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Decision 06-12-031 December 14, 2006

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for Authority to Integrate Their Gas Transmission Rates, Establish Firm Access Rights, and Provide Off-System Gas Transportation Services.	Application 04-12-004 (Filed December 2, 2004)

(See Attachment A for the List of Appearances)

OPINION REGARDING THE PHASE II ISSUES

Table of Contents

Title **Page**

Table of Contents (cont.)

OPINION REGARDING THE PHASE II ISSUES

I. Summary

Today's decision addresses the Phase II issues concerning a system of firm access rights (FAR) for San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas). Other issues that we address are the SDG&E and SoCalGas proposals for an off-system delivery service to Pacific Gas and Electric Company (PG&E) and for a gas pooling service, and whether SoCalGas' peaking rate tariff should be retained.

This decision represents the end of a journey that began in 1998 when we first opened a proceeding to identify reforms to the gas industry in California. The decision also represents the beginning of a new journey as we adopt a FAR system for SDG&E and SoCalGas.

The FAR system will enable any market participant (e.g., end-user, gas supplier, gas marketer) in southern California to hold FAR on the various receipt points on the SDG&E and SoCalGas integrated gas transmission system. This system will ensure that the holders of the FAR will be able to access the receipt points on the transmission system and have their gas transported to the designated delivery points. This is in contrast to the current system where upstream gas shippers and end-use customers have no guarantee that their gas will flow through the receipt points. This problem is exacerbated under the current system when there are capacity constraints on the SoCalGas transmission system.

The FAR system that we adopt is based on SDG&E and SoCalGas' FAR proposal, together with the unbundling of the five cents per decatherm (Dth) per day FAR reservation charge from the end-user's volumetric transmission rate. We also incorporate elements of the Joint Proposal into the FAR system, as well as certain modifications to the FAR proposal that parties had requested. The adopted FAR system represents a balanced approach where the competing interests of all the market participants and the utilities have been considered. With the FAR system, we can expect gas markets to develop at the citygate, as well as at the border. The FAR system will provide gas shippers, marketers, and end-users with new options and opportunities.

Today's decision also approves the off-system delivery service to PG&E, and the gas pooling service. The off-system service will allow gas supplies to flow from SoCalGas' transmission system onto PG&E's transmission system. This off-system service will open up new markets in northern California to potential gas suppliers based in southern California. The gas pooling service will improve and facilitate gas trading and exchanges on the SDG&E and SoCalGas system.

The decision also retains SoCalGas' peaking rate tariff, but does not adopt the proposal to include the multi-unit electric generation (EG) provision as part of the peaking rate tariff.

II. Background

The origin of this proceeding can be traced back to our efforts regarding the assessment of the market and regulatory framework of California's natural gas industry in Order Instituting Rulemaking (R.) 98-01-011.[1] In that rulemaking, we considered and identified appropriate reforms to the natural gas market

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[1] The rulemaking process involved the use of a staff report, comments on the report and to a list of questions, a full panel hearing, working groups, hearings, briefs, and oral argument. (See D.99-07-015, pages 5-9.)

structure in California with the objectives of fostering market competition and benefiting California natural gas consumers.[2]

As a result of the rulemaking process, the Commission issued D.99-07-015. This decision identified the most promising options for changes to the regulatory and market structure of California's natural gas industry.[3] The options revolve around a market structure that "preserves the utilities' traditional role of providing fully-integrated default service to core customers, while clearing obstacles to the competitive offering of gas commodity, transmission, storage, balancing and other services for all customers in the service territories of regulated local distribution companies throughout the state." (D.99-07-015, page 2.)

In D.99-07-015, we acknowledged that the Gas Accord structure, implemented in PG&E's service territory, could be enacted in SoCalGas' service territory. (D.99-07-015, page 3.)[4] We also stated that "We consider the creation of a statewide system of tradable intrastate transmission rights to be worthy of

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[2] As we noted in Decision (D.) 98-08-030, our use of the term "market structure" refers to the way in which "gas and related services are provided to customers." (81 CPUC2d 527, 530.)

[3] The most promising options identified in D.99-07-015 include the following: more vigorous consumer protection rules; removal of limits on participation in the core aggregation program; development of a secondary market to trade access rights to transmission and storage assets; and better flow of information.

[4] The Commission adopted PG&E's Gas Accord market structure and rates in D.97-08-055 (73 CPUC2d 754). The Gas Accord established the access rules to PG&E's backbone and local transmission system, and to PG&E's storage system. The Gas Accord structure was extended most recently in D.04-12-050, and remains in place through December 31, 2007.

closer examination in the next phase of this proceeding."[5] (D.99-07-015, pages 14, 141, COL 1.)

I.99-07-003 was issued concurrently with D.99-07-015. In this investigation, the Commission asked the parties to prepare a more detailed analysis of the costs and benefits associated with the more promising structural changes. The Commission also encouraged all stakeholders to develop and agree on "a comprehensive set of terms for restructuring the gas industry in a manner consistent with [D.99-07-015]." (I.99-07-003, page 3.)[6] This process resulted in three settlement proposals, which we addressed in D.01-12-018.[7]

In D.01-12-018, the Commission adopted the Comprehensive Gas OII Settlement Agreement (CSA), with certain modifications. The CSA was to modify the regulatory and market structure for regulating the transportation and storage of natural gas on the SoCalGas and SDG&E systems. With the adoption of the CSA, customers were to have access to firm tradable transmission rights on SoCalGas' backbone transmission system, and the costs associated with intrastate backbone transmission were to be unbundled from transportation rates. The CSA also placed SoCalGas at-risk for the recovery of its backbone transmission costs.[8] D.01-12-018 also provided that the utilities' retail core procurement

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[5] The "next phase of this proceeding" occurred in Order Instituting Investigation (I.) 99-07-003.

[6] The Commission addressed the "most promising options" for PG&E in D.00-02-050 and D.00-05-049.

[7] The three settlement proposals are known as the Interim Settlement Agreement, the Post-Interim Settlement Agreement, and the CSA.

[8] The CSA also addressed the following: creation of firm tradable storage rights and a secondary market to trade those rights; separate balancing for the core and noncore to

Footnote continued on next page

department would continue to reserve interstate capacity, intrastate backbone transmission capacity, and storage capacity to meet the requirements of retail core procurement customers. The CSA market structure would have allowed noncore customers to acquire intrastate backbone transmission capacity through an open season, or to purchase gas at the city gate. D.01-12-018 anticipated that the availability of firm tradable transmission rights would allow customers to place an increased reliance on long-term contracts.

In D.01-12-018, the Commission ordered SoCalGas to file advice letters (ALs) to implement the CSA. SoCalGas filed nine ALs to establish an implementation schedule, tariffs and rules. Eight of the nine ALs were protested. On February 27, 2003, the Commission issued Resolution G-3334, which consolidated and denied the ALs without prejudice. In the resolution, we ordered SoCalGas to file an application to implement D.01-12-018.

On June 30, 2003, SoCalGas filed Application (A.) 03-06-040. SoCalGas proposed two options in its application. Option 1 is the "compliance case," which proposed to implement the tariff provisions that are in compliance with the CSA adopted in D.01-12-018. Option 2 was described as the "preferred case," which contained recommended changes to D.01-12-018. Protests and responses were filed. On September 29, 2003, assigned Commissioner Brown issued a

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eliminate the potential for cross-subsidization; anonymous monthly imbalance trading; the trading of operational flow order imbalance rights; reducing restrictions for participation in the core aggregation transmission program; and eliminating core subscription service. (D.01-12-018, page 3.)

scoping memo that limited the scope of A.03-06-040 to the compliance case filing.[9] Following the evidentiary hearings, we issued D.04-04-015.

D.04-04-015 adopted tariffs to implement D.01-12-018. However, we recognized that the regulatory structure adopted in D.01-12-018, which we were implementing in D.04-04-015, might not be consistent with the direction being taken in R.04-01-025.[10] For that reason, we issued a stay of D.04-04-015 until a decision was reached in Phase I of R.04-01-025. In staying D.04-04-015, we stated, "Although we are staying implementation of this decision, we fully support a market structure that includes firm tradable rights." (D.04-04-015, page 70.)

In D.04-09-022, the Phase I decision in R.04-01-025, we continued the stay of D.04-04-015 until further notice.[11] We also ordered SDG&E and SoCalGas to file an application regarding their system integration and FAR proposals.

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[9] The scoping memo in A.03-06-040 ruled that the preferred case option sought to modify many of the elements of the approved CSA, and would have required a substantial re-examination of the policies and programs adopted in D.01-12-018. Since the focus of A.03-06-040 was to adopt implementing tariffs, the issues were limited to the proposed tariffs in SoCalGas' compliance case.

[10] The focus of R.04-01-025 was to establish policies and rules to ensure that reliable, long-term supplies of natural gas will flow to California. The rulemaking was opened due to concerns that there may not be sufficient natural gas supplies or infrastructure to meet the future gas needs of California.

[11] Among other things, D.04-09-022 addressed access to the intrastate gas pipelines by liquefied natural gas (LNG) suppliers, authorized SDG&E and SoCalGas to establish Otay Mesa as a joint receipt point, and adopted the presumption that LNG suppliers are to pay the infrastructure costs for their projects and that requests for rolled-in or alternative ratemaking treatment could occur by filing an application. (D.04-09-022, pages 3-4.)

(D.04-09-022, pages 67, 73, 93, OP 8.)[12] As a result of the continuing stay of D.04-04-015, the CSA and its system of firm transmission rights have not been implemented for SoCalGas and SDG&E.

SDG&E and SoCalGas filed their proposals for system integration and FAR in this proceeding on December 2, 2004. The system integration proposal was bifurcated from the FAR proposal and the off-system delivery issues. In D.06-04-033, we approved the system integration proposal.

Thereafter, a ruling was issued to set the procedural schedule for addressing the remaining issues in this proceeding. This proceeding was categorized as ratesetting and that hearings were necessary. Over 100 exhibits and 12 days of evidentiary hearings make up the record in this phase of the proceeding. This phase was submitted on September 27, 2006.

III. Issues Presented

This phase of the proceeding addresses three principal issues. These issues are as follows: (1) whether the Commission should adopt a system of FAR as the gas market structure for SDG&E and SoCalGas, or should it retain the current system of allocating capacity; (2) whether SoCalGas should be permitted to provide off-system transmission service to PG&E; and (3) whether this Commission should retain the SoCalGas peaking rate. Other issues are whether the Commission should authorize a citygate pooling service, when SDG&E and

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[12] SDG&E and SoCalGas proposed in R.04-01-025 that the Commission adopt their transmission system integration proposal and their FAR proposal. Due to the rate effects of the system integration proposal, and how the changes adopted in D.04-09-022 might impact the FAR proposal, we ordered SDG&E and SoCalGas to file these proposals in a new application.

SoCalGas should file their next Biennial Cost Allocation Proceeding (BCAP), and what impact today's decision has on D.01-12-018 and D.04-04-015.

Although this proceeding is addressing many of the issues addressed in the CSA and in I.99-07-003, this proceeding is not addressing gas balancing operations, diversion and curtailment procedures, and gas storage and hub transactions. (See May 24, 2005 Scoping Memo.)

IV. Firm Access Rights

A. Introduction

This phase of the proceeding addresses the latest proposal of SDG&E and SoCalGas to have a system of FAR apply to their transmission system. Some parties support the utilities' FAR proposal with modifications, while other parties oppose the FAR proposal and recommend that the current system remain in place or that competing proposals be adopted.

There are four main proposals to change the current gas market structure for SDG&E and SoCalGas. The first proposal is the utilities' FAR proposal. The second proposal is the unbundled FAR proposal sponsored by several other parties. The third proposal is the Joint Proposal sponsored by other parties, including most of the LNG project developers. The fourth is a proposal of the Division of Ratepayer Advocates (DRA) in the event the Commission decides to adopt a FAR system. Many of the parties who participated in the proceeding propose assorted modifications to the various proposals should one or more of the proposals be adopted by the Commission.

In the sections that follow, we describe the current capacity allocation system, each of the proposals and the criticisms and proposed modifications to each proposal, followed by our discussion of the FAR issues.

B. Current System

The integrated transmission system of SDG&E and SoCalGas has the capability to take 3,875 million cubic feet per day (MMcfd) of intrastate and interstate gas supplies from the receipt points on the system and to deliver those supplies to end-users or gas storage fields. This take-away capability is greater than SoCalGas' annual average load, which in 2005 was approximately 2,500 MMcfd. The total supplies on the interstate upstream pipelines that can theoretically reach SDG&E and SoCalGas on any given day are 5,675 MMcfd. If new gas supply sources come to fruition, the upstream delivery capability is expected to increase. Due to the difference between the delivery capability of the upstream gas supplies and the take-away capacity of the receipt points on the SDG&E and SoCalGas system, problems in the delivery of one's gas supply can result from what the parties refer to as a "mismatch" or "bottleneck."

Under the current system, the end-use customer is the only one who can transport gas over the SoCalGas and SDG&E systems. SoCalGas allocates receipt point capacity to the upstream interstate pipelines daily. It is then up to the upstream interstate pipelines to allocate that capacity among its shippers using the capacity allocation rules of the upstream interstate pipelines, which have been approved by the Federal Energy Regulatory Commission (FERC). In the event the shippers' volumes on the interstate pipeline exceed the physical take-away capacity of a specific receipt point, the upstream shippers' contractual rights govern whose gas will flow on that particular day. Such an allocation process can result in a situation where access to the SDG&E and SoCalGas systems are available only on an interruptible basis, and the shippers' gas supplies are pro-rated. In addition, constraints at a receipt point can reduce the amount of upstream supplies that can enter through a particular receipt point.

SDG&E and SoCalGas point out that many of their receipt points interact with other receipt points within certain transmission zones. As a result, whenever the combined supplies flowing through the multiple receipt points exceed the take-away capacity in a particular zone, SoCalGas has to allocate the total available transmission zone capacity to each of the upstream pipelines. Under the current system, this process results in the grandfathering of a preference for gas supplies from El Paso Natural Gas Company (El Paso) and Transwestern Pipeline Company (Transwestern) in the Northern transmission zone over other suppliers in that zone. For the Wheeler Ridge transmission zone, the allocation of receipt point capacity is based on the previous day's total flow at Wheeler Ridge. As a result, the Wheeler Ridge allocation process means that a shipper who is flowing gas on a constant daily basis may be cut on a subsequent day because of the actions of other shippers who reduced their flows during the prior period.

SDG&E and SoCalGas contend that the current allocation methods frustrate both suppliers and end-users, create confusion in the marketplace, and do not necessarily allow the lowest cost gas to reach the end-use markets.

C. SDG&E and SoCalGas FAR Proposal

1. Description of the FAR Proposal

SDG&E and SoCalGas are proposing a system of tradable FAR[13] which govern whose gas supplies get to flow into the five transmission zones which

[13] The FAR proposal is described in the testimony of the SDG&E and SoCalGas witnesses, and in the proposed Schedule No. G-RPA attached to Exhibit 15.

make up their integrated transmission system.[14] Using a three-step open season process, the FAR proposal would allocate access rights to the capacity at a particular receipt point to various market participants on a firm basis. All unutilized firm receipt point access capacity would be made available on an interruptible basis. SDG&E and SoCalGas contend that their FAR proposal will eliminate the unpredictable pro-rationing that occurs under the current system when the upstream pipelines allocate the available capacity on the SoCalGas system.

Under the FAR proposal, the holder of the FAR would be entitled to firm receipt point access at a particular receipt point. This allows the holder to ship its gas onto the SDG&E and SoCalGas transmission system at the specified receipt point for shipment to the specified delivery point. The following four delivery points are available under the FAR proposal: (1) to an end-user pursuant to an end-user's local transportation agreement; (2) to a citygate pool account; (3) to a storage account; or (4) to a contracted marketer or core aggregator transportation account. (Ex. 15, Schedule No. G-RPA, Delivery Points.) The FAR assures the holder that its designated gas will flow to the specified delivery point.

Under the FAR proposal, the FAR holder will have first priority in scheduling nominations to the receipt point. The FAR proposal also allows the holder of the FAR to exercise the FAR at another receipt point within the same

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[14] The five transmission zones are the Southern transmission zone, the Northern transmission zone, the Wheeler transmission zone, the Line 85 transmission zone, and the Coastal transmission zone. (See Exhibit 15, Schedule No. G-RPA; Exhibit 30.)

transmission zone on an "alternate firm basis."[15] In response to parties' concerns, SDG&E and SoCalGas are also willing to allow the FAR to be used for out-of-zone receipt points without an additional charge, which would be scheduled after alternate firm nominations within a zone.

SDG&E and SoCalGas propose that a reservation charge for the FAR be set at five cents per Dth per day. This reservation charge is payable each month regardless of the quantity of gas scheduled during the billing period. SDG&E and SoCalGas propose that the five cents per Dth reservation charge be credited back to their end-users, which has the effect of reducing the transmission rate for end-users. Under the FAR proposal, the transmission and distribution costs remain bundled and are included in the cost of the system integrated transmission rate.

For interruptible receipt point access service, SDG&E and SoCalGas propose that they be allowed to charge a volumetric rate of up to five cents per Dth. SDG&E and SoCalGas propose that a 90/10 ratepayer/shareholder incentive sharing mechanism, with a $5 million per year cap on the shareholder portion, be established for interruptible revenues. They contend this will provide an incentive to ensure that the maximum amount of interruptible capacity is offered, and to ensure that firm capacity cannot be profitably withheld from the secondary market.

In addition to the reservation charge, SDG&E and SoCalGas propose an in-kind fuel charge of 0.28% on the gross scheduled quantities of gas specified in

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[15] This process is described in Special Condition 10 of the proposed G-RPA tariff in Exhibit 15.

the customer's Receipt Point Access Contract. The fuel charge reflects the cost of the compressor fuel used to move the gas from the receipt point to the citygate.

The utilities' FAR proposal calls for a three-step open season process for the initial allocation of FAR at the existing and new receipt points. The open season process would take place every three years. The testimony contained in Exhibit 15, and proposed Schedule No. G-RPA in Exhibit 15, describe the three-step open season process in more detail. We summarize the process in the paragraphs that follow.

In Step 1, the FAR proposal calls for a set-aside of FAR for retail and wholesale core customers, Core Transportation Aggregators (CTAs), holders of certain long-term contracts, and California gas producers. The Step 1 set-aside is for a period of three years.

The set-aside for retail core customers is on behalf of SoCalGas' core customers and SDG&E's core customers. They would receive a FAR set-aside in Step 1 to match their qualifying upstream pipeline contracts. SDG&E and SoCalGas' Gas Acquisition Departments would be charged the five cents per Dth per day reservation charge under the G-RPA1 rate schedule.

Other wholesale customers who serve core loads would have the option to elect to receive a set-aside based on their qualifying upstream interstate pipeline commitments. If the wholesale customer selects the set-aside option, the option would apply to all eligible core quantities. These wholesale customers would be charged the reservation charge under the G-RPA1 rate schedule. If the wholesale customer elects not to select this set-aside option, the customer would be responsible for deciding whether to bid for FAR in Steps 2 and 3.

For the wholesale customers' noncore customers, a wholesale customer may elect to have its noncore customers participate directly in Steps 2 and 3, or it can elect to participate in the open season process on behalf of its noncore customers' requirements.

The CTAs will have the option to receive a FAR set-aside based on their qualifying upstream interstate pipeline commitments. If a CTA elects to receive the set-aside, it must do so for all eligible quantities. CTAs would be charged the reservation charge under the G-RPA1 rate schedule. If the CTA elects not to receive the set-aside, or the set-aside is less than the CTA's historical demand, the CTA would be responsible for deciding whether to bid for FAR in Steps 2 and 3.

For a customer who has a Commission-approved long-term firm transportation contract for firm deliveries at a particular receipt point, which contract is in effect at the time the FAR system is implemented, that customer will have the option to receive a FAR set-aside at the specified receipt point. The quantity of the set-aside would be based on the daily quantities specified in the contract. According to SDG&E and SoCalGas, there are currently four contracts that meet these criteria for a total quantity of 80 MMcfd in the Wheeler Ridge transmission zone. Those customers electing the set-aside would be charged the reservation charge under the G-RPA1 rate schedule but would receive an equivalent credit on their monthly bill to account for the payment of the reservation charge. Any customer who chooses not to receive the set-aside may participate in Steps 2 and 3 like other noncore customers.

California gas producers whose facilities are connected directly to Line 85, the Coastal transmission zone, or another system where there is not an identified receipt point, would receive a set-aside option for a quantity up to their individual historical peak month production delivered into the SoCalGas system in the base period. These producers may elect all or a portion of the peak month deliveries as the set-aside quantity, and they would be charged the reservation charge under the G-RPA1 rate schedule. The California producer set-aside on Line 85 is estimated at 140 MMcfd, and 100 MMcfd on the Coastal transmission zone.

Step 2 provides for end-use customers[16] or their designated agents to bid in an open season for up to 75% of the capacity at each existing receipt point, minus any capacity that has been taken as a set-aside. There would be three rounds of bidding. The end-user's maximum bidding rights for such capacity would be based on a base load maximum plus a monthly peaking maximum over a base period. The base load maximum is based on the customer's average daily historical consumption during the base period.[17] Customers would be awarded as much of the capacity that they requested subject to the 75% limitation and the limit of the capacity in the zone. If the capacity bid exceeds the available capacity at a particular receipt point or transmission zone, all bids would be pro-rated. In awarding receipt point access capacity in Step 2, a preference would be given to annual base load bids over monthly bids. The contract period for Step 2 capacity is for three years. The reservation charge under the G-RPA1 rate schedule would apply.

Step 3 of the FAR proposal calls for an open season for the remaining existing receipt point capacity, expansions at existing receipt points, and new receipt capacity at new receipt points at Center Road, Salt Works, North Baja

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[16] As mentioned earlier, a wholesale customer may elect to have its noncore customers participate in Step 2.

[17] The calculation for how the maximum bidding rights are determined is described in Exhibit 15 at pages 13 to 14, and in Special Condition 34 of the proposed Schedule No. G-RPA. Under the Step 2 process, an end-user would be allowed to justify a higher bidding right than the end-user's recent historical usage.

Pipeline at Blythe, and Otay Mesa, or other new receipt points that become available prior to each open season cycle.[18] Step 3 would be open to all creditworthy market participants. Participants would be allowed in a single bidding round to submit annual base load receipt point access bids. As originally proposed, the contract term for Step 3 capacity is 15 years. At the end of the term, the holder would have a right of first refusal.

The contracts for existing capacity would incur the reservation charge under the G-RPA1 rate schedule. The contracts for new receipt point capacity would be charged the reservation charge under the G-RPA1 rate schedule, plus the specific reservation charge for the cost of the necessary incremental facilities under the G-RPA2 rate schedule.

Once a contract is executed for the new receipt point capacity, an upfront payment of the estimated costs will be required prior to the commencement of the construction of the required facility enhancements.[19] This payment will be charged to all 15-year contract holders on a pro-rata basis. In the event this new capacity is approved by the Commission for rolled-in ratemaking treatment, the contract holders would be permitted to relinquish the capacity before the end of the contract term and be relieved of the associated reservation charges.

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[18] SDG&E and SoCalGas executed Collectible Systems Upgrade Agreements with Sempra LNG and Coral Energy to construct facilities that will allow 400 MMcfd of supplies to be received at Otay Mesa on a displacement basis.

[19] The actual cost of the facility enhancement will be reflected in a revision to the G-RPA2 reservation charge. Once the construction of the facilities is completed and placed into service, an AL would be filed to update the costs and to establish the final reservation charge under the G-RPA2 rate schedule. After the AL is approved, the customers who executed the contract will be charged the approved reservation charge.

If there is sufficient customer interest in expanding the receipt point capacity or expanding the take-away capacity from a receipt point or transmission zone, SDG&E and SoCalGas would conduct an open season using the Step 3 process.

After the three-step open season process is completed and SoCalGas posts the available receipt point access capacity on its electronic bulletin board (EBB), the holders of the FAR would be allowed during a two week period to "re-contract" any part of their FAR capacity from their designated receipt point to a different receipt point in the same transmission zone or in a different transmission zone, so long as capacity is available at the requested receipt point. At the end of the two-week period, SoCalGas will evaluate all requests for changes and grant the requests where receipt point capacity is available. If more capacity at a particular receipt point or transmission zone is requested than is available, SoCalGas will pro-rate the requests among the requesting holders.

Following the re-contracting process, SDG&E and SoCalGas propose to post all remaining firm receipt point capacity on their EBB. Any creditworthy market participant may acquire available capacity on a first-come, first-served basis for a minimum term of one month and a maximum term up to three years at the G-RPAN rate. SoCalGas would also be allowed to post the availability of monthly receipt point capacity at a negotiated level below the G-RPA1 rate, and to hold an open season for that capacity. If the bids are in excess of the posted receipt point access capacity at a particular receipt point or within a particular transmission zone, the participant awards will be pro-rated so that the awarded receipt point access capacity does not exceed the available capacities.

