Decision 09-11-006 November 20, 2009

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)

OPINION REGARDING THE SETTLEMENT OF THE PHASE TWO ISSUES

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OPINION REGARDING THE SETTLEMENT OF THE PHASE TWO ISSUES

1. Summary

This decision addresses the Phase Two issues in the cost allocation proceeding filed by San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) regarding their natural gas transmission and storage services. Most of the active parties to this proceeding agreed to, or did not oppose, a settlement of all of the Phase Two issues.

A joint motion to adopt the Settlement Agreement was filed on June 2, 2009 by SDG&E, SoCalGas, and 12 other parties.[1] Shell Energy North America (US), L.P. (Shell Energy) opposes certain provisions of the settlement agreement and requests that the provisions be eliminated or clarified.

Today's decision grants the joint motion to adopt the Settlement Agreement of the Phase Two issues, and adopts all of the terms and conditions of the Settlement Agreement[2] except for the filing of additional briefs on the issue of whether the shareholders of SDG&E and SoCalGas should in the future be at risk for gas throughput.[3] The Settlement Agreement resolved all of the Phase Two issues, which include the following:

- Allocating the revenue requirement associated with the gas transmission, distribution, and storage operations of SDG&E and SoCalGas, as previously authorized in

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1 We refer to these 14 parties as the "settlement parties."

2 The Settlement Agreement, with all the pertinent attachments (Attachments 1-4), was attached to the joint motion as Appendix A. A copy of the Settlement Agreement without the attachments is attached to this decision as Appendix A.

3 As discussed later in this decision, we also adopt Shell Energy's proposal that SoCalGas clarify Rule 30(d)(4).

Decision (D.) 08-07-046, to the various customer classes of SDG&E and SoCalGas.[4]

- Agrees to use the gas demand forecasts of SDG&E and SoCalGas.
- Agrees to allocate the gas transmission and storage costs using an embedded cost methodology, and to allocate the gas distribution costs using a long run marginal cost (LRMC) methodology.
- Agrees to the provisions concerning gas operations, cost allocation, rate design, and other issues, as set forth in the Settlement Agreement.
- Using and applying the agreed upon provisions, this results in the rates shown in Appendix B for SoCalGas' customers, and in Appendix C for SDG&E's customers.
- The new rates in Appendix B and Appendix C of this decision are to go into effect the later of January 1, 2010, or the first day of the month that is at least 60 days from the date of Commission approval of the Settlement Agreement.[5]

Under the Settlement Agreement, a typical residential gas customer in SDG&E's service territory, who uses 40 therms per month, will experience a 1.7% increase in their monthly bill, from about $42.21 per month to $42.94 per month.

For a typical residential gas customer in SoCalGas' service territory, who uses 46 therms per month, that customer will experience a 1% decrease in their monthly bill, from about $ 40.10 per month to $39.73 per month.

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[4] D.08-07-046 authorized a gas revenue requirement of $1.685 billion for SoCalGas, and a gas revenue requirement of $280.57 million for SDG&E.

[5] The rates shown in Appendix B and Appendix C of this decision contain additional allocation tables with more detail than what was shown in Attachment 3 to Appendix A of the joint motion.

2. Background

SDG&E and SoCalGas filed the above-captioned application on February 4, 2008. Following the April 3, 2008 prehearing conference, the April 17, 2008 scoping memo and ruling bifurcated this proceeding into two phases and established separate procedural schedules for each phase.

Following the July 2008 evidentiary hearings on the Phase One issues, the parties agreed to a settlement of the Phase One issues. A motion to adopt the Phase One Settlement Agreement was filed and the Commission granted the motion and adopted the terms of the Phase One Settlement Agreement in D.08-12-020.

Evidentiary hearings in Phase Two were originally scheduled to begin on February 23, 2009. The parties prepared and served their testimony on the Phase Two issues. On February 3, 2009, SDG&E and SoCalGas e-mailed a notice of an all-party settlement conference to be held on February 13, 2009. Following the February 13, 2009 settlement conference, SDG&E and SoCalGas requested that the start of the evidentiary hearings be rescheduled to April 20, 2009 to allow the parties additional time to discuss settlement of the Phase Two issues. That request was granted as described in the February 19, 2009 ruling of the Administrative Law Judge (ALJ).

On April 16, 2009, SDG&E and SoCalGas informed the ALJ and the service list that they had reached an agreement in principle with most of the active parties to settle the Phase Two issues. SDG&E and SoCalGas requested that the start date for the evidentiary hearings be postponed to June 4, 2009 so that the Settlement Agreement and a motion to adopt the Settlement Agreement could be prepared and filed with the Commission. All of the active parties agreed to, or did not oppose, the new start date. In an April 16, 2009 e-mail to the service list, the ALJ granted the request to postpone the start of the evidentiary hearing to June 4, 2009.

A joint motion to adopt a Settlement Agreement of the Phase Two issues was filed on June 2, 2009. A copy of the Settlement Agreement was attached to the joint motion as Appendix A. The Settlement Agreement also consists of Attachments 1 through 4, which were included as part of Appendix A to the joint motion. A copy of the Settlement Agreement, without the attachments, is attached to this decision as Appendix A.

The joint motion also requested that the 53 documents that were submitted and served in connection with the Phase Two issues be admitted into evidence, and that the evidentiary hearings scheduled to start on June 4, 2009 be taken off-calendar.

The evidentiary hearings were taken off-calendar in a June 2, 2009 e-mail from the ALJ to the service list. Pursuant to the procedure set forth in the June 11, 2009 ruling of the ALJ, the parties were allowed to file comments on the joint motion to adopt the Settlement Agreement and to make any objections to the admission of the 53 documents.

On July 2, 2009, Shell Energy filed its comments on the joint motion and requested that an evidentiary hearing be held on the operational flow order (OFO) protocols contained in the Settlement Agreement. Shell Energy also requested that other provisions of the Settlement Agreement be clarified or eliminated. Shell Energy did not object to the admission of any of the documents. Joint reply comments to Shell Energy's comments were filed on July 17, 2009.

The request in the joint motion to admit the 53 documents into evidence was granted in the ALJ ruling of July 22, 2009. On July 31, 2009, Shell Energy's request for a hearing on the OFO protocols was denied in the ruling of the assigned Commissioner and ALJ. The request for a hearing was denied after a review of the prepared testimony did not reveal any material contested issues of fact, and to hold a hearing so that parties could repeat or reinforce their respective viewpoints would not have been a productive use of time and resources.

3. Discussion

3.1. Overview of the Phase Two Issues

The April 17, 2008 scoping memo bifurcated the issues in this proceeding into two phases. The Phase Two issues were identified in the scoping memo as follows:

1. Whether the updated cost allocations and rates presented are just and reasonable and should be adopted.
2. Whether the demand forecast presented by the applicants is reasonable and should be adopted.
3. Whether the proposed rate design for transportation services is just and reasonable and should be adopted.
4. Whether the applicants' proposals to narrow the regulatory gap with competing interstate pipelines are reasonable and should be adopted.
5. Whether the application's request to revise the monthly balancing tolerances should be adopted.
6. Whether the applicants' request for a three-year period between cost allocation filings should be adopted.
7. Whether the discount for master meter customers should be revised.
8. Whether the Sempra-wide electric generation rate should be eliminated.
9. Whether merchant generators should be exempt from the regulatory surcharge in the G-SRF tariff.

10. Whether all of the remaining issues in the application have been adequately addressed and should be adopted.

The above issues in this phase of the proceeding address the various costs that are associated with serving the natural gas customers of SoCalGas and SDG&E, as well as the methods that SoCalGas and SDG&E propose be used to allocate the costs and to design the rates for their customers.

Before evaluating whether the joint motion to adopt the Settlement Agreement of the Phase Two issues should be granted or denied, we summarize below the Settlement Agreement's proposed recommendations, followed by a comparison of the parties' litigation positions, as set forth in their prepared testimony and in their pleadings to the joint motion to adopt the Phase Two Settlement Agreement, to the positions agreed to in the Settlement Agreement.

3.2. The Settlement Agreement's Recommendation

The Settlement Agreement in Phase Two was agreed to by SDG&E, SoCalGas, Bridge Housing, Inc. (Bridge Housing), California Cogeneration Council, California Manufacturers and Technology Association, City of Long Beach (Long Beach), Division of Ratepayer Advocates (DRA), Electric Generator Alliance, Indicated Producers, Southern California Edison Company (SCE), Southern California Generation Coalition (SCGC), Southwest Gas Corporation, The Utility Reform Network (TURN), and Watson Cogeneration Company.[6]

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[6] We collectively refer to the Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company as the "Indicated Producers et al."

Shell Energy and Kern River Gas Transmission Company (Kern River), both active parties in this proceeding, did not join in the Phase Two Settlement Agreement. As discussed below, Shell Energy filed comments on the joint motion to adopt the Settlement Agreement, and requested that parts of the settlement be clarified or eliminated.

