STATE OF CALIFORNIA GRAY DAVIS, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

November 26, 2001

Alternate Order to H-2
From 11/8/2001

TO: PARTIES OF RECORD IN INVESTIGATION 99-07-003

Enclosed is the Alternate Proposed Decision of Commissioner Carl Wood to the Proposed Decision of Administrative Law Judge (ALJ) John Wong previously mailed to you.

When the Commission acts on this agenda item, it may adopt all or part of it as written, amend or modify it, or set aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

As set forth in Rule 77.6(d), parties to the proceeding may file comments on the enclosed alternate at least seven days before the Commission meeting or no later than December 4, 2001. Reply comments should be served by December 6, 2001. An original and four copies of the comments and reply comments with a certificate of service shall be filed with the Commission's Docket Office and copies shall be served on all parties on the same day of filing. The Commissioners and ALJ shall be served separately by overnight service.

Lynn T. Carew, Chief
Administrative Law Judge

LTC:epg

Enclosure

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Decision **ALTERNATE PROPOSED DECISION OF COMISSIONER WOOD**
(Mailed 11/26/2001)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Investigation on the Commission's Own Motion to Consider the Costs and Benefits of Various Promising Revisions to the Regulatory and market Structure Governing California's Natural Gas Industry and to Report to the California Legislature on the Commission's Findings.	Investigation 99-07-003 (Filed July 8, 1999)

(See List of Appearances in Attachment A)

FINAL OPINION
APPROVAL WITH MODIFICATIONS OF THE INTERIM SETTLEMENT ENHANCING AND ENABLING COMPETITIVE MARKETS ON THE SOUTHERN CALIFORNIA GAS COMPANY SYSTEM AND OTHER DECISIONS ON THE PROMISING OPTIONS SET FORTH IN DECISION 99-07-015 AS APPLIED TO SOUTHERN CALIFORNIA GAS COMPANY'S SYSTEM AND SAN DIEGO GAS AND ELECTRIC COMPANY'S SYSTEM

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I. Summary

In this opinion, we consider three contested settlement proposals addressing the promising options raised in Decision (D.) 99-07-015 as applied to the Southern California Gas Company (SoCalGas) natural gas system, and to a lesser extent, the San Diego Gas and Electric Company (SDG&E) gas system. The three settlements are known as the Interim Settlement Agreement (IS) filed in December 1999, the Post-Interim Settlement Agreement (PI) filed in February 2000 and the Comprehensive Settlement Agreement (CS) filed in April 2000. At the time of submission, all three settlements still had supporters.

Based on the record developed regarding costs and benefits, as well as the dramatic developments in the electric industry and in gas prices at the border and at Pacific Gas and Electric Company's (PG&E) citygate in the months since the close of the evidentiary hearing, we choose not to adopt many of the promising options at this time. In light of energy market conditions at this time, we choose instead to approve portions of the IS, with some modifications. Our actions, today, are also prompted by recent proposals by SoCalGas in other dockets to eliminate the windowing process and institute firm intrastate transmission rights through bundled rates.

The adopted provisions: (1) establish Hector Road as a formal receipt point on SoCalGas' system at which nominations may be made; (2) provide for the establishment of "pools" of gas on the SoCalGas transmission system that are intended to increase the liquidity of trading of gas supplies; (3) allow trading of imbalances to some extent; and (4) provide for recovery in rates of all implementation costs actually incurred by SoCalGas to implement its provisions, in a capitalized amount not to exceed $3.5 million. The IS, and its appendices A-F, is attached as Appendix I to this opinion.

Additionally, based on the evidence in the record, we elect not to unbundle core interstate transportation from rates at this time, and we eliminate core contribution to noncore interstate transition cost surcharges (ITCS) and the core subscription option as well as the caps and thresholds for core aggregation programs following Commission implementation of consumer protections. We reduce the core aggregation program threshold, and offer billing options to core aggregators.

We emphasize that we see our action today as an interim measure. We put the parties on notice that we may open another investigation two years after the effective date of the tariff revisions arising from this decision, regarding the gas industry, in light of conditions in the market that time.

II. Background

On January 21, 1998, the Commission issued an Order opening Rulemaking (R.) 98-01-011 to assess the market and regulatory framework of California's natural gas industry and to consider reforms that might foster competition and benefit all California natural gas consumers. In D.99-07-015, on July 8, 1999, the Commission identified the most promising options for changes to the regulatory and market structure of the natural gas industry. The Order Instituting Investigation herein issued the same day, designating this as a quasi-legislative case appropriate for hearing. That order asked parties to prepare more detailed analyses of the costs and benefits of the promising options,[1] but allowed a short hiatus for exploring the possibility of settlement before prepared testimony was due. At the first prehearing conference in this case, on

[1] We also incorporated the entire record from R.98-01-011 into the record for this proceeding.

September 1, 1999, an extension of time was granted for the submission of testimony in order to facilitate settlement.[2]

Meanwhile, the Legislature enacted Assembly Bill (AB) 1421 in 1999, repealing the former Pub. Util. Code § 328,[3] which had arrested the Commission in its restructuring program until January 1, 2000. In its place the Legislature substituted statutes clarifying its intent that the utilities continue to serve the core with bundled services.[4]

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[2] Since that time, two further extensions were granted regarding PG&E's system, and a third granted with regard to the natural gas industry in the southern part of the state.

[3] All statutory references are to the Public Utilities Code, unless otherwise noted.

[4] Section 328. Legislative Findings. The Legislature finds and declares both of the following:

(a) In order to ensure that all core customers of a gas corporation continue to receive safe basic gas service in a competitive market, each existing gas corporation should continue to provide this essential service.

(b) No customer should have to pay separate fees for utilizing services that protect public or customer safety.

Section 328.1. Definitions.

As used in this chapter, the following terms have the following meanings:

(a) "Basic gas service" includes transmission, storage for reliability of service, and distribution of natural gas, purchasing natural gas on behalf of a customer, revenue cycle services, and after-meter services.

(b) "Revenue cycle services" means metering services, billing the customer, collection, and related customer services.

(c) "After-meter services" includes, but is not limited to, leak investigation, inspecting customer piping and appliances, carbon monoxide investigation, pilot relighting, and high bill investigation.

Footnote continued on next page

This case proceeded on two tracks, one for the PG&E system, and one for the SoCalGas and SDG&E systems. All issues with regard to the PG&E system were resolved in two separate settlements, approved in D.00-02-050 and D.00-05-049, respectively. The southern California settlement discussions proved more difficult. On December 27, 1999, the IS, supported by SoCalGas and SDG&E as well as 20 other parties, was filed.[5] On January 28, 2000, three other proposed settlements and one proposal for consolidating settlements were filed. The parties were directed by the Assigned Commissioner to go back to the negotiating table to try to consolidate the proposals by April 3, 2000.

(d) "Metering services" includes, but is not limited to, gas meter installation, meter maintenance, meter testing, collecting and processing consumption data, and all related services associated with the meter.

Section 328.2. Required Gas Service.

The commission shall require each gas corporation to provide bundled basic gas service to all core customers in its service territory unless the customer chooses or contracts to have natural gas purchased and supplied by another entity. A public utility gas corporation shall continue to be the exclusive provider of revenue cycle services to all customers in its service territory, except that an entity purchasing and supplying natural gas under the commission's existing core aggregation program may perform billing and collection services for its customers under the same terms as currently authorized by the commission, and except that a supplier of natural gas to noncore customers may perform billing and collection for natural gas supply for its customers. The gas corporation shall continue to calculate its charges for services provided by that corporation. If the commission establishes credits to be provided by the gas corporation to core aggregation or noncore customers who obtain billing or collection services from entities other than the gas corporation, the credit shall be equal to the billing and collection services costs actually avoided by the gas corporation. The commission shall require the distribution rate to continue to include after-meter services.

[5] Along with the IS, attached as Appendix I, exemplary implementing tariffs were filed.

On that date, the three settlements filed on January 28 were withdrawn, but a new settlement was filed, the PI, to which SoCalGas and SDG&E were not parties. SoCalGas asked for, and received, more time to complete another settlement proposal. On April 17, 2000, SoCalGas, SDG&E and approximately 26 other parties filed the CS. At that point, three settlements were extant: the IS, the PI and the CS. Since each of these settlements was obviously contested, the case was set for hearing.[6] There were pre-hearing discovery motions aimed at clarifying whether SoCalGas still supported the IS; SoCalGas still supported the IS if the Commission did not find the CS acceptable.

There were eight days devoted to an evidentiary hearing[7] from May 30 to June 8, 2000. The Assigned Commissioner was present on four days of the hearing. On July 10, 2000, late-filed exhibits were received into evidence or rejected and the evidentiary record was closed. Opening briefs were concurrently filed by 20 parties on July 10, 2000; reply briefs were concurrently filed on July 31, 2000.[8] The case was deemed submitted on August 1, 2000.

On September 20, 2000, SoCalGas petitioned to reopen in order to submit amendments to the CS necessitated by the refusal of a company, which was

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[6] As mandated by § 1708, an opportunity to request a hearing must be afforded to the parties if the Commission plans to alter or amend a previous decision affecting them. Parties to a number of previous Commission decisions affecting SoCalGas were notified of the upcoming hearing.

[7] There were seven days of prehearing or informational conferences, including those relating to PG&E. The Assigned Commissioner was present at three prehearing conferences.

[8] Southwest Gas Corporation (Southwest Gas) requested leave to late-file its reply brief, because it had changed its position on the CS, to support it. The permission to late file is granted.

specifically named in the CS to provide the third-party trading platform, to enter into a contract. The record was reopened on October 6, 2000, the amendments and declaration in support thereof received into the record, and the evidentiary record was closed again and the matter resubmitted. The Administrative Law Judge (ALJ) mailed her proposed decision within the 90 days prescribed by law.

III. Discussion

A. Prior Decisions

The Commission has pursued a course of cautious deregulation in the gas industry. In D.91-02-040, the Commission first approved the core aggregation program. In D.92-07-025, this Commission allowed the unbundling of the costs of interstate transmission of gas for noncore customers. Core customers shouldered up to 10% of the stranded costs from that unbundling and continue to do so. In D.97-08-055, the Commission approved the Gas Accord,[9] which, among other actions, unbundled from rates the cost of PG&E's intrastate backbone transmission system in northern California. The Commission made it clear that it intended to monitor the effect of that unbundling and would take corrective action if necessary. In R.98-01-011 and D.98-08-030, it began a statewide gas policy review to determine whether existing rules and structures adequately supported the functioning of efficient markets and protected consumers.

In D.99-07-015, in R.98-01-011, slip *op.* at p. 9, the Commission identified as "promising options" changes that touched on intrastate transmission, storage, balancing, hub services, core procurement including interstate capacity

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[9] The Gas Accord is the common name of the settlement approved, with modifications, in D.97-08-055.

unbundling, information sharing, revenue cycle services, and statewide consistency. Some of these options pertained to SoCalGas only, not to PG&E. The Commission opened the instant proceeding, I.99-07-003, to investigate the costs and benefits of each option, while inviting the parties to engage in settlement discussions before proceeding to hearing.

The Commission approved an initial agreement in D.00-02-050, regarding the Operational Flow Order (OFO) protocol on the PG&E system, a subject of much discussion in R.98-01-011. In D.00-05-049, the Commission unanimously approved an uncontested settlement agreement that dealt with virtually all of the remaining promising options on the PG&E System, and that extended the unbundling begun in the Gas Accord. However, no uncontested settlements were forthcoming with regard to the SoCalGas system.

B. Current Situation

Since the Commission issued D.00-05-049, and since the development of the record in this proceeding, Californians have experienced an unprecedented upsurge in the cost of electric power and the benefits of electric restructuring have become less obvious. Moreover, keeping the cost of gas low has proven to be more difficult. For extended periods of time from March 2000-May 2001, the cost of gas was much higher than normal at the border,[10] showing a differential

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[10] The Gas Daily Price Guide May Regional Price Sampler, published in May 2000, listed a mid-point average April price for San Juan/El Paso basin gas of $2.74/Dth, with SoCalGas large packages at $3.01/Dth. The same publication in September 2000 listed a mid-point average August price for San Juan-El Paso as $3.41/Dth, and the SoCalGas large package price at $5.24/Dth. Gas Daily and the associated Gas Daily Price Guide Monthly are well-regarded and widely recognized sources for gas prices in the industry. We take official notice of the prices in the May 2000-June 2001 price guides as facts in this case. These prices are also reflected in the charts found in Section III in this decision.

between the basin and border prices that is more than the cost of transport and related services; we question whether there will be an opportunity for discounting by marketers if more competition is allowed. In addition, the California Energy Commission reports that businesses have expressed an interest in constructing more than 38,000 megawatts of new gas-fired generation in California. Event the construction of a modest portion of this new generation could significantly alter gas market forces. In light of these changes, it is appropriate to adopt in this docket only those modifications which can be found reasonable prior to taking evidence related to the new market factors.

Rather than proceeding to unbundle transmission and storage in southern California, we approve elements of the IS that appear likely to improve the function of the markets now. We note that SoCalGas has filed two proposals in recent weeks that will enable the Commission to consider changes to windowing procedures and the creation of firm transmission rights, both in the context of current market conditions.[11]

C. Summary of Each Proposed Settlement[12]

1. Summary of Interim Settlement

The IS is supported by SoCalGas and other parties[13] if the CS is not approved by the Commission. Notably, this settlement is the settlement

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[11] See SoCalGas Advice Letter No. 2837-A, filed November 1, 2001, and Appendix K to Application 01-09-024, filed September 21, 2001.

[12] These summaries are not exhaustive recapitulations of every provision of each settlement agreement.

[13] For instance, the California Industrial Group and the California Manufacturers Association (CIG/CMA) and Coral Energy still support the IS if the Commission does not approve the CS. PG&E, an IS signatory, still supports the IS, and not the CS. The

Footnote continued on next page

supported by the most customer groups.[14] It applies only to the SoCalGas system, not to the SDG&E system.

This Settlement eliminates SoCalGas' current "windowing" process, which limits the flexibility of shippers on its system to change their nominations for gas deliveries between various receipt points on SoCalGas' system. This Settlement establishes Hector Road as a formal receipt point on SoCalGas' system for which nominations may be made. It also provides a mechanism that will trigger additional investment by SoCalGas to increase its capacity to receive gas at the Wheeler Ridge receipt point if specified criteria are met. This Settlement also provides a forum for further changes in Operational Flow Order (OFO) procedures during the term of this Settlement if their frequency exceeds a stated threshold.

This Settlement provides for the establishment of "pools" of transportation gas on the SoCalGas system which is intended to increase the liquidity of trading of gas supplies in southern California and to provide other benefits to gas consumers and marketers in southern California.

This Settlement also makes changes in the transportation balancing rules on SoCalGas' system, while retaining the current 10% monthly imbalance tolerance for transportation customers. This settlement explicitly subjects

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Utility Reform Network (TURN) and the Southern California Generation Coalition (SCGC) support the IS as part of the Post-Interim settlement, but only SCGC was a signatory initially to the IS. Aglet Consumer Alliance (Aglet), though not a signatory, supports the IS as part of the PI. The Department of General Services, though not a signatory, wholeheartedly supports the IS. The position of the other original signatories is not clear, although a number of them support the IS as part of the PI. (See footnote 14.)

[14] ORA does not support the IS.

SoCalGas' Gas Acquisition department to the same balancing rules and penalties as all other shippers on the SoCalGas system, except that the current winter balancing rules that apply special flowing supply requirements to core gas suppliers, including SoCalGas' gas acquisition function and core aggregation transportation marketers, will be retained. A detailed methodology for determining the daily imbalances of core gas suppliers including SoCalGas' gas acquisition function is specified by this Settlement. SoCalGas' Gas Acquisition department will no longer buy or sell through its supply portfolio imbalances of transportation customers outside their tolerance levels. Rather, cumulative imbalances will remain the property of the transportation customer, but the customer will be subject to modified imbalance charges intended to substantially deter imbalances outside allowed tolerances. Current rules that limit the trading of imbalances will be liberalized.

This Settlement provides express language in SoCalGas' tariffs giving unbundled storage customers the right to assign and reassign their storage contracts in a secondary market (including for terms less than the full contract terms). SoCalGas would establish a voluntary electronic bulletin board ("EBB") for secondary trading in storage contracts on SoCalGas' system. The storage capacity required for minimum core reliability purposes would remain bundled in core transportation rates. The storage capacity allocated by the Commission in SoCalGas' pending biennial cost allocation proceeding (BCAP) A.98-10-012 which exceeds that required for core minimum reliability would be unbundled from core transportation rates. SoCalGas' Gas Acquisition department would be assigned a proportionate share of the cost of storage other than for core reliability, which it will recover through the Purchased Gas Account (PGA) Core Sub-Account. Core aggregation transportation (CAT) marketers would have the option to accept or decline assignment of a proportionate share of storage allocated to the core market which exceeds that required for core minimum reliability.

This Settlement provides for rate recovery of all capital costs incurred by SoCalGas for developing and implementing new or enhanced computer systems necessary to implement the IS in an amount not to exceed $3.5 million.

A collaborative forum would be established for stakeholders to discuss possible further restructuring changes, including those that could be implemented on or after January 1, 2003. If no settlement of those issues is filed by September 1, 2000, the settlement provides that the Commission will promptly institute a new proceeding to consider proposals in time so that they can be implemented by January 1, 2003.

Obviously, the timeframe for a new proceeding for consideration of further restructuring has been overtaken by the continuation of the instant proceeding. The term of the IS is through December 31, 2002, which is the same termination date as the Gas Accord in northern California.

2. Summary of Post-Interim Settlement[15]

This settlement proposal incorporates the IS, and the Joint Recommendation adopted in the SoCalGas 1999 BCAP decision, D.00-04-060, and adds some additional provisions. However, unlike the IS, the PI, if approved without modification, would remain in effect until September 1, 2006, with the exception of a few provisions. The long term of the agreement works as

15 The PI is supported by TURN, SCGC, Aglet, City of Burbank, City of Glendale, City of Pasadena, Imperial Irrigation District, Los Angeles Department of Water and Power, Reliant Energy Power Generation, Southern California Utility Power Pool, and Williams Energy Services.

a barrier to the unbundling of intrastate transmission and the use of demand charges[16] until September 1, 2006. The BCAP decision provisions, however, apply only until January 1, 2003. Thus, for example, the 75/25 (ratepayer/shareholder) balancing account treatment for noncore revenues, including existing EAD contracts and future contracts, as specified in the Joint Recommendation, does not go until 2006.

Under the PI, the core's 10% contribution to noncore ITCS coverage would be eliminated entirely on January 1, 2002. ITCS costs would be shared 75/25 between noncore ratepayers and SoCalGas, beginning January 1, 2002. Under the PI, and according to its supporters, in accordance with Federal Energy Regulatory Commission (FERC) Order No. 637, Docket No. RM 98-10-00, Reg-Preamble, FERCSR 31, 091 at 31, 270, et seq. (Feb. 25, 2000), there would no longer be rate ceilings for short-term capacity release transactions by SoCalGas, giving SoCalGas the opportunity to derive additional revenue through the release of unbundled interstate pipeline capacity.

Under the PI, the interstate pipeline capacity associated with service to CAT customers would be unbundled on the effective date of the PI. Any stranded costs that resulted from unbundling interstate pipeline capacity for CAT customers would be allocated 50/50 between core transportation and bundled core sales customers. The portion of stranded costs allocated for recovery from core sales customers would be allocated between

[16] Under the terms of the PI, if the Commission allows SoCalGas to institute a demand charge as part of a peaking tariff implemented to replace SoCalGas' current Residual Load Service ("RLS") tariff, such a charge shall apply only to partial bypass customers to the extent they are subject to the peaking tariff.

commercial/industrial customers and residential customers in proportion to their participation in the CAT program, as redetermined annually.

