APPENDIX A

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for Authority to Revise Their Rates Effective January 1, 2009, in Their Biennial Cost Allocation Proceeding.	Application 08-02-001 (Filed February 4, 2008)

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SETTLEMENT AGREEMENT

June 2, 2009

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SETTLEMENT AGREEMENT

Pursuant to Article 12 of the Commission's Rules of Practice and Procedure ("Rules"), San Diego Gas & Electric Company ("SDG&E"), Southern California Gas Company, ("SoCalGas")(jointly "SDG&E/SoCalGas" or "Applicants"), the Division of Ratepayer Advocates, Southern California Edison Company (U338 E), the Indicated Producers, the Southern California Generation Coalition, the City of Long Beach,[1/] Southwest Gas Corporation, Watson Cogeneration Company and the California Cogeneration Council, the California Manufacturers and Technology Association, The Utility Reform Network, Bridge Housing, and the Electric Generator Alliance (collectively referred to hereafter as "Joint Parties") respectfully submit to the Commission this Settlement Agreement ("SA"). In this SA, the Joint Parties provide to the Commission a recommended resolution of the issues reserved for Phase Two of this proceeding by the "Scoping Memo."[2/]

1/ The Settlement Agreement requires approval by the City of Long Beach City Council which approval is pending.

2/ "Scoping Memo and Ruling of the Assigned Commissioner and Administrative Law Judge" dated April 17, 2008.

I.

REASONABLENESS OF THE PHASE TWO SETTLEMENT

As discussed in more detail in the motion to which this SA is attached, the Joint Parties submit that the SA fully complies with the Commission's requirements that settlements be reasonable, consistent with law, and in the public interest. The Joint Parties have recognized that there is risk involved in litigation, and that a party's filed position might not prevail, in whole or in part, in the Commission's final determination. The Joint Parties have vigorously argued their positions in this matter, and have reached compromise positions that they believe are appropriate in light of the litigation risks. This SA reflects the Joint Parties' best judgments as to the totality of their positions and risks, and their agreement herein is explicitly based on the overall results achieved.

II.

PHASE TWO SETTLEMENT TERMS AND CONDITIONS

A. Effective Date; Term of Agreement

1. The Effective Date of this Settlement is the date upon which the Commission approves the Settlement. The rates set forth in Attachment 3 shall go into effect the later of (i) January 1, 2010 or (ii) the first day of the month that is at least 60 days from the date of Commission approval of this settlement.

2. The Settlement Term shall extend from the date of Commission approval of the Settlement through the effective date of rates that are established in the next SDG&E/SoCalGas cost allocation proceeding.

B. Settlement Terms

1. Operational Issues

A. The SDG&E/SoCalGas Utility Gas Control Department is the sole authority for operating the SDG&E/SoCalGas pipeline and storage system, and for developing the system sendout forecasts to be used for purposes of

determining Southern System minimum flow requirements and for calling Operational Flow Orders ("OFOs").

The Utility Gas Control Department will continue its current practice of fully utilizing storage injection capacity prior to calling an OFO. The Gas Control Department will provide the forecasted sendout and the physical injection capacity figures. For every nomination cycle, the SDG&E/SoCalGas Gas Scheduling Department shall calculate the system capacity as the sum of the forecasted demand ("sendout"), the physical injection capacity, and the available off-system nominations. The forecasted system capacity shall then be compared to the latest scheduled quantities. An OFO may be called only if the level of scheduled quantities exceeds the forecasted system capacity. System linepack is not part of the formula used to determine when an OFO shall be called.

B. SDG&E/SoCalGas shall hold an annual SDG&E/SoCalGas Customer Forum (the "Forum"). The Forum will provide an opportunity for SDG&E/SoCalGas to provide information on and to address the following matters with interested parties:

i. Review of the timing, method, formulas, and all inputs to formulas by which OFO events are triggered;
ii. Review of requests for the Operational Hub to acquire additional supplies to meet minimum flow requirements;
iii. Review of Operational Hub purchases/actions to meet minimum flow requirements and plans for the coming year by providing information regarding the individual transactions, including transactions executed pursuant to the Operational Hub contractual arrangements. Transaction-specific information shall identify price, volume, date, delivery/receipt points, and any special terms;
iv. Review the need for any additional minimum flow requirements on the SDG&E/SoCalGas system beyond then-current defined requirements;
v. Review potential additional tools to support system operations and potential system improvements to reduce or eliminate the need for any minimum flowing supply requirements.

To facilitate an informed discussion of these issues, SDG&E/SoCalGas shall prepare an annual report ("Report") of system reliability issues. The Report shall (1) identify the need for new minimum flow requirements, (2) identify potential tools and/or infrastructure improvements that can be used to mitigate new or existing reliability problems (*e.g.* minimum flow requirements and OFOs), and (3) provide information on the matters identified in (i) through (v) above. SDG&E/SoCalGas shall post the Report on their respective websites at least two weeks prior to each annual Forum.

C. SDG&E/SoCalGas and participants in each Forum shall collaborate in good faith to develop a post-Forum report. Each post-Forum report shall summarize the matters discussed at the relevant Forum and shall identify any action items, tariff changes and/or procedural modifications determined to be necessary by parties participating in the Forum. The post-Forum report shall include descriptions of the proposals presented by parties. If a party's proposal is rejected by SDG&E/SoCalGas, the post-Forum report shall provide the basis for the rejection of the proposal. If any party is dissatisfied with the description of its proposal set forth in the post-Forum report or with the basis cited by SDG&E/SoCalGas for rejection of the proposal, the post-Forum report shall include that party's own description of its proposal and comments on the rejection of the proposal in an appendix to the post-Forum report. SDG&E/SoCalGas shall file each post-Forum Report with the Commission by advice letter no later than 60 days after conclusion of the relevant Forum. SDG&E/SoCalGas shall also submit any tariff changes proposed in the Forum and agreed-to by SDG&E/SoCalGas for Commission approval by advice letter no later than 60 days after conclusion of each annual Forum.

D. SDG&E/SoCalGas shall include the following in their respective gas tariffs: Utility System Operator structure, procedures, and operation protocols; any specific formulas used to call OFOs and to determine the volume of any additional supplies necessary to meet minimum flow requirements; the Operational Hub's minimum flowing supply requirement; RFO procedures, including information requirements for the advice letter filing discussed in 1.C; the Operational Hub's general spot gas commodity purchasing and selling practices and procedures to meet minimum flowing supply requirements; descriptions of any ongoing minimum flow requirements; and a statement of the Utility System Operator's mission to maintain system reliability and integrity while minimizing costs at all times. The provisions that shall be included in the SDG&E/SoCalGas tariffs are appended to this settlement agreement in Attachment 4.

E. In addition to the information that SDG&E/SoCalGas post on SoCalGas' Electronic Bulletin Board ("EBB") to comply with Commission decisions D.06-12-031 ("FAR Decision") and D.07-12-039 ("Omnibus Decision"), SDG&E/SoCalGas shall post on their EBB operational information on a current-day and forecast basis. Forecast information shall be for the current day and the next three days. Forecasted information will be updated for each nomination cycle. The information that shall be posted is as follows:

a. Composite weighted system average temperature;
b. System send-out, off-system deliveries by delivery point, storage injection, transmission fuel;
c. Total system supply broken out by scheduled quantities at all receipt points and storage withdrawals;

d. Storage injections and withdrawals for balancing;
e. Total daily customer imbalance;
f. Daily storage injections and withdrawals;
g. Unsubscribed unbundled firm storage injection and withdrawal capacity;
h. OFO status.

F. SDG&E/SoCalGas hereby withdraw their "high OFO" trigger proposal in this proceeding. They shall also be precluded from proposing the adoption of this or any similar high OFO trigger to become effective during the settlement period.

G. The Operational Hub will continue to use the tools established in D.07-12-019 to support the Southern System minimum flow requirement, including purchase/sale of spot gas supplies and holding RFOs for proposals to enable SDG&E and SoCalGas to manage their minimum flow requirements to the Southern System delivery points. All purchases and sales of spot gas to support the minimum flow requirement will be made subject to Section 1.N and 1.O. The initial daily quantity of supplies needed will be determined by the Utility Gas Control Department based on the following formula:

Minimum Flowing Supply Requirement – Best Available Scheduled Quantities reflecting customer flows into the Southern System = Additional Supplies Needed by the Utility Gas Control Department

"Best Available Scheduled Quantities" means the last available scheduled quantities. The last available scheduled quantities will be adjusted by the Utility Gas Control Department to account for revised customer nominations for a particular day if the last available scheduled quantities cannot be achieved on the day in question. On those days, a lower number would be utilized to reflect expected deliveries. The same would apply if the Utility Gas Control Department becomes aware of pipeline issues such as approaching maintenance or lack of upstream pipeline/supplier performance, in which case the last available scheduled quantities would be reduced to reflect the expected deliveries.

H. The cost and revenues of Operational Hub transactions (*e.g.*, natural gas purchases, sales, or exchanges resulting from approved contracts) that are necessary to meet minimum flow requirements shall be recorded in the System Reliability Memorandum Account ("SRMA"). Prospective changes to types of Operational Hub natural gas transactions ("tools") to meet minimum flow requirements shall be considered in conjunction with the annual Forums.

Standards and criteria for spot purchases or sales of gas commodity for which standards and criteria are not specified in Commission-approved contracts shall be as follows:

1. Should it be necessary for the Operational Hub to purchase or sell spot supplies of gas in the day-ahead market, the Operational Hub shall be deemed to have made reasonable (1) spot purchases if the purchase price is less than or equal to 110% of the Platt's Gas Daily Midpoint for the flow date for the relevant trading point and (2) spot sales if the sale price is greater than or equal to 90% of the Platt's Gas Daily Midpoint for the flow date for the relevant trading point.

2. Should it be necessary for the Operational Hub to purchase or sell spot supplies of gas in the intraday market, the Operational Hub shall be deemed to have made reasonable (1) spot purchases if the purchase price is less than or equal to 110% of the Platt's Gas Daily high of the Common range for the current flow date for the relevant trading point and (2) spot sales if the sale price is greater than or equal to 90% of the Platt's Gas Daily low of the Common range for the current flow date for the relevant trading point.

3. Purchases or sales at prices that are outside the ranges specified in (1) and (2) above shall nevertheless be deemed reasonable if the Operational Hub abides by the following procedure: When the Gas Control Department determines that spot purchases are necessary to meet minimum flow requirements, the Operational Hub shall monitor the Intercontinental Exchange ("ICE") and record the relevant price information, if available, for deliveries of gas at all relevant trading points. If volumes available on ICE exceed the minimum flow requirements, transactions for the volumes offered through ICE shall be deemed reasonable. The Operational Hub may also post an offer on ICE for volumes. When less than the required volumes are available on ICE, the Operational Hub shall contact gas suppliers (other than the SDG&E/SoCalGas Gas Procurement Department or affiliates), request offers for the necessary supplies, and record their offers for gas delivered to the relevant trading points to ensure at least three offers from three different suppliers are available for comparison. The Operational Hub shall compare prices posted on ICE and, if applicable, prices quoted in the Operational Hub supplier contacts and select the best prices available to meet the quantities required to meet minimum flow requirements. Verification that the Operational Hub has followed this procedure shall be provided to the Commission in the Annual Compliance Report described in subsection 1.H.4 below.

   Purchases and sales other than those described above will not be deemed "unreasonable" but shall be subject to review by the Commission's

Energy Division and requests for explanation in conjunction with the Annual Compliance Report described in subsection 1.H.4 below.

4. SDG&E/SoCalGas shall provide on an annual basis a report ("Annual Compliance Report") demonstrating that the Operational Hub's procurement activities during the prior year were in compliance with the standards, criteria, and procedures described in this Section 1.H. The Annual Compliance Report shall be submitted to the Energy Division by advice letter and shall be subject to comment or protest. Upon Energy Division review and verification of the Annual Compliance Report and Commission Resolution approving the Annual Compliance Report, all transactions entered into the SRMA balance for the year in question that are found reasonable by the Energy Division shall be amortized in customer transportation rates over the following year

5. Upon Commission approval of this Settlement, the requirement set forth in Ordering Paragraph 17 of D.07-12-019 that SoCalGas and SDG&E submit to a reasonableness review of Utility System Operator costs recorded in the SRMA before passing the costs through to customers shall be eliminated. The standards, criteria, and procedures set forth in this Section 1.H shall govern review of Operational Hub's purchases and sales as of April 1, 2009.

I. SDG&E/SoCalGas shall retain current winter balancing rules as set forth in tariff schedule Rule No. 30 with the following modification: When SDG&E/SoCalGas are in the 70% minimum daily flow regime or the 90% minimum daily flow regime, and SDG&E/SoCalGas call an OFO, then the 70% minimum daily flow requirement or the 90% minimum flow requirement is waived for the days that the OFO is in effect.

J. SDG&E/SoCalGas' proposal in this proceeding to allow interruptible withdrawals to count towards balancing requirements shall be adopted and incorporated into their respective gas tariffs.

K. SDG&E/SoCalGas hereby withdraw their proposal in this proceeding regarding the Southern System Flow Order and shall not propose such a reliability measure to become effective during the Settlement Period. SDG&E/SoCalGas shall continue to meet the Southern System flow requirements through the actions of the Utility System Operator and the tools approved by the Commission as described in Sections 1.G, 1.H, 1.N, and 1.O.

L. SDG&E/SoCalGas shall seek Commission authority for any additional tools (other than system modifications that can be completed without an application under current Commission rules) necessary to meet the Southern System flow requirement through an application. Any contracts that are not obtained through an RFO process relating to already-approved tools (*i.e.*; gas

purchases, gas exchanges) will be submitted to the Commission for approval by advice letter. Advice letters seeking approval of the Operational Hub contractual arrangements shall identify the order in which contracts will be implemented to ensure system reliability and integrity at least cost.