The Settlement Agreement, which is appended to this decision as Appendix A, contains the recommendations of the settlement parties regarding the Phase Two issues. These recommendations address a number of different issues, which are set forth in the section of the Settlement Agreement labeled "Phase Two Settlement Terms and Conditions." A summary of the key provisions of the Settlement Agreement are described below, and a discussion of those provisions are set forth in Section 3.3. of this decision. Attachments 1 to 4 of the Settlement Agreement contain detailed explanations of the Transmission Level Service (TLS) rate design, the uncontested proposals, the agreed-upon rates for SDG&E and SoCalGas, and the updated tariffs that SDG&E and SoCalGas plan to use to implement the Settlement Agreement, respectively.[7]

The Settlement Agreement is to become effective on the date that the Commission approves the Settlement. The rates set forth in the Settlement Agreement are to go into effect the latter 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. The term of the Settlement Agreement is to extend from the date of Commission approval of the Settlement through the effective date of the rates

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[7] Attachments 1 to 4 of the Settlement Agreement are attached to the June 2, 2009 joint motion to adopt the Phase Two Settlement Agreement. Due to the size of Attachments

Footnote continued on next page

that are established in the next cost allocation proceeding for SDG&E and SoCalGas. Since the Settlement Agreement includes a provision to file the cost allocation application triennially instead of every two years, the rates in this Settlement Agreement will terminate around December 31, 2012.[8]

The two key components that affect the rates agreed to in the Settlement Agreement, are the forecasts of gas throughput for the various customer classes, and the methodology for allocating the gas transmission, storage, and distribution costs. Under section II.B.2.T. of the Settlement Agreement, the parties agree to use the gas demand forecasts of SDG&E and SoCalGas. To allocate the gas transmission and storage costs, the parties agree in section II.B.2.A. of the Settlement Agreement to use the embedded cost methodology. To allocate the costs of the gas distribution facilities, a LRMC methodology is used. The other cost allocation and rate design issues are resolved as described in section II.B.2. of the Settlement Agreement.

The rates derived from the gas throughput forecasts, the agreed-upon allocation methodologies, and the other cost allocation and rate design factors, are set forth in Attachment 3 of the Settlement Agreement. These agreed-upon rates for SoCalGas and SDG&E are also attached to this decision as Appendix B and Appendix C, respectively.

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1 to 4, they have not been appended to this decision, but are incorporated into this decision by reference.

[8] Under the Settlement Agreement, SDG&E and SoCalGas are to file a new cost allocation application no later than September 1, 2011, for rates to be effective for a three year period starting on January 1, 2013 and ending on December 31, 2015.

The Settlement Agreement addresses 16 operational issues as described in sections II.B.1.A. through II.B.1.P. of the Settlement Agreement. The following is an overview of the operational issues agreed to in the Settlement Agreement:

(a) Specifies that the Utility Gas Control Department is responsible for operating the SDG&E and SoCalGas pipeline and storage system, and for developing the system sendout forecasts to be used for determining Southern System minimum flow requirements and for calling OFOs. The Settlement Agreement also specifies the procedures that the Utility Gas Control Department must follow before an OFO is called, and states that system line pack is not part of the formula used to determine when an OFO shall be called.

(b) SDG&E and SoCalGas will hold an annual Customer Forum to provide information on and to address: how OFO events are triggered; to review requests for the Operational Hub to acquire additional supplies to meet minimum flow requirements; to review Operational Hub purchases and actions; to review the need for any additional minimum flow requirements on the system beyond then-current defined requirements; and to review additional tools to support system operations and potential system improvements to reduce or eliminate the need for any minimum flowing supply requirements. To facilitate discussion of these issues, SDG&E and SoCalGas shall prepare an annual report of the system reliability issues with certain required information, and post the report on their websites at least two weeks before each annual Customer Forum.

(c) After each annual Customer Forum, SDG&E, SoCalGas, and the other participants shall collaborate to develop a report that describes what was discussed and to identify any action items, tariff changes, and/or procedural modifications needed, and to file the report with the Commission by advice letter.

(d) SDG&E and SoCalGas shall include the following in their respective gas tariffs: information about the Utility System Operator structure, procedures and operation protocols; any specific formulas used to call OFOs and to determine the volume of any additional supplies needed to meet the minimum flow requirements; the request for offer (RFO) procedures; the Operational Hub's general spot gas commodity purchasing and selling practices and the procedures to meet minimum flowing supply requirements; descriptions about any ongoing minimum flow requirements; and a statement about the Utility System Operator's mission to maintain system reliability and integrity while minimizing costs at all times.

(e) In addition to the information that SDG&E and SoCalGas post to comply with D.06-12-031 and D.07-12-039, SDG&E and SoCalGas shall post certain operational information on their Electronic Bulletin Board (EBB) on a current-day and forecast basis.

(f) SDG&E and SoCalGas withdraw their high OFO trigger proposal that they proposed in Phase Two, and are precluded from proposing the adoption of any similar high OFO trigger that is to become effective during the settlement period.

(g) Specifies that the Operational Hub will continue to use the tools established in D.07-12-019 to support the Southern System minimum flow requirement; that the purchases and sales of spot gas to support the minimum flow requirement will be subject to sections II.B.1.N. and II.B.1.O. of the Settlement Agreement; and specifies the formula for how the Utility Gas Control Department will determine the need for the initial daily quantity of supplies.

(h) Describes that the costs and revenues of the Operational Hub transactions necessary to meet minimum flow requirements shall be recorded in the System Reliability Memorandum Account (SRMA).

Prospective changes to the Operational Hub gas transactions to meet minimum flow requirements are to be considered in conjunction with the annual Customer Forum. Specifies the standards and criteria for spot purchases or sales of gas commodity for which standards and criteria are not specified in Commission-approved contracts.

(i) SDG&E and SoCalGas are to retain the current winter balancing rules as set forth in tariff schedule Rule No. 30 with the modification set forth in section II.B.1.I.

(j) The SDG&E and SoCalGas proposal to allow interruptible withdrawals to count towards the balancing requirements are adopted and incorporated into their respective tariffs.

(k) SDG&E and SoCalGas withdraw their proposal regarding the Southern System flow order and will not propose such a reliability measure to be effective during the term of the settlement agreement. SDG&E and SoCalGas shall continue to meet the Southern System flow requirement through the actions of the Utility System Operator and the tools approved by the Commission as described in sections II.B.1.G., II.B.1.H., II.B.1.N., and II.B.1.O. of the Settlement Agreement.

(l) SDG&E and 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 by filing an application. Any contracts that are not obtained through an RFO process relating to already-approved tools will be submitted for approval by advice letter.

(m) The Utility Gas Control Department is to remain physically separated from those departments that engage in marketing and sales activities. Describes the type of information and contacts that the Utility Gas Control Department and the Operational Hub are prohibited from having, and the circumstances under which the Utility Gas Control Department can communicate with the Operational Hub.

(n) Describes how gas commodity purchases and sales between the Operational Hub and the Utility Gas Procurement Department or a Sempra affiliate are to occur through an independent party. Describes when the Utility Gas Procurement Department, acting as the provider of last resort, must post certain transactions.

(o) Describes the circumstances under which the Utility Gas Procurement Department becomes the provider of last resort at the request of the Operational Hub.

(p) Operational Hub G-PAL transactions with Sempra affiliates or the Utility Gas Procurement Department, if the transaction is discounted below the maximum tariff rate, shall be posted the next business day on the EBB.

In addition to the agreed-upon cost allocation methodology and the use of the utilities' gas throughput forecasts, the other cost allocation and rate design issues are set forth in section II.B.2. of the Settlement Agreement. The following provides an overview of how these other cost allocation and rate design issues are addressed in the Settlement Agreement:

(a) Section II.B.2.A. describes the cost allocation methodologies that are adopted for transmission, storage, and distribution facilities, and the cost allocation adjustments to base margin that are implied by the Settlement Agreement rates. Also provides that SDG&E and SoCalGas shall not be required to propose a LRMC cost allocation for transmission or storage costs in their next cost allocation proceeding.

(b) Section II.B.2.B. adopts the rates set forth in Attachment 3 to Appendix A of the joint motion. These rates are subject to the utilities' routine rate adjustments to reflect updated Regulatory Accounts and implementation of other Commission decisions.

(c) Section II.B.2.C. provides that the embedded cost transmission revenue requirement is a total of $201.2 million ($163.2 million for SoCalGas and $38 million for SDG&E), and that the embedded cost storage revenue requirement is $83.3 million. Agreement to these amounts is not meant by the parties to indicate their approval or acceptance of any of the various cost allocation proposals, principles, or methodologies that have been proposed, except that the parties agree that the transmission and storage functions will be allocated on the basis of embedded costs.

(d) Section II.B.2.D. describes how the annual changes in base margin are to be allocated by the System Average Percent Change.

(e) Section II.B.2.E. describes the methods to be used for allocating the balance in any balancing account.

(f) Section II.B.2.F. sets the cost of gas at $5.08 per MMBtu for company use fuel and unaccounted for fuel. The paragraph further states that the actual cost of company use fuel and unaccounted for fuel will be balanced through the appropriate regulatory accounts, and describes how that 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.

(g) Section II.B.2.G. adopts and describes the utilities' proposal for balancing account treatment for in-kind storage fuel for core and noncore storage injections and for load balancing.

(h) Section II.B.2.H. provides that the review of the proposed changes to the firm access rights (FAR) system will occur in the FAR review proceeding that is to be held in accordance with D.06-12-031.

(i) Section II.B.2.I. adopts and describes TURN's proposal for developing the residential tier differential.

(j) Section II.B.2.J. adopts the utilities' proposal for customer charges and rate tiers for commercial and industrial customers.

(k) Section II.B.2.K. provides that SoCalGas shall retain the existing methodology for recording the authorized margin of the Core Fixed Cost Account (CFCA).

(l) In response to the proposal of Bridge Housing, section II.B.2.L. provides that SDG&E and SoCalGas shall modify their tariffs to allow accounts with residential common area gas usage the option to choose a commercial rate so long as the common area gas equipment is separately metered from the dwelling units. This section also describes how SDG&E and SoCalGas will notify their customers of this rate option.

(m) Section II.B.2.M. describes and adopts the proposal of TURN and DRA for the deaveraging of core rates.

(n) Section II.B.2.N. describes and adopts DRA's rate proposal for Borrego Springs in SDG&E's service territory.

