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Witness: Allison F. Smith

**PREPARED DIRECT TESTIMONY OF
ALLISON F. SMITH
SOUTHERN CALIFORNIA GAS COMPANY**

September 3, 2003

2005 BIENNIAL COST ALLOCATION PROCEEDING

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1 access, the FRCA application establishes the treatment of storage costs. Consistent with
2 SoCalGas' FRCA application, embedded storage costs will be excluded from this LRMC study.
3 Therefore, this LRMC study focuses on only four major functional categories: customer-related,
4 medium pressure distribution, high pressure distribution, and transmission functions.

5 SoCalGas submits this LRMC study in compliance with D.92-12-058. However, for the
6 reasons stated in the testimony of SoCalGas witness Herbert S. Emmrich, SoCalGas supports the
7 allocation of costs using the embedded cost methodology for this BCAP.

8 **A. BACKGROUND**

9 The Commission adopted the LRMC methodology to allocate Base Margin costs in
10 D.92-12-058.¹ The Commission has periodically updated SoCalGas' base margin LRMC in
11 D.94-12-052, D.97-04-082, and D.00-04-060. In each of these cost allocation proceedings,
12 SoCalGas presented marginal customer costs based on the "rental" method, and marginal costs
13 for distribution and transmission based on the estimated cost of incremental facilities required to
14 meet demand growth. SoCalGas' use and support of the rental method is consistent with the
15 standard definition of LRMC and with the Commission's initial LRMC methodological
16 approach which rejected the new customer only ("NCO") method and approved the rental
17 method, stating: "The NCO proposals of TURN and PG&E provide no persuasive reasons for
18 the Commission to deviate from **established methodology**." D.92-12-058; 97 CPUC 2d 438,
19 463 (emphasis added). On certain occasions since then, the Commission has deviated from that
20 established methodology and approved of use of the NCO method in LRMC allocations.

21 In its 1999 BCAP, SoCalGas submitted a Joint Recommendation with the Office of
22 Ratepayer Advocates (ORA), and others, that presented a comprehensive settlement of the most
23 contentious issues litigated in that proceeding. As part of the Joint Recommendation, marginal
24 customer costs were developed based on the NCO methodology. The Joint Recommendation,
25 however, was submitted as a package and clearly stated that endorsement by the parties thereto
26 (including SoCalGas) of the settlement should not be construed as acceptance of any individual
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¹ The LRMC allocation methodology was adopted in D.92-12-058, with implementation effective June 1, 1993 per D.93-05-066.

1 positions or policies underlying the recommendation.² Consequently, SoCalGas' support of the
2 Joint Recommendation did not reflect a change in SoCalGas' position on using the rental method
3 for LRMC allocations.

4 In addition, SoCalGas continues to support the application of LRMC without use of a
5 replacement cost adder for customer-related, distribution or transmission costs. Once again,
6 SoCalGas' position is consistent with the standard definition of LRMC and with the
7 Commission's initial position on this issue. In D.92-12-058 the Commission did not include
8 replacement costs in its definition of marginal costs, and the Commission expressly rejected a
9 TURN proposal that was characterized by the Department of Ratepayer Advocates (DRA)³ as a
10 replacement cost approach. Four years later, in its decision in the SoCalGas 1996 BCAP, the
11 Commission again expressly rejected use of a replacement cost adder finding that replacement
12 costs are adequately accounted for in the Real Economic Carrying Charge ("RECC") factors
13 used in the marginal cost calculations. (D.97-04-028, mimeo at 48). The Commission has also
14 deviated from its original position on replacement cost adders by including them for customer-
15 related and distribution functions for Pacific Gas and Electric's ("PG&E's") LRMC rates.

16 **B. 2005 LRMC STUDY**

17 In this BCAP, SoCalGas has updated its LRMC study to reflect 2002 actual costs.⁴ The
18 appropriate marginal unit costs are developed for each functional category. These costs are then
19 escalated to 2005 dollars to reflect SoCalGas' estimated marginal unit cost for the BCAP period.
20 These marginal unit costs are then multiplied by the Commission adopted Marginal Demand
21 Measures (MDMs) to determine the Total System Marginal Cost Revenue.

