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Witness: Marjorie Schmidt-Pines
Chapter: 9

PREPARED DIRECT TESTIMONY OF

MARJORIE SCHMIDT-PINES

ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY

(COST ALLOCATION AND LONG RUN MARGINAL COST STUDY)

July 2018

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CHAPTER 9

PREPARED DIRECT TESTIMONY OF MARJORIE SCHMIDT-PINES

(COST ALLOCATION AND LONG RUN MARGINAL COST STUDY - SOCALGAS)

I. PURPOSE

The purpose of my testimony is to present the allocation of the authorized revenue requirement to customer classes for Southern California Gas Company (SoCalGas). My testimony ultimately proposes Customer-related, Medium Pressure Distribution-related, and High Pressure Distribution-related marginal unit costs and marginal cost revenue, using the Long Run Marginal Cost (LRMC) method. The LRMC method refers to the incremental cost to serve one additional unit in the long run; such a unit cost is called the marginal unit cost.

I also present total allocation of SoCalGas' authorized base margin revenue requirement, which combines the results of my LRMC analysis for Customer-related and Medium and High Pressure Distribution -related costs, and which incorporates inputs from witness Sim-Cheng Fung (Chapter 8) on Transmission-related and Storage-related costs, as well as from witness Sharim Chaudhury (Chapter 12) on the Natural Gas Vehicle (NGV) compression adder.

II. OVERVIEW OF COST ALLOCATION

Cost allocation refers to the process of determining the cost of each utility function and allocating these functional costs to the customer classes. My testimony results in the allocation of base margin revenue requirements across customer classes. This cost allocation is conducted by first allocating the authorized revenue requirement to the functions performed by SoCalGas in order to provide natural gas service. These functions are:

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

(ii) Medium Pressure Distribution System;

(iii) High Pressure Distribution System;

(iv) Local Transmission System;

(v) Backbone Transmission System; and

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

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

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

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

(iii) Other (backbone transportation service).

Finally, I present total cost allocations among all customer classes in Table 5.

III. COST ALLOCATION PRINCIPLES

In determining cost allocation, the following principles are followed by SoCalGas: allocate costs to customer classes based on cost causality, and maintain consistency with the existing practices whenever possible. The fundamental principle applicable to these LRMC cost studies, for purposes of allocating costs to customer groups, is the concept of cost causation. Cost causation seeks to determine which customer or group of customers causes the utility to incur particular types of costs. The essential element in the selection and development of a reasonable cost allocation methodology is the establishment of relationships between customer requirements, load profiles, usage characteristics, and the costs incurred by the utility in serving those requirements. A cost allocation based solely on cost causation therefore seeks to present cost-based rates.

IV. COST ALLOCATION METHOD PROPOSED FOR SOCALGAS

SoCalGas proposes to continue the LRMC method for the three major functional categories: Customer-related, Medium Pressure Distribution-related, and High Pressure Distribution-related. The LRMC method was proposed in Application (A.) 15-07-014, the last Triennial Cost Allocation Proceeding (TCAP) application.[1] In addition, SoCalGas proposes to continue to use the Embedded Cost method for the Transmission and Storage functions as presented in Chapter 8 (Fung). The Embedded Cost method was also proposed in the last TCAP.

LRMC refers to the incremental cost to serve one additional unit in the long run, such a unit cost is called marginal unit cost. The cost causation unit is called a marginal demand measure. The consolidated marginal demand measures are presented by witness Wei Bin Guo (Chapter 5). The LRMC-based functional revenue (i.e., marginal cost revenue) is derived by multiplying the LRMC by the number of marginal demand measures. For Customer-related costs, the marginal demand measure is the number of customers. For Medium Pressure Distribution-related and High Pressure Distribution-related costs, the marginal demand measure is peak day demand[2] and peak month demand,[3] respectively.

In this TCAP, SoCalGas updates the LRMC study presented in prior TCAPs to reflect 2016 actual costs and allocations based on 2016 underlying activities.[4] These costs are then

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[1] See D.16-10-004.
[2] Peak Day Demand is the December Peak Day. See Chapter 2 (Teplow).
[3] Peak Month is defined as December. See Chapter 2 (Teplow).
[4] Recorded 2016 costs were used because 2017 costs were not available when the study was completed.

escalated to 2020 dollars to reflect SoCalGas costs for the first year of the new TCAP cycle.[5] For the Customer-related and Medium and High Pressure Distribution-related functions, the marginal unit costs are then multiplied by the forecasted marginal demand measures to determine the marginal cost revenues.

Each functional marginal unit cost consists of two components: a capital cost component and an operations and maintenance (O&M) cost component. The capital cost component reflects the capital investment required to serve an additional unit. Customer-related capital costs are associated with service lines as well as meters and regulators (meter set assemblies, or MSAs). For Customer-related costs, this is the cost of serving an additional customer. Marginal Customer-related capital costs have been developed using the Rental method, which reflects the annualized capital cost of hooking up an additional customer. SoCalGas proposes the Rental method because the Rental method captures the concept of LRMC accurately by estimating the cost of providing an additional customer with the access to gas service.[6]

For Medium and High Pressure Distribution-related costs, LRMC represents the cost of providing an additional increment of gas throughput[7] through the distribution system. Marginal demand capital costs have been developed using linear regression models to determine the relationship between demand growth and investments over a 15-year period spanning historical and forecast periods.[8]

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[5] Escalation factors updated to reflect Global Insight's forecast as of first quarter of 2017. See A.17-10-008 (2019 GRC), Exhibit SCG-40, SoCalGas Direct Testimony of Scott R. Wilder, October 6, 2017.
[6] For more discussion of the Rental method, see Chapter 12 (Chaudhury).
[7] Medium Pressure Distribution is peak day demand. High Pressure Distribution is peak month demand.
[8] See D.92-12-058, where the Commission adopted the regression methodology, which has been utilized in every subsequent cost allocation proceeding, to my knowledge.

