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Application: A.22-09-015
Witness: Marjorie Schmidt-Pines
Chapter: 9b

PREPARED DIRECT TESTIMONY OF
MARJORIE SCHMIDT-PINES
ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY

(COST ALLOCATION AND LONG RUN MARGINAL COST STUDY)

September 30, 2022
(Errata dated August 31, 2023)

TABLE OF CONTENTS

| | <u>Page</u> |
|---|-------------|
| I. PURPOSE | 1 |
| II. OVERVIEW OF COST ALLOCATION | 1 |
| III. COST ALLOCATION PRINCIPLES | 2 |
| IV. COST ALLOCATION METHOD PROPOSED FOR SOCALGAS | 3 |
| V. CUSTOMER-RELATED MARGINAL UNIT COST | 5 |
| A. Marginal Capital Cost..... | 5 |
| 1. MSA Costs | 6 |
| 2. Service Line Costs | 6 |
| B. Marginal Direct O&M Costs | 7 |
| 1. Customer Services O&M Costs | 7 |
| 2. Customer Accounts O&M Costs | 8 |
| 3. Meters and Regulators O&M Costs..... | 9 |
| 4. Service Lines O&M Costs | 10 |
| 5. Customer Services and Information Costs..... | 10 |
| C. Calculation of Customer-Related Marginal Unit Cost and Marginal Cost Revenue | 10 |
| VI. MEDIUM AND HIGH PRESSURE DISTRIBUTION-RELATED MARGINAL UNIT COSTS..... | 11 |
| A. Medium Pressure Distribution Marginal Unit Cost and Marginal Cost Revenue | 11 |
| 1. Marginal Capital Cost..... | 11 |
| 2. Marginal Direct O&M Costs | 13 |
| 3. Calculation of Medium Pressure Distribution Marginal Unit Cost and Marginal Cost Revenue..... | 13 |
| B. High Pressure Distribution Marginal Unit Cost and Marginal Cost Revenue | 14 |
| VII. MARGINAL COST ESTIMATION FACTORS..... | 16 |
| A. Real Economic Carrying Charge (RECC) Factors | 16 |
| B. O&M Loaders..... | 17 |
| 1. A&G Loading Factor | 18 |
| 2. General Plant Loading Factor | 18 |
| 3. M&S Loading Factor | 19 |
| VIII. RESULTS OF THE COST ALLOCATION STUDIES | 20 |
| IX. COMPARISON OF PROPOSED COST ALLOCATION TO CURRENT COST ALLOCATION | 25 |
| X. QUALIFICATIONS | 27 |

1 **CHAPTER 9**

2 **PREPARED DIRECT TESTIMONY OF MARJORIE SCHMIDT-PINES**

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

4 **I. PURPOSE**

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

11 I also present total allocation of SoCalGas’s authorized base margin revenue requirement,
12 which combines the results of my LRMC analysis for Customer-related, Medium and High
13 Pressure Distribution -related costs, and which incorporates inputs from witness Frank Seres
14 (Chapter 8a) on Transmission-related and Storage-related costs, as well as from witness Michael
15 Foster (Chapter 13b) on the Natural Gas Vehicle (NGV) compression adder costs.

16 **II. OVERVIEW OF COST ALLOCATION**

17 Cost allocation refers to the process of determining the cost of each utility function and
18 allocating these functional costs to the customer classes. My testimony results in the allocation
19 of Base Margin¹ revenue requirements across customer classes. This cost allocation is

¹ SoCalGas’s Base Margin is authorized in a General Rate Case (GRC). Pipeline Safety Enhancement Plan (PSEP) cost components of the Base Margin are functionally allocated to High Pressure Distribution and Transmission functions per D.14-06-007 and D.16-12-063. AB32 Administrative fees (CARB fee) are allocated on an Equal Cents Per Therm (ECPT) basis.

1 conducted by first allocating the authorized revenue requirement to the functions performed by
2 SoCalGas in order to provide natural gas service. These functions are:

- 3 (i) Customer-related (provisions for service lines, regulators, meters,
4 call centers, service representatives);
- 5 (ii) Medium Pressure Distribution System;
- 6 (iii) High Pressure Distribution System;
- 7 (iv) Local Transmission System;
- 8 (v) Backbone Transmission System; and
- 9 (vi) Storage (injection, inventory, and withdrawal).

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

- 12 (i) Core (residential, commercial/industrial, natural gas vehicle (NGV), gas
13 air conditioning, gas engine);
- 14 (ii) Noncore (commercial/industrial, electric generation, wholesale, enhanced
15 oil recovery); and
- 16 (iii) Other (backbone transportation service).

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

18 **III. COST ALLOCATION PRINCIPLES**

19 In determining cost allocation, the following principles are followed by SoCalGas:
20 allocate costs to customer classes based on cost causality, and maintain consistency with the
21 existing practices whenever possible. The fundamental principle applicable to these LRMC cost
22 studies, for purposes of allocating costs to customer groups, is the concept of cost causation.
23 Cost causation seeks to determine which customer or group of customers causes the utility to
24 incur particular types of costs. The essential element in the selection and development of a

1 reasonable cost allocation methodology is the establishment of relationships between customer
2 requirements, load profiles, usage characteristics, and the costs incurred by the utility in serving
3 those requirements. A cost allocation based on cost causation therefore seeks to present cost-
4 based rates.

