Decision 06-09-039 September 21, 2006

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies and Rules to Ensure Reliable, Long-Term Supplies of Natural Gas to California.	Rulemaking 04-01-025 (Filed January 22, 2004)

(APPENDIX - Settlement Agreement Attached)

PHASE 2 ORDER ADDRESSING INFRASTRUCTURE ADEQUACY & SLACK CAPACITY, INTERCONNECTION & OPERATIONAL BALANCING AGREEMENTS, AN INFRASTRUCTURE WORKING GROUP, NATURAL GAS SUPPLY AND INFRASTRUCTURE ADEQUACY FOR ELECTRIC GENERATORS, NATURAL GAS QUALITY, AND OTHER MATTERS

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Summary

This decision is the culmination of a proceeding initiated by the Commission in January 2004 to assess the sufficiency of natural gas supplies and infrastructure in California. The Commission issued a Phase I decision in September 2004, specifically resolving some matters related to the anticipated introduction of gas supplies derived through liquefied natural gas (LNG). This order addresses the remaining issues in the proceeding. This order, among other things, does as follows:

1. Approves Interconnection Agreements and Operational Balancing Agreements for LNG providers (including gas arriving at Otay Mesa).
2. Directs the Pacific Gas and Electric Company (PG&E), the San Diego Gas & Electric Company (SDG&E), and the Southern California Gas Company (SoCalGas) to adopt, as a backbone transmission planning standard, one-in-ten cold and dry year average demand.
3. Approves an agreement between PG&E and independent storage providers for direct interconnection to storage customers.
4. Endorses the creation of an Infrastructure Working Group which will enable all participants and relevant state agencies to monitor system utilization and identify expansion needs.
5. Clarifies and expands policies related to receipt point expansion on the SoCalGas system.

6. Finds that no party has identified a specific example of inadequate infrastructure affecting the delivery of gas over the next decade.

7. Finds that the backbone transmission capacity on both the PG&E and SoCalGas systems is adequate and that we are comfortable with the proposed slack capacity ranges for backbone capacity as proposed by the utilities.

8. Modifies SoCalGas' proposed revisions to its rules affecting open seasons related to local transmission capacity. SoCalGas seeks to establish a requirement that customers seeking firm capacity commit to 5- or 10-year contracts. Affirms current practice of requiring no more than 2-year commitments for smaller customers. For larger customers we require take or pay commitments until the earlier of either (1) two years elapsing from the date that the associated facilities are placed into service, or five years elapsing from the customer's sign up date. Requires SoCalGas and SDG&E to upgrade system when nominations exceed available capacity, or explain its reason not to. Requires that tradeable rights be implemented for local transmission capacity.

9. Adopts rule changes to SoCalGas and PG&E tariffs regarding gas quality. SoCalGas Rule 30 is revised to reflect a maximum Wobbe Index of 1385. The California Environmental Quality Act (CEQA) does not apply to these tariff rules changes.

10. Historical California natural gas production is grandfathered under current tariff rules.

11. Adopts various other changes to PG&E's Rule 21 and SoCalGas' Rule 30 establishing gas quality standards, to make the two rules more consistent with each other.

Background

The Commission explained the purpose of this proceeding in D.04-09-022. The rulemaking docket was opened in response to new reports, recent Federal Energy Regulatory Commission (FERC) orders, and ongoing changes in the natural gas market, which indicated that there may not be sufficient natural gas supplies or infrastructure to meet the long-term needs of the state's residential and business consumers. The Commission concluded that it needed to act in 2004 to ensure that: (1) energy efficiency and renewable energy programs help moderate the potential future supply imbalance; (2) there is sufficient firm interstate and intrastate pipeline capacity to serve California; (3) storage facilities will be fully and beneficially utilized; and (4) the utilities and their customers would have access to new natural gas supplies.

The Commission determined that it needed to decide a number of issues in 2004, due to the long lead time needed to construct LNG facilities and due to certain deadlines in 2004 involving the expiration of existing interstate pipeline capacity contracts and open seasons for certain pipelines, including pipelines related to proposed LNG projects. The Commission considered LNG to be an important new source of natural gas supply.

Because of deadlines facing the utilities and other participants in the natural gas market, the Commission established two phases in this rulemaking. The initial rulemaking ordered the respondents utilities to file, by February 24, 2004, Phase I proposed guidelines prescribing how they would:

1. enter into contracts with interstate pipelines (whether new contracts or renewals of existing contracts) to meet core supply obligations;
2. provide access on intrastate pipelines to LNG supplies; and
3. provide access to interconnecting facilities with interstate pipelines to increase California's access to natural gas supplies.

The initial rulemaking identified the following as issues for Phase II:

1. how the designated utilities should provide emergency reserves consisting of slack intrastate pipeline capacity, contracts for additional firm interstate pipeline transportation rights, and supplies of natural gas in storage dedicated for emergency needs;
2. The process by which the utilities would keep the Commission informed about the infrastructure and services provided to noncore customers, and to propose a crediting mechanism in the event a noncore backstop recovery charge is adopted; and
3. new ratemaking policies that will be consistent with the goal of ensuring adequate and reliable long-term supplies of natural gas at reasonable rates to California.

The Commission resolved Phase I issues in D.04-09-022. After various rounds of proposals and comments, the Assigned Commissioners issued a Scoping Memo on February 28, 2005, that identified the specific questions to be addressed in Phase II as follows:

- Should the natural gas quality specifications for California be revised, and if so, how?
- Should the Commission adopt a standardized operational balancing agreement or certain specific criteria for upstream pipelines connecting to the gas utility's transmission system?
- Can the California gas utilities' existing infrastructure and operations adequately protect California from short-term or long-term natural gas shortages caused by interruptions in natural gas supply?
- Should the Commission order the gas utilities to provide emergency reserves for California in the form of additional intrastate capacity or slack capacity, additional interstate capacity, and/or additional in-state natural gas storage?
- Should independent gas storage facilities be permitted to directly connect with other market participants such as California producers, electric generators, or other noncore customers, which Public Utilities Code sections are relevant to this issue, and should the Commission be concerned with bypass?
- Should the Commission form a working group to monitor the infrastructure and services provided to noncore customers and to keep the Commission informed about the situation so that the Commission can consider whether the utilities should provide a backstop function for noncore customers?
- Should the Commission order the utilities to provide a backstop function for noncore customers who fail to provide for their own gas supply needs?
- Should the Commission adopt a crediting mechanism or another mechanism so that noncore customers who procure their own supplies do not have to pay for any such backstop function?

- Should the cost allocation issues regarding emergency reserves or a backstop function be addressed now or deferred until such time the Commission decides whether or not to adopt emergency reserves or the backstop function?

- Should the Commission determine in this proceeding whether the gas utilities' backbone transmission capacity is sufficient to accept maximum withdrawals from all gas storage facilities during peak periods, if emergency gas storage reserves are authorized, or should the Commission defer this issue until such time as it decides whether or not to adopt an emergency gas storage reserve?

- Are the current at-risk ratemaking provisions consistent with the goal of ensuring adequate and reliable long term natural gas supplies, and should the at-risk provisions remain in place or be eliminated for the gas utilities?

- Should PG&E remain at risk for noncore throughput, while at-risk ratemaking is eliminated for SoCalGas and SDG&E?

- Should the Commission address whether a balancing account should be established for PG&E's core local transmission revenue requirement in this proceeding or should this issue be addressed in PG&E's 2008 gas market structure proceeding? If it is to be addressed here, should such an account be established?

In a revised scoping memo issued May 11, 2005, the assigned Commissioners expanded the scope of Phase II to examine electric utility plans to supply, transport and store natural gas for electric generation in those plants for which the utility is responsible to provide the gas.

The Commission held hearings on infrastructure adequacy issues beginning June 22, 2005, and ending September 1, 2005. The Commission held hearings on gas quality issues beginning December 12, 2005, and ending

December 16, 2005. The administrative law judge (ALJ) declared Phase II of this proceeding submitted as of the receipt of reply briefs on February 1, 2006.

Discussion

I. Measuring Infrastructure Adequacy for Natural Gas Utilities

A. Backbone Capacity - Defining the Standard

How much backbone pipeline capacity is enough?

Most of the natural gas used in California comes from out-of-state natural gas basins. Natural gas from out-of-state production basins is delivered into California via the interstate natural gas pipeline system. The five major interstate pipelines that deliver out-of-state natural gas to California consumers are the Gas Transmission Northwest Pipeline, Kern River Pipeline, Transwestern Pipeline, El Paso Pipeline, and Mojave Pipeline. (Another pipeline, the North Baja Pipeline, takes gas off of the El Paso Pipeline at the California/Arizona border, and delivers that gas through California into Mexico.)

Most of the natural gas transported via the interstate pipelines, as well as some of the California-produced natural gas, is delivered into the PG&E and SoCalGas intrastate natural gas transmission pipeline systems (commonly referred to as California's "backbone" natural gas pipeline system). Natural gas on the utilities' backbone pipeline systems is then delivered into the local transmission and distribution pipeline systems, or to natural gas storage fields. The SDG&E system does not include storage, and does not interconnect directly with interstate pipelines. SDG&E refers to its largest pipelines as local transmission. Thus SDG&E does not consider itself as having a backbone pipeline system.

SoCalGas suggests that it should maintain total surplus capacity on its backbone system of 20-25% above average annual system total demand during an average temperature year and normal hydroelectric conditions. PG&E proposes that the utilities should be required to maintain backbone transmission capacity sufficient to result in an 80%-90% utilization factor under cold temperature and dry hydroelectric conditions that have a one-in-ten-year likelihood of occurrence. This is the equivalent of an 11%-25% average surplus capacity during a cold and dry year[1].

In general, the parties believe that the state's backbone pipeline capacity is adequate—with the exception of SCE. On behalf of The Utility Reform Network (TURN), Michael Florio states in his prepared testimony (p. 2, 3) that "For once this Commission has received some good news – the receipt point capacity and the backbone transmission facilities that PG&E and the Sempra Utilities currently have in place should provide sufficient infrastructure to assure physical reliability for at least the next ten years, through 2016, in both northern and southern California. In other words, new transmission capacity per se is not needed for the foreseeable future, even under fairly stringent planning criteria." Florio further asserts that PG&E's proposed guideline is generally consistent with historical reliability planning for electric service and should be sufficient to

[1] Of the SoCalGas total backbone receipt capacity, 20-25% of that capacity would be unused during an average temperature year and under normal hydroelectric conditions. PG&E proposes that, under cold and dry conditions, demand would amount to 80-90% of the available firm backbone capacity on average. This is equivalent to saying 11-25% of the available backbone transmission capacity would be unused.

ensure both reliable natural gas service and a reasonable opportunity for price competition among competing supply sources. He notes that this would be somewhat stricter than what the Commission has endorsed in the past, in the sense that it takes into consideration the impact of adverse hydroelectric conditions on gas demand for electric generation, in addition to the traditional focus on the effects of colder-than-average temperatures on core gas demand. Florio argues that given the growing reliance on natural gas for electric generation, and the loss of alternative fuel capability in the electric sector, inclusion of dry hydroelectric conditions in the planning criteria is appropriate.

The Division of Ratepayer Advocates (DRA)[2] does not see the need for a specific reserve margin over the existing utility planning standards. ORA notes that in I.00-11-002[3] SoCalGas and SDG&E requested authorization for slack capacity guidelines. While the Commission adopted system planning capacity criteria for both SoCalGas and SDG&E, it did not adopt intrastate slack capacity guidelines. It concluded the following: "This planning standard should ensure all SoCalGas customers of adequate transportation capacity, without burdening any customers with the cost of maintaining excess slack capacity."(Opinion on Adequacy of Southern California Gas Company's and San Diego Gas and Electric Company's Gas Transmission Systems to Serve the Present and Future Needs of Core and Noncore Customers (2002) D.02-11-073, mimeo p. 30.)

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[2] During the courses of the proceeding, after filing briefs on infrastructure adequacy, the Office of Ratepayer Advocates changed its name to the Division of Ratepayer Advocates.

[3] Order Instituting Investigation Into the Adequacy of the SoCalGas and SDG&E Gas Transmission Systems to Serve the Present and Future Gas Requirements of SDG&E's Core and Noncore Customers

Woodside Natural Gas (Woodside) states that "There is no question, based on the record in this proceeding, that the gas transmission system in California is currently adequate to reliably deliver natural gas to California's end users." (Opening Brief, pg. 8).

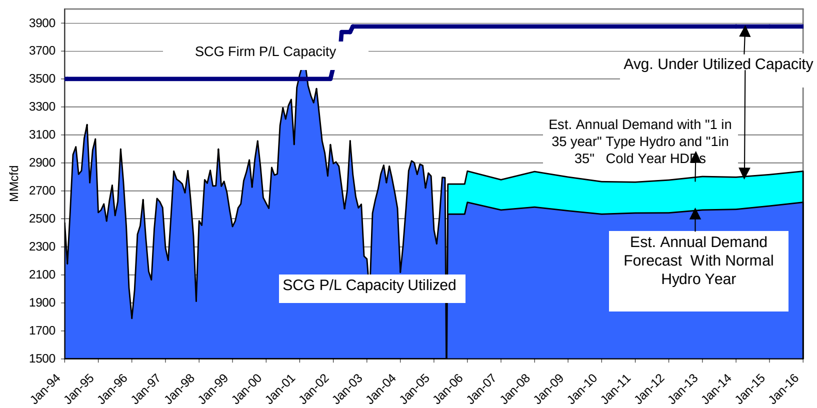
Trans Canada's GTN and North Baja Systems (GTN) support the utilities' views that intrastate capacity on both PG&E and SoCalGas/SDG&E's systems is sufficient for both immediate demand and for the foreseeable future. GTN opposes expensive capacity expansions when more economical options are available.

Lodi Gas Storage (Lodi) asserts that record developed in the proceeding is reasonably clear that the state's pipeline infrastructure is adequate, in general.

Kern River Gas Transmission Company (Kern River) states that SoCalGas' means of assessing the adequacy of its backbone transmission and receipt point capacity is "overly simplistic" and does not reflect the manner in which its system is used. Kern River emphasizes the importance of adequate receipt point capacity during peak periods.

In contrast to the other parties, SCE offers a lengthy critique of the SoCalGas/SDG&E proposal. SCE asks the Commission to reject SoCalGas and SDG&E's proposed slack capacity guideline, and adopt an alternative measure of infrastructure adequacy that takes into account peak period (stress) conditions, receipt point constraints, uncertainties in forecast loads and conditions, and other factors.

First, SCE argues that using average daily demand figures to determine slack capacity is wholly ineffective, particularly when considering the actual variability that occurs on SoCalGas and SDG&E's system during the year. System flows vary from day-to-day and month-to-month during the year, and do not adhere to simple flat annual averages. SCE points to Figure 1 in SoCalGas witness Jeffrey Hartman's testimony (Exhibit 8) to illustrate this point. This figure is duplicated below:



SCE points to the left side of the graph which shows the variability in the day-to-day and month-to-month capacity utilization on SoCalGas' system from 1994 to 2005, and argues that this variability highlights the flaw in using average annual flows to calculate the availability of capacity to meet system standards.

SCE argues that the problem with the SoCalGas/SDG&E proposal is further exposed when considering peak conditions such as those that occurred in the course of the 2000-2001 energy crisis. As Hartman's Figure 1 shows, the SoCalGas/SDG&E system was highly constrained during 2000-2001. This is not immediately obvious from examining the average demand for the period June 1, 2000 through May 31, 2001, which was only 65% (3,410 MMcf/day[4]) of the peak send out of 5,210 MMcf/day on January 16, 2001.

[4] "MMcf/day" refers to "million cubic feet per day."

Using data from the 2000 California Gas Report, Luis Pando, testifying for SCE, demonstrated that by looking only at averages, one would not have anticipated that problems were looming. He calculated that the annual average demand in mid-2000 yielded slack capacities of 24% on SoCalGas' system, and 59% for SDG&E's system, suggesting that there was more than adequate capacity at the time in both systems. Nonetheless, the SoCalGas backbone transmission system operated at peak capacity on several days. The SDG&E experience in 2000/2001 is similar. Despite the 59% slack capacity suggested by using averages based on the 2000 California Gas Report data, there were 17 days of curtailment on SDG&E's system between November 2000 and March 2001.

SCE recommends that the Commission require SoCalGas to provide for the evidentiary record a peak-day capacity that SoCalGas is willing to stand by without qualification, or that the Commission complete an independent analysis of the SoCalGas system to determine the peak-day capacity of the SoCalGas system.

SCE also questions the merits of SoCalGas' and SDG&E's planning approach, which uses different planning criteria for different parts of the system (for instance, there is one adequacy standard for the backbone system, and a different standard for local transmission). This can lead to contradictory conclusions concerning gas system infrastructure adequacy. Hartman's testimony suggests that when SDG&E's system is treated as if it were backbone transmission, it appears to have a very large slack capacity level (about 85%). However, Hartman then considers SDG&E's transmission system as local transmission, and concludes that SDG&E will need to expand its transmission capacity either by June 2007 or the winter of 2008/2009. SCE argues that using two different planning standards that produce inconsistent results makes no sense.

Another concern raised by SCE relates to the SoCalGas and SDG&E forecast of gas demand related to the generation of electricity. SCE argues that the gas forecast should consider the possibility that additional gas-fired generation could be needed if the San Onofre Nuclear Generating Station (SONGS) or the coal-fired Mohave Generating Station (Mohave) were to experience a prolonged outage or face retirement. Forecasting the gas demand for electric generation—although complex—is a threshold issue in determining the long-term reliability of gas transmission capacity. In addition, SoCalGas and SDG&E's proposed slack capacity measure does not quantify the strain put on the system by an extremely hot and dry summer or similar unusual load conditions over a five-month winter period. Existing criteria for local transmission do consider peak day deliveries, but these criteria do not explicitly cover system or backbone adequacy for peak day deliveries. We will wish to make this requirement explicit. Although summer constraints may not be a present concern on the SoCalGas system, higher electric demand in California and any corresponding increase in gas-fired generation to serve that demand could place a strain on SoCalGas and SDG&E's system in future years. SCE argues that SoCalGas and SDG&E's method of calculating slack capacity would be unable to detect such a constraint on their systems.

SoCalGas responds that its storage resources are sufficient to address these within-year swings in demand. When demand is lower than average annual levels, it can inject gas into storage, and when demand is higher than average annual levels, it can withdraw from its storage inventory to meet the load that exceeds the capacity of the backbone transmission system.

SCE argues that even if the total deliverable capacity on the SoCalGas and SDG&E system equals the sum of its backbone transmission capacity and its storage withdrawal capacity (including system draft), SoCalGas has the potential to substantially reduce the effective deliverability of the SoCalGas system because of its market discretion in procuring gas supplies for the core.

When a holder of withdrawal rights elects not to use them on any given day, but rather opts to import supplies, the capacity of the system to meet the needs of its customers is reduced. Currently, there is no requirement that the core use any or all of its storage withdrawal capacity when the system is constrained. SCE argues that if the core is not required to utilize its storage withdrawal rights on a peak-day, the calculation of slack capacity should not include that storage withdrawal capacity.

Pando testifies that if economic conditions do not motivate the core to use its storage capacity, what would otherwise be a 1,630 MMcf/day (37%) positive slack capacity could become a 305 MMcf/day (7%) shortfall. Under a 1-in-10 cold year peak-day conditions, a decision by the core not to use its storage capacity on a peak day could mean the difference between a 735 MMcf/day (14%) surplus and 1,182 MMcf/day (23%) shortfall.

SDG&E and SoCalGas respond in their reply brief (p. 21-23) that their witness Mr. Hartman never suggested that the transmission system alone should be capable of handling peak day conditions:

> Neither SDG&E nor SoCalGas has ever maintained that the utility receipt capacity or backbone facilities should be designed to meet a peak day send-out. All of our previous resource plans and rate case applications have been predicated upon investment in an **integrated**

> **network** of facilities that **collectively** provide the utilities with the capability to meet peak day demand.[5/]

SDG&E and SoCalGas go on to say that the alternate infrastructure adequacy measure proposed by SCE is little more than a transparent attempt by SCE to avoid the necessity of purchasing storage capacity in order to support its gas needs.[6/] Adoption of SCE's proposal would require massive expansion of the receipt point/backbone transmission system in order to add capacity necessary to handle extreme intra-year conditions. SDG&E and SoCalGas add that SCE witness Pando admitted that much of the transmission capacity would go unused:

> [O]ne could build enough receipt point capacity to serve a peak-load day. The problem with doing that from an economic standpoint is that pipe would then sit empty a large part of the year.[7/]

SDG&E and SoCalGas argue that their position is bolstered by TURN as Mr. Florio observes:

> [V]ariations in usage during the year should be handled through the use of storage, not by overbuilding transmission. If Edison is concerned about capacity availability during particular time periods, it should sign up for storage services to address that situation, as the core is *required* to do. But it is not reasonable to suggest that **all**

5/ SDG&E/SoCalGas/Hartman, Exh. 10, pp. 1-2 (emphasis added).

6/ SDG&E/SoCalGas OB, pp. 57-60.

7/ SCE/Pando, Tr. Vol. 4, p. 547.

customers should pay more for additional transmission so that noncore customers do not have to worry about purchasing storage.[8/]

SDG&E and SoCalGas state that SCE appears unwilling to take on the responsibility of managing and planning for its own gas needs by maintaining adequate storage capacities.[9/] It instead seeks an approach that would reduce or even eliminate the need for noncore storage by imposing on all ratepayers the cost of a major system expansion. As Mr. Hartman remarked, "[t]his is an extremely costly suggestion and [is] unsupported by any cost-benefit assessment."[10/]

The testimony of SDG&E/SoCalGas witnesses Jeffrey Hartman, Herbert Emmrich and David Bisi establishes that the backbone transmission systems of

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8/ TURN/Florio, Exh. 43, p. 3 (emphasis in original).

9/ SCE suggests that the strain placed on the SDG&E/SoCalGas system during the 2000-2001 energy crisis is proof of the need to expand the transmission system in order to ensure that it is capable of handling extreme intra-year conditions. (SCE OB, pp. 8-9). In fact, the energy crisis highlights the folly of relying exclusively on flowing supply and makes clear that sensible reliability planning by noncore customers involves ensuring that adequate reserve supplies are held in storage. SCE witness Pando, in fact, admits that lack of storage withdrawals during the energy crisis harmed noncore customers. (SCE/Pando, Tr. Vol. 4, p. 535).

10/ SDG&E/SoCalGas/Hartman, Exh. 10, p. 3.

both SDG&E[11/] and SoCalGas are adequate to meet forecasted customer demand. In fact, both systems enjoy ample reserve margins.[12/] Mr. Hartman noted that:

> Our comparison of expected demand and available capacity indicates that SoCalGas and SDG&E have sufficient backbone transmission capacity to meet the needs of our customers for well into the future . . . Over the last two years, firm backbone capacity exceeded deliveries by more than 40%. Without any additions beyond the recent additions of 375 MMcfd in SoCalGas' firm backbone receipt capacity, SoCalGas forecasts it will have a reserve margin of about 50% through 2010. Based on PG&E's April 23, 2004 comments, this reserve margin appears to exceed that in northern California.[13/]

Mr. Hartman estimated the reserve margin that would exist under extremely dry hydro conditions in combination with an extreme cold day:

> [I]f electric generation gas transportation requirements increase due to reduced availability of the supply of hydroelectricity power, *i.e.*, the 1-in-35 year "dry hydro" condition, coupled with a 1-in-35 year high degree day, cold year condition scenario, as outlined in the testimony of Mr. Emmrich, SoCalGas would still have receipt capacity in excess of this projected demand by approximately 38% which is in excess of 1.0 Bcf per

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11/ The SDG&E gas transmission system is currently classified as a local transmission system in relation to the SoCalGas system, but functions as a backbone transmission system from the perspective of SDG&E. (SDG&E/SoCalGas/Bisi, Exh. 7, pp. 5-6).

12/ The term "slack capacity" was formerly used to describe the backbone capacity in excess of demand on the system. In order to achieve consistency with methodology and terminology used by PG&E, the term "reserve margin" is used herein.

13/ SDG&E/SoCalGas/Hartman, Exh. 8, p. 3 (internal references omitted).

day through 2016.[14/]

Mr. Hartman observed further that:

> For SDG&E, the same conclusion of the adequacy of the of the SoCalGas backbone receipt system would apply, since SDG&E receives all of its supply from SoCalGas. Thus, for this assessment, SDG&E is no different than the Los Angeles Basin or San Joaquin Valley. The SDG&E transmission system is currently considered "local" rather than "backbone," but if it were considered to be a stand-alone backbone system, comparing average throughput to the firm backbone receipt capacity would show an even greater reserve margin for receipt capacity compared to the SoCalGas firm backbone receipt system . . . By 2008, if additional LNG supply causes an expansion of firm SDG&E receipt capacity, that investment to accommodate new supply could double the SDG&E receipt capacity (or add 15% to the integrated SoCalGas/SDG&E system capacity).[15/]

SDG&E and SoCalGas conclude that they have sufficient backbone capacity to meet expected customer demand through 2016.

Finally, SCE asserts that the proposed backbone planning approach does not provide any insight into individual receipt point or transmission zone constraints. In fact, despite the fact that SoCalGas and SDG&E conclude that there is "adequate slack capacity" the utilities identify three areas of potential local transmission capacity constraint: the Imperial Valley, the San Joaquin Valley, and San Diego. Whether SoCalGas and SDG&E have identified all of the areas with potential capacity constraints is not clear at this time. SCE urges the Commission to pursue this matter further.

[14/] SDG&E/SoCalGas/Hartman, Exh. 8, p. 4.

[15/] *Id*. at p. 5 (internal references omitted).

B. Analysis

Before us in this part of the discussion are questions about the merits of maintaining slack, or reserve, capacity on the backbone transmission system, and the appropriate standard to apply in determining whether and to what extent such a reserve exists. It would not be correct to suggest that the backbone pipeline, or any other individual component of the utility storage and delivery system, can be viewed entirely in isolation. A pipeline is only sufficient if it works in harmony with the remaining infrastructure to provide relative assurance of meeting customers' needs.

The proposals offered by the utilities are variations on a common theme – one with which we fundamentally agree: each utility can and should plan to ensure the overall adequacy of its storage and delivery system; however, since local constraints are largely the result of decisions made by individual shippers, it is incumbent on the utilities to work with individual shippers to determine their needs. A properly-administered "open season" process can be one tool to help the utilities make that determination. An open season is a public solicitation designed to secure commitments from shippers for the use of the pipeline or storage facility. Although SCE is correct in suggesting that an adequate storage and delivery system is one that is free of local constraints, the utilities often can only plan to meet demand in the aggregate and to respond to individual constraints and expansion requirements as they arise.

The decision that launched this proceeding asked the utilities to propose "an emergency reserve for their systems consisting of excess intrastate pipeline and interstate pipeline capacity, as well as an additional reserve of natural gas in storage." The proposals were to specify "how much slack capacity should be available on their intrastate pipelines for emergencies…; whether or not PG&E's

or SoCalGas' storage facilities should be expanded to help meet future California demand for natural gas; whether existing or new independent storage facilities should be expanded or constructed; and/or the extent to which expansion of intrastate pipelines may be necessary to enhance access to and flexibility in storage operations." (Rulemaking (R.) 04-01-025, *mimeo.*, p. 18.)

In order to determine the amount of slack capacity that should be available in the case of emergencies, it is necessary to identify, at least in a general sense, the nature of the emergencies against which the excess capacity would protect. SoCalGas and SDG&E did not offer an assessment of system adequacy as part of its Phase II proposals, filed April 23, 2004. Nor did those companies discuss the applicable planning contingencies. PG&E did assess system adequacy as part of its Phase II proposals, and identified the following functions of emergency capacity:

1. To moderate gas prices through gas-on-gas competition.

2. To ensure that gas customers do not become captive to a limited choice of supplies and rising prices during times of constraint.

3. To ensure that gas at the California border is available to compete against any other supply source that might attempt to charge a commodity price higher than the otherwise available marginal supply.

4. To guard against the impact of dry hydroelectric years on price and availability.

5. To respond to increasing gas demand for electric generation.

6. To moderate prices during some pipeline and storage facility emergency events (such as a sudden loss of capacity), as well as during periods of short-term variability of demand.

7. To rely on long-term planning to avoid the high commodity prices that may result if the utility were to wait for the market to decide when there is a need for more capacity.

In prepared testimony, SoCalGas and SDG&E do not address the scope of the emergency contingencies. Instead, these utilities answer that it is reasonable to rely on both stored and flowing gas to meet peak requirements—that a system developed to meet all peak requirements through flowing gas would, by definition, be overbuilt. We agree.

We want to encourage a balanced reliance on stored gas, because of the seasonal difference in gas demand and price, because there is a substantial storage capability, and because stored gas is an important physical hedge. For instance, consider this table from the Prepared Testimony of Steven Watson on behalf of SDG&E and SoCalGas (Exhibit 11, p. 6):

Table 7: PG&E & SoCalGas Comparison

	SoCalGas MMcfd	PG&E MMcfd
Backbone Capacity	3875	3286
2003 Throughput	2608	2414
Annual Reserve Margin	49%	36%
Backbone Capacity	3875	3286
Firm Withdrawal Capacity	3175	2223
Theoretical Peak Service*	7050	5509
Peak-Day Demand 2006/7**	5578 (3414 Core 1-35) (2164 Noncore)	4755 (3255 Core 1-90) (1500 Noncore per 2004 CGR)
Peak-Day Reserve Margin	26%	16%

*Both systems have constraints that prevent them from simultaneously using all firm withdrawal in addition to all backbone capacities. Therefore, reserve margins on both systems are somewhat overestimated.

**SoCalGas has a 1-35 year peak-day planning criteria. PG&E's core planning criteria, APD, is 1-90. Neither utility plans to actually fully serve noncore under these conditions.

That said, it is not enough to know that the combined available pipeline capacity and storage withdrawal rights[16] exceed peak demand by a certain amount. It is necessary to know that sufficient gas will be stored and that withdrawn gas can be delivered where it is needed when the system is most severely stressed. In addition, the simple existence of storage and delivery capability does not ensure that each customer will actually choose to withdraw its full allotment of stored gas during peak periods.

For planning purposes, PG&E, SDG&E and SoCalGas appear to have depended on shippers choosing to use storage fully at peak, and either assumed that stored gas could be delivered during peak conditions, or disregarded the issue. This may reflect an expectation, based on many past decisions, that core and noncore customers are basically on their own, in terms of establishing a storage strategy, and determining how to use stored gas. Stemming from this expectation is a sense that as long as there is sufficient capacity in the storage fields, it is up to the individual shippers to use it properly. This perspective is exemplified by SoCalGas' argument that there must be enough storage capacity

[16] For physical and economic reasons, not all of the gas in a storage reservoir can be withdrawn at any given time. A storage operator must determine its reliable withdrawal capacity and assign rights for individual customers to withdraw gas at any given time. These rights are referred to as withdrawal rights.

on its system, because the noncore customers have not been fully subscribing to the storage rights available to them.

In order to demonstrate this sort of system-wide ability to serve and to allow for the kind of flexibility needed to meet emergencies, it is not sufficient to demonstrate that the core customers have enough capacity for their purposes, and the noncore customers have as much as they are asking for. The critical questions go to the way the system operates as a whole. Enough capacity on the backbone system to satisfy demand on an average day is not adequate for system planning purposes if planners cannot depend on stored gas to make up the difference on the most severe peak day. That is what happens if customers do not reserve sufficient storage capacity, inject enough gas, and commit to make sufficient net withdrawals from storage during peak periods.

