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Chapter: 12

PREPARED DIRECT TESTIMONY OF
SHARIM CHAUDHURY
ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY
AND SAN DIEGO GAS & ELECTRIC COMPANY

(RATE DESIGN)

July 2018

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1 **CHAPTER 12**

2 **PREPARED DIRECT TESTIMONY OF SHARIM CHAUDHURY**

3 **(RATE DESIGN)**

4 **I. PURPOSE**

5 The purpose of my testimony is to present the proposed natural gas transportation rates of
6 Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company
7 (SDG&E) (collectively, Applicants). These proposed rates reflect revisions to current rates
8 based on Applicants' proposed cost allocation proposals in this proceeding to allocate each
9 utility's authorized base margin¹ across customer classes. Applicants' cost allocation proposals,
10 based on updated cost studies, are described by witnesses Sim-Cheng Fung (Chapter 8), Marjorie
11 Schmidt-Pines for SoCalGas (Chapter 9), and Michael Foster for SDG&E (Chapter 10).

12 **A. Overview of Rate Design**

13 Applicants' rate design models start with the proposed allocated base margin, and then
14 incorporate the integration of the local transmission system costs for the two utilities,² along with
15 the unbundling of the Backbone Transportation Service (BTS) costs.³ Additionally, Applicants'
16 rate design models recover in rates all Commission-authorized non-base margin costs, which
17 reflect other costs incurred by the Utilities in providing transportation services to its customers
18 during the cost allocation period. These non-base margin costs include, but are not limited to,

¹ Base margin is authorized by the California Public Utilities Commission (Commission) in the General Rate Case (GRC) or equivalent cost of service proceedings.

² This integration reflects the splitting of total local transmission costs between the utilities by the % share of cold-year peak month throughput.

³ BTS costs represent the costs of SoCalGas' and SDG&E's transmission lines from the receipt points to SoCalGas' Citygate.

1 unaccounted-for gas (UAF),⁴ company-use fuel, regulatory account balances (over-or-under
2 collections), and any additional revenue requirements authorized by the Commission in
3 proceedings outside the GRC.

4 **B. Non-Margin Cost Allocation and Rate Design Proposals**

5 Except as noted below, the methods employed to develop and allocate non-margin costs
6 are consistent with those underlying the 2017 Triennial Cost Allocation Proceeding (TCAP)
7 (Phase 2), a proceeding which resulted in a Commission-approved settlement. See Decision (D.)
8 16-10-004.

9 My testimony incorporates the following rate design and non-margin cost allocation
10 proposals:

- 11 (1) For SoCalGas, increase the residential customer charge from \$5 to \$10 per
12 customer per month;
- 13 (2) For SDG&E, replace the current residential minimum bill of \$3 per customer
14 per month with a residential customer charge of \$10 per customer per month;
- 15 (3) Update SoCalGas' and SDG&E's submeter credits;
- 16 (4) Update SoCalGas' and SDG&E's Natural Gas Vehicle (NGV) compression
17 costs;
- 18 (5) Provide a new method to allocate SoCalGas' and SDG&E's Self Generation
19 Incentive Program (SGIP) costs across customer classes; and

⁴ As described by witness Wei Bin Guo (Chapter 5), UAF gas is the difference between total receipts into SoCalGas' and SDG&E's respective service territories and total deliveries within SoCalGas' and SDG&E's respective service territories over a specified period.

(6) Propose methods to allocate SoCalGas' Storage Inventory for Balancing Function Memorandum Account (SIBFMA) costs and Reliability Function Cost Memorandum Account (RFCMA) costs across customer classes.

C. Illustrative Rates

The allocated non-margin costs are added to the allocated base margin costs to derive the transportation revenue requirement to be recovered in rates. The allocated transportation revenue requirements across customer classes become the starting point for the development of rates for each customer class.

Table 1 below shows SoCalGas' proposed 2020 class-average transportation rates and the resulting rate changes relative to the current rates.⁵

Table 1: Class Average Rates (\$/therm)				
	7/1/2018	TCAP Proposed	\$/th Change	% Change
<u>SoCalGas:</u>				
Res	\$0.748	\$0.743	(\$0.005)	-0.7%
CCI CA	\$0.325	\$0.380	\$0.056	17.1%
Gas A/C	\$0.154	\$0.159	\$0.004	2.7%
Gas Engine	\$0.161	\$0.163	\$0.002	1.1%
NGV Uncompressed post-SW	\$0.113	\$0.129	\$0.017	14.9%
Core Class Average	\$0.599	\$0.608	\$0.009	1.4%
NCCI-D CA	\$0.077	\$0.084	\$0.008	10.1%
EG-D Tier 1 post-SW	\$0.127	\$0.129	\$0.002	1.9%
EG-D Tier 2 post-SW	\$0.056	\$0.074	\$0.018	31.5%
TLS-CI CA Rate (w/ CSITMA & CARB adders) ¹	\$0.024	\$0.032	\$0.008	33.0%
TLS-EG CA Rate (w/CARB adder)	\$0.021	\$0.029	\$0.008	37.6%
UBS \$1,000/yr	\$23,290	\$0	(\$23,290)	-100.0%
BTS w/Balancing Accounts \$/dth/d	\$0.264	\$0.262	(\$0.001)	-0.4%
System Average Rate w/ BTS	\$0.280	\$0.288	\$0.008	2.9%
1 CSITMA is the California Solar Initiative Program Adder CARB adder is for CARB administrative fees.				

⁵ As of July 1, 2018, which is the effective date of updated rates incorporating Aliso Canyon Turbine Replacement revenue requirement per approved Advice Letter 5294-A.

1 SoCalGas' proposed rates include the regulatory account balances as reflected by witness
 2 S. Nasim Ahmed (Chapter 6), who presents the regulatory account balances amortized in current
 3 rates.

4 Table 2 below shows SDG&E's proposed 2020 class-average transportation rates and the
 5 resulting rate changes relative to the current rates.

Table 2: Class Average Rates (\$/therm)				
	7/1/2018	TCAP Proposed	\$/th Change	% Change
<u>SDG&E:</u>				
Res	\$0.916	\$0.926	\$0.010	1.1%
CCI CA	\$0.278	\$0.323	\$0.046	16.4%
NGV Uncompressed post-SW	\$0.113	\$0.130	\$0.016	14.6%
Core Class Average	\$0.665	\$0.671	\$0.006	0.8%
NCCI-D	\$0.117	\$0.099	(\$0.018)	-15.4%
EG-D Tier 1 post-SW	\$0.127	\$0.130	\$0.003	2.0%
EG-D Tier 2 post-SW	\$0.056	\$0.074	\$0.018	31.7%
TLS-CI CA Rate (w/ CSITMA & CARB adders) ¹	\$0.025	\$0.033	\$0.008	32.6%
TLS-EG CA Rate (w/CARB adder)	\$0.021	\$0.029	\$0.008	38.4%
System Average Rate	\$0.298	\$0.342	\$0.044	14.8%
1 CSITMA is the California Solar Initiative Program Adder CARB adder is for CARB administrative fees.				

6
 7 SDG&E's proposed rates include the regulatory account balances as reflected by witness
 8 John Roy (Chapter 7), who presents the regulatory balances amortized in current rates.

9 Appendix A contains a complete set of rate tables for SoCalGas and SDG&E
 10 incorporating all the proposed cost allocation methods in this TCAP corresponding to Tables 1
 11 and 2.

1 **II. CORE RATE DESIGN**

2 In this section, Applicants describe their respective individual core rate updates. For
3 residential customers, the rate updates include Applicants’ proposed increase in customer charge
4 and the corresponding compensating decrease in volumetric rates.

5 **A. Residential Rates**

6 Residential rates apply to three categories of residential customers: single-family, multi-
7 family, and small master-metered dwellings.⁶ SoCalGas’ current residential transportation rates
8 structure consists of a fixed customer charge of about \$5 per customer per month for customers
9 who are not in the California Alternative Rates for Energy (CARE) program;⁷ and a two-tiered
10 volumetric rate, baseline and non-baseline, with the baseline rate lower than the non-baseline
11 rate. The baseline rate and the non-baseline rates are related to each other through the concept of
12 Composite tier differential, where a Composite baseline rate is defined by adding gas price and
13 the customer charge revenues per unit of baseline volume to the baseline rate. The current tier
14 differential between SoCalGas’ composite baseline and non-baseline rates is 1.15.

15 For SDG&E, the current residential rate structure consists of about \$3 per customer per
16 month⁸ minimum bill⁹ and a two-tiered volumetric rate, baseline and non-baseline. SDG&E

⁶ SoCalGas’ master meters with annual usage less than 100,000 therms, on weather-normalized basis, for the last two calendar years. SDG&E’s residential rates apply to all master-metered customers.

⁷ The Commission adopted the current \$5 per month fixed customer charge for non-CARE customers in the 1993 BCAP (see D.94-12-052). In SoCalGas’ tariff, customer charge is implemented as per-meter per-day charge (currently at \$0.16438). Hence, the monthly customer charge varies slightly around \$5 from month to month depending on the number of days in a month.

⁸ The Commission adopted a \$3 per month minimum bill in the last TCAP Phase 2 (see D.16-10-004) for non-CARE customers. In SDG&E’s tariff, minimum bill charge is implemented as per-meter per-day charge (currently at \$0.09863). Hence, the monthly minimum bill varies slightly around \$3 from month to month depending on the number of days in a month.

⁹ For SDG&E, a non-CARE residential customer pays, at a minimum, \$3 per-month bill. If the customer’s calculated gas bill based on the volume of gas used, comprising cost of gas, gas transportation cost and public purpose program surcharge (PPPS), exceeds \$3 per month, then the \$3 minimum bill no

1 never had a fixed customer charge, and prior to the last TCAP decision, SDG&E simply had
2 two-tiered volumetric rates with baseline rate lower than the non-baseline rate.

3 **1. SoCalGas' and SDG&E's Proposed Residential Customer Charges**

4 In this TCAP, Applicants propose to implement a \$10 per month residential non-CARE
5 customer charge for both SoCalGas and SDG&E.¹⁰ CARE customers would receive a 20%
6 discount on the residential fixed charge, as they do on their other gas charges today. In the prior
7 TCAP Phase 2 proceeding (A.15-07-014), the Commission did not adopt Applicants' \$10 fixed
8 non-CARE customer charge proposals.¹¹ Since that decision was rendered, the Commission
9 issued D.17-09-035, *Decision Identifying Fixed Cost Categories to be Included in a Fixed*
10 *Charge*. Issued in Pacific Gas and Electric Company's application to revise its electrical
11 marginal costs, allocation, and rate design (A.16-06-013), the Commission made several key
12 determinations which provide prescriptive guidance on how electric utilities should calculate and
13 present fixed charge proposals. To be clear, this decision does not approve any specific fixed
14 charges for any of the utilities.¹² However, by establishing "a process designed to ensure that
15 any fixed charge that may be adopted in the future: (1) reflects appropriate costs; (2) is
16 calculated using a consistent methodology across utilities; and (3) would be implemented after
17 each utility has shifted to default time-of-use (TOU) rates,"¹³ Applicants believe the Commission
18 has articulated a process by which it would give due consideration to a fixed customer charge.

longer applies and the customer pays the calculated bill. Under minimum bill, a customer pays either the \$3 or the calculated bill whichever is higher.

¹⁰ As with SoCalGas' and SDG&E's current tariffs, this charge would be implemented as per-meter per-day charge of \$0.32877 per-meter, per-day. Hence, the monthly customer charge would vary slightly around \$10 from month to month depending on the number of days in a month. For convenience, I refer to the customer charge proposal as \$10 per month.

¹¹ See D.16-10-004.

¹² See D.17-09-035 at 41.

¹³ Id. at 3-4.

1 Guided by this newly adopted process, Applicants are proposing a fixed customer charge in this
2 TCAP.

3 Decision.17-09-035 identified fixed cost categories to be included in a fixed residential
4 customer charge if electric utilities were to propose implementing residential fixed customer
5 charge in their respective cost allocation and rate design proceedings. Such fixed cost categories
6 eligible to be recovered in residential fixed customer charge for electric utilities are directly
7 comparable to fixed cost categories for gas utilities. I discuss the Commission's findings and
8 rationale articulated in that decision regarding residential fixed customer charges, which have
9 applicability here in determining whether Applicants' non-CARE gas customers can be assessed
10 a \$10 fixed charge. Applicants propose a \$10 fixed non-CARE customer charge, which would
11 be consistent with the \$10 fixed charge cap articulated by the Commission in D.17-09-035 with
12 respect to electric non-CARE customer fixed charge proposals.¹⁴

13 **2. A Review of D.17-09-035 on Issues Pertaining to Residential Fixed**
14 **Customer Charge**

15 In D.17-09-035, the Commission addressed multiple issues pertaining to residential fixed
16 customer charge. They included (a) fixed cost categories that are appropriate for recovery
17 through a fixed charge; (b) review of alternative methods to calculate marginal customer
18 connection cost; (c) proper timing for the potential introduction of new or increased fixed charge;
19 and (d) marketing, education and outreach efforts necessary prior to implement fixed charge. In
20 the sections below, the Applicants will discuss each of these issues and how their proposed
21 residential fixed charges in this TCAP follow the directives identified in the decision.

¹⁴ See Id. at 3.

1 **a. Categories of Fixed Costs Appropriate for Recovery Through a**
2 **Residential Fixed Customer Charge**

3 The Commission identified “categories of fixed costs that could be included in the
4 calculation of a fixed charge, in the event a fixed charge proposal is brought before the
5 Commission for approval in future applications.”¹⁵ More specifically, the decision determined
6 that “a fixed charge should include only revenue cycle services costs (costs for account set-up,
7 metering services, billing and payment) with certain exclusions, all meter capital costs, and
8 minimum service drop and final line transformer (FLT) costs calculated by using the minimum
9 observed cost for residential class.”¹⁶ The decision suggested that the minimum observed costs
10 for FLT and service drop could be the 10th or 20th percentile of respective cost distributions, or
11 the average cost for the bottom 10% or 20%.¹⁷ The decision also allowed for other approaches
12 “as long as they are reasonably consistent with the ‘minimum observed cost’ approach we adopt
13 here.”¹⁸

14 While the decision focused on categories of fixed costs eligible for inclusion in a
15 residential fixed customer charge for electric utilities, it is directly applicable to gas utilities.¹⁹ In
16 this TCAP, Applicants have calculated fixed costs eligible to be recovered in residential fixed
17 customer charge following the Commission’s directive in D.17-09-035: comprising of revenue
18 cycle services costs, and minimum service line, regulator and meter costs.²⁰

¹⁵ D.17-09-035 at 2.

¹⁶ Id. at 2. See also p. 33, Table 2: Cost Category Eligibility for Inclusion in a Fixed Charge.

¹⁷ See Id. at 44.

¹⁸ Id.

¹⁹ Gas utilities, like electric utilities, incur revenue cycle services costs. Measurement of gas usage requires installation of meters. The counterparts of electric service drop and final line transformer are, respectively, gas service line and regulator for gas utilities.

