**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)

**PHASE I PROPOSALS AND DATA RESPONSE OF
RESPONDENT PACIFIC GAS AND ELECTRIC COMPANY (U 39 G)**

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EXECUTIVE SUMMARY

I. PG&E PROPOSES SUPPLY RELIABILITY PLANNING CRITERIA THAT PROVIDE A HIGH LEVEL OF RELIABILITY AT REASONABLE COST.

All costs and benefits must be weighed in the process to determine the right amount of pipeline capacity and storage for PG&E to hold.

- For long-term planning purposes, PG&E recommends that the Commission adopt firm capacity planning standards for gas procurement. Such firm capacity planning standards would consider the needs of all customers and the effect of the standards on the California economy. The process for acquiring capacity should allow sufficient flexibility to respond to changes in the market and serve as a guiding basis for long-term decisions to acquire more capacity or storage.
- PG&E's proposal identifies two criteria for planning for PG&E: 1) a peak-day planning standard and 2) a cold-winter planning standard. PG&E specifically proposes standards that would meet a 1-in-10-year event for both peak-day and cold-winter planning.
- In order for PG&E's rates to remain competitive, the Commission must carefully examine the benefits of additional capacity or storage versus additional costs.
- PG&E proposes, in the near term, to increase its holding of firm annual interstate pipeline capacity to between 1,000 and 1,200 thousand decatherms per day (MDth/day), which is more than PG&E's current holdings of approximately 960 MDth/day.

II. PG&E SUPPORTS A PREAPPROVAL PROCESS FOR INTERSTATE PIPELINE CAPACITY, STORAGE CONTRACTS AND NEW FACILITIES

To fulfill its obligation to provide reliable gas supply to its core customers, PG&E will need to extend current pipeline and storage capacity contracts or acquire additional capacity.

- PG&E must be assured up front that all reasonable costs will be recovered in a timely manner. PG&E earns no return on Core Procurement's holdings of pipeline and storage capacity, and the Commission should not impose any significant disincentives for acquiring capacity in accordance with the Commission's policies. PG&E looks forward to working with the Commission to develop a pre-approval process for interstate pipeline capacity and storage contracts. The process must be relatively quick and cost recovery must be guaranteed in order for PG&E to acquire adequate pipeline capacity and storage for its core customers.
- If PG&E needs to build new intrastate facilities to connect to a new supply source such as Liquefied Natural Gas (LNG), the certificate approval process must guarantee recovery of PG&E's reasonable costs.
- If the addition of new supply or capacity results in some existing PG&E transmission or storage facilities being used less, PG&E should not be penalized for the reduced use of the existing facilities.

III. PG&E SUPPORTS THE DEVELOPMENT OF LNG AS A NEW SUPPLY SOURCE.

PG&E supports the development of environmentally sound and operationally safe LNG facilities.

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- The availability of LNG supplies on the west coast will benefit customers by providing an additional supply source and gas-on-gas competition.
- PG&E, with Commission approval, would transport LNG supplies to customers. Project-specific approval and full cost recovery should be granted prior to construction of projects.

IV. THE COMMISSION SHOULD PROMOTE A LEVEL PLAYING FIELD FOR INTERCONNECTING FACILITIES WITH INTERSTATE AND UPSTREAM PIPELINES.

- Southern California Gas Company's (SoCalGas) current allocation of capacity at Kramer Junction favors El Paso Natural Gas Company (El Paso) and Transwestern Pipeline Corporation (Transwestern) and their shippers.
- PG&E proposes a reasonable and non-discriminating allocation process that benefits all California customers.

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Respondent Pacific Gas and Electric Company (PG&E) welcomes the opportunity to work with the California Public Utilities Commission (CPUC or Commission) and interested parties to develop new rules designed to ensure continued safe, reliable long-term natural gas supplies to its customers. PG&E remains committed to being able to reliably serve its customers while achieving an appropriate balance among the sometimes-competing concerns of diverse supply options, reasonable cost, and environmentally sensitive service. Toward that end, PG&E provides herein its response to Order Instituting Rulemaking (OIR) 04-01-025, including the proposals requested to be addressed by the respondent utilities in Phase I of this proceeding and responses to the data requests propounded in Appendix A of the rulemaking. PG&E expects to fully participate in the proceeding, and will be providing comments or proposals at each opportunity in the adopted schedule. PG&E notes that it is also filing today a motion to delay the opening comments in Phase II of this proceeding by one month, to April 23, because of the scope of the issues to be considered in that phase.

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I. SUFFICIENT INTERSTATE PIPELINE CAPACITY TO MEET CORE PROCUREMENT SUPPLY OBLIGATIONS

A. Core Capacity Planning Criteria.

In order to propose a specific portfolio of pipeline and storage holdings for the core customers, it is first necessary to define certain key planning criteria that reflect core customers' underlying risk preferences. It is also necessary to consider broader societal considerations, since decisions relating to core storage and transmission holdings have implications for other customer classes. PG&E has identified two planning criteria that together bound the problem of determining an "optimal" portfolio mix. These criteria are: 1) a peak-day planning standard for firm core holdings to storage and production basins; and 2) a cold winter planning standard for these same firm holdings. Once these criteria have been established, the most economic mix of assets to meet the criteria can then be determined.