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

24 The capital-related cost component reflects the capital investment required to serve an
25 additional unit. In the case of customer-related costs, this is the cost of serving an additional
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27 ² SoCalGas continued to support the use of the rental method, if the Commission chose not to adopt the Joint
Recommendation.

28 ³ The DRA was the predecessor of the Office of Ratepayer Advocates (ORA).

⁴ In certain instances, 2001 costs were used in this study, i.e., the unit costs for MSA and service lines are based on
2001 actual costs.

1 customer. For demand-related costs, this is the cost of serving an additional increment of
2 throughput. Marginal customer-related capital costs have been developed using the rental
3 method, which reflects the annualized capital cost of new hookups. Marginal distribution capital
4 costs have been developed using a linear regression model to determine the relationship between
5 demand growth and cumulative investment over a 10-year historical and 5-year forecast period.
6 Marginal transmission capital costs have been developed using the prospective 15-year
7 transmission resource plan presented in the testimony of SoCalGas witness David Bisi.

8 In addition to the capital-related costs, this study presents the O&M cost for each
9 functional category. First, the total direct O&M costs for customer-related and demand-related
10 functions are determined. These costs reflect the activities of field personnel and support
11 services associated with field activities. Next, a series of O&M loaders are applied to the direct
12 O&M costs to reflect the indirect costs associated with providing natural gas service. Indirect
13 costs include pension and benefits, payroll taxes, general plant, and other costs that are
14 supportive in nature. The O&M loading factors are applied to the direct O&M costs to develop
15 the “fully-loaded” O&M cost for each class. These “fully-loaded” O&M costs are added to the
16 capital-related marginal costs to develop the unit marginal cost for each functional category.

17 Further discussion on these marginal cost calculations are presented later in this
18 testimony.

19 20 **III. MARGINAL COST ESTIMATION**

21 **A. RECC FACTORS**

22 Real Economic Carrying Cost (RECC) factors are used to convert capital investment into
23 annualized capital costs. The RECC factor, when applied to a capital investment, produces the
24 first year revenue requirement of a series of annual capital charges that remains constant in real
25 terms over the life of the asset. The RECC factor is a function of authorized rate of return,
26 inflation, salvage value, book life, and tax rates. Based on the differing book lives and salvage
27 values of utility assets, separate RECC factors have been developed for service lines, regulators,
28 meters, distribution, and transmission capital investments.

1 SoCalGas has updated its RECC factors using inflation assumptions from the Global
2 Insight TREND25YEAR0203 forecast report, updated tax rates, and SoCalGas' before-tax
3 discount rate of 8.68%, revised pursuant to SoCalGas Advice Letter 3199-A. The authorized
4 book lives and salvage values for the different assets are unchanged from those used by
5 SoCalGas for calculating the RECC factors in SoCalGas' 1999 BCAP testimony.

6 The RECC factors by FERC account proposed in this proceeding are shown in Table 1 at
7 the end of my testimony.

8 **B. O&M LOADERS**

9 SoCalGas develops three distinct O&M loaders that are applied to direct marginal costs
10 to develop the "fully-loaded" O&M cost for each functional category. These loading factors
11 reflect indirect costs for: (1) administrative and general (A&G) expenses, (2) general plant, and
12 (3) materials and supplies (M&S). The A&G and general plant loading factors are percentages
13 that are applied to the direct O&M costs for each functional category. M&S costs are assigned to
14 each functional category based on plant investment. Since embedded storage-related costs have
15 been excluded from this study to reflect SoCalGas' FRCA application, storage-related O&M
16 costs have been removed from the calculation of loading factors.

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

18 Marginal A&G expenses and payroll taxes are combined into a single loading factor.
19 This loading factor is calculated consistent with the methodology established by D. 92-12-058,
20 with an adjustment to reflect the exclusion of storage-related costs⁵. The loading factor reflects
21 the ratio of marginal A&G expenses plus payroll taxes to net O&M expenses. Net O&M
22 expenses are calculated as total O&M expenses minus fuel-related expenses, total storage
23 expenses, total production expenses and total A&G expenses.