²⁰ To estimate minimum service line cost, SoCalGas multiplied the 20th percentile line length in feet for half-inch plastic pipe (the cheapest service line pipes) by the average cost of half-inch plastic pipe per foot. SoCalGas also used size 1 meter and regulator commonly used for residential customers. SDG&E

1 **b. Alternative Methods to Calculate New Customer Connection**
2 **Cost**

3 In discussing marginal customer costs, the Commission stated,

4 Because the Commission’s goal has been to design and set rate structures
5 based on marginal cost and cost-causation principles, among others, a
6 major focus in R.12-06-013 and in this proceeding has been on marginal
7 customer costs.²¹

8 The Commission recognized that marginal customer cost is the sum of revenue cycle
9 services costs and new connection costs (comprising meter, service drop, and FLT).²²

10 Additionally, the Commission noted that parties mostly agreed with including revenue cycle
11 services costs in a fixed customer charge.²³ However, the Commission did not adopt a single
12 method to calculate new customer connection cost (capital-related customer cost).²⁴ Parties

13 proposed different methods to calculate new customer connection cost,²⁵ including the Rental
14 method and New Customer Only (NCO) method, both of which have been addressed in

15 Applicants’ prior cost allocation proceedings. In addition, the Commission addressed the Energy
16 Division’s two proposed alternative modifications to the Rental method, referred to as the
17 Adjusted Rental methods.²⁶ The Commission directed the electric utilities to show the range of

used the average of the 20% of the lowest-cost projects out of the 1,520 one-inch plastic pipe projects completed during January 2017 through June 2018.

²¹ D.17-09-035 at 18.

²² See Id.

²³ See Id.

²⁴ See Id. at 38.

²⁵ In this testimony, I use the terms new customer connection cost, capital-related marginal customer cost, and marginal customer capital cost interchangeably.

²⁶ D.17-09-035 at 34-39, contains a discussion of these methods. Also, see the Energy Division Staff Proposal on Adjusted Rental Method for Marginal Customer Cost in PG&E GRC Phase 2 (A.16-06-013) Second Fixed Cost Workshop (November 2, 2016).

1 marginal customer-related cost estimates using the Rental, NCO, and Adjusted Rental methods
2 when they propose fixed charges in the future.²⁷

3 Applicants have applied that Commission direction to calculate and present marginal
4 customer-related costs under these methods. Table 3 (for SoCalGas) and Table 4 (for SDG&E)
5 show the estimated costs derived under the four methods.²⁸

6
Table 3: SoCalGas' Residential Minimum Connection Cost Per Month²⁹

	Rental Method	NCO Method	Adjusted Rental Method 1	Adjusted Rental Method 2
	\$22.21	\$15.74	\$10.11	\$20.32

7
Table 4: SDG&E's Residential Minimum Connection Cost Per Month³⁰

	Rental Method	NCO Method	Adjusted Rental Method 1	Adjusted Rental Method 2
	\$16.56	\$21.97	\$5.77	\$14.08

8
9 As shown in Tables 3 and 4, even the minimum estimates of the range of estimated
10 customer-related costs would support \$10 per month customer charges for SoCalGas and \$5.00
11 per month for SDG&E. However, the Rental method is the only method that accurately captures
12 marginal capital-related customer cost for the reasons I describe below. Tables 3 and 4 show
13 that the Rental method would support a fixed residential customer charge as high as
14 approximately \$22 and \$16 per month per customer, respectively, for SoCalGas and SDG&E;

²⁷ D.17-09-035 at 39.

²⁸ The NCO method includes replacement costs of service lines, regulators and meters for 1.5% of existing service lines (both SoCalGas and SDG&E), 1.8% of SoCalGas' meters and regulators, and 2.5% of SDG&E's meters and regulators.

²⁹ Source: witness Schmidt-Pines (Chapter 9).

³⁰ Source: witness Foster (Chapter 10).

1 however, as stated earlier, Applicants are proposing \$10 per month per customer charge for
2 SoCalGas and SDG&E.³¹

3 In D.17-09-035, the Commission defines marginal customer cost as the cost of providing
4 service to an additional customer.³² The Commission also identifies that “[n]ew connections
5 costs are composed of costs associated with the investment required to provide access to a new
6 customer . . .”³³ Algebraically, this can be expressed in basic marginal cost definition as follows:

$$7 \quad \text{Marginal customer capital cost} = \frac{\Delta \text{ in total capital cost}}{\Delta \text{ in one additional customer}}$$

8 Marginal cost is defined for small additional units, in this case gas service to an
9 additional customer. This is precisely how the Rental method calculates marginal customer
10 capital cost. Trying to express the NCO method algebraically shows that it is inconsistent with
11 the basic definition of marginal cost:

$$12 \quad \text{NCO method customer capital cost} = \frac{\Delta \text{ in total capital cost for all new customers}}{\text{all customers (existing and new)}}$$

13 As the above equation shows, the denominator captures all customers, not a change in the
14 number of customers, let alone change in one additional customer. NCO is an average cost
15 method, not a marginal cost method. If the Commission is seeking to determine a true marginal
16 customer cost, it must reject the NCO method, as it does not calculate the cost of providing
17 service to an additional customer.

³¹ The electric utilities have a maximum allowable residential fixed charge of \$10 per month for non-CARE customers that can be adjusted by no more than the annual percentage increase in the Consumer Price Index for the prior calendar year (see D.17-09-035 at 3).

³² See D.17-09-035 at 18, fn 29. See also D.92-12-058 at 11 and 38.

³³ D.17-09-035 at 55 Finding of Fact 9.

1 **c. Adjusted Rental Methods**

2 In A.16-06-013, the Commission’s Energy Division proposed two alternative methods by
3 adjusting marginal capital-related customer cost derived by the Rental method: Adjusted Rental
4 Method 1 (ARM1) and Adjusted Rental Method 2 (ARM2).³⁴

5 As a conceptual matter, underlying the proposed Adjusted Rental methods, and the notion
6 that they would produce legitimate marginal capital cost, renowned Economist Alfred Kahn was
7 quoted as a supporting source. The quote states in part, “. . . marginal cost is the cost of
8 producing one more unit; it can equally be envisaged as the cost that will be saved by producing
9 one less unit.”³⁵ This quote was applied in the context of marginal customer related cost as “. . .
10 marginal cost is the cost of connecting one more customer; it can equally be envisaged as the
11 cost that would be saved by connecting one fewer customer.”³⁶ This application of Dr. Kahn’s
12 quote leads to the belief that neither the Rental nor the NCO method satisfied the basic symmetry
13 property of marginal cost in that “[t]he cost of a new hookup (embodied in both methods) is not
14 the same as the cost saved due to a permanent loss of an existing customer hookup.”³⁷

15 The rationale appears to be that since the cost of a new hookup is not the same as the cost
16 saved due to a permanent loss of an existing customer, and the fact that both Rental and NCO
17 methods rely on new hookup costs only, these methods are not appropriately calculating capital-
18 related marginal customer costs. Accordingly, in such situations one must somehow include

³⁴ The ARM1 and ARM2 methods are being addressed here because I am providing an illustrative analysis guided by the directives articulated by the Commission in D.17-09-035 for electric utilities should they propose a fixed customer charge. I am not suggesting that Energy Division is a party to this TCAP or that ARM1 and ARM2 methods are being proposed in this proceeding.

³⁵ See Energy Division Staff Proposal on Adjusted Rental Method for Marginal Customer Cost in PG&E GRC Phase 2 (A.16-06-013) Second Fixed Cost Workshop, p. 2 (November 2, 2016). See Appendix B.

³⁶ Id.

³⁷ Id. at 6.

1 both the cost of new hookup and the cost saved due to a permanent loss of an existing customer
2 to derive appropriate capital-related customer cost.

3 In fact, Dr. Kahn does not discuss any such symmetry property of marginal cost. To
4 provide the proper context of Dr. Kahn's discussion of marginal cost, I provide from Dr. Kahn's
5 book the expanded quote:

6 . . . marginal cost is the cost of producing one more unit; it can equally be envisaged
7 as the cost that would be saved by producing one less unit. Looked at the first way,
8 it may termed incremental cost—the added cost of (a small amount of) incremental
9 output. Observed the second way, it is synonymous with avoidable cost—the cost
10 that would be saved by (slightly) reducing output. (Although these three terms are
11 often used synonymously, marginal cost, strictly speaking, refers to the additional
12 cost of supplying a single, infinitesimally small additional unit, while “incremental”
13 and “avoidable” are sometimes used to refer to the average additional cost of a finite
14 and possibly a large change in production or sales.) Why does the economist argue
15 that, ideally, every buyer ought to pay a price equal to the cost of supplying one
16 incremental unit?³⁸

17 Clearly, Dr. Kahn does not state or imply that the cost of producing one more unit must
18 equal the cost that would be saved by producing one less unit. The last sentence in the quote is
19 consistent the with definition of capital-related customer cost as the capital cost of one additional
20 hookup. The cost of providing access to an additional customer will be different than the cost
21 saved due to removing access to an existing customer.

³⁸ Kahn, Alfred E., *The Economics of Regulation, Principles and Institutions*, The MIT Press, Cambridge, Massachusetts and London, England, 1988, pp. 65-66.

1 Mathematically, I attempt to show why ARM1 and ARM2 would not produce a true
2 marginal cost result.

3 **i. ARM1**

4 ARM1 is mathematically depicted as follows:

$$5 \quad \text{ARM1 MCAC} = r1 * \text{Rental MCAC} \quad (1)$$

6 Where,³⁹

$$7 \quad r1 = \frac{\text{TSM rate base value}}{\text{TSM replacement cost new value}}$$

8 The ARM1 method adjusts the Rental capital-related marginal customer cost downward
9 by an adjustment factor (r1) which the ratio of system-wide TSM rate base value to all TSM
10 (existing and new) valued at the Rental method capital-related marginal customer cost. Energy
11 Division proposed this adjustment factor to be at the system level; however, at least
12 conceptually, it is more appropriate to develop this adjustment factor using residential TSMs
13 only since our focus here is on residential TSM marginal cost. For the analysis below, I assume
14 that the adjustment factor is based on residential TSMs only, not system-wide TSMs. The Rental
15 MCAC in the equation (1) above can be rewritten as:

$$16 \quad \text{Rental MCAC} = \text{TSM replacement cost new value} * \left(\frac{\text{RECC}}{\text{All residential customers}} \right) \quad (2)$$

17 Plugging in this expression for Rental MCAC into ARM1 in equation (1) above result in:

³⁹ MCAC is the capital-related component of marginal customer access cost,
r1 is a system value and not customer-class specific,
TSM is final line transformer, service drop and meter,
replacement cost new value is the rental calculation (before RECC is applied) summed over all the
Utilities' customers, and RECC is real economic carrying cost.
Note: O&M are added after MCAC is calculated for both ARM1 MCAC and ARM2 MCAC.

$$ARM1 MCAC = \left(\frac{TSM \text{ rate base value}}{TSM \text{ replacement cost new value}} \right) * TSM \text{ replacement cost new value} \\ * \left(\frac{RECC}{All \text{ residential customers}} \right) \quad (3)$$

Cancelling the TSM replacement cost new value in the numerator and the denominator in equation (3) leads to:

$$ARM1 MCAC = TSM \text{ ratebase value} * \frac{RECC}{All \text{ residential customers}} \quad (4)$$

ARM1 is supposed to reflect an adjustment to new connection cost under the Rental method with the adjustment being “correction” to the Rental method for violating the “basic symmetry property” of marginal cost. However, equation (4) shows that ARM1 new connection cost does not depend on new connection cost at all; rather, it depends on the rate base value of residential TSMs attributable to all past customer hookups. ARM1, therefore, is a backward-looking embedded cost method, not a forward-looking marginal cost method. In D.17-09-035, the Commission made it clear that new connection costs are forward-looking.⁴⁰

ii. ARM2

ARM2 is mathematically depicted as follows:

$$ARM2 MCAC = r2 * Rental MCAC \quad (5)$$

where,

$$r2 = \frac{TSM \text{ replacement cost new value less depreciation}}{TSM \text{ replacement cost new value}},$$

The ARM2 method adjusts the Rental capital-related marginal customer cost downward by an adjustment factor (r2) which the ratio of TSM replacement cost new value less

⁴⁰ See D.17-09-035 at 17, Table 1.

1 depreciation to TSM replacement cost new value. Again, this adjustment factor is proposed to
2 be at the system level. As with ARM1, it is more appropriate to develop this adjustment factor
3 using residential TSMs only since our focus here is on residential TSM marginal cost. Using
4 similar steps described for ARM1 above, the ARM2 can be rewritten, assuming the r2
5 adjustment factor should be based on residential TSMs, not system-wide TSMs, as follows:

$$6 \quad \text{ARM2 MCAC} = \text{TSM replacement cost new less depreciation} \\ 7 \quad \quad \quad * \frac{\text{RECC}}{\text{All residential customers}} \quad (6)$$

8 While ARM2 still requires the calculation of Rental capital-related marginal customer
9 cost, lowering this marginal cost by an adjustment representing depreciation costs attributable to
10 all past customer hookups violates the concept that new connection cost should be forward-
11 looking.

12 As discussed above, the proposed adjustment to Rental method-based new connection
13 cost to retain the so-called basic symmetry property of marginal cost is unsupported.
14 Additionally, as demonstrated above, ARM1 simply depends on backward-looking rate base
15 value, and, hence, an embedded cost method. By adjusting Rental method-based new connection
16 cost using backward-looking depreciation, ARM2 does not portray a forward-looking concept of
17 marginal cost. Therefore, if the Commission is seeking a true marginal cost, the Adjusted Rental
18 methods would not produce this result.

1 **d. Proper Timing of Potential New or Increased Residential Fixed**
2 **Customer Charge**

3 D.17-09-035 refers to an earlier Commission decision (D.15-07-001),⁴¹ which established
4 four conditions to be met prior to further consideration of introducing fixed residential customer
5 charge for electric utilities. These four conditions are:⁴²

- 6 (1) for each IOU, A GRC Phase 2 decision issues that approves a calculation of fixed
7 charges. To accomplish this, each IOU, in its next GRC Phase 2, must provide
8 sufficient evidence to identify and calculate fixed customer costs that are specifically
9 intended to represent marginal customer costs that would be the basis of a fixed
10 charge;
- 11 (2) a GRC Phase 2 decision issues approving categories of fixed costs for consideration
12 of a future fixed charge;
- 13 (3) a decision in the IOU's 2018 residential rate design window that approves a new
14 fixed charge request from the utility;
- 15 (4) default TOU rate is implemented.

16 The gas utilities' cost allocation and rate design proceedings are comparable to electric
17 utilities' GRC Phase 2 proceedings in that both allocate authorized base margins that are
18 determined in GRC or similar cost of service proceedings. Applicants believe that they have met
19 the first condition above by estimating fixed customer costs following the directives in D.17-09-
20 035 that specifically intended to represent marginal customer costs that are the basis for the
21 Applicants' proposed fixed customer charge. Applicants believe that the categories of fixed

⁴¹ D.15-07-001, Decision on Residential Rate Reform for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company and Transition to Time-Of-Use Rates.

⁴² See D.17-09-035 at 48-49.

1 costs identified in D.17-09-035 for consideration of a future fixed charge satisfy the second
2 condition above. Applicants hope that the Commission will address the third condition in this
3 TCAP proceeding. The fourth condition is not applicable to the gas utilities. In D.17-09-035,
4 the Commission noted that the Office of Ratepayer Advocates and The Utility Reform Network
5 (i.e., parties in that proceeding) recommended postponing the implementation of fixed charges
6 for electric utilities until 2020.⁴³ The Commission’s consideration of a residential fixed customer
7 charge for natural gas for Applicants beginning in 2020 does not conflict with that recommended
8 timing.

