Exhibit No.: ______________________
Application: A.25-09-XXX
Witness: M. Schmidt-Pines
Chapter: 9a

PREPARED DIRECT TESTIMONY OF MARJORIE SCHMIDT-PINES

ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY

AND SAN DEIGO GAS & ELECTRIC COMPANY

(COST ALLOCATION AND LONG RUN MARGINAL COST STUDY)

September 30, 2025
(Redlined dated June 9, 2026)

TABLE OF CONTENTS

CHAPTER 9

PREPARED DIRECT TESTIMONY OF MARJORIE SCHMIDT-PINES

(COST ALLOCATION AND LONG RUN MARGINAL COST STUDY)

I. PURPOSE

The purpose of my testimony is to present the allocation of the authorized revenue requirements to customer classes for Southern California Gas Company (SoCalGas) and San Diego Gas and Electric (SDG&E). My testimony provides 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.

My testimony also presents the total allocation of SoCalGas's authorized base margin revenue requirement, which combines the results of my LRMC analysis for Customer-related, Medium and High Pressure Distribution -related costs, and which incorporates inputs from witnesses Frank Seres and Marjorie Schmidt-Pines (Chapter 8) on Transmission-related and Storage-related costs, as well as from witness Michael Foster (Chapter 12) on the Natural Gas Vehicle (NGV) compression adder costs.

These LRMC updated studies are in compliance with CPUC Decision (D.) 24-07-009, Ordering Paragraph (OP) 2. OP 2 states that the "all party settlement […] attached to this decision as Attachment A is approved and adopted without modification."[1] Attachment A to D.24-07-009, states in relevant part that "The next Cost Allocation Proceeding application will contain, at a minimum, a fully embedded cost study based on 2024 FERC Form 2, as well as a benchmark cost

[1] D.24-07-009 at 35 (OP 2).

allocation utilizing Long Range Marginal Cost (LRMC) studies for the customer-related and distribution functions. The benchmark cost allocation may leverage underlying LRMC data presented in this cost allocation proceeding, updated to account for changes in line extension allowance policy, loaders, and demand projections, and scaled to representative dollars in the corresponding test year."[2]

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[3] 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 (service lines that deliver gas from the distribution main to the end-use customers' home or business), regulators (adjust gas pressure), meters (measure gas consumed), customer support functions);

(ii) Medium Pressure Distribution System (mains lines that operate at medium pressure and transport gas to service lines);

(iii) High Pressure Distribution System (mains lines that operate at high pressure and transport gas to service lines and medium pressure pipelines);

---

2 D.24-07-009, Attachment A, section II (A)(6).

3 SoCalGas's Base Margin is authorized in a General Rate Case (GRC). Pipeline Safety Enhancement Plan (PSEP) cost components that are not in Base Margin are not included in the LRMC and Embedded Cost studies and they are functionally allocated to High Pressure Distribution and Transmission functions per D.14-06-007 and D.16-12-063. PSEP included in Base Margin are part of the Embedded Cost Study for Transmission and LRMC Study's High Pressure Distribution functions. AB32 Administrative fees (CARB fee) are allocated on an Equal Cents Per Therm (ECPT).

(iv) Local Transmission System (large pipelines that transport supplies from the backbone transmission system to distribution and to service lines);

(v) Backbone Transmission System (large pipelines that take supplies from interstate pipelines to the local 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 (NGV), 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 Tables ~~5~~ 12 and 27.

III. COST ALLOCATION PRINCIPLES

In determining cost allocation, the following principles are followed by SoCalGas and SDG&E: 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 on cost causation therefore seeks to present cost-based rates.

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

SoCalGas proposes the Embedded Cost method for all functional categories - Transmission, Storage, Customer-related, Medium Pressure Distribution-related, and High Pressure Distribution-related - for the reasons presented in the direct testimony of Frank Seres and Marjorie Schmidt-Pines (Chapter 8). This is especially true since the Long Run Marginal Cost (LRMC) study is based on the cost of the last marginal unit. The residential cost has significantly decreased with the capital cost going to zero. [4]

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 in the testimony of Eduardo Martinez (Chapter 5). The LRMC-based functional revenue (i.e., marginal cost revenue) is derived by multiplying the marginal unit cost by the number of marginal demand measures (MDM). 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 measures are peak day demand[5] and peak month demand,[6] respectively.

In this Cost Allocation Proceeding (CAP), SoCalGas LRMC study reflects 2021 actual costs and allocations based on 2021 underlying activities. The O&M loaders which are based on 2024 actual costs. The demand in the Distribution studies is updated to reflect historical data through 2024 and the CAP forecast. These costs are escalated to 2027 dollars to reflect SoCalGas costs for

---

4 Line Extension Allowance for residential customers is zero. SoCalGas Rule No. 20, C2, SDG&E Rule No. 15, C3.

5 Peak Day Demand is forecast to be in December. *See* direct testimony of Eduardo Martinez (Chapter 2).

6 Peak Month is defined as December. *See* Chapter 2 (Martinez).

the first year of the new CAP cycle.[7] For the Customer-related and Medium and High Pressure Distribution-related functions, the marginal unit costs are then multiplied by the forecasted MDM 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 (collectively called 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, adopted in the last CAP, which reflects the annualized capital cost of hooking up an additional customer.

For Medium and High Pressure Distribution-related costs, LRMC represents the cost of providing an additional increment of gas throughput[8] 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.[9]

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 indirect costs associated with field activity labor. O&M loaders represent indirect costs, and

---

[7] Peak Month is defined as December. *See* Chapter 2 (Martinez).

[8] The MDM for Medium Pressure Distribution is peak day demand. The MDM for High Pressure Distribution is peak month demand.

[9] D.92-12-058 adopted the regression methodology and has since been utilized in every subsequent cost

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. The O&M loading factors are using 2024 FERC data. Fully-loaded O&M costs are added to the marginal capital costs to derive the marginal unit cost for each functional category.

SOCALGAS LRMC STUDY AND COST ALLOCATION

V. SOCALGAS 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,[10] 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, the capital costs are adjusted to zero. Starting July 1, 2023, Residential New Construction Builders no longer receive allowances for natural gas line extensions.[11] Small core commercial and industrial customers, marginal capital costs are calculated using the actual new customer hookups in SoCalGas's service territory using the recent five years of available data (2017 - 2021). For other customer classes, all customers, not just new customers, belonging to a specific customer class are used to estimate marginal capital costs for MSAs and service lines because of low customer growth rates and the large variations in meter costs for these customers.

allocation proceeding to my knowledge.

[10] D.92-12-058 at 38.

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's Customer Information System;

b) Applied actual 2021 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 line history are based on 2017 - 2021 data from Gas Distribution. The service unit costs were escalated for labor and nonlabor overheads;[12] and

---

[11] SoCalGas Rule No. 20, C2, SDG&E Rule No. 15, C3.

[12] For new service lines and meters, I took into consideration Line Extension Allowance, per SoCalGas's 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 2021 recorded O&M expenses.

1. Customer Services O&M Costs

Customer Services O&M costs include the 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's 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, are substantially low with the deployment of Advanced Meter Infrastructure (AMI) for 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. In 2021, these costs are low due to the COVID_19 Relief Payment Plan.

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 2021.

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 transmission planning; gas sustainability; environmental affairs; biofuels market development; clean energy innovations; 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.