5 **IV. COST ALLOCATION METHOD PROPOSED FOR SOCALGAS**

6 SoCalGas proposes to continue the LRMC method for the three major functional
7 categories: Customer-related, Medium Pressure Distribution-related, and High Pressure
8 Distribution-related. The LRMC method was proposed in Application (A.) 18-07-024, the last
9 Triennial Cost Allocation Proceeding (TCAP) application.² In addition, SoCalGas proposes to
10 continue to use the currently-adopted Embedded Cost method for the Transmission and Storage
11 functions as presented in the testimony of Frank Seres (Chapter 8). The Embedded Cost method
12 was also proposed in the last TCAP.

13 LRMC refers to the incremental cost to serve one additional unit in the long run; such a
14 unit cost is called marginal unit cost. The cost causation unit is called a marginal demand
15 measure. The consolidated marginal demand measures are presented in the testimony of Wei
16 Bin Guo (Chapter 5). The LRMC-based functional revenue (i.e., marginal cost revenue) is
17 derived by multiplying the marginal unit cost by the number of marginal demand measures
18 (MDM). For Customer-related costs, the marginal demand measure is the number of customers.
19 For Medium Pressure Distribution-related and High Pressure Distribution-related costs, the
20 marginal demand measures are peak day demand³ and peak month demand,⁴ respectively.

² See D.20-02-045.

³ Peak Day Demand is forecast to be in December. See Chapter 2 (Guo).

⁴ Peak Month is defined as December. See Chapter 2 (Guo).

1 In this Cost Allocation Proceeding (CAP), SoCalGas updates the LRMC study presented
2 in prior TCAPs to reflect 2021 actual costs and allocations based on 2021 underlying activities.
3 These costs are then escalated to 2024 dollars to reflect SoCalGas costs for the first year of the
4 new CAP cycle.⁵ For the Customer-related and Medium and High Pressure Distribution-related
5 functions, the marginal unit costs are then multiplied by the forecasted MDM to determine the
6 marginal cost revenues.

7 Each functional marginal unit cost consists of two components: a capital cost component
8 and an operations and maintenance (O&M) cost component. The capital cost component reflects
9 the capital investment required to serve an additional unit. Customer-related capital costs are
10 associated with service lines as well as meters and regulators (collectively called meter set
11 assemblies, or MSAs). For Customer-related costs, this is the cost of serving an additional
12 customer. Marginal Customer-related capital costs have been developed using the Rental
13 method, adopted in the last TCAP, which reflects the annualized capital cost of hooking up an
14 additional customer.

15 For Medium and High Pressure Distribution-related costs, LRMC represents the cost of
16 providing an additional increment of gas throughput⁶ through the distribution system. Marginal
17 demand capital costs have been developed using linear regression models to determine the
18 relationship between demand growth and investments over a 15-year period spanning historical
19 and forecast periods.⁷

⁵ Peak Month is defined as December. *See* Chapter 2 (Guo).

⁶ The MDM for Medium Pressure Distribution is peak day demand. The MDM for High Pressure Distribution is peak month demand.

⁷ D.92-12-058 adopted the regression methodology and has since been utilized in every subsequent cost allocation proceeding to my knowledge.

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

9 **V. CUSTOMER-RELATED MARGINAL UNIT COST**

10 Customer-related marginal unit cost reflects the cost of a customer's access to the gas
11 utility's supply system,⁸ and is comprised of: (1) the marginal capital cost of service lines and
12 MSAs; (2) the marginal direct O&M costs associated with the installation and service of those
13 assets, as well as other customer support functions; and (3) O&M loaders. Each of these
14 components are discussed next.

15 **A. Marginal Capital Cost**

16 Marginal capital cost reflects the facilities and equipment for MSAs and service lines.
17 For residential and small core commercial and industrial customers, marginal capital costs are
18 calculated using the actual new customer hookups in SoCalGas's service territory using the
19 recent five years of available data (2017 - 2021). For other customer classes, all customers, not
20 just new customers, belonging to a specific customer class are used to estimate marginal capital

⁸ *Id.* at 38.

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

3 **1. MSA Costs**

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

- 7 a) Extracted meter size, type, and service pressure level information, at the customer
8 level, from SoCalGas's Customer Information System;
- 9 b) Applied actual 2021 MSA cost data for the various meter sizes, types, and service
10 pressure levels to MSA configurations at the customer level; and
- 11 c) Derived customer class-specific marginal MSA costs as the weighted average
12 MSA costs for all customers in each customer class.

13 **2. Service Line Costs**

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

- 15 a) Extracted service line lengths, pipe types, and pipe diameter data, at the customer
16 level;
- 17 b) Applied unit cost data by pipe type and diameter to the average length of service
18 lines for each customer in the various customer classes. The service line history
19 are based on 2017 - 2021 data from Gas Distribution. The service unit costs were
20 escalated for labor and nonlabor overheads⁹; and

⁹ For new service lines and meters, I took into consideration Line Extension Allowance, per SoCalGas's Rule 20.

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

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

4 Customer-related marginal O&M costs are broken into five components: (1) customer
5 services, (2) customer accounts, (3) meters and regulators, (4) service lines, and (5) O&M
6 loaders. The first four components comprise the total direct O&M costs, which are based on
7 2021 recorded O&M expenses.

