

Application No.: A.03-09-

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Date: September 3, 2003

Witness: Steven R. Lango

**PREPARED DIRECT TESTIMONY OF
STEVEN R. LANGO
SOUTHERN CALIFORNIA GAS COMPANY**

September 3, 2003

2005 BIENNIAL COST ALLOCATION PROCEEDING

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**PREPARED DIRECT TESTIMONY OF
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SOUTHERN CALIFORNIA GAS COMPANY**

A. PURPOSE

The purpose of my testimony is to present SoCalGas' proposed gas rates, including related changes to cost allocation and rate design. The proposed rates rely upon embedded cost ("EC") principles for allocating base margin costs among customer classes. The proposed rates also incorporate certain SoCalGas proposals in Application (A.) 03-06-040, the Firm Rights for California ("FRCA") proceeding.

B. SUMMARY

The proposed changes in SoCalGas' transportation rates are shown in Tables 1 through 8 (set forth in attached Appendix A). As illustrated in Table 1, the proposed rates reflect a change in the gas transportation revenue requirements of \$79.3 million, or 4.7% more than transportation revenues collected at present rates.

The rate results are based on the proposed cost allocation and demand forecasts sponsored by other SoCalGas witnesses. SoCalGas witness Mr. Herbert S. Emmrich sponsors the allocation of base margin costs among customer classes using an EC methodology. My testimony completes the cost allocation process by adding the non-base margin cost allocation to the base margin cost allocation results sponsored by the various SoCalGas witnesses. The cost allocation process gathers together the various cost and demand forecasts, computes system revenue requirements from these forecasts, and allocates the revenue requirements among customer classes. The rate design section of my testimony explains how I developed specific unit charges to recover the class specific revenue requirements from customers.

The following summarizes proposals incorporated in my testimony that differ from current ratemaking practices. My testimony:

1. Reflects the recommended revenue changes related to storage and load balancing costs contained in SoCalGas' FRCA application.

- 1 2. Modifies the allocation of self-generation incentive costs to better align program
2 costs with the program participants and beneficiaries. SoCalGas witnesses Mr.
3 Joseph S. Velasquez and Mr. Jeffrey B. Horn sponsor this allocation factor.
- 4 3. Proposes to recover company use fuel costs related to transmission and storage
5 services through an “*In-Kind*” fuel charge. This proposal is consistent with
6 SoCalGas’ FRCA application.
- 7 4. Proposes to transfer procurement adder costs from core transportation rates to
8 core procurement rates.
- 9 5. Reflects residential rates consistent with SoCalGas’ submission in Phase 2 of the
10 Commission’s Rulemaking (R.) 01-05-047 (“Baseline OIR”). In that proceeding,
11 SoCalGas proposes to adjust its baseline and non-baseline rates to eliminate any
12 revenue shortfalls in the current rate design associated with a change in baseline
13 allowances per D.02-04-026, the Baseline OIR Phase 1 decision. This adjustment
14 includes amortization of any outstanding regulatory balances associated with this
15 issue.
- 16 6. Allocates changes to proposed residential rates entirely to the non-baseline rate if
17 the class average change is a decrease, or on an equal percent of rate change basis
18 if the class average change is an increase.
- 19 7. Proposes to completely de-average residential and G-10 rates in two years.
- 20 8. Reduces the alternatives for a monthly customer charge applicable to G-10
21 customers from two charges to one.
- 22 9. Reflects a single set of “Sempra wide” NGV rates applicable to both SoCalGas
23 and San Diego Gas & Electric Company (“SDG&E”). SoCalGas witnesses Mr.
24 Joseph S. Velasquez and Mr. Jeffrey B. Horn provide the rationale for this
25 proposal.
- 26 10. Updates the monthly customer charges applicable to G-30 and electric generation
27 customers to better reflect the customer-related costs of service.
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1 **C. COST ALLOCATION**