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:

MUC_C ($/customer) = [CAPEX[13] per customer x RECC[14]%] + [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

---

13 CAPEX refers to capital expenditures for marginal MSA and service line capital costs.

14 RECC refers to real economic carrying charge described in Section VII below. RECC is applied to annualize marginal capital costs.

Table MSP-1 below shows the total MUC_C for each customer class.

Table MSP-1 Calculation of Marginal Customer Costs 2027 $/Customer					
Customer Class	CAPEX $/customer	RECC %	Annualized CAPEX ($/customer/year)	O&M and Loaders ($/customer/ year)	Marginal Unit Cost 2024 ($/customer/ year)
Residential	$0.00		$0.00	$106.32	$106.32
Core C/I[15]	$16,092.55	6.98%	$1,123.24	$555.92	$1,679.16
Gas A/C[16]					
Gas Engine[17]	$269,069.90	6.79%	$18,279.37	$1,015.02	$19,294.39
NGV	$229,873.20	7.58%	$17,423.40	$20,617.22	$38,040.62
Noncore C/I[18]	$755,145.54	7.28%	$54,981.81	$18,527.91	$73,509.72
Small EG[19]	$379,253.54	7.33%	$27,807.46	$8,022.30	$35,829.76
Large EG[20]	$2,219,865.48	8.05%	$178,778.01	$28,327.74	$207,105.74
EOR[21]	$944,927.05	7.81%	$73,831.43	$26,207.01	$100,038.45
Long Beach[22]	$13,818,202.97	8.97%	$1,239,598.65	$183,864.62	$1,423,463.27
SDG&E[23]	$35,517,278.40	8.97%	$3,186,171.93	$172,611.25	$3,358,783.18
Southwest Gas[24]	$7,214,188.70	8.97%	$647,167.99	$227,861.02	$875,029.00
Vernon[25]	$6,900,339.96	8.97%	$619,013.35	$132,978.03	$751,991.38
Ecogas[26]	$1,015,578.62	8.97%	$91,105.18	$75,592.79	$166,697.98

15 Core C&I are the Core Commercial & Industrial customers.

16 Gas A/C are the Gas Air Conditioning for Commercial & Industrial customers, Chapter 12, this class is being eliminated.

17 Gas Engine are Core Gas Engine Water Pumping Service for Commercial and Industrial.

18 Noncore C/I are Noncore Commercial & Industrial customers.

19 Small EG are Electric Generation customers with usage less than 3 million therms/year.

20 Large EG are Electric Generation customers with usage greater than 3 million therms/year.

21 EOR are Enhanced Oil Refinery customers.

22 Long Beach is the Wholesale - City of Long Beach customer.

23 SDG&E is the Wholesale – San Diego Gas & Electric customer.

24 SW Gas is the Wholesale – Southwest Gas Corporation’s service territory in southern California.

25 Vernon is the Wholesale – City of Vernon customer.

26 Ecogas is the Wholesale – ECOGAS Mexico, S. de R.L. de C.V. customer.

VI. SOCALGAS 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 by 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 MDM or cost driver for the Medium Pressure Distribution system. The regression analysis establishes the causal relationship between cumulative load growth-related capital investment in the Medium Pressure Distribution system (the dependent variable[27]) and cumulative peak day demand growth (the independent variable[28]).

---

[27] The dependent variable represents the output or outcome whose variation is being studied.

[28] 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: ten years of historical data (2015 - 2024) and five years of forecast data (2025 - 2029). The demand numbers have been updated to reflect historical and forecast data. The CAPEX represents the data from the last CAP, for years 2025 to 2029 using escalation of 3% per year.[29] The numbers are shown as 2027 dollars. The resulting estimated regression 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. Table MSP-2 below shows the cumulative peak day demand and the cumulative load growth-related capital investment in the Medium Pressure Distribution system.

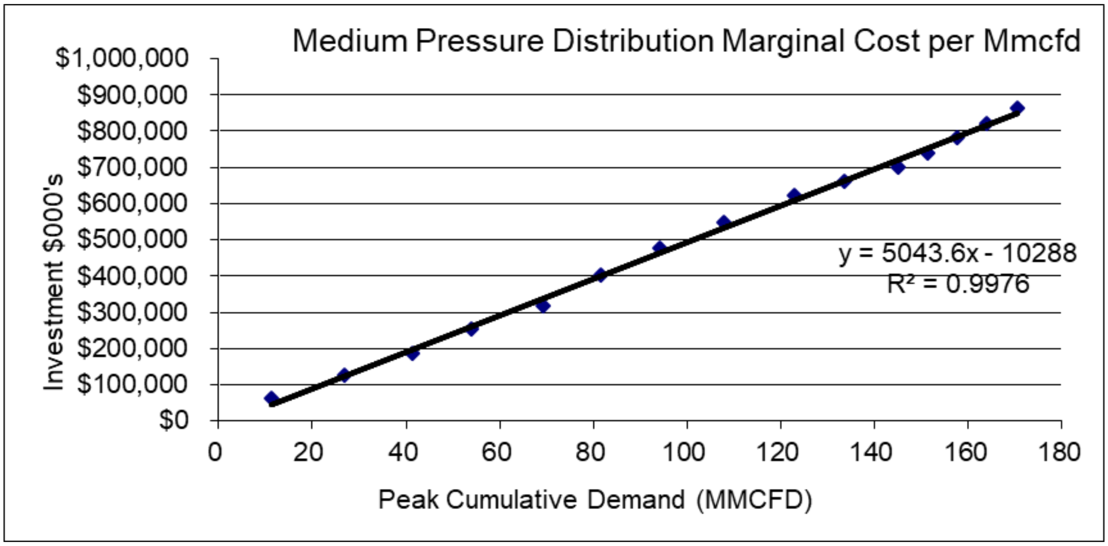
Table MSP-2

Year	Cumulative MMcfd	Cumulative CAPEX $000's
2015	11	$63,738
2016	27	$127,575
2017	41	$186,890
2018	54	$252,556
2019	69	$317,615
2020	81	$401,394
2021	94	$475,861
2022	108	$547,792
2023	123	$621,584
2024	133	$660,693
2025	145	$700,330
2026	151	$740,511
2027	158	$781,253
2028	164	$822,572
2029	170	$864,485

The regression analysis results are depicted in Figure MSP-1 below.

29 D.24-12-074 at 895-902.

Figure MSP-1



2. Marginal Direct O&M Costs

The 2024 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[30]) = [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

Table MSP-3 shows the calculation of the MUC_MPD. Marginal Cost Revenue is presented in Section VIII.