1. Peak-day Planning Standard for Core Firm Capacity.

In PG&E's Gas Accord II –2004 Application 01-10-011, PG&E recommended that the Commission adopt a 1-in-10-year cold temperature peak-day planning standard. Under this standard PG&E would hold for the core a combination of firm storage and pipeline capacity that would deliver sufficient gas supply to serve a peak-day core load with an expected 1-in-10-year recurrence interval. In Decision 03-12-061, the Commission decided not to adopt PG&E's proposal for 2004, but the Commission made it clear that this was without prejudice for the future. As a result, there is no adopted planning standard for PG&E. The Commission stated that PG&E's proposals "may be raised again when we review the type of gas structure that should be in place for 2006 and beyond, or in another proceeding where the long-range service aspects of PG&E's gas transmission services are being examined." – Decision 03-12-061, at mimeo p. 54.

Based on recent forecasts, under the approved Gas Accord allocation, PG&E currently holds firm storage and pipeline capacity contracts sufficient to meet approximately a 1-in-3-year peak-day standard. This relatively low amount of firm capacity subjects the core customers to significant price risk at times when demands exceed the 1-in-3-year level. This price risk can manifest itself in the form of high spot gas prices. It also subjects core customers to the risk of severe imbalance penalties in the event that noncore supplies are diverted to ensure service to core customers. The prospect of diversion also has significant implications for noncore customers, since they are at risk of supply disruption from the core, which would impose additional costs and uncertainty. Disruptions in gas service to electric generators would be especially problematic, and would impose additional costs and service reliability risks on electric customers.

A 1-in-10-year peak-day standard would reduce core customer exposure to the extreme price volatility that often occurs during peak events, while significantly lowering the probability of noncore curtailments.[1] Moreover, a higher standard would move PG&E's level of core reliability closer to that of other utilities in the country.

2. Cold-Winter Planning Standard for Core Firm Capacity.

In addition to the 1-in-10-year peak day planning criterion, PG&E also proposes a cold-winter planning standard. This standard specifies the amount of firm capacity held under contract, given the specified forecasted winter load, which is expected to occur once every ten years, core supplies could be obtained to meet the specified load without the necessity of purchasing border or Citygate spot supplies.[2]

The inclusion of a cold-winter standard stems directly from the experience of the 2000-2001 energy crisis when PG&E's core customers were exposed to extreme price run-

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[1] This 1-in-10-year peak day standard is contingent on maintaining the current diversion and curtailment rules. If these rules were to change as a result of Phase II in this proceeding or a subsequent proceeding, the peak day standard would need to be revised.

[2] The proposed contract holdings necessary to meet this standard are derived from a forecasted monthly allocation of load. The adoption of the cold winter planning standard does not preclude actual purchasing activity at the California border or at Citygate. Purchases at these points will still occur in order to accommodate daily load variation. However, the standard will effectively lower the overall exposure to these trading points over the course of the winter.

ups in the monthly and daily gas markets at the California border. At that time PG&E held only 150 MDth/d of firm interstate pipeline capacity on Transwestern, which gives PG&E direct access to Southwest gas production. This obligated PG&E, even under the load conditions that prevailed during the 2000-2001 winter months, to purchase between 400 and 500 MDth/day of gas at Topock. The core's exposure would, of course, have been even higher under colder than average conditions. Since the energy crisis, and at the behest of the Commission, PG&E has contracted for an additional 204 MDth/d of El Paso capacity, but core customers remain exposed to between 200 and 300 MDth/d under normal weather conditions.[3]

Given the context of this OIR, PG&E is proposing a 1-in-10-year cold-winter planning standard, which means that PG&E would contract for sufficient firm storage, and firm inter- and intra-state pipeline capacity to meet a 1-in-10-year cold year winter forecast without requiring purchases at the California border or at the Citygate. Whether the proposed level of price exposure is appropriate or not is fundamentally a question of risk preference. Ascertaining core customers' risk preferences is difficult and ultimately fraught with uncertainty. However, PG&E believes that core customers tend toward a high degree of risk aversion, and therefore PG&E recommends that the Commission consider a further reduction of the core's price exposure in determining the appropriate planning standard to adopt. As representatives of residential and core customers, PG&E invites the Office of Ratepayer Advocates (ORA) and The Utility Reform Network (TURN) to express their views on the appropriate planning criterion.

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[3] PG&E notes that in the proceedings (R.02-06-041) leading up to Decision 04-01-047, PG&E argued that it holds adequate capacity at the present time, but that was using its current 1-in-3-year peak day planning criterion.

3. PG&E Currently Has an Appropriate Level of Supply Diversity

One of the issues the Commission has asked the parties to address is supply diversity. PG&E is currently exceptionally well-situated to purchase natural gas from a variety of competing sources in Canada and the U.S. Southwest. PG&E's pipeline capacity contracts are structured to afford PG&E the opportunity to purchase gas from these competing sources. PG&E's comments herein are intended to preserve and expand upon this existing level of supply diversity. Obviously, PG&E would not support any proposals that would have the effect of limiting PG&E's ability to access natural gas supplies from competing sources.

B. Proposed Capacity Mix.

PG&E has developed an asset portfolio that attempts to minimize cost while meeting its current planning criterion. Using the forecasted load associated with a 1-in-10-year cold-winter and 1-in-10-year peak-day forecast for 2006,[4] in combination with estimates of transmission and storage capacity costs, estimated brokering revenue from unused pipeline capacity during the summer period, and assumptions about seasonal gas price differentials, PG&E has developed a proposed capacity portfolio that attempts to minimize cost while meeting the proposed winter planning criterion. Based on PG&E's analysis, PG&E recommends holding 43,000 MDth of in-state storage inventory and 1,080 MDth/day of interstate and winter intrastate capacity. During the summer, PG&E Core Procurement would hold 800 MDth/day of intrastate capacity to minimize core costs and make more capacity available to summer peaking noncore and electric generation end users.

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[4] Although PG&E's analysis is based on its forecast of 2006 demands, PG&E envisions working closely with the Commission on the optimal timing for implementation of an adopted capacity mix.