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

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

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

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

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

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

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

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

21 Meter reading costs, which are recorded in FERC Account 902, a component of
22 Customer Accounts O&M, are substantially low with the deployment of Advanced Meter
23 Infrastructure (AMI) for core customers. The costs associated with manually reading core

1 meters are allocated based on the weighted read times for core customers. The costs associated
2 with the daily collection of electronic measurement for noncore customers are allocated by the
3 number of noncore active meters.

4 Bill distribution and remittance costs are for postage and remittance processing costs and
5 are recorded in FERC Account 903.700. The allocation of these costs across customer classes is
6 performed based on the number of active customer accounts.

7 Office credit and collections and field collections costs are for costs associated with
8 active and closed collections processing which include the following activities: following up on
9 delinquent accounts, investigating fraudulent activity, skip tracing of unpaid closed accounts,
10 postage costs for mailing collections notices, handling bankruptcies/receivership/probates, and
11 collection of non-gas payments. These costs are recorded in FERC Account 903.104. FERC
12 Account 903.105 reflects costs incurred for field collection activity that involves either collecting
13 the delinquent amount due or terminating gas services. The allocation of these costs across
14 customer classes is performed based on the number of field orders. In 2021, these costs are low
15 due to the COVID_19 Relief Payment Plan.

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

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

22 Meters and Regulators O&M costs include repair of MSAs and meter guards. Meters and
23 Regulators O&M costs are allocated based on two allocation methods. First, costs that are

1 common to all customer segments are allocated according to each customer segment's share of
2 total connected meters in service. Second, costs specifically identifiable as meter repair and
3 replacement are allocated based on each customer segment's share of the total number of meter
4 repairs and replacements during the year.

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

6 Service maintenance work is generally corrective in nature and is required to keep the
7 natural gas system operating safely and reliably. Service Lines O&M costs are allocated to each
8 customer class based on each class's share of total service line footage at year end 2021.

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

10 Customer Services and Information costs are for activities which include account
11 management services to nonresidential and residential customers; products and services for
12 homebuilders and developers; services for capacity, pipeline, and storage; gas transmission
13 planning; gas sustainability; environmental affairs; biofuels market development; clean energy
14 innovations; and customer research, outreach, communication, and education and are booked to
15 FERC Accounts 907 through 910. These costs are broken down between market segments and
16 allocated by the number of customers. The exception is the Energy Markets costs, which are
17 broken down by staff responsibilities.

18 **C. Calculation of Customer-Related Marginal Unit Cost and Marginal** 19 **Cost Revenue**

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

$$22 \quad MUC_C (\$/customer) = [CAPEX^{10} \text{ per customer} \times RECC^{11}\%] + [fully \text{ loaded O\&M}]$$

¹⁰ CAPEX refers to capital expenditures for marginal MSA and service line capital costs.

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

$$3 \quad \text{Customer-related MCR (\$)} = \text{MUC_C} \times \# \text{ of customers}$$

4 Table 1 shows the total MUC_C for each customer class.

5 **VI. MEDIUM AND HIGH PRESSURE DISTRIBUTION-RELATED MARGINAL** 6 **UNIT COSTS**

7 Medium and High Pressure Distribution-related marginal unit costs consist of three types
8 of costs: (1) capital-related, (2) direct O&M, and (3) O&M loaders. The capital costs are
9 recorded in the plant accounts for mains (FERC Account 376) and measuring and regulating
10 station equipment (FERC Account 378). Direct O&M costs are recorded in FERC Accounts
11 874, 875, 887, and 889 for mains and measuring and regulating stations. Distribution O&M
12 work includes maintenance on mains, application of corrosion control measures, valve
13 maintenance, regulator station maintenance, checking for odorant, and locating and marking
14 buried pipes to avoid damage caused from digging by non-company individuals or entities.

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

17 **A. Medium Pressure Distribution Marginal Unit Cost and Marginal Cost** 18 **Revenue**

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

21 **1. Marginal Capital Cost**

22 The marginal capital cost is developed using a linear regression model, recognizing that

¹¹ RECC refers to real economic carrying charge described in Section VII below. RECC is applied to annualize marginal capital costs.

1 peak day demand is the MDM or cost driver for the Medium Pressure Distribution system. The
 2 regression analysis establishes the causal relationship between cumulative load growth-related
 3 capital investment in the Medium Pressure Distribution system (the dependent variable¹²) and
 4 cumulative peak day demand growth (the independent variable¹³).

5 Load growth-related investments include new business, pressure betterment, and meter
 6 and regulating station investments. The period for the regression analysis is 15 years: ten years
 7 of historical data (2012 - 2021) and five years of forecast data (2022 - 2026). The resulting
 8 estimated regression coefficient of the independent variable represents the marginal capital cost.

9 The cumulative peak day demand growth is calculated based on the net positive change
 10 in the number of customers per year multiplied by the average peak day demand per customer for
 11 each class. Table 2 below shows the cumulative peak day demand and the cumulative load
 12 growth-related capital investment in the Medium Pressure Distribution system.