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

Table MSP-3

Marginal Cost for Medium Pressure Distribution (MPD) (2027 $/Mcfd peak day)	
Capital-related Charge:	
MPD Regression Coefficient $/Mcfd	$5,043.62
x RECC Factor	6.89%
= Annualized Capital-related Charge ($/Mcfd)	$347.65
+ Direct O&M	$17.87
+ A&G	$8.38
+ GP	$8.03
+ M&S	$0.68
= Marginal Unit Cost ($/Mcfd)	**$382.61**

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

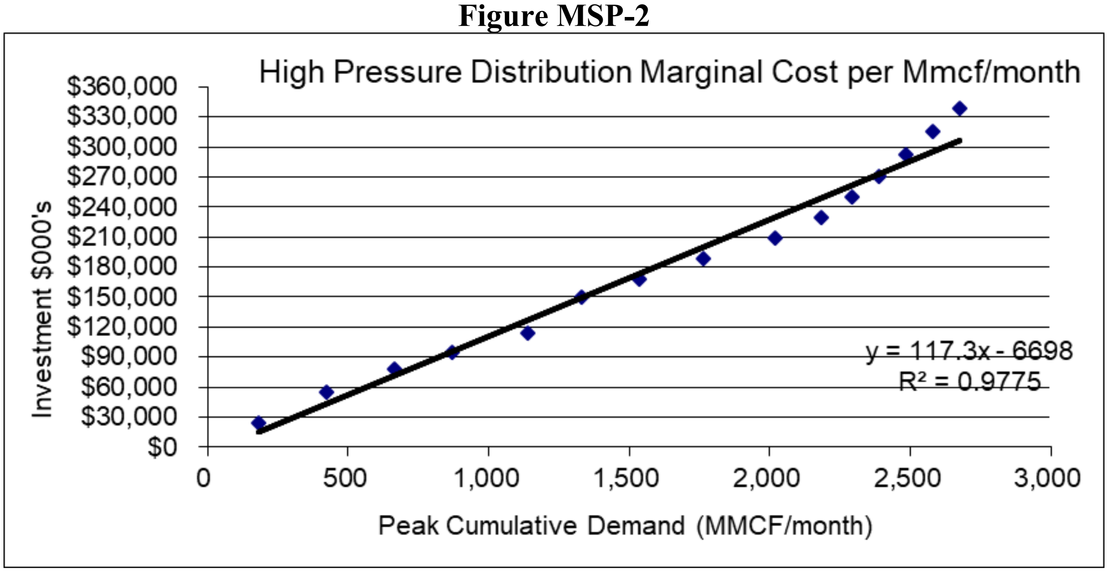
The methodology for calculating the marginal capital-related cost for the High Pressure Distribution system is analogous to the methodology used for the Medium Pressure Distribution system. Cumulative load growth-related investment costs in the High Pressure Distribution system are regressed against cumulative load growth. The coincident peak month demand served off the High Pressure Distribution system is used as the measure of MDM or cost driver for the HPD system. The demand numbers have been updated to reflect historical and forecast data. Table MSP-4 below shows the cumulative coincident peak month demand and the cumulative load growth-related capital investment in the High Pressure Distribution system.

Table MSP-4

Year	Cumulative Mmcf/ month	Cumulative CAPEX $000's
2015	182	$23,472
2016	422	$54,819
2017	663	$78,408
2018	869	$94,278
2019	1,139	$113,417
2020	1,330	$150,096
2021	1,534	$167,836
2022	1,764	$188,594
2023	2,017	$208,859
2024	2,182	$229,067
2025	2,293	$249,782
2026	2,388	$271,020
2027	2,484	$292,797
2028	2,578	$315,128
2029	2,674	$338,030

The regression analysis results are depicted in Figure 2 below.

Figure MSP-2



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

Table MSP-5 below shows the calculation of the MUC_HPD.

Table MSP-5

Marginal Cost for High Pressure Distribution
(2027 $/MCF/month)

Capital-related Charge:	
HPD Regression Coefficient $/Mcf/month	$117.30
x RECC Factor	6.84%
= Annualized Capital-related Charge ($/Mcf/month)	$8.02
+ Direct O&M	$6.70
+ A&G	$3.14
+ GP	$3.01
+ M&S	$0.25
= Marginal HP Distribution Cost($/MCF/month)	$21.13

VII. SOCALGAS 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.[31]

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's discount rate of 7.67% was approved via SoCalGas's Advice Letter 6207-G that allowed for Cost of Capital Mechanism (CCM) adjustment under D.08-05-035. The authorized book lives and salvage values for the different investments have also been updated to reflect current factors.

B. O&M Loaders

There are 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 investment. Application of O&M loaders to

[31] D.92-12-058 at 32.

direct marginal O&M costs produces fully-loaded marginal O&M cost.

C. A&G Loading Factors

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 Table 6 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] total A&G expenses, total transmission expenses, total storage expenses and exclusions not included in the base margin.

Recorded 2024 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.

Table MSP-6
A&G Loading Factor
`

Total Marginal A&G Costs $000's	$295,808	
+ Total Payroll Taxes $000	$60,908	
= Marginal A&G and Payroll Taxes $000	$356,716	
/ Net O&M Costs $000	$760,282	
= Marginal A&G Loading Factor as a % of O&M		**46.92%**

1. General Plant Loading Factor

Gross general plant, as reflected in FERC Accounts 390 through 398, includes general plant in service as of year-end 2024 for structures and improvements, office furniture and equipment, computer applications and equipment, shop and garage equipment, and communication equipment.

[32] Total Production Expenses reflects gas costs.

RECC factors associated with each capital category and the amounts of gross plant in service at year-end 2024 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, 2024, to derive an annualized cost for general plant. This annualized general plant cost is divided by year 2024 net O&M expenses to derive the general plant loading factor, as shown in Table 7 below. Like the A&G loading factor, the derivation of general plant loading factor excludes Storage- and Transmission-related costs.

Table MSP-7
General Plant Loading Factor

Total General Plant $000	$2,574,220
* Weighted Average RECC for General Plant	13.28%
= Annualized General Plant Costs	$341,771
/ Net Recorded O&M Costs $000	$760,282
= General Plant Loading Factor as a % of O&M	44.95%

2. 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 2024 M&S costs are allocated based on gross gas plant in each functional category. Applying an M&S loading factor is appropriate because M&S 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 for customer-related and distribution functions, 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 to derive fully-allocated O&M costs. The Table MSP-8 below shows the functionalization of the year 2024 M&S costs and the derivation of annual M&S costs for each function.

Table MSP-8
M&S Annual Costs

Function	
Customer Related $000	$5,191
Load Related $000	$5,628
Total	$10,819

VIII. RESULTS OF THE SOCALGAS COST ALLOCATION STUDIES

Upon completing the cost studies to allocate costs to functional categories, SoCalGas allocates each functional cost to customer classes using the following MDMs: number of customers for the customer costs, peak day demand for Medium Pressure Distribution costs and peak month demand for High Pressure Distribution costs. Each MDM reflects the four-year average of forecast annual MDM for the years 2027- 2029, reflecting the duration of the CAP period.

For the customer-related functional category, Table 9 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 cost revenue for each customer class, not adjusted or “scaled” to equal SoCalGas’s authorized base margin. A scalar factor is applied to adjust total marginal cost revenues so that the total revenue requirement from the cost studies, both LRMC and Embedded cost studies, equal the authorized base margin.

Table MSP-9

UNSCALED LONG RUN MARGINAL COST REVENUES

CUSTOMER COST

$000's

Customer Class	Customer LRMC $/customer	Customer Count	Customer Cost $000's
	A	B	C
Residential	106	5,844,466	$621,358
Core C/I	1,679	201,694	338,677
Gas A/C	10,357	0	-
Gas Engine	19,294	603	11,640
NGV	38,041	390	14,836
Total Core			$986,510
Noncore C/I	73,510	502	36,902
Small EG	35,830	309	11,071
Large EG	207,106	57	11,805
EOR	100,038	28	2,754
Total Retail Noncore			$62,532
Long Beach	1,423,463	1	1,423
SDG&E	3,358,783	1	3,359
Southwest Gas	875,029	1	875
Vernon	751,991	1	752
Ecogas	166,698	1	167
Total Wholesale			$6,576
UBS	$0	0	$0
BTS	$0	0	$0
Total Noncore			$69,108
Total SoCalGas			**$1,055,618**

Table MSP-10 shows unscaled 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 High Pressure Distribution service level peak month demand.

