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DISCLAIMER

This report was prepared by the staff to identify emerging trends and issues associated with the State's natural gas infrastructure. This report will be the subject of a hearing on June 5, 2001 held by the California Energy Commission's Electricity & Natural Gas Committee. The views and recommendations contained in this document are not the official policy of the Energy Commission until they are formally adopted.

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Executive Summary

Summary

The natural gas system in California is strained in meeting growing demand, especially for gas-fired electric generators. This is reflected in high natural gas prices. The extent to which the natural gas system will continue to be strained will be determined by several significant natural gas infrastructure constraints that require close monitoring.

Natural gas market participants have plans to improve the natural gas infrastructure. These improvements will help to assure that California has adequate supplies of natural gas in both the short- and long-term and to mitigate the current high natural gas prices that California is experiencing. However, if their current plans do not materialize, State actions may be needed.

The purpose of this report is to raise emerging natural gas infrastructure issues that should be watched closely to assure that infrastructure improvements are coming on-line as forecast. This will provide an early warning of developing problems so there will still be time for government to take actions to prevent shortages or ameliorate their adverse consequences.

Storage levels are a key indicator of whether the gas system will be able to meet the summer peaking needs of gas-fired generators and the winter peaking needs of core residential and commercial customers. In addition, natural gas prices are a key indicator of natural gas infrastructure constraints. The Energy Commission is proposing specific actions to track these and other indicators over the next few months to determine the extent of problems in the gas system.

Four Critical Infrastructure Issues in the Natural Gas System

This paper addresses four critical infrastructure elements of the natural gas system including:

- Active drilling rigs that bring natural gas reserves from underground resource basins to the surface for processing and delivery into the interstate pipeline systems, and gathering systems that deliver gas from California production to the intrastate pipeline system.

- Interstate pipeline capacity to deliver natural gas supplies from the remote resource basins to the California border.

- Intrastate pipeline systems of California natural gas utilities that deliver gas supplies received at the California border to end-use customers.

- Natural gas storage facilities from which gas can be withdrawn to supplement natural gas supplies flowing through pipelines at times of peak natural gas demand.

In addition, the paper addresses two key drivers of infrastructure constraints and its effect on gas prices:

- The current historical drought experienced throughout the West has driven the demand for natural gas by electric generators to unprecedented levels, challenging the natural gas infrastructure.

- Current high prices for natural gas are being driven by inadequate natural gas infrastructure that is largely a result of increased natural gas demand by electric generators.

Findings and Conclusions

This paper highlights several findings and conclusions regarding natural gas infrastructure. It also identifies proposed recommendations for monitoring natural gas infrastructure expansions and improvements. These include:

Natural Gas Supply

Natural gas supplies in North America appear to be sufficient to meet demand in California and the remainder of the United States for the next 50 years, according to the United States Geological Survey.

> The Energy Commission will continue to monitor drilling rig activity and production levels to assess whether production is keeping pace with growing demand in the long-term. Key trends to monitor include the number of active drilling rigs and increases in production from drilling activity.

In-state production of natural gas from existing wells has been declining over the last decade to about 15 percent of total State consumption today. Additional production in California could help to meet California's growing demand for natural gas.

> The Energy Commission and California Public Utilities Commission (CPUC) should identify barriers to increased in-state gas production and recommend actions to increase in-state gas supplies.

Interstate Pipeline Capacity

The problem with natural gas supplies in the near-term is assuring that sufficient interstate pipeline capacity is available to deliver necessary gas supplies to California. Interstate pipeline capacity expansions will be necessary to meet the growing demand in California and throughout the West. Market forces are currently spurring expansions of these pipelines.

The Energy Commission will continue to monitor interstate pipeline expansions to determine whether California utilities, marketers and electric generators are securing sufficient pipeline capacity to meet the State's gas demand.

Intrastate Pipeline Capacity

Intrastate gas pipelines and storage facilities of the gas utilities' natural gas systems especially in Southern California are strained and create bottlenecks in delivering supplies from interstate pipelines to gas consumers, including electric generators.

California should support expansion of the backbone systems of Pacific Gas and Electric Company (PG&E) and Southern California Gas Company (SoCal) Gas systems that are in the economic interest of consumers to eliminate bottlenecks and create the slack pipeline capacity that is necessary to promote competition.

The Energy Commission and the CPUC should undertake a joint evaluation of the design criteria for intrastate gas infrastructure, including pipelines and storage facilities, to determine specific projects that would remove bottlenecks in the utilities' gas systems.

Natural Gas Storage

Gas storage plays an important role in balancing supply and demand, especially during times of peak demand for winter heating needs and in recent years for summer peak electricity demand.

The Energy Commission and CPUC should, in assessing the need for expansion of natural gas utilities intrastate system, explicitly investigate trade-offs between storage and expanded intrastate pipeline capacity to meet future natural gas demand.

The demand for natural gas by the existing and new electric generators will stress the natural gas infrastructure in 2001. The California natural gas utilities will likely be able to just barely satisfy the demand of electric generators during the summer of 2001 and still store enough gas to serve core needs at peak during the winter of 2001-2002.

SoCal Gas is at the greatest risk for having to choose between serving electric generators and storing sufficient gas for winter. San Diego Gas and Electric (SDG&E) will likely have to curtail natural gas delivery this summer to electric generators that have fuel-switching capability. These two situations call for an integrated assessment of the interactions between the electricity and natural gas marketers.

> The Energy Commission will continue to forecast electricity and natural gas supply and demand. In particular, the Energy Commission will continue to track utility and private storage levels for core and noncore gas customers. In addition, the Energy Commission will begin conducting risk analyses to determine at what point withdrawal from storage to meet the electric generator natural gas demand this summer threatens the ability of utilities to meet storage targets for winter core demand.

The natural gas and electricity markets are becoming increasingly intertwined. Major uncertainties exist over how much natural gas California will need in the longer term as a result of in-state versus out-of-state gas-fired power plant development.

> The Energy Commission will undertake an integrated assessment of forces shaping the interconnection between electricity and natural gas supply and demand in the entire Western Region. The Energy Commission should track actual natural gas demand this summer for electric generators in-state and out-of-state to identify natural gas consumption trends for use in future forecasts and assessments.
>
> In addition, the Energy Commission will conduct studies to determine if expected hourly electric generator demand would cause insufficient gas injection, during the electricity peak summer months, to build up gas storage for winter peaking natural gas demand.

Natural Gas Prices

An inadequate natural gas infrastructure is a major contributor to high prices for natural gas in California. In addition, market participants may have manipulated prices even higher than justified by existing infrastructure bottlenecks, but it is the inability to rely on competition between gas suppliers that contributed to higher prices in California. The lack of surplus or slack capacity enables interstate pipeline shippers to charge transportation premiums for gas sold in California.

> The Energy Commission will continue to monitor the adequacy of natural gas infrastructure and its effect on natural gas prices. In addition, the Energy Commission should develop tools and models that better incorporate the effects of market forces and conditions on natural gas prices.

Specific Actions for the Energy Commission

This section identifies specific actions the Energy Commission proposes to take to assure adequate tracking of natural gas infrastructure operations, expansions and improvements. The actions listed below will help provide an early warning system for problems that may be developing over the course of the next few months so that appropriate State actions can be developed and implemented in a timely and responsive manner.

Prepare short- and long-term natural gas supply and demand analysis focused primarily on the Western United States.

- Test current analysis using various assumptions regarding natural gas demand in California, the United States and Canada.

- Identify the ability of the United States and Canadian resources to meet demand.

- Determine wellhead prices necessary to cause production to meet demand.

- For interstate pipelines, identify when, where and how much growth in interstate pipeline capacity will be needed for gas-fired electric generators.

- For California intrastate pipelines, identify when, where and how much growth in California natural gas utility pipeline capacity and related infrastructure will be needed.

- Modify existing models, and develop additional tools and models as necessary, to allow market conditions to be more explicitly incorporated into natural gas and electricity supply and demand analysis.

Determine if the market is responding to the natural gas needs as analysis indicates.

- Actively track daily, weekly and monthly
  - Electric generation natural gas demand in California and the surrounding states.
  - Storage levels for each of the California natural gas utilities and private storage facilities.

- Maintain time lines that identify strategic dates and track progress to insure:
  - Core storage levels will meet winter demand.

  - Natural gas utility infrastructure additions will be operational for winter needs.

  - Sufficient new interstate pipeline capacity will be operational to meet the projected needs during the next two to three years.

- Prepare risk assessment analysis to determine at what point summer storage withdrawal to meet electricity generation natural gas demand threatens the utility's ability to meet storage targets for core winter needs.

- Alert necessary parties if storage levels begin to slip, infrastructure developments are lagging, or other adverse conditions are developing.

- Track natural gas resource development on a continental basis, including active drilling rigs and new production being brought on line.

On an integrated basis, investigate peak summer and winter natural gas demand periods for the Western States Coordinating Council area.

- Investigate whether pipeline and storage capacities are adequate to meet peak demand periods.

- Prepare the analysis by integrating both natural gas and electricity demand.

Proposed Actions the State Should Further Investigate

Increasing In-State Natural Gas Production

- The Energy Commission and CPUC should identify barriers to increased in-state gas production and recommend actions to increase in-state gas supplies. In particular, the Energy Commission and CPUC should investigate any disincentives that may prevent market participants from expanding in-state production and make necessary changes to eliminate these.

Improving Intrastate Pipeline Systems

California should support expansion of the backbone systems of PG&E and SoCal Gas systems that are in the economic interest of consumers to eliminate bottlenecks and create the slack pipeline capacity that is necessary to promote competition. The State should establish a government intrastate gas system planning function to better examine both the short-term and long-term need for system upgrades and improvements.

The Energy Commission and CPUC should investigate whether proper incentives exist to support utility investments in intrastate natural gas systems and make necessary regulatory changes to eliminate any disincentives that may exist at the State level.

The Energy Commission and the CPUC should conduct a joint evaluation of design criteria for planning the intrastate infrastructure, including pipelines and storage facilities. Current design criteria are outdated, focusing primarily on meeting winter peak demands. Growing demand by gas-fired generators has heightened the importance of adequately planning for summer peaking needs.

Promoting Efficient Gas Use through Changes in Curtailment Rules

The Energy Commission and the CPUC should work together to develop an efficiency natural gas curtailment policy that would curtail the least efficient (high heat rate) generators first and the more efficient (low heat rate) generators last. In this way, the total amount of natural gas used for electric generation could be reduced lessening the possibility of impacts due to strained natural gas supplies.

Rebundling Utility Storage Function

The Energy Commission and CPUC should investigate rebundling each gas utility's noncore storage function. This would allow utilities to optimally use its entire storage inventory to meet peak needs. In addition, it would allow utilities to allocate rebundled storage costs to all customer classes, which would be offset by less volatile spot market prices.

Encouraging More Independent Storage

The Energy Commission and the CPUC should jointly investigate the prospects for developing additional independent storage facilities throughout the State, but especially in Southern California where none currently exist. Noncore customers who choose to inject and withdraw natural gas from storage for economic reasons would be free to use these facilities for these purposes. This would allow the gas utilities to optimize their storage, including noncore portions, to meet peak demands.

Chapter 1 – Introduction to Natural Gas Infrastructure Issues

Overview

This chapter provides a synopsis of the issues associated with California's natural gas infrastructure on a chapter-by-chapter basis. Although natural gas supplies have historically been considered to be abundant in North America, California faces several challenges in assuring sufficient supplies and helping mitigate the current high prices for natural gas in the State. The following discussion outlines the primary issues being faced by California with respect to the key elements of natural gas infrastructure.

Chapter 2 addresses important background issues related to gas infrastructure including: deregulation of natural gas markets, increased electric generator demand and uncertainties regarding future in-state electric generation demand, and the need for slack capacity on pipelines to support effective competition.

Natural Gas Supplies

If prices for natural gas are very low for sustained periods, natural gas production can lag behind consumption levels, as economic incentives are insufficient to encourage sustained drilling and production activity. The number of active drilling rigs is a key indicator of whether natural gas production can keep pace with growth in demand.