M. The Utility Gas Control Department shall continue to be physically separated from those departments engaging in marketing/sales activities, shall continue to have no knowledge of or involvement in any marketing/sales activities, and shall continue to be strictly concerned with the operation, safety, and integrity of the pipeline and storage system. Also, the Operational Hub shall not have access to non-public customer-specific information other than the information it obtains through its own contacts and negotiations with customers. The Utility Gas Control Department may communicate with the Operational Hub to discuss changes to Southern System minimum flow requirements, circumstances that might require the Operational Hub to obtain supplies, and options to ensure minimum flowing supplies requirements are met. Discussions may also take place with regard to short-term operational needs for flowing supplies to support system reliability elsewhere on the system that may arise to support O&M activities, related pipeline integrity work, or to address a force majeure event such as a line breakage or failure.

All requests for supplies by the Utility Gas Control Department to the Operational Hub shall be posted on the EBB no later than 72 hours after the minimum flow event in order to avoid an increase in the cost of such services that may result from posting this information contemporaneously.

N. SDG&E/SoCalGas' Utility System Operator agrees, except for transactions related to the Utility Gas Procurement Department's role as "provider of last resort," that any gas commodity purchases and sales between the Operational Hub and the Utility Gas Procurement Department or a Sempra affiliate will occur through an Independent Party, where the counterparties are not known until after the transaction is completed. "Independent Party" refers to gas trading exchanges such as ICE, gas brokers who have been instructed to provide no preference to Sempra affiliates or the Utility Gas Procurement Department, or open auctions available to all qualified parties conducted by the Operational Hub, in which gas purchases or sales are made with counter-parties that are not known until after the transaction is completed. In the case of the Operational Hub communicating with the Utility Gas Procurement Department as provider of last resort to maintain the Southern System flow requirement, SDG&E/SoCalGas agree to post the terms of any resulting transaction within 72 hours after the conclusion of the transaction. SDG&E/SoCalGas will post the following information about any such transaction: price, volume, date, delivery/receipt points and any special terms. The Utility Gas Procurement Department will act on a best-efforts basis to

provide gas supplies based on the Operational Hub's request, if called upon as a provider of last resort.

O. "Provider of last resort" relates to the circumstance in which the Operational Hub has attempted to use all other available tools, has entered the open market for gas commodity purchases, has been unsuccessful in meeting its need to bring a required volume of flowing supplies at a specific location, and system reliability is therefore jeopardized. If the Operational Hub has exhausted its other options available to acquire the required flowing supplies, it will contact the Utility Gas Procurement Department and request that it provide gas to meet the remaining minimum flow requirement. Such requests will occur as soon as possible during the actual flow day. The Utility Gas Procurement Department will charge the Operational Hub the actual incremental costs incurred to provide the specific supplies. Verification that SDG&E/SoCalGas have followed this procedure will be included in the Annual Compliance Report provided to the Commission in conjunction with the advice letter addressed above in Section 1.H.4.

P. Operational Hub G-PAL transactions with Sempra affiliates or the Utility Gas Procurement Department, if discounted below the maximum tariff rate, will be posted the next business day on the EBB, consistent with rules governing the posting of discounted transportation services for affiliates.

2. Cost Allocation/Rate Design

A. Adopt embedded cost allocation for transmission and storage facilities and long-run marginal cost ("LRMC") allocation for distribution facilities for both SDG&E and SoCalGas, and adopt the "compromise" cost allocation adjustments to base margin that are implied by the rates set forth in Attachment 3. SDG&E and SoCalGas shall not be required to propose LRMC cost allocation for transmission or storage costs in their next cost allocation proceeding.

B. Adopt the rates set forth in Attachment 3 hereto. These rates will be subject to the utilities' routine rate adjustments to reflect updated Regulatory Accounts and implementation of other Commission decisions, such as SDG&E and SoCalGas' general rate case ("GRC") decision.

C. The embedded cost transmission revenue requirement is $201.2 million total ($163.2 million SoCalGas + $38 million SDG&E). The embedded cost storage revenue requirement is $83.3 million. Agreement to these figures and this settlement as a whole is not meant by the parties to indicate their approval or acceptance of any of the various cost allocation proposals, principles, or methodologies offered in this proceeding, except that the parties explicitly

agree that costs will be allocated to the transmission and storage functions on the basis of embedded costs.

D. Annual changes in base margin are to be allocated by System Average Percent Change ("SAPC"). SAPC is defined as the authorized increase in base margin divided by the current base margin, on a pre-system integration and pre-FAR unbundled basis. The SAPC shall then be applied to each functional category of the base margin (also on a pre-system integration and pre-FAR unbundled basis), for each customer class.

E. To the extent that the method for allocating the balance in any balancing account is changed by this Settlement, the change is explicitly identified herein. Where no change to the method for allocating the balance in a balancing account is identified herein, the balancing account will continue to be allocated according to the method in effect as of the date this Settlement is filed with the Commission. Costs that are currently allocated using the Equal Percent Marginal Cost ("EPMC") method shall be allocated using the Equal Percent of Authorized Margin ("EPAM") method, unless explicitly identified herein. For purposes of this settlement only, the EPAM method shall be defined as the percent of base margin, on a post-system integration and post-FAR unbundled basis, allocated to each class.

F. The cost of gas for determining the cost of Company Use ("CU") fuel and Unaccounted-For Fuel ("UAF") shall be $5.08/MMBtu. The actual cost of CU fuel and UAF will be balanced through the appropriate regulatory accounts. To minimize the likelihood of under-/over-collections, the underlying gas price will be updated through the annual October adjustment to transportation rates using a forecast of Southern California border gas prices for the next year that is based on current futures prices. In preparing this forecast, SDG&E/SoCalGas shall use the methodology most recently approved by the Commission in Resolution E-4214 for establishing the Market Price Referent ("MPR") by forecasting the near-term natural gas prices at the southern California border. This method uses a recent 22-day sample of both NYMEX forward gas prices at the Henry Hub and basis swap prices for the southern California border using NYMEX Clearport data. Modifications to the MPR methodology made subsequent to issuance of Resolution E-4214 and/or issuance of future Commission Resolutions approving the MPR for subsequent years will not affect the methodology used to forecast the cost of fuel under this Settlement.

G. Adopt balancing account treatment for in-kind storage fuel for core and noncore storage injections and for load balancing, as proposed by SDG&E/SoCalGas in this proceeding. The initial injection fuel rate shall be set at 2.4% for the first full storage year under this settlement commencing on April 1, 2010, and shall be adjusted for each subsequent storage year under this settlement on the basis of a three-year rolling average.

H. Proposed changes to the system of Firm Access Rights ("FAR") adopted in D.06-12-031 will be examined in the 18-month FAR review proceeding held in accordance with Ordering Paragraph 7 of D.06-12-031.

I. Adopt TURN's proposal for developing the residential tier differential. Residential rates for SoCalGas customers will be set to achieve a composite tier differential of 15% between the non-baseline rate and the baseline rate, where the baseline and non-baseline rates include the commodity rate adopted in this proceeding. However, the rate difference between the baseline and non-baseline rates, excluding commodity rate, shall be capped at 24 ¢/therm for 2010, 25¢/therm for 2011, and 26¢/therm for 2012.

J. Adopt the SDG&E/SoCalGas proposal for C/I customer charges and rate tiers: Core C/I customers will be charged a single customer charge for all customers ($10 for SDG&E customers; $15 for SoCalGas customers) and seasonality shall be removed from core C/I rates.

K. SoCalGas shall retain the existing 1/12 methodology for recording the authorized margin of the Core Fixed Cost Account ("CFCA"), which records the authorized margin on a monthly basis rather than on a seasonalized basis.

L. Bridge Housing's proposal: With regard to Bridge Housing's proposal, SDG&E/SoCalGas shall modify all applicable tariffs so that accounts with residential common area usage are provided the option to choose a commercial rate for which they are eligible. For SDG&E accounts with residential common area gas usage, the commercial rate option is Schedule GN-3. For SoCalGas accounts with residential common area gas usage, the commercial rate option is Schedule G-10. As a condition of service, the common area gas equipment must be separately metered from the dwelling units. SDG&E/SoCalGas shall include notice of this rate option in a mailing sent within 120 days following the implementation of rates adopted in this proceeding to active accounts that can be readily identified in SDG&E/SoCalGas' customer information databases as serving residential common area load through a separate meter and meeting the usage criteria specified below. Based upon the final rates and rate design adopted in this proceeding, SDG&E/SoCalGas will determine a gas usage threshold at which a customer may potentially benefit from taking service under a commercial rate. Customers exceeding this threshold will receive the mailing, which will include a table showing typical savings at various usage levels.

This mailing shall constitute official notice of this rate option. A rate change request received from an eligible customer shall become effective for service rendered after the next regular meter reading following the date of notice to the Utility, based on the availability of metering and billing requirements. Under no circumstances will a customer be eligible for a retroactive bill

adjustment that applies the new rate to the customer's account for a period prior to the customer's request for this rate.

M. Adopt the TURN/DRA proposal for core rate de-averaging that provides for 5% de-averaging per year, converted to an annual dollar amount due to the compromise nature of this settlement. For SoCalGas, the annual de-averaging increment shall be $8.35 million per year for the term of this settlement. For SDG&E, the annual de-averaging increment shall be $1.57 million per year for the Settlement Term. These de-averaging increments shall be applied starting in the first January of the second year of the settlement period, and will continue through the Settlement Term.

N. Adopt DRA's rate proposal for Borrego Springs: SDG&E will maintain the existing requirement that the average combined liquefied natural gas ("LNG") and electric bill for residents of the Roadrunner Home Park in Borrego Springs, California will not exceed the average Borrego Springs all-electric bill. The parties agree, however, that notwithstanding this requirement, SDG&E will implement for the Settlement Term the rates it proposed in this proceeding.

O. Adopt DRA's proposal in this proceeding regarding retention of the current gas engine rate cap. SoCalGas will preserve the existing rate cap for customers taking service under the G-EN tariff for core gas engine service for water pumping.

P. Adopt TLS rates as described in Attachment 1 hereto and as set forth in Attachment 3 hereto. Upon Commission approval of the advice letter submitting SoCalGas' proposed GT-TLS tariff rate schedule and implementation of the TLS service, SoCalGas shall eliminate its peaking service and shall terminate the GT-PS tariff rate schedule. Customers served under the GT-PS tariff rate schedule will transfer to the GT-TLS tariff rate schedule upon termination of the GT-PS tariff rate schedule. In addition, upon Commission approval of the above-referenced advice letter, wholesale customers served under the GW-LB, GW-SD, GW-SWG, GW-VRN and GW-ECO will be served under the GT-TLS tariff schedule and these tariff schedules will be eliminated.

Q. Allocate the Firm Access and Storage Rights Memorandum Account ("FASRMA"), the Blythe Operational Flow Requirement Memorandum Account ("BOFRMA"), the Otay Mesa System Reliability Memorandum Account ("OMSRMA"), and the new SRMA memorandum account balances on Average Year (Equal Cents Per Therm ["ECPT"]) Throughput basis.

R. Maintain the current ECPT methodology for allocating CFCA and NFCA balances. However, beginning in the second year of the BCAP period, adopt the EPAM methodology, as proposed by SDG&E/SoCalGas in section 2.E,

for allocating the base margin portions of Non-Core Fixed Cost Account ("NFCA") balances and ECPT method for the non-base margin portions.

S. Adopt SDG&E/SoCalGas proposal regarding development of a Sempra-wide rate for natural gas service provided to natural gas vehicle ("NGV") stations. Both the transportation rate and the compression surcharge will be developed on a Sempra-wide basis. SDG&E and SoCalGas will modify their respective G-NGV tariff rate schedules to reflect identical transmission charges, customer charges and commodity costs, subject to differences in Franchise Fee and Uncollectible ("FF&U") factors.[3] Adoption of uniformity between the components of the utilities' respective NGV rates will result in identical or near identical "compressed" NGV rates between the SDG&E and SoCalGas service territories, as well as identical or near identical "uncompressed" NGV rates.

T. Adopt SDG&E/SoCalGas' gas demand forecasts for residential, core commercial, industrial, non-core commercial and industrial, enhanced oil recovery ("EOR"), natural gas vehicle ("NGV"), wholesale, EG and ECOGAS customers for the Settlement Term.

U. Adopt the uncontested SDG&E/SoCalGas proposals in this proceeding described in Attachment 2 hereto.

3. Other issues

A. SDG&E/SoCalGas shall not be at risk for throughput during the Settlement Term. The parties shall separately address through briefs filed in this proceeding whether the Commission should establish a formal policy in favor of de-coupling SDG&E/SoCalGas profits from throughput. In the event the Commission adopts a formal policy in favor of throughput risk, such action by the Commission shall not operate to modify the terms of this Settlement Agreement and shall not result in SDG&E/SoCalGas being placed at risk for throughput during the Settlement Term. Opening Briefs shall be filed no later than 30 days after the date of the Commission order approving this settlement with Reply Briefs due 15 days after Opening Briefs.

B. SDG&E, SoCalGas, DRA and TURN agree to negotiate in good faith the substance, format, and timing of a periodic report addressing aggregate customer data relating to such issues as customer turn-offs for non-payment of bills.

C. SoCalGas shall modify its tariff to exempt digester and landfill gas supplies from being considered sources of alternate fuel that result in a customer being placed on partial requirements service.

3/ SDG&E's G-NGV tariff will be revised to include a customer charge.

D. The question of whether SDG&E/SoCalGas should offer backbone-only service at a backbone-only rate shall be deferred to the next SDG&E/SoCalGas cost allocation proceeding and shall not be included within the scope of issues to be considered in the 18-month FAR review proceeding.

E. Except as specifically provided herein, this settlement does not limit the utilities' or parties' right to make proposals in the 18-month FAR review proceeding.