Table MSP-10

UNSCALED LRMC COST REVENUES

DISTRIBUTION COSTS

$000's

Customer Class	Medium Pressure Distribution LRMC $/mcfd	Medium Pressure Distribution Peak Day (mcfd)	Medium Pressure Distribution Costs $000's	High Pressure Distribution LRMC $/mcfd	High Pressure Distribution Peak Month Demand (mcf)	High Pressure Distribution Costs $000's
	A	B	C	D	E	F
Residential	$382.61	2,026,866	$775,507	$21.13	31,388,468	$663,195
Core C/I	$382.61	511,768	$195,810	$21.13	10,202,401	$215,563
Gas A/C	$382.61	0	$0	$21.13	0	$0
Gas Engine	$382.61	1,954	$748	$21.13	75,327	$1,592
NGV	$382.61	36,916	$14,125	$21.13	1,852,738	$39,146
Total Core			$986,189			$919,495
Noncore C/I	$382.61	93,784	$35,883	$21.13	6,599,410	$139,436
Small EG	$382.61	19,378	$7,414	$21.13	814,166	$17,202
Large EG	$382.61	10,129	$3,875	$21.13	1,535,767	$32,449
EOR	$382.61	31	$12	$21.13	629,074	$13,291
Total Retail Noncore			$47,185			$202,379
Long Beach	$382.61	0	$0	$21.13	0	$0
SDG&E	$382.61	0	$0	$21.13	0	$0
Southwest Gas	$382.61	0	$0	$21.13	0	$0
Vernon	$382.61	0	$0	$21.13	0	$0
Ecogas	$382.61	0	$0	$21.13	0	$0
Total Wholesale			$0			$0
UBS	$382.61	0	$0	$21.13	0	$0
BTS	$0.00	0	$0	$0.00	0	$0
Total Noncore			$47,185			$202,379
Total SoCalGas			**$1,033,374**			**$1,121,874**

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 costs directly allocated to the Transmission, Storage, Uncollectible,[34] and NGV Public Access functions. In this CAP, marginal costs are scaled at a rate of 84% in order to reconcile to the base margin of $2,697,933 thousand. Table MSP-11 shows this process.

---

33 D.92-12-058 at 50.

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

Table MSP-11

LRMC COST SCALED REVENUES

SCALED CUSTOMER & DISTRIBUTION COSTS

$000's

Customer Class	Customer Cost	Medium Pressure Distribution	High Pressure Distribution	Unscaled LRMC Revenues	Scalar	Scaled LRMC Revenues
	A	B	C	D=A+B+C	E	F=D*E
Residential	$621,358	$775,507	$663,195	$2,060,060	84%	$1,730,856
Core C/I	$338,677	$195,810	$215,563	$750,049	84%	$630,189
Gas A/C	$0	$0	$0	$0	84%	$0
Gas Engine	$11,640	$748	$1,592	$13,979	84%	$11,745
NGV	$14,836	$14,125	$39,146	$68,106	84%	$57,223
Total Core	$986,510	$986,189	$919,495	$2,892,195	84%	$2,430,012
Noncore C/I	$36,902	$35,883	$139,436	$212,222	84%	$178,308
Small EG	$10,570	$7,414	$17,202	$35,186	84%	$29,563
Large EG	$4,763	$3,875	$32,449	$41,088	84%	$34,522
EG Transmisson	$7,543			$7,543	84%	$6,338
EOR	$2,754	$12	$13,291	$16,057	84%	$13,491
Total Retail Noncore	$62,532	$47,185	$202,379	$312,095	84%	$262,221
Long Beach	$1,423	$0	$0	$1,423	84%	$1,196
SDG&E	$3,359	$0	$0	$3,359	84%	$2,822
Southwest Gas	$875	$0	$0	$875	84%	$735
Vernon	$752	$0	$0	$752	84%	$632
Ecogas	$167	$0	$0	$167	84%	$140
Total Wholesale	$6,576	$0	$0	$6,576	84%	$5,525
UBS	$0	$0	$0	$0	84%	$0
BTS	$0	$0	$0	$0	84%	$0
Total Noncore	$69,108	$47,185	$202,379	$318,671	84%	$267,747
Total SoCalGas	**$1,055,618**	**$1,033,374**	**$1,121,874**	**$3,210,866**	**84%**	**$2,697,759**

After the derivation of scaled customer and distribution marginal cost revenues by customer classes, the remaining base margin items for Transmission, Storage, NGV, and Uncollectible costs are allocated to customer classes, as shown in Table MSP-12. Transmission and Storage are escalated by 3%/year to 2027.[35] Local Transmission costs[36] are allocated to customer classes using cold year peak month throughput. Backbone Transmission costs[37] are isolated to derive the Backbone Transmission System (BTS) rate. Storage costs[38] are allocated to customer classes using the storage rates (for inventory, injection, and withdrawal) applied to the capacities for core storage, load balancing, and load balancing plus functions proposed in this CAP.[39] Uncollectible and NGV Public Access Station costs are also included. The system average uncollectible rate is ~~0.278%~~ 0.375%. The NGV Public Access Station cost is allocated to the NGV class for recovery through the NGV Compressor Adder cost.

Finally, scaled LRMC costs are combined with the Transmission, Storage, Uncollectible, and NGV Public Access costs to determine the proposed cost allocation of authorized base margin. This is presented in Column G of Table MSP-12.

---

35 *See* Chapter 8 (Seres/Schmidt-Pines). FF&U and Escalation added. D.24-12-074 at 895-902.

36 *See* Chapter 8 (Seres/Schmidt-Pines). FF&U and Escalation added. D.24-12-074 at 895-902.

37 *Id.*

38 *Id.*

39 *See* direct testimony of Michelle Dandridge (Chapter 1).

Table MSP-12

ALLOCATION OF BASE MARGIN

$000's

Customer Class	Scaled LRMC Revenues	Uncollect	BTS	Local Transmission	NGV Public Access	Storage	Allocated Base Margin
	A	B	C	D	E	F	G
Residential	$1,730,856	$8,563	$0	$110,185	$0	$173,439	$2,023,043
Core C/I	$630,189	$3,040	$0	$32,256	$0	$43,406	$708,891
Gas A/C	$0	$0	$0	$0	$0	$0	$0
Gas Engine	$11,745	$56	$0	$202	$0	$1,085	$13,088
NGV	$57,223	$332	$0	$5,154	$5,629	$5,720	$74,057
Total Core	$2,430,012	$11,992	$0	$147,798	$5,629	$223,649	$2,819,079
Noncore C/I	$178,308	$1,306	$0	$34,500	$0	$22,757	$236,872
Small EG	$29,563	$157	$0	$2,057	$0	$1,539	$33,316
Large EG	$34,522	$212	$0	$4,245	$0	$2,877	$41,857
EG Transmission	$6,338	$807	$0	$49,157	$0	$29,312	$85,614
EOR	$13,491	$0	$0	$2,208	$0	$1,561	$17,261
Retail Noncore	$262,221	$2,482	$0	$92,168	$0	$58,047	$414,918
Long Beach	$1,196	$0	$0	$3,229	$0	$1,248	$5,672
SDG&E	$2,822	$0	$0	$31,772	$0	$32,583	$67,177
Southwest Gas	$735	$0	$0	$3,819	$0	$1,316	$5,870
Vernon	$632	$0	$0	$1,725	$0	$1,251	$3,608
Ecogas	$140	$0	$0	$2,827	$0	$2,035	$5,002
Total Wholesale	$5,525	$0	$0	$43,371	$0	$38,433	$87,330
UBS	$0	$0	$0	$0	$0	$35,508	$35,508
BTS			$502,896				$502,896
Total Noncore	$267,747	$2,482	$502,896	$135,539	$0	$131,988	$1,040,652
Total SoCalGas	**$2,697,759**	**$14,474**	**$502,896**	**$283,337**	**$5,629**	**$355,636**	**$3,859,731**

