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Chapter: 10

PREPARED DIRECT TESTIMONY OF

MICHAEL FOSTER

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

(COST ALLOCATION AND LONG RUN MARGINAL COST STUDY)

September 30, 2022

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CHAPTER 10

PREPARED DIRECT TESTIMONY OF MICHAEL FOSTER

(COST ALLOCATION AND LONG RUN MARGINAL COST STUDY – SDG&E)

I. PURPOSE

The purpose of my prepared direct testimony is to present the Long Run Marginal Cost (LRMC) study for San Diego Gas & Electric Company's (SDG&E) Customer-related, Medium Pressure Distribution-related, and High Pressure Distribution-related service functions and to allocate gas base margin to SDG&E's six customer classes. My testimony is organized as follows:

- Section II describes principles of cost allocation;
- Section III provides an overview of SDG&E's cost allocation proposal;
- Section IV explains the derivation of Customer-related marginal costs;
- Section V explains the derivation of Medium and High Pressure Distribution-related marginal costs;
- Section VI presents SDG&E's Real Economic Carrying Charges and marginal loading factors;
- Section VII summarizes the method for allocating gas base margin to SDG&E's customer classes; and
- Section VIII shows the allocated costs.

II. COST ALLOCATION PRINCIPLES

Cost allocation refers to the process of determining the cost of each utility function and allocating these functional costs to the utility's customer classes. The cost allocation proposal described below allocates costs to customer classes based on cost causality and maintains 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, and usage characteristics, and the costs incurred by the utility in serving those requirements. A cost allocation based solely on cost causation seeks to present cost-based rates.

III. COST ALLOCATION PROPOSAL

I propose to continue the cost allocation framework that was adopted by the California Public Utilities Commission (CPUC or Commission) for SDG&E in the 2020 Triennial Cost Allocation Proceeding (TCAP), Application (A.) 18-07-024. That TCAP resulted in cost allocation outcomes approved in Decision (D.) 20-02-045.

For SDG&E's LRMC study, I derived the cost allocations for the Customer-related and Medium and High Pressure Distribution-related functions using the LRMC method. LRMC of a service refers to incremental cost to serve one additional unit in the long run; such unit cost is called marginal unit cost. The cost causation unit is called a marginal demand measure. The consolidated marginal demand measures are presented by in the testimony of Wei Bin Guo (Chapter 5). The LRMC-based functional revenue (marginal cost revenue) is derived by multiplying the marginal unit cost 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 for each system.[1]

[1] Peak Day Demand is forecast to be in December. *See* Chapter 2 (Guo).

Customer-related costs reflect the capital-related and operations and maintenance (O&M) expenses incurred by SDG&E to provide customer access to the gas supply system. This includes provisions for service lines, regulators, meters, call centers, and service representatives. Medium Pressure and High Pressure Distribution costs are associated with building and maintaining systems that deliver gas to customer load centers from the gas transmission system. The LRMC study also incorporates inputs from the testimony of Frank Seres (Chapter 8) for Transmission-related costs and the testimony of Sharim Chaudhury (Chapter 13) for the Natural Gas Vehicle (NGV) compression adder costs.

Marginal costs are based on the incremental costs incurred by SDG&E to provide an additional unit of output, or serve one additional customer, in the long run. This unit cost is referred to as the marginal unit cost. As described in the testimony of Sharim Chaudhury (Chapter 13), the Rental methodology is used to determine marginal customer costs per customer and results in a single effective marginal unit cost for all customers in each rate class. Medium Pressure and High Pressure Distribution marginal costs are forecasted using a linear regression analysis[2] that predicts cumulative marginal investment[3] as a function of cumulative marginal peak-day demand. This analysis is conducted for the Medium Pressure and High Pressure Distribution systems separately, producing a unique unit marginal capital cost forecast for both the High Pressure Distribution and the Medium Pressure Distribution systems.

SDG&E's authorized margin is allocated to its six customer classes using marginal demand measures applied to the marginal unit costs. These demand measures were established

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[2] *See* D.92-12-058 at 38. The Commission adopted the regression methodology, which SDG&E has utilized in every subsequent cost allocation proceeding to the best of my knowledge.