Under the PI, there would be no additional storage unbundling for the term of the 1999 BCAP, except as provided in the IS. Costs associated with the Montebello storage field would be removed from rates effective September 16, 1999. The core storage reservation would remain as set forth in the BCAP decision adopting the Joint Recommendation for the term of the BCAP, as would the 50/50 balancing account treatment for unbundled storage revenues, with the at-risk unbundled storage revenues being set at $21 million. Noncore Storage Balancing Account (NSBA) treatment for unbundled storage revenues would cease effective January 1, 2003 for the term of the PI (until 2006). Consistent with the Joint Recommendation, SoCalGas would have pricing flexibility for all storage products, provided that the reservation charge would be no higher than 120% of the ceiling reservation charge currently specified in SoCalGas' G-TBS tariff. Effective January 1, 2003, and extending for the remaining term of the Settlement Agreement, SoCalGas would have pricing flexibility for storage products, provided the reservation charge would be no higher than the ceiling reservation charge currently specified in the G-TBS tariff. In other words, the price would be capped at a lower rate for the three years farthest in the future of the settlement term.

No storage capacity used for balancing would be unbundled from SoCalGas transportation rates for the term of the 1999 BCAP. The issue of whether there should be unbundling of balancing capacity thereafter would be subject to reconsideration in the next BCAP. The 1999 BCAP storage balancing reservation (355 MMcfd injection, 250 MMcfd withdrawal, 5.3 bcf inventory) would remain in place for the term of the 1999 BCAP. The level of the core reservation would be subject to reconsideration in the next SoCalGas BCAP. In order to permit the timely consideration of issues in the next SoCalGas BCAP, SoCalGas would file its next BCAP application no later than July 1, 2001, i.e., 18 months before the proposed effective date, January 1, 2003.

SoCalGas would be permitted to recover the capitalized costs associated with developing and implementing enhanced computer systems needed for implementation of the provisions of the IS. SoCalGas would be allowed to book such costs to an account, provided that the cost associated with development and implementation that is booked to the account would not exceed $3.5 million.

3. Summary of Comprehensive Settlement

The Office of Ratepayer Advocates (ORA) and over 30 other parties representing all segments of the natural gas industry are sponsoring the CS.[17] Approval of this settlement, as opposed to the other two, would create a gas system in southern California that closely resembles that created in northern California through the adoption of the Gas Accord (D.97-08-055) and the two previous settlements in this case. The CS also attempts to address all the

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[17] Parties currently supporting the CS include: California Cogeneration Council; CIG; California Manufacturers and Technology Association (CMTA, formerly known as CMA); California Utility Buyers; Calpine Corporation; City of Vernon; Coral Energy Resources; Dynegy, Inc.; El Paso Natural Gas (possibly with reservations); Enron, Inc.; GreenMountain.com; Amoco Energy Trading Company; BP Amoco Corporation; Burlington Resources; Chevron U.S.A. Inc.; Conoco Inc.; Occidental Energy Marketing Incorporated; Texaco Natural Gas Inc.; ORA; REMAC; SDG&E; Shell Energy Services; Southern California Edison Company (SCE); SoCalGas; Southwest Gas; SPURR; Transwestern Pipeline Company; TXU Energy Services; United Energy Management; Utility.com; Watson Cogeneration Company; Western Hub Properties; Wild Goose Storage Inc.

SCE neither supports nor opposes the retail sections.

promising options in D.99-07-015 and applies in explicit provisions to SDG&E. Its focus is on creating opportunities for competition, while minimizing cost shifts between customer classes. While the agreement as a whole terminates on August 31, 2006, many of its provisions terminate or are subject to change well before that date. The parties to the CS refer to the "capacity-related" sections of the agreement and the "retail" sections of the agreement. We do so in this summary as well.

a) The Capacity Related Sections

Intrastate Transmission

Effective October 1, 2001, the cost of SoCalGas' backbone intrastate transmission system would be unbundled from rates on an embedded cost basis[18] and SoCalGas would be placed at risk for the annual revenue requirement for this segment of its system. In order to meet its revenue requirement, SoCalGas would establish a system of firm tradable rights for transportation[19] from specific receipt points to any on-system customer. The CS designs a multi-stage system for buying these rights, first reserving capacity at a fixed rate at each receipt point for the core customers of SoCalGas' Gas Acquisition Department, and then giving wholesale customers and core

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[18] This cost is set at $73.7 million for year 2000; however, this cost is arrived at after shifting $4.1 million in cost to the local transmission system as part of the negotiations. (Ex. 2, Att. 3.) The attributed embedded cost of the backbone system escalates on Jan.1, 2001, pursuant to the PBR formula in D.97-07-054 until the next PBR decision, at which point a new formula, if one is adopted, will be used.

[19] Presently, SoCalGas is operating a "windowing system" that may cut back the amount of an initial nomination of gas to be received at each receipt point on the SoCalGas transmission system.

transport agents (CTAs)[20] already on the system, reservations of their historical load at each receipt point at a fixed price if they wish. These customers may find their desired reservations at a particular receipt point pro-rated because only 50% of the capacity remaining at each receipt point after the Gas Acquisition Department's reservation will be available in the first stage of the open season. In the second stage of the open season, these customers then have another chance to bid for any uncontracted capacity within the 50% available at each receipt point. In the final third stage of the open season, the remaining 50% of non-Gas Acquisition Department capacity is available to any creditworthy person for any length of term up to the termination of the settlement. However, 20% of the remaining 50% is reserved for a one year length of term only, to be repeatedly made available for a one year term annually after 2001 in an open season with no preferential bidding.

The CS employs a postage stamp rate for its reservation charge, subject to adjustment annually using the PBR formula. Bids may be made at either a 100% reservation charge or 50% reservation charge-50% volumetric charge (at a slight premium) or in any combination of the two rate designs.[21] A seasonal capacity rate is available at 120% of the reservation charge; the 50/50 alternative is not available for seasonal capacity. Length of term is the deciding factor in the award of capacity if more volume is bid than is available for a particular receipt point in a particular stage. Notably, there is a 40% market

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[20] CTA is sometimes used interchangeably with CAT marketer in this opinion.

[21] SoCalGas Gas Acquisition and CTAs have the same option as all other entities to contract for backbone transmission at the 100% reservation fee rate design or the 50/50 reservation/volumetric rate design.

concentration limit for capacity held by one entity and its affiliates at each receipt point, other than the Gas Acquisition Department or the wholesale and CTA customers using their reservations.

A secondary market for capacity rights on the SoCalGas system is also established under the CS, in which the Gas Acquisition Department may take part. This market would be facilitated by a utility provided electronic bulletin board, as envisioned by the Commission, but a third party sole source contract would be let, if possible, to facilitate anonymous trading.

A new receipt point at Hector Road would also be established at which volumes can be nominated by customers. The CS sets forth the capacity at each of seven receipt points and designates a primary shipper at each, with the exception of Wheeler Ridge, which has a more complicated system.

Local transmission rates, derived from an agreed-upon total non-backbone cost of $64.3 million, would be reallocated between customer classes based on cold year throughput, as of October 1, 2001. Until the end of the 1999 BCAP period set forth in D.00-04-060, there would be 100% balancing account treatment in the core market and 75/25 ratepayer/shareholder treatment in the noncore market for differences between actual and forecast throughput. The CS provides for a change in the allocation of local transmission costs in bundled transportation rates between customer classes after the BCAP period. The CS seeks to bind the Commission until 2006 to an allocation of transmission costs that is consistent with the CS' allocation between local and backbone, as well as to a consistent 7.5% allocation of common costs (A&G and general plant) to the transmission function.

Storage

The core would retain a storage reservation (including for balancing purposes) of 55 Bcf of inventory capacity, 327 MMcfd of injection, and

1935 MMcfd of withdrawal capacity. This is less inventory than established in SoCalGas' BCAP, D.00-04-060, which was set at 70 Bcf. Subject to certification of alternate resources, under the CS, CTAs may reject all their non-reliability reservation and any portion of their reliability storage reservation, thereby reducing the total core storage reservation.[22] The noncore can also choose to provide their own storage assets, even for balancing purposes.

Effective April 1, 2001, SoCalGas' storage in excess of the amounts reserved would be unbundled on the basis of embedded cost, with escalators and allocation commitments like that described for transmission unbundling. A system of firm tradable storage rights would be established together with a secondary market for the trading of those rights. Unbundled storage packages of a linked ratio of inventory, injection and withdrawal capacity would be made available at a fixed reservation charge through an open season, with 20% of available storage capacity marketed for a term of one year annually.

Unbundled storage not reserved or sold through the open season could be marketed by SoCalGas subject to ceiling and floor rates initially, and a changing ratio of shareholder risk to ratepayer responsibility over the term of the settlement. Thus, under the CS, SoCalGas would be placed at 100% risk for recovery of the costs of unbundled storage after two years of partial shareholder risk, and at that time there would be no floor or ceiling on rates charged for storage.

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[22] However, until March 31, 2003, there is a cap on the total amount of reliability storage that CTAs as a group may reject.

No wholesale customer contracts are altered by the CS, but when a contract expires during the term of the CS, the wholesale customer may exercise an option to contract for a specific amount of storage to meet its core customers' reliability and balancing needs. This contracted amount would come from unbundled storage, but be charged at the rate for SoCalGas' core customers.

If SoCalGas divests itself of 20% or more of its existing storage inventory plus associated amounts of injection and withdrawal capacity before April 1, 2003, it would thereupon be entitled to total pricing flexibility (no floors or ceilings). Divestiture of the Montebello storage fields[23] does not count toward the 20%, and the Commission must still approve any divestiture.

<u>Balancing</u>

The main features of the CS regarding balancing are a daily self-balancing option for noncore, wholesale and core transport customers, a system for imbalance trading, and an OFO system and OFO Forum to be established if there are more than eight OFOs in the first two months of the procedure.

Effective April 1, 2001, an OFO procedure would supercede SoCalGas Rule 30, overnomination events, windowing at receipt points and winter balancing rules. On a daily basis, SoCalGas would assess separately whether core (including CTA) and noncore (including wholesale) customers were delivering gas into the system within a balancing tolerance of their expected usage plus assigned storage assets. Core and noncore classes would be

[23] Montebello capacity and costs are not included in the CS. They are left to other Commission proceedings. In other words, the revenue requirement associated with Montebello is still bundled into base margin, subject to further Commission action.

balanced separately, thereby eliminating any potential for cross-subsidization but also any benefit from diverse usage patterns.

For those entities choosing daily self-balancing, the cost of almost all balancing would be removed from their local transportation rate and their pro-rata share of storage for balancing would be moved to the unbundled storage program. SoCalGas' Gas Acquisition Department could not choose self-balancing, nor could SDG&E. Those choosing self-balancing could not exceed a daily imbalance of ±5% of that day's metered or forecast usage, including on OFO days, <u>and</u> the accumulated daily imbalance cannot exceed ±1% of that month's projected usage. Daily noncompliance charges, in addition to OFO day and monthly imbalance charges, could be applied.

The core has no tolerance band under the CS, since it has access to storage for balancing purposes, but the noncore customers using SoCalGas' balancing service have a ± 10% tolerance during an OFO. Customers in each class may trade imbalance "chips" within the class to bring themselves into compliance,[24] but imbalance charges would be applied if imbalances remain after chip trading on an OFO day. Targeted OFO's, of interest to the Commission in D.99-07-015, slip op. at p. 41 & p. 50, FoF 23, CoL 9, will not be initiated without the recommendation of the OFO Forum to the Commission.

For those CTAs and noncore entities not choosing self-balancing, monthly balancing within the ±10% tolerance continues under the CS, but

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[24] The core's OFO tolerance level, for chip trading purposes, would be the lesser of 10% of burn or any unused firm storage rights. Also, if an OFO is called for core and noncore on the same day, there can be trading between the classes for that day. SDG&E end-use transportation only customers would be able to trade with any other SDG&E end-use transportation only customer, including SDG&E's Core Gas Supply.

monthly imbalances can also be traded immediately following the end of the month and only after that trading are cash-out provisions applied. For the core's monthly imbalances, storage can be used to manage to no imbalance between supply deliveries and forecast (not actual) usage. There is a complex formula for forecasting that would be used by CTAs and SDG&E core transportation-only customers who do not have Automatic Meter Reading. The SoCalGas Gas Acquisition Department is subject to the same rules and penalties as CTAs.

All trading can take place through the current SoCalGas platform, GasSelect, for no fee, but SoCalGas will look for a third party to provide the service.

Like the IS, the CS permits customers and marketers to establish "pools" of gas supply on the SoCalGas transmission system for liquidity in trading.

Hub Services

In D.99-07-015, slip op. at pp. 48-49, CoL 10, the Commission wished to separate hub services, where possible, from the procurement function to eliminate the possibility of a conflict of interest. Under the CS, the Gas Acquisition Department would continue providing hub services using core storage and balancing assets with any revenues flowing to the Gas Cost Incentive Mechanism (GCIM). The Gas Operations Department would also be authorized to file tariffs to provide hub services with available unbundled storage assets that were not reserved or purchased.

Core Procurement

Although D.99-07-015, pp. 50-59, recommended re-examination of local distribution company core procurement and default provider function upon a certain percentage of competitive market share, AB 1421 has partially addressed this issue. Nevertheless, the CS provides that within three months of approval of the CS, parties would attempt to come to an agreement regarding competitive alternatives for providing procurement services to those not choosing a CTA, as well as performance mechanisms for SoCalGas and SDG&E for serving energy service providers (ESPs) and CTAs and for commodity procurement. If no agreement was forthcoming, within six months SoCalGas and SDG&E would file an application addressing these issues.

Other changes in the core procurement area include the phased elimination of the core subscription service currently offered noncore customers for both SoCalGas and SDG&E and an increase in the core brokerage fee. Presently, the brokerage fee for SoCalGas is 2.0 cents/Dth and for SDG&E it is 0.95 cents/Dth, per the 1996 BCAP decision. The significant increase, to 2.4 cents/Dth for SoCalGas and SDG&E upon the effective date of the CS, is a negotiated number, not necessarily related to actual cost of brokerage services, chosen because it is exactly that amount on the PG&E system.

Reducing Core Aggregation Transportation Thresholds and Eliminating the Cap

In keeping with D.99-07-015, pp. 59-61, FoF 30, the minimum size requirement for a CTA program is reduced from 250,000 therms per year to 120,000 therms per year, with no cap on the core market share participating. Consumer protection measures are not addressed in this context.

Unbundling Core Interstate Capacity and Eliminating Core Contribution to Noncore ITCS

The Commission also recommended the unbundling of SoCalGas core interstate capacity costs. (D.99-07-015, p. 49, pp. 60-61, FoF 31.) The CS does unbundle these costs, allowing CTAs to arrange for their own delivery of gas to the SoCalGas system.[25] SoCalGas would have discretion in how to release the capacity no longer allocated to CTAs and to sell it above the as-billed rate to the extent permitted by FERC Order 637, with any difference over the as-billed rate used to offset stranded costs or reduce rates.

Any stranded costs associated with this capacity would initially be allocated to core (both utility and CTA customers) and noncore customers on a 50/50 basis.[26] After January 1, 2002, the core would no longer be responsible for any stranded interstate capacity costs associated with noncore capacity.[27] On that date, the core would assume full responsibility for any stranded costs

[25] SDG&E has already unbundled these costs.

[26] If the stranded costs for noncore customers exceed $5 million in 2001, the amounts in excess will be allocated to CTA customers only, and not to the noncore.

[27] In other words, the core 10% contribution to noncore ITCS costs would end.

resulting from the unbundling of core interstate capacity. The CS provides that the costs associated with the first 7% of total core capacity would be allocated to all core customers on an equal-cents-per-therm (ECPT) basis in the transportation rate. The costs associated with the stranded capacity beyond that 7% would be allocated between core residential and core non-residential customer classes in proportion to the percentage of CAT market share of each class. Within each class, stranded costs would be recovered in the transportation rate, equally from utility and CTA customers.

Cost of Implementation

For the capacity-related sections of the agreement alone, approval of the settlement would authorize the recovery in rates of an additional $2 million per year, plus the related franchise fees and uncollectibles, beginning on the decision effective date to the decision effective date of a new SoCalGas PBR that authorizes a new margin for SoCalGas. The cost recovery is allocated on an ECPT basis among customer classes. Additionally, under the CS, SoCalGas would retain any pooling service fees, imbalance fees, net revenues from the sale or purchase of gas beyond tolerances provided under balancing rules, or portion of rights trading fees it is entitled to retain under agreements with third-party providers of trading platforms. However, if the $2 million plus the sums from the fees and revenues exceeds the actual revenue requirement for implementation, SoCalGas would refund in bundled volumetric rates on an ECPT basis the excess above $2 million (not amount actually spent). This arrangement would be in place until December 31, 2002.

SDG&E would not be entitled to any increase in authorized revenue as a result of the capacity-related sections unless an intervening decision before its next PBR institutes a firm, tradable intrastate transmission rights system for SDG&E. At its next PBR, SDG&E would be entitled to seek recovery of reasonably-incurred projected costs of the capacity-related sections.

b) The Retail Sections

Information

The Commission believed that customer access to real-time consumption data, at the customer's expense, was a promising option. (D.99-07-015, pp. 72-73, FoF 33 & 36, CoL 15 & 16.) The CS allows core customers access to any existing information regarding the customer's gas usage, and provides that SoCalGas and SDG&E should have already convened data access workshops. SoCalGas would continue its daily and real-time information services for noncore customers and make certain improvements, such as an expanded website, that are not chargeable to customers. SoCalGas would post on its GasSelect system operating information as extensive as that required of PG&E, including post-OFO data by customer class sufficient to allow readers to understand why the OFO was called. SDG&E does not provide a real-time access service, but the Commission would not be prevented from addressing this during the term of the CS.

Transparency regarding transaction details is also a Commission goal. Under the CS, SoCalGas agrees to post a monthly negotiated intrastate transmission contract report on its GasSelect system after October 1, 2001, but it would omit customer names. It would post a quarterly report on negotiated storage contracts, omitting names, for contracts in effect between April 1, 2001 and March 31, 2003. After that, when SoCalGas bears 100% of the risk of unbundled storage, the posting would also exclude price.

Revenue Cycle Services

The Commission, prior to AB 1421, decided that after-meter services should continue to be provided by the local distribution company, but believed that the competitive provision of meters themselves was a promising option. Under the CS, a pilot program would be implemented giving SoCalGas and SDG&E customers access to competitive metering technologies at customer expense while retaining the utilities' responsibility for installing, reading, removing, servicing and maintaining the meters. This program would extend through 2002, with a July 2002 evaluation report from the utilities.

Billing options comparable to those available in the electric industry, like utility consolidated billing, would also be instituted under the CS, as soon as the billing systems of SoCalGas and SDG&E allow it. Upon the effective date of the CS, SoCalGas and SDG&E would no longer have to send information-only bills when the CTA is sending a consolidated CTA-utility bill, and the CTA agrees to send the requisite bill inserts and customer protection materials for the utility. The customers of the CTAs performing consolidated billing would receive a credit that reflects the actual avoided costs of billing. The credit would eventually be a line item on their monthly bill for transportation services, but they would receive checks for the appropriate amount prior to billing system changes.

Cost of Implementation

For implementation of the core interstate capacity unbundling and retail sections, SoCalGas would not be authorized to increase its margin until the next PBR. However, if an intervening Commission decision approved fees associated with the retail sections, SoCalGas could retain those revenues prior to the next PBR. Moreover, at the next PBR, this settlement would compel a result in which noncore customers paid no direct costs[28] of retail section implementation that are incurred to serve core customers or CTAs.

SDG&E would have the same rights of recovery of costs for implementation of the retail sections.

4. Summary of Long Beach Proposal

Through its witnesses, Paul Premo and Elizabeth Wright, and in its briefs, the City of Long Beach proposes a different method of allocating the rights to receipt point capacity. As explained in its reply brief,

> "Long Beach proposes to auction receipt point capacity, not transmission capacity. Long Beach proposes that the receipt point auction would require the payment of a reservation charge, based on the amount of the bid, times the volume awarded. That reservation charge is a fixed monthly charge, and not a volumetric rate."
>
> "Long Beach proposes that the volumetric rate treatment continue for the transmission service provided by SoCalGas. Long Beach proposes that the auction proceeds would be credited against the transmission rates of all customers. In that way, all SoCalGas customers would share in the value of the receipt points, without having to hold firm receipt point capacity at any point."