24 Recorded year 2002 A&G expenses have been classified as marginal and non-marginal
25 on an account-by-account basis. Consistent with D.92-12-058, any costs that vary with either the
26 size of labor force or the size of plant are deemed marginal costs for this study. As shown in
27 Table 2, the proposed A&G expenses and payroll tax loader is 27.6%.

28 ⁵ Pursuant to D.01-12-018 and consistent with SoCalGas' FRCA application, 3.6 percent of A&G expenses are assigned to the storage function.

1 **2. General Plant Loading Factor**

2 Gross general plant, as reflected in Federal Energy Regulatory Commission (“FERC”) accounts 390 through 398, includes general plant in service as of year-end 2002 for structures and improvements, office furniture and equipment, computer applications and equipment, shop and garage equipment, and communication equipment. RECC factors associated with each capital category and the amounts of gross plant in service at year-end 2002 are used to calculate a weighted average RECC factor. This factor is then applied to gross general plant in service at December 31, 2002 to derive an annualized cost for general plant. This annualized general plant cost is divided by year 2002 net O&M expenses to derive the general plant loading factor. Like the A&G loading factor, the general plant loading factor reflects the exclusion of storage related costs. In Table 3, the proposed general plant loading factor based on year 2002 recorded data is 13.1%.

13 **3. M&S Loading Factor**

14 M&S is comprised of materials and supplies kept in stock for use in daily field operations and in capital projects. Examples of M&S items include pipe, valves, fittings, and safety equipment. Recorded year 2002 M&S costs are allocated based on gross gas plant in each functional category. Distribution M&S is further categorized as customer-related and demand-related distribution plant investment. As with the other O&M loaders, storage-related M&S costs have been removed from this analysis.

20 The functionally allocated M&S costs are annualized using an RECC factor of 15.1%, developed for M&S investments. The annualized M&S costs are then added to the marginal O&M costs for each function as part of the fully-allocated O&M costs.

23 Table 4 shows the functionalization of the year 2002 M&S costs and the derivation of annual M&S costs for each function.⁶

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⁶ M&S costs escalated to 2005 dollars when applied to customer-related, distribution, and transmission functions.

1 **IV. CUSTOMER-RELATED MARGINAL COST**

2 Customer-related marginal cost reflects “the cost of a customer’s access to the gas
3 utility’s supply system” (D.92-12-058, pg. 38). The marginal customer cost is comprised of: (1)
4 the marginal capital cost of service-regulators-meters (SRM) and exclusive use facilities; and (2)
5 the marginal O&M costs associated with SRM, Customer Services, and Customer Accounts.

6 Table 5 presents a summary of the capital and O&M components of the customer-related
7 marginal cost for each customer class.

8 **A. MARGINAL CAPITAL COST**

9 Consistent with D.92-12-058, the marginal capital cost reflects the facilities and
10 equipment for: a) meters, regulators, and MSAs, b) service lines, and c) exclusive use facilities.
11 Under the rental method, the annualized marginal capital cost was calculated using RECC factors
12 for each class.⁷

13 For residential and small core commercial and industrial (G-10) customers, marginal
14 MSA and service line costs are calculated based on new customer hookups in SoCalGas’ service
15 territory for the years 1998 through 2002. For other customer classes, all customers (not just new
16 customers) belonging to a specific customer class are used to estimate marginal MSA and service
17 line costs because of low customer growth rates and the large meter cost diversity.

18 **1. MSA Costs**

19 MSA costs include the cost of the meter, regulator and other equipment required in
20 hooking up a new customer to receive gas and the direct labor cost for installing the equipment.

21 Consistent with prior BCAPs, the marginal costs of MSAs have been updated as follows:

- 22 a) Meter size, type, and service pressure level information, at the customer level,
23 were extracted from the Customer Information System (“CIS”).
- 24 b) Updated unit cost data for the various meter sizes, types, and service pressure
25 levels are applied to MSA configurations at the customer level.
- 26 c) Customer-class-specific marginal MSA costs are the average MSA costs for all
27 customers in each customer class.

28 ⁷ Class-specific MSA RECC factors reflect the weighted average RECC based on the proportions of capital for meters, regulators and MSAs.