F. The embedded cost allocated to the SDG&E/SoCalGas integrated transmission system as a whole (including both local transmission costs and backbone transmission costs) is established by this settlement for the entire settlement period, subject to annual escalation in the authorized base margin in accordance with SDG&E and SoCalGas' most recent GRC decision, D.08-07-046.

G. The split of backbone costs between backbone and local transmission is specifically reserved as an issue for the 18-month FAR review to establish the FAR reservation charge for the three-year FAR cycle that begins October 1, 2011.

H. Enhanced Oil Recovery ("EOR") rates: Eliminate the 5% EOR shareholder incentive.

I. G-SRF: The G-SRF surcharge shall not apply to transportation services provided to electric generators located in SoCalGas' service territory, consistent with the revised G-SRF tariff schedule appended hereto in Attachment 4, provided that such transportation services relate directly to wholesale sales by such electric generators to electric, gas or steam heat public utilities or the California Independent System Operator.

J. Adopt IP/CCC/CMTA/Watson's proposal to revise the descriptions of the balancing accounts in the Preliminary Statements to clarify how actual company use compressor fuel costs are tracked and recovered.

K. Sempra-wide rate adjustment: Retain the Sempra-wide EG rate adjustment for distribution-level customers that are not included in the TLS rate class.

L. Eliminating out-dated accounts: Eliminate accounts as proposed by SDG&E/SoCalGas in this proceeding, including the NGVA and NGV-RDD accounts.

M. SDG&E/SoCalGas shall file cost allocation applications triennially instead of biennially.

a. SDG&E/SoCalGas shall file a new cost allocation application no later than September 1, 2011, for rates to be effective January 1, 2013 for the three year period ending on December 31, 2015.

b. The application identified above in Section 3.M.a above shall include data on actual revenues from service provided under the TLS Reservation Rate Option and actual volumes of service provided under that Option.

N. The new or revised tariff provisions that are required to implement this settlement are appended hereto in Attachment 4.

III.

ADDITIONAL TERMS AND CONDITIONS

A. The Public Interest.

The Joint Parties agree jointly by executing and submitting this SA that the relief requested herein is just, fair and reasonable, and in the public interest.

B. Non-Precedential Effect.

Except as specifically provided in the SA, this SA is not intended by the Joint Parties to be precedent for any future proceeding. The Joint Parties have assented to the terms of this SA only for the purpose of arriving at the settlement embodied in this SA. Except as expressly precluded in this SA, each of the Joint Parties expressly reserves its right to advocate, in current and future proceedings, positions, principles, assumptions, arguments and methodologies which may be different than those underlying this SA, and the Joint Parties expressly declare that, as provided in Rule 12.5 of the Commission's Rules, this SA should not be considered as a precedent for or against them. Likewise, the SA explicitly does not establish any precedent on the litigated issues in the case.

C. Indivisibility.

This SA embodies compromises of the Joint Parties' positions. No individual term of this SA is assented to by any of the Joint Parties, except in consideration of the

other Joint Parties' assents to all other terms. Thus, the SA is indivisible and each part is interdependent on each and all other parts. Any party may withdraw from this SA if the Commission modifies, deletes from, or adds to the disposition of the matters stipulated herein. The Joint Parties agree, however, to negotiate in good faith with regard to any Commission-ordered changes to the SA in order to restore the balance of benefits and burdens, and to exercise the right to withdraw only if such negotiations are unsuccessful.

The Joint Parties acknowledge that the positions expressed in the SA were reached after consideration of all positions advanced in the prepared testimony of SDG&E/SoCalGas and the other interested parties, as well as proposals offered during the settlement negotiations. This document sets forth the entire agreement of the Joint Parties on all of those issues, except as specifically described within the SA. The terms and conditions of this SA may only be modified in writing subscribed by all Joint Parties.

Dated this 2nd day of June, 2009.

SAN DIEGO GAS & ELECTRIC COMPANY and
SOUTHERN CALIFORNIA GAS COMPANY

By: /s/ Richard M. Morrow
Richard M. Morrow
Vice President – Customer Services

DIVISION OF RATEPAYER ADVOCATES

By: /s/ Dana Appling
Dana Appling
Director

SOUTHERN CALIFORNIA EDISON COMPANY

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By: /s/ Patrick H. West
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SOUTHWEST GAS CORPORATION

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Operations Manager

ELECTRIC GENERATOR ALLIANCE

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APPENDIX B

TABLE 1
Transportation Rate Revenues
Southern California Gas Company
2009 BIENNIAL COST ALLOCATION PROCEEDING A.08-02-001

	Present Rates			BCAP Authorized Rates			Changes		
	Jan-1-09 Volumes Mth	Jan-1-09 Revenues $000's	Average Rate $/therm	BCAP Volumes mtherms	BCAP Revenues $000's	BCAP Rate $/therm	Revenue Change $000's	Rate Change $/therm	% Rate change %
CORE									
Residential	2,546,852	$1,158,440	$0.45485	2,483,989	$1,154,332	$0.46471	($4,108)	$0.00986	2.2%
Commercial & Industrial	834,635	$245,489	$0.29413	970,519	$281,866	$0.29043	$36,377	($0.00370)	-1.3%
NGV - Pre SempraWide (1)				117,231	$11,201	$0.09555			
SempraWide Adjustment				117,231	($3)	($0.00003)			
NGV - Post SempraWide				117,231	$11,197	$0.09552			
Gas A/C	1,200	$168	$0.14019	1,210	$108	$0.08923	($60)	($0.05096)	-36.3%
Gas Engine	16,040	$1,866	$0.11636	18,080	$1,924	$0.10640	$57	($0.00996)	-8.6%
Total Core	3,398,727	$1,405,964	$0.41367	3,591,030	$1,449,427	$0.40362	$43,463	($0.01005)	-2.4%
NONCORE COMM & IND									
Distribution Level Service	1,156,023	$68,136	$0.05894	982,465	$61,037	$0.06213	($7,099)	$0.00319	5.4%
Transmission Level Service (2)	300,734	$4,247	$0.01412	457,697	$10,412	$0.02275	$6,166	$0.00863	61.1%
Total Noncore C&I	1,456,757	$72,382	$0.04969	1,440,163	$71,449	$0.04961	($933)	($0.00008)	-0.2%
NONCORE EG									
Distribution Level Service									
Pre Sempra Wide	2,944,257	$65,689	$0.02231	353,995	$11,363	$0.03210			
Sempra Wide Adjustment	2,944,257	$2,457	$0.00083	353,995	$513	$0.00145			
Post Sempra Wide	2,944,257	$68,146	$0.02315	353,995	$11,876	$0.03355			
Transmission Level Service (2)				2,472,969	$56,259	$0.02275			
Total Electric Generation	2,944,257	$68,146	$0.02315	2,826,964	$68,134	$0.02410	($11)	$0.00096	4.1%
TOTAL RETAIL NONCORE	4,401,014	$140,528	$0.03193	4,267,127	$139,584	$0.03271	($944)	$0.00078	2.4%
WHOLESALE & INT'L									
Wholesale Long Beach (2)	77,821	$1,652	$0.02123	117,093	$2,664	$0.02275	$1,012	$0.00152	7.2%
SDGE Wholesale	1,445,680	$5,110	$0.00353	1,230,285	$10,822	$0.00880	$5,712	$0.00526	148.9%
Wholesale SWG (2)	91,672	$1,748	$0.01906	81,737	$1,859	$0.02275	$112	$0.00369	19.3%
Wholesale Vernon (2)	51,620	$824	$0.01596	116,135	$2,642	$0.02275	$1,818	$0.00679	42.5%
International (2)	36,419	$652	$0.01790	53,990	$1,228	$0.02275	$576	$0.00485	27.1%
Total Wholesale & Int'l	1,703,212	$9,985	$0.00586	1,599,240	$19,215	$0.01202	$9,230	$0.00615	104.9%
TOTAL NONCORE	6,104,226	$150,513	$0.02466	5,866,366	$158,799	$0.02707	$8,285	$0.00241	9.8%
Unalloc.Costs to NSBA		$16,634					($16,634)		
Unbundled Storage		$21,000			$24,575		$3,575		
Total (excluding FAR)	**9,502,953**	**$1,594,112**	**$0.16775**	**9,457,396**	**$1,632,801**	**$0.17265**	**$38,690**	**$0.00490**	**2.9%**
FAR Amount (3)		$52,307			$53,038				
SYSTEM TOTAL w/ SI, FAR, TLS, Sempra Wide Adj	9,502,953	$1,646,419	$0.17325	9,457,396	$1,685,839	$0.17826	$39,421	$0.00500	2.9%
EOR Revenues	482,707	$22,779		156,187	$4,427	$0.02834			
Total Throughput w/ EOR Mth/yr	9,985,660			9,613,583					

1) Under present rates, NGV is not directly allocated costs and is not calculated on Sempra-Wide basis. It is not shown in Table 1. See Table 3 for Present NGV Rates.
2) These authorized costs and rates for Transmission Level Service customers represents the average transmission rate. See Table 5 for actual transmission level service rates.
3) FAR charge is authorized as a separate rate. Core will pay through procurement rate, noncore as a separate charge. See Table 5 for actual FAR charge.
4) Composite rate changed in 2009 BCAP to include gas costs.

TABLE 2
Core Transportation Rates
Southern California Gas Company
2009 BIENNIAL COST ALLOCATION PROCEEDING A.08-02-001

	Present Rates			BCAP Authorized Rates		
	Jan-1-09 Volumes Mth	Jan-1-09 Rate $/th	Jan-1-09 Revenue $000's	BCAP Volumes Mth	Rate $/th	Revenue $000's
RESIDENTIAL SERVICE						
Customer Charge						
Single Family	3,091,427	$5.00	$185,486	3,676,464	$5.00	$220,588
Multi-Family	1,485,811	$5.00	$89,149	1,685,965	$5.00	$101,158
Small Master Meter	118,240	$5.00	$7,094	92,860	$5.00	$5,572
Submeter Credit-$/unit/day	146,025	($0.30805)	($16,419)	149,095	($0.30805)	($16,764)
Volumetric Transportation Rate						
Baseline Rate	1,664,422	$0.29056	$483,614	1,703,882	$0.26612	$453,443
Non-Baseline Rate	844,693	$0.47413	$400,496	768,363	$0.50612	$388,887
	2,509,115	$0.45810	$1,149,421	2,472,246	$0.46633	$1,152,883
NBL/BL Ratio:						
Composite Rate $/th		$0.44996			$0.95639	
Gas Rate $/th		n/a			$0.50800	
NBL/Composite rate ratio (4)		1.05			1.06	
Large Master Meter						
Customer Charge	183	$321.13	$705	61	$339.80	$249
Baseline Rate	27,925	$0.19892	$5,555	9,017	$0.08386	$756
Non-Baseline Rate	9,812	$0.28025	$2,750	2,726	$0.15949	$435
	37,737	$0.23875	$9,010	11,743	$0.12262	$1,440
Core Aggregation Transport (CAT):						
CAT Adder to Volumetric Rate	13,656	$0.00075	$10	13,319	$0.00070	$9
Residential:						
BaseLine Rate		$0.29131			$0.26682	
NonBaseLine Rate		$0.47488			$0.50682	
Large Master Meter:						
BaseLine Rate		$0.19967			$0.08456	
NonBaseLine Rate		$0.28100			$0.16019	
TOTAL RESIDENTIAL	2,546,852	$0.45485	$1,158,440	2,483,989	$0.46471	$1,154,332
CORE COMM & IND						
Customer Charge 1	82,094	$10.00	$9,851	127,666	$15.00	$22,980
Customer Charge 2	118,386	$15.00	$21,310	87,620	$15.00	$15,772
Volumetric Transportation Rate						
Tier 1 = 250th/mo	161,001	$0.49751	$80,100	215,926	$0.48180	$104,032
Tier 2 = next 4167 th/mo	510,030	$0.24101	$122,924	488,341	$0.24121	$117,795
Tier 3 = over 4167 th/mo	163,604	$0.06903	$11,294	266,252	$0.07991	$21,275
	834,635	$0.29411	$245,478	970,519	$0.29042	$281,854
Core Aggregation Transport (CAT):						
CAT Adder to Volumetric Rate	15,040	$0.00075	$11	17,488	$0.00070	$12
Tier 1 = 250th/mo		$0.49826			$0.48250	
Tier 2 = next 4167 th/mo		$0.24176			$0.24192	
Tier 3 = over 4167 th/mo		$0.06978			$0.08061	
TOTAL CORE C&I	834,635	$0.29413	$245,489	970,519	$0.29043	$281,866

See footnotes Table 1

TABLE 3
Other Core Transportation Rates
Southern California Gas Company
2009 BIENNIAL COST ALLOCATION PROCEEDING A.08-02-001

	Present Rates			BCAP Authorized Rates		
	Jan-1-09 Volumes Mth	Jan-1-09 Rate $/th	Jan-1-09 Revenue $000's	BCAP Volumes Mth	Rate $/th	Revenue $000's
NATURAL GAS VEHICLES (SempraWide Authorized Rates)						
Customer Charge, P-1		$13.00		229	$13	$36
Customer Charge, P-2A		$65.00		44	$65	$34
Uncompressed Rate	24,350	$0.10503	$2,558	117,231	$0.08418	$9,868
Total Uncompressed NGV	24,350	$0.10503	$2,558	117,231	$0.08478	$9,938
Compressed Rate Adder		$0.74624		1,484	$0.84823	$1,259
TOTAL NGV SERVICE	24,350	$0.10503	$2,558	117,231	$0.09552	$11,197
RESIDENTIAL NATURAL GAS VEHICLES (optional rate)						
Customer Charge				5,455	$10.00	$655
Uncompressed Rate				3,416	$0.13893	$475
				3,416	$0.33059	$1,129
NON-RESIDENTIAL GAS A/C						
Customer Charge	18	$150.00	$32	22	$150	$40
Volumetric Rate	1,200	$0.11319	$136	1,210	$0.05651	$68
	1,200	$0.13978	$168	1,210	$0.08923	$108
Core Aggregation Transport (CAT):						
CAT Adder to Volumetric Rate	646	$0.00075	$0.5			
Gas A/C Rate		$0.11394			$0.05651	
TOTAL A/C SERVICE	1,200	$0.14019	$168	1,210	$0.08923	$108
GAS ENGINES						
Customer Charge	698	$50.00	$419	1,094	$50	$656
Volumetric	16,040	$0.09025	$1,448	18,080	$0.07009	$1,267
	16,040	$0.11636	$1,866	18,080	$0.10640	$1,924
Core Aggregation Transport (CAT):						
CAT Adder to Volumetric Rate	0	$0.00075	$0.0			
Gas Engine Rate		$0.09100			$0.07009	
TOTAL GAS ENGINES	16,040	$0.11636	$1,866	18,080	$0.10640	$1,924