IX. COMPARISON OF SOCALGAS PROPOSED COST ALLOCATION TO CURRENT COST ALLOCATION

The following is a comparison of the proposed 2027 cost allocation to the current allocation effective September, 2025. This comparison is pre-System Integration[40] and pre-BTS unbundling,[41] as discussed in the direct testimony of Michael Foster (Chapter 12). The difference of $198 million is due to PSEP costs included in Base Margin. The PSEP costs are included in the studies and not allocated separately as is in current rates.

Relative to the current allocation, the proposed CAP allocation of base margin across customer classes shows a decrease for core customers, including residential customers, an increase for noncore customers and an increase for unbundled backbone transmission service. These allocation changes reflect the impacts of updated cost studies for customer-related, distribution, transmission and storage functions and updated lower demand forecasts. The residential allocation shows a decrease due to the residential customer-related capital costs going to zero.

---

[40] 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.

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

Table MSP-13

COST ALLOCATION COMPARISON

$000's

Customer Class	Proposed Allocation of Base Margin	% Total	Current Allocation of Base Margin	% Total
	A	B	C	D
Residential	$2,023,043	52.4%	$2,280,942	62.3%
Core C/I	$708,891	18.4%	$538,916	14.7%
Gas A/C	$0	0.0%	$61	0.0%
Gas Engine	$13,088	0.3%	$12,599	0.3%
NGV	$74,057	1.9%	$40,058	1.1%
Total Core	$2,819,079	73.0%	$2,872,577	78.5%
Noncore C/I	$236,872	6.1%	$143,801	3.9%
Small EG	$33,316	0.9%	$22,702	0.6%
Large EG	$41,857	1.1%	$20,771	0.6%
EG Transmission	$85,614	2.2%	$61,354	1.7%
EOR	$17,261	0.4%	$10,281	0.3%
Total Retail Noncore	$414,918	10.7%	$258,910	7.1%
Long Beach	$5,672	0.1%	$5,285	0.1%
SDG&E	$67,177	1.7%	$59,347	1.6%
Southwest Gas	$5,870	0.2%	$4,417	0.1%
Vernon	$3,608	0.1%	$3,576	0.1%
Ecogas	$5,002	0.1%	$4,234	0.1%
Total Wholesale	$87,330	2.3%	$76,859	2.1%
UBS	$35,508	0.9%	$30,850	0.8%
BTS	$502,896	13.0%	$422,225	11.5%
Total Noncore	$1,040,652	27.0%	$788,844	21.5%
Total SoCalGas	**$3,859,731**	**100.0%**	**$3,661,421**	**100.0%**

SDG&E LRMC STUDY AND COST ALLOCATION

X. SDG&E CUSTOMER-RELATED MARGINAL COSTS

Customer-related marginal unit cost reflects the cost of a customer's access to the gas utility's supply system and is comprised of: (1) the marginal capital cost of service lines and meter set assemblies; (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.

A. Marginal Capital Costs

Service line, regulator, and meter (SRM) costs reflect the capital expense associated with providing customer access to the gas supply system. These costs include gas meters, regulators, pipes, and installation labor. For residential, the capital costs are adjusted to zero. Starting July 1, 2023, Residential New Construction Builders no longer receive allowances for natural gas line extensions.[42] The SDG&E Gas Distribution Engineering Department provides updated customer data, including:

- Meter size, type, regulator, fitting costs and installation costs;
- Service footages;
- Service costs for new hook-ups and replacements;
- Costs of service line installations; and
- Series of flow ranges,[43] and corresponding equipment profiles, at each range.

Twenty-six flow ranges are identified for which SRM costs are summarized. These total capital costs are annualized using corresponding Real Economic Carrying Charge factors, which I discuss

---

[42] SoCalGas Rule No. 20, C2, SDG&E Rule No. 15, C3

[43] The SDG&E Gas Distribution Engineering Department defines flow ranges to specify typical meter and regulator equipment design flow capacity used to support different levels of gas flow.

in Section VI. The annualized costs are multiplied by the number of meters for each customer class represented within each flow range to determine the total annual capital cost associated with serving each class. Finally, the total annualized capital cost is divided by the forecast number of customers in each class to determine each class's average marginal SRM cost. Table MSP-14 shows the resulting 2027[44] annualized marginal capital-related costs per customer.

Table MSP-14
CUSTOMER-RELATED LRMC - CAPITAL COSTS

Customer Class	Rental-Method Customer Cost (2027 $/customer)
Residential	$0
Core Commercial/Industrial	$379
Natural Gas Vehicle	$1,191
Noncore Commercial/Industrial	$2,115
Small Electric Generation	$942
Large Electric Generation	$2,245

B. Marginal Direct O&M Costs

Customer Services direct O&M expenses are accounted for in FERC Accounts 901-905 and 907-910 and are allocated entirely as Customer-related function. These expenses are associated with responding to customer service field orders and generally operating and maintaining service lines, meters, and house regulators. FERC Accounts 870-894 record Distribution O&M. These expenses are associated with the maintenance of customers' meters, regulators, and service lines, as well as distribution mains.

[44] Escalation factors updated to reflect S&P Global Handy Whitman 4th Quarter utility cost forecast, released January 2025.

Distribution O&M costs are assigned to market segments by classifying the costs as either Customer-related or Medium Pressure and High Pressure Distribution-related. Customer-related distribution O&M is allocated entirely to the Customer-related function. These activities include meter reading, customer services, credit collections, and billing services. The Medium and High Pressure Distribution-related expenses are allocated between the High Pressure Distribution, Medium Pressure Distribution, and Customer-related functions based on pipeline mileage as of December 31, 2024. The SDG&E Gas Distribution Engineering Department identifies the marginal portion of each of the FERC Accounts 870-894.

Customer-related distribution O&M is allocated to the customer classes using the effective percentage of total annualized SRM investment costs. The resulting allocation of Customer-related distribution O&M expenses to customer classes is combined with Customer Services O&M expenses, and then divided by the number of customers in each class to determine a per-customer direct O&M expense. The direct O&M costs are allocated to customer classes in three steps. First, Customer Services marginal direct O&M expenses are classified into functions. Expenses by Customer Services function are then assigned to one of these operational activities. Finally, these expenses are allocated to customer classes based on either the operational activity performed, or the market segment supported. Once Customer Services costs are allocated to the customer classes, they are combined with the portion of Distribution O&M costs allocated to Customer-related function in order to develop total Customer-related direct O&M costs. Table MSP-15 shows the Customer-related direct O&M costs.