There are additional planning criteria that require our attention. First, we must consider the choices made by the utilities concerning the type of day or year for which they would plan. To consider the adequacy of its backbone capacity, SDG&E and SoCalGas looked at average daily demand during a year with average weather conditions. For a similar purpose, PG&E looked at average daily demand assuming a year that is both the coldest and driest (least hydroelectric generation) one in ten years.[17] TURN endorses PG&E's approach.[18] DRA does not offer an opinion concerning the standard that should apply.

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[17] It is common for all three utilities to assume more severe service conditions when examining the adequacy of core resources.

[18] TURN also argues that if the system planning criteria are to take into account dry hydro conditions, then cost allocation to electric generation customers should be based on forecasted demand under the same dry hydro conditions that are used in system planning. While we note this concern, the issue is not before us in this proceeding.

There is nothing scientific about choosing a 1 in 10 year standard, but there is something very logical about planning and maintaining a backbone system that can support an average day in a challenging year. It must be remembered that even in such a year, customers will often place significantly higher-than-average demand on each utility's gas supply system. The system must serve demand every year, not just during an average one. Looking at severe weather conditions over a rolling ten-year period appears adequate. It is reasonable to require that each of the utilities (PG&E, SoCalGas, and SDG&E) to plan for one-in-ten year cold and dry conditions, and we will direct them to do so.

While the percentages of backbone slack capacity put forth by the utilities differs, no party, with the exception of SCE, finds it inadequate to meet California's natural gas needs over the next decade. The utilities have stated that reserve margins on their backbone pipelines have routinely been in the 40 – 50% level and are likely to remain in this range for the foreseeable future. And while the utilities have taken a different approach in estimating slack capacities, SoCalGas and SDG&E relying on average annual system demand vs. PG&E relying on utilization rates under cold temperature and dry hydroelectric conditions, both approaches yield similar levels of slack capacities. As we have noted, however, we prefer PG&E's approach in using one-in-ten year cold and dry year. We take comfort that consumer advocates, pipelines, and LNG suppliers all support the utilities' proposals. We reiterate that it would be a mistake to suggest that the backbone pipeline, or any other individual component of the utility storage and delivery system can be viewed in isolation. We agree with the utilities that an integrated network of facilities is necessary to provide the utilities with the capability to meet peak day demands. While this makes it more difficult to assess the adequacy of the backbone capacity by itself, we have not found evidence to find that the backbone capacity is inadequate at this time.

SDG&E and SoCalGas have stated that it is appropriate to maintain a 20-25% "slack capacity" margin above the level of expected annual average demand during an average temperature year and normal hydroelectric conditions. From the data SoCalGas and SDG&E provided at the beginning of this proceeding, we know that total end-use load in a one-in-ten cold and dry year is about 9% higher than in an average year for SoCalGas and about 4% higher for SDG&E. [19] As such, we conclude that the proposed effective slack capacity standard in a one-in-ten cold dry year ranges from 11% to 16% for SoCalGas and 16% to 21% for SDG&E. PG&E proposes an annual capacity utilization of 80-90%, which is the equivalent of a reserve margin of 11-25% during cold temperature and dry hydroelectric conditions. Both proposals appear to be virtually equivalent. In either case, the existing annual reserve margins greatly exceed these slack capacities.

While the slack capacity proposals appear reasonable and enjoy the support of many parties, we still have no quantifiable basis upon which to decide the "right" number.

At this time, we are comfortable with the total amount of firm backbone transmission capacity on both the PG&E and SoCalGas systems. We are also comfortable with the proposed slack capacity ranges for backbone capacity proposed by the utilities in this proceeding. We will direct the utilities to assure

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[19] Data submitted on February 24, 2004 in response to CPUC data request. See Question 1.

adequate backbone transmission capacity under one-in-ten year cold and dry conditions. We will also make explicit the requirement that the utilities plan their backbone and storage systems so as to meet the peak day criteria already in place for their local transmission systems[20].

We will require SoCalGas and PG&E to demonstrate in advice letter filings with the Commission's Energy Division that they hold adequate backbone transmission capacity, and have slack capacity consistent with their proposals presented herein. These advice letter filings shall be made on a biennial basis starting in 2008. The first filing will be due July 1, 2008. We will also require the utilities to notify the Commission's Energy Division as soon as they believe a backbone transmission expansion is necessary.

C. Looking Specifically at Receipt Points - Management, Use and Expansion of Receipt Points

A receipt point designates the place on the delivery system where natural gas is transferred from one party to another. The nature of receipt points becomes an important factor in the context of this proceeding because SoCalGas manages its backbone pipelines by defining the maximum amount of flowing gas that the pipeline system can successfully receive and transport from any given receipt point along the backbone. The receipt point capacity is largely limited by downstream demand, the size of the backbone pipeline and the pressure of the flowing gas. These defined limits become a major point of contention between shippers who want the flexibility to introduce gas in the system at the place that

[20] For SoCalGas and SDG&E, this is one event in 35 years for core customers and one event in ten years for firm noncore customers. For PG&E, the standard is one event in 90 years for core customers and one event in three years for the noncore.

provides the greatest economic benefit for them, and SoCalGas, which has an obligation to protect its ratepayers from excessive infrastructure investments.

Some parties have raised concerns related to the management and use of receipt points. Woodside Natural Gas advocates a specific way to allocate costs for receipt point expansions. We will address this issue later. Kern River shares SCE's concern for what it calls SoCalGas' lack of analysis of the adequacy of its receipt point capacity and a lack of clarity around its proposed framework for future receipt point expansions. SoCalGas submits that it "will construct additional facilities to increase transmission backbone receipt capacity if the Commission decides southern California needs additional capacity or … if other parties fund such expansion."[21]

SoCalGas continues:

> "A more reasonable suggestion [for determination of the need of receipt point expansion] would be to monitor the utilization of SoCalGas receipt points. Then … consider expanding only those where shippers consistently seek access above the available capacity, despite an overall system wide excess reserve margin, if the receipt point can be expanded at a reasonable cost. If the Commission should find that the benefits of expansion outweigh the cost, the utility should expand the point's capacity. Alternatively, if the Commission does not find that the benefits outweigh the costs, shippers should be given the opportunity to fund the receipt point expansion. If shippers are willing to make such a commitment, the utility would undertake the construction."[22]

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[21] Exh. 10 (SoCalGas –Hartman), p. 2, lines 8-11.

[22] *Id.*, p. 4, lines 14-22.

Kern River suggests that SoCalGas' proposed policy framework is comprised of three components: (1) monitor the utilization of the receipt points and consider expanding a point when shippers consistently seek access above available capacity; (2) perform a cost-benefit analysis to determine whether the benefits of the expansion outweigh the costs; and (3) where the Commission does not find that the benefits outweigh the costs, expand the system only if shippers are willing to fund it.

Kern River points out that under this proposal, monitoring the utilization of its receipt points is a critical event. The record is unclear, however, as to who would be doing the monitoring and how the data produced from the monitoring would be used to determine the need for receipt point expansions. Kern River asserts that in order for SoCalGas' proposal to work, the Commission must insist that SoCalGas better define the monitoring process – the Commission should place a specific obligation on SoCalGas to monitor the receipt points and report its findings to the Commission on a regular basis.

For Kern River, the next element of SoCalGas' proposed policy framework—the necessary cost-benefit analysis—is equally ill-defined.

SoCalGas has provided no concrete proposal on how such an analysis will be performed. Kern River offers that in order for SoCalGas' proposal to work, SoCalGas must establish, and the Commission must approve, a specific methodology to calculate the benefits of a proposed receipt point expansion.

Finally, we do not have before us reliable estimates of the costs of expanding SoCalGas' receipt point capacity. According to SDG&E and SoCalGas' witness Bisi, the cost estimates in his testimony are not detailed construction estimates and, as a result, are only generally accurate to plus or minus 30 percent—a significant margin of error. Further, in his testimony, Bisi offered cost estimates that he or his staff prepared in early 2004, and did not updated prior to SoCalGas' submission of testimony 18 months later.[23] During the hearings, he said, "If I were to prepare this testimony today, I would escalate all pipeline costs by approximately 30 percent."[24] He also agreed when asked if it would be very difficult to decide how to apply the 30 percent adder.[25] Another concern is the lack of clarity about how long the performance of a detailed engineering construction estimate of a receipt point expansion would take. The record indicates that such an analysis could take six to eight months.[26] In order for the Commission to perform a cost benefit analysis of any proposed receipt point expansion, it must have a timely and accurate assessment of the costs.

Kern River argues that if the Commission adopts SoCalGas' proposed policy framework for determining the need for receipt point expansions, then it must provide some directives to make that framework effective. First, the Commission should require SoCalGas to monitor the use of the receipt points and to provide quarterly reports to the Commission clearly showing the extent to which shippers are (or are not) seeking access above available capacity. The Commission, with the assistance of interested parties, can then use this data to determine whether a cost benefit analysis of a particular receipt point expansion

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[23] Tr. Vol. 3 (SoCalGas-Bisi), p. 279, line 27 to page 280, line 7. In a motion dated December 1, 2005, after the submission of reply briefs on this issue, SoCalGas offered updated cost data regarding some potential receipt point expansions. The motion is untimely and opposed. In addition, we do not need specific cost information for the purposes of this decision. For these reasons, the motion is denied.

[24] Tr. Vol. 2 (SoCalGas-Bisi), p. 235, lines 27-28.

[25] Tr. Vol. 3 (SoCalGas-Bisi) p. 282, line 22 to p. 283, line 2.

[26] *See discussion*, Vol. 3, page 304, line 25 to page 305, line 13.

should be performed. Second, SoCalGas should be required to devise, and submit to the Commission within three months of the issuance of an order in this proceeding, a methodology for performing a cost benefit analysis for receipt point expansions. Parties should then be provided an opportunity to comment on the methodology. Finally, SoCalGas should be required to provide the Commission with usable cost estimates for receipt point expansions. Once having provided those estimates, SoCalGas should be required to update them on a periodic basis.

SDG&E and SoCalGas focused on their disagreement with the suggestion that the utilities should include specific receipt point capacity in their periodic resource adequacy assessments, citing the testimony of SDG&E/SoCalGas witness Hartman, and TURN witness Florio concerning the risk inherent in expanding specific receipt points in response to periodic demand.[27] Hartman offered his opinion that overall system capacity is a more reliable indication of infrastructure adequacy than capacity of particular receipt points, since demand at specific receipt points fluctuates over time.[28] Florio argued that heavy use of a particular receipt point does not necessarily justify expansion of that receipt point:

> "The mere fact that a particular receipt point may be constrained on occasion, or even over a fairly extended period, does not necessarily mean that an expansion is economically justified. As has often been observed in the context of electric resource planning, a certain level of congestion on the transmission system may in fact be

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[27] *See* SDG&E/SoCalGas Opening Brief, pp. 12-13.

[28] SDG&E/SoCalGas/Hartman, Exh. 8, p. 9.

> economic, and new construction to relieve the constraint may not be cost-effective. This is especially true in an environment where the costs of different gas supply sources vary relative to each other over time. Just because the gas delivered at a particular receipt point is cheaper than other sources today does not necessarily mean that this condition will persist for a long enough period to justify the cost of system expansion."[29]

The utilities argue that heavy utilization of specific receipt points may not be a sign of system inadequacy, but may be the result of commodity pricing or other market factors that are subject to change.[30] Hartman stated that "utilization of commercially attractive receipt points can change over time."[31] He cited the example of the Topock receipt point, where receipts equaled or exceeded 90% of total firm capacity more than 75% of the time during the two storage cycles (April 1999-March 2001) coincident with the 2000-2001 energy crisis. During the past two years (May 2003-05), however, Topock receipts have declined significantly as the result of lower overall demand, and higher volumes both at the expanded Wheeler Ridge and the recently constructed Kramer Junction receipt points. As another example, PG&E expects decreased use of the Kern River Station receipt point for off-system deliveries to SoCalGas once LNG supplies flow into southern California.[32] Thus, SDG&E and SoCalGas argue, to the extent that expansion of a particular receipt point is prompted not by system

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[29] TURN/Florio, Exh. 43, pp. 1-2.

[30] SDG&E/SoCalGas/Hartman, Tr. Vol. 1, pp. 61-65.

[31] SDG&E/SoCalGas/Hartman, Exh. 8, p. 9.

[32] PG&E Opening Brief, p. 7.

reliability considerations, but rather by the desire to access supply on commercially favorable terms and conditions, it is wise to proceed cautiously.

This is a debate in which no one has to be proven wrong. Just as SDG&E and SoCalGas make a strong case for the complexity of receipt point planning, Kern River is persuasive when it asserts that the assessment of receipt point adequacy must be a disciplined part of overall system planning. It is conceivable that there could be more than enough capacity on the SoCalGas system as a whole, yet the system might be unable to deliver some of the potential flowing supply because of constraints at one or more receipt points.

To protect the integrity of the system and to ensure the ability to respond to emergencies, SoCalGas must track and document constraints, determine whether they are temporary or long-term, and respond accordingly. We agree with Kern River that SoCalGas has a specific obligation to monitor the receipt points and report its findings to the Commission on a regular basis. We are not persuaded by SDG&E/SoCalGas' concerns about reporting specific receipt point capacities. The suggestion behind their argument is that the Commission may be unreasonably influenced by what may be just a temporary constraint and order expansion that is not justified from a long-term perspective. This is not a necessary result. The utilities must report the numbers, but they also must report on their rationale for expanding or not expanding the capability of a particular receipt point. The burden is the utility's to make the case for the reasonableness of its planning decisions. We will adopt Kern River's recommendation of requiring SoCalGas to monitor the use of the receipt points and to provide reports to the Commission showing the extent to which shippers are (or are not) seeking access above available capacity. In addition, we will require SoCalGas to explain, in each report, why the company should or should not pursue receipt point expansion in response to existing or forecast constraints. Instead of requiring quarterly reports as recommended by Kern River, we find that semi-annul reports are more reasonable.

We also observe that the utility's analysis of the costs and benefits of a potential receipt point expansion could be a matter of significant controversy. Kern River suggests that we require SoCalGas to establish, and submit to us for approval, a specific methodology for calculating the benefits of a proposed receipt point expansion.

SDG&E/SoCalGas respond that in the Phase 1 decision, the Commission rejected their effort to establish a standard cost/benefit methodology and instead declared its intention to look at benefits and costs on an ad hoc basis. In the Phase 1 decision, the Commission considered the utilities' generic proposal to allow for rolled-in rate treatment of LNG-related receipt point expansions. The Commission rejected this proposal, concluding that only once it is certain which LNG facilities will be constructed could the utilities or the Commission determine the true cost of system expansion. However, the Commission allowed that requests for rolled-in, or any alternative ratemaking treatment, could be filed as applications, with appropriate notice to customers. Those proposals, including the costs and cost recovery mechanisms, could then be evaluated on a case-by-case basis.[33] This is not a call for the use of an ad hoc approach for assessing benefits and costs.

That said, we will not adopt Kern River's recommendation to pre-establish a cost / benefit methodology for receipt point expansions. It is unclear to us

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[33] D.04-09-022, p. 68.

whether such a methodology can be pre-determined on a generic basis and the applicability of such a methodology on a specific expansion project.

Kern River's third proposal—to require SoCalGas to prepare and regularly update cost estimates for receipt point expansions—presents an even more difficult challenge. As the utilities point out, there are numerous variables affecting receipt point expansion including location, the size of the new demand, timing, and current downstream or upstream activities. SoCalGas could not, as a practical matter, model every likely permutation. In addition, such cost studies or updates take a lot of time and cost money. On the other hand, the lack of transparency related to expansion cost could hamper large shippers trying to make long-term supply decisions.

The appropriate balance is one where the utilities are not required to maintain and continually update the estimated cost of various expansion options, but are obligated to produce detailed cost estimates on request, in a reasonable amount of time, at a reasonable cost. SoCalGas stated on the record that cost estimates sometimes take six to eight months. This is not a reasonable timeframe for responding to a business request in this world of constantly fluctuating gas prices, even taking into account the iterative nature of the exercise. SoCalGas should take the steps necessary to respond more promptly to requests for cost estimates, whether this requires hiring additional personnel, having consultants on call, or both. We anticipate that customers will let us know if the company fails to meet this expectation.

D. Looking at Storage Adequacy and Practices - Is There Enough?

Storage service in PG&E's service territory consists of those facilities owned and operated by the utility, and those owned and operated by Wild Goose Gas Storage (Wild Goose) and Lodi Gas Storage (Lodi) (two independent storage providers). PG&E makes its case for the adequacy of the storage capability in its service territory by looking at potential usage from two perspectives: injection season and withdrawal season. In the months of April through October, there typically is a net injection of gas into storage. During this injection season, the system's ability to absorb a high demand or short supply event is relatively strong. For an example, PG&E discusses a major heat wave in the summer lasting five days that could result in as much as 300 MMcf/day of additional gas demand. This could be met with available pipeline capacity, or to the extent backbone transmission is flowing near capacity, with reduced storage injections. If, in this example, the demand initially was met entirely by reducing storage injections, then injections would fall behind by 1.5 billion cubic feet (Bcf). However, PG&E asserts that it would not be difficult to make up such a temporary shortfall in injections, by increasing injections by an average of 50 MMcf/day for 30 days, or 15 MMcf/day for 100 days, etc.

Similarly, during a winter cold snap, storage customers could increase withdrawals to cover the additional demand and replenish stored quantities during the injection season. In the Incremental Core Storage Application (A.05-03-001), PG&E has proposed that PG&E's core customers hold backbone and storage capacity to meet a 1-in-10-year peak day demand.

Offering another example, P&GE discusses a major pipeline outage of an extended duration, causing loss of 600 MMcf/day of capacity for 30 days, that would result in a total loss of 18 Bcf of capacity. (PG&E notes that a pipeline outage of this magnitude is extremely unlikely.) In this example, there would be a need for 18 Bcf of additional supply and 600 MMcf/day of deliverability. Assuming 10 percent of the backbone capacity was available on PG&E's system (312 MMcf/day), and that 90 percent of this available capacity were used, 281 MMcf/day of supply could be delivered on the intrastate pipeline from supplies not interrupted by the outage. The remaining supply and deliverability in this instance could be met by using storage. The storage requirement would be 320 MMcf/day of deliveries for a total inventory of 9.6 Bcf. PG&E reports that during the injection season, there is a minimum of 1,100 MMcf/day of firm withdrawal capacity between PG&E, Wild Goose and Lodi Gas Storage. During the withdrawal season, the withdrawal capacity increases to over 2,000 MMcf/day. There is 79.2 Bcf of firm working gas storage inventory capacity.

PG&E presents these scenarios to support its contention that storage capacity on its system is adequate. Assuming that these hypothetical situations reflect the outward boundaries of likely contingencies (we note that PG&E has not asserted this to be the case), PG&E's contention appears to be reasonable.[34]

SDG&E and SoCalGas face different circumstances related to storage. In southern California, SoCalGas is the only storage provider. Although SoCalGas asserts that there are other realistic storage options for southern California shippers due to the presence of Wild Goose and Lodi to the north, SoCalGas has not offered sufficient evidence to support this contention. It has not demonstrated that southern California shippers could rely on the transmission capability necessary to move gas to storage in the north, or to take southern delivery of gas withdrawn from Wild Goose or Lodi storage facilities. Nor has it demonstrated that these facilities comprise an economically viable option in light

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[34] As part of a settlement between PG&E independent storage providers, to be discussed later, those parties stipulated that PG&E's backbone capacity is sufficient to deliver withdrawn gas during peak periods.

of the added transportation costs involved in moving stored gas across the state. Neither has any other party proven that this contention is incorrect.

SoCalGas currently holds 122.1 Bcf of storage capacity, 3175 MMcfd of firm withdrawal capacity and 850 MMcfd of firm injection capacity.[35] SoCalGas' Watson asserts that SoCalGas' existing storage capacity is adequate to meet forecasted customer demand through 2016, observing:

> "Over the next several years, SoCalGas' existing storage facilities have sufficient capacity to meet customer needs. This can be demonstrated by (1) the fact that bundled core and balancing storage requirements can be accommodated with current storage facilities without significantly diminishing the size of the unbundled storage program, (2) the lack of long-term contracts for unbundled storage, (3) the modest level of market prices for short-term sales of SoCalGas' unbundled storage, and (4) the fact that there are many competitive alternatives to SoCalGas' unbundled storage service that can provide customers the same values as SoCalGas storage."[36]

He noted further that the total storage inventory and withdrawal capacity of SoCalGas significantly exceeds that of all northern California storage fields combined.

The relevant question before us is whether the storage capacity, injection rights, and withdrawal rights are sufficient to meet customer demand and provide a sufficient cushion to respond to emergencies. When SoCalGas states that bundled core and balancing storage requirements can be accommodated with current storage facilities without significantly diminishing the size of the

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[35] Injection and withdrawal capacity depends on physical inventory.

[36] SDG&E/SoCalGas/Watson, Exh. 11, p. 1.

unbundled storage program, it is saying little to address the issue of overall system adequacy. Instead, it is commenting on the sufficiency of storage to meet core demand without significantly reducing unbundled storage opportunity. These observations could be true even if there were too little storage, beyond the needs of core customers, to meet total noncore demand, maintain system reliability, and anticipate emergencies.

When SoCalGas remarks on the lack of long-term contracts for unbundled storage and the modest level of market prices for short-term sales of SoCalGas' unbundled storage, it is reflecting on its incentive, under current storage policy, to develop additional storage capability, regardless of the need. SoCalGas is not arguing that it is unable to sell its unbundled capacity, injection rights and withdrawal rights. To the contrary, unbundled capacity and injection rights have been oversubscribed in recent years, and withdrawal rights sales have hovered at about 80% of the total amount available. Neither is SoCalGas arguing that it is unable to recover its fixed and variable cost of unbundled storage service. To the contrary, it has been able, in recent years, to recover all of its variable and fixed costs and still have revenues that exceed fixed costs by 40%. .

We have already commented on SoCalGas' assertion that there are many competitive alternatives to SoCalGas storage. In this regard, the company has not made its case. Even if it had, the question would remain as to whether the SoCalGas system is adequate. For these other asserted opportunities to have an impact on that analysis, SoCalGas would not only have to demonstrate their practical availability, it would also have to quantify their impact on SoCalGas' system reliability.

Perhaps the most relevant portion of SoCalGas' analysis can be found in Table 7 in Watson's Direct Testimony (Exhibit 11, p. 6), which is replicated earlier in this decision. This table attempts to demonstrate that the utility has sufficient capacity to meet peak day demand, and sufficient reserve to secure against emergencies. This addresses the correct question. The numbers suggest the existence of a 26% cushion above peak day demand in 2006-2007 when one compares that forecast to the sum of total backbone pipeline capacity and total firm storage withdrawal capacity, Watson acknowledges that SoCalGas cannot simultaneously use all firm withdrawal and all backbone capacity, which means that its estimated cushion is overstated.

Based on the record before us, we cannot tell how overstated that estimate is. In addition, Watson's calculation does not reflect an assessment of the probability of injection and withdrawal by various shippers actually occurring, nor does he assess the deliverability of withdrawn gas over the local transmission system on a peak day. It is unrealistic to rely on the exercise of all withdrawal rights if customers are not required to inject enough gas or to exercise their withdrawal rights, or if SoCalGas cannot deliver all of the withdrawn gas to the customer. Each company must factor the likelihood of these occurrences into its assessment of system adequacy.

SCE argues, in assessing system adequacy, that the utilities do not appear to consider the impact of a major change in the demand for gas to serve electric generation due to the extended loss of a nuclear unit, or the shutdown of another non-gas-fired generator such as the Mohave Generating Station (which closed after the completion of hearings in this phase of the proceeding as anticipated in D.04-12-016).

SDG&E and SoCalGas responded by arguing that:

> "SCE appears to believe that the [electric generation] forecast should take into account every potential occurrence that might affect demand. This approach to ensuring system

> reliability and meeting customer demand is ill-advised, however. Planning backbone transmission facilities to meet all extreme conditions that might occur would result in a needless build-up of capacity and unnecessarily high rates."[37]

PG&E made a similar point in its Opening Brief.

We agree.

SCE argues that a problem for electric ratepayers is what SCE characterizes as SoCalGas' market power over the sale of storage rights. SCE and the Southern California Generation Coalition assert that SoCalGas has a monopoly on natural gas storage in southern California and has unparalleled pricing flexibility in the sale of its storage services. While an interstate pipeline experiences flexibility in charging for pipeline services, including storage services, no interstate pipeline can charge an amount for a service that is greater than its cost of service cap for such services. These parties further add that for SoCalGas, under its G-TBS tariff, its price cap for any given service is the sum of the cost of all services under the tariff. Therefore, it is the non-core customers, particularly electric generation customers that bear the most of the burden of those charges. SCE argues, further, that as the backbone transmission system grows tighter and non-core gas-fired electric generation load swings get larger, SoCalGas' ability to price its storage services at well above cost-of-service levels will become more economically burdensome to electric ratepayers.

SoCalGas storage services are divided among core services, system balancing services, and the SoCalGas unbundled storage program. Core storage services and system balancing services are provided to customers on a cost of

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[37] Reply Brief of SDG&E and SoCalGas, p. 27.

service basis, with the cost being bundled into transportation rates. SoCalGas has 100 percent balancing account treatment of transportation revenues. SoCalGas unbundled storage services are offered on a negotiated basis under several storage tariff schedules. The majority of SoCalGas contracts for unbundled storage services are executed under SoCalGas' Schedule G-TBS. In SoCalGas' 1999 Biennial Cost Allocation Proceeding (BCAP), D.00-04-060, SoCalGas is permitted to charge negotiated rates up to a ceiling of "120% of the ceiling reservation charge currently specified in the G-TBS tariff." Under D.00-04-060, if SoCalGas' unbundled storage program fails to generate at least $21 million, SoCalGas is permitted to recover 50 percent of the difference between the actual revenues and the $21 million from ratepayers through the non core storage balancing account. However, if SoCalGas' unbundled storage program produces revenues that are in excess of $21 million, 50 percent of the excess revenues will be retained by shareholders.

Testifying for the Southern California Generation Coalition, Catherine Yap argues that SoCalGas is making an extraordinary amount of money under its current ratemaking arrangement with a minimal amount of risk.

> "SoCalGas characterizes its unbundled storage revenues as $47.4 million of which it shares 50 percent or $23.7 with ratepayers. Watson Direct at Table 8. A copy of SoCalGas' Response to SCGC DR 4.20 has been attached to this testimony as Attachment C, which shows the annual revenues for SoCalGas' unbundled storage program from 2000 to 2004. SoCalGas only bears 50 percent of the risk of the $21 million dollars allocated to the unbundled storage program, or a total of $10.5 million. Therefore, SoCalGas is making a return of $23.7 million while risking only $10.5 million. This amounts to a return of 226 percent on top of the return that SoCalGas otherwise earns on its storage facilities in rate base. This sort of return doesn't seem very modest at all." (Exhibit 50, p. 5.)

In Watson's rebuttal testimony, SoCalGas responds that the excess returns in 2003 were $26.4 million, rather than the $23.7 million reported by Yap, and then went on to say:

> "Of the $26.4 million of 'excess returns' in 2003, half were refunded to ratepayers through the Noncore Storage Balancing Account. Therefore, in 2003 SoCalGas shareholders earned $13.2 million over and above a $21 million allocated cost, or a 63 percent above-normal pre-tax return." (Exhibit 12, p. 4.)

SCE finds SoCalGas' pricing discretion in the market for natural gas storage services particularly disturbing given its proposal, here, to transfer a proportion of its firm withdrawal rights from its "unbundled" storage program and system balancing to the core. According to Watson, SoCalGas proposes to reallocate its 3,175 MMcf/day of firm withdrawal capability as follows: the core's rights would increase from 1,935 MMcf/day to 2,289 MMcf/day, while the unbundled program's rights would decrease from 990 MMcf/day to 726 MMcf/day, and the system balancing figures would decrease from 250 MMcf/day to 160 MMcf/day. With less supply of unbundled withdrawal rights available to the market and less balancing flexibility for non-core transportation customers, SoCalGas would arguably be in a better position to increase prices for services under its G-TBS tariff.

SoCalGas also proposes to require non-core customers seeking an increase in firm storage withdrawal rights to commit to 15 year contracts. SCE argues that by transferring additional storage rights to the core, SoCalGas hastens the time when there will be no alternative to such a non-core commitment. SDG&E and SoCalGas respond to SCE's market power concerns by stating that unbundled storage customers have many alternatives they can and do consider, including financial mechanisms to price-hedge, flowing supply alternatives to balancing supply and demand, and storage outside of the SoCalGas territory.

It is true that unbundled storage customers can consider financial hedges and flowing supply as procurement planning options. However, storage serves purposes far beyond price hedging, and provides certainty that cannot be matched by a reliance on flowing supply. Similarly, neither SoCalGas nor its unbundled storage customers could rely exclusively on flowing supply in lieu of storage. In their Opening Brief, SDG&E and SoCalGas characterized flowing gas as a "near-perfect" substitute for unbundled storage. The essence of this argument is that electric generators, as the largest noncore customers, experience their highest gas demand in the summer, when there is most likely to be excess capacity available on the backbone system.

The SCGC does not address this point directly, but argues that flowing supply is not a near-perfect substitute for an electric generator that needs to protect its native load customers from the results of constrained transmission capacity. In such circumstances, holding storage capacity rights downstream of a transmission constraint can ensure the supply of gas needed to meet demand. The Coalition argues that the alternative to storage in this situation would not be flowing supply. It would be to go out of balance and, in effect, commandeer storage services by taking supply off of the SoCalGas system and exceeding imbalance tolerances. Of course, Commission policy and SoCalGas tariffs strongly discourage this practice.

Hartman, on behalf of SDG&E and SoCalGas, acknowledges that by relying on flowing supply, the price of gas will be higher than it would be if one were to buy gas pro rata all through the year, inject it into storage in the summertime, and then withdraw it in the winter.[38]

Storage is a unique service. There is value to maintaining physical reserves that cannot be matched through paper transactions, or flowing supplies. SoCalGas understands that, and is seeking to set aside even more storage to protect its full-service customers. As we have said earlier, while SoCalGas argues that storage facilities outside of its service territory are worthy competitors, it has not supported its assertion with facts.

In its testimony, SoCalGas describes the process under which it seeks to maximize the revenue it receives from providing non-core storage service. When SoCalGas discusses the adequacy of its storage capacity, it does not suggest that it has reached that critical point where it could not achieve additional net revenues by providing more storage service. SoCalGas merely asserts that at the current level of profitability, it is not motivated to increase its storage capability. Clearly, unbundled storage revenues are sufficient to cover costs. Instead, SoCalGas states that the revenues are not as high as it would like, and the purchase commitments are not for as long as it would like.

These conditions suggest that the adequacy of the core storage set-aside should be reviewed not in a generic infrastructure adequacy context, but in a proceeding more directly focused on core service. Permission to increase the core set-aside must be based on a showing that it is the appropriate step to take as part of the overall core procurement effort. For these reasons, we will not rule on SoCalGas' core set-aside proposal in this proceeding.

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[38] Tr. 82.