See footnotes Table 1

TABLE 4
Noncore Commercial & Industrial and Electric Generation Rates
Southern California Gas Company
2009 BIENNIAL COST ALLOCATION PROCEEDING A.08-02-001

	Present Rates			BCAP Authorized Rates		
	Jan-1-09 Volumes Mth	Jan-1-09 Rate $/th	Jan-1-09 Revenue $000's	BCAP Volumes Mth	Rate $/th	Revenue $000's
NonCore Comm & Ind Distribution						
Customer Charge	1,140	$350.00	$4,788	670	$350.00	$2,816
Volumetric Rates						
Tier 1 = 250k th/yr	236,030	$0.11956	$28,221	147,174	$0.14465	$21,289
Tier 2 = 250k to 1 million th/yr	312,418	$0.07025	$21,947	244,409	$0.08430	$20,603
Tier 3 = 1 to 2 million th/yr	149,105	$0.03870	$5,771	130,163	$0.04500	$5,857
Tier 4 = over 2 million th/yr	458,470	$0.01616	$7,409	460,719	$0.02273	$10,472
Volumetric totals (excl itcs)	1,156,023	$0.05480	$63,348	982,465	$0.05926	$58,221
ITCS	1,156,023	$0.00000	$0			
NCC&I - DISTRIBUTION	1,156,023	$0.05894	$68,136	982,465	$0.06213	$61,037
NonCore Comm & Ind Transmission (2)						
Customer Charge	22	$700.00	$189			
Volumetric Rates						
Tier 1 0-2,000,000 th/yr	24,319	$0.07118	$1,731			
Tier 2 over 2,000,000 th/yr	276,414	$0.00842	$2,327			
Volumetric totals (excl itcs)	300,733	$0.01349	$4,058			
ITCS	300,733	$0.00000	$0			
NCC&I-TRANSMISSION (2)	300,733	$0.01412	$4,247	457,697	$0.02275	$10,412
TOTAL NONCORE C&I	1,456,756	$0.04969	$72,383	1,440,163	$0.04961	$71,449
ELECTRIC GENERATION						
Small EG (Authorized rates are Distribution-only)						
Customer Charge	172	$50.00	$103	134	$50.00	$80
Volumetric Rate (excl ITCS)	48,406	$0.04565	$2,210	60,420	$0.05279	$3,190
ITCS	48,406	$0.00000	$0			
Total Volumetric Rate Tier 1	48,406	$0.04565	$2,210	60,420	$0.05279	$3,190
EG Distribution Level Tier 1	48,406	$0.04779	$2,313	60,420	$0.05412	$3,270
Large EG (Authorized rates are Distribution-only)						
Customer Charge	66	$0.00	$0	32	$0.00	$0
Volumetric Rate (excl ITCS)	2,895,851	$0.02273	$65,833	293,575	$0.02931	$8,606
ITCS	2,895,851	$0.00000	$0			
Total Volumetric Rate Tier 2	2,895,851	$0.02273	$65,833	293,575	$0.02931	$8,606
EG Distribution Level Tier 2	2,895,851	$0.02273	$65,833	293,575	$0.02931	$8,606
EG Distribution Level	2,944,257	$0.02315	$68,146	353,995	$0.03355	$11,876
EG Transmission Level (2)				2,472,969	$0.02275	$56,259
TOTAL ELECTRIC GENERATION	2,944,257	$0.02315	$68,146	2,826,964	$0.02410	$68,134
EOR Rates & Revenue:						
Distribution Level EOR:						
Customer Charge				14	$500.00	$84
Volumetric Rate				80,880	$0.03251	$2,629
Distribution Level EOR				80,880	$0.03355	$2,713
Transmission Level EOR				75,307	$0.02275	$1,713
Total EOR				156,187	$0.02834	$4,427

See footnotes Table 1

TABLE 5
Transmission Level Service Transportation Rates
Southern California Gas Company
2009 BIENNIAL COST ALLOCATION PROCEEDING A.08-02-001

	Present Rates			BCAP Authorized Rates		
	BCAP Volumes Mth	Rate $/th	Revenue at BCAP Vols $000's	BCAP Volumes Mth, Mdth	Rate $/th	Revenue $000's
Rate applicable to NonCore C&I EOR & EG customer Classes:						
Transmission Level Service						
Reservation Rates:						
Base Margin Items = Reservation Charge $/th/day					$0.01241	
NonBase Margin Items = Usage Charge $/th					$0.00483	
Class Average Volumetric Rates						
Base Margin Items = Volumetric Rate $/th					$0.01790	
NonBase Margin Items = Usage Charge $/th					$0.00483	
					$0.02273	
120% Class Average Volumetric Rate $/th					$0.02728	
135% Class Average Volumetric Rate $/th					$0.03069	
Total Transmission Level Service (NCCI, EOR, EG)				2,930,667	$0.02275	$66,671
Rate applicable to Wholesale & Int'l Customer Classes:						
Transmission Level Service						
Reservation Rates:						
Base Margin Items = Reservation Charge $/th/day					$0.01238	
NonBase Margin Items = Usage Charge $/th					$0.00481	
Class Average Volumetric Rates						
Base Margin Items = Volumetric Rate $/th					$0.01786	
NonBase Margin Items = Usage Charge $/th					$0.00481	
					$0.02268	
120% Class Average Volumetric Rate $/th					$0.02721	
135% Class Average Volumetric Rate $/th					$0.03061	
Total Transmission Level Service (WS & Int'l)				368,955	$0.02275	$8,393
Average Transmission Level Service				3,299,622	$0.02275	$75,064
Firm Access Rights						
FAR Reservation Charge $/dth/day				2,906	$0.05000	$53,038

See footnotes Table 1

TABLE 6 (Page 1 of 3)
SUMMARY OF COST ALLOCATION AND REVENUE REQUIREMENTS ($000s)
SOUTHERN CALIFORNIA GAS COMPANY 2009 Biennial Cost Allocation Proceeding A.08-02-001

COST COMPONENTS	Core	Retail Noncore	Noncore Wholesale	Noncore International	Unbundled Storage	System Total
Base Margin Costs:						
Customer Related Costs	$637,866	$13,678	$573	$28	$0	$652,145
Medium Pressure Distribution Costs	$514,660	$21,536	$0	$0	$0	$536,195
High Pressure Distribution Costs	$115,073	$31,230	$0	$0	$0	$146,303
Backbone Transmission Costs	$31,750	$36,255	$13,161	$442	$0	$81,607
Local Transmission Costs	$41,199	$26,724	$13,332	$352	$0	$81,607
Storage - Seasonal	$43,017	$0	$5,915	$0	$0	$48,933
Storage - Load Balancing	$3,302	$4,759	$1,662	$58	$0	$9,781
Storage - TBS	$0	$0	$0	$0	$24,575	$24,575
Non-DSM Marketing Related Costs	$42,794	$2,364	$1,167	$146	$0	$46,471
Uncollectibles	$4,898	$454	$0	$0	$0	$5,352
NGV compression adder	$1,278	$0	$0	$0	$0	$1,278
Total Margin Allocation pre-SI, pre-FAR Unbundle w/FFU	**$1,435,837**	**$136,999**	**$35,811**	**$1,026**	**$24,575**	**$1,634,247**
Less Backbone Transmission Costs	($31,750)	($36,255)	($13,161)	($442)	$0	($81,607)
Less Local Transmission Costs	($41,199)	($26,724)	($13,332)	($352)	$0	($81,607)
Plus Backbone Transmission Costs w/SI, FFU w/oFAR	$18,618	$21,246	$1,550	$259	$0	$41,672
Plus Local Transmission Costs w/SI, FFU	$50,845	$32,961	$3,109	$433	$0	$87,348
Total Allocated Base Margin post-SI, post-FAR Unbundle w/ FFU	**$1,432,349**	**$128,227**	**$13,977**	**$924**	**$24,575**	**$1,600,052**
Other Operating Costs and Revenues						
Co Use Transmission w/ FFU	$4,300	$5,293	$376	$64	$0	$10,033
Company Use Gas: Other	$816	$1,004	$350	$12	$0	$2,183
Company Use Gas: Storage Load Balancing	$692	$852	$298	$10	$0	$1,853
Exchange Revenues & Interutility Transactions	$9	$10	$4	$0	$0	$23
Fuel Cell Equipment Revenues	$0	$0	$0	$0	$0	$0
Marketing: DSM Program Awards	$0	$0	$0	$0	$0	$0
Unaccounted For (UAF) Gas	$31,463	$9,433	$3,289	$115	$0	$44,301
Well Incidents & Surface Leaks	$103	$122	$44	$2	$0	$271
Subtotal Other Operating Costs and Revenues	**$37,383**	**$16,715**	**$4,362**	**$204**	**$0**	**$58,663**
Transition Costs						
MPO Transition Cost Adjustment	$0	$0	$0	$0	$0	$0
Pitco/Popco Transition Costs	$0	$0	$0	$0	$0	$0
Total Transition Costs	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

TABLE 6 (Page 2 of 3)
SUMMARY OF COST ALLOCATION AND REVENUE REQUIREMENTS ($000s)
SOUTHERN CALIFORNIA GAS COMPANY 2009 Biennial Cost Allocation Proceeding A.08-02-001

COST COMPONENTS	Core	Retail Noncore	Noncore Wholesale	Noncore International	Unbundled Storage	System Total
Regulatory Accounts						
Affiliate Transfer Fee Account (ATFA)	($77)	($7)	($1)	($0)	$0	($84)
Blythe Operational Flow Req't Memo Account (BOFRMA)	$1,905	$2,264	$818	$29	$0	$5,015
FERC Settlement Proceeds Memorandum Account (FSPMA)	$22	$0	$0	$0	$0	$22
GRC Revenue Requirement Memo Account	($54,448)	($4,707)	($530)	($35)	$0	($59,720)
Firm Access & Storage Rights Memo Account (FARSMA)	$1,389	$1,650	$596	$21	$0	$3,656
California Solar Initiative Balancing Account (CSIBA)	$0	$0	$0	$0	$0	$0
G-PAL Balancing Account (GPBA)	$0	$0	$0	$0	$0	$0
Core Fixed Cost Account (CFCA)	$73,785	$0	$0	$0	$0	$73,785
Economic Practicality Shortfall Memo Account (EPSMA)	$53	$64	$23	$1	$0	$141
Enhanced Oil Recovery Account (EORA) CORE	$2,021	$0	$0	$0	$0	$2,021
Enhanced Oil Recovery Account (EORA) NONCORE	$0	$184	$21	$1	$0	$206
Hazardous Substance Cost-Recovery Account (HSCRA)	$2,307	$2,741	$990	$35	$0	$6,074
Interim Call Center Memorandum Account (ICCMA)	$0	$0	$0	$0	$0	$0
Intervenor Award Memorandum Account (IAMA)	$50	$59	$21	$1	$0	$132
Gain / Loss on Sale Memorandum Account (GLOSMA)	($82)	($7)	($1)	($0)	$0	($90)
Montebello True-Up Tracking Account (MTTA)	$0	$0	$0	$0	$0	$0
Montebello True-Up Tracking Account (MTTA)	$0	($2,901)	($1,051)	($37)	$0	($3,989)
Noncore Fixed Cost Account (NFCA)	$0	$9,854	$3,560	$124	$0	$13,539
Noncore Storage Memorandum Account (NSMA)	$0	$0	$0	$0	$0	$0
Integrated Transmission Balancing Account (ITBA)	$391	$431	$33	$5	$0	$861
Otay Mesa System Reliability Memo Account (OMSRMA)	$0	$0	$0	$0	$0	$0
Company-Use Fuel for Load Balancing Account (CUFLBA)	$0	$0	$0	$0	$0	$0
System Reliability Memorandum Account (SRMA)	$0	$0	$0	$0	$0	$0
Noncore Storage Balancing Account (NSBA)	($13,229)	($15,720)	($5,679)	($198)	$0	($34,827)
Pension Balancing Account (PBA)	($4,402)	($381)	($43)	($3)	$0	($4,829)
PBOP Balancing Account (PBOPBA)	($33,580)	($2,903)	($327)	($22)	$0	($36,831)
RD&D Expense Account (RDDEA)	$0	$0	$0	$0	$0	$0
Research Royalty Memo Account (RRMA)	$0	$0	$0	$0	$0	$0
Self-Generation Program Memo Account (SGPMA)	$3,090	$3,672	$1,327	$46	$0	$8,135
Total Regulatory Accounts	**($20,805)**	**($5,706)**	**($242)**	**($32)**	**$0**	**($26,785)**

TABLE 6 (Page 3 of 3)
SUMMARY OF COST ALLOCATION AND REVENUE REQUIREMENTS ($000s)
SOUTHERN CALIFORNIA GAS COMPANY 2009 Biennial Cost Allocation Proceeding A.08-02-001