O&M costs for both Customer-related and Medium and High Pressure Distribution-related functional categories reflect the activities of field personnel and support services associated with field activities. O&M loaders are applied to the direct O&M costs to reflect a proportional share of the associated indirect costs associated with field activity labor. O&M loaders represent indirect costs, and include pension and benefits, general plant, and other costs that support the direct labor costs. The O&M loading factors are applied to the direct O&M costs to develop fully-loaded O&M costs for each customer class. Fully-loaded O&M costs are added to the marginal capital costs to derive the marginal unit cost for each functional category.

V. CUSTOMER-RELATED MARGINAL UNIT COST

Customer-related marginal unit cost reflects the cost of a customer's access to the gas utility's supply system,[9] and is comprised of: (1) the marginal capital cost of service lines and MSAs; (2) the marginal direct O&M costs associated with the installation and service of those assets, as well as other customer support functions; and (3) O&M loaders. Each of these components are discussed next.

A. Marginal Capital Cost

Marginal capital cost reflects the facilities and equipment for MSAs and service lines. For residential and small core commercial and industrial customers, marginal capital costs are calculated using the actual new customer hookups in SoCalGas' service territory using five years of available data (2012 - 2016). For other customer classes, the number of all customers, not just new customers, belonging to a specific customer class are used to estimate marginal capital costs

[9] See Id. at 38.

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

1. MSA Costs

MSA costs include the cost of the meter, regulator, and other equipment required in hooking up a new customer and the direct labor cost for installing the equipment. The marginal costs of MSAs have been derived in the following manner:

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

b) Applied actual 2016 MSA cost data for the various meter sizes, types, and service pressure levels to MSA configurations at the customer level; and

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

2. Service Line Costs

The marginal costs of service lines have been derived as follows:

a) Extracted service line lengths, pipe types, and pipe diameter data, at the customer level;

b) Applied unit cost data by pipe type and diameter to the average length of service lines for each customer in the various customer classes. The service unit costs are based on 2015 - 2017 data from Gas Distribution. The service unit costs were escalated for labor and nonlabor overheads[10]; and

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[10]For new service lines, I took into consideration Line Extension Credit, per SoCalGas' Rule 20.

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

B. Marginal Direct O&M Costs

Customer-related marginal O&M costs are broken into five components: (1) customer services, (2) customer accounts, (3) meters and regulators, (4) service lines, and (5) O&M loaders. The first four components comprise the total direct O&M costs, which are based on 2016 recorded O&M expenses.

1. Customer Services O&M Costs

Customer Services O&M costs include the 2016 field services' recorded expenses associated with the O&M of SoCalGas-owned equipment, as well as inspection and service of customer-owned appliances. Customer Services activities and the associated costs result from responses to customer service requests and company generated work orders, including investigating reports of potential gas leaks and responding to other emergencies, establishing/terminating gas service, conducting customer appliance checks, shutting off and restoring gas service for fumigations, performing meter and regulator changes, inspecting meter sets for atmospheric corrosion and remediating conditions found during the inspections, and other related services at customer premises. Requests are categorized into general order types for which both frequency and duration are recorded. Costs also include support costs associated with related field activities, such as field order dispatch costs, staff and supervision costs, communication costs, as well as an allocation of vehicle, tools, and uniform costs.

Orders are apportioned to customers and customer classes using data from SoCalGas' Customer Services dispatching system, the Portable Automated Centralized Electronic Retrieval

(PACER) system. The Data Analysis Reporting Tools (DART) system tracks orders by time to complete each activity by customer class.

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

2. Customer Accounts O&M Costs

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

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

Meter reading costs, which are recorded in FERC Account 902, a component of Customer Accounts O&M, have substantially decreased with the deployment of Advanced Meter Infrastructure (AMI) for the core customers. The costs associated with manually reading core meters are allocated based on the weighted read times for core customers. 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 costs are for postage and remittance processing costs and are recorded in FERC Account 903.700. The allocation of these costs across customer classes is performed based on the number of active customer accounts.

Office credit and collections and field collections costs are for costs associated with active and closed collections processing which include the following activities: following up on delinquent accounts, investigating fraudulent activity, skip tracing of unpaid closed accounts, postage costs for mailing collections notices, handling bankruptcies/receivership/probates, and collection of non-gas payments. These costs are recorded in FERC Account 903.104. FERC Account 903.105 reflects costs incurred for field collection activity that involves either collecting the delinquent amount due or terminating gas services. The allocation of these costs across customer classes is performed based on the number of field orders.