13 **TABLE 2**

14

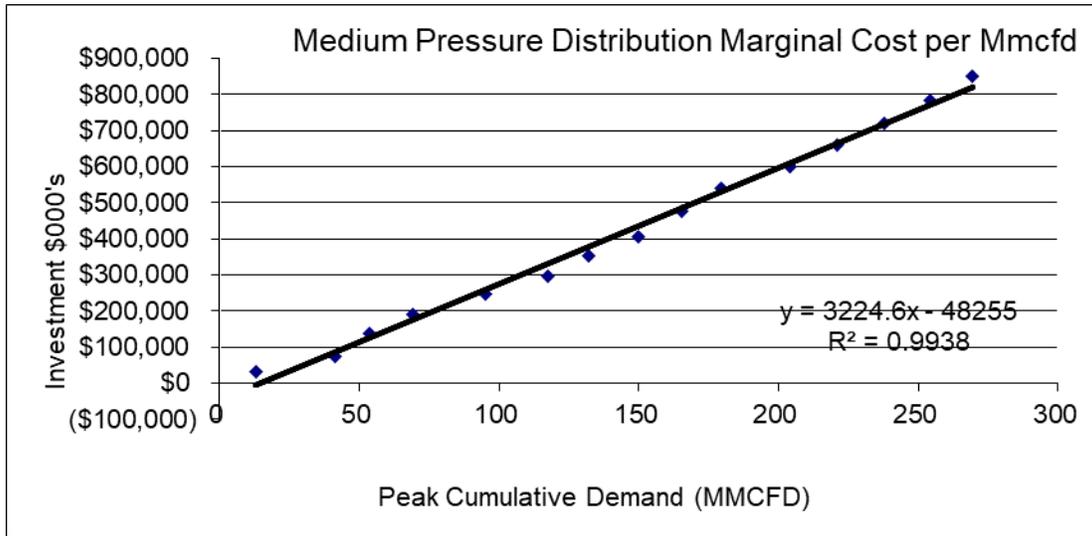
| Year | Cumulative MMcfd | Cumulative CAPEX \$000's |
|-------------|-----------------------------|---|
| 2012 | 13 | \$32,152 |
| 2013 | 41 | \$74,960 |
| 2014 | 54 | \$138,143 |
| 2015 | 69 | \$192,211 |
| 2016 | 95 | \$246,579 |
| 2017 | 117 | \$297,050 |
| 2018 | 132 | \$352,829 |
| 2019 | 150 | \$407,911 |
| 2020 | 165 | \$478,173 |
| 2021 | 179 | \$539,825 |
| 2022 | 204 | \$599,310 |
| 2023 | 221 | \$660,385 |
| 2024 | 238 | \$722,083 |
| 2025 | 254 | \$785,577 |
| 2026 | 269 | \$850,941 |

12 The dependent variable represents the output or outcome whose variation is being studied.

13 The independent variables represent inputs or causes, i.e., potential reasons for variation.

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

2 **FIGURE 1**



3
4 **2. Marginal Direct O&M Costs**

5 The 2021 recorded direct O&M costs are allocated between Medium Pressure and High
6 Pressure Distribution systems based on the split in total distribution capital investment between
7 those two systems. Direct O&M costs are booked to FERC Accounts 874, 875, 887, and 889.

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

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

12
$$MUC_MPD (\$/Mcf^{14}) = [CAPEX\ per\ Mcfd \times RECC\%] + [fully\ Loaded\ O\&M]$$

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

15
$$MPD_MCR (\$) = MUC_MPD \times Mcfd$$

¹⁴ Mcfd is a unit of measurement for gas representing a thousand cubic feet per day.

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

3 **TABLE 3**

| Marginal Cost for Medium Pressure Distribution (MPD) (2024 \$/Mcf peak day) | |
|--|-----------------|
| Capital-related Charge: | |
| MPD Regression Coefficient \$/Mcf | \$3,224.58 |
| x RECC Factor | 6.98% |
| = Annualized Capital-related Charge (\$/Mcf) | \$225.14 |
| + Direct O&M | \$26.54 |
| + A&G | \$23.14 |
| + GP | \$23.04 |
| + M&S | \$0.31 |
| = Marginal Unit Cost (\$/Mcf) | \$298.17 |

4 **B. High Pressure Distribution Marginal Unit Cost and Marginal Cost**
 5 **Revenue**

6 The methodology for calculating the marginal capital-related cost for the High Pressure
 7 Distribution system is analogous to the methodology used for the Medium Pressure Distribution
 8 system. Cumulative load growth-related investment costs in the High Pressure Distribution
 9 system are regressed against cumulative load growth. The coincident peak month demand
 10 served off the High Pressure Distribution system is used as the measure of MDM or cost driver
 11 for the HPD system. Table 4 below shows the cumulative coincident peak month demand and
 12 the cumulative load growth-related capital investment in the High Pressure Distribution system.