C. Benefits of PG&E's Proposed Capacity Portfolio.

The capacity mix proposed by PG&E will move the level of core reliability closer to that of other utilities in the country. This mix also provides further protection against sustained high commodity prices that may occur in a colder-than-average winter. In addition to these benefits, PG&E's proposal recommends increasing the level of firm interstate and storage capacity held on behalf of core customers. Starting with PG&E's existing contracts, having the core planning standards in place will provide PG&E the opportunity to tailor its portfolio of core capacity holdings to best meet the needs of core customers. With such standards in place, PG&E will have the flexibility to tailor its firm holdings to take full advantage of PG&E's supply diversity to meet changing market conditions, including the addition of new supply sources such as LNG, staggering the term of the contracts, or holding short term or seasonal capacity contracts.

D. PG&E Supports the Adoption of a Core Planning Standard and Pre-Approved Capacity Range.

PG&E wholeheartedly supports the establishment of a pre-approval process for acquisition of core firm interstate and intrastate capacity, firm storage and potentially LNG supply contracts held by utilities on behalf of their core customers. The process starts by establishing an acceptable range around the recommended core firm capacity holdings proposed in Section I.B, above. As long as the amount of capacity held by PG&E for core customers falls within the proposed range, PG&E will be deemed in compliance and the associated costs will be deemed reasonable.

1. The Commission should approve a Core Planning Standard.

PG&E does not currently hold enough firm pipeline and storage capacity to serve its core customers under all circumstances. An essential step in the development of a pre-approval process is the approval of a Core Planning Standard. For PG&E, the Core Planning Standard should be flexible enough to accommodate a variety of capacity and supply contracts, including not only pipeline transportation capacity, but also storage and potentially LNG. In order to propose a meaningful capacity range, PG&E must have a formal and recognized firm contract level that provides reliability and price protection benefits for which it should plan. As described above, PG&E has proposed holding firm transportation, storage or LNG capacity to meet a 1-in-10-year peak day and a 1-in-10-year winter load. PG&E also proposes to hold matching amounts of intrastate capacity to ensure that PG&E and other core suppliers has the capability to transport these gas supplies to their end-use core customers in northern and central California. It would be unreasonably expensive for the utility to hold all of the capacity necessary to access supplies on a firm basis under any conditions. Since the amount of capacity that is held entails a balancing of public interest and public cost, it is ultimately the role of the Commission to determine the level of firm contracts to support these benefits that is appropriate. PG&E believes that, at this time, 1-in 10-year peak day and cold winter month standards are reasonable goals.

2. A Pre-Approved Capacity Range Enhances PG&E's Ability to Take Advantage of Specific Opportunities.

A range of capacity holdings is needed because opportunities to acquire or replace capacity from new projects, expand existing facilities, and terminate or renew existing agreements with other shippers are likely to become available in specific quantities at specific times. To fully take advantage of these opportunities for transport and storage, and to access the most competitively-priced supply, it is very likely to be advantageous to hold slightly more or less than the exact amount needed to meet the proposed standard.

E. PG&E proposes a Pre-Approved Capacity Range Consistent with Its Core Planning Standard.

Assuming the Commission adopts the proposed core planning standard, PG&E has performed analysis to determine the appropriate mix of storage and pipeline capacity.

PG&E proposes a pre-approved capacity range based on meeting the requirements of the proposed 1-in-10-year peak day and 1-in-10-year cold winter planning standard.

1. Proposed Range of Interstate and Intrastate Pipeline Capacity

To meet the requirements of a 1-in-10-year peak day and a 1-in-10-year cold winter, analysis shows that PG&E should hold approximately 1080 MDth/day of interstate (including Southwest, Rocky Mountain and Canadian (which includes TransCanada NOVA and TransCanada BC) capacity) and intrastate capacity. During the winter, PG&E proposes to hold firm annual interstate and intrastate transportation capacity between 1000 MDth/day and 1200 MDth/day. During the summer months, PG&E will hold between 750 and 850 MDth/day of intrastate capacity.

2. Proposed Range of Storage Capacity.

To meet the requirements of a 1-in-10-year peak day and a 1-in-10-year cold winter standard, analysis shows that PG&E core should hold approximately 43 MMDth of storage inventory. PG&E proposes to hold between 40 and 46 MMDth of storage capacity with sufficient withdrawal rights to meet the proposed standards.[5] Core's current storage inventory holding is 33.5 MMDth.

[5] Decision 93-02-013 obligates PG&E to build and use storage facilities to provide reliable core service. See also Application 01-10-011, PG&E Opening Brief, Section V.A., at page 35.

F. A Clearly Articulated Contract Pre-Approval Process Is Necessary

On behalf of its core gas customers, PG&E currently holds multiple capacity contracts on the following interstate and Canadian pipelines:

	MDth/d	Expiration	Evergreen?
Southwest			
El Paso Natural Gas			
Contract 9NK4	63,532	12/31/2004	No
Contract 9NK7	40,000	3/31/2007	No
Contract 9Q7B	100,000	4/30/2005	No
Transwestern	150,000	3/31/2007	No
Northwest			
GTNC	609,968	10/31/2005	Yes
TransCanada – BC	583,576	10/31/2005	Yes
TransCanada – Nova	593,110	12/31/2005	Yes

By the end of 2007, all of PG&E's core interstate and Canadian pipeline capacity contracts will expire or convert to year-to-year terms under the evergreen provisions. The expiration of these contracts presents PG&E with a significant opportunity to review its current portfolio of capacity holdings, as well as negotiate for any additional capacity that may be necessary to provide the needed level of reliability and price protection for PG&E's core customers. Depending on the location of potential LNG facilities, LNG may also be considered as a potential substitute for storage, interstate pipeline capacity or basin supplies.