As discussed in more detail in ***Chapter 3***, active drilling rigs in North America gradually increased from 1990 through late-1997, and then declined precipitously beginning in 1998. However, the increases in natural gas prices since last summer have dramatically increased the number of active drilling rigs. While up to a one- or two-year lead time can exist between the time that drilling rigs are placed in operation and gas wells actually supply gas to the market, increased natural gas production throughout North America is anticipated to keep pace with demand for the foreseeable future.

Production of natural gas supplies in California declined from the mid-1980s, reaching its lowest production levels in 1996. In recent years there has been a slight increase, however in-state production could significantly increase if it could be quickly and efficiently connected to a gathering system. The Energy Commission and CPUC should investigate barriers to in-state production and make recommendations to increase these supplies.

Interstate Pipeline Capacity and Expansions

When interstate pipelines delivering natural gas supplies from remote production basins are running at or near their full capacity and expansions are not added to keep pace with growing demand, shortages of pipeline capacity can constrain the ability to deliver sufficient gas supplies to California to meet gas demand. The interstate pipeline system is addressed in more detail in ***Chapter 4*** and ***Appendix A***.

In addition, when pipeline systems are running at or near their design capacity, there is little slack capacity to take advantage of competitive forces that help drive prices downward. With slack capacity natural gas suppliers compete to meet the gas customers needs.

The absence of slack capacity means there is effectively no opportunity for customers to bargain with competing suppliers on the different interstate gas pipeline systems to get better deals and drive prices to lower levels. These and other factors have resulted in California paying higher prices for natural gas than many other states in the United States and reducing consumption of natural gas.

Because California is located at the end of interstate natural gas pipelines, upstream demand for gas threatens the long-term supply of natural gas to California. Increased upstream demand for natural gas includes the proposed addition of several tens of thousand of megawatts of gas-fired electric generation in the Pacific Northwest, the Southwest region and Mexico. It is uncertain how much of these additions will displace in-state natural gas-fired generation.

In addition, because of growing demand for natural gas by sectors other than electric generation in Nevada, Arizona and the Pacific Northwest, several interstate pipelines may not always have enough capacity to serve their upstream customers and California at the same time. As an example, population and economic growth in the Las Vegas, Nevada area has already consumed some of the existing pipeline capacity that used to deliver gas to California.

Likewise, economic growth in the Pacific Northwest and cold weather demand has decreased the ability of the interstate pipeline from Canada to deliver to California. In response, the interstate pipeline companies are moving to add pipeline capacity to meet this growing demand on their systems.

While a number of interstate pipeline companies have plans for expanding interstate pipeline capacity, it is unclear, at this time, whether and to what extent electric generators or other gas customers in surrounding states have acquired capacity from proposed interstate pipeline expansions. As a result, it is difficult to determine whether interstate pipeline capacity additions will increase the overall amount of natural gas supply available to California.

The Energy Commission should monitor the progress of key interstate pipeline projects that would affect interstate pipeline capacity to California. These projects are listed in **Table 1-1.**

Table 1-1
Interstate Pipeline Projects

Name	Capacity (MMcfd)	On-line Date
Kern River Pipeline Expansions	135 900	July 1, 2001 May 2003
Kern/Mojave Pipeline Expansion at Daggett	135	Summer 2001
PG&E-GTN Pipeline Expansions	42 169 1,000	November 2001 Summer 2002 Within Next 10 Years
Questar Southern Trails Pipeline	87.5 120	Spring 2002 Undetermined
El Paso Plains-All American Pipeline	230	Late August 2001
Transwestern Pipeline	150	Winter 2001
North Baja Pipeline	500	September 2002
Otay Mesa Generating Company Pipeline	110	September 2002
Sonoran Pipeline Phase I to CA Border Phase II in CA	 750 1500	 Summer 2003 Undetermined
Ruby Pipeline	750	Late 2003
Tuscarora Gas Transmission Company Pipeline	96	Early 2003
Sacramento Valley Project	Undetermined	Undetermined
El Paso Bi-directional Lateral	Undetermined	Undetermined

Intrastate Pipeline Capacity

If the intrastate pipeline systems of California's gas utilities are not expanded to keep pace with growing and/or changing load patterns, bottlenecks in these systems can result in shortages of natural gas supply to some specific regions within a gas utility service area or for the service area as a whole. Intrastate pipeline capacity issues are addressed in more detail in ***Chapter 5***.

Intrastate pipeline capacity, especially in Southern California, currently constrains the ability of gas utilities to deliver natural gas from interstate pipelines at the California border to customers throughout their systems.

Until the unprecedented use of natural gas by electric generators in Southern California in 2000, the mismatch, between the capacity of interstate pipelines to deliver gas and the capacity of intrastate pipelines to receive gas, did not restrict deliveries to California. In other words, the demand for natural gas was less than the receipt capability and deliveries were sufficient to meet demand at a price that did not include any premiums such as those being charged today.

Expanding intrastate capacity in Southern California would remove the present bottlenecks and provide California with insurance against shortages and price

spikes. The question the State faces is how much additional pipeline capacity does California need to insure that California has adequate supplies of natural gas and at what price?

The Energy Commission and CPUC should monitor the progress of key intrastate infrastructure improvements listed in **Table 1-2**.

Table 1-2
Intrastate Pipeline Expansions

Name of Pipeline	Capacity (MMcfd)	On-line Date
PG&E Intrastate Pipeline Expansions		
Redwood Path (Line 400-401) from Malin	400	Undetermined
Baja Path (Line 300) from Topock	200	Undetermined
SoCal Gas Intrastate Pipeline Expansions		
Wheeler Ridge (from Kern/Mojave and PG&E)	85	December 2001
North Needles (from Transwestern)	50	"
Receipt for Instate Production in San Joaquin	40	"
SoCal Gas & SDG&E Line 6900 Expansion	70	July 2001
Kramer Junction Interconnect	200	December 2001
SDG&E Intrastate Pipeline Expansion	130	Undetermined

Intrastate pipeline capacity, especially in Southern California, currently constrains the ability of gas utilities to deliver natural gas from interstate pipelines at the California border to customers throughout their systems.

Natural Gas Storage Facilities

Natural gas from storage is used to supplement supply flowing through pipelines when demand is high. If sufficient gas is not injected into storage facilities during periods of low demand, stored gas cannot be used to supplement deliveries of natural gas from interstate pipelines to meet higher peak demands as described in ***Chapter 6***. Because of expected high demand for natural gas in the spring and summer of 2001, gas utilities may not be able to inject sufficient natural gas into storage to carry California customers through next winter's peak heating demand. In addition, if electric generators and industrial customers do not place gas into storage before the summer electric peaking season, curtailments of natural gas supplies for these loads could exacerbate electricity shortage conditions and lead to additional blackouts.

The natural gas demand by electric generators is driving the need to expand the natural gas infrastructure. The demand for natural gas for other customer groups is in line with expectations. It is the unprecedented demand for natural gas by electric generators starting in summer of 2000 and anticipated for the summer of 2001 that is stressing the natural gas supply and delivery system of California.

The estimates of natural gas demand during a peak summer week for electricity demand, and the peak hour within that week, show that natural gas conditions will be tight this summer. It is estimated that the PG&E system will need to draw on 2.1 billion cubic feet (Bcf) of natural gas from storage to meet high natural gas

demand by electric generators this summer. It is also estimated that the SoCal Gas system will need to draw about 13 Bcf of natural gas from storage to meet high natural gas demand by electric generators this summer. The SDG&E system will likely need to curtail natural gas deliveries electric generators that have dual-switching capability.

Plans are underway to increase the storage capacity of utility and private natural gas storage facilities. The Energy Commission should monitor the progress of proposed storage expansions listed in **Table 1-3** below.

Table 1-3
Gas Storage Facility Expansions

Storage Facility Name	Capacity	On-line Date
PG&E McDonald Island Storage Expansion	400-600 MMcfd*	Undetermined
SoCal Gas Modifications to Aliso Canyon and La Goleta Storage Facilities	14 Bcf	December 2001
SoCal Gas Montibello Abandonment (over next 5 yrs.)	12 Bcf*	Summer 2001
Wild Goose Storage Facility	24 Bcf	Undetermined
Lodi Storage Facility	12 Bcf	December 2001

*Increase in withdrawal rate.

Natural Gas Prices

Insufficient natural gas infrastructure at the wellhead, on interstate pipelines, on intrastate pipelines or on storage facilities contributes to higher natural gas prices, as discussed in ***Chapter 7***. When the supply is less than demand, prices rise. Marketers may manipulate prices even higher than market conditions warrant. Expanding the natural gas infrastructure will reduce prices caused by both supply constraints and any market manipulation that might exist.

Chapter 2 – Background

Introduction

The following discussion provides background information that is necessary to more fully understand the natural gas infrastructure challenges that California faces. Over the past 20 years, California increasingly relied on natural gas as a major energy supply source. As a result of abundant supplies, low prices, and the air quality benefits of natural gas compared to other fuels many residential, commercial and industrial users have switched, where possible, to gas. Electric generation that was fueled primarily by oil in the 1970s has also been converted to burn natural gas. New power plants proposed or under construction throughout the West are natural gas-fired generators.

Until the summer of 2000, natural gas prices were extremely attractive in California and throughout the United States. However, natural gas prices rose dramatically during the summer of 2000 as prices in the electricity market spiked to extremely high levels. Today, California consumers who buy in the spot market or under contracts indexed to the spot price pay the highest natural gas prices in the continental United States.

In addition, the dramatic growth in electric generator use of natural gas strained the ability of the natural gas system to deliver sufficient natural gas supplies to all users last summer. This problem may become more acute during the summer electric peaking season of 2001. Improvements in natural gas infrastructure will be necessary for California to adequately meet its demand for natural gas and help to put downward pressure on natural gas prices.

Natural Gas Utility Systems

Natural gas systems have historically been designed to meet peak natural gas demand for core (residential and commercial) customers in the winter. The PG&E[1] and SoCal Gas[2] systems are designed to meet cold weather criteria based on historic weather conditions. These criteria determine the amount of intrastate infrastructure; including pipelines, compressors, and storage that is necessary to maintain service to core customers during peak winter natural gas demand.