9 **e. Marketing, Education and Outreach Efforts Necessary to**
10 **Implement Residential Fixed Customer Charge**

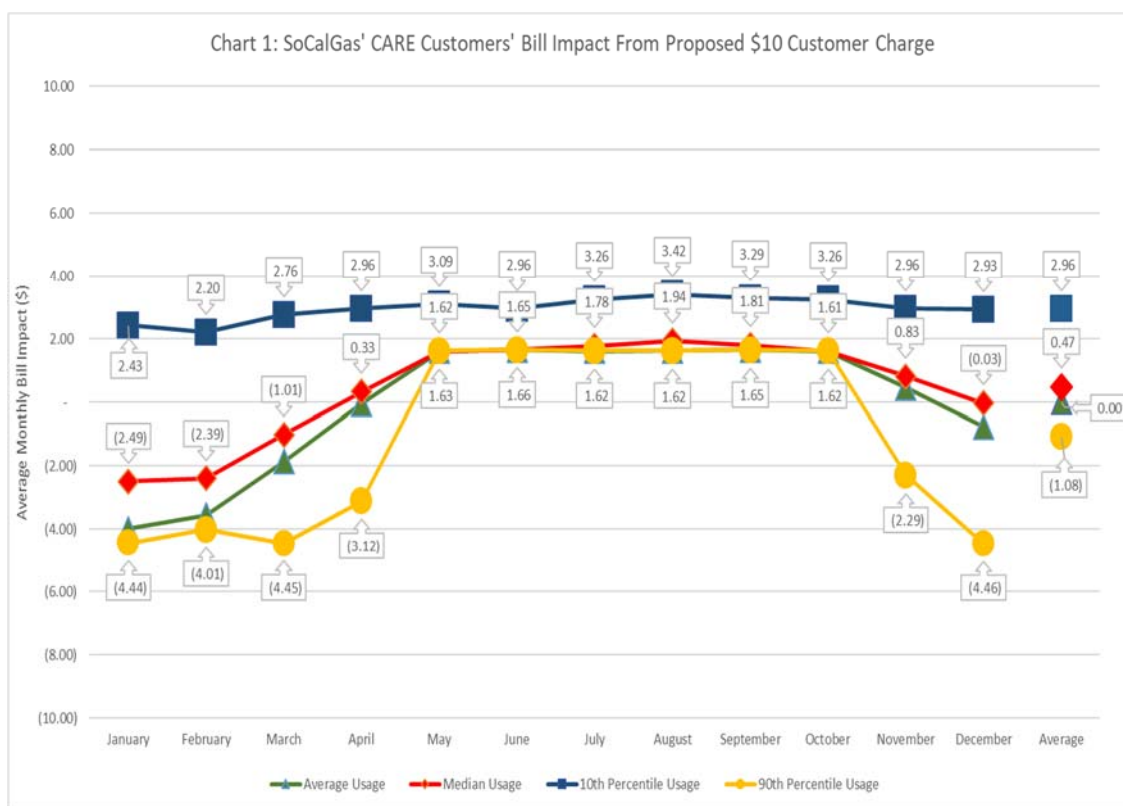
11 D.17-09-035 states, “[t]he Commission expects a showing on the plans for marketing,
12 education, and outreach efforts with respect to the proposed fixed charges and in relation to the
13 TOU rates and in compliance with the directives of D.15-07-01, if and when, a utility files a
14 proposal for a fixed charge.”⁴⁴ The marketing, education and outreach efforts are particularly
15 important for the electric utilities because of significant electric residential rate reforms
16 comprising of tier consolidation, flattening of tier differentials and the introduction TOU rates.
17 On the gas side, there has been no such rate reforms. In addition, SoCalGas already has a
18 residential fixed customer charge. The Applicants are not proposing any marketing, education
19 and outreach efforts pertaining to their proposed fixed customer charges in this TCAP
20 application. However, the Applicants will undertake any such marketing, education and
21 outreach efforts that the Commission deems necessary.

⁴³ See Id. at 48.

⁴⁴ Id. at 52.

3. Bill Impacts of Proposed Residential Customer Charge

To evaluate the bill impacts of their proposed \$10 per month customer charge and compensating lower volumetric rates on low income customers, the Applicants focused on their CARE customers' bills. Based on 2017 gas usage data for CARE customers, the Applicants estimated monthly bill impacts under four alternative gas usage scenarios: average, median, 10th percentile and 90th percentile usage.⁴⁵ The Applicants chose the 10th percentile usage scenario to represent low usage customers and the 90th percentile usage scenario to represent high usage customers. Charts 1 and 2 below show the monthly bill impacts for the four usage scenarios for CARE customers, respectively, for SoCalGas and SDG&E.

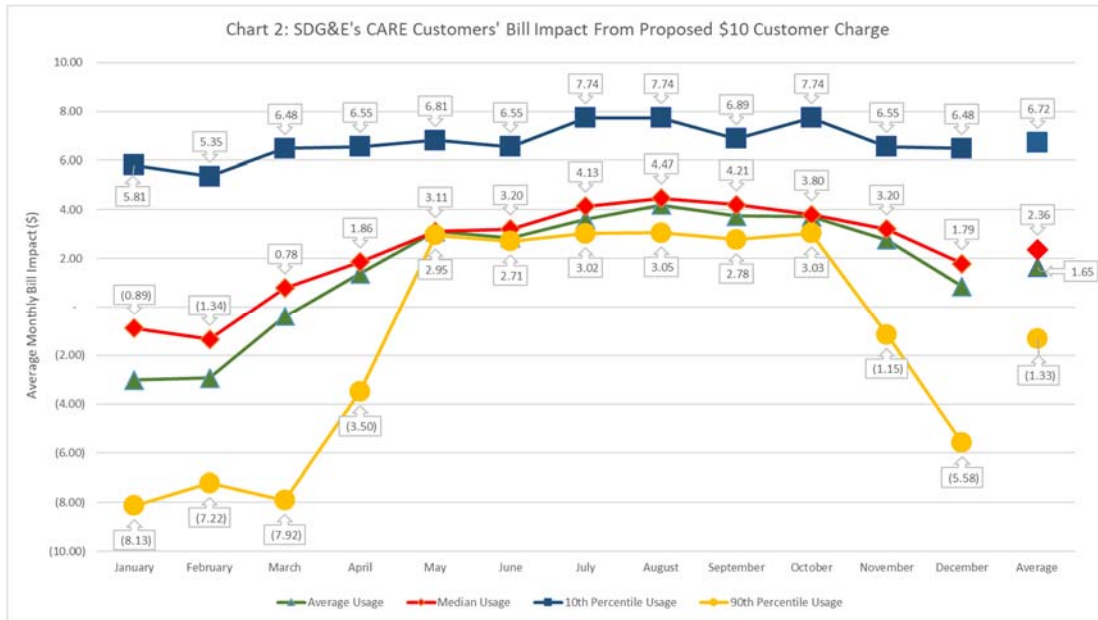


⁴⁵ 10th percentile usage means that 10% of the CARE customers' gas usage is at or below the 10th percentile usage level. 90th percentile usage means that 90% of the CARE customers' gas usage is at or below the 90th percentile usage level (10% of the CARE customers gas usage is above the 90th percentile usage level). As of December 2017, SoCalGas and SDG&E had 1,552,775 and 172,013 CARE customers, respectively.

1 Chart 1, shows bill impact for each month, as well as average monthly bill impact for
2 SoCalGas' CARE customers for the four usage scenarios I described above. The bill impacts
3 capture the difference in bills between SoCalGas' proposed \$10 per month customer charge and
4 status quo \$5 per month customer charge. A positive monthly bill impact value reflects that the
5 monthly bill will increase under the proposed \$10 per month customer charge relative to the
6 status quo \$5 per month customer charge. Similarly, a negative monthly bill impact value
7 reflects that the monthly bill will decrease under the proposed \$10 per month customer charge
8 relative to the status quo \$5 per month customer charge.

9 For low gas usage (10th percentile) CARE customers, Chart 1 shows that the monthly bill
10 is expected to increase every month, with an average monthly bill increase of \$2.96 per month.
11 For a CARE customer with median gas usage, average monthly bill will likely increase by \$0.47
12 per month; however, such a customer's winter bills will be lower when the gas bills are generally
13 higher due to heating load. For a CARE customer with average usage, average monthly bill will
14 likely remain the same; however, such a customer's winter bills will be lower when the gas bills
15 are generally higher due to heating load. For high usage (90th percentile) CARE customers, the
16 average monthly bill is likely to be lower by \$1.08 per month, with higher decreases in winter
17 months.

18



1

2 The bill impacts in Chart 2 capture the difference in bills between SDG&E's proposed

3 \$10 per month customer charge and the status quo \$3 per month minimum bill. For low gas

4 usage (10th percentile) CARE customers, Chart 2 shows that the monthly bill is expected to

5 increase every month, with an average monthly bill increase of \$6.72 per month. For a CARE

6 customer with median gas usage, average monthly bill will likely increase by \$2.36 per month;

7 however, such a customer's winter bills for some winter months will be lower when the gas bills

8 are generally higher due to heating load. For a CARE customer with average usage, average

9 monthly bill will likely increase by \$1.65 per month; however, such a customer's winter bills

10 will be lower for some winter months when the gas bills are generally higher due to heating load.

11 For high usage (90th percentile) CARE customers, the average monthly bill is likely to be lower

12 by \$1.33 per month, with higher decreases in winter months.

13 In the past, some parties have opposed the introduction of customer charge for SDG&E

14 and an increase in customer charge for SoCalGas on the grounds that such customer charges will

15 lead to bill increases for low income customers with low gas usage. While this is true, it is also

1 true that there are low income customers with relatively high gas usage who would benefit from
2 the Applicants' proposed \$10 per month customer charges. As demonstrated above, these CARE
3 customers with relatively high gas usage will benefit from the Applicants' proposed customer
4 charges through lower monthly bills, particularly during winter months when their bills are high.
5 In evaluating the Applicants' proposed customer charges, the Commission should keep this low
6 income higher usage customer segment in mind.

7 In the last TCAP decision, D.16-10-004, the Commission correctly noted that the
8 proposed \$10 customer charge leads to much higher bill impacts for SDG&E's residential
9 customers compared to those for SoCalGas. Comparing the monthly bill impacts in Chart 1 and
10 Chart 2 above, the Applicants also noticed that the bill impacts are higher (both positive and
11 negative) for SDG&E's CARE customers relative to those for SoCalGas' CARE customers.
12 This is because SDG&E never had a customer charge and the \$10 customer charge (a movement
13 from \$0 to \$10) leads to higher bill impacts for SDG&E's residential customers relative to
14 SoCalGas' residential customers (a movement from \$5 to \$10). This is precisely the reason that
15 the Commission should introduce a customer charge now for SDG&E. The longer the
16 Commission waits to introduce a specific customer charge for SDG&E, the more difficult it will
17 get because the bill impacts attributable to the introduction of a customer charge are likely get
18 larger over time. A large bill impact should not dissuade the Commission from introducing a
19 customer charge or increasing a customer charge. In D.17-09-035, the Commission noted that
20 "Joint Utilities suggest that any bill impacts that are deemed excessive could be resolved through
21 a reasonable phase-in process. We find merit in exploring this option in the relevant rate design
22 proceedings."⁴⁶

⁴⁶ D.17-09-035 at 49.

1 **B. Submeter Credit**

2 Submeter credits apply to utility customers with a master meter who provide gas service
3 to residential sub-units (*e.g.*, multi-family dwelling units and mobile home parks). D.04-04-043
4 established a method for calculating submeter credits. In that decision, certain categories of
5 costs were defined as “Utility Avoided Costs,” the costs that utilities avoid for which a master
6 meter customer is reimbursed through the submeter credit provided by the utility.⁴⁷ In this
7 proceeding, the Applicants’ proposed submeter credits are based on an updated study in
8 compliance with the methodology set forth in D.04-04-043, and as was used most recently to
9 update the submeter credits in the 2017 TCAP (Phase 2) approved by D.16-10-004. Currently,
10 SoCalGas’ submeter credit is set at \$0.27386 /meter/day and SoCalGas proposes to set it at
11 \$0.13742/meter/day for this TCAP term.⁴⁸

12 SDG&E’s submeter credits are currently set at \$0.38268/meter/day for multi-family (GS)
13 customers and \$0.40932/meter/day for mobile home (GT) customers. SDG&E proposes to set
14 them at \$0.26499/meter/day and \$0.28570/meter/day, respectively, for this TCAP term.⁴⁹

15 **C. Core C&I Rates**

16 SoCalGas and SDG&E each have a single tariff serving its core commercial and
17 industrial (C&I) customers, Schedule G-10 for SoCalGas and Schedule GN-3 for SDG&E.
18 Presently, SoCalGas’ G-10 rate design consists of a \$15 customer charge and three tiers of

⁴⁷ To the extent these costs do not exceed the average costs that a utility would have incurred in providing direct service sub-unit customers.

⁴⁸ Per the method for calculating submeter credit, SoCalGas’ proposed \$10 per month customer has the effect of lowering submeter credit relative to that in current rates.

⁴⁹ Per the method for calculating submeter credit, SDG&E’s proposed \$10 per month customer has the effect of lowering submeter credit relative to that in current rates.

1 declining block volumetric rates. SDG&E's GN-3 rate design consists of a \$10 customer charge
2 and three tiers of declining block volumetric rates.

3 In D.16-10-004, the Commission-approved settlement retained the then-existing rate
4 structure for the different tiers within SoCalGas' G-10 rate design and SDG&E's GN-3 rate
5 design. Neither SoCalGas nor SDG&E proposes any changes to the current methodology.

6 **D. Natural Gas Vehicle (NGV) Compression Rate Adder**

7 A compression surcharge or compression rate adder is intended to cover the cost of
8 providing compressed natural gas (CNG) to motor vehicles fueling at public access CNG vehicle
9 refueling stations owned and operated by Applicants. The compression rate adder is charged to
10 customers on a volumetric basis. This adder is incremental to the uncompressed commodity
11 charge and transportation charge. The compression rate adder reflects the capital and operating
12 costs of compressing the natural gas and providing public access to CNG fuel for NGV owners.
13 Additional state fuel tax, federal excise tax, and utility user taxes, which can vary by location, are
14 also charged to customers. Currently, there is a Sempra-wide⁵⁰ compression rate adder across
15 both SoCalGas and SDG&E. Therefore, the compression rate adders for SoCalGas and SDG&E
16 are nearly identical, with only a small difference due to differences in the Franchise Fees and
17 Uncollectibles between the utilities.

18 In this TCAP, Applicants have updated the NGV compression rate adders to reflect
19 current costs. These costs are composed of a capital-related revenue requirement related to
20 public-access refueling equipment and a fully-loaded O&M-related revenue requirement. The
21 Sempra-wide NGV compression rate adder is derived by dividing the combined SoCalGas and

⁵⁰ Sempra-wide rate refers to the calculation of a single rate between SoCalGas and SDG&E for a customer class, before applying utility-specific adders, such as Franchise Fees and Uncollectibles.

1 SDG&E compression cost revenue requirements by the combined demand forecast for
2 compressed NGV volumes.⁵¹ The resulting NGV compression rate adders proposed for this
3 TCAP term are \$1.04238 per therm and \$1.04809 per therm for SoCalGas and SDG&E,
4 respectively.

5 **III. NONCORE RATE DESIGN**

6 **A. Noncore Distribution Rates**

7 Applicants' current distribution-level service for noncore C&I and electric generation
8 (EG) customers is provided under Schedule GT-NC for SoCalGas and Schedules GTNC and EG
9 for SDG&E. The current noncore C&I rate design consists of a customer charge of \$350 per
10 month for both the utilities, four tiers of declining block volumetric rates for SoCalGas and a
11 single tier volumetric rate for SDG&E. For EG customers, there are Sempra-wide rates; small
12 EG customers pay a \$50 customer charge and a volumetric rate, and large EG customers pay a
13 lower volumetric rate. Neither SoCalGas nor SDG&E proposes any changes to the current
14 methodology.

15 **B. Transmission Level Service Rates**

16 Applicants' current Sempra-wide rates for transmission-level service customers are
17 provided under Schedule GT-TLS for SoCalGas and Schedule TLS for SDG&E. The current
18 rate design consists of a class-average volumetric rate option and a reservation rate option for
19 customers served off of the transmission system. Neither SoCalGas nor SDG&E proposes any
20 changes to the current methodology.

⁵¹ The compressed NGV volumes are presented by witness Rose-Marie Payan (Chapter 3).