(o) Section II.B.2.O. describes and adopts DRA's proposal regarding the retention of the current gas engine rate cap by SoCalGas.

(p) Section II.B.2.P. eliminates the SoCalGas' peaking service rate and adopts a rate design for transmission level service customers with four rate options as described in Attachment 1 of Appendix A of the joint motion, and as set forth in Attachment 3 of Appendix A of the joint motion.

(q) Section II.B.2.Q. allocates the balances in certain memorandum accounts on an average year (equal cents per therm) throughput basis.

(r) Section II.B.2.R. describes the adopted methodologies for allocating the balances in the CFCA and the Noncore Fixed Cost Account (NFCA).

(s) Section II.B.2.S. adopts and describes the proposal of SDG&E and SoCalGas to develop a Sempra-wide rate for natural gas service provided to natural gas vehicle stations.

(t) Section II.B.2.T. adopts the utilities' gas demand forecasts for the term of the Settlement Agreement.

(u) Section II.B.2.U. adopts the uncontested proposals of SDG&E and SoCalGas as described in Attachment 2 of Appendix A of the joint motion.

The Settlement Agreement also addresses 14 other issues as described in section II.B.3. The following is an overview of those issues:

(a) Section II.B.3.A. provides that SDG&E and SoCalGas shall not be at risk for throughput during the term of the Settlement Agreement. This section also provides that 30 days after the date of a Commission order approving the Settlement Agreement, the parties are to file opening and reply briefs on the issue of whether the Commission should establish a formal policy in favor of decoupling SDG&E and SoCalGas profits from throughput.

(b) Section II.B.3.B. provides that SDG&E, SoCalGas, DRA, and TURN agree to negotiate the substance, format and timing of a periodic report that addresses aggregate customer data relating to such issues as customer turn-offs for non-payment of bills.

(c) Section II.B.3.C. provides that 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.

(d) Section II.B.3.D. provides that the issue of whether SDG&E and SoCalGas should offer backbone-only service at a backbone-only rate shall be deferred to the next cost allocation proceeding of SDG&E and SoCalGas, and shall not be considered in the 18 month FAR review proceeding.

(e) Section II.B.3.E provides that this settlement does not limit the rights of the utilities or parties to make proposals in the 18-month FAR review proceeding, except as provided for in the Settlement Agreement.

(f) Section II.B.3.F. provides that the embedded cost allocated to the SDG&E and SoCalGas integrated transmission system is established for the entire settlement period, subject to the annual escalation in the authorized base margin as set forth in D.08-07-046.

(g) Section II.B.3.G. provides that the split of backbone costs between backbone and local transmission to establish the FAR reservation charge is reserved as an issue in the 18 month FAR review for the three year FAR cycle that begins October 1, 2011.

(h) Section II.B.3.H. eliminates the 5% enhanced oil recovery shareholder incentive.

(i) Section II.B.3.I. provides that the G-SRF surcharge, which collects monies to fund the Commission's operations, shall not apply to gas transportation services provided to electric generators located in SoCalGas' service territory, 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) Section II.B.3.J. adopts the proposal of the Indicated Producers et al. to revise the balancing account descriptions in the Preliminary Statements to clarify how actual company use compressor fuel costs are tracked and recovered.

(k) Section II.B.3.K. retains the Sempra-wide electric generation (EG) rate adjustment for distribution level customers that are not included in the TLS rate class.

(l) Section II.B.3.L. eliminates certain out-dated accounts as proposed by SDG&E and SoCalGas.

(m) Section II.B.3.M. provides that SDG&E and SoCalGas shall file cost allocation applications every three years instead of every two years, and that the next application is to be filed no later than September 1, 2011 and is to include data on actual revenues from service provided under the TLS rate option and actual volumes of service provided under that option.

(n) Section II.B.3.N. provides that the new or revised tariff provisions that are required to implement the Settlement Agreement are appended as Attachment 4 to Appendix A of the joint motion.

Section III of the Settlement Agreement addresses additional terms and conditions. These terms and conditions include statements that: the Settlement Agreement is just, fair and reasonable, and in the public interest; the Settlement Agreement is not intended by the settlement parties to have any precedent for any future proceeding, and the parties reserve their rights to advocate different positions in current and future proceedings; and the Settlement Agreement embodies compromises of the settlement parties' positions, and that the Settlement Agreement is indivisible and each part is interdependent on each and all other parts.

3.3. Should the Proposed Settlement Agreement be Adopted?

3.3.1. Introduction

In deciding whether the joint motion to adopt the Settlement Agreement should be granted or not, we are guided by Rule 12.1(d) of the Commission's Rules of Practice and Procedure. That subdivision states: "The Commission will not approve settlements, whether contested or uncontested, unless the settlement is reasonable in light of the whole record, consistent with law, and in the public interest." In determining whether the Settlement

Agreement is reasonable in light of the whole record and in the public interest, we compare the original positions of the parties to the recommended outcomes in the Settlement Agreement.

3.3.2. Gas Demand Forecasts

SDG&E and SoCalGas proposed in their application that their gas demand forecasts for the BCAP period be adopted. The gas demand forecasts for SoCalGas and SDG&E are described in Exhibit 58. Total gas throughput of 961,358 thousand decatherms (MDth) per year is forecasted on the SoCalGas system during the BCAP period. The gas demand forecasts for SoCalGas and SDG&E are based on a number of factors such as economic growth, historical and projected gas demand for each customer group during average and peak days, temperature, the gas price forecast, and unaccounted for gas.

The Indicated Producers et al. recommended in Exhibit 76 that the July 2008 gas throughput forecast of 963,224 MDth in the 2008 California Gas Report be used to replace the forecasts of the utilities. The Indicated Producers et al. advocated that the forecast from the California Gas Report be used because that forecast is more recent than that of the utilities. Exhibit 76 acknowledged that the gas throughput forecast from the California Gas Report is within one percent of the utilities' forecast.

The rebuttal and reply testimony of the parties contained additional arguments on which forecasts should be used.[9]

The parties agreed in the Settlement Agreement to use the utilities' forecasts of gas throughput. Based on the litigation positions of the parties, the small percentage difference between the forecasts, and because the forecast is derived from a number of factors that reasonably predict the demand forecast, the Settlement Agreement's use of the utilities' gas throughput forecasts is reasonable and in the public interest.

3.3.3. Cost Allocation Methodologies

SDG&E and SoCalGas presented two methods of allocating the costs in their application. SDG&E and SoCalGas recommended that the Commission adopt the use of the embedded cost method for allocating all of the costs of providing natural gas service to their customers. In compliance with D.92-12-058, the utilities also included a cost allocation methodology using long run marginal costs (LRMC). SCE supported the proposal of SDG&E and SoCalGas for the Commission to use an embedded cost methodology, while the Indicated Producers et al. supported the use of an embedded cost methodology with certain changes.

In Exhibits 101 and 102, TURN presented testimony on perceived errors that it detected in the embedded cost and LRMC studies the utilities had prepared. TURN argued that neither the utilities' LRMC study nor the embedded cost study provided a reasonable basis for cost allocation. TURN advocated that the Commission should continue its support of using LRMC to allocate the customer, distribution, and local transmission costs in this proceeding. For the unbundled services of gas storage and backbone transmission, TURN recommended that those costs be allocated on an embedded cost basis.

DRA favored the use of a LRMC methodology for SoCalGas, and an embedded cost methodology for SDG&E.

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[9] See Exhibits 60, 89, and 98.

In the event the Commission adopts an embedded cost methodology, DRA and TURN recommended that 50% of the administrative and general (A&G) expenses should continue to be allocated to all customers (except wholesale) on an equal cents per therm (ECPT) basis. SDG&E, SoCalGas, Indicated Producers et al., SCE, and SCGC oppose allocating 50% of the A&G expenses on an ECPT basis.

SCGC recommended in Exhibits 97 and 98 that the Commission use the LRMC methodology to allocate the costs, and argued that an embedded cost methodology could lead to distorted results. However, if an embedded cost methodology is to be adopted, SCGC recommended that the current marginal demand measures be used instead of using new marginal demand measures as suggested by SDG&E and SoCalGas.

DRA advocated that some of the cost studies that were used by the utilities to develop the cost allocators should be updated to reflect more current data. SDG&E and SoCalGas argued that the use of selective updates, as suggested by DRA, would lead to inconclusive and unsupported cost shifts to non-core customers.

TURN and DRA also disagreed with SDG&E and SoCalGas about how customer-related investments should be treated if the Commission adopts the LRMC methodology. SDG&E and SoCalGas favored the use of the "rental method" for allocating the costs of customer-related investments, while TURN and DRA favored the "new customer only" method. SCE and SCGC also favored the use of the rental method. The Indicated Producers et al. proposed the use of the "mortgage method" as an alternative over the rental method and new customer only method.

The exhibits summarized above reveal a range of conflicting views over what cost methodology and factors the Commission should adopt for use in this proceeding. The various positions of the parties affect how the costs will be allocated to the various customer classes of SDG&E and SoCalGas. By agreeing in the Settlement Agreement to use an embedded cost methodology for transmission and storage facilities, the LRMC methodology for distribution facilities, and the cost allocation adjustments to base margin that are implied by the rates set forth in Appendix B and Appendix C of this decision, the settlement parties have reached compromises regarding their litigation positions. In doing so, they have balanced their competing interests and have come up with customer rates that each of the settlement parties are willing to accept. The cost allocations to the various customer classes are also fair in light of the compromises. Accordingly, the Settlement Agreement's resolution of the cost allocation methodology is reasonable and in the public interest.

3.3.4. Operational Issues

Section II.B.1. of the Settlement Agreement addresses the operational issues associated with the operations of the SDG&E and SoCalGas gas transmission system.