2 **1. Overview**

3 Cost allocation is a two-step process that requires developing a revenue
4 requirement and allocating the revenues among customer classes. Both base margin costs
5 and non-base margin (“non-margin”) costs are allocated. Base margin costs include what
6 is generally considered the utility’s authorized gas margin. Consistent with SoCalGas’
7 proposal in the FRCA proceeding, I removed storage costs, including load balancing,
8 from base margin costs and treated them as non-margin costs. SoCalGas witness Mr.
9 Herbert S. Emmrich sponsors the allocation of base margin costs using the EC
10 methodology. Mr. Emmrich’s base margin cost results do not take into account revenues
11 allocated to the EOR class. I adjust the base margin cost allocation results in my
12 testimony to include an estimate of EOR revenue collections. Since I preserve the same
13 system total for base margin costs as sponsored by Mr. Emmrich, my EOR revenue
14 adjustment effectively becomes a revenue credit to all other customer classes. I describe
15 in further detail the EOR adjustments in Section C.1.e. of my testimony.

16 Non-margin costs (for ratemaking purposes) reflect all other costs not considered
17 “margin costs” incurred by the utility to provide basic transportation services to
18 customers during the forecasted BCAP period. These costs include, but are not limited
19 to, storage services, load balancing services, regulatory account amortizations, transition
20 costs, equalizing the electric generation rates between SoCalGas and SDG&E, and costs
21 resulting from core de-averaging.

22 Except as noted in this testimony, the methods employed to develop and allocate
23 non-margin costs are consistent with the methods employed to develop the SoCalGas
24 transportation rates adopted in D. 00-04-060, SoCalGas’ most recent BCAP decision.

25 **2. Non-Margin Costs**

26 I have aggregated non-margin costs into five major categories: (a) FRCA-related
27 costs, (b) other operating costs, (c) transition costs, (d) regulatory account amortizations,
28 (e) and miscellaneous cost adjustments. I discuss on the recovery of company use costs
in section C.2.(f) below. I used generally the same allocation factors to allocate costs
among customer classes as those employed to develop transportation rates for SoCalGas
pursuant to the most recent BCAP decision (except as noted).

1 **(a) FRCA-Related Costs**

2 In the FRCA proceeding, SoCalGas recently filed proposed changes to compute
3 storage costs, including load balancing and company use fuel costs. Under SoCalGas’
4 proposal, storage costs would be escalated from year to year and company use fuel costs
5 would be collected as an “In-Kind” charge, or a percent reduction in volumes. The rates
6 presented in my testimony reflect SoCalGas’ proposals in the FRCA proceeding.

7 Although the FRCA proposals offered by SoCalGas would remove all storage costs,
8 including load balancing, from base margin revenue requirements, core storage costs and
9 load balancing costs would remain bundled in and recovered through core transportation
10 rates. Proposed noncore transportation rates would continue to reflect recovery of load
11 balancing costs. Proposed noncore storage costs would continue to be recovered from

12 The proposed allocation of core storage costs is consistent with current methods.
13 Core storage costs are divided into three categories: inventory, injection, and withdrawal
14 costs. Inventory and injection costs are currently allocated to core customers on the basis
15 of excess winter demand, which is the level of core demand during the winter season in
16 excess of flowing supplies.¹ I allocate core withdrawal costs to customers on the basis of
17 core peak day volumes.

18 Load balancing costs are allocated only to noncore customers, including EOR, on
19 an Equal Cents Per Therm (“ECPT”) basis. These costs are recovered from noncore
20 customers through their transportation rates. These two approaches are consistent with
21 current methods.

22 **(b) Other Operating Costs**

23 Other operating costs include, but are not limited to, exchange revenues and
24 unaccounted-for gas costs (“UAF”). These costs are generally allocated to customer
25 classes: 1) on a cold weather throughput basis, such as a coincident peak-season, peak-
26 month, or cold-year throughput; 2) on a base margin allocation basis (e.g., EPMC); or, 3)
27 are directly assigned (based on a cost study). Energy efficiency (EE) costs and similar

28 ¹ The current allocation excludes gas A/C, gas engine, and NGV loads. The proposed allocation excludes
gas A/C and gas engine loads.