1 **IV. OTHER PROPOSALS**

2 **A. Allocation of Self Generation Incentive Program (SGIP) Funds Based on**
3 **Program Participation**

4 Currently, SGIP Costs are allocated across all customer classes based on equal cents per
5 therm, which means that all customers are allocated the same cost per therm of natural gas usage.
6 On April 26, 2018, the Commission adopted Resolution E-4926, which requires the allocation of
7 SGIP funds to be based on program participation over the previous three years. Per the
8 Resolution, going forward, SGIP costs will be allocated across customer classes based on each
9 class’s past program participation. A re-allocation of SGIP costs based on program participation
10 will align customer class participation with their respective program costs. As stated by the
11 Commission, “SGIP cost allocation should be consistent with the Legislative intent to provide
12 equitable allocation of costs and benefits.”⁵²

13 The resolution recommends that “[t]he allocation methodology should be based on actual
14 incentives paid out and should take into account the impact of program changes as they occur.”⁵³
15 The proposed allocation method conforms to the Commission’s directive by totaling the
16 incentives awarded in the most recent 3 years and allocating funds based on the percentage of
17 incentives disbursed to each class.

18 Pursuant to Resolution E-4926, I used three years of data (in this case, May 30, 2015
19 through May 30, 2018) to calculate the proposed allocation percentages. Tables 5 and 6 below
20 show proposed SGIP cost allocation percentages based on previous three years’ program
21 participation and the current allocation percentages across customer classes for SoCalGas and
22 SDG&E, respectively. As directed in Resolution E-4926, these allocation percentages will be

⁵² Resolution E-4926 at 18, Finding 4.

⁵³ Id. at 19, Finding 4.

1 updated each year based on the most recent three years of actual data. The updated allocations
 2 will be presented for approval in Applicants' Regulatory Account Update advice letter
 3 submissions in October each year.

Table 5: SoCalGas SGIP Cost Allocation

Class	3 Year Total Incentives Paid	Proposed % Allocation	Current % Allocation
Residential	\$38,448	0.1%	25.9%
Core C&I	\$356,733	1.3%	10.9%
Noncore EG	\$28,023,417	98.6%	28.4%
Other Noncore	\$0	0.0%	32.9%
Other Core	\$0	0.0%	1.9%
Total	\$28,418,597	100.0%	100.0%

Table 6: SDG&E SGIP Cost Allocation

Class	3 Year Total Incentives Paid	Proposed % Allocation	Current % Allocation
Residential	\$34,564	0.4%	85.7%
Core C&I	\$936,060	11.9%	11.0%
Noncore EG	\$6,900,054	87.7%	2.0%
Other Noncore	\$0	0.0%	0.9%
Other Core	\$0	0.0%	0.4%
Total	\$7,870,677	100.0%	100.0%

B. New Regulatory Accounts

1. Storage Inventory for Balancing Function Memorandum Account (SIBFMA)

9 As discussed in Chapter 6 (Ahmed), SoCalGas is proposing to establish the Storage
 10 Inventory for Balancing Function Memorandum Account (SIBFMA). As discussed in Chapter 1
 11 (Dandridge), Applicants propose that SoCalGas procure up to eight billion cubic feet (Bcf) of
 12 gas for 8% monthly balancing due to customers' creating negative cumulative imbalances.
 13 Because the costs recorded in the SIBFMA relate to the balancing function, SoCalGas proposes
 14 to allocate the SIBFMA balance across customer classes based on each class's share of average

1 year throughput (i.e., equal cents per therm), the same method currently used for allocating load
2 balancing storage costs.

3 **2. Reliability Function Cost Memorandum Account (RFCMA)**

4 As discussed in Chapter 6 (Ahmed), SoCalGas is proposing to establish the Reliability
5 Function Cost Memorandum Account (RFCMA). The purpose of the RFCMA is to record the
6 revenue requirement on the gas purchase and transportation costs for procuring 21 Bcf of gas
7 needed to provide withdrawal capability for daily operational needs throughout the year, as
8 discussed in Chapter 1 (Dandridge). SoCalGas proposes a two-step approach to allocate the
9 RFCMA balance across customer classes, which would be consistent with how the
10 corresponding 21 Bcf of reliability function inventory capacity is allocated to customer classes.
11 The first step is to split the RFCMA balance based on core storage inventory and load balancing
12 inventory. In the second step, SoCalGas proposes to allocate the Core storage inventory
13 component of the RFCMA using the method discussed in Chapter 5 (Guo), Table 14, and the
14 load balancing inventory component of the RFCMA using average year throughput to all
15 customer classes.

16 This concludes my prepared direct testimony.

1 **V. QUALIFICATIONS**

2 My name is Iftkharul (Sharim) Bar Chaudhury. I am employed by SoCalGas and
3 SDG&E as the Rate Design and Demand Forecasting Manager within the CPUC/FERC Gas
4 Regulatory Affairs Department, which supports gas regulatory activities of both SoCalGas and
5 SDG&E. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011.

6 I hold a Bachelor of Arts degree in Economics from Illinois State University. I received
7 my Masters and Ph.D. degrees in Economics from the University of California, San Diego.

8 I have held my current position managing the rates group since August 2014, and have
9 been managing the demand forecasting group since April 2013. Prior to joining SoCalGas, I
10 worked at Southern California Edison Company from June 1999 to March 2013, holding several
11 positions of increasing responsibility, from Senior Analyst to Manager of Price Forecasting to
12 Manager of Long-Term Demand Forecasting. From October 1998 to May 1999, I worked at the
13 National Economic Research Associates (NERA) as a Senior Consultant. Prior to joining
14 NERA, I worked at SoCalGas from 1991 to 1998, holding several positions of increasing
15 responsibility, starting as Marketing Analyst to Senior Economist in the Rate Design group to
16 Manager of Rate Design. I also worked for about a year at the California Energy Commission in
17 the Demand Analysis Office.

18 I have previously testified before this Commission.

APPENDIX A

TABLE 1
Natural Gas Transportation Rates
Southern California Gas Company
2020 TCAP Application

	Proposed Rates			Proposed Rates			Changes		
	Jul-1-18	Proposed	Jul-1-18	Jan-1-20	Proposed	Jan-1-20	Revenue	Rate	% Rate
	Volumes	Rate	Revenues	Volumes	Rate	Revenues	Change	Change	change
	Mth	\$/therm	\$000's	Mth	\$/therm	\$000's	\$000's	\$/therm	%
	A	B	C	D	E	F	G	H	I
1 CORE									
2 Residential	2,435,160	\$0.74844	\$1,822,559	2,346,353	\$0.74324	\$1,743,897	(\$78,662)	(\$0.00520)	-0.7%
3 Commercial & Industrial	1,023,186	\$0.32464	\$332,163	992,706	\$0.38013	\$377,357	\$45,195	\$0.05549	17.1%
4									
5 NGV - Pre Sempra-Wide	157,095	\$0.12882	\$20,237	178,769	\$0.14814	\$26,484	\$6,247	\$0.01932	15.0%
6 Sempra-Wide Adjustment	157,095	(\$0.00166)	(\$260)	178,769	(\$0.00163)	(\$292)	(\$32)	\$0.00002	-1.4%
7 NGV - Post Sempra-Wide	157,095	\$0.12716	\$19,977	178,769	\$0.14651	\$26,192	\$6,215	\$0.01935	15.2%
8									
9 Gas A/C	772	\$0.15436	\$119	416	\$0.15857	\$66	(\$53)	\$0.00422	2.7%
10 Gas Engine	20,699	\$0.16141	\$3,341	22,302	\$0.16318	\$3,639	\$298	\$0.00177	1.1%
11 Total Core	3,636,911	\$0.59890	\$2,178,159	3,540,545	\$0.60758	\$2,151,151	(\$27,008)	\$0.00867	1.4%
12									
13 NONCORE COMMERCIAL & INDUSTRIAL									
14 Distribution Level Service	865,102	\$0.07674	\$66,392	919,735	\$0.08449	\$77,712	\$11,320	\$0.00775	10.1%
15 Transmission Level Service (2)	660,238	\$0.02441	\$16,114	626,080	\$0.03248	\$20,333	\$4,218	\$0.00807	33.1%
16 Total Noncore C&I	1,525,339	\$0.05409	\$82,506	1,545,814	\$0.06343	\$98,045	\$15,538	\$0.00934	17.3%
17									
18 NONCORE ELECTRIC GENERATION									
19 Distribution Level Service									
20 Pre Sempra-Wide	285,096	\$0.08176	\$23,310	331,442	\$0.09191	\$30,463	\$7,153	\$0.01015	12.4%
21 Sempra-Wide Adjustment	285,096	(\$0.00626)	(\$1,784)	331,442	(\$0.00298)	(\$989)	\$795	\$0.00328	-52.3%
22 Distribution Post Sempra Wide	285,096	\$0.07550	\$21,525	331,442	\$0.08893	\$29,474	\$7,949	\$0.01343	17.8%
23 Transmission Level Service (2)	2,392,699	\$0.02064	\$49,379	2,246,336	\$0.02866	\$64,375	\$14,996	\$0.00802	38.9%
24 Total Electric Generation	2,677,795	\$0.02648	\$70,904	2,577,778	\$0.03641	\$93,849	\$22,945	\$0.00993	37.5%
25									
26 TOTAL RETAIL NONCORE	4,203,134	\$0.03650	\$153,411	4,123,593	\$0.04654	\$191,894	\$38,483	\$0.01004	27.5%
27									
28 WHOLESALE									
29 Wholesale Long Beach (2)	73,520	\$0.02035	\$1,496	79,646	\$0.02837	\$2,260	\$763	\$0.00802	39.4%
30 Wholesale SWG (2)	65,367	\$0.02035	\$1,330	66,431	\$0.02837	\$1,885	\$554	\$0.00802	39.4%
31 Wholesale Vernon (2)	95,137	\$0.02035	\$1,936	96,890	\$0.02837	\$2,749	\$813	\$0.00802	39.4%
32 International (2)	91,378	\$0.02035	\$1,860	116,299	\$0.02837	\$3,300	\$1,440	\$0.00802	39.4%
33 Total Wholesale & International	325,403	\$0.02035	\$6,623	359,267	\$0.02837	\$10,193	\$3,570	\$0.00802	39.4%
34 SDG&E Wholesale	1,251,556	\$0.01483	\$18,558	1,118,614	\$0.02195	\$24,555	\$5,997	\$0.00712	48.0%
35 Total Wholesale Incl SDG&E	1,576,959	\$0.01597	\$25,181	1,477,881	\$0.02351	\$34,748	\$9,567	\$0.00754	47.2%
36									
37 TOTAL NONCORE	5,780,093	\$0.03090	\$178,592	5,601,473	\$0.04046	\$226,642	\$48,050	\$0.00956	31.0%
38									
39 Unbundled Storage (4)			\$23,290			\$0	(\$23,290)		
40 System Total (w/o BTS)	9,417,004	\$0.25274	\$2,380,041	9,142,019	\$0.26009	\$2,377,793	(\$2,248)	\$0.00736	2.9%
41 Backbone Transportation Service BTS (3)	2,690	\$0.26353	\$258,736	2,690	\$0.26245	\$257,673	(\$1,063)	(\$0.00108)	-0.4%
42 SYSTEM TOTAL w/BTS	9,417,004	\$0.28021	\$2,638,777	9,142,019	\$0.28828	\$2,635,467	(\$3,311)	\$0.00807	2.9%
43									
44 EOR Revenues	231,570	\$0.05313	\$12,303	208,941	\$0.07162	\$14,964	\$2,661	\$0.01849	34.8%
45 Total Throughput w/EOR Mth/yr	9,648,574			9,350,960					

1) These rates are for Natural Gas Transportation Service from "Citygate to Meter." The Backbone Transportation Service (BTS) rate is for service from Receipt Point to Citygate.
2) These Transmission Level Service (TLS) amounts represent the average transmission rate, see Table 7 for detailed list of TLS rates.
3) BTS charge (\$/dth/day) is proposed as a separate rate. Core will pay through procurement rate, noncore as a separate charge. Charge is for both core and noncore customers
4) Unbundled Storage costs are not part of the Core Storage or Load Balancing functions (those are included in transport rates).
5) All rates include Franchise Fees & Uncollectible charges.

TABLE 2
Residential Transportation Rates
Southern California Gas Company

	Present Rates			Proposed Rates			Changes			
	Jul-1-18 Volumes Mth A	Average Rate \$/th B	Jul-1-18 Revenue \$000's C	Jan-1-20 Volumes Mth D	Rate \$/th E	Jan-1-20 Revenue \$000's F	Revenue Change \$000's G	Rate Change \$/th H	% Rate change % I	
1	RESIDENTIAL SERVICE									
2	Customer Charge									
3	3,750,414	\$5.00	\$225,025	3,808,652	\$10.00	\$457,038	\$232,013	\$5.00000	100.0%	
4	1,743,024	\$5.00	\$104,581	1,784,011	\$10.00	\$214,081	\$109,500	\$5.00000	100.0%	
5	124,314	\$5.00	\$7,459	121,819	\$10.00	\$14,618	\$7,159	\$5.00000	100.0%	
6	148,373	(\$0.27386)	(\$14,831)	141,547	(\$0.13742)	(\$7,100)	\$7,731	\$0.13644	-49.8%	
7	Volumetric Transportation Rate Exclude CSITMA and CAT:									
8	1,839,570	\$0.53602	\$986,048	1,707,243	\$0.30496	\$520,636	(\$465,412)	(\$0.23106)	-43.1%	
9	584,298	\$0.86474	\$505,266	630,017	\$0.84936	\$535,112	\$29,846	(\$0.01538)	-1.8%	
10	2,423,869	\$0.74820	\$1,813,547	2,337,260	\$0.74206	\$1,734,386	(\$79,162)	(\$0.00614)	-0.8%	
11	NBL/BL Ratio:									
12	Composite Rate \$/th		\$1.02367			\$0.97933			(\$0.04434)	-4.3%
13	Gas Rate \$/th		\$0.31248			\$0.27687			(\$0.03561)	-11.4%
14	NBL/Composite rate ratio (4) =		1.15			1.15				
15	NBL- BL rate difference \$/th		0.32872			0.54441			\$0.21569	65.6%
16										
17	Large Master Meter Rate (Excludes Rate Adders for CAT):									
18	57	\$411.17	\$280	49	\$411.17	\$244	(\$36)	\$0.00	0.0%	
19	9,428	\$0.24993	\$2,356	7,787	\$0.12454	\$970	(\$1,387)	(\$0.12540)	-50.2%	
20	1,863	\$0.40321	\$751	1,306	\$0.34686	\$453	(\$298)	(\$0.05635)	-14.0%	
21	11,291	\$0.30004	\$3,388	9,093	\$0.18327	\$1,666	(\$1,721)	(\$0.11677)	-38.9%	
22										
23	Residential Rates Include CSITMA, CARB and GHG Excludes CAT:									
24	1,800,739	\$0.00308	\$5,550	1,745,667	\$0.00311	\$5,421	(\$129)	\$0.00002	0.8%	
25	CSITMA Adder to Volumetric Rate									
26	CARB Adder to Volumetric Rate									
27	GHG End User Adder to Volumetric Rate									
28	Residential:									
29	Customer Charge		\$5.00			\$10.00			\$5.00000	100.0%
30	Baseline \$/therm		\$0.53910			\$0.30908			(\$0.23003)	-42.7%
31	Non-Baseline \$/therm		\$0.86782			\$0.85348			(\$0.01434)	-1.7%
32	Average NonCARE Rate \$/therm		\$0.75129			\$0.74618			(\$0.00511)	-0.7%
33	Large Master Meter:									
34	Customer Charge		\$411.17			\$411.17			\$0.00	0.0%
35	BaseLine Rate		\$0.25302			\$0.12866			(\$0.12436)	-49.2%
36	Non-Baseline Rate		\$0.40629			\$0.35098			(\$0.05531)	-13.6%
37	Average NonCARE Rate \$/therm		\$0.30312			\$0.18739			(\$0.11573)	-38.2%
38	Residential Rates Include CSITMA & CAT:									
39	49,671	\$0.00150	\$74	27,389	\$0.00167	\$46	(\$29)	\$0.00017	11%	
40	CAT Adder to Volumetric Rate									
41	Residential:									
42	Customer Charge		\$5.00			\$5.00			\$0.00000	0.0%
43	BaseLine Rate		\$0.54060			\$0.31075			(\$0.22986)	-42.5%
44	Non-Baseline Rate		\$0.86932			\$0.85515			(\$0.01417)	-1.6%
45	Large Master Meter:									
46	Customer Charge		\$411.17			\$411.17			\$0.00000	0.0%
47	BaseLine Rate		\$0.25452			\$0.13033			(\$0.12419)	-48.8%
48	Non-Baseline Rate		\$0.40779			\$0.35265			(\$0.05514)	-13.5%
49	Other Adjustments:									
50	TCA for CSITMA exempt customers		(\$0.00308)			(\$0.00311)			(\$0.00002)	0.8%
51	California Climate Credit - April Bill		\$0.00			(\$26.19)				
52	TOTAL RESIDENTIAL	2,435,160	\$0.74844	\$1,822,559	2,346,353	\$0.74324	\$1,743,897	(\$78,662)	(\$0.00520)	-0.7%

See footnotes, Table 1.