Under the FAR proposal, all unutilized firm receipt point access capacity will be made available on an interruptible basis at the G-RPA1 rate, and will be scheduled in accordance with SoCalGas' Rule 30 for interruptible capacity. SoCalGas would also have the flexibility to post the daily interruptible volumetric charge at a level below the G-RPA1 rate for all interruptible receipt point service or just for a particular receipt point. If this is done, all interruptible service used by customers at the designated receipt point on that day will be charged the reduced volumetric charge.

The FAR proposal also calls for a secondary market, utilizing an electronic trading platform on the EBB, where a FAR holder can release and sell all or a portion of its FAR, and where a creditworthy party may purchase a FAR. The details of how this secondary market would operate are described in Exhibit 15 at pages 26 to 29, and in proposed Schedule No. G-RPA in Special Conditions 12 to 17.

Upon the implementation of the FAR system, SDG&E and SoCalGas propose to terminate any remaining Wheeler Ridge Access Agreements with Southern California Edison Company (SCE) or SDG&E and to eliminate the G-ITC rate schedule.[20] These access agreements require SoCalGas to make available a specific amount of daily access capacity through Wheeler Ridge, but do not provide any specific FAR to either SCE or SDG&E.

SDG&E and SoCalGas are not proposing an ownership limit on FAR capacity or that there be price caps in the secondary market. They believe these kinds of measures are unnecessary because of the trading opportunities in the secondary market and the availability of interruptible service.

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[20] SCE agrees that its contract for capacity at Wheeler Ridge should be terminated. SCE notes that this contract is to expire in the fourth quarter of 2006, and that it provided notice of the termination of the contract to SoCalGas.

To assist the Commission in addressing market power concerns, SDG&E and SoCalGas propose that quarterly reports be provided to the Commission. The reports would provide information about the intrastate capacity rights held by market participants, such as the name of the entity holding the FAR, the volume held, usage of the rights, and the terms of those rights. The same information, except for usage, would also be posted on the EBB and updated on a daily basis.[21] Should the Commission determine that the market is not functioning in a sufficiently competitive manner, the Commission would be free to impose price caps or ownership limits, or to order SDG&E and SoCalGas to release a portion of a participant's FAR should market concerns arise.

SDG&E and SoCalGas propose that the implementation of the FAR proposal and other proposed services occur over a 12-month period following a final Commission decision.[22] They point out that the overall implementation schedule depends on the enhancements to their information and computer systems. Time is also needed to provide information to and to educate their customers about the FAR system and new service offerings. The schedule also allows end-users to work with their marketers and agents to formulate their procurement options.

The cost to implement the FAR system and the other services described above are estimated at $3.5 million. SDG&E and SoCalGas propose that a memorandum account, the FAR Memorandum Account, be established to track the implementation costs.

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[21] Special Condition 16 of the proposed Schedule No. G-RPA provides that a detailed summary of the completed secondary market transactions be posted on the EBB.

[22] The proposed implementation schedule is set forth in Exhibit 15 at pages 32 and 33.

2. Criticisms and Proposed Modifications to the FAR Proposal

a) The FAR Proposal and Other Proposals

Various parties criticize or seek modifications to the FAR proposal of SDG&E and SoCalGas.[23]

DRA favors the retention of the current system because it believes the ratepayers of SDG&E and SoCalGas will be better off. DRA contends the FAR proposal is less flexible and would increase the risk of higher prices because of reduced gas-on-gas competition. DRA also contends the FAR proposal is too burdensome because of the three-step open season process. DRA further contends that the reservation charge has no cost basis, that it will increase the cost of gas, and that the credit back will not lead to a decrease in rates. If the Commission intends to adopt a system of FAR, DRA proposes that its firm rights allocation method be adopted. DRA's proposal is described in more detail below.

Clearwater Port LLC (Clearwater) contends that the FAR proposal is, in many respects, consistent with the principles of open and non-discriminatory access to the California gas markets. Clearwater, however, recommends that certain aspects of the FAR proposal be amended in order to ensure fair competition between all suppliers of natural gas. Clearwater proposes the following amendments: that all existing excess capacity be made available to all potential users on a non-discriminatory basis; that alternate FAR should be

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[23] We do not separately list the arguments or the positions of each party in this decision. Instead, we have considered all the arguments of the parties and have selectively chosen representative samples from various parties' positions to provide the reader with an overview of the various arguments.

usable at any alternative receipt point in any transmission zone; that the bidding on new expansion capacity take place in Step 3 only; and that penalties should be imposed on anyone who artificially nominates deliveries in an effort to limit secondary market access to system capacity.

Watson Cogeneration Company, the Indicated Producers, California Cogeneration Council, and the California Manufacturers and Technology Association (Watson/IP/CCC/CMTA) assert that the FAR proposal will move rates away from the cost of service because there is no unbundling of costs and because of the arbitrary five cents per Dth reservation charge. The FAR proposal also discriminates among shippers because they do not receive the credit back of the reservation charge. Watson/IP/CCC/CMTA point out that the FAR proposal has limited market benefits, and allows the utilities' shareholders to receive annual revenue incentives of up to $10 million.

In the opening and reply comments to the ALJ's proposed decision, several parties recommend that if the Commission adopts the FAR reservation charge of five cents per Dth, instead of the 15.75 cents per Dth charge, that the Commission should unbundle the five cents FAR charge from the end-user's volumetric transmission rate. By doing so, FAR holders will contribute towards the costs of the transmission system, and there will be no need for the utilities' credit-back mechanism, which would only credit end-users with the five cents FAR reservation charge.

Watson/IP/CCC/CMTA propose that the unbundled FAR proposal be adopted instead. Since the 15.75 cents per Dth reservation charge reflects the cost of the noncore backbone transmission service, no credit back mechanism is needed and the remaining transportation rate will be lower. The unbundled FAR proposal also places the utilities at risk for recovery of the noncore backbone transmission costs, which balances risk and the opportunity for reward. Watson/IP/CCC/CMTA contend that its proposal will facilitate the creation of a citygate market in southern California.

Coral Energy Resources, L.P. (Coral Energy) opposes the FAR proposal. Coral Energy contends that a system of FAR for existing receipt point capacity is not needed. Since the customers of both SDG&E and SoCalGas have paid for existing receipt point capacity, all customers should continue to have equal access to the existing receipt point capacity. Coral Energy contends that a system of FAR could limit an end-user's gas supply options as compared to the current receipt point allocation structure.

Coral Energy contends that the current system provides a rational basis for allocating existing receipt point access during periods of capacity constraints. The protocols in place for allocating and scheduling nominations at constrained receipt points have been effective, and do not require shippers to pay a reservation charge as they would under the FAR proposal. Coral Energy contends that any receipt point allocation structure should be limited to providing firm access to new or expanded receipt point capacity to those entities that bear the incremental costs, as provided for in the Joint Proposal.

BHP Billiton LNG International Inc. (BHP) is in favor of continuing the current system. BHP also favors the adoption of the Joint Proposal for new or expanded receipt point capacity.

Sempra LNG prefers that the Joint Proposal be adopted. If the FAR proposal and the Joint Proposal are both adopted, Sempra LNG proposes that the scheduling rights provisions and the incremental cost approach of the Joint Proposal be incorporated into the utilities' proposal. This could be accomplished by providing the parties that fund the facilities with a FAR set-aside in Step 1 that is equal to the quantity of the funded capacity.

Kern River Gas Transmission Company (Kern River) is concerned about the current system's regulatory preference in the Northern transmission zone for gas flowing from El Paso and Transwestern. Due to this preference, gas supplies from these two pipelines take precedence over other sources of gas seeking to enter SoCalGas' system from receipt points within the same transmission zone. This preference restricts the ability of SoCalGas' customers from taking lower priced gas supplies from Kern River and Questar Southern Trails Pipeline (Questar) through the Kramer Junction and Needles receipt points in the Northern transmission zone. According to SDG&E and SoCalGas, if the FAR proposal is adopted, this preference would be eliminated. Kern River contends that this preference should be eliminated regardless of whether the FAR proposal is adopted or not.

b) FAR Reservation Charge and In-Kind Fuel Charge

Some criticize the five cents per Dth per day reservation charge as an arbitrary charge that is either too much or too little, and that it should be eliminated or increased. Some parties criticize the proposed credit back of the reservation charge and contend that this credit mechanism should apply to all the holders of the FAR and not just to end-users.

Coral Energy and the Southern California Generation Coalition (SCGC) contend that the proposed reservation charge is an unlawful charge on interstate shippers that are not being provided with transportation on the SDG&E and SoCalGas system. To the extent that SDG&E and SoCalGas seek to impose an access charge on shippers that are not end-use customers on the system, the access charge is unlawful and must be rejected. They assert that the reservation charge is the same type of charge that the FERC determined in 77 FERC Par. 61,283 (December 19, 1996) was in violation of the Natural Gas Act.[24] In that FERC decision, the FERC found that the charge violated the Natural Gas Act because it was a charge to interstate shippers for the act of moving gas over an interstate pipeline and delivering it to SoCalGas rather than a charge for any service performed by SoCal after its receipt of the gas. SCGC contends that the credit back serves to collect the costs of intrastate facilities from interstate shippers who do not transport gas over those facilities. Coral Energy also asserts that the access charge unduly discriminates against upstream suppliers and marketers in violation of Pub. Util. Code § 453(a).

SDG&E and SoCalGas, SCE, and Watson/IP/CCC/CMTA contend that the reservation charge is not unlawful. They contend that the reservation charge in the FAR proposal is distinguishable from the type of charge that was found to be unlawful by the FERC.

Woodside Natural Gas Inc. (Woodside) is concerned that the five cents per Dth charge does not accurately reflect the costs of firm access to all areas of the SoCalGas system from the different receipt points. Woodside contends that the proposed interconnections on the west side of the SoCalGas system require fewer facilities to accept the gas and flow the gas to the load center. For that reason, Woodside contends that the Commission should adopt a system of zonal prices, instead of a postage stamp rate, that reflects the costs of creating firm access from particular receipt points and zones. Woodside contends zonal pricing would

[24] See D.94-01-048, pages 4-5; 76 FERC Par. 61,300 at page 62,495 (Sept. 19, 1996); 77 FERC Par. 61,283 (Dec. 19, 1996); 143 F.3d 610.

encourage the development of the most cost effective source of natural gas supplies for the California market.

Coral Energy contends that the payment of the FAR reservation charge has the effect of reducing flexibility because it discourages a customer or shipper from switching to a different receipt point to take advantage of lower priced gas supplies.

SES Terminal LLC (SES) contends that SDG&E and SoCalGas have not justified the FAR reservation charge, or adequately explained why end-users are the only ones who will receive a credit for the FAR reservation charge, while those who are not end-users, but pay for the charge, will not receive any credit. SES views this credit mechanism as another financial impediment from discouraging or preventing LNG suppliers from accessing the SDG&E and SoCalGas system. If the reservation charge is adopted, SES recommends that the credit also go to the holders of the FAR who are not end-use customers.

Watson/IP/CCC/CMTA and SCGC propose that the FAR revenues be credited back on the basis of average year throughput (equal cents per therm) instead of on a cold-year throughput basis. SCGC contends that the FAR charge has no relationship at all to cold-year throughput.

DRA opposes the 90/10 sharing mechanism for interruptible revenues. Since the FAR proposal does not put shareholders at-risk, DRA contends it is unreasonable for the utilities to share in any reward. In addition, DRA believes that the utilities should be expected to make all interruptible capacity available without the need for a financial incentive.

Several parties oppose the proposal of SDG&E and SoCalGas to collect an in-kind fuel charge from the holders of the FAR. The parties opposed to the charge contend that because transmission costs have not been unbundled and because SoCalGas is not at-risk, the fuel charge should not be unbundled either. Others contend the in-kind fuel charge would shift the cost responsibility from the end-use customer, who they contend should pay the costs associated with transmission-related fuel costs, to the holders of FAR and to the suppliers who are delivering gas to the SDG&E and SoCalGas system. BHP contends that if an in-kind fuel charge is adopted, that LNG shippers should receive a credit for the fuel charge.

c) The Open Season Process

(1) Transmission Zones

SES and BHP are concerned with the way in which the transmission zones were designed and how the receipt points were designated. They contend that this provides an advantage to the LNG supplies which enter through Otay Mesa. The other competing LNG supply projects would be in their own transmission zone with a single receipt point.

(2) Step 1

Various parties propose that they receive set-asides in the Step 1 process. Occidental of Elk Hills, Inc. (OEHI) proposes that it be provided with a set-aside of 90 MMcfd for its natural gas production at the Gosford interconnection.[25] OEHI contends that a set-aside is justified because it is a California producer, and at SoCalGas' request, invested more than $13 million to construct an outlet for its

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[25] The Gosford interconnection is located east of Elk Hills and northwest of Wheeler Ridge. The interconnection is to a pipeline that is jointly owned by SoCalGas (Line 225) and PG&E (Line 7200) that runs from Kern River Station to Wheeler Ridge. The only gas that is capable of being delivered to the Gosford interconnection is the OEHI production.

production at the Gosford interconnection. Without a set-aside, OEHI would not be able to reliably deliver its production to the Gosford interconnection or to another outlet, which could result in a shut in of its oil and gas production.

The "Oxnard 3" propose that they receive a FAR set-aside at Wheeler Ridge using historical demand with adjustments to account for expected load growth as reasonably demonstrated by the customers.[26] Under the FAR proposal, Step 1 provides the Oxnard 3 with a set-aside using the Tier I contract quantities in the Oxnard 3 contracts. Watson/IP/CCC/CMTA[27] contend that the proposed set-aside is deficient in two ways. First, the set-aside is limited to Tier I volumes. The Oxnard 3 contracts, however, allow for firm Wheeler Ridge service for both Tier I and Tier II quantities. Second, the proposed reservation charge would require the Oxnard 3 to pay for Wheeler Ridge capacity even if the Oxnard 3 does not use the capacity. The Oxnard 3 contracts only require the Oxnard 3 to pay for the service that they actually use.

SDG&E and SoCalGas do not object to the set-aside being based on the higher of Tier I volumes or the most recent annual average usage. They are, however, concerned with the Oxnard 3's proposal to base the set-aside on "projected maximum daily demand." SDG&E and SoCalGas are also concerned about the Oxnard 3's proposal that they be charged for capacity on a volumetric basis.

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[26] The Oxnard 3 are three cogeneration customers who are members of the CCC. D.04-04-015 previously addressed the set-aside provision in the CSA as it relates to these three contracts. (See D.04-04-015, pages 27-29, 78, COL 33.)

[27] The CCC filed a separate brief in support of the Oxnard 3 set-aside.

PG&E proposes that the holders of PG&E's long-term GX-F contracts for off-system delivery into the SoCalGas system be provided with set-asides at the PG&E Kern River Station receipt point. There are six Commission-approved long-term G-XF contracts with a maximum daily delivery of 86 thousand Dth per day (MDthd) into the SoCalGas territory with Kern River Station as the specified delivery point. Kern River Station delivers into the Wheeler Ridge transmission zone. The largest of the six contracts is for 52 MDthd with SDG&E's core. That contract is already included in the core set-asides that SDG&E and SoCalGas are proposing. The five other contracts have not been allocated a capacity set-aside.

PG&E contends that the five G-XF contract holders should be granted a set-aside. These Commission-approved contracts are long-term contracts with original terms of 30 years and have remaining terms of 8 to 17 years. These five contracts have a maximum daily quantity of 34.5 MDthd, which is less than five percent of the Wheeler Ridge transmission zone capacity. Without a set-aside, PG&E contends it would be very difficult for these contract holders to obtain an exact match for their contracted capacity under the proposed open season.[28] Since the contract holders are not end-users, they would not be able to bid until Step 3, when there may be no capacity left.

Exxon Mobil Corporation (Exxon Mobil) contends that if a FAR system is adopted, it should receive a set-aside in Step 1 for its gas production from its Santa Ynez unit that delivers into the Coastal transmission zone. Exxon Mobil

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[28] PG&E supports the proposal of other customers, in particular OEHI and SCGC, for set-asides. PG&E contends that as the market transitions to a new market structure, all customers with long-term contracts on upstream pipelines will face the same problems in acquiring FAR on the SoCalGas system to match their upstream holdings.

contends that its gas production has the same attributes as other California gas production that qualifies for the set-aside.

SCGC proposes that noncore customers who hold long-term commitments to upstream pipeline capacity that deliver into the SDG&E and SoCalGas transmission system should be provided with set-asides. SCGC notes that although most noncore customers do not hold commitments to upstream pipeline capacity, electric generation customers do. SCE agrees with SCGC that electric generation customers should be able to receive set-asides to match their upstream pipeline contracts.

Watson/IP/CCC/CMTA oppose SCGC's proposal for a set-aside for noncore customers who hold interstate pipeline capacity. Watson/IP/CCC/CMTA contend that, in contrast to SoCalGas' long-term transportation contracts that provide contract holders with specific firm receipt point rights, SoCalGas never made a long-term agreement with these noncore customers that they would have firm service for their supplies from interstate pipelines. Watson/IP/CCC/CMTA point out that SCGC has not provided any details on how such a proposed set-aside should work and how the proposed set-aside will affect the remaining capacity to noncore customers.

Watson/IP/CCC/CMTA propose two modifications to the Step 1 process. The first modification is to split the process so that California producers with existing rights to deliver a maximum daily volume (MDV) be allowed to exercise their set-aside rights before those producers with interruptible access agreements. Watson/IP/CCC/CMTA contend that such a modification is warranted because the producers with MDV rights should not have their set-aside rights pro-rated with the set-aside rights of producers with interruptible access agreements, and that it will preserve the benefit of the bargain that the producers had negotiated.

The second modification proposed by Watson/IP/CCC/CMTA is to base the California producer set-aside on an individual producer's peak month production delivered into the SoCalGas system over the most recent three years, instead of the utilities' proposal to base the set-aside on the most recent year of production data. Watson/IP/CCC/CMTA contend that the proposal of SDG&E and SoCalGas may not accurately reflect future peak output. In addition, Watson/IP/CCC/CMTA propose that producers should be allowed to justify a set-aside greater than that indicated by the historical data "if the producer had historical peak-month production that was shut-in or restricted due to operating constraints, or if the producer can show the utility it has obtained permits and ordered equipment that will increase production above historical levels."

SCE is concerned about the length and the term of the core upstream contracts. SCE proposes that the core not receive set-aside rights for upstream contracts that expire during the three year cycle, or alternatively, that the core be precluded from re-contracting the same upstream space if the contract expires during the cycle.

SCE proposes that any capacity acquired as a set-aside for reliability purposes should not be allowed to be re-contracted for capacity at another point. This is to protect against a set-aside from being traded or sold for a marketing opportunity, instead of being used for its intended purpose. SCE would allow the release of the set-aside capacity if the contracted capacity is no longer needed for its intended purpose.

(3) Step 2

Two members of the Indicated Producers, Aera Energy LLC (Aera) and Midway Sunset Cogeneration Company (MSCC) request that as long-term enhanced oil recovery (EOR) contract holders, that they be permitted to acquire FAR under the same terms and conditions as other customers in Step 2 of the open season, and to receive the reservation charge credit against their firm long-term contracts. Although SoCalGas considers these EOR contracts to be interruptible contracts pursuant to D.90-09-089, Aera and MSCC contend that the decision only determined the EOR contracts to be interruptible for the purpose of determining end-use curtailment priority. Aera and MSCC are concerned that if their EOR contracts are treated as interruptible contracts, they may lose their long standing level of receipt point access priority.

SDG&E and SoCalGas contend that these long-term EOR contracts are interruptible contracts under D.90-09-089 and D.04-04-015.[29] SDG&E and SoCalGas will permit the holders of these interruptible contracts, such as Aera and MSCC, to bid for FAR in Step 2 if they upgrade their service from interruptible to firm and pay the associated reservation charge.

(4) Step 2 - Maximum Bidding Rights

Several parties expressed concern about how the maximum bidding rights in Step 2 will be derived.

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[29] D.04-04-015 determined that SoCalGas' proposal to allow customers with interruptible long-term contracts to purchase interruptible backbone capacity to match their needs was reasonable and consistent with the CSA. Aera, MSCC, and Chevron USA Inc. filed an application for rehearing of D.04-04-015 but due to the pendency of this phase of the proceeding, the Commission has not acted on the rehearing application.

Southwest Gas Corporation (SWG) is concerned that it would only be provided with a base load maximum bidding right based on an historical annual average usage during the base period. SWG contends that if its bidding rights are based on historical annual average usage, it will not have enough bidding rights to secure all of the FAR it needs to serve its core customers during extreme cold weather conditions. In addition, SWG is concerned that if its core demands continue to grow, that this growth will not be adequately reflected in the bidding rights methodology.

SWG recommends that in Step 2, local distribution companies such as SWG, be allocated the bidding rights it needs to serve their core extreme weather demands during the three-year term. SWG also recommends that any remaining existing receipt point capacity in Step 3 have a maximum term of three years instead of the proposed 15 years.

For Step 2, SCGC proposes that the customer's bidding rights be set at the customer's highest usage in each month over the past three years. SCGC contends that such a modification is needed because the load of an electric generation customer can vary from year to year due to weather. The use of this method will provide an electric generation customer with a better opportunity to meet its potential load.

Watson/IP/CCC/CMTA do not believe that SCGC's proposal to use the highest usage in each month reflects typical operations. Instead of adopting SCGC's proposal, Watson/IP/CCC/CMTA propose that the customer be allowed to choose that its annual bidding right be determined on the basis of the annual average of three years of recent historical consumption data, or the existing contract quantity.

SCE proposes that the calculation of the maximum bidding rights in Step 2 be modified to account for the tolling agreements. The tolling agreements require SCE, SDG&E and PG&E to deliver the gas needed to generate electricity to those electric generators who have contracted with the Department of Water Resources (DWR) or with the utility. Due to the way in which the tolling agreements were written, it is unclear whether they would be included as part of the historical usage that the maximum bidding rights are based upon. In addition, under the tolling agreements, the plant owner of the electric generator is considered the end-use customer under the existing gas transportation tariffs, even though it has no role in the purchase or transport of this gas. Under Step 2 of the open season, the end-use customer is considered the plant owner. Since the end-use customer's bidding rights in Step 2 are based on the customer's historical annual throughput, the tolling agreements are not recognized.

In order for these tolling agreements to be considered in Step 2, SCE requests that the Commission direct SDG&E and SoCalGas to assign the Step 2 bidding rights to the electric utility (or applicable load serving entity) with the tolling obligation. SCE recommends that the Commission require that when an end-use customer (i.e., the plant owner of an electric generation facility) has contracted with a third party (i.e., DWR or one of the electric utilities) to supply natural gas for electric generation under the terms of a tolling agreement, that the Step 2 bidding rights be provided to the third party that supplies the natural gas for the electric generation.

SCGC is concerned that the preference in the bidding process for annual base loaded bids over monthly bids is inappropriate because it will result in economic harm to low load factor electric generators. DRA is concerned that the impact of this preference has not been fully examined on these low load factor customers.

Watson/IP/CCC/CMTA contend that the preference for annual bids over seasonal bids is reasonable because the annual bids provide greater economic value to the utilities and maximize the use of system capacity. They contend that if a seasonal bid is given the same priority as an annual bid, that this could force the utilities to pro-rate the annual bids during certain months when the receipt point is full.

(5) Step 2 - Treatment of New Capacity

In the Step 2 process, end-use customers have priority access to existing receipt points. Watson/IP/CCC/CMTA point out that the new receipt points at Otay Mesa and with the North Baja Pipeline at Blythe are not included in the receipt points that are available to end-use customers. Watson/IP/CCC/CMTA contend that both of these new receipt points should be made available to end-use customers in Step 2. Including these two receipt points in the Step 2 process will make 400 MMcfd and 600 MMcfd available at Otay Mesa and North Baja at Blythe, respectively.

Coral Energy opposes the proposal of Watson/IP/CCC/CMTA to have new capacity bid on in Step 2 by end-users only. If this new capacity is on a rolled-in basis, Coral Energy asserts that all market participants should have equal access to the new capacity, including the party who paid to build that capacity. Under the proposal of Watson/IP/CCC/CMTA, the core and noncore customers, by bidding in Step 2 for the new capacity, could limit the amount of capacity Coral Energy could obtain in Step 3.

(6) Step 2 - 75% Limitation on Available Capacity

SCE and SCGC propose that the 75% receipt point capacity limit in Step 2 be eliminated, and that 100% of receipt point capacity be made available in Step 2. SCE points out that the application of the 75% limitation may result in a situation that reduces access to the most popular receipt points in a zone, and gas would have to be obtained at less economic receipt points which raises the price of gas.