1 public purpose costs once categorized as “other operating costs” are now recovered
2 through the utility’s public purpose program surcharges, and are unbundled from utility
3 transportation rates.² The allocation of these costs is consistent with current methods.

4 The only notable difference in this filing is that the total level of UAF costs is
5 substantially higher than UAF costs currently recovered in rates. This increase in UAF
6 costs reflects the difference in forecasted gas commodity prices proposed in this filing
7 and those adopted in the last BCAP decision, D.00-04-060. UAF costs are a simple
8 calculation of UAF volumes multiplied by the utility’s forecasted gas commodity price
9 for the BCAP period.

10 **(c) Transition Costs**

11 Transition costs include PITCO/POPCO costs and Interstate Transition Cost
12 Surcharge (ITCS) costs. PITCO/POPCO costs are allocated to all customers, excluding
13 EOR customers, on an ECPT basis. ITCS costs are allocated to all noncore customers,
14 excluding EOR customers, on an ECPT basis. This allocation methodology is consistent
15 with current practice.

16 **(d) Regulatory Account Balances**

17 Regulatory account balances are allocated using various parameters, including
18 average-year throughput or a direct benefits study. For example, the Core Fixed Cost
19 Account (“CFCA”) balance is allocated on an ECPT basis to core customers only, while
20 the Noncore Fixed Cost Account (“NFCA”) balance is allocated on an ECPT basis to
21 noncore customers only. Some accounts are currently allocated on an Equal Percent of
22 Marginal Cost (“EPMC”) basis. Since the proposed rates reflect an embedded cost
23 approach to rate-setting for which EPMC factors do not exist, I allocated accounts that
24 are currently allocated on an EPMC basis using an Equal Percent of Base Margin
25 (“EPBM”) basis instead. An EPBM allocation factor is comparable to an EPMC
26 allocation factor.

27 ² PPP surcharge costs are currently unbundled from transportation rates and recovered through PPP
28 surcharge rates. There is a difference between the current and proposed modeling of these charges. The
current modeling process keeps PPP costs as a part of the primary cost allocation, with PPP costs removed
at the very end of the modeling process. The proposed modeling process simply leaves out any calculation
of PPP costs and defers such calculations to the PPP proceeding.

1 The baseline memorandum account is amortized exclusively to the residential
2 class. This account was established in D.02-04-026, the Baseline OIR decision adopted
3 in Phase 1 of that proceeding (R.01-05-047). The proposed allocation is consistent with
4 SoCalGas' filed position in Phase 2 of the Baseline OIR proceeding.

5 SoCalGas proposes that the self-generation incentive costs incurred by SoCalGas
6 pursuant to Assembly Bill ("AB") 970 be allocated to customers using a multi-factor
7 methodology reflecting an equal weighting between the beneficiaries of the
8 environmental benefits and the beneficiaries of the financial benefits associated with this
9 program. SoCalGas witnesses Mr. Joseph S. Velasquez and Mr. Jeffrey B. Horn sponsor
10 this proposal and the resulting allocation factor.

11 (e) **Miscellaneous Cost Adjustments**

12 There are four miscellaneous cost adjustments: core de-averaging, core pipeline
13 demand charges, other miscellaneous procurement adders, and EOR revenue adjustments.
14 Core de-averaging, which gradually removes the existing subsidy in residential rates by
15 core C&I customers, results in an increase to the residential class and a corresponding
16 decrease to the G-10 customer class. Since core de-averaging is revenue neutral between
17 residential and G-10 classes, it does not affect the cost allocations of noncore or
18 wholesale classes.