TABLE 3
Core Nonresidential Transportation Rates
Southern California Gas Company

	Present Rates			Proposed Rates			Changes			
	Jul-1-18 Volumes Mth A	Average Rate \$/th B	Jul-1-18 Revenue \$000's C	Jan-1-20 Volumes Mth D	Rate \$/th E	Jan-1-20 Revenue \$000's F	Revenue Change \$000's G	Rate Change \$/th H	% Rate change I	
1										
2	CORE COMMERCIAL & INDUSTRIAL									
3	Customer Charge 1	146,202	\$15.00	\$26,316	141,378	\$15.00	\$25,448	(\$868)	\$0.00	0.0%
4	Customer Charge 2	61,115	\$15.00	\$11,001	62,136	\$15.00	\$11,185	\$184	\$0.00	0.0%
5	Volumetric Transportation Rate Exclude CSITMA & CAT:									
6	Tier 1 = 250th/mo	203,321	\$0.54303	\$110,409	202,399	\$0.65195	\$131,955	\$21,545	\$0.10893	20.1%
7	Tier 2 = next 4167 th/mo	453,170	\$0.29523	\$133,789	449,431	\$0.34795	\$156,377	\$22,588	\$0.05272	17.9%
8	Tier 3 = over 4167 th/mo	366,694	\$0.12908	\$47,333	340,876	\$0.14411	\$49,123	\$1,790	\$0.01503	11.6%
9		1,023,186	\$0.32140	\$328,849	992,706	\$0.37684	\$374,088	\$45,239	\$0.05544	17.2%
10										
11	Volumetric Transportation Rate Include CSITMA & GHG, Exclude CAT:									
12	CSITMA Adder to Volumetric Rate	1,008,238	\$0.00308	\$3,107	978,185	\$0.00311	\$3,038	(\$70)	\$0.00002	0.8%
13	GHG Adder to Volumetric Rate	1,023,186	\$0.00000	\$0	992,706	\$0.00000	\$0			
14	Tier 1 = 250th/mo		\$0.54611			\$0.65506			\$0.10895	19.9%
15	Tier 2 = next 4167 th/mo		\$0.29831			\$0.35105			\$0.05274	17.7%
16	Tier 3 = over 4167 th/mo		\$0.13216			\$0.14721			\$0.01505	11.4%
17			\$0.32448			\$0.37994			\$0.05546	
18	Volumetric Transportation Rate Include CSITMA & CAT:									
19	CAT Adder to Volumetric Rate	137,753	\$0.00150	\$206	139,308	\$0.00167	\$232	\$26	\$0.00017	11%
20	Tier 1 = 250th/mo		\$0.54761			\$0.65673			\$0.10912	19.9%
21	Tier 2 = next 4167 th/mo		\$0.29981			\$0.35272			\$0.05291	17.6%
22	Tier 3 = over 4167 th/mo		\$0.13366			\$0.14888			\$0.01522	11.4%
23			\$0.32598			\$0.38161			\$0.05563	17.1%
24	Other Adjustments:									
25	TCA for CSITMA exempt customers		(\$0.00308)			(\$0.00311)			(\$0.00002)	0.8%
26	GHG Fee Credit \$/th		\$0.00000			\$0.00000				
27	TOTAL CORE C&I	1,023,186	\$0.32464	\$332,163	992,706	\$0.38013	\$377,357	\$45,195	\$0.05549	17.1%
28										
29	NATURAL GAS VEHICLES (a sempra-wide rate)									
30	Customer Charge, P-1	229	\$13.00	\$36	263	\$13.00	\$41	\$5	\$0.00000	0.0%
31	Customer Charge, P-2A	130	\$65.00	\$101	115	\$65.00	\$90	(\$11)	\$0.00000	0.0%
32	Uncompressed Rate Exclude CSITMA, GHG & CAT	157,095	\$0.10943	\$17,192	178,769	\$0.12514	\$22,372	\$5,180	\$0.01571	14.4%
33	Total Uncompressed NGV	157,095	\$0.11031	\$17,329	178,769	\$0.12587	\$22,502	\$5,174	\$0.01557	14.1%
34	Compressed Rate Adder	2,099	\$1.03136	\$2,164	2,833	\$1.04238	\$2,953	\$789	\$0.01102	1.1%
35										
36	Uncompressed Rate Include CSITMA, CARB and GHG Exclude CAT									
37	CSITMA Adder to Volumetric Rate	157,073	\$0.00308	\$484	178,769	\$0.00311	\$555	\$71	\$0.00002	0.8%
38	CARB Adder to Volumetric Rate				178,769	\$0.00101	\$181			
39	GHG End User Adder to Volumetric Rate				178,769	\$0.00000	\$0			
40	Uncompressed Rate \$/therm		\$0.11252			\$0.12926			\$0.01675	14.9%
41	Other Adjustments:									
42	TCA for CSITMA exempt customers		(\$0.00308)			(\$0.00311)			(\$0.00002)	0.8%
43	Low Carbon Fuel Standard (LCFS) Credit		\$0.00000			\$0.00000			\$0.00000	
44	TOTAL NGV SERVICE	157,095	\$0.12716	\$23,609	178,769	\$0.14651	\$26,192	\$2,582	\$0.01935	15.2%
45										
46	RESIDENTIAL NATURAL GAS VEHICLES (optional rate)									
47	Customer Charge	5,618	\$10.00	\$674	216	\$10.00	\$26	(\$648)	\$0.00000	0.0%
48	Uncompressed Rate Exclude CSITMA & CAT	5,501	\$0.20696	\$1,138	166	\$0.28630	\$48	(\$1,091)	\$0.07934	38.3%
49		5,501	\$0.32951	\$1,813	166	\$0.44205	\$73	(\$1,739)	\$0.11254	34.2%
50	Uncompressed Rate Include CSITMA, Exclude CAT									
51	CSITMA Adder to Volumetric Rate		\$0.00308		5,501	\$0.00311	\$17		\$0.00002	0.8%
52	CARB Adder to Volumetric Rate				5,501	\$0.00101	\$6			
53	GHG End User Adder to Volumetric Rate				5,501	\$0.00000	\$0			
54	Uncompressed Rate \$/therm		\$0.21004			\$0.29042			\$0.08038	38.3%
55										
56	Uncompressed Rate Include CSITMA & CAT									
57	CAT Adder to Volumetric Rate	0	\$0.00150	\$0	0	\$0.00167	\$0	\$0	\$0.00017	11.3%
58	Uncompressed Rate		\$0.21154			\$0.29209		\$0	\$0.08055	38.1%
59	Other Adjustments:									
60	TCA for CSITMA exempt customers		(\$0.00308)			(\$0.00311)			(\$0.00002)	0.8%
61										
62	TOTAL RESIDENTIAL NATURAL GAS VEHICLE	5,501	\$0.32951	\$1,813	166	\$0.57841	\$96	(\$1,716)	\$0.24891	75.5%

TABLE 5
Noncore Commercial & Industrial Rates
Southern California Gas Company

	Present Rates			Proposed Rates			Changes		
	Jul-1-18 Volumes Mth	Average Rate \$/th	Jul-1-18 Revenue \$000's	Jan-1-20 Volumes Mth	Rate \$/th	Jan-1-20 Revenue \$000's	Revenue Change \$000's	Rate Change \$/th	% Rate change %
	A	B	C	D	E	F	G	H	I
1 NonCore Commercial & Industrial Distribution Level									
2 Customer Charge	584	\$350.00	\$2,452	563	\$350.00	\$2,367	(\$85)	\$0.00000	0.0%
3									
4 Volumetric Rates Include CARB Fee, Exclude GHG, and CSITMA									
5 Tier 1 = 250kth/yr	121,573	\$0.15737	\$19,132	124,403	\$0.18285	\$22,747	\$3,615	\$0.02548	16.2%
6 Tier 2 = 250k to 1000k	205,061	\$0.09908	\$20,317	217,228	\$0.11328	\$24,607	\$4,290	\$0.01420	14.3%
7 Tier 3 = 1 to 2 million th/yr	109,960	\$0.06179	\$6,794	118,763	\$0.06877	\$8,168	\$1,374	\$0.00699	11.3%
8 Tier 4 = over 2 million th/yr	428,508	\$0.03514	\$15,057	459,341	\$0.03697	\$16,982	\$1,925	\$0.00183	5.2%
9 Volumetric totals (excl itcs)	865,102	\$0.07086	\$61,300	919,735	\$0.07883	\$72,503	\$11,203	\$0.00797	11.2%
10									
11 Volumetric Rates Include CARB, GHG, CSITMA									
12 CSITMA Adder to Volumetric Rate		\$0.00308	\$2,640		\$0.00311	\$2,843	\$203	\$0.00002	0.8%
13 GHG Adder to Volumetric Rate		\$0.00000	\$0		\$0.00000	\$0	\$0	\$0.00000	
14 Tier 1 = 250kth/yr		\$0.16045			\$0.18595			\$0.02550	15.9%
15 Tier 2 = 250k to 1000k		\$0.10216			\$0.11638			\$0.01422	13.9%
16 Tier 3 = 1 to 2 million th/yr		\$0.06487			\$0.07188			\$0.00701	10.8%
17 Tier 4 = over 2 million th/yr		\$0.03822			\$0.04008			\$0.00185	4.9%
18 Other Adjustments:									
19 TCA for CSITMA exempt customers		(\$0.00308)			(\$0.00311)			(\$0.00002)	0.8%
20 CARB Fee Credit \$/th		(\$0.00100)			(\$0.00101)			(\$0.00001)	1.2%
21 GHG Fee Credit \$/th		\$0.00000			\$0.00000			\$0.00000	
22 NCCI - DISTRIBUTION LEVEL	865,102	\$0.07674	\$66,392	919,735	\$0.08449	\$77,712	\$11,320	\$0.00775	10.1%
23									
24 NCCI-TRANSMISSION LEVEL Incl CARB & GHG Fee Excl CSITMA (1)	6,438	\$0.02136	\$137	2,957	\$0.02939	\$87	(\$51)	\$0.00803	37.6%
25 NCCI-TRANSMISSION LEVEL Incl CARB & GHG Fee and CSITMA (1)	653,799	\$0.02444	\$15,977	623,122	\$0.03249	\$20,246	\$4,269	\$0.00805	33.0%
26 NCCI-TRANSMISSION LEVEL (2)	660,238	\$0.02441	\$16,114	626,080	\$0.03248	\$20,333	\$4,218	\$0.00807	33.1%
27									
28 TOTAL NONCORE C&I	1,525,339	\$0.05409	\$82,506	1,545,814	\$0.06343	\$98,045	\$15,538	\$0.00934	17.3%

TABLE 6
Noncore Electric Generation Rates and Enhanced Oil Recovery Rates
Southern California Gas Company

	Present Rates			Proposed Rates			Changes			
	Jul-1-18 Volumes Mth A	Average Rate \$/th B	Jul-1-18 Revenue \$000's C	Jan-1-20 Volumes Mth D	Rate \$/th E	Jan-1-20 Revenue \$000's F	Revenue Change \$000's G	Rate Change \$/th H	% Rate change % I	
1										
2	<u>ELECTRIC GENERATION</u>									
3										
4										
5	<u>Small EG Distribution Level Service (a Sempra-Wide rate) Exclude CARB & GHG Fee & CSITMA:</u>									
6	Customer Charge	201	\$50.00	\$121	308	\$50.00	\$185	\$64	\$0.00000	0.0%
7	Volumetric Rate	77,207	\$0.12566	\$9,702	88,449	\$0.12810	\$11,330	\$1,628	\$0.00244	1.9%
8	Small EG Distribution Level Service	77,207	\$0.12722	\$9,822	88,449	\$0.13019	\$11,515	\$1,693	\$0.00297	2.3%
9										
10	<u>Large EG Distribution Level Service (a Sempra-Wide rate) Exclude CARB & GHG Fee & CSITMA</u>									
11	Customer Charge	28	\$0.00	\$0	30	\$0.00	\$0	\$0	\$0.00000	
12	Volumetric Rate	207,889	\$0.05493	\$11,419	242,993	\$0.07253	\$17,624	\$6,205	\$0.01760	32.0%
13	Large EG Distribution Level Service	207,889	\$0.05493	\$11,419	242,993	\$0.07253	\$17,624	\$6,205	\$0.01760	32.0%
14										
15	<u>EG Distribution excl CARB Fee & CSITMA</u>	285,096	\$0.07451	\$21,242	331,442	\$0.08792	\$29,139	\$7,897	\$0.01341	18.0%
16										
17	<u>Volumetric Rates Include CARB & GHG Fee, Exclude CSITMA</u>									
18	CARB Fee Cost Adder	283,261	\$0.00100	\$284	330,876	\$0.00101	\$335	\$52	\$0.00001	1.2%
19	GHG Cost Adder	90,289	\$0.00000	\$0	104,031	\$0.00000	\$0	\$0	\$0.00000	
20	EG-Distribution Tier 1 w/CARB Fee		\$0.12666			\$0.12911			\$0.00245	1.9%
21	EG-Distribution Tier 2 w/CARB Fee		\$0.05593			\$0.07354			\$0.01761	31.5%
22	Total - EG Distribution Level	285,096	\$0.07550	\$21,525	331,442	\$0.08893	\$29,474	\$7,949	\$0.01343	17.8%
23	CARB Fee Credit \$/th		(\$0.00100)			(\$0.00101)			(\$0.00001)	1.2%
24	GHG Fee Credit \$/th		\$0.00000			\$0.00000			\$0.00000	
25										
26	EG Transmission Level Service Excl CARB & GHG Fee & CSITMA (1)	1,714,769	\$0.02035	\$34,902	2,246,336	\$0.02837	\$63,732	\$28,831	\$0.00802	39.4%
27	EG Transmission Level CARB Fee				634,285	\$0.00101	\$643			
28	EG Transmission Level Service - GHG End User Fee				30,343	\$0.00000	\$0			
29	<u>EG Transmission Level Service Incl CARB & GHG Fee, Exclude CSITMA (1)</u>	677,930	\$0.02136	\$14,477						
30	EG Transmission Level (2)	2,392,699	\$0.02064	\$49,379	2,246,336	\$0.02866	\$64,375	\$14,996	\$0.00802	38.9%
31										
32	<u>TOTAL ELECTRIC GENERATION</u>	2,677,795	\$0.02648	\$70,904	2,577,778	\$0.03641	\$93,849	\$22,945	\$0.00993	37.5%
33										
34	<u>EOR Rates & revenue Exclude CARB Fee & CSITMA:</u>									
35	Distribution Level EOR:									
36	Customer Charge	17	\$500.00	\$102	23	\$500.00	\$138	\$36	\$0.00000	0.0%
37	Volumetric Rate Excl CARB & GHG Fee & CSITMA	137,620	\$0.07476	\$10,289	151,758	\$0.08701	\$13,204	\$2,915	\$0.01225	16.4%
38										
39	<u>Volumetric Rates Include CARB & GHG Fee, Exclude CSITMA</u>									
40	CARB Fee		\$0.00100			\$0.00101				
41	GHG Fee		\$0.00000			\$0.00000				
42	<u>Volumetric Rate Incl CARB Fee & Excl CSITMA</u>		\$0.07576			\$0.08802			\$0.01226	16.2%
43	Distribution Level EOR	137,620	\$0.07550	\$10,391	151,758	\$0.08792	\$13,342	\$2,951	\$0.01241	16.4%
44	CARB Fee Credit \$/th		(\$0.00100)			(\$0.00101)			(\$0.00001)	1.2%
45	GHG Fee Credit \$/th		\$0.00000			\$0.00000			\$0.00000	
46	Transmission Level EOR Exclude CARB & GHG Fee & CSITMA	93,950	\$0.02035	\$1,912	57,184	\$0.02837	\$1,622	(\$290)	\$0.00802	39.4%
47	<u>Total EOR</u>	231,570	\$0.05313	\$12,303	208,941	\$0.07162	\$14,964	\$2,661	\$0.01849	34.8%

1) CSITMA - Noncore C&I D Tariff rate Include CSITMA. Customers exempt, including Constitutionally Exempt, receive Transportation Charge Adjustment (TCA).