In its comments to the joint motion to adopt the Settlement Agreement, Shell Energy raised nine issues, seven of which related to operational issues. Shell Energy requested in its comments to the joint motion that an evidentiary hearing be held on the OFO protocols that were agreed to in the Settlement Agreement. Shell Energy's request for an evidentiary hearing on the OFO protocols was denied in the July 31, 2009 ruling for the reasons stated earlier. The ruling stated that the issues that Shell Energy raised would be used to evaluate whether the Phase Two Settlement Agreement should be adopted or not, and whether certain sections of the Settlement Agreement should be modified or clarified. In the paragraphs that follow, we address Shell Energy's concerns with the operational issues agreed to in the Phase Two Settlement Agreement.

The first operational issue that Shell Energy raised pertains to the OFO protocol agreed to in section II.B.1.A. of the Settlement Agreement. Shell Energy argues that the OFO protocol improperly ignores system inventory, i.e., line pack, as a factor in the formula for determining when an OFO should be called.

Section II.B.1.A. of the Settlement Agreement provides that the SDG&E/SoCalGas Utility Gas Control Department is the sole authority for operating the gas pipeline and storage system, and for developing the system sendout forecasts to be used for the purposes of determining Southern System minimum flow requirements and for calling OFOs. That section also provides the formula for determining when an OFO will be called, and specifically states that "System linepack is not part of the formula used to determine when an OFO shall be called."

Shell Energy provided testimony in Exhibit 96 as to why it believed that the OFO protocol should consider system line pack before an OFO is called. Shell Energy argued in Exhibit 96 and in its comments on the joint motion that: the current OFO protocol, which was agreed to in the Settlement Agreement, is not based on an objective measure of transmission system reliability; the protocol provides free hourly balancing service to electric generation customers and core customers through the use of system line pack; the protocol allows SoCalGas to call unnecessary OFOs in order to benefit the shareholders of SDG&E and SoCalGas; the potential for OFOs increases costs for customers; and the protocol provides SoCalGas with too much discretion in calculating the daily forecast of system demand, which is an integral element of the OFO calculation.

In Exhibit 97, SCGC stated that SoCalGas had too much flexibility in declaring a high OFO on its system, which creates problems for customers who may be forced to sell or turn back nominated supplies of gas at a loss. SCGC also recommended that line pack should be explicitly included in the OFO formula.

SDG&E and SoCalGas provided testimony in Exhibit 55, and arguments were raised in the joint reply comments to Shell Energy's comments, as to why system line pack should not be considered as an input in determining when an OFO should be called, and that functional and operational restrictions are in place to prevent SoCalGas from calling an OFO so as to benefit its shareholders. Testimony and argument were also presented on the differences between the SDG&E and SoCalGas systems and the PG&E system, and why line pack is a consideration on the PG&E system but not on the SDG&E and SoCalGas systems.

We are not persuaded that section II.B.1.A. of the Settlement Agreement should be rejected because of Shell Energy's argument that system line pack is not part of the formula that SoCalGas considers in determining when an OFO should be called. As summarized above, the testimony and concerns of Shell Energy were refuted by the testimony of SDG&E and SoCalGas. For example, Exhibit 55 described the difference between the PG&E system and the SDG&E and SoCalGas systems. PG&E has more miles of large transmission pipelines, while the SDG&E and SoCalGas systems have a lot more storage. Also, the pipeline designs are different, which allows PG&E to take advantage of its linepack capacity. In addition, SCGC which had originally advocated to include system line pack as part of the OFO formula, agreed with the other settlement parties to continue the use of the OFO protocol. The formula for the OFO protocol has been in use for a number of years, and the parties who agreed to its continued use in the Phase Two Settlement Agreement represent a cross section of customers with many different views and interests. Accordingly, there is sufficient testimony in the record to decide that the OFO protocol agreed to in section II.B.1.A. of the Settlement Agreement is reasonable and in the public interest and should be adopted.

The second operational issue that Shell Energy raised has to do with the Customer Forum process agreed to in section II.B.1.B. of the Settlement Agreement. Among other things, that section provides that SDG&E and SoCalGas shall hold an annual Customer Forum to provide information on, and to review the timing, method, formula, and inputs for deciding when an OFO is triggered. In addition, the Customer Forum process also provides the opportunity to review potential additional tools to support system operations and potential system improvements to reduce or eliminate the need for any minimum flowing supply requirements.

Shell Energy contends that the Customer Forum review of the OFO protocol improperly excludes system line pack from the inputs that may be considered in this review. Shell Energy requests that the first Customer Forum be held no later than six months after the date of a final Commission decision in this phase of the proceeding.

As mentioned above, SDG&E and SoCalGas presented testimony, and arguments were made in the joint reply comments, as to why line pack should not be considered as an input for determining when an OFO should be called. The joint reply comments did not respond to Shell Energy's comment as to when the first Customer Forum should be held.

For the reasons stated earlier, Shell Energy's request to include system line pack as part of the formula for determining when an OFO should be called will not be adopted for the term of the settlement. However, we will allow the parties to discuss at the Customer Forum whether information about the amount of line pack should be posted on SoCalGas' EBB for use as a potential tool to mitigate the number of OFOs. Any agreement reached in the Customer Forum about the posting of line pack information will need to specify what kind of data is to be reported (e.g., total system line pack or individual transmission pipe line pack, operating pressure or other unit of measure, real time or forecasted data) and the frequency of posting on the EBB. We also decline to modify section II.B.1.B of the Settlement Agreement to require that the first Customer Forum be held no later than six months after a final decision is rendered in this phase of the proceeding. In our estimation, requiring the first customer forum to be held within six months would not provide the parties with adequate time to gather and evaluate the type of information that is to be reviewed in the annual Customer Forum. Instead, the first annual Customer Forum should occur within one year of the approval of the Phase Two Settlement Agreement.

The third operational issue that Shell Energy raised concerns the information that is to be posted on SoCalGas' EBB, as provided for in section II.B.1.E. of the Settlement Agreement.

Shell Energy contends that the Settlement Agreement improperly fails to include current and projected system inventory, i.e., line pack, and customer imbalance data among the data that is to be posted on the EBB by the System Operator. Shell Energy recommends at page 2 of its comments to the joint motion that the EBB provision be modified to "require the System Operator to post current (daily) and forecasted system inventory, as well as daily changes in pipeline and customer storage imbalance inventories, on the EBB."

In the joint reply comments, the settlement parties argue that Shell Energy's request to modify the type of information that should be reported on the EBB should be rejected. The settlement parties argue that since the level of line pack is not a factor in determining an OFO event on the SDG&E and SoCalGas systems, Shell Energy's request to include the "forecasted system inventory" is unnecessary. The settlement parties also argue that the information that is to be posted on the EBB, as listed in sections II.B.1.A. through II.B.1.E. of the Settlement Agreement, are similar to what PG&E provides and should provide all the information needed to anticipate an OFO event on the SDG&E and SoCalGas systems.

We believe the information that is required to be posted on the EBB pursuant to prior decisions, and the information that section II.B.1.E of the Settlement Agreement requires to be posted, is sufficient. Since line pack is not included as a factor in determining when an OFO should be called, Shell Energy's request to modify section II.B.1.E of the Settlement Agreement to post current and forecasted system inventory, and daily changes in pipeline and customer storage imbalance inventories, on the EBB is not needed at this time. As part of the annual Customer Forum, there will be a review "of the timing, method, formulas, and all inputs to formulas by which OFO events are triggered," and a review of the minimum flow requirements. The annual Customer Forum is the place where interested parties should examine whether additional information should be posted on the EBB. As discussed earlier, the parties shall be permitted to discuss at the Customer Forum whether information about line pack should be reported on the EBB for use as a tool to help mitigate the calling of OFOs. Although information about line pack may be raised at the Customer Forum and possibly posted on the EBB, during the term of the settlement line pack shall not be included as part of the formula for deciding when an OFO should be called.

The fourth and fifth operational issues concern Shell Energy's argument that the System Operator must bear either a firm or interruptible receipt point access charge for all deliveries of gas to or through a receipt point by the System Operator, or for any transaction between the System Operator and the Core Procurement Department or a Sempra affiliate.

Shell Energy points out that sections II.B.1.H, II.B.1.N., and II.B.1.O. of the Settlement Agreement contain provisions that address gas purchases and sales by the System Operator. However, these provisions do not address whether the System Operator should be required to pay a receipt point access charge in connection with its gas deliveries to and through the SDG&E and SoCalGas receipt points. Shell Energy argues that any purchase and delivery of gas supplies by the System Operator to or through an SDG&E or SoCalGas receipt point must include either a firm or interruptible receipt point access charge.

In the joint reply comments, the settlement parties argue that the proposal of Shell Energy raises a question of policy, and that none of the testimony in this proceeding nor the Settlement Agreement addressed this proposal.

In D.07-12-019 the Commission deferred the issue of whether the System Operator should have to pay the FAR charge to this cost allocation proceeding, where there was an opportunity to develop an adequate record on this issue. However, the testimony in this phase of the proceeding did not address the applicability of the FAR charge to the System Operator. This issue only came up during Shell Energy's comments on the joint motion to adopt the Settlement Agreement, and in the joint reply comments.

Recently, in Resolution G-3435, the FAR charge issue was raised in connection with the approval of some contracts to support SoCalGas' minimum flow requirements on its Southern System. The Commission noted in the resolution that no record on the issue of whether the System Operator should have to pay the FAR charge was developed in this proceeding. The Commission resolution required that SoCalGas pay a firm or interruptible FAR charge for any contract related to Southern System reliability and spot purchases, just as any other purchaser of receipt point access would have to pay. However, the Commission stated in the resolution that "either SoCalGas or interested parties may bring up this issue in the 18-month review of the FAR program."