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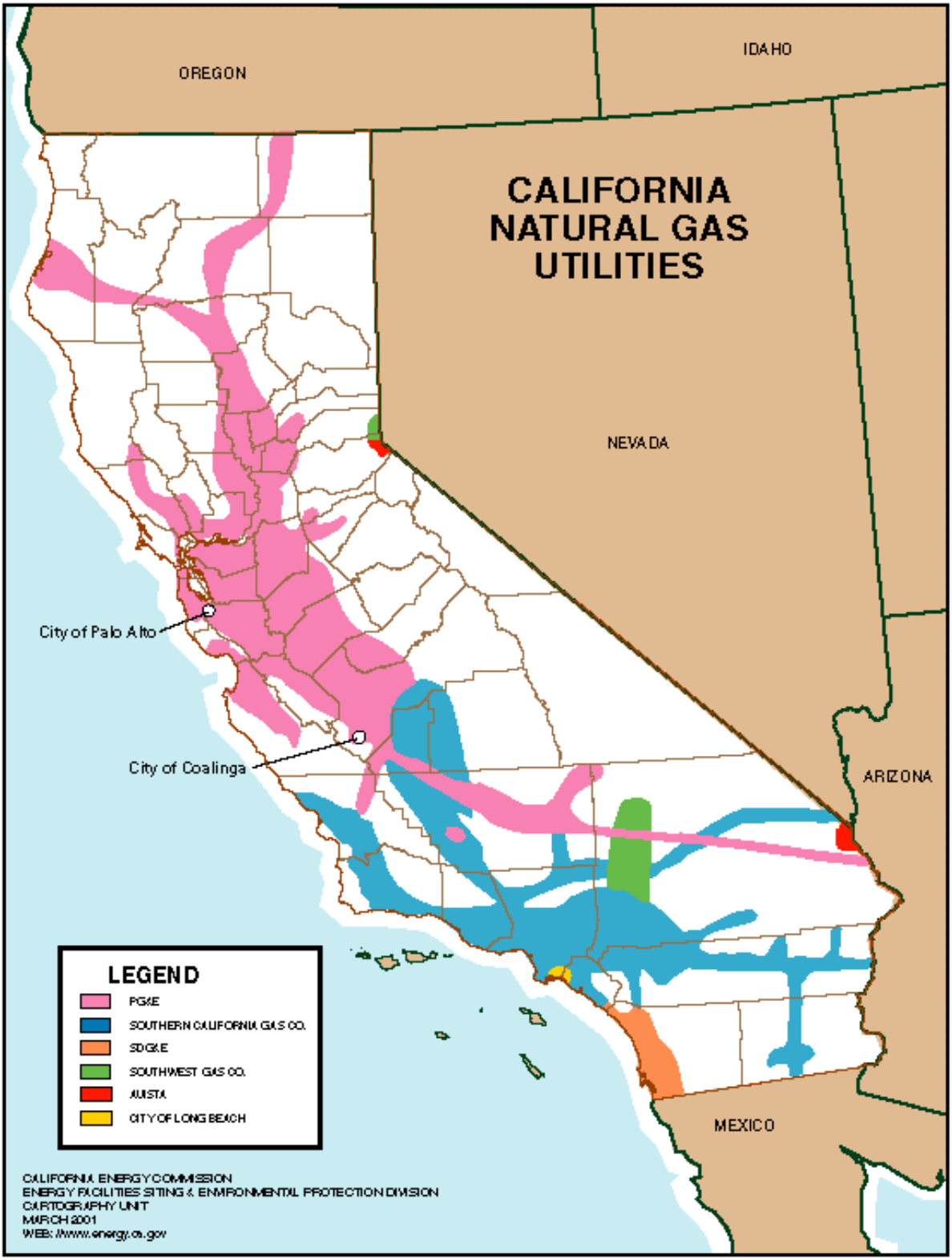
[1] PG&E uses a combination of an abnormal peak day and a cold winter day criteria for its system design. The abnormal peak day is the coldest systemwide temperature of 31 degrees that is expected to be reached or exceeded for one day in 40 years. A cold winter day is based on a series of three to four cold days of about 38 degrees that is expected to occur every five years.

[2] SoCal Gas uses a cold weather criteria based on a systemwide temperature of 38 degrees that has a probability of occurrence of once in every 35 years.

Figure 2-1
Map of California Natural Gas Utilities Service Areas



Given current design criteria, the economics of natural gas systems require that not all customers will be served on the peak cold winter day. The natural gas system would have to have at least twice the pipeline capacity to serve all customers on the coldest expected day. Since the historic coldest day occurs only rarely, the excess pipeline capacity would be underutilized for a majority of the time. This is not economically feasible.

On a natural gas system, the physical nature of natural gas allows flexibility in operating the pipelines and storage facilities in the system to balance supply and demand. If deliveries from the interstate suppliers exceed demand, gas can be stored. Gas storage can be accomplished in the distribution utility pipeline by increasing the pressure in the pipeline system to temporarily increase the amount of gas the pipeline can hold. Storage can also be accomplished by injecting gas into underground storage facilities. Conversely, if the demand exceeds supply that demand can be met by decreasing pressure in the pipeline or by removing gas from storage.

If the gas utility cannot meet the needs of core residential and commercial customers by withdrawing from storage, they will then curtail noncore customers. In California, the natural gas system was originally designed on the assumption that large industrial and electric generating customers have dual fuel capability. In the event of a natural gas interruption, the dual fueled customers would switch to oil and as a result they would be able to maintain operations. In this way curtailment of noncore customers instead of core customers would minimize the impacts of natural gas supply shortages.

During the 1990s the natural gas system was temporarily in an excess or surplus conditions and curtailments were rare. At the same time, more stringent air regulations during this period caused most dual fueled customers to abandon their oil burning capability. Now that supply and demand is more in balance, diversions and curtailments of noncore customers are more likely to occur in accordance with the design of the current system.

If California continues to rely on the current design criteria for the natural gas system to meet peak winter demand means, then there will be an increasing chance of electric generator curtailments in unusually cold winter conditions. In the event that the total demand for natural gas by all customers, including electric generators and industrial facilities, exceed intrastate pipeline systems capacity, curtailments of natural gas to generators under current curtailment rules could exacerbate electricity supply problems.

The Move to Competition in Natural Gas Markets

The interstate and intrastate gas market has evolved over the last 20 years from one that was completely regulated to one that is primarily a competitive structure. Before 1984, the interstate pipeline purchased the gas at the wellhead and delivered the gas to the California border. The California gas utility then bought

the gas from the interstate pipeline and sold it to the retail customer. Originally, all interstate pipelines stopped at the California border and delivered gas to either a PG&E or SoCal Gas intrastate pipeline. The SDG&E system received its gas from SoCal Gas. The three California gas utilities would then resell the gas to consumers. No gas consumer in the State could buy natural gas from any entity other than the three gas utilities. The only exceptions were companies that could be directly linked to gas fields in California; a practice that continues today.

In 1984, FERC took the first step toward addressing pipeline competition with an order eliminating a requirement that utilities purchase gas from interstate pipelines. FERC Orders 436 and 500 required interstate pipelines to provide nondiscriminatory service to all transporters of natural gas. Today, transporters, including gas marketers and large-end users, buy the gas at the wellhead, arrange to ship the gas to California, and then sell or use the gas in California.

At the State level, the CPUC ended the obligation of California gas utilities to purchase and supply gas to all customers. To protect the residential and small commercial customers, the CPUC created the concept of core customers. To meet the service needs of these core customers, the gas utilities set aside an amount of intrastate pipeline capacity that varies by pipeline and season. In addition, the gas utilities reserve space on the interstate pipelines to serve the core customer needs. Assuring sufficient supplies on interstate pipeline for noncore natural gas customers, including electric generators, was no longer the responsibility of the regulated utility. Acquiring upstream pipeline capacity to serve the noncore customers is now the responsibility of the noncore customers and the marketers that supply them with natural gas. The gas utility is now responsible for assuring that the backbone pipeline system is adequate to receive the flow from the interstate pipelines.

Increased Near-Term Natural Gas Demands for Electric Generation

During the summer of 2000, dramatic increases in the use of natural gas for electricity generation in California stressed the natural gas system's ability to deliver sufficient natural gas supplies. Construction plans for electric generators fueled by natural gas will pose increasing demands for natural gas throughout the Western states and Mexico. Increased electric generation in California will place additional stresses on the gas utilities systems.

Both the PG&E and SoCal Gas natural gas systems may face unprecedented demand for natural gas at the time of the summer 2001 electric peak demand. However, because more gas-fired electric generators are located in Southern California, problems in natural gas supply are more likely to occur there than in Northern California. The need for natural gas to meet summer peak demand and the need to use gas from storage this summer is addressed in more detail in

Chapter 6. Several factors will affect the amount of natural gas needed for gas-fired electric generation in California this summer.

First, summer weather conditions can cause a wide variation in the level of demand for electricity at peak periods from year to year. If California and surrounding states experience hotter than normal weather this summer, the electric system will be extremely strained.

Second, the amount of hydro generation that California can rely on from both in-state generation and imports from the Pacific Northwest also varies extensively from year to year. This year hydro conditions are well below average for California, and are critically low in the Pacific Northwest. The limitation on hydro generation will increase the amount of gas burned for electric generation in California.

Third, the amount of non-hydro imports that California can receive from other states in the western regional interconnected grid also varies depending on the load resource balances of individual utilities. Depending on the amount of load growth and resource capacity expansion in other states, there could be surplus power that California can import. However, if the Southwestern states, in particular, experience high summer temperatures, electricity resources throughout the West could be severely constrained.

In California, the events in 2000, and potential problems identified for the natural gas and electricity systems, demonstrate the increasingly interconnected nature of California electricity and natural gas markets. Both markets have been partially deregulated and are subject to price spikes whenever capacity limits are approached. These changing circumstances of natural gas demand need to be explicitly addressed. The current events in electricity and natural gas markets are calling into question the prudence of relying totally on the market to plan for the State's need for natural gas supplies and infrastructure to serve electric generators.

In addition, the existing natural gas curtailment policies for PG&E and SoCal Gas call for a pro-rata reduction in natural gas supplies to all noncore customers, electric generators and industrial customers alike. Curtailment of natural gas supplies to electric generators could exacerbate rolling blackouts this summer and winter. At the same time, curtailments of industrial customers could increase the economic impacts from lost production that industrials are likely to bear because of electricity outages. The State should examine changes to curtailment rules that would minimize disruptions of electric generation and industrial operations.

Meeting the Long-Term Needs of Electric Generators

As stated earlier, it has not been economical, under the current design criteria, for the intrastate gas system, to build sufficient pipeline or storage capacity to avoid curtailing noncore customers, including electric generators, during periods of high peak natural gas demand. This may not be true in the future because there are limited alternatives to burning gas.

Reliable firm gas service can be obtained, but at a price. Those requiring firm service, such as electric generators should pay for that service. Unfortunately, many electric generators appear to be relying on interruptible service. This puts the electric generators at risk for being curtailed during high demand periods. When electric generators are curtailed it is the consumers, not the electric generators that suffer.

Electric generators also affect other gas customers when they decide whether or not to place gas in storage. All customers will benefit through lower gas prices and greater reliability of gas service if electric generators store gas to met their needs during peak demand periods. Currently, there is no requirement for electric generators to store gas. Inadequate supply planning by electric generators causes higher prices for both natural gas and electricity for all customers. Insuring reliable gas supply for electric generators will require sufficient capacity to meet their needs in adverse conditions.

Some measures have been designed into the natural gas system that allow some noncore customer demand to be met during peak demand periods. For example, gas systems can continue to serve customers even though the demand at a given moment exceeds the flow of gas being delivered to the system at that moment in time. The gas system can draw on “gas packed” in its pipeline system or can draw on storage. However, these are temporary measures and cannot be sustained for extended periods of time.

While noncore customers were deregulated to engender competition and choice, the increasing demand for electric generation and the present tight supply of electricity resources places noncore customers at increasing risk of curtailment.

In Northern California, the customers such as industrial gas users and electric generators are all considered noncore customers and have less reliable service by definition than core customers. The noncore customers use the capacity that is left after the core and off-system transportation[3] capacities are subtracted from

[3] Off system transportation is the shipping of non-utility owned gas by a utility to another utility system.

the PG&E backbone capacity[4]. The remaining capacity is available for marketers and qualified customers under an CPUC-approved tariff to ship natural gas.

For Southern California, industrial customers and electric generators can select different levels of service from “firm” to “interruptible” service. These customers can elect to be part of the core service provided by SoCal Gas if they are willing to pay for this service. However, many noncore customers have instead chosen to secure their own supplies either from marketers or through other arrangements at lower cost options. As a result, SoCal Gas must currently plan for those industrial and electric generation customers who choose to be core customers. The CPUC is presently considering a proposal to switch SoCal Gas to a system similar to that of PG&E.

Gas utilities can reserve capacity for the residential and commercial core customers indefinitely with little risk. The utility knows that as a whole core customers will continue to demand a fairly constant amount of natural gas. This relative predictability in demand allows them to adequately plan to meet the needs of the core customers indefinitely.

Natural gas marketers and noncore customers who were buying their own natural gas supplies, under market conditions before the summer of 2000, were less likely to take a long-term view of the future. Consequently, they were unlikely to commit to very long-term payments for capacity on pipelines as short-term purchases offered cost savings. This lack of long-term commitments has consequences for California. California is at the end of the pipeline system and has not contracted for firm capacity for all of its needs. As a result, whenever the demand upstream increases, California loses pipeline capacity. Gas consumers, particularly electric generators, appear to have responded to this fact by bidding for capacity on all the recent interstate pipeline expansions.

Because electricity and natural gas markets are increasingly intertwined, California must consider an integrated approach to planning for natural gas capacity to assure all critical natural gas demand, including electric generators, can be met in the future.