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

3. Meters and Regulators O&M Costs

Meters and Regulators O&M costs include repair of MSAs and meter guards. Meters and Regulators O&M costs are allocated based on two allocation methods. First, costs that are common to all customer segments are allocated according to each customer segment's share of total connected meters in service. Second, 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 maintenance work is generally corrective in nature and is required to keep the natural gas system operating safely and reliably. Service Lines O&M costs are allocated to each customer class based on each class's share of total service line footage at year end 2016. For costs associated with the O&M of service lines, service line footage is the basis for allocating Service Lines O&M costs.

5. Customer Services and Information Costs

Customer Services and Information costs are for activities which include account management services to nonresidential and residential customers; products and services for homebuilders and developers; services for capacity, pipeline, and storage; gas scheduling; gas transmission planning; and customer research, outreach, communication, and education and are booked to FERC Accounts 907 through 910. These costs are broken down between market segments and allocated by the number of customers. The exception is the Energy Markets costs, which are broken down by staff responsibilities.[11]

C. Calculation of Customer-Related Marginal Unit Cost and Marginal Cost Revenue

The marginal unit cost for Customer-related costs (MUC_C) for capital and O&M is calculated as follows:

[11] Energy Markets is an organization outside of Customer Services which has account executives who serve different noncore customers.

MUC_C ($/customer) = [CAPEX[12] *per customer x RECC*[13]*%] + [fully loaded O&M]*

Once the MUC_C is calculated, then for each customer class, the marginal cost revenue (MCR) is then calculated as follows:

Customer-related MCR ($) = MUC_C x # of customers

The following table shows the total MUC_C for each customer class.

Calculation of Marginal Customer Costs $2020/Customer					
Customer Class	**CAPEX** ($/customer)	**RECC** (%)	**Annualized CAPEX** ($/customer/year)	**O&M and Loaders** ($/customer/year)	**Marginal Unit Cost** ($/customer/year)
Residential	$2,296.91	8.08%	$185.65	$108.38	$294.03
Core C/I[14]	$13,269.27	8.01%	$1,063.42	$410.42	$1,473.84
Gas A/C[15]	$16,564.66	8.72%	$1,444.74	$5,437.92	$6,882.66
Gas Engine[16]	$215,383.82	7.84%	$16,893.23	$1,088.70	$17,981.93
NGV	$135,363.77	8.39%	$11,355.21	$34,234.98	$45,590.19
Noncore C/I[17]	$451,835.01	8.24%	$37,234.29	$17,905.45	$55,139.74
Small EG[18]	$172,741.89	8.45%	$14,598.37	$11,435.85	$26,034.22
Large EG[19]	$1,332,110.55	9.05%	$120,576.05	$33,959.11	$154,535.16
EOR[20]	$517,080.69	8.74%	$45,206.77	$39,249.98	$84,456.75
Long Beach[21]	$4,656,772.60	10.05%	$467,862.08	$315,310.40	$783,172.48
SDG&E[22]	$10,947,781.49	10.05%	$1,099,914.53	$297,570.68	$1,397,485.22
Southwest Gas[23]	$3,096,235.69	10.05%	$311,076.23	$376,146.69	$687,222.92
Vernon[24]	$2,321,309.97	10.05%	$233,220.09	$235,810.55	$469,030.64
Ecogas[25]	$501,886.62	10.05%	$50,424.13	$132,198.71	$182,622.84

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[12] CAPEX refers to capital expenditures for marginal MSA and service line capital costs.
[13] RECC refers to real economic carrying charge described in Section VII below. RECC is applied to annualize marginal capital costs.
[14] Core C/I means core Commercial & Industrial customers.
[15] Gas A/C means gas air conditioning C&I customers.
[16] Gas Engine means core gas engine water pumping service C&I customers.
[17] Noncore C/I means noncore Commercial &Industrial customers.
[18] Small EG means electric generation customers with usage less than 3 million therms/year.
[19] Large EG means electric generation customers with usage greater than 3 million therms/year.
[20] EOR means enhanced oil refinery customers.
[21] Long Beach is the City of Long Beach, a wholesale customer.
[22] SDG&E is San Diego Gas & Electric Company, a wholesale customer.
[23] SW Gas is Southwest Gas Corporation, a wholesale customer.
[24] Vernon is the City of Vernon, a wholesale customer.
[25] Ecogas is Ecogas Mexico, S. de R.L. de C.V., a wholesale customer.

VI. MEDIUM AND HIGH PRESSURE DISTRIBUTION-RELATED MARGINAL UNIT COSTS

Medium and High Pressure Distribution-related marginal unit costs consist of three types of costs: (1) capital-related, (2) direct O&M, and (3) O&M loaders. The capital costs are recorded in the plant accounts for mains (FERC Account 376) and measuring and regulating station equipment (FERC Account 378). Direct O&M costs are recorded in FERC Accounts 874, 875, 887, and 889 for mains and measuring and regulating stations. Distribution O&M work includes maintenance on mains, application of corrosion control measures, valve maintenance, regulator station maintenance, checking for odorant, and locating and marking buried pipes to avoid damage caused from digging from non-company individuals or entities.

SoCalGas develops separate marginal costs for Medium Pressure Distribution and High Pressure Distribution functions because the cost drivers are different between the two functions.

A. Medium Pressure Distribution Marginal Unit Cost and Marginal Cost Revenue

The marginal unit cost for Medium Pressure Distribution consists of: (1) an annualized capital-related cost (or marginal capital cost), and (2) fully-loaded marginal O&M cost.