Table MSP-15				
CUSTOMER-RELATED DIRECT MARGINAL O&M EXPENSES (2027 $)				
Customer Class	FERC 870-894 $000	FERC 901-910 $000	Customers per Class	Direct O&M $/Customer
Residential	$57,770	$1,029	886,131	$66
Core Commercial/Industrial	$4,822	$36	30,662	$158
Natural Gas Vehicle	$19	$0.0	36	$516
Noncore Commercial/Industrial	$52	$8	67	$902
Small Electric Generation	$32	$11	91	$475
Large Electric Generation	$11	$1	9	$1,397

C. O&M Loaders

Three distinct O&M loaders are applied to direct marginal O&M costs to develop the fully loaded O&M. These loading factors reflect indirect costs for: (1) administrative and general (A&G) expenses, (2) general plant, and (3) materials and supplies (M&S), as discussed in Section XII below. 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. Application of O&M loaders to direct costs produces a fully loaded marginal unit cost.

D. Fully Loaded Customer-Related LRMC

Table MSP-16 provides the total marginal customer costs for the six SDG&E customer classes. These costs are the result of combining the fully loaded O&M costs with the capital related costs from Table 1. The fully loaded O&M costs include direct O&M and O&M loaders. The noncore customer classes post significantly higher marginal costs per customer than the core customer classes because noncore customers have much higher gas service demands and require larger and more specialized metering and service facilities compared to core customers.

Table MSP-16
CUSTOMER-RELATED LONG RUN MARGINAL COSTS
(2027 $/customer)

Customer Class	Annualized Capital Cost	Expense-Related O&M Direct	M&S	A&G	General Plant	Total $/Customer
Residential	$0	$66	$1	$17	$14	$99
Core Commercial/Industrial	$379	$158	$2	$41	$34	$614
Natural Gas Vehicle	$1,191	$516	$6	$135	$110	$1,958
Noncore Commercial/Industrial	$2,115	$902	$10	$235	$192	$3,455
Small Electric Generation	$942	$475	$5	$124	$101	$1,647
Large Electric Generation	$2,245	$1,397	$16	$365	$297	$4,319

XI. SDG&E MEDIUM PRESSURE AND HIGH-PRESSURE DISTRIBUTION-RELATED MARGINAL COSTS

Marginal costs are calculated for both the Medium Pressure and High Pressure Distribution systems. Separate marginal costs are calculated for the Medium Pressure and High Pressure Distribution systems because the marginal demand measures driving the costs for the two systems are different.

A. Marginal Direct O&M Costs

This LRMC study utilizes ten years of historical (2015-2024) and five years of forecast (2025-2029) distribution plant investments and marginal demand measures. The SDG&E Gas Distribution Engineering Department provides the historical period investments from an analysis of accounting data for Medium Pressure Distribution and High Pressure Distribution capital investments. The forecast investments are also provided by that department. For years 2025 to 2029 the investment was escalated 3% per year.[45] The marginal demand measures are based on an analysis of peak-day throughput[46] on the Medium Pressure Distribution and High Pressure

45 D.24-12-074 at 895-902.

46 Throughput is defined as the volume of gas flowing through a meter over a specified period of time.

Distribution systems. Marginal demand measures, including peak-day load by market segment, are from the consolidated demand forecast presented in Chapter 5 (Martinez).

Linear regression is used to determine the marginal capital costs of the Medium Pressure Distribution and High Pressure Distribution systems. This method plots the cumulative incremental investment as the dependent variable against the cumulative incremental changes in peak-day demand, which is the independent variable. The slope of the best-fit line is taken to be the marginal capital cost. This capital cost is then annualized by using a weighted-average Real Economic Carrying Charges factor applicable to Distribution Demand-related distribution pipeline investments. The linear regression analysis is described in Section D below.

B. Marginal Direct O&M Costs

FERC Accounts 870-894 record Distribution-related O&M, and these expenses are assigned to market segments by classifying the costs as either Customer-related or Distribution-related. The Distribution-related expenses are allocated between the High Pressure Distribution, Medium Pressure Distribution, and Customer-related functions based on pipeline mileage as of December 31, 2021. The SDG&E Gas Distribution Engineering Department identifies the marginal portion of each of FERC Account Medium Pressure Distribution and High Pressure Distribution direct O&M expenses are divided by the peak-day demand of each system to determine their respective direct O&M expenses. Table MSP-17 below presents a summary of direct distribution O&M expenses by market segment.

Table MSP-17			
DISTRIBUTION-RELATED DIRECT MARGINAL O&M EXPENSES (2027 $)			
Distribution Function	FERC 870-894 $000	Peak-day Load (mcfd)	Direct O&M $/mcfd
Medium-Pressure	$30,376	413,415	$73.48
High-Pressure	$1,317	340,550	$3.87

C. O&M Loaders

A&G, general plant, and M&S loaders are applied to direct costs to produce a fully loaded marginal unit cost. The development of these loaders is described in Section VI.

D. Fully Loaded Distribution LRMC

Fully-loaded O&M costs are added to distribution marginal capital costs to determine the total marginal costs for the Medium Pressure Distribution and High Pressure Distribution systems. Table MSP-18 presents the total marginal costs for the Medium Pressure Distribution systems.

Table MSP-18 MEDIUM-PRESSURE DISTRIBUTION LRMC (2027 $/MCF MPD peak day)		
	Marginal Investment Cost	$5,438.21
x	RECC Factor	6.98%
=	Annualized Investment Cost	$379.62
	Expense-Related	
+	O&M Cost	$97.63
+	A&G Cost	$25.49
+	General / Common Plant Cost	$20.76
+	M&S Cost	$2.87
=	**Total Marginal Cost**	$526.37

The following chart, Figure MSP-3, depicts the results of the regression analysis in graphical form.

Figure MSP-3

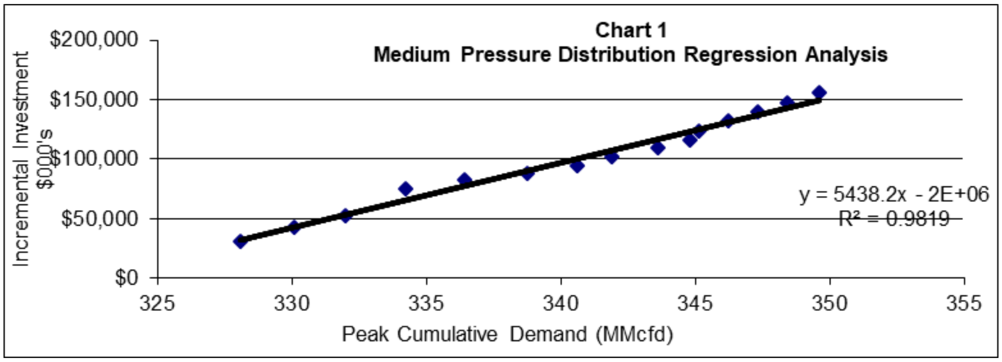
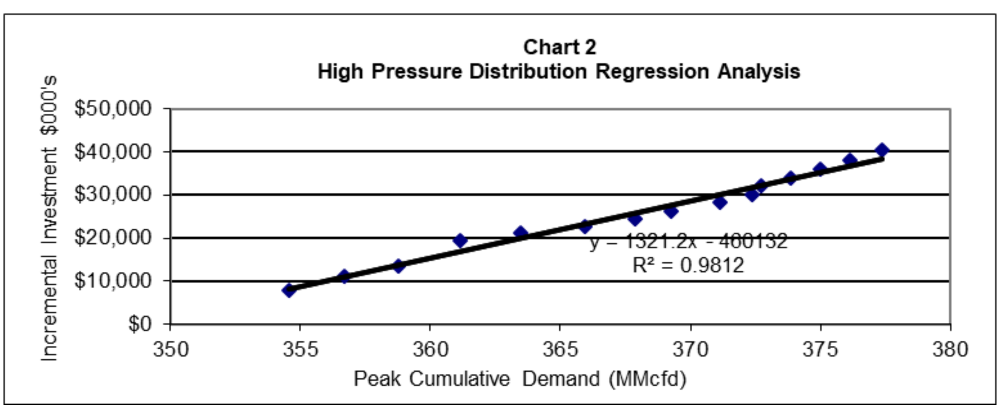


Table MSP-19 presents the total marginal costs for the High Pressure Distribution systems.