Coral Energy, PG&E and Sempra LNG also favor the elimination of the 75% limitation. Sempra LNG proposes that the capacity limitations be based upon historical utilization by month at each individual receipt point, using a five year average (2001 through 2005). Sempra LNG contends that such a change will assure customers and shippers that the firm capacity awarded in Step 1 and Step 2 will reflect the historical patterns relevant to each receipt point, while reducing the uncertainty caused by the 75% limitation.

(7) Step 2 - Length of Contract Term

SCGC proposes that the contract terms for Steps 1 and 2 should be for a two-year term instead of three years. SCGC points out that trying to match a three-year FAR cycle with a two-year G-FT contract will create additional transaction costs. Coral Energy is also concerned about the length of the three year term.

Watson/IP/CCC/CMTA oppose SCGC's proposal for a two-year FAR contract term, and favor a three-year term instead. Watson/IP/CCC/CMTA suggest that the G-FT agreements be extended to three years to match the term of the FAR cycle.

(8) Step 3

In the event the Joint Proposal is not adopted, Sempra LNG recommends that the Step 3 bids by a party or parties that advanced the construction funds for new expansion or displacement capacity receive first priority for firm rights up to the amount of the new capacity. This proposal preserves the principle in the Joint Proposal that the parties who are willing to pay for the cost of new capacity should receive the benefits.

Coral Energy is concerned that the Step 3 process does not take into account that Coral Energy and Sempra LNG already paid for the incremental cost for 400 MMcfd of receipt point capacity at Otay Mesa. Coral Energy contends that those who paid for capacity should not have to compete in the open season bidding process for that capacity.

Clearwater points out that under the FAR proposal, new expansion capacity with rolled-in rate treatment would be made available in all three steps. However, new expansion capacity that has been paid on an incremental basis by a party would only be made available in Step 3. This proposal would allow end-users to receive a set-aside in Step 1 or to bid on the expanded capacity in Step 2 and Step 3. End-users and all other market participants can only bid for expansion capacity that has been paid for on an incremental basis in Step 3. Clearwater proposes that the bidding for all new expansion capacity take place in Step 3 only so that all expansion capacity can be made available to all end-users and other market participants at the same time.

BHP opposes Clearwater's proposal to hold the bidding for all expansion capacity in Step 3. BHP contends that the Clearwater proposal would result in a delay of the funding and commitment for the facilities needed for the expansion capacity until it is known who is awarded the FAR for that capacity.

Some of the parties suggest bifurcating the Step 3 process into two stages. The first stage would allow market participants to bid for existing capacity. The second stage would allow market participants to bid on expansion capacity. The parties contend that bifurcation of the bids for existing and expansion capacity avoids the problem in the FAR proposal of having those who want existing capacity ending up paying for a share of the expansion capacity.

Watson/IP/CCC/CMTA and Woodside are concerned with the Step 3 proposal that a shipper who wants to establish a new receipt point, or to expand an existing interconnection, will have to pay the FAR reservation charge plus the levelized incremental costs for the new receipt capacity. They contend it is unfair to require new suppliers to pay for both the costs of the existing transmission system (collected through the reservation charge) and for the incremental costs to expand the system. Watson/IP/CCC/CMTA recommend that shippers pay the higher of the Commission adopted FAR reservation charge or the 15-year levelized costs for the expansion capacity that is being added. Watson/IP/CCC/CMTA contend that this is more fair because a shipper that adds relatively low cost displacement capacity at a receipt point will pay at least the basic FAR reservation charge for the existing system, while a shipper that adds expensive expansion capacity will pay for the full costs of that capacity over 15 years.[30]

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[30] "Displacement" capacity refers to the construction of a receipt point that involves only the improvements necessary to allow the new supply to displace existing supplies so that the overall level of firm receipt point capacity remains unchanged. "Expansion" capacity refers to the construction of a receipt point that requires the improvements necessary to allow the new supply to increase the firm receipt point capacity of the entire system. (See Exhibit 40, page 7, fn. 6.)

Some parties contend that the Step 3 process favors Sempra LNG and Coral Energy because they would be allowed to bid for displacement capacity at Otay Mesa and the North Baja receipt points, while LNG projects located at Long Beach or Oxnard would have to pay for more expensive expansion capacity. Clearwater recommends that there be separate bidding in Step 3 for displacement capacity first, and then bidding for expansion capacity.

SES asserts that displacement capacity encourages gas-on-gas competition because the most competitively priced gas will enter the system through the receipt point serving that cheaper priced supply. As a result, for a new supplier to get its gas to the market, it must compete to displace the gas supplies at other receipt points. SES recommends that the construction of receipt point capacity should normally be done on a displacement basis, and that construction on an expansion basis should be the exception. The Commission should therefore adopt a standard that "if the requested establishment or increase in receipt point capacity can be accommodated on a displacement basis without interfering with SoCalGas/SDG&E's ability to provide adequate service to its *existing* load, then SoCalGas/SDG&E must construct the receipt point on a displacement basis, unless requested by the entity funding the expansion to do otherwise." (Exhibit 40, page 16.) SES contends that the burden must be placed on SoCalGas to justify why the receipt point cannot be built on a displacement basis, and that SDG&E and SoCalGas "should be directed to provide full and complete access for the requesting party to all work papers, models, flow diagrams, computer-based modeling and other information utilized in the determination of the necessary facilities and associated costs." (Exhibit 40, page 17.)[31]

Although the original position of SDG&E and SoCalGas was to require the other LNG suppliers to bid for expansion capacity, SDG&E and SoCalGas subsequently clarified their earlier position and agreed that all new suppliers should have the option to obtain displacement capacity in those situations where expansion capacity costs even slightly more than displacement capacity.

SCE opposes the change in position that SDG&E and SoCalGas have taken on displacement capacity. SCE opposes the change because displacement expansions diminish the firm and interruptible rights of existing customers and drives out lower priced gas. If the objective is to increase the number of gas supplies so as to reduce gas prices for customers, then an incremental expansion should be used instead of a displacement expansion.

Several parties expressed concern about the length of the 15-year commitment in Step 3. Kern River is concerned that the 15-year commitment in Step 3 for existing receipt point capacity may not be warranted for all situations. Sempra LNG asserts that a longer term may reduce the ability for FAR holders to respond rapidly to changing market conditions. Kern River proposes that there be a term of three years for existing capacity, and that a customer paying for expansion capacity should be able to negotiate the term of the amortization of the capital costs and the length of the commitment. Sempra LNG proposes that

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[31] SES notes that these concerns are reflected in the Joint Proposal, which SES is co-sponsoring. If the Joint Proposal is adopted by the Commission, the concerns of SES will be addressed. If the Joint Proposal is not adopted, SES believes its concerns should be reflected in the Commission's discussion about the construction of receipt point capacity.

bidders in Step 3 be allowed to acquire new capacity for a minimum term of three years, and that longer terms be available in three year increments, with a maximum term of 20 years.

SCE opposes including a right of first refusal, i.e., the right to extend, in the term of the contract. SCE believes that such a provision would diminish flexibility in the market.

(9) Secondary Market

Kern River and SCE propose that price caps be imposed on the secondary market transactions. Kern River contends that there are constrained receipt points on the SoCalGas system, and without a price cap, the FAR on the secondary market could "extract an exorbitant price." (Exhibit 33, page 16.) Kern River also contends that many of the shippers on the interstate pipelines are California end-users with firm transportation contracts, and that the rates under these contracts do not change when the basin differential prices change. As a result, if there is no price cap, California end-users are likely to end up paying significantly more for FAR if no price caps are in place. Kern River also points out that the lack of price caps in the secondary market for capacity on the FERC regulated pipelines during the winter of 2000-2001 contributed to the problems experienced during the energy crisis. Kern River cautions that if the Commission waits until the market becomes dysfunctional, a large amount of damage can result before changes are made.

SCE believes that the Commission should be proactive and put a price cap in place until the market has had a chance to mature and the Commission has been able to evaluate market behavior. SCE recommends a price cap of about

125%, i.e., a maximum price of 6.25 cents per MMcfd.[32] SCE also suggests that the name of the acquiring shipper be added to the secondary market information that SDG&E and SoCalGas intend to provide.

Watson/IP/CCC/CMTA note that price caps have not been needed in the secondary market for PG&E's Gas Accord, which the unbundled FAR proposal is modeled after.

(10) Nominations and Scheduling

Kern River and SES expressed concern that limiting alternate nominations to within-the-zone locations reduces the flexibility for FAR holders, and favors the affiliate of SDG&E and SoCalGas in the Southern transmission zone.[33] In contrast, the FAR holders at either the Salt Works or Center Road receipt points will not have alternate firm rights in any other receipt point on the system if alternate nominations are limited to within-the-zone. Kern River and SES propose that out-of-zone nominations be allowed at no additional cost, and that such a nomination have a lower priority than any firm nomination or within-the-zone nomination, but before interruptible.

In their rebuttal testimony, Exhibit 16, SDG&E and SoCalGas support the change to allow alternate firm nominations out-of-zone at no additional cost, and that such a nomination be scheduled after the alternate firm nominations within-the-zone. Clearwater supports allowing alternate firm nominations to be made out-of-zone.

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[32] The 6.25 cents is based on an assumed FAR reservation charge of five cents per Dthd.

[33] Since the Southern transmission zone includes the Ehrenberg and Otay Mesa receipt points, alternate rights could be exercised by Sempra LNG within the zone without having to pay an additional fee.

In the event the Commission does not adopt the alternate firm rights out-of-zone proposal, SES recommends that FAR holders have priority access to interruptible receipt point capacity, up to the amount of their FAR, at no additional charge.

(11) Additional Wheeler Ridge Capacity

PG&E proposes that the level of firm capacity at the Wheeler Ridge transmission zone be increased. Although the stated firm capacity of the Wheeler Ridge transmission zone is 765 MDthd, the data from SoCalGas' EBB system shows that there is frequently a large amount of capacity above the stated level. PG&E contends that increasing the level of firm capacity will be beneficial because shippers prefer the certainty of firm access. Accordingly, PG&E recommends that SoCalGas create short-term secondary-only FAR at Wheeler Ridge above the 765 MDthd level. PG&E proposes that this short-term FAR be scheduled after the primary FAR. PG&E proposes that these rights be sold on a daily, weekly, or monthly basis.

PG&E notes that SDG&E and SoCalGas propose a workable solution in their rebuttal testimony where they propose to offer short-term FAR for capacity at Wheeler Ridge above 765 MDthd, where in the judgment of SDG&E and SoCalGas, additional capacity can reasonably be expected to be available on a firm basis for shorter periods such as one month. PG&E believes, however, that the better solution is to have these short-term FAR scheduled after the primary FAR, versus SoCalGas' proposal to have these short-term rights treated the same as annual FAR.

(12) Continental Forge Settlement and SCE Settlement[34]

SES contends that the provision in the Continental Forge settlement, which calls for Sempra LNG to sell and SDG&E and SoCalGas to purchase LNG supplies up to 500 MMcfd at the California border price minus two cents for 20 years, runs completely counter to the argument used by SDG&E and SoCalGas that a system of FAR will create greater gas-on-gas competition by allowing customers and shippers to choose their preferred suppliers.

Coral Energy is concerned that the provisions in the Continental Forge settlement and the SCE settlement that call for the sale of up to 500 MMcfd from Sempra LNG's Energia Costa Azul (ECA) facility to SDG&E and SoCalGas may result in preferential access to the capacity in the Southern transmission zone through set-asides at Otay Mesa and/or Blythe/Ehrenberg, and on the upstream pipelines that will transport the gas from the ECA facility.

Coral Energy is also concerned about the provision in the Continental Forge settlement which calls for the core procurement programs of SDG&E and SoCalGas to be combined. If the two are combined, Coral Energy contends that the combined core portfolios could enjoy enhanced market power in Step 1 and Step 2 of the open season process to the disadvantage of noncore customers and new gas suppliers seeking access at existing receipt points.

Watson/IP/CCC/CMTA contend that the competitive concerns that SES raised could be mitigated if all end-users, not just SDG&E and SoCalGas, are

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[34] The Continental Forge settlement and the SCE settlement are two separate settlements that SDG&E and SoCalGas have agreed to. SDG&E, SoCalGas, and SCE seek Commission approval of those two settlements in A.06-08-026. We will address those settlements in A.06-08-026 and do not do so here.

allowed to have access to the Sempra LNG volumes at the same price. Watson/IP/CCC/CMTA contend that no group of end-users should have a set-aside at Otay Mesa or North Baja that allows preferential access to the Sempra LNG volumes at the price specified in the Continental Forge settlement.

Coral Energy is also concerned about the provision in the SCE settlement that market participants be allowed to fund an expansion of a receipt point with limited delivery rights. Coral Energy contends that this provision could allow a customer to construct a lateral expansion to a receipt point to obtain firm access without expanding the receipt point's takeaway capacity and without having to participate in an open season.

The SCE settlement also references the minimum flow requirement. Coral Energy is concerned about how this requirement will work, and notes that the testimony in this proceeding did not address the minimum flow obligation.

(13) Future Review

SCE proposes that the Commission review the FAR system to determine how it is operating, and to determine if it should be continued or eliminated. SCE suggests that this review take place in an application to be filed by SDG&E and SoCalGas no later than 120 days from the end of the second FAR open season.

D. Unbundled FAR Proposal

1. Description of the Unbundled FAR Proposal

The unbundled FAR proposal refers to the proposal in Exhibit 43, the testimony of R. Thomas Beach, that Watson/IP/CCC/CMTA are sponsoring. The unbundled FAR proposal is modeled after elements of the FAR proposal and PG&E's Gas Accord market structure. Watson/IP/CCC/CMTA contends that the Gas Accord structure has worked well for PG&E. The unbundled FAR proposal allows the holder of the FAR to move its gas through the receipt point to the citygate.

There are two major differences between the FAR proposal and the unbundled FAR proposal: the unbundling of backbone transmission costs; and putting SDG&E and SoCalGas at-risk for the recovery of the backbone transmission costs.

The first difference is the unbundling of $157.3 million in annual backbone transmission costs that were allocated to noncore customers in the system integration decision, D.06-04-033. Under the unbundled FAR proposal, these transmission costs would be recovered through the 15.75 cents per Dth per day FAR reservation charge, instead of the five cents per Dth reservation charge under the utilities' FAR proposal. According to Beach, the 15.75 cents per Dth "provide a reasonable measure of the costs of backbone transmission on the SoCalGas/SDG&E system." (Exhibit 43, page 32.) In contrast to the utilities' FAR proposal, the 15.75 cents per Dth reservation charge would not be credited back to end-users under the unbundled FAR proposal because that rate recovers the unbundled backbone transmission costs. Since the 15.75 cents reservation charge is based on the transmission component of the rates adopted in D.06-04-033, Watson/IP/CCC/CMTA contend there is no need at this time for a cost study to unbundle rates.

Watson/IP/CCC/CMTA contend that the 15.75 cents reservation charge provides better market-based signals. The higher FAR reservation charge will create a more robust citygate market by allowing and encouraging greater competitive savings in the market. Watson/IP/CCC/CMTA also point out that the unbundled FAR proposal is fair to all customers because they are all charged the same 15.75 cents per Dth rate and no credit back is needed.[35]

The second major difference between the unbundled FAR proposal and the utilities' FAR proposal is that Watson/IP/CCC/CMTA would put SDG&E and SoCalGas 100% at-risk for the recovery of the unbundled noncore transmission costs. Watson/IP/CCC/CMTA assert that placing SDG&E and SoCalGas at-risk is consistent with the at-risk provisions in PG&E's Gas Accord structure. It will also provide SDG&E and SoCalGas with the incentive to expand their services to new markets, and will provide the utilities with an incentive to keep their rates competitive with competing suppliers.

Watson/IP/CCC/CMTA support balancing account protection for the core transmission costs. They contend that the balancing account protection for the core will ensure "the utilities do not have an incentive to increase core loads that conflicts with utility-administered energy efficiency programs for the core." (Exhibit 43, page 33.)

Since the FAR reservation charge does not depend on the amount of throughput, as opposed to the utilities' current all-volumetric rate structure, Watson/IP/CCC/CMTA contend that this change in rate design will mitigate the utilities' risk of under-recovering their noncore transmission costs.

Watson/IP/CCC/CMTA propose that the maximum rate for interruptible access be set at 120% of the firm reservation charge. Setting the interruptible

[35] Several parties, including the CMTA and the IP, stated in their opening comments to the proposed decision, that if the five cents FAR reservation charge is adopted, the Commission should unbundle the charge from the end-user's transmission rate and the credit back mechanism be eliminated.

charge at a 20% premium will give shippers a strong incentive to contract for firm service, which should further aid in mitigating the risk of under-recovering the noncore transmission costs.

2. Criticisms and Proposed Modifications

SDG&E and SoCalGas are opposed to the unbundled FAR proposal because of the at-risk provision and the unbundling of costs.

SDG&E and SoCalGas criticize the at-risk provision because it would create disincentives for encouraging energy efficiency and conservation efforts, and discourage them from constructing additional slack capacity on the backbone transmission system. Due to the at-risk provision, SDG&E and SoCalGas contend that this will provide them with the incentive to maximize their throughput, i.e., to ensure that as much gas as possible is transported through the backbone transmission system, in order to make sure that they can recover their noncore backbone transmission costs. SDG&E and SoCalGas contend that such an incentive is contrary to the energy efficiency and conservation goals.

The at-risk provision would also discourage SDG&E and SoCalGas from constructing additional slack capacity. This is because once the backbone transmission costs and the base load factor are determined, SDG&E and SoCalGas have the financial incentive to increase the actual load factor by increasing throughput, while ensuring that the backbone transmission costs do not increase.

SDG&E and SoCalGas point out that arriving at a base load factor for purposes of determining the at-risk rate structure is also a highly contentious issue.

SDG&E, SoCalGas, and The Utility Reform Network (TURN) are concerned about the unbundling aspect of the unbundled FAR proposal. The unbundling of backbone transmission costs from transportation rates could result in cost shifts to smaller customers. One possible result of unbundling transmission costs is that this could lead to a backbone-only rate that would allow a customer directly connecting to the backbone transmission system to avoid making a contribution to the fixed costs of the local transmission and distribution system. A backbone-only rate would result in a shift of the fixed costs of the local transmission and distribution costs onto the remaining customers that rely on these parts of the system, primarily the smaller noncore customers and core customers. SDG&E and SoCalGas recommend that if the Commission decides to adopt the unbundling of backbone transmission costs from transportation rates, the Commission should make clear that it does not intend to adopt a backbone-only rate.

SCGC also expressed concern that the unbundled FAR proposal would shift recovery of the backbone transmission costs from on system transportation customers of SDG&E and SoCalGas to the upstream entities that hold the FAR. Through the unbundling of transmission costs, SCGC believes that the industrial customers will purchase their gas supplies at the citygate, thereby avoiding having to pay the backbone transmission cost. The upstream entities and on-system customers, such as electric generators, who need to hold FAR, would end up paying all of the unbundled transmission costs. SCGC further contends that since this proceeding is not the BCAP, this proceeding should be neutral on how the costs should be allocated among customers and customer classes.

Several parties oppose the unbundled FAR proposal because of the 15.75 cents per Dthd charge that Watson/IP/CCC/CMTA recommend be adopted.

These parties contend that the 15.75 cents is excessive, that it will discourage parties from holding FAR, that the gas shippers will bear the costs of backbone transmission, and that the rate will create a significant barrier to the entry of new supplies.

SCGC is concerned that no cost studies were performed in conjunction with the unbundling aspect of the unbundled FAR proposal. SCGC contends that there is no support for deriving the cost of the backbone transmission and the cost of local transmission and distribution.

In the event the Commission decides to unbundle backbone transmission costs from the transportation rate, SDG&E and SoCalGas recommend that this be done without adopting the at-risk provision so that the adopted FAR system does not conflict with the energy efficiency and conservation goals. In addition, if rates are unbundled and the at-risk provision is not adopted, a separate "Backbone Balancing Account" would have to be established to track the undercollection or overcollection of the backbone transmission costs.

The parties who oppose the unbundled FAR proposal also contend that it has many of the same flaws as the FAR proposal. That is, the unbundled FAR proposal reduces customer flexibility, it may lead to increased gas costs, hoarding of capacity, market manipulation, and a reduction in the value of the interstate pipeline capacity that end-users hold. For the same reasons mentioned with respect to the FAR proposal, the 15.75 cents per Dth reservation charge in the unbundled FAR proposal would also be unlawful.

E. Division of Ratepayer Advocates' Proposal

1. Description of Proposal

The DRA supports the retention of the current market structure for SoCalGas and SDG&E. In the event the Commission wants to establish a system of FAR for SDG&E and SoCalGas, DRA recommends the Commission do so by directly allocating FAR to end-use customers based on the current allocation of intrastate gas transmission costs in the last BCAP, D.00-04-060. DRA proposes that the allocation process exclude the California gas production receipt points in order to simplify the allocation process. DRA estimates that SoCalGas' transmission costs are allocated 42% to the core and 58% to the noncore. Under DRA's proposal, the core would be allocated 1,455 MMcfd, and the noncore would be allocated 2,010 MMcfd.

DRA proposes that core customers be allowed to match their current interstate rights if the allocation based on the BCAP cost allocation would result in a mismatch at a given receipt point, in exchange for fewer rights at another receipt point. Under DRA's proposal, customers would be able to trade and assign their rights, and the term for the allocation of the FAR could range from one to three years.

DRA contends that allocating FAR on the basis of cost responsibility is fair because the allocation is based on the customers' share of the transmission costs. Compared to the current system, DRA acknowledges its proposal is less flexible. However, as compared to the FAR proposal and the unbundled FAR proposal, DRA contends that its allocation proposal has the following advantages: it is simpler; it does not impose additional costs on customers and does not increase the cost of delivered gas; no additional costs are needed to prevent hoarding or market manipulation; the value of the FAR benefits those customers who are paying the costs; and it avoids the legal issues concerning the imposition of an access charge.

With respect to the $10 million in displacement expansion capacity that is to be built at Otay Mesa, DRA recommends that the 400 MMcfd of displacement capacity at Otay Mesa be rolled-in and allocated to ratepayers. DRA contends that this per unit cost of expansion for the first 400 MMcfd is much cheaper (2.5 cents per cubic feet per day) than the next 300 MMcfd of displacement capacity (78 cents per cubic feet per day).

2. Criticisms and Proposed Modifications

SDG&E and SoCalGas oppose DRA's capacity allocation proposal. They contend that DRA's proposal does not permit customers to choose the receipt points they desire, and does not provide them with the flexibility to match their capacity with their upstream contract rights. SCE notes that under DRA's proposal, all customers would receive some capacity at every receipt point. SDG&E and SoCalGas, as well as SCE, state that DRA's proposal is likely to require significant secondary market transactions after the allocation process to match capacity with supply. SDG&E and SoCalGas also point out that DRA's proposed allocation method fails to provide non-end-use customers, such as suppliers and marketers, with an opportunity to acquire FAR so that they can deliver their supplies into the system. Also, DRA's allocation of 100% of the capacity does not provide for any displacement expansion capacity for LNG supplies.

TURN and Sempra LNG oppose DRA's proposal to roll-in the 400 MMcfd of displacement expansion capacity at Otay Mesa, while Clearwater supports DRA's roll-in proposal. TURN contends that the Otay Mesa displacement capacity should be paid for on an incremental basis. Sempra LNG contends that there should be a set-aside in Step 1 for whoever paid for the new receipt capacity.

F. Joint Proposal

1. Description of Joint Proposal

The Joint Proposal establishes a process for expanding receipt point capacity on the SDG&E and SoCalGas transmission system. A copy of the Joint Proposal is attached to Exhibit 85. The Joint Proposal is sponsored by the following parties: BHP, Coral Energy, SES, Sempra LNG, SCGC, TURN and Woodside.

The Joint Proposal focuses on four topics pertaining to new or expanded receipt point capacity. The first topic is that the parties that either construct and surrender or advance the incremental cost for new or expanded receipt point capacity would be granted a "scheduling right" in the amount of the receipt point capacity for 20 years. The second topic is the protocol for determining whether the new or expanded capacity is to be on a displacement or expansion capacity basis. The third topic provides for optional funding methods for creditworthy entities to construct and surrender or finance the construction of new or expanded receipt point capacity. The fourth topic of the Joint Proposal addresses specific protocols for granting scheduling rights for new or expanded receipt point capacity in the Southern transmission zone.

The Joint Proposal states that it is a stand-alone proposal that is to operate independently of whether a system of FAR is adopted or not. The Joint Proposal further provides that if a system of FAR is adopted together with the Joint Proposal, the scheduling rights in the Joint Proposal shall not be diminished by the FAR system.