1. Marginal Capital Cost

The marginal capital cost is developed using a linear regression model, recognizing that peak day demand is the cost driver for the Medium Pressure Distribution system. The regression analysis establishes the relationship between cumulative load growth-related capital investment in the Medium Pressure Distribution system (the dependent variable[26]) and cumulative peak day demand growth (the independent variable[27]).

[26] The dependent variable represents the output or outcome whose variation is being studied.
[27] The independent variables represent inputs or causes, i.e., potential reasons for variation.

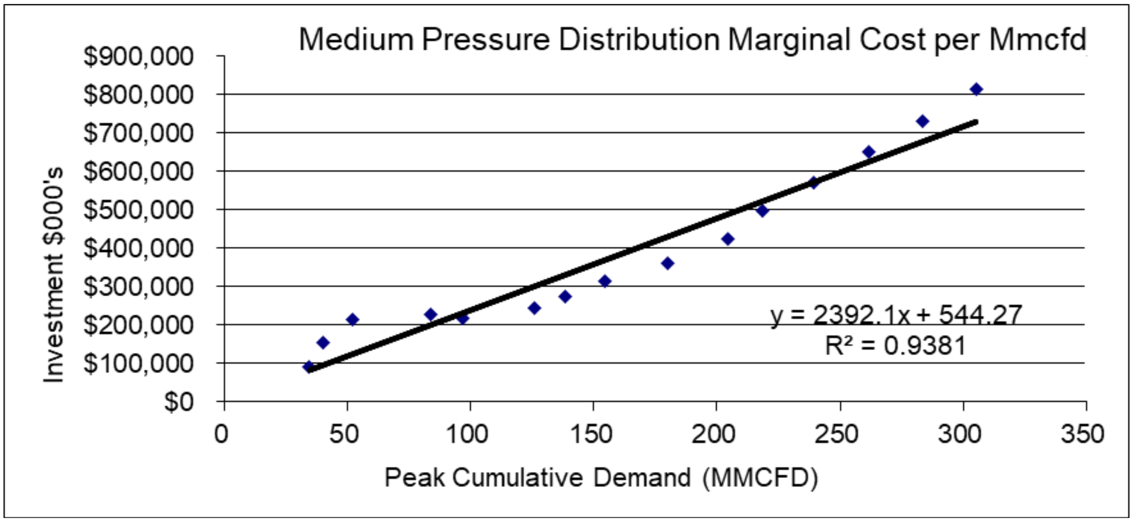
Load growth-related investments include new business, pressure betterment, and meter and regulating station investments. The period for the regression analysis is 15 years: nine years of historical data (2008 - 2016) and six years of forecast data (2017 - 2022). The resulting estimated coefficient of the independent variable represents the marginal capital cost.

The cumulative peak day demand growth is calculated based on the net positive change in the number of customers per year multiplied by the average peak day demand per customer for each class. The total annual footage[28] for new business and pressure betterment by distribution pipe size and type is multiplied by the associated unit costs to obtain total historical annual investment costs. The distribution unit costs are based on 2015 - 2017 data from Gas Distribution. The distribution unit costs were escalated for labor and nonlabor overhead. The table below shows the marginal capital costs for 2008 - 2022.

Year	**Cumulative MMcfd**	**Cumulative CAPEX ($000)**
2008	34	$92,422
2009	40	$154,255
2010	52	$213,663
2011	84	$228,769
2012	97	$219,558
2013	126	$245,210
2014	139	$274,122
2015	154	$313,269
2016	180	$362,786
2017	204	$424,132
2018	219	$496,696
2019	240	$572,407
2020	261	$650,709
2021	283	$731,673
2022	305	$815,410

[28] Historical distribution mains footages.

The regression analysis results are depicted in the chart below.



2. Marginal Direct O&M Costs

The 2016 recorded direct O&M costs are allocated between Medium Pressure and High Pressure Distribution systems based on the split in total distribution capital investment between those two systems. Direct O&M costs are booked to FERC Accounts 874, 875, 887, and 889.

3. Calculation of Medium Pressure Distribution Marginal Unit Cost and Marginal Cost Revenue

The calculation of marginal unit cost for Medium Pressure Distribution (MUC_MPD) is as follows:

MUC_MPD ($/Mcfd[29]) = [CAPEX per Mcfd x RECC%] + [fully Loaded O&M]

Once the MUC_MPD is calculated for each customer class, the marginal cost revenue (MPD_MCR) is then calculated as follows:

MPD_MCR ($) = MUC_MPD x Mcfd

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[29] Mcfd is a unit of measurement for gas representing a thousand cubic feet per day.

The following table shows the calculation of the MUC_MPD. Marginal Cost Revenue is presented in Section VIII.