The retail core could buy a designated amount at each receipt point at the high bid price. Wholesale core would be allowed to designate which receipt point it wished to use and reserve at the high bid price or participate in the auction. All receipt point capacity would be posted on the SoCalGas bulletin

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[28] Inclusion of these costs in equal percent of marginal cost scaling or another mechanism to allocate A&G or General Plant overhead costs to all customer classes is not precluded.

board at no minimum bid. If a capacity buyer did not use the capacity, it would be resold to the highest bidder, again with proceeds going to customers.

There are no provisions for implementation costs, or other details of the proposal. Nor does the proposal address other promising options.

The provisions of each of the settlements, but not the Long Beach proposal, are compared to the promising options of D.99-07-015 in Joint Exhibit 300, appended hereto as Appendix II.

D. The Legal Standard for Considering Settlements

Rule 51.1(e) of the Commission's Rules of Practice and Procedure provides that the Commission must find a settlement "reasonable in light of the whole record, consistent with the law, and in the public interest" before it may approve a settlement. Because these are not all-party settlements subject to the guidance in D.92-12-019, we follow the criteria set forth in Rule 51.1(e), as explained in D.96-01-011.

> "[W]e consider whether the settlement taken as a whole is in the public interest. In so doing, we consider individual elements of the settlement in order to determine whether the settlement generally balances the various interests at stake as well as to assure that each element is consistent with our policy objectives and the law." (*Re Southern California Edison Company*, 64 CPUC2d 241, 267, citing D.94-04-088.)

The supporters of each settlement contend that their settlement is in the public interest and reaches a fair compromise at this juncture in the proceeding.

We believe that when we are presented with three contested settlement proposals in one proceeding, and hearings have been held on the contested issues in each, we are free to consider the settlements under Rule 51.1(e) or as joint recommendations that may or may not be supported by the evidence in the record. Under Rule 51.1(e), we are still free to reject a settlement if one or more of its elements is not consistent with our policy or the law. We must do so here.

1. Public Interest

a) The PI and the Public Interest

Relatively few parties subscribe to the PI in its entirety. Significantly, while it is sponsored by organizations that represented residential core customers and electric generators in this proceeding, it does not have the agreement of the major utilities that serve them or other stakeholders such as shippers and core aggregators. The one-sided interests of the parties in support of the PI make it difficult to view as a settlement at all. There is no balance struck between the interests of various parties. The PI is more in the nature of a joint recommendation of a few parties.

However, much of the PI is already in place because of the adoption of the Joint Recommendation in the 1999 SoCalGas BCAP decision. The IS portion of the PI would be realized by the approval of either the IS or, in part, the CS. Therefore, our analysis must focus on the PI's distinguishing provisions. If these provisions were particularly in the public interest, they might overcome the narrow support given to the PI.

In looking at public interest, we must first assure ourselves that each element of the settlement is consistent with our policy. We are not ready to conclude, as does the PI, that no intrastate transmission unbundling should be allowed prior to 2006.

We need to remain flexible. There is reason for less certainty about the beneficent effect of unbundling in light of the situation in the electric industry in the summer of 2000, we acknowledge. But the Commission is authorized by the State Constitution to act; it is not our policy to cede our ability to act to settling parties. A settlement with a duration of six years is not in the public interest.

We also cannot countenance another aspect of the PI. The provision that rates should be retroactively rolled back to reflect the elimination of the Montebello storage fields as a "used and useful" part of base rate is not acceptable. We have no evidence on this issue in this record. We adopted a settlement in I.99-04-022 (D.00-09-034), noting that it did not address or resolve the reasonableness of SoCalGas' conduct at Montebello for ratemaking purposes. We left that for another proceeding. In D.01-06-081, issued on June 28, 2001, the Commission approved a settlement in SoCalGas' application A.00-04-031 that provided for SoCalGas to remove the Montebello costs from base rates. The Montebello provisions of the PI are therefore now moot. Since the unbundling-prohibition cornerstone of the PI is inconsistent with our policy and we have already addressed the Montebello rate issue elsewhere, there is no purpose served in a close analysis of other aspects of the PI in order to judge it as a whole. It cannot be approved as a whole, and it was as a whole that the sponsors urged it upon us. Moreover, its key element is not consistent with our policy; therefore, we should not move on to an overall balancing of its provisions to determine whether it is in the public interest. Other provisions can now be seen as recommendations that might or might not be supported by evidence. We will return to some of these later in this opinion.

b) The CS and the Public Interest

The Assigned Commissioner and the ALJ in this proceeding made it clear to the parties that they would like to see a settlement that addressed most, if not all, of the promising options and that created a southern California market structure that was very much like the northern California market structure. The parties worked long and hard to negotiate a settlement along the lines requested, and we believe that they did so with the CS. If we were convinced that unbundling intrastate transmission at this time in southern California was still a wise choice, we would probably be approving the CS, with modifications, in this decision.

We recognize that the CS is the result of many months of discussion and negotiation and that some parties may now wonder if this was time well-spent. We hope the parties take a more pragmatic view. Settlements are accepted by the Commission, and have been in this docket. However, with regard to southern California, parties did not produce an uncontested settlement; its core provision is highly controversial. Nonetheless, the CS provides a starting point for future discussion. For example, in its current BCAP, SoCalGas has offered a proposal for firm transmission rights that draws from the CS proposal. Circumstances have overtaken the agreement forged, making it unwise to adopt key proposals based on the existing record. By rejecting the CS, we are not concluding that the unbundling of intrastate transmission in southern California should never happen.

In determining whether the CS is in the public interest, we must first assure ourselves that each element of the settlement is consistent with our policy. We acknowledge that the Commission's policy to date has been to foster competition through unbundling intrastate transmission; the goals of this restructuring investigation reflect that policy. However, current and recent market conditions suggest that unbundling intrastate transmission at this time is not consistent with our goal of protecting low rates. Moreover, based on the current record, we cannot conclude, in the terms of the promising options decision, that the benefits of intrastate transmission unbundling would outweigh the costs.

First, we have yet to explore what the exorbitant electricity prices charged to California utilities and huge profits for electric generators should teach us about the risks attached to further restructuring gas markets. While we agree with SoCalGas that what is being proposed in the CS may differ from the divestiture and unbundling in the electricity industry in significant ways, the CS does open the gas market further and by so doing, may invite manipulation.

Hearings in this proceeding concluded on June 8, 2000, when electric markets were beginning to unravel and when the scope of the rise in gas prices was just beginning to be apparent. This is also well before the avalanche of new applications before the CEC to build gas-fired power plants – a phenomenon that could drastically change the landscape of California gas markets. By relying on the record in this proceeding to further restructure markets, we would be setting policy for the future based on expectations that are out-of-date.

Through SoCalGas' more recent filings, we can consider restructuring proposals in the context of current market conditions. In PG&E's application to extend its GasAccord provisions for another two years, we can examine the actual experience on the restructured PG&E system in the north under current market conditions, rather than rely on the theoretical benefits on the SoCalGas system.

(1) Costs to the Core

The CS parties determined the intrastate backbone system cost $77,813,000. They reallocated $4.1 million to the local transmission system. (Lorenz, Ex.2, Attachment 3.) This type of cost shifting means that unbundling itself is not cost-neutral, before implementation and other consequences are even considered.

The chart purporting to show the cost savings to the core by virtue of the CS (Lorenz, Ex. 2, Attachment 8) also concerns us. We note that the major savings to the core would result not from unbundling intrastate transmission, but from eliminating the core contribution to stranded cost from unbundling noncore interstate transmission (and that is the major cost shift to electric generators). It is a negotiated tradeoff in the context of the CS, but it is simply not a benefit of unbundling intrastate transmission per se. Without that savings, it appears from Attachment 8 that costs would go up for the core residential ratepayers, the C&I noncore and wholesale customers, but down slightly for the nonresidential core and a lot for electric generators including cogenerators.

Let us consider the benefits the parties contend can be brought about by unbundling intrastate transmission.

(2) Gas Cost Savings may be Ephemeral

The CS proponents claim that unbundling intrastate transmission will create a citygate market at which prices will be cheaper than the cost of border gas plus transportation. This claim is largely based on the analysis performed by Thomas Beach of actual citygate and border prices on PG&E's system under the Gas Accord. Beach testified and created a chart showing that citygate prices have averaged lower through April 2000 than border prices plus intrastate backbone transportation[29] (See Ex. 5, pp. 4-5 and chart following and Ex. 18).

[29] We note that there are different transportation costs associated with the Redwood Path versus the Baja Path.

In his rebuttal testimony (Ex. 18) Beach showed that over a twelve-month period from May 1999 through April 2000, PG&E citygate prices were:

5 cents/Dth lower than Malin plus Redwood firm;

11 cents/Dth lower than Malin plus Redwood as-available;

7 cents/Dth lower than Topock plus Baja firm;

11 cents/Dth lower than Topock plus Baja as-available.

In analyzing whether a similar savings might be expected on the SoCalGas system, a critical difference must be kept in mind. PG&E backbone rates are much higher than the SoCalGas proposed backbone rates under the CS; the margin for savings on SoCalGas is therefore less than on the PG&E system. Beach showed that the PG&E Redwood and Baja firm rates were about 32 cents/Dth and 22 cents/Dth, respectively. Lad Lorenz, SoCalGas' expert, in his prepared testimony for SoCalGas (Ex. 2) noted that SoCalGas' proposed backbone rates would only be about 7.2 cents/Dth.

Assuming that a similar level of savings could be achieved on the SoCalGas system associated with citygate discounts for customers who choose not to purchase firm capacity, a potential for savings of 16-32% of the backbone rate might exist. This amounts to a savings of 1.1 cents to 2.3 cents/Dth. This is supported by a response by the CS parties to the ALJ's Q. 6, p. 1 (Ex. 20, p. 8). There, they indicate that "if the PG&E experience is any example," a 2 cents/Dth discount could be expected for citygate purchases. Lorenz, in Ex. 20, Response 23.1, assumed that core customers would only get 1 cent/Dth for sales of capacity, indicating a discount of 6 cents/Dth.

Lorenz (Ex. 2, p. 6) notes that the CS implementation costs amount to $2 million per year in incremental revenue requirement. Indeed, it is clear that the CS supporters think that it is possible that total yearly implementation costs will be well above $2 million, because there is provision for SoCalGas to keep various fees and revenues to offset costs over $2 million if necessary.[30] The implementation costs will be allocated on an equal cents per therm basis, not equal percentage of marginal costs, so noncore customers will be paying the bulk of these costs, at least initially. (See Ex. 2, Att. 8.) In Ex.2, Att. 8, Lorenz shows that core customers will pay only $715,000 of the $2 million, while noncore customers will pay $1.285 million. He further breaks this down in Ex. 20.

To match a $1.3 million revenue requirement for noncore customers just with the benefits of citygate discounts, a savings of 1.1 to 2.3 cents/Dth, about 155 to 324 MDth/d would need to be delivered using citygate pricing.[31] Noncore average year throughput on the SoCalGas system is 1672 MDth/d.[32] Thus, the noncore would realize sufficient benefit from "citygate discounts" associated with unbundled capacity to offset its share of implementation costs, if citygate prices are less than border prices plus the cost of intrastate transport.

But that assumption can no longer be made.

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[30] By inadvertence, the exact implementation cost that derives from intrastate transportation unbundling alone is not in the record because an attachment to Ex. 20, referred to at p. 8, was not actually provided.

[31] PG&E's Market Assessment Report of April 28, 1999, submitted in R.98-01-011, showed that marketers held 37.5% of total subscribed PG&E backbone capacity, including the core reservation. PG&E stated that it had about 1100 noncore non-cogen end-use customers but only 22 held backbone capacity. The remainder were generally being served at the citygate.

[32] Ex. 20.

As previously noted, we have taken official notice of the gas prices reflected in Gas Daily's Monthly Contract Index and Previous Month Mid-point Average. The following Table I reflects the Monthly Contract Index prices, assuming an MFV rate and 100% load.

Table I: Averages Comparable to Tom Beach

	SoCalGas SoCal Bdr	Malin	PG&E CG	Redwood Firm	As-Avail	Baja Firm	As-Avail	PG&E SoCal Bdr
May-00	$3.03	$2.93	$3.12	$0.31	$0.37	$0.22	$0.26	$3.02
June	$4.34	$3.92	$4.46	$0.34	$0.39	$0.25	$0.28	$4.33
July	$4.97	$4.46	$5.01	$0.34	$0.40	$0.25	$0.29	$4.89
August	$4.50	$3.93	$4.40	$0.33	$0.39	$0.24	$0.28	NA
Sept	$6.29	$5.58	$6.23	$0.37	$0.42	$0.28	$0.31	$6.01
October	$5.56	$5.29	$5.90	$0.34	$0.39	$0.24	$0.28	$5.34
Nov	$5.19	$5.05	$5.33	$0.34	$0.39	$0.24	$0.27	$5.00
Dec	$14.45	$14.42	$14.51	$0.46	$0.52	$0.36	$0.40	$13.72
Jan-01	$16.41	$13.89	$14.58	$0.46	$0.51	$0.39	$0.43	$14.33
February	$12.69	$10.03	$12.47	$0.42	$0.46	$0.36	$0.38	$12.27
March	$12.63	$8.37	$11.66	$0.38	$0.44	$0.34	$0.38	$12.47
April	$12.53	$7.43	$9.64	$0.37	$0.42	$0.35	$0.38	$8.03
May	$14.98	$10.00	$12.59	$0.40	$0.46	$0.37	$0.41	$11.97
June	$11.71	$5.98	$9.61	$0.35	$0.40	$0.33	$0.37	$6.79
Average Sept 2000 - June 2001	**$11.24**	**$8.60**	**$10.25**	**$0.39**	**$0.44**	**$0.33**	**$0.36**	**$9.59**

While PG&E citygate prices were less than Malin plus Redwood firm in May, November and December 2000, they were not from June through October 2000, nor were they lower in January through June 2001. On average of the months May 2000 through June 2001, Malin plus Redwood firm was less than the citygate. Baja firm plus PG&E SoCal Border prices were lower than the citygate October through December 2000, and April through June 2001. Indeed, on average, as Table II shows below, for the months September 2000 through June 2001, the price of natural gas bought at the border and transported at the tariffed intrastate PG&E rate to the citygate beat the PG&E citygate price by $.30-1.25/dth.

Table II: Analysis Similar to Tom Beach's Table 1 of his Rebuttal Testimony (Exh. 18)

Natural Gas Market Sept 2000-June 2001			
Gas Prices	**Malin**	**PG&E SoCal Border**	**PG&E Citygate**
California Border	$8.60	$9.59	
Citygate Market			$10.25
PG&E Transportation	**Redwood**	**Baja**	
Firm	$0.39	$0.33	
As-Available	$0.44	$0.36	
Price of Border Purchases at Citygate			
Firm	$8.99	$9.92	
As-Available	$9.05	$9.95	
Benefits (Loss) of Citygate over Border Purchases			
Firm	($1.26)	($0.33)	
As-Available	($1.21)	($0.30)	

Moreover, the border price in many of the months shown is so high, even factoring in the effects of such events as the El Paso outage last fall as a cause, we must assume that interstate firm capacity, like that owned by SoCalGas, has become a valuable asset once again.

Other figures from Gas Monthly indicate that if customers bought at the San Juan basin and then used Baja firm, they would also beat the citygate price.

Table III: Analysis Comparing SW Basin Purchases to Citygate Purchases

Natural Gas Market July 2000-June 2001

Gas Prices	**San Juan**	**Permian**	**PG&E Citygate**
Basin	$4.83	$5.35	
Citygate Market			$9.33
PG&E Transportation		**Baja**	
Firm		$0.31	
As-Available		$0.35	
El Paso Transportation	**San Juan**	**Permian**	
Firm	$0.50	$0.54	
Price of SW Basin Purchases at Citygate	**San Juan**	**Permian**	
Using Baja Firm	$5.64	$6.20	
Using Baja As-Available	$5.68	$6.24	
Benefits (Loss) of Citygate over Basin Purchases			
Firm	($3.68)	($3.12)	
As-Available	($3.65)	($3.09)	

We have not determined what conditions on the PG&E system caused the citygate prices to be higher than border plus transportation prices during many of the months between May 2000 and June 2001. However, data demonstrating higher citygate prices at most times over the course of more than a year, is a compelling factor we must consider. Since we cannot pinpoint the causal conditions, we cannot conclude that ideal conditions will pertain on the SoCalGas system. As prices at the border rise, the opportunities to receive discounts at the citygate may dwindle.

Evidence regarding the Georgia experience is also unpersuasive in light of later developments. While Ex. 26, "Consumer Benefits from Natural Gas Deregulation – the Georgia Example," indicates somewhat lower prices through July 1999, later developments show prices have risen dramatically there, as well.[33] Moreover, the Georgia structure for deregulating the industry is not identical to the proposal made in the CS.

Thus, even for the noncore, prices at the citygate will not necessarily be lower than border price plus transportation. We must conclude that we cannot rely on the citygate discount in making our decision.

For the core, the benefit of citygate pricing is even more tenuous. Core customers have reserved for them, under the CS, 1,000 MMcfd in firm receipt point rights. This closely matches 1998 and 1999 actual deliveries to core customers. However, this is an average figure. Core customers will need additional supply during the winter and possibly early in the injection season. Some of that supply could be obtained from storage withdrawals, and some might be obtained by purchasing citygate gas. Since core customers have 1,935 MMcfd of firm storage withdrawal rights, the only time core customers might rely on citygate gas would be when it would be priced low, or on <u>very</u> cold days. As noted, the current trend is for more expensive gas at the citygate with a narrow exception. Thus, since SoCalGas rarely buys gas at the citygate for

[33] Gas Daily, September 2000, "Record Prices Put Customer Choice Programs on Uncertain Footing." p.2.

core customers, it seems unlikely that the core's liability for yearly implementation costs would be covered by its savings from citygate discounts.

ORA asserts that it supported the CS, in part, because the CS gave the core a generous allocation of firm capacity receipt rights at Topock. But in light of the FERC's Decision regarding complaints against El Paso Natural Gas Company (93 FERC 61,060), the 290 MMcfd allocation to the bundled core is by no means assured. In that decision, FERC concluded that El Paso allocated receipt point capacity unreasonably. FERC called for shippers to elect capacity allocations at constrained receipt points, like Topock, and based on those elections, pro-rated firm receipt point rights, up to physical capacity. We also note that the FERC has recently approved significant full requirements customer additions to El Paso's system upstream of its California delivery points, putting even further into jeopardy California shippers' otherwise firm contract demand delivery capabilities.[34] SoCalGas' firm receipt rights at Topock could be cut back substantially from its current allocation, based on the election amounts of other shippers. Thus, the promise of 290 MMcfd for the bundled core at Topock, one of the most favorable aspects for the bundled core in the CS, is no longer viable.

In sum, the evidence of a likely price benefit from intrastate capacity unbundling is slim. At best the evidence shows more potential benefit for the noncore than the core. Therefore the arguments that this unbundling will bring the price benefits already available to the noncore to the core are not supported by a close analysis of the record evidence, let alone by the ensuing developments in the marketplace.

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[34] *See* FERC Decision (95 FERC 61,461)

(3) Matching Service to Need In Changing Circumstances

Foremost among benefits mentioned from unbundling is the matching of service to need. Customers would be able to buy only what they needed. Certainly the avoidance of paying for transmission service that is not needed is a benefit. However, that particular benefit is more appropriate to balancing or storage services than transmission. Transmission is available on a volumetric basis now. The problem, the record suggests, is more often that customers are not getting as much transmission capacity at certain interconnect points with interstate pipelines as they want. (Ex. 8 in R.98-01-011, pp. 29-31 (Southern California Edison Company (SCE) Market Conditions Report) and Ex. 15 in R.98-01-011, pp. 7-6 to 7-8, (PG&E's Rebuttal to Market Conditions Report).)