The scheduling right is defined in the Joint Proposal as follows:

> If a Funding Party either constructs and surrenders, or advances the incremental costs of facilities that add Displacement Capacity or Expansion Capacity on the

> SoCalGas/SDG&E system, the Funding Party shall acquire a 'Scheduling Right.' A Scheduling Right is the right to schedule the use of Displacement Capacity or Expansion Capacity on a firm basis from a receipt point on the SoCalGas/SDG&E system. The nature of the Scheduling Right that is acquired by a Funding Party depends upon whether the takeaway capacity that is established or increased at a particular receipt point is Displacement Capacity or Expansion Capacity. The Scheduling Right shall be transferable. (Exhibit 85, Exhibit A, pages 3-4.)

The scheduling right that a funding party will receive depends on whether the increased receipt point capacity reflects expansion capacity or displacement capacity. If the capacity is done on an expansion capacity basis, "the Funding Party shall have the right each day to nominate and schedule a volume of gas for delivery into the SoCalGas/SDG&E transmission system at that receipt point on a firm basis in an amount up to at least the amount of the Expansion Capacity for which the Funding Party advanced the cost." (Exhibit 85, Exhibit A, page 6.) The scheduling right for an expansion capacity is not subject to reduction from nominations by shippers at other receipt points within the same transmission zone.

If the capacity is done on a displacement capacity basis, the Joint Proposal provides:

> The Funding Party shall have the right each day to nominate and schedule a volume of gas for delivery into the SoCalGas/SDG&E transmission system on a firm basis at that receipt point in an amount up to at least the amount of the Displacement Capacity for which the Funding Party constructed the facilities or advanced the cost, subject to reduction only to accommodate, on a nondiscriminatory basis (but subject to Paragraph 7 below), nominations at other receipt

> points in the same Transmission Zone and to accommodate force majeure, scheduled maintenance, or unscheduled maintenance situations as defined in SoCalGas Rules 1 and 23. (Exhibit 85, Exhibit A, pages 6-7.)

The scheduling right for displacement capacity is subject to reduction to accommodate nominations at other receipt points in the same transmission zone.

The term of the scheduling right is to be for the lesser of the term of the contract or 20 years. At the end of the term, the funding party may renew its scheduling right for the same or shorter term. The scheduling right would be transferable.

The second topic of the Joint Proposal addresses the protocol for determining whether the capacity should be built on an expansion capacity or displacement capacity basis. The protocol provides that upon an entity's request to establish or increase takeaway capacity from a receipt point, SDG&E or SoCalGas is to make a timely determination of the facilities, facility modifications, and associated costs that are required to add the takeaway capacity on both a displacement capacity and expansion capacity basis. The protocol also provides that the utility is to provide the requesting entity with access to all cost and engineering information used in the determination, subject to an agreed upon protective order if one is requested by the utility or the requesting entity. Based upon the facility and cost information and any physical system limitations reflected in that information, the Joint Proposal provides that the funding party "shall be permitted" to decide if the capacity should be funded on a displacement capacity or expansion capacity basis.

The third topic of the Joint Proposal describes three funding options for how a funding party may choose to pay for the facilities. The first option is for the party to construct the necessary facilities up to the interconnection with the utility's current facilities and to transfer ownership and operating responsibilities to SoCalGas or SDG&E, without further charges for the transferred facilities.[36] The second option is for the party to contribute the costs of the necessary facilities to the utility without refund or repayment and without ongoing charges for the facilities. The third option is for the party to advance the funds to the utility in accordance with an executed Collectible System Upgrade Agreement (CSUA), in which case the funding party is to receive a refund of the advanced funds when the gas first flows through the receipt point, subject to the party entering into a contract with the utility that obligates the funding party to pay "a monthly facilities charge that is equal to the utility's revenue requirement for the capitalized construction costs based on amortization of the construction costs over the term of the contract and the utility's authorized rate of return, including depreciation, taxes, and fees." (Exhibit 85, Exhibit A, page 5.)

The fourth topic of the Joint Proposal describes the scheduling rights for receipt point capacity additions in the Southern transmission zone that are done on a displacement capacity basis. The Joint Proposal provides that incremental cost allocation shall apply to the first 700 MMcfd of displacement capacity at the Otay Mesa receipt point, and that rolled-in cost allocation treatment will not be adopted for this amount of displacement capacity. The Joint Proposal further provides that any funding party that advanced the costs of establishing and/or increasing the Otay Mesa receipt point capacity to an amount of displacement capacity of at least 400 MMcfd is to receive a scheduling right at the Otay Mesa

[36] The sponsoring witnesses of the Joint Proposal clarified the first funding option in Volume 12 of the transcript at pages 1926-1927.

receipt point.[37] If a party funds additional displacement capacity at Otay Mesa above the 400 MMcfd, up to 700 MMcfd, that party will receive a scheduling right at the Otay Mesa receipt point, but will not diminish the scheduling right held by any funding party that previously obtained a scheduling right at the Otay Mesa receipt point.

Due to the addition of displacement capacity at the Otay Mesa receipt point, the Joint Proposal provides that the scheduling rights at Otay Mesa are subject to the following two scheduling provisions. First, if the cycle 1 scheduled flows into SoCalGas' Southern transmission zone exceeds the total zone capacity, SDG&E and SoCalGas will adjust the available takeaway capacity from each of the Southern transmission zone receipt points on a pro rata basis in subsequent nomination cycles, subject to honoring the scheduling rights at each receipt point, and subject to the second scheduling provision. The second scheduling provision provides that the pro rata reduction of nominations shall be adjusted, if necessary, so as not to affect the nominations of SoCalGas' Gas Acquisition Department at Blythe/Ehrenberg, up to the minimum flow requirement, for as long as the Gas Acquisition Department is responsible for meeting SoCalGas' Southern transmission zone minimum flow requirement.

2. Criticisms and Proposed Modifications

SDG&E and SoCalGas point out that the Joint Proposal does not modify the current system of allocating capacity, and does not modify the current scheduling procedures in the Northern transmission zone or the Wheeler Ridge

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[37] Coral Energy and Sempra LNG have each executed a CSUA with SDG&E and have advanced incremental costs totaling $10 million for displacement capacity of 400 MMcfd at Otay Mesa.

transmission zone.[38] The existing scheduling problems will still remain if the Joint Proposal is adopted by itself.

The Joint Proposal contains a provision that if the Southern transmission zone receives nominations in excess of the firm takeaway capacity, that the nominations will be reduced on a pro rata basis. SDG&E and SoCalGas contend that if this zone is flooded with new supplies from LNG from Baja California, and LNG supplies from the gulf coast, there could be significant pro rata reductions in the zone if the Joint Proposal is adopted.

SDG&E and SoCalGas also contend that if the Joint Proposal is adopted by itself, that the core may not be able to use all of its firm interstate pipeline capacity on the El Paso system because of pro rata reductions that can take place if scheduled nominations are greater than the total zone capacity. In addition, due to the timing of the cycling process and the ability to react and move gas elsewhere, together with possible pro rata reductions in the Southern transmission zone, will create uncertainty for parties as to whether their gas will flow.

SDG&E and SoCalGas also contend that the optional funding provision that states LNG developers may build the facilities for providing access to their supplies and then turn those facilities over to SDG&E and SoCalGas is not needed. If the Commission believes that such a provision is necessary, the utilities request the Commission state in this decision that the facility design and construction must meet utility standards, the utility must monitor the actual

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[38] As mentioned earlier, the current procedures can result in a preference for certain gas supplies in the Northern transmission zone, or restricting the delivery of gas in the Wheeler Ridge transmission zone.

construction, and the LNG developer must pay the utility the gross-up for contributions in aid of construction to cover the taxes owed by the utility on such contributions. Also, the Commission needs to address how the ongoing O&M costs of these takeaway facilities will be collected.

SDG&E and SoCalGas also expressed security concerns about the Joint Proposal's requirement that they be required to provide access to the various information, data, and models used by the utilities to determine the facilities that are needed to accommodate new supplies. SDG&E and SoCalGas currently provide access to this information at their offices, and are concerned about others obtaining copies of these kinds of materials.

SDG&E and SoCalGas point out that the Joint Proposal provides that the Joint Proposal can be implemented together with a system of FAR so long as the Scheduling Rights contained in the Joint Proposal are maintained. If both are adopted, SDG&E and SoCalGas propose how the two can be reconciled. To accommodate the provision in the Joint Proposal that scheduling rights be granted to those who fund facility enhancements, a FAR set-aside in Step 1 could be created that is equal to the quantity of funded capacity. By providing the set-aside at a particular receipt point and a particular zone, the issue of how the scheduling rights would operate becomes moot.

SCE opposes the Joint Proposal because it is unnecessary and inferior to the FAR proposal. It is unnecessary because the open season of the FAR proposal already contains a process for the expansion of receipt point capacity that is superior to the Joint Proposal. The Joint Proposal is only intended to provide firm access for LNG providers, which does not create a level playing field. SCE contends that the certainty of firm access should be provided to everyone. SCE asserts that the FAR proposal is superior to the Joint Proposal because it is more inclusive, fairer, and more objective than the first-come, first-served approach.

SCE also contends that the FAR proposal places a limit on displacement expansions while the Joint Proposal does not. If unlimited displacement expansions are permitted, other gas supplies will be displaced that can result in higher gas prices. Incremental expansions, on the other hand, would increase the receipt point capacity and the takeaway capacity of the transmission zone. SCE believes that the Commission should review and assess the potential impact of any additional proposed displacement expansions before allowing them to proceed.

Under the Joint Proposal, the first party that either funds or constructs the new facilities would be given the scheduling right. The FAR proposal, on the other hand, would allocate new or expanded receipt point capacity in Step 3 of the open season. SCE contends that under the first-come, first-served approach, the developers that are further along in the application process would have an advantage over the other projects. Although this encourages early entry into the market, it discourages later developers because of the higher costs of subsequent expansions. SCE also contends that it is uncertain when scheduling rights actually vest, and what first-come, first-served means.

Clearwater opposes the adoption of the Joint Proposal. Clearwater contends that the Joint Proposal lacks the following details: how the scheduling rights will be allocated among the competing parties; what is needed for scheduling rights to vest; and how the scheduling rights can be transferred.

Watson/IP/CCC/CMTA oppose the adoption of the Joint Proposal. They contend that the Joint Proposal results in an unwarranted give-away to Coral Energy and Sempra LNG of the FAR at Otay Mesa for a price that is far below cost. Watson/IP/CCC/CMTA assert that their calculation shows that Coral Energy and Sempra LNG will pay less than one cent per Dth for this receipt point capacity over the next 20 years. This cost is far below the five cents per Dth FAR rate that SDG&E and SoCalGas proposed and the 15.75 cents per Dth rate that Watson/IP/CCC/CMTA proposed.

Watson/IP/CCC/CMTA contend that the cost is so low because ratepayers are already paying for the $100 million that it cost to construct the pipeline to flow gas from SDG&E into Baja California through Otay Mesa in the 1990s as part of the "Pipeline 2000" project. Watson/IP/CCC/CMTA contend that due to the Pipeline 2000 construction, the costs of which are already in rates, the LNG from Sempra LNG's ECA facility will be able to flow from south to north through the Otay Mesa receipt point into southern California. Watson/IP/CCC/CMTA contend it is unfair for Coral Energy and Sempra LNG to receive 400 MMcfd of receipt capacity at Otay Mesa when the ratepayers paid for the facilities that are needed to access this supply.

Due to the manner in which the Otay Mesa receipt point and associated pipelines were developed, Watson/IP/CCC/CMTA recommend that Otay Mesa should be treated as an existing receipt point by rolling in the costs of the 400 MMcfd of capacity. 300 MMcfd, which is 75% of the 400 MMcfd, should be available to end-use customers in Step 2, and the remaining 100 MMcfd should be made available in Step 3. The capacity from North Baja should also be made available in the same manner.

SDG&E and SoCalGas propose that if the costs of the Otay Mesa and North Baja receipt points are not rolled-in, that they be included in Step 3 since these receipt points are intended to deliver new supplies to the system, and because the Otay Mesa receipt point involves the construction of new facilities which, under D.04-09-022, is presumed to require incremental ratemaking treatment.

DRA supports having ratepayers fund the $10 million cost of reversing the flow at Otay Mesa, and that this low cost displacement capacity at Otay Mesa be allocated to the ratepayers. DRA believes that the $10 million cost is a cost effective investment that will provide value to all end-use customers. For that reason, DRA opposes Paragraphs 7.a and 7.b of the Joint Proposal. If these paragraphs of the Joint Proposal are adopted, that would secure firm rights to this 400 MMcfd capacity. DRA states that "Allowing developers to cherry-pick the most inexpensive displacement capacity expansion with incremental cost allocation ratemaking and providing these shippers significant firm rights is not in the end-users best interest." (Exhibit 51, page 2.)

DRA supports granting priority scheduling rights to LNG suppliers, shippers, developers and other interested parties who advance the funds on an incremental cost basis to undertake an expansion capacity of the system. For a displacement expansion, DRA proposes that the funding party be provided with firm access at the receipt point but in the event of a transmission zone constraint, such rights would be subject to reduction.

TURN does not take a position on the proposals for FAR, but if a FAR system is adopted, it should be tailored so as not to undermine the terms of the Joint Proposal. If a system of FAR and the Joint Proposal are both adopted, and a conflict arises between the two, TURN contends the Joint Proposal should control.

G. Discussion

1. Introduction

In this Discussion section we provide our reasoning and analysis for adopting a system of FAR as the new gas market structure for SDG&E and SoCalGas. We analyze and compare the current system to the competing proposals. We select the FAR proposal of the utilities as the model for the FAR system, and describe why certain elements of the unbundled FAR proposal and the Joint Proposal have been incorporated into the FAR system. The adopted FAR system also incorporates some of the modifications that the parties proposed to the FAR proposal.

The question that we need to ask ourselves at the outset is whether we should change the existing market structure for southern California now or whether we should we wait to see how the future develops. We have reached this juncture once before. In a span of nine years, we have essentially come full circle, starting with R.98-01-011, the Gas Accord structure as a promising option for SoCalGas, and the adoption and then stay of the CSA. SDG&E and SoCalGas then filed this application, where we are revisiting many of the same issues that we considered when we decided to adopt the CSA. As summarized in the preceding sections, the various parties continue to disagree on what kind of market structure is best for southern California.

We firmly believe that should we postpone a decision on whether a system of FAR should be adopted for SDG&E and SoCalGas, we are likely to be in the same position again in a couple of years trying to resolve the same problems and issues that we have been struggling with for the last nine years. The time is ripe to adopt a system of FAR for southern California.

We have already adopted a system of FAR for PG&E through the Gas Accord and related decisions. The Gas Accord structure has been in existence for PG&E since 1998. Although the parties are correct in noting the differences between PG&E's and SDG&E and SoCalGas' transmission systems, and the differences between the Gas Accord market structure and the proposals that are before us today, the basic underlying system of firm tradable transmission rights has worked and functioned well in northern California. As we stated in D.03-12-061 at page 32:

> The evidence shows that the Gas Accord structure has resulted in many gas procurement options and strategies for core and noncore customers, and for gas marketers. Market participants can arrange to purchase gas supplies at the gas basins, and have their supplies transported over interstate and intrastate pipelines to the citygate or to the end-user. Or they can choose to purchase supplies at the border, and have the supplies delivered over the intrastate system, or they can choose to purchase their gas supplies at the citygate. The unbundled, firm tradable capacity rights has created a secondary market which allows market participants to sell or trade their rights to maximize their gas procurement strategies.

In prior decisions, we specifically addressed how a system of firm tradable rights could be beneficial for SoCalGas and SDG&E. In suspending the implementation of the CSA, we stated in D.04-04-015 that "we fully support a market structure that includes firm tradable rights." (D.04-04-015, page 56.) In adopting the CSA, we recognized that the CSA "will provide significant benefits to all utility customers by allowing customers access to firm tradable transmission rights on SoCalGas' system." (D.01-12-018, page 2.) While formulating the most promising options for reforming the gas industry, we recognized that the Gas Accord's creation of tradable access rights to transmission, and the development of a secondary market for those rights, should be examined for SoCalGas' service territory. (D.99-07-015, pages 3, 14.) Based on our past review of the functioning of the Gas Accord structure for PG&E, we continue to believe that a system of FAR will be of benefit to the southern California market as well.

Our decision to adopt a system of FAR for SoCalGas and SDG&E does not hinge solely on the basis that the Gas Accord is functioning well for PG&E, or that we approved the CSA in a prior decision. Instead, as we discuss below, there are other reasons why a system of FAR should be adopted for SDG&E and SoCalGas.

2. Analysis of the Current System

The current system of customers' access to SDG&E and SoCalGas' transmission system can be improved. An analysis of the current system helps illustrate why.

As Watson/IP/CCC/CMTA point out, the circumstances giving rise to the adoption of the CSA are not that much different from what we are faced with today in the southern California market. In the most promising options decision, we were concerned about improving access to SoCalGas' transmission system by potential shippers. (See D.99-07-015, pages 10-14.) In this proceeding, the LNG project sponsors, as well as others, seek assurance that their gas can be delivered. The question that needs to be answered is how can we best provide market participants with this assurance.

No one disputes that under SoCalGas' current system of capacity allocation that all transmission is on an interruptible basis. The issue of whether or not an end-user on the SoCalGas system can transport its gas depends on the upstream shipper's rights, and on system constraints. If the nomination for gas at a popular receipt point exceeds the capacity of the receipt point, capacity constraints will result. Although capacity constraints have not been much of a problem during the past couple of years, that does not mean these constraint problems have gone away.

As all of the parties recognize, constraints at receipt points have been a problem in the past. Some of the parties contend that these constraints will decline over time because of possible changes in gas flows. Others suggest that there is no need for a system of FAR because most of the time, an upstream shipper seeking to deliver gas into the SDG&E and SoCalGas system is able to schedule the full amount that it nominates. However, with the possibility of LNG supplies flowing into southern California, and other changes in the gas market, receipt point constraints may occur again at other receipt points.

Some of the parties contend that the current system offers flexibility, and that this flexibility can be used at other receipt points should a constraint at a particular receipt point occur. However, as pointed out by several of the parties, the flexibility to move to another receipt point is not always available during times of high demand on the system. As a result, under the current system, end-users face uncertainty over whether their gas will flow through the constrained receipt point. Instead of SoCalGas' end-users determining whose gas flows, the upstream pipelines make the decision as to whose gas can flow through the constrained receipt points.

One solution for resolving these constraints at the various receipt points is to build sufficient takeaway capacity on the backbone transmission system. However, no one in this proceeding has proposed that. As several parties point out, the cost of expanding the takeaway capacity would be a very expensive and inefficient solution. The transmission system already has slack capacity, and expanding system capacity to meet infrequent peaks in demand is not a cost-effective solution.

Unless there is more takeaway capacity, capacity allocation is necessary because of the mismatch between the takeaway capacity and the deliverability of the upstream pipelines.

The uncertainty over whose gas will flow also affects the procurement decisions of end-users. Due to possible interruptions in the flow of gas, end-users may be reluctant to enter into longer term contracts, and gas suppliers may have to use higher priced gas if receipt point constraints occur.

We can continue to operate under the current system and wait to see if receipt point constraint problems surface again, or we can take proactive steps to provide market participants with assurances that they can access the SDG&E and SoCalGas transmission systems on a firm basis, and that market participants' nominated gas will flow on any given day. Due to the anticipated changes in gas flows, the likelihood that additional gas supplies will flow into California, and the constraint problems that have occurred in the past and which can reoccur again under the existing market structure, we believe that the current system should be replaced by a system of FAR.

As discussed below, the system of FAR we adopt is based on the utilities' FAR proposal, elements of the unbundled FAR proposal and the Joint Proposal, and certain modifications to the FAR proposal.

3. Analysis of the Different Proposals

a) Introduction

Since the current system does not offer assurance to end-users that their gas will flow during times of constraint, the FAR proposal, the unbundled FAR proposal, DRA's proposal, and the Joint Proposal should be reviewed as possible solutions to providing market participants with assurance that they can access the transmission system of SDG&E and SoCalGas on a firm basis. As Sempra LNG noted, the "manner in which access rights are granted to the SoCalGas/SDG&E systems will determine the attractiveness of the California market to upstream suppliers." (Exhibit 108, page 4.)

b) DRA's Proposal

We first examine DRA's alternative proposal. If a system of FAR is to be adopted, DRA proposes that the transmission capacity be allocated on the basis of how the transmission costs were allocated in the last BCAP. Under DRA's allocation method, core customers would first be allocated sufficient receipt point capacity to match their upstream commitments, with the difference allocated on a proportional basis at each receipt point. The remaining capacity would then be allocated to noncore customers on a pro rata basis in proportion to their individual average demand over the last three years.

DRA's proposed allocation method does not provide shippers and marketers with any firm capacity. Instead, shippers and marketers would either have to procure firm capacity on the secondary market, or have the end-use customer assign their capacity rights to them. Such a system is likely to result in a lot of trading in the secondary market so that shippers and marketers can obtain the firm capacity that they need to transport their gas. DRA's method is also likely to lead to confusion by those noncore end-use customers who receive allocations of firm capacity but are not familiar with what to do with that capacity.

Although DRA's allocation method is simple, we do not believe that DRA's proposal provides all the market participants with what they need or want. Due to the manner in which the firm capacity is allocated, the core and noncore are likely to end up with receipt point capacity that does not match their needs. Under DRA's proposal, market participants are going to spend a lot of time trying to match their needs. Therefore, DRA's proposal is not a practical solution for allocating capacity to market participants and should not be adopted.

c) Joint Proposal

The next proposal that we examine is the Joint Proposal.

The Joint Proposal is limited to creating scheduling rights for new or expanded receipt point capacity. It does not establish a system of FAR for the existing receipt points.

As mentioned earlier, we believe that a system of FAR should be adopted to remedy the problem of constrained receipt points. Although the Joint Proposal addresses how the new receipt point at Otay Mesa will interact when the scheduled flows into the Southern transmission zone exceed the capacity of that zone, it fails to address the allocation of capacity at other receipt points on the system.

The premise of the Joint Proposal is that a firm scheduling right to capacity is created for new or expanded receipt points that are built on a displacement capacity or expansion capacity basis, and paid for by a funding party. Inherent in the premise of the Joint Proposal is the recognition of the need for firm rights to capacity when the receipt point has been paid for by the funding party. This suggests to us that instead of limiting capacity rights to new or expanded receipt points, that all receipt points, which have been paid for in rates, should be allocated capacity rights. Instead of adopting a proposal that establishes firm scheduling rights for capacity for only new or expanded receipt points, we should look toward a system of FAR that allows equal access to all market participants at all receipt points.

The above analysis, however, does not preclude us from adopting the Joint Proposal in conjunction with a system of FAR, or adapting elements of the Joint Proposal into our system of FAR. The Joint Proposal specifically provides that it can be adopted on a standalone basis. If the Joint Proposal is adopted with a system of FAR, the Joint Proposal provides that the terms of the Joint Proposal would override the terms of the FAR system.

The Joint Proposal is supported by all but one of the LNG project sponsors, by a gas marketer (Coral Energy), a coalition of electric generators (SCGC), and by a consumer group representing core interests (TURN). A review of the Joint Proposal, and the positions of the supporters, reveals why they support the Joint Proposal. For the LNG project sponsors and Coral Energy, they are assured under the Joint Proposal that if they fund the cost to construct facilities to bring their gas supplies to the receipt points in southern California that they will receive a firm scheduling right to move their gas onto the gas transmission system. The main attraction of the Joint Proposal for SCGC and TURN is that gas supplies at Otay Mesa will be made available, and the cost of the facility, up to 700 MMcfd, will not be rolled into the rates of the customers they represent.

The Joint Proposal is attractive to us for two reasons. First, the creation of a firm scheduling right for new or expanded capacity will provide assurances to gas suppliers and marketers that if they pay for the facilities on an incremental cost basis, that they will be able to move all (expansion capacity) or a substantial portion (displacement capacity) of their gas onto the SDG&E and SoCalGas transmission system. In order to obtain this scheduling right, the funding party must be willing to pay for this new or expanded capacity on an incremental cost basis. By doing so, ratepayers receive assurance that they are not burdened with the cost of the new facilities. The funding of the new or expanded capacity on an incremental cost basis is consistent with our policy that "presumes LNG suppliers will pay the actual system infrastructure costs associated with their projects." (D.04-09-022, page 66.)

We recognize that this scheduling right may impact gas supply projects where two or more project sponsors seek to deliver the gas through the same receipt point. The project sponsor whose project is first in line would obtain a firm scheduling right to move its gas, which may discourage or make it more expensive for the second project sponsor to proceed with its project.[39]

We addressed a similar argument concerning how the costs of a receipt point expansion should be allocated in D.06-09-039. We stated that a "first-in-time cost allocation is a crude and, in some ways, unfair approach," but rejected the approach of soliciting interest in a capacity expansion and then allocating the costs equally among the interested parties. We stated that such an approach "could discourage investment," and that incremental expansion costs should be taken into account when siting facilities. (D.06-09-039, pages 76-80, 168-169, 174, FOF 38-39, 41, COL 14.) We are concerned that if a first-in-time approach is not used that investment may be discouraged because a project sponsor may have to delay its schedule on account of a project that is second in line. The delay may cause the first project sponsor to look elsewhere to make its investment. In addition, there is no guarantee as to which gas supply projects will eventually be

[39] Clearwater proposes that the Joint Proposal be rejected, that a FAR system be adopted, and that bidding for new or expanded capacity take place in Step 3 of the open season process.

built. If we allow the second project to catch up to the first, there is no assurance that either project will be built.