Marginal Unit Cost for Medium Pressure Distribution (MPD)
($2020/Mcfd peak day)

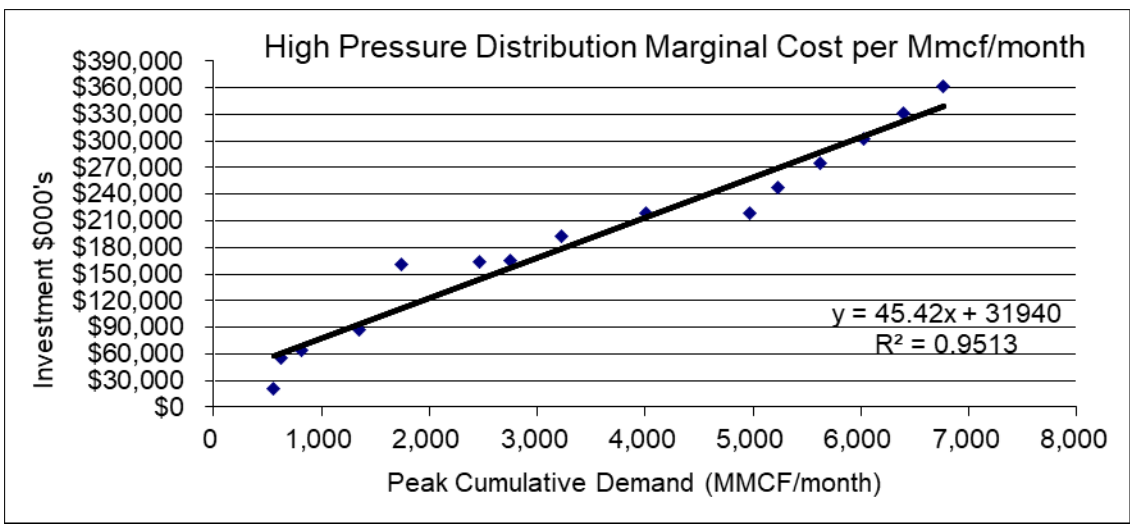
Capital-related Charge:	
MPD Regression Coefficient $/Mcfd	$2,392.05
x RECC Factor	7.61%
= Annualized Capital-related Charge ($/Mcfd)	$182.00
+ Direct O&M	$8.33
+ A&G	$3.63
+ GP	$3.74
+ M&S	$0.36
= Marginal Unit Cost ($2020/Mcfd peak day)	**$198.08**

B. High Pressure Distribution Marginal Unit Cost and Marginal Cost Revenue

The methodology for calculating the marginal capital-related cost for the High Pressure Distribution system is analogous to the methodology used for the Medium Pressure Distribution system. Cumulative load growth-related investment costs in the High Pressure Distribution system are regressed against cumulative load growth. The coincident peak month demand served off the High Pressure Distribution system is used as the measure of cost driver for the HPD system. The table below shows the marginal capital costs for 2008 - 2022.

Year	Cumulative Mmcf/ month	Cumulative CAPEX ($000)
2008	555	$20,754
2009	626	$55,893
2010	811	$64,667
2011	1,348	$86,664
2012	1,742	$160,425
2013	2,471	$164,354
2014	2,748	$165,265
2015	3,224	$191,910
2016	4,011	$219,153
2017	4,968	$219,153
2018	5,230	$246,963
2019	5,620	$274,280
2020	6,028	$302,545
2021	6,398	$331,787
2022	6,768	$362,043

The regression analysis results are depicted in the chart below.



The calculation of the marginal unit cost for High Pressure Distribution (MUC_HPD) cost is as follows:

MUC_HPD ($/Mcf/month) = [CAPEX per Mcf/month x RECC%] + [fully loaded O&M]

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

HPD_MCR ($) = MUC_MPD x Mcf/month

The following table shows the calculation of the MUC_HPD.

Marginal Cost for High Pressure Distribution
(2020$/Mcf/month)

Capital-related Charge:	
HPD Regression Coefficient $/Mcf/month	$45.42
x RECC Factor	7.57%
= Annualized Capital-related Charge ($/Mcf/month)	$3.44
+ Direct O&M	$0.22
+ A&G	$0.09
+ GP	$0.10
+ M&S	$0.19
= Marginal HP Distribution Cost(2020$/Mcf/month)	**$4.04**

VII. MARGINAL COST ESTIMATION FACTORS

A. Real Economic Carrying Charge (RECC) Factors

In the previous sections, RECC factors appeared in the calculation of marginal unit costs for customer-related costs as well as for Medium and High Pressure Distribution. RECC factors are used to convert capital investment into annualized capital costs. The LRMC Decision established the use of RECC factors in LRMC studies:

> The Total Investment computes an arithmetic average by dividing the total investment during the planning horizon by the total load growth using the same period. The resulting unit marginal cost is than annualized using a Real Economic Carrying Cost (RECC) factor. The RECC capital amortization formula levelizes a stream of future payments in a manner similar to an annuity calculation but with an inflation adjustment. RECC models incorporate

assumptions for service life, salvage value, cost of capital, inflation rates, and discount rates.[30]

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

SoCalGas has updated its RECC factors using inflation assumptions from Global Insight's forecast, updated tax rates, and SoCalGas' discount rate of 8.02% revised per Advice Letter No. 4442.[31] The authorized book lives and salvage values for the different investments have also been updated to reflect current factors.

B. O&M Loaders

I developed three distinct O&M loaders that are applied to direct marginal O&M costs to develop the fully-loaded O&M cost for each functional category, customer costs, and distribution. 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

[30] D.92-12-058, p. 32.
[31] SoCalGas' January 1, 2013 Consolidated Rate Update which implemented SoCalGas' updated costs of capital and capital structure, effective January 1, 2013.

investment. Application of O&M loaders to direct costs produces a fully-loaded marginal unit cost.