Presently, parties nominate capacity at the receipt point, but their nominations can be cut back on a pro rata basis if the receipt point is overnominated, despite "firm transportation" rights on the system. Under the CS, parties would be allowed to pay for firm receipt point rights. Thus, parties would benefit from the stability of securing receipt point rights that cannot be cut back. We note that the bundled core particularly was offered premium receipt point rights under the CS.

However, pre-paid rights at a particular receipt point can lock customers into bad situations as well as good ones. Our concern, in light of the recent El Paso pipeline explosion[35] and El Paso's manipulation of almost one-

[35] We take official notice of the following information reported in "Gas Daily," the well-regarded industry information source published by Financial Times Energy. Gas Daily, Vol.17, Number 163, p. 2 reports in an article entitled "El Paso lines likely out of service several days"(August 25, 2000), at p. 3 that "El Paso has been able to divert supplies

Footnote continued on next page

third of its capacity to California, is with a system of limited flexibility. While it is true that in the normal course of events under the CS scheme any extra capacity bought by a customer for "insurance" might be sold in the secondary market, events do not always take the normal course. Firm pre-paid receipt point rights become less beneficial when an explosion or other problem has interrupted supply to certain receipt points; flexibility becomes more beneficial. Among other things, customers may not recover pre-payment for capacity rights from a receipt point fed by El Paso, even if El Paso cannot or will not deliver the gas.

The current nomination system allows flexibility and does not require pre-payment. There are means, other than firm rights, to increase the security of shippers. Under the IS, SoCalGas could post the physical capacity at each receipt point each day so that shippers could nominate with more knowledge of the likelihood of pro-rated allocations at any given receipt point. Considering last winter's extremely volatile gas prices and the uncertainty facing gas prices this winter, flexibility is a benefit that trumps the benefit of inviolable receipt point of rights.

There is also the question of whether the cost of matching service to need outweighs the benefit of security. The CS proponents claim that its three stage method of allocating intrastate transmission would enable SoCalGas, CTAs and wholesale customers serving core customers to ensure that

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through other parts of its system at about half the volume normally carried on the closed lines, about 500 million cfd." See also, Gas Daily, Vol.17, Number 165, p. 1 in an article entitled "Calif. bonanza continues…," where it is reported that "The 500 million cf-plus El Paso outage stemming from its mainline rupture was compounded yesterday by a *force majeure* event on Transwestern Pipeline, which reduced flows into southern California by another 65 million cf."

100% of their needs are covered. The CS proponents argue that a low-load generators could use the MFV rate and look to the secondary market in peak periods to keep its costs down.

SCGC and Long Beach question whether they will be able to buy what they need, and buy it at a favorable price. (Ex. 101 in I. 99-07-003, pp. 18-21 (Prepared Direct Testimony of Catherine Yap, for SCGC); Ex. 102 in I.99-07-003, pp. 20-22 (Prepared Rebuttal Testimony of Michel Peter Florio, James Weil, and Catherine E. Yap).) They argue that the allocation method is crafted to bring marketers into the system in the third stage, and marketers are in business to make a profit. If these parties do not purchase their peak needs as firm capacity, they will have to buy peak need capacity from marketers or others in the secondary market. It is reasonable to fear that such customers may be forced to pay a premium for this incremental capacity that they do not currently pay, makes sense

In sum, while matching service to need is clearly a benefit, it is not clear that inviolable pre-paid receipt point rights are cost efficient particularly when a receipt point is incapacitated. Additionally, the CS provision for secondary market purchase when needed might raise costs unconscionably in a suddenly-changed tight market. Finally, after implementation of the FERC Decision (93 FERC 61,060), shippers will have firm receipt point rights at Topock and other constrained receipt points. A flexible intrastate transportation system can fluidly adapt to the changed situation, whereas a system of firm pre-paid rights would require additional transaction costs as entities sought to match receipt point rights to intrastate transport rights in a changing market.

We are not convinced that such rights are the goal we wish to pursue on the SoCalGas system. We look to SoCalGas' more recent filings to improve our understanding of the merits of creating firm transmission rights under current market conditions.

(4) Innovation and Value-Added Services Are Speculative

Proponents of the CS claim that marketers competing among themselves and against the utility at the citygate can innovate and offer packages of services that do not now exist but that are of value to customers, particularly in tandem with the other new options in the CS for storage services, balancing, hub services and revenue cycle services. Witness Richard Counihan, for the Core Aggregators, listed some possibilities in his testimony: (1) Aggregating gas service with other goods or services to achieve bundled discounts; (2) Combining gas service with appliance sales to achieve "end result" pricing; (3) Discounts dependent upon payment terms; (4) Varied pricing plans for small users similar to the pricing options currently available to larger users; (5) Aggregating users across utility borders to achieve discounts; (6) Combining billing for electric and gas service; (7) Providing innovative internet-based billing options; and (8) Commodity sales discounts used as fundraising engines for schools and charities. (Ex. 7 (Counihan) at pp. 8-9.) He also mentioned bill payment at "kiosks" in shopping malls, promotional incentives such as sign-up bonuses, free gas in the summer, energy conservation software, home safety kits, frequent flier miles and grocery coupons. (Ex. 7 at p. 11.)

These are certainly possible benefits, each of which might be of value to some customers. We recognize that certain discounting and special offers were part of the opening of the market in Georgia. (Ex. 26.) However, there was no specific evidence of a plan for discounts or innovative packages in California and we can only view these benefits as speculative. In the balance of costs and benefits, they can be given little weight.

Not only are these benefits speculative, but they could also be weighed against the equally speculative possibility that some market entrants would fail, causing service disruption, hassle and confusion for customers. In such a scenario, any initial marketing innovation would be obviated.

(5) Intrastate Transmission Unbundling Has Weak Customer Support

Additionally, while the sheer number of parties joining the CS suggests that many feel that the settlement is in their best interest, we have concerns that not all parties representing residential ratepayers support it. For example, ORA[36] supports the CS while Aglet and TURN are vehemently opposed to the CS. We do not know how ORA would view intrastate unbundling divorced from the other benefits it sees in the CS.

Changes in the gas industry market structure will affect ratepayers not only through their gas rates but through their electricity rates as well, to the extent that gas-fired generators are providing power. Gas-powered generators are not unanimous in supporting the CS. SCGC argues that the CS would impair the ability of generators to provide power at a reasonable cost. In light of the present crisis arising from high wholesale electric rates across California , we are reluctant to make changes that have the remotest possibility of leading to even higher rates.

Thus, on balance, we believe that the benefit to the public of unbundling intrastate transmission is not very concrete at this time, and this

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[36] ORA also represents non-residential ratepayers. Those wholesale customers other than SDG&E that serve both residential and non-residential ratepayers were against the CS during the hearing, although Southwest Gas decided to support the CS at the time of its final reply brief.

speculative benefit is outweighed by the real cost of implementation, the embedded cost shift to local transmission and the inevitable cost of additional administrative burden to customers trying to manage the new system.

The unbundling of intrastate transmission is a keystone of the CS, just as not unbundling for six years is a keystone of the PI. Since we are not willing to unbundled intrastate transmission based on the record before us, we are not prepared to approve the CS, regardless of the merits of its other provisions. The parties supporting the CS seek to have it ratified as it is, without changes, claiming that any change will disturb the bargains made and the fine balances drawn. In light of that, we see no need to continue discussing all the other provisions of the CS in this opinion. We will return to some provisions later in this opinion.

c) The Long Beach Proposal and the Public Interest

The intent of the Long Beach proposal appears to be to provide a method for allocating receipt point capacity that is more in the control of the shippers than in the control of SoCalGas. It does not appear to offer a solution to other receipt point problems.

However, we do not see how allowing a high bidder to dominate Topock or some other valuable receipt point will help advance anyone's goals except those of the high bidder. We do not understand why Long Beach thinks it will outbid Enron, for example, for Topock receipt point capacity. If it does, its customers will still be paying for the receipt point capacity, even if some of the money comes back to them through transportation rate reductions. Its delivered gas will probably cost more, particularly if gas basin prices tend toward a middle ground. If Long Beach does not outbid Enron, will not Enron then arrange contracts to supply customers with gas at prices that defray its high receipt point bid, gas cost, interstate cost, and intrastate transmission cost as well as make a profit? Perhaps the real purpose of the plan is to add value to the Blythe receipt point.

The bundled retail core will also be paying this market price for receipt point capacity at each receipt point. Wholesale customers seem to be accorded more flexibility to choose receipt points. While we see the benefit of this plan in terms of giving market signals regarding which receipt point needs to be expanded at any given time, we do not see how it will keep costs low. We are not clear on SoCalGas' risk for unbundled costs under this proposal, or what the provision would be for stranded costs. There is no provision in Long Beach's plan to allocate implementation costs either. We do not know how often the auctions would take place or whether each receipt point would be auctioned simultaneously or sequentially or iteratively or continuously.

We reject the Long Beach proposal as it is currently presented. We recognize the frustration that shippers have felt with the windowing procedures at SoCalGas receipt points. The filing of the windowing tariff immediately following the issuance of D.99-07-015 was a first step in providing more understanding to shippers of SoCalGas' procedures. We look forward to reviewing SoCalGas' recently-proposed changes to its windowing procedures. Today we approve designating Hector Road as a receipt point. We intend to monitor the receipt point situation to ensure that it is managed fairly and with transparency so that shippers can plan for a reliable, if not an inviolable, flow of gas.

d) The IS and the Public Interest

We now discuss the merits of provisions in the IS, which we will adopt, in part.

(1) Receipt Points/ Intrastate Transmission

In R.98-01-011, the record reflects dissatisfaction among customers and shippers with the lack of clarity on how SoCalGas schedules gas shipments through its windowing system, and SoCalGas' sole use of the Hector Road interconnection as a receipt point. (Ex. 8 in R. 98-01-011, pp. 29-31 (SCE Market Conditions Report), (Panel Hearing Testimony of Mr. Paul Carpenter, SCE, Tr. pp. 931-932, Jan 25, 1999).) Our decision in D.99-07-015 directed investigation into using the Hector Road interconnection, even on an interim basis, and the publication of SoCalGas' windowing criteria in tariffs. SoCalGas filed Advice Letter 2837, which detailed its process of basing a maximum amount of gas scheduled for shipment through a receipt point on the prior day's nominations, except at the first of the month. SoCalGas' Advice Letter 2837-A, filed on November 1, 2001, would significantly change the windowing procedure. Early in the instant proceeding, the ALJ held in abeyance active consideration of the windowing procedure tariff SoCalGas filed, pending this decision. (Prehearing Conference of September 1, 1999, p. 34.)

The revised Advice Letter would adopt a procedure much like that proposed in the IS. The IS would replace the current windowing process with a system under which SoCalGas would establish receipt point capacities, subject to daily revision, on the basis of the physical maximums for each receipt point under the operating conditions expected for that day. Customers and shippers would know the daily maximums because they will be posted on SoCalGas' GasSelect system daily prior to the nomination deadlines. If, in the aggregate, customers nominate more than the physical capacity at any receipt point, gas would be scheduled based on the upstream pipeline's capacity rights system. For Wheeler Ridge, at which more than one upstream pipeline delivers gas, the maximum daily physical capacity would be allocated between upstream sources pro rata on the basis of the prior day's scheduled deliveries from each source.

We will review this proposal in response to the new Advice Letter, which will allow us to receive comments from interested parties in the context of the gas and electric markets as they have evolved since the completion of the record in this proceeding. For that reason, we will not adopt this aspect of the IS in this decision.

In R.98-01-011, PG&E and Edison particularly complained about the restrictions at Wheeler Ridge. (Ex. 15 in R.98-01-11, pp. 7-9 (PG&E Rebuttal to Market Conditions Report), and Ex. 8 in R. 98-01-011, pp. 29-31, (SCE Market Conditions Report).) One response in the IS to these complaints is the establishment of a formal receipt point at Hector Road for all customers, subject to Wheeler Ridge access fees and surcharges. Its capacity will be 50 MMcfd or greater as long as there are nominations of that volume and Mojave Pipeline Company delivers that much in response to those nominations. This provision should allow greater flexibility for shippers and customers as well as providing more balanced opportunities for SoCalGas and others at this interconnection. We will support SoCalGas' application to the FERC for approval of Hector Road as a formal delivery point by Mojave.

El Paso Natural Gas Company objected strongly to the provision in the IS for automatically expanding Wheeler Ridge capacity[37] by

[37] While this was not an option specifically mentioned in D.99-07-015, we do not choose to stand on that technicality to exclude it from consideration here. Once a proceeding is open to settlement, the dynamics of settlement talks may bring in matters outside the delineated scope, as they have done here with regard to Wheeler Ridge expansion and,

Footnote continued on next page

100 MMcfd if a certain number of curtailments occurred, and for automatically allowing the expenses of that expansion to be rolled into rates. We will not pre-approve here the rate treatment for facility expansion, but we believe that developing criteria for expansion of receipt points is useful. Hector Road may not entirely alleviate the problem of constraints on northern gas flowing to the south.

Therefore, we approve that portion of Section III of the IS that sets forth criteria for expansion. Upon the meeting of that criteria, and consistent with Public Utility Code Section 1005.5, if the cost of that expansion exceeds $50 million, SoCalGas shall submit an application for an expansion of the receipt point capacity. Such an application would be considered as would any other expansion request, with the issues of need in the context of the entire system and foreseeable market conditions considered. Such questions as rate treatment and allocation of cost among classes would remain open for consideration in that proceeding.

Thus, we will modify Section III of the IS after the first sentence of the first full paragraph on page 8. Following "…SoCalGas will construct an expansion.", the words "If that project costs more than $50 million to construct, SoCalGas will first file an application with the California Public Utilities Commission proposing such expansion." We specifically disapprove

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for instance, pooling. Both proposals respond to concerns raised in R.98-01-011, (see citations in text above as well as Panel Hearing Testimony of Mr. Benjamin C. Campbell, PG&E, Tr. pp. 267-268, Jan 19, 1999) and neither was specifically excluded from further consideration in D.99-07-015. We therefore view them as within the scope of this proceeding. To the extent that other receipt points are also viewed as constrained, we welcome evidence to that effect in a future proceeding, as well as proposals for criteria to determine when expansion should be applied for.

the IS language in the middle on page 8 beginning with the words "This Settlement" through the end of the paragraph, and the concomitant language in Appendix A setting the cost at $12 million in 1999 dollars.

(2) Storage Unbundling

In D.99-07-015, the Commission asked the parties to consider the costs and benefits related to creating a system of tradable storage rights in southern California that places the utility at risk for unused resources and that treats the utility's core procurement department like any other customer.

The IS would designate 50% of inventory and associated injection capacity allocated to core service in D.00-04-060 as being for purposes other than minimum core service reliability. CAT marketers be allowed to decide whether to accept, at unscaled LRMC rates, that portion of the non-reliability 50% that is their pro rata share. The IS would provide that, for each CAT marketer that decides not to accept its pro rata share, that share would be unbundled at its unscaled LRMC value.[38] Additionally, wholesale customers could choose to reject all, some or none of their storage allocations, including the portion dedicated to reliability.

This is one area in which circumstances have overtaken our previous directive. At this time, we are not comfortable unbundling from core rates even the "non-reliability" portions of storage from core rates. We have no record here on what portion of core storage serves a specific reliability function. On the other hand, the wildly fluctuating prices at the California border over the last year suggest that storage is one of the critical tools at California's disposal in putting downward pressure on wholesale natural gas prices. Furthermore, as

[38] The scalar associated with this capacity remains bundled in core transportation rates.

noncore customers entered last winter with historically low storage inventories, we believe core storage played a critical role in maintaining the integrity of noncore – as well as core – system deliveries when noncore inventories were depleted. In this context, then, we are uncomfortable taking any action that could compromise reliability at all, and elect not to unbundle any portion of storage from core rates.

In Section VII, the IS provides that customers who have purchased SoCalGas' unbundled storage may assign their storage contracts in a secondary market, for all or a portion of the term of the contract. SoCalGas must establish an electronic bulletin board for the storage contract trading, without fees other than those now required to access the GasSelect system. However, the bulletin board need not be used for trading – traders can contact each other. While price is not disclosed without approval of the parties, the parties and term of the assignment will be public. The SoCalGas Gas Select System is the interim trading mechanism under the CS as well.

The IS is less responsive to our indicated desire to move toward more shareholder risk for unbundled storage. The IS leaves to us the discretion to adopt the provisions of the Joint Recommendation proffered in A.98-10-012[39] (the 1999 SoCalGas BCAP) or retain the Noncore Storage Balancing Account.[40] Time has moved on, and this choice no longer makes sense. We have already approved the provisions of the Joint Recommendation for 50/50 risk

39 "The Parties agree to 50/50 balancing account treatment of unbundled storage revenues." See FoF 9(k) of D.00-04-060.

40 The Noncore Storage Balancing Account provided 100% risk protection for shareholders for unbundled noncore balancing capacity.

sharing in D.00-04-060. Again we must acknowledge the recent escalation in gas prices. Storage becomes a valuable commodity in such a situation, so that relatively low-priced gas can be bought and saved against a time when flowing supplies cost even more. Because we do not believe there will be a great deal of unbundled storage in the next year or so, we believe the IS proposal to stay with the 50/50 risk sharing is acceptable until the next opportunity to reconsider storage unbundling and the appropriate balance of ratepayer/shareholder risk.

(3) Balancing, Imbalance Trading, Information about OFOs, and Pooling

In D.99-07-015, the Commission also asked the parties to propose improvements to balancing practices. SoCalGas currently requires shippers to deliver gas to the system that is within 10% of usage by the end of the month. During the winter months, there are additional requirements for customers to keep inventory at an acceptable level, on pain of penalty, and the Gas Acquisition Department must keep flowing supplies at a certain level on a daily basis. When the shipper is out of this tolerance, SoCalGas calls it an "overnomination" or "undernomination" event. SoCalGas has used its core procurement gas supplies to balance its system, and it has also borrowed from noncore supplies. We viewed as "critical" a means for providing balancing services without drawing on core assets.

Section IV of the IS eliminates the overnomination event process and provides for amendments to tariff Rule 30 which would establish an OFO procedure, while section V provides for OFO imbalance trading.

The IS does not deal with the "critical" element of removing core assets from the balancing function. TURN and SCGC argue that this diversity of need is a strength of the SoCalGas system, not a problem. SCGC's witness, Catherine Yap, testified that core as well as noncore took advantage of the ability to be out of balance by buying and receiving a huge amount of gas when it was less expensive, and storing it (Ex. 101, pp. 29-30 redlined version filed May 30, 2000.) The core used all of its injection rights as well as some or all of the noncore injection rights from April 15 to June 30, 1999. The noncore also exceeded its rights. Yet, "[t]he combined core/noncore exceeded its combined injection capacity on only 23 days versus the 83 days for the core and 56 days for the noncore. Similarly, the combined core/noncore <u>never</u> exceeded its combined withdrawal capacity versus the 75 days [on which noncore customers did exceed withdrawal capacity]." (Ibid. at p. 30.) We are convinced that the SoCalGas balancing system is more symbiotic than was the PG&E system prior to the changes in balancing practices on that system.

We also believe that the introduction of imbalance trading will provide the opportunity to extract value from staying within tolerances and limit the uncompensated use of another class' balancing assets. The IS would change the present system by subjecting all customers, including the SoCalGas Gas Acquisition Department, to penalties for violating the 10% monthly tolerance, the OFO 10% tolerance, and the winter balancing rules.[41] Each customer would be required to correct imbalances through trading or adjustment of subsequent deliveries or consumption. While the Gas Acquisition Department would no longer automatically buy or sell gas for the purpose of eliminating another customer's imbalance, it could choose to do so to gain the value of the transaction. Furthermore, all customers would benefit to some extent when one customer uses system resources to stay out-of-balance because the penalties

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[41] The winter flowing supply requirements continue to apply only to the Gas Acquisition Department and CAT marketers.

would be applied to reduce customer transportation rates on an equal cents per therm basis.