1

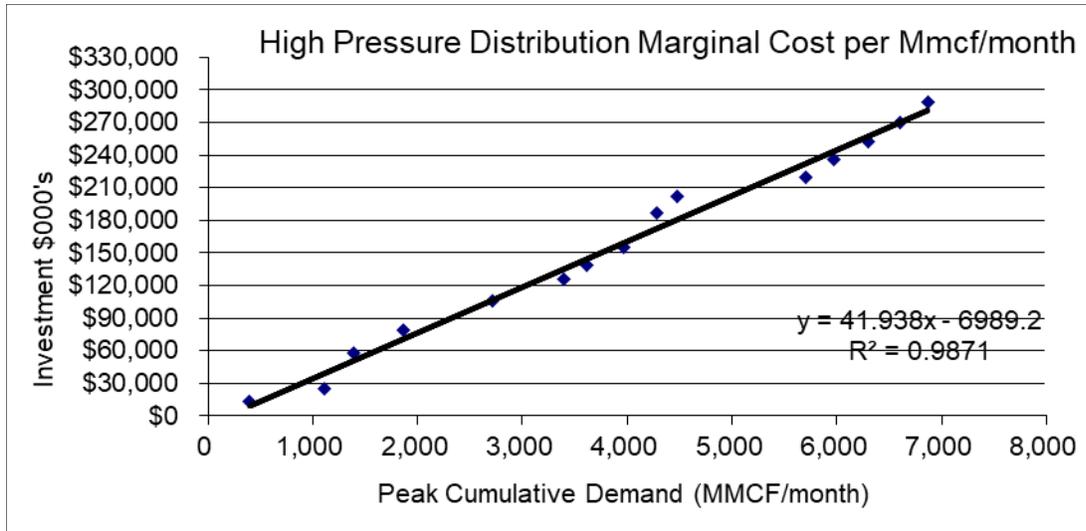
TABLE 4

| Year | Cumulative Mmcf/month | Cumulative CAPEX \$000's |
|------|-----------------------|--------------------------|
| 2012 | 396 | \$12,856 |
| 2013 | 1,117 | \$24,490 |
| 2014 | 1,386 | \$58,268 |
| 2015 | 1,867 | \$78,405 |
| 2016 | 2,716 | \$105,383 |
| 2017 | 3,401 | \$125,656 |
| 2018 | 3,615 | \$139,226 |
| 2019 | 3,970 | \$155,572 |
| 2020 | 4,282 | \$186,789 |
| 2021 | 4,478 | \$201,641 |
| 2022 | 5,702 | \$219,070 |
| 2023 | 5,971 | \$236,078 |
| 2024 | 6,296 | \$253,038 |
| 2025 | 6,607 | \$270,570 |
| 2026 | 6,869 | \$288,699 |

2 The regression analysis results are depicted in Figure 2 below.

3

FIGURE 2



4

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

7

$$MUC_HPD (\$/Mcf/month) = [CAPEX \text{ per } Mcf/month \times RECC\%] + [fully \text{ loaded } O\&M]$$

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

$$HPD_MCR (\$) = MUC_MPD \times Mcf/month$$

Table 5 shows the calculation of the MUC_HPDP.

TABLE 5
Marginal Cost for High Pressure Distribution
(2024 \$/MCF/month)

| | |
|--|---------------|
| Capital-related Charge: | |
| HPD Regression Coefficient \$/Mcf/month | \$41.94 |
| x RECC Factor | 6.95% |
| = Annualized Capital-related Charge (\$/Mcf/month) | \$2.91 |
| + Direct O&M | \$0.44 |
| + A&G | \$0.39 |
| + GP | \$0.38 |
| + M&S | \$0.10 |
| = Marginal HP Distribution Cost(\$/MCF/month) | \$4.23 |

VII. MARGINAL COST ESTIMATION FACTORS

A. Real Economic Carrying Charge (RECC) Factors

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

The Total Investment computes an arithmetic average by dividing the total investment during the planning horizon by the total load growth using the same period. The resulting unit marginal cost is then 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

1 calculation but with an inflation adjustment. RECC models incorporate
2 assumptions for service life, salvage value, cost of capital, inflation rates, and
3 discount rates.¹⁵

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

12 SoCalGas has updated its RECC factors using inflation assumptions from Global
13 Insight's forecast, updated tax rates, and SoCalGas's discount rate of 9.39% revised per the 2020
14 Cost of Capital Decision (D.19-12-056). The authorized book lives and salvage values for the
15 different investments have also been updated to reflect current factors.

16 **B. O&M Loaders**

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

¹⁵ D.92-12-058 at 32.

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

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

4 Marginal A&G expenses and payroll taxes are combined into a single loading factor, with
5 an adjustment to reflect the exclusion of Storage-related and Transmission-related costs. The
6 loading factor derived in Table 6 below reflects the ratio of marginal A&G expenses plus payroll
7 taxes to net O&M expenses. Net O&M expenses are calculated as total O&M expenses minus
8 the sum of total production expenses,¹⁶ total A&G expenses, total transmission expenses, total
9 storage expenses and exclusions not included in the base margin.

10 Recorded 2021 A&G expenses have been classified as either marginal or non-marginal
11 on an account-by-account basis. Any costs that vary with either the size of labor force or the size
12 of plant are deemed marginal costs for this study.

TABLE 6
A&G Loading Factor

| | |
|--|-----------------|
| Total Marginal A&G Costs \$000's | \$231,530 |
| + Total Payroll Taxes \$000 | <u>\$48,408</u> |
| = Marginal A&G and Payroll Taxes \$000 | \$279,938 |
| / Net O&M Costs \$000 | \$321,026 |
| = Marginal A&G Loading Factor as a % of O&M | 87.20% |

13 **2. General Plant Loading Factor**

14 Gross general plant, as reflected in FERC Accounts 390 through 398, includes general
15 plant in service as of year-end 2021 for structures and improvements, office furniture and

¹⁶ Total Production Expenses reflects gas costs.