	Table MSP-19 **HIGH-PRESSURE DISTRIBUTION LRMC** **(2027 $/MCF HPD peak day)**	
	Marginal Investment Cost	$1,321.21
x	RECC Factor	6.98%
=	Annualized Investment Cost	$92.23
	Expense-Related	
+	O&M Cost	$4.07
+	A&G Cost	$1.06
+	General / Common Plant Cost	$0.86
+	M&S Cost	$0.71
=	**Total Marginal Cost**	$98.93

The following chart, Figure MSP-4, depicts the results of the regression analysis in graphical form.

Figure MSP-4



XII. SDG&E MARGINAL COST ESTIMATION FACTORS

A. Real Economic Carrying Charges (RECC)

In the previous sections, RECC factors appeared in the calculation of marginal unit costs for customer-related costs as well as Medium Pressure and High Pressure Distribution capital costs. RECC factors are used to convert capital investment into annualized capital costs.[47]

The RECC factors used in Tables MSP-14, MSP-16, MSP-18 and MSP-19 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. SDG&E has updated its RECC factors using inflation assumptions from Standard and Poor (S&P)'s forecast, updated tax rates, and SDG&E's authorized rate of return of 7.67% revised per Advice Letter No. 3239-G.[48] The authorized book lives and salvage values for the different investments have also been updated to reflect current factors.

[47] Refer to Section VI, *supra.*

[48] SDG&E's Cost of Capital Mechanism (CCM) Trigger Adjustment Effective January 1, 2024, Pursuant to D.22-12-031.

Table MSP-20 REAL ECONOMIC CARRYING CHARGE FACTORS	
Cost Type	RECC %
Meters and Regulators	7.69%
Meter/Regulator Installation	8.04%
Service Line Pipe	6.98%
Weighted-Average Distribution	6.98%
Materials and Supplies	9.85%
Weighted-Average General/Common Plant	7.07%

B. Marginal O&M Loading Factors

Loading factors account for costs related to A&G expenses and payroll taxes, general plant, and M&S. SDG&E derives loading factors using the same methodology adopted in the 2020 TCAP application, A.18-07-024. 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. Application of O&M loaders to direct costs produces fully loaded marginal O&M costs.

1. A&G Loading Factor

A&G refers to operational expenses that are not directly associated with the production of any good or service and include items such as rent and insurance. Marginal A&G expenses and payroll taxes are combined into a single loading factor. I relied on the recorded year 2024 A&G expenses from the Annual Report, which are then classified as either marginal or non-marginal by account. As shown below in Table MSP-21, the proposed A&G expenses and payroll tax loader is 26.11%. The A&G loading factor is calculated as a percentage of total O&M (less A&G) and then multiplied by the direct O&M unit cost for each function.

Table MSP-21 A&G LOADING FACTOR		
	Account Description	Marginal Costs 2027 $ 000s
	A&G Expenses	$30,102
+	Payroll Taxes	$6,731
=	Total A&G with Payroll Taxes	$36,833
/	Total O&M Expenses excluding A&G	$141,078
=	A&G Loading Factor	26.11%

2. General Plant Loading Factor

General plant includes structures and improvements, office furniture and equipment, computer applications and equipment, shop and garage equipment, and communication equipment, as well as plant shared between SDG&E electric and gas operations allocated to the gas function. The recorded year 2024 general plant[49] total is multiplied by the weighted-average RECC factor of 7.07% to obtain an annualized general plant of $58.8 million. The general plant loading factor is then determined by dividing annualized general plant by total O&M expenses. Table MSP-22 shows the derivation of the general plant loading factor.

[49] Total 2021 General Plant of $831,562 thousand is the sum of Total General Plant of $32,339 thousand (source: 2024 SDG&E FERC Form 2) and Common Utility Plant – Gas of $799,223 thousand (source: 2024 SDG&E Gas FERC Form 1).

Table MSP-22
GENERAL PLANT LOADING FACTOR

	Account Description	2024 Recorded Costs 2027 $ 000s
	Total General Plant	$831,562
+	Average General Plant RECC	7.07%
=	Annualized General Plant	$58,791
/	Total O&M Expenses	$276,485
=	General Plant Loading Factor	21.26%

3. M&S Loading Factor

M&S includes those materials in stock for use in company operations. Examples of M&S items include pipe, valves, fittings, and safety equipment. Recorded year 2024 M&S costs of $21.2 million are allocated to the functions based on percentage of gross plant in each functional category and then multiplied by a factor of 9.85% to obtain annualized M&S costs. M&S costs allocated to the customer cost function are further allocated to the customer classes at the same relative percentage as direct O&M. M&S loaders are then derived by dividing allocated M&S costs by the number of customers in each class. For the Distribution functions (i.e., Medium Pressure Distribution-related and High Pressure Distribution-related), allocated M&S costs are divided by peak-day load in order to determine the loader amounts. Table MSP-23 presents the resulting M&S loading costs by customer class and function.

Table MSP-23 M&S LOADING FACTORS (2027 $)			
Customer Class	Allocated M&S	Customers per Class	M&S Loader $/Customer
Residential	$661,455	886,131	$0.75
Core Commercial/Industrial	$54,650	30,662	$1.78
Natural Gas Vehicle	$209	36	$5.81
Noncore Commercial/Industrial	$680	67	$10.15
Small Electric Generation	$486	91	$5.34
Large Electric Generation	$141	9	$15.71
Distribution Function	Allocated M&S	Peak-day Load (mcfd)	M&S Loader $/mcfd
Medium-Pressure	$892,142	413,415	$2.16
High-Pressure	$230,433	340,550	$0.68

XIII. SDG&E ALLOCATED BASE MARGIN

Upon completing the cost studies to allocate costs to functional categories, SDG&E allocates each functional cost to customer classes using the marginal demand measures: number of customers for the customer costs and peak day demand for both Medium Pressure Distribution costs and High Pressure Distribution costs. Each marginal demand measure reflects the forecast annual average marginal demand measures (listed above) for the years 2027 - 2029, reflecting the duration of the 2027 TCAP period.

For the Customer-related functional category, Table MSP-24 shows marginal unit costs, the customer counts, and the marginal cost revenues by customer classes 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 SDG&E’s authorized base margin. A scalar factor is applied to adjust total marginal cost revenues so that the total revenue requirement from both the LRMC and embedded cost studies equal the authorized base margin.

Table MSP-24 UNSCALED LONG RUN MARGINAL COST CUSTOMER COST			
Customer Class	Customer LRMC $/customer	Customer Count	Customer Cost $000's
	A	B	C
Residential	$99	898,254	$88,509
Core C/I	$614	30,723	$18,872
NGV	$1,958	36	$70
Total Core			$107,452
Noncore C/I	$3,455	67	$231
Small EG	$1,647	86	$142
Large EG	$4,319	13	$56
Total Noncore			$429
Total SoCalGas			**$107,881**

Table MSP-25 shows the allocation of unscaled Medium Pressure Distribution 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 / 1-in-10 cold day noncore High Pressure Distribution service level peak day demand.