Trade-Off Between In-State and Out-Of-State Natural Gas Use for Electric Generation

One of the difficulties in assessing future infrastructure needs for natural gas-fired power plants in California is the relationship between available interstate pipeline capacity and power generation needs upstream of the California border. Natural gas power plants in surrounding states that sell electricity into California theoretically displace natural gas-fired power plants in

[4] The backbone system of the gas utilities consists of gas transmission and storage facilities.

California. Therefore, the reduction in pipeline capacity to meet upstream demands may be offset by reduced natural gas demand for electric generation within California.

Table 2-1

Status (3/20/01)	No. West	So. West	Rocky Mtns	Calf/Mex	Total
Under construction/completed	3,104	3,295	375	6,037	12,811
Approved	3,187	5,600	1,367	3,336	13,490
Applications under review	4,510	5,440	1,107	8,145	19,202
Starting application process	8,027	3,640	1,000	2,300	14,967
Press release only	1,248	6,470	496	7,957	16,171
Total	20,076	24,445	4,345	27,775	76,641

Source: CEC Website updated March 20, 2001

Table 2-1 shows power plants proposed for construction throughout the Western states. Many gas-fired power plants are proposed or under development in Nevada and Arizona. These plants, if constructed in excess of the needs of Nevada and Arizona, may export their electricity into Southern California. These imports will displace natural gas usage on the SoCal Gas system and reduce the need for expanding the intrastate system to meet gas-fired generator demand.

It is uncertain how new electric generation for Baja Mexico at Rosarito will impact the natural gas demand and electricity generation mix. Because Baja, Mexico already has several hundred megawatts of older inefficient gas-fired generators, Mexico will not immediately need the entire output of the proposed 550 megawatts (MW) of generating capacity. Natural gas demand in Mexico could actually decrease as this new highly efficient combined cycle unit displaces the older inefficient steam units.

On the other hand, Mexico may elect to sell electricity into California. If so, it could run its older units, increasing gas demand in Mexico. In that instance, electric generation on the SDG&E system or elsewhere in California could be displaced, thereby reducing gas demand in San Diego or other areas of the State.

The Pacific Northwest also has ambitious construction plans for gas-fired power plants that may be surplus to their native electric loads. As a result, additional imports of electricity from the Pacific Northwest may be available to California. These imports could further displace the use of gas-fired generators in California in the future.

Need for "Slack Capacity" on Interstate and Intrastate Pipeline System

Slack capacity is defined as the amount of pipeline capacity that is in excess of the natural gas demand that is needed to generate the benefits of competition.[5] There is no slack capacity when natural gas demand is equal to the amount of pipeline capacity available to deliver gas into the State through interstate pipelines or to deliver to customers on the intrastate pipeline system. When there is no slack capacity, customers lose the benefits of competition, and prices increase overall or spike upward.

As a rule of thumb, price competition for pipeline capacity prevails when pipelines operate with sufficient slack capacity to engender competition. Once slack capacity is reduced, a premium starts to creep into the market. At minimum levels of slack capacity, those who hold capacity can exercise market power and, therefore, they can arguably control prices. As the system loses virtually all of its capacity, price spikes appear.

This situation exists in California today. Since the State's gas utilities are generally short of slack capacity this situation has contributed to natural gas price increases that have been sustained over the last year, as well as to occasional very high spikes. Marketers may have taken advantage of the absence of slack capacity to manipulate gas prices higher than is justified by supply and demand conditions. Given the cost to consumers, the State needs to recognize the role played by the natural gas-fired generators in causing strains on the utility natural gas pipeline system and take steps to assure that the current bottlenecks are eliminated.

California should support cost-justified expansion on the gas utility backbone systems to meet future demand, as well as provide for slack capacity to mitigate price impacts. This need for expansions appears to be especially true for Southern California where the natural gas system is already stressed, as discussed in ***Chapter 6***.

When considering whether to invest in capacity expansion in their utility systems to add slack capacity, one of the primary concerns of the utility is whether they can recover their costs for backbone expansions in rates. A regulatory approach that encourages such investment to assure slack capacity can mitigate or prevent price spikes and overall price increases such as those California is currently experiencing.

To a large extent, the issues regarding expanding capacity on the intrastate backbone gas system is a question of recovery of investment and the willingness

[5] CPUC Decision 97-08-055.

of the various shippers to support expansion.[6] However, these decisions need to be put in perspective. The reality of today's gas market is that pipelines are cheap and gas is expensive. From a public interest standpoint, it is better to put in slack capacity and to pay a few cents more for transportation than to pay dimes or dollars more for gas supplies.

[6] A number of gas marketers and electric generators have commented that SoCal Gas should remove the bottlenecks on its backbone system and allow for a free flow of natural gas into southern California.

Chapter 3 – Natural Gas Supply

Overview

This chapter addresses natural gas supply issues. California produces about 15 percent of its natural gas in the State while the remaining 85 percent of supplies are brought into the State from natural gas resource basins in North America via a system of interstate pipelines.

Since the mid-1980s, in-state production has been declining and drilling activity in North America has also declined. However, with the recent increase in natural gas prices, drilling activity has increased over the last 12 to 18 months.

To increase available natural gas supplies, California could take steps to increase in-state production. This increased activity should provide adequate natural gas supplies to meet the needs of California and the rest of the United States for the foreseeable future.

Natural Gas Supply Sources

As shown in **Figure 3-1**, California receives gas supply from five areas. These resource basins include the Western Canadian Sedimentary Basin, the Rocky Mountain Basin, the Anadarko Basin, the Permian Basin, and the San Juan Basin.

The North American natural gas resource base is estimated at 975 trillion cubic feet (Tcf) in the United States, including nearly 160 of proven reserves and an additional 417 trillion cubic feet (Tcf) in Canada. The United States Geological Service estimates that this resource base, which includes proven reserves ready for production and resources that could be developed and produced economically, should provide affordable natural gas supplies to serve the nation for the next 50 years.[7]

In addition to these natural gas resources, the natural gas industry is continually exploring all options for natural gas development. Potential options to increase gas supply for California range from natural gas from far Northern Canada and Alaska to liquefied natural gas that would be shipped by tanker to West Coast terminals.

Natural Gas Production Trends

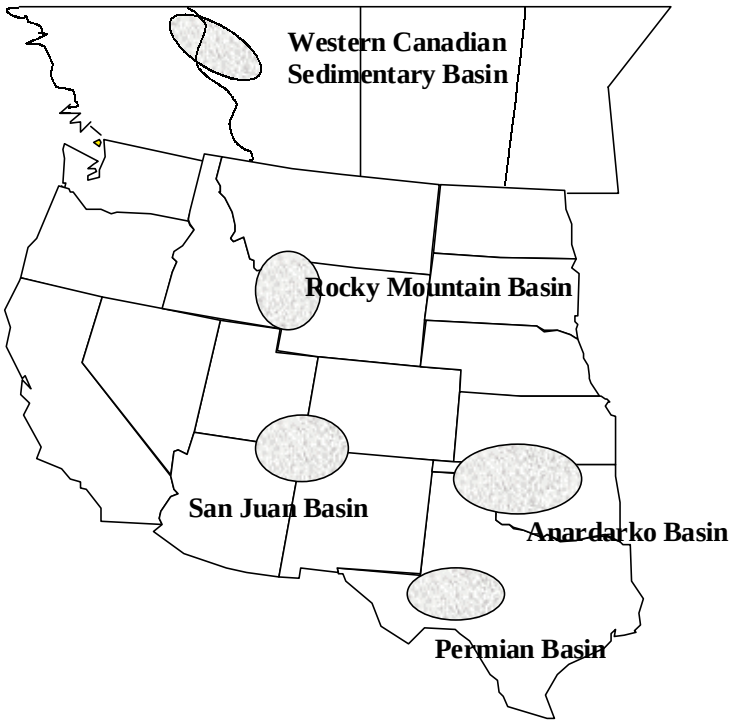
Drilling rigs are deployed in a cyclical pattern. Surpluses of gas supply tend to depress natural gas prices below the cost of production. As a result of low prices, producers reduce exploration and production and the number of operating

[7] United States Geological Survey, ***1995 Assessment of the United States Oil and Gas Resources*** and ***An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf***.

drilling rigs decreases. Shortages of gas supplies increase prices above the cost of production. This price increase provides economic incentives for producers to increase exploration and production and the number of operative drilling rigs increases. This cycle continues indefinitely with prices averaging out roughly at the cost of production.

Figure 3-1

Natural Gas Supply Basins to California



At the wellhead, growth in supply has not kept up with demand growth in North America. Producer exploration and development budgets were relatively low in North America, which is currently in the midst of a gas production boom.

Gas production in the United States in 1998 was 19 Tcf. The National Petroleum Council projects production to increase to 25 Tcf by 2010. Much of the increase can be attributed to the need to supply increased power generation both in the United States and Canada.[8]

To keep up with production, drilling activity has reached record levels. In September 2000, more than 800 rigs were actively drilling which is far above the

[8] National Petroleum Council, ***Meeting the Challenges of the Nation's Growing Gas Demand***, 1999.

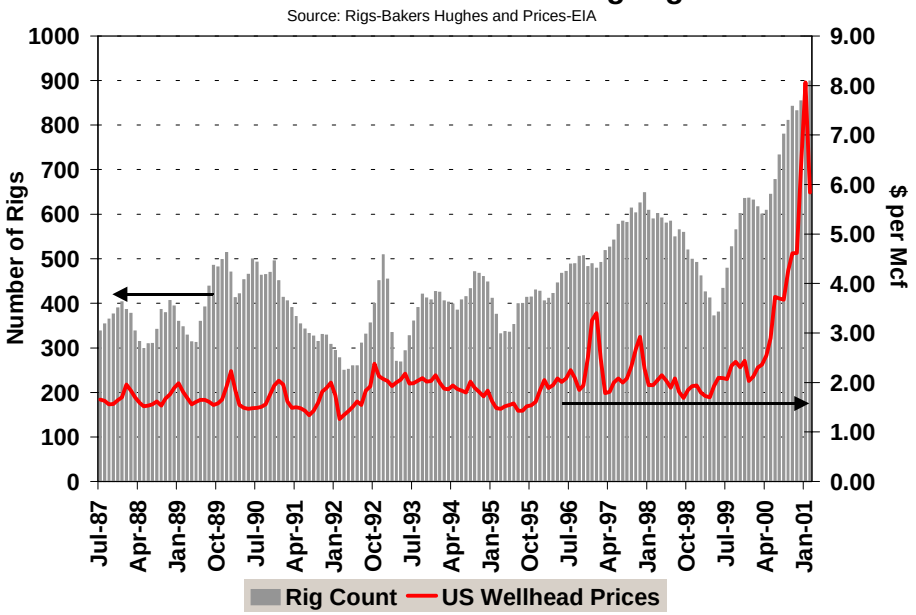
10 year average of 454 rigs per year. The current total of 971 supports industry opinion of a need to have 600 to 800 rigs actively drilling to match production capacity with expected growth in demand.[9] To maintain the current level of drilling, wellhead prices must remain higher than the prices experienced in 1999.

As **Figure 3-2** indicates, in April 1999 the active rig count dropped to 371, as average wellhead prices fell below $2.00 per MMBtu. Shortly after that point, the average wellhead price in the United States began to climb and drilling activity followed. By September 2000, the active rig count had risen to 813 and more recently is to 971. Once drilling activity begins, natural gas deliveries normally take several months to a year for wellhead supply to be brought to market; thus, with sustained higher rig activity, natural gas wellhead production should be in balance with demand in the next two to three years.