1 equipment, computer applications and equipment, shop and garage equipment, and
 2 communication equipment. RECC factors associated with each capital category and the amounts
 3 of gross plant in service at year-end 2021 are used to calculate a weighted average general plant
 4 accounts RECC factor. The general plant accounts RECC factor is then applied to gross general
 5 plant in service as of December 31, 2021, to derive an annualized cost for general plant. This
 6 annualized general plant cost is divided by year 2021 net O&M expenses to derive the general
 7 plant loading factor, as shown in Table 7 below. Like the A&G loading factor, the derivation of
 8 general plant loading factor excludes Storage- and Transmission-related costs.

TABLE 7
General Plant Loading Factor

| | |
|---|---------------|
| Total General Plant \$000 | \$1,894,525 |
| * Weighted Average RECC for General Plant | <u>14.71%</u> |
| = Annualized General Plant Costs | \$278,751 |
| / Net Recorded O&M Costs \$000 | \$321,026 |
| = General Plant Loading Factor as a % of O&M | 86.83% |

3. M&S Loading Factor

9 M&S is comprised of materials and supplies kept in stock for use in daily field operations
 10 and in capital projects. Examples of M&S items include pipe, valves, fittings, and safety
 11 equipment. Recorded 2021 M&S costs are allocated based on gross gas plant in each functional
 12 category. Applying an M&S loading factor is appropriate because M&S is a component of the
 13 indirect costs. Distribution M&S is further categorized as customer-related and demand-related
 14 distribution plant investment. As with the other O&M loaders for customer-related and
 15 distribution functions, Storage-related and Transmission-related M&S costs have been removed
 16 from this analysis.
 17

1 The functionally allocated M&S costs are annualized using the RECC factor developed
2 for M&S investments. The annualized M&S costs are then added to the marginal O&M costs for
3 each function to derive fully-allocated O&M costs. The Table 8 below shows the
4 functionalization of the year 2021 M&S costs and the derivation of annual M&S costs for each
5 function.

TABLE 8
M&S Annual Costs

| Function | |
|------------------------|----------------|
| Customer Related \$000 | \$1,807 |
| Load Related \$000 | \$2,479 |
| Total | \$4,286 |

6 **VIII. RESULTS OF THE COST ALLOCATION STUDIES**

7 Upon completing the cost studies to allocate costs to functional categories, SoCalGas
8 allocates each functional cost to customer classes using the following MDMs: number of
9 customers for the customer costs, peak day demand for Medium Pressure Distribution costs and
10 peak month demand for High Pressure Distribution costs. Each MDM reflects the four-year
11 average of forecast annual MDM for the years 2024 - 2027, reflecting the duration of the CAP
12 period.

13 For the customer-related functional category, Table 9 shows marginal unit costs,
14 customer counts, and marginal cost revenues by customer class on an unscaled basis. The term
15 “unscaled” refers to the sum of the marginal cost revenue for each customer class, not adjusted
16 or “scaled” to equal SoCalGas’s authorized base margin. A scalar factor is applied to adjust total
17 marginal cost revenues so that the total revenue requirement from the cost studies, both LRMC
18 and Embedded cost studies, equal the authorized base margin.

**TABLE 9
UNSCALED LONG RUN MARGINAL COST REVENUES
CUSTOMER COST**

| Customer Class | Customer LRM \$/customer | Customer Count | Customer Cost \$000 |
|-----------------------|-----------------------------|----------------|---------------------|
| | A | B | C |
| Residential | \$288 | 5,853,689 | \$1,688,067 |
| Core C/I | \$1,604 | 203,022 | \$325,550 |
| Gas A/C | \$10,374 | 5 | \$47 |
| Gas Engine | \$15,498 | 667 | \$10,337 |
| NGV | \$43,623 | 376 | \$16,411 |
| Total Core | | | \$2,040,411 |
| Noncore C/I | \$67,852 | 556 | \$37,725 |
| Small EG | \$32,231 | 322 | \$10,378 |
| Large EG | \$207,138 | 60 | \$12,428 |
| EOR | \$91,611 | 32 | \$2,932 |
| Total Retail Noncore | | | \$63,464 |
| Long Beach | \$1,174,228 | 1 | \$1,174 |
| SDG&E | \$2,615,750 | 1 | \$2,616 |
| Southwest Gas | \$789,930 | 1 | \$790 |
| Vernon | \$641,585 | 1 | \$642 |
| Ecogas | \$169,575 | 1 | \$170 |
| Total Wholesale | | | \$5,391 |
| UBS | \$0 | 0 | \$0 |
| BTS | \$0 | 0 | \$0 |
| Total Noncore | | | \$68,855 |
| Total SoCalGas | | | \$2,109,266 |

³⁰Ecogas is the Wholesale – ECOGAS Mexico, S. de R.L. de C.V.

³¹UBS is the Unbundled Storage Program

³² BTS is Backbone Transportation Service

1 Table 10 shows unscaled Medium Pressure and High Pressure Distribution marginal cost
2 revenues by customer classes. Medium Pressure Distribution costs are allocated using 1-in-35
3 peak day core / 1-in-10 cold day noncore Medium Pressure Distribution service level peak day

1 demand. High Pressure Distribution costs are allocated using High Pressure Distribution service
 2 level peak month demand.