COST COMPONENTS	Core	Retail Noncore	Noncore Wholesale	Noncore International	Unbundled Storage	System Total
Core Interstate Pipeline Demand Charges (IPDC)	$0	$0	$0	$0	$0	$0
Core Averaging (25% of Res/Retail Diff Phased over 3 years)	$0	$0	$0	$0	$0	$0
Transport Rev Req before EOR & G-EN CAP adjustments	$1,448,927	$139,236	$18,096	$1,096	$24,575	$1,631,930
EOR Revenue allocated to Other Classes	($4,036)	($349)	($39)	($3)	$0	($4,427)
EOR Costs allocated to Other Classes	$4,540	($4,587)	$44	$3	$0	$0
Gas Engine Rate CAP adjustment	$0	$0	$0	$0	$0	$0
Transport Rev Req w/SI, FFU, EOR Cr w/o FAR Rev, SW adj, TLS	**$1,449,431**	**$134,300**	**$18,101**	**$1,097**	**$24,575**	**$1,627,503**
Average Rate w/oFAR $/th	$0.40363	$0.03147	$0.01171	$0.02031	$0.00000	$0.17209
Sempra Wide & TLS Adjustments::						
Transport Rev Req w/SI, FFU, EOR Cr w/o FAR Rev, SW adj, TLS	$1,449,431	$134,300	$18,101	$1,097	$24,575	$1,627,503
SW NGV Adjustment	($3)	$0	$0			($3)
SW EG Adjustment	$0	$513	$0			$513
TLS Adjustment						
Amount allocated to TLS Class	$0	($61,900)	($7,279)	($1,097)		($70,276)
TLS revenue paid by class @ average TLS rate	$0	$66,671	$7,165	$1,228		$75,064
	$0	$4,771	($114)	$132	$0	$4,788
Transport Rev Req w/SI, FFU, EOR Cr, SW adj, TLS w/o FAR Rev	**$1,449,427**	**$139,584**	**$17,987**	**$1,228**	**$24,575**	**$1,632,801**
AYTP Mth/yr	3,591,030	4,267,127	1,545,250	53,990		9,457,396
Average Rate w/oFAR $/th	$0.40362	$0.03271	$0.01164	$0.02275		$0.17265
FAR w/FFU Charge	$20,776	$23,723	$8,250	$289	$0	$53,038
Transport Rev Req w/SI, FFU, EOR Cr, SW adj, TLS, FAR Rev	$1,470,203	$163,307	$26,237	$1,517	$24,575	$1,685,839
Average Rate w/ FAR $/th	$0.40941	$0.03827	$0.01698	$0.02811		$0.17826

TABLE 7 (Page 1 of 3)
SUMMARY OF COST ALLOCATION AND REVENUE REQUIREMENTS ($000s)
SOUTHERN CALIFORNIA GAS COMPANY 2009 Biennial Cost Allocation Proceeding A.08-02-001

COST COMPONENTS	Residential	Core C&I	NonRes A/C	Gas Eng	NGV	Total Core
Base Margin Costs:						
Customer Related Costs	$562,728	$71,705	$41	$828	$2,564	$637,866
Medium Pressure Distribution Costs	$423,843	$90,093	$5	$271	$448	$514,660
High Pressure Distribution Costs	$89,149	$24,283	$16	$174	$1,450	$115,073
Backbone Transmission Costs	$22,299	$8,333	$10	$148	$960	$31,750
Local Transmission Costs	$31,677	$8,702	$6	$65	$750	$41,199
Storage - Seasonal	$36,687	$6,306	$0	$9	$16	$43,017
Storage - Load Balancing	$2,284	$892	$1	$17	$108	$3,302
Storage - TBS	$0	$0	$0	$0	$0	$0
Non-DSM Marketing Related Costs	$24,954	$16,982	$0	$8	$850	$42,794
Uncollectibles	$4,126	$748	$0	$4	$20	$4,898
NGV compression adder	$0	$0	$0	$0	$1,278	$1,278
Total Margin Allocation pre-SI, pre-FAR Unbundle w/FFU	**$1,197,746**	**$228,044**	**$80**	**$1,524**	**$8,443**	**$1,435,837**
Less Backbone Transmission Costs	($22,299)	($8,333)	($10)	($148)	($960)	($31,750)
Less Local Transmission Costs	($31,677)	($8,702)	($6)	($65)	($750)	($41,199)
Plus Backbone Transmission Costs w/SI, FFU w/oFAR	$13,076	$4,886	$6	$87	$563	$18,618
Plus Local Transmission Costs w/SI, FFU	$39,092	$10,740	$7	$80	$926	$50,845
Total Allocated Base Margin post-SI, post-FAR Unbundle w/ FFU	**$1,195,939**	**$226,635**	**$77**	**$1,477**	**$8,222**	**$1,432,349**
Other Operating Costs and Revenues						
Co Use Transmission w/ FFU	$2,974	$1,162	$1	$22	$140	$4,300
Company Use Gas: Other	$564	$220	$0	$4	$27	$816
Company Use Gas: Storage Load Balancing	$479	$187	$0	$3	$23	$692
Exchange Revenues & Interutility Transactions	$6	$2	$0	$0	$0	$9
Fuel Cell Equipment Revenues	$0	$0	$0	$0	$0	$0
Marketing: DSM Program Awards	$0	$0	$0	$0	$0	$0
Unaccounted For (UAF) Gas	$21,764	$8,503	$11	$158	$1,027	$31,463
Well Incidents & Surface Leaks	$71	$28	$0	$1	$3	$103
Subtotal Other Operating Costs and Revenues	**$25,859**	**$10,103**	**$13**	**$188**	**$1,220**	**$37,383**
Transition Costs						
MPO Transition Cost Adjustment	$0	$0	$0	$0	$0	$0
Pitco/Popco Transition Costs	$0	$0	$0	$0	$0	$0
Total Transition Costs	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

TABLE 7 (page 2 of 3)
SUMMARY OF COST ALLOCATION AND REVENUE REQUIREMENTS ($000s)
SOUTHERN CALIFORNIA GAS COMPANY 2009 Biennial Cost Allocation Proceeding A.08-02-001

COST COMPONENTS	Residential	Core C&I	NonRes A/C	Gas Eng	NGV	Total Core
Regulatory Accounts						
Affiliate Transfer Fee Account (ATFA)	($64)	($12)	($0)	($0)	($0)	($77)
Blythe Operational Flow Req't Memo Account (BOFRMA)	$1,318	$515	$1	$10	$62	$1,905
FERC Settlement Proceeds Memorandum Account (FSPMA)	$9	$12	$0	$0	$0	$22
GRC Revenue Requirement Memo Account	($45,462)	($8,615)	($3)	($56)	($313)	($54,448)
Firm Access & Storage Rights Memo Account (FARSMA)	$961	$375	$0	$7	$45	$1,389
California Solar Initiative Balancing Account (CSIBA)	$0	$0	$0	$0	$0	$0
G-PAL Balancing Account (GPBA)	$0	$0	$0	$0	$0	$0
Core Fixed Cost Account (CFCA)	$51,039	$19,941	$25	$371	$2,409	$73,785
Economic Practicality Shortfall Memo Account (EPSMA)	$37	$14	$0	$0	$2	$53
Enhanced Oil Recovery Account (EORA) CORE	$1,688	$320	$0	$2	$12	$2,021
Enhanced Oil Recovery Account (EORA) NONCORE	$0	$0	$0	$0	$0	$0
Hazardous Substance Cost-Recovery Account (HSCRA)	$1,596	$624	$1	$12	$75	$2,307
Interim Call Center Memorandum Account (ICCMA)	$0	$0	$0	$0	$0	$0
Intervenor Award Memorandum Account (IAMA)	$35	$14	$0	$0	$2	$50
Gain / Loss on Sale Memorandum Account (GLOSMA)	($69)	($13)	($0)	($0)	($0)	($82)
Montebello True-Up Tracking Account (MTTA)	$0	$0	$0	$0	$0	$0
Montebello True-Up Tracking Account (MTTA)	$0	$0	$0	$0	$0	$0
Noncore Fixed Cost Account (NFCA)	$0	$0	$0	$0	$0	$0
Noncore Storage Memorandum Account (NSMA)	$0	$0	$0	$0	$0	$0
Integrated Transmission Balancing Account (ITBA)	$275	$103	$0	$2	$12	$391
Otay Mesa System Reliability Memo Account (OMSRMA)	$0	$0	$0	$0	$0	$0
Company-Use Fuel for Load Balancing Account (CUFLBA)	$0	$0	$0	$0	$0	$0
System Reliability Memorandum Account (SRMA)	$0	$0	$0	$0	$0	$0
Noncore Storage Balancing Account (NSBA)	($9,151)	($3,575)	($4)	($67)	($432)	($13,229)
Pension Balancing Account (PBA)	($3,676)	($697)	($0)	($5)	($25)	($4,402)
PBOP Balancing Account (PBOPBA)	($28,037)	($5,313)	($2)	($35)	($193)	($33,580)
RD&D Expense Account (RDDEA)	$0	$0	$0	$0	$0	$0
Research Royalty Memo Account (RRMA)	$0	$0	$0	$0	$0	$0
Self-Generation Program Memo Account (SGPMA)	$2,137	$835	$1	$16	$101	$3,090
Total Regulatory Accounts	**($27,365)**	**$4,527**	**$19**	**$258**	**$1,756**	**($20,805)**

TABLE 7 (Page 3 of 3)
SUMMARY OF COST ALLOCATION AND REVENUE REQUIREMENTS ($000s)
SOUTHERN CALIFORNIA GAS COMPANY 2009 Biennial Cost Allocation Proceeding A.08-02-001

COST COMPONENTS	Residential	Core C&I	NonRes A/C	Gas Eng	NGV	Total Core
Core Interstate Pipeline Demand Charges (IPDC)	$0	$0	$0	$0	$0	$0
Core Averaging (25% of Res/Retail Diff Phased over 3 years)	($40,521)	$40,521	$0	$0	$0	$0
Transport Rev Req before EOR & G-EN CAP adjustments	$1,153,912	$281,786	$108	$1,923	$11,198	$1,448,927
EOR Revenue allocated to Other Classes	($3,370)	($639)	($0)	($4)	($23)	($4,036)
EOR Costs allocated to Other Classes	$3,790	$718	$0	$5	$26	$4,540
Gas Engine Rate CAP adjustment	$0	$0	$0	$0	$0	$0
Transport Rev Req w/SI, FFU, EOR Cr w/o FAR Rev, SW adj, TLS	**$1,154,332**	**$281,866**	**$108**	**$1,924**	**$11,201**	**$1,449,431**
Average Rate w/oFAR $/th	$0.46471	$0.29043	$0.08923	$0.10640	$0.09555	$0.40363
Sempra Wide & TLS Adjustments::						
Transport Rev Req w/SI, FFU, EOR Cr w/o FAR Rev, SW adj, TLS	$1,154,332	$281,866	$108	$1,924	$11,201	$1,449,431
SW NGV Adjustment					($3)	($3)
SW EG Adjustment						$0
TLS Adjustment						
Amount allocated to TLS Class						$0
TLS revenue paid by class @ average TLS rate						$0
	$0	$0	$0	$0	$0	$0
Transport Rev Req w/SI, FFU, EOR Cr, SW adj, TLS w/o FAR Rev	**$1,154,332**	**$281,866**	**$108**	**$1,924**	**$11,197**	**$1,449,427**
AYTP Mth/yr	2,483,989	970,519	1,210	18,080	117,231	3,591,030
Average Rate w/oFAR $/th	$0.46471	$0.29043	$0.08923	$0.10640	$0.09552	$0.40362
FAR w/FFU Charge	$14,591	$5,453	$6	$97	$628	$20,776
Transport Rev Req w/SI, FFU, EOR Cr, SW adj, TLS, FAR Rev	$1,168,924	$287,319	$114	$2,021	$11,825	$1,470,203
Average Rate w/ FAR $/th	$0.47058	$0.29605	$0.09459	$0.11176	$0.10087	$0.40941

TABLE 8 (Page 1 of 3)

SUMMARY OF COST ALLOCATION AND REVENUE REQUIREMENTS ($000s)

SOUTHERN CALIFORNIA GAS COMPANY 2009 Biennial Cost Allocation Proceeding A.08-02-001