1 Table 5 presents the customer-class-specific marginal MSA investment costs on Line 2
2 and the annualized marginal investment costs on Line 6.

3 **2. Service Lines Costs**

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

- 6 a) Service line lengths, pipe types, and pipe diameter data, at the customer level,
7 were extracted from SoCalGas' service history file.
- 8 b) Updated unit cost data by pipe type and diameter are applied to the average length
9 of service lines for each customer in the various customer classes.
- 10 c) Customer-class-specific marginal service lines costs are the average service lines
11 costs for all customers in each customer class.

12 The customer-class-specific marginal investment costs of service lines are shown on Line
13 3 of Table 5 and the annualized marginal investment cost is shown on Line 7 of Table 5.

14 **3. Exclusive Use Facilities Costs**

15 An exclusive use facility refers to any transmission main, distribution main, service line,
16 gas electronic metering system (GEMS) and certain MSA costs that have been identified as
17 being solely dedicated to a particular customer. Transmission and distribution mains are treated
18 as an exclusive use facility if, for all practical purposes, such a main functions as a service line to
19 a specific noncore customer only. GEMS costs for large customers have been identified by
20 customer class and included as exclusive use. In addition, the GEMS and MSA costs for
21 wholesale customers have been included in the exclusive use study.

22 The replacement cost estimates for exclusive use facilities have been updated to 2005
23 dollars. The customer-class-specific costs of exclusive use facilities are shown on Line 4 of
24 Table 5 and the annualized marginal investment cost is shown on Line 8 of Table 5.

25 **B. MARGINAL O&M COSTS**

26 Customer-related marginal O&M costs are broken into five components: a) Customer
27 Services, b) Customer Accounts, c) Meters and Regulators, d) Service Lines, and e) O&M
28 Loaders. The first four components comprise total direct O&M costs. O&M loaders, as

1 discussed in Section III B, are applied to direct O&M costs to derive fully-loaded O&M costs.

2 In this BCAP, SoCalGas updates customer-class-specific O&M costs using year 2002
3 recorded O&M expenses.

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

5 Customer Services O&M costs include the field services' recorded expenses associated
6 with the maintenance and safe and reliable operation of SoCalGas-owned equipment (e.g.,
7 meters and regulators), as well as customer-owned appliances. Customer service activities, and
8 the associated costs, result from responses to customer service requests and internal work
9 requirements. Requests are categorized into generalized order types for which both frequency
10 and duration are recorded. Customer Services O&M costs also include support costs associated
11 with related field activities such as field order dispatch costs, staff and supervision costs,
12 communication costs as well as an allocation of vehicle, tools and uniform costs.

13 Orders are apportioned to customers and customer classes using data from SoCalGas'
14 Customer Services dispatching system, PACER.⁸ The PACER system tracks orders by time to
15 complete for each activity and customer class.

16 Customer Services O&M costs are recorded in functional accounts 870, 878 and 879.
17 These costs are allocated across customer classes at each functional account level based on either
18 the total time to complete the orders or the total order volume. Functional account 879.010
19 (Customer Services Field) is the largest customer services account. These costs are allocated
20 across customer classes based on the field time to recorded for each customer class. For
21 activities where all orders are processed at approximately the same cost, the order volume is used
22 to allocate costs across customer classes. Functional account 880.302 (Customer Services
23 Dispatch) is an example of costs allocated by order volume.

24 The updated Customer Services O&M costs are shown on Line 10 of Table 5.

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

26 Customer Accounts O&M costs are booked to FERC accounts 901-905. These accounts
27 include the recorded expenses incurred to receive calls from customers requesting service, obtain

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⁸ SoCalGas' Customer Services dispatch system is called the Portable Automated Centralized Electronic Retrieval (PACER) system.

1 metered gas consumption data from over 5 million meters, calculate and reconcile billing
2 information, print and mail gas bills and collection notices to customers, respond to inquiries
3 related to billing and collections, perform collection activities and process customer payments.
4 The customer account O&M costs were analyzed at each sub-account level to determine the
5 appropriate driver to allocate costs amongst the customer segments.