Since there was no record developed in this phase about whether the System Operator, or its counterparty to a transaction, should have to pay for the FAR charge, we decline to modify sections II.B.1.H, II.B.1.N., and II.B.1.O. of the Settlement Agreement to require that the System Operator be responsible for the FAR charge. As discussed above, Resolution G-3435 requires SoCalGas to pay the FAR charge, and we do not modify that resolution here. However, the issue of whether the system operator or counter party should pay for the FAR charge in other situations may be raised in the upcoming 18-month review of the FAR program, where testimony on this issue should be developed.

The sixth operational issue of Shell Energy concerns its recommendation in Exhibit 96 to eliminate SoCalGas' 5-day winter balancing rule that is contained in section II.B.1.I. of the Settlement Agreement. Shell Energy states that the 5-day winter balancing rule is the functional equivalent of a low inventory OFO. Shell Energy contends that if transmission system inventory, i.e., line pack, is adopted as the objective measure of system reliability for SDG&E and SoCalGas, the winter balancing rule is unnecessary because the System Operator would be able to call a low inventory and high inventory OFO when line pack tolerances are exceeded.

The settlement parties argue in the joint reply comments that the proposal of Shell Energy would replace the winter balancing rules with a low inventory OFO. They point out that the proposal to eliminate the winter balancing rule should be rejected because in the settlement of the Phase One BCAP decision, D.08-12-020, the parties agreed to the withdrawal of the proposal of SDG&E and SoCalGas to institute a low OFO trigger. D.08-12-020 also precluded SDG&E and SoCalGas from instituting a low OFO trigger for the duration of the Phase One settlement term.

Shell Energy's request to eliminate the winter balancing rule is related to its request that system line pack be incorporated as a factor into determining when an OFO should be called. Since we do not adopt Shell Energy's proposal to include system line pack as an OFO factor, and because eliminating the winter balancing rule would be contrary to what was negotiated and adopted in the Phase One settlement in D.08-12-020, Shell Energy's proposal to eliminate the winter balancing rule contained in section II.B.1.I. of the Settlement Agreement is not adopted.

The seventh operational issue that Shell Energy raised is to allow firm storage capacity holders to bump interruptible storage injections and withdrawals through all five nomination cycles, subject to the "elapsed pro rata" rule. In its comments to the joint motion, Shell Energy states that section II.B.1.J. of the Settlement Agreement provides that interruptible storage withdrawals may be used by shippers to meet their balancing requirements. Shell Energy does not object to this provision, but argues that the Commission must clarify how this provision will be reflected in SoCalGas Rule 30(D)(4). Specifically, SoCalGas should be directed to clarify Rule 30(D)(4) by allowing firm storage capacity holders to bump interruptible storage capacity through all five nomination cycles. Shell Energy argues that this change is needed in order to ensure that firm storage holders have access to their capacity in all five nomination cycles in order to manage imbalances.

The settlement parties did not respond to Shell Energy's request to clarify Rule 30(d)(4).

We will direct SoCalGas to clarify its Rule 30(D)(4) to allow a firm storage capacity holder to bump interruptible storage capacity through all five nomination cycles. The clarification to SoCalGas' rule is consistent with the provision in section II.B.1.J. of the Settlement Agreement to allow interruptible withdrawals to count towards the balancing requirements. The clarification to Rule 30(d)(4) shall occur in the advice letter filing to implement today's decision.

In summary, Shell Energy's proposals to reject or to modify certain operational provisions of the Phase Two Settlement Agreement will not be adopted, except for the clarification of SoCalGas' Rule 30(D)(4). The operational issues agreed to by the settlement parties, who represent a variety of different interests and viewpoints, are reasonable, are in the public interest because the resolution of the operational issues are fair to all the customers and provide different avenues for resolving the operations issues, and should be adopted.

3.3.5. Cost Allocation and Rate Design Issues

The cost allocation and rate design issues that were agreed to by the settlement parties are set forth in section II.B.2. of the Settlement Agreement.

3.3.5.1. In-Kind Storage Fuel

SDG&E and SoCalGas originally proposed in Exhibit 73 that in-kind storage fuel for core and noncore storage injections and for load balancing, receive balancing account treatment. SDG&E and SoCalGas also recommended that core and unbundled storage injections be assessed a 2.5% in-kind charge throughout the storage year.

In Exhibit 97, SCGC points out that unbundled storage customers are currently charged an in-kind fuel charge of 2.44% for injections during April through November, and that core and noncore customers pay for storage injection fuel as part of their transportation rates. SCGC proposed that a fixed in-kind charge of 2.4% be used instead of the 2.5%, and that this charge be updated in each subsequent cost allocation proceeding. SCGC's proposed charge of 2.4% is based on a three-year average.

Section II.B.2.G. of the Settlement Agreement adopts the utilities' proposal for balancing account treatment for in-kind storage fuel for core and noncore storage injections and for load balancing. The initial in-kind charge is to be set at 2.4%, and shall be adjusted for each subsequent storage year on the basis of a three-year rolling average.

3.3.5.2. FAR Review

Section II.B.2.H. of the Settlement Agreement provides that proposed changes to the FAR system will be examined in the 18-month FAR review.

Shell Energy does not oppose this provision, but in its comments to the joint motion it seeks to clarify that FAR implementation issues and operational issues can also be addressed in other forums such as an advice letter or a petition for modification.

The joint reply comments acknowledge that D.06-12-031, which established the 18-month FAR review, did not preclude parties from raising issues related to FAR through other procedural mechanisms. However, the parties in the joint reply comments argue that unless there is a compelling or urgent need to address a FAR-related issue, those issues should be addressed in the 18-month FAR review. They also note that the FAR review is scheduled to begin in March 2010.

We are not persuaded by Shell Energy's argument that section II.B.2.H. of the Settlement Agreement should be clarified to allow for other forums in which to raise FAR-related issues. As noted in the joint reply comments, if an issue involving FAR raises an urgent need to resolve the issue before the 18-month FAR review, section II.B.2.H. of the Settlement Agreement does not prevent us from doing so. Also, the 18-month FAR review will occur in the near future. Unless there is a need to resolve a particular FAR issue in a timely manner, it would be a better use of resources to wait until the 18-month FAR review.

3.3.5.3. Residential Tier Differential

For residential rate design, SoCalGas proposed a rate differential between baseline and non-baseline residential gas transportation rates of about 5%, exclusive of the cost of gas.

In Exhibit 101, TURN argued that when the commodity costs are added to develop the full retail rate that a residential customer will pay, that the tier differential proposed by SoCalGas will be negligible. TURN proposed that residential rates should have a tier differential of 15% between total baseline and non-baseline rates, and that the tier differential be reduced as gas prices increase.

Section II.B.2.I. of the Settlement Agreement adopts TURN's proposal for developing the residential tier differential, but includes a cap on the rate difference between the baseline and non-baseline rates.

3.3.5.4. Core Commercial and Industrial Customer Charges

SoCalGas' current core commercial and industrial rate design consists of two tiers of customer charges and three tiers of declining block volumetric rates. In Exhibits 63 and 64, SoCalGas proposed to: (1) consolidate its current two customer charges of $10 (for customers with usage less than 1000 therms/month) and $15 (for customers exceeding 1000 therms/month) per month to a single customer charge of $15 per month; and (2) remove the seasonality in the tier 1 usage threshold by maintaining a constant year-round tier 1 threshold of 250 therms per month. Currently, the tier 1 rate applies to the first 100 therms per month in the summer, and the first 250 therms during the winter.

In Exhibits 56 and 57, SDG&E proposed that its current three customer charges of $5.58 (for customers with usage of 1000 therms/month or less), $11.16 (for customers with usage of 21,000 therms/month or less), and $111.61 (for customers with usage greater than 21,000 therms/month) per month be changed to a single customer charge of $10 per month. SDG&E also proposed to remove the seasonal difference in rates.

In Exhibit 83, DRA opposed the proposals to consolidate the commercial and industrial customer charges of SoCalGas and SDG&E, and to remove the seasonality from the rates.

Section II.B.2.J. of the Settlement Agreement adopts the SoCalGas and SDG&E proposals for core commercial and industrial customers. For SDG&E's customers the customer charge will be $10, and for SoCalGas' customers the customer charge will be $15. Seasonality shall be removed from the core commercial and industrial rates.

3.3.5.5. Authorized Margin of the CFCA

SoCalGas proposes to seasonalize the authorized margin in the CFCA, instead of recording 1/12 of the authorized margin on a monthly basis in the CFCA.

In Exhibit 83, DRA opposed SoCalGas' recommendation to seasonalize the authorized margin in the CFCA, and pointed out that the current method has been used for many years.

Section II.B.2.K. of the Settlement Agreement agrees to retain the existing 1/12 methodology for recording the authorized margin of the CFCA.

3.3.5.6. Bridge Housing Proposal

Bridge Housing proposed that the residential common area gas customers of SDG&E and SoCalGas be allowed the option of migrating to the core commercial and industrial rate schedule.

SDG&E and SoCalGas opposed the proposal of Bridge Housing because of inadequate information to justify such a change.

Section II.B.2.L. of the Settlement Agreement adopts the proposal of Bridge Housing. SDG&E and SoCalGas agree to modify all applicable tariffs so that gas accounts with residential common area usage are provided with the option to choose a commercial rate for which they are eligible. As a condition of service, the common area gas equipment must be separately metered from the dwelling units.