The second reason we are attracted to the Joint Proposal is that it addresses displacement capacity at the Otay Mesa receipt point. The sponsoring parties agree that up to 700 MMcfd of displacement capacity may be built, and that the funding parties will pay the incremental cost of the expansions. None of this displacement capacity will be rolled in. This provision of the Joint Proposal will permit gas supplies to enter through the Otay Mesa receipt point, and the costs of this displacement expansion will be borne by the funding parties.

There is one feature in the Joint Proposal that we do not care for. This provision allows the funding party to decide whether the additional capacity should be built as displacement capacity or expansion capacity. The Joint Proposal lets the funding party make this determination. SCE points out that expansion capacity should be preferred over displacement capacity because expansion capacity results in more gas supplies entering the marketplace. We agree with SCE that there may be situations where the utilities or the Commission should have input in deciding whether new or expanded capacity should be built on a displacement capacity or expansion capacity basis. Also, the FAR proposal and the unbundled FAR proposal have a workable solution in Step 3, as discussed later in this decision, for allowing market participants to bid on new capacity.

Due to the features of the Joint Proposal that we like and don't like, the Joint Proposal should not be adopted. We will, however, incorporate many of the aspects of the Joint Proposal into the FAR system, as described below. The features that we will incorporate into the FAR system are the following.

First, the procedure described in the first two sentences of the section titled "Determination of Facilities, Costs, and Character of New Takeaway Capacity" in Exhibit A of Exhibit 85 will be incorporated into the FAR system. As for the third sentence that provides for "access to all cost and engineering information," we agree with SDG&E and SoCalGas that this information may contain sensitive customer-specific information, as well as pipeline information that may pose security concerns. Accordingly, access to this kind of information is to take place at the offices of the utility, unless otherwise agreed to. In addition, any runs of a computer model shall be done in accordance with Rule 10.4 of our Rules of Practice and Procedure. In the event the parties requesting this kind of information believe that the utility is not providing this information in good faith, the requesting party may request the Commission's Energy Division to assist in determining whether certain information should be made available to the requesting party.

Second, all three of the funding options described in Exhibit A of Exhibit 85 shall be adopted and reflected in the Special Conditions of the proposed Schedule G-RPA that is contained in Exhibit 15. Regarding the first funding option, if a funding party decides to construct the needed facilities by itself, the planning and construction of the facilities will need to be coordinated with the utility and meet all utility-required safety requirements. As for the 20-year contract term referenced in the funding options, that term may be for a shorter period of time so long as all the construction costs are fully amortized over the shorter term.[40] The determination as to whether the additional capacity

[40] In the "Step 3 Modifications" discussion, we adopt a contract term of three to 20 years.

should be built on an expansion capacity or displacement capacity basis is described later in this decision.

Third, the logic and theory behind the "Scheduling Rights for Expansion Capacity," the "Scheduling Rights for Displacement Capacity," and the "Scheduling Right Associated with Receipt Point Capacity Additions in the Southern Zone" that appear in Exhibit A of Exhibit 85 shall be incorporated into the open season process of the FAR system in the following manner.[41]

If a funding party builds new capacity or expands existing capacity on a displacement capacity basis at Otay Mesa, up to 700 MMcfd, and the funding party pays for it on an incremental cost basis, the funding party shall be eligible to receive a Step 1 set-aside for firm rights in the Southern Zone at Otay Mesa in the open season for the amount of capacity that the funding party paid for.[42]

If a funding party builds new capacity or expands existing capacity on an expansion capacity basis, and the funding party pays for it on an incremental cost basis, the funding party shall receive a Step 1 set-aside for the capacity that the funding party paid for.[43]

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41 These three sections in Exhibit A of Exhibit 85 suggest that four types of scheduling right situations may be encountered that will require conversion from a scheduling right into a FAR set-aside, or other step in the adopted FAR system.

42 This is an appropriate set-aside because the funding parties agree that rolled-in capacity shall not apply to this Otay Mesa displacement capacity of up to 700 MMcfd. Such a result is also consistent with the general proposition that if a customer is required to pay for the construction of new facilities, that they should have a higher priority access to the use of those facilities (D.06-09-039, page 80), and with the incremental cost approach in D.04-09-022 at page 66.

43 This is consistent with D.06-09-039 at page 80 and D.04-09-022 at page 66.

If a funding party builds new capacity or expands existing capacity on a displacement capacity basis, and the funding party pays for it on an incremental cost basis, the funding party shall be eligible to receive a Step 1 set-aside in the appropriate zone for the amount of capacity that the funding party paid for, but that set-aside shall be subject to nominations at other receipt points in the same transmission zone.[44]

If the costs of those facilities required to add new or expanded receipt point capacity receive rolled-in rate treatment by the Commission, all ratepayers shall have access to that capacity through Steps 1, 2 and 3 of the open season process.[45]

And fourth, to the extent the "Definitions" in Exhibit A of Exhibit 85 are needed to explain or clarify those provisions of the Joint Proposal which we incorporate into the FAR system, those definitions shall be incorporated into the FAR system.

SDG&E and SoCalGas shall be directed to incorporate the features of the Joint Proposal that we have adopted, as discussed above, into the FAR system that we discuss in more detail below.

The adoption of these key features from the Joint Proposal, and their incorporation into the FAR system will provide certainty to potential gas suppliers that their gas supplies will be able to access the southern California gas market. At the same time, the adopted features provide a set-aside capacity incentive for those parties who are willing to fund the cost of new or expanded

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44 This is consistent with D.06-09-039 at page 80 and D.04-09-022 at page 66.

45 Such a result is consistent with D.04-09-022 at page 66.

capacity on an incremental cost basis, and assurance to ratepayers that the cost of this capacity will not be recovered in their rates.

d) FAR Proposal and Unbundled FAR Proposal

(1) Introduction

In this section, we compare and choose between the FAR proposal of SDG&E and SoCalGas, and the unbundled FAR proposal sponsored by Watson/IP/CCC/CMTA. The two key differences between the two proposals are putting SDG&E and SoCalGas at-risk for the recovery of their noncore backbone transmission costs, and the unbundling of the backbone transmission costs.

Several parties oppose both proposals and contend that a system of FAR is not needed in southern California. These parties contend that the two FAR proposals will result in less flexibility, increase complexity, increase costs, favor an affiliate of the utilities, and that the reservation charges and the credit-back mechanism are illegal. Many of the parties also propose a series of modifications to the two proposals should the Commission decide to adopt a system of FAR.

In the discussion which follows, we first make some general observations about the two proposals. We then address the opposition of the parties to both proposals, the key differences between the two FAR proposals, our selection of the FAR proposal, the unbundling of the five cents FAR reservation charge, and the parties' proposed modifications to the FAR proposal.

(2) Relationship to the CSA

The scoping memo for this proceeding raised the issue of whether the CSA adopted in D.01-12-018, and implemented and stayed in D.04-04-015, is still relevant in light of the history of this proceeding and the changes that have taken place since the CSA was adopted.[46] The CSA and the other settlements considered in D.01-12-018 were designed, in part, to create a system of allocation of capacity for southern California. This proceeding was initiated to consider proposals to allocate capacity. In response, the parties proposed five options on how to allocate gas transmission capacity in southern California. The five options are: the current system of capacity allocation, the FAR proposal, the unbundled FAR proposal, the Joint Proposal, and DRA's allocation method.

The FAR proposal and the unbundled FAR proposal are patterned after the CSA, but as noted in the descriptions of both proposals, vary from the CSA. Since the capacity allocation proposals before us today are different from what was adopted in the CSA, the CSA merely serves as a reference for deciding which of the capacity allocation methods we should adopt based on the options and evidence before us. Thus, the decisions regarding the adoption of the CSA (D.01-12-018) and the implementation of the CSA (D.04-04-015) are now moot as a result of today's decision and the adoption of a new gas market structure and capacity allocation method for SDG&E and SoCalGas.

(3) The FAR System In General

In contrast to the current system, the FAR proposal and the unbundled FAR proposal allow the holder of the FAR to determine the choice of gas supply that will flow through the receipt point. In addition, the FAR proposal moves the control of the SoCalGas receipt points from the FERC-regulated interstate pipelines to the holders of FAR on the transmission system of SDG&E and SoCalGas. As described earlier, a system of FAR allocates the transmission

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[46] According to the terms of the CSA, the CSA terminated on August 31, 2006.

capacity so that the uncertainty under the current system of whether one's gas will be able to enter the transmission system of SDG&E and SoCalGas is eliminated. Under the current system, during a period of receipt point constraints, a customer does not have any assurance that its gas will be able to enter the transmission system. A system of FAR remedies that problem.

(4) Flexibility

The parties opposed to a system of FAR contend that the current system provides more flexibility, and that the FAR proposal and the unbundled FAR proposal will reduce their ability to get the gas they need from the supply source they want it from. Under the current system, an end-user may choose to have its gas delivered through an alternate receipt point.

We are not persuaded by the arguments of the parties who contend that the two FAR proposals will result in less flexibility than the current system. The current system is only flexible when there are not constraints on the system. During times of high demand at alternative receipt points, that flexibility is not available.

The two FAR proposals will not reduce flexibility, as there will be many different options for market participants to choose from. The two FAR proposals allow the holder of the FAR to move its gas through the designated receipt point to the designated delivery point in southern California. The holder of the FAR will also have alternate rights. These alternate rights allow a holder of a FAR to bring in gas through receipt points within the same zone and through receipt points outside the FAR holder's zone. To the extent there is any unused capacity on the system, interruptible access will be available. Market participants can also turn to the secondary market to meet their needs. With all of these tools available to the market participants, the two FAR proposals will continue to provide market participants with flexible options.

Adopting a system of FAR will also result in the creation of a citygate market for southern California.[47] End-users will then have the option of purchasing gas at the producing basin, at the border, or purchasing gas at the citygate. The option of purchasing gas at the citygate is currently not available to end-users in southern California, and may be attractive to customers who do not want to hold FAR. Having multiple points at which end-users can purchase their gas will no longer restrict an end-user having to buy border gas, which reflects the highest priced gas for the southern California market.

The adoption of a system of FAR will also provide certainty to FAR holders that their gas can be delivered from the receipt point to the citygate. (See 5 R.T. 749; 10 R.T. 1504.) This in turn will encourage parties to enter into long-term gas supply contracts because of this assurance. Under the current system, an end-user lacks the assurance that its gas will be delivered if constraints occur on SoCalGas' system.

(5) Alleged Complexities of the FAR System

Several of the parties opposed to the two FAR proposals contend that the FAR system and the open season process will be too complex. We disagree.

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[47] SCGC argues that its historical analysis of the citygate market for PG&E demonstrates that citygate prices have not benefited PG&E's customers. Watson/IP/CCC/CMTA contend that its analysis shows that PG&E's customers have benefited from the creation of a citygate market. Both analyses use different historical data and calculations to arrive at their conclusions. Having reviewed the evidence and the arguments critiquing each other's analyses, we find the analyis of Watson/IP/CCC/CMTA to be more persuasive.

Those who currently use the transmission system, and those who are interested in holding FAR, are large sophisticated gas customers. The FAR system will allow these market participants to get what they need in order to move gas to the market. Those who are not interested in holding FAR have other options such as buying at the citygate.

As with all new systems and procedures, there will be a learning curve to understand how the FAR system and the open season process will work. We are not persuaded by the argument that the new system of FAR will be too complex or too difficult to understand. We estimate that the new FAR system will not be fully operational until the first quarter of 2008. Conforming tariffs, as discussed below, will have to be filed within 45 days of the effective date of today's decision. This implementation schedule provides plenty of time for parties to understand how the new FAR system will work, what market participants will have to do, and what type of gas procurement strategies they should pursue. In addition, a similar system has been in place on PG&E's system for over eight years, and similar processes have been used on the interstate pipelines.

(6) Increased Costs

Some of the parties contend that the two FAR proposals will result in additional costs to market participants in order to understand the FAR system and to participate in the FAR open season.

As we discussed in the section above, market participants are going to have to invest some time in order to understand the workings of the new FAR system. The costs of transitioning from the current system to the new FAR system should not be insurmountable for the market participants. Even if there are new transaction costs for market participants and those costs are passed on to end-users, the competition in the marketplace is likely to minimize the effect of any additional transaction costs.

(7) Affiliate Relationship

Several parties contend that the two FAR proposals provide the affiliate of SDG&E and SoCalGas with an advantage over other market participants.

We are concerned with Sempra LNG's relationship to SDG&E and SoCalGas, but do not believe that the FAR system that we adopt today provides Sempra LNG with an advantage over other market participants.[48] The parties complain that the zone arrangements and receipt points benefit the affiliate. However, under the FAR proposal, all FAR holders will have the option to use alternate receipt point rights within the same transmission zone, as well as outside the zone. As a result, a FAR holder in a transmission zone with only one receipt point could use the alternate receipt point in another zone.

As for the argument that Sempra LNG's use of displacement capacity at Otay Mesa disadvantages those who have to fund construction on an expansion basis, SDG&E and SoCalGas agreed that all new suppliers will be able to obtain some level of displacement capacity.

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[48] If the parties detect that the operation of the FAR system is providing an unfair advantage to the affiliate in violation of the affiliate transaction rules, a complaint should be filed.

(8) Legality of Reservation Charge and Credit-Back

This section addresses the legal objections to the imposition of the reservation charge under the two FAR proposals, and the operation of the credit-back mechanism under the FAR proposal.[49]

Several parties contend that the reservation charge under both of the FAR proposals are illegal. They contend that the FERC decided in Union Pacific Fuels, Inc., *et a.l* vs. SoCalGas, 76 FERC Par. 61,300 (1996)[50] that an access fee cannot be charged on interstate pipeline shippers for the right to nominate gas into the SoCalGas system.

The facts addressed in the Union Pacific Fuels decision are different and distinguishable from the reservation charge that would be assessed on FAR holders. In Union Pacific Fuels, the FERC found the access charge to be unlawful because it was "a charge to interstate shippers for the act of moving gas over the Kern/Mojave pipeline and delivering it to SoCal rather than a charge for any

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[49] As discussed in the "Unbundling Provision" section, we do not adopt the credit-back mechanism. In response to comments on the ALJ's proposed decision, we have unbundled the FAR reservation charge of five cents per Dth from the end-user's transmission rate. We address the legal argument concerning the credit-back mechanism because a similar argument could be raised with respect to the unbundling of the five cents FAR reservation charge.

[50] Referred to herein as Union Pacific Fuels. On rehearing before the FERC, the Union Pacific Fuels decision was affirmed on its merits in 77 FERC Par. 61,283. On the issue of ordering a refund, the FERC declined in 77 FERC Par. 61,283 to order a refund and held that the refund issue should be taken up with this Commission. The parties then petitioned the United States Court of Appeal for review. In 143 F.3d 610, that court held that the FERC acted reasonably when it concluded that the tariff at issue in Union Pacific Fuels was an access charge. The court further held that the FERC acted arbitrarily in refusing to act on the refund and remanded the refund issue to the FERC.

service performed by SoCal after its receipt of the gas." (Union Pacific Fuels, page 62,495.) The reservation charge under the two FAR proposals is assessed on those market participants who have a FAR at a receipt point on the SDG&E and SoCalGas transmission system. The holder of the FAR has the firm right to have its gas transported over the transmission system to the citygate. The reservation charge at issue is being assessed for the right to access the SDG&E and SoCalGas receipt point, and to have the gas transported over the transmission system of SDG&E and SoCalGas. We therefore conclude that the reservation charge is not unlawful under the holding of Union Pacific Fuels.

We turn now to the credit back mechanism in the FAR proposal. The credit back mechanism proposes to credit the end-users of SDG&E and SoCalGas with the five cents per Dth reservation charge that all FAR holders would be required to pay. Some of the parties question whether the credit back mechanism discriminates against those who pay the reservation charge but do not receive the credit because they are not end-users.

The purpose of the credit-back mechanism is to credit end-users on the system with the five cents per Dth reservation charge that all FAR holders pay. The reservation charge provides the FAR holder with access to the transmission system. The transmission system has been paid for in rates by the end-users of SDG&E and SoCalGas. The shippers and marketers, who do not receive a credit-back, but who use the transmission system to deliver and sell their gas have not paid for the cost of the facilities that provide this service. It is entirely appropriate that these shippers and marketers pay for a share of the transmission facilities through the reservation charge in order to access the transmission system.[51] The credit-back mechanism appropriately credits the reservation charge back to those who have paid for the transmission facilities in their rates. If the shippers and marketers are allowed a credit-back for the payment of the FAR reservation charge, they would end up paying nothing for the right to access the transmission system of SDG&E and SoCalGas on a firm basis.

Furthermore, under the system integration decision (D.06-04-033), the transmission rates of SoCalGas' end-use customers increased slightly due to the integration of the two transmission systems. In this context, the credit-back of the reservation charge helps to reduce the transmission rates of the end-use customers of SoCalGas whose rates were increased due to the system integration. We conclude that the credit back mechanism is not discriminatory. Furthermore, the replacement of the credit-back mechanism with the unbundling of the FAR reservation charge from the end-user's transmission rate eliminates any alleged discriminatory effect.

(9) At-Risk Provision

The unbundled FAR proposal is different from the FAR proposal due to the unbundling of the noncore backbone transmission costs, and because it puts SDG&E and SoCalGas at-risk for the recovery of these noncore backbone transmission costs.

SDG&E and SoCalGas oppose adoption of the at-risk provision. Their primary argument is that the at-risk provision would create the incentive to

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[51] Similarly, the FAR reservation charge of five cents per Dth is appropriate because that charge pays for some of the costs associated with the utilities' transmission service. By unbundling the five cents reservation charge, that directly reduces the end-user's transmission rate by five cents.

maximize their throughput on the backbone transmission system in order to recover the costs associated with the unbundled backbone transmission. They contend that such an incentive is contrary to the Commission's energy efficiency and conservation goals and therefore the at-risk provision should not be adopted.

Their other argument is that by putting them at-risk, this will provide an incentive for SDG&E and SoCalGas to keep a lid on their costs by using existing facilities instead of adding additional facilities.

Watson/IP/CCC/CMTA contend that placing SDG&E and SoCalGas at-risk will provide the utilities with an incentive to expand their services to new markets and to keep their rates competitive with competing suppliers.

The at-risk provision operates in conjunction with the proposal of Watson/IP/CCC/CMTA to unbundle the backbone transmission costs. As discussed in the next section, the 15.75 cents reservation charge, which approximates the noncore's backbone transmission costs, is likely to act as a deterrent to those market participants who want FAR. A lower reservation charge is needed to stimulate participation for holding FAR. Also, the FAR system that we adopt today will take some time for the utilities and market participants to adjust to the new market structure. With a lower reservation charge and the absence of an at-risk provision, that will provide a baseline for determining whether future adjustments to the FAR system should be made.

In addition, putting SDG&E and SoCalGas at risk would act as an incentive for them to maximize throughput on their system, which encourages more consumption of natural gas, and is contrary to the Commission's energy efficiency and conservation goals. Such a result should not be encouraged.

We find that including an at-risk provision in the FAR system is not appropriate at this time.

(10) Unbundling Provision

The unbundled FAR proposal removes the noncore backbone transmission costs from the rate for transmission and distribution. The reservation charge of 15.75 cents per Dth, which approximates these unbundled noncore costs, would be charged to holders of the FAR. The charge, in conjunction with the at-risk provision, is designed to recover part of the unbundled transmission costs. In contrast, the FAR proposal does not separate the noncore backbone transmission costs from the overall rate for transmission and distribution. Instead, under the FAR proposal, the end-users continue to pay the full cost of transmission and distribution, and the holders of the FAR pay the five cents reservation charge, which is then credited back to system end-users. The credit-back reduces the end-users' transmission and distribution rate. There is no credit-back under the unbundled FAR proposal since the holders of the FAR pay for the costs of transmission over the backbone transmission system.

Several of the parties, who are likely to be holders of FAR, oppose the unbundling of the backbone transmission costs. They contend that the unbundling of these costs will lead to a cost shift because those who are holders of FAR will end up paying all of the backbone transmission costs, while those who purchase their gas at the citygate will not pay the backbone transmission costs. In addition, some of these parties oppose the 15.75 cents per Dth reservation charge as too high, and that it will discourage market participants from holding FAR.

We agree that the 15.75 cents per Dth reservation charge is likely to discourage many market participants from holding FAR because of the high reservation charge. In order to encourage participation in the holding of FAR, the reservation charge needs to be set at a lower level. With more holders of FAR, the FAR holders and end-use customers will have more flexible options on where the gas can be made available and from whom the gas can be purchased.

In addition, the 15.75 cents per Dth reservation charge is intended to unbundle the cost of the backbone transmission costs from the end-user's transmission rate. However, none of the parties specifically identified what transmission assets should be designated backbone transmission assets. Accordingly, we do not believe that full unbundling of the backbone transmission costs is justified with today's adoption of a FAR system.

Several parties recommend in their comments to the ALJ's proposed decision that if the Commission decides to adopt the five cents per Dth FAR reservation charge, instead of the 15.75 cents per Dth charge, that the unbundling of the reservation charge from the end-user's transmission rate should still occur. These parties contend that the unbundling, together with the elimination of the credit-back mechanism, will also eliminate the legal objections to the adoption of a FAR system.

Upon reflection, the unbundling concept will be adopted in conjunction with a FAR reservation charge of five cents per Dth. Since the FAR reservation charge provides access to the FAR holder so that its gas can gain access at the receipt point for delivery to the designated delivery point, that charge represents part of the cost of transmission. It is appropriate, therefore, that this reservation charge of five cents per Dth be unbundled from the end-user's bundled transmission rate, and that the credit-back mechanism not be adopted. Through the unbundling of the FAR reservation charge, the end-user's transmission rate will be reduced by five cents per Dth. This unbundling will more closely align the FAR system that we adopt today for SDG&E and SoCalGas, with the gas market structure that is in place for PG&E. As part of the adopted FAR system, SDG&E and SoCalGas shall unbundle the FAR reservation charge of five cents per Dth from the end-user's bundled transmission rate.

We also agree with some parties that a cost-based FAR reservation charge tied to the cost of the backbone transmission system is desirable. We are adopting a system of FAR because of the potential for backbone transmission constraints, so establishing a cost-of-service FAR charge based on backbone transmission costs will send the appropriate price signals to users of the system. However, in the absence of a cost study identifying backbone transmission-related costs, we cannot adopt a cost-based rate in this decision. The BCAP is the appropriate proceeding to fully assess the cost of the backbone transmission system.

Therefore, we direct SDG&E and SoCalGas to include a cost study of the backbone transmission system in their next BCAP. We intend to incorporate a cost-based FAR charge into the FAR system in time for the second three-year open season of FAR. In the interim, it is important to implement a system of FAR, and a five cent reservation charge is appropriate at this time. Moving forward with a system of FAR now will give SDG&E, SoCalGas, market participants, and the Commission valuable experience with a FAR market structure in southern California, and will give FAR holders an assurance that they can bring gas into southern California on a firm basis.

Since we do not adopt the at-risk provision in this decision, SDG&E and SoCalGas should be authorized to establish a balancing account so that they will not be at risk for under-recovery of the unbundled FAR reservation charge revenues, and any over-recovery is refunded to ratepayers.

e) The Adopted FAR System

(1) The FAR System Model

Based on all of the above discussion, the adoption of a system of FAR, together with the unbundled FAR reservation charge and selected elements of the Joint Proposal, for SDG&E and SoCalGas is in the interests of all market participants and consumers. The FAR system will result in a rational system of allocating transmission system capacity that will assure gas suppliers, gas marketers, and end-users that their gas will be able to access the receipt point on the SDG&E and SoCalGas transmission system for delivery to the designated receipt point.

The model for the FAR system that we adopt today shall be the FAR proposal of SDG&E and SoCalGas, with an unbundled FAR reservation charge of five cents per Dth. The FAR proposal, with the unbundled FAR reservation charge, is being selected over the unbundled FAR proposal with the 15.75 cents reservation charge because it provides a better starting point for introducing a system of FAR to southern California. While the unbundling and at-risk provisions are in use for PG&E, we do not believe that full unbundling of the backbone transmission costs and the at-risk provision are ripe for adoption for SDG&E and SoCalGas at this time. Specifically, the unbundled FAR proposal charge of 15.75 cents per Dth is too high. We believe that this higher reservation charge could discourage a number of market participants from holding FAR, which could impact the options in the marketplace.