6 Customer Contact Center activity, which is recorded in FERC accounts 903.101,
7 903.107, 903.110, and 903.900, is the largest components of Customer Accounts O&M. This
8 includes field service calls, billing calls, customer account inquiries, and general customer
9 inquiries. Customer Contact Center costs are allocated among customer classes based on the
10 number of accounts and the call volume weighted by the average time to handle different types
11 of calls.⁹

12 Meter reading, which is recorded in FERC account 902, is another significant component
13 of Customer Accounts O&M. The costs associated with manually reading core customer meters
14 are allocated based on the number of connected meters weighted by the average time to read
15 meters for each core customer class. The costs associated with the daily collection of electronic
16 measurement for noncore customers are allocated by the number of noncore active meters by
17 customer class.

18 Bill distribution, which is recorded in FERC accounts 903.330 and 903.380, is another
19 large component of Customer Accounts O&M. These accounts reflect postage costs and the cost
20 of printing, inserting, and mailing customer bills. The allocation of these costs across customer
21 classes is performed based on the number of active customer accounts.

22 Supervision and staff support costs, FERC accounts 901, 903.1, and 905, are allocated
23 based on the activities supported. For example, billing systems supervision, Account 901.301,
24 reflects the same allocator and number of active accounts, as the costs for bill distribution and
25 remittance in account 903.330.

26 The updated Customer Accounts O&M costs are shown on Line 11 of Table 5.

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28 ⁹ Customer Contact Center calls have been identified as field service order, billing-related and miscellaneous calls. Billing-related and miscellaneous calls are allocated by the number of active accounts in each class and the call volume weighted by the average call handle time. Field service order calls are allocated by the number of active accounts and the number of field orders weighted by the average call handle time.

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

2 Consistent with the methodology adopted in the D.92-12-058, Meters and Regulators
3 O&M costs are allocated based on two allocation methods. Costs that are common to all
4 customer segments are allocated according to each customer segment's share of total connected
5 meters in service. Costs specifically identifiable as meter repair and replacement are allocated
6 based on each customer segment's share of the total number of meter repairs and replacements
7 during the year.

8 The updated Meters and Regulators O&M costs are shown on Line 12 of Table 5.

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

10 In this BCAP, SoCalGas proposes to allocate service line O&M costs to each customer
11 class based on each class' share of total service line footage at year-end 2002. For the 1999
12 BCAP, service line O&M costs were allocated to each customer class based on each class' share
13 of the combined total of the other three direct O&M costs: Customer Services, Customer
14 Accounts, and Meters and Regulators O&M costs. At the time SoCalGas submitted its 1999
15 BCAP application, complete service line footage information by class was not available. This
16 information is available now. There is a direct relationship between service line footage and
17 costs associated with the operation and maintenance of service lines. Therefore, service line
18 footage is a more appropriate basis for allocating service line O&M costs than the combined total
19 of the other three direct O&M costs.

20 The updated service lines O&M costs by customer class are shown on Line 13 of Table 5.

21 **5. O&M Loaders**

22 O&M loaders are applied to direct O&M costs to derive fully loaded O&M costs. The
23 updated O&M loaders by customer class are shown on Lines 15, 16 and 17 of Table 5. The fully
24 loaded O&M costs are shown on Line 19.

25 The combination of marginal capital costs and the fully loaded customer-related marginal
26 O&M costs form the total customer-related marginal cost for each customer class. These values
27 are shown on Line 20 of Table 5.

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1 **V. DEMAND-RELATED DISTRIBUTION MARGINAL COST**

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

10 The Commission decided in D.92-12-058 that it is appropriate for SoCalGas to develop
11 separate marginal costs for medium pressure distribution (“MPD”) and high pressure distribution
12 (“HPD”). This segmentation is appropriate because a significant portion of the SoCalGas’ total
13 load is served directly off the high-pressure distribution system.