1. A&G Loading Factor

Marginal A&G expenses and payroll taxes are combined into a single loading factor, with an adjustment to reflect the exclusion of Storage-related and Transmission-related costs. The loading factor derived in the table below 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 total production expenses[32] and total A&G expenses.

Recorded 2016 A&G expenses have been classified as either marginal or non-marginal on an account-by-account basis. Any costs that vary with either the size of labor force or the size of plant are deemed marginal costs for this study.

A&G Loading Factor

Total Marginal A&G Costs ($000)	$176,788
+ Total Payroll Taxes ($000)	$50,092
= Marginal A&G and Payroll Taxes ($000)	$226,880
/ Net O&M Costs $000	$519,934
= Marginal A&G Loading Factor as a % of O&M	**43.64%**

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 2016 for structures and improvements, office furniture and equipment, computer applications and equipment, shop and garage equipment, and

[32] Total Production Expenses means gas used.

communication equipment. RECC factors associated with each capital category and the amounts of gross plant in service at year-end 2016 are used to calculate a weighted average general plant accounts RECC factor. The general plant accounts RECC factor is then applied to gross general plant in service as of December 31, 2016, to derive an annualized cost for general plant. This annualized general plant cost is divided by year 2016 net O&M expenses to derive the general plant loading factor, as shown in the table below. Like the A&G loading factor, the general plant loading factor excludes Storage- and Transmission-related costs.

General Plant Loading Factor

Total General Plant ($000)	$1,419,347
* Weighted Average RECC for General Plant	16.46%
= Annualized General Plant Costs	$233,654
/ Net Recorded O&M Costs ($000)	$519,934
= General Plant Loading Factor as a % of O&M	**44.94%**

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 2016 M&S costs are allocated based on gross gas plant in each functional category. Applying an M&S loading factor is appropriate because is a component of the indirect costs. Distribution M&S is further categorized as customer-related and demand-related distribution plant investment. As with the other O&M loaders, Storage-related 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. The table below shows the functionalization of the year 2016 M&S costs and the derivation of annual M&S costs for each function.

M&S Annual Costs
($000)

Function	
Customer-related	$2,930
Medium and High Pressure Distribution -related	$3,294
Total	**$6,225**

VIII. RESULTS OF THE COST ALLOCATION STUDY

Upon completing the cost studies to allocate costs to functional categories, SoCalGas allocates each functional cost to customer classes using the marginal demand measures: number of customers for the customer costs, peak day throughput for Medium Pressure Distribution costs and peak month throughput for High Pressure Distribution costs. Each marginal demand measure reflects the forecast annual average marginal demand measures (listed above) for the years 2020 - 2022, reflecting the duration of the 2020 TCAP period.

For the customer-related functional category, Table 1 shows marginal unit costs, customer counts, and marginal cost revenues by customer class on an unscaled basis. The term "unscaled" refers to the sum of the marginal demand measures multiplied by the marginal unit costs for each customer class, not adjusted or "scaled" to equal SoCalGas' authorized base margin. A scalar factor is applied to adjust total revenues to equal the authorized base margin.

TABLE 1
UNSCALED LRMC REVENUES
CUSTOMER COST

Customer Class	**Customer LRMC** ($/customer)	**Customer Count**	**Customer Cost** ($000)
	A	B	C
Residential	$294	5,714,531	$1,680,240
Core C/I	$1,474	203,514	$299,948
Gas A/C	$6,883	4	$28
Gas Engine	$17,982	712	$12,803
NGV	$45,590	378	$17,233
Total Core			$2,010,251
Noncore C/I	$55,140	593	$32,700
Small EG	$26,034	323	$8,398
Large EG	$154,535	67	$10,293
EOR	$84,457	34	$2,872
Total Retail Noncore			$54,263
Long Beach	$783,172	1	$783
SDG&E	$1,397,485	1	$1,397
Southwest Gas	$687,223	1	$687
Vernon	$469,031	1	$469
Ecogas	$182,623	1	$183
Total Wholesale			$3,520
UBS	$0	0	$0
BTS	$0	0	$0
Total Noncore			$57,782
Total SoCalGas			**$2,068,033**

Table 2 shows the allocation of Medium Pressure and High Pressure Distribution 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 Medium Pressure Distribution service level peak day demand. High Pressure Distribution costs are allocated using 1-in-35 peak day core/cold peak month High Pressure Distribution service level peak month demand.

TABLE 2
UNSCALED LRMC COST REVENUES
MEDIUM AND HIGH PRESSURE DISTRIBUTION COSTS

Customer Class	Medium Pressure Distribution LRMC ($/mcfd)	Medium Pressure Distribution Peak Day (mcfd)	Medium Pressure Distribution Costs ($000)	High Pressure Distribution LRMC ($/mcfd)	High Pressure Distribution Peak Month Demand (mcf)	High Pressure Distribution Costs ($000)
	A	B	C	D	E	F
Residential	$198.08	2,327,403	$461,001	$4.04	37,986,877	$153,339
Core C/I	$198.08	527,626	$104,510	$4.04	11,298,836	$45,609
Gas A/C	$198.08	45	$9	$4.04	2,524	$10
Gas Engine	$198.08	2,524	$500	$4.04	89,085	$360
NGV	$198.08	19,041	$3,772	$4.04	1,149,783	$4,641
Total Core			$569,791			$203,959
Noncore C/I	$198.08	96,259	$19,067	$4.04	7,676,934	$30,989
Small EG	$198.08	19,008	$3,765	$4.04	726,597	$2,933
Large EG	$198.08	15,209	$3,013	$4.04	1,968,123	$7,945
EOR	$198.08	350	$69	$4.04	1,246,196	$5,030
Total Retail Noncore			$25,913			$46,897
Long Beach	$198.08	0	$0	$4.04	0	$0
SDG&E	$198.08	0	$0	$4.04	0	$0
Southwest Gas	$198.08	0	$0	$4.04	0	$0
Vernon	$198.08	0	$0	$4.04	0	$0
Ecogas	$198.08	0	$0	$4.04	0	$0
Total Wholesale			$0			$0
UBS	$198.08	0	$0	$4.04	0	$0
BTS	$0.00	0	$0	$0.00	0	$0
Total Noncore			$25,913			$46,897
Total SoCalGas			**$595,705**			**$250,856**