TABLE 10
UNSCALED LRMC COST REVENUES
DISTRIBUTION COSTS

| Customer Class | Medium Pressure Distribution LRMC \$/mcf | Medium Pressure Distribution Peak Day (mcf) | Medium Pressure Distribution Costs \$000 | High Pressure Distribution LRMC \$/mcf | High Pressure Distribution Peak Month Demand (mcf) | High Pressure Distribution Costs \$000 |
|-----------------------|--|---|--|--|--|--|
| | A | B | C | D | E | F |
| Residential | \$298.17 | 2,144,132 | \$639,325 | \$4.23 | 34,561,076 | \$146,204 |
| Core C/I | \$298.17 | 477,606 | \$142,410 | \$4.23 | 9,832,908 | \$41,596 |
| Gas A/C | \$298.17 | 28 | \$8 | \$4.23 | 866 | \$4 |
| Gas Engine | \$298.17 | 2,278 | \$679 | \$4.23 | 82,770 | \$350 |
| NGV | \$298.17 | 22,338 | \$6,661 | \$4.23 | 1,251,089 | \$5,292 |
| Total Core | | | \$789,083 | | | \$193,446 |
| Noncore C/I | \$298.17 | 100,714 | \$30,030 | \$4.23 | 7,344,958 | \$31,071 |
| Small EG | \$298.17 | 22,821 | \$6,805 | \$4.23 | 940,813 | \$3,980 |
| Large EG | \$298.17 | 11,394 | \$3,398 | \$4.23 | 1,773,980 | \$7,504 |
| EOR | \$298.17 | 4 | \$1 | \$4.23 | 907,410 | \$3,839 |
| Total Retail Noncore | | | \$40,234 | | | \$46,394 |
| Long Beach | \$298.17 | 0 | \$0 | \$4.23 | 0 | \$0 |
| SDG&E | \$298.17 | 0 | \$0 | \$4.23 | 0 | \$0 |
| Southwest Gas | \$298.17 | 0 | \$0 | \$4.23 | 0 | \$0 |
| Vernon | \$298.17 | 0 | \$0 | \$4.23 | 0 | \$0 |
| Ecogas | \$298.17 | 0 | \$0 | \$4.23 | 0 | \$0 |
| Total Wholesale | | | \$0 | | | \$0 |
| UBS | \$298.17 | 0 | \$0 | \$4.23 | 0 | \$0 |
| BTS | \$0.00 | 0 | \$0 | \$0.00 | 0 | \$0 |
| Total Noncore | | | \$40,234 | | | \$46,394 |
| Total SoCalGas | | | \$829,317 | | | \$239,840 |

1 In D.92-12-058, the Commission stated that “marginal cost revenues need to be scaled to
2 the embedded-based authorized revenue requirement under our ratemaking procedures.”¹⁷ The
3 scalar is employed to adjust the proposed marginal cost revenues to the base margin, excluding
4 costs directly allocated to the Transmission, Storage, Uncollectible,¹⁸ and NGV Public Access
5 functions. In this CAP, marginal costs are scaled at a rate of 70% in order to reconcile to the
6 base margin of \$2,216,057 thousand. Table 11 shows this process.

¹⁷ D.92-12-058 at 50.

¹⁸ Uncollectible (not collected revenues) are treated separately because SoCalGas’ wholesale customers do not have any uncollectibles.

TABLE 11
LRMC COST SCALED REVENUES
SCALED CUSTOMER & DISTRIBUTION COSTS
(\$000)

| Customer Class | Customer Cost A | Medium Pressure Distribution B | High Pressure Distribution C | Unscaled LRMC Revenues D=A+B+C | Scalar E | Scaled LRMC Revenues F=D*E |
|--|--------------------|--------------------------------------|------------------------------------|---|-------------|----------------------------------|
| Residential | \$1,688,067 | \$639,325 | \$146,204 | \$2,473,596 | 70% | \$1,724,638 |
| Core C/I | \$325,550 | \$142,410 | \$41,596 | \$509,556 | 70% | \$355,272 |
| Gas A/C | \$47 | \$8 | \$4 | \$59 | 70% | \$41 |
| Gas Engine | \$10,337 | \$679 | \$350 | \$11,366 | 70% | \$7,925 |
| NGV | \$16,411 | \$6,661 | \$5,292 | \$28,364 | 70% | \$19,776 |
| Total Core | \$2,040,411 | \$789,083 | \$193,446 | \$3,022,941 | 70% | \$2,107,651 |
| Noncore C/I | \$37,725 | \$30,030 | \$31,071 | \$98,827 | 70% | \$68,904 |
| Small EG | \$10,378 | \$6,805 | \$3,980 | \$21,163 | 70% | \$14,755 |
| Large EG | \$12,428 | \$3,398 | \$7,504 | \$23,330 | 70% | \$16,266 |
| EOR | \$2,932 | \$1 | \$3,839 | \$6,771 | 70% | \$4,721 |
| Total Retail Noncore | \$63,464 | \$40,234 | \$46,394 | \$150,091 | 70% | \$104,647 |
| Long Beach | \$1,174 | \$0 | \$0 | \$1,174 | 70% | \$819 |
| SDG&E | \$2,616 | \$0 | \$0 | \$2,616 | 70% | \$1,824 |
| Southwest Gas | \$790 | \$0 | \$0 | \$790 | 70% | \$551 |
| Vernon | \$642 | \$0 | \$0 | \$642 | 70% | \$447 |
| Ecogas | \$170 | \$0 | \$0 | \$170 | 70% | \$118 |
| Total Wholesale | \$5,391 | \$0 | \$0 | \$5,391 | 70% | \$3,759 |
| UBS | \$0 | \$0 | \$0 | \$0 | 70% | \$0 |
| BTS | \$0 | \$0 | \$0 | \$0 | 70% | \$0 |
| Total Noncore | \$68,855 | \$40,234 | \$46,394 | \$155,483 | 70% | \$108,405 |
| Total SoCalGas | \$2,109,266 | \$829,317 | \$239,840 | \$3,178,423 | 70% | \$2,216,057 |
| Calculation of Scalar: | | | | | | |
| Scalar = [Base Margin - Transmission – Storage -Uncollectibles-NGV Compression Adder] / [Unscaled Customer + Distribution] | | | | | | |
| Scalar = \$2,216,057 divided by \$3,178,423 | | | | | | |