However, to seize the best opportunities, PG&E will need to enter into negotiations with LNG suppliers, pipelines and storage capacity providers. In addition, to retain its existing capacity in the Southwest, PG&E will be required to exercise Rights of First Refusal (ROFR). To exercise those rights, PG&E will be required to notify the pipeline 6-12 months prior to the expiration of the contract. The pipeline will then post the capacity for the required period of time, in which any party may attempt to bid for the capacity. PG&E may only retain the capacity if it chooses to match the successful bid. Under current Federal

Energy Regulatory Commission rules, competing bidders are not limited as to the term they may bid on capacity.[6] When capacity is in short supply and market demand is high, the terms that shippers are willing to bid for capacity can be quite long. Contract terms of 20 years or longer have been common, and in one recent instance a shipper on Gas Transmission Northwest (formerly Pacific Gas Transmission Company) bid a term in excess of 50 years.

The need to establish a pre-approval process for pipeline and storage capacity and LNG supply contracts is essential for PG&E to enter into contracts under favorable terms and conditions, and often within a limited window of time. PG&E and other gas utilities will be very hesitant to enter into long-term capacity contracts, unless they are provided assurance that they will receive full recovery of costs for the term of the contract.

G. PG&E Supports the Pre-Approval Procedural Approach Proposed by SoCalGas

In an application filed on December 15, 2003, SoCalGas proposed a set of procedures to govern SoCalGas' acquisition of transportation capacity and guide SoCalGas in fulfilling its responsibility to provide reliable gas supplies to its core customers. Specifically, SoCalGas proposed that the Commission approve an "Authorized Capacity Commitment" procedure whereby commitments of a limited amount and/or term for interstate capacity within a "Transportation Capacity Commitment Range" are deemed just and reasonable and fully recoverable in rates. SoCalGas also proposed an "Expedited Capacity Advice Letter" process whereby SoCalGas would file an advice letter for expedited approval of proposed capacity commitments for amounts that exceed the limits of the Authorized Capacity Commitment.[7]

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[6] See Order No. 637, "Order on Remand," 101 FERC ¶61,127 (2002), *rehearing denied,* 106 FERC ¶61,088 (2004).

[7] The Commission recently dismissed the application, noting that the issues raised therein would be addressed in this proceeding.

PG&E wholeheartedly supports the concepts proposed by SoCalGas. The proposed procedure provides a balance between regulatory oversight and the ability of the utilities to effectively contract for pipeline capacity given the short lead times common to the industry. PG&E agrees with the proposed consultation process with the Office of Ratepayer Advocates, The Utility Reform Network, and the Energy Division. Over the next four years, all of PG&E's interstate transportation contracts will either expire or convert to year-to-year "evergreen" terms. The expiration of these contracts along with the conversion to evergreen terms on some of the contracts, will give PG&E a significant opportunity to tailor its portfolio of storage, intrastate and interstate pipeline capacity to best fit the level of reliability and diversity desired by its core customers.

H. PG&E's Specific Proposal for Contract Pre-Approval

The following elements should be included in the contract approval process: a specific approved Capacity Range, within which PG&E's costs would be fully recoverable; and the filing for advice letter approval under specific circumstances not covered by the approved Capacity Range.

1. Pre-Approved Capacity Range.

PG&E proposes that the Commission develop rules providing that the utilities will be deemed in compliance with the pre-approved Capacity Range if the range is not exceeded for a cumulative period of six months in any 36-month period. If, for any reason, PG&E capacity commitments fall below or above the pre-approved Capacity Range, PG&E would file an advice letter describing the circumstances and proposing a course of action to address compliance with the standard.

PG&E proposes to consult with the Office of Ratepayer Advocates, The Utility Reform Network, and Energy Division periodically regarding PG&E capacity holdings for core customers. The Commission should establish clear rules providing that all capacity commitments within the pre-approved Capacity Range described above shall be deemed reasonable and fully recoverable in rates for any of the following:

- Any existing interstate, intrastate, and storage capacity;
- Individual interstate, intrastate, storage capacity, and LNG supply contracts with terms of three years or less;
- Individual interstate, intrastate, storage capacity and LNG supply contracts with terms of more than three years and quantities less than or equal to 100 MDth/day or 3 MMDth of storage; and
- Interstate, intrastate, storage capacity or LNG supply maintained by the exercise of ROFR options (in response to other shippers' bids) or evergreen terms.

2. Expedited Capacity Advice Letter.

Consistent with SoCalGas' proposal for approval of interstate, intrastate, storage, and LNG capacity commitments that fall outside the terms described above, and for all capacity in excess of current holdings acquired initially to meet the standards set forth in this proceeding, PG&E will file an Expedited Capacity Advice Letter upon consultation with ORA, TURN, and Energy Division. The Expedited Capacity Advice Letter procedure should allow ten days for protests and comments and three days for replies, and seek Commission approval within 21 days of the filed date. If the Commission does not act within 21 days of the filed date, the Expedited Capacity Advice Letter will be deemed disapproved without prejudice.

3. Other Advice Letters.

After consultation with ORA, TURN and Energy Division, PG&E may file an advice letter, pursuant to the Commission's standard procedures for advice letters, to seek modifications to the Capacity Commitment Range, and to the Expedited Capacity Advice Letter procedures.

4. Other Actions Not Requiring Approval through the Advice Letter Process

Capacity renewals not needing additional advice letter filings should also include capacity held under evergreen provisions in addition to capacity renewed under ROFR rights.