The FAR proposal shall be integrated with the unbundling of the five cents per Dth FAR reservation charge, and with those elements of the Joint Proposal that we discussed above. In addition, the parties have proposed modifications to the FAR proposal, some of which we adopt as discussed below. The adopted modifications to the FAR proposal shall also be incorporated into the FAR system.

(2) Modifications to the FAR System

(a) Introduction

The parties have proposed a number of modifications to the FAR proposal. In addition, the comments to the ALJ's proposed decision suggested a number of modifications to the proposed decision. The modifications that we adopt, as discussed below, are to be incorporated into the FAR system.

(b) The FAR System Rates

Under the FAR proposal, anyone holding a FAR would pay the reservation charge of five cents per Dth per day on a monthly basis. The rate for interruptible access would be on a volumetric basis up to five cents per Dth.

Some parties contend that the five cents reservation charge is not cost based and therefore should be rejected. We are not persuaded by this argument. The evidence in this proceeding indicates that the five cents per Dth reservation charge is lower than the embedded cost of the backbone transmission, and that the total transmission costs are around 16 cents. There is also evidence that the credit-back of the reservation charge will reduce the transmission rate of end-use customers. The FAR reservation charge is related to the cost of transmission.

Some contend that the reservation charge for FAR and the rate for interruptible access should be set at zero. Such a suggestion means that market participants would not have to pay anything for access to the transmission system. That could result in all customers trying to obtain as much capacity as possible in all steps of the open season process, and then hoarding or reselling the access rights in the secondary market for whatever the market is willing to pay. Such an outcome would be undesirable.

The five cents per Dth per day reservation charge, and the interruptible rate are appropriate. The reservation charge acts as a deterrent to market participants hoarding receipt point capacity. The reservation charge is being assessed on those who use the transmission system to move gas from the receipt points to the citygate. It is appropriate that the market participants who access the receipt points to transport their gas over the transmission system pay for a part of the transmission costs. Setting the reservation charge at zero would encourage hoarding, and the FAR holder would not have to pay for any of the costs of the transmission system.

The interruptible service discourages the hoarding of capacity. If a holder of a FAR decides not to use their right to receipt point capacity, SDG&E and SoCalGas should be permitted to market that unused capacity for up to five cents per Dth.

The proposed decision recommended that the FAR system use the five cents FAR reservation charge and that the reservation charge be credited back to end-users, as proposed by SDG&E and SoCalGas. In the comments to the proposed decision, several parties recommended that the five cents FAR reservation charge be unbundled from the end-user's transmission rates, which will reduce the end-user's bundled transmission rate by five cents per Dth. By doing so, there is no need to adopt the credit-back mechanism. The correlation of the five cents per Dth FAR reservation charge with a reduction of five cents in the end-user's bundled transmission rate has appeal because the FAR reservation charge reflects part of the cost of transmission.

Some parties oppose the 90/10 sharing/incentive mechanism for interruptible transmission revenues. The availability of interruptible service provides a check on those FAR holders who seek to maximize their financial gain by withholding FAR capacity during a time of need for capacity. Under the proposed G-RPA tariff, SoCalGas is obligated to "make available all unutilized firm receipt point access capacity on an interruptible basis … ." (Ex. 15, Schedule No. G-RPA, Special Condition 67.) There is no need to provide SoCalGas with an incentive to sell unused receipt point access capacity when it is required under the tariff to do so. The proposal of SDG&E and SoCalGas for a shareholder incentive sharing mechanism for the revenues associated with interruptible receipt point access capacity is not adopted.

SCGC and Watson/IP/CCC/CMTA propose that the FAR revenues be credited back on the basis of average year throughput (equal cents per therm) instead of on a cold year throughput basis. Watson/IP/CCC/CMTA contend that if the FAR revenues are credited back on the basis of cold year throughput, core customers will receive a larger FAR credit per Dth than noncore customers. The rate design witness for SDG&E and SoCalGas points out that the difference in allocating the revenue credit on an average year throughput basis as opposed to a cold year throughput basis, is quite small. We agree with SCGC's argument that the FAR revenues bear no relationship to cold year throughput. Despite the small monetary difference, we will require SDG&E and SoCalGas to use average year throughput, instead of cold year throughput, to allocate the FAR reservation charge credit.

(c) Fuel Charge

Several parties oppose the proposed in-kind fuel charge of 0.28%. Under the current method, fuel costs are recovered on a lagged basis using a balancing account. SDG&E and SoCalGas contend that the in-kind fuel charge will recover the cost of operating the compressors on a more timely basis and better aligns the cost recovery with the cost causation.

The disadvantage that we see with imposing the in-kind fuel charge is that the shippers will be responsible for paying this cost upfront with in-kind fuel. When that in-kind fuel charge is coupled with the FAR reservation charge, it is understandable why the shippers are opposed to the in-kind fuel charge proposal. Under the existing cost recovery, these costs are recovered through the rates of the core and noncore customers. We believe that in designing a fair and balanced system of FAR, that the fuel charges should continue to be recovered in the rates of end-use customers instead of being paid for by the shippers in the form of in-kind fuel.

(d) Step 1 Modifications

SDG&E and SoCalGas oppose the proposed 90 MMcfd set-aside for OEHI at the Gosford interconnection. SDG&E and SoCalGas do not believe the set-aside at the Gosford interconnection is appropriate because OEHI has other delivery options, and because OEHI is delivering into the heavily used Wheeler Ridge transmission zone. SDG&E and SoCalGas contend that providing OEHI with a set-aside would disadvantage the pipelines delivering into Wheeler Ridge and the potential customers who want to obtain FAR in this zone.

Based on the testimony of the OEHI witness, and the reasoning for the set-asides for the other California producers, it is appropriate to have a set-aside of 90 MMcfd for OEHI at the Gosford interconnection. The interconnection was built at SoCalGas' urging so that the production at OEHI could avoid having to use Line 85, which was not capable of handling the gas volumes from OEHI. The access agreement and the construction agreement between SoCalGas, PG&E and OEHI contemplated that the Gosford interconnection would serve the gas production from OEHI, and that OEHI was to pay for the cost of those facilities. Based on those documents, OEHI should receive the benefit of what it bargained for. Although OEHI has other outlets for its gas production, the evidence suggests that it cannot reliably depend on obtaining access to the other outlets. OEHI shall be provided with a set-aside of 90 MMcfd in Step 1 at the Gosford interconnection.

PG&E requests a set-aside in Step 1 for five of the six G-XF long-term contracts that deliver into Kern River Station. SDG&E and SoCalGas point out that the holders of these G-XF contracts signed contracts for PG&E capacity without any assurance of SoCalGas providing firm access to the SoCalGas system.

The five G-XF long-term contracts, which specify Kern River Station as the delivery point, were approved by the Commission. In that respect they are similar to the set-asides for the four Commission approved long-term contracts that SDG&E and SoCalGas propose in Step 1. Accordingly, SDG&E and SoCalGas shall provide a set-aside for the five G-XF long-term contracts with PG&E at the Kern River Station receipt point.[52]

Exxon Mobil contends that it should receive a set-aside for its gas production from its Santa Ynez unit, which is located in federal waters offshore of California, and which delivers into the Coastal transmission zone. SDG&E and SoCalGas contend that because the production is located in federal waters, it does not qualify as a California producer, but the utilities are willing to provide Exxon Mobil with a set-aside if it signs a standard producer access agreement.

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[52] The sixth G-XF long-term contract is already included in the Step 1 set-aside for SDG&E's core.

We do not agree that Exxon Mobil should be required to sign a standard producer access agreement in order to receive the set-aside.[53] Although Exxon Mobil is located in federal waters offshore of California, SoCalGas included Exxon Mobil's gas production when it determined the amount of set-aside capacity for California producers. In addition, the gas produced by Exxon Mobil flows into the Coastal transmission zone. If other California gas producers who deliver their production into SoCalGas' transmission system receive a set-aside, Exxon Mobil should receive a similar set-aside without having to execute a new access agreement. SDG&E and SoCalGas shall include a set-aside for Exxon Mobil's production from its Santa Ynez unit in Step 1.

SCGC requests that set-asides be provided for noncore customers with long-term commitments on the upstream pipelines. SCGC notes that electric generation customers have long-term upstream contracts, but most noncore customers do not. Watson/IP/CCC/CMTA argue that the noncore upstream contracts never contemplated firm service onto the SoCalGas system. SCGC's request that a set-aside for noncore customers who have long-term contract commitments on the upstream pipelines is not adopted. Such a set-aside is likely to reduce the amount of capacity available to end-users at the most popular receipt points, and little, if any, capacity would be available to end-users and other market participants in Steps 2 and 3.

SDG&E and SoCalGas have proposed that each of the Oxnard 3 customers be provided with a set-aside up to their respective Tier I contract quantities, and

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[53] We extensively reviewed the access agreement that Exxon Mobil and its affiliate have with SoCalGas in D.06-06-065. We noted that SoCalGas has treated Exxon Mobil and its affiliate in a similar manner as other California gas producers. (D.06-06-065, page 42.)

that they receive a credit-back to maintain the benefit of the bargain that was agreed to originally in their Commission-approved long-term contracts.

SDG&E and SoCalGas are agreeable to basing the set-aside for the Oxnard 3 contracts "on the higher of Tier I volumes or the most recent annual average usage." (SDG&E and SoCalGas Reply Brief, page 36.) SDG&E and SoCalGas would allow the Oxnard 3, just as all noncore customers would be allowed to do in Step 2, to adjust their set-aside volume if they can demonstrate that their annual average usage will increase.

The utilities' proposal is substantially similar to the CCC's proposal that the set-aside be "based upon recent historical demand with adjustments to account for expected load growth as reasonably demonstrated by the customers." (CCC Opening Brief, page 7.) The CCC, however, ties its proposal to testimony in A.03-06-040, in which the CSA and the other settlements were considered. The CCC attached that testimony to Exhibit 43, and recommended that the CSA set- aside for the Oxnard 3 be "in an amount equal to their projected maximum daily demand for the initial term of the CSA." (Exhibit 43, Att. RTB-3, page 2; CCC Opening Brief, page 7.) We agree with the argument of SDG&E and SoCalGas that if the set-aside is based on "projected maximum daily demand," that this could lead to disputes. Since the Oxnard 3 would be permitted to adjust their set-aside under the utilities' proposal if they can demonstrate that their annual average usage will increase, we will adopt the wording used by SDG&E and SoCalGas. Accordingly, SDG&E and SoCalGas shall provide a set-aside to the Oxnard 3 based on the higher of their Tier I volumes or the most recent annual average usage. The Oxnard 3 shall be permitted to increase their set-aside if they can demonstrate that their annual average usage will increase.

The Oxnard 3 also contend they should only be required to pay for the access that they use, and that the charge should be on a volumetric basis.[54] They contend that the credit-back proposal of SDG&E and SoCalGas will result in the Oxnard 3 paying more for capacity than they use, which conflicts with the long-term contracts. Since the credit-back mechanism is not being adopted, this issue is now moot.

In our earlier discussion regarding the Joint Proposal, we adopted elements of the Joint Proposal, including how the scheduling rights are to be incorporated into the FAR open season process. Four scenarios for how the scheduling rights will be converted into a FAR were listed.[55] SDG&E and SoCalGas shall incorporate those four scenarios into the appropriate steps of the FAR system. Any FAR awarded under these four scenarios will be required to pay the five cents per Dth reservation charge.

SCE contends that the core should not be awarded set-aside rights for upstream contracts that expire during the three-year cycle. SDG&E and SoCalGas assert there is no reason to limit the rights of the core customers because under the FAR proposal, a set-aside for the core will only be permitted if the upstream contracts last for at least 18 of the 36 months of the three-year cycle.[56] We agree with SDG&E and SoCalGas that the core set-aside language should govern which upstream core contracts are eligible for the core set-aside.

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[54] The long-term contracts had an all volumetric rate structure.

[55] Since we are not adopting the Joint Proposal, there is no need to discuss when a scheduling right will vest under the Joint Proposal.

[56] See Special Conditions 19 and 20 of the proposed Schedule G-RPA in Exhibit 15.

If a qualifying core contract expires before the three-year term has expired, the utility has the flexibility with the set-aside to secure additional supplies to meet the core needs for the remaining time. Accordingly, SCE's suggestion is not adopted.

Under the FAR proposal, all FAR holders, including those who receive a set-aside in Step 1, would be allowed to re-contract. SDG&E and SoCalGas contend that the ability to re-contract allows all customers to match the FAR with upstream supply choices. SCE proposes to prohibit any re-contracting of capacity that was acquired as a set-aside in Step 1.

SCE contends that those who receive a set-aside in Step 1 should use it for its intended purpose, that of reliability.[57] SCE's proposed prohibition would restrict how the holders of the set-asides could use them. Instead of being able to trade or sell the FAR that they receive in the set-aside, SCE's proposal would limit all holders of set-asides to ensure that the set-asides are serving the purpose for which they were created. SDG&E and SoCalGas believe that this is an intra-shipper issue, but point out that SCE's proposal would end up restricting a set-aside customer's ability to optimize their FAR.

SCE's point is well-taken. If someone receives a set-aside, that presumes there must be a good reason for doing so, and in theory the holder of the set-aside FAR should not be allowed to defeat the purpose of the set-aside. However, as SDG&E and SoCalGas point out, there may be situations where those with a set-aside, especially those that serve core loads, may be able to take advantage of cheaper priced gas from another receipt point. Restricting one's

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[57] It is arguable whether the set-asides for those other than the core in Step 1 are for reliability purposes.

ability to trade or sell the FAR set-aside could disadvantage the core in that situation. In order to allow the holder of a FAR set-aside to have as much trading flexibility as possible, we decline to adopt SCE's proposed prohibition. As we discuss later, since we are adopting the suggestion to impose a price cap on the FAR in the secondary market, the price cap will limit the financial reward that a FAR set-aside holder may receive if it decides to trade or sell the FAR in the secondary market.[58]

Watson/IP/CCC/CMTA propose that the set-aside process for California producers should be based on a three-year historical average instead of historical peak average monthly production over the prior 12 months. They also propose that the California producers should have the ability to justify a set-aside greater than indicated by the historical data if the producer had historical peak month production that was shut in or restricted due to operating constraints, or if the producer can show the utility it has obtained permits and ordered equipment that will increase production above historical levels. SDG&E and SoCalGas point out that basing the California producer set-asides on peak deliveries in the last three years could affect the FAR available in the Wheeler Ridge zone since any capacity not taken on Line 85 could be used to increase the FAR at Wheeler Ridge.

The proposal of Watson/IP/CCC/CMTA to base the set-aside for California producers in Step 1 on an individual producer's peak month

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[58] We are concerned that if the holders of the FAR set-asides, other than to serve core load, consistently trade or sell their set-asides, that may mean the set-aside may not be appropriate or that it should be adjusted. SDG&E and SoCalGas should include their observations about the selling or trading of set-aside capacity when the FAR system comes up for review.

production delivered into the SoCalGas system over the most recent three-year period, instead of the proposed historical peak average monthly production over the prior 12 months, shall be adopted. We believe that the three-year historical average provides a better indicator of production for the California producers. Since we are adopting a three-year historical average for the California producers, there is no need to adopt their other proposal. If production is likely to increase, and the producer can justify the increase in production, the proposed tariff permits such a showing.

(e) Step 2 Modifications

SCE raised the issue about tolling agreements, and how Step 2 of the FAR proposal should account for these agreements. SDG&E and SoCalGas have no objection to SCE's approach as long as there is sufficient evidence that the plant owner is willing to forego its FAR in favor of the party providing the tolling service.

We agree with SCE that Step 2 of the open season process must account for the tolling agreements. Due to the way in which the FAR proposal and the tolling agreements were developed, Step 2 of the open season process needs to be clarified. Thus, we will require that when an end-use customer (i.e., the plant owner of an electric generation facility) of SDG&E or SoCalGas has contracted with a third party (i.e., with DWR or one of the California electric utilities) to supply natural gas for electric generation under the terms of a tolling agreement, that the Step 2 bidding rights is to be provided to the third party that supplies the natural gas for the electric generation. Furthermore, we direct SDG&E and SoCalGas to include the usage under the tolling agreements as part of the historical usage for the purpose of calculating the bidding rights of the third party responsible for obtaining the gas under the tolling arrangements. SDG&E

and SoCalGas shall also meet with the parties providing the tolling service and with the electric generation plant owners, to develop a satisfactory release form agreeable to all affected parties.

Next, we address how the long-term EOR contracts of Aera and MSCC should be treated under the FAR proposal. Aera and MSCC expressed concern that it was not clear if they would be permitted to bid in Step 2 for FAR capacity. Exhibit 16 made it clear that Aera and MSCC would be treated like other noncore customers and would be permitted to bid for FAR capacity in Step 2.

Aera and MSCC assert that if they are able to obtain FAR or interruptible receipt point access service, that they should receive a dollar-for-dollar credit-back of the charge for the FAR or the charge for the interruptible service.[59]

In the event Aera and MSCC obtain and pay for the FAR reservation charge, SDG&E and SoCalGas propose that Aera and MSCC not receive a credit-back. SDG&E and SoCalGas consider these contracts to be interruptible contracts, and therefore no credit-back of the FAR reservation charge is warranted because of the interruptible nature of the contract. Aera and MSCC contend that the interruptible nature of their contracts was for curtailment purposes only.

We agree with the argument of Aera and MSCC that one's curtailment priority has no relationship to a customer's gas nominations. SoCalGas should unbundle the five cents reservation charge from the Aera and MSCC contract

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[59] In their comments to the ALJ's proposed decision, Aera and MSCC propose that if the FAR reservation charge of five cents per Dth is unbundled, that the credit-back references should be eliminated and that they should be treated in the same manner as other customers.

rates in the same manner as these charges are unbundled from the rates of other customers. This will place Aera and MSCC in the same position as other customers, permitting them to elect firm access rights in the amount and at the locations of their choosing without the risk of duplicative charges.

SWG recommends that in Step 2, local distribution companies be allocated the bidding rights it needs to serve their core extreme weather demands. SDG&E and SoCalGas point out that SWG would receive the same type of set-aside and maximum bidding rights that SDG&E and SoCalGas core customers will receive. They point out that SWG has options available to it such as the purchase of storage, or it can purchase additional capacity in Steps 2 or 3, or use interruptible transmission. These are the same options that the utilities and wholesale customers will have for their core customers.

We do not adopt SWG's recommendation. As SDG&E and SoCalGas point out, there are other options under the FAR system that SWG can use in order to ensure they have sufficient gas supplies to meet any extreme weather demand.

Some of the parties propose to eliminate the 75% receipt point capacity limit in Step 2, while others believe the limitation should be upheld. This limit operates to limit the bidding for capacity in Step 2 to 75% of the receipt point capacity less any amount that was set-aside in Step 1. Some of the parties concerned with the 75% limit believe that in certain situations it may limit the total amount of capacity available in a transmission zone to end-users in Step 2 and to all market participants in Step 3. They also contend that end-users may be forced to compete with marketers and shippers for capacity in Step 3 in order to satisfy their gas needs, even though end-users have paid for the cost of these facilities in rates. Sempra LNG proposes that the capacity limitation be based upon historical utilization by month at each individual receipt point using the five year average from 2001 through 2005. SDG&E and SoCalGas believe that the 75% limit on each receipt point's capacity is a reasonable balance, and that increasing or decreasing the total amount of capacity in Step 2 will have an effect on other market participants.

We have considered the various arguments about the 75% capacity limit. On the one hand, we are concerned that the end-use customers who pay for the transmission costs in their rates should get what they pay for. On the other hand, we recognize that the FAR system should provide all market participants with the opportunity to obtain FAR. In achieving a balance between the competing interests, we will adopt a slight variation on Sempra LNG's proposal. The limit on how much end-users can bid at any individual receipt point in Step 2 shall be limited to the historical utilization by month at each individual receipt point using the five year average from January 1, 2001 through December 31, 2005, less any Step 1 set-aside capacity.[60]

SCGC proposes that the base period for determining the customers' maximum Step 2 bidding rights should be based on the previous three years' experience rather than just one year. SCGC contends that for many customers, especially electric generators, usage can vary significantly from year to year due to weather and other factors. The FAR proposal calls for the maximum bidding in Step 2 to be based on "the twelve consecutive months of consumption ending

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[60] When the subsequent open seasons are held, this five-year average should be advanced by two years to form a rolling five-year average. For example, the five-year average for the second open season should run from January 1, 2003 through December 31, 2007.

four months prior to the start of the process to assign/award receipt point rights." (Exhibit 15, Schedule G-RPA, Sheet 9.)

In the Step 1 modification, we adopted a similar modification for the calculation of the California producers' set-aside. SCGC's proposal raises the same concern that usage can vary over a one-year period. Accordingly, SCGC's proposal that an end-user's base period for determining the customers' maximum Step 2 bidding rights shall be based on the 36 consecutive months of consumption ending four months prior to the start of the open season process.

SCGC is concerned about the FAR proposal's preference for annual bids over seasonal bids. Watson/IP/CCC/CMTA contend that such a preference is reasonable because annual bids provide greater economic value to the utilities and maximize the use of system capacity. SDG&E and SoCalGas contend that its method is preferable because monthly bids can create gaps in the use of capacity. We are not persuaded by SCGC's argument that the preference for an annual bid over a monthly bid should be eliminated. Also, with the set-aside for the upstream contracts of electric generators, they should be able to obtain most, if not all, of what they need.

SCGC proposes that the contract terms for Steps 1 and 2 should be for a two-year term instead of three years. SDG&E and SoCalGas contend that the three-year term provides for greater stability with respect to access rights, as well as the supply choices of end-use customers. We will leave the length of the contract terms in Step 1 and Step 2 at three years. The three-year term is an appropriate balance between having supply certainty and a preference for shorter term contracts.

(f) Step 3 Modifications

Several parties suggest that the 15-year contract term in Step 3 be reduced. The contract terms that parties recommend range from two years to 20 years. SDG&E and SoCalGas agreed during the hearing that the contract term in Step 3 should be reduced. The utilities, however, point out that the costs of any new or expanded capacity needs to be fully amortized over the shorter term. We shall permit the contract term in Step 3 to range from three years to 20 years. The minimum of a three-year contract term will make Step 3 consistent with the contract term in Step 1 and Step 2.

Some parties recommend that the Step 3 bids should be divided into two separate bids, one for existing capacity remaining after Step 2, and one for expansion and new capacity. They point out that this will avoid the problem in the SDG&E and SoCalGas proposal of having the cost of expansion and new capacity borne partially by those who want existing capacity only. We agree that Step 3 should take place in two bidding stages, one for existing capacity remaining after Step 2, and one for expansion and new capacity.

PG&E proposes that there be short-term FAR for any available capacity at Wheeler Ridge above 765 MMcfd, and that the short-term FAR be scheduled after the primary FAR. SDG&E and SoCalGas proposed in their rebuttal testimony to sell short-term FAR to take advantage of additional capacity that they reasonably expect to be available for shorter periods, but that the short-term FAR have the same priority as any other FAR. The proposal of the utilities will make more firm capacity available at Wheeler Ridge on a short-term basis. We agree with the approach of SDG&E and SoCalGas that short-term FAR service for Wheeler Ridge be made available to take advantage of any additional capacity that SDG&E and SoCalGas expect to be available for shorter periods.

The parties spent a lot of time in this proceeding litigating the issue of displacement capacity and expansion capacity. As discussed earlier, we have incorporated elements of the Joint Proposal into the FAR system which address displacement and expansion capacity. Instead of adopting the element in the Joint Proposal that a requesting party can choose whether to build on an expansion capacity or displacement capacity basis, we have decided, as clarified above,[61] to use the FAR proposal's approach that the parties bid in Step 3 for new receipt point capacity or for expanding existing capacity. That leaves the door open for the Commission to decide whether facilities should be constructed on a displacement or expansion capacity basis.

As SCE points out, there may be situations where expansion capacity should be preferred over displacement capacity because an expansion capacity will result in an overall increase in pipeline capacity. Accordingly, SDG&E and SoCalGas shall contact the Energy Division regarding preliminary discussions with any third party to construct new capacity or to expand existing capacity on the utilities' transmission system. If the Energy Division believes the Commission should become involved in such a decision, we may require that an application be filed before allowing such a project to proceed. Such a process is consistent with our recent decision in D.06-09-039 where we required SoCalGas to monitor the receipt points and to provide us with semi-annual reports on such issues as the "rationale for expanding or not expanding the capability of a particular receipt point," and "why the company should or should not pursue

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61 The clarification we refer to is dividing the Step 3 bid into two separate bids.

receipt point expansion in response to existing or forecast constraints." (D.06-09-039, page 32.)