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."[33] The scalar is employed to adjust the proposed marginal cost revenues to the base margin, excluding

[33] D.92-12-058, p. 50.

costs directly allocated to the Transmission, Storage, Uncollectible,[34] and NGV Public Access functions. In this TCAP, marginal costs are scaled at a rate of 63% in order to reconcile to the base margin of $1,823,654. Table 3 shows this process.

TABLE 3
LRMC COST SCALED REVENUES
SCALED CUSTOMER, MEDIUM AND HIGH PRESSURE DISTRIBUTION COSTS
($000)

Customer Class	Customer Cost A	Medium Pressure Distribution B	High Pressure Distribution C	Unscaled LRMC Revenues D=A+B+C	Scalar E	Scaled LRMC Revenues F=D*E
Residential	$1,680,240	$461,001	$153,339	$2,294,580	63%	$1,435,890
Core C/I	$299,948	$104,510	$45,609	$450,066	63%	$281,640
Gas A/C	$28	$9	$10	$47	63%	$29
Gas Engine	$12,803	$500	$360	$13,663	63%	$8,550
NGV	$17,233	$3,772	$4,641	$25,646	63%	$16,049
Total Core	$2,010,251	$569,791	$203,959	$2,784,001	63%	$1,742,158
Noncore C/I	$32,700	$19,067	$30,989	$82,756	63%	$51,786
Small EG	$8,398	$3,765	$2,933	$15,096	63%	$9,447
Large EG	$10,293	$3,013	$7,945	$21,250	63%	$13,298
EOR	$2,872	$69	$5,030	$7,971	63%	$4,988
Total Retail Noncore	$54,263	$25,913	$46,897	$127,073	63%	$79,519
Long Beach	$783	$0	$0	$783	63%	$490
SDG&E	$1,397	$0	$0	$1,397	63%	$875
Southwest Gas	$687	$0	$0	$687	63%	$430
Vernon	$469	$0	$0	$469	63%	$294
Ecogas	$183	$0	$0	$183	63%	$114
Total Wholesale	$3,520	$0	$0	$3,520	63%	$2,202
UBS	$0	$0	$0	$0	63%	$0
BTS	$0	$0	$0	$0	63%	$0
Total Noncore	$57,782	$25,913	$46,897	$130,592	63%	$81,721
Total SoCalGas	**$2,068,033**	**$595,705**	**$250,856**	**$2,914,594**	**63%**	**$1,823,879**

Calculation of Scalar:

Scalar = [Base Margin - Transmision – Storage -Uncollectibles-NGV Compression Adder] / [Unscaled Customer + Distribution]

Scalar = $1,823,879 divided by $2,914,594

[34] Uncollectible (not collected revenues) are treated separately because SoCalGas' wholesale customers do not have any uncollectibles.

After the allocation of customer and distribution functional costs across customer classes, the remaining base margin items for Transmission, Storage, NGV, and Uncollectible costs are allocated to customer classes, as shown in Table 4. Local Transmission costs[35] are allocated to customer classes using cold year peak month throughput. Backbone Transmission costs[36] are allocated to the Backbone Transmission System (BTS) rate. Storage costs[37] are allocated to customer classes using the storage rates (for inventory, injection, and withdrawal) applied to the capacities for core storage, load balancing, and reliability functions proposed in this TCAP.[38] Uncollectible and NGV Public Access Station costs are also included. The system average uncollectible rate is 0.298%. The NGV Public Access Station cost is allocated to the NGV class for recovery through the NGV Compressor Adder.

Finally, scaled LRMC costs are combined with the Transmission, Storage, Uncollectible, and NGV Public Access costs to determine the proposed cost allocation of authorized gas base margin. This is presented in column G of Table 4 and represents a completely cost-based allocation.

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[35] See Chapter 8 (Fung). FF&U added.
[36] See Id.
[37] See Id.
[38] See Chapter 1 (Dandridge).