I. Cost Recovery

The Commission should issue a rule providing that all interstate, intrastate, storage and LNG costs incurred on behalf of core customers will continue to be recorded to the applicable core procurement balancing accounts (e.g. Purchased Gas Account, Core Pipeline Demand Charge Account and Core Firm Storage Account) and be recovered from Core Procurement customers through monthly core procurement rates, similar to current procedures. The fixed and variable costs of all pipeline and storage capacity would be included in PG&E's Core Procurement Incentive Mechanism benchmark.

II. ACCESS ON INTRASTATE PIPELINES TO LNG SUPPLY

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A. PG&E Supports the Development of LNG

PG&E supports the development of LNG facilities on the west coast. A new alternative supply source is likely to provide substantial gas commodity cost benefits to consumers in the PG&E service territory in much the same way as PG&E's expansion of the gas transmission Line 400/401 system from Canada benefits California consumers. Significant alternative gas supply sources help reduce price volatility by increasing available supplies and providing greater gas-on-gas competition.

PG&E has two primary interests in the development of LNG facilities. The availability of a LNG regasification facility on the west coast will benefit PG&E's customers by providing an additional supply source and gas-on-gas competition. PG&E also has a role in the transportation of LNG supplies and the management of gas quality issues associated with LNG. Thus, PG&E's comments herein with respect to LNG are from the perspectives of a buyer, and a transporter and distributor of gas.

B. LNG and PG&E's Role as a Buyer of Gas.

LNG holds the promise of an additional supply source which will moderate prices as well as create additional opportunities to enhance diversity of supply. PG&E's core customers are likely to benefit from the arrival of LNG either through contracting directly for supplies or indirectly from the freeing-up of traditionally-sourced supplies that are displaced by LNG in other downstream markets. While it is unclear how the LNG market will ultimately evolve in terms of contracting practices, PG&E anticipates that in the early stages of the market development, marketers of LNG supplies will be primarily interested in promoting multi-year baseload-type contracts. PG&E intends to work closely with ORA and TURN in evaluating any specific contract proposals; however, because of the anticipated long-term nature of LNG contracts, and because contracting for significant volumes of LNG may require adjustments to the core's transport and storage portfolio, it is imperative that that LNG contracts be subject to the same pre-approval process as the transport and storage contracts.

C. LNG and PG&E's Role as a Transporter of Gas.

The nearer-term access issues presented in this proceeding are primarily associated with LNG facilities which may be located in Baja Mexico or Southern California. LNG facilities proposed in PG&E's service territory do not appear to be as far along in the development process. PG&E's comments focus first on guiding principles for PG&E and its customers to gain access to future LNG projects. PG&E's comments then provide specifics related to: 1) PG&E's access to the LNG facilities proposed for Southern California and Mexico; and 2) connecting a proposed LNG project in PG&E's service area in Humboldt County.

1. Guiding Principles

a. PG&E, with Commission approvals, should transport supplies from the LNG facility to the customer.

PG&E stands ready to apply for Commission approvals and to connect to any LNG facility that meets the guiding principles set forth below. PG&E will build the facilities necessary to transport the gas from the LNG facility (or another utility's or pipeline's facilities interconnected to the LNG facility) to PG&E's existing gas transmission and distribution network. PG&E's involvement in planning these facilities would help to ensure that existing facility use is maximized. Since any new facilities will be built to provide additional supply assurances for PG&E's customers, including those in Southern California, pursuant to Commission goals, the Commission's certificate approval to build new facilities to connect to an LNG project must include assurance that the facility costs will be fully recoverable and included in rates.

PG&E's proposed policy to build a Commission-authorized connection to new LNG facilities differs from PG&E's current interconnection policy. Currently, PG&E requires interstate pipelines and third-party storage providers to build their own facilities to PG&E's system and pay PG&E for its costs to build the interconnect and make nomination system changes. PG&E believes a policy change is warranted if the Commission wants to encourage the siting of LNG facilities in or near California.

b. Project-specific approval should be granted prior to construction of facilities to LNG projects.

Each proposed LNG project will present unique issues. The approval process for each LNG connection and associated PG&E downstream facilities should allow for a dialogue among interested parties on the needed facilities, costs, economic feasibility, demand for the project, potential changes in the utilization of existing pipeline facilities, rate impacts, and gas quality and interchangeability issues. If the Commission decides that an LNG project fails to provide benefits sufficient to outweigh the financial risks, PG&E would not build the connecting pipeline. In that case, in order for the project to go forward, the LNG facility developer would need to build its own facilities or else pay PG&E to construct the necessary facilities to the nearest interconnect point on the existing transmission system. PG&E is not suggesting that the Commission assert authority over whether the LNG project is built, but the Commission does have authority over whether a California-jurisdictional utility's gas transmission assets should be built and included in rates.

Some projects may require PG&E to file an application for a Certificate of Public Convenience and Necessity (CPCN) to construct the necessary facilities to connect an LNG facility. While this filing would provide a public forum for discussing the project specifics, PG&E has concerns that some CPCN requirements place undue risk on the utility that could discourage a utility from supporting new LNG facilities. For example, for projects expected to exceed $50,000,000 in cost, Public Utilities Code Section 1005.5 requires the Commission to specify a maximum reasonable and prudent cost for the facility, subject to revision for reasonable additional costs. To facilitate the construction of facilities to an LNG project, the Commission needs to assure the utilities in advance that <u>all</u> reasonable construction costs will be recoverable in rates, similar to the assurances that the Commission provided in Decision 02-07-037 that new interstate pipeline capacity acquired on the El Paso Natural Gas Company system in compliance with the Decision would be found reasonable and recoverable in rates.