Table MSP-25 UNSCALED LONG RUN MARGINAL COST DISTRIBUTION COSTS						
Customer Class	MPD LRMC $/mcfd	MPD Peak-Day (Mcfd)	MPD Costs $000	HPD LRMC $/mcfd	HPD Peak-Day (Mcfd)	HPD Costs $000
Residential	$526	199,189	$104,847	$99	199,216	$19,709
Core C/I	$526	87,547	$46,082	$99	88,410	$8,747
NGV	$526	5,617	$2,957	$99	9,749	$964
Total Core			$153,886			$29,420
Noncore C/I	$526	11,300	$5,948	$99	11,996	$1,187
Small EG	$526	5,287	$2,783	$99	7,617	$754
Large EG	$526	987	$520	$99	7,601	$752
Total Noncore			$9,250			$2,692
Total SoCalGas			**$163,136**			**$32,112**

In D.92-12-058, the Commission stated that marginal cost revenues need to be scaled to the embedded-based authorized revenue requirement under SDG&E's ratemaking procedures. The current SDG&E gas base margin for transportation rates effective September 1, 2025, is $547 million and this is the revenue requirement used to determine the scalar. The scalar adjusts allocated marginal costs to the authorized base margin, excluding embedded costs directly assigned to the Transmission ($61.4 million)[50] and NGV Public Access ($0.4 million) functions, which are not scaled.

In this cost allocation proceeding (CAP), marginal costs are scaled at a rate of 160% in order to reconcile to the adjusted base margin[51] of $470 million. Table MSP-25 shows the total cumulative SDG&E costs being allocated. Finally, scaled LRMC costs are added to the

[50] Including Franchise Fees and Allowance for Uncollectible (FF&U) and escalation of 3%/year from 2024 to 2027. *See* D.24-12-074 at 895-902.

[51] Adjusted Base Margin refers to base margin excluding non-scaled items: Backbone Transmission

Transmission and NGV Public Access costs to determine the cost-based allocation of authorized gas base margin of $547 million.[52] The total costs for SDG&E being allocated is presented in Table MSP-26.

Table MSP-26

LONG RUN MARGINAL COST SCALED CUSTOMER AND DISTRIBUTION COSTS

$000's

Customer Class	Customer Cost	Medium Pressure Distribution	High Pressure Distribution	Unscaled LRMC Revenues	Scalar	Scaled LRMC Revenues
Residential	$88,509	$104,847	$19,709	$213,065	160%	$341,264
Core C/I	$18,872	$46,082	$8,747	$73,701	160%	$118,046
NGV	$70	$2,957	$964	$3,992	160%	$6,393
Total Core	$107,452	$153,886	$29,420	$290,758	160%	$465,703
Noncore C/I - D	$214	$5,948	$1,187	$7,349	160%	$11,771
Noncore C/I - T	$17	$0	$0	$17	160%	$28
Small EG Distribution	$166	$2,783	$754	$3,702	160%	$5,930
Large EG Distribution	$6	$520	$752	$1,278	160%	$2,046
EG Transmission	$26	$0	$0	$26	160%	$42
Total Noncore	$429	$9,250	$2,692	$12,372	160%	$19,816
Total SDG&E	**$107,881**	**$163,136**	**$32,112**	**$303,130**	160%	**$485,519**

Service (BTS) and NGV public access.

52 Per Chapter 8 (Seres/Schmidt-Pines), the SDG&E transmission system is 100% backbone. For the purposes of this testimony, SDG&E's $77 million (including FF&U and escalation) in backbone transmission costs are allocated to the Backbone Transmission Service rate class. These costs will be incorporated in System Integration in Chapter 12 (Foster), which unbundles part of the combined Southern California Gas Company (SoCalGas)/SDG&E transmission system into the BTS tariff, with the remaining transmission costs being allocated to the local transmission function and, ultimately, back to the customer classes.

Table MSP-27 ALLOCATION OF BASE MARGIN $000's							
Customer Class	Scaled LRMC	+	Backbone Transmission	+	NGV Public Access	=	Unadjusted Allocated Base Margin
Residential	$341,264		$0		$0		$341,264
Core C/I	$118,046		$0		$0		$118,046
NGV	$6,393		$0		$428		$6,821
Total Core	$465,703		$0		$428		$466,131
Noncore C/I - D	$11,771		$0		$0		$11,771
Noncore C/I - T	$28		$0		$0		$28
Small EG	$5,930		$0		$0		$5,930
Large EG	$2,046		$0		$0		$2,046
EG Transmission	$42		$0		$0		$42
Total Noncore	$19,816		$0		$0		$19,816
BTS	$0		$61,352		$0		$61,352
Total SDG&E	**$485,519**		**$61,352**		**$428**		**$547,299**

XIV. COMPARISON OF SDG&E PROPOSED COST ALLOCATION TO CURRENT COST ALLOCATION

Table MSP-28 shows a comparison of the proposed cost allocation to the current allocation. This comparison is pre-System Integration[53] and pre-BTS unbundling.[54] The difference of $15 million is due to PSEP costs included in Base Margin. The PSEP costs are included in the studies and not allocated separately as is in current rates.

---

53 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.

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

Relative to the current allocation, the proposed CAP allocation of base margin across customer classes shows a decrease for core customers, including residential customers, an increase for noncore customers (except for electric generation distribution-level customers) and an increase for unbundled backbone transmission service. These allocation changes reflect the impacts of updated cost studies for customer-related, distribution, transmission and storage functions and updated lower demand forecasts.

Table MSP-28
COST ALLOCATION COMPARISON
$000's

Customer Class	Proposed Allocation of Base Margin	% Total	Current Allocation of Base Margin	% Total
Residential	$341,264	62.4%	$377,156	70.9%
Core C/I	$118,046	21.6%	$66,501	12.5%
NGV	$6,821	1.2%	$2,536	0.5%
Total Core	$466,131	85.2%	$446,193	83.9%
Noncore C/I - D	$11,771	2.2%	$3,901	0.7%
Noncore C/I - T	$28	0.0%	$23	0.0%
Small EG	$5,930	1.1%	$2,845	0.5%
Large EG	$2,046	0.4%	$1,131	0.2%
EG Transmission	$42	0.0%	$37	0.0%
Total Noncore	$19,816	3.6%	$7,937	1.5%
Backbone Transmission	$61,352	11.2%	$77,685	14.6%
Total SDG&E	**$547,299**	**100%**	**$531,815**	**100%**

This concludes my prepared direct testimony.

XV. 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.

I hold a Bachelor of Science degree in Business Administration with an emphasis in Accounting from California State University at Northridge, California. I have been employed by SoCalGas since 1981 and have held positions of increasing responsibilities as an Accountant and Senior Accountant in the Accounting & Finance department, as an Analyst and a Budget Coordinator in the Gas Supply department, as a Senior Market Analyst and Market Advisor for the Marketing and Customer Services departments and Principal Regulatory Economic Advisor in the Regulatory Affairs Department.

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 rate design for each class, calculating customer rate changes, and computing customers' bill impacts.

I have previously testified before the California Public Utilities Commission.