TABLE 4
ALLOCATION OF BASE MARGIN
($000)

Customer Class	Scaled LRMC Revenues	Uncollect	BTS	Local Transmission	NGV Public Access	Storage	Allocated Base Margin
	A	B	C	D	E	F	G
Residential	$1,435,890	$4,940	$0	$26,588	$0	$85,446	$1,552,864
Core C/I	$281,640	$1,020	$0	$7,960	$0	$20,826	$311,446
Gas A/C	$29	$0	$0	$2	$0	$10	$41
Gas Engine	$8,550	$30	$0	$66	$0	$566	$9,211
NGV	$16,049	$70	$0	$996	$2,964	$2,163	$22,241
Total Core	$1,742,158	$6,059	$0	$35,611	$2,964	$109,011	$1,895,804
Noncore C/I	$51,786	$313	$0	$9,491	$0	$11,673	$73,264
Small EG	$9,447	$39	$0	$528	$0	$737	$10,751
Large EG	$13,298	$283	$0	$14,150	$0	$18,729	$46,460
EOR	$4,988	$0	$0	$1,201	$0	$1,578	$7,767
Retail Noncore	$79,519	$635	$0	$25,370	$0	$32,717	$138,242
Long Beach	$490	$0	$0	$715	$0	$601	$1,806
SDG&E	$875	$0	$0	$8,246	$0	$19,969	$29,090
Southwest Gas	$430	$0	$0	$784	$0	$502	$1,716
Vernon	$294	$0	$0	$562	$0	$732	$1,587
Ecogas	$114	$0	$0	$668	$0	$878	$1,660
Total Wholesale	$2,202	$0	$0	$10,975	$0	$22,682	$35,859
UBS	$0	$0	$0	$0	$0	$0	$0
BTS			$176,587				$176,587
Total Noncore	$81,721	$635	$176,587	$36,345	$0	$55,400	$350,688
Total SoCalGas	**$1,823,879**	**$6,695**	**$176,587**	**$71,956**	**$2,964**	**$164,411**	**$2,246,492**

IX. COMPARISON OF PROPOSED COST ALLOCATION TO CURRENT COST ALLOCATION

The following is a comparison of the proposed 2020 cost allocation to the current allocation effective January 1, 2018. This comparison is pre-System Integration[39] and pre-BTS unbundling,[40] as discussed in Chapter 12 (Chaudhury).

The proposed allocation of base margin across customer classes is comparable to the current allocation. The proposed and current base margins in Table 5 differ by $6 million because of the net effect of the 2020 Aliso Canyon Turbine Replacement (ACTR) revenue requirement increase of $6 million compared to July 2018 ACTR revenue requirement, as discussed in Chapter 8 (Fung)[41] and an update to the SoCalGas brokerage fee study described in Chapter 3 (Payan).

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[39] Shows rates pre-System Integration. Under System Integration, the costs of local transmission facilities are recovered on a common (or integrated) basis from customers of both SDG&E and SoCalGas. This integration reflects the splitting of total local transmission costs between the utilities by the % share of cold-year peak month throughput.

[40] Shows allocation pre-BTS unbundling. BTS represents the costs of SoCalGas' and SDG&E's transmission lines from the California Border receipt points to SoCalGas' Citygate.

[41] Includes FF&U.

TABLE 5
COST ALLOCATION COMPARISON
($000)

Customer Class	Proposed Allocation of Base Margin A	% Total B	Current Allocation of Base Margin C	% Total D
Residential	$1,552,864	69.1%	$1,626,188	72.6%
Core C/I	$311,446	13.9%	$264,112	11.8%
Gas A/C	$41	0.0%	$74	0.0%
Gas Engine	$9,211	0.4%	$4,276	0.2%
NGV	$22,241	1.0%	$16,094	0.7%
Total Core	$1,895,804	84.4%	$1,910,743	85.3%
Noncore C/I	$73,264	3.3%	$58,183	2.6%
Small EG	$10,751	0.5%	$10,733	0.5%
Large EG	$46,460	2.1%	$34,214	1.5%
EOR	$7,767	0.3%	$6,006	0.3%
Total Retail Noncore	$138,242	6.2%	$109,136	4.9%
Long Beach	$1,806	0.1%	$1,477	0.1%
SDG&E	$29,090	1.3%	$20,598	0.9%
Southwest Gas	$1,716	0.1%	$1,501	0.1%
Vernon	$1,587	0.1%	$1,211	0.1%
Ecogas	$1,660	0.1%	$961	0.0%
Total Wholesale	$35,859	1.6%	$25,748	1.1%
UBS	$0	0.0%	$23,290	1.0%
BTS	$176,587	7.9%	$171,727	7.7%
Total Noncore	$350,688	15.6%	$329,902	14.7%
Total SoCalGas	**$2,246,492**	**100.0%**	**$2,240,645**	**100.0%**

This concludes my prepared direct testimony.

X. QUALIFICATIONS

My name is Marjorie Schmidt-Pines. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011. I am Senior Principal Regulatory Economic Advisor in the CPUC/FERC Gas Regulatory Affairs Department for SoCalGas and SDG&E as of December 2017.

I hold a Bachelor of Science degree in Business Administration and Accounting from California State University at Northridge, California. I have been employed by SoCalGas since 1981, and have held positions of increasing responsibilities throughout the company.

As Senior Principal Regulatory Economic Advisor, I represent the Gas Rate Design Group for both SoCalGas and SDG&E in the role of Project Manager, Senior Analyst and witness in various major regulatory proceedings and filings dealing with allocating authorized revenue requirements to functions and customer rate classes, developing the design of the rate for each class, calculating customer rate changes, and computing the impact on customers' monthly bills. I train new rate design analysts in the concepts of cost allocation and rate design, how to obtain data from different organizations, how to run the various cost allocation and rate design models.

I have previously submitted testimony before the California Public Utilities Commission.