The SCGC asks the Commission to go further by concluding that in the absence of meaningful competition, SoCalGas should be required to charge for its unbundled storage services based on the cost of service. In the alternative, SCGC seeks price ceilings for storage inventory, injection, and withdrawal services. In SDG&E's and SoCalGas' reply comments, they note that they have recently filed with the Commission in A.06-08-026, their settlement agreement with SCE which, among other things, would place a cap on the prices of storage products. The Commission may review these and other storage issues in A.06-08-026, to determine if the settlement agreement adequately addresses the parties' concerns. For now, the rules remain in effect and we decline to alter them in the instant proceeding.

While both PG&E and SoCalGas assert that there is currently more than enough storage capacity, Lodi argues that demand exists for additional gas storage, injection and withdrawal capacity. To support its position, Lodi points to evidence of the full utilization of Lodi's storage facility, Wild Goose's recent expansion of its storage facility, Lodi's application for further expansion of its storage facility, and both PG&E and SoCalGas' interest in increasing the core storage set-aside. Lodi does not offer its opinion as to what the Commission should do, if it finds Lodi's arguments to be persuasive.

The Commission has addressed Lodi's issues in a subsequent decision, which approved Lodi's expansion application. Nothing prevents Lodi or Wild Goose from seeking authority for further expansions. The fact that Wild Goose and Lodi are both willing to expand their facilities might suggest that those entities foresee unmet demand, although it also just might suggest that they see an opportunity to win over utility storage customers by offering a superior product or lower prices.

Our interest is to ensure that there is sufficient storage to meet the demand for storage and to work in concert with the pipeline system in a manner that ensures overall system reliability. For all of the reasons we have discussed, we cannot reach the conclusion Lodi seeks based on the record before us.

We take comfort in the fact that all parties (with the exception of Lodi) support the contention that the current backbone pipeline and storage infrastructure are sufficient. While we noted several concerns with the utilities' proposals, we have no reason to believe at this time that the utilities' storage facilities are inadequate.

E. How Should the Gas Utilities Use Core Storage?

SCE points to events during the energy crisis of 2000-2001, when, it argues, SoCalGas withheld withdrawal capacity during several days in December 2000. SCE argues that the use of the storage system in this instance reflects a choice by core procurement to rely on flowing supplies that in turn constrained capacity at receipt points as they operated at above 90% capacity factor for the month of December, and that this choice had a direct impact on the high gas and electricity prices that severely impacted electric ratepayers.

Johannes Van Lierop, testifying for SoCalGas, points out that non-core customers, not just the core, injected gas and had decisions to make about withdrawal. SCE responds that any party that can control the greatest amount of storage withdrawal can control the amount of congestion and prices at the SoCalGas border, and that the Commission should require the party that controls significant withdrawal capacity to utilize that capacity to alleviate any receipt point congestion.

SoCalGas argues that SCE's proposal for such storage withdrawal guidelines would lead to an unfair subsidization of non-core customers by core customers. The utility noted that the Commission has previously addressed noncore customers' management of their own storage and reliability needs and has stated that it "never intended that SoCalGas would be a provider of last resort for gas shippers who did not wish to assume the risk associated with market price variability which occurs with the change in seasons," and expressly rejected the notion that the SoCalGas storage system should be available for the economic convenience of noncore customers."[39] DRA agrees with SoCalGas. SCE counters that the core receives preferential treatment in obtaining its storage withdrawal capacity, and that this results in a cost to noncore customers who are left to pay a steeper price for the remaining storage opportunities.

SCE raises an important concern: the effect that the failure to withdraw gas from storage during peak periods can have on all other customers. A failure to withdraw at such times may constrain the capacity of the backbone pipeline, and put upward pressure on gas prices at the California border. It reduces the capability of the intrastate system to respond to emergencies.

Our current rules and incentives do little to guard against this result. SCE would address the problem by creating a withdrawal obligation for SoCalGas on behalf of its core customers. Since SoCalGas controls by far the largest share of storage capacity on behalf of its customers, SCE's proposal is understandable. The problem is that it lacks symmetry. If SoCalGas should have an obligation to withdraw gas, why not place the same obligation on unbundled storage customers? Perhaps one reason is that such an obligation might discourage noncore customers from acquiring and using injection rights in the first place.

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[39] D.97-11-070, at p. 12.

Under current practices, all customers, including core, are encouraged to act in their own best interest. This is the distinguishing characteristic of an increased reliance on market forces and economic signals. What SCE demonstrates is that when all customers have to rely on a single network of pipes and storage, self-interest is not always consistent with that of the greater body of customers. This is a problem that we cannot address without reconsidering the obligations of shipping customers and the way that economic incentives are applied. It is a problem beyond the stretch of this admittedly broad proceeding, but one that is worthy of our further attention.

F. Should New Storage Facilities Be Part of Rate Base?

It appeared, to several parties, that SDG&E and SoCalGas were proposing that new or expanded unbundled storage facilities be included in rate base. The utilities responded by stating that they are making no such proposal. Since this is the case, we will not address that issue here.

G. Planning and Expanding the Local Transmission System

In its showing, PG&E has not addressed its local transmission adequacy or planning approach in significant detail. SDG&E and SoCalGas, on the other hand, discussed these issues in detail and engendered a debate with some of the other active parties.

The Commission requires SDG&E and SoCalGas to apply the following planning criteria to their local transmission systems: the systems must be designed to provide service to core customers during a 1-in-35 year cold day event (one curtailment event in 35 years) and service to firm non-core customers during a 1-in-10 year cold day event (one curtailment event in 10 years).[40] These utilities often use open seasons to measure the level of commitment of various customers to the use of local transmission capacity.

Hartman describes the current SDG&E/SoCalGas proposal as follows:

> "For non-constrained local transmission service areas, all noncore customers would be able to obtain firm transportation service by simply executing the standard two-year transportation agreement. For purposes of establishing the monthly contract quantity (MCQ), the following conditions would apply:
>
> "MCQs shall be derived from historical daily consumption data based on the most recent 24 months for which data is available. The MCQ may not exceed the highest recorded peak day usage for a particular month times the number of operating days.
>
> "Alternatively, customers may provide a forecast of consumption as the basis for their MCQ, provided those quantities do not exceed recorded historical usage.
>
> "Customers may request higher MCQs by submitting a letter attesting to changes in their operation or equipment warranting adjustments to historical peak day usage (i.e., pursuant to condition 1) and the schedule timing for these changes. A load survey will be required documenting the increase as a result of adding new equipment or increasing load.
>
> "Speculative or unsubstantiated requests for MCQ amounts will not be permitted.

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[40] D.02-11-073, *supra* note 13 at *46, Conclusions of Law Nos. 1 and 10 at *68-70; SDG&E/SoCalGas/Bisi, Exh. 7, pp. 13-14.

> "SoCalGas believes that these existing mechanisms are workable in areas where there does not appear to be any potential constraint based on historical load and customer projections of future load."[41]

With regard to the overall adequacy of local transmission facilities, SDG&E and SoCalGas' Morrow observed:

> "SoCalGas and SDG&E are prepared to expand transmission facilities as needed to serve core needs and firm commitments of noncore customers. Due to the wide geographic distribution of our system, and the nature of customer loads, local areas of the system can become constrained where demand for firm capacity can exceed the available firm capacity. Although there is a limit on the firm capacity in these areas, so far the available capacity has been sufficient to meet customer requests in the most recent open seasons except for some minor prorations in the Imperial Valley."[42]

Although Morrow states that available capacity on the SDG&E and SoCalGas systems has generally been sufficient to meet customer demand, SDG&E and SoCalGas' witness Bisi identified three areas of potential local transmission constraint: the Imperial Valley,[43] the San Joaquin Valley[44] and San

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41 SDG&E/SoCalGas/Hartman, Exh. 8, p. 11.

42 SDG&E/SoCalGas/Morrow, Exh. 4, pp. 7-8.

43 During the most recent open season that concluded in March, 2005, the capacity of the Imperial Valley System was fully subscribed during the summer operating season, however excess capacity is available during the winter operating season. (SDG&E/SoCalGas/Bisi, Exh. 7, pp. 14-15.)

44 During the most recent open season that concluded in March, 2005, the capacity of the San Joaquin System was undersubscribed during both the summer and winter operating seasons. (*Id*. at p. 15.)

Diego.[45] D.02-11-073 authorized SDG&E and SoCalGas to hold open seasons in these areas for purposes of allocating firm transmission capacity.[46] Under the open season approach adopted by the Commission in D.02-11-073, parties may bid for capacity on the basis of 24-month commitments, and are subject to take-or-pay obligations intended to "encourage customers to bid realistically and to prevent gaming on the system."[47] In the event that bidders oversubscribe to the available firm capacity, the utility prorates available capacity equally across the customer base.[48] To date, SoCalGas has concluded two open seasons in both the Imperial Valley and the San Joaquin Valley, and SDG&E has now concluded its second open season in San Diego. Morrow testified that the open seasons held in San Diego and in the Imperial and San Joaquin Valleys have proven to be useful in gauging customer needs and expectations.[49]

In D.02-11-073, the Commission was somewhat ambiguous as to the applicability of the 1-in-10 year planning standard. It clearly applies to a determination of whether the local transmission facilities serving a firm customer are sufficiently reliable. What is less clear is whether the Commission intended to require that the utilities apply the 1-in-10 year standard to the adequacy of the

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45 During the open season that concluded in May, 2005, the SDG&E system was fully subscribed during the winter operating season, while excess capacity was available during the summer operating season. (*Id*. at pp. 15-16.)

46 D.02-11-073, *supra* note 13 at *20-22, 47-49.

47 *Id*. at *21, 48-49.

48 *Id*. at *22, 49.

49 SDG&E/SoCalGas/Morrow, Tr. Vol. 2, pp. 161-162.

system to serve all noncore customers, whether or not they have made a firm commitment to pay for transmission capacity. The Commission recognized in D.02-11-073 that "[o]pen seasons can test the need for further expansions beyond those indicated by application of the planning criteria," and further that reliability of demand estimates increases when customers are required to commit to the level of their bids and are made subject to take-or-pay provisions.[50] SDG&E and SoCalGas now propose a local transmission expansion policy that places even greater reliance on the result of an open season. As explained by Hartman:

> We are proposing to modify the existing firm service provisions in the utility tariffs in the following manner to align long-term customer needs more closely with timeframes required for utility expansion of local transmission systems. In areas where we anticipate that requests for firm service exceed the capacity of the local system, either through a proration of existing capacity in a two-year open season, or specific information from customers that their firm service requirements are increasing, and the cost of the required expansion exceeds $5 million, SoCalGas and SDG&E would conduct an open season for long-term firm service needs. For that open season, we would estimate the needs for core customers over a ten year period, and then solicit binding bids for firm service by noncore customers for daily capacity based on the following segmentation:
>
> Customers that have loads that have significant impacts on sizing of facilities would be provided the option of bidding for daily firm transportation service for a 10-year term based on a [use-or-pay provision ("UOP")] as currently defined in utility tariffs.[51] That UOP is roughly

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[50] D.02-11-073, *supra* note 13 at *48.

[51] If during any billing period, the customer's firm noncore usage is less than 75% of the customer's firm noncore MSQ, the customer will be assessed use-or-pay charges equal to 80% of the transmission charges multiplied by the difference between 75% of the

Footnote continued on next page

comparable to a financial commitment for 60% of the value of firm transportation service. We propose that G-30 customers with peak usage of at least 20 MMcfd and EG Tier 2 customers would be eligible to obtain long-term firm service under this provision.

Customers with smaller peak loads, i.e., EG Tier 1 and G-30 customers less than 20 MMcfd, would be eligible to secure firm service under current full requirements tariff provisions (no UOP)[52] with three modifications:

1. The minimum term would be 5-years
2. The firm service reservation (i.e., monthly schedule quantity, or MSQ) would reflect demonstrated historical daily usage
3. If a customer desired to increase its MCQ during the course of the 5-year term, the change would activate a

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customer's firm noncore MSQ and the customer's firm noncore usage for that month. (Special Condition 33, Rate Schedule GT-F).

[52] The three tariff conditions specifying Full Requirements Service are:

(1) Customers may elect full requirements service under this schedule. Full requirements customers are not required to contract for a stated annual quantity.

(2) Full requirements customers are prohibited from using alternate fuels or bypass pipeline service (1) except in the event of curtailment, (2) to test alternate fuel capability, or (3) where the Utility has provided prior written authorization for the use of alternate fuels or bypass for temporary periods.

(3) In the event of any unauthorized alternate fuel use or bypass, customers must provide the Utility written notice thereof quantifying the extent to which alternate fuel or bypass use occurred. Such notice must be provided prior to the end of the month in which the usage took place. Any unauthorized alternate fuel or bypass use will be subject to a use-or-pay charge equal to 80% of the applicable transmission charge. No other use-or-pay charges are applicable to full requirements service. (Special Conditions 10, 11 and 12, SoCalGas Rate Schedule GT-F.)

new 5-year term commitment and the higher MCQ would take effect consistent with the timing of:

- o The amended contract (if no additional facility construction is required to provide the higher MCQ), or
- o Upon completion of any utility facilities required to provide additional firm transportation service.[53]

SDG&E and SoCalGas further propose to continue to treat these investments as common transmission facility costs and to include them in general ratebase. In addition, SDG&E and SoCalGas propose that any revenues received from use-or-pay charges be credited toward the same accounts in the same manner as all other intrastate transportation revenues.[54]

The proposal can be summarized as follows:

4. Where there is a potential for constraint in the local transmission system, EG Tier 1 and G-30 customers demanding less than 20 MMcf/day that want to ensure delivery must commit to a 5-year use-or-pay arrangement for a specified capacity.

5. Faced with a similar potential constraint, customers in these classes with larger demand must commit to a 10-year firm daily capacity user-or-pay arrangement.

6. If such contractual commitments do not exceed firm local transmission capacity, the utilities will not expand the local transmission system.

7. Any resulting new investments would be treated as common transmission facility costs and included in general ratebase.

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53 SDG&E/SoCalGas/Hartman, Exh. 8, p. 13-14 (internal footnotes in original).

54 *Id*. at p. 15.

In discussing the rationale for this proposal, Hartman argued that the policy would permit each customer to self-select the level of firm transportation service appropriate to its needs, and that those decisions would ensure that the utility receives proper signals as to when it should expand its local transmission system. Hartman also discussed what he saw as the benefits of relying on open seasons to evaluate customer demand:

> "[O]pen seasons that require customers to make binding commitments for firm service are superior to the utility relying solely on its internal demand forecasting. Since the bids require that the customer commit to a use-or-pay (UOP) provision, the bidding process provides better assurance that customers will bid the amount of firm service they really need. Although the demand forecast sponsored by Mr. Emmrich represents the utilities' best estimate of demand, his testimony notes a number of factors that could alter actual usage. Also, the forecast is a single point estimate of total demand, unlike requests for firm service. Moreover, customers and potential customers frequently express an interest in taking additional gas service at various locations in our service area. If we built out our local transmission system based on those expressions of interest, it would likely entail significant investments for facilities that might not actually be needed, raising all customers' rates unnecessarily. We believe basing expansion decisions on customer commitments is a more cost-effective method to ensure that expansions of the local transmission system meet customer requirements."[55] (Emphasis added.)

This proposal does not offer an opportunity, as Hartman characterizes it, to self-select the appropriate level of firm transmission service. Rather, any customer of a certain size would be forced to take one set of firm service terms,

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[55] *Id*. at p. 12.

or none at all. To some customers, SDG&E and SoCalGas may be offering a Hobson's choice: commit to 5 or 10 year use-or-pay firm daily transportation payments or risk the utilities maintaining an undersized local transmission system.

While such an approach would likely ensure that the utilities did not overbuild, there are many countervailing considerations that we must weigh. Under such an approach, if an individual shipper could not predict its needs as much as 10 years in advance, then the utility would not commit to provide service. Shippers that are not privy to the detailed, area-specific demand information in the possession of the utility would be required nonetheless to determine the need for committing to a use-or-pay contract. Equipped with imperfect information, individual shippers are much more likely to make inefficient decisions.

This is a matter of great significance to ratepayers, who also buy electric power from many of the larger gas customers. Duke Energy argues that this proposal has the potential to require a customer to pay a large amount of money for transportation service that it may never use. Duke offers its South Bay power plant as a good illustration of the dilemma customers may face as they confront the 10-year commitment. Duke operates the South Bay plant under a lease with the Port of San Diego. That lease expires at the end of 2009. The South Bay units are also subject to a Reliability Must-Run agreement with the California Independent System Operator (ISO), and Duke needs firm transportation service to South Bay because the RMR units are required to run when called on by the ISO. If Duke is required to make a 10-year commitment in order to obtain firm transportation service to South Bay, it could be stuck with making payment for several years after the lease expires, even though it might not need transportation service then. Duke points out that large industrial customers whose operations demand firm service, and who are considering moving to another location or who go out of business, face a similar problem.

On the other hand, TURN points out that if large noncore customers that demand system expansions to provide them with firm service are allowed to thereafter reduce or discontinue their usage without consequence, all other ratepayers would be stuck paying for idled facilities that were built to meet the demand of those customers. TURN suggests that a large noncore customer has better information regarding its future gas consumption than the serving utility, and more than the other ratepayers that would remain to pay for the unused capacity. It is unreasonable, TURN argues, to expect the general body of customers to pay for facilities that a specific large customer asks for and then fails to utilize. SDG&E also argues that Duke's concern just confirms that the utility should not expand its transmission system in reliance on Duke's plant continuing to place demands on the SDG&E transmission system beyond 2009.

In the proceeding that led to D.02-11-073, SDG&E proposed requiring long-term commitments much like those that SDG&E and SoCalGas propose here, although the terms would have been 5 or 15 years, depending on the level of demand. The Commission rejected that proposal because SDG&E did not offer a tradable rights program that would have helped protect customers unable to use all of their firm rights. The utilities asked for approval of a tradable firm rights mechanism in Phase I of this docket. In D.04-09-022, the Commission directed SDG&E and SoCalGas to file a new application (A.04-12-004) to consider issues related to SDG&E/SoCalGas system integration, tradable firm rights, and off-system sales. We are considering tradable receipt point rights in the second part of that proceeding, which is now underway. Although tradable rights for congestion on the local transmission system is not being addressed there, it was addressed briefly in this proceeding.

In a proposal offered subsequent to their opening testimony, SoCal described a mechanism for trading Use-or-Pay commitment obligations. In this scheme, customers would "offer their daily capacity rights on the utility's Envoy electronic bulletin board. Trading pairs of customers reach a bilateral agreement and then notify the utility in writing of their intention to trade."[56] The utility would ensure adequate local capacity and creditworthiness prior to authorizing the trade. Although it only sketches out the proposal, we believe the proposal is constructive and should be implemented. And so we will order the utility to implement this provision through an advice letter, filed with the Commission within 90 days of the date of this decision.

However, we are not persuaded that even the proper trading program would make it reasonable for the utilities to require the type of long-term contracts proposed here.

An exclusive reliance on long-term commitments to determine system adequacy would not do enough to ensure that the system would function well during emergencies, since an integrated system such as this must be planned and managed in an integrated way. Further, because individual customers cannot function as overall system planners, firm contracts provide no assurance that withdrawn storage gas can be delivered, reducing our confidence in the adequacy of the entire delivery system.

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[56] SDG&E/SoCalGas/Hartman, Exh.9 p.13.

An over-reliance on firm contracts at the expense of other planning tools runs the risk of allowing a utility to take its eye off of the overall adequacy of its infrastructure. Although the Commission has allowed the utilities to make use of open seasons, it has not authorized them to abandon other means of forecasting and planning to meet demand.

The Southern California Generation Coalition raises this concern, and cites the Commission's description of the utilities' obligation to provide firm noncore service and to expand facilities as needed:

> "We authorize SDG&E to limit firm service to noncore customers to the firm capacity available, but, as discussed, we have also authorized a reliability standard of 1-in-10. This reliability standard, along with the service interruption credits, will serve as sufficient incentive to SDG&E to continue making investments in its system to meet the needs of its firm noncore customers and to avoid curtailments." (D.02-11-073 at 14.)

The Southern California Generation Coalition argues that while SDG&E may limit firm service on constrained local transmission systems as an interim measure, it must also expand constrained systems:

If a customer requests firm service, and SDG&E determines there is insufficient capacity on its system to ensure firm service, it must offer that customer interruptible service at an interruptible rate. However, SDG&E must also expand its gas transmission system so that it complies with the 1-in-10, cold weather conditions, for firm noncore customer reliability standard adopted in this decision. (*Id*.)

The Commission also addressed SoCalGas' use of open seasons:

> "SoCalGas can plan the timing and location of capacity additions through a combination of various mechanisms including a thorough analysis of the subscriptions to its open

> season, adherence to a system planning criteria of 1 in 10 for noncore customers and 1 in 35 for core customers for location [sic] transmission, and nonbonding [sic] expressions of interest in long-term agreements in the event customer commitments exceed available capacity in any of the 24 months of the open season." (D.02-11-073 at 37-38.)

The Southern California Generation Coalition argues that this language obligates the utilities to go beyond the results of an open season and determine the adequacy of the transmission system for noncore customers in a more traditional way: through forecasts and the utility-initiated expansion projects that would result from those forecasts. We find this to be an overly expansive reading of what the Commission said in D.02-11-073. All that is clear from that order is that the utilities must use a 1-in-10 year planning approach to ensure that its facilities to serve firm demand are sufficiently reliable. The Commission has not clearly stated a broader planning obligation.

However, the Coalition's position reflects a legitimate concern. If a utility relies exclusively on bids for firm capacity, it could lose accountability for the adequacy of the local transmission system, and could blame any curtailment on the failure of individual shippers to subscribe adequately to transmission capacity. This is inconsistent with our goal of ensuring the overall adequacy of the intrastate infrastructure not only to meet normal demand, but also to respond to emergencies. We cannot allow the utilities to rely exclusively on the interests and practices of individual shippers to ensure the adequacy of the transmission system. It must be remembered, for instance, that the entire delivery system for SDG&E depends on the adequacy of local transmission. For these reasons, the utilities must continue to study and report on the adequacy of their entire system, including local transmission, and act to ensure that it remains reliable.

Another concern is the apparently arbitrary nature of the proposed 5- and 10-year contract commitments. The record does not suggest why 5 years or 10 years would be the right period. At the same time, as discussed above, the record does provide evidence suggesting that 10 years might be too long.

The Southern California Generation Coalition also argues that requiring larger customers either to commit to a 10-year use-or-pay arrangement or face the inability to firm up any local transmission could encourage bypass.[57] While this assertion may be the product of conjecture, it has some logical support. It makes sense that a customer will be more determined in looking for service elsewhere as the utility shifts more of the market risk to that individual customer. SDG&E and SoCalGas respond by saying that such bypass would require choosing interstate transmission over local transmission. The record suggests that the interstate pipelines require 15-year commitments. The utilities argue that it is illogical to suggest that a customer would run away from a 10-year local transmission commitment in order to make a 15-year interstate pipeline commitment.

The utilities do not cite to the record for their suggestion that interstate pipelines provide the only bypass option. However, even if that is the case, it is not necessarily illogical to choose a longer commitment for transmission on an interstate line over a 10-year local transmission commitment. Perhaps interstate capacity might be more valuable because its use is less location-specific and it is more tradable. Because this line of reasoning was not developed for our consideration, we cannot reach a firm conclusion one way or another.

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[57] Bypass refers to a customer electing to receive service from a provider other than the utility. In this instance, the service would be natural gas transmission.

In comments SoCalGas/SDG&E argue that that "it can take two years just to design and permit even minor transmission facilities", and that "[f]ive-year contracts will ensure that the noncore customers whose demand has caused the need to expand will actually use the expansion facilities and will provide some protection to all other customers from the risk that new facilities will not be utilized." At a minimum, SoCalGas/SDG&E request that the Commission require a two-year commitment from the date the associated facilities are placed into service to ensure that these facilities are utilized, and paid for, for at least two years.

We agree.

We will adopt differential treatment for large customers (G-30 customers with peak usage of at least 20 MMcfd and EG Tier 2 customers.) and smaller customers (G-30 customers less than 20 MMcfd and EG Tier 1 customers.). We reject any modification to the existing two-year take-or-pay requirements for smaller customers. For large customers, we require that they make take-or-pay commitments which last until the earlier of the following two events occurs: either two years shall have elapsed from the date that the associated facilities are placed into service; or five years shall have elapsed from the customer's sign-up date.

We will require that SoCalGas and SDG&E hold open seasons for firm capacity over those segments of the local transmission system which are experiencing or are expected to soon experience congestion, and that they publicize the results. Customers will be required to make the appropriate use-or-pay commitments. If nominations exceed the available capacity, then our expectation is that the utility will promptly upgrade the system. If, even in the event that nominations exceed capacity, the utility declines to upgrade the system, it shall file a publicly available advice letter with the Commission explaining its decision. That said, we also expect the utilities to expand their local transmission systems based on system planning analyses (using the one-in-ten year criterion), instead of relying solely on open seasons.

As requested by SDG&E and SoCalGas, it is appropriate to roll into general rates many expansions that are required as part of the 1-in-10 year planning process. However, for those expansions required largely to serve individual projects, such as LNG terminals, the policy established in the Phase I decision (D.04-09-022) applies. In that decision, the Commission stated that it is presumed that LNG suppliers will pay the actual system infrastructure costs associated with their projects. However, requests for rolled-in, or any alternative ratemaking treatment, will be allowed through the application process and addressed on a case-by-case basis. LNG suppliers will also be responsible for the costs to interconnect with the utilities' pipelines.

In sum, we modify SDG&E and SoCalGas' proposed changes to their rules for conducting open seasons on the local transmission system. Thus, the utilities shall conduct any approved open seasons in a manner consistent with this decision. And the utilities shall file revised tariff rules to reflect the changes adopted herein. The utilities shall use system planning as well as open seasons, as discussed herein, to minimize congestion and assure one-in-ten year reliability for firm customers. As discussed above, the utilities shall file an advice letter to implement the tradable rights for local transmission discussed in Witness Hartman's testimony.

II. Measuring Gas Infrastructure Adequacy for Electric Utilities

Electric generators providing power to customers of California investor-owned utilities were expected to burn about 1,800MMcf/day of natural gas in 2005.[58] Currently, the California electric utilizes are responsible for supplying about one third of this gas, and expect to be responsible for about half of the generation-related supply within five years. This gas demand can be broken into three categories: utility-owned electric generation; gas tolling contracts under the California Department of Water and Power (DWR) electric contracts; and gas tolling contracts not under DWR electric contracts. The DWR tolling contracts represent the largest category, and the non-DWR tolling contracts represent the smallest. The utility-owned generation category is quite small, but will grow substantially in the next five years, as each of the major electric utilities begins to procure natural gas for new power plants in California.

In its May 11, 2005 Ruling in R.04-01-025, the Assigned Commissioner included the following directive:

> … in order to more fully understand the adequacy of the California natural gas infrastructure and the impacts of current procurement practices, we have asked the Energy Division to examine electric utility plans to supply, transport and store natural gas for electric generation in those plants for which the utility is responsible to provide the gas. The Energy Division will then issue a report including any recommended actions for the Commission to take. The target date for release of the report is September 15, 2005. Comments on the report will be due October 17, 2005. The comments should address

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[58] Based on responses to data requests submitted by the Commission's Energy Division to California electric utilities.

> the merits of the Energy Division recommendations, and specifically identify any factual disputes related to the report that would suggest the need for evidentiary hearings prior to including the report in the record for this proceeding.

On September 13, 2005 the ALJ in R.04-01-025 granted an Energy Division request, and extended the due date for this report to October 6, 2005, with comments due November 4.

A. The Energy Division Issued a Report

The Energy Division report does not describe or critique the specific strategies that each electric utility employs in ensuring adequate natural gas supplies. The Energy Division offers very broad policy recommendations:

1) *secure firm transportation contracts for baseloaded electric generation gas supplies*:

   The electric utilities should consider assuring delivery of commodities purchased at the production basin by securing firm interstate capacity rights for the baseloaded utility-owned electric generation plants and for baseloaded plants under contract with DWR. Firm interstate pipeline capacity rights will ensure the reliable delivery of those supplies. Without such contracts, deliveries to California cannot be assured, even if the physical pipeline capacity to California exists.

2) *promote gas and electric end-use efficiency and conservation:*

   These investments will have significant impacts on electricity and gas consumption. In addition to ensuring diverse access to supplies, including new supplies, California needs to take, and is taking, measures to limit natural gas demand.

3) *promote efficient electricity generation from gas:*

   Since 2000, many old plants have been replaced with efficient new generators, resulting in a significant savings in gas use. This improvement is largely the result of plant owners seeking to become more cost competitive and has occurred without any mandates from governmental authorities.

4) *promote generation of electricity from non-gas resources:*

The Commission has adopted the Renewable Portfolio Standard, which will ensure that no later than 2017 at least 20% of California's electricity will be generated by non-gas resources. The Public Utilities Commission and the California Energy Commission have also adopted Energy Action Plan II, which envisions a 33% renewable portfolio by 2020.

5) *continue to allow for and encourage hedging, storing, and long-term commodity procurement, where effective or necessary:*

These tools are currently in use by the electric utilities procuring gas for generation. The utilities should be encouraged to use these tools prudently, guided by the Customer Risk Tolerance and market signals to reduce costs. Natural gas volatility could give rise to higher seasonal spreads in prices, making storage more valuable as a means by which to manage natural gas costs. Of course, if storage is seen as more valuable, the price of storage may increase as well.

6) *consider introducing an incentive mechanism for Electric Generation gas procurement:*

The cost-minimizing advantages of Performance Based Ratemaking need to be weighed against their disadvantages, including the tendency to encourage all short-term market purchases and to discourage certain kinds of hedging activity. Prior to going down this road, these pros and cons should be evaluated, and ways of avoiding typical pitfalls should be envisioned.

7) *provide access to new supplies, including LNG supplies:*

In D.04-09-022 the Commission recognized that LNG could be an important future component of California's gas resource base. Indeed, one of the thrusts of

R.04-01-025 is to facilitate access to this resource on an equitable and safe basis. The creation of open access tariffs and standardized agreements and the development of new gas quality standards are two aspects of this effort to facilitate importation of LNG and access to new supplies.

8) *monitor the potential for intrastate and interstate pipeline congestion:*

One of the recommendations of D.04-09-022 was to establish an advisory committee comprised of natural gas utilities state agency officials, and other parties who would monitor the interstate pipeline capacity situation to ensure sufficiency. This recommendation is being implemented. The first meeting of natural gas utilities and state agencies has already taken place, and an expanded meeting of this group with other interested parties will be scheduled shortly.

B. Various Parties Offered Comments

The Energy Division's recommendations are largely non-controversial since, with the exception of a procurement incentive mechanism and the acquisition of firm interstate transmission rights, the Commission and the utilities have already implemented each of the enumerated proposals. Comments largely focused on the firm transmission rights option.

PG&E, SDG&E, and SCE all express support for the option of acquiring firm interstate transmission rights, as needed. Not surprisingly, El Paso and Kern River (interstate pipeline operators) concur. TURN agrees that the utilities should consider acquiring firm interstate pipeline capacity, especially if they are able to negotiate contracts at less than full tariff rates.