Figure 3-2

Comparing Monthly U.S. Wellhead Natural Gas Prices and Active Gas Drilling Rigs

Source: Rigs-Bakers Hughes and Prices-EIA



California Natural Gas Production

Starting in the mid-1980s, California's in-state natural gas production declined, mostly from non-associated gas or gas that is not produced as a by-product of oil production. In 1985, in-state natural gas production averaged 1,352 MMcfd. However, by 1996, in-state production levels had sunk to about 800 MMcfd. Since reaching its lowest levels in 1996, production has climbed to over 1,000 MMcfd in 2000. The California Division of Oil, Gas, and Geothermal Resources reported that, in 2000, natural gas production climbed to about 1,030 MMcfd, up from about 880 MMcfd in 1998.

[9] Bakers-Hughes, May 2001

California producers hold a locational advantage over gas producers in other regions. In spite of this advantage, in-state gas has lost significant levels of market share during the past 10 to 15 years. The steady decline in market share was largely the combination of increased competition at the wellhead and contractual restrictions between producers and PG&E that precluded producers from gaining access to the potential customers. The PG&E Gas Accord settlement was to relax this situation, by providing that PG&E would sell its gathering systems. Presumably, an independent natural gas gathering company would be keenly interested in providing rapid and efficient service for producers to bring new production to market. Due to various reasons, PG&E has yet to divest its gathering system. Producers report that PG&E continues to restrict their access to the market.

While overall in-state natural gas production has increased since 1996, California's market percentage share of the natural gas market has declined. In 1986, California gas satisfied more than one-quarter of consumer needs. However, by 1997, in-state producers supplied only about 15 percent of the California gas market, a share that continues today.

Figure 3-3 illustrates the trends in California natural gas production. As shown in the graph, non-associated gas production has experienced the greatest decline. However, the Energy Commission estimates that California production has the potential to grow over the next two decades, reaching over 1,200 MMcfd by 2022.

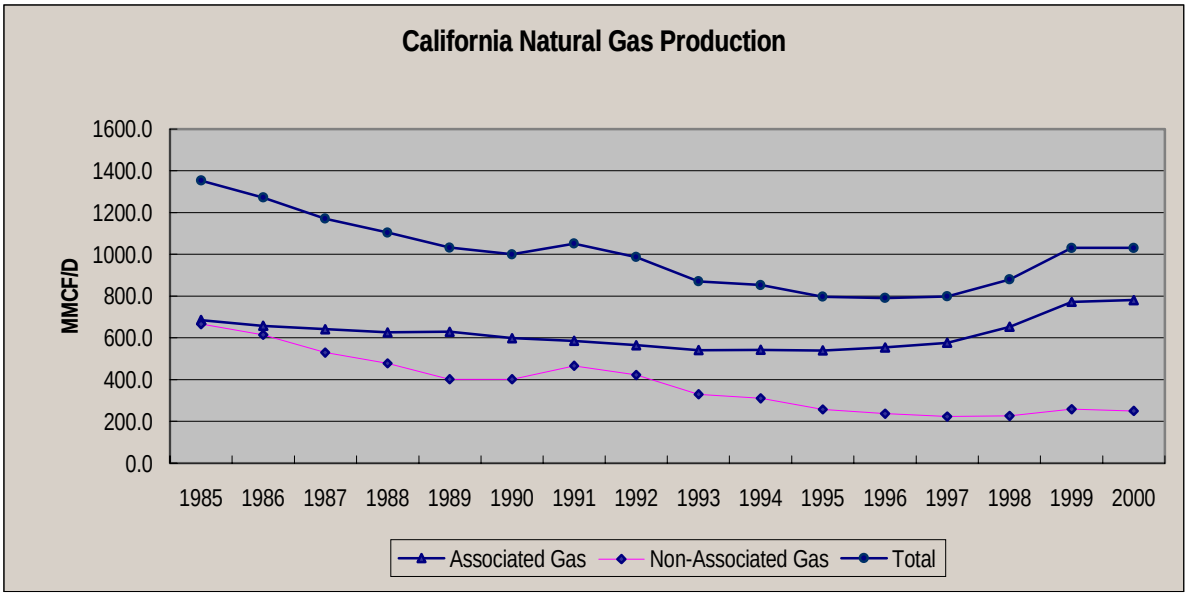
Elk Hills contributed significantly to the recent upturn in total in-state natural gas production. Elk Hills, located in Kern County, remains the largest producer of associated natural gas in California. Originally, Elk Hills was part of the Naval Petroleum Reserve. About half of the Elk Hills natural gas produced there was re-injected into oil producing formations to stimulate crude oil production. When Occidental Petroleum purchased Elk Hills in 1998, it began to sell all the production. This accounts for much of the increase in production statewide.

In addition, developments in northwest Kern County may provide new resources for California. East Lost Hills, located in this area, may contain 190 Bcf of natural gas[10]. Increased production from Elk Hills, Rio Vista, and new areas can increase California's in-state production market share outlook. For example, Tri-Valley recently reported it might have found another 3 Tcf in gas reserves near Delano, California.[11]

[10] Berkley Petroleum: Reported in the Bakersfield Californian.

[11] NGI, April 16, 2001.

Figure 3-3



Source: Data for graph came from the California Division of Oil, Gas, and Geothermal Resources.

At the end of 1999, estimated proven reserves, for onshore and offshore, stood at 3.48 Tcf. California producers will continue to provide approximately 15 percent of the California market. In-state market share could change if producers expand their drilling activity as a result of higher natural gas prices, and obtain increased access to the market.

California could pursue implementation of the PG&E Gas Accord provisions immediately to improve gathering system access and probably increase in-state gas production.

Chapter 4 – Interstate Pipeline Capacity and Expansions

Overview

The following chapter describes the potential constraints on the interstate pipeline system to meeting California's growing demand for natural gas. California depends on a system of *interstate* pipelines to deliver natural gas to the State from the different resources basins throughout North America as outlined above. For the most part, these interstate pipelines flow natural gas into the *intrastate* natural gas pipeline systems of the California natural gas utilities for delivery to end-use customers.

Interstate Pipeline System

As previously noted, interstate natural gas pipelines supply about 85 percent of the natural gas consumed in California. Upstream demand and California intrastate pipeline bottlenecks jeopardize this supply in the long-term. In the short-term, these bottlenecks, along with increased demand, have contributed to high prices for natural gas in California starting last summer, continuing through the winter of 2000-01 and the spring of 2001. Eliminating pipeline bottlenecks in California may be necessary to put an end to Californians paying more than the rest of the country for natural gas.

Because California is at the end of the interstate pipelines, California is at a disadvantage in the current market-based natural gas pipeline system.[12] With the shift to competition in the United States natural gas market over the last two decades, California must now depend on the market to expand interstate pipeline capacity to meet growing demand. Increases in upstream demand do not automatically cause interstate pipelines to expand capacity.

The current practice by interstate pipeline companies is to test market demand for expansions through an open season process. Without the necessary contractual commitments from natural gas transporters or marketers, pipeline expansions are unlikely to occur. If market participants do not anticipate increased demand, they can run short of interstate pipeline capacity.

There currently is a mismatch between interstate delivery capacity and utility receiving capacity. With the 1992 expansion of the Transwestern pipeline, more gas can be delivered to California than it can receive.

[12] California would not be at a disadvantage if gas consumers entered into enough long-term contracts. These contracts could help to mitigate prices and assure long-term supplies.

Existing Interstate Pipelines Connected to Supply Basins

Four interstate pipelines connect California to supply basins. The four primary interstate pipelines that deliver gas from remote natural gas production basins into the California gas utilities systems are the following:

- The PG&E Gas Transmission-Northwest (GTN) pipeline that extends from the Canadian border to the California-Oregon border at Malin.
- The Kern River Gas Transmission Company (Kern River) pipeline that originates in Wyoming and merges with the Mojave pipeline at Daggett, California, to form the Kern/Mojave pipeline.
- The Transwestern pipeline that extends from West Texas to the California-Arizona border at Needles, California.
- The El Paso Pipeline System that is divided into a Northern and Southern system, delivering gas from the San Juan, Permian and Anadarko basins into California at Topock and Ehrenberg.

Table 4-1 shows the capacity of interstate pipelines at the California border currently coming into the State. Appendix A provides details on how these pipeline systems operate and current capacities.

Table 4-1

Interstate Pipeline	Delivery Capacity (MMcfd)
PG&E-GTN @ Malin	1,930
Kern River	700
Transwestern @ Needles	1,090
El Paso @ Ehrenberg	1,240
El Paso @ Topock	2,080
Total Delivery Capacity	7,040

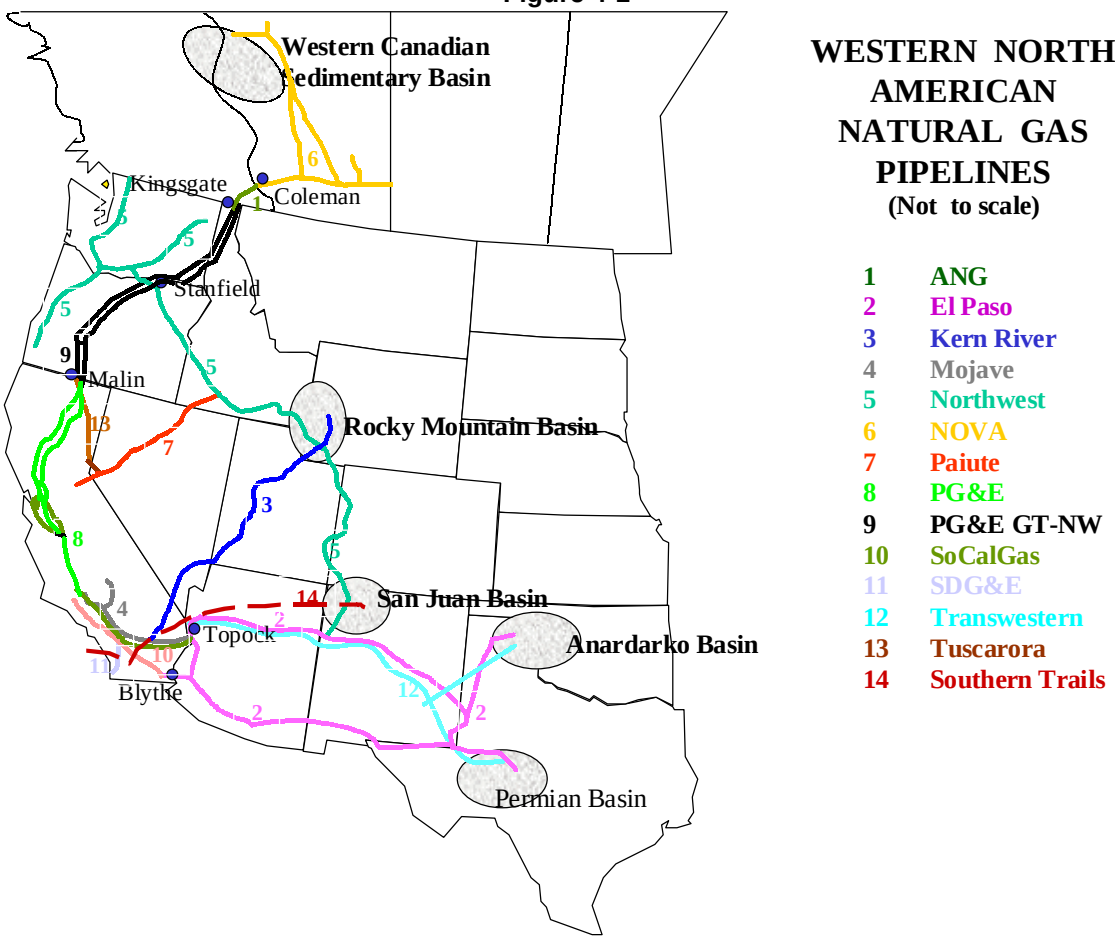
The locations of major interstate pipelines are shown in **Figure 4-1**. These interstate pipelines can deliver more gas supply to California than the California gas utilities can accept. As discussed below, steps are being taken to increase receipt capacity in California.

Interstate Pipelines not Connected to Supply Basins

In addition to interstate pipelines that are connected to supply basins, the Mojave interstate pipeline also receives gas from the El Paso Northern system, which originates at Topock, Arizona, and connects with the Kern River Pipeline at Daggett to form the Kern/Mojave Pipeline.