14 **A. MEDIUM-PRESSURE DISTRIBUTION (MPD) MARGINAL COST**

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

17 **1. Marginal Capital Cost**

18 Consistent with D.92-12-058 and subsequent BCAP filings, the capital-related marginal
19 MPD cost is developed using a linear regression model. The regression analysis establishes the
20 relationship between cumulative peak day demand growth (the independent variable) and
21 cumulative load-growth related capital investment in the MPD system (the dependent variable).
22 Load-growth-related investment includes new business, pressure betterment and meter and
23 regulating station investment. The analysis period for the regression analysis is 15 years, using
24 10 years of historical data and 5 years of forecast data. The resulting estimated coefficient of the
25 independent variable represents the MPD marginal capital cost.

26 The cumulative peak day demand growth is calculated based on the net positive change
27 in the number of customers per year multiplied by the average peak day demand per customer.
28 Table 6 shows the number of customers used to develop the cumulative peak day growth.

1 The total annual footage for new business and pressure betterment by distribution pipe
2 size and type is multiplied by the associated unit costs to obtain total annual investment costs.

3 Table 7 summarizes the regression analysis results for the MPD system. The top portion
4 of Table 7 shows the 15 years of data used in the regression with the years 1993-2002 as the
5 historical data period and years 2003-2007 as the forecast data period. The regression analysis
6 yields a marginal capital cost for the MPD system of \$825 thousand per million cubic feet
7 (MMcf) of peak-day demand.

8 The marginal capital cost is multiplied by the weighted average RECC factor for
9 distribution mains and M&R stations to yield an annualized marginal capital cost of \$73.86 per
10 Mcfd (in 2005\$) of peak-day demand as shown on Line 4 of Table 8.

11 **2. Marginal O&M Costs**

12 The marginal O&M costs for the MPD system include direct O&M costs and O&M
13 loaders. The year 2002 recorded direct distribution O&M costs are allocated between medium-
14 pressure and high-pressure systems based on the split in total distribution investment between the
15 medium and high-pressure distribution systems. Table 8 shows the proposed direct and indirect
16 marginal O&M costs.

17 The proposed MPD marginal cost, capital and O&M combined, is \$81.7391 per Mcfd (in
18 2005\$) as shown on Line 21 of Table 8.

19 **B. HIGH-PRESSURE DISTRIBUTION (HPD) MARGINAL COST**

20 The methodology for calculating the marginal capital-related cost for the HPD system is
21 analogous to the methodology used for the MPD system. Cumulative load-growth-related
22 investments in the HPD system are regressed against cumulative load growth. Consistent with
23 the methodology adopted in D.92-12-058, and used in subsequent BCAPs, the coincident peak-
24 month demand served off of the HPD system is used as the measure of customer load for the
25 HPD system.

26 The capital cost regression for HPD is shown on Table 9. The resulting marginal capital
27 cost and marginal O&M costs for HPD are on Table 10. The proposed HPD marginal cost,
28 capital and O&M combined, is \$0.7276 per Mcfd (in 2005\$) as shown on Line 21 of Table 10.

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VI. TRANSMISSION-RELATED MARGINAL COSTS

Consistent with the methodology proposed in D.92-12-058 and subsequent BCAP filings, the capital-related marginal Transmission cost reflects the Total Investment method. In its 1999 BCAP decision, the Commission adopted SoCalGas’ proposal to treat Wheeler Ridge as a common facility and eliminate the zone rate credit. Therefore, the transmission marginal cost presented in this testimony was calculated as a system-wide marginal cost.

The Transmission marginal cost consists of an annualized capital-related cost and a marginal O&M cost, as described below.

A. Marginal Capital Cost

Under the Total Investment Method, the cumulative transmission investment required to meet cold year demand growth over a 15-year period is used to determine the capital-related marginal cost. The 15-year transmission resource plan is presented by SoCalGas witness Mr. David M. Bisi. In his testimony, Mr. Bisi indicates there is zero capital investment required on the SoCalGas transmission system to meet the expected incremental demand growth over the next 15 years. Therefore, the capital-related marginal cost for transmission is zero, as shown on Table 11.

B. Marginal O&M Costs

The marginal O&M cost for the transmission system includes direct O&M costs and O&M loaders. The year 2002 recorded direct transmission O&M cost is shown on Line 6 of Table 12. This transmission marginal cost reflects the total transmission O&M costs in FERC accounts 850-867, excluding compressor fuel and the shareholder funded portion of the Cuyama-Casitas lease payment. The direct transmission O&M cost is then loaded with A&G, General Plant and M&S to determine the fully-loaded transmission O&M cost.