When reviewing individual projects, the Commission's support for new facilities to connect a new LNG project should consider market demand to assure that the gas transmission system is not over-built and that unnecessary transportation costs are not incurred. History has shown that lower-than-expected demand growth, which eventually caused the PG&E/SoCalGas LNG project at Point Conception, California to be canceled, can derail some projects, and the costs of transporting and cooling LNG can make it a higher-cost commodity during periods of falling gas prices, which caused some existing East Coast LNG facilities to be shut down for several years.

The utilities, the California Energy Commission (CEC), and this Commission need to work cooperatively to forecast demand, supply availability, and price volatility, including recognition that the connecting utility might have a role in transporting gas supplies to other markets that also need new supply. Support for new LNG facilities, and the associated connection facilities the utilities might build, should only occur if demand forecasts demonstrate a benefit in comparison to costs of connecting other additional supplies. To be economical, LNG facilities need a steady demand. But boom-and-bust cycles have occurred in the past and are likely to occur in the future. PG&E (and undoubtedly an LNG facility developer) will not want to incur substantial facility investments only to see the LNG facility suspend operations because of insufficient demand. Either cost recovery of the reasonable investment in facilities must be assured regardless of short-term fluctuations in gas demand and supply, or the LNG developer should be required to assume the risk of building out to existing facilities with no additional costs incurred by the gas utility as part of its assessment whether to proceed with the project.

c. Utilities should not be penalized if the addition of new supply sources, such as LNG, causes some existing facilities to be utilized less.

Another consideration that must be taken into account is the potential for changes in pipeline flow patterns as a result of connecting to new LNG facilities. For example, LNG projects that are located near load centers[8] could reduce the use of existing gas transmission facilities. Since the purpose of this proceeding is to provide assurance that California gas users will continue to have reliable, competitively-priced gas supplies, the utilities should not be penalized if some pipeline facilities are not fully utilized because of a substantial change in flow patterns on the system after LNG facilities are built. Specifically, if throughput on an

[8] For example, a proposed Long Beach LNG facility is located near the load center of SoCalGas' service territory.

existing pipeline goes down as a result of new supplies coming from another source at a different point on the system, the utility's rates should be adjusted so it continues to fully recover the cost of the existing facilities.

d. The LNG supplier, PG&E, and its customers should work cooperatively to ensure that the LNG supplier's delivered gas is in compliance with the receiving utility's gas quality and interchangeability requirements.

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The ability of customer equipment to successfully utilize fuel gas depends on the make-up or composition of the fuel. The ability of customer appliances to use natural gas can be affected by the percentages of the various hydrocarbon components (i.e., methane, ethane, propane, etc.) and inert components such as nitrogen or carbon dioxide that can be part of any gas source. A new fuel gas is considered interchangeable with the current gas if the new fuel does not adversely affect appliance and equipment operation.[9] In the case of residential appliances, adverse impacts can include incomplete combustion resulting in yellow tipping, low flame or lifting, or flashback. In the case of internal combustion engines, the result can be poor performance, excessive emissions or engine damage. Turbines for industrial purposes such as electric generation are also subject to problems when the fuel gas is not interchangeable or falls outside the gas quality tolerances for the end use.

Similar to most pipelines, PG&E has gas quality and interchangeability requirements. PG&E currently relies on AGA Bulletin 36 to assess the interchangeability of new gas streams for residential customers. The California Air Resources Board has established composition criteria for gas used for vehicle fuel. Various regional air resources boards have set fuel gas composition criteria as a part of the permitting process for new emissions sources such as turbines for electric generation. PG&E has established gas BTU limits as a surrogate

[9] PG&E's contracts with suppliers address these concerns in the context of gas quality. The Federal Energy Regulatory Commission is also addressing these concerns in the context of workshops on the interchangeability of natural gas supplies.

measure of interchangeability. These limits for the most part result in acceptable appliance and equipment operation. The existing interchangeability requirements apply to all gas sources including interstate pipelines and California production.

The composition and therefore interchangeability of LNG will vary depending on the source gas and the degree of processing that takes place at the point of origination and at the receiving location. The ability to utilize a particular LNG source also depends on the ability to mix the LNG stream with other gas to achieve a fuel that is interchangeable. As new LNG projects are considered, it is essential that the interchangeability requirements be well known so that source and processing requirements can be accurately assessed. Gas that cannot be utilized by consumers consistently with these requirements cannot be used.

The interchangeability requirements of California utilities must be assessed as part of the evaluation of any future fuel source and site option since it is not feasible or economical to make changes at the customer level (such as appliance orifice changes) to accept LNG supplies that do not meet acceptable gas interchangeability requirements. Actions at the customer level would be prohibitively expensive and burdensome on PG&E's customers. The Commission's should enact rules providing that all LNG suppliers be required to process their gas to meet existing utility interchangeability requirements.

2. Specific Access Issues

a. Access to LNG facilities proposed in southern California and Mexico

PG&E expects LNG supplies from Baja California to flow both north to San Diego and east to Ehrenberg on the Arizona border. To flow east, the flow on the North Baja pipeline would need to be reversed to a west-to-east flow. PG&E's understanding is that the North Baja pipeline, with its flow reversed, could deliver as much as 500 MDth/d to Ehrenberg on a firm basis.

PG&E could directly receive LNG supplies from the LNG regasification projects proposed in Mexico if El Paso places into service Line 1903, a California segment of the former All American oil pipeline. This pipeline roughly parallels PG&E's Line 300 from Bakersfield to Daggett and eventually heads south through Ehrenberg. El Paso has already refurbished another portion of line from Texas to Ehrenberg and has put it into natural gas service. El Paso is currently holding an open season in February 2004 to gauge market interest in converting to natural gas service the portion of Line 1903 from Ehrenberg to as far as Wheeler Ridge.