However, TURN opposes a requirement that these utilities do so, arguing that any type of regulatory mandate would severely limit the utilities' bargaining power and could have the perverse effect of increasing ratepayer costs. Given that there currently appears to be a surplus of pipeline capacity available to California gas consumers, and the fact that electric generation tends to peak when core customer gas demand is lowest during the summer period, TURN argues that capacity availability may not be a major concern for the electric utilities. TURN also advocates that potential capacity arrangements be examined by the utilities on a case-by-case basis in consultation with their Procurement Review Groups (established a part of the broader electric resource procurement effort).

At the same time, TURN argues that gas storage, for both price and stability purposes, deserves consideration at least equal to that given to firm pipeline capacity. As a general matter, TURN believes that the utilities should keep, perhaps, a 10-day average winter gas burn supply in storage, but does not propose that the Commission impose a requirement to do this.

TURN also believes that this Commission must keep in mind that electric utilities own or contract for only a portion of the natural gas-fired electric generation in California. TURN expresses much more concern about the gas supply planning of non-utility generators. As the Energy Division report points out, the electric utilities operate under Customer Risk Tolerance guidelines that strongly encourage appropriate forward hedging arrangements. They also have an obligation to serve. But, TURN argues, California and other states across the country have experienced situations in which unregulated electric generators have sold off their gas supplies during peak gas demand periods because they can make more money selling the gas than using it to generate and sell electricity. TURN expresses concern that in 2005, some Qualifying Facilities (QFs) under fixed price contracts with the utilities have shut down their electric generation and sold their gas for higher profit instead. This type of behavior may be beyond this Commission's direct control, but it is a matter of concern nonetheless from an electric reliability standpoint. TURN proposes that the Commission consider requiring that any electric utility contracts for power supply (including future contracts with QFs) contain provisions sufficient to ensure that the generation does not suddenly "disappear" when gas prices rise and create other market opportunities for the generators. Electric resource adequacy cannot be achieved if the generating units that the state relies upon to meet its needs are free to cease operations in response to changes in fuel input prices.

PG&E states that it is a good idea to allow for firm interstate transportation contracts, but that there must be a Commission pre-approval process. PG&E also says that while an incentive mechanism may be helpful, it must be explored in a separate proceeding. SCE generally agrees, as does SDG&E, although the latter emphasizes that the current interstate capacity surplus is likely to grow.

C. Discussion

Electric generation facilities are usually the largest noncore natural gas transportation customers. It is logical that the failure of these customers to plan adequately could have repercussions for all natural gas customers. We agree with TURN that the need to ensure appropriate electric generator natural gas procurement planning goes beyond the regulated electric utilities and reaches to all gas-fired generators. We begin with consideration of the regulated electric companies because they are the most clearly subject to our jurisdiction in this regard. Securing needed firm interstate gas pipeline capacity rights is an important element of electric utility resource planning and an important factor in assuring the reliability of the natural gas delivery system.

Focusing on intrastate infrastructure, as generally we are in this proceeding, the importance of reliable delivery to the California border becomes clear. The natural gas utilities expect customers to rely on a combination of storage and flowing supply to meet demand. If these large noncore customers do not secure the delivery of supply to the border, then they may not be able to do their share to maintain flowing gas supplies.

We also agree with TURN that electric generators should do their part to fill storage fields, and to withdraw gas during times of system peak. Although the generators themselves will usually peak during the summer while gas demand is highest in the winter, the generators create significant gas demand throughout the year. To ensure uninterrupted generation capability and appropriately support the gas supply system, we would expect the electric generators to be active storage customers.

We expect the electric utilities to demonstrate, as part of the integrated resource planning process, that they have taken all necessary steps to ensure gas supply. As part of each planning cycle, they should actively consider the role of firm interstate capacity and report on their reasons for pursuing the strategy that they propose. We also expect the electric utilities to inject and withdraw gas consistently, as part of the annual fuel supply cycle. TURN offers one goal (maintaining a 10-winter-day supply in storage). As is true with other aspects of gas infrastructure and supply reserve, the electric utilities should define and work toward achieving a storage goal that is quantitatively related to the nature of their resource portfolios and the level of gas usage. This, too, should be developed and explained fully as part of each procurement plan.

We are not persuaded, at this point, that there are benefits in pursuing a performance incentive. We will leave it to parties to make a persuasive case for such an incentive in the general rate proceeding for each electric utility.

III. Creating an Infrastructure Working Group

Despite the utilities' primary obligation to ensure infrastructure adequacy, there appeared to be early consensus among the parties that it would be useful to establish an ongoing working group to monitor infrastructure adequacy. Parties disagreed somewhat as to the proper composition of the group. There is an existing body consisting of representatives of state agencies calling itself the Natural Gas Working Group that meets periodically. That group offered to develop a proposal for expanding the process to include other interested parties.

A. The Proposal

Since the existing Natural Gas Working Group is chaired by a representative of the California Energy Commission (CEC), the CEC submitted the requested proposal on behalf of the group. All other parties were given an opportunity to comment on the proposal.

The stated purpose was to establish a working group that allows more frequent discussion and exchange of information on California's natural gas context, focusing on supply, infrastructure needs and operations, and emerging issues. The CEC described the objectives as follows:

- Monitor California and western United States natural gas demand,
- Monitor natural gas supply from instate and out of state sources,
- Monitor interstate natural gas pipeline operations,
- Monitor intrastate natural gas pipeline operations,
- Monitor instate and out of state natural gas storage operations,
- Monitor the adequacy of California's natural gas infrastructure,

- Monitor natural gas market prices important to California consumers,
- Identify emerging issues that could potentially affect the above,
- Ensure that Working Group members have a common information set on these issues,
- Seek additional viewpoints and information that could benefit Working Group participants and California consumers,
- Establish a reporting system that provides timely alerts on near term issues, as needed, and
- Establish working relationships that encourage an open and informal exchange of information and discussion between the participants.

The CEC proposed the following structure for this expanded group:

- Establish a California Natural Gas Infrastructure Stakeholders Working Group (NGWG+),
- Membership of the NGWG+ would be self-selected and composed of all stakeholders interested in California's natural gas supply and infrastructure,

The NGWG+ would:

- meet January and July of each year,
- hold its meetings in northern California and southern California on an alternating basis,
- keep its meetings open to any interested party with a stake in California's natural gas future,
- advertise its meetings on the CEC's and the California Public Utilities Commission's websites,
- conduct informal discussion only and issue no summary report,
- determine additional structure for the working group after its initial meeting.

The CEC proposes also to maintain the current the Natural Gas Working Group, but modify its practices in some respects. The smaller group would have the following members:

- California State Agencies
- California Air Resources Board
- California Energy Commission
- California Public Utilities Commission
- California State Lands Commission
- Department of Conservation, Division of Oil, Gas, and Geothermal Resources
- Department of General Services, Natural Gas Services Program
- Department of Water Resources, California Energy Resources Scheduling
- Office of Planning and Research

The smaller group would:

- Maintain the current monthly Natural Gas Working Group (NGWG) meetings ,
- Invite the California natural gas investor-owned utilities to attend the NGWG meetings on a quarterly basis,
- Hold these quarterly meetings in a month preceding each season in time to take last-minute action if needed to avert potential problems (e.g., April, July, October, and January),
- Keep the meetings informal and off-the-record,
- Use these meetings to explore possible problems with California's natural gas infrastructure and operations and potential solutions that benefit consumers,
- Establish a sunset date of July 2007, extendable as determined by the group, to consider the need to continue these meetings.
- The CEC offers to organize these new working groups and initially chair them, with the formal chair to be selected by each group on a permanent or rotating basis.

B. Comments on the Proposal

Transcanada's GTN and North Baja Systems, Indicated Producers, Lodi, PG&E and SDG&E/SoCalGas filed comments.

While GTN states that it strongly supports the CEC's idea to allow all natural gas stakeholders to participate, in some form, in NGWG meetings, GTN does not see the need or rationale to segregate California natural gas investor-owned utilities and all other parties into two separate groups. GTN argues that the fact that, under CEC's proposal, "last minute actions to avert potential problems" could be made in the meetings that are limited to the NGWG and California utilities is problematic if not dangerous. Other non-California natural gas stakeholders, many of which are regulated entities that operate critical natural gas infrastructure both in and upstream of California, can provide valuable insights during these times of crisis. For this reason, GTN proposes that all interested parties with a stake in California's natural gas future meet with the NGWG on a quarterly basis. The format of these meetings would otherwise be consistent with the CEC's proposal.

Indicated Producers also support the proposal, but add that in addition to opening the NGWG membership to the investor-owned utilities, an invitation should be extended to a representative from the Governor's office, given the important issues at stake in California's electric and natural gas industries. Indicated Producers further argues that these quarterly meetings must also be open to the public with an opportunity for interested parties to provide public comments, because there may be instances in which issues must be addressed at the quarterly Natural Gas Working Group meeting instead of waiting for the biannual meeting of the California Natural Gas Infrastructure Stakeholders Working Group. Finally, Indicated Producers offers as a word of caution: the industry stakeholder group should not be placed in a position of monitoring the market and reviewing information that should be kept confidential. As noted in the proposal, the forums should be for the purpose of exploring possible problems and discussing potential solutions that will be brought before the appropriate regulatory bodies for consideration. Only open and informal exchanges will foster the desired objectives.

Lodi offers its support for the creation of the NGWG+ and its intention to participate actively. PG&E, SDG&E and SoCalGas concur, and add their enthusiastic support for the expansion of the NGWG to include utility representatives at quarterly meetings. PG&E objects to the proposals from GTN and Indicated Producers to open the NGWG meetings to more participants and public scrutiny. PG&E argues that there is a legitimate need for separate, confidential consultations between the gas utilities and the professional staffs of this Commission and the CEC, regarding issues of concern to gas consumers in California. PG&E adds that "these consultations should be allowed to occur without the prying eyes of suppliers, pipelines and other commercial operators, whose interests are not always aligned with the interests of the customers served by the utility companies."

The purpose of establishing regular meetings to discuss infrastructure adequacy is to add another source of information and feedback to the utilities' normal planning process. As such, we endorse this effort and encourage active participation. We are sympathetic to the arguments of GTN and Indicated Producers, however we also wish to foster the free exchange of potentially confidential information with the gas IOUs. Such exchanges are best encouraged by regular, frank discussions. For this reason, we will adopt the CEC proposal, with the modification of extending its sunset provision, still extendable, to July 2008.

In other words, the NGWG will meet monthly. Once a quarter, representatives from the gas IOUs will be invited to join. And twice a year, corresponding to two of these quarterly meetings, the meeting will be open to all interested parties. And as suggested by IP, a representative from the governor's office is always welcome.

IV. Paying for and Gaining Access to New Facilities

A. Charging All Ratepayers vs. Charging the New Users

In Phase I, there was a lively debate on appropriateness of rolling into rates the cost of system expansions needed to serve LNG providers. In

D.04-09-022, the Commission adopted a presumption that LNG suppliers will pay the actual system infrastructure costs associated with their projects. However, the utilities can file requests for rolled-in, or any alternative ratemaking treatment, through the application process, with appropriate notice to customers. Those proposals, including the costs and cost recovery mechanisms, can then be evaluated on a case-by-case basis. Several parties attempted to revisit this issue in Phase II. We see no need to deviate from the case-by-case approach adopted in D.04-09-022, and will not discuss the issue further, here.

B. The Woodside Natural Gas Proposal Concerning the Cost of Receipt Point Expansion

The cost of upgrading each receipt point varies substantially based on the scope of the expansion. For example, Center Road can be expanded to accommodate 800 MMcf/day of deliveries for approximately $27 million.[59] However, it would cost approximately $107 million more for the next supplier to deliver 400 MMcf/day of gas to that receipt point.[60] Woodside Natural Gas argues that this provides the first supplier with a substantial competitive advantage over the subsequent supplier.

The additional $107 million might be sufficient to prevent that second supplier from seeking to supply California. The situation may be even more extreme when expansions at multiple receipt points are considered.

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[59] SoCalGas/SDG&E Witness Bisi Exhibit 7 at 11, Table 5.

[60] *Id.*

SoCalGas/SDG&E has indicated that if more than one receipt point is upgraded, the total costs will exceed the sum of the cost of expanding each receipt point individually.[61] For example, Salt Works Station can be upgraded to accommodate 800 MMcf/day on an expansion basis for approximately $78 million, and Otay Mesa can be upgraded to accommodate 600 MMcf/day of expansion capacity for approximately $206 million. However, if both receipt points are upgraded, the total cost of the expansion would be approximately $418 million; $134 million higher than the sum of the cost of upgrading each individual receipt point. Under a first-come, first-served policy, if the supplier seeking to upgrade Otay Mesa was first to be awarded a contract, it would pay $206 million. The second supplier, seeking to upgrade Salt Works Station, would see its costs climb from $78 million to $212 million. Conversely, if the supplier at Otay Mesa was second, it would experience a cost increase of $134 million.

Woodside argues that either situation could result in one supplier being unwilling to pay the increased costs, and California losing access to the relevant supply, based solely on timing. Woodside proposes that rather than simply relying on a "race to the contract," the Commission should establish a "more rational" process for allocating the costs of capacity expansions at individual receipt points and at multiple receipt points: identify suppliers interested in obtaining access to capacity expansions and allocate costs equally, on a dollars per MMcf/day basis, among all interested suppliers.

Woodside points out that SoCalGas has already used this type of process in determining whether capacity upgrades are required in certain constrained

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[61] *Id.* at 12:3-5.

areas of its local distribution system.[62] Woodside asserts that it should not be difficult for the utilities to implement a similar policy when evaluating interest in receipt point and backbone transmission system capacity expansions. This would allow any potential supplier to be aware that expansions are being considered and give them the opportunity to participate in the expansion. Arguably, it could also increase the likelihood that more suppliers would connect with California because both the low-cost and more expensive upgrades would be allocated among all suppliers rather than simply requiring suppliers that come later to pay for the high-cost upgrades. Woodside argues that this would allocate cost responsibility in a fair, open and equitable manner, allowing suppliers to compete with each other based on the economics of their projects, rather than the timing of their receipt point requests.

Coral and Sempra LNG, proponents of an LNG project that may be closer to fruition than that supported by Woodside, strongly object to this proposal. Coral asserts that Woodside's proposal, if adopted, would undermine the ability of new gas suppliers to ascertain the terms and costs of access. Coral argues that a "first-come, first-served" incremental expansion approach for interconnecting new supplies serves the important purpose of providing cost certainty. Under this approach, sponsors of new supply sources would know what the costs of access would be, and they would be able to make rational economic choices on this basis. Coral concedes that the incremental nature of capacity expansion on a gas utility's integrated transmission system makes it likely that later expansion projects will be relatively more or less expensive than the expansion projects that preceded them, but argues that this does not make a first-come, first-served

[62] SoCalGas/SDG&E Witness Hartman Tr. at 67:23-69:13.

approach unfair. Rather, a first-come, first-served incremental cost allocation approach provides an incentive for shippers with new supply projects to assess the downstream expansion costs in conjunction with the timing of their supply projects. Coral concludes that the cost certainty that such an approach will assist all project sponsors in making economic decisions concerning their gas supply projects. Sempra LNG agrees, saying:

> "Adoption of Woodside's proposal could fundamentally undermine years of planning and investment in selecting the transportation routes, facilities and systems needed to move gas to market. In the case of the Energia Costa Azul facility in Baja, for example, some significant decisions have been made – and others must be made in the very near future – about how much gas to move via the Otay Mesa receipt point to the Southern California market versus how much gas to take east and north through the Bajanorte and North Baja pipelines. These decisions involve the design, permitting and construction of new transmission facilities in Mexico and the United States and necessarily have long lead times. Gas from the Energia Costa Azul facility is on schedule to begin to flow on or about January 1, 2008. If other projects in Baja come on line at a later time (whether one or two or three or more years later) and the Commission were to shift the costs of the upgrades needed to permit gas to flow into Otay Mesa from those projects to the original sponsors of the expansion, this would fundamentally alter the economics of the original sponsors' business investments."[63]

Sempra LNG argued, in conclusion, that anything other than a clear rejection of Woodside's cost sharing proposal in this proceeding likely would inject significant additional uncertainty in the Commission's ultimate LNG

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[63] Sempra LNG Reply Brief, p. 5.

access policies and may cause delays in getting gas from Mexico to the California market.

In D.04-09-022, we established a policy that presumes that LNG suppliers would pay for the cost of utility infrastructure upgrades required to enable deliveries of those supplies. Utilities were also allowed the option of making an application for rolled-in ratemaking treatment of the upgrade costs.

There is no disputing the fact that first-in-time cost allocation is a crude and, in some ways, unfair approach. Why should two LNG suppliers delivering to California, with potentially equal delivery amounts, pay vastly different costs for utility infrastructure upgrades? However, in some instances, the cure may be worse than the disease. One of the most significant reasons for imposing incremental expansion costs on the entity making the additional deliveries is to require the incremental supplier to take those costs into account when siting its facilities. That economic signal may be diluted, if not destroyed, if the costs are subject to change over time. It is also easy to understand how a changeable allocation of expansion costs could discourage investment. For these reasons, we will not adopt Woodside's proposal.

C. Gaining and Maintaining Access to New Facilities

Several parties have argued that if customers are required to pay for the construction of new facilities, they should have higher priority access to the use of those facilities. As a general proposition, this appears to be reasonable. We note that broader issues about access rights related to SDG&E and SoCalGas are currently before the Commission in A.04-12-004. In that proceeding, we will explore the appropriate means to provide higher priority access to such customers.

V. Interconnection and Operational Balancing Agreements

A. Background

In Phase 1, some parties representing potential LNG developers expressed the desire to ensure that all gas suppliers receive equal treatment in their relations with SoCalGas and SDG&E. In order to promote parity and transparency, the Commission provided notice that in Phase 2, the Commission would "establish a process to consider the adoption of standardized operational balancing agreements to connect all new upstream gas pipelines that interconnect with the pipeline systems of SDG&E and SoCalGas."[64] Such an agreement requires a shipper of natural gas to eliminate or mitigate operational imbalances created when the actual physical gas flow is different than the scheduled quantities.

On October 4, 2004, SDG&E, SoCalGas, and PG&E filed advice letters (1474-G, 3413, and 2577-G, respectively) proposing open access tariffs. On March 17, 2005, Resolution G-3376 approved PG&E's advice letter as filed, and ordered that SDG&E and SoCalGas re-file their open access tariffs with modifications, and also include drafts of four of the standardized contracts which were referred to in the proposed tariffs. On April 1, 2005, SDG&E and SoCalGas filed advice letters (1474-G-A and 3413-A, respectively) containing the revised open access tariffs (for both utilities, this is "Rule 39") along with the four proposed standardized contracts.[65] On September 22, 2005 in Resolution G-3382,

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[64] D.04-09-022, ordering paragraph 10.

[65] SDG&E and SoCalGas referred to an Interconnection and Operational Balancing Account in the open access tariffs but, in compliance with Resolution G-3376, did not include a draft agreement in these advice letters.

the Commission approved the re-filed open access tariffs (Rule 39) and approved, with modifications, three of the agreements.[66] The fourth agreement, the Interconnect Collectible System Upgrade Agreement (ICSUA), was deferred to R.04-01-025, to be developed and approved alongside the Interconnection Agreement.

Meanwhile, on April 1, 2005, SDG&E and SoCalGas filed a proposed pro forma Interconnection and Operational Balancing Agreement (IOBA) in R.04-01-025. On April 21, 2005, the Commission issued an Assigned Commissioner Ruling in R.04-01-025 setting a schedule to explore further the issues related to the IOBA. The ruling called for comments to be filed by parties on May 2, 2005, followed by a workshop on May 11. Accordingly, parties filed comments and participated in the workshop. The Energy Division submitted a report on June 8, 2005, summarizing the written comments and the findings from the workshop, and providing recommendations.[67]

In addition to commenting on a number of specific terms and conditions in the proposed standardized contracts, the Energy Division offered recommendations concerning a number of "threshold" issues, which we discuss below.

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[66] On October 7, 2005, SDG&E and SoCalGas filed compliance advice letters 1474-G-B and 3413-B containing the approved Rule 39 and the three revised standardized tariffs. The Commission approved these as filed.

[67] In theory, the IOBA agreements (and successor agreements) could apply to all California gas utilities. But in actuality, their main practical purpose has been to address connection with new LNG facilities, and all of the new LNG facilities currently being considered for California would interconnect with the SoCalGas/SDG&E grid. For this reason, the agreements being developed now are meant to be effective only for SoCalGas and SDG&E.

Finally, the Energy Division report encouraged parties to pursue negotiations to narrow differences, and then report back to the Commission. Accordingly, on June 17, 2005, SoCalGas and SDG&E filed revised proposals for the Interconnection Agreement and the Operational Balancing Agreement, followed on June 24 by parties' comments.[68] In July and August, the parties met for further negotiations, and on August 16, 2005, SoCalGas and SDG&E filed another round of proposed standardized contracts, this time also including the ICSUA,[69] followed again by parties' comments on August 24, 2005.[70]

On November 22, 2005, SoCalGas and SDG&E filed a supplemental report on the negotiations. The companies reported that further engineering studies revealed the need for tighter operational constraints for gas being supplied into the SoCalGas/SDG&E grid from Baja California at Otay Mesa, and they filed a revised OBA reflecting these tighter constraints. Three parties filed comments on December 2, 2005.[71]

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68 BHP Billiton, Coral Energy, El Paso, ExxonMobil, Independent Producers, Kern River, PG&E, SDG&E and SoCalGas, Sempra Global, Sound Energy Systems, Southern California Generation Coalition, and Transwestern filed comments on June 24, 2005.

69 The Energy Division had notified the utilities informally that the Commission was planning to defer the development of a standardized ICSUA to R.04-01-025. This was effectuated by Resolution G-3382.

70 Coral Energy, Indicated Producers, Kern River, Sound Energy Systems, and Transwestern filed comments on August 24, 2005.

71 Coral Energy Resources, Sempra Global, and Sound Energy Systems filed comments on December 2, 2005.

B. Discussion

Most parties expressing opinions on the disposition of the standardized contracts asked that the Commission issue a ruling without recourse to hearings. We agree that hearings are not necessary and will now rule on these contracts.

We believe that the recommendations offered by the Energy Division in its June 8, 2005 report on the "threshold" issues listed in the first five subsections below are reasonable and will adopt them, as discussed. Thereafter, we discuss issues that are still in contention.

C. The IOBA Should Be Separated Into an Interconnection Agreement and anOperational Balancing Agreement.

The two agreements have traditionally been separate documents, dealing with separate issues. Furthermore, many have argued that separation is expeditious, as it allows parties to terminate one set of agreements while maintaining the other. All commenting parties supported this separation.

D. In-State Gas Suppliers Should Not Be Subject to These Contracts.

There is already an open proceeding that is addressing standardized contracts for in-state producers.[72] Furthermore, there appear to be significant differences between in-state producers and other suppliers. These include smaller average size of contract capacity, greater hour-to-hour flow fluctuations, and less control over those fluctuations.

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[72] In A.04-08-018 the Commission is addressing the issue of standardized contracts for California-based gas suppliers.

E. The Contracts Should Not Affect Existing Agreements With Interstate Facilities and PG&E.

The existing interstate agreements and the agreement with PG&E appear to be working well. These entities have been operating in balance, and furthermore the distance of their interconnects from the SoCalGas load center make the SoCalGas and SDG&E's grid less sensitive to imbalances from the interstate pipelines. By contrast, new suppliers such as those utilizing Otay Mesa will need to adhere to the standardized agreements. These standardized agreements should be considered the standard template, with deviations obtained through the advice letter process.

F. Interconnect Collectible System Upgrade Agreement

No party raised any objection to the ICSUA version filed by SDG&E and SoCalGas on August 16, 2005, and we will approve it.

G. Issues Specific to the Interconnection Agreement and the Operational Balancing Agreement

The following is a discussion of the issues identified by parties as still subject to disagreement. The discussion will refer to the last versions filed (the Interconnection Agreement filed on August 16, 2005, and the OBA filed on November 22, 2005).

a) Hinshaw Exemption Is Protected

The Interconnection Agreement and the OBA contain the same clause (Sections 1.c. and 1.4.1., respectively) exempting SoCalGas from jurisdiction of the FERC under the Hinshaw Amendment to the Natural Gas Act, and allowing SoCalGas to refrain from any action that might possibly jeopardize this exemption.

In its August 24, 2005 comments, Sound Energy Solutions asks that the Commission include language stipulating that the Hinshaw Exemption clause of the contract "does not conflict with parties' rights to advocate for or utilize any off-system delivery rights authorized by the applicable state and federal agencies." Either in the standardized contracts, or in a settlement document accompanying adoption of the agreements, or in this decision. We decline to modify the proposed language in this clause, lest it jeopardize in any way the utility's Hinshaw Exemption.

b) Agreements Will Refer Only to Tariffed Gas Quality Standards

The Interconnection Agreement contains a clause (Section 4.a.i.) allowing SoCalGas/SDG&E to refuse delivery of gas not meeting certain specifications and a clause (Section 4.a.ii.) establishing the conditions under which the interconnecting entity can negotiate with SoCalGas/SDG&E to alter the gas quality specifications to which it is subject. The gas quality language of Paragraph 4.a.i. is of great concern to many parties.

Currently SDG&E and SoCalGas have tariffs (Rule 30) governing the quality of gas supplied to them. In their gas deliveries, the utilities are further constrained by gas quality standards established by the California Air Resources Board (ARB) that apply to mobile pollution sources (i.e., vehicles). These ARB standards are more stringent than the standards contained in the utilities' tariffs. Because the vast majority of gas supplied to SoCalGas/SDG&E by North American sources complies with ARB standards as well as the SoCalGas/SDG&E tariff standards, SoCalGas/SDG&E has been able to meet the ARB standards by blending the gas it receives from the different supply streams.

LNG supplies may be delivered to California, perhaps within the next few years, and while most LNG will probably meet existing SoCalGas/SDG&E tariff standards, it will likely not all meet the current ARB standards. Faced with the impending arrival of much larger quantities of gas that will not meet ARB standards, SoCalGas/SDG&E is concerned that it will no longer be able to comply with the ARB standards. The interconnecting parties complain that they should be subject only to standards contained in the utility tariffs.

In their filing on August 16, 2005, the utilities propose on an interim basis to include language from their June 17, 2005 IA and OBA versions which allows them to turn away gas that does not meet ARB standards. Once the new uniform gas quality standards are issued, SoCalGas/SDG&E would put into effect the new standardized contracts with all reference to gas standards imposed by other entities removed.

In its August 24, 2005 comments, Coral objects to SoCalGas/SDG&E's assertion that it will not sign agreements with interconnecting parties until the Commission issues new gas quality standards. In its August 24, 2005 comments, the Indicated Producers argue that the replacement language offered by SoCalGas/SDG&E is unnecessarily vague about where the gas quality standards are contained. The Indicated Producers offer a proposed edit which clarifies that gas quality standards are contained in the utility tariffs. We agree that this specificity is an improvement, and order the utilities, when they file the new gas quality standards (Rule 30), to adopt the proposed language for the Interconnection Agreement.

The Indicated Producers also note that the language proposed by SoCalGas/SDG&E contains no protocol for determining whether a supplier is in compliance with the gas quality standard. At a minimum, they argue, the Commission should be certain that the gas standards are applied in a nondiscriminatory fashion. We are not certain that such a protocol would be sufficiently useful to merit adding so much detail to the tariff at such a late stage in the proceeding. Consequently, we will not require the company to file such a protocol at this time. Of course we expect and require that the utilities apply their gas quality standards in a nondiscriminatory fashion.

As discussed later, this decision resolves all gas quality standards and orders corresponding changes to SDG&E's and SoCalGas's Rule 30. We adopt the August 24, 2005 version of IA paragraph 4.a.i, which refers only to Rule 30, and we incorporate the change proposed by Indicated Producers as discussed above. We thus remove from these contracts reference to authority which other government agencies may have on gas quality, while recognizing that SoCalGas and SDG&E will still need to deliver gas to natural gas vehicle customers that meets ARB standards. Because the gas quality standards we adopt in this ruling will limit how "hot" new supplies can be, the utilities should be able to meet ARB standards for these customers as they do now, namely, by blending.

c) Uniform Hourly Flow Requirements

SoCalGas/SDG&E's proposed Interconnection Agreement Section 4.b. requires that interconnecting entities supply uniform hourly deliveries, while allowing for intra-day schedule changes that may occur. Proposed remedies for noncompliance include suspended service and/or the installation of an automated flow control device, at the interconnecting entity's sole expense.

Coral characterizes the remedies proposed by SoCalGas/SDG&E as "unduly burdensome." Coral argues that under the utility proposal the utility could suspend service for even a ten percent deviation from uniform hourly flows. Instead, Coral offers language that provides more explicit and more lenient operational requirements.

Part of the problem we face is that the Uniform Hourly Flow clause requires that flows be "approximately" equal to the calculated hourly scheduled quantity, but provides no definition of "approximately". Coral offers a definition of +/- 20%. In their comments, SoCalGas/SDG&E argue that a 20% swing is excessive and instead propose a definition of +/- 5%, to which Coral did not object in its reply comments. We will accept the definition proposed by SoCalGas/SDG&E and order that SoCalGas/SDG&E insert this definition, applicable only to the measurement of hourly flows, into the clause. Aside from this addition, we will adopt the clause as proposed by SoCalGas/SDG&E.

d) Tighter Balancing Provisions Are Justified

Imbalances refer to differences between what a supplier schedules ahead of time with the utility and what the supplier actually delivers. Imbalances can result from either over- or under-deliveries. Once an imbalance occurs, SoCalGas/SDG&E's proposed OBA clause 2.3 provides for its elimination. This includes imbalances in hourly deliveries as defined in the IA.

Coral complains that SoCalGas/SDG&E improperly and confusingly addresses the issue of uniform hourly deliveries in the OBA, which is concerned rather with imbalances (which are daily and not hourly phenomena). We agree with Coral that discussion of uniform hourly deliveries in the OBA is confusing and unnecessary, and will order SoCalGas/SDG&E to remove reference to uniform hourly deliveries from Section 2.3 of the OBA.

Previous versions of the OBA's operational imbalance clause contained provisions for "cash-out" of imbalances, i.e., financial penalties for under- or over-deliveries to the SoCalGas/SDG&E grid. In response to complaints that these penalties were unduly harsh, SoCalGas/SDG&E now proposes an operational imbalance clause that focuses on physical adjustments to rectify imbalances. The proposed clause allows for the utility and the interconnecting entity to work out a schedule to eliminate the imbalance over a 30-day period but, if no agreement can be worked out, allows the utility to demand that the imbalance be rectified within seven days.

Throughout negotiations, parties have complained that the payback period of seven days, which SoCalGas/SDG&E have proposed, is far more stringent than the payback period contained in the existing interstate contracts.[73] Coral and the Indicated Producers argue out that the payback period proposed by SoCalGas/SDG&E (up to 30 days, but with the default as seven) in the OBA is much shorter than those contained in existing interstate agreements, and thus violates Conclusion of Law 18 of D.04-09-022 which states that new gas supplies "should be allowed to compete on an equal footing with existing supplies."

We are sympathetic to the arguments raised and reaffirm the policy goal expressed in D.04-09-022. But we must also be mindful of other facts. SoCalGas/SDG&E have repeatedly explained that unforeseen fluctuations in supply volumes arriving from the new proposed LNG receipt points are more difficult to respond to effectively because of their proximity to the load centers.[74] This argument makes logical sense.