19 Core pipeline demand charges reflect a forecast of interstate pipeline costs to
20 serve SoCalGas core customers. SoCalGas assumes that there will continue to be 1,044
21 million cubic feet per day ("MMcfd") of bundled contractual mainline capacity reserved
22 on the El Paso and Transwestern pipeline systems to serve core customers during the
23 entire BCAP forecast period. In reality, the current service agreements for this capacity
24 end at varying times during the BCAP forecast period. SoCalGas intends to file an
25 application later this year in order to address, among other things, future core interstate
26 transportation requirements. For purposes of this BCAP, SoCalGas assumes that the
27 existing bundled capacity reservations on El Paso and Transwestern will continue
28 through the BCAP period. SoCalGas reserves the right to update these assumptions
based upon the outcome of the future SoCalGas application.

Other miscellaneous procurement adders include recovery for the Carrying Cost
of Storage Inventory ("CCSI") and San Juan Lateral pipeline costs. Currently, these

1 costs are computed as a part of transportation revenues and recovered as an adder to the
2 core transportation rates of bundled service customers. SoCalGas proposes to transfer
3 recovery of these costs from core transportation rates to core procurement rates under
4 SoCalGas Schedule G-CP. These costs are exclusively allocated to and recovered from
5 core customers receiving utility procurement services. These same customers pay the
6 charges under Schedule G-CP for core procurement services. Therefore, it makes sense
7 to simply put in one place (i.e., in Schedule G-CP) all charges paid by core customers for
8 utility procurement services.

9 EOR revenue adjustments reflect three separate occasions where I adjust the cost
10 allocation results to ensure that the EOR revenue class is in *rate parity* with the electric
11 generation customer class. I perform these adjustments at the base margin level, the pre-
12 Sempra-wide level, and at the post-Sempra-wide level.

13 SoCalGas allocation witnesses Herbert S. Emmrich does not allocate base margin
14 costs to the EOR class. I carve out from the same base margin revenue total used by Mr.
15 Emmrich, an amount allocated to the EOR class. I proportionately reduce (i.e., an equal
16 percent reduction of base margin) the allocated costs of the other classes until I achieve
17 the necessary revenues to allocate to the EOR class. The EOR share of the base margin is
18 the sum of revenues collected from EOR customers billed at contract prices and EOR
19 customers billed at the proposed class average rates of the EG class. All EOR revenue
20 collections above the class average Sempra-wide EG rate are booked as a revenue credit
21 in the Enhanced Oil Recovery Account (EORA). SoCalGas will amortize the EORA
22 balance to customers during the next update of regulatory account amortizations.

23 (f) **Company Use Costs**

24 SoCalGas proposes to recover certain company use costs through "*In-Kind*" fuel
25 charges consistent with SoCalGas' proposals in the FRCA proceeding. These charges
26 will be a percentage reduction to volumes received by SoCalGas in providing utility
27 service to customers. Currently, SoCalGas recovers three types of company use fuel
28 costs through its transportation rates: 1) a fuel cost for providing transmission services; 2)
a fuel cost for providing storage services, and; 3) a fuel cost for providing fuel use related
services not covered by the first two services. In past BCAPs, SoCalGas has estimated
for all three costs, a volume that the utility consumes (i.e., fuel use) to provide the three

1 aforementioned services. The estimated volumes are then multiplied by the utility's
2 forecasted commodity price to derive a revenue amount to be recovered in rates.

3 SoCalGas proposes to eliminate the revenues collected in rates for company fuel
4 use for transmission and storage services. Instead, SoCalGas proposes to recover
5 company fuel use transmission costs through an *In-Kind* charge of 0.39 percent.

6 SoCalGas proposes to recover company fuel use storage costs through an *In-Kind* charge
7 of 2.44 percent.

8 **3. Completed Revenue Requirements**

9 The non-margin cost allocation results are added to the results of the base margin
10 cost allocation to complete the transportation rate revenue requirements. The completed
11 transportation revenue requirements become the starting point for rate design
12 calculations.