[3] Defined as the forecasted investment amount required to support one additional unit of peak-day demand.

in D.92-12-058, and have been updated in the subsequent cost allocation proceedings since, most recently in D.20-02-045. SDG&E allocates costs to three core customer classes and three noncore customer classes. The three core classes are residential, core commercial and industrial (C&I), and NGV. The noncore customer classes are C&I, small electric generation (EG) (less than 3 million therms per year), and large EG (greater than 3 million therms per year).

IV. 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. 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,[4] and corresponding equipment profiles, at each range.

[4] 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.

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 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 1 shows the resulting 2024[5] annualized marginal capital-related costs per customer.

TABLE 1
CUSTOMER-RELATED LRMC - CAPITAL COSTS

Customer Class	Rental-Method Customer Cost (2024 $/customer)
Residential	$202
Core Commercial/Industrial	$398
Natural Gas Vehicle	$1,250
Noncore Commercial/Industrial	$2,370
Small Electric Generation	$987
Large Electric Generation	$2,353

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.

[5] Escalation factors updated to reflect Global Insight's forecast as of fourth quarter of 2021. *See* A.22-05-015/016 (cons.) (2024 GRC), Exhibit SDG&E-41 Direct Testimony of Scott R. Wilder (May 16, 2022).

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, 2021. 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 2 shows the total Customer-related direct O&M costs.

TABLE 2 CUSTOMER-RELATED DIRECT MARGINAL O&M EXPENSES (2024 $)				
Customer Class	870-894 $000	901-910 $000	Customers per Class	Direct O&M $/Customer
Residential	$36,705	$888	864,505	$43
Core Commercial/Industrial	$3,232	$28	26,214	$124
Natural Gas Vehicle	$10	$0	45	$230
Noncore Commercial/Industrial	$32	$8	58	$675
Small Electric Generation	$19	$9	71	$390
Large Electric Generation	$11	$1	10	$1,233

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 VI 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 3 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 3 CUSTOMER-RELATED LONG RUN MARGINAL COSTS (2024 $/customer)						
		Expense-Related O&M				
Customer Class	Annualized Capital Cost	Direct	M&S	A&G	General Plant	Total $/Customer
Residential	$202	$43	$0	$12	$11	$269
Core Commercial/Industrial	$398	$124	$1	$35	$31	$590
Natural Gas Vehicle	$1,250	$230	$2	$64	$57	$1,603
Noncore Commercial/Industrial	$2,370	$675	$7	$189	$168	$3,409
Small Electric Generation	$987	$390	$4	$109	$97	$1,588
Large Electric Generation	$2,353	$1,233	$13	$344	$307	$4,251

V. 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 Capital Costs

This LRMC study utilizes ten years of historical (2012 - 2021) and six years of forecast (2022 - 2027) 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. The marginal demand measures are based on an analysis of peak-day throughput[6] on the Medium Pressure Distribution and High Pressure Distribution systems. Marginal demand measures, including peak-day load by market segment, are from the consolidated demand forecast presented in the testimony of Wei Bin Guo (Chapter 5).

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

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 Accounts 870-894.

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 4 below presents a summary of direct distribution O&M expenses by market segment.

TABLE 4 DISTRIBUTION-RELATED DIRECT MARGINAL O&M EXPENSES (2024 $)			
Distribution Function	FERC 870-894 $000	Peak-day Load (mcfd)	Direct O&M $/mcfd
Medium-Pressure	$19,699	440,066	$44.76
High-Pressure	$1,172	462,002	$2.54

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 5 presents the total marginal costs for the Medium Pressure Distribution systems.

	TABLE 5 MEDIUM-PRESSURE DISTRIBUTION LRMC (2024 $/MCF MPD peak day)	
	Marginal Investment Cost	$2,400.53
x	RECC Factor	7.37%
=	Annualized Investment Cost	$176.82
	Expense-Related	
+	O&M Cost	$44.76
+	A&G Cost	$12.51
+	General / Common Plant Cost	$11.17
+	M&S Cost	$1.46
=	**Total Marginal Cost**	$246.73

The following chart depicts the results of the regression analysis in graphical form.