The proposed transmission marginal cost (capital and O&M combined) is \$0.0527 per Mcf (in 2005 dollars), as shown on Line 13 of Table 12.

1 **VII. COMPARISON OF MARGINAL COSTS**

2 Table 13 shows a comparison of present and proposed values for the three O&M loaders
3 as well as marginal cost estimates for customer cost, distribution (high and medium pressure)
4 and transmission. The values adopted in the 1999 BCAP decision (D.00-04-060) are shown
5 compared to the 2005 proposed values.

6
7 **VIII. ALLOCATION OF BASE MARGIN**

8 This section addresses the allocation of SoCalGas' base margin using the LRMC
9 methodology. Table 14 (A, B, C, and D) presents the allocation of base margin costs. The first
10 page (14-A) shows the overall system allocation of base margin. The second page (14-B)
11 presents the allocation to core market segments and the final two pages (14-C and D) present the
12 allocation to noncore market segments.

13 The unit marginal costs discussed previously are multiplied by marginal demand
14 measures (MDMs) to calculate the marginal cost revenue for each class. The Commission
15 adopted the following MDMs for SoCalGas in D.92-12-058:

- 16 • Customer-related = number of forecasted customers in the class
- 17 • Medium Pressure Distribution = Cold Year Peak Day Throughput
- 18 • High Pressure Distribution = Cold Year Peak Month Throughput
- 19 • Transmission = Cold Year Annual Throughput

20 The peak day, peak month, and cold year throughput forecasts for the various classes are
21 presented in the testimonies of SoCalGas witnesses Christopher H. Roberts, Luis Pando, Brenda
22 H. Chen, Sharon R. Pope, and Mark Otrahalek. The class specific MDMs are shown on Table
23 14-A at Lines 1, 4, 7, and 11 for customer-related, MPD, HPD, and transmission, respectively.

24 The resulting class-specific marginal cost revenue is then calculated for the forecast
25 period. The total system marginal cost, as shown on Table 14-A, is then reconciled to the
26 authorized base margin using a scaling factor based on the Equal Percent of Marginal Cost
27 ("EPMC").¹⁰ Certain costs, such as non-Energy Efficiency Customer Service & Information

28 _____
¹⁰ The marginal cost revenue for the EOR class is scaled to the forecasted level of EOR revenues, which is largely determined by long-term contracts.

1 costs, the SDG&E Moreno credit, the costs associated with public access NGV compressor
2 stations, and uncollectibles are directly assigned and added to the scaled marginal cost revenues
3 to derive the utility's base margin costs.

4 The SDG&E Moreno credit was established in D.97-04-082. Consistent with that
5 decision, the costs are allocated on an EPMC basis, excluding SDG&E.

6 The non-EE CS&I costs have been allocated based on an assessment of the resources
7 devoted to each customer segment. A description of the allocation of non-EE CS&I costs is
8 presented in Mr. Emmrich's testimony. The NGV compression adder cost and the expected
9 EOR revenues in Lines 30 and 18, respectively, reflect the values developed for the embedded
10 cost study.

11 The LRMC-based allocation of SoCalGas' Total authorized base margin, \$1.39 billion, is
12 presented on Table 14-A.

13 This concludes my prepared direct testimony.

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QUALIFICATIONS

My name is Allison F. Smith. My business address is 555 West Fifth Street, Los Angeles, California 90013-1011.

I am employed by SoCalGas as the Gas Analysis Manager in the California Regulatory Affairs Department for SoCalGas and San Diego Gas & Electric (SDG&E). I hold a Bachelor of Science degree in Mechanical Engineering from the University of California at Berkeley. I have been employed by SoCalGas since 1990, and have held positions of increasing responsibilities in the engineering, customer service, and regulatory departments. I have been in my current role as Analysis Manager since March 30, 2002. In my current position, I am responsible for developing rate design policies and establishing gas rates for both utilities.

I have previously testified before the Commission.

TABLES