If El Paso were to convert Line 1903 in California to natural gas service between Ehrenberg and points within California, and if PG&E (or El Paso) were to build an interconnection between this line and PG&E's Line 300, then these facilities could be used to give PG&E customers access to Mexican LNG supplies. LNG supplies could be transported on the North Baja interstate pipeline from the Mexican coast to Ehrenberg, and then Line 1903 could transport these supplies to PG&E's Line 300. At this point, the LNG supplies would be like other interconnected supply and would be transported to PG&E's Citygate on a Baja Path contract. If gas supplies from traditional North American sources were to decline and Mexico becomes a source of significant LNG facilities, then PG&E may need to expand the Baja Path to access these supplies.

Another way that Baja Mexico LNG supplies could physically reach PG&E's system would be by a new pipeline along the Colorado River between Ehrenburg and Topock.

A third way for PG&E's customers to gain access to LNG supplies would be for SoCalGas to allow nominations from a Los Angeles Citygate delivery point to an off-system connection with PG&E. This assumes that SoCalGas eventually will develop a Los Angeles Citygate delivery point, and that LNG supplies have access to this Citygate. During the early stages of LNG development, these supplies would not necessarily need to be physically transported to the PG&E system; allowing off-system nominations and fulfilling them through displacement would facilitate additional gas-on-gas competition that would benefit PG&E customers. In the long run, however, it would be appropriate for SoCalGas to be able to physically transport LNG supplies to PG&E's system, or alternatively for the North Baja pipeline to develop this capability. The Commission's policies should be designed to allow these off-system nominations and, eventually, physical flows, to occur.

b. Access to Calpine's proposed LNG facility in Humboldt Bay near Eureka.

Calpine Corporation (Calpine) has proposed to construct an LNG facility at Humboldt Bay near Eureka. Conceptually, Calpine's proposal to build an LNG facility would be a good use of PG&E's existing transportation network, even though the connection costs appear to be high. If supplies available from Canada were to diminish or increase in price, LNG supplies from Calpine's facility could substitute without further expansion of the Redwood path (Lines 400 and 401).

The Calpine facility proposed for Eureka is in an early stage of development and the specifics, such as transport volume, available pipeline pressures and gas interchangeability are not yet known. However, PG&E has developed preliminary estimates of the costs to connect this facility to PG&E's transportation system.

The Humboldt facility would be located approximately 150 miles from PG&E's Redwood Path. PG&E currently operates Line 177 from the Redwood Path at Gerber Compressor Station to Eureka. This pipeline is 12 inches in diameter with pressure limitations, and would be incapable of providing adequate access from the Calpine LNG facility to PG&E's backbone system. PG&E estimates that a new large-diameter pipeline, capable of delivering 1 Bcf/day, would be needed, depending on the flow rate and available pressure from Calpine's facility.

PG&E's preliminary estimate of the cost to build a pipeline from an LNG regasification facility in Eureka to the Gerber Compressor Station is between $350 million and $400 million, based on PG&E's recent experience with installing a large diameter pipeline through difficult mountainous terrain, as would be the case with this pipeline.

In addition, PG&E has estimated the cost to expand the Redwood Path to accommodate additional flow from this facility, if Canadian gas were to continue to flow at historical levels. The size of a Redwood path expansion would depend on how much gas is forecasted to use the Redwood path from all sources including from Malin, Wild Goose Storage, Lodi Gas Storage and the Calpine LNG facility. To expand the Redwood capacity from Malin, PG&E estimates that adding compression at various stations could achieve a 200 MMcf/d expansion for an approximate cost of $35 million and a 400 MMcf/d expansion for an approximate cost of $100 million. To achieve a larger, 1 Bcf/d expansion from Gerber (the connection point for the Calpine LNG supplies) to the Bay Area would require a new pipeline to be installed parallel to the existing two pipelines for approximately 150 miles, which will cost approximately $300 million.[10]

If PG&E were to build the 150-mile interconnect pipeline from Gerber to Eureka, PG&E would request assurance that cost recovery is assured prior to construction. Alternatives for cost recovery could include a separate lateral fee to charge shippers that use this pipeline to ship LNG gas. This lateral fee would be in addition to the Redwood Path rate. A second alternative would be to roll the cost of this lateral into the Redwood path rate and have all shippers pay the same rate whether they ship gas from Malin or from the LNG facility. A third alternative would be to develop a new path that covered the cost of the lateral and costs of the common portion of Line 400/401 from Gerber south.

At this point in time, PG&E is not advocating a specific cost recovery mechanism, but merely identifying three examples that could be considered. As can be seen from the discussion, the cost of fully integrating the Calpine project into PG&E's pipeline system could be significant.

Because the new facilities would be built in furtherance of the Commission's policy to provide additional assurances that customers continue to receive safe, reliable gas service,

[10] PG&E's cost estimates are all preliminary and have not yet undergone rigorous engineering studies. Once the project is defined and a route is selected, PG&E would optimize horsepower and new pipe to determine the most cost effective construction design.

PG&E opposes any proposal to place PG&E at risk for these facilities or for the lessened use of any existing facilities, including PG&E's Line 401.

The current backbone rate design, in particular the "at-risk adjustment" for Line 401 which the Commission adopted in Decision 03-12-061, acts as a bar to full recovery of its backbone transmission investment. This rate policy creates a disincentive for PG&E to install any additional backbone facilities. This is an issue that needs to be resolved in Phase II of this proceeding before PG&E can make any backbone investment to accommodate new LNG supplies.