The option of daily balancing and the possibility of targeted OFOs are not incorporated in the IS. As the stakeholders in the SoCalGas system gain experience with the new balancing options we approve here, the usefulness of these options for the post-2002 period will become clearer. Additionally, the experience on the PG&E system may be available if a daily balancing option is chosen by some of the customers on that system.

Information about conditions on the SoCalGas system and after-the-fact information establishing the need for the OFOs called will be made available to all parties on the GasSelect system, as will demand forecasts for different customer classes. The provision of this information would put SoCalGas on par with the PG&E information system, as recently approved by the Commission in D.00-02-050 and responds to the Commission's call for improved information processes as discussed in D.99-07-015, pp. 39, 83-84. Customers should be able to understand the reasons for OFOs and be able to adapt their operations to avoid them.

Parties have expressed concerns that numerous OFOs can be costly, as well as some trepidation about the change to an OFO system in general. (Ex. 13 in R. 98-01-011, pp. 5-7, (Calpine Corporation Rebuttal to Market Conditions Report) and Panel Hearing Testimony of Mr. Bryan Cope, SCGC, Tr. p. 964 (Jan 25, 1999).) The IS provides for the convening of an "OFO Forum" if there are more than eight OFOs called in the first two months of settlement implementation. We find that this solution is reasonable and in the public interest.

Finally, the IS introduces a new concept to help manage gas supplies and to enhance the liquidity of trading of gas. Although pooling of customer and marketer supplies was not addressed in D.99-07-015, we endorse the concept and believe it is in the public interest. (But see, in R.98-01-011, Panel Hearing Testimony of Mr. Benjamin C. Campbell for PG&E, Tr. pp. 267-268 (Jan. 19, 1999), also, Panel Hearing Testimony of Mr. Steve Watson, SoCalGas, Tr. p. 828 (Jan. 22, 1999.) Pools function as points on the SoCalGas system, like storage, from and to which gas may flow. However, an imbalance cannot be held in a pool after the first nomination cycle of the day.[42] Pooling fees would be charged after a certain daily number of transfers among pools.

(4) Modifications to the IS

The passage of time and intervening events have made some terms of the IS moot. Accordingly, our approval of the IS does not extend to these terms. Section X, regarding issues to be removed from A.98-10-012 (already determined in D.00-04-060), is moot. Section XI, regarding a collaborative process for further regulatory changes, is moot in that further negotiations led to the CS. However, we have no objection to continued informal talks among the parties. Additionally, those portions of Sections III, X, XI and XIII that limit the Commission's ability to approve the settlement in part are specifically disapproved.

(5) Implementation Costs

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[42] In the CS, an imbalance cannot be held in the pool even in the first nomination cycle because SoCalGas had second thoughts about the advisability of this provision in the new balancing environment. Recognizing this as a potential problem, we suggest that if SoCalGas concludes that the ability to hold imbalances in a pool for the first nomination cycle is leading to OFOs, it convene the OFO Forum to determine how best to deal with the problem. We put the parties on notice that we will consider a request to revise the tariff on this issue and will not feel bound by the term of the agreement.

The capital costs of implementing the various provisions of the IS were estimated at $2.7 million and capped at not more than $3.5 million. The IS provides that SoCalGas will be able to recover in transportation rates or Commission-approved fees up to $3.5 million, with pooling fees offsetting these implementation costs. Allocation among customers of the revenue requirement and revenues is not resolved by the Settlement.

Advice Letter 2895 and Advice Letter 1185-G

On February 17, 2000, SoCalGas filed an Advice Letter (A.L. 2895) seeking to establish a Gas Industry Restructuring Memorandum Account (GIRMA) to book its costs. Entries recorded into this memorandum account would be subjected to review by the Commission before SoCalGas would be allowed recovery of the costs in rates. The early filing of AL 2895 was meant to ensure that recovery of such costs would not be barred by the rule against retroactive ratemaking should the Commission find after the fact that it was reasonable to allow SoCalGas to recover such costs.

The Memorandum Account proposed by SoCalGas is divided into five subaccounts; (1) the Capacity Service Trading Systems Cost Subaccount to record incremental expenditures related to the development, implementation, and operation of new or enhanced computer systems to accommodate pooling, imbalance trading, and trading of storage contract rights and firm intrastate transmission rights; (2) the Customer Education Program Subaccount to record the incremental costs incurred by SoCalGas to inform customers and other stakeholders of the changes in the gas industry resulting from R.98-01-001, I.99-07-003, and any future successor or associated proceedings, and to provide customers with information to help them make appropriate choices as to their gas service, (3) the Direct Access Implementation Costs Subaccount to record costs related to incremental expenses incurred for Customer Service, ESP

Services, Employee Training, and Direct Access Support, (4) The UDC (Utility Distribution Company) Systems Modification Costs Subaccount to record incremental costs associated with development of systems and processes within Retail Billing, Revenue Reporting, Credit and Collections, and third party meter ownership, and (5) the Customer Information Release Systems Cost Subaccount to record incremental costs related to the development, implementation, and operation of systems and processes related to various Customer Service information release requests.

On the same date, SDG&E filed Advice Letter 1185-G seeking authority to establish a similar GIRMA to record incremental costs related to the planning and implementation of gas industry restructuring. AL 1185-G revises Section III—Listing of Memorandum Accounts, of SDG&E's gas Preliminary Statement. AL 1185-G does not refer to a particular settlement in I.99-07-003, but instead anticipates that the Commission may soon adopt a number of regulatory changes for the gas industry structure in California with the intention of enhancing competition and improving efficiency for the benefit of consumers.

In its advice filing, SDG&E suggests that the costs may include but are not necessarily limited to four subaccounts: (1) Customer Education Program Subaccount, (2) The Direct Access Implementation Cost Subaccount, (3) The UDC System Modification Costs Subaccount, and (4) The Customer Information Release Systems Cost Subaccount.

SoCalGas explains that the memorandum account treatment proposed by SoCalGas for the gas industry restructuring is very comparable to the memorandum account treatment the Commission authorized for electric industry restructuring in D.96-12-077, D.97-03-069, and D.97-05-040. SoCalGas states that the language in the tariff is patterned directly on SDG&E's electric Industry Restructuring Memorandum Account (IRMA) for gas industry restructuring activities that are likely to parallel electric industry restructuring activities.

Protests

On March 2, 2000, CIG/CMA filed protests of SoCalGas AL 2895 and SDG&E AL 1185-G on the grounds that they were premature and speculative. On March 8, 2000, Aglet, ORA, and TURN (together, Joint Protestants) filed a joint protest of SoCalGas AL 2895 and SDG&E's AL 1185-G. CIG/CMA suggested that such accounts should only be established once the programs are authorized, as was done in electric industry restructuring. Moreover, the settlements under consideration include the cost of implementing new programs and how such costs should be recovered, if at all, by the utilities.

Additionally, CIG/CMA believes that the applicability of individual subaccounts such as Consumer Education Program, Direct Access Implementation Costs and UDC System are highly dubious; these subaccounts made sense in the electric industry restructuring, but do not make sense here. CIG/CMA submits that there is little or no need to incur any incremental costs related to ESPs, employee training, and direct access support, as suggested by the utility. Both core and noncore customers have been able to do "direct access" gas transactions for many years. These are not new programs created by further gas industry restructuring, CIG/CMA believes.

The Joint Protestants oppose the requested relief entirely, agreeing with CIG/CMA's points and adding more. The GIRMA, the Joint Protestants believe, is not comparable to the memorandum account treatment authorized by the Commission for electric industry restructuring, because the latter is a matter of law and is directly tied to stranded costs and other risks that are authorized in Section 376. They argue that there is no parallel between large, undepreciated investments in electric generation plants, which led to shareholder protections against stranded costs, and the restructuring considered in the settlements here. Compared to electric industry transition costs, which are in the order of $20 billion, the Joint Protestants claim, the amounts at stake for gas industry restructuring are insignificant and undeserving of special regulatory protection.

The Joint Protestants also believe that the claim made by SoCalGas and SDG&E that the gas industry restructuring costs are not included in rates is false. They argue that future test year ratemaking enables the Commission to consider historical information about recorded costs of service. Those recorded costs include implementation costs for new services and programs or for modifications of existing services and programs. Between test years, it is inevitable that the utility will incur some costs that were not anticipated in the rate case and will not incur some costs that were anticipated in the rate case. In the long run, these inaccuracies in forecasting of utility expenditures will offset each other.

The Joint Petitioners assert that restructuring implementation costs are no different in content or scale from costs embedded in rates. The Joint Protestants are concerned that the authorization of implementation costs through GIRMA treatment would open the door for double recovery of costs that are already in rates, particularly because of the vague definition of "incremental costs related to the planning and implementation of gas industry restructuring" and overbroad scope allowing the booking of costs "of any successor or associated proceedings."

Finally, the Joint Protestants point out, the proposed tariffs would allow each utility, at its discretion, to record the GIRMA balance as a deferred debit on its balance sheet with related entries to income statement accounts. This means that SoCalGas and SDG&E could characterize GIRMA debits as assets for financial reporting purposes, which would be contrary to conventional practice for memorandum accounts.

SCGC also protests AL 2895 and urges the Commission to reject it. SCGC claims that through AL 2895, SoCalGas seeks permission to circumvent the "Z" factor provisions of SoCalGas' Performance Based Ratemaking (PBR). SCGC also points out that D.97-07-054 provides that the first $5 million per event of otherwise compensable Z factor adjustments will be absorbed by SoCalGas' shareholders. SCGC recommends that if SoCalGas expects to incur incremental costs of implementing gas industry restructuring, SoCalGas should add relevant subaccounts consistent with D.97-07-054.

SCGC acknowledges that parties, including SCGC, have agreed to one exception from the otherwise applicable provisions of D.97-07-054 and SoCalGas' Preliminary Statement regarding Z Factors. In the IS, parties agreed specifically to the establishment of a new account to record the costs of enhanced computer systems that would be required to implement pooling and to establish an electronic bulletin board for trading storage contracts under the IS. Therefore, SCGC believes that the only costs that SoCalGas should be allowed to record in the GIRMA should be costs that would result from the implementation of pooling and establishment of an electronic bulletin board for the trading of storage contracts. The proposed subaccounts are not relevant to any proposed changes.

<u>Sempra's Response</u>

In its reply to the protests filed on March 15, 2000, Sempra Energy states that Z-factor treatment is not automatically appropriate for Commission-approved costs of restructuring. These costs are not necessarily "exogenous and unforeseen events," Sempra claims. Edison, Sempra notes, has booked and recovered its electric restructuring costs through a memorandum account even though it was subject to a base-rate PBR mechanism adopted for it in 1996 that includes a Z-factor mechanism. Sempra also is concerned that the use of the Z-factor treatment for industry restructuring costs for those utilities that are subject to a Z-factor mechanism would result in inequities because the utilities such as PG&E that are not subject to Z-factor treatment would not have to incur the "deductible" such as the $5 million specified in the SoCalGas PBR.

Sempra concedes that there is no existing authority for the GIRMA but points out that the utility is seeking such authority through the advice filings. Sempra believes that the Commission has given it enough guidance from the "promising options" decision (D.99-07-015) and from Commission actions on the electric side. Furthermore, Sempra believes, the utilities can reasonably anticipate the need to deal with a significant increase in the number of core customers electing transportation-only service, regardless of the details of the particular reforms that will be adopted by the Commission.

Sempra opposes the Joint Protestants' claim that the costs covered by the GIRMA are already reflected in rates by pointing out that the accounts for both utilities cover "incremental" costs not already included in rates, for new initiatives. Sempra also believes that at the time when such costs are actually included in rates, the Commission and the parties can review the costs to ensure that they are not duplicative.

<u>Rulings on the Protests</u>

We are perplexed that CIG/CMA and SCGC, parties to the IS, protest many aspects of the GIRMA advice letter filing made by SoCalGas. The IS at pp. 17-18 clearly specifies that:

> "SoCalGas will begin programming the necessary enhancements immediately upon submission of this Settlement. SoCalGas will establish an account

> to which the costs associated with development and implementation will be booked. SoCalGas will capitalize these costs and as of the date this settlement is implemented will be entitled to recover in transportation rates or Commission-approved fees the revenue requirement associated with these costs."

However, as we were faced with a multitude of settlements in this proceeding, we saw fit to postpone any decision regarding the advice letter filings until we decided which settlement, if any, to approve. Now that we have made that determination in this decision, we find the argument that the accounts were premature to be moot. It makes no sense to require SoCalGas to re-file now for that reason alone.

We find that the allegations made by CIG/CMA, SCGC, and Joint Protestants regarding the over-broad scope of SoCalGas' proposed memorandum account have merit. The IS specifically prescribes that a memorandum account will be established for the purpose of development and enhancement of computer systems required to implement the settlement. However, the subaccounts proposed by SoCalGas go far beyond that mandate, and include all sorts of costs related to ESP services, direct access support, retail billing, etc., that are not directly related to any provision in the IS. Moreover, the IS does not authorize such subaccounts.

We also agree with the protesting parties that SoCalGas' stated purpose to establish the GIRMA for the "planning and implementation of gas industry restructuring being considered by the Commission in R.98-01-011, I.99-07-003, and the cost of any successor or associated proceedings that may be established, which are not presently being recovered by SoCalGas," to be extremely sweeping. With such a far-reaching, self-prescribed, and all-inclusive mandate, it will be difficult for us to deny the utility any future recovery of costs that it might claim under the account.

We agree with Sempra that the Z-Factor mechanism in its PBR was not intended for gas industry restructuring costs. We believe that "exogenous and unforeseen" events are those that are outside of the purview of either the utility or this Commission. Industry restructuring costs, particularly when they are specifically covered by a settlement, we believe, are not covered by Z-factor provisions.

However, we agree with the Joint Protestants and SCGC that cost of service ratemaking allows for changes in costs of current programs as well as some new programs, and that between test years, the utility should incur some costs that are unforeseen. SCGC and the Joint Protestants are correct in asserting that costs other than those specified in the IS' GIRMA provision are already included in SoCalGas' rates under its PBR mechanism and should not be allowed to be recovered through this new account.

Therefore, the Joint Protestants and Sempra appear to agree that the costs covered by the account should be incremental; i.e. they should be costs that are not already included in rates. The question remains which costs those are. We leave the answer to that question to another proceeding reviewing the costs booked to the account.

<u>Findings on the GIRMA</u>

We will order the utility to establish, in conjunction with the tariffs that it will implement pursuant to this order, a gas industry memorandum account with the restricted purpose of "developing and implementing new or enhanced computer systems," effective on the date of this decision. The costs recorded in this account will be limited to no more than $3.5 million, as per the IS. The costs logged into the account will not be recovered through rates until the legitimacy of the costs and their incremental nature is verified in SoCalGas' next BCAP subsequent to the date of this decision.

Because we agree with the Joint Protestants' argument that the GIRMA should be accorded the same accounting treatment as the utility's other memorandum accounts, and that it should not be characterized as an asset for financial planning purposes, Sempra should change its proposed accounting treatment of the GIRMA in the revised and refiled tariff revision.

The authority for the account for SDG&E is less clear. The IS pertains only to SoCalGas, and contains no mention of "flow through" costs for SDG&E. Moreover, SDG&E's AL 1185-G prescribes no specific amounts to be recovered through the memorandum account, nor does it cite specific authority for doing so. We therefore reject SDG&E's AL 1185-G. If, during implementation of the IS, as approved here, SDG&E finds it necessary to seek approval for costs related to the development of computer systems, SDG&E should seek authority from us to establish such an account, after providing us with justification for it.

(6) IS-related Tariff Approval

The joint motion to approve the IS included a request that the tariffs accompanying the IS, and the later-filed pooling tariff, be approved in tandem with the IS, so that implementation would not be delayed. We received no specific objections to the tariff revisions filed, but our modifications and the passage of time lead us to believe that summary approval is inadvisable. Therefore, we do not approve the tariffs as attached to the IS.

Rather, we instruct SoCalGas and SDG&E to file, through one or more advice letters, new and revised tariffs that implement the IS as modified herein within 10 business days of the effective date of this decision. The tariffs filed in compliance with this order will become effective within 30 days of filing unless rejected by the Energy Division. These tariffs will remain in effect, despite the termination date in the settlement agreement, until they are ordered revised or eliminated by the Commission or one of its divisions.

2. Reasonable In Light Of The Whole Record

Pursuant to Rule 51 of the Commission's Rules of Practice and Procedure, the Commission will not approve a settlement unless it is found to be reasonable in light of the whole record in the proceeding. Here, we do not approve any settlement in its entirety. Instead, we adopt and modify portions of the IS. In the preceding sections, we have assessed the merits of each portion of the IS by reviewing the record in this proceeding. Thus, we have found each of the proposals adopted herein to be reasonable in light of the whole record.

3. Consistent with the Law

a) Section 1708

Section 1708 provides that the Commission may alter or amend any decision upon providing parties with an opportunity to be heard. Unlike the CS, the IS does not significantly change previous decisions. Nonetheless, notice was given to the parties to the BCAP case and a number of other cases involving SoCalGas and SDG&E that a decision in this investigation might alter or amend the BCAP and other decisions. We are satisfied that all interested parties were aware of this proceeding and had an opportunity to participate in the hearing.

Under these circumstances, § 1708 does not require that the Commission hold any further hearings before approving the IS.

b) Section 328 et seq.

The IS consistent with Section 328. On August 25, 1998, Senate Bill (SB) 1602, became effective, creating Section 328 of the Public Utilities Code.

That section expressly allowed the Commission to investigate issues associated with the further restructuring of natural gas services, but prohibited the Commission from "enacting" any gas industry restructuring decisions affecting the core prior to January 1, 2000. It stated that if the Commission determined that further natural gas industry restructuring for core customers was in the public interest, the Commission should "submit its findings and recommendations to the Legislature." As of January 1, 2000, § 328 was repealed by virtue of AB 1421, and replaced by a new § 328, as well as new §§ 328.1 and 328.2, setting forth requirements for bundled gas service to the core, among other things. There is no longer a requirement to report to the Legislature before acting to restructure the gas industry.[43]

c) SoCalGas Merger Conditions

Under the IS, Mitigation Measure III.Q (Remedial Measure 17) as set forth in Attachment B to the Pacific Enterprises/Enova Corporation merger decision, D.98-03-073[44], provides that SoCalGas must make a proposal designed to eliminate the need for SoCalGas Gas Acquisition to provide system balancing. SoCalGas has done so with the CS. The mitigation measure further provides that

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[43] In the interests of comity, we have sent the proposed decision and attached settlement (Appendix I) to the Legislature as our submission of findings and recommendations.

[44] Mitigation Measure III.Q provides: "SoCalGas shall propose to the Commission in the upcoming Gas Industry Restructuring proceeding a set of provisions designed to eliminate the need for SoCalGas Gas Acquisition to provide system balancing. If the system reliability and balancing function is separated from SoCalGas Gas Acquisition, all communications between Gas Operations and SoCalGas Gas Acquisition shall be through, and posted contemporaneously on, the GasSelect EBB, except for the telephonic and facsimile communications addressed above in (3). (Remedial Measure 17.)"

only *if* such a separation is *adopted* should communications between Gas Acquisition and SoCalGas' Gas Operations be carried out only over the Gas Select EBB. We are not adopting such a separation, although it has been proposed, at this time. Accordingly, it is not required that communications be carried out only over the GasSelect EBB at this time.

No inconsistency with the law has been brought to our attention, and we conclude that there is no inconsistency with the law. Therefore, there is no impediment to making these changes since we have also found them reasonable in light of the whole record, and in the public interest. (Rule 51.1(e).)