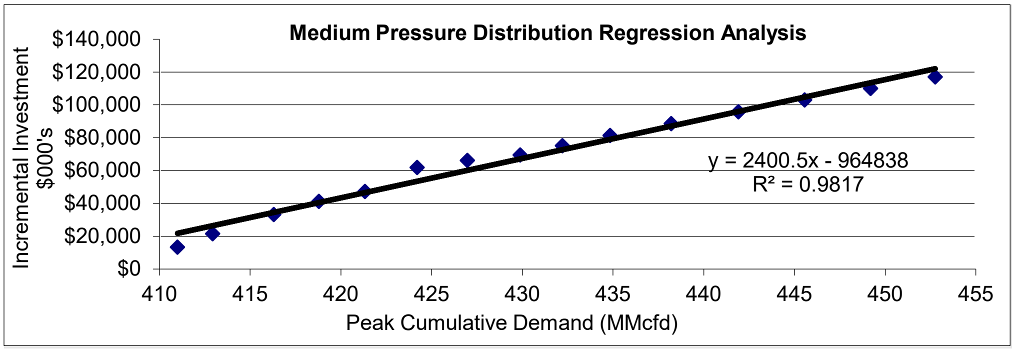
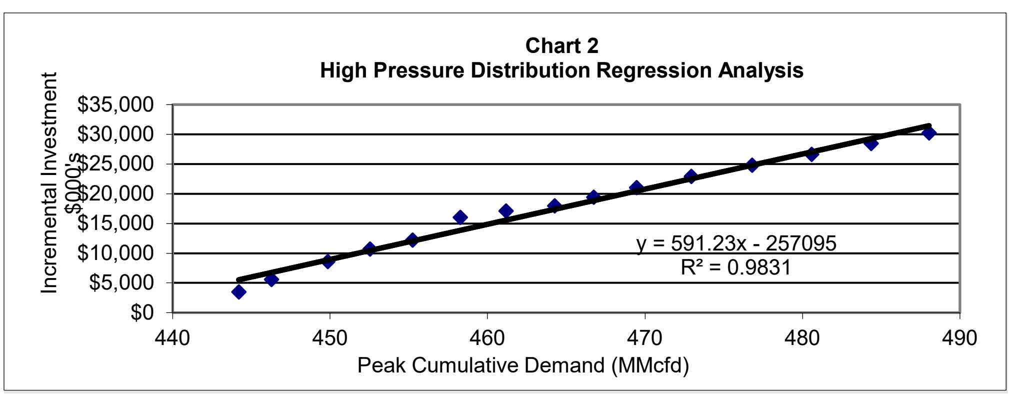


Table 6 presents the total marginal costs for the High Pressure Distribution systems.

TABLE 6 HIGH-PRESSURE DISTRIBUTION LRMC (2024 $/MCF HPD peak day)		
	Marginal Investment Cost	$591.23
x	RECC Factor	7.37%
=	Annualized Investment Cost	$43.55
	Expense-Related	
+	O&M Cost	$2.54
+	A&G Cost	$0.71
+	General / Common Plant Cost	$0.63
+	M&S Cost	$0.36
=	**Total Marginal Cost**	$47.79

The following chart depicts the results of the regression analysis in graphical form.



VI. 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. The LRMC Decision[7] 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.[8]

The RECC factors used in Tables 1, 3, 5 and 6 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

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[7] D.92-12-058.

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

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 Global Insight's forecast, updated tax rates, and SDG&E's authorized rate of return of 7.55% revised per Advice Letter No. 2638-G.[9] The authorized book lives and salvage values for the different investments have also been updated to reflect current factors.

TABLE 7
REAL ECONOMIC CARRYING CHARGE FACTORS

Cost Type	RECC %
Meters and Regulators	8.02%
Meter/Regulator Installation	8.36%
Service Line Pipe	7.37%
Weighted-Average Distribution	7.37%
Materials and Supplies	13.12%
Weighted-Average General/Common Plant	10.95%

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

[9] SDG&E's January 1, 2018 Consolidated Rate Update which implemented SDG&E's updated costs of capital and capital structure, effective January 1, 2018.

