 post-SW $/th	$0.055	$0.099	81%	($1,725)	$0.060	10%	$0.066	10%	$0.073	10%
EG-D Tier 2 post-SW $/th	$0.024	$0.033	36%	($900)	$0.027	10%	$0.029	8%	$0.031	7%
TLS CA Rate csitma/efba exempt	$0.017	$0.011	-36%	$2,625	$0.012	-29%	$0.012	-2%	$0.012	-2%
TLS CA Rate csitma/efba non-exempt	$0.018	$0.012	-34%	$0	$0.013	-28%	$0.013	-2%	$0.012	-2%
UBS $1,000/yr	$27,530	$26,476	-4%	$0	$26,476	-4%	$26,476	0%	$26,476	0%
BTS w/BTBA $/dth/d	$0.110	$0.126	15%	$0	$0.126	15%	$0.126	0%	$0.126	0%
SAR w/ BTS $/th	$0.206	$0.199	-4%	$0	$0.199	-3%	$0.199	0%	$0.199	0%
SDGE:										
Res $/th	$0.592	$0.675	14%	($8,000)	$0.649	10%	$0.675	4%	$0.675	0%
CCI CA $/th	$0.191	$0.135	-29%	$8,000	$0.179	-7%	$0.135	-24%	$0.135	0%
NGV Uncompressed post-SW $/th	$0.058	$0.060	4%	$0	$0.060	4%	$0.060	0%	$0.060	0%
Core Class Average $/th	$0.449	$0.465	4%	$0	$0.465	4%	$0.465	0%	$0.465	0%
NCCI-D $/th	$0.122	$0.091	-25%	$0	$0.091	-25%	$0.091	0%	$0.091	0%
EG-D Tier 1 post-SW $/th	$0.055	$0.100	81%	($300)	$0.061	10%	$0.067	10%	$0.073	10%
EG-D Tier 2 post-SW $/th	$0.024	$0.033	36%	($800)	$0.027	10%	$0.029	8%	$0.031	7%
TLS CA Rate csitma/efba exempt	$0.017	$0.011	-36%	$1,100	$0.012	-29%	$0.012	-2%	$0.012	-2%
TLS CA Rate csitma/efba non-exempt	$0.019	$0.013	-33%	$0	$0.014	-27%	$0.013	-2%	$0.013	-2%
SAR $/th	$0.200	$0.203	2%	$0	$0.203	2%	$0.203	0%	$0.203	0%

APPENDIX 1 (Continued)

	2015 Rate $/th	2016 rate $/th	% Change from prior year	2017 Rate $/th	% Change from prior year	2018 Rate $/th	% Change from prior year	2019 rate $/th	% Change from prior year
	I	K	L	M	N	O	P	Q	R
SCG:									
Res $/th	$0.568	$0.568	0%	$0.568	0%	$0.568	0%	$0.568	0%
CCI CA $/th	$0.243	$0.242	0%	$0.242	0%	$0.242	0%	$0.242	0%
Gas A/C	$0.079	$0.079	0%	$0.079	0%	$0.079	0%	$0.079	0%
Gas Engine	$0.117	$0.122	4%	$0.122	0%	$0.122	0%	$0.122	0%
NGV Uncompressed post-SW $/th	$0.059	$0.059	0%	$0.059	0%	$0.059	0%	$0.059	0%
Core Class Average $/th	$0.457	$0.457	0%	$0.457	0%	$0.457	0%	$0.457	0%
NCCI-D CA $/th	$0.053	$0.053	0%	$0.053	0%	$0.053	0%	$0.053	0%
EG-D Tier 1 post-SW $/th	$0.073	$0.080	10%	$0.088	10%	$0.097	10%	$0.099	2%
EG-D Tier 2 post-SW $/th	$0.031	$0.033	7%	$0.033	0%	$0.033	0%	$0.033	0%
TLS CA Rate csitma/efba exempt	$0.012	$0.011	-2%	$0.011	-1%	$0.011	-1%	$0.011	0%
TLS CA Rate csitma/efba non-exempt	$0.012	$0.012	-2%	$0.012	-1%	$0.012	-1%	$0.012	0%
UBS $1,000/yr	$26,476	$26,476	0%	$26,476	0%	$26,476	0%	$26,476	0%
BTS w/BTBA $/dth/d	$0.126	$0.126	0%	$0.126	0%	$0.126	0%	$0.126	0%
SAR w/ BTS $/th	$0.199	$0.199	0%	$0.199	0%	$0.199	0%	$0.199	0%
SDGE:									
Res $/th	$0.675	$0.675	0%	$0.675	0%	$0.675	0%	$0.675	0%
CCI CA $/th	$0.135	$0.135	0%	$0.135	0%	$0.135	0%	$0.135	0%
NGV Uncompressed post-SW $/th	$0.060	$0.060	0%	$0.060	0%	$0.060	0%	$0.060	0%
Core Class Average $/th	$0.465	$0.465	0%	$0.465	0%	$0.465	0%	$0.465	0%
NCCI-D $/th	$0.091	$0.091	0%	$0.091	0%	$0.091	0%	$0.091	0%
EG-D Tier 1 post-SW $/th	$0.073	$0.080	10%	$0.089	10%	$0.098	10%	$0.100	2%
EG-D Tier 2 post-SW $/th	$0.031	$0.033	7%	$0.033	0%	$0.033	0%	$0.033	0%
TLS CA Rate csitma/efba exempt	$0.012	$0.011	-2%	$0.011	-1%	$0.011	-1%	$0.011	0%
TLS CA Rate csitma/efba non-exempt	$0.013	$0.013	-2%	$0.013	-1%	$0.013	-1%	$0.013	0%
SAR $/th	$0.203	$0.203	0%	$0.203	0%	$0.203	0%	$0.203	0%