13 **D. RATE DESIGN**

14 In this section, SoCalGas updates its individual tariff rates. This section describes
15 specific changes to current rate design methods.

16 **1. Residential Rates**

17 Current residential rates consist of a \$5 monthly customer charge and baseline
18 (“BL”) and non-baseline (“NBL”) volumetric rates. These rates are applicable to three
19 categories of residential customers: single-family, multi-family, and small master
20 metered dwellings with loads less than 100,000 therms of weather normalized usage for
21 the past two calendar years. In an effort to promote energy conservation, California
22 Public Utilities Code Section 739.7 mandates that the NBL rate must be higher than the
23 BL rate. In SoCalGas' last BCAP decision, the CPUC set the rate differential between
24 the BL and NBL rates on a “composite” rate basis. A composite rate basis divides the
25 NBL tariff rate by a “composite” BL average rate, which is equal to the sum of the
26 customer charge revenues and BL volumetric rate revenues divided by the BL volumes.
27 The current composite tier differential is 1.05 (i.e., the NBL rate is 5% higher than the
28 composite BL average rate).

 SoCalGas proposes to use a different formula in calculating the tier differential.
SoCalGas proposes to allocate any changes to residential rates resulting from this BCAP

1 as follows: 1) if the class average change to the residential class is a decrease, then the
2 entire decrease is allocated to the NBL rate; and, 2) if the class average change to the
3 residential class is an increase, then the revenue increase is allocated proportionately (i.e.,
4 the same percent change) to BL and NBL rates. Both these proposals will be adjusted (if
5 necessary) to ensure compliance with Public Utilities Code §739(c), which mandates an
6 inverted block rate structure. And, on a going forward rate-setting basis, both proposals
7 would comply with Public Utilities Code §739.7, which mandates that revenues collected
8 from increases to BL rates would be used to reduce NBL rates.

9 **2. Residential Large Master Meter Rates**

10 These rates are currently applicable to all master metered loads in excess of
11 100,000 therms of weather-normalized usage for the past two calendar years. Large
12 master meter rates consist of a rate design that is similar to the default residential rate
13 design as described above. However, large master meter rates consist of a higher
14 monthly customer charge, which is set at its cost-based value. The BL and NBL rates
15 applicable to large master meter customers retain the same inverted rate block structure
16 (i.e., the NBL rate is higher than the BL rate). The BL and NBL rates for this group are
17 substantially lower in comparison with the same rates applicable to all other residential
18 customers. This outcome is due to two factors. The first factor is that the class average
19 rate for this subgroup is lower than the class average rate applicable to other residential
20 customers. Because the cost to serve this subgroup is lower than the cost to serve
21 remaining residential customers (i.e., the utility does not have to read the meters behind a
22 master meter). The second factor is that more of this subgroup's costs are recovered
23 through its monthly customer charge relative to the customer charge applicable to all
24 other residential customers. Since more subclass revenues are recovered through this
25 subgroup's customer charge, the remaining revenues that are recovered through
26 volumetric rates need not be as high as is necessary for all other residential customers.

27 In this filing, SoCalGas proposes no changes to the current rate design for large
28 master meter customers. SoCalGas proposes only to update the volumetric charges in
order to reflect the proposed cost allocation results and demand forecasts to this class.

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3. Residential Baseline Allowances

In D. 02-04-026, the Commission revised SoCalGas' baseline allowances without making a corresponding revision to residential rates to preserve revenue neutrality to this class. In that decision, the Commission allowed utilities to establish a baseline regulatory account to track any revenue differences associated with the change in baseline allowances without a corresponding rate change. The question of how to account for any revenue shortfalls or how to treat the resulting balances in the new baseline regulatory account was deferred to Phase 2 of R. 01-05-047. As of today, the Commission has not issued a decision in Phase 2. Accordingly, the proposed residential rates reflect SoCalGas' filed position in that proceeding. In Phase 2, SoCalGas proposed to adjust residential rates to remove any revenue shortfalls on a forward-looking basis, and would amortize to the residential class only the forecasted balance in SoCalGas' baseline regulatory account. This proposal has no impact on the rates of non-residential customer classes.