COST COMPONENTS	Noncore C&I	EG Tier 1	EG Tier 2	EOR	Total Retail Noncore	Long Beach	SDG&E	South-West Gas	Vernon	Total Wholesale	DGN	UBS	Total Noncore	System Total
Base Margin Costs:														
Customer Related Costs	$8,066	$4,939	($18)	$691	$13,678	$120	$115	$231	$106	$573	$28	$0	$14,279	$652,145
Med Pressure Distrib Costs	$19,520	$1,140	$843	$33	$21,536	$0	$0	$0	$0	$0	$0	$0	$21,536	$536,195
High Pressure Distribution Costs	$18,918	$968	$9,866	$1,478	$31,230	$0	$0	$0	$0	$0	$0	$0	$31,230	$146,303
Backbone Transmission Costs	$11,829	$624	$22,523	$1,279	$36,255	$1,012	$10,511	$686	$951	$13,161	$442	$0	$49,857	$81,607
Local Transmission Costs	$9,821	$453	$15,503	$947	$26,724	$1,040	$10,807	$744	$741	$13,332	$352	$0	$40,408	$81,607
Storage - Seasonal	$0	$0	$0	$0	$0	$0	$5,915	$0	$0	$5,915	$0	$0	$5,915	$48,933
Storage - Load Balancing	$1,549	$82	$2,959	$168	$4,759	$126	$1,324	$88	$125	$1,662	$58	$0	$6,479	$9,781
Storage - TBS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$24,575	$24,575	$24,575
Non-DSM Marketing Related Costs	$1,070	$1,044	$104	$146	$2,364	$292	$292	$292	$292	$1,167	$146	$0	$3,677	$46,471
Uncollectibles	$246	$26	$182	$0	$454	$0	$0	$0	$0	$0	$0	$0	$454	$5,352
NGV compression adder	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,278
Total Margin Alloc pre-SI, pre-FAR Unbund w/FFU	$71,019	$9,276	$51,962	$4,742	$136,999	$2,590	$28,963	$2,042	$2,215	$35,811	$1,026	$24,575	$198,410	$1,634,247
Less Backbone Transmn Costs	($11,829)	($624)	($22,523)	($1,279)	($36,255)	($1,012)	($10,511)	($686)	($951)	($13,161)	($442)	$0	($49,857)	($81,607)
Less Local Transmission Costs	($9,821)	($453)	($15,503)	($947)	($26,724)	($1,040)	($10,807)	($744)	($741)	($13,332)	($352)	$0	($40,408)	($81,607)
Plus Bb Trans Costs w/SI+FFU w/oFAR	$6,936	$366	$13,207	$737	$21,246	$592	$0	$401	$556	$1,550	$259	$0	$23,055	$41,672
Plus Local Transmission Costs w/SI, FFU	$12,120	$559	$19,132	$1,149	$32,961	$1,280	$0	$916	$913	$3,109	$433	$0	$36,503	$87,348
Total Alloc Base Margin post-SI, post-FAR Unbund w/ FFU	$68,425	$9,124	$46,275	$4,403	$128,227	$2,411	$7,645	$1,929	$1,992	$13,977	$924	$24,575	$167,702	$1,600,052
Other Oper Costs and Revenues														
Co Use Transmission w/ FFU	$1,724	$91	$3,293	$184	$5,293	$140	$0	$98	$139	$376	$64	$0	$5,734	$10,033
Company Use Gas: Other	$327	$17	$625	$35	$1,004	$27	$279	$19	$26	$350	$12	$0	$1,367	$2,183
Co. Use Gas: Storage Load Balancing	$278	$15	$530	$30	$852	$23	$237	$16	$22	$298	$10	$0	$1,161	$1,853
Exch Revenues & Interutil Transactns	$3	$0	$6	$0	$10	$0	$3	$0	$0	$4	$0	$0	$14	$23
Fuel Cell Equipment Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Marketing: DSM Program Awards	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Unaccounted For (UAF) Gas	$3,073	$163	$6,870	$328	$9,433	$249	$2,619	$174	$247	$3,289	$115	$0	$12,837	$44,301
Well Incidents & Surface Leaks	$41	$2	$79	$0	$122	$3	$35	$2	$3	$44	$2	$0	$168	$271
Subtotal Other Oper Costs & Rev	$5,447	$288	$10,404	$576	$16,715	$442	$3,173	$308	$438	$4,362	$204	$0	$21,280	$58,663
Transition Costs														
MPO Transition Cost Adjustment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Pitco/Popco Transition Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Transition Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

TABLE 8 (Page 2 of 3)

SUMMARY OF COST ALLOCATION AND REVENUE REQUIREMENTS ($000s)

SOUTHERN CALIFORNIA GAS COMPANY 2009 Biennial Cost Allocation Proceeding A.08-02-001

NONCORE BALANCING TRACKING & MEMO ACCTS	Noncore C&I	EG Tier 1	EG Tier 2	EOR	Total Retail Noncore	Long Beach	SDG&E	South-West Gas	Vernon	Total Wholesale	DGN	UBS	Total Noncore	System Total
Regulatory Accounts														
Affiliate Transfer Fee (ATFA)	($4)	($0)	($2)	$0	($7)	($0)	($0)	($0)	($0)	($1)	($0)	$0	($7)	($84)
Blythe Oper Flow Req Memo (BOFRMA)	$764	$40	$1,459	$0	$2,264	$62	$651	$43	$61	$818	$29	$0	$3,110	$6,015
FERC Settlmt Proceeds Memo (FSPMA)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$22
General Rate Case Revenue Req't Memo	($2,601)	($347)	($1,759)	$0	($4,707)	($91)	($290)	($73)	($76)	($530)	($35)	$0	($5,272)	($59,720)
Firm Acc & Stor Rts Memo (FARSMA)	$557	$29	$1,064	$0	$1,650	$45	$475	$32	$45	$596	$21	$0	$2,267	$3,656
CA Solar Init Balancing Acct (CSIBA)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
G-PAL Balancing Account (GPBA)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Core Fixed Cost Account (CFCA)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$73,785
Econ Pract Shortfall Memo (EPSMA)	$21	$1	$41	$0	$64	$2	$18	$1	$2	$23	$1	$0	$87	$141
Enhanced Oil Recovery (EORA) CORE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,021
EOR (EORA) NONCORE	$102	$14	$69	$0	$184	$4	$11	$3	$3	$21	$1	$0	$206	$206
Haz Subst Cost-Recovery (HSCRA)	$925	$49	$1,767	$0	$2,741	$75	$789	$52	$74	$990	$35	$0	$3,766	$6,074
Interim Call Center Memo (ICCMA)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Intervenor Award Memo (IAMA)	$20	$1	$38	$0	$59	$2	$17	$1	$2	$21	$1	$0	$82	$132
Gain / Loss on Sale Memo (GLOSMA)	($4)	($1)	($3)	$0	($7)	($0)	($0)	($0)	($0)	($1)	($0)	$0	($8)	($90)
Montebello True-Up Tracking (MTTA)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Montebello True-Up Tracking (MTTA)	($979)	($52)	($1,870)	$0	($2,901)	($80)	($836)	($56)	($79)	($1,051)	($37)	$0	($3,989)	($3,989)
Noncore Fixed Cost Account (NFCA)	$3,326	$176	$6,352	$0	$9,854	$270	$2,834	$188	$268	$3,560	$124	$0	$13,539	$13,539
Noncore Storage Memo (NSMA)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Integrated Transmn Bal Acct (ITBA)	$146	$8	$278	$0	$431	$12	$0	$8	$12	$33	$5	$0	$469	$861
Otay Mesa Sys Relia Memo (OMSRMA)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Co.-Use Fuel for Load Bal (CUFLBA)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
System Reliability Memo (SRMA)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Noncore Storage Balancing (NSBA)	($5,306)	($281)	($10,134)	$0	($15,720)	($430)	($4,522)	($300)	($427)	($5,679)	($198)	$0	($21,597)	($34,827)
Pension Balancing Account (PBA)	($210)	($28)	($142)	$0	($381)	($7)	($23)	($6)	($6)	($43)	($3)	$0	($426)	($4,829)
PBOP Balancing Account (PBOPBA)	($1,604)	($214)	($1,085)	$0	($2,903)	($56)	($179)	($45)	($47)	($327)	($22)	$0	($3,251)	($36,831)
RD&D Expense Account (RDDEA)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Research Royalty Memo (RRMA)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Self-Gen Program Memo (SGPMA)	$1,239	$66	$2,367	$0	$3,672	$101	$1,056	$70	$100	$1,327	$46	$0	$5,045	$8,135
Total Regulatory Accounts	($3,608)	($538)	($1,560)	$0	($5,706)	($94)	$0	($81)	($68)	($242)	($32)	$0	($5,980)	($26,785)

TABLE 8 (Page 3 of 3)

SUMMARY OF COST ALLOCATION AND REVENUE REQUIREMENTS ($000s)

SOUTHERN CALIFORNIA GAS COMPANY 2009 Biennial Cost Allocation Proceeding A.08-02-001

COST COMPONENTS	Noncore C&I	EG Tier 1	EG Tier 2	EOR	Total Retail Noncore	Long Beach	SDG&E	South-West Gas	Vernon	Total Whole-sale	DGN	UBS	Total Noncore	System Total
Core Interst PL Demand Chrges (IPDC)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Core Avging (25% of Res/Ret Diff Phased 3yrs)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transp Rev Req before EOR & G-EN CAP adj	$70,264	$8,873	$55,119	$4,979	$139,236	$2,759	$10,819	$2,156	$2,362	$18,096	$1,096	$24,575	$183,003	$1,631,930
EOR Rev allocated to Other Classes	($193)	($26)	($130)		($349)	($7)	($22)	($5)	($6)	($39)	($3)	$0	($391)	($4,427)
EOR Costs allocated to Other Classes	$217	$29	$147	($4,979)	($4,587)	$8	$24	$6	$6	$44	$3	$0	($4,540)	$0
Gas Engine Rate CAP adjustment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transport Rev Req w/SI, FFU, EOR Cr w/o FAR Rev, SW adj, TLS	**$70,288**	**$8,877**	**$55,135**	**$0**	**$134,300**	**$2,760**	**$10,822**	**$2,157**	**$2,363**	**$18,101**	**$1,097**	**$24,575**	**$178,073**	**$1,627,503**
Average Rate w/oFAR $/th	$0.04881	$0.11649	$0.02004	$0.00000	$0.03147	$0.02357	$0.00880	$0.02639	$0.02034	$0.01171	$0.02031	$0.00000	$0.03035	$0.17209
Sempra Wide & TLS Adjustments::														
Transport Rev Req w/SI, FFU, EOR Cr w/o FAR Rev, SW adj, TLS	$70,288		$64,012		$134,300	$2,760	$10,822	$2,157	$2,363	$18,101	$1,097	$24,575	$178,073	$1,627,503
SW NGV Adjustment					$0					$0			$0	($3)
SW EG Adjustment			$513		$513					$0			$513	$513
TLS Adjustment														
Amount allocated to TLS Class	($9,251)		($52,649)		($61,900)	($2,760)		($2,157)	($2,363)	($7,279)	($1,097)		($70,276)	($70,276)
TLS rev paid by class @ avg TLS rate	$10,412		$56,259		$66,671	$2,664		$1,859	$2,642	$7,165	$1,228		$75,064	$75,064
	$1,161		$3,610		$4,771	($96)	$0	($297)	$279	($114)	$132	$0	$4,788	$4,788
Transport Rev Req w/SI, FFU, EOR Cr, SW adj, TLS w/o FAR Rev	**$71,449**		**$68,134**		**$139,584**	**$2,664**	**$10,822**	**$1,859**	**$2,642**	**$17,987**	**$1,228**	**$24,575**	**$183,374**	**$1,632,801**
AYTP Mth/yr	1,440,163		2,826,964		4,267,127	117,093	1,230,285	81,737	116,135	1,545,250	53,990		5,866,366	9,457,396
Average Rate w/oFAR $/th	$0.04961		$0.02410		$0.03271	$0.02275	$0.00880	$0.02275	$0.02275	$0.01164	$0.02275		$0.03126	$0.17265
FAR w/FFU Charge	$7,740	$408	$14,738	$837	$23,723	$662	$6,517	$449	$622	$8,250	$289	$0	$32,263	$53,038
Transport Rev Req w/SI, FFU, EOR Cr, SW adj, TLS, FAR Rev	$79,190	$408	$82,872	$837	$163,307	$3,326	$17,338	$2,308	$3,264	$26,237	$1,517	$24,575	$215,636	$1,685,839
Average Rate w/ FAR $/th	$0.05499	$0.00536	$0.03013		$0.03827	$0.02841	$0.01409	$0.02824	$0.02811	$0.01698	$0.02811		$0.03676	$0.17826

APPENDIX C

TABLE 1
Gas Transportation Rate Revenues
San Diego Gas & Electric
2009 BIENNIAL COST ALLOCATION PROCEEDING A.08-02-001

	At Present Rates			BCAP Authorized Rates			Changes		
	Jan-1-09 Volumes mtherms	Jan-1-09 Revenues $1,000	Average Rate $/therm	BCAP Volumes mtherms	Revenues $1,000	Average Rate $/therm	Revenues $1,000	Rates $/therm	Rate change %
CORE									
Residential	326,207	$209,852	$0.64331	326,003	$213,767	$0.65572	$3,915	$0.01241	1.9%
Comm & Ind	129,794	$39,508	$0.30439	158,725	$44,170	$0.27828	$4,661	($0.02611)	-8.6%
NGV Pre SempraWide	4,030	$3,894	$0.96634	15,238	$1,407	$0.09236	($2,487)	($0.87399)	-90.4%
SempraWide Adjustment				15,238	$4	$0.00023	$4		
NGV Post SempraWide	4,030	$3,894	$0.96634	15,238	$1,411	$0.09259	($2,483)	($0.87376)	-90.4%
Total CORE	460,031	$253,255	$0.55052	499,967	$259,348	$0.51873	$6,093	($0.03179)	-5.8%
NONCORE COMM & IND									
Distribution Level Service	75,005	$6,249	$0.08331	37,270	$3,885	$0.10425	($2,364)	$0.02094	25.1%
Transmission Level Service (1)	11,206	$459	$0.04095	3,193	$73	$0.02275	($386)	($0.01820)	-44.4%
Total Noncore C&I	86,211	$6,708	$0.07781	40,463	$3,958	$0.09782	($2,750)	$0.02001	25.7%
NONCORE EG									
Dist Level Service (2008 is all EG; no separate transm rate in 2008)									
Pre Sempra Wide	897,926	$24,820	$0.02764	179,522	$6,483	$0.03611	($18,338)	$0.00847	30.6%
Sempra Wide Adjustment	897,926	($2,457)	($0.00274)	179,522	($516)	($0.00287)	$1,941		
Post Sempra Wide	897,926	$22,364	$0.02491	179,522	$5,967	$0.03324	($16,397)	$0.00833	33.5%
Transmission Level Service (1)				496,393	$11,293	$0.02275			
Total Electric Generation	897,926	$22,364	$0.02491	675,916	$17,259	$0.02553	($5,104)	$0.00063	2.5%
TOTAL NONCORE	984,137	$29,071	$0.02954	716,379	$21,217	$0.02962	($7,854)	$0.00008	0.3%
Total (excluding FAR) (2)	1,444,168	$282,326	$0.19549	1,216,345	$280,565	$0.23066	($1,761)	$0.03517	18.0%
System Total	**1,444,168**	**$282,326**	**$0.19549**	**1,216,345**	**$280,565**	**$0.23066**	**($1,761)**	**$0.03517**	**18.0%**

1) These authorized costs and rates for Transmission Level Service customers represents the average transmission rate. See Table 5 for actual transmission level service rates.
2) FAR charge is authorized as a separate rate. Core will pay through procurement rate, noncore as a separate charge. See SCG Rate Table 5 for actual FAR charge.