payroll taxes are combined into a single loading factor. I relied on the recorded year 2021 A&G expenses from the Annual Report, which are then classified as either marginal or non-marginal by account. As shown below in Table 8, the proposed A&G expenses and payroll tax loader is 27.94%. 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 8
A&G LOADING FACTOR

	Account Description	Marginal Costs 2024 $ 000s
	A&G Expenses	$31,234
+	Payroll Taxes	$5,194
=	Total A&G with Payroll Taxes	$36,429
/	Total O&M Expenses excluding A&G	$130,388
=	A&G Loading Factor	27.94%

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 2021 general plant[10] total is multiplied by the weighted-average RECC factor of 10.95% to obtain an annualized general plant of $65.6 million. The general plant loading factor is then determined by dividing annualized general plant by total O&M expenses. Table 9 shows the derivation of the general plant loading factor.

[10] Total 2021 General Plant of $598,940 thousand is the sum of Total General Plant of $27,319 thousand (source: 2021 SDG&E FERC Form 2) and Common Utility Plant – Gas of $571,620 thousand (source: 2021 SDG&E Gas FERC Form 1).

TABLE 9 GENERAL PLANT LOADING FACTOR		
	Account Description	2021 Recorded Costs 2024 $ 000s
	Total General Plant	$598,940
+	Average General Plant RECC	10.95%
=	Annualized General Plant	$65,571
/	Total O&M Expenses	$262,847
=	General Plant Loading Factor	24.95%

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 2021 M&S costs of $11.5 million are allocated to the functions based on percentage of gross plant in each functional category and then multiplied by a RECC factor of 13.12% 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 10 presents the resulting M&S loading costs by customer class and function.

TABLE 10 M&S LOADING FACTORS (2024 $)			
Customer Class	Allocated M&S	Customers per Class	M&S Loader $/Customer
Residential	$409,445	864,505	$0.47
Core Commercial/Industrial	$35,504	26,214	$1.35
Natural Gas Vehicle	$112	45	$2.50
Noncore Commercial/Industrial	$426	58	$7.35
Small Electric Generation	$302	71	$4.25
Large Electric Generation	$134	10	$13.42
Distribution Function	Allocated M&S	Peak-day Load (mcfd)	M&S Loader $/mcfd
Medium-Pressure	$644,432	440,066	$1.46
High-Pressure	$166,452	462,002	$0.36

VII. 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 2024 - 2027, reflecting the duration of the 2024 TCAP period.

For the Customer-related functional category, Table 11 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 the both the LRMC and embedded cost studies equal the authorized base margin.

TABLE 11 UNSCALED LONG RUN MARGINAL COST CUSTOMER COST			
Customer Class	Customer LRMC $/customer	Customer Count	Customer Cost $000
Residential	$269	909,359	$244,982
Core C/I	$590	30,488	$17,981
NGV	$1,603	36	$58
Total Core			$263,020
Noncore C/I	$3,409	58	$198
Small EG	$1,588	83	$132
Large EG	$4,251	15	$64
Total Noncore			$393
Total SDG&E			**$263,414**

Table 12 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 12 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	$247	292,353	$72,131	$48	292,372	$13,972
Core C/I	$247	95,840	$23,646	$48	97,556	$4,667
NGV	$247	3,491	$861	$48	6,175	$295
Total Core			$96,639			$18,934
Noncore C/I	$247	8,451	$2,085	$48	9,163	$438
Small EG	$247	5,759	$1,421	$48	8,101	$387
Large EG	$247	1,119	$276	$48	10,369	$496
Total Noncore			$3,782			$1,321
Total SDG&E			**$100,421**			**$20,254**

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 January 1, 2022, is $450 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 ($69.6 million)[11] and NGV Public Access ($0.8 million) functions, which are not scaled.

[11] Including Franchise Fees and Allowance for Uncollectible (FF&U).

In this cost allocation proceeding (CAP), marginal costs are scaled at a rate of 99% in order to reconcile to the adjusted base margin[12] of $380 million. Table 13 shows the total cumulative SDG&E costs being allocated. Finally, scaled LRMC costs are added to the Transmission and NGV Public Access costs to determine the cost-based allocation of authorized gas base margin of $450 million.[13] The total costs for SDG&E being allocated is presented in Table 14.