III. ACCESS ON INTERCONNECTING FACILITIES WITH INTERSTATE PIPELINES.

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Kern River Pipeline Corporation (Kern River) completed a major pipeline expansion in 2003. The expansion can provide up to 900 MMcf/d of new Rocky Mountain gas supplies into California.[11] The Kern River system interconnects with PG&E's Baja Path in two places, Daggett and Fremont Peak. The Daggett interconnect is the receipt point most frequently used. The capacity at this interconnect is about 325 MDth/day depending on pressures. Fremont Peak is typically a delivery point where gas sourced from PG&E's system flows to the High Desert Power Plant connected to Kern River. This point can also be used as a receipt point to transport gas from Kern River's mainline through Kern River's High Desert Lateral, and then into PG&E's system. A shipper pays an extra lateral fee on Kern River's system to use the High Desert Lateral, so shippers typically only use this route if Daggett is constrained. The Fremont Peak capacity is about 285 MDth/day.

To date, the Daggett interconnect with Kern River has proven to be adequate to accommodate the market that would like to deliver gas from Kern River to PG&E. PG&E's tap is sized for more than double the amount that can be currently flowed through Kern

[11] The Kern River expansion was approximately 900 MMcf/d; some of the capacity was contracted by customers with loads upstream of California.

River's meters at Daggett. To expand this interconnect would require Kern River to install additional metering. PG&E's costs to expand PG&E-owned regulation at the Daggett interconnect would be low.

Kern River also connects to SoCalGas in two places: Wheeler Ridge and Kramer Junction. However, the intrastate capacity made available by SoCalGas to Kern River shippers has proven to be inadequate.

SoCalGas has expanded the Wheeler Ridge interconnect by 80 MMcf/d and installed the new Kramer Junction interconnect. The new interconnect at Kramer Junction was sized to allow 500 MMcf/d of flows from Kern River to SoCalGas. SoCalGas has only made 200 MMcf/d of the 500 MMcf/d available for scheduling. The remaining 300 MMcf/d is not available because SoCalGas believes shippers on the Transwestern system and El Paso system have "grandfathered" rights to this capacity. SoCalGas cannot accept 500 MMcf/d from Kern River at Kramer Junction and accept the historical maximum flows from Transwestern of 800 MMcf/d and El Paso of 540 MMcf/d. In order to ensure Transwestern and El Paso can always deliver their historical maximum SoCalGas limits receipts from Kern River at Kramer Junction to only 200 MMcf/d.

The result of this policy of "grandfathering" historical capacity to Transwestern and El Paso has been to allow a significant amount of capacity on the SoCalGas system to go unused. Meanwhile, the Wheeler Ridge interconnect, the other interconnect between SoCalGas and Kern River, was constrained for most of the summer of 2003. Gas from the PG&E system to SoCalGas must also go though Wheeler Ridge. The constraint at Wheeler Ridge consistently reduced off-system flows on the PG&E system from June through October 2003.

SoCalGas should not continue to favor shippers on the Transwestern and El Paso system over shippers on the Kern River system. Until such time as SoCalGas implements a system of firm capacity rights, SoCalGas should implement a capacity allocation process similar to the process used at Wheeler Ridge. SoCalGas should create a process to allocate the take away capacity between all the affected pipelines based on final scheduled volumes from 2 days prior. This is the same process that is used to allocate the available take-away capacity at Wheeler Ridge between PG&E, Kern River and deliveries from Elk Hills.

Based on publicly-available data on SoCalGas' website, PG&E estimates that Transwestern shippers underutilized 160 MMcf/d on average during the summer of 2003. This additional capacity could have been available to Kern River shippers if SoCalGas had allocated capacity in a process similar to that used at Wheeler Ridge. This additional capacity could have significantly reduced the constraints at Wheeler Ridge for both Kern River and PG&E shippers.

PG&E has urged the Commission to take immediate action to ameliorate this problem in SoCalGas' pending receipt point capacity rights proceeding (Application 03-06-040).[12] If the Commission does not take action in that proceeding, then it should order SoCalGas in Phase I of this proceeding to implement an allocation process between Kern River, Transwestern, El Paso and Questar.

IV. CONCLUSION

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PG&E supports the Commission's efforts to establish policies and rules to ensure safe, reliable long-term supplies of natural gas to California.

PG&E requests that the Commission adopt the following guidelines and procedures:

1. PG&E will adopt a Core planning standard of a 1-in-10 year peak day and a 1-in-10 year cold winter demand standard for its core customers. To meet this standard, PG&E should be authorized to hold between 1050 MDth/day and 1250 MDth/day of firm interstate (including Canadian, Rocky Mountain and Southwest pipelines) and winter intrastate pipeline capacity, and between 40 and 46 MMDth of storage inventory capacity.

[12] See A.03-06-040 – "Comments of Pacific Gas and Electric Company on Alternate Decision of Commissioner Lynch," filed February 18, 2004.

2. All pipeline, storage and LNG contracts meeting the Core planning standard proposed by PG&E and falling within the Capacity Commitment Range, are pre-approved for cost recovery in accordance with the procedures described herein.
3. The Commission should also approve the Expedited Capacity Advice Letter procedure proposed by PG&E for approval of pipeline, storage and LNG contracts with quantities and terms not meeting the pre-approval criteria.
4. For each proposed LNG facility that has actually filed with the appropriate jurisdiction seeking authority to operate an LNG receiving facility that is contemplated to supply gas to PG&E's customers, PG&E is ordered to conduct analysis on the cost and feasibility of PG&E building a connection to PG&E's existing gas transmission system. If promising, PG&E is ordered to file an application with this Commission seeking authority to build the connection and include the cost in rates.

Respectfully submitted,

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APPENDIX:

Data Responses