The Kern/Mojave interstate pipeline is referred to as a “bypass” pipeline. Bypass occurs when an interstate pipeline directly serves a customer without utilizing existing local distribution company facilities. In this way, customers can avoid the regulation of the CPUC, thus avoiding the regulated costs imposed on all users of a particular natural gas utility’s intrastate pipeline system.

Figure 4-1*



*** Lighter lines on map denote light colors that can be viewed in electronic version.**

Kern River and Mojave were the first interstate pipelines that came within the California border and thus were the first interstate pipelines in the State to bypass the intrastate system regulated by the CPUC. Before Kern River and Mojave, all the interstate pipelines ended at the California border and transferred the gas to a California utility pipeline.

The California gas utilities have a monetary incentive to limit interstate pipeline activity in California. They want to avoid bypass since a customer that does not utilize existing local distribution company facilities does not pay for those facilities. Nor do they pay for any of the overhead associated with taking service from the local distribution company.

Bypassing the interstate pipeline system has important consequences for pipeline capacity and expansions. For example, a customer that leaves the utility system no longer shares in the cost of operating that system. This can cause the rates for the remaining customers to increase. In contrast, a new customer can directly connect to an interstate pipeline thus avoiding connection to a gas utility system. Neither of these customers shares in the costs of operating the utility system. Avoiding these costs may explain in part the interest in Kern River by electric generation developers.

Bypass may also explain the reluctance of gas utilities, such as SoCal Gas, to invest in capacity expansion to eliminate bottlenecks on its system. As explained in the section on SoCal Gas in **Chapter 5**, SoCal Gas believes that there will be growth in gas demand by electric generators on bypass pipelines. SoCal Gas has used this rationale to justify its failure to begin making any investment to eliminate the bottlenecks on its system until April 2001.

Upstream Demand on Interstate Pipeline Capacity

Upstream demand on the interstate pipelines will reduce the flow of gas to California unless additional interstate pipeline capacity is built. Upstream users can displace California users because California noncore gas users have historically relied, for the most part, on short-term (one to two years) contracts to transport gas into the State. These short-term contracts generally have been either interruptible or recallable capacity from secondary markets, not firm uninterruptible capacity.

Since upstream users are signing firm, long-term contracts for transportation services, their demand for natural gas reduces capacity into California. In response, California noncore gas users have bid on new capacity expansion to secure firm long-term supplies. The Energy Commission should monitor the market for transportation services to determine whether California will continue to receive sufficient supplies of natural gas.

Interstate Pipeline Expansions

As previously discussed, increasing upstream demands for natural gas will decrease the flow of natural gas into California, unless new pipeline capacity is added. Market participants are recognizing the need for new capacity, as illustrated by recent “open seasons” to solicit interest in expansion of interstate pipelines. The market is displaying a keen interest with offered capacity being significantly oversubscribed. The details of the expansions are presented in **Appendix A**.

Any new pipeline capacity would be added to meet not only California’s needs but also the needs of neighboring states. Therefore, how much of the proposed

incremental interstate capacity additions will reach California depends on who contracts for the new capacity and what demand they intend to serve. Those winning bids for open season pipeline capacity may intend all or part of the new pipeline capacity to serve new power plants in Oregon, Washington, Nevada, and Arizona. New out-of-state gas-fired power plants may displace California gas fired plants or may create the need for peaking capacity, as opposed to base load capacity, in California.

California must rely on electric generators to obtain the necessary pipeline capacity to serve their units to assure that California can rely on in-state gas-fired generation. California's electricity system is part of an integrated western grid, which over time has provided significant opportunities to take advantages of economies of seasonal diversity and other variations between states throughout the West. Likewise, California is part of a regional natural gas market. This market determines the timing and extent of pipeline expansions and indirectly impacts the location of gas-fired power plants with assured supplies of natural gas throughout the West.

California needs to continuously monitor the expansion plans of interstate pipelines and determine whether California gas utilities, marketers and electric generators are securing sufficient supplies to meet California's needs for natural gas.

Chapter 5 – Intrastate Pipeline System

Overview

The following chapter addresses the existing intrastate pipeline system and the need for system expansions. Interstate pipeline systems bring natural gas supplies to the California border for delivery to the State's three natural gas utilities, PG&E, SoCal Gas and SDG&E. The receipt capacity for the gas utilities is shown in **Table 5-1**. These utilities have intrastate pipeline systems that deliver gas throughout their service areas to end-use customers.

The configuration and operations of these intrastate pipeline systems vary depending on the physical characteristics of loads and interstate pipelines, as well as the weather conditions that the natural gas system is designed to accommodate. The backbone system of the utilities consists of the gas transmission and storage facilities.

Table 5-1

California Receipt Capacity	**MMcfd**
PG&E	
Redwood- Malin	1,905
Baja Path Kern/River/Mojave (400) Needles (400) Topock (1,140)	1,140
SoCal Gas	
Needles	750
Hector Road	50
Topock	540
Ehrenberg	1,210
Mojave Needles (300) Topock (400)	400
Kern River	700
Total	**6,675**
Winter Receipts at Malin drop to 1,500 to 1,750 MMcfd due to increased demand in PNW Region. In addition to transmission listed there is approximately 1,000 MMcfd in California Production.	

The gas utilities have the responsibility to supply the needs of the core customers, the residential and small commercial and industrial customers, whose demand for natural gas increases in the winter as space heating needs increase. The gas utilities also have the responsibility to assure that the backbone system can accommodate the needs of all customers, both core and noncore. The actual acquisition and billing arrangements for the noncore customers are provided by the over 50 marketers serving California.

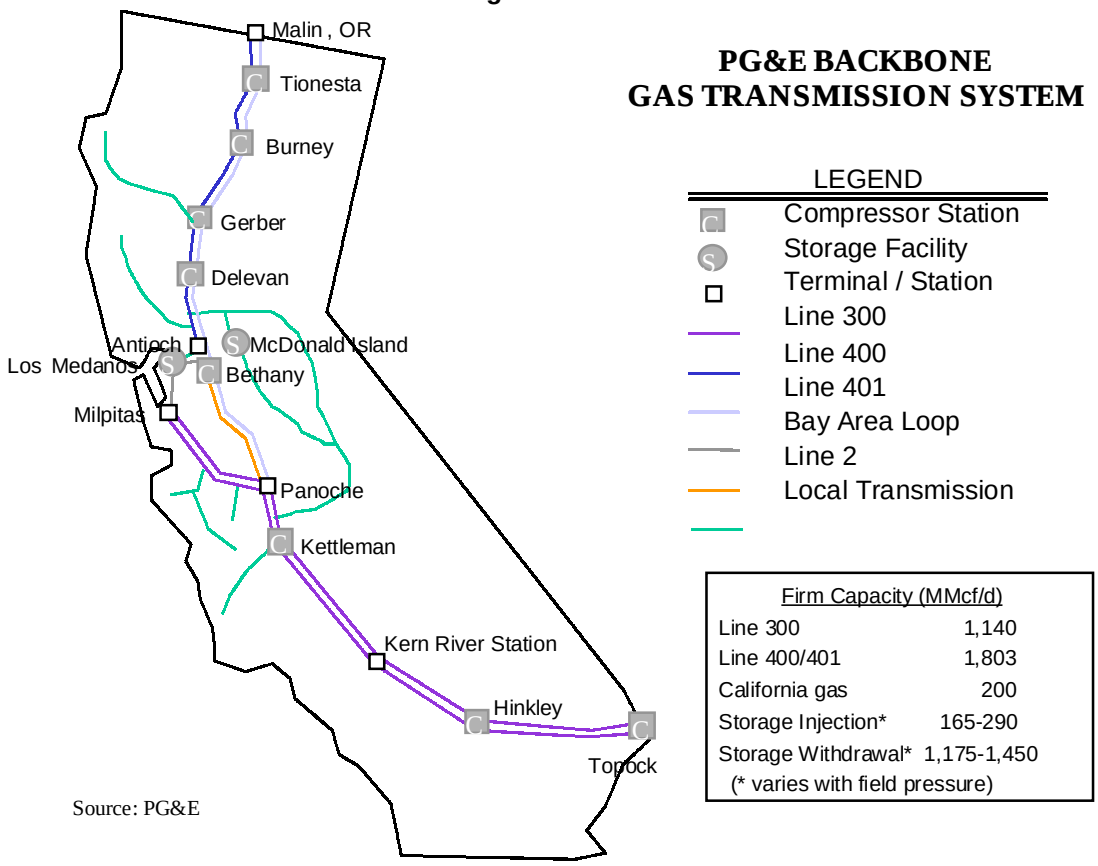
PG&E and SoCal Gas use a slack capacity standard to determine when to expand their backbone pipeline capacity. The CPUC defined slack capacity in its Decision 97-08-055 at page 777 as: "Slack capacity is capacity in excess of demand *needed* to generate the benefits of competition." (emphasis added) When demand equals capacity, there is no slack capacity. When there is no slack capacity, customers lose the benefits of competition, and prices increase overall or spike upward.

PG&E and SoCal Gas also determine whether they can recover their costs in rates from backbone expansions before making such investments. A regulatory approach that encourages such investment to assure slack capacity can mitigate or prevent the price spikes experienced this past year in California.

PG&E - California Gas Transmission System

Figure 5-1 shows a map of the PG&E Backbone Gas Transmission System. The 1140 MMcfd Line 300 originates at Topock and terminates in the San Francisco Bay area at Milpitas. The 1,905 MMcfd Line 400/401 originates at Malin on the Oregon border, with Line 400 terminating at Antioch and Line 401 terminating at Panoche. The third source of gas for PG&E is in-state production that is rated at 200 MMcfd.

Figure 5-1



At Malin, the GTN interstate pipeline from Canada and the PG&E Line 400/401 receipt pipeline are roughly matched. On the other hand, the capacity of the interstate pipelines delivering natural gas from the Southwest exceeds the receipt capability of PG&E's Line 300. PG&E has the option to take 300 MMcfd from Kern/Mojave at Daggett, 1,140 MMcfd from El Paso at Topock, and 225 MMcfd from Transwestern at Topock. The PG&E Line 300 receipt pipeline has a total capacity of 1,140 MMcfd, which is 525 MMcfd short of what PG&E could take if their system was expanded.

Table 5-2 shows the amount of capacity that PG&E has reserved for its core customers on its backbone system based on the PG&E Gas Accord (CPUC Decision #D.97-08-055). The capacity reserved for core customers on the Line 400/401 for receiving Canadian gas from GTN is 600 MMcfd. California production reserved for core customers remains constant year round at 50 MMcfd. The capacity reserved from Topock on Line 300 varies from 150 MMcfd in the low demand months to as high as 600 MMcfd in the winter months.

Table 5-2
Retail Capacity Allocation for PG&E System

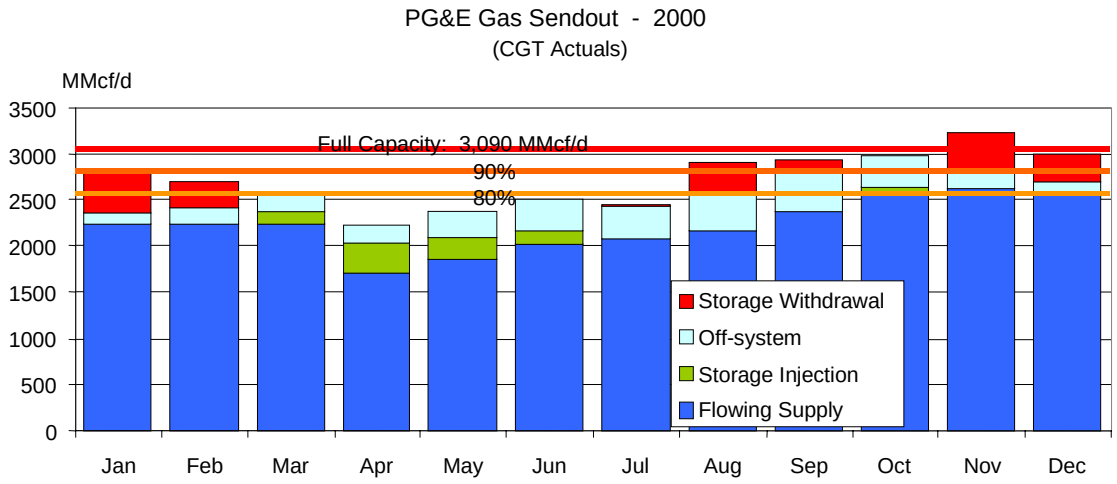
	Malin to On-System	Topock to On-System	California Production	Total
April to October	600 MMcfd	150 MMcfd	50 MMcfd	800 MMcfd
November to March	600 MMcfd	300 MMcfd	50 MMcfd	950 MMcfd
December to February	600 MMcfd	450 MMcfd	50 MMcfd	1100 MMcfd

PG&E has also agreed to allocate pipeline capacity to natural gas marketers for off-system deliveries. Recently, PG&E has been shipping from 300 to 400 MMcfd on Line 300 from Topock and Daggett to Wheeler Ridge on the SoCal Gas system. This gas is consumed by a cross-section of the SoCal Gas customers including core and noncore customers.