Finally, SoCalGas/SDG&E noted during the May 11 technical workshop that they have seen suppliers deviating from their flow schedules in order to take advantage of market price fluctuations, effectively placing higher costs on utility

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[73] This fact was also observed in the Energy Division's report of June 8, 2005, which summarized many of the terms of the existing interstate contracts.

[74] See SoCalGas/SDG&E May 2, 2005 pre-workshop comments, p.6. During the May 11 workshop, SoCalGas/SDG&E argued that proximity allows less time to dispatch gas from other sources and allows fewer intervening connections with major pipelines and storage fields which otherwise could mitigate the impact of the supply disruptions.

customers.[75] SoCalGas/SDG&E argues that the shorter imbalance payback period is needed to protect its customers from such abuse.

As a result of these considerations, we are willing to adopt the tighter operating guidelines proposed by SoCalGas/SDG&E. We are in fact treating the various supply streams in accordance with the same principles, and two of those principles are protection of customer service (i.e., system reliability) and protection of customer costs. The fact that the application of these uniform principles may result in different operating rules for specific interconnectors does not violate the fact that these supplies are being treated on an equal basis. There is no undue discrimination.

e) New Special Provisions for Otay Mesa Are Justified, and Will Be Revisited

For each day's operation of the intrastate gas system, there are four nomination "cycles"—two occur the day before the flow day, and two occur during the flow day. Previous language in the OBA had allowed for interconnecting entities to change their nominations (i.e., statement of the amount they plan to flow) between Cycle 1 and Cycle 4 from the full capacity of the receipt point all the way down to zero. In October and November 2005, SoCalGas/SDG&E announced that based on the results of new engineering studies it had conducted, the utilities would revise language in the OBA to place much tighter operational constraints on supplies arriving into the utility grid at

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[75] SoCalGas/SDG&E noted during the May 11, 2005 technical workshop that they have seen this behavior especially from interconnecting entities that own the commodity they are supplying (these typically are California based suppliers), and have not observed this with the interstate entities, which typically do not own the commodity they are shipping.

Otay Mesa. Under the new proposed constraints, the supplier at Otay Mesa would only be able to reduce its nominations between Cycle 1 and Cycle 4 by a total of 50 MMcf/day. Otay Mesa is expected to have an initial capacity of about 400 MMcf/day, so this is a significant constraint on operations.

The new constraints are contained in Section 2.2 of the proposed OBA. In addition, SoCalGas/SDG&E have added a new Section 2.4 which defines the penalties (i.e., "cash out") that would be imposed on a supplier at Otay Mesa whose under-deliveries exceed the 50 MMcf/day threshold. The proposed penalty is 150% of the current border spot gas price, applied to the amount of under-delivery exceeding 50 MMcf/day. Over-deliveries at Otay Mesa would not have cash out provisions and would be treated the same as imbalances at other receipt points.

Coral argues that SoCalGas/SDG&E has not provided sufficient information to explain the necessity of the stringent measures of Section 2.2, and raises the possibility of alternative operational responses to supply shortfalls at Otay Mesa, such as increased flows from the SoCalGas backbone at Moreno Station. Coral suggests that reduced flows should be allowed at Otay Mesa in the event that demand by SDG&E customers were also to drop. Coral says that it simply wants more flexibility in the operational rules. Coral also complains that the immediate cash-out provisions of Section 2.4 are unjustified, unduly discriminatory, and punitive.

Sempra LNG argues that the rules SoCalGas/SDG&E are proposing for supplies arriving at Otay Mesa would apply to no other receipt point, and thus they would violate the mandate of D.04-09-022.[76] Sempra Global also questions the need to base operating constraints on the worst-case scenario.

It is important to apply the same principles to all sources of supply. However, the application of these principles may result in different operational rules for different receipt points, without resulting in undue discrimination. For the reasons discussed above, we will approve the new restrictions on Otay Mesa supplies as contained in the November 22, 2005 version of the OBA. We also agree with Sempra LNG that revisiting this issue one year after the beginning of operations could be useful, and will order the utilities to file a report to the Commission, one year after the beginning of gas flows from Baja Mexico at Otay Mesa, discussing their experience with the operational guidelines contained in the OBA, and offering recommendations on whether, and how, to modify them. The Commission may then choose to adopt the recommendations, convene a technical workshop, or take other action as appropriate.

f) New Operational Balancing Agreement Section 2.5 Protects System Integrity

In its November 22, 2005 revised OBA filing, SoCalGas/SDG&E has included a clause (Section 2.5) that allows the utility to reduce the capacity of a receipt point when necessary to maintain system integrity. In its comments, Coral supports the goal of system integrity, but questions the lack of constraint placed on utility discretion in this matter, and also reminds us of the need for the utility to avoid discriminatory behavior. Although we understand Coral's concern, the utility must remain accountable for system integrity and have the

[76] Conclusion of Law 18.

tools to ensure that this occurs. Of course, the utility is obligated to exercise this discretion in a reasonable manner. Consequently, we approve it, with the following modification.

In its comments, Sound Energy Solutions asks that the utilities insert language to this clause pledging that any capacity reduction would be announced prior to Cycle 1. We believe that such a notification requirement would be helpful to shippers managing their supplies, and so we agree to this modification.

g) Odorization Fees to be Paid by LNG Suppliers

Section 3.a of the Interconnection Agreement briefly discusses fees for operation and maintenance, and refers to the attached Exhibit C, which discusses in greater detail the methodology for calculating this fee. In addition, Section 4.h describes the process SoCalGas will take if it is required to odorize the delivered gas. When it is required, odorization comprises the lion's share of maintenance costs. In its August 24, 2005 progress report, SoCalGas estimates that odorizing incoming LNG supplies could cost $300,000 per year per Bcf/day, whereas continuing supplemental odorization of interstate supplies costs a nominal amount.

Kern River points out that FERC does not require interstate pipelines to odorize their gas supplies, but does require local distribution companies to do so. Kern River seeks to ensure that it does not have to pay odorization costs, as a result of this proceeding. As noted above in the discussion of "threshold" issues, the contracts with existing interconnecting entities, such as Kern River, are not affected by this decision. Coral points out that, by its own admission, SoCalGas "currently provides supplemental odorant facilities at existing interconnections with interstate pipelines," and that equal treatment requires that SoCalGas do the same for new LNG supplies.

There is more than one way to interpret the requirement of equal treatment. One could conclude that each supplier should pay the same amount. Since existing interstate gas suppliers pay little or nothing to odorize the gas, this interpretation would suggest that new LNG suppliers should also pay little or nothing. On the other, one could conclude that the utility should pay the same amount for odorization, regardless of the source of the gas. Since the utility pays little or nothing to odorize existing supplies, this approach suggests that it should also pay little or nothing to odorize new LNG supplies. Because of this ambivalence, the principle of equal treatment here provides no clear direction.

Another important principle is economic efficiency. Requiring each gas supplier to pay for odorization, rather than the utility, would provide a clearer indication of how much the gas from that source actually costs, and thus promotes more efficient resource allocation. As a corollary, a failure to charge new providers for odorization costs in excess of those related to odorizing gas from other sources would result in a subsidy to the new providers. Rather than ensuring equal treatment of new sources, it would provide special treatment. We will require those providing gas from new sources of supply to pay for any odorization costs in excess of those faced by the utility in treating gas from other sources. The utilities will file advice letters within 60 days of the day of this decision in which they provide estimates of the average amount they are spending, per mmBtu, to odorize gas from existing interstate sources, and modifying the Interconnection Agreements accordingly.

h) Extra Equipment to be Specified in Notice

Proposed Interconnection Agreement Section 3.b allows the utilities to install additional equipment (e.g., odorizing and metering) needed to receive gas up to the full capacity of a receipt point, and to do so at the interconnecting entity's expense. In response to previous complaints, the utilities added language stating that the interconnecting entity would receive notice prior to installation. Sound Energy Solutions argues that this language still offers the utility too much latitude, and requests adding language to this clause that (a) requires that the notice include identification of the nature and the cost of the equipment to be installed and (b) allows for the interconnecting entity to challenge the utility's determination.

Requiring specification of the nature and/or cost of the equipment to be installed would provide reasonable additional protection to interconnecting entities, and we will direct the utilities to make this change. However, providing the opportunity to challenge the utility's determination could impede the ability of the utility to safely and efficiently provide service. It is also redundant, since interconnecting entities already have the ability to file complaints at the Commission, using both informal and formal channels. The utilities are under an obligation to only impose reasonable charges on interconnecting entities. For both of these reasons, we deny the request to add another avenue for challenge.

i) Language Is Clarified to Allow for Previously Installed Metering Equipment

The proposed Interconnection Agreement contains alternative sections covering situations where the metering equipment is owned by the interconnecting entity. Proposed Section 4.d, would require the installation of metering equipment. Transwestern notes that the current language incorrectly implies that the interconnecting entity has not already installed the equipment when it states the "Interconnector shall install equipment that meets all SoCalGas specifications and is necessary to measure deliveries to SoCalGas at the Interconnect Points." Transwestern suggests it be revised to read, "Interconnector has installed or shall install equipment that meets all SoCalGas specifications and is necessary to measure deliveries to SoCalGas at the Interconnect Points."

We find Transwestern's proposal helpful and adopt it.

j) Unilateral Termination Provisions Are Allowed

Conditions where unilateral termination of the agreement is allowed are discussed in Interconnection Agreement Sections 2.d, 4.i.i, and 4.i.ii and in OBA Sections 1.4.2, 1.4.3, and 3.2.

SoCalGas/SDG&E argue that these are necessary. Coral argues that parties should be able to terminate the agreements only with Commission approval.

Service suspension affects not only the interconnecting entity, but also utility customers. If the utility does take an action of this severity, it must be prepared to demonstrate to the Commission the necessity and prudence of this action, and to show that it was not unduly discriminatory. The fact that the utility is accountable to the Commission should serve to prevent it from undertaking such an extreme measure recklessly. With this cautionary note, we will not eliminate the right of either party to terminate the agreement unilaterally.

k) Dispute Resolution

The August 16, 2005 version of Section 9 in the Interconnection Agreement (as well as Section 6 of the OBA) contains language acknowledging that the

Commission can resolve disagreements, but that disputes involving interconnecting entities regulated by the FERC would be resolved through binding arbitration. In the November 22, 2005 version of the OBA, only binding arbitration is allowed, regardless of the jurisdictional nature of the interconnecting entity. We will not impose binding arbitration requirements on parties in that this would unlawfully constrain their legal rights. Binding arbitration is only a fair and reasonable approach when all parties to an agreement freely agree to resolve disputes in that manner.

Interconnection Agreement Section 10.j and OBA Section 3.2 state that the agreements shall be subject to future actions that may be taken by the Commission to modify the terms. Transwestern argues that the statement is not true when the agreements are with FERC-regulated interconnecting entities, and asks that the language be changed to reflect this. We are not persuaded that we should make this change. The agreements apply to the interface between SoCalGas, which owns pipelines subject to the jurisdiction of this commission, and other entities. Whether those other entities are regulated by a federal agency, a state agency, or by no agency at all, the Commission has an obligation to ensure that the terms of these agreements are in the public interest. As part of our approval here, we require that those agreements continue to serve the public interest, and that the Commission remain able to influence the terms accordingly, in the unlikely event that this should be necessary.

l) "Regulatory Impairment" Clause Will Be Allowed to Stand As Is

The "regulatory impairment" clause, Section 3.2 of the OBA, allows for parties to terminate the agreement if the Commission should take actions that could render the agreement unacceptable. The Indicated Producers point out that the regulatory landscape surrounding these agreements—firm access rights, off-system deliveries, etc., —is still being developed, and asks for a statement by the Commission that changes in these areas will not be allowed to trigger contract termination under the regulatory impairment clause. We are not willing to tie the hands of the parties in this way, and decline to accept this suggestion.

VI. Independent Storage Provider Direct Interconnection With California Producers, As Well As Electric Generators and Other Noncore Customers

A. Background

The February 28, 2005, Scoping Ruling included two storage provider issues among those to be considered:

> "Should independent gas storage facilities be permitted to connect directly with other market participants such as California producers, electric generators, or other noncore customers, which Public Utilities Code sections are relevant to this issue, and should the Commission be concerned with bypass?
>
> "Should the Commission determine in this proceeding whether the gas utilities' backbone transmission capacity is sufficient to accept maximum withdrawals from all gas storage facilities during peak periods…?"

The issue of interconnections by independent storage providers was, in part, the result of a joint petition for rulemaking filed on October 15, 2003, by Wild Goose and the California Natural Gas Producers Association. That earlier petition preceded R.04-01-025 and requested that the Commission establish a rulemaking on storage provider interconnection issues. The second issue, regarding the adequacy of PG&E's backbone facilities to accept storage withdrawals, was left open in the Scoping Memo, in that it asked for comments on how to proceed in addressing this issue. However, the proposed settlement attempts to resolve this issue and not leave it to further comments or litigation.

By subsequent ruling issued April 21, 2005, the Assigned Commissioners established a Phase II schedule. Among other things, it allowed the parties 60 days to attempt to resolve the interconnection issues. At the request of the settling parties and based upon reports of progress in those settlement discussions, the assigned ALJ twice extended the deadline for reaching a settlement, with the final deadline being September 30, 2005.

The settling parties report that they participated in multiple settlement meetings and held regular phone discussions starting in May, and exchanged numerous settlement drafts. PG&E notified the entire service list of this process and invited all parties to participate. Parties that expressed an interest in participating in the settlement discussions, and agreed to be bound by Rule 51, were invited to the various settlement meetings and were provided drafts of the settlement documents. The primary parties to the negotiations were PG&E and the independent storage providers, although a number of other parties, representing a broad cross-section of the gas and electric industries, also attended the settlement meetings.

On September 12, 2005, PG&E notified all parties on the service list in R.04-01-025 of a formal Settlement Conference pursuant to Rule 51.1. The settling parties held a formal settlement conference at PG&E's offices on September 20, 2005.

The result was an uncontested settlement, which includes the pro forma tariffs and agreements needed to implement it. The agreement is attached to this decision as an appendix.

B. Description of the Settlement

Wild Goose is connected to PG&E Line 400 near Delevan and PG&E Line 167 near Gridley. Lodi is connected to PG&E Line 401 near Lodi and is proposing a nearby interconnection with Line 400 in A.05-07-018. The interconnections with these two independent storage providers are subject to Operating and Balancing Agreements. The terms and conditions of these OBAs, which include many operating parameters such as pressure, gas quality, and balancing requirements, are not affected or modified by the Settlement.

The settlement prescribes the circumstances and requirements: (a) for an interconnection with an independent storage provider so that PG&E can provide service to a noncore or producer customer using the independent storage facilities and an exchange of gas with the independent storage provider (Exchange Service) or (b) for third-party interconnections with an independent storage provider so that it can provide that customer storage services, and nothing else (Direct Connect Storage Service). At a minimum, an independent storage provider offering Exchange Service to PG&E customer would provide storage services for balancing.

The following defines which PG&E customers would be eligible for Exchange Service (Exchange Service Customer):

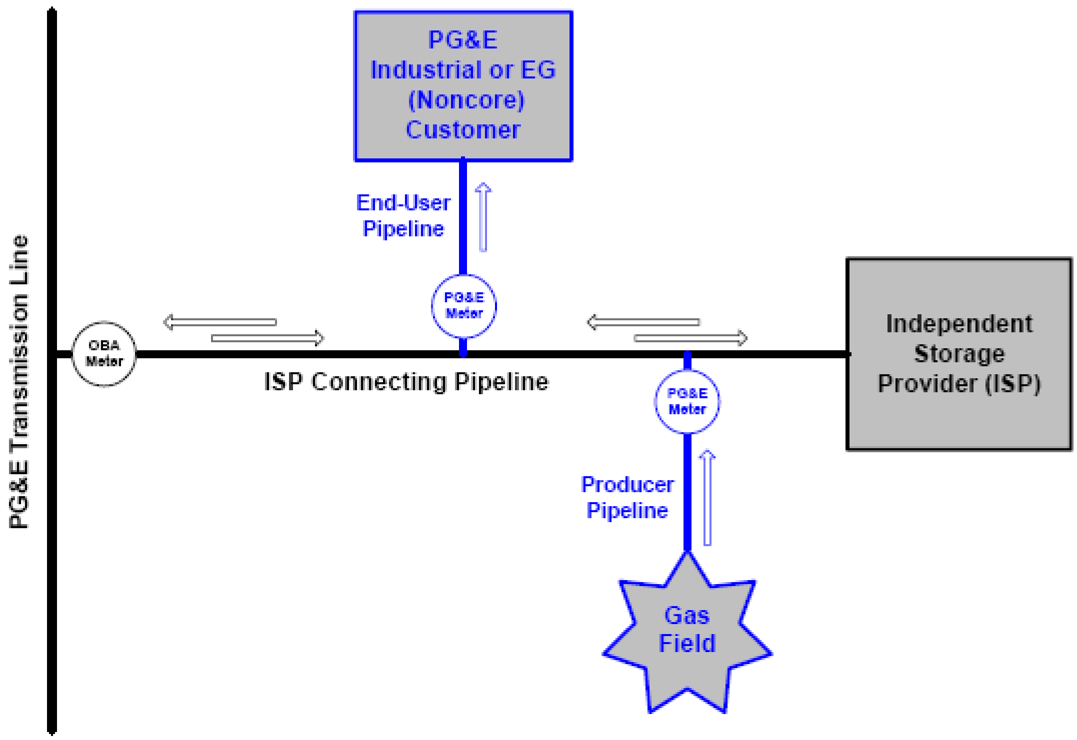
a. PG&E noncore end-use customer (industrial or electric generation facility) that is, or will be taking service under rate Schedules G-NT or G-EG, and is of a sufficient size as specified in the implementing agreements and tariffs. Other PG&E end-use customers would not be eligible.

b. A California gas producer, as defined in PG&E's gas Rule 1, which includes a gathering system operator acting on the producer's behalf.

c. Any PG&E customer that is already connected to an independent storage provider by a customer-owned pipeline.

For Exchange Service to an end-use customer, PG&E would deliver gas to the independent storage provider at a point of interconnection with PG&E, and the independent storage provider would deliver the gas through an exchange at a PG&E meter facility that is connected to the storage provider on one side and to the end-use customer on the other side. For Exchange Service to a California gas producer, the producer would deliver the gas through the PG&E meter facility directly connected to the storage provider, which would deliver the gas through an exchange to the point of interconnection with PG&E. PG&E would then deliver the gas either on-system or off-system under a Gas Transportation Service Agreement in the same way as if the gas were delivered directly to PG&E. In essence, gas to or from a PG&E customer would be exchanged with gas from the independent storage facilities, and that provider would receive an Exchange Fee for providing Exchange Service. The following diagram, from Appendix A of the settlement, shows these types of facility connections.

Schematic of Exchange Service Interconnections and Facilities



These new Exchange Service arrangements would require separate agreements between PG&E, the Exchange Service Customer and the independent storage provider, including new PG&E tariffs. The primary agreement would be an Exchange Agreement between the independent storage provider and PG&E. PG&E would also establish a new rate Schedule G-ESISP, "Exchange Service through [Independent Service Provider] Facilities." Schedule G-ESISP would be in addition to the otherwise applicable tariff requirements for the PG&E customer, and would allow PG&E to collect the Exchange Fee and provide for a self-balancing credit to the Exchange Service end-use customer, among other provisions. Associated with this new rate Schedule would be a G-ESISP Service Agreement (Service Agreement) signed by all three parties—the customer, the independent storage provider, and PG&E. The Service Agreement would require that all the other agreements and arrangements necessary to provide Exchange Service be in place before service would commence.

A PG&E Exchange Service Customer also would have the opportunity to enter into a contract with an independent provider for storage services. However, at a minimum, an Exchange Service Customer would be required to obtain storage services from the independent storage provider for purposes of balancing that customer's actual flows with its scheduled flows on the independent provider's system, so that the customer will continue to meet is operating and balancing obligations with PG&E.

For Direct Connect Storage Service, accounting and auditing procedures would be established to verify that storage is the only service being provided by the independent storage provider to the direct-connect customer, and that the customer is not bypassing PG&E's system and its Commission-approved tariffs and rules.

The settlement also includes pro forma agreements and tariffs consistent with terms of the settlement.

Further, the settlement declares that PG&E's current backbone capacity is adequate to ensure maximum withdrawals from the independent storage fields, and provides a mechanism for the independent storage providers to meet and confer with PG&E on this issue in the future.

C. Discussion

The primary question presented for our consideration is whether the terms of the settlement comply with Rule 51 of the Commission's Rules of Practice and Procedure. Only PG&E, Lodi, Wild Goose, and Calpine are signatories. However, no party opposes the settlement.

Under Rule 51.1(e), in order for a settlement to be approved by the Commission, the settlement must be: (1) reasonable in light of the whole record, (2) consistent with law, and (3) in the public interest.

First, the settlement is reasonable in light of the whole record. The theme focus of this proceeding is to ensure adequate infrastructure to deliver gas to customers under even the most severe conditions. As various parties have argued, a key to infrastructure adequacy is to maintain sufficient backbone and local transmission capacity, as well as sufficient storage capacity, and ensure that the utilities can use these facilities effectively to meet demand. By facilitating direct connections between independent storage providers and both large end-use customers and California gas producers, and by facilitating a more flexible working relationship between PG&E and the independent storage providers, there should be more ways to ensure that the gas delivery system supports demand, and greater likelihood that pipeline and storage will work together to ensure reliability.

Second, the settlement is consistent with the law. By its own terms, the settlement does not modify the Gas Accord market structure or associated services and rates as approved by the Commission in D.04-12-050. It furthers the goal of ensuring open access transmission and storage services on a non-discriminatory basis, and fully complies with Section 453(a) of the Public Utilities Code, which provides that: "No public utility shall, as to rates, charges, service, facilities, or in any other respect, make or grant any preference to any corporation or person or subject any corporation or person to any prejudice or disadvantage." The services and rates of Lodi, Wild Goose and PG&E are all subject to Commission jurisdiction and approval. The settlement merely allows PG&E to add certain new services that will increase the opportunities for customers to obtain cost-effective solutions to their needs in the context of the Commission-approved Gas Accord market structure and for subsequent or successor "Accords" or other market structures for the PG&E service area.

Third, the settlement is in the public interest. It provides for a reasonable disposition of the issues raised by the independent storage providers in this rulemaking proceeding. The settlement will save the parties considerable litigation costs and uncertainty. By avoiding what could have been extensive filing of testimony, evidentiary hearings and post-hearing briefing, the settlement also has the benefit of facilitating and expediting the Commission's review and approval of these new services. Also, the compliance process will be simplified by the fact that the settling parties have included detailed pro forma agreements, tariffs and forms as part of the settlement itself.

We note the stipulation among the settling parties to the capability of the backbone system to deliver gas withdrawn from storage during periods of peak demand. In approving this settlement, we are not expressing agreement or disagreement with this contention. As is true with all settlements under our rules, this one has no value as precedent. While the settling parties may be satisfied about the adequacy of the intrastate system for this purpose, this stipulation does not constitute a factual determination. We cannot find that infrastructure is either adequate or deficient based on an agreement of various parties. Our mission in this regard is not to resolve disputes, but to ensure that the delivery system is reliable, and sufficient to respond to emergencies. We must be persuaded of this fact based on data, analysis, and tested expert opinion—not based on a settlement which, according to its own terms, is the product of compromise.[77]

VII. Gas Quality

A. San Diego Gas & Electric Company and Southern California Gas Company

San Diego Gas & Electric Company and Southern California Gas Company (SDG&E/SoCalGas)[78] recommend that the Commission approve its proposal to narrow their existing gas quality tariff specifications by (1) establishing a clearly defined range of acceptability based on minimum and maximum Wobbe Numbers of 1290 and 1400; (2) raising their minimum Heating Value specification from 970 British Thermal Units (Btu) per standard cubic feet (scf) to 990 Btu/scf; (3) reducing their Carbon Dioxide (CO_2) specifications from 3% to 2% by volume; (4) reducing their Oxygen (O_2) specification from 0.2% to 0.1% by volume.[79] SDG&E/SoCalGas recommend that the Commission not approve a Wobbe Number cap for PG&E at this time.[80]

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[77] Section 1.5 of the settlement reads as follows:

"This Settlement Agreement is a negotiated compromise of issues and is broadly supported or not opposed by parties to R.04-01-025 who are local distribution companies, gas producers, marketers, shippers, independent storage providers, wholesale and retail end-use customers, and regulatory representatives. Nothing contained herein will be deemed to constitute an admission or an acceptance by any Settlement Party of any fact, principle, or position contained herein…"

[78] "SDG&E/SoCalGas" is used to describe the joint position of the two utilities. References to "SDG&E" or "SoCalGas" individually are intended to refer to just one of the two utilities.

[79] SDG&E/SoCalGas Opening Brief, pp. 6-8.

[80] *Id.*, p. 17.

SDG&E/SoCalGas believe that the adopted gas quality tariffs must apply to all gas supplies entering the utility system, other than California production that receives deviations.[81] To rule otherwise would impose the burden and cost of blending large volumes of non-compliant gas on the utilities and their ratepayers. SDG&E/SoCalGas argue that while such blending should be permitted on a case by case basis, it is only practicable in small batches. Furthermore, SDG&E/SoCalGas assert that allowing non-compliant gas to enter the system is contrary to the rules established in D.04-09-022.

SDG&E/SoCalGas propose that the Commission retain utility specific tariff specifications for gas quality standards while continuing efforts to develop statewide gas quality tariff specifications. SDG&E/SoCalGas maintain that they have been working closely with PG&E to minimize the differences between their gas quality specifications but that differences still remain. SDG&E/SoCalGas suggest that the proposed revisions to SDG&E/SoCalGas' gas quality specifications reflect the utilities' cooperative efforts and should be adopted.

SDG&E/SoCalGas strongly oppose regionalized gas quality specifications. It explains that their gas transmission and storage systems operate on an integrated basis that does not take regional boundaries into account. Trying to impose a regional structure onto the SDG&E/SoCalGas systems would greatly increase costs to ratepayers. For example, SDG&E/SoCalGas say that in order to supply different regions with gas meeting different quality specifications, they would be forced to build additional backbone transmission facilities that do not currently exist. It might be possible to isolate a remote part of the SoCalGas

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[81] *Id.*, p. 29.

system, but it would be "particularly difficult, if not impossible" to isolate the Los Angeles basin from the rest of the SoCalGas service territory, as proposed by the District.[82] The District's proposal would therefore have to be adopted on a system-wide basis.[83]

SDG&E/SoCalGas recommend amending their gas quality tariff specifications to specify a Wobbe Index range of 1290 to 1400, or plus or minus four percent of the national average Wobbe Number.[84] At present, SDG&E/SoCalGas' tariff would allow gas with a Wobbe Number of up to 1437.[85] SDG&E/SoCalGas reason that a range of plus or minus four percent of the national average Wobbe Index is appropriate because, (1) it has broad general support among stakeholders as reflected in the NGC+ White Paper; and (2) it would allow California to receive the full benefits of new gas supplies, without adversely affecting equipment performance or air quality.[86]

SDG&E/SoCalGas counsel the Commission to recognize that any new restrictions on gas supply in the form of narrowed quality specifications will likely increase the cost to California consumers.[87] They support this assertion by

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[82] *Id.*, pp. 35-36.

[83] SDG&E/SoCalGas Reply Brief, p. 6.

[84] The NGC+ White Paper, which SDG&E/SoCalGas uses to support its recommendation, characterizes 1992 national "average" gas as having a Wobbe Number of 1345 (NGC+ White Paper, p. 26). SDG&E/SoCalGas proposes a Wobbe Number range that is plus or minus four percent of 1345.

[85] SDG&E/SoCalGas Opening Brief, pp. 17-18.

[86] *Id.*, pp. 19-20.

[87] *Id.*, p. 10.

selecting relevant testimony from various participants in the Joint Workshop and evidentiary hearings. To illuminate the potential benefit of increasing the state's natural gas supplies, SDG&E/SoCalGas cite comments made by Mr. David Maul of the CEC at the Joint Workshop, who estimated that a reduction of 50 cents per million British thermal units (MMBtu) in the cost of natural gas could result in savings of a billion dollars to California consumers.[88] SDG&E/SoCalGas also cite the testimony of SDG&E/SoCalGas witness Mr. Stewart, who estimated that a one percent increase in the cost of gas at $5.00 per MMBtu would increase the aggregate cost of gas by $50 million in SoCalGas' service territory.[89]

SDG&E/SoCalGas also argue that additional supplies will increase supply and lower costs by citing the prepared direct testimony of Mr. Chancellor for Calpine, who argued that adding additional sources of supply will increase competition among gas suppliers and improve the reliability of California's supply.[90] Finally, SDG&E/SoCalGas point to Mr. Bamburg, who on behalf of Sempra LNG, reasoned that establishing more inclusive specifications in this proceeding will give investors the regulatory certainty they need to make investments in the California market, thereby increasing supply and reducing costs to consumers.[91] SDG&E/SoCalGas conclude that any Wobbe Number cap

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[88] *Id.*, p. 16.

[89] SDG&E/SoCalGas Reply Brief, pp. 6-7.

[90] SDG&E/SoCalGas Opening Brief, p. 12.

[91] *Id.*, pp. 13-14.

below 1400 would preclude SDG&E or SoCalGas from accepting significant sources of supply.[92]

To address potential air quality impacts, SDG&E/SoCalGas describe the testimony of Mr. Joseph Hower, who estimated the impact of introducing higher heat content gas, including gas with a Wobbe Index of 1400 and above, to the South Coast Air Basin (Air Basin). His analysis estimated that emissions of NOx would increase by less than 0.11% if half of the gas used in the Air Basin were high heat content gas. He further argued that restricting the Wobbe Index of gas may not be the most cost effective means to offset a small increase in NOx emissions.[93]

SDG&E/SoCalGas witness Larry J. Sasadeusz also addressed potential air quality impact by describing testing conducted by SoCalGas. The testing found that "above Wobbe number 1400, CO and NOx had a tendency to increase at a very rapid rate in the new pre-mixed equipment as opposed to virtually no change in the majority of the atmospheric equipment." He went on to emphasize that the majority of existing equipment is "legacy" equipment, not newer pre-mixed equipment.[94]

SDG&E/SoCalGas argue that generators can accommodate 1400 Wobbe Index gas "through the adoption of prudent operating practices and the implementation of readily available proven technology."[95] Mr. Baerman,

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[92] *Id.*, p. 20.

[93] *Id.*, pp. 23-24.

[94] *Id.*, p. 21.

[95] *Id.*, p. 22.

SDG&E's Director of Generation, explained that new combustion turbines, such as the GE turbine being constructed for SDG&E's Palomar facility, are more sensitive to gas composition. However, GE has indicated that with the addition of gas fuel heaters, 1400 Wobbe Index gas would be within the acceptable range. He also noted that Siemens supported a 1400 Wobbe Index maximum in a letter to FERC.[96]

SDG&E/SoCalGas advocate increasing the minimum heating value from 970 Btu/scf to 990 Btu/scf, while maintaining a maximum of 1150 Btu/scf, all on a dry basis.[97] The current minimum heating value, they assert, was adopted in anticipation of Synthetic Natural Gas supplies coming from coal gasification plants during the energy crisis of the 1970's. Since the anticipated supply never came to pass, SDG&E/SoCalGas advocate raising the standard to reflect the characteristics of today's gas supply.