E. Decisions on Other Matters Litigated

1. Core Interstate Transportation Capacity Unbundling

Under core interstate capacity unbundling, CTAs would arrange for their own delivery of gas to the SoCalGas system[45] and the cost of the interstate service would be removed from their SoCalGas rates. Since it is expected that retail core customers will not need all of the interstate capacity allocated to core customers, this will create stranded capacity costs associated with core interstate capacity. The charge used to cover interstate capacity stranded costs is called the interstate transition cost surcharge (ITCS).

In the Promising Options decision, the Commission recommended the unbundling of SoCalGas' core interstate transportation capacity costs. (D.99-07-015, p. 49, pp. 60-61, FoF 31.) The IS does not address unbundling of SoCalGas' core interstate capacity, but explicitly states that unbundling of interstate pipeline capacity for SoCalGas core transportation customers would

[45] SDG&E has already unbundled these costs.

not be inconsistent with the IS. Both the proponents of the CS and the PI set forth proposals on how core interstate capacity costs should be unbundled, and eliminated core contribution to noncore ITCS. No party argued against the unbundling of core interstate capacity costs.

Core interstate capacity unbundling has been a contentious issue before the Commission since interstate capacity costs were first unbundled for noncore customers in 1993. (See Ex. 4 (Pocta) at p. 5.) In D.95-07-048, the Commission decided that it was appropriate to unbundle interstate capacity costs for core transportation customers. Five years later, core interstate unbundling still has not been achieved on the SoCalGas system. As with storage unbundling, we believe that time and events over the last year have overtaken this goal. We are not prepared to unbundle interstate capacity from core rates at this time. However, we are prepared at this time to relieve the core of its responsibility for a contribution to stranded cost[46] arising from noncore interstate transmission capacity unbundling.

a) Treatment of "Noncore ITCS"

The Commission has rejected, a number of times, proposals by TURN and ORA to eliminate the core contribution to noncore ITCS. (Tr. 109; See Ex. 4 (Pocta, ORA) at p. 5; see also D.97-04-082 at pp. 69-70.) In this proceeding, the elimination of the core contribution to noncore ITCS, effective January 1, 2002, has been incorporated in both the CS and the PI, and this appears to have generally been acceptable to parties as a compromise, given

[46] Stranded costs are those costs of the long-term interstate transportation contracts that SoCalGas has with El Paso and Transwestern pipelines that are not covered by the sales of released capacity.

other aspects of both settlements. Core aggregators who signed on with the CS testified that settlement on this issue was critical to their agreement.

In the CS, elimination of the core portion of noncore ITCS was the quid pro quo for the parties' agreement on the allocation of the stranded costs arising from core interstate unbundling. (Ex. 2 (Lorenz) at p. 27; Ex. 4 (Pocta) at pp. 5-7; Ex. 13 (Counihan) at pp. 3-4.) Under the CS, additional costs borne by SoCalGas' core customers as a result of core interstate unbundling were expected to be offset, on the whole, by the cost reduction resulting from elimination of the core portion of noncore ITCS effective January 1, 2002. SoCalGas witness Lorenz testified that the annual benefit of this provision, to the entire core customer market, will be between $8 and $10 million.[47] For example, CS supporters estimated that residential core customers would pay $3.5 million for core ITCS, but would receive a benefit of $5.7 million due to the elimination of noncore ITCS from core rates. However, non-residential core customers were expected to pay more under the "tradeoff." Ex. 2 shows that non-residential core customers were expected to receive a benefit of only $1.9 million due to the elimination of noncore ITCS from core rates, while paying $2.6 million for core ITCS.

Noncore customers are the ones who will bear the additional costs of noncore ITCS. We recognize that noncore customers may have agreed to the CS approach (eliminating the core contribution to noncore ITCS) because they would have faced none of the core ITCS costs after 2001 under the CS. Thus, both the CS and the PI allowed for the 2001 end to noncore ITCS for core

[47] (Ex. 2 at pp. 6, 27.) SCGC witness Catherine Yap testified that based upon a market value for released interstate capacity of approximately 40 percent, the annual benefit for core customers would be slightly less than $10 million. (Tr. 111. See also Ex. 4 (Pocta, ORA) at p. 6 ($11.9 million maximum annual benefit).)

customers, albeit each settlement involved different "tradeoffs" for different sets of parties. But we have not adopted either the CS or the PI. Their trade-offs are not applicable. We question the need for trade-offs at all.[48]

Recognizing that the trade-offs anticipated are no longer in play, our approach to stranded cost allocation is based on policy considerations. We still believe that the long-term interstate pipeline transportation contracts were entered into for the benefit of all SoCalGas' customers, and all customers should pay some share of total stranded costs.

We believe this is the appropriate time for the core contribution to noncore ITCS to end, effective with the tariffs implementing this decision. Noncore customers have received substantial benefits from the unbundling of interstate capacity costs, benefits that have been partially subsidized by core customers for eight years.

According to TURN, core customers have been paying over $160 million in stranded costs from 1993 through 2000, eight years,[49] without receiving benefit from unbundled noncore capacity, while noncore customers have achieved very substantial savings for their payment of stranded costs. ORA's Pocta roughly estimated that the core contribution to noncore ITCS from

[48] GreenMountain.com testified on behalf of core aggregators that the elimination of the core portion of [noncore] ITCS was traded for taking on the stranded costs that arise as a result of core interstate transportation unbundling. (Ex. 13, pp. 3-4.) We note that core aggregators had nothing to trade. Core aggregators bore none of the costs of noncore ITCS yet they may gain some of the savings from core interstate unbundling because there is nothing to ensure that core aggregators pass savings on to their customers.

[49] $128 million from 1993-1997, and over $35 million amortized in 1997 to 2000 (TURN Opening Brief, p. 9, fn. 7.)

1992-1993 to 2001 will be between $111-127 million.[50] In contrast, the PI would have noncore customers pay nothing and the CS would have them pay only a few million dollars for core ITCS through 2001.

While the future is not foreseeable, the strong demand for gas currently is causing the value of released capacity to be close to 100% of the full as-billed rate, at least in the near term. If this trend continues, the ITCS costs will be low, and the incremental 10% of those costs added to the noncore will be even lower. It simply does not strike us as reasonable for core customers to have paid well over $100 million for noncore ITCS (allowing noncore customers to achieve substantial benefits), and to continue those payments.

We anticipate that noncore parties will argue that they will be paying for all noncore ITCS for six more years, and they will simply pass all the stranded costs through to their customers. Generators, in particular, will argue that electricity costs will increase. We note only that it is possible for these entities not to pass all the costs through, while if the costs are allocated to the core, the core will definitely pay them. In today's electricity market, generators in particular are not just scraping by. We prefer to adopt the correct policy position here, and order the full noncore contribution to its own ITCS.

b) Brokerage Fee

The IS and the PI do not make any change to the procurement brokerage fee. Section 5.5.3 of the CS provides an increase in the core brokerage

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[50] See Tr. p. 983. ORA estimated that from 1992 or 1993 through 1998, core customers had paid about $13 million per year. This amounts to $78-91 million. For 1999 through 2001, ORA estimated that core customers could pay about $11-12 million per year, or another $33-36 million. Therefore, through 2001, core customers may have paid $111-127 million in noncore ITCS.

fee from its current level of 2.01 cents/Dth to 2.4 cents/Dth. In Exhibit 20, SoCalGas explained that the proposed fee is equal to the fee adopted for PG&E in the Gas Accord, was a negotiated amount not based on any cost study, and reflects the desires of the parties to implement a temporary mutually satisfactory fee until a permanent figure can be developed based on actual cost. The last detailed study of the brokerage fee was performed by SoCalGas in its 1996 BCAP, A.96-03-031. The Commission then adopted a brokerage fee of 2.01 cents/Dth in D.97-04-082.

This fee is included in the procurement rate charged to bundled core customers and core subscription customers. The brokerage fee is intended to reflect the costs incurred by the utility in providing its procurement service and one benefit of breaking it out of the rate is to provide core marketers with a mark against which to compete with the utility for procurement customers. The forecasted revenue requirement associated with the core brokerage fee is backed out of the SoCalGas base margin. That revenue requirement is then balanced against actual revenues in SoCalGas' PGA. Any difference between authorized and actual revenues is collected through the amortization of the PGA. So, an increase in the brokerage fee (resulting in an increase in the procurement rate) would result in a corresponding decrease in the amount collected in the transportation rates for <u>all</u> core customers, but only <u>bundled</u> core customers would be paying for it.

We see no reason to arbitrarily increase the core brokerage fee when there is no basis to do so. We cannot allow an arbitrary increase in a fee outside the context of a settlement agreement, particularly where it shifts costs to the bundled core. We have no evidence as to what core marketers need to charge their customers for procurement activities. The evidence we have is the cost study in an earlier BCAP when we adopted the current rate, and the PG&E rate, arrived at in a settlement. It is not clear that the PG&E figure does not have is applicable to SoCalGas' operations.

c) Effect and Implementation of Stranded Cost Allocation Determinations

Thus, as of the effective date of the tariffs arising out of this decision, the core shall stop contributing to the noncore ITCS, and the noncore will pay all the noncore ITCS. SoCalGas should not change the brokerage fee of $0.201/Dth. SoCalGas should file tariff revisions in a rate adjustment advice letter reflecting the changes discussed above within 30 calendar days from the effective date of this decision. The rates shall be effective within 60 days from the effective date of this decision. These revisions can track the CS language on these issues to the extent that it is consistent with this opinion.

2. "Retail" Promising Options

The Core Aggregators, in their brief in support of the CS, argue that unbundled interstate capacity and unbundled non-reliability core storage alone are not sufficient to give core aggregators the "shot in the arm" they need to successfully compete with the utility. They contend that unbundled intrastate transmission and unbundled reliability storage are also needed, in addition to unbundled balancing, a hike in the core brokerage fee and billing options.

For the reasons previously stated, we do not think that the more aggressive unbundling of transmission, storage and balancing set forth in the CS is in the public interest at this time, nor do we raise the brokerage fee artificially for the purpose of consistency with PG&E or to level the playing field for small core aggregators. In addition, we find no compelling reason to remove the threshold and cap on core aggregation, but recommend that the Legislature act on our proposals for consumer protection in this area. We eliminate the core subscription rate so that those noncore customers now opting for core procurement through the utility must become core customers, with the concomitant rights and responsibilities, or choose another procurement method. We will monitor these reforms and decide in a later proceeding whether additional support for retail natural gas competition is in the public interest.

a) Elimination of Core Subscription

SoCalGas previously offered core subscription to its noncore customers under contracts with a two-year term. Approximately 138 noncore customers participate in the core subscription program on the SoCalGas system, receiving core procurement service. These customers represent less than one percent of total noncore volumes and more than one-half of that number are currently on two-year contracts that expire on or before July 31, 2001. (Ex. 3, p. 21.)

Effective December 2000, SoCalGas stopped adding customers to its core subscription program, pursuant to Resolution G-3304. In that Resolution, the Commission recognized that the extraordinarily high gas prices of last winter provided significant incentives to many noncore customers to opt-in to SoCalGas' core portfolio, at significant risk to existing core customers. Under G-3304, SoCalGas is prohibited from allowing customers not already participating in the program, to sign up for core subscription service.

Under the CS, SoCalGas would cease offering new core subscription contracts by April 1, 2001. Beginning on the effective date of a Commission order approving the CS, SoCalGas would offer new core subscription contracts for a term that extends no later than July 31, 2001, the date at which the majority of existing contracts expire. While all core subscription contracts in effect on April 1, 2001 will remain in effect until the end of the contract's life, after April 1, 2001, all noncore eligible customers must either choose a competitive provider for gas commodity service or take service from SoCalGas at core rates (GN-10).

To facilitate the transition toward elimination of the core subscription program, SoCalGas would provide customers with adequate advance notice of their choices and would provide these customers with a list of interested gas marketers operating on its system, so that customers can contact these marketers regarding their commodity choices. In the event that customers do not make a choice by the deadline, they would automatically become core customers. (Ex. 3, p. 21.)

The core subscription and noncore procurement options would also be eliminated for SDG&E's customers under the same terms described above for SoCalGas. There are currently 19 noncore customers receiving core subscription service and 115 noncore customers receiving procurement service from SDG&E, which represents 12 percent of total noncore volume on the SDG&E system.

We believe that there is no reason to continue to allow some noncore customers the benefit of the core subscription program without the costs. TURN suggests in its Opening Brief (p. 61) that the provision in the CS terminating the core subscription program will limit customer choice and force current core subscription customers to incur the transaction costs necessary to obtain desirable service packages from marketers. It will not. Those customers now on core subscription service may remain on it until the termination of their contracts, at which time they must elect whether to become core or noncore. These customers can choose to remain part of the bundled core, but it is unfair to SoCalGas' other core customers to bear the burden of paying for sufficient capacity and commodity contracts for customers who want the *future option* of being served by SoCalGas. It is also unrealistic for SoCalGas to adequately plan long term for customers who do not wish to make a commitment. Accordingly, we adopt the CS provisions on this issue with the following exception.

We do not agree with the CS provision regarding the accounting treatment of this change. Under the CS, SoCalGas wanted to continue to treat transportation revenues from customers switching to core status as noncore revenue (i.e., the revenues would be recorded in the Noncore Fixed Cost Accounts (NFCA) and not the Core Fixed Cost Account (CFCA)), until the switch from noncore to core could be reflected in the throughput forecast in SoCalGas' next BCAP. This treatment, SoCalGas claims, is necessary given the different regulatory accounting treatment applicable to revenues for core and noncore volumes on the SoCalGas system. Keeping the revenues from the noncore customers who have become core customers in the NFCA until throughput amounts are adjusted in the next BCAP benefits SoCalGas at the expense of the core. We see no reason to do that. The customers, once they have switched, are core customers and the revenues from them belong in that account. The throughput amounts involved (less than 1% of noncore volume) are not so large that it is an undue burden on SoCalGas to put it at a slightly increased risk of not covering its forecast. We prefer to order that the sums involved be recorded in the CFCA. SoCalGas and SDG&E should file implementing tariffs for these changes in its implementation package due 10 business days after the effective date of this decision.

b) Core Aggregation Program Cap and Threshold

The Commission believed the reduction of the core aggregation threshold and elimination of the core participation cap would expand the competitive options available to residential and small commercial customers. *(D.99-07-015, pp. 59-61, FoF 30, Appendix C.)*

Currently, there is a 250,000 therms/year minimum threshold size on any persons seeking to qualify as or remain a core aggregation transportation marketer on SoCalGas or SDG&E's systems. Also, there is a 10% cap on the percentage of total core market share by volume that can be served by core aggregation transportation marketers on the systems of SoCalGas and of SDG&E, but SoCalGas and SDG&E are obliged to file for Commission review of this cap if the actual market share reaches 8%.

From the inception of the program in 1991 through 1998, customer participation has been fairly stable on the SoCalGas system, ranging from approximately 7,000 to 9,000 customers and representing about four percent of core market volume. At present, there are more than 24,000 SoCalGas customers participating in the CTA program, representing 4.3 percent of total core volume. (Ex. 3, p. 10.) This increase in customer participation is attributed to residential customers who have recently joined the program. On the SDG&E system, there are currently almost 3,000 customers, representing 3.8 percent of core volume, participating in the CTA program. (Ex. 3, pp. 9-10.)

Not only is the present penetration into the residential core market by CTAs under 5%, but testimony indicated only one CTA serves the core residential market. (Ex. 3, p. 5.) Given the very low rate of penetration into the residential core customer market, we do not believe that dispensing with either the cap or the threshold will make a significant difference. We reject the resolution reached by the parties to the CS.

c) Data Access for Customers and their ESPs

SoCalGas and SDG&E customers already have access to information regarding their own gas usage through a variety of sources. The parties to the CS agreed to make available to ESPs for SoCalGas customers the same universe of usage data presently made available electronically to ESPs in SDG&E's service territory. While ESPs are generally satisfied with the present availability of customer consumption data, they seek improvements in the information delivery and data presentation options currently available. Specifically, ESPs desire that the utilities furnish consumption data in consistent formats across different contexts. (Ex. 3, p. 12.)

Again, we are loathe to order, at this time, an expensive new way to present customer consumption data, just as we are loathe to order the development of new Service Request/Account Management systems, before we see a massive shift to core aggregators in PG&E's territory as the result of more extensive unbundling. To the extent possible, SoCalGas and SDG&E should work with customers and/or ESPs to provide customer-specific information, consistent with consumer protection and privacy considerations. Customers and/or their ESPs will pay the reasonable costs of any requests for such information. Information related to the calculation of transportation bills and historical consumption will remain with the utilities.

Additionally, we are informed and believe that data access workshops have already occurred, bringing together SoCalGas, ESPs and various customers. We urge the parties to go forward with these workshops, but to bear in mind that before there is evidence of greater movement by core customers to ESPs, it would be premature to construct an expensive information retrieval and transfer system.

On another data access issue, that of when an OFO is likely to be called, information about conditions on the SoCalGas system and after-the-fact information establishing the need for the OFOs called will be made available to all parties on the GasSelect system, as will demand forecasts for different customer classes. This information will be helpful to individual customers and the OFO Forum as well.

d) Consumer Protections for those using ESPs and CTAs

On August 16, 1999 the Commission delivered specific recommendations to the Legislature regarding necessary consumer protections before the effective date of this decision. In Georgia and elsewhere, companies in competition with the utility have gone bankrupt, had billing problems[51] and otherwise failed to deliver needed gas at the prices offered. Georgia has recently decided to promulgate rules concerning billing by CTAs because of problems in that area. Although the decision we adopt today limits the risk to the small portion of customers who voluntarily choose core aggregation, we believe we should have in place protections and standards to address such circumstances, or at the very least, to have the information to help customers act on their own behalf.

The Commission has broad jurisdiction to implement consumer protection programs as to public utilities. (See e.g. Public Utilities Code §§ 451, 701, 702, 761, 770.) The Commission may develop and implement a consumer protection program applicable to the gas industry pursuant to such authority, as it has done in other industries. On the telephone side, for instance, the

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[51] See previously cited Gas Daily article at fn. 34; Gas Daily, Vol. 17, Number 140, p.1 (July 24, 2000) "Ga. Marketers Face Losses if Snafus Continue," and Georgia Public Service Commission Rulemaking Docket 12720-U, regarding billing practices in Georgia at http://www.psc.state.ga.us/consumer_corner/gmgbsNOPR.htm. We take official notice of the general facts that companies providing gas in Georgia have gone bankrupt, had billing problems and otherwise failed to deliver needed gas at the prices offered, as well as that the Georgia Public Service Commission has recently decided to promulgate rules concerning billing.

Commission proposed and adopted consumer protection rules applicable to competitive local carriers (CLCs) pursuant to its general authority over telephone corporations. (See R.95-04-043/I.95-04-044; D.95-07.054).[52] On the electric side, the Commission proposed in the Preferred Policy Decision to develop consumer protection requirements. (See D.95-12-063, as modified by D.96-01-009, at pp. 5-7 (choice serves consumer protection function), 53-60 (Power Exchange serves consumer protection function), 188 (proposal for education program, consumer protection rules, and registration process)).[53]

Gas corporations are public utilities under Section 216(a). Section 222 defines gas corporations to include "every corporation or person owning, controlling, operating, or managing any gas plant for compensation within this state . . . " Section 221 defines "gas plant" to include "all real estate, fixtures, and personal property, owned, controlled, operated, or managed in connection with or to facilitate the production, generation, transmission, delivery, underground storage, or furnishing of gas, natural or manufactured, except propane, for light, heat, or power." The statutory definition is sufficiently broad to encompass most gas industry participants for purposes of establishing consumer protection rules. Property such as telephones, computers and other office goods used to facilitate sales of gas to consumers is sufficient to bring an entity within the statute. Thus, marketers and brokers, for instance, who have "personal property" in California, which is "owned, controlled, operated, or

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[52] The Commission developed consumer protection rules applicable to NDIECs pursuant to Public Utilities Code § 495.7, which permits the Commission to authorize exemptions from certain tariffing requirements under specified circumstances, and requires consumer protection rules to be established as part of that process.