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4. Submeter Credits

Submeter credits are applicable to individual dwellings served behind a master meter that is owned and operated by the utility. In this filing, SoCalGas proposes no changes to the current submeter credits. Please note that on March 13, 2003, the Commission issued an OIR (Rulemaking 03-03-017) and an OII (Investigation 03-03-018) into mobile home park issues, which will review how submeter credits are calculated. Therefore, SoCalGas will not pursue changes in submeter credits in this proceeding. We will, however, incorporate the results of the OIR/OII on mobile home park issues when the Commission issues a final decision in that proceeding.

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5. Core De-Averaging

SoCalGas proposes to de-average its core rates entirely during the 2005 BCAP period. With its current core rates already 75% de-averaged, SoCalGas proposes to eliminate the remaining 25% in two steps. On January 1, 2005, core rates will be de-averaged by 14 percentage points, which reduces the level of "averaged" core rates from 25 to 11 percent. The remaining 11 percent will be de-averaged from core rates beginning January 1, 2006.

6. Core C&I Rates

1 SoCalGas proposes to consolidate its current two customer charges to a single
2 customer charge of \$15 per month. Currently, G-10 customers with annual usage less
3 than 1,000 therms pay a \$10 monthly customer charge and all other G-10 customers pay a
4 \$15 monthly customer charge.

5 There are two reasons for this change. The first reason is simplicity. One
6 customer charge is easier for a customer to understand than two. Further, because all
7 customers in this class would have the same charge, this proposal would end any debate
8 (and possible gaming) over whether or not a customer qualifies for a particular charge.
9 The second reason is that the current rate structure, in tandem with a single customer
10 charge, provides the same “cost-based” price signal as does a rate structure with multiple
11 customer charges. This is particularly true for larger use customers. Since the same cost-
12 based price signals are provided under either customer charge structure, SoCalGas
proposes a rate structure that has the fewest customer charges.

13 Utility customer-related costs are for utility services such as meter reading, bill
14 processing, and related services. These costs are generally referred to as “fixed costs”
15 because they remain, in general, unaffected by changes in customer usage. Accordingly,
16 if the goal is to match cost causation with rate recovery (i.e., cost-based rates), then all
17 costs classified as fixed costs should be recovered through fixed charges. Moreover, a
18 larger use customer typically has a bigger meter and regulator set than does a smaller use
19 customer. A larger meter and regulator set may require more sophisticated meter
reading, maintenance relative to a smaller use customer.

20 One way to achieve cost-based fixed fees is to have multiple customer charges,
21 with higher charges for higher use customers. Another way to achieve the same thing is
22 have a single customer charge with declining block rates. For larger use customers, the
23 initial tiered rate effectively becomes another fixed fee because these customers will
24 always consume volumes in excess of the initial tiered usage block. This is not be the
25 case for smaller use customers. At a minimum, while a smaller use customer may always
26 pay the monthly customer charge, the larger use customer will always pay the monthly
27 customer charge **plus** the first tiered rate charge. Therefore, the larger use customer will
28 pay “fixed fees” that are generally larger than the “fixed fees” paid by a lower use

1 customer under a rate structure that consists of a single customer charge and declining
2 block rates.

3 SoCalGas proposes no other changes to the current rate design of G-10 rates.

4 **7. Non-Residential Air Conditioning Rates**

5 The current rate design consists of a \$150 monthly customer charge and a single
6 volumetric rate. SoCalGas does not propose to change the current rate design.

7 **8. Gas Engine Rates**

8 The current rate design consists of a \$50 monthly customer charge and a single
9 volumetric rate. SoCalGas does not propose to change the current rate design.