1 After the derivation of scaled customer and distribution marginal cost revenues by
2 customer classes, the remaining base margin items for Transmission, Storage, NGV, and
3 Uncollectible costs are allocated to customer classes, as shown in Table 12. Local Transmission

1 costs¹⁹ are allocated to customer classes using cold year peak month throughput. Backbone
2 Transmission costs²⁰ are isolated to derive the Backbone Transmission System (BTS) rate.
3 Storage costs²¹ are allocated to customer classes using the storage rates (for inventory, injection,
4 and withdrawal) applied to the capacities for core storage, load balancing, and load balancing
5 plus functions proposed in this CAP.²² Uncollectible and NGV Public Access Station costs are
6 also included. The system average uncollectible rate is 0.278%. The NGV Public Access
7 Station cost is allocated to the NGV class for recovery through the NGV Compressor Adder cost.

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

11 **IX. COMPARISON OF PROPOSED COST ALLOCATION TO CURRENT COST** 12 **ALLOCATION**

13 The following is a comparison of the proposed 2024 cost allocation to the current
14 allocation effective March 1, 2022. This comparison is pre-System Integration²³ and pre-BTS
15 unbundling,²⁴ as discussed in the testimony of Michael Foster (Chapter 13b).

16 Relative to the current allocation, the proposed CAP allocation of base margin across
17 customer classes shows a decrease for core customers, including residential customers, an

¹⁹ See Chapter 8 (Seres). FF&U added.

²⁰ *Id.*

²¹ *Id.*

²² See Chapter 1 (Rincon and Yen).

²³ 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.

²⁴ 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.

1 increase for noncore customers and an increase for unbundled backbone transmission service.

2 These allocation changes reflect the impacts of updated cost studies for customer-related,

3 distribution, transmission and storage functions and updated lower demand forecasts.

TABLE 13
COST ALLOCATION COMPARISON
(\$000)

| Customer Class | Proposed Allocation of | | Current Allocation of | |
|-----------------------|------------------------|---------------|-----------------------|---------------|
| | Base Margin | % Total | Base Margin | % Total |
| | A | B | C | D |
| Residential | \$1,944,806 | 64.9% | \$2,124,714 | 70.8% |
| Core C/I | \$411,688 | 13.7% | \$424,019 | 14.1% |
| Gas A/C | \$48 | 0.0% | \$54 | 0.0% |
| Gas Engine | \$9,037 | 0.3% | \$12,656 | 0.4% |
| NGV | \$36,070 | 1.2% | \$28,391 | 0.9% |
| Total Core | \$2,401,649 | 80.1% | \$2,589,834 | 86.3% |
| Noncore C/I | \$123,642 | 4.1% | \$97,451 | 3.2% |
| Small EG | \$18,754 | 0.6% | \$14,364 | 0.5% |
| Large EG | \$80,193 | 2.7% | \$53,917 | 1.8% |
| EOR | \$9,727 | 0.3% | \$9,994 | 0.3% |
| Total Retail Noncore | \$232,317 | 7.7% | \$175,725 | 5.9% |
| Long Beach | \$4,979 | 0.2% | \$2,087 | 0.1% |
| SDG&E | \$53,441 | 1.8% | \$33,225 | 1.1% |
| Southwest Gas | \$4,391 | 0.1% | \$1,972 | 0.1% |
| Vernon | \$3,609 | 0.1% | \$1,787 | 0.1% |
| Ecogas | \$4,488 | 0.1% | \$1,814 | 0.1% |
| Total Wholesale | \$70,909 | 2.4% | \$40,886 | 1.4% |
| UBS | \$0 | 0.0% | \$0 | 0.0% |
| BTS | \$293,281 | 9.8% | \$194,258 | 6.5% |
| Total Noncore | \$596,507 | 19.9% | \$410,869 | 13.7% |
| Total SoCalGas | \$2,998,156 | 100.0% | \$3,000,704 | 100.0% |

4 This concludes my prepared direct testimony.

5

1 **X. QUALIFICATIONS**

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

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

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

19 I have previously testified before the California Public Utilities Commission.