In order to better manage pipeline safety while supporting in-state natural gas and oil production, SDG&E/SoCalGas advocate reducing the permissible level of CO_2 from 3% by volume to 2% by volume and lowering the permissible level of O_2 from 0.2% by volume to 0.1% by volume.[98] Reducing the current levels of CO_2 and O_2 is necessary to prevent corrosion in pipelines. CO_2 and O_2 can lead to pipeline corrosion in the presence of water. The utilities argue that despite their best efforts to prevent water from entering the system, water

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[96] *Id.*, pp. 22-23.

[97] *Id.*, p. 28.

[98] *Id.*, p. 28.

remains.[99] SDG&E/SoCalGas advocate reducing the permissible level of CO_2 and O_2 for new supplies, but allowing existing California production, much of which is associated gas, to meet the older, more lenient CO_2 and O_2 constituent requirements through a deviation process. A CO_2 limit of 2% is closer to PG&E's limit, but still twice as high. SDG&E/SoCalGas argue that maintaining a higher allowable amount is necessary to accommodate the characteristics of southern Californian associated gas production. An O_2 limit of 0.1% would bring SDG&E/SoCalGas's tariff in line with PG&E's.[100]

SDG&E/SoCalGas assert that the Wobbe Index rate-of-change proposal put forward by SCE is not possible to implement. However, the utilities can provide electronic bulletin board posting of real-time information on the Wobbe Index of gas at identified points in the pipeline system.[101]

SDG&E/SoCalGas oppose including the California Air Resources Board (CARB) Compressed Natural Gas (CNG) fuel specifications in the gas quality tariff specifications. Citing Mr. Stewart's reasoning on the subject, SDG&E/SoCalGas believe that since the natural gas vehicle market consumes less than 1% of SDG&E/SoCalGas system deliveries, applying the CARB CNG fuel specifications to the other 99% of supply would unnecessarily drive up costs for natural gas customers.[102] CARB fuel specifications are designed partly to ensure the reliability of a small fleet of heavy-duty vehicles and, therefore, are

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[99] SDG&E/SoCalGas Reply Brief, pp. 12-13.

[100] SDG&E/SoCalGas Opening Brief, p. 28.

[101] SDG&E/SoCalGas Reply Brief, pp. 11-12.

[102] SDG&E/SoCalGas Opening Brief, p. 25.

inappropriate for the other various end-uses of natural gas. Mr. Stewart testified that retrofitting the entire fleet of CNG vehicles would be far more cost-effective than imposing CARB CNG fuel specifications on the entire supply of natural gas.[103]

With regards to other parts of their gas quality tariffs, SDG&E/SoCalGas propose to keep the existing specifications for hydrogen sulfide, mercaptan sulfur, total sulfur, water vapor, hydrocarbon dew point, temperature, and total inert substances. SDG&E/SoCalGas support changes to the following specifications: (1) There shall be no liquids at or immediately downstream of the receipt point; (2) There shall be no dust, sand, dirt, gums, oils, or other substances injurious to the utility facilities or that would cause the gas to be unmarketable; (3) Gas from landfills will not be accepted or transported; (4) Biogas must be free of bacteria, pathogens, and any other substance injurious to utility facilities or what would cause the gas to be unmarketable and it shall conform to all gas specifications applicable to natural gas generally.[104]

SDG&E/SoCalGas propose a deviation process for California production through which each utility would file an Advice Letter to grant a deviation for all existing California production that does not comply with the new gas quality tariff "where there is no evidence of negative system impacts."[105] SDG&E/SoCalGas would work with producers of new production to obtain a

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[103] *Id.*, p. 26.

[104] *Id.*, p. 27.

[105] Exhibit 105, SDG&E/SoCalGas Natural Gas Quality Testimony of Lee Stewart, pp. 5-6.

deviation if warranted. SDG&E/SoCalGas would obtain subsequent deviations through Advice Letters.[106]

SDG&E/SoCalGas support additional research and studies on gas quality. They cite studies by the U.S. Department of Energy (DOE), the Gas Appliances Manufacturers Association, the California Energy Commission (CEC), and SoCalGas as all being of interest and relevance. They describe two timeframes for the completion of gas quality studies: January 2008 for equipment testing and accommodation strategies in anticipation of the introduction of new supplies of LNG; and, no more than 3 years for updated Natural Gas Interchangeability standards. SDG&E/SoCalGas state their intent to continue to work with the CEC and other stakeholders to complete studies on the statewide and local levels.[107]

B. South Coast Air Quality Management District

The South Coast Air Quality Management District (District) argues that the Commission should adopt an interim Wobbe Index range of 1332, plus or minus two percent with a maximum of 1360, and apply this standard solely to the South Coast Air Basin (Air Basin).[108] The District asserts that this standard will "preserve the status quo" because it corresponds to the five-year historical average Wobbe Index within the Air Basin.[109] Once the collection of additional

[106] SDG&E/SoCalGas Reply Brief, p. 13.

[107] SDG&E/SoCalGas Opening Brief, p. 46.

[108] The South Coast Air Basin consists of all of Orange County and the urban portions of Los Angeles, Riverside and San Bernardino counties.

[109] District Opening Brief, p. 3.

data is complete, the District believes the Commission could revisit the issue and set a long-term standard.[110] The District does not make any recommendations to change the gas quality tariff in PG&E's service territory, nor in areas of SoCalGas's or SDG&E's service territories that are outside of the Air Basin.

The District recommends that its proposed standard only apply to imported supplies of LNG. The occasional interstate supplies that exceed the District's standard are not of concern since they are blended into the system.[111] Furthermore, the portions of the SoCalGas service territory that currently receive higher Wobbe Index gas would not be impacted by the proposal since they are outside of the Air Basin, and would not be subject to the standard.[112]

The District believes that its proposed standard is necessary because the effects of introducing higher Wobbe Index gas are uncertain. According to the District no comprehensive testing has been performed on the environmental impacts of burning high Wobbe Index gas in turbines, and only limited testing has been done on appliances.[113] Additionally, the effects of high Wobbe Index gas on gas-fired electric generation reliability are uncertain.[114] A standard that preserves the status quo should be put in place while additional research and studies are performed.

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110 District Reply Brief, p. 6.

111 *Id.*, p. 31.

112 District Reply Brief, p. 7.

113 District Opening Brief, p. 4.

114 *Id.*, p. 4.

The District contrasts the SDG&E/SoCalGas proposal with its own, warning that the high Wobbe Index gas that could result from the utility proposal "is simply too risky from both an environmental and an operational standpoint."[115] The District disagrees that a standard that may be appropriate as a national guideline, as recommended by the NGC+ White Paper, is suitable in the Air Basin since the Air Basin's air pollution problems differentiate it from other parts of the country.[116] In any case, the NGC+ report does not advocate adoption of a 1400 maximum Wobbe Index in regions where the historical Wobbe Index has been far lower.[117]

The District describes the challenges it faces meeting federal ozone and particulate matter standards, and pleads that the District "vitally needs *additional* NOx emission reductions from stationary sources."[118] The District goes on to argue that the SDG&E/SoCalGas proposal would likely result in increased NOx emissions from some equipment, including equipment that relies on high air-to-fuel ratios and high excess air to reduce NOx.[119] The District also asserts that the conclusions reached by SoCalGas consultant Mr. Hower regarding NOx emissions are unreliable.[120]

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[115] *Id.*, p. 5-6.

[116] *Id.*, p. 8.

[117] District Reply Brief, p. 12.

[118] District Opening Brief, pp. 34-35, (emphasis in original).

[119] *Id.*, p. 37.

[120] *Id.*, p. 38-41.

The District does not believe that the appliance testing performed by SDG&E/SoCalGas was extensive enough to support the utilities' 1400 Wobbe Index proposal.[121]

The District supports increasing natural gas supplies in California. The District has in the past encouraged the use of natural gas, in vehicles for example, to help improve air quality.[122] However, the impact of any particular gas quality standard on natural gas supply and price cannot be determined based on the information in this record. A more thorough assessment is needed. Any costs that end users incur to adjust to a particular standard should be considered as part of such an assessment.[123]

The District does not propose any specific gas constituent standards, but maintains that any constituent standards should preserve the gas quality status quo in the Air Basin.[124]

The District believes that the Commission should adopt the CARB CNG fuel specification in order to protect the CNG vehicle fleet in the Air Basin. Alternative approaches could be considered in an Environmental Impact Report (EIR) process.[125]

The District asserts that the Commission should order the parties to agree on a testing process to determine what impact high Wobbe Index gas, and

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[121] District Reply Brief, pp. 24-27.

[122] *Id.*, p. 1.

[123] District Opening Brief, pp. 12-17.

[124] *Id.*, p. 30.

[125] *Id.*, pp. 29-30.

fluctuating Wobbe Index gas, could have on emissions in the Air Basin. The testing should also identify what mitigation measures may be available. The District proposes that the studies be done in the context of an EIR prepared under CEQA (see CEQA discussion below).[126] The District disagrees with the conclusion of Calpine that the necessary studies could not be complete by 2008.

The District is opposed to the suggestion of the Producers that the Commission should adopt the SDG&E/SoCalGas proposal now, before all the identified research is complete, and re-address the tariff if the research results support a different gas quality standard. Such an approach could have negative long-term impacts on the economy, consumers and environment.[127]

C. BHP Billiton

BHP Billiton (BHP) recommends either maintaining current gas quality specifications or adopting the Wobbe cap of 1400 and other gas quality specifications proposed by SDG&E/SoCalGas.128 BHP also recommends making any specifications that may be adopted "compatible and uniform" for all three affected utilities in order to facilitate interchangeability of gas.[129]

BHP concurs with SDG&E/SoCalGas analysis of the detrimental impact more restrictive gas quality specifications would likely have on gas supplies and price.[130]

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[126] District Opening Brief, pp. 11-12 and 47.

[127] District Reply Brief, pp. 10-11.

[128] BHP Opening Brief, p. 5.

[129] *Id.*, p. 6.

[130] *Id.*, pp. 7-8.

BHP strongly opposes including the CARB CNG fuel specifications in the utilities' gas quality tariff specification.[131] BHP argues that the CARB specifications were adopted in order to address the temporary problems posed by aging equipment. As that equipment is phased out, the CARB specifications will no longer be necessary for any natural gas supplies, even those for vehicular use.[132] Applying the CARB standards to all gas supplies entering the state, BHP asserts, is (1) unnecessary since the CARB standards themselves will eventually be phased out and (2) counter to the Commission's goals since doing so would drastically limit supply options, thereby driving up costs.

D. Calpine

Calpine believes that the existing gas quality tariffs are outdated because end-use technology has changed and new gas supplies from LNG are anticipated. The existing standards much be changed to prevent equipment damage and increased emissions.[133]

Calpine proposes that the Commission adopt a statewide Wobbe Index standard of 1153 to 1391. Calpine explains that its proposal was developed based on GE and Siemens turbine specifications, and is necessary to prevent flashback, knocking, autoignition and excessive NOx emissions. The company also proposes constituent standards described below.[134]

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[131] *Id.*, p. 11.

[132] *Id.*

[133] Calpine Opening Brief, pp. 2-3.

[134] *Id.*, pp. 9-10.

Calpine is concerned with the impacts of gas quality on power plant turbines. Calpine does not believe that the potential emissions and cost impact of the SDG&E/SoCalGas proposed standard on Dry Low NOx/Dry Low Emissions (DLN/DLE) turbines is known.[135] DLN/DLE turbines are designed to reduce NOx emissions.[136] Burning gas outside of the manufacturers specifications could result in NOx emissions increasing beyond permitted limits.[137] A Calpine witness testified that operating, under construction and permitted plants in California that use DLN/DLE turbines have a total generating capacity greater than 4,000 megawatts.[138]

Calpine's proposed specifications also include adopting a minimum and maximum heating value range of 900 to 1,200 Btu/scf, maximum ethane of 15 percent, maximum propane of 2.5 percent, maximum butane of one percent, and maximum inerts of 15 percent. Calpine also based theses specifications on GE and Siemens DLN/DLE gas turbine specifications.[139] Calpine opposes Sempra's recommendation to adopt a maximum butanes and heavier cap of 1.5 percent. Calpine argues that Sempra introduced its butane proposal for the first time in its Opening Brief, denying parties the opportunity to cross-examine Sempra's

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135 *Id.*, pp. 3-7.

136 *Id.*, p. 18.

137 *Id.*, p. 16.

138 *Id.*, p. 10.

139 *Id.*, pp. 11-12.

witness on the issue. Furthermore, the proposal contradicts Calpine's proposal.[140]

In addition to recommending a Wobbe Index range, Calpine argues that the Wobbe Index rate-of-change should be limited to two percent per minute. Otherwise, frequent combustion tuning could be needed to keep turbines operating properly. Each tuning event would result in the plant being shut down for eight to ten hours, which would impact costs and system reliability.[141]

E. Chevron

Chevron filed a Reply Brief to make clear that while Chevron would meet all gas quality standards that are in place when importing LNG, the company is not indifferent to what standard is adopted. Chevron is a member of the Producers and support its position that a maximum Wobbe Number of 1400 should be adopted.[142]

F. Crystal Energy

Crystal Energy (Crystal) filed a Reply Brief in which the company supported the changes proposed by SDG&E/SoCalGas and PG&E. Crystal believes that the tariffs should allow the broadest possible range of natural gas suppliers.[143]

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[140] Calpine Reply Brief, p. 11.

[141] *Id.*, pp. 16-17.

[142] Chevron Reply Brief.

[143] Crystal Opening Brief.

G. Exxon Mobil

Exxon Mobil supports implementing a Wobbe number cap of 1400 for gas delivered to California.[144] Exxon Mobil argues that such a standard will help provide stability for suppliers and end-use customers alike. Whatever the Commission's decision, Exxon Mobil urges it to affirm that existing contracts between the utilities and interconnecting pipelines and producers be honored.[145]

Exxon Mobil echoes the concerns of SDG&E/SoCalGas and numerous other parties that overly restrictive gas quality standards could limit supplies and drive up prices.[146]

Exxon Mobil supports applying the proposed tariff changes to all gas supplies entering the utilities' systems, so long as the changes incorporate the terms of existing supply contracts.[147] Deleting the existing rule's contract-based language from the tariff, Exxon Mobil contends, would undermine the regulatory framework upon which new and existing suppliers rely.[148]

Exxon Mobil asserts that given the differences between the Southern California and Northern California gas supplies, no practical reason exists to require uniform gas quality specifications for PG&E and SDG&E/SoCalGas.[149]

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[144] Exxon Mobil Opening Brief, pp. 4-5.

[145] *Id.*, p. 6.

[146] *Id.*

[147] *Id.*, p. 8.

[148] *Id.*, p. 12.

[149] *Id.*, p. 14.

Exxon Mobil opposes changing the gas quality specifications to further limit CO_2 content and O_2 content.[150] It argues that SDG&E/SoCalGas failed to demonstrate that a causal connection between these inert constituents and pipeline corrosion in fact exists. Without such evidence, Exxon Mobil argues, there is no basis for changing the rule to further limit CO_2 or O_2 content. In the event that the Commission does change the maximum levels of CO_2 or O_2 content, it should grant a deviation for existing California Production, 60% of which does not meet the proposed standard.[151]

Exxon Mobil opposes including the CARB CNG fuel specifications in the utilities gas quality specifications.

Exxon Mobil argues that before rules are adopted that would impose new specifications upon existing gas supplies, the Commission would need to do a thorough study of the impact of such rules on a supplier's costs as well as any possible loss of supply that might occur as a result.[152]

H. Indicated Producers, the Western States Petroleum Association And the California Independent Petroleum Association

The Indicated Producers, the Western States Petroleum Association, and the California Independent Petroleum Association (Producers) support setting a Wobbe cap of 1400 and oppose all other changes to the utility's gas quality tariffs.

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[150] *Id.*, p. 7.

[151] *Id.*

[152] *Id.*, p. 15.

The Producers opposes adopting regional gas quality specifications.[153] They argue that there is no basis in the record demonstrating the feasibility of actually setting and maintaining different standards by region or Btu District.[154]

Noting that there is broad industry agreement on narrowing the Wobbe range to 1290-1400 for SDG&E/SoCalGas, the Producers support this proposal. The Producers support a Wobbe cap of 1400 for SDG&E/SoCalGas and oppose a cap for PG&E for the same reasons outlined in SDG&E/SoCalGas' and PG&E's Opening Briefs.[155]

The Producers concur in SDG&E/SoCalGas' conclusion that setting a Wobbe number below 1400 would likely have a detrimental impact on natural gas supply and price.

The Producers argue against changing SDG&E/SoCalGas' current limits on CO_2 and O_2. The proposed changes are not pertinent to the introduction of new LNG supplies and are, therefore not needed at this time.[156] Lowering acceptable levels of CO_2 from 3% to 2% and of O_2 from 0.2% to 0.1%, the Producers argue, would exclude California production from the SoCalGas system. The Producers cite specific testimony that estimates that 60% of California production volumes would be unable to meet the proposed CO_2 standard, and 10% of production volumes would not meet the proposed O_2

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153 *Id.*, p. 36.

154 *Id.*

155 *Id.*, p. 3.

156 *Id.*, p. 21.

standard.[157] The Producers point out that Lee Stewart, a SDG&E/SoCalGas witness, stated that SoCalGas has successfully managed historical California gas supplies of varied composition.[158] The Producers support the testimony of their own witness, Dr. Craig, who testified that SoCalGas has not demonstrated that the higher levels of CO_2 and O_2 are causing any kind of corrosion problem in the pipeline.[159] They further assert that adopting the proposed limits on CO_2 and O_2 would be inconsistent with the California Natural Gas Policy Act which requires that the Commission "encourage, as a first priority, the increased production of gas in this state."[160] Finally, the Producers argue that SoCalGas has effectively addressed the problem of pipeline corrosion by monitoring dewpoint and upgrading dehydration facilities.[161]

The Producers propose that the Commission adopt four principles regarding the scope of applicability of the utilities' gas quality tariffs:

1) The utilities' gas quality tariff should be established prospectively as the default tariff for gas received from any source. As a default tariff, it should represent the most restrictive of conditions.
2) Existing agreements concerning quality that the utility and a pipeline or other interconnecting party have previously entered into should be grandfathered and approved to the extent that gas quality

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[157] *Id.*, p. 11.

[158] *Id.*, p. 11.

[159] *Id.*, p. 23.

[160] *Id.*

[161] *Id.*, p. 30.

specifications less onerous than the default tariff. If a new agreement contains gas quality specifications less restrictive that the default tariff, then the agreement shall require either generic or specific approval by the Commission. If the existing agreement has quality provisions more restrictive than the revised Rule 30, the quality provisions of the agreement should be replaced by Rule 30.

3) California-produced gas delivered at historical points of interconnection should be granted generic deviations from specifications adopted in this proceeding if the default specifications would lead to a restriction of California production.
4) Gas withdrawn from on-system storage should be required to meet the utilities' gas quality tariffs before entering the utility transportation system.

If the above principles are observed, the Producers support applying the utilities' gas quality tariffs to all gas delivered into the utility system.

The Producers oppose including the CARB CNG fuel specification in the utilities' gas quality tariff specifications because doing so would limit the receipt of both historical and prospective LNG supplies in the SoCalGas system.[162] The Producers highlight the fact that today, only five percent of today's California production meets the current CARB vehicle fuel specification mainly due to the low Methane Number standard.[163]

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[162] *Id.*, p. 12.

[163] *Id.*, p. 12. (citing Gas Quality Workshop Tr. 20-21, February 12, 2005 (Stewart/SoCalGas))

The Producers call for additional studies on CARB vehicle fuel specifications. These studies are not required for the Commission to issue a decision in this proceeding, however.

I. Kern River Gas Transmission Company

Kern River Gas Transmission Company (Kern) cautions the Commission against establishing an overly restrictive gas quality standard that might keep potential gas supplies out of California.[164] Kern argues that the Commission should not adopt standards that are more restrictive than those adopted by FERC. Kern also recommends that the Commission align its final decision with the original purpose of the OIR, which is to ensure a reliable supply of gas for the state at reasonable prices.[165] Accordingly, Kern opposes any overly restrictive Wobbe cap and supports SoCalGas' analysis on this issue.

According to testimony the Kern River pipeline currently supplies about 20% of southern California's gas supply. Over the past three years the Wobbe Index has averaged 1360, with a maximum daily Wobbe Index of 1379.[166] For the gas flowing through the Kern River pipeline to consistently meet the 1360 Wobbe Index maximum proposed by the District, gas producers would need to add additional facilities to strip out additional hydrocarbons. Producers could opt to send their gas to markets with less restrictive requirements.[167]

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[164] Kern Opening Brief, p. 5.

[165] *Id.*, p. 9.

[166] *Id.*, pp. 6-7.

[167] Kern Reply Brief, pp. 3-4.

Kern does not oppose the deviation process recommended by SDG&E/SoCalGas if it applies to all supply sources, including interstate gas.[168] Kern also notes that if any changes are made to the SDG&E/SoCalGas tariffs, Kern will need at least 12 months to make the equivalent changes to its FERC tariff.[169]

J. PG&E

PG&E does not believe that major changes to its gas quality tariff are warranted at this time. The utility recommends several minor changes which are intended to bring PG&E's gas quality tariff into closer alignment with the tariffs of SoCalGas and SDG&E.[170] These proposed changes are contained in Exhibit 101 (Bronner), Attachment 1. PG&E does not support adopting a Wobbe Index cap or range as part of its tariff.[171] More generally, PG&E does not support changing its interchangeability standards until further studies have been completed.[172]

PG&E is concerned that adopting a gas quality standard that is too strict could exclude some potential California production and LNG supplies from the state. At the same time end user safety and reliability must be ensured, and environmental impacts should be minimized.[173]

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[168] Kern Opening Brief, p. 8.

[169] Kern Reply Brief, p. 5.

[170] PG&E Opening Brief, p. 2.

[171] *Id.*, p. 4.

[172] *Id.*, pp. 6-7.

[173] *Id.*, pp. 8-9.

PG&E states that its gas quality tariff applies to all gas entering the system other than interstate pipeline supplies, which must comply with the gas quality requirements in each pipeline's FERC tariff.[174]

PG&E does not support adopting a single state-wide gas quality standard due to differences between the historical gas supplies handled by the PG&E pipeline system and the SDG&E/SoCalGas systems.[175] Pipeline systems in California may also have different abilities to blend and different tolerances for components such as carbon dioxide and water, justifying non-uniform standards.[176]

PG&E is concerned with any proposal that would adopt regional gas quality standards within a utility's service territory, such as the District has proposed within SoCalGas' territory. PG&E does not believe that the record is sufficient to change current practice and adopt a regional standard. Supplies within a particular region presently change on a seasonally or weekly basis in response to constantly shifting market dynamics. Regional standards could potentially impact the availability of lowest-cost supplies throughout a utility's service territory.[177]

PG&E is opposed to Calpine's recommendation to adopt a two percent per minute Wobbe Index rate-of-change limitation. PG&E explains that the utility does not have the equipment to monitor or control this parameter. Generators

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[174] *Id.*, p. 14.

[175] *Id.*, p. 4.

[176] *Id.*, p. 13.

[177] *Id.*, pp. 16-17.

are in the best position to have the tuning equipment necessary to monitor and control this type of fluctuation.[178]

PG&E does not propose adopting the current CARB CNG specifications as part of its tariff, but does propose adding a requirement that Methane Number must be 80 or higher, which is consistent with revisions CARB has proposed. PG&E supports the goals of CARB's natural gas vehicle fuel standards and has natural gas fueling stations throughout its service territory.[179]

PG&E strongly supports completing the studies identified in the NGC+ White Paper.[180] PG&E supports additional research to examine the impacts of new gas supplies on end-use equipment performance and emissions, utility equipment, and gas supply and price.[181]

PG&E believes the research effort needs to be a nation-wide collaboration. The utility notes that research is already underway by the US DOE, AGA, CEC, Gas Appliance Manufacturers Association, Gas Technology Institute, and SDG&E/SoCalGas. PG&E anticipates working with the Northeast Gas Association NYSEARCH research program to investigate the potential impacts of new gas supplies on utility equipment.[182]

PG&E believes that the studies should "be funded as public interest research programs on a national basis, with California stakeholders participating

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[178] *Id.*, p. 5.

[179] *Id.*, pp. 11-12.

[180] *Id.*, p. 9.

[181] *Id.*, p. 20.

[182] *Id.*, p. 23.

actively in this work." The CEC should sponsor any California-specific research, and the utilities should fund studies on the impacts on utility equipment.[183]

K. Sempra LNG

Sempra LNG (Sempra) supports changing existing gas quality tariff specifications to (1) require that all natural gas supplies fall within a Wobbe Number range of 1290-1400 Btu/scf; (2) limit content of butane and heavier hydrocarbons to 1.5%; and, (3) require that all natural gas supplies have a minimum 85% methane content.[184] Sempra proposes that these standards be applied uniformly to all utilities.

Sempra argues that the utilities' gas interchangeability specifications should apply to all gas supplies equally. This means that uniform standards should be applied, regardless of the date of market entry and regardless of the source of supply. Sempra also points out that it is the Commission's stated policy to encourage new LNG supplies to enter the market and compete on equal footing with existing gas supplies and that it should not create artificial barriers that would hinder that objective.[185] Adopting uniform standards that would apply equally to all suppliers and utilities, Sempra asserts, would best advance the Commission's stated goals.

Sempra states that the Commission can retain utility-specific tariffs at this time, but should work towards adopting state-wide, industry-wide standards.

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[183] *Id.*, p. 23.

[184] Sempra Opening Brief, p. 3.

[185] *Id.*, p. 11, citing D.04-09-022 (Conclusion of Law 18) and the Energy Action Plan (at p. 10)

However, Sempra opposes the adoption of regional specifications because regulatory complexity will only hinder the introduction of new supplies.[186]

Echoing the concerns of other participants in this proceeding, Sempra cautions that if the Commission adopts overly restrictive gas interchangeability requirements it could significantly impact the availability of natural gas and, as a result, drive up the price. Sempra asserts that if the Commission were to adopt the 1360 Wobbe cap proposed by the District it would exclude 60% of California production; a significant portion of Kern River supplies, which constitutes 20% of the SDG&E/SoCalGas supply; and 80% to 90% of potential LNG supplies.[187] Sempra explains that this will drive the price of gas up by either diverting that supply from the California market altogether, or raising the floor price at which LNG supplies compete with other gas by requiring that LNG undergo conditioning.[188] Conversely, adding supply will "place downward pressure on prices by increasing gas-on-gas competition."[189] Sempra encourages the Commission to adopt standards that will ensure greater access to diverse sources of supply, which in turn will reduce prices and price volatility.[190]

Sempra disagrees with the assertion of SCE that any costs required to condition LNG to meet California requirements will necessarily be borne by the LNG supplier, and will not be passed on in the form of higher gas costs. Sempra

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[186] Sempra Opening Brief, p. 13.

[187] *Id.*, p. 6.

[188] *Id.*, p. 9.

[189] *Id.*, p. 10, citing Tr. Vol. 10 (Sempra LNG witness Bamburg) at p. 1260.

[190] *Id.*, p. 8.

points out that while LNG may not be the marginal supply of gas in the short-run, in the future LNG could be the supply that sets prices.[191]

Sempra believes that the District's assertion that a 1400 Wobbe cap burdens end-users is exaggerated. The company points out that 80 to 90 percent of residential and small commercial appliances are "legacy" equipment that is tolerant to gas composition changes. Furthermore, large equipment is frequently tuned under normal conditions to adjust for emissions.[192]

Sempra argues that adopting the 1400 Wobbe cap will work to reduce overall emissions and improve air quality better than the 1360 cap proposed by the District. Sempra explains that if the Commission were to limit supply by adopting an overly-restrictive Wobbe cap, like 1360, it would drive up the price and result in the use of less-environmentally friendly fuels.[193] Furthermore, driving down the cost of natural gas will encourage the conversion from less-environmentally fuels, like diesel.[194]

Sempra describes its 85% methane minimum as being responsive to the concerns of SCE.[195] Sempra states that carbon dioxide, hydrogen sulfide, sulfur, and oxygen content are not an issue for the company since these constituents only in minimal levels in LNG.[196]

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[191] Sempra Reply Brief, p. 13.

[192] Sempra Opening Brief, p. 16.

[193] *Id.*, p. 10.

[194] *Id.*, p. 14.

[195] Sempra Opening Brief, p. 4.

[196] *Id.*, p. 11.

Sempra opposes including the CARB CNG fuel specification in the gas quality tariff specification because the standard will significantly restrict available gas supplies.[197] Sempra disagrees with the District that adopting the CARB CNG fuel specification is necessary to protect the natural gas vehicle fleet. Newer natural gas vehicles are adequately protected by the SDG&E/SoCalGas proposal. There are less than one thousand older, heavy duty vehicles that could face potential issues. Of those, less than ninety may actually require modification. Therefore, Sempra points to the statement of SDG&E/SoCalGas that retrofitting the small number of affecting vehicles could be a cost effective approach to addressing the issue.[198]

Sempra supports the suggestion of Kern that all sources of supply should be eligible for a deviation process. However, proposals to exempt California production from the new tariff should be rejected.[199]

Sempra argues that there is currently enough information to adopt the changes it recommends in this proceeding. It recognizes that additional research is needed, however, and requests that both federal and state agencies take a more active role in that process.[200]

L. Shell Trading Gas & Power

Shell Trading Gas & Power (Shell) supports the tariff changes proposed by SDG&E/SoCalGas in their opening brief. Shell encourages the Commission to

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[197] *Id.*, p. 10 and Sempra Reply Brief, p. 20.

[198] Sempra Reply Brief, p. 20.

[199] Sempra Reply Brief, pp. 23-24.

[200] *Id.*, pp. 15-16.

approve a Wobbe index range of 1290 to 1400 for gas supplies delivered to SDG&E's and SoCalGas' systems. Citing the testimony of Mr. Sasadeusz on studies conducted by SoCalGas, Shell supports using the Wobbe index as a measure of gas quality since it is a better predictor of the response of end-use appliances' response to varying gas compositions.[201] Shell does not think it is necessary to revise PG&E's gas specifications at this time since PG&E is not expected to connect to any new gas supply source in the foreseeable future.[202]

Shell does not support regional gas quality specifications. In practice a supplier would have to comply with the most restrictive gas quality specification that the supplier's gas could potentially flow into. A restrictive regional standard would therefore become the de facto system-wide standard.[203]

Shell cautions the Commission to be mindful that an overly restrictive Wobbe cap would likely limit supply and drive up the cost of gas.[204] Shell offers the testimony of Dr. Kuipers who explained that most of the LNG coming into California will be coming from the Asia Pacific region. These LNG supplies tend to have relatively higher Wobbe numbers. However, with 3 percent nitrogen injection, most Asia Pacific LNG supplies can comply with a 1400 maximum Wobbe Index. Three percent nitrogen injection would not be sufficient to reduce the Wobbe Index of most supplies to comply with the District's 1360 maximum proposal. If the maximum Wobbe Index is set below 1400, Shell contends, some

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[201] Shell Opening Brief, p. 9, citing Ex. 107, p.4.

[202] *Id.*, p. 12.

[203] Shell Opening Brief, pp. 31-32.

[204] *Id.*, p. 16.