(g) Secondary Market

Kern River and SCE have proposed to put price caps on the secondary market transactions. SDG&E and SoCalGas contend that price caps are not needed, and that the holder of the FAR should receive the market value of the FAR. We view the price cap as a preventative measure to prevent a possible reoccurrence of some of the gaming that occurred during the energy crisis. Since today's decision adopts a system of FAR for SDG&E and SoCalGas, we believe that price caps on the price of the FAR in the secondary market will reduce the potential for future problems as we gain experience with the FAR system in southern California. In addition, we noted earlier that the set-asides in Step 1 should be used for their intended purposes. Establishing a price cap will help ensure that a holder of a FAR set-aside does not unduly profit from their set-aside. Accordingly, a price cap of 125% of the FAR reservation charge shall apply to all secondary market transactions.

As part of their FAR proposal, SDG&E and SoCalGas agree to provide quarterly reports and to post secondary market information on the EBB. SCE suggested that the name of the acquiring shipper be provided as part of the secondary market information that SDG&E and SoCalGas intend to provide. SCE's suggestion shall be incorporated into the market monitoring information that SDG&E and SoCalGas have agreed to provide in quarterly reports and the EBB.

SCE also proposes that any party that has more than 30% of the capacity at any receipt point be required to provide the Commission with the economic justification for that capacity. The amount of capacity that a party has will be reported in the quarterly reports that SDG&E and SoCalGas will be required to provide to us. We do not see the necessity at this time to require a FAR holder to justify its FAR holdings. The quarterly reports, and the daily operation of the FAR system, should reveal any potential market power issues.

(h) Continental Forge and SCE Settlement

Some of the parties contend that portions of the FAR proposal are inconsistent with the terms of the Continental Forge settlement or with the SCE settlement. We have reviewed the parties' arguments, as well as the exhibits in this proceeding, and do not believe that there are any provisions in either settlement that should prevent us from adopting the FAR proposal in this decision as the model for the FAR system. We also note that the Commission is reviewing the terms of the Continental Forge settlement and the SCE settlement in A.06-08-026, and will issue its decision on those settlements in that application.

4. Implementation of the FAR System

The cost to implement the FAR system and the other services described in this decision are estimated to cost $3.5 million. SDG&E and SoCalGas propose that the FAR Memorandum Account be established to track the implementation costs. We approve the establishment of the FAR Memorandum Account to track and recover the costs of implementing the FAR system, and the other services, that we adopt in today's decision.

SDG&E and SoCalGas shall file an AL with the tariffs and services needed to implement this decision. The AL shall be filed within 45 days of the effective date of this decision. The tariffs and services shall be consistent with, and comply with the gas market structure that we adopt in today's decision. The ALs are subject to protest, and such protests shall be filed within 20 days after the AL has been filed. SDG&E and SoCalGas shall serve the respective ALs by e-mail on the service list to this proceeding, as well as on the interested parties who have requested notification of AL filings for SDG&E and SoCalGas.

In accordance with the implementation schedule proposed by SDG&E and SoCalGas, the FAR system approved in this decision shall be implemented and operational beginning no later than 365 days after a decision, resolution, or Energy Division has approved the implementing tariffs and related services.

5. Future Review

Today's decision represents the start of a new gas market structure for southern California. In order to assess how this new system of FAR is working, and to determine if any adjustments or modifications need to be made, we should provide for a review process. This review process shall take place in an application filing by SDG&E and SoCalGas 18 months after the initial open season has concluded. In that proceeding, we intend to review how the system of FAR has operated, the impact on the gas market in southern California, the impact on end-use customers and market participants, and whether any changes or modifications to the FAR system are needed.[62]

V. Citygate Pooling Service

A. The Proposal and Parties' Responses

SDG&E and SoCalGas propose that a citygate pooling service be established to facilitate the transfer and delivery of gas within the transmission system after the gas has been scheduled through the receipt points.[63] This

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[62] Further unbundling and the at-risk proposals are examples of changes or modifications that could be made.

[63] The proposed tariff for the pooling service is attached to Exhibit 15 as Schedule No. G-POOL.

citygate pooling service is an optional service that allows for the aggregation and disaggregation of natural gas at the citygate, and creates a pricing point for customers to buy and sell gas. The service facilitates the delivery of gas from a receipt point or pool account to end-use customers, storage accounts, other pool accounts, and off-system deliveries, and the receipt of gas from a receipt point, storage account, or other pooling accounts.[64] Under the pooling service proposal, the pool accounts will be required to balance during each scheduling cycle each day. For at least the first six months of the pooling service, there will be no transfer charges for a pool-to-pool transfer.[65]

No one expressed opposition to the creation of the pooling service.

Several parties contend that a citygate pooling service can be established even if a system of FAR is not adopted.

B. Discussion

Several parties explained why the pooling service proposed by SDG&E and SoCalGas will be beneficial to market participants. The pooling service facilitates the delivery and transfer of gas among the pool participants in an effortless manner, and provides market participants with greater flexibility in managing their gas supplies. The pooling service allows market participants to manage and reconcile gas flows in real time, provides them with an alternative to

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[64] See the diagram at page 26 of Exhibit 15 and Special Condition 11 of the proposed Schedule No. G-POOL in Exhibit 15 for the various pooling transactions that can take place.

[65] Proposed Schedule No. G-POOL provides that SoCalGas reserves the right to review the status of the transfer charges no earlier than six months following the effective date of the tariff.

the use of hub and storage services, and minimizes imbalance and contractual non-performance exposure that market participants currently face.

Some parties seem to suggest that the pooling service should be implemented sooner rather than later. SDG&E and SoCalGas propose in their implementation schedule that the pooling service be implemented in conjunction with the start of the FAR system. Although the utilities did not address the type of changes that may be needed to allow their systems to accommodate the pooling service, we assume that some time is needed to make these kind of changes. Due to the adoption of the FAR system and the changes needed to implement that system, the best course of action is to allow the pooling service to go into effect at the same time the FAR system becomes operational at the receipt points. That should result in a pooling service that is fully integrated with the FAR system.

To the extent the costs of implementing the pooling service are not already included in the FAR system implementation costs, SDG&E and SoCalGas shall be allowed to track and recover the costs of implementing this service. Although the pooling service is likely to be used by marketers, shippers, and large noncore customers, the pooling service benefits all end-users on the system. The reasonable costs of implementing this service, which we shall limit to a maximum of $500,000, shall be recovered from all ratepayers.

The proposal to offer a pooling service is approved. SDG&E and SoCalGas shall file an AL with the tariff and service needed to implement the pooling service. The AL shall be filed within 45 days of the effective date of this decision. The tariff and service shall be consistent with our discussion of this service. The AL is subject to protest, and such protests shall be filed within 20 days after the

AL has been filed. The AL shall be served as described in the FAR system discussion.

VI. Off-System Deliveries

A. SDG&E and SoCalGas' Proposal

In D.04-09-022, the Commission directed SoCalGas to make a showing in this proceeding about providing firm off-system delivery to PG&E. SDG&E and SoCalGas propose to offer two types of off-system delivery service to PG&E.

The first is firm backhaul service. SDG&E and SoCalGas propose to conduct an open season for firm backhaul service to PG&E that would require new facilities at either the Adelanto/Kramer Junction area or Kern River Station. If sufficient interest is expressed through the open season, SDG&E and SoCalGas propose to determine whether the project costs should be rolled-in or whether this project should be priced on an incremental basis, and to submit the project to the Commission for approval.

The second service that SDG&E and SoCalGas propose is interruptible off-system service through backhaul.[66] This service utilizes off-setting transactions on both the SoCalGas and PG&E system to serve a customer on the PG&E system that purchases gas from a gas supplier located on the SoCalGas system. This service would be interruptible because it depends on there being sufficient forward haul deliveries from PG&E into SoCalGas. SDG&E and SoCalGas propose that a 75/25 ratepayer/shareholder incentive sharing mechanism apply to these interruptible off-system revenues, with a $5 million per year cap on the shareholder portion. SDG&E and SoCalGas contend that this

[66] The proposed tariff for this service appears in Schedule No. G-OSD in Exhibit 15.

will ensure that the maximum amount of interruptible capacity is offered, and that firm capacity cannot be profitably withheld from the market. The rate for this interruptible off-system service would be a negotiated volumetric rate up to a maximum rate of 16 cents per Dth.

B. Criticisms and Proposed Modifications

PG&E is concerned that the off-system proposal offers firm delivery at either Kern River Station or Kramer Junction. Kern River Station is the existing bi-directional interconnection point between PG&E and SoCalGas, and is closer to the PG&E citygate than Kramer Junction. PG&E points out that the proposal fails to consider the indirect operational or cost impacts on PG&E resulting from the siting of this delivery point. PG&E supports the proposal to let the market decide the location of the delivery point, so long as the prospective shippers are fully informed of all the costs on the SoCalGas system, as well as on the PG&E system.[67] PG&E recommends that SDG&E and SoCalGas be required to include the potential for increased costs on the PG&E system in their communications and materials for off-system service. The rebuttal testimony of SDG&E and SoCalGas acknowledges PG&E's concern and agrees to work with PG&E so that the potential costs can be communicated to potential off-system shippers seeking to deliver gas to PG&E.

DRA is not convinced that new facilities will be needed to provide firm off-system service. DRA recommends that the Commission direct SoCalGas to provide further evidence on whether new facilities will be needed to provide

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[67] In order to minimize costs to northern and southern California customers and shippers, PG&E prefers that off-system deliveries from the SoCalGas system be made at Kern River Station.

firm off-system service. BHP proposes that path-specific rates be considered due to the different locations of potential shippers.

Several parties expressed concern about the rate for interruptible off-system service. Some contend that there should be no charge because backhaul is being used, while others contend that the rate should reflect the actual cost or the short-run marginal cost of providing the service.

TURN and SCGC raised concerns about the proposed 75/25 sharing mechanism. TURN proposes an incentive of 10%, while SCGC asserts that no incentive is needed.

Sempra LNG proposes that the FAR reservation charge be refunded back to the shipper in the event of an off-system sale. Sempra LNG contends that since the end-user of the gas is not an SDG&E or SoCalGas customer, no additional costs on the system are being incurred, and the PG&E customer will end up paying more for the gas if the FAR reservation charge is not refunded to the shipper.

SCGC proposes that the Commission prohibit the use of SoCalGas' storage facilities to support the delivery of gas to PG&E's system. SCGC contends that such a restriction is needed because storage use is in high demand, and if it is used for delivering gas to PG&E, that will increase the cost of storage. SDG&E, SoCalGas and several other parties oppose SCGC's proposed prohibition of using storage to support off-system deliveries.

C. Discussion

This proceeding limited the issue of off-system service to PG&E only. While recognizing this limited scope, several parties continue to advocate that the Commission expand off-system deliveries to other interconnections besides

PG&E. We first address the off-system service to PG&E, followed by a brief discussion of whether off-system services should be expanded in the future.

None of the parties object to the idea of having SDG&E and SoCalGas provide off-system delivery service to PG&E. As mentioned by many of the parties, off-system service provides gas suppliers with another market to sell their gas. This is especially attractive to the LNG project sponsors who seek to provide gas supplies at various west coast locations. Off-system service will benefit northern California because additional gas supplies will be able to flow to customers of PG&E. These additional gas supplies flowing through the transmission systems of SDG&E, SoCalGas, and PG&E are likely to put downward pressures on the price of natural gas for the benefit of the entire California market. Off-system deliveries can also reduce transmission costs if system throughput is increased on the SDG&E and SoCalGas system as a result of these deliveries. With these benefits in mind, we believe that appropriate measures should be taken to encourage off-system deliveries to PG&E.

PG&E prefers that the off-system delivery from SoCalGas occur at Kern River Station, but recognizes that potential shippers may decide another location is more preferable. We will let the market decide which location is more preferable for off-system deliveries to PG&E. However, the determination as to where the off-system delivery point should be needs to consider all of the potential costs on the SDG&E and SoCalGas system, and on PG&E's system. SDG&E and SoCalGas acknowledge that they will work with PG&E to obtain PG&E's costs. We expect PG&E to provide these potential costs to SDG&E and SoCalGas when potential shippers express an interest in firm off-system service to PG&E. We also expect SDG&E and SoCalGas to inform potential shippers of PG&E's costs as well as their own.

SDG&E and SoCalGas propose to hold an open season for firm off-system delivery, and then to file an application for approval. In that application, the utilities expect to ask that the project costs either be rolled-in or that it be priced on an incremental basis. DRA's concern about what facilities are needed, and BHP's concern about the rate structure, can be raised as issues when the application is filed.

BHP recommends that SoCalGas' wholesale transmission tariff be changed so that LNG suppliers can make off-system deliveries to PG&E. We do not adopt BHP's suggestion. The LNG suppliers are different from wholesale customers of SoCalGas. As pointed out by SDG&E and SoCalGas, wholesale service is offered only to utilities or municipalities that transport natural gas across the SoCalGas system for their customers. In addition, the off-system service is different from that of a wholesale service. Accordingly, BHP's proposal is not adopted. The proposed Schedule No. G-OSD, attached to Exhibit 15, is a more appropriate tariff to use for providing off-system delivery service.

SDG&E and SoCalGas propose that the rate for interruptible off-system service be a negotiable volumetric charge up to 16 cents per Dth. Several parties contend that the rate should be zero or lower than the 16 cents. Coral Energy suggests that the rate be set between three to five cents per Dth. Others have suggested that the rate be set at the actual cost or the short run marginal cost of providing the service, but no one provided testimony on how much that should be.

The main argument for a zero or lower rate is that the use of backhaul does not require, or it requires very little, transportation on the SoCalGas system. Instead, the backhaul depends on the use of forward haul transportation on the SoCalGas system that has already been paid for. SDG&E, SoCalGas and

Watson/IP/CCC/CMTA essentially argue that in order for the backhaul to occur, the entire transmission system is being used to allow the off-system delivery to occur.

Our view is that in order for the backhaul to occur, the shipper requesting the off-system delivery must still send out gas onto SoCalGas' system in order for the gas to be delivered to the PG&E customer. Although the shipper's gas may not travel the full distance to the interconnection with PG&E, some use of the SoCalGas transmission system will occur. The transmission rate that is paid for on the forward haul on SoCalGas' transmission system needs to be taken into consideration as well, since SoCalGas is receiving revenue for the forward haul's usage on the transmission system. With these factors in mind, the 16 cents rate is too high. Since the off-system backhaul proposal was based on our desire to encourage access to additional gas supplies,[68] a 16 cents rate is likely to discourage potential shippers from wanting to make an off-system delivery to PG&E. As suggested by Coral Energy's witness, a fixed rate of five cents per Dth for interruptible off-system service to PG&E appears reasonable. This amount will encourage off-system service, as opposed to a higher rate, and it also recognizes that the shipper requesting the off-system service on a backhaul basis does not place as much of a cost burden on the SoCalGas system. For those reasons, a fixed charge of five cents per Dth shall apply on the gas volumes delivered under the interruptible off-system service to PG&E.

SDG&E and SoCalGas propose a 75/25 sharing incentive mechanism for interruptible off-system service revenues, subject to a $5 million annual cap.

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[68] See D.04-09-022, page 74.

TURN proposes that the incentive be limited to 10% of the revenues, subject to the annual cap. SCGC proposes to eliminate the incentive mechanism. With a lower interruptible off-system service rate, this should encourage potential gas shippers to use this service. SoCalGas is also obligated under the proposed G-OSD tariff to "make available physical displacement capability at the receipt points on an interruptible basis … ." (Ex. 15, Schedule No. G-OSD, Special Condition 9.) If gas marketers have excess supplies that they want to sell in northern California, they will seek out the availability of this interruptible service. Accordingly, the proposals for a sharing incentive mechanism for interruptible off-system service revenues are not adopted.

Sempra LNG proposes that the shipper receive a credit-back of the FAR reservation charge when a shipper makes an off-system delivery to a PG&E customer. SDG&E and SoCalGas oppose Sempra LNG's proposal, and assert that such revenues should be credited to end-use customers on the system. Since we are no longer adopting the credit-back mechanism, the unbundling of the five cents FAR reservation charge will result in a reduction in the end-user's transmission rate. Sempra LNG's credit-back concern is moot as a result of the adoption of the unbundling of the FAR reservation charge.

SCGC seeks to prohibit the use of SoCalGas' storage services to support the off-system delivery of gas to PG&E's system. SCGC is concerned that potential gas suppliers seeking to deliver into PG&E's system will increase the demand for storage, which will result in higher storage prices and less storage space.

We are not persuaded that potential suppliers of gas should be prevented from using the gas storage facilities of SoCalGas. As SDG&E and SoCalGas point out, if demand for storage exceeds the supply, this will drive the need for expansion of storage facilities. In addition, if storage revenues from SoCalGas' unbundled storage program exceed $21 million, ratepayers are entitled to a 50% share of the revenues. Ratepayers benefit if storage revenues are maximized. If gas suppliers are unable to use storage, this will deter them from transporting gas to PG&E, and will deprive PG&E customers with an additional source of gas. For those reasons, SCGC's proposal is not adopted.

The proposal to offer interruptible off-system service to PG&E by backhaul is approved, subject to our modifications, as discussed above. The proposal to use an open season process to solicit interest in firm off-system service, and to file an application for approval, is also approved. SDG&E and SoCalGas shall file an AL with the tariffs and services needed to implement these two services. The AL shall be filed within 45 days of the effective date of this decision. The tariffs and services shall be consistent with our discussion of these two services. The AL is subject to protest, and such protests shall be filed within 20 days after the AL has been filed. The AL shall be served as described in the FAR system discussion.

Several parties suggest that off-system deliveries to other pipelines are needed. We recognize that the suppliers of gas would like to pursue markets other than just PG&E. With the potential for large quantities of LNG to reach California, the opening of new markets is of tremendous importance to these shippers. To the extent the opening of new markets utilize the facilities of California-regulated gas utilities, that can help to reduce the transmission rates of California customers. The flow of additional gas supplies through the transmission systems of the California utilities should also result in more competition among gas suppliers. However, the use of SoCalGas' transmission facilities to transport gas to points outside of California raises FERC jurisdictional issues pertaining to the Hinshaw exemption of SoCalGas' transmission system, and has operational ramifications for intrastate transmission. (See 15 U.S.C. § 717(c).)

As we move forward with the FAR system, and with the recent completion of R.04-01-025 in D.06-09-039, we believe the time for us to consider off-system deliveries to pipeline interconnections other than PG&E will soon be here. Much of that will depend on whether the LNG project developers are successful in their efforts to bring LNG to California. The LNG project that is the furthest along estimates that regasified LNG will flow from Baja California in the early part of 2008. If other LNG projects are successful in their permitting efforts, those projects will follow. Accordingly, we will permit SDG&E and SoCalGas to file an application, no earlier than May 1, 2008, to offer off-system service to pipeline interconnections other than PG&E. By that time, we will have a clearer picture of what LNG projects are likely to be built, and what, if any, gas flows will be coming from LNG suppliers into California. The application shall address the impact of the Hinshaw exemption on the proposed service to other pipelines, and how this proposed service may impact the daily operations of the two utilities with respect to all their intrastate customers.

VII. Peaking Rate

A. Background of the Peaking Rate Tariff

The following section addresses the issue of whether SoCalGas' peaking rate tariff should be retained. In addition, we address SDG&E and SoCalGas' proposal to reinstate the multi-unit EG provision as part of peaking rate tariff.[69]

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[69] In D.04-09-022, the peaking rate was raised as an issue by some of the parties in that proceeding. We recognized in D.04-09-022 that the issue was related to the system

Footnote continued on next page

For the reasons set forth in the discussion, SoCalGas' peaking rate tariff is retained. The proposal to include the multi-unit EG provision as part of the peaking rate tariff is not adopted.

The peaking rate tariff is found in SoCalGas' Schedule GT-PS. The tariff, which refers to "peaking service" rather than "peaking rate," applies to gas transportation service provided to any noncore customer who bypasses SoCalGas, in part or in whole. As we stated, the peaking rate is "the tariff charged to a noncore customer who uses an interstate pipeline for baseload service, and returns to the SoCalGas system for peakload service." (D.01-08-020, page 31, FOF 2.) As described by the witnesses for SDG&E, SoCalGas and TURN, "The peaking rate is merely intended to charge partial bypass customers the cost to the utility of standing by to provide peaking service that might be used only infrequently." (Exhibit 86, page 1.)

The proposal to reinstate the multi-unit EG provision would extend the application of the peaking rate to all electric generation units owned by an entity if one of the plants owned by the entity bypasses the SoCalGas system. The multi-unit EG provision used to be in the RLS tariff, but was eliminated when the peaking rate tariff was adopted. This provision was contained in Special Condition 6 of the former GT-RLS tariff which stated: "For purposes of this tariff schedule, the entire load of a Utility Electric Generating (UEG) customer will be subject to this tariff schedule should one or more of the UEG's facilities meet the criteria for application of this tariff."

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integration proposal and allowed the parties to raise the issue in this proceeding or in a future BCAP. (D.04-09-022, p. 69.) The scoping memo in this proceeding identified the peaking rate as an issue to be addressed in this phase.

B. Criticisms and Proposed Modifications

Several parties favor the elimination of the peaking rate tariff. These parties represent interests that include interstate pipelines, oil and gas producers, cogenerators, manufacturers, independent and municipal electric generators, and LNG project sponsors. Several parties also oppose the proposal to reinstate the multi-unit EG provision.

The parties oppose the peaking rate for a number of reasons, most of which are contained in the following descriptions of their arguments:

- The peaking rate restricts pipeline-to-pipeline competition.
- The peaking rate has discouraged the siting of electric generation facilities in SoCalGas' service territory.
- The peaking rate is not cost based.
- Absent system integration, the peaking rate would apply to SDG&E for deliveries of gas at Otay Mesa.

The parties who oppose the multi-unit EG provision contend that if it is reinstated as part of the peaking rate tariff, the provision will be difficult to apply and easy to evade through the establishment of ownership by separate legal entities. They also contend that the ability to baseload a high load unit using the competing pipeline, and using SoCalGas to serve the other unit for peaking needs, would be limited or that the impact would be insignificant. They also contend that SoCalGas will collect more revenues than it costs to serve as a result of this provision.

C. Discussion

The peaking rate has been an issue in our proceedings since the interstate gas pipelines began serving customers in California in the early 1990s. In our prior decisions on this subject, the Commission has consistently recognized two main concerns. The first concern is to protect the remaining ratepayers on the system from having to pay the costs of the customers who leave to take gas service from the interstate pipelines. The second concern is to how to permit pipeline competition while ensuring the utility can recover its cost of providing service. These two concerns provided the impetus for the adoption of the RLS tariff in D.95-05-046. When we decided to move from the RLS tariff to a peaking rate, these concerns did not go away, and were still part of our reasoning for having the peaking rate tariff. With these concerns in mind, we discuss the arguments concerning the peaking rate tariff.

The purpose of the peaking rate is to close the regulatory gap between the rate design of the interstate pipelines, which uses a fixed rate structure, and SoCalGas' volumetric rate design. With this regulatory gap, it can be advantageous for certain customers to take baseload service from a competing interstate pipeline, and rely on SoCalGas for their peak needs. The peaking rate is also designed to recover SoCalGas' cost of providing service to customers who bypass or migrate to the competing pipeline, but may call upon SoCalGas to provide them with service in the future. This cost recovery also helps prevent the shifting of costs from those who bypass to the remaining ratepayers on the system.

The prior decisions regarding the RLS and peaking rate tariff have all recognized these kinds of impacts and adopted the tariffs for those reasons. Although the Commission changed the RLS tariff to develop a rate that narrowed the regulatory gap, we expressed the same concerns when we adopted the peaking rate tariff. The evidence presented in this proceeding has not changed the circumstances behind the adoption of the RLS and peaking rate tariff. We still want to encourage pipeline competition, but we need to ensure that bypass does not harm the remaining ratepayers, especially when the bypassing customer returns to SoCalGas for some or all of its gas needs.

There is ample evidence in the record to understand what is likely to occur if we eliminate SoCalGas' peaking rate tariff. The parties who support the elimination of the tariff include certain interstate pipelines and LNG project sponsors who compete, or may compete in the future, against SoCalGas for customers; large industrial and manufacturing customers who consume gas; and electric generators who use gas to generate electricity. The gas usage of these kinds of end-use customers is not trivial. If the peaking rate is eliminated, these pipelines, gas suppliers, and large gas customers have the most to gain.

When these large gas customers begin to migrate to the gas service of these competing pipelines, there is no doubt that there is going to be less throughput on the SoCalGas system. If heavy users of gas leave the system, the throughput volumes will decline dramatically. As a result, the costs of SoCalGas' transmission system will be allocated to fewer remaining ratepayers.

Some of these large gas customers may also be in a position to take their baseload service from a competing pipeline, but rely on SoCalGas for their peaking needs. This allows them to take advantage of the fixed rate and volumetric differences that exist between the rate structure of the competing pipeline and SoCalGas. In the absence of a peaking rate, this advantage is even greater.