TABLE 2
Core Gas Transportation Rates
San Diego Gas & Electric
2009 BIENNIAL COST ALLOCATION PROCEEDING A.08-02-001

	Present Rates			BCAP Authorized Rates		
	Jan-1-09 Volumes Mth	Jan-1-09 Rate $/therm	Jan-1-09 Revenue $1,000	BCAP Volumes Mth	Rates $/therm	Revenue $1,000
Schedule GR,GM						
Baseline $/therm	220,148	$0.57027	$125,544	220,010	$0.61372	$135,025
Non-Baseline $/therm	106,059	$0.84050	$89,143	105,993	$0.77501	$82,145
Average Rate $/therm	326,207	$0.65813	$214,686	326,003	$0.66616	$217,171
NBL/BL Composite Ratio (incl G-PC)		1.14			1.14	
Schedule GS,GT						
GS Unit Discount $/day	5,818	($0.25493)	($541)	6,004	($0.25493)	($559)
GT Unit Discount $/day	27,494	($0.34064)	($3,418)	27,745	($0.34064)	($3,450)
Other Adjustments :						
Employee Discount						($459)
SDFFD			(944)			$988
Schedule GL-1						
LNG Facility Charge, domestic use $/month		$14.79		321	$14.79	$57
LNG Facility Charge, non-domestic use $/mth/mbtu		$0.05480			$0.05480	
LNG Volumetric Surcharge $/th		$0.16571		110	$0.16571	$18
						$75
Schedule GTC & GTCA (transpt-only SCG & SDGE)						
CAT Adder to Volumetric Rate	9,281	$0.00755	$70	0	$0.00000	$0
Baseline $/therm		$0.57782			$0.61372	
Non-Baseline $/therm		$0.84805			$0.77501	
Average Rate $/therm		$0.66566			$0.66616	
Schedule GTC-SD (transport-only SDGE system)						
GTC-SD Rate Adder		($0.00471)				
Baseline $/therm		$0.57311				
Non-Baseline $/therm		$0.84334				
Average Rate $/therm		$0.66095				
Total Residential	326,207	$0.64331	$209,852	326,003	$0.65572	$213,767
Other Core Rates $/therm						
Schedule GPC - Procurement Price		$0.55392			$0.50800	
		$0.75522				
Schedule GN-3						
Customer Charge $/month				29,831	$10.00	$3,580
0 to 1,000 therms/month	13,777	$5.58	$923			
1,001 to 21,000 therms/month	12,769	$11.16	$1,711			
over 21,000 therms/month	920	$111.61	$1,232			
Volumetric Charges $/therm - Winter Months						
Tier 1 = 0 to 1,000 therms/month	24,932	$0.43792	$10,918	69,961	$0.32849	$22,982
Tier 2 = 1,001 to 21,000 therms/month	23,107	$0.17205	$3,976	74,938	$0.20120	$15,078
Tier 3 = over 21,000 therms/month	5,489	$0.11574	$635	13,826	$0.16524	$2,285
Volumetric Charges $/therm - Summer Months						
Tier 1 = 0 to 1,000 therms/month	40,197	$0.34324	$13,797			
Tier 2 = 1,001 to 21,000 therms/month	36,069	$0.16691	$6,020			
Tier 3 = over 21,000 therms/month	0	$0.09831	$0			
Adjustment for SDFFD			$296			$246
Total Core C&I	129,794	$0.30439	$39,508	158,725	$0.27828	$44,170

See footnotes Table 1

TABLE 3
Other Core Gas Transportation Rates
San Diego Gas & Electric
2009 BIENNIAL COST ALLOCATION PROCEEDING A.08-02-001

	Present Rates			BCAP Authorized Rates		
	Jan-1-09 Volumes Mth	Jan-1-09 Rate $/therm	Jan-1-09 Revenue $1,000	BCAP Volumes Mth	Rates $/therm	Revenue $1,000
Schedule G-NGV & GT-NGV				*Sempra-Wide NGV Rates*		
Customer Charge						
P1 $/month		$0.00		30	$13.00	$5
P2A $/month		$0.00		10	$65.00	$8
Uncompressed Rate $/therm	4,030	$0.16284	$656	15,238	$0.08466	$1,290
Co-funded Station $/therm	0	$0.56327	$0			
Compressor Adder $/therm	4,022	$0.80086	$3,221	119	$0.85310	$102
Schedule GTC-SD						
Customer Charge						
P1 $/month						
P2A $/month						
Uncompressed Rate $/therm						
Co-funded Station $/therm						
Compressor Adder $/therm						
SDFFD			$17			$7
Total NGV	4,030	$0.96634	$3,894	15,238	$0.09259	$1,411

See footnotes Table 1

TABLE 4
NonCore Gas Transportation Rates
San Diego Gas & Electric
2009 BIENNIAL COST ALLOCATION PROCEEDING A.08-02-001

	Present Rates			BCAP Authorized Rates		
	Jan-1-09 Volumes Mth	Jan-1-09 Rate $/therm	Jan-1-09 Revenue $1,000	BCAP Volumes Mth	Rates $/therm	Revenue $1,000
NonCore Comm & Ind Distribution Level						
Volumetric Charges $/therm						
MPS - Winter	13,442	$0.10789	$1,450	37,270	$0.09749	$3,633
MPS - Summer	27,078	$0.08572	$2,321			
HPS - Winter	11,440	$0.07086	$811			
HPS - Summer	23,045	$0.05427	$1,251			
Customer Charges $/month						
0 to 3,000 therms/month	5	$17.86	$1	60	$350.00	$252
3,001 to 7,000	1	$92.64	$1			
7,001 to 21,000	15	$168.54	$29			
21,001 to 126,000	62	$338.19	$250			
126,001 to 1,000,000	11	$678.61	$90			
SDFFD			$45			
NCC&I-Distribution Total	75,005	$0.08331	$6,249	37,270	$0.10425	$3,885
NonCore Comm & Ind Transmission Level (1)						
Volumetric Charges $/therm						
Transmission - Winter	3,717	$0.04753	$177			
Transmission - Summer	7,489	$0.03647	$273			
Customer Charges $/month						
Over 1,000,000 therms/month	0.3	$1,439.82	$6			
SDFFD			$3			
NCC&I-Transmission Total (1)	11,206	$0.04095	$459	3,193	$0.02275	$73
AMR Charges		$137.36				
Noncore C&I Total	86,211	$0.07781	$6,708	40,463	$0.09782	$3,958
ELECTRIC GENERATION						
Distribution Level Service Group A						
Customer Charge, $/month	51	$50.00	$31	57	$50.00	$34
Volumetric Rate (Incl ITCS) $/therm	83,765	$0.04565	$3,824	27,097	$0.05310	$1,439
Distribution Level Service Group B						
Volumetric Rate (Incl ITCS) $/therm	814,161	$0.02273	$18,509	152,425	$0.02948	$4,494
Total EG-Distribution	897,926	$0.02491	$22,364	179,522	$0.03324	$5,967
EG Transmission Level Service (1)				496,393	$0.02275	$11,293
TOTAL ELECTRIC GENERATION	897,926	$0.02491	$22,364	675,916	$0.02553	$17,259
OTHER RATES:						
ITCS Rate						

See footnotes Table 1

TABLE 5

Transmission Level Service Gas Transportation Rates

San Diego Gas & Electric

2009 BIENNIAL COST ALLOCATION PROCEEDING A.08-02-001

	Present Rates			BCAP Authorized Rates		
	Jan-1-09 Volumes Mth	Jan-1-09 Rate $/therm	Jan-1-09 Revenue $1,000	BCAP Volumes Mth	Rates $/therm	Revenue $1,000
Transmissiom Level Service						
Reservation Rates:						
Base Margin Items = Reservation Charge $/th/day					$0.01248	
NonBase Margin Items = Usage Charge $/th					$0.00485	
Class Average Volumetric Rates						
Base Margin Items = Volumetric Rate $/th					$0.01801	
NonBase Margin Items = Usage Charge $/th					$0.00485	
					$0.02286	
120% Class Average Volumetric Rate $/th					$0.02743	
135% Class Average Volumetric Rate $/th					$0.03086	
Average Transmission Level Service				499,587	$0.02275	$11,365

See footnotes Table 1

TABLE 6 (Page 1 of 3)
Summary of Cost Allocation and Revenue Requirement ($000s)
San Diego Gas & Electric
2009 Biennial Cost Allocation Proceeding A.08-02-001

COST COMPONENTS	Core	Retail Noncore	System Total
Embedded Costs:			
Customer Related Costs	$138,816	$2,821	$141,637
Medium Pressure Distribution Costs	$55,433	$1,451	$56,884
High Pressure Distribution Costs	$5,787	$892	$6,679
Backbone Transmission Costs	$10,197	$8,817	$19,014
Local Transmission Costs	$8,282	$10,732	$19,014
Storage - Borrego	$0	$0	$0
Functionalized A&G	$0	$0	$0
Core Seasonal Storage	$0	$0	$0
Storage - Load Balancing	$0	$0	$0
NGV	$83	$0	$83
Ttl Marg Alloc pre-SI/FAR Unbundle w/FFU	$218,597	$24,713	$243,310
Less Backbone Transmission Costs	($10,197)	($8,817)	($19,014)
Less Local Transmission Costs	($8,282)	($10,732)	($19,014)
Plus Bbone Trnsm Cost w/SI,FFUw/oFAR	$2,414	$3,459	$5,873
Plus Local Transmission Costs w/SI,FFU	$7,112	$6,149	$13,261
Total Allocated Base Margin post-SI post-FAR Unbundle, w/ FFU	$209,645	$14,773	$224,418
Other Operating Costs and Revenues			
SCG Transpt excl Core Storge & Load Bal	$1,507	$2,159	$3,665
SCG Core Seasonal Storage	$6,052	$0	$6,052
SCG Load Bal Allocated to ALL SDGE	$557	$798	$1,354
Co Use Transmission w/FFU	$602	$863	$1,465
LUAF	$3,282	$2,281	$5,563
Company Use Gas: Other	$78	$112	$191
AMI rev req incl FF&U AL 1693-G	$9,262	$653	$9,914
Attrition	$0	$0	$0
Core Averaging (10% of Res/Retail Diff)	$0	$0	$0
Subtotal Other Oper Costs and Revenues	**$21,340**	**$6,865**	**$28,205**

TABLE 6 (Page 2 of 3)
Summary of Cost Allocation and Revenue Requirement ($000s)
San Diego Gas & Electric
2009 Biennial Cost Allocation Proceeding A.08-02-001

COST COMPONENTS	Core	Retail Noncore	System Total
Balancing, Tracking & Memorandum Accts			
Adv Mtring Infrastr Bal Acct AMIBA	$0	$0	$0
Adv Mtring Infrastr Memo Acct AMIMA	$5	$0	$6
Baseline Balance BA	$0	$0	$0
CFCA -Margin Only	$10,778	$0	$10,778
CFCA -Nonmargin Other	$3,799	$0	$3,799
CFCA -Nonmargin SCG	$446	$0	$446
CA Solar Initiative Balancing Acct CSIBA	$0	$0	$0
FERC Settlement Proceeds MA	$0	$0	$0
Core Gas Storage Balancing Acct. GSBA-C	$5,304	$0	$5,304
Haz Substance Cleanup Cost Acct HSCCA	$207	$296	$503
Interim Call Ctr Memo Acct. (ICCMA)	$0	$0	$0
Interst Transition Cost Surchrg Acct ITCSA	$0	$0	$0
NFCA -Margin Only	$0	($2,233)	($2,233)
NFCA -Nonmargin Other	$0	$4,921	$4,921
NFCA -Nonmargin SCG	$0	$692	$692
NGVA	$100	$144	$244
Noncore Gas Storage Bal Acct GSBA-NC	$0	$438	$438
PBOPBA	$0	$0	$0
Pension BA	$0	$0	$0
RD&D 1-Way Bal Acct (Pre-2001)	$0	$0	$0
Rewards & Penalties Bal Acct RPBA	$787	$55	$842
Self Gen Memo Acct - SGPMA-CSI	$722	$51	$773
Self Gen Memo Acct - SGPMA-NonCSI	$0	$0	$0
SGPMA - Rev Req for NEXT Year	$0	$0	$0
Gain/Loss on Sale Memo Acct GLOSMA	$0	$0	$0
Integrated Transmission ITBA	$66	$86	$152
Natural Gas Supp Refund Track Acct	$0	$0	$0
GRC Rev Reqt Memo Acct (GRCRRMA)	$6,145	$433	$6,578
Total Regulatory Accounts	$28,360	$4,884	$33,243

TABLE 6 (Page 3 of 3)
Summary of Cost Allocation and Revenue Requirement ($000s)
San Diego Gas & Electric
2009 Biennial Cost Allocation Proceeding A.08-02-001

COST COMPONENTS	Core	Retail Noncore	System Total
Transp Rev Req w/SI, FFU w/o FAR Rev, SW adj, TLS	$259,344	$26,521	$285,866
AVERAGE YEAR THROUGHPUT, Mth/yr	$499,967	$716,379	$1,216,345
Average Rate $/th	$0.51872	$0.03702	$0.23502
Sempra Wide & TLS Adjustments::			
Trnsp Rev Req w/SI,FFUw/oFAR,SWadj,TLS	$259,344	$26,521	$285,866
SW NGV Adjustment	$4	$0	$4
SW EG Adjustment	$0	($516)	($516)
TLS Adjustment			
Amount allocated to TLS Class	$0	($16,154)	($16,154)
TLS revenue paid by class @ avg TLS rate	$0	$11,365	$11,365
	$0	($4,788)	($4,788)
Transport Rev Req w/SI, FFU SW adj, TLS w/o FAR	$259,348	$21,217	$280,565
AYTP Mth/yr	$499,967	$716,379	$1,216,345
Average Rate w/oFAR $/th	$0.51873	$0.02962	$0.23066