Various parties including municipal utilities, customers and marketers use the remaining capacity on the PG&E backbone pipelines after the core and off-system transportation capacities are subtracted form the PG&E backbone capacity. This capacity is available for these marketers and customers to use under a CPUC approved tariff to ship natural gas.

Figure 5-2 shows that in the year 2000 PG&E had no slack capacity. When presenting this slide at the January 25, 2001 Energy Commission hearings on siting constraints, PG&E testified about: "… the need to have slack capacity available to basically tone down the prices that we have seen from the commodity side of the market." (transcript p. 48) PG&E further explained: "…as you run the system tighter and tighter you're not leaving room to use storage or flowing capacity for arbitrage because essentially your system is full or very close to being full every day." (transcript p. 54)

Figure 5-2



Source: PG&E-California Gas Transmission

The drought-induced increase in electric generator demand for natural gas has eliminated the slack capacity on the gas pipelines in California. The result has been billions of dollars in increased costs of gas to consumers in California. This extraordinary expense brings into question the design criteria used by SoCal Gas and PG&E to assure the availability of slack capacity. If the utilities design their systems to have slack capacity available in an average year, what risks are California gas consumers undertaking? The Western United States is increasing its reliance on natural gas. This raises questions about how often there will be average hydro conditions, average summer and winter temperatures, average output from coal and nuclear electric plants, and average economic and population growth in the United States.

The design criteria currently used by SoCal Gas and PG&E were adopted when there was fuel switching capability and much less upstream demand. There is now sufficient justification to support a risk analysis of the California natural gas backbone infrastructure to determine under what circumstances slack capacity is warranted. No one questions that SoCal Gas is spending $14 million to partially de-bottleneck its system is justified when the lack of slack capacity is costing billions of dollars. Perhaps more such investment is needed.

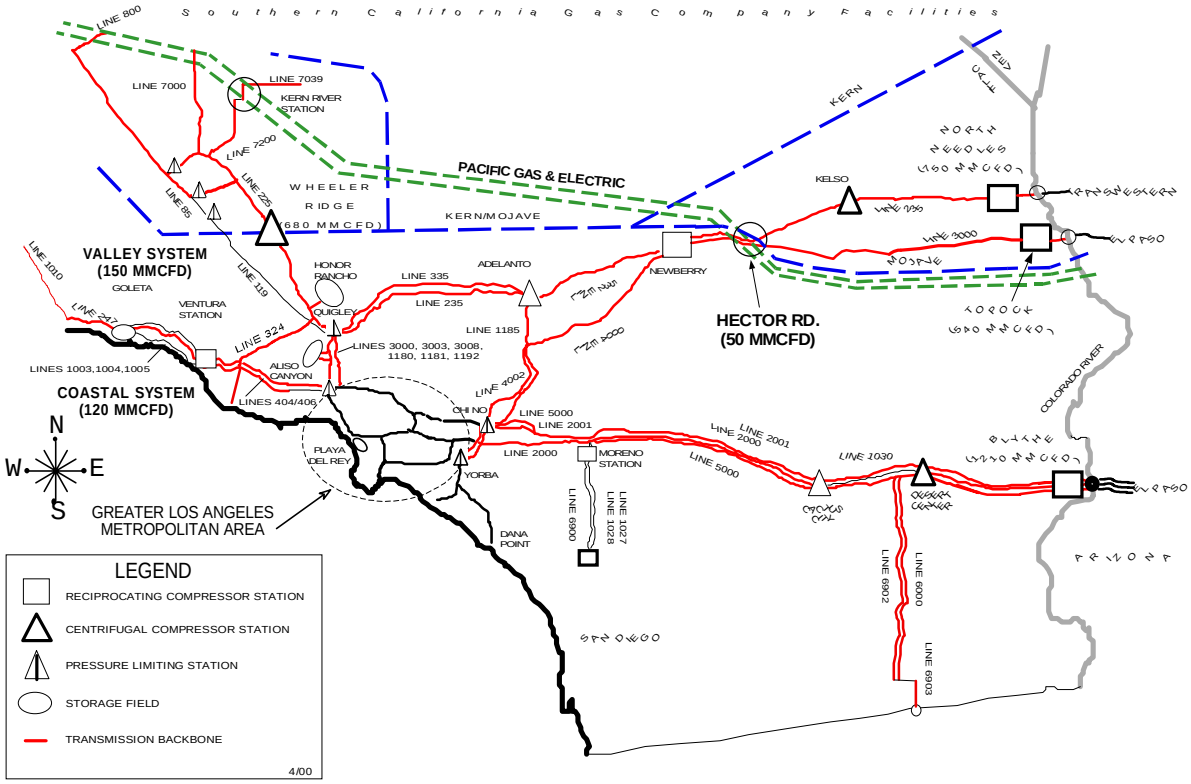
Proponents of the proposed interstate pipelines in all likelihood have estimates of the following: the probable future transportation premiums due to the aging of coal and nuclear units in the West; the population and economic growth upstream from California; the likelihood of summer heat storms; the potential freezing at gas wellheads in Canada and the Rocky Mountains; and other such events. California needs to assess the likely costs of such events and invest in the natural gas infrastructure needed to limit the future exposure of gas consumers.

SoCal Gas System

Figure 5-3 is a map showing the SoCal Gas system. The SoCal Gas system has 3,500 MMcfd of firm receipt capacity. In addition, SoCal Gas has access to 200 MMcfd of interruptible capacity. This added capacity, primarily at Ehrenberg and Wheeler Ridge, is available on cold days with high supplier pressure and high local demands.

The SoCal Gas storage fields are capable of storing a total of 105.6 Bcf of natural gas. The withdrawal rate for SoCal Gas is 3,200 MMcfd, of which 1,900 MMcfd is reserved for core customers. Together, storage and backbone can theoretically meet a 6,000 MMcfd peak demand day in January. The historical peak on the SoCal Gas system is 5,300 MMcfd.

Figure 5-3



NOT TO SCALE

Source: SoCal Gas Company

Table 5-3 shows the amount of capacity that SoCal Gas has reserved for its core customers on its backbone system. SoCal Gas sets the retail core firm receipt capacity to match the interstate core capacity of 1,044 MMcfd. To this is added 70 MMcfd from California natural gas production.

Table 5-3
Capacity Allocation for SoCal Gas System

Receipt Point	Total Firm Rights	Core Reservation	Firm Receipt Rights
Wheeler Ridge	680 MMcfd	-0-	680 MMcfd
Transwestern	770 MMcfd	285 MMcfd	485 MMcfd
El Paso Topock	520 MMcfd	333 MMcfd	187 MMcfd
El Paso Blythe	1210 MMcfd	374 MMcfd	836 MMcfd
Subtotal	3180 MMcfd	992 MMcfd	2188 MMcfd
California Line 85	150 MMcfd	-0-	150 MMcfd
California Coastal	120 MMcfd	70 MMcfd	50 MMcfd
CAT for Aggregators*	-0-	52 MMcfd	-0-
Total	3470 MMcfd	1114 MMcfd	2408 MMcfd
* CAT is the Core Aggregation Transportation program for SoCal Gas.			

Source: SoCal Gas Company

SoCal Gas designs its backbone system to maintain 15 to 20 percent slack capacity over projected demands, assuming normal weather conditions. This policy is consistent with the CPUC interstate pipeline interconnection policy as expressed in Decision 90-02-015. As explained above, slack capacity is needed for operational flexibility and to foster competition among gas suppliers.[13]

Current interstate delivery capability exceeds receipt capacity by about 300 MMcfd. If receipt capacity met or exceeded delivery capacity there would be greater operational flexibility on the California systems and more gas on gas competition for California. The deficit in receipt capacity contributes to the high prices of natural gas in California and the tight supplies to meet natural gas demand by electric generators.

Given the role of gas fired generators in creating the tight conditions on the SoCal Gas system, the Energy Commission and the CPUC should continue to investigate the benefits and costs of expanding the SoCal Gas backbone capacity.

One concern that SoCal Gas has regarding expanding its backbone system is the regulatory treatment given its last such expansion. In about 1993, the CPUC put SoCal Gas at risk for recovery of its investment in the Wheeler Ridge expansion. If volumes of gas flowing across the SoCal Gas system had not justified the Wheeler Ridge expansion, then SoCal Gas would not have fully recovered its investment.

The SoCal Gas is expanding its backbone system. SoCal Gas believes that the natural gas demand in its territory will decrease in the future due to: 1) a return to

[13] SoCal Gas testified at the January 25, 2001 Energy Commission hearing on siting constraints regarding slack capacity: "…we would not want to be operating with no less than 10 percent excess or slack capacity on a long-term basis, and we're going to continually look at that situation and we may decide to build more excess backbone capacity as a means of encouraging gas on gas competition in Southern California." (transcript p. 65)

average hydro conditions, 2) imports of electricity from out-of-state, and 3) increased pipeline bypass.

In mid-March 2001 SoCal Gas held a Capacity Forum to discuss with customers, producers, pipelines, marketers, and government agencies, thirteen proposed projects to increase its receiving capacity. Subsequent to this forum, SoCal Gas advised the CPUC in an April 2001 letter to CPUC President Lynch that they were going to implement three projects.

The letter indicted that by this coming winter, 175 MMcfd of new receiving capacity would be installed and 24 Bcf of gas already in storage would become useable. The projects proposed by SoCal Gas would increase firm receiving capacity by adding permanent compression at three sites. Capacity would increase 85 MMcfd at Wheeler Ridge, 50 MMcfd at Needles, and by 40 MMcfd from lower San Joaquin producers.

On May 15, 2001, SoCal Gas announced plans to construct a 32-mile pipeline link to the Kern-Mojave pipeline system that will allow it to deliver an additional 200 MMcfd into its system.

SoCal Gas has elected to move ahead with these projects and will seek rate recovery in its next biennial cost allocation proceeding (BCAP).

San Diego Gas and Electric System

SDG&E has no direct connection with any of the interstate pipelines. Instead, the SDG&E system receives its gas from its connection with SoCal Gas. Besides serving customers in its traditional service territory, SDG&E also delivers gas to Mexico for electric generation facilities at Rosarito Beach. Currently, SDG&E has a long-term contract with El Paso for 10 MMcfd of firm transportation capacity and for 52.5 MMcfd with GTN to serve core customers. SoCal Gas on behalf of the SDG&E receives supplies from these pipelines.

SDG&E has no storage inside its territory, although it does utilize the SoCal Gas storage. SDG&E is totally dependent on flow from SoCal Gas to serve the demands of its customers. The connection between the SDG&E system and the SoCal Gas system is rated at 575 MMcfd. This past winter, the demand on the SDG&E system exceeded that amount on 11 separate days. This required curtailing SDG&E's noncore customers including electric generators.