If the peaking rate is eliminated, the remaining ratepayers will have to pay higher rates because they will have to bear the costs that the departing customers would have paid.[70] The remaining ratepayers, who are going to end up paying more, are the core and the smaller noncore customers. They are likely to remain as captive customers of SoCalGas, and it is highly unlikely that the competing pipelines will compete to serve these kind of customers.

SoCalGas has the obligation to serve all end-users in its service territory. Those who bypass to take service from a competing pipeline will no longer be paying anything to SoCalGas. Due to the obligation to serve, SoCalGas is required to have a system design that is capable of serving all customers, including those who bypass the system, but may one day call on SoCalGas again to provide full or partial service. As a utility service, certain facilities are needed in order to provide that service. Without the peaking rate tariff, when those customers call on SoCalGas to provide service, they would only pay the same rate for their gas as those customers who remain on the system. These returning customers receive the benefit of not paying for the overall costs of the system, but are still able to demand service when they want. This is unfair to SoCalGas and to the remaining ratepayers.

Another way of looking at this issue is that the peaking rate tariff is essentially a rate for providing standby service. There are certainly costs associated with having to provide a standby service. SoCalGas is being asked to standby, with the connections and facilities in place, to provide gas transmission service upon request. From SoCalGas' point of view, these standby costs include

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[70] We previously stated: "Two things are assured should the RLS tariff be immediately abolished: (1) the large noncore users on SoCalGas' system will migrate to the Pipelines for baseload and take peaking service from SoCalGas, and (2) the captive ratepayers of SoCalGas will pay higher rates." (D.00-04-060, p. 89.)

all of the costs associated with the transport of gas from the receipt point to the end-user. It is only equitable that someone who wants service on a standby basis should have to pay for a share of the facilities providing the service. That is what the peaking rate tariff is designed to do.[71] The peaking rate is higher than the otherwise applicable rate because the tariff is designed to recover some of the costs of providing service from those who use the service infrequently. The peaking rate tariff fairly compensates SoCalGas for standing ready to provide service when the bypassing customer returns to SoCalGas for service.

Another aspect of the peaking rate issue is that the tariff is a voluntary rate and only applies if the bypassing customer knows it will have to take service from SoCalGas at some point. If a customer leaves SoCalGas and takes full service from a competing pipeline all of the time, that person will not have to pay SoCalGas anything. That is a fair and reasonable result because that person is not causing any costs on the SoCalGas system. If, however, that person relies on SoCalGas for partial or full service, that customer should be required to pay for a share of the costs to provide service to that customer.[72] That too, is a fair and reasonable result.

[71] The peaking rate contains a demand charge that applies each month, regardless of whether the customer takes peaking service in that month. As we stated when the peaking rate tariff was approved, "This approach fairly compensates SoCalGas for the facilities associated with standing ready to provide firm peaking level service." (D.01-08-020, p. 25.)

[72] We decline to lower the peaking rate tariff because the rate is based on class average costs. If the rate is reduced, this would result in other customers subsidizing the partial bypass customers.

The opponents of the peaking rate contend that the tariff has discouraged electric generators from siting their facilities within SoCalGas' territory. They also point to the number of generating units that have been built in PG&E's territory, as opposed to those that have been built in SoCalGas' territory.

We are unpersuaded by this argument. The record shows that more generating units have been built in PG&E's territory than in SoCalGas' territory. However, none of the electric generators that were referenced in the various exhibits submitted testimony as to the reasons why their plants were sited outside of SoCalGas' territory. The testimony also contains a number of other significant reasons why generating plants decide to site at various locations.

The opponents of the peaking rate argue that the system integration decision, D.06-04-033, eliminated the peaking rate for SDG&E. Since the peaking rate no longer applies to SDG&E when it takes service from someone other than SoCalGas, other customers of SoCalGas should be able to take gas service from someone else without having to pay the peaking rate if they return to take full or partial service from SoCalGas.

We made it clear in the system integration decision that the peaking rate did not contemplate the situation where "LNG would be a new supply source for SDG&E and SoCalGas, or that Otay Mesa would become a joint receipt point," and that those "changes should be considered in deciding whether SoCalGas' peaking rate should apply to its noncore customers who procure gas through the Otay Mesa receipt point." (D.06-04-033, page 54.) We concluded that because Otay Mesa would be another receipt point on the integrated system, that the peaking rate did not apply. The bypassing customers who leave SoCalGas are not getting their gas service from a receipt point. Rather, they are receiving gas service from an alternate provider, in which case the peaking rate applies.

We realize that in order to fully address any problems associated with the peaking rate, we will have to carefully examine the underlying issues that led to the creation of the peaking rate. Specifically, we need to take a hard look at how we can close or minimize the regulatory gap created by the use of a volumetric rate design on the SoCalGas system and the interstate pipelines' use of a rate design that recovers the fixed costs of the pipeline in a fixed charge and the variable costs through a volumetric charge. The appropriate time and place to reexamine these issues is in the next BCAP, and eliminating the peaking rate now without addressing the underlying problems that the peaking rate attempts to resolve may cause additional problems.

For all of the above reasons, SoCalGas' peaking rate tariff shall continue in effect.

Having decided to retain the peaking rate, the next issue to address is whether the multi-unit EG provision should be adopted as part of the peaking rate tariff.[73] That provision would allow the peaking rate to apply to a situation where an entity that has two or more electric generating units takes baseload service from a competing pipeline for one unit, and service from SoCalGas for the other unit. The argument for adopting such a provision is that the entity can take advantage of the differences in the two rate structures to serve all of its units without having to pay the peaking rate tariff.

During the hearing, it became clear that the administration of the multi-unit EG provision will be difficult. There are likely to be situations where

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[73] It is not clear whether SDG&E and SoCalGas intend for this provision to only apply to "utility" electric generation, or whether it should apply to all multi-unit EG units. For purposes of this decision, that distinction does not make a difference.

the electric generating units are owned by different entities, but may or may not be owned by a common parent company. That will make it difficult for SoCalGas to detect when the multi-unit EG provision should apply.

In addition, the manner in which the generating units are operated may make it difficult for plant owners to take advantage of the differences in rate structures by baseloading the unit using gas from a competing pipeline, while using the second unit, served by SoCalGas, to meet peaking needs. Also, application of the multi-unit EG provision might also result in SDG&E and SoCalGas recovering more revenue than it should.

For all of those reasons, we do not adopt the proposal to reinstate the multi-unit EG provision as part of the peaking rate tariff.

The peaking rate has been explored in prior SoCalGas BCAPs. We have acknowledged that the differences between the rate structures of the interstate pipelines and SoCalGas can be narrowed even further or eliminated if the rate design for SoCalGas is changed from a volumetric structure to a straight fixed variable rate structure. (See D.00-04-060 [5 CPUC3d 697, 747-748].) Although a customer charge was included as part of the peaking rate tariff that was adopted in D.01-08-020, this rate design change is not satisfactory to those who may want to use the peaking rate. A wholesale change in rate design may be needed if parties want to truly resolve the peaking rate issue,[74] promote pipe-to-pipe competition, and protect the captive customers who remain on the system.[75] A wholesale redesign of rates, however, may be controversial as well.

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[74] The multi-unit EG issue could also be solved by a redesign of rates.

[75] See Exhibit 56 at page 5.

The continuing opposition of certain parties to the peaking rate tariff, and the fact that only one customer has signed up for peaking service, indicates that the peaking rate may need to be adjusted further or eliminated altogether. This continuing opposition to the peaking rate also suggests that we need to reexamine SoCalGas' underlying rate structure that gave rise to the peaking rate. Accordingly, SoCalGas will be ordered to propose in its next BCAP a redesign of the peaking service tariff or a total redesign of its rates to ensure that viable partial bypass can occur while allowing pipe-to-pipe competition to occur. In the next BCAP, we intend to fully reexamine the causes of the regulatory gap that have led to the peaking rate including the utilities' rate design, balancing requirements, and other factors. Therefore, upon closing of the regulatory gap, we will sunset the peaking rate at the conclusion of the next BCAP.

VIII. Biennial Cost Allocation Proceeding

A. Introduction

The Commission's last complete adjudication of the BCAPs for SDG&E and SoCalGas occurred in D.00-04-060.[76] Subsequent BCAP applications requesting revised rates effective January 1, 2003 were filed by SoCalGas (A.01-09-024) and SDG&E (A.01-10-005) on September 21, 2001 and October 5, 2001, respectively. Due to the Commission's approval of the CSA in D.01-12-018, SoCalGas and SDG&E were to file revised BCAP applications. As a result of parties' requests to defer the proceedings, the Commission in D.03-05-050 dismissed these two BCAP applications. The Commission

[76] The issue of when SDG&E and SoCalGas should be required to file their next BCAP applications was identified in the scoping memo and amended scoping memo as an issue.

recognized in D.03-05-050 that SoCalGas and SDG&E would be filing new BCAP applications in September 2003, and that those BCAP applications would receive new proceeding numbers.

SoCalGas and SDG&E filed their new BCAP applications on September 3, 2003 (A.03-09-008) and September 17, 2003 (A.03-09-031), respectively. Those two applications requested that the revised rates go into effect on January 1, 2005. On April 1, 2004, the Commission adopted D.04-04-015, which addressed the implementation of the tariffs adopted in the CSA decision. However, the Commission stayed D.04-04-015 until a decision in Phase 1 of Order Instituting Rulemaking R.04-1-025 could be issued. In an April 4, 2004 ruling in A.03-09-008 and A.03-09-031, the BCAP schedule was suspended pending a further ruling or a Commission decision.

In D.04-05-039, the Commission dismissed A.03-09-008 and A.03-09-031 without prejudice. D.04-05-039 directed SoCalGas and SDG&E to file new BCAP applications within 120 days of the date the stay of D.04-04-015 is lifted, or as otherwise ordered by the Commission.

In the Phase 1 decision in R.04-01-025, D.04-09-022, we continued the stay of D.04-04-015 until further notice. (D.04-09-022, page 73.) As a result of the continuing stay, the Commission has not set a date for SDG&E and SoCalGas to file new BCAP applications.

B. Discussion

More than six years have elapsed since we fully examined the cost allocation issues pertaining to SDG&E and SoCalGas' gas transmission system. Some of the parties recommend that if the FAR proposal is adopted, SDG&E and SoCalGas' BCAP filings occur shortly after the open season, or that the filings be delayed until after the Commission has gained experience with the new FAR system. SDG&E and SoCalGas recommend that they file their BCAP applications within eight months of this decision. SCGC recommends that if a system of FAR is adopted, the BCAP should be deferred until at least a year after the FAR has been implemented.

Due to the various proceedings involving the gas industry in general, and the gas market structure for southern California, the BCAPs for SoCalGas and SDG&E have been postponed. Today's decision marks a significant change to the basic structure of the natural gas market in southern California and will result in an unbundled element in SoCalGas' rates that are not reflected in its current rate structure. We support a cost-based FAR reservation charge policy, and it is our intention to address this issue in the next BCAP.

A new BCAP is long overdue. Furthermore, due to our intention to adopt a cost-based FAR charge and reexamine the regulatory gap that has led to the peaking rate, we believe the next BCAP should begin within the next year. Accordingly, SDG&E and SoCalGas shall be directed to file their respective BCAP applications no earlier than October 1, 2007 and no later than December 15, 2007.

IX. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was served on the parties in accordance with Pub. Util. Code § 311 and Rule 14.2 of the Rules of Practice and Procedure. The comments and reply comments to the proposed decision have been considered and appropriate changes have been made to this decision.

X. Assignment of Proceeding

Geoffrey F. Brown is the assigned Commissioner, and John S. Wong is the assigned ALJ in this proceeding.

Findings of Fact

1. The origin of this proceeding can be traced back to R.98-01-011 wherein we considered and identified appropriate reforms to the natural gas market structure in California.

2. D.99-07-015 acknowledged that PG&E's Gas Accord market structure should be considered for SoCalGas.

3. D.01-12-018 adopted the CSA, which called for a system of firm tradable transmission rights on SoCalGas' backbone transmission system, the unbundling of the backbone costs from transportation rates, and an at-risk rate structure for the recovery of the backbone transmission costs.

4. D.04-04-015 adopted the tariffs to implement D.01-12-018, but due to another proceeding, D.04-04-015 was stayed and extended in D.04-09-022 until further notice.

5. D.04-09-022 directed SDG&E and SoCalGas to file an application regarding their system integration and FAR proposals.

6. The system integration issue was addressed in the first phase of this proceeding in D.06-04-033.

7. Due to the difference between the delivery capability of the upstream gas supplies and the take-away capacity of the receipt points on the SDG&E and SoCalGas integrated transmission system, problems in the delivery of gas can result.

8. Under the current system of allocating capacity on the SDG&E and SoCalGas transmission system: (1) end-use customers are the only ones who can transport gas; (2) SoCalGas allocates the available receipt point capacity to the upstream pipelines daily; and (3) the upstream interstate pipelines allocate the

capacity among their shippers using their FERC-approved capacity allocation rules.

9. The current system of capacity allocation can result in a situation where access to the system is available only on an interruptible basis, shippers' gas supplies are pro-rated, and receipt points are constrained.

10. SDG&E and SoCalGas' FAR proposal would allocate access rights to the capacity at a particular receipt point on the integrated transmission system to various market participants using a three-step open season process.

11. The two major differences between the unbundled FAR proposal and the FAR proposal is the unbundling of backbone transmission costs from transmission rates, and putting SDG&E and SoCalGas at-risk for the recovery of the backbone transmission costs.

12. DRA's proposal allocates FAR to end-use customers based on the current allocation of intrastate gas transmission costs in the last BCAP, excluding the California gas production receipt points.

13. The Joint Proposal addresses a process for granting scheduling rights for new or expanded receipt point capacity, and a process for granting scheduling rights for new or expanded receipt point capacity in the Southern transmission zone.

14. This phase of the proceeding revisits many of the same issues that were considered when the CSA was adopted, and the various parties continue to disagree on what kind of market structure is best for southern California.

15. The time is ripe to adopt a system of FAR for southern California.

16. The basic underlying system of firm tradable transmission rights has worked and functioned well in northern California.

17. LNG project sponsors, as well as others, seek assurance that their gas can be delivered into the receipt points on the SDG&E and SoCalGas transmission systems.

18. Although capacity constraints have not been much of a problem during the past couple of years, that does not mean these constraint problems have gone away.

19. With the possibility of LNG supplies flowing into southern California, and other changes in the gas market, receipt point constraints may occur again at other receipt points.

20. Under the current system, end-users face uncertainty over whether their gas will flow through a constrained receipt point.

21. The uncertainty over whose gas will flow affects the procurement decisions of end-users.

22. DRA's proposed allocation method does not provide shippers and marketers with any firm capacity, is likely to result in market participants spending a lot of time to match their needs, and is likely to lead to confusion.

23. The Joint Proposal is limited to creating scheduling rights for new or expanded receipt point capacity, and does not establish a system of FAR for existing receipt points on the transmission system.

24. The capacity allocation proposals considered in this decision vary from the capacity allocation method contained in the CSA that was adopted in D.01-12-018.

25. According to its terms, the CSA was terminated on August 31, 2006.

26. The FAR proposal will continue to provide market participants with flexible options and result in the creation of a citygate market for southern California.

27. The adoption of the FAR proposal provides certainty to FAR holders that their gas can be delivered from the receipt point to the citygate, which in turn will encourage parties to enter into long-term gas supply contracts.

28. The concerns regarding the FAR proposal's complexity, increased costs, and affiliate preference are unwarranted.

29. The facts addressed in the Union Pacific Fuels decision are different and distinguishable from the reservation charge that would be assessed on FAR holders.

30. The transmission system has been paid for in rates by the end-users of SDG&E and SoCalGas.

31. The FAR reservation charge provides the FAR holder with access to the transmission system.

32. It is appropriate that shippers and marketers, who have not paid for the cost of the transmission system, pay for a share of the transmission facilities through the reservation charge.

33. The at-risk provision operates in conjunction with the unbundling of the backbone transmission costs and the 15.75 cents per Dth reservation charge.

34. A reservation charge lower than the unbundled FAR proposal rate of 15.75 cents per Dth is needed to stimulate participation for holding a FAR.

35. A cost-of-service FAR charge based on backbone transmission costs will send the appropriate price signals to users of the system.

36. A FAR system that has a lower unbundled reservation charge and no at-risk provision will provide a baseline for determining whether future adjustments to the FAR system are needed.

37. Putting SDG&E and SoCalGas at risk would act as an incentive to maximize throughput on their system, which is contrary to the energy efficiency and conservation goals, and is not appropriate at this time.

38. It is appropriate to unbundle the FAR reservation charge of five cents per Dth from the end-user's bundled transmission rate, and that the credit-back mechanism not be adopted.

39. The parties proposed a number of modifications to the FAR proposal.

40. The citygate pooling service allows for the aggregation and disaggregation of natural gas at the citygate, and creates a pricing point for customers to buy and sell gas.

41. SDG&E and SoCalGas propose to offer firm backhaul service and interruptible off-system service through backhaul.

42. Off-system service provides gas suppliers with another market to sell their gas.

43. The peaking rate tariff applies to gas transportation service provided to any noncore customer who bypasses SoCalGas, in part or in whole.

44. The multi-unit EG provision used to be in the RLS tariff, but was eliminated when the peaking rate tariff was adopted.

45. The evidence presented in this proceeding has not changed the circumstances behind the adoption of the RLS and peaking rate tariff.

46. If the peaking rate is eliminated, the remaining ratepayers will have to pay higher rates because they will bear the costs that the departing customers would have paid.

47. Without the peaking rate, a bypassing customer who calls on SoCalGas for service would only pay the same rate for gas as those customers who remain on the system.

48. The argument that the peaking rate has discouraged electric generators from siting within SoCalGas' service territory is unpersuasive.

49. D.06-04-033 described why the peaking rate does not apply if SDG&E obtains gas at the Otay Mesa receipt point.

50. The evidence does not support the reinstatement of the multi-unit EG provision as part of the peaking rate tariff.

51. The last complete adjudication of the BCAPs for SDG&E and SoCalGas occurred in D.00-04-060.

Conclusions of Law

1. Due to anticipated changes in gas flows, the likelihood that additional gas supplies will flow into California, and the constraint problems that have occurred in the past and which can reoccur again, the current system of allocation should be replaced by a system of FAR.

2. DRA's proposal is not a practical solution for allocating capacity to market participants and should not be adopted.

3. SDG&E and SoCalGas should incorporate the unbundling concept from the unbundled FAR proposal for the FAR reservation charge of five cents per Dth, and the features of the Joint Proposal that we adopt, as described in this decision, into the adopted FAR system.

4. SDG&E and SoCalGas should perform a cost study of the backbone transmission system prior to filing the next BCAP, and the Commission should adopt a new cost-based FAR charge based on the results of the next BCAP.

5. The conversion of the four types of scheduling right situations into the three-step process of the adopted FAR system, as described in the decision, are appropriate and consistent with prior decisions.

6. D.01-12-018 and D.04-04-015 are now moot as a result of today's adoption of the FAR system.

7. The FAR reservation charge is not unlawful under the holding of Union Pacific Fuels.

8. The credit-back mechanism is not discriminatory, and the replacement of the credit-back mechanism with the unbundling of the FAR reservation charge from the end-user's transmission rate eliminates any alleged discriminatory effect.

9. SDG&E and SoCalGas should be authorized to establish a balancing account so that they are not at risk for any under-recovery of the unbundled FAR reservation charge revenues, and any over-recovery is refunded to ratepayers.

10. SDG&E and SoCalGas' FAR proposal, as modified by today's decision, should be adopted as the model for the FAR system, and SDG&E and SoCalGas should incorporate the adopted modifications to the FAR proposal, as described in this decision, into the adopted FAR system.

11. There are no provisions in the Continental Forge or SCE settlements that prevent us from adopting the FAR proposal as the model for the FAR system.

12. SDG&E and SoCalGas should be authorized to establish the FAR Memorandum Account to track and recover the costs of implementing the FAR system and the other services.

13. SDG&E and SoCalGas should file an AL to implement the tariffs and services needed for the FAR system.

14. A review process to assess how the FAR system is working, and whether any changes or modifications are needed, should be initiated by application 18 months after the initial open season has concluded.

15. SDG&E and SoCalGas' proposal to offer a pooling service should be approved, and an AL should be filed to implement the tariff and services needed for the pooling service.

16. To the extent the costs of implementing the pooling service are not included in the FAR system implementation costs, SDG&E and SoCalGas should be allowed to track and recover from all ratepayers the reasonable costs of implementing this service up to a maximum of $500,000.

17. SDG&E and SoCalGas' proposal to offer off-system delivery service to PG&E, as modified by our discussion in this decision, should be approved, and an AL should be filed to implement the tariff and services needed for the off-system delivery service.

18. The use of SoCalGas' transmission facilities to transport gas to points outside of California raises FERC jurisdictional issues, and has operational ramifications for intrastate transmission.

19. SDG&E and SoCalGas should be permitted to file an application to offer off-system service to pipeline interconnections other than PG&E no earlier than May 1, 2008.

20. The SoCalGas peaking rate tariff should continue in effect, and the multi-unit EG provision should not be included as part of the peaking rate tariff.

21. SoCalGas should be ordered to propose in its next BCAP a redesign of the peaking service tariff or a total redesign of its rates to ensure that viable partial bypass can occur while allowing pipe-to-pipe competition to occur.

22. The causes of the regulatory gap that have led to the peaking rate, including the utilities' rate design, balancing requirements, and other factors, should be reexamined in the next BCAP, and upon closure of the regulatory gap, the peaking service tariff should expire at the conclusion of the next BCAP.

23. SDG&E and SoCalGas should file their BCAP applications no earlier than October 1, 2007 and no later than December 15, 2007.

O R D E R

IT IS ORDERED that:

1. A firm access rights (FAR) system is adopted as the new gas market structure for the integrated gas transmission system of San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas).

    a. The adopted FAR system shall be comprised of the SDG&E and SoCalGas FAR proposal, the unbundling of the FAR reservation charge of five cents per decatherm from the end-user's transmission rate, the adopted features of the Joint Proposal, and the adopted modifications to the FAR proposal, as described in this decision.

    b. SDG&E and SoCalGas shall incorporate all of these adopted elements into the FAR system.

2. SDG&E and SoCalGas are authorized to offer a gas pooling service on the SDG&E and SoCalGas integrated transmission system, and an off-system delivery service to Pacific Gas and Electric Company (PG&E).

3. SDG&E and SoCalGas shall file appropriate advice letters (AL) to implement the FAR system, the gas pooling service, and off-system delivery service to PG&E.

    a. The ALs shall contain the tariff and service offerings, and shall be consistent with, and in compliance with today's decision.

    b. The ALs shall be filed within 45 days of the effective date of this decision. The ALs are subject to protest, and such protests shall be filed within 20 days after the ALs have been filed.

    c. SDG&E and SoCalGas shall serve the ALs by e-mail on the service list to this proceeding, as well as on interested parties who have requested notification of AL filings for SDG&E and SoCalGas.

4. The FAR system, the gas pooling service, and the off-system delivery service to PG&E shall be implemented and operational beginning no later than

365 days after a decision, resolution, or Energy Division has approved the implementing tariffs and related services.

5. SDG&E and SoCalGas are authorized to establish the FAR Memorandum Account to track and recover the costs of implementing the FAR system and the other services.

   a. To the extent the costs of the pooling service are not included in the estimate of the FAR system implementation costs, SDG&E and SoCalGas are authorized to track and recover from all ratepayers the reasonable costs of implementing the pooling service, up to a maximum of $500,000.

6. SDG&E and SoCalGas are authorized to establish a balancing account to track and recover the difference for any under- or over-recovery of the unbundled FAR reservation charge revenues.

7. A review process of the FAR system will be conducted to assess how the FAR system is working, and whether any changes or modifications to the FAR system are needed.

   a. SDG&E and SoCalGas shall file an application 18 months after the initial open season has concluded, and shall include the type of information described in this decision.

8. SDG&E and SoCalGas shall be permitted to file an application, no earlier than May 1, 2008, to offer off-system service to pipeline interconnections other than PG&E.

   a. The application shall include the type of information described in this decision.

9. The SoCalGas peaking rate tariff shall continue in effect, and the proposal to include the multi-unit electric generation provision into the peaking rate tariff is not adopted.

a. In its next Biennial Cost Allocation Proceeding (BCAP), SoCalGas shall include a proposal for a total redesign of its rate consistent with the discussion regarding closing or minimizing the regulatory gap.

b. Upon closing of the regulatory gap, the existing peaking service tariff shall sunset at the conclusion of the next BCAP.

10. SDG&E and SoCalGas shall file their BCAP applications no earlier than October 1, 2007 and no later than December 15, 2007.

a. The BCAP applications shall include a cost study of the backbone transmission system and a proposal for a new cost-based FAR reservation charge.

11. Application 04-12-004 is closed.

This order is effective today.

Dated December 14, 2006, at San Francisco, California.

MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
Commissioners

Commissioner Chong reserves the
right to file a concurrence.