EG Tariff Rate Exclude CSITMA, since EG customers are exempt.

2) CARB & GHG Fees - EG-D and NCCI-D rates include CARB & GHG Fees.

3) EOR customers tariff Include CARB & GHG Fees and Excludes CSITMA; since EOR customers are exempt from CSITMA and get a credit for CARB & GHG Fees.

See footnotes, Table 1.

TABLE 7
Transmission Level Service Transportation Rates
Southern California Gas Company

	Present Rates			Proposed Rates			Changes			
	Jul-1-18 Volumes Mth A	Average Rate \$/th B	Jul-1-18 Revenue \$000's C	Jan-1-20 Volumes Mth D	Rate \$/th E	Jan-1-20 Revenue \$000's F	Revenue Change \$000's G	Rate Change \$/th H	% Rate change % I	
1	Rate Excluding CSITMA & CARB Fee:									
2	Reservation Service Option (RS):									
3		\$0.00671			\$0.00963		\$0.00292	43.6%		
4		\$0.00994			\$0.01406		\$0.00412	41.4%		
5	Class Average Volumetric Rate (CA)									
6		\$0.01040			\$0.01430		\$0.00390	37.5%		
7		\$0.00994			\$0.01406		\$0.00412	41.4%		
8	Class Average Volumetric Rate (CA) \$/th									
9		\$0.02034			\$0.02836		\$0.00802	39.4%		
10		\$0.02339			\$0.03261		\$0.00922	39.4%		
11		\$0.02746			\$0.03828		\$0.01082	39.4%		
12	Total Transmission Level Service (NCCI, EOR, EG)	3,052,937	\$0.02035	\$62,138	2,872,415	\$0.02837	\$81,495	\$19,357	\$0.00802	39.4%
13										
14	C&I Rate Including CSITMA & CARB & GHG Fee:									
15		653,799	\$0.00308	\$2,015	623,122	\$0.00311	\$1,935	(\$80)	\$0.00002	
16		1,338,168	\$0.00100	\$1,340	1,260,365	\$0.00101	\$1,277		\$0.00001	
17		123,450	\$0.00000	\$0	109,151	\$0.00000	\$0		\$0.00000	
18	Reservation Service Option (RS):									
19		\$0.00671			\$0.00963		\$0	\$0.00292	43.6%	
20		\$0.01403			\$0.01818		\$0	\$0.00415	29.6%	
21	Class Average Volumetric Rate (CA)									
22		\$0.01040			\$0.01430		\$0	\$0.00390	37.5%	
23		\$0.01403			\$0.01818		\$0	\$0.00415	29.6%	
24	Class Average Volumetric Rate (CA) \$/th									
25		\$0.02442			\$0.03248		\$0	\$0.00805	33.0%	
26		\$0.02747			\$0.03673		\$0	\$0.00926	33.7%	
27		\$0.03154			\$0.04240		\$0	\$0.01086	34.4%	
28	Other Adjustments:									
29		(\$0.00308)			(\$0.00311)			(\$0.00002)		
30		(\$0.00100)			(\$0.00101)			(\$0.00001)		
31		\$0.00000			\$0.00000			\$0.00000		
32	Total Transmission Level Service Include CSITMA & CARB Fee	3,052,937	\$0.02145	\$65,493	2,872,415	\$0.02949	\$84,708	\$19,215	\$0.00804	37.5%
33										
34	EG & EOR Rate Including CARB Fee & GHG, excluding CSITMA:									
35		\$0.00100			\$0.00101			\$0.00001		
36		\$0.00000			\$0.00000			\$0.00000		
37	Reservation Service Option (RS):									
38		\$0.00671			\$0.00963		\$0	\$0.00292	43.6%	
39		\$0.01095			\$0.01508		\$0	\$0.00413	37.7%	
40	Class Average Volumetric Rate (CA)									
41		\$0.01040			\$0.01430		\$0	\$0.00390	37.5%	
42		\$0.01095			\$0.01508		\$0	\$0.00413	37.7%	
43	Class Average Volumetric Rate (CA) \$/th									
44		\$0.02134			\$0.02937		\$0	\$0.00803	37.6%	
45		\$0.02439			\$0.03363		\$0	\$0.00923	37.9%	
46		\$0.02846			\$0.03930		\$0	\$0.01084	38.1%	
47										
48	Other Adjustments:									
49		(\$0.00100)			(\$0.00101)			(\$0.00001)	1.2%	
50		\$0.00000			\$0.00000			\$0.00000		
51										
52	Rate Excluding CSITMA, CARB, GHG Fee, & Uncollectibles (applicable to Wholesale & International):									
53	Reservation Service Option (RS):									
54		\$0.00669			\$0.00960		\$0.00292	43.6%		
55		\$0.00991			\$0.01402		\$0.00411	41.4%		
56	Class Average Volumetric Rate (CA)									
57		\$0.01036			\$0.01425		\$0.00389	37.5%		
58		\$0.00991			\$0.01402		\$0.00411	41.4%		
59	Class Average Volumetric Rate (CA) \$/th									
60		\$0.02028			\$0.02827		\$0.00799	39.4%		
61		\$0.02332			\$0.03251		\$0.00919	39.4%		
62		\$0.02738			\$0.03817		\$0.01079	39.4%		
63	Total Transmission Level Service (WS & Int'l)	325,403	\$0.02035	\$6,623	359,267	\$0.02837	\$10,193	\$3,570	\$0.00802	39.4%
64										
65	Average Transmission Level Service	3,378,340	\$0.02135	\$72,116	3,231,682	\$0.02937	\$94,901	\$22,784	\$0.00802	37.6%

TABLE 8
Backbone Transmission Service and Storage Rates
Southern California Gas Company

	Present Rates			Proposed Rates			Changes			
	Jul-1-18 Volumes Mth	Average Rate \$/th	Jul-1-18 Revenue \$000's	Jan-1-20 Volumes Mth, Mth	Rate \$/th	Jan-1-20 Revenue \$000's	Revenue Change \$000's	Rate Change \$/th	% Rate change %	
	A	B	C	D	E	F	G	H	I	
1	Backbone Transmission Service BTS									
2	BTS SFV Reservation Charge \$/dth/day	2,690	\$0.26353	\$258,736	2,690	\$0.26245	\$257,673	(\$1,063)	(\$0.00108)	-0.4%
3	BTS MFV Reservation Charge \$/dth/day		\$0.21083			\$0.20996				
4	BTS MFV Volumetric Charge \$/dth		\$0.05271			\$0.05249				
5	BTS Interruptible Volumetric Charge \$/dth		\$0.26353			\$0.26245		(\$0.00108)	-0.4%	
6										
7										
8	Storage Costs: (incl. HRSMA)									
9	Core \$000		\$59,943			\$93,797	\$33,854			
10	Load Balancing \$000		\$27,353			\$70,614	\$43,261			
11	Unbundled Storage \$000		\$23,290			\$0	(\$23,290)			
12			\$110,586			\$164,411	\$53,825			

See footnotes, Table 1.

1) CSITMA - NCCI and EG TLS Tariff rates include CSITMA. Customers exempt (Constitutional Exempt and EG) receive Transportation Charge Adjustment (TCA).

2) CARB Fee - TLS NCCI, EOR and EG Tariff rates include CSITMA. TLS NCCI, EOR and EG customers exempt as they pay CARB Fees directly receive credit.

3) Wholesale Customers excludes CSITMA and CARB Fee since these customers are exempt.

TABLE 1
Natural Gas Transportation Rate Revenues
San Diego Gas & Electric Company
2020 TCAP Application

	At Present Rates			At Proposed Rates			Changes		
	Jul-1-18	Average	Jul-1-18	Jan-1-20	Average	Jan-1-20	Revenues	Rates	Rate
	Volumes	Rate	Revenues	Volumes	Rate	Revenues	Revenues	Rates	change
	mtherms	\$/therm	\$000's	mtherms	\$/therm	\$000's	\$000's	\$/therm	%
	A	B	C	D	E	F	G	H	I
CORE									
Residential	319,982	\$0.91560	\$292,977	313,234	\$0.92590	\$290,025	(\$2,952)	\$0.01030	1.1%
Commercial & Industrial	182,660	\$0.27781	\$50,744	194,777	\$0.32346	\$63,002	\$12,258	\$0.04565	16.4%
NGV - Pre Sempra-Wide	18,501	\$0.14069	\$2,603	24,129	\$0.14570	\$3,515	\$913	\$0.00501	3.6%
Sempra-Wide Adjustment	18,501	\$0.01414	\$262	24,129	\$0.01216	\$294	\$32	(\$0.00197)	-13.9%
NGV Post Sempra-Wide	18,501	\$0.15482	\$2,864	24,129	\$0.15786	\$3,809	\$945	\$0.00304	2.0%
Total CORE	521,144	\$0.66505	\$346,586	532,140	\$0.67057	\$356,836	\$10,250	\$0.00552	0.8%
NONCORE COMMERCIAL & INDUSTRIAL									
Distribution Level Service	27,807	\$0.11678	\$3,247	29,376	\$0.09876	\$2,901	(\$346)	(\$0.01802)	-15.4%
Transmission Level Service (2)	17,168	\$0.02443	\$419	17,569	\$0.03239	\$569	\$150	\$0.00796	32.6%
Total Noncore C&I	44,975	\$0.08152	\$3,667	46,945	\$0.07392	\$3,470	(\$196)	(\$0.00760)	-9.3%
NONCORE ELECTRIC GENERATION									
Distribution Level Service									
Pre Sempra-Wide	95,807	\$0.05180	\$4,963	68,867	\$0.07993	\$5,505	\$542	\$0.02813	54.3%
Sempra-Wide Adjustment	95,807	\$0.01873	\$1,794	68,867	\$0.01444	\$994	(\$800)	(\$0.00429)	-22.9%
Distribution Level post SW	95,807	\$0.07053	\$6,757	68,867	\$0.09437	\$6,499	(\$258)	\$0.02384	33.8%
Transmission Level Service (2)	574,075	\$0.02048	\$11,756	461,363	\$0.02844	\$13,123	\$1,367	\$0.00797	38.9%
Total Electric Generation	669,882	\$0.02764	\$18,513	530,230	\$0.03701	\$19,621	\$1,109	\$0.00937	33.9%
TOTAL NONCORE	714,857	\$0.03103	\$22,179	577,175	\$0.04001	\$23,092	\$912	\$0.00898	28.9%
SYSTEM TOTAL	1,236,000	\$0.29835	\$368,765	1,109,315	\$0.34249	\$379,928	\$11,163	\$0.04413	14.8%

- 1) These rates are for Natural Gas Transportation Service from "Citygate to Meter." The Backbone Transportation Service (BTS) rate is for service from Receipt Point to Citygate. The BTS rate is a SoCalGas tariff and service is purchased from SoCalGas.
- 2) The average Transmission Level Service (TLS) rate is shown here, see Rate Table 6 for detailed list of TLS rates.
- 3) All rates include Franchise Fees & Uncollectible charges.

TABLE 2
Core Gas Transportation Rates
San Diego Gas & Electric Company

	At Present Rates			At Proposed Rates			Changes		
	Jul-1-18 Volumes mtherms A	Average Rate \$/therm B	Jul-1-18 Revenues \$000's C	Jan-1-20 Volumes mtherms D	Average Rate \$/therm E	Jan-1-20 Revenues \$000's F	Revenues \$000's G	Rates \$/therm H	Rate change % I
1 Residential RATES Schedule GR,GM									
2 Rates Exclude CSITMA & CAT									
3 Minimum Bill/Customer Charge	884,624	\$3.00	\$221	874,067	\$10.00	\$104,888	\$104,667		
4									
5 Baseline \$/therm	215,947	\$0.86668	\$187,156	255,260	\$0.48617	\$124,101	(\$63,055)	(\$0.38050)	-43.9%
6 Non-Baseline \$/therm	104,035	\$1.04355	\$108,566	57,974	\$1.07317	\$62,217	(\$46,349)	\$0.02962	2.8%
7 Average Rate \$/therm	319,982	\$0.92487	\$295,943	313,234	\$0.92967	\$291,206	(\$4,738)	\$0.00480	0.5%
8 NBL/BL Ratio									
9 Composite Rate \$/th		\$ 1.18018			\$1.17395			-\$0.00623	
10 Gas Rate \$/th		\$ 0.31248			\$0.27687			-\$0.03561	-11.4%
11 NBL/Composite rate ratio		1.15			1.15				
12 NBL- BL rate difference \$/th		0.17687			\$0.58700			\$0.41013	
13									
14 Rates Include CSITMA, CARB and GHG Adders, Excludes CAT									
15 CSITMA Adder to Volumetric Rate	258,048	\$0.00331	\$855	258,322	\$0.00318	\$822	(\$33)	(\$0.00013)	-3.9%
16 CARB Adder to Volumetric Rate				313,234	\$0.00083	\$261			
17 GHG End User Adder to Volumetric Rate				319,982	\$0.00000	\$0			
18 Baseline \$/therm		\$0.86999			\$0.49019			(\$0.37980)	-43.7%
19 Non-Baseline \$/therm		\$1.04686			\$1.07719			\$0.03033	2.9%
20 Average NonCARE Rate \$/therm		\$0.92819			\$0.93369			\$0.00550	0.6%
21									
22 Sub Meter Credit Schedule GS,GT									
23 GS Unit Discount \$/day	5,870	(\$0.38268)	(\$820)	5,879	(\$0.26499)	(\$569)	\$251	\$0.11770	-30.8%
24 GT Unit Discount \$/day	27,189	(\$0.40932)	(\$4,062)	26,104	(\$0.28570)	(\$2,722)	\$1,340	\$0.12362	-30.2%
25									
26 Schedule GL-1									
27 LNG Facility Charge, domestic use \$/month	321	\$14.79	\$57	293	\$14.79	\$52		\$0.00000	0.0%
28 LNG Facility Charge, non-domestic \$/mth/mbtu		\$0.05480			\$0.05480			\$0.00000	0.0%
29 LNG Volumetric Surcharge \$/th	74	\$0.16571	\$12	76	\$0.16571	\$13		\$0.00000	0.0%
30			\$69			\$65			
31 Volumetric Rates Include All Adders & CAT									
32 CAT Adder to Volumetric Rate	2,764	\$0.00000	\$0	2,253	\$0.00000	\$0	\$0	\$0.00000	
33 Baseline \$/therm		\$0.86999			\$0.49019			(\$0.37980)	-43.7%
34 Non-Baseline \$/therm		\$1.04686			\$1.07719			\$0.03033	2.9%
35 Average Rate \$/therm		\$0.92819			\$0.93369			\$0.00550	0.6%
36									
37 Other Adjustments:									
38 Employee Discount			(\$349)			(\$367)	(\$18)		
39 SDDFD			\$1,340			\$1,330	(\$11)		
40									
41 Credit for CSITMA Exempt Customers:		(\$0.00331)			(\$0.00318)			\$0.00013	-3.9%
42									
43 California Climate Credit - April Bill		\$0.00			\$0.00				
44 Total Residential	319,982	\$0.91560	\$292,977	313,234	\$0.92590	\$290,025	(\$2,952)	\$0.01030	1.1%

See footnotes, Table 1.