LNG supplies will go to markets other than California. Furthermore, there are economic and regulatory constraints that prevent nitrogen injection of greater than 3 percent. For example, the transmission pipelines in Arizona will only accept gas with a maximum nitrogen content of 3 percent.[205]

Shell contends that SoCalGas' April 2005 Report established that a 1400 Wobbe cap would ensure the safe and satisfactory performance of all gas-fired equipment.[206] Shell points out that variation in the Wobbe Index between different gas supplies are commonplace in the US gas industry.[207] In the past, gas of various Wobbe ranges has been successfully utilized.[208] Furthermore, the manufacturers specifications on commonly used gas-fired turbines, like GE and Westinghouse, as well as all of the new DLN/DLE gas turbines being built in southern California, provide for Wobbe ranges that include the proposed 1400 cap.[209]

Shell argues that California's air quality will improve as a result of the introduction of new natural gas supplies.[210] Shell contends that natural gas operates more cleanly than alternative fossil fuels in end-use equipment. When burning higher Wobbe gas, equipment tends to produce higher levels of NO_X. In the Southern California Air Basin introduction of higher Wobbe LNG supplies

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[205] *Id.*, pp. 16-18.

[206] *Id.*, p. 21.

[207] *Id.*, p. 37.

[208] *Id.*

[209] *Id.*, p. 38.

[210] *Id.*, p. 39.

could lead to an increase the amount of NO_X produced. Over time, however, Shell believes that as equipment is re-tuned and replaced and new technologies are introduced the use of 1400 Wobbe gas will not result in any greater level of NO_X than currently exists.[211] Furthermore, Shell notes that any increase in NOx emissions from a lean-mix burner would be accompanied by a decrease in unburned hydrocarbons, which may reduce ozone formation and particulate matter concentrations.[212]

Shell suggests that certain cost-effective mitigation measures can be used in order to offset the effect of whatever short-term increase in emissions result from the new standard.[213]

Shell disputes SCE's claim that turbines in its Mountainview plant cannot handle 1400 Wobbe Index gas. Shell points out that since the gas delivered to the turbine is preheated to 365°F, 1400 Wobbe Index gas satisfies GE's requirements.[214] Shell contends that Calpine misunderstands the manufacturer specifications of its turbines, and that properly adjusting Calpine's calculations would result in a Wobbe Index of about 1445, not 1391.[215] Shell also disputes Calpine's claim that changing gas quality will require frequent shut-downs for retuning, which will negatively impact electric reliability. Shell points out that the turbines have to be periodically shut-down in any event to recalibrate for

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[211] *Id.*, p. 43.

[212] Shell Reply Brief, p. 6.

[213] Shell Opening Brief, pp. 45-46.

[214] Shell Reply Brief, p. 13.

[215] Shell Opening Brief, pp. 23-24

changes in temperature, humidity, and air pressure, so adjustments for changing gas quality could occur at the same time.[216]

Shell is opposed to the rate-of-change requirement advocated by Calpine and SCE. Shell believes that since the rate-of-change is a function of both gas demand and supply, it is a "gas control" issue rather than a gas quality issue, and does not belong in the tariff.[217]

Shell is opposed to including the CARB CNG specifications in the SDG&E/SoCalGas tariff because the CARB's six percent limit on ethane and three percent limit on propane and heavier hydrocarbons is incompatible with most if not all Asia Pacific LNG supplies. Furthermore, the extraction of natural gas liquids (NGLs) is not an option at the Energia Costa Azul LNG regasification terminal, where Shell holds capacity. There is no nearby refinery or liquids pipeline to transport NGLs, and the Mexican government-owned oil monopoly PEMEX does not permit third parties to operate facilities in Mexico to sell propane and heavier hydrocarbons. Shell does not, however, oppose a minimum methane content of 85 percent.[218]

Shell contends that no further information is needed to adopt the proposed changes the gas quality tariffs. Shell recognizes that there may be further research in the future in order to gauge any effect that relaxing an established Wobbe cap might have.[219]

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[216] Shell Reply Brief, p. 14.

[217] *Id.*, p. 35.

[218] *Id.*, p. 32.

[219] Shell Opening Brief, p. 52.

M. Southern California Edison

SCE argues that the existing SDG&E/SoCalGas Tariff Rule 30 is "woefully inadequate" to protect customers and end-use equipment if natural gas enters the pipeline system from LNG imports.[220] SCE supports the District's proposal to adopt a Wobbe Index range of plus or minus two percent of the historical Wobbe Index, which equates to a maximum Wobbe Index of 1360.[221] SCE characterizes the geographic application of the standard differently than the District, stating that the standard would apply to gas brought into California from outside including LNG and interstate gas.[222]

SCE would prefer a state-wide gas quality tariff specification, but finds that regional standards could be appropriate due to the impact of California gas production in some regions.[223]

SCE supports increasing California gas supplies with LNG, but warns that the introduction of gas of an unsuitable quality could threaten air quality, cause equipment failure, result in the shut down of power plants when emission limits are reached, and threaten electric grid reliability.[224]

SCE urges the Commission to discount arguments that the District's proposal will eliminate new supplies. As support, the utility points to statements made by LNG developers Sound Energy Solutions and BHP that they

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[220] SCE Opening Brief, p. 6.

[221] *Id.*, p. 7.

[222]*Id.*, pp. 7 and 34.

[223] *Id.*, p. 36.

[224] *Id.*, pp. 9-10.

will each meet whatever gas quality standard is adopted by the Commission.[225] At the same time SCE speculates that a maximum Wobbe Index of 1360 could eliminate some supplies with slightly higher Wobbe Index that current end-user equipment could handle.[226]

SCE also believes that parties' assertions that a 1360 Wobbe Index maximum will increase gas prices is speculative. SCE relates the testimony of Dr. Kuipers of Shell who stated that the Energia Costa Azul LNG project in Mexico would have to incur an additional cost of $0.05 to $0.10 per MMBtu to meet a 1360 Wobbe Index maximum using inert injection. However, Shell also testified that the gas from the terminal would not be setting the gas price in Southern California. Therefore, the cost of the injection process would not be reflected in Southern California gas prices.[227]

SCE opposes the proposal of SDG&E/SoCalGas to adopt a 1400 maximum Wobbe Index. SCE points to testimony that refutes the claim of parties that SDG&E/SoCalGas customers have experienced 1400 Wobbe Index gas in the past. The record demonstrates that only limited areas within the SoCalGas service territory, but outside the South Coast Air Basin, have seen gas with a Wobbe Index of 1400 or above. SDG&E's service territory has not experienced gas approaching 1400 Wobbe Index. Most SoCalGas and SDG&E customers have never experienced 1400 Wobbe Index gas.[228]

[225] *Id.*, pp. 12-13 and 17.

[226] *Id.*, p. 28.

[227] *Id.*, pp. 18-19.

[228] *Id.*, pp. 21-22.

SCE further argues that SDG&E/SoCalGas have misapplied the recommendations of the NGC+ White Paper, which recommends adopting a maximum Wobbe Index limit of four percent above historical average gas. Since the historical system average Wobbe Index in the combined SDG&E/SoCalGas system is 1332, the maximum Wobbe Index recommended by the NGC+ White Paper would be 1385. SCE does not, however, support a 1385 maximum.[229]

SCE is very concerned about the impact of higher Wobbe Index gas on the GE frame 7F gas turbines used in its Mountainview power plant. According to SCE, the turbines are designed to handle gas with a Wobbe Index as high as 1391. However, each particular turbine is calibrated based on a sample of gas, and can only operate within a Wobbe Index range of plus or minus 4-1/2% of the sample level. The Mountainview turbines were calibrated using 1321 Wobbe Index gas. GE has not been able to identify specific modifications that would enable SCE to burn gas outside of the GE specification. Gas quality standards that would allow a Wobbe Index outside of historical ranges could, therefore, damage SCE's turbines.[230]

SCE also proposes that Tariff Rule 30 should include a constituent standard that requires a minimum methane composition of 85 percent of reactant gases for gas brought into the state. Alternatively, a one percent limitation on butane and heavier hydrocarbons would be acceptable.[231,232] SCE describes its 85

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[229] *Id.*, p. 23.

[230] *Id.*, pp. 24-26.

[231] *Id.*, p. 7.

percent of reactant gases requirement as being consistent the 88 percent of total gas minimum required by CARB's CNG specifications.[233] A minimum methane requirement of 85 percent is necessary to stay within the fuel specification for SCE's GE frame 7F gas turbines at its Mountainview power plant.[234] SCE also supports adopting the other constituent standards in the CARB CNG specifications.[235]

SCE also argues that the tariff should contain a "rate-of-change" requirement that would limit the change in Wobbe Index per minute to two percent, as proposed by Calpine. SCE explains that some customers will receive entirely LNG-derived gas supplies, while others will receive primarily interstate gas supplies. Normal fluctuations in demand and supply could impact whether a particular customer's gas is from LNG or interstate pipelines. SCE points to representations in its testimony by General Electric that fluctuating gas quality is a concern for the General Electric Frame 7F turbines at SCE's Mountainview plant.[236]

SCE advocates additional testing and research be performed to analyze air quality impacts, effects on end-use equipment, and equipment modifications

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[232] The constituent percentages recommended by SCE are assumed to be molar percents, although SCE does not specify such in its comments.

[233] SCE Opening Brief, pp. 28-29.

[234] *Id.*, p. 30.

[235] *Id.*, p. 33.

[236] *Id.*, pp. 14-15.

options to address higher Wobbe Index gas and changing Wobbe Index gas.[237] SCE points out that the CEC, gas utilities, General Electric and others have already conducted research related to these issues. The utility recommends that the Commission's Energy Division conduct a workshop so that stakeholders can identify additional studies needed. The Energy Division should oversee the monitoring, evaluating, and reporting back to the Commission of the studies. SCE expects that some studies will be funded by the commercial market, but believes that the studies directed by the Commission should be funded by natural gas customers.[238]

VIII. NGC+ Report

Several parties rely upon the recommendations of the NGC+ Interchangeability Work Group (NGC+ Work Group) contained in the White Paper on Natural Gas Interchangeability and Non-Combustion End Use (NGC+ White Paper or White Paper).[239] The NGC+ Work Group is a group of natural gas industry stakeholders under the leadership of the Natural Gas Council, an umbrella organization of natural gas industry trade associations. The Work Group includes representatives of LNG suppliers, natural gas pipelines, utilities, power generators, industrial process gas users, appliance manufacturers, and natural gas processors. Specific trade associations represented on the NGC+ Work Group include the American Gas Association, Interstate Natural Gas Association of America, American Public Gas Association, Electric Power Supply

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[237] *Id.*, pp. 42-43.

[238] *Id.*, p. 42.

[239] Filed as Ex. 107, Attach B.

Association, Process Gas Consumers, Gas Appliance Manufacturers Association, Association of Home Appliance Manufacturers, and Gas Processors Association. The Work Group also includes representatives of 36 individual companies in the natural gas industry.[240]

The NGC+ Work Group convened in response to a 2003 report issued by National Petroleum Council, a FERC natural gas conference in 2003, and a FERC technical conference held in February 18, 2004.[241]

On February 28, 2005 the NGC+ Work Group issued the NGC+ White Paper, which contains consensus recommendations of the Work Group participants. The objective of the White Paper is "to define acceptable ranges of natural gas characteristics that can be consumed by end users while maintaining safety, reliability, and environmental performance. [footnote omitted]"[242]

The Work Group examined the impact of changing natural gas quality end-use equipment including appliances; industrial boilers, furnaces and process heaters; reciprocating engines including natural gas vehicles; combustion turbines; and non-combustion uses. Older and newer technologies were considered within each equipment category.[243]

The Work Group identified a number of undesirable effects that can result from changing natural gas composition in end use applications. The White Paper lists seven "combustion specific phenomena": auto-ignition (i.e. engine

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[240] NGC+ White Paper, pp. 34-35.

[241] *Id.*, p. 3.

[242] *Id.*, p. 4.

[243] *Id.*, pp. 8-9.

knock), combustion dynamics, flashback, lifting, blowout, incomplete combustion, and yellow tipping. The paper also lists four "emission characteristics": nitrogen oxides, unburned hydrocarbons, carbon monoxide, and the response of supplemental emission control technology.[244]

In order to develop its natural gas specification guidelines, the Work Group introduced the idea of developing an "operating regime." The operating regime is developed by identifying several parameters that address the specific combustion phenomena and emission characteristics caused by changing gas quality, and defining an acceptable range for those parameters.[245]

The group identified Wobbe Index as the "most robust single parameter" that can address a large number of end-use effects.[246] A minimum Wobbe Index can be used to address lifting, blowout and carbon monoxide formation. A maximum Wobbe Index can be applied to address yellow tipping, incomplete combustion, nitrogen oxide emissions and carbon monoxide emissions. Wobbe Index alone, however, is insufficient to address all the potential end-use effects. The paper determines that an additional parameter is necessary to address auto-ignition, flashback, and combustion dynamics. The Work Group found that a maximum heating value, or a maximum value for a specific fraction of hydrocarbons, could address these effects.[247]

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[244] *Id.*, p. 9.

[245] *Id.*, pp. 12-13.

[246] *Id.*, p. 13.

[247] *Id.*, p. 13.

The Work Group found that understanding the historical composition of gas in a region is essential to establishing acceptable interchangeability standards. For example, the report describes the importance of historical composition for home appliances:

> These units are initially installed and placed into operation using the natural gas as received, in a given region or market area. Appliance performance degrades when the appliance is operated with gas that is not interchangeable with the gas used to tune the appliance when it was first installed. Although the safety certification of appliances ensures that they perform safely when operated well above and below their design firing rates, much of that margin has historically been used to accommodate fluctuations in air temperature and humidity that also affect appliance performance.[248]

Consistent with this finding, the Work Group recommended that "acceptable interchangeability ranges for specific regions or market areas may be more restrictive as a consequence of historical compositions and corresponding end use settings."[249]

The NGC+ Work Group adopted the following interim gas quality specification guidelines in the White Paper:

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[248] *Id.*, p. 9.

[249] *Id.*, p. 22.

A. A range of plus and minus 4% Wobbe Number Variation from Local Historical Average Gas or, alternatively, Established Adjustment or Target Gas for the service territory.[250]

Subject to:

Maximum Wobbe Number Limit: 1,400[251]

Maximum Heating Value Limit: 1,110 Btu/scf[251]

B. Additional Composition maximum limits:[250]

Maximum Butanes+: 1.5 mole percent

Maximum Total Inerts: 4 mole percent

C. EXCEPTION: Service territories with demonstrated experience[252] with supplies exceeding these Wobbe, Heating Value and/or Composition Limits may continue to use supplies conforming to this experience as long as it does not unduly contribute to safety and utilization problems of end use equipment.[253]

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250 Experience has shown that using this plus/minus four percent formula in combination with the compositional limits will result in a local Wobbe range that is above 1,200.

251 Based on gross or higher heating value (HHV) at standard conditions of 14.73 psia, 60°F, dry, real basis.

252 Demonstrated experience refers to actual end use experience established by end-use testing and monitoring programs.

253 NGC+ White Paper, p. 27.

The Work Group made this interim recommendation based on "extensive data and analysis for traditional gas appliances and combustion behavior in appliances" and "the lack of data on gas interchangeability for a broad range of other end use applications."[254] The report contains two tables that identify specific data gaps that need to be filled in order to move from an interim standard to a longer-term guideline.[255] The Work Group recommends that the data gaps be filled within three years of the White Paper's issue date.

The Work Group finds that a collaborative effort will be necessary to conduct additional research including the U.S. Department of Energy, equipment manufacturers, natural gas suppliers, pipelines, local distribution companies and other industry trade groups.[256]

The Natural Gas Council filed the White Paper at FERC on February 28, 2005, and FERC solicited public comment on the report. On June 15, 2006, FERC issued a policy statement on natural gas quality in which FERC recommended that interstate gas pipelines and their customers use the NGC+ interim guidelines as a reference point for resolving gas quality disputes.[257]

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[254] *Id.*, p. 25.

[255] *Id.*, pp. 28-33.

[256] *Id.*, p. 21.

[257] *Policy Statement on Provisions Governing Natural Gas Quality and Interchangeability in Interstate Natural Gas Pipeline Company Tariffs*, 115 F.E.R.C. P61,325 (FERC 2006), p. 13.

IX. Discussion

A. Should the Commission Approve any Changes to the Existing Gas Quality Tariff Specifications of SDG&E and SoCalGas?

All parties support changing the gas quality tariffs of SDG&E and SoCalGas. We agree and believe that approving changes to SDG&E/SoCalGas' tariffs now is important to provide regulatory certainty to LNG developers and other potential natural gas suppliers. LNG developers and supplies should incorporate the new gas quality standards into their supply arrangements and project designs.

All parties also agreed that a maximum Wobbe Index should be included as an element of the revised tariff. As concluded in the NGC+ White Paper, the Wobbe Index is the most robust single gas quality parameter. We therefore will adopt revised gas quality tariffs for SDG&E and SoCalGas that incorporate a maximum Wobbe Index.

B. Should the Commission Approve any Changes to the Existing Gas Quality Tariff Specifications of PG&E?

We agree with PG&E that a Wobbe Index standard should not be incorporated into its standard at this time since no application has been filed for an LNG terminal that would supply gas directly to PG&E's service territory. Therefore, there is less need to provide immediate regulatory certainty. Crystal, the Producers and SDG&E/SoCalGas supported PG&E's position, and no party opposed it.

As discussed below, we will adopt the minor changes recommended by PG&E and endorsed by Crystal in order to bring the gas quality tariff of PG&E into closer alignment with that of SDG&E/SoCalGas.

C. State-Wide, Utility Specific and Regional Gas Quality Standards

By supporting the adoption of a Wobbe Index standard for SDG&E/SoCalGas, but not PG&E, we are rejecting the recommendation of BHP and Calpine that the Commission adopt a single state-wide gas quality standard. In the long-run we support efforts to promote gas interchangeability throughout California. However, we agree with Exxon, PG&E, the Producers, SDG&E/SoCalGas, and Shell that differences in historical gas supplies and the lack of LNG proposals in PG&E's territory justify utility-specific standards at this point in time.

The District recommends adopting a regional gas quality standard that would apply specifically to the South Coast Air Basin, due to the air quality challenges that are unique to that area. SCE also believes that regional standards are justifiable due to differences in California production. SDG&E/SoCalGas, PG&E, the Producers, Sempra, and Shell are all opposed to adopting regional gas quality standards. The utilities that operate the state's intrastate gas infrastructure, PG&E and SDG&E/SoCalGas, question the feasibility and cost of managing a pipeline system with regional standards. SDG&E/SoCalGas suggest that a regional standard in the South Coast Air Basin may be impossible to effect. Other opponents argue that a restrictive regional standard would become the de facto system-wide standard if a supplier cannot guarantee that its supplies will not flow into the restrictive region.

We are persuaded that adopting regional gas quality tariffs is not feasible and will instead continue to apply each utility's gas quality tariff on a service territory-wide basis.

D. Wobbe Index

Parties disagree vigorously on what maximum Wobbe Index should be adopted as part of SDG&E/SoCalGas' tariffs. The District and SCE advocate a maximum Wobbe Index of 1360, which is supposed to maintain the status quo while additional research is performed on the emissions and performance impacts of high Wobbe gas on end-use equipment.[258] SDG&E/SoCalGas, BHP, Chevron, the Producers, Sempra, and Shell recommend the Commission adopt a maximum Wobbe Index of 1400 in order to allow a wide range of natural gas supplies into the state while addressing potential end-use equipment performance and emissions impacts. Calpine backs a maximum Wobbe Index of 1391 in order to protect modern, low emissions turbines. Kern does not recommend a specific maximum Wobbe Index, but cautions the Commission that adopting a Wobbe Index that is too low could cut California off from some natural gas supplies.

Parties generally focused their comments on the maximum Wobbe Index, and not the minimum Wobbe Index, since LNG supplies could have relatively high Wobbe Indices.

Diversifying California's gas supply sources is a state policy adopted in the Energy Action Plan II (EAP II).[259] Increased supplies will necessarily result in lower natural gas costs. Lower natural gas costs will directly lower the energy

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[258] The District's proposal is for the South Coast Air Basin alone. However, as discussed below, we believe their proposed standard would have to be applied to the entire SoCalGas service territory.

[259] The Energy Action Plan II was adopted by the CPUC and CEC on September 21, 2005.

bills of California's natural gas and electricity consumers, helping to stimulate the economy. We must therefore consider the impact of gas quality requirements on natural gas supply and cost.

We agree with the proponents of a 1400 Wobbe Index that a 1360 maximum Wobbe would unnecessarily constrain California's natural gas supplies. While the precise impact cannot be determined based on the record, a 1360 Wobbe limit could clearly discourage some supplies from entering the state. Even if California production and interstate gas were granted some sort of exemption from a 1360 cap, the impact on LNG supplies could be significant due to the high Wobbe indices of most Asia-Pacific LNG supplies. At the very least, the need to condition gas for the California market will add costs. Furthermore, Shell claims that the Energia Costa Azul terminal in Mexico cannot condition gas beyond injecting up to 3 percent nitrogen. We believe that the costs associated with additional conditioning will have cost impacts on California gas consumers. Conditioning costs will raise the hurdle price that LNG importers require to ship gas to the California market, or if LNG becomes the marginal gas supply, the conditioning cost could be directly passed on to consumers.

Policies that increase natural gas supply and lower natural gas costs help to address many of California's most critical environmental challenges. For example, the CPUC is aggressively pursuing policies to address the threat of climate change. The Commission is investigating adopting a greenhouse gas emissions performance standard for new electricity procurement contracts entered into by the investor-owned utilities that would limit greenhouse gas emissions to the level emitted by modern natural gas-fired generation. If the Commission determines that promoting natural gas-fired generation over other types of generation is necessary to achieve our climate change goals, then the

Commission should clearly adopt policies that increase supplies of the natural gas needed to fuel these plants.[260]

The EAP II identifies key environmental actions related to transportation fuels that are furthered by increasing the state's gas supplies. The plan states that the CPUC and CEC will work with the California EPA to implement the California Hydrogen Highway Blueprint. The California Hydrogen Highway Blueprint recognizes the important role of natural gas to promote the use of hydrogen in the state.[261] The EAP II also states that the CPUC will pursue policies to promote the use of natural gas vehicles. Policies that increase gas supplies and lower gas costs will help the Commission achieve these goals.

We are concerned with the potential impacts of high Wobbe gas on emissions and the performance of end-use equipment. The NGC+ White Paper lists eleven different undesirable performance behaviors and emissions characteristics that can result from changing natural gas quality. The District correctly notes that many gaps remain in our understanding of precisely how different Wobbe Indices influence these behaviors. The District proposes a precautionary approach that would attempt to maintain the status quo until further studies have been completed.

We disagree with the District's conclusion that in the face of uncertainty, the Commission should adopt a policy that would only permit gas supplies that are similar to average historical gas supplies. The job of the Commission is to consider the available evidence and adopt a reasonable policy. We support the

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[260] See "Policy Statement on Greenhouse Gas Performance Standards" (October 6, 2005).

[261] California Hydrogen Blueprint Plan, Volume 1 (May 2005), p. 15.

approach of the NGC+ White Paper, which explicitly acknowledges the data gaps and recommends a gas quality standard consistent with those gaps.

Given the potential impacts on gas supply, gas costs, emissions, and end-use equipment performance, the Commission should adopt a gas quality standard that is consistent with the best information currently available. We agree that further research is needed to fully understand the impacts of higher Wobbe Index gas on emissions and end-use equipment performance. However, the Commission cannot postpone implementing a new gas quality tariff until all additional research is complete. LNG developers need regulatory certainty today to design and build LNG import projects and arrange for sources of LNG supply. Federal and state agencies are also considering specific LNG projects, and since revising the gas quality tariff could have implications on those specific projects, it is in the interest of the reviewing agencies to have this issue settled sooner rather than later. Adopting a reasonable standard today, based on the best information available is therefore in the public interest.

It is prudent to adopt the interim gas quality specifications recommended in the NGC+ White Paper. The NGC+ White Paper is the consensus recommendation of a group that included representatives of all major segments of the natural gas industry. The NGC+ Work Group included LNG importers, who have an interest in adopting rules that allow LNG to be sold into U.S. markets; local distribution companies and interstate pipelines, who have an interest in safe and reliable operation of their infrastructure; and appliance manufacturers, turbine manufacturers and power plant operators, who are concerned with the reliable operation of their equipment and compliance with emissions rules. The group reached its recommendation based on the available information and recommended specific additional studies. The report also received the endorsement of FERC in its recent policy statement.

The proponents of adopting a maximum Wobbe Index of 1400 relied upon the NGC+ recommendation. NGC+ recommends adopting a Wobbe range equal to plus and minus four percent of average historical gas subject to a maximum Wobbe of 1400. As SCE points out, applying the NGC+ recommendation to the five-year historical average Wobbe Index in the SoCalGas service territory, 1332, results in a Wobbe range of 1279 to 1385.[262] Since all of SDG&E's gas flows through the SoCalGas service territory, it is reasonable to assume that SDG&E's historical average is also near 1332. Proponents of a 1400 Wobbe maximum rely on the NGC+ recommendation that "service territories with demonstrated experience with supplies exceeding these Wobbe…Limits may continue to use supplies conforming to this experience as long as it does not unduly contribute to safety and utilization problems of end use equipment." Parties argue that since some parts of the SoCalGas service territory have experienced gas with a Wobbe Index of 1400, and even higher, adopting the maximum Wobbe Index recommendation of the NGC+ report is appropriate.

We disagree and do not find that the service territories of SoCalGas or SDG&E have "demonstrated experience" with gas that exceeds a Wobbe Index of 1385. While SDG&E/SoCalGas demonstrated that certain Btu Districts have experienced gas with a Wobbe Index over 1385, the utilities did not demonstrate that most districts have experience with higher than 1385 Wobbe Index, or even that a high Wobbe Index is typical for those areas that have experienced high

[262] SCE did not support a maximum Wobbe Index of 1385.

Wobbe Index gas in the past. We therefore will adopt a maximum Wobbe Index range equal to plus and minus four percent of the historical average Wobbe Index. The minimum Wobbe Index will be 1279, and the maximum Wobbe Index will be 1385.

Impact on Turbines

Calpine and SCE are concerned that the newest low-emissions gas turbines that they own will be unable to handle high Wobbe Index gas. SDG&E/SoCalGas, another owner of power plants with modern gas turbines, has no such concerns. Calpine has advocated a Wobbe Index of 1153 to 1391, since the manufacturers specifications only guarantee performance within that Wobbe range. The Wobbe range we are adopting here is within the range Calpine has advocated, so it would not create reliability or operational problems for the turbines Calpine has described in its testimony. If Shell is correct that Calpine misunderstands it manufacturers specifications, then our adopted Wobbe range would be even further within the acceptable range for Calpine's turbines.

SCE asserts that the acceptable Wobbe Index for its Mountainview GE frame 7f turbines is a function of the characteristics of the gas used to calibrate the turbine. Since the turbines were calibrated with 1321 Wobbe Index gas, the acceptable range of plus or minus 4.5 percent would imply a maximum Wobbe Index of 1380. That is below the maximum Wobbe Index we are adopting. However, Shell points out the turbines could be recalibrated during a routine recalibration.

It is unreasonable to adopt a lower Wobbe Index due to the requirements of one power plant within the SDG&E/SoCalGas service territories, especially when the plant can be recalibrated to accept the new Wobbe range. Once recalibrated based on 1332 Wobbe Index gas, the turbines would be able to accept gas with a Wobbe Index of up to 1391.

E. Heating Value

We will adopt SDG&E/SoCalGas' proposal to increase the minimum allowed heating value from 970 Btu/scf to 990 Btu/scf. We will not change the maximum allowed heating value which is now 1150 Btu/scf since no party argued for changing this standard. Calpine proposed minimum and maximum heating values of 900 and 1200 Btu/scf respectively, and our adopted requirements will be within that range.

F. Limits on Specific Hydrocarbons

The Wobbe and Heating Value requirements constrain the possible combinations of hydrocarbons that compliant gas can contain. SDG&E/SoCalGas' tariff also contains a hydrocarbon dew point limit requirement that could constrain the percentage of heavier hydrocarbons. Several parties proposed additional hydrocarbon constituent minimums and maximums. SCE argued for a requirement that methane content must exceed 85 percent of reactive components, i.e. excluding inerts. Sempra and Shell endorsed a minimum methane requirement of 85 percent, although they did not specify that the 85 percent should be of reactant components only. Calpine argued for an ethane limit of 15 percent, a propane limit of 2.5 percent, and a butane limit of one percent. Sempra endorsed a butane limit of 1.5 percent, which is the same as the NGC+ recommendation. The District and SCE also implicitly endorsed the adoption of constituent limits through their support of the CARB CNG standards.

No party offered compelling arguments for adopting these recommendations, so we decline to adopt any new hydrocarbon constituent standards.

G. Inert Content

We will retain the current SDG&E/SoCalGas total inert limit of four percent. Calpine supports a maximum of 15 percent, and SDG&E/SoCalGas' tariff is well below that.

We decline to adopt the proposals of SDG&E/SoCalGas to reduce the maximum permitted carbon dioxide content from 3 to 2 percent and reduce the maximum oxygen content from 0.2. to 0.1 percent.

The carbon dioxide and oxygen specifications have no bearing on LNG imports since LNG contains only trace amounts of these components. These requirements do, however, impact California production. We are not convinced by SDG&E/SoCalGas' argument that reducing these components is necessary to reduce pipeline corrosion. The utility could have provided evidence to substantiate this claim, but did not.

H. Wobbe Rate-of-Change Requirement

Calpine and SCE support adding a requirement to the tariff that the Wobbe Index cannot change at a rate greater than two percent per minute. PG&E, SDG&E/SoCalGas, and Shell oppose this proposal.

We decline to adopt this proposal. The ability of a supplier or pipeline operator to comply with this type of requirement is doubtful. The intrastate pipeline systems are complex, and the gas flows change constantly based on shifts in supply and demand. Instead, for SDG&E/SoCalGas we will require its proposal to post real-time information on the Wobbe Index of gas at identified points in the pipeline system on an electronic bulletin board. End-users can use the information to manage their operations if necessary.

I. CARB CNG Specifications

The District and SCE argue for incorporating CARB's CNG specifications into the SDG&E/SoCalGas tariffs. SDG&E/SoCalGas, BHP, Exxon, the Producers, Sempra, and Shell are opposed. We are concerned about the impact that the CARB CNG specifications could have on supply. According to the Producers testimony, only five percent of California production could meet the current CARB CNG specifications. The specific constituent requirements could also limit LNG supplies. The impact on supplies would likely raise costs for all the state's gas consumers. The public benefits that would accompany these costs appear to be quite small. Natural gas vehicles consume only a small fraction of the total volume of gas consumed in the state. Furthermore, the current CARB CNG specifications are only necessary for a small subset of vehicles within the current natural gas vehicle fleet. Therefore, we do not adopt the CARB CNG specifications as part of the SDG&E/SoCalGas tariff. We encourage SDG&E/SoCalGas to work with the owners of the older CNG vehicles and relevant governmental agencies so that the natural gas vehicle fleet in southern California gets the gas supplies it needs.

PG&E has proposed adding a requirement that Methane Number must be 80 or higher to be consistent with revisions CARB has proposed. We do not adopt that revision since the new CARB standard is still proposed, and we are unsure of the impact on natural gas supplies.

J. Other Tariff Changes Proposed by PG&E and SDG&E/SoCalGas

PG&E and SDG&E/SoCalGas proposed a number of other minor tariff changes that are intended to bring the tariffs of the utilities into closer alignment.