[53] The subsequent enactment of AB 1890 and SB 477 defined the boundaries of consumer protection in the restructured electric industry.

managed in connection with or to facilitate the production, generation, transmission, delivery, underground storage, or furnishing of gas" fall within the statutory definition.[54]

Section 216(c) provides an alternative definition of public utility. This section states:

> "When any person or corporation performs any service for, or delivers any commodity to, any person, private corporation, municipality, or other political subdivision of the state, which in turn either directly or indirectly, mediately or immediately, performs that service for, or delivers that commodity to, the public or any portion thereof, that person or corporation is a public utility subject to the jurisdiction, control, and regulation of the[C]ommission and the provisions of this part.

At least some services performed by gas industry participants such as marketers, brokers and aggregators, including, but not limited to, identifying trade opportunities, matching buyers with sellers, and facilitating the delivery of natural gas, are within the meaning of Section 216(c). The statute affords the Commission jurisdiction over entities who performed such services.

When we initially considered the jurisdiction issue in establishing the core aggregation program, the Commission determined that there was no

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[54] See also Legal Division's July 12, 1996, and January 17, 1997, memoranda on the various applications for rehearing of the Preferred Policy Decision, at pages 56-61, recommending denial of applications for rehearing by marketers and brokers who had asserted that the Commission lacked jurisdiction as to them. The applicants claimed that because marketers, brokers and aggregators do not own, operate or control either transmission or generation facilities, they were not electric corporations. Legal Division concluded that Joint Applicants II had incorrectly read "electric plant" to be limited to generation and transmission facilities. (The definitions of "gas corporation" and "gas plant" in sections 221 and 222 correspond to those for "electric corporation" and "electric plant" in sections 217 and 218). This challenge was later mooted by the enactment of AB 1890, which expressly gave the Commission jurisdiction over marketers, brokers, and aggregators.

need for enhanced consumer protection, but did not conclusively disclaim the ability to regulate marketers and brokers in retail transactions. In D.90-11-061, the Commission indicated that we had no jurisdiction over "non-utility gas marketers." (Re New Regulatory Framework for Gas Utilities [D.90-11-061], supra, 38 CPUC2d at p. 336.) We believe that the Commission's goal in this instance was pragmatic: the Commission would not "place any burdens on marketers . . . because [we did] not want to discourage the development of more competitive markets for core customers that can aggregate loads." (Re New Regulatory Framework for Gas Utilities [D.90-11-061], supra, 38 CPUC2d at p. 336.) The Commission believed that "natural gas core customers which aggregated loads [were] sophisticated enough" to protect themselves from marketers. (Id.)

The Core Aggregation program in California is now ten years old. With plenty of experience in the larger volume market, we are concerned that marketers and brokers over whom we have previously declined to impose consumer protection rules, may now turn their attention to the less-sophisticated, lower-volume customers.

We believe that the Commission has not previously intended to exclude all marketers and brokers from our jurisdiction, especially with regard to establishing and enforcing consumer protections, but rather that the Commission's intent was to disclaim jurisdiction over out-of-state entities. In the Commission's Order on Rehearing of D.91-11-025, in Re Natural Gas Procurement and Reliability Issues ("Order Denying Rehearing of D.91-11-025" [D.92-02-042]) (1992) 43 CPUC2d 275, 281, the Commission said, "if marketers or brokers over whom we have no jurisdiction were to obtain intrastate rights at a time that intrastate capacity was scarce, it could compromise our obligations to protect consumers in California." Thus, read in conjunction with D.92-02-042, we believe Commission recognized our central, ongoing role in protecting consumers given the programs in place at the time. As those programs change, we must change our rules protecting consumers along with them. We intend to establish consumer protection rules for natural gas retail market participants consistent with our recommendations to the Legislature in 1999.

Additionally, TURN argues in its Opening Brief that core customers would be well-served if core aggregators, whether CTAs or ESPs (providing both electricity and gas) were required to furnish the current utility core procurement price in each end-user bill rendered by the aggregator (p. 59). According to TURN, disclosure of the utility procurement price, or at least some market-index commodity price, would allow consumers to compare gas prices and avoid falling prey to aggregators who charge more, not less, than the utility.

We hope that CTAs will provide this information,[55] but decline to order CTAs to provide this additional piece of information on all CTA bills. We assume that if the comparison is favorable, the CTAs will do so voluntarily. If it is not favorable, perhaps this is a service that TURN can provide on a website, just as various websites now claim to help consumers decide whether to switch telephone companies. However, the choice of service provider will probably be more complicated than a decision based on gas procurement price once ESPs and CTAs begin to provide unique services to customers. By ordering this one piece of comparative information, which may change from month to month, we might be unduly weighting one factor and thereby mislead customers.

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[55] We recognize that under the uncontested PG&E Comprehensive Settlement, this information is required, at least in the short term.

e) Costs of Implementation of Retail Reforms

We follow the model set forth in the CS with regard to the minimal costs of the retail reforms we institute today. In sum, neither SoCalGas nor SDG&E would collect for those expenditures at this time. Rather, at the next PBR or rate case, they each may set forth their expenditures up to that point without a reasonableness review and attempt to make their case that these expenses should be included in their rate base (for capital expenses) and prospective O&M expenditures.

TURN at pp. 59-61 of its opening brief attacks the provisions (Part I, Section 1.6.1.2 and 1.6.2.2) of the CS that would allow SoCalGas and SDG&E to earn a regulated return on their actual capital investment to implement the retail and core interstate portions of the CS, effective with the effective date of their next PBR/Cost-of-Service decision. This will not be before January 1, 2003 for both utilities.

TURN's principal opposition is to the provision that would not allow "reasonableness review" of the amount that SoCalGas and SDG&E spend on capital for this purpose. However, the reasonableness review is dispensed with for two reasons. First, SoCalGas and SDG&E are allowed <u>no</u> recovery in rates of retail implementation costs prior to the effective date of their next PBR/Cost-of-Service proceedings. That means that shareholders will absorb all retail implementation costs for about two years. This includes both O&M costs and return, depreciation and taxes on capital investment. SoCalGas and SDG&E will have an incentive to minimize its capital investment in this period because it will earn no return on it until at least 2003. Second, we have eliminated the most expensive portions of the retail as well as the core interstate proposals, the new computer systems and software for data transfers to ESPs and utility consolidated billing for ESPs. In light of the shareholder absorption of all retail implementation costs in the first two years, and the expectation that they will be minimal, it is reasonable not to subject SoCalGas and SDG&E to reasonableness review of their capital spending for implementation in this period.

IV. CONCLUSION

SoCalGas, SDG&E, and other parties have been highly responsive to the Commission's direction in this proceeding. However, recent events lead us to conclude that we should not, at this point, adopt the centerpiece of this investigation, the unbundling of intrastate transmission and the implementation of a system of firm, tradable intrastate transmission and storage rights. This unbundling is the basis of the CS, and we cannot approve it. We will, however, review SoCalGas' most recent firm transmission rights proposal in the currently pending BCAP.

We are convinced that the IS generally balances the various interests at stake for the period of the settlement. Thus, we find that the IS, as modified, is reasonable in light of the whole record, consistent with the law and in the public interest.

Based on the record in R.98-01-011 and I.99-07-003, we also find that now is the time for other gas industry reforms. These include the elimination of core contribution to the ITCS, and the elimination of core.

V. Comments On Draft Decision

The proposed alternate decision of President Lynch in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Rules of Practice and Procedure. Comments to the draft decision were filed on __________________, and reply comments were filed _____________________.

VI. Findings of Fact

Southwest Gas' Motion

1. Southwest Gas filed its Reply Brief late because it was in discussion with SoCalGas regarding side agreements that would allow Southwest Gas to endorse the CS.

Context of Proceeding and Decision

2. In R.98-01-011, the Commission set goals for its restructuring of the natural gas industry and compiled a record concerning different reforms that might achieve those goals.

3. In D.99-07-015, the Commission relied upon the testimony in R.98-01-011 in choosing the most promising options for further analysis as to costs and benefits prior to adoption as part of the restructuring of the natural gas industry.

4. In I.99-07-003, the Commission allowed the parties to use the promising option framework to negotiate for mutually agreeable changes in the natural gas industry.

5. After the close of the evidentiary hearing, gas prices rose markedly at the producing basins, the California border, and the PG&E citygate.

6. While PG&E citygate prices were less than Malin plus Redwood firm in May, November and December 2000, they were not June through October 2000, nor were they lower January through June 2001.

7. On average of the months May 2000 through June 2001, Malin plus Redwood firm was less than the citygate.

8. Baja firm plus PG&E SoCal Border prices were lower than the citygate October through December 2000, and April through June 2001. On average, for the months September 2000 through June 2001, the price of natural gas bought at the border and transported at the tariffed intrastate PG&E rate to the citygate beat the PG&E citygate price between $.30-1.25/dth.

9. Three settlements and one proposal regarding intrastate transmission unbundling were finally considered in this proceeding.

The Settlements

10. Each settlement addressed many of the promising options set forth, as well as the elimination of the interstate transition cost surcharge burden borne by core customers, and each was objected to by some parties.

11. After adequate notice, no party to the SoCalGas BCAP, or other pertinent SoCalGas decisions, requested a hearing on the settlements precisely because of potential alterations to those decisions. However, hearings were held.

12. The CS addressed more promising options than other settlements, but a pivotal provision is inconsistent with current Commission policy and, as a whole, it is not the settlement that is most in the public interest based on the facts and reasons set forth in the opinion.

13. The PI is not the settlement that is most in the public interest based on the facts and reasons set forth in the opinion.

14. The Long Beach proposal is not reasonable.

The Interim Settlement

15. The IS is the settlement that is most in the public interest at this time based on the facts and reasons set forth in the opinion, and those stated below.

16. The IS filed on December 27, 1999, Appendix I to this decision, addresses many of the issues raised in the testimony in R.98-01-011 regarding the southern California gas systems and advances the Commission’s goals in restructuring the natural gas industry cautiously.

17. The IS is supported by the largest coalition of customer groups of any settlement, as well as by the utilities. It provides some benefit to and balances the interests of gas suppliers, shippers, storage operators, wholesale and retail end-use customers, and regulatory representatives, as well as SoCalGas and SDG&E.

18. The IS eliminates SoCalGas' current "windowing" process, which limits the flexibility of shippers on its system to change their nominations for gas deliveries between various receipt points on SoCalGas' system. Instead, SoCalGas would post the daily physical capacity at each receipt point and allow the upstream pipeline's capacity rights system to determine which shipper's gas will flow when a receipt point is overnominated. The pre-nomination posting of capacity will give some advance notice to customers for planning purposes.

19. Pursuant to the IS, Wheeler Ridge capacity, in an overnomination situation, would be allocated between upstream delivery sources pro rata on the basis of the prior day's scheduled deliveries from each upstream source. This method addresses the problem posed by two pipelines feeding the receipt point.

20. The IS establishes Hector Road as a formal receipt point on SoCalGas' system for which nominations may be made. This increases the flexibility of the overall system for all customers and shippers.

21. The IS provides criteria for indicating to SoCalGas when it needs to increase its capacity to receive gas at the Wheeler Ridge receipt point.

22. That portion of Section III of the IS that allows automatic construction of an expansion of Wheeler Ridge when the criteria is met does not allow for consideration of any change in circumstances at that time. That portion of Section III of the IS that allows for automatic cost recovery in rates as of the date the expansion is in service up to $12 million in 1999 dollars, does not allow for Commission decision regarding whether rates should be rolled in or incremental.

23. The IS provides a forum for further changes in OFO procedures during the term of the Settlement if the frequency of OFOs exceeds a stated threshold initially or at a later stage. The IS also requires SoCalGas to post on its GasSelect system operating information that is as extensive as that required of PG&E and

that includes post-OFO data by customer class so that customers can understand why an OFO was called.

24. The IS provides for the establishment of "pools" of transportation gas on the SoCalGas system that are intended to increase the liquidity of trading of gas supplies in southern California and to provide other benefits to gas consumers and marketers in southern California.

25. The IS changes balancing rules so that cumulative imbalances will remain the property of the transportation customer, and the customer will be subject to modified imbalance charges intended to substantially deter imbalances outside the allowed 10% monthly imbalance tolerance and daily OFO tolerances. Current rules that limit the trading of these imbalances are liberalized.

26. The IS explicitly subjects SoCalGas' Gas Acquisition Department to the same balancing rules and penalties as all other shippers on the SoCalGas system, except that the current winter balancing rules still apply only to SoCalGas' Gas Acquisition Department and core aggregation transportation marketers.

27. The IS provides a detailed methodology for determining the daily imbalances of core gas suppliers including SoCalGas' gas acquisition function.

28. The IS does not require SoCalGas' Gas Acquisition Department to buy or sell, through its supply portfolio, imbalances of transportation customers outside their tolerance levels.

29. The IS provides for the unbundling of storage capacity in excess of that needed for core reliability as determined in D.00-06-040, with provisions for the retail core's payment and retention of its share of unbundled capacity and core transport agents' options to take or decline their pro rata share.

30. In D.00-04-060, the Commission approved the provisions of the Joint Recommendation, providing for ratepayers and shareholders to share the risk of storage unbundling equally.

31. The IS provides exemplary language for SoCalGas' tariffs giving unbundled storage customers the right to assign and reassign their storage contracts in a secondary market (including for terms less than the full contract terms).

32. The IS commits SoCalGas to establishing a voluntary electronic bulletin board ("EBB") for secondary trading in storage contracts on SoCalGas' system.

33. The IS provides for rate recovery of all capital costs incurred by SoCalGas for developing and implementing new or enhanced computer systems necessary to implement the provisions of the settlement, in an amount not to exceed $3.5 million.

34. The provision of the IS involving a collaborative forum for stakeholders to discuss possible further restructuring changes is moot in light of the later filed CS. The provision regarding the BCAP is also moot.

35. The IS, as modified in this decision, is reasonable in light of the whole record of R.98-01-011, I.99-07-015 and the officially noticed facts in this opinion.

36. No party raised an argument that the IS is inconsistent with the law.

37. The tariffs filed with the IS are exemplary in nature and need to be finalized, including incorporating intervening tariff revisions from D.00-06-040.

38. To the extent that provisions in the IS seek to limit the Commission's authority to act in future proceedings, the provisions are inappropriate. The Commission has a duty to act as it sees fit within the ambit of its authority.

<u>Unbundling Interstate Core Transportation Costs</u>

39. California border price data over the last year indicates that the value of interstate capacity has significantly increased.

40. Time and events over the last year have overtaken the Commission's previously-stated goal of unbundling interstate pipeline capacity charges from core rates.

41. The last detailed study of the brokerage fee was performed by SoCalGas in its 1996 BCAP, leading to the Commission-adopted brokerage fee of $.0201/Dth. There is no evidence to support raising the brokerage fee to $.024/Dth.

<u>Eliminating Core Contribution to Noncore ITCS</u>

42. Core customers have been contributing to Noncore ITCS since 1993.

43. Core customers have paid between $111 and $160 million, depending upon whose calculation is used, since 1993 for noncore ITCS.

44. Core customers have not received benefit from unbundling of noncore interstate transportation capacity that even approach the costs to the class.

45. By requiring the noncore to take over the remaining years of core contribution to noncore ITCS, we will be requiring the noncore to take on what we expect to be a diminishing stranded cost liability as the value of brokered capacity rises.

46. By requiring the noncore to take over the remaining years of core contribution to noncore ITCS, we will be requiring the noncore to take on at most $7.4 million per year.

47. The heavy usage of interstate capacity seen recently would decrease stranded costs and noncore responsibility for those costs.

<u>Other Reforms</u>

48. Other reforms to the gas industry market structure, not included in the IS, are supported by the evidence in this record, are consistent with the law and are in the public interest at this time.

49. Public Utilities Code § 328 no longer requires a report to the Legislature before we act on gas industry restructuring that affects core customers.

50. The current core subscription option, whereby noncore customers have the advantage of core procurement services through the utilities without

participating in the entire core rate structure, is unfair to core customers and restricts the market for noncore gas commodity procurement.

51. These customers will have the option to choose to become part of the core class or use an ESP or CTA for procurement purposes.

52. Keeping the revenues from the noncore customers who have become core customers in the NFCA until throughput amounts are adjusted in the next BCAP is unfair to the core.

53. The amount of throughput involved is anticipated to be small.

54. The core aggregation program on the SoCalGas system represents about 4.3% of total core volume. The core aggregation program on the SDG&E system represents about 3.8% of total core volume. Even with unbundled intrastate transmission, core aggregation programs in the PG&E territory have not reached 10% of total core volume.

55. The Gas Accord set the threshold for core aggregation programs in northern California at 120,000 therms per year.

56. Consumer protections like that proffered to the Legislature in 1999 is still needed.

57. Gas procurement entities and their customers have a legitimate need for information from the utilities. Given the small percentage of customers using non-utility gas procurement entities, it is reasonable to require SoCalGas and SDG&E to work with customers and/or ESPs to provide customer-specific information like consumption data in consistent formats across different contexts, consistent with consumer protection and privacy considerations.

58. It is also reasonable to require customers and/or ESPs to pay the reasonable costs of any requests for such information until such time as the percentage rises to 8% of total core volume. An application or BCAP proposal for a rate increase to fund, in conjunction with ESPs, necessary computer

hardware, software, training and education efforts at that point will more closely match customer needs instead of being well in advance of such needs.

Implementation

59. The reforms herein need to be implemented.

60. The implementation of the IS as modified and the other reforms approved herein can take place quickly because most tariff revisions and new tariffs have been drafted and circulated already.

61. Implementation of the IS and the other reforms we approve today can be detailed in one or more compliance advice letters showing tariff revisions for both SoCalGas and SDG&E. The compliance filings need to include specifics regarding compliance monitoring, cost responsibility, and enforcement measures.

62. Advice Letter No. 2895 would create a GIRMA with subaccounts that are unnecessary, and definitions that are vague and overbroad.

63. SoCalGas needs to have a memorandum account to book implementation costs allowed under the IS, up to $3.5 million.

64. SDG&E may need to have a memorandum account to book implementation costs.

65. The reforms pertinent to the core aggregation programs and customer information exchange can be accomplished without large expenditures while participation in the core aggregation programs remains under 10% of total core volume.

66. The costs of the retail reforms will be low for the next few years and can be paid by the utilities until the next PBR or rate case.

67. As stated in Resolution G-3301, Finding No. 9, we will accept an application from SoCalGas for a permanent tariff for G-CBS to coincide with its

next BCAP application to allow for the comprehensive review of consolidated billing and the associated cost and labor implications.

Next Steps

68. The Legislature needs to be informed of our decisions regarding the settlements and other proposed reforms.

69. We need evidence of the effect of the changes wrought in the gas industry as a result of this decision, and the effect of the more profound changes approved in PG&E's territory. A Market Assessment Report filed with the Energy Division two years after the effective date of the tariff revisions ordered in this decision will elucidate the situation and point out what further evidence is needed to aid in the determination of necessary next steps. The parties in the best position to file such a report are the utilities in southern California in cooperation with PG&E.

70. Upon receipt of the Market Assessment Report, a new investigation may need to be initiated to determine whether further reforms are needed in the gas industry structure in southern California. If initiated, such an investigation will begin by requesting responses to the utilities' market assessment report and may be consolidated or otherwise linked to extant proceedings regarding the gas industry structure in northern California.

71. The reforms approved in this decision, both in the modified IS and otherwise, need to continue in place until changed by action of the Commission or its staff.

VII. Conclusions of Law

1. Southwest Gas filed its Reply brief late with good cause and without prejudicing other litigants.

2. The market structure of the gas industry should be reformed cautiously in light of recent energy and gas price rises.

3. The interests of the many stakeholders in the gas industry should be balanced by approving the IS and its appendices in part and disapproving them in part.

4. The IS should be approved, with modifications, because it is in the public interest, reasonable in light of the record as a whole and consistent with law.

5. With regard to the choice given to the Commission in the IS, Section VII.E, on how to deal with risk in storage unbundling, we should adhere to the provisions of the Joint Recommendation approved in D.00-04-060, for 50/50 ratepayer/shareholder risk-sharing.