3.3.5.7. Core Rate Deaveraging

SDG&E proposed that residential and core commercial and industrial rates be 100% deaveraged by the end of the three-year cost allocation period. SDG&E's core rates are currently 85% deaveraged. SDG&E proposed to phase the remaining core deaveraging at approximately 5% per year to achieve 90.1%, 95.1% and 100% deaveraging in Year 1, Year 2, and Year 3, respectively.

For SoCalGas, it proposes to completely deaverage residential core and core commercial and industrial rates by the end of the three-year cost allocation period. SoCalGas' core rates are currently 75% deaveraged. SoCalGas proposed to move to fully deaveraged rates over three years at a rate of about 8.3% per year.

DRA did not oppose SDG&E's proposal to fully deaverage core rates. However, in Exhibits 83 and 101, DRA and TURN opposed SoCalGas' proposal to deaverage the rates over the three-year period. DRA proposed that the deaveraging of SoCalGas' rates be limited to no more than 5% per year. TURN supported DRA's deaveraging proposal.

Section II.B.2.M. of the Settlement Agreement adopts the DRA and TURN proposal for core deaveraging of 5% per year.

3.3.5.8. SDG&E Borrego Springs

SDG&E currently provides liquefied natural gas (LNG) service to about 310 customers in the Roadrunner Home Park in Borrego Springs. SDG&E proposed to retain the Commission-approved rates from the 1999 BCAP. SDG&E also recommended that the Commission eliminate the requirement that the average combined LNG and electric bill not exceed the average Borrego Springs area all-electric bill.

Although DRA does not oppose the SDG&E proposed Borrego Springs LNG rate, DRA opposes SDG&E's proposal to eliminate the existing Commission requirement that the Borrego Springs average combined LNG and electric bill not exceed the average Borrego Springs all-electric bill.

Section II.B.2.N. of the Settlement Agreement adopts DRA's proposal to retain the existing requirement that the average combined LNG and electric bill for residents of the Roadrunner Home Park in Borrego Springs not exceed the average Borrego Springs all-electric bill.

3.3.5.9. SoCal Gas Engine Rate Cap

SoCalGas proposes to remove the existing cap of approximately 12.2 cents per therm on the gas engine rate (G-EN) for core commercial and industrial customers. This rate is used by customers for water pumping.

In Exhibit 83, DRA opposed SoCalGas' proposal to eliminate the cap on the gas engine rate. DRA recommended that the cap on the gas engine rate be maintained.

Section II.B.2.O. of the Settlement Agreement adopts DRA's proposal to retain the current cap on the gas engine rate.

3.3.5.10. Allocation of Certain Memorandum Accounts

SoCalGas proposed that the Firm Access and Storage Rights Memorandum Account (FASRMA), the Blythe Operational Flow Requirement Memorandum Account (BOFRMA), and the Otay Mesa System Reliability Memorandum Account (OMSRMA) be allocated on the basis of cold year throughput. According to SoCalGas, a cold year throughput allocation is appropriate because these three accounts are related to periods of high demand.

In Exhibit 83, DRA opposed SoCalGas' proposed allocation of these three accounts. DRA argued that these three accounts have no relationship to periods of high demand. DRA recommended that the FASRMA, BOFRMA, and OMSRMA be allocated on an ECPT basis. Also, DRA recommended that when the System Reliability Memorandum Account (SRMA) is implemented to replace the FARSMA, that the ECPT allocation basis should be used.

Section II.B.2.Q. of the Settlement Agreement agrees to allocate the FASRMA, BOFRMA, OMSRMA, and the new SRMA memorandum account balances on an ECPT throughput basis.

3.3.5.11. Allocation of CFCA and NFCA Balances

Currently, both the base margin and non-base margin costs of the CFCA and the NFCA are allocated on an ECPT basis. SDG&E and SoCalGas proposed to change the allocation of the base margin costs to an equal percent marginal cost (EPMC) basis, and to continue with the allocation of non-base margin costs on an ECPT basis. Since there is a year lag in recording the balances in the base margin and non-base margin sub-accounts, SDG&E and SoCalGas recommended that this proposal not be implemented until the second year of the BCAP period.

In Exhibit 83, DRA opposed the utilities' proposal to modify the existing allocation of the CFCA and NFCA balances, and recommended that the current ECPT allocation be retained. The utilities argued that the use of the EPMC allocation for the base margin portion of these two account balances is appropriate because that allocation takes into consideration the costs of the different functions required to serve each customer class. DRA argued that the subaccounts for the CFCA and NFCA do not have subaccounts for the various customer classes, and therefore one cannot determine which specific customer class contributed to the balance in the account.

SCGC recommended in Exhibit 97 that the balances in the NFCA should be allocated on an EPMC basis rather than on an ECPT basis.

Section II.B.2.R. of the Settlement Agreement agrees to maintain the current ECPT allocation methodology for the CFCA and NFCA balances. However, in the second year of the BCAP period, the equal percent of authorized margin (EPAM) allocation methodology, as described in section II.B.2.E. of the Settlement Agreement, will be used for allocating the base margin portions of the NFCA balances, and the ECPT allocation method shall be used for the non-base margin portions.

3.3.5.12. Natural Gas Vehicle Stations

Currently, SDG&E and SoCalGas provide separate G-NGV rates for customers that use natural gas as a motor vehicle fuel. Customer-funded natural gas vehicle (NGV) stations are charged an uncompressed rate that includes a customer charge, a procurement charge, and a transmission charge. Utility-funded NGV stations are charged a compressed rate that includes the uncompressed rate and a compression charge. The uncompressed rate that SoCalGas charges is 4.7 cents per therm lower than what SDG&E charges. The compressed rate that SoCalGas charges is 10.1 cents per therm lower than what SDG&E charges.

SDG&E and SoCalGas proposed to establish a single Sempra-wide NGV rate for use in both service territories. The effect of the proposal is to provide a single, consistent rate for NGVs who travel across both service territories.

Section II.B.2.S. of the Settlement Agreement adopts the utilities' proposal for a Sempra-wide rate for natural gas provided to NGV stations.

3.3.5.13. Summary of Cost Allocation and Rate Design Issues

Based on the parties' testimony on the cost allocation and rate design issues, and the agreements on these issues in the Settlement Agreement, it is clear that the parties were able to reach compromises on the various issues. Some of the agreed-upon issues adopt the utilities' positions, while other issues adopt or incorporate the proposals of the other parties. When all of these cost allocation and rate design issues are considered as a whole and with the agreements reached on the other issues in the Settlement Agreement, as well as the rate impact on the different customer classes, these agreements concerning cost allocation and rate design are reasonable and in the public interest, and should be adopted.

3.3.6. Peaking Service Rate and Transmission Level Service

In D.06-12-031, the Commission addressed the gas transportation bypass issue. SoCalGas' peaking service rate, Schedule GT-PS, applies to gas transportation service to a noncore customer who bypasses SoCalGas, in part or in whole. In certain situations, a noncore customer may use an interstate pipeline for baseload service, and at some point may return to the SoCalGas system for peak load service. The issue over the peaking rate has to do with the cost of serving these returning bypass customers, while narrowing the rate differences with the transportation rate charged by the competing interstate pipelines.

In Exhibit 63, SoCalGas proposed the TLS rate as an alternative to the peaking service rate. The TLS rate proposed two firm transportation alternatives: (1) a combined fixed reservation rate and a volumetric usage rate option; or (2) a volumetric-only rate option. SoCalGas would also be permitted to discount the price in order to compete with other alternatives available to potential bypass customers. The proposed TLS rate would apply to all customers that take gas service at the transmission level.

Long Beach pointed out in Exhibit 94 that if the TLS rate is adopted, the TLS rate would be the only firm transportation service that it could use. Long Beach currently obtains transmission service under SoCalGas' GW-LB tariff. Long Beach stated that there would be significant increases in Long

Beach's transportation service costs and rates under the two TLS rate options. Other service options available to Long Beach would present unacceptable financial and reliability risks to Long Beach and its core customers. Long Beach recommended that it be allowed to take service under a volumetric rate option with the rate set at the class-average rate for transmission level customers of 2.8 to 2.9 cents per therm, and that this rate be made available to electric generation customers as well.

In Exhibit 101, TURN argued for the retention of the peaking service rate. TURN viewed the peaking service rate as the most effective means to address the regulatory gap and to discourage uneconomic partial bypass of the utility system. TURN asserted that the TLS rate might not be effective in closing the regulatory gap with the interstate pipeline rate. If, however, the Commission decides to eliminate the peaking service rate, TURN states that the TLS rate is the second-best alternative.

SCE opposed SoCalGas' proposed TLS rate in Exhibits 88 and 89. SCE is concerned that the TLS rate will result in negative policy implications for electric generation customers by raising the rates paid by low load factor customers such as electric generators. That is because the TLS rate would apply to all customers who are directly connected to the transmission line. Due to the state's encouragement to use renewable energy, that could increase the peak nature of the electric generators' demand for gas, which would lower the load factor for electric generators and result in higher costs for gas under the TLS rate. SCE recommended that the peaking service rate be modified as described in Exhibit 88.

In Exhibit 98, SCGC recommended that the proposed TLS rate be rejected, and that the existing peaking service rate be retained. SCGC asserted that the TLS rate would force low load factor customers, such as electric generators who are less costly to serve, to subsidize high load factor customers that cost more to serve. As a result, this would increase the cost of electricity for customers in southern California. If the TLS rate is adopted, SCGC recommended that Long Beach and electric generation customers be allowed to remain on their existing tariffs instead of the TLS rate. If the TLS rate is adopted for all customers, then SCGC recommended that Long Beach be allowed to take service under a volumetric rate option with the rate set at the class-average rate for transmission level customers, and that this rate be made available to electric generation customers as well.