These proposed changes are contained in Exhibit 101, Prepared Testimony of Joseph W. Bronner, Attachment 2. No party specifically opposed these changes.[263] We adopt these changes, except as previously discussed.

For PG&E, we adopt the utility's proposed changes to the following specifications: hydrogen sulfide, mercaptan sulfur, total sulfur, water vapor, hydrocarbon dew point, liquids, landfill gas, and biogas. For SDG&E/SoCalGas we adopt the utilities' proposed changes to the following specifications: hydrogen sulfide, mercaptan sulfur, total sulfur, water vapor, hydrocarbon dew point, liquids, merchantability, landfill gas, and biogas.

K. Deviations from the SDG&E/SoCalGas Tariff

SDG&E/SoCalGas proposes granting California production deviations from the new gas quality tariffs through Advice Letters. The Producers recommend a process that would grant a generic deviation for historical California supplies. We do not want the new gas quality tariffs to limit existing California production in any way since no party has provided convincing evidence that existing California production negatively impacts the pipeline system. Furthermore, promoting gas supply diversity is a goal of this Commission, and California production plays an important role in the state's supply portfolio. We will grant a generic deviation for historical California production according to the definition proposed by the Producers in their Opening Brief if that production complied with the prior SDG&E/SoCalGas

[263] The Producers are generally opposed to changes to the tariffs other than adopting a maximum Wobbe for SDG&E/SoCalGas.

tariff or if that production has a deviation already in place.[264] SDG&E/SoCalGas is required to work with producers of new sources of California supply to determine if any noncompliant gas would have a negative system impact. If the noncompliant gas would not have a negative system impact, SDG&E/SoCalGas must file an Advice Letter to grant a deviation.

Sempra and Kern argue that all production should be eligible for the deviation process. Except as discussed in the section on timing below, we will not allow LNG supplies and interstate gas supplies to receive deviations. Since one of the objectives of this proceeding is to establish a consistent gas quality standard for the state's gas supplies, allowing exemptions for what may become the state's largest natural gas sources would make the gas quality tariff meaningless.

L. Additional Studies

The NGC+ White Paper recommended that additional research on gas quality be performed to fill specific data gaps. The District and SCE recommended that the Commission should order the parties to agree on a testing process and oversee the completion of additional research. Other parties, including SDG&E/SoCalGas, PG&E, and Sempra, pointed out that the U.S. Department of Energy, the California Energy Commission, trade organizations, specific companies and other stakeholders are already carrying out extensive research.

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[264] The definition of historical California supplies is at Producers Opening Brief, p. 34, footnote 107.

The NGC+ Work Group has already identified the data gaps that need to be filled, and numerous stakeholders are actively working to fill the data gaps. Therefore, we see no reason why this Commission should order parties to perform particular studies or oversee the completion of studies. We encourage all stakeholders to participate in the collaborative effort necessary to complete further research.

M. Timing of New Tariffs

PG&E, SDG&E and SoCalGas are each directed to file an Advice Letter by November 1, 2006 to implement the revised tariff specifications as ordered herein. In order to provide Kern sufficient time to make any necessary changes to its FERC tariff, SoCalGas and SDG&E must provide a deviation for gas flowing through the Kern pipeline if requested by Kern for a period of time no greater than 12 months from the time this decision is adopted.

The NGC+ Work Group describes its recommendations as "interim" for a period of no more than three years from the date of the report (February 28, 2005), until outstanding data gaps have been filled. If additional studies suggest that this Commission should modify the gas quality tariffs adopted herein, parties may file a Petition for Modification of this decision.

X. Requirements of CEQA

The California Environmental Quality Act (CEQA) is triggered when a public agency exercises its discretionary power to carry out or approve a project that may have a significant physical impact on the environment. Before CEQA is triggered, the public agency conducts a preliminary review to determine whether CEQA applies to the proposed activity or if the activity is exempt from CEQA. If the activity is not a "project" or is exempt from CEQA, the CEQA inquiry does not need to proceed further. If the agency determines that CEQA is applicable to the project, the agency must consider whether the project may have a significant physical impact on the environment. If it is determined that the project may not have a significant physical impact on the environment, the agency is to issue a negative declaration. If the agency determines that the project may have a significant physical impact on the environment, an environmental impact report must be done. (Public Resources Code (Pub. Res. Code), §§ 21000, 21063, 21065, 21080, 21100; and Title 14, California Code of Regulations, §§ 15002, 15060, and 15061[265].)

Section 15060(c) of the CEQA Guidelines provides that an activity is not subject to CEQA if:

(1) The activity does not involve the exercise of discretionary powers by a public agency;

(2) The activity will not result in a direct or reasonably foreseeable indirect physical change in the environment; or

(3) The activity is not a project as defined in Section 15378.

In order for CEQA to apply, there must be a project. As relevant here, the term "project" is defined in section 15378(a) of the CEQA Guidelines as "the whole of an action, which has a potential for resulting in either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment, and that is….[a]n activity directly undertaken by any public

[265] Title 14 of the California Code of Regulations is cited herein as the "CEQA Guidelines".

agency". Under CEQA, a project has been defined to include a broad array of actions taken by California agencies, though it is not intended to include every discretionary decision that is made.[266]

In this case the CPUC is revising tariff Rule 30 to narrow the parameters of the acceptable quality of natural gas in the utilities' pipelines. Some parties argue that the narrowing of the existing gas quality specifications would be a project triggering CEQA review unless the CPUC acts to adopt their Wobbe number proposals. For example, SCAQMD argues that CEQA would not be triggered if the Commission adopts its Wobbe number proposal because under its proposal the same quality of gas, which is currently flowing in pipelines, would continue to flow, and, thus, there would be no impact to the environment. Conversely, SCAQMD maintains that if the Commission adopts a Wobbe range with a maximum number that is higher than that in its proposal, then potentially hotter burning LNG gas will be able to flow in utility pipelines; therefore, on average, the gas flowing in utility pipelines will become hotter burning than is the gas currently flowing in pipelines, and the use by end user customers of the hotter burning gas will in turn produce higher NOx emissions causing a potentially adverse environmental impact.

However, the narrowing of the existing gas quality parameters of tariff Rule 30 is not a project under CEQA because this action is not an essential step

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[266] See *Simi Valley Recreation and Park Dist. v. Local Agency Formation Commission*, 51 Cal.App.3d 648, 663 (1975), "CEQA was not intended to and cannot reasonably be construed to make a project of every activity of a public agency, regardless of the nature and objective of such activity."

culminating in action that may affect the environment. (*Kaufman & Board-South Bay, Inc. v. Morgan Hill Unified School District,* 9 Cal. App. 4th 464, 475 (1992)). In *Kaufman,* the court concluded that there was no causal link between the decision to create a new planning district and the alleged environmentally impacting action of opening a new school. Similarly, here, there is no causal link between the narrowing of the parameters of the gas quality rules and the alleged impact to air quality through the flow of hotter burning gas. Here, narrowing the parameters of the gas quality specifications of Rule 30 would not lead to the importation of potentially hotter burning LNG gas. Rather it would be the construction of new LNG terminals or receiving stations that would likely cause the potentially higher level Wobbe LNG gas to be introduced into California. Thus, the narrowing of the existing gas quality specifications is not an *essential step* culminating in action that could lead to the environmental impacts alleged above. Accordingly, this action is not a project under CEQA, and no CEQA environmental review is triggered here. Moreover, we are doing nothing more than narrowing the existing gas quality specifications, and this action will allow for the flow of gas of a certain quality, including regasified LNG, which already is permitted under the existing specifications of the tariff rule. The current Rule 30 allows for the flow of gas with a Wobbe range of 1271-1437. Indeed, gas with varying qualities, including gas with higher Wobbe numbers than those proposed by parties raising CEQA objections here, is already coming into California, as permitted for under the existing rule.

Comments on Proposed Alternate Decision

The proposed alternate decision of President Peevey in this matter was mailed to the parties on August 8, 2006 in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Rules of Practice and Procedure. Comments were filed on August 28, 2006 and reply comments were filed five days later. Comments were received from Clearwater Port LLC, Southwest Gas Corporation, Kern River Gas Transmission Company, Questar Southern Trails Pipeline Company, SoCalGas / SDG&E, South Coast Air Quality Management District, SES Terminal LLC, Calpine, Shell Trading Gas and Power, SCE, DRA, El Paso Natural Gas Company, PG&E, Southern California Generation Coalition, Indicated Producers, Transwestern Pipeline Company, BHP Billiton, and Sempra LNG. Reply comments were received from SoCalGas / SDG&E, South Coast Air Quality Management District, Shell Trading Gas and Power, SCE, DRA, PG&E, Indicated Producers, BHP Billiton and Sempra LNG. To the extent changes were necessary as a result of the filed comments, they were made in the body of this order.

Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Steven A. Weissman is the assigned ALJ in this proceeding.

Findings of Fact

1. Emergency concerns for which utility should plan include the failure of a major component of the delivery or storage system, an artificially induced constraint on the flow of gas, a sudden or persistent loss of supply, an unpredicted and unplanned-for rapid increase in demand, or an excessive increase in the market price for gas.

2. We want to encourage a balanced reliance on stored gas because of the seasonal difference in gas demand and price, because there is a substantial storage capability, and because stored gas is an important physical hedge.

3. It is not enough to know that the combined available pipeline capacity and storage withdrawal rights exceed peak demand by a certain amount. It is necessary to know that sufficient gas will be stored and that withdrawn gas can be delivered where it is needed when the system is most severely stressed.

4. For planning purposes, PG&E, SDG&E and SoCalGas appear to have depended on shippers choosing to use storage fully at peak, and either assumed that stored gas could be delivered during peak conditions, or disregarded the issue.

5. Enough capacity on the backbone system to satisfy demand on an average day is not adequate for system planning purposes if planners cannot depend on stored gas to make up the difference on the most severe peak day.

6. It is reasonable to require that each of the utilities plan its backbone system to meet one-in-ten year cold and dry conditions.

7. It is reasonable to require that each of the utilities plan their backbone and storage systems so as to meet the peak day criteria already in place for their local transmission systems.

8. Reserve margins on backbone pipelines have routinely been in the 40% to 50% level.

9. Consumer advocates, pipelines and LNG suppliers all support the slack capacity margins proposals put forth by SDG&E, SoCalGas and PG&E.

10. SCE opposes the slack capacity proposal of SDG&E and SoCalGas.

11. The slack capacity proposals appear reasonable, but we have no quantifiable basis upon which to decide the "right" number.

12. We are comfortable with the backbone transmission capacity of the utilities.

13. We are comfortable with the slack capacity ranges proposed by the utilities.

14. To protect the integrity of the system and to ensure the ability to respond to emergencies, SoCalGas must track and document receipt point constraints, determine whether they are temporary or long-term, and respond accordingly.

15. For potential receipt point expansion, the appropriate balance is one where the utilities are not required to maintain and continually update the estimated cost of various expansion options, but are obligated to produce detailed cost estimates on request, in a reasonable amount of time, at a reasonable cost.

16. Six to eight months is not a reasonable timeframe for responding to a business request for a receipt expansion cost estimate in this world of constantly fluctuating gas prices, even taking into account the iterative nature of the exercise.

17. Assuming that PG&E's hypothetical situations reflect the outward boundaries of likely contingencies, PG&E's contention that its storage capacity is adequate would appear to be reasonable.

18. Although SoCalGas asserts that there are other realistic storage options for Southern California shippers due to the presence of Wild Goose and Lodi Storage to the north, SoCalGas has not offered sufficient evidence to support this contention.

19. SoCalGas' unbundled storage capacity and injection rights have been oversubscribed in recent years, and withdrawal rights sales have hovered at about 80% of the total amount available.

20. It is unrealistic to rely on the exercise of all withdrawal rights if customers are not required to inject enough gas or to exercise their withdrawal rights, or if SoCalGas cannot deliver all of the withdrawn gas to the customer.

21. Planning backbone transmission facilities to meet all extreme conditions would result in a needless build-up of capacity.

22. Storage serves purposes far beyond price hedging, and provides certainty that cannot be matched by a reliance on flowing supply.

23. Neither SoCalGas nor its unbundled storage customers could rely exclusively on flowing supply in lieu of storage.

24. SDG&E and SoCalGas have recently filed with the Commission in A.06-08-026, their settlement agreement with SCE which, among other things, would place a cap on the prices of storage products. The Commission may review unbundled storage services charges and other storage issues in this application, to determine if the settlement agreement adequately addresses the parties' concerns.

25. All parties (with the exception of Lodi) support the contention that the current backbone pipeline and storage infrastructure are sufficient.

26. We have no reason to believe at this time that the utilities' storage facilities are inadequate.

27. When all customers have to rely on a single network of pipes and storage, self-interest is not always consistent with that of the greater body of customers.

28. SDG&E and SoCalGas, in their open season proposal, require customers to commit to 5- or 10-year use-or-pay firm daily transportation payments or risk the utilities maintaining an undersized local transmission system.

29. The record does not suggest why 5 years or 10 years would be the correct period.

30. In D.04-09-022, the Commission directed SDG&E and SoCalGas to file a new application (A.04-12-004) to consider issues related to SDG&E/SoCalGas system integration, tradable firm rights, and off-system sales. We are considering tradable rights in the second part of that proceeding, which is now underway.

31. Tradable rights for congestion on the local transmission system is not being addressed in A.04-12-004.

32. A proposal for tradable rights on the local transmission system was offered by SoCalGas / SDG&E in the instant proceeding.

33. An exclusive reliance on long-term commitments to determine system adequacy would not do enough to ensure that the system would function well during emergencies, since an integrated system such as this must be planned and managed in an integrated way.

34. Although the Commission has allowed the utilities to make use of open seasons, it has not authorized them to abandon other means of forecasting and planning to meet demand.

35. Interstate capacity might be more valuable than local transmission capacity because its use is less location-specific and it is more tradable.

36. It is appropriate to roll into general rates many expansions that are required as part of the 1-in-10 year planning process. However, for those expansions required largely to serve individual projects, such as LNG terminals, the policy established in the Phase I decision (D.04-09-022) applies.

37. Securing needed firm interstate gas pipeline capacity rights is an important element of electric utility resource planning and an important factor in assuring the reliability of the natural gas delivery system.

38. First-in-time cost allocation for receipt point expansion is a crude and, in some ways, unfair approach.

39. One of the most significant reasons for imposing incremental expansion costs on the entity creating the demand is to enable the incremental customer to take those costs into account when siting its facilities, or when making a commitment to procure gas from a geographically-specific source.

40. Electric utilities should demonstrate, as part of the integrated resource planning process, that they have taken all necessary steps to ensure gas supply.

41. We reject Woodside's proposal to require utilities to identify all potential suppliers interesting in obtaining access to capacity expansions and allocate costs equally.

42. The standardized interconnection, and operational and balancing agreements as described and modified in this decision are reasonable.

43. The proposed independent storage provider agreement described in this decision is reasonable in light of the entire record, consistent with the law, and consistent with the public interest.

44. All parties support changing the gas quality tariffs of SDG&E and SoCalGas.

45. Approving changes to SDG&E's and SoCalGas' tariffs now will provide regulatory certainty to LNG developers and other potential natural gas suppliers.

46. The NGC+ White Paper concludes that the Wobbe Index is the most robust single gas quality parameter.

47. No application has been filed for an LNG terminal that would supply gas directly to PG&E's service territory.

48. Historical gas supplies in PG&E's service territory differ from historical gas supplies in SDG&E's and SoCalGas' service territories.

49. The feasibility and cost of managing a pipeline system with regional standards is uncertain.

50. A regional standard in the South Coast Air Basin may be impossible to effect.

51. A restrictive regional standard could become the de facto system-wide standard if a supplier cannot guarantee that its supplies will not flow into the restrictive region.

52. The maximum Wobbe Index is important since LNG supplies could have relatively high Wobbe Indices.

53. Diversifying California's gas supply sources is a state policy adopted in the EAP II.

54. Increased sources of natural gas supplies will lower natural gas costs.

55. Lower natural gas costs will reduce the energy bills of California's natural gas and electricity consumers.

56. Most Asia-Pacific LNG supplies have high Wobbe indices when compared to traditional natural gas supplies in California.

57. Conditioning costs will raise the hurdle price that LNG importers require to ship gas to the California market, and could be passed on to consumers.

58. Increases in the sources of natural gas supply will lower natural gas costs and will enable broader use within California, displacing the use of other less environmentally friendly fuels.

59. The District proposes a maximum Wobbe Index standard that is intended to maintain the status quo until further studies have been completed.

60. The NGC+ White Paper lists eleven different undesirable performance behaviors and emissions characteristics that can result from changing natural gas quality.

61. NGC+ White Paper is the consensus recommendation of a group composed of representatives of all major segments of the natural gas industry, including LNG suppliers, natural gas pipelines, utilities, power generators, industrial process gas users, appliance manufacturers, and natural gas processors.

62. The NGC+ Work Group reached its recommendation based on the available information and recommended specific additional studies.

63. The NGC+ White Paper identifies data gaps and recommends a gas quality standard consistent with those gaps.

64. Further research is needed to fully understand the impacts of higher Wobbe Index gas on emissions and end-use equipment performance.

65. LNG developers need regulatory certainty today to design and build LNG import projects and arrange for sources of LNG supply.

66. FERC has recommended that interstate gas pipelines and their customers use the NGC+ interim guidelines as a reference point for resolving gas quality disputes.

67. NGC+ recommends adopting a Wobbe range equal to plus and minus four percent of average historical gas subject to a maximum Wobbe of 1400.

68. Applying the NGC+ recommendation to the five-year historical average Wobbe Index in the SoCalGas service territory, 1332, results in a Wobbe range of 1279 to 1385.

69. The NGC+ White Paper recommends that service territories with demonstrated experience with supplies exceeding the recommended Wobbe Limits may continue to use supplies conforming to this experience.

70. Most Btu districts in SDG&E's and SoCalGas' service territories have not experienced gas with a Wobbe Index higher than 1385.

71. Turbines can be recalibrated for a new gas quality standard during routine recalibrations.

72. The Wobbe and Heating Value requirements constrain the possible combinations of hydrocarbons that compliant gas can contain.

73. SDG&E and SoCalGas proposed to reduce the maximum permitted carbon dioxide content from 3 to 2 percent and reduce the maximum oxygen content from 0.2 to 0.1 percent.

74. The intrastate pipeline systems are complex, and the gas flows change constantly based on shifts in supply and demand.

75. Five percent of California production could meet the current CARB CNG specifications.

76. The CARB CNG specifications could limit LNG supplies.

77. Natural gas vehicles consume a small fraction of the total volume of gas consumed in the state.

78. The current CARB CNG specifications are only necessary for a small subset of vehicles within the current natural gas vehicle fleet.

79. PG&E, SDG&E, and SoCalGas proposed a number of minor changes to bring the tariffs of the utilities into closer alignment.

80. California production plays an important role in the state’s supply portfolio.

81. The NGC+ White Paper recommended that additional research on gas quality be performed to fill specific data gaps.

82. The U.S. Department of Energy, the California Energy Commission, trade organizations, specific companies and other stakeholders are researching the effects of natural gas quality.

83. Kern may require at least twelve months to make any necessary changes to its FERC tariff.

Conclusions of Law

1. We should adopt a backbone adequacy standard of one-in-ten cold, and dry-hydroelectric year reliability.

2. We should make explicit the requirement that the utilities plan their backbone and storage systems so as to meet the peak day criteria already in place for their local transmission systems.

3. We should require the utilities to demonstrate in biennial advice letter filings with the Commission's Energy Division that they hold adequate backbone transmission capacity and have slack capacity consistent with their proposals presented herein.

4. We should adopt Kern River's recommendation of requiring SoCalGas to monitor the use of the receipt points and to provide reports to the Commission showing the extent to which shippers are (or are not) seeking access above available capacity. We will require these reports on a semi-annual basis instead of on a quarterly basis as requested by Kern River.

5. We should require SoCalGas to explain, in each report, why the company should or should not pursue receipt point expansion in response to existing or forecast constraints.

6. SoCalGas should take the steps necessary to respond more promptly to requests for cost estimates, whether this requires hiring additional personnel, having consultants on call, or both.

7. The adequacy of the core storage set-aside should be reviewed not in a generic infrastructure adequacy context, but in a proceeding more directly focused on core service.

8. Charges for SoCalGas' unbundled storage services an other storage issues may be addressed by the Commission in A.06-08-026.

9. Each utility must continue to study and report on the adequacy of its entire system, including local transmission, and act to ensure that it remains reliable.

10. We do not adopt SDG&E and SoCalGas' proposed changes to their rules for conducting open seasons on the local transmission system.

11. For smaller customers, SoCalGas and SDG&E should retain the current practice of requiring no more than 2-year commitments from those seeking firm capacity through open seasons. For large customers, SoCalGas and SDG&E should require that they make take-or-pay commitments which last until the earlier of the following two events occurs: either two years shall have elapsed from the date that the associated facilities are placed into service; or five years shall have elapsed from the customer's sign-up date.

12. SoCalGas and SDG&E should file an advice letter within 90 days of the adoption of this decision to implement its proposal to offer tradable capacity rights on its local transmission system, as well as revisions to its open season commitment period as described herein.

13. Electric generators should do their part to fill storage fields, and to withdraw gas during times of system peak.

14. Woodside's proposal to require utilities to identify all potential suppliers interesting in obtaining access to capacity expansions and allocate costs equally is rejected. One of the most significant reasons for imposing incremental expansion costs on the entity making the additional deliveries is to require the incremental supplier to take those costs into account when siting its facilities. That economic signal may be diluted, if not destroyed, if the costs are subject to change over time.

15. We should adopt the Interconnection and Operational Balancing agreements as described and modified in this decision.

16. We should adopt the proposed Independent Storage Provider Agreement described in this decision.

17. A maximum Wobbe Index should be included as an element of SDG&E's and SoCalGas' revised tariffs.

18. A Wobbe Index standard should not be incorporated into PG&E's tariff at this time.

19. The Commission need not adopt a single state-wide gas quality standard at this time.

20. The Commission should not adopt regional gas quality standards to replace the utility systemwide standards in place today.

21. The Commission should consider the impact of gas quality requirements on natural gas supply and cost to fulfill its constitutional and statutory mandate to ensure reliable service at the lowest reasonable cost.

22. A 1360 maximum Wobbe Index would unnecessarily constrain California's natural gas supplies.

23. A maximum Wobbe Index that requires conditioning gas for the California market would add costs for California consumers.

24. The Commission may adopt policies that increase supplies of natural gas to ensure reliable service at a reasonable cost.

25. The Commission should consider the potential impacts of high Wobbe gas on emissions and the performance of end-use equipment.

26. The District's proposal that the Commission should adopt a policy within the Air Basin that would only permit gas supplies that are similar to average

historical gas supplies is not reasonable because regional standards should not replace utility systemwide standards.

27. The approach of the NGC+ White Paper is reasonable because it is a consensus of the natural gas industry based upon the best available information.

28. The Commission should adopt a gas quality standard that is consistent with the best information currently available today.

29. Further delays in the implementation of a new gas quality tariff until all additional research is completed may have adverse impacts on the reliability and cost of natural gas within California.

30. Adopting a reasonable standard today, based on the best information available is in the public interest.

31. It is prudent to adopt the interim gas quality specifications recommended in the NGC+ White Paper because this is an industry wide consensus based upon the best available information.

32. A Wobbe range of 1279 to 1385 is consistent with the NGC+ recommendation.

33. It is unreasonable to adopt a systemwide Wobbe Index standard due to the requirements of one power plant within the SDG&E's or SoCalGas' service territory.

34. SDG&E's and SoCalGas' proposal to increase the minimum allowed heating value from 970 Btu/scf to 990 Btu/scf is reasonable.

35. The Commission should not adopt any new hydrocarbon constituent standards since no party offered compelling arguments for adopting these recommendations.

36. SDG&E's and SoCalGas' gas quality specifications should be brought into closer alignment with PG&E's tariff.

37. The utilities' gas quality tariffs should not include a Wobbe Index rate-of-change requirement.

38. End-users should be provided real-time information on the Wobbe Index to manage their operations if necessary.

39. The Commission should not adopt the current CARB CNG specifications as part of the SDG&E/SoCalGas tariff.

40. SDG&E and SoCalGas should work with the owners of older CNG vehicles and relevant governmental agencies so that the natural gas vehicle fleet in Southern California gets the gas supplies it needs.

41. PG&E should not add a minimum Methane Number requirement to its gas quality tariff.

42. The new gas quality tariffs should not limit existing California production.

43. Historical California production should be granted a generic deviation from the new SDG&E and SoCalGas gas quality tariffs.

44. LNG supplies and interstate gas supplies should not receive deviations.

45. The Commission should not order parties to perform studies or oversee the completion of studies.

46. If additional studies suggest that the Commission should modify the gas quality tariffs adopted herein, parties may file a Petition for Modification of this decision.

47. The narrowing of the parameters of the gas quality standards in SoCalGas Rule 30 is not an essential step culminating in action that may affect the environment and, therefore, is not a project under CEQA.

48. The narrowing of the parameters of the gas quality standards in SoCalGas Rule 30 does not trigger CEQA review.

O R D E R

IT IS ORDERED that:

1. The Pacific Gas and Electric Company and the Southern California Gas Company shall plan and maintain intrastate natural gas backbone transmission systems sufficient to serve all system demand on an average day in a one-in-ten cold and dry-hydroelectric year.

2. The Pacific Gas and Electric Company and the Southern California Gas Company shall plan their backbone and storage systems so as to meet the peak day criteria already in place for their local transmission systems.

3. The Pacific Gas and Electric Company and the Southern California Gas Company shall demonstrate in biennial advice letter filings to the Commission's Energy Division starting 2008 that they hold adequate backbone transmission capacity and have slack capacity consistent with their proposals presented herein. The first filing is due July 1, 2008.

4. SoCalGas shall monitor the use of the receipt points on its backbone system and provide semi-annual reports to the Commission showing the extent to which shippers are (or are not) seeking access at levels above available capacity. In addition, we will require SoCalGas to explain, in each report, why the company should or should not pursue receipt point expansion in response to existing or forecast constraints. In addition to filing these reports at the Commission, SoCalGas shall serve copies of the reports on any parties to this proceeding requesting service.

5. SoCalGas shall take the steps necessary to respond more promptly to requests for receipt point expansion cost estimates, whether this requires hiring additional personnel, having consultants on call, or both. It is not reasonable to take six to eight months to prepare such estimates.

6. In assessing the adequacy of in-state infrastructure, the utilities shall consider the physical system as a whole (the interaction of backbone pipelines, storage, and local transmission) including the probability of storage withdrawal and the deliverability of withdrawn gas during periods of peak demand.

7. SDG&E/SoCalGas' request for revisions to the open season process for expansion of local transmission facilities is modified.

8. For smaller customers, SoCalGas and SDG&E shall retain the current practice of requiring no more than 2-year commitments from those seeking firm capacity through open seasons. For large customers, SoCalGas and SDG&E shall require that they make take-or-pay commitments which last until the earlier of the following two events occurs: either two years shall have elapsed from the date that the associated facilities are placed into service; or five years shall have elapsed from the customer's sign-up date.

9. SoCalGas and SDG&E should file an advice letter within 90 days of the adoption of this decision to implement its proposal to offer tradable capacity rights on its local transmission system, as well as revisions to its open season commitment period as described herein.

10. In addition to the use of open seasons to allocate access to constrained resources, SDG&E and SoCalGas shall include the expansion of local transmission facilities in its usual system planning process, and undertake expansion projects as needed to serve all types of customers.

11. We expect PG&E, SDG&E, and the Southern California Electric Company to demonstrate, as part of the integrated resource planning process, that they have taken all necessary steps to ensure gas supply. As part of each planning cycle, they shall actively consider the role of firm interstate capacity and report on their reasons for pursuing the strategy that they propose. We also expect the

electric utilities to inject and withdraw storage gas consistently, as part of the annual fuel supply cycle. As is true with other aspects of gas infrastructure and supply reserve, the electric utilities should define and work toward achieving a storage goal that is quantitatively related to the nature of their resource portfolios and the level of gas usage. This, too, should be developed and explained fully as part of each procurement plan.

12. The Commission hereby endorses the effort to expand and encourage active participation in the Natural Gas Working Group. Meetings between state agency representatives and utility representatives should generally be open to the general public. The Commission asks that all meetings involving more than just state agency representatives be open to all participants. However, it may be necessary, at times, for the utilities to discuss confidential matters. Therefore, two of the quarterly meetings will be restricted to the state agencies and the utilities as described Section III. We encourage the Group to err on the side of sunshine in its communications as a body with outside entities, and to function more privately only when necessary.

13. Woodside's proposal to require utilities to identify all potential suppliers interesting in obtaining access to capacity expansions and allocate costs equally is rejected. One of the most significant reasons for imposing incremental expansion costs on the entity making the additional deliveries is to require the incremental supplier to take those costs into account when siting its facilities. That economic signal may be diluted, if not destroyed, if the costs are subject to change over time.

14. The standardized Interconnection Agreement and Operational Balancing Agreement described and modified in Section V of this decision are approved.

15. Those entities providing gas from new sources of supply shall pay for any odorization costs in excess of those faced by the utility in treating gas from other sources. The utilities shall file advice letters within 60 days of the effective date of this decision in which they provide estimates of the average amount they are spending, per mmBtu, to odorize gas from existing interstate sources, and modifying the Interconnection Agreements accordingly.

16. The settlement agreement between PG&E and independent storage providers concerning direct interconnection of those independent providers with California producers, as well as electric generators and other noncore customers is approved.

17. SDG&E and SoCalGas are directed to file revised Rule 30 tariffs that contain the following specifications:

18. Minimum Wobbe Index of 1279

19. Maximum Wobbe Index of 1385

20. Minimum Heating Value of 990 Btu/scf

21. Maximum Heating Value of 1150 Btu/scf

22. Changes to hydrogen sulfide, mercaptan sulfur, total sulfur, water vapor, hydrocarbon dew point, liquids, merchantability, landfill gas, and biogas specifications contained in Exhibit 101, Prepared Testimony of Joseph W. Bronner, Attachment 2.

23. PG&E is directed to file a revised Rule 21 tariff that adopts the changes to the hydrogen sulfide, mercaptan sulfur, total sulfur, water vapor, hydrocarbon dew point, liquids, landfill gas, and biogas, as contained in Exhibit 101, Prepared Testimony of Joseph W. Bronner, Attachment 2.

24. SDG&E and SoCalGas are required to post real-time information on the Wobbe Index of gas at identified points in the pipeline system on an electronic bulletin board.

25. Historical California production is granted a generic deviation according to the definition proposed by the Producers in their Opening Brief if that production complied with the prior SDG&E and SoCalGas tariffs or if that production already has a deviation in place.

26. SDG&E and SoCalGas are required to work with producers of new sources of California supply to determine if any noncompliant gas would have a negative system impact. If the noncompliant gas would not have a negative system impact, SDG&E and SoCalGas must file Advice Letters to grant deviations.

27. PG&E, SDG&E and SoCalGas are each directed to file an Advice Letter by November 1, 2006 to implement the revised tariff specifications as ordered herein.

28. SoCalGas, SDG&E and PG&E must provide a deviation for gas flowing through each interstate pipeline connected to their respective systems, if requested, for a period of time no greater than 12 months from the date of this decision.

29. Rulemaking 04-01-025 remains open.

This order is effective today.

Dated September 21, 2006, at San Francisco, California.

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