10 **9. NGV Rates**

11 SoCalGas proposes to create a single set of “Sempra-wide” NGV rates applicable
12 to both SoCalGas and San Diego Gas and Electric (SDG&E) customers. SoCalGas
13 witnesses Joseph S. Velasquez and Jeffrey B. Horn sponsor the reasons for this proposal.

14 **10. Retail Noncore C&I Rates**

15 SoCalGas proposes to increase its G-30 customer charges to better reflect the
16 customer-related costs for this service. The proposed customer charges are \$375 for
17 distribution services and \$750 for transmission services. The definition of cost-based
18 customer charges is the total level of customer-related costs allocated to the G-30 class
19 divided by the forecasted number of customers. The allocation of G-30 customer related
20 costs between distribution and transmission services is developed on the basis of meter
21 size weighted by the number of customers.

22 Retail noncore C&I rates are also revised to reflect a proposal to differentiate the
23 volumetric rates for firm and interruptible noncore service. Under this proposal, noncore
24 interruptible volumetric rates are set equal to 130 percent of the volumetric rate for firm
25 noncore service, excluding ITCS. SoCalGas witnesses Joseph S. Velasquez and Jeffrey
26 B. Horn sponsor these rate proposals.

27 **11. Electric Generation (EG) Rates**

28 SoCalGas does not propose any changes to the existing rate design for this
customer class except to reflect the firm and interruptible rate differentiation proposal
mentioned above.

12. **Wholesale Rates**

1 SoCalGas currently computes all volumetric tariff rates applicable to wholesale
2 customers. SoCalGas does not propose to change the current rate design except to reflect
3 the firm and interruptible rate differentiation proposal mentioned above.

13. **Peaking Service Rates**

4 SoCalGas does not propose changing the current peaking service rate design. The
5 current rate design for peaking services was adopted in D.01-08-020. These rates are
6 applicable to customers who bypass in part or in whole the SoCalGas pipeline system.

14. **Public Purpose Program Rates**

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8 In Resolution G-3329, dated December 11, 2001, the Commission initiated a
9 process that would update its Public Purpose Program (PPP) rates at the start of each
10 calendar year. The PPP costs, CARE program costs, DSM, DAP, and the public purpose
11 portion of RD&D, are recovered from SoCalGas customers through a separate tariff, rate
12 Schedule G-PPPS. As a result, the proposed PPP revenues presented in this testimony
13 are illustrative with one change relative to current PPP revenue collections. This one
14 change ensures that all PPP charges are recovered through PPP rates.³ The new PPP rates
15 will be established in accordance with Resolution G-3329 as described above.

16 This concludes my prepared testimony.
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22 ³ Current PPP rates for SoCalGas do not fully recover its allocated level of PPP costs. There is currently
23 approximately \$23,000 being allocated to the electric generation customer class. Since the PPP surcharge is
24 not collected from EG customers, SoCalGas currently incurs a shortfall of \$23,000 annually. SoCalGas' proposed revenue requirement in this application reflects the recovery of this \$23,000 shortfall from non-EG customers.

QUALIFICATIONS

My name is Steven R. Lango. My business address is 8330 Century Park Court, San Diego, CA 92123. I am employed as a Principal Economic Advisor in the Regulatory Affairs Department for the San Diego Gas & Electric Company (SDG&E). My responsibilities are to develop utility rates and provide regulatory support, including the preparation of exhibits, for SoCalGas and SDG&E.

I received a Master's degree in Economics in 1986 from the University of California at Santa Barbara and a Bachelor of Arts degree in Economics in 1980 from California State University, Fresno.

I joined SDG&E in 1986 and I have held various positions of increasing responsibility in the area of gas and electric utility ratemaking for SDG&E specifically, Associate Energy Analyst (1986), Pricing Analyst (1987-90), Pricing Design Analyst (1990-92), Senior Pricing Analyst (1992-98), Regulatory Analyst (1998-2001), and Principal Economic Advisor (2001 to present). I have previously testified before the Commission.