TABLE 3
Natural Gas Transportation Rate Revenues
San Diego Gas & Electric

	At Present Rates			At Proposed Rates			Changes		
	Jul-1-18 Volumes mtherms A	Average Rate \$/therm B	Jul-1-18 Revenues \$000's C	Jan-1-20 Volumes mtherms D	Average Rate \$/therm E	Jan-1-20 Revenues \$000's F	Revenues \$000's G	Rates \$/therm H	Rate change % I
CORE COMMERCIAL & INDUSTRIAL RATES Schedule GN-3									
Customer Charge \$/month	30,265	\$10.00	\$3,632	30,937	\$10.00	\$3,712	\$81	\$0.00000	0.0%
Rates Exclude CSITMA & CAT									
Tier 1 = 0 to 1,000 therms/month	82,658	\$0.32811	\$27,121	87,627	\$0.39272	\$34,413	\$7,292	\$0.06461	19.7%
Tier 2 = 1,001 to 21,000 therms/month	84,219	\$0.19690	\$16,583	88,939	\$0.23099	\$20,544	\$3,961	\$0.03409	17.3%
Tier 3 = over 21,000 therms/month	15,783	\$0.15984	\$2,523	18,211	\$0.18530	\$3,375	\$852	\$0.02546	15.9%
Rates Includes CSITMA, Excludes CAT									
CSITMA Adder to Volumetric Rate	182,649	\$0.00331	\$605	187,959	\$0.00318	\$598	(\$7)	(\$0.00013)	-3.9%
Tier 1 = 0 to 1,000 therms/month		\$0.33142			\$0.39590			\$0.06448	19.5%
Tier 2 = 1,001 to 21,000 therms/month		\$0.20022			\$0.23417			\$0.03396	17.0%
Tier 3 = over 21,000 therms/month		\$0.16315			\$0.18849			\$0.02533	15.5%
Rates Include CSITMA & CAT									
CAT Adder to Volumetric Rate	35,463	\$0.00000	\$0	39,978	\$0.00000	\$0	\$0	\$0.00000	
Tier 1 = 0 to 1,000 therms/month		\$0.33142			\$0.39590			\$0.06448	19.5%
Tier 2 = 1,001 to 21,000 therms/month		\$0.20022			\$0.23417			\$0.03396	17.0%
Tier 3 = over 21,000 therms/month		\$0.16315			\$0.18849			\$0.02533	15.5%
Other Adjustments:									
Adjustment for SDDFD			\$281			\$360	\$79		
Credit for CSITMA Exempt Customers:		(\$0.00331)			(\$0.00318)			\$0.00013	-3.9%
Total Core C&I	182,660	\$0.27781	\$50,744	194,777	\$0.32346	\$63,002	\$12,258	\$0.04565	16.4%

1) CSITMA - Tariff rate Include CSITMA, exempt customers (including CARE participants and Constitutionally Exempt) receive Credit for CSITMA. CARE participants receive 20% CARE discount (Tariff rate less Credit for CSITMA Exempt Customers)*20%.
See footnotes, Table 1.

TABLE 4
Other Core Gas Transportation Rates
San Diego Gas & Electric Company

	At Present Rates			At Proposed Rates			Changes		
	Jul-1-18 Volumes mtherms A	Average Rate \$/therm B	Jul-1-18 Revenues \$000's C	Jan-1-20 Volumes mtherms D	Average Rate \$/therm E	Jan-1-20 Revenues \$000's F	Revenues \$000's G	Rates \$/therm H	Rate change % I
1 NATURAL GAS VEHICLE RATES G-NGV & GT-NGV	Sempra-Wide NGV Rates			Sempra-Wide NGV Rates					
2 Customer Charge									
3 P1 \$/month	28	\$13.00	\$4	15	\$13.00	\$2	(\$2)	\$0.00	0.0%
4 P2A \$/month	10	\$65.00	\$8	13	\$65.00	\$10	\$2	\$0.00	0.0%
5									
6 Uncompressed Rate Exclude CSITMA & CAT \$/therm	18,501	\$0.11003	\$2,036	24,129	\$0.12583	\$3,036	\$1,000	\$0.01579	14.4%
7 Compressor Adder \$/therm exclude CSITMA & CAT	744	\$1.03701	\$772	628	\$1.04809	\$659	(\$113)	\$0.01108	1.1%
8 Combined transport & compressor adder \$/th		\$1.14704			\$1.17392			\$0.02688	2.3%
9									
10 Volumetric Rates Include CSITMA, CARB and GHG excludes CAT									
11 CSITMA Adder to Volumetric Rate	11,409	\$0.00331	\$38	23,583	\$0.00318	\$75	\$37	(\$0.00013)	-3.9%
12 CARB Adder to Volumetric Rate				24,129	\$0.00083	\$20			
13 GHG End User Adder to Volumetric Rate				24,129	\$0.00000	\$0			
14 Uncompressed Rate \$/therm		\$0.11335			\$0.12984			\$0.01650	14.6%
15 Combined transport & compressor adder \$/th		\$1.15036			\$1.17794			\$0.02758	2.4%
16									
17 Volumetric Rates Include CSITMA & CAT									
18 CAT Adder to Volumetric Rate		\$0.00000			\$0.00000				
19 Uncompressed Rate \$/therm		\$0.11335			\$0.12984		\$0	\$0.01650	14.6%
20 Combined transport & compressor adder \$/th		\$1.15036			\$1.17794			\$0.02758	2.4%
21 Other Adjustments:									
22 Adjustment for SDDFD			\$7			\$7	\$0		
23 Credit for CSITMA Exempt Customers \$/th		(\$0.00331)			(\$0.00318)			\$0.00013	-3.9%
24 Low Carbon Fuel Standard (LCFS) Credit		\$0.00000			\$0.00000				
25 Total NGV	18,501	\$0.15482	\$2,864	24,129	\$0.15786	\$3,809	\$945	\$0.00304	2.0%
26									
27 RESIDENTIAL NATURAL GAS VEHICLES (optional rate)									
28 Customer Charge	885	\$5.00	\$53	15	\$5.00	\$1	(\$52)	\$0.00	0.0%
29 Uncompressed Rate w/o CSITMA & CAT \$/therm	969	\$0.25853	\$251	9	\$1.72275	\$16	(\$235)	\$1.46423	566.4%
30	969	\$0.31329	\$304	9	\$1.81923	\$17	(\$287)	\$1.50594	480.7%
31									
32 Volumetric Rates Including CSITMA , Excluding CAT									
33 CSITMA Adder to Volumetric Rate		\$0.00331		9	\$0.00318	\$0		(\$0.00013)	-3.9%
34 CARB Adder to Volumetric Rate				9	\$0.00083	\$0			
35 GHG End User Adder to Volumetric Rate				9	\$0.00000	\$0			
36 Uncompressed Rate \$/therm		\$0.26184			\$1.72677			\$1.46493	559.5%
37									
38 Volumetric Rates Include CSITMA & CAT									
39 CAT Adder to Volumetric Rate	0	\$0.00000	\$0	0	\$0.00000	\$0	\$0	\$0.00000	
40 Uncompressed Rate \$/therm		\$0.26184			\$1.72677			(\$1.50594)	\$5
41									
42 Other Adjustments:									
43 Adjustment for SDDFD			\$0			\$0	\$0		
44 Credit for CSITMA Exempt Customers \$/th		(\$0.00331)			(\$0.00318)			\$0.00013	-3.9%
45									
46 Total Residential NGV	969	\$0.31329	\$304	9	\$1.82324	\$17	(\$287)	\$1.50996	482.0%

1) CSITMA - Tariff rate Include CSITMA, exempt customers (including CARE participants and Constitutionally Exempt) receive Credit for CSITMA.

TABLE 5
NonCore Gas Transportation Rates
San Diego Gas & Electric Company

	At Present Rates			At Proposed Rates			Changes		
	Jul-1-18	Average	Jul-1-18	Jan-1-20	Average	Jan-1-20	Revenues	Rates	Rate
	Volumes	Rate	Revenues	Volumes	Rate	Revenues	\$000's	\$/therm	change
	mtherms	\$/therm	\$000's	mtherms	\$/therm	\$000's			%
	A	B	C	D	E	F	G	H	I
NonCore Commercial & Industrial Distribution Level									
Customer Charges \$/month	42	\$350.00	\$177	44	\$350.00	\$185	\$8	\$0.00	0.0%
Volumetric Charges Exclude CARB, GHG, CSITMA	27,807	\$0.10741	\$2,987	29,376	\$0.08951	\$2,629	(\$357)	(\$0.01790)	-16.7%
CSITMA Adder to Volumetric Rate	25,154	\$0.00331	\$83	27,293	\$0.00318	\$87	\$4	(\$0.00013)	-3.9%
GHG Adder to Volumetric Rate		\$0.00000	\$0		\$0.00000	\$0	\$0	\$0.00000	
Volumetric Charges Include CARB, GHG, and CSITMA									
Volumetric Rates \$/therm		\$0.11072			\$0.09269			(\$0.01803)	-16.3%
Other Adjustments:									
SDDFD									
Credit for CSITMA Exempt Customers \$/th		(\$0.00331)			(\$0.00318)			\$0.00013	-3.9%
Credit for CARB Fee Exempt Customers \$/th		(\$0.00076)			(\$0.00083)			(\$0.00007)	9.8%
Credit for GHG Fee Exempt Customers \$/th		\$0.00000			\$0.00000			\$0.00000	
NCCI-Distribution Total	27,807	\$0.11678	\$3,247	29,376	\$0.09876	\$2,901	(\$346)	(\$0.01802)	-15.4%
NCCI-Transmission Total (1)	17,168	\$0.02443	\$419	17,569	\$0.03239	\$569	\$150	\$0.00796	32.6%
NCCI-Transmission Class Average	17,168	\$0.02443	\$419	17,569	\$0.03239	\$569			
Total NonCore C&I	44,975	\$0.08152	\$3,667	46,945	\$0.07392	\$3,470	(\$196)	(\$0.00760)	-9.3%
ELECTRIC GENERATION									
Small EG Distribution Level Service (a Sempra-Wide rate) exclude CARB, GHG, and CSITMA									
Customer Charge, \$/month	46	\$50.00	\$28	69	\$50.00	\$41	\$14	\$0.00	0.0%
Volumetric Rate \$/therm	19,210	\$0.12635	\$2,427	24,662	\$0.12880	\$3,176	\$749	\$0.00	1.9%
Large EG Distribution Level Service (a Sempra-Wide rate) exclude CARB, GHG, and CSITMA									
Customer Charge, \$/month		\$0.00			\$0.00			\$0.00	
Volumetric Rate (Incl ITCS) \$/th	76,596	\$0.05523	\$4,230	44,206	\$0.07293	\$3,224	(\$1,007)	\$0.02	32.0%
EG Distribution exclude CARB & GHG Fee, CSITMA	95,807	\$0.06978	\$6,685	68,867	\$0.09353	\$6,441	(\$244)	\$0.02	34.0%
Volumetric Rates Includes CARB Fee, GHG Fee Excludes CSITMA:									
CARB Fee Cost Adder - Small	17,675	\$0.00076	\$13	24,560	\$0.00083	\$20	\$7	\$0.00007	
CARB Fee Cost Adder - Large	76,596	\$0.00076	\$58	44,206	\$0.00083	\$37	\$0	\$0.00000	
GHG Fee Cost Adder - Small	18,266	\$0.00000	\$0	23,450	\$0.00000	\$0	\$0	\$0.00000	
GHG Fee Cost Adder - Large	8,082	\$0.00000	\$0	4,665	\$0.00000	\$0	\$0	\$0.00000	
EG-Distribution Tier 1 Incl CARB & GHG Fee, Excl CSITMA		\$0.12711			\$0.12963			\$0.00252	2.0%
EG-Distribution Tier 2 Incl CARB & GHG Fee, Excl CSITMA		\$0.05599			\$0.07376			\$0.01777	31.7%
Total - EG Distribution Level	95,807	\$0.07053	\$6,757	68,867	\$0.09437	\$6,499	(\$258)	\$0.02384	33.8%
Credit for CARB Fee Exempt Customers \$/th		(\$0.00076)			(\$0.00083)				
Credit for GHG Fee Exempt Customers \$/th		\$0.00000			\$0.00000				
EG Transmission Level Service Excl CARB & GHG fee & CSITMA	479,795	\$0.02035	\$9,765	461,363	\$0.02837	\$13,090	\$3,324	\$0.00802	39.4%
EG Transmission Level Service - CARB				39,584	\$0.00083	\$33			
EG Transmission Level Service - GHG				4,857	\$0.00000	\$0			
EG Transmission Level Service Incl CARB & GHG Fee & CSITMA	94,280	\$0.02007	\$1,893						
EG Transmission Level Service - Average (1)	574,075	\$0.02048	\$11,756	461,363	\$0.02844	\$13,123	\$1,367	\$0.00797	38.9%
TOTAL ELECTRIC GENERATION	669,882	\$0.02764	\$18,513	530,230	\$0.03701	\$19,621	\$1,109	\$0.00937	33.9%

1) CSITMA - Tariff rate Include CSITMA, exempt customers (including CARE participants and Constitutionally Exempt) receive Credit for CSITMA. Schedule EG Tariff Rate exclude CSITMA, since EG customers are exempt.
2) CARB - GTNC and EG Tariff rates Include CARB. Those EG and GTNC customers that are exempt will receive CARB credit.
3) GHG - GTNC and EG Tariff rates Include GHG. Those EG and GTNC customers that are exempt will receive GHG credit.

See footnotes, Table 1.