Kern River supported SoCalGas' proposal to eliminate the peaking service rate, but did not take a position on which rate design proposal should be adopted. The Indicated Producers et al. agreed that the peaking service rate should be eliminated, and supported SoCalGas' proposal to use the TLS rate if the term for volumetric service is shortened from six years to no more than three years.

The Settlement Agreement adopts the TLS rates as described in Attachment 1, and as reflected in the rates shown in Attachment 3, to Appendix A of the joint motion. The peaking service rate is eliminated. Under the TLS service, customers may choose from four different rate options. These four rate options incorporate various elements from the other parties' proposals.

The elimination of the peaking service rate, and the TLS rate as proposed by SoCalGas, generated a lot of comments by those who would be affected by this change. The TLS rates adopted in the Settlement Agreement reflect a balance between SoCalGas' interest of recovering its cost of serving transmission level customers while ensuring that partial bypass customers pay their share of the costs, and the interests of other transmission level customers who want fair and reasonable rates tailored to their gas supply needs. The four rate options for the TLS service are reasonable and in the public interest, and should be adopted.

3.3.7. Other Issues in the Settlement Agreement

3.3.7.1. Throughput Risk

SDG&E and SoCalGas proposed that they should not be at risk for noncore throughput as a result of a variation between the forecasted and actual throughput. SDG&E and SoCalGas recommended that they receive 100% balancing account protection for noncore throughput.

DRA recommended that SDG&E and SoCalGas be at risk for 10% of the noncore throughput, while the Indicated Producers et al. recommended that SDG&E and SoCalGas be placed 100% at risk for the recovery of noncore throughput. SCGC opposed the proposals of DRA and the Indicated Producers et al.

Section II.B.3.A. of the Settlement Agreement provides that SDG&E and SoCalGas shall not be at risk for throughput during the term of the Settlement Agreement. The agreement not to place SDG&E and SoCalGas at risk for any variation between the forecasted and actual throughput during the settlement term represents a recognition that the balancing account protection is important to foster the Commission's energy efficiency goals of reducing gas usage while providing an incentive for the utilities to promote energy conservation. Accordingly, the agreement not to place SDG&E and SoCalGas at risk for gas throughput is reasonable and in the public interest, and should be adopted.

However, we take issue with the other provision in the Settlement Agreement that provides for the parties to "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." (Appendix A, p. 13.) The Settlement Agreement provides that if the Commission were to adopt a formal policy in favor of throughput risk, that such action would not affect the terms in the Settlement Agreement and SDG&E and SoCalGas would not be placed at risk for throughput during the term of the Settlement Agreement. The Settlement Agreement provides that the opening briefs on this issue are to be filed no later than 30 days after the date of a Commission order approving the settlement, and that reply briefs will be due 15 days after the opening briefs.

We do not adopt the second, third and fourth sentences in section II.B.3.A. of the Settlement Agreement calling for briefs on whether the Commission should adopt in the future a formal policy regarding whether the utilities should be at risk for gas throughput. Since the Settlement Agreement already provides that SDG&E and SoCalGas shall not be at risk for gas throughput during the term of the Settlement Agreement, there is no need for this Commission to establish a policy at this point in an attempt to bind a future Commission examining the same issue. (See Pub. Util. Code § 1708, which authorizes the Commission at anytime, upon notice to the parties, and with opportunity to be heard as provided in the case of complaints, to rescind, alter, or amend any order or decision made by it; D.04-05-055 at p. 42.) The parties were provided with an opportunity to comment on our non-adoption of these sentences in their comments to the proposed decision.[10] No one commented on this issue.

3.3.7.2. Reporting of Customer Arrears

TURN recommended in Exhibit 102 that SDG&E and SoCalGas be required to submit monthly reports to the Commission. The reports would contain information about the number of residential customers who are in arrears on their bills, the amount of the arrears, and the number of customers who have been terminated for nonpayment. TURN stated that such reports could provide the Commission with information about customer defaults, the conditions which lead to defaults, and guidance on whether rate increases or more costs should be passed on to residential customers.

Section II.B.3.B. of the Settlement Agreement provides that SDG&E, SoCalGas, DRA and TURN will negotiate in good faith to come up with a periodic report that addresses aggregate customer data relating to such issues as customer turn-offs for non-payment of bills.

3.3.7.3. Landfill and Digester Gas

In Exhibit 97, SCGC recommended that SoCalGas modify its tariffs to exempt landfill and digester gas supplies from being considered an alternate fuel. Currently, if a SoCalGas customer uses an alternate fuel source to fuel its electric generation plant, SoCalGas places that customer on partial requirements service instead of full requirements service. Under SoCalGas' current GT-F tariff, a full requirements customer is prohibited from using

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[10] Section III.C. of the Settlement Agreement provides in part that any party may withdraw from the settlement agreement if the Commission modifies, deletes from, or adds to the disposition of the matters stipulated in the agreement.

alternate fuels or bypass service.[11] SCGC argues that the landfill and digester gas should not be considered an alternate fuel because those fuels are not being used to bypass the gas utility, and the use of such fuels are consistent with government and social policies to encourage the use of these types of gas supplies to reduce greenhouse gases.

In Exhibit 70, SoCalGas argued that the service options available to customers who use landfill or digester gas are consistent with its tariffs, and are being applied without discrimination. SoCalGas expressed a willingness to work with such customers about seeking possible deviations to the tariff.

In section II.B.3.C. of the Settlement Agreement, SoCalGas agrees to modify its tariff to exempt digester and landfill gas supplies from being considered sources of alternate fuel. Such a change will allow a SoCalGas customer, who uses such fuels, to be eligible to take full requirements service.

3.3.7.4. Backbone-Only Service

Section II.B.3.D. of the Settlement Agreement provides that the issue of whether to offer a backbone-only service is to be deferred to the next cost allocation proceeding and shall not be included in the scope of issues in the 18-month FAR review.

In Shell Energy's comments to the joint motion, it objects to this provision and requests that the provision be eliminated. Shell Energy contends that this issue about backbone-only service should be allowed to be raised in the

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[11] Under the GT-F tariff, a full requirements customer is not required to contract for a stated annual quantity of gas transmission service. A partial requirements customer must contract for an annual quantity of gas transmission service.

18-month FAR review, where a cost study of the backbone transmission costs is to be examined.

In their joint reply comments, the settlement parties contend that the cost study in the 18-month FAR review is for the purpose of developing a cost-based FAR reservation charge, and not for the purpose of deciding whether a backbone-only service should be offered. The settlement parties also contend that the issue of whether a backbone-only service should be offered needs to be considered in the context of all the proposed rates and service options, and the usual forum for this is in a cost allocation proceeding.

We agree with the settlement parties that the issue of a backbone-only service should be addressed in the next cost allocation proceeding, rather than in the upcoming 18-month FAR review. The focus of the FAR review is to examine how the FAR system has operated and how it can be improved, and the amount that should be charged for the firm access receipt point. Whether a backbone-only service should be offered is an issue that affects the rates of other customers and the cost of serving each of those customers. That kind of issue should be in the cost allocation proceeding, and Shell Energy's request to eliminate section II.B.3.D. from the Settlement Agreement is not adopted.

3.3.7.5. The G-SRF Surcharge

In accordance with Public Utilities Code § 404, regulated utilities such as SoCalGas impose a surcharge on their customers to recover the cost of the Public Utilities Commission Reimbursement Fee. SoCalGas recovers this fee through the Schedule No. G-SRF surcharge.

In Exhibit 90, SCE recommended that SoCalGas not apply the G-SRF surcharge to an electric utility, such as SCE, for gas transported to the electric utility's wholly owned subsidiary for generation of electricity for sale to the electric utility's customers, or to a generator whose electrical generation is subject to a tolling arrangement with an electric utility for the generation of electricity for sale to the electric utility's customers. SCE contends that SoCalGas' collection of this surcharge on SCE's subsidiary and on third party generators with whom SCE has tolling arrangements results in SCE's customers having to pay the surcharge twice.

SCGC recommended in Exhibit 98 that SCE's proposal should be extended to exempt all gas-fired generation from the G-SRF surcharge. SCGC's rationale for broadening SCE's proposal is because gas-fired electric generators are exempt from the California Solar Initiative costs in Pub. Util. Code § 2851(d)(1) and from the Solar Water Heating and Efficiency Act in Pub. Util. Code § 2863(b)(4).

DRA recommended that SCE's proposal be rejected. SoCalGas recommended that more data be gathered to estimate the revenue impact of SCE's exemption proposal before such an exemption is granted.

The parties agree in section II.B.3.I. of the Settlement Agreement that the G-SRF surcharge schedule will be revised to exempt transportation services provided to electric generators so long as the 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. Such an exemption is reasonable and does not conflict with any code section because such services are being provided at a wholesale level. That is, these wholesale customers are not "providing service directly to customers," and therefore, should be exempt from the G-SRF surcharge. (See Pub. Util. Code § 431.)

3.3.7.6. Compressor Fuel Costs

The Indicated Producers et al. expressed concern in Exhibits 76 and 77 that it was unclear whether SoCalGas has an authorized balancing account to track and recover the difference between the utilities' authorized and actual costs for transmission compressor fuel. The Indicated Producers recommended that the utilities should, at a minimum, revise the descriptions of their balancing accounts in their Preliminary Statements to clarify how compressor fuel costs are tracked and recovered.

In Exhibits 51 and 68, SoCalGas and SDG&E provided an explanation of how transmission compressor fuel has been accounted for.

In section II.B.3.J. of the Settlement Agreement, the parties agreed that the descriptions of the balancing accounts in the Preliminary Statements would be clarified to describe how actual company use compressor fuel costs are tracked and recovered.