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

Customer Class	Customer Cost	+	MPD	+	HPD	=	Unscaled LRMC	x	Scalar	=	Scaled LRMC
Residential	$244,982		$72,131		$13,972		$331,085		99%		$327,566
Core C/I	$17,981		$23,646		$4,667		$46,294		99%		$45,802
NGV	$58		$861		$295		$1,214		99%		$1,202
Total Core	$263,020		$96,639		$18,934		$378,593		99%		$374,570
Noncore C/I - D	$181		$2,085		$438		$2,704		99%		$2,675
Noncore C/I - T	$17		$0		$0		$17		99%		$17
Small EG Distribution	$160		$1,421		$387		$1,968		99%		$1,947
Large EG Distribution	$10		$276		$496		$782		99%		$773
EG Transmission	$26		$0		$0		$26		99%		$26
Total Noncore	$393		$3,782		$1,321		$5,496		99%		$5,438
Total SDG&E	**$263,414**		**$100,421**		**$20,254**		**$384,089**		99%		**$380,008**

12 Adjusted Base Margin refers to base margin excluding non-scaled items: Backbone Transmission Service (BTS) and NGV public access.

13 Per Chapter 8 (Seres), the SDG&E transmission system is 100% backbone. For the purposes of this testimony, SDG&E's $69.6 million (including FF&U) in backbone transmission costs are allocated to the Backbone Transmission Service rate class. These costs will be incorporated in System Integration in Chapter 13 (Chaudhury), 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 14
ALLOCATION OF BASE MARGIN
$ 000

Customer Class	Scaled LRMC	+	Backbone Transmission	+	NGV Public Access	=	Allocated Base Margin
Residential	$327,566		$0		$0		$327,566
Core C/I	$45,802		$0		$0		$45,802
NGV	$1,202		$0		$774		$1,976
Total Core	$374,570		$0		$774		$375,344
Noncore C/I - D	$2,675		$0		$0		$2,675
Noncore C/I - T	$17		$0		$0		$17
Small EG	$1,947		$0		$0		$1,947
Large EG	$773		$0		$0		$773
EG Transmission	$26		$0		$0		$26
Total Noncore	$5,438		$0		$0		$5,438
Backbone Transmission	$0		$69,374		$0		$69,374
Total SDG&E	**$380,008**		**$69,374**		**$774**		**$450,156**

VIII. COMPARISON OF PROPOSED COST ALLOCATION TO CURRENT COST ALLOCATION

Table 15 shows a comparison of the proposed cost allocation to the current allocation. This comparison is pre-System Integration[14] and pre-BTS unbundling.[15] 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

[14] 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.

[15] 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.

customer-related, distribution, transmission and storage functions and updated lower demand forecasts.

TABLE 15 COST ALLOCATION COMPARISON $ 000				
Customer Class	Adjusted Allocation of Base Margin	% Total	Current Allocation of Base Margin	% Total
Residential	$327,566	72.8%	$339,615	75.4%
Core C/I	$45,802	10.2%	$55,304	12.3%
NGV	$1,976	0.4%	$2,273	0.5%
Total Core	$375,344	83.4%	$397,192	88.2%
Noncore C/I - D	$2,675	0.6%	$2,400	0.5%
Noncore C/I - T	$17	0.0%	$25	0.0%
Small EG	$1,947	0.4%	$2,289	0.5%
Large EG	$773	0.2%	$1,390	0.3%
EG Transmission	$26	0.0%	$36	0.0%
Total Noncore	$5,438	1.2%	$6,140	1.4%
Backbone Transmission	$69,374	15.4%	$46,823	10.4%
Total SDG&E	**$450,156**		**$450,156**	

This concludes my prepared direct testimony.

IX. QUALIFICATIONS

My name is Michael W. Foster. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011. I received a Bachelor of Arts degree in Economics from the University of California, Santa Barbara in 1995. I received a Master of Business Administration degree from the Darden School of Business at the University of Virginia, Charlottesville in 2000.

As Principal Regulatory Economic Advisor, I support the gas transportation rates for both SoCalGas and SDG&E. This includes allocating authorized revenue requirements to customer rate classes, developing the design of the rate for each class, and computing the impact on customers' monthly bills.

I have previously testified before the Commission.