6. We should not unbundle the storage held in excess of meeting core reliability requirements from core rates.

7. Sections III, X, XI, and XIII should be modified by deleting that portion of each section limiting the Commission's ability to approve the settlement in part. Those portions of each of these sections should be disapproved.

8. Section III of the IS should be modified to set forth criteria for expansion of Wheeler Ridge, but provide that upon the meeting of that criteria, SoCalGas shall submit an application, if appropriate under Public Utility Code Section 1005.5, for an expansion of the receipt point capacity. That application shall be processed regularly, with all issues subject to Commission decision.

9. The modification in Section III should be in the first sentence of the first full paragraph on page 8. The words "apply to" should be inserted after "SoCalGas will". The IS language in the middle on page 8 beginning with the words "This Settlement" through the end of the paragraph, and the concomitant language in Appendix A setting the cost at $12 million in 1999 dollars should be disapproved.

10. The exemplary tariffs attached to the IS should not be approved, although SoCalGas should file similar tariffs as part of the implementation of this decision.

11. In order to deter any question of the applicability of this decision if any of the parties to the IS no longer support the IS with the modifications we make, this decision should be viewed as a decision on the record made in R.98-01-011 and I.99-07-015 and officially noticed facts, as well as an approval of the settlement as modified.

12. The provisions in this decision and the IS regarding core aggregation programs do not substantially change the existing core aggregation program so as to exclude core aggregators from providing billing to their customers.

13. SoCalGas should withdraw Advice Letter No. 2837 and file instead a tariff embodying the IS provisions we are approving.

14. SoCalGas' Advice Letter No. 2895 and SDG&E's Advice No. 1185-G should be rejected. The protests of SCGC, CIG/CMA, TURN, Aglet and ORA should be granted.

15. Because Advice Letter No. 2895 is rejected, within 10 business days from the effective date of this decision, SoCalGas should file a new advice letter to implement a gas industry restructuring memorandum account with the restricted purpose of implementing the IS, including "developing and implementing new or enhanced computer systems" with a ceiling of $3.5 million. This advice letter should not include the provisions disapproved in Advice Letter No. 2895 at pp. 66 to 69 in this decision. The costs booked should be limited to those beginning on the effective date of this decision. The booked costs should be subject to review for their reasonableness, duplicativeness, and their incremental nature in the next BCAP.

16. As of the effective date of the tariffs arising out of this decision, the core should stop contributing to the noncore ITCS, and the noncore should pay all the noncore ITCS.

17. SoCalGas should not unbundle its core interstate transportation costs from core rates at this time.

18. SoCalGas should not change the brokerage fee of $.0201/Dth.

19. SoCalGas should file a rate adjustment advice letter regarding noncore ITCS and related matters within 30 calendar days from the effective date of this decision. The revised rates should become effective within 60 days of the effective date of this decision.

20. No core subscription contracts should be let after April 1, 2001, and contracts let between the effective date of this decision and April 1, 2001, should expire on July 31, 2001.

21. The revenues from those core subscription customers switching to core status should be recorded in the CFCA.

22. SoCalGas should post on its GasSelect system operating information as extensive as that required of PG&E and including post-OFO data by customer class sufficient to allow readers to understand why an OFO was called.

23. SoCalGas and SDG&E should work with customers and/or ESPs to provide customer-specific information like consumption data in consistent formats across different contexts, consistent with consumer protection and privacy considerations. Customers and/or ESPs should pay the reasonable costs of any requests for such information.

24. SoCalGas and SDG&E should be authorized to file applications for rate changes based on needed expenditures to cope with customer transfers to core aggregators when transfers exceed 8% of total core volume has switched from utility procurement to core aggregator procurement. An application or BCAP proposal for a rate increase to fund, in conjunction with ESPs, necessary computer hardware, software, training and education efforts at that point should closely match customer needs instead of being well in advance of such needs.

25. The Energy Division should first deal with any disputes concerning the content of a utility-provided insert. This process may lead to a recommendation for a resolution, with other offices of the Commission participating as parties.

26. The costs of the retail reforms should be paid by the utilities until the next PBR or rate case.

27. SoCalGas should withdraw Advice Letter No. 2895.

28. SoCalGas should file one or more compliance advice letters to implement this decision within 10 business days from the effective date of this decision unless another provision of our order allows longer for a specific matter. The new and revised tariffs should be effective unless rejected by the Energy Division within 30 days after their filing.

29. The compliance filing should specify compliance monitoring, cost responsibility, and enforcement measures.

30. Sempra, on behalf of SoCalGas and SDG&E, should file a Market Assessment Report with the Energy Division two years after the effective date of the tariff revisions ordered in this decision, elucidating the effect on the market of the reforms instituted herein, and, in cooperation with PG&E, the effect on the market in northern California of the reforms instituted through the earlier decisions in this docket at least through the end of 2002 and longer if desired.

31. Upon receipt of the Market Assessment Report, a new investigation may be initiated by the Commission to determine whether further reforms are needed in the gas industry structure in southern California. If initiated, such an investigation should begin by requesting responses to the utilities' market assessment report and may be consolidated or otherwise linked to extant proceedings regarding the gas industry structure in northern California.

32. The terms of the IS that are adopted, and the other reforms adopted herein should continue in place until changed by action of the Commission.

33. The proposed decision herein should be our draft report to the Legislature. The final decision should be our final report.

34. The Commission should establish natural gas consumer protections as outlined in our 1999 consumer protection report to the Legislature.

35. This proceeding should be closed.

36. This order should be effective today, so that the restructuring provisions found in the settlement and adopted by us with modifications may be implemented expeditiously.

O R D E R

IT IS ORDERED that:

1. The motion of Southwest Gas Corporation to allow the late filing of its Reply Brief is granted.

2. The Joint Motion for Approval of Interim Settlement Enhancing and Enabling Competitive Markets on the Southern California Gas Company (SoCalGas) System, filed December 27, 1999, is granted in part and denied in part.

3. We approve sections II, V, VIII, and IX and associated appendices of the Interim Settlement (IS), which is attached in full as Appendix I to this Opinion.

4. We do not approve sections III, X, XI, and XIII insofar as each section limits the Commission's ability to approve the settlement in part.

5. We approve that portion of Section III of the IS that sets forth criteria for expansion, but provide that upon the meeting of that criteria, SoCalGas shall submit an application, if appropriate, for an expansion of the receipt point capacity. That application shall be processed regularly, with all issues subject to Commission decision.

6. We approve the third paragraph of section IV of the IS, which requires SoCalGas to provide certain operating and OFO information.

7. We approve section VI.C of the IS, which allows for continued trading of monthly imbalances and for the trading of OFO imbalances.

8. Thus, we will modify the IS in the first sentence of the first full paragraph on page 8. The words "apply to" shall be inserted after "SoCalGas will." We specifically disapprove the IS language in the middle on page 8 beginning with the words "This Settlement" through the end of the paragraph, and the concomitant language in Appendix A setting the cost at $12 million in 1999 dollars.

9. We do not approve the exemplary tariffs filed along with the IS, although we expect similar tariffs to be filed as part of the implementation of this decision.

10. The provisions regarding core aggregation programs shall not be construed as substantially changing the existing core aggregation program so as to exclude core aggregators from providing billing to their customers.

11. SoCalGas shall withdraw Advice Letter No. 2837 and file instead a tariff embodying the IS provisions we are approving.

12. SoCalGas' Advice Letter No. 2895 and San Diego Gas & Electric Company's (SDG&E) Advice Letter No. 1185-G are rejected. The protests of Southern California Generation Coalition, California Industrial Group and California Manufacturers Association, The Utility Reform Network, Aglet Consumer Alliance, and the Office of Ratepayer Advocates are granted.

13. Because Advice Letter No. 2895 is rejected, within 10 business days from the effective date of this decision, SoCalGas shall file a new advice letter to implement a gas industry restructuring memorandum account with a ceiling of $3.5 million and the restricted purpose of implementing the IS including "developing and implementing new or enhanced computer systems." This

advice letter shall not include the provisions disapproved in Advice Letter No. 2895 in this decision. The costs booked shall be limited to those beginning on the effective date of this decision. The booked costs shall be subject to review for their reasonableness, their duplicativeness and their incremental nature in the next BCAP.

14. The costs of the retail reforms shall be paid by the utilities until the next PBR or rate case.

15. As of the effective date of the tariffs arising out of this decision, the core shall stop contributing to the noncore interstate transition cost surcharges (ITCS), and the noncore shall pay all the noncore ITCS.

16. SoCalGas shall not change the brokerage fee of $.0201/Dth.

17. SoCalGas shall file a rate adjustment advice letter regarding noncore ITCS and related matters within 30 calendar days from the effective date of this decision. The revised rates will become effective within 60 days of the effective date of this decision.

18. No core subscription contracts shall be let by either SoCalGas or SDG&E after April 1, 2001, and contracts let between the effective date of this decision and April 1, 2001, must expire on July 31, 2001.

19. The revenues from those core subscription customers switching to core status shall be recorded in the Core Fixed Cost Account.

20. SoCalGas shall post on its GasSelect system operating information as extensive as that required of Pacific Gas and Electric Company (PG&E) and including post- operational flow order (OFO) data by customer class sufficient to allow readers to understand why an OFO was called.

21. SoCalGas and SDG&E shall work with customers and/or energy service providers (ESPs) to provide customer-specific information like consumption data in consistent formats across different contexts, consistent with consumer

protection and privacy considerations. Customers and/or ESPs shall pay the reasonable costs of any requests for such information.

22. SoCalGas and SDG&E may file applications for rate changes based on needed expenditures to cope with customer transfers to core aggregators when 8% of total core volume has switched from utility procurement to core aggregator procurement. Such applications shall include provision for ESP or CTA contribution.

23. SoCalGas shall file compliance advice letters to implement this decision within 10 business days from the effective date of this decision except for those provisions of this decision for which we have explicitly ordered that more time can be taken. The new and revised tariffs shall be effective unless rejected by the Energy Division within 30 days after their filing.

24. The compliance filing shall specify compliance monitoring, cost responsibility, and enforcement measures.

25. Sempra, on behalf of SoCalGas and SDG&E, shall file a Market Assessment Report with the Energy Division two years after the effective date of the tariff revisions ordered in this decision, elucidating the effect on the market of the reforms instituted herein, and, in cooperation with PG&E, the effect on the market in northern California of the reforms instituted through the earlier decisions in this docket at least through the end of 2002 and longer if desired.

26. Upon receipt of the Market Assessment Report, a new investigation may be initiated to determine whether further reforms are needed in the gas industry structure in southern California. Such an investigation, if any, shall begin by requesting responses to the utilities' Market Assessment Report and may be consolidated or otherwise linked to extant proceedings regarding the gas industry structure in northern California.

27. The terms of the IS that are adopted, and the other reforms adopted herein shall continue in place until changed by action of the Commission or its staff.

28. This proceeding is closed.

This order is effective today.

Dated __________ , 2001, at San Francisco, California.

ATTACHMENT A

LIST OF APPEARANCES

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(END OF ATTACHMENT A)

APPENDIX I

INTERIM SETTLEMENT ENHANCING AND ENABLING COMPETITIVE MARKETS ON THE SOCALGAS SYSTEM

Note: See CPUC Formal Files for 'SoCalGas Pooling' pages.

APPENDIX II

COMPARISON OF COMPREHENSIVE, INTERIM, AND POST INTERIM SETTLEMENTS

Comparison of Comprehensive, Interim, and Post Interim Settlements in I.99-07-003

CPUC IDENTIFIED MOST PROMISING OPTIONS	INTERIM SETTLEMENT	POST INTERIM PROPOSAL	COMPREHENSIVE SETTLEMENT
Effective dates	Effective first day of second month after month of approval. Continues through 12/31/02.	Same effective date as Interim. Continues through August 31, 2006.	Implementation is phased from 90 days after approval through 10/1/01. Continues through August 2006
TRANSMISSION			
Create Firm, Tradable Intrastate Rights	No	No	Yes
Create Secondary Market for Intrastate Rights	N/A	N/A	Yes -- The secondary market will not be regulated with respect to price or term.
Place Utility at Risk for Unused Capacity Resources	Utility at risk for 25% of noncore transmission revenues through 12/31/02. No risk for core transmission capacity.	Same as Interim through 12/31/02. Issue open for consideration after 1/1/03.	Utility at risk for 100% of noncore backbone transmission capacity. Utility at risk for 25% of noncore local transmission capacity through 12/31/02, unresolved after 1/1/03. No risk for retail core transmission capacity.
Develop Clear Procedure for Allocating Capacity	Receipt point capacities established on basis of physical maximums. Allocation through receipt points based on upstream pipeline capacity rights system.	Same as Interim.	Receipt point capacities initially established based on physical maximums. Defined backbone rights are then established through an open season effective 10/1/01.
Make Hector Road Delivery Point	Yes	Yes	Yes

CPUC IDENTIFIED MOST PROMISING OPTIONS	INTERIM SETTLEMENT	POST INTERIM PROPOSAL	COMPREHENSIVE SETTLEMENT
STORAGE			
Create Firm, Tradable Storage Rights	Customers granted right to assign storage contracts. CTAs have option to reject portion of core's 35 Bcf and associated injection.	Same as Interim.	Customers given firm storage inventory, withdrawal, or injection rights.
Create Secondary Market for Storage Rights	Provides for assignment of storage contracts. Creates EBB to facilitate trading.	Same as Interim.	Customers can trade any portion of their storage injection, withdrawal and inventory rights in the secondary market. Expanded trading opportunities through third-party provider ALTRA.
Place Utility at Risk for Unused Storage Resources	Utility at risk for 50% of unbundled storage through 12/31/02.	Utility at risk for 50% of unbundled storage through 12/31/02. Utility 100% at risk after 1/1/03.	50/50 risk between shareholders/ratepayers through 3/31/02. 75/25 through 3/31/03. SoCalGas 100% at risk effective 4/1/03.
BALANCING			
Examine structural means for SoCalGas to provide balancing services without drawing on core assets	Maintains system-wide balancing.	Same as Interim.	Separate balancing of core and noncore.
Cost and Rate Separation for Balancing Services	Maintain bundled balancing service through 12/31/02.	Same as Interim through 12/31/02. Issue open for consideration after 1/1/03.	Customers may opt out of the default balancing service and elect to self balance while receiving a self-balancing credit.
Electronic Trading of Imbalances	Permit daily and winter imbalance trading.	Same as Interim.	Expanded imbalance trading flexibility and independent trading opportunities through third-party provider ALTRA.

CPUC IDENTIFIED MOST PROMISING OPTIONS	INTERIM SETTLEMENT	POST INTERIM PROPOSAL	COMPREHENSIVE SETTLEMENT
HUB SERVICES			
Separate Utility Hub Services from Procurement Function	Hub revenues in GCIM through 12/31/02.	Same as Interim through 12/31/02. Issue open for consideration after 1/1/03.	Core Hub revenues in GCIM through 12/31/02. Separates core Hub activity and creates gas operations HUB.
CORE PROCUREMENT			
Re-Examine Utility Role in Core Procurement Once a Specified Competitor Market Share has Been Established	No	No	Within 6 months of settlement approval, SoCalGas shall file an application to address competitive alternatives.
Eliminate Core Aggregation Transportation Thresholds After Adoption of Consumer Protection Measures	Does not address.	Does not address.	Reduces participation eligibility to 120,000 therms/year and eliminates 10% market cap.
Unbundle Utility Interstate Capacity Costs for Core Customers	No	Unbundles all interstate capacity for CTA customers. Stranded costs allocated 50/50 between core transport and core sales.	Unbundles all interstate capacity for CTA customers. Stranded costs allocated 50/50 between core/noncore (with cap) until 12/31/01; and within core class after 1/1/02.
Unbundle Utility Storage Costs for Core Customers	Unbundle 50% of core injection and inventory storage reservation for CTA customers.	Same as Interim.	Unbundle all storage costs (associated with non-reliability and reliability storage for CTA customers) subject to certain caps.
Eliminate Core Subscription Service	Does not address.	Does not address.	Yes
Separate Costs and Rates for Core Utility Services. Treat Utility Core Procurement Departments as Any Other Utility Customer	Core procurement subject to same rules and penalties as noncore for monthly, OFO and winter balancing, except winter flowing supply requirements continue to apply to core.	Same as Interim.	Core procurement subject to same rules and penalties as noncore.

CPUC IDENTIFIED MOST PROMISING OPTIONS	INTERIM SETTLEMENT	POST INTERIM PROPOSAL	COMPREHENSIVE SETTLEMENT
INFORMATION			
Provide Real-Time, Customer-Specific Information	No change to current system.	No change to current system.	Offers noncore customers real-time access; provides for daily customer data.
Provide Details of Completed Transactions	No change to current system.	No change to current system.	Adds information regarding open season contracts.
Establish Secondary Market Via a Utility Electronic Bulletin Board	Yes	Yes	Yes -- Also includes a third party auctioneer, ALTRA, for imbalance trading.
Provide pipeline operator demand forecasts by customer class	Yes	Yes	Yes
REVENUE CYCLE SERVICES			
Provide for Competitive Metering Technologies	Does not address.	Does not address.	Customer meter ownership and add-on pilot program through 12/31/02.
Provide Competitive Billing Options to Customers Similar to Those Offered in the Electric Industry	Does not address.	Does not address.	Yes
Other Relevant Issues (not identified as "Most Promising Options")			
Creation of Pools for Transmission	Creates receipt point pools.	Creates receipt point pools.	Creates both receipt point and city gate pools.
Provide for Wheeler Ridge Expansion	Yes -- Automatic trigger on expansion during Interim period.	Same as Interim.	Does not address.
Eliminate Core contribution to traditional ITCS	No	Yes -- Effective 1/1/02 Noncore will bear 75% of costs SoCalGas will bear 25% of the costs of traditional ITCS.	Yes -- Effective 1/1/2002, Noncore will bear full costs of traditional ITCS.

APPENDIX III

LIST OF ACRONYMS

SOCALGAS - Southern California Gas Company
SDG&E – San Diego Gas & Electric Company
IS – Interim Settlement Agreement
PI – Post-Interim Settlement Agreement
CS – Comprehensive Settlement Agreement
PG&E – Pacific Gas and Electric Company
OFO – Operational Flow Order
ITCS – Interstate Transition Cost Surcharges
ALJ – Administrative Law Judge
PGA – Purchased Gas Account
CAT – Core Aggregation Transportation
BCAP – Biennial Cost Allocation Proceeding
NSBA – Noncore Storage Balancing Account
ORA – Office of Ratepayer Advocates
ESP – Energy Service Provider
CTA – Core Transport Agent
GCIM – Gas Cost Incentive Mechanism
ECPT – Equal-Cents-Per-Therm
TURN – The Utility Reform Network
UDC – Utility Distribution Company
GIRMA –Gas Industry Restructuring Memorandum Account
IRMA – Industry Restructuring Memorandum Account
SCGC – Southern California Generation Coalition
MFV – Modified-Fixed Variable
LRMC – Long-Run Marginal Cost
PBR – Performance-Based Ratemaking
NFCA – Noncore Fixed Cost Account
CFCA – Core Fixed Cost Account
DASR – Direct Access Service Request

CERTIFICATE OF SERVICE

I certify that I have by mail this day served a true copy of the original attached Alternate Proposed Decision of Commissioner Wood on all parties of record in this proceeding or their attorneys of record.

Dated November 26, 2001, at San Francisco, California.

/s/ EVELYN P. GONZALES
Evelyn P. Gonzales

N O T I C E

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address to insure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.

* *

The Commission's policy is to schedule hearings (meetings, workshops, etc.) in locations that are accessible to people with disabilities. To verify that a particular location is accessible, call: Calendar Clerk (415) 703-1203.

If specialized accommodations for the disabled are needed, e.g., sign language interpreters, those making the arrangements must call the Public Advisor at (415) 703-2074, TTY 1-866-836-7825 or (415) 703-5282 at least three working days in advance of the event.