3.3.7.7. Sempra-wide Electric Generation Rate

The Sempra-wide EG rate provides that EG customers of both SDG&E and SoCalGas pay the same rates for distribution service in the two service territories.

In Exhibit 88, SCE argued that this rate amounts to a subsidy of SDG&E's EG customers by SoCalGas' EG customers. SCE proposed that the Sempra-wide EG rate be eliminated.

In Exhibit 70, SDG&E and SoCalGas argued that SCE's argument for the elimination of the Sempra-wide EG rate was no longer valid.

The parties agree in section II.B.3.K. of the Settlement Agreement to retain the Sempra-wide EG rate adjustment for distribution-level customers that are not included in the TLS rate class.

3.3.7.8. Elimination of Outdated Accounts

SoCalGas proposed to eliminate the Natural Gas Vehicle Account (NGVA), and to move the recording of the discretionary program costs from the NGVA into the CFCA on an ECPT basis. SoCalGas also proposed to eliminate the Natural Gas Vehicle Research Development & Demonstration (NGV RDD) account, and to allocate the balance to the CFCA and NFCA on an ECPT basis.

DRA did not oppose the elimination of these regulatory accounts. SCGC proposed that the NGVA and NGV RDD accounts be closed, and the balances allocated between the CFCA and NFCA based on an average year throughput basis excluding SDG&E's loads.

Section II.B.3.L. of the Settlement Agreement agrees to eliminate out-dated accounts, including the NGVA and NGV-RDD accounts, as proposed by SDG&E and SoCalGas.

3.3.7.9. Triennial Cost Allocation Proceeding

SDG&E and SoCalGas recommended that instead of having a cost allocation proceeding every two years, that the proceeding be every three years.

SCGC recommended that if the cost allocation proceeding is held every three years, that the Commission should delink the term for noncore customer service agreements from the three-year regulatory cycle. SCE and TURN supported the idea for a regular cost allocation proceeding, whether on a two or three-year basis, to promote rate stability and to update rates.

The parties agree in section II.B.3.M. of the Settlement Agreement to have a cost allocation proceeding for SDG&E and SoCalGas every three years instead of every two years.

3.3.7.10. Summary of Other Issues

Based on the original positions of the parties and the agreements reached in the Settlement Agreement, these provisions resolving the other issues are reasonable and in the public interest, and should be adopted.

3.3.8. Rates

The rates agreed to in the Settlement Agreement are set forth in Attachment 3 to Appendix A of the joint motion, and are the rates authorized by today's decision, as shown in Appendix B for SoCalGas, and in Appendix C for SDG&E. The rates in the Settlement Agreement are based on the cost allocation methodologies and rate designs agreed to in the Settlement Agreement. As provided for in the Settlement Agreement, the rates are also subject to the utilities' routine rate adjustments to reflect updated Regulatory Accounts and implementation of other Commission decisions.

A comparison of the various customer rates in the Settlement Agreement, as shown in Appendix B and Appendix C of this decision, to the original positions of SDG&E and SoCalGas, as shown in Exhibits 56 and 63, reflect movement by all of the parties on the cost allocation and rate design issues and their acceptance of the rates in the Settlement Agreement. The rates are also fair to all the customer classes.

Given the original competing positions of the parties regarding the cost allocation methodologies, the various rate design proposals, and the proposed rates based on those positions, the rates agreed to in the Settlement Agreement, as reflected in the rates and cost allocations shown in Appendix B and Appendix C of this decision, are reasonable and in the public interest, and should be authorized for use in this proceeding.

3.3.9. Conclusion

Based on our evaluation of the Settlement Agreement, as compared to the original litigation positions of the various parties, the Settlement Agreement represents a balanced compromise of all the different viewpoints and interests of all the parties. Except for the filing of additional briefs as provided for in section II.B.3.A. of the Settlement Agreement, the terms and conditions of the Phase Two Settlement Agreement are reasonable in light of the whole record, consistent with the law, in the public interest. Shell Energy's proposal for SoCalGas to clarify Rule 30(D)(4) is adopted, but Shell Energy's remaining proposals to clarify or eliminate other sections of the Settlement Agreement are not adopted. Accordingly, the June 2, 2009 joint motion to adopt the Settlement Agreement in Phase Two of this proceeding should be granted, and the remaining terms and conditions of the Settlement Agreement, as set forth in Appendix A of this decision, in Attachments 1 to 4 to Appendix A in the joint motion, and in the rates shown in Appendix B and Appendix C of this decision, should be adopted.

SDG&E and SoCalGas should be directed to file a Tier 2 advice letter with the Energy Division within 30 days of today's date to implement the terms and conditions of the Settlement Agreement, and to provide the necessary tariff revisions for review.

4. Comments on Proposed Decision

The proposed decision of ALJ John S. Wong in this matter was mailed to the parties in accordance with § 311 of the Public Utilities Code and comments were allowed pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedure. Opening and reply comments were filed by Shell Energy and the settlement parties. Those comments have been considered and appropriate changes have been incorporated into the decision.

5. Assignment of Proceeding

Timothy Alan Simon is the assigned Commissioner and John S. Wong is the assigned ALJ in this proceeding.

Findings of Fact

1. A joint motion to adopt a Settlement Agreement of the Phase Two issues was filed on June 2, 2009.

2. On July 2, 2009, Shell Energy filed its comments on the joint motion to adopt the Settlement Agreement and requested that certain provisions of the Settlement Agreement be clarified or eliminated.

3. The Settlement Agreement contains the recommendations of the settlement parties on the Phase Two issues, and Attachments 1 to 4 of the Settlement Agreement contain detailed explanations of the TLS rate design, the uncontested proposals, the agreed-upon rates for SDG&E and SoCalGas, and the updated tariffs that SDG&E and SoCalGas plan to use to implement the Settlement Agreement.

4. The two key components that affect the rates agreed to in the Settlement Agreement are the forecasts of gas throughput, and the methodology for allocating the gas transmission, storage, and distribution costs.

5. Based on the litigation positions of the parties and the small percentage difference between the forecasts, the Settlement Agreement's use of the utilities' gas throughput forecasts is reasonable and in the public interest.

6. The cost allocation methodologies and adjustments agreed to in the Settlement Agreement, and the resulting rates, represent a compromise and balancing of the parties' positions and competing interests.

7. A sufficient record exists to adopt the operational issues, cost allocation issues, rate design issues, and other issues agreed to in the settlement agreement.

8. Shell Energy's request for SoCalGas to clarify Rule 30(d)(4) was not responded to by the settlement parties.

9. A comparison of the various customer rates in the Settlement Agreement, as shown in Appendix B and Appendix C of this decision, to the original positions of the utilities, reflect movement by all of the parties on the cost allocation and rate design issues and their acceptance of the rates in the Settlement Agreement.

Conclusions of Law

1. Shell Energy's proposals to reject or modify certain operational provisions of the Settlement Agreement will not be adopted except for the clarification of SoCalGas' Rule 30(D)(4).

2. SoCalGas should be directed in its implementation advice letter to revise its tariff to clarify its Rule 30(D)(4) to allow a firm storage capacity holder to bump interruptible storage capacity through all five nomination cycles.

3. The second, third, and fourth sentences in section II.B.3.A. of the Settlement Agreement, calling for briefs on whether the Commission should adopt a future formal policy on whether the utilities should be at risk for gas throughput, should not be adopted because such a policy may bind a future Commission examining the same issue.

4. For all of the reasons discussed in this decision, the Settlement Agreement is reasonable in light of the whole record and in the public interest, and should be adopted.

5. The Settlement Agreement is consistent with the law.

6. The rates agreed to in the Settlement Agreement, as reflected in the rates and cost allocations shown in Appendix B and Appendix C of this decision, are reasonable and in the public interest, and should be authorized for use in this proceeding.

7. SDG&E and SoCalGas should be directed to file a Tier 2 advice letter with the Energy Division within 30 days of today's date to implement the terms and conditions of the Settlement Agreement, and to present the necessary tariff revisions for review.

O R D E R

IT IS ORDERED that:

1. The June 2, 2009 joint motion to adopt the Settlement Agreement in Phase Two of this proceeding is granted, and except as provided for in Ordering Paragraph 3 below, the terms and conditions of the Settlement Agreement (as set forth in Appendix A of this decision, in Attachments 1 to 4 to Appendix A in the joint motion, and in the rates and cost allocations shown in Appendix B and Appendix C of this decision), are adopted in this cost allocation proceeding of San Diego Gas & Electric Company and Southern California Gas Company.

2. The rates shown in Appendix B for the customers of Southern California Gas Company, and in Appendix C for the customers of San Diego Gas & Electric Company, are authorized and shall be allocated to those customer classes.

3. The second, third, and fourth sentences in section II.B.3.A. of the Settlement Agreement, calling for briefs on whether the Commission should adopt a future formal policy of whether San Diego Gas & Electric Company and Southern California Gas Company should be at risk for gas throughput, is not adopted.

4. Within 30 days from today's date, San Diego Gas & Electric Company and Southern California Gas Company shall file an advice letter with the Energy Division under Tier 2 of General Order 96-B to implement and carry out the terms and conditions of the Settlement Agreement, and to present the necessary tariff revisions, with an effective date of February 1, 2010.

    a. Any interested party may protest the advice letter filing as provided for in General Order 96-B.

    b. In its advice letter filing, Southern California Gas Company must clarify its Rule 30(D)(4) to allow a firm storage capacity holder to bump interruptible storage capacity through all five nomination cycles.

5. Pursuant to Public Utilities Code § 1701.5, Application 08-02-001 is closed.

This order is effective today.

Dated November 20, 2009, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

[APPENDICES A B C A0802001 Wong]