TABLE 7 (Page 1 of 3)
Summary of Cost Allocation and Revenue Requirement ($000s)
San Diego Gas & Electric
2009 Biennial Cost Allocation Proceeding A.08-02-001

COST COMPONENTS	Res	NGV	Core C&I	Total Core
Embedded Costs:				
Customer Related Costs	$126,737	$61	$12,017	$138,816
Medium Pressure Distribution Costs	$43,573	$149	$11,711	$55,433
High Pressure Distribution Costs	$4,489	$60	$1,238	$5,787
Backbone Transmission Costs	$7,524	$175	$2,498	$10,197
Local Transmission Costs	$5,540	$228	$2,514	$8,282
Storage - Borrego	$0	$0	$0	$0
Functionalized A&G	$0	$0	$0	$0
Core Seasonal Storage	$0	$0	$0	$0
Storage - Load Balancing	$0	$0	$0	$0
NGV	$0	$83	$0	$83
Ttl Marg Alloc pre-SI/FAR Unbundle w/FFU	$187,862	$756	$29,979	$218,597
Less Backbone Transmission Costs	($7,524)	($175)	($2,498)	($10,197)
Less Local Transmission Costs	($5,540)	($228)	($2,514)	($8,282)
Plus Bbone Trnsm Cost w/SI,FFUw/oFAR	$1,574	$74	$766	$2,414
Plus Local Transmission Costs w/SI,FFU	$5,247	$122	$1,742	$7,112
Total Allocated Base Margin post-SI post-FAR Unbundle, w/ FFU	**$181,621**	**$549**	**$27,475**	**$209,645**
Other Operating Costs and Revenues				
SCG Transpt excl Core Storge & Load Bal	$982	$46	$478	$1,507
SCG Core Seasonal Storage	$4,770	$0	$1,282	$6,052
SCG Load Bal Allocated to ALL SDGE	$363	$17	$177	$557
Co Use Transmission w/FFU	$393	$18	$191	$602
LUAF	$2,140	$100	$1,042	$3,282
Company Use Gas: Other	$51	$2	$25	$78
AMI rev req incl FF&U AL 1693-G	$8,024	$24	$1,214	$9,262
Attrition	$0	$0	$0	$0
Core Averaging (10% of Res/Retail Diff)	($4,711)	$0	$4,711	$0
Subtotal Other Oper Costs and Revenues	**$12,012**	**$208**	**$9,120**	**$21,340**

TABLE 7 (Page 2 of 3)
Summary of Cost Allocation and Revenue Requirement ($000s)
San Diego Gas & Electric
2009 Biennial Cost Allocation Proceeding A.08-02-001

COST COMPONENTS	Res	NGV	Core C&I	Total Core
Balancing, Tracking & Memorandum Accts				
Adv Mtring Infrastr Bal Acct AMIBA	$0	$0	$0	$0
Adv Mtring Infrastr Memo Acct AMIMA	$5	$0	$1	$5
Baseline Balance BA	$0	$0	$0	$0
CFCA -Margin Only	$7,028	$329	$3,422	$10,778
CFCA -Nonmargin Other	$2,477	$116	$1,206	$3,799
CFCA -Nonmargin SCG	$291	$14	$142	$446
CA Solar Initiative Balancing Acct CSIBA	$0	$0	$0	$0
FERC Settlement Proceeds MA	$0	$0	$0	$0
Core Gas Storage Balancing Acct. GSBA-C	$3,459	$162	$1,684	$5,304
Haz Substance Cleanup Cost Acct HSCCA	$135	$6	$66	$207
Interim Call Ctr Memo Acct. (ICCMA)	$0	$0	$0	$0
Interst Transition Cost Surchrg Acct ITCSA	$0	$0	$0	$0
NFCA -Margin Only	$0	$0	$0	$0
NFCA -Nonmargin Other	$0	$0	$0	$0
NFCA -Nonmargin SCG	$0	$0	$0	$0
NGVA	$65	$3	$32	$100
Noncore Gas Storage Bal Acct GSBA-NC	$0	$0	$0	$0
PBOPBA	$0	$0	$0	$0
Pension BA	$0	$0	$0	$0
RD&D 1-Way Bal Acct (Pre-2001)	$0	$0	$0	$0
Rewards & Penalties Bal Acct RPBA	$682	$2	$103	$787
Self Gen Memo Acct - SGPMA-CSI	$625	$2	$95	$722
Self Gen Memo Acct - SGPMA-NonCSI	$0	$0	$0	$0
SGPMA - Rev Req for NEXT Year	$0	$0	$0	$0
Gain/Loss on Sale Memo Acct GLOSMA	$0	$0	$0	$0
Integrated Transmission ITBA	$44	$2	$20	$66
Natural Gas Supp Refund Track Acct	$0	$0	$0	$0
GRC Rev Reqt Memo Acct (GRCRRMA)	$5,323	$16	$805	$6,145
Total Regulatory Accounts	**$20,134**	**$651**	**$7,575**	**$28,360**

TABLE 7 (Page 3 of 3)
Summary of Cost Allocation and Revenue Requirement ($000s)
San Diego Gas & Electric
2009 Biennial Cost Allocation Proceeding A.08-02-001

COST COMPONENTS	Res	NGV	Core C&I	Total Core
Transp Rev Req w/SI, FFU w/o FAR Rev, SW adj, TLS	**$213,767**	**$1,407**	**$44,170**	**$259,344**
AVERAGE YEAR THROUGHPUT, Mth/yr	326,003	15,238	158,725	499,967
Average Rate $/th	$0.65572	$0.09236	$0.27828	$0.51872
Sempra Wide & TLS Adjustments::				
Trnsp Rev Req w/SI,FFUw/oFAR,SWadj,TLS	$213,767	$1,407	$44,170	$259,344
SW NGV Adjustment		$4		$4
SW EG Adjustment				$0
TLS Adjustment				
Amount allocated to TLS Class				$0
TLS revenue paid by class @ avg TLS rate				$0
	$0	$0	$0	$0
Transport Rev Req w/SI, FFU SW adj, TLS w/o FAR	$213,767	$1,411	$44,170	$259,348
AYTP Mth/yr	326,003	15,238	158,725	499,967
Average Rate w/oFAR $/th	$0.65572	$0.09259	$0.27828	$0.51873

TABLE 8 (Page 1 of 3)
Summary of Cost Allocation and Revenue Requirement ($000s)
San Diego Gas & Electric
2009 Biennial Cost Allocation Proceeding A.08-02-001

COST COMPONENTS	NCCI	EG Tier 1	EG Tier 2	Total EG	Retail Noncore	System Total
Embedded Costs:						
Customer Related Costs	$1,729	$775	$317	$1,092	$2,821	$141,637
Medium Pressure Distribution Costs	$898	$553	$0	$553	$1,451	$56,884
High Pressure Distribution Costs	$205	$102	$585	$687	$892	$6,679
Backbone Transmission Costs	$469	$295	$8,053	$8,347	$8,817	$19,014
Local Transmission Costs	$606	$506	$9,620	$10,126	$10,732	$19,014
Storage - Borrego	$0	$0	$0	$0	$0	$0
Functionalized A&G	$0	$0	$0	$0	$0	$0
Core Seasonal Storage	$0	$0	$0	$0	$0	$0
Storage - Load Balancing	$0	$0	$0	$0	$0	$0
NGV	$0	$0	$0	$0	$0	$83
Ttl Marg Alloc pre-SI/FAR Unbundle w/FFU	$3,907	$2,231	$18,575	$20,805	$24,713	$243,310
Less Backbone Transmission Costs	($469)	($295)	($8,053)	($8,347)	($8,817)	($19,014)
Less Local Transmission Costs	($606)	($506)	($9,620)	($10,126)	($10,732)	($19,014)
Plus Bbone Trnsm Cost w/SI,FFUw/oFAR	$195	$163	$3,101	$3,264	$3,459	$5,873
Plus Local Transmission Costs w/SI,FFU	$327	$334	$5,488	$5,822	$6,149	$13,261
Total Allocated Base Margin post-SI post-FAR Unbundle, w/ FFU	**$3,355**	**$1,927**	**$9,491**	**$11,418**	**$14,773**	**$224,418**
Other Operating Costs and Revenues						
SCG Transpt excl Core Storge & Load Bal	$122	$102	$1,935	$2,037	$2,159	$3,665
SCG Core Seasonal Storage	$0	$0	$0	$0	$0	$6,052
SCG Load Bal Allocated to ALL SDGE	$45	$38	$715	$752	$798	$1,354
Co Use Transmission w/FFU	$49	$41	$773	$814	$863	$1,465
LUAF	$129	$107	$2,045	$2,152	$2,281	$5,563
Company Use Gas: Other	$6	$5	$101	$106	$112	$191
AMI rev req incl FF&U AL 1693-G	$148	$85	$419	$504	$653	$9,914
Attrition	$0	$0	$0	$0	$0	$0
Core Averaging (10% of Res/Retail Diff)	$0	$0	$0	$0	$0	$0
Subtotal Other Oper Costs and Revenues	**$499**	**$378**	**$5,988**	**$6,366**	**$6,865**	**$28,205**

TABLE 8 (Page 2 of 3)
Summary of Cost Allocation and Revenue Requirement ($000s)
San Diego Gas & Electric
2009 Biennial Cost Allocation Proceeding A.08-02-001

COST COMPONENTS	NCCI	EG Tier 1	EG Tier 2	Total EG	Retail Noncore	System Total
Balancing, Tracking & Memorandum Accts						
Adv Mtring Infrastr Bal Acct AMIBA	$0	$0	$0	$0	$0	$0
Adv Mtring Infrastr Memo Acct AMIMA	$0	$0	$0	$0	$0	$6
Baseline Balance BA	$0	$0	$0	$0	$0	$0
CFCA -Margin Only	$0	$0	$0	$0	$0	$10,778
CFCA -Nonmargin Other	$0	$0	$0	$0	$0	$3,799
CFCA -Nonmargin SCG	$0	$0	$0	$0	$0	$446
CA Solar Initiative Balancing Acct CSIBA	$0	$0	$0	$0	$0	$0
FERC Settlement Proceeds MA	$0	$0	$0	$0	$0	$0
Core Gas Storage Balancing Acct. GSBA-C	$0	$0	$0	$0	$0	$5,304
Haz Substance Cleanup Cost Acct HSCCA	$17	$14	$266	$280	$296	$503
Interim Call Ctr Memo Acct. (ICCMA)	$0	$0	$0	$0	$0	$0
Interst Transition Cost Surchrg Acct ITCSA	$0	$0	$0	$0	$0	$0
NFCA -Margin Only	($126)	($105)	($2,002)	($2,107)	($2,233)	($2,233)
NFCA -Nonmargin Other	$278	$232	$4,412	$4,643	$4,921	$4,921
NFCA -Nonmargin SCG	$39	$33	$621	$653	$692	$692
NGVA	$8	$7	$129	$135	$144	$244
Noncore Gas Storage Bal Acct GSBA-NC	$25	$21	$392	$413	$438	$438
PBOPBA	$0	$0	$0	$0	$0	$0
Pension BA	$0	$0	$0	$0	$0	$0
RD&D 1-Way Bal Acct (Pre-2001)	$0	$0	$0	$0	$0	$0
Rewards & Penalties Bal Acct RPBA	$13	$7	$36	$43	$55	$842
Self Gen Memo Acct - SGPMA-CSI	$12	$7	$33	$39	$51	$773
Self Gen Memo Acct - SGPMA-NonCSI	$0	$0	$0	$0	$0	$0
SGPMA - Rev Req for NEXT Year	$0	$0	$0	$0	$0	$0
Gain/Loss on Sale Memo Acct GLOSMA	$0	$0	$0	$0	$0	$0
Integrated Transmission ITBA	$5	$4	$77	$81	$86	$152
Natural Gas Supp Refund Track Acct	$0	$0	$0	$0	$0	$0
GRC Rev Reqt Memo Acct (GRCRRMA)	$98	$56	$278	$335	$433	$6,578
Total Regulatory Accounts	**$368**	**$275**	**$4,241**	**$4,516**	**$4,884**	**$33,243**

TABLE 8 (Page 3 of 3)
Summary of Cost Allocation and Revenue Requirement ($000s)
San Diego Gas & Electric
2009 Biennial Cost Allocation Proceeding A.08-02-001

COST COMPONENTS	NCCI	EG Tier 1	EG Tier 2	Total EG	Retail Noncore	System Total
Transp Rev Req w/SI, FFU w/o FAR Rev, SW adj, TLS	**$4,222**	**$2,580**	**$19,720**	**$22,300**	**$26,521**	**$285,866**
AVERAGE YEAR THROUGHPUT, Mth/yr	40,463	33,749	642,167	675,916	716,379	1,216,345
Average Rate $/th	$0.10434	$0.07643	$0.03071	$0.03299	$0.03702	$0.23502
Sempra Wide & TLS Adjustments::						
Trnsp Rev Req w/SI,FFUw/oFAR,SWadj,TLS	$4,222			$22,300	$26,521	$285,866
SW NGV Adjustment					$0	$4
SW EG Adjustment				($516)	($516)	($516)
TLS Adjustment						
Amount allocated to TLS Class	($336)			($15,817)	($16,154)	($16,154)
TLS revenue paid by class @ avg TLS rate	$73			$11,293	$11,365	$11,365
	($264)			($4,524)	($4,788)	($4,788)
Transport Rev Req w/SI, FFU SW adj, TLS w/o FAR	$3,958			$17,259	$21,217	$280,565
AYTP Mth/yr	40,463			675,916	716,379	1,216,345
Average Rate w/oFAR $/th	$0.09782			$0.02553	$0.02962	$0.23066