TABLE 6
Transmission Level Service Gas Transportation Rates
San Diego Gas & Electric Company

	At Present Rates			At Proposed Rates			Changes		
	Jul-1-18 Volumes mtherms A	Average Rate \$/therm B	Jul-1-18 Revenues \$000's C	Jan-1-20 Volumes mtherms D	Average Rate \$/therm E	Jan-1-20 Revenues \$000's F	Revenues \$000's G	Rates \$/therm H	Rate change % I
1 Transmission Level Service Rate Excluding CSITMA, CARB, and GHG Fees									
2 Reservation Service Option (RS):									
3 Daily Reservation rate \$/th/day		\$0.00674			\$0.00968			\$0.00294	43.6%
4 Usage Charge for RS \$/th		\$0.01000			\$0.01414			\$0.00414	41.4%
5									
6 Class Average Volumetric Rate (CA)									
7 Volumetric Rate \$/th		\$0.01045			\$0.01437			\$0.00392	37.5%
8 Usage Charge for CA \$/th		\$0.01000			\$0.01414			\$0.00414	41.4%
9 Class Average Volumetric Rate CA \$/th		\$0.02045			\$0.02851			\$0.00806	39.4%
10									
11 115% CA (for NonBypass Volumetric NV) \$/th		\$0.02352			\$0.03279			\$0.00927	39.4%
12 135% CA (for Bypass Volumetric BV) \$/th		\$0.02761			\$0.03849			\$0.01088	39.4%
13									
14 Average Transmission Level Service	591,243	\$0.02035	\$12,034	478,932	\$0.02837	\$13,588	\$1,554	\$0.00802	39.4%
15									
16 C&I Rate Include CSITMA, CARB, and GHG Fees									
17 CSITMA Adder to Usage Rate \$/th	17,168	\$0.00331	\$57	17,569	\$0.00318	\$56	(\$1)	(\$0.00013)	-3.9%
18 CARB Cost Adder	111,448	\$0.00076	\$85	57,153	\$0.00083	\$48		\$0.00007	9.8%
19 GHG Cost Adder	2,824	\$0.00000	\$0	5,718	\$0.00000	\$0		\$0.00000	
20									
21 Reservation Service Option (RS):									
22 Daily Reservation rate \$/th/day		\$0.00674			\$0.00968			\$0.00294	43.6%
23 Usage Charge for RS \$/th		\$0.01407			\$0.01816			\$0.00408	29.0%
24									
25 Class Average Volumetric Rate (CA)									
26 Volumetric Rate \$/th		\$0.01045			\$0.01437			\$0.00392	37.5%
27 Usage Charge for CA \$/th		\$0.01407			\$0.01816			\$0.00408	29.0%
28 Class Average Volumetric Rate CA \$/th		\$0.02452			\$0.03253			\$0.00801	32.6%
29									
30 115% CA (for NonBypass Volumetric NV) \$/th		\$0.02759			\$0.03681			\$0.00922	33.4%
31 135% CA (for Bypass Volumetric BV) \$/th		\$0.03168			\$0.04251			\$0.01083	34.2%
32									
33 Other Adjustments:									
34 Credit for CSITMA Exempt Customers \$/th		(\$0.00331)			(\$0.00318)			\$0.00013	-3.9%
35 CARB Fee Credit for Exempt Customers \$/th		(\$0.00076)			(\$0.00083)			(\$0.00007)	9.8%
36 GHG Fee Credit for Exempt Customers \$/th		\$0.00000			\$0.00000			\$0.00000	
37									
38 EG Rate Include CARB & GHG Fees, excludes CSITMA:									
39 CARB Fee Cost Adder		\$0.00076			\$0.00083			\$0.00007	
40 GHG Fee Cost Adder		\$0.00000			\$0.00000			\$0.00000	
41 Reservation Service Option (RS):									
42 Daily Reservation rate \$/th/day		\$0.00674			\$0.00968			\$0.00294	43.6%
43 Usage Charge for RS \$/th		\$0.01076			\$0.01497			\$0.00421	39.2%
44									
45 Class Average Volumetric Rate (CA)									
46 Volumetric Rate \$/th		\$0.01045			\$0.01437			\$0.00392	37.5%
47 Usage Charge for CA \$/th		\$0.01076			\$0.01497			\$0.00421	39.2%
48 Class Average Volumetric Rate CA \$/th		\$0.02121			\$0.02935			\$0.00814	38.4%
49									
50 115% CA (for NonBypass Volumetric NV) \$/th		\$0.02428			\$0.03362			\$0.00935	38.5%
51 135% CA (for Bypass Volumetric BV) \$/th		\$0.02837			\$0.03933			\$0.01096	38.6%
52									
53 Other Adjustments:									
54 CARB Fee Credit for Exempt Customers \$/th		(\$0.00076)			(\$0.00083)			(\$0.00007)	9.8%
55 GHG Fee Credit for Exempt Customers \$/th		\$0.00000			\$0.00000			\$0.00000	
56									
57 Average Transmission Level Service	591,243	\$0.02059	\$12,175	478,932	\$0.02859	\$13,692	\$1,516	\$0.00800	38.8%

See footnotes, Table 1.

APPENDIX B



Adjusted Rental Method for Marginal Customer Cost

An Energy Division Staff Proposal

For Presentation at the PG&E GRC Phase 2 (A.16-06-013)
Second Fixed Cost Workshop - November 2, 2016

Robert Levin – Energy Division





What is a Marginal Cost?

...”marginal cost is the cost of producing one more unit; it can equally be envisaged as the cost that would be saved by producing one less unit.” -- Alfred Kahn*

→ Marginal costs are symmetric

In the context of Marginal Customer Access Cost (MCAC):

...”marginal cost is the cost of connecting one more customer; it can equally be envisaged as the cost that would be saved by connecting one fewer customer.”

*The Economics of Regulation, Volume 1, pp.65-66





Marginal Cost and Opportunity Cost

When economists refer to the “opportunity cost” of a resource, they mean the value of the next-highest-valued alternative use of that resource.—Concise encyclopedia of Economics

“If consumers are to make the choices that will yield them the greatest possible satisfaction from society’s limited aggregate productive capacity, the prices they must pay for the various goods and services available to them must accurately reflect their respective ***opportunity costs***;” ...Alfred Kahn

*The Economics of Regulation, Volume 1, p. 66, emphasis added





Two Methods for Capital-Related Marginal Customer Access Cost

Rental (RECC) Method

Assigns the real level annualized cost of a **new** final line transformer, service drop, and meter (TSM) to **all** customers.

New Customer Only (NCO) Method

Assigns the full cost* of a new TSM set to **new customers only**; and spreads those costs over all customers in a customer class.

*Net present value of TSM revenue requirement over its service life.





Why Does the Choice of MC Methodology Matter?

- Both Columns B and C of PG&E's Table F-1 Are Affected

**TABLE F-1
PG&E RESIDENTIAL FIXED COSTS
AND FIXED CHARGES**

(A)	(B)	(C)	(D)	(E)	(F)=(C)+(D)+(E)	(G)=(B)-(F)	(H)=(C)+(G)
Residential	Revenue Requirement (\$ million)	Marginal Costs			Total Marginal Cost (\$ million)	Additional Fixed Costs (\$ million)	Total Fixed Costs (\$ million)
		Customer-Related (\$ million)	Capacity-Related (\$ million)	Energy-Related (\$ million)			
Distribution	\$2,432	\$742	\$497	\$0	\$1,239	\$1,193	\$1,935
Generation	\$2,661	\$0	\$205	\$993	\$1,198	\$1,464	\$1,464
PPP	\$355	\$0	\$0	\$0	\$0	\$355	\$355
Total	\$5,448	\$742	\$702	\$993	\$2,436	\$3,011	\$3,753
Customer-months	57,003,455	57,003,455	57,003,455	57,003,455	57,003,455	57,003,455	57,003,455
\$/cust-mo	\$95.57	\$13.01	\$12.31	\$17.42	\$42.74	\$52.83	\$65.84





Rental vs NCO

Neither method satisfies the basic symmetry property of a marginal cost:

- The cost of a **new** hookup (embodied in both methods) is not the same as the cost saved due to a permanent loss of an existing customer hookup.
 - Meters and transformers have salvage value- less than Replacement Cost New (RCN)
 - In case of annexation or condemnation, TSM facilities are valued less than RCN
 - If a site becomes uninhabitable, the utility's write-down would be at book value, less than RCN





Rental vs NCO (2)

Rental (RECC) Method

“...we believe that the rental method does not produce a competitive price for customer hookups and, in fact, significantly overstates the price that would prevail a competitive market.”

- “In effect, the rental method assumes that everyone has to pay rent at 10.21 percent (the RECC rate) of the replacement cost of new equipment. “

D.96-04-050*, p.67

*This decision devoted 7 pages [pp.62-69] to a thorough discussion of Rental vs. NCO; This issue has not been examined in depth in more recent CPUC decisions.

New Customer Only (NCO) Method

- Depends on customer growth assumptions that are highly unstable from year to year, and that it produces anomalous results when customer growth rates are very high, very low, or negative.
- Further, NCO assigns no MC value (or opportunity value) to existing TSM equipment.





Neither Method Values Existing Hookup Equipment Correctly

Rental (RECC) Method

Values used, depreciated TSM equipment at its Replacement Cost New (RCN) value--- well above its opportunity value or the book value that is embedded in the rates.

New Customer Only (NCO) Method

Values used, depreciated TSM equipment at **zero***, in spite of the positive opportunity value associated with such equipment.

*NCO treats existing hookups as sunk costs.





So What is the Opportunity Cost of Hookups?

It is the value of the next best alternative use:

- In the event of a permanent departure of a customer, the Utility could:
 - Salvage and reuse (or sell) the meter and transformer, at a value less than replacement cost new (RCN)
 - In case of annexation or condemnation, obtain compensation (typically sought at replacement cost new less depreciation (RCNLD))
 - If a site becomes uninhabitable, the utility's write-down would be at book value, less than RCN





Adjusted Rental Method 1 (ARM1)

ARM1 MCAC = r_1 * rental MCAC, where

$r_1 = (\text{TSM rate base value}) / (\text{TSM replacement cost new value})$

(r_1 is a system value and not customer-class-specific, but does vary by asset class)

Notes: The rental calculation (before the RECC is applied), when summed over all the IOU's customers, represents the replacement cost new ("RCN") value of all the utility's hookup equipment (TSM sets).

- However, most of the TSM equipment service customers is used, of various vintages, and is substantially depreciated. The revenue requirement associated with TSM is based on the associated rate base, which is far less than the RCN value. Thus, normally $r_1 < 1$ (and could be close to 0.5, except for meters, which are relatively new).
- The ARM1 MCAC represents the current value of a TSM set, and approximates the rate that the customer would pay for TSM if the utility only provided connectivity (TSM) service.
- This formula applies only to the capital (TSM)-related component of the MCAC. The expense components (which are identical in the rental and NCO methods) are unaltered.





Adjusted Rental Method 2 (ARM2)

ARM2 MCAC = r2 * rental MCAC, where

$r2 = (\text{TSM RCNLD* value}) / (\text{TSM replacement cost new value})$

(r2 is a system value and not customer-class-specific, but does vary by asset class)

Notes: The rental calculation (before the RECC is applied), when summed over all the IOU's customers, represents the replacement cost new ("RCN") value of all the utility's hookup equipment (TSM sets).

- However, most of the TSM equipment service customers is used, of various vintages, and is substantially depreciated. If annexed or condemned, typically the utility would seek compensation based on RCNLD (see, for example, D.03-04-032, pp.42-43)
- The ARM2 MCAC represents the theoretical market value of a TSM set if it were condemned by a governmental agency, or annexed by another utility.
- Again, this formula applies only to the capital (TSM)-related component of the MCAC. The expense components (which are identical in the rental and NCO methods) are unaltered.

*Replacement cost new less depreciation





ARM (either version) As Marginal Cost (1)

The ARM MCAC has a legitimate interpretation as an MC, for the following reasons:

- First, it reasonably reflects the opportunity value of TSM equipment, which is its market value if sold. Utilities when selling their distribution systems do not price them at the cost of new facilities (RCN). Much as they might like to price at RCN, no buyer would pay that amount. Instead, utilities typically ask a lower price based on replacement cost new less depreciation (RCNLD). The RCNLD price is the “gold standard” price to which utilities aspire if they wish to (or are required to) sell part of their distribution system. The actual sale price for utility distribution plant is often less than RCNLD (ARM2), and may approximate the lower Book Value (ARM1)





ARM (either version) As Marginal Cost (2)

- Unlike the Rental or NCO methods, the ARM calculation is reasonably symmetric.
 - If a customer were to leave the system permanently, his TSM equipment could be retired, shrinking the rate base accordingly, and the ARM1 calculation would reasonably represent the avoided cost to ratepayers. This is not the case for rental, because the disused TSM equipment cannot generally economically be reused at another site (while meters and transformers can sometimes be returned to stock and reused, there are significant associated unavoidable removal and installation costs).
 - If a customer is added, the utility could (theoretically) buy a used TSM set on the market, and would pay an amount for depreciated TSM equipment that would be similar to the rate base (ARM1) value of its existing TSM equipment.





ARM (either version) As Marginal Cost (3)

- The ARM method (like the rental method) avoids the NCO method's undesirable dependence on customer growth, and thus avoids the possibility of anomalous results described above.
- Unlike both the rental and NCO, the ARM method correctly captures the opportunity value of existing TSM equipment.
 - Rental method overvalues existing TSM equipment (treating it as if it were new)
 - NCO undervalues existing TSM equipment (assigning a value of zero).





Conclusion

Adoption of the ARM (1 or 2) could end a 24-year-old controversy in MC-based ratemaking; It could also end the practice of simply averaging the outcome of 2 competing MC calculations in “black-box” settlements.

- The ARM methodology has a legitimate interpretation as an MC
- The ARM method is easy to implement, requiring only a single step beyond the Rental calculation
- The ARM method fairly reflects the value of existing hookup equipment in utility rate base.
- The ARM method avoids dependence on customer growth rates





Appendix: More on Marginal Cost and Opportunity Cost

- The term “**marginal cost**” may refer to an [opportunity cost](#) at the margin, or to marginal [pecuniary](#) cost — that is to say marginal cost measured by forgone money. –Wikipedia
- In [microeconomic theory](#), the **opportunity cost of a choice** is the [value](#) of the best alternative forgone where, given limited [resources](#), a choice needs to be made between several [mutually exclusive](#) alternatives.
- Assuming the best choice is made, it is the "cost" incurred by not enjoying the *benefit* that would have been had by taking the second best available choice.
- -The [New Oxford American Dictionary](#) defines it as "the loss of potential gain from other alternatives when one alternative is chosen."
- Opportunity cost is a key concept in [economics](#), and has been described as expressing "the basic relationship between [scarcity](#) and [choice](#)"
- The notion of opportunity cost plays a crucial part in attempts to ensure that scarce resources are used efficiently. Thus, opportunity costs are not restricted to monetary or financial costs: the [real cost](#) of [output forgone](#), lost time, pleasure or any other benefit that provides [utility](#) should also be considered an opportunity cost.—Wikipedia





Appendix: RCNLD

See, for example, the following excerpt from D.03-04-032, authorizing a sale of certain PG&E distribution facilities to the Turlock Irrigation District (TID):

- “LID [Laguna Irrigation District] argues that PG&E and TID considered only one method of determining the value of the assets, replacement cost less depreciation new (RCNLD), and that other valuation methods might have yielded a lower and more reasonable sales price. LID therefore asks the Commission to include a condition that provides that the use of RCNLD to value the assets sold to TID shall not be precedent in other cases involving transfers of utility assets. Laguna has been recently involved in litigation with PG&E to condemn certain electric distribution facilities. (Laguna Irrigation District v. Pacific Gas and Electric Company, Kings County Superior Court No. 99 C 052.) Laguna is therefore concerned that the valuation method here may be precedent in its pending litigation. We agree with PG&E that the courts will assess whether evidence regarding the valuation of utility assets in Commission proceedings should be considered in the condemnation proceedings, as well as the weight to be given Commission decisions pursuant to California law. LID does not oppose the sales price and has presented no evidence to show that the use of the RCNLD method of valuation has created an unfair or unrealistic price for the assets being sold to TID, or that another method of valuation would have resulted in a different price. Previous Commission decisions have found that a sales price for utility assets based on RCNLD, when negotiated between the parties in arms-length transactions, is fair and reasonable. We therefore approve the sales price here based on RCNLD. However, we recognize that RCNLD is only one method of valuation, and we may consider different valuation methodologies in other cases”. (D.03-04-032, pp. 42-43, emphasis added).