The recent stress on the SDG&E natural gas system is due both to high electric generator gas demand at Encina and South Bay and a recent pipeline extension into Mexico to provide gas to a generator at Rosarito. At present, the Rosarito facility draws from 30 to 70 MMcfd with a maximum of about 90 MMcfd. The maximum amount is projected to increase to 182 MMcfd when Rosarito III with a capacity of 550 MW becomes operational in 2002.

To alleviate the constraint on deliveries to SDG&E, SoCal Gas is increasing Line 6900 capacity to provide an additional 70 MMcfd of capacity in SDG&E. In addition, SDG&E could make internal adjustments to its delivery system that would increase its delivery capacity an additional 130 MMcfd. These adjustments could be operational for the summer of 2005.

The 130 MMcfd may not be needed if the North Baja Pipeline is constructed. For example, Otay Mesa has announced that it has applied to the Federal Energy Regulatory Commission for approval to construct a 100 MMcfd pipeline from its proposed electric generating facility in San Diego to Mexico.

As discussed in **Appendix A**, the North Baja pipeline is proposed to bring gas from the El Paso delivery point at Ehrenberg through Mexico and into the SDG&E system. Once completed, the North Baja pipeline will potentially relieve the natural gas capacity bottleneck for SDG&E.

The North Baja Pipeline may relieve SDG&E from the responsibility of delivering gas to Mexico plus delivering gas into the SDG&E system. However, it may divert enough gas from SoCal Gas to cause gas shortages in Southern California.

Chapter 6 – Natural Gas Storage

Overview

The following chapter addresses the natural gas storage issues and potential impacts of increased electric generator demand on meeting storage targets. Natural gas utilities typically rely on natural gas from storage to augment supplies flowing through the pipeline system to meet total natural gas demand throughout the year. A natural gas system designed to meet the peak demands that does not include the ability to draw on storage would be significantly more costly than the current system. This happens because at many times of the year there would be substantial amounts of unused pipeline capacity. This unused capacity would not generate sufficient revenues to cover investments in pipelines and related facilities.

Consequently, California's existing natural gas pipeline system is designed to meet peak demands by drawing on additional natural gas supplies from storage facilities. Without storage, the gas utilities would literally be unable to meet demand on the peak winter day. Storage is essential to meeting natural gas demand in California.

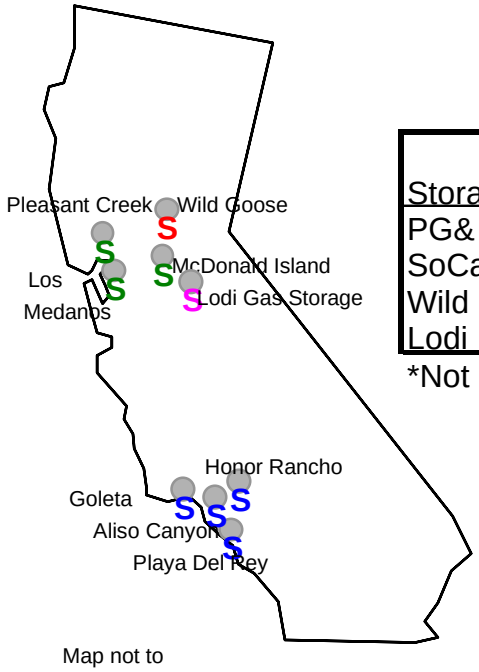
In the summer of 2000, increased electric generator demand for natural gas stressed the natural gas system in California. Both PG&E and SoCal Gas were forced to draw on storage to meet the high electric generation gas use. In addition, California experienced extremely cold weather in November 2000 that placed additional demands on gas in storage. As a result, both PG&E and SoCal Gas drew heavily on their storage resources during this past winter. These high levels of demand for natural gas and reliance on storage are expected to continue in 2001.

Therefore, there is a need to determine whether there will be sufficient gas storage in California to serve the needs of the core customers and the year-round needs of electric generators.

Storage Facilities

Figure 6-1 shows the location of the underground storage facilities in California. The figure also shows the storage capacity, maximum injection, and withdrawal rates for PG&E, SoCal Gas, Wild Goose and Lodi Gas. Wild Goose and Lodi Gas are privately owned storage facilities. The storage facilities are depleted oil and gas fields that have been modified to allow both injection and withdrawal of gas.

Figure 6-1



Storage	Storage	Max (MMcfd	Max (MMcfd
PG&	98	375	153
SoCalGa	105	800	320
Wild	14	80	200
Lodi	*12*	*400*	*500*

*Not operational

As shown on **Table 6-1**, PG&E has the ability to store annually about 98 Bcf of natural gas of which 33 Bcf is reserved for core customers. SoCal Gas can store about 105 Bcf of natural gas, of which 70 Bcf is reserved for core customers.

Table 6-1
Natural Gas Storage Information

Storage Facilities	**Annual Cycle Capacity Bcf**		**Injection Capacity MMcfd**		**Withdrawal Capacity MMcfd**	
	Core	Total	Core	Total	Core	Total
PG&E	33	98	200	250	1,006	1,534
SoCal Gas	70	105	327	800	1,985	3,200
Wild Goose		14		80		200
Lodi Gas		*12*		*400*		*500*

Wild Goose and Lodi Gas Field are unregulated natural gas storage fields
Lodi Gas Field is expected to be operational by December 2001.

In addition to utility storage facilities, there are two relatively new independent storage facilities that are considerably smaller than the utility storage facilities. The Wild Goose facility is now operational. Noncore natural gas customers, such as industrial and electric generators, could use these facilities to store gas for use during their peak periods.

Proposed Expansions

SoCal Gas intends to modify its Aliso Canyon and La Goleta storage fields to add 14 Bcf in storage for the winter of. The modifications would shift gas currently used to maintain pressure to gas available for withdrawal.

SoCal Gas will also have available 10 to 12 Bcf due to the abandonment of the Montebello storage facility as the gas is withdrawn. However, once withdrawn, this storage facility will be closed and no longer be available for storage.

PG&E is currently considering expanding the withdrawal rate from McDonald Island storage facility by 400-600 MMcfd. The expansion would depend on the installation of a new pipeline from the storage field to the PG&E system.

A private entity is developing the Lodi Gas storage facility in Lodi, California, in the PG&E service territory. If permitted and constructed, this facility would add 12 Bcf in storage capacity to northern California. The Wild Goose storage facility operator has announced its intentions to expand from 14 to 38 Bcf by spring 2003.

Storage Operations

This section discusses the outlook for meeting core storage needs for the winter. Each of the storage injection graphs is based on a monthly natural gas supply and demand analysis. Daily and hourly balances could be considerably different due to changes in weather, availability of electric imports and natural gas supply, and unscheduled maintenance needs for electric and natural gas facilities. The storage injection season begins on April 1 and extends until October 31.

Historically, natural gas injection into underground storage facilities begins in the spring and continues though the fall months when gas demand is the lowest. Besides injection capacity, the limit to placing gas into storage is the availability of unused pipeline capacity. Unused pipeline capacity is generally available after winter demand has dropped to lower levels. This unused pipeline capacity is usually available in the spring and fall and on low demand days in the summer.

This past year is a good example of the need to have natural gas in storage. From the first of November 2000 until February 2001, PG&E and SoCal Gas withdrew over 90 Bcf of gas from storage. Without the gas in storage, 775 MMcfd of noncore customer gas use on average would have been curtailed. If only electric generators had been curtailed, that is equivalent to about 3,000 MW. In an actual curtailment, a mixture of industrial customers and electric generation would have been curtailed due to lack of fuel.

Year 2001 Natural Gas Storage Needs

To assess potential demand for natural gas for the next year, the Energy Commission has prepared a monthly natural gas demand forecast for the natural

gas utility service areas. The forecast extends from May 2001 through December 2001. It includes core, noncore, and electric generation. Two scenarios were developed to analyze policy alternatives. The first is a base case that reflects average summer temperature conditions. The second is a high gas use case that assumes a hotter than average summer resulting in increased demand for natural gas by electric generators.

Assumptions

The residential, commercial and industrial demand forecasts for each of the natural gas service areas was derived from the Energy Commission staff forecast published in June 2000.[14] For the purposes of this analysis, residential and commercial were considered core and industrial was considered noncore.

An average of 350 MMcfd in deliveries to the SoCal Gas Service area at Wheeler Ridge was added to the PG&E demand. This 350 MMcfd reflects contractual commitments by PG&E to transport gas across its system to the SoCal Gas system.

The electric generator gas demand was estimated using the following assumptions. The electrical and natural gas demand for residential, commercial and industrial customers for each of the natural gas service areas was derived from the Energy Commission staff forecast published in June 2000. The June 2000 forecast assumes average weather conditions for 2001. Comparisons between forecasts and historical experience may be affected by differences between average and actual weather conditions.

The resources available in the base case assume hydro conditions based on estimates made in March 2001 regarding snow pack and rainfall expected for the remainder of the season, one unit at SONGS out until mid-June and no gas fired plants shut down for air emission control retrofits this year.

The resources available in the high gas use case assume that hydroelectric output in California and British Columbia is less than the base case. In addition, 3,000 MW and 1,500 MW of QF capacity is off line between April 1 and May 30 and June 1 through December 31 respectively. Finally, the ISO schedule for air emission control retrofits is assumed.

Pacific Gas and Electric Assessment

There are three operational issues facing natural gas storage in the PG&E service area. They are financial, physical, and deregulation.

[14] California Energy Commission Staff Report, California Energy Demand 2000-2010, June 2000, #P200-00-002

The preliminary staff analysis indicates that PG&E should have enough pipeline capacity between April 1st and October 31st to inject gas to meet the storage needs of the core and noncore sectors. Based on the Energy Commission's monthly analysis, the storage injection could be at a lower rate and still meet core storage targets.

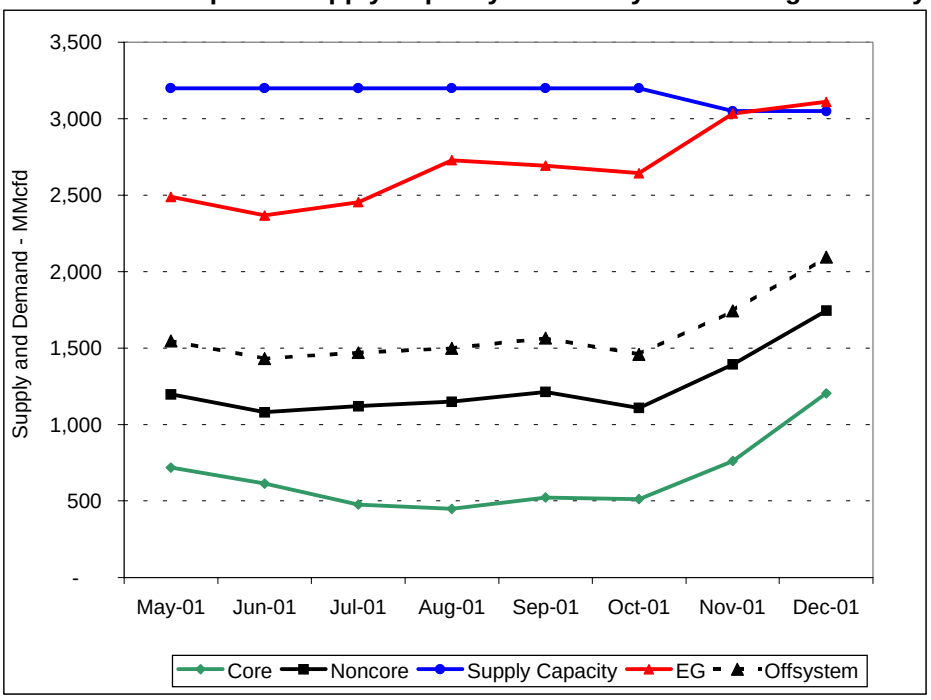
Monthly Analysis

Figure 6-2 shows the monthly natural gas demand by sector in the PG&E service area. PG&E's 3,200 MMcfd supply capacity is also shown on the figure, which consists of California production and pipeline capacity to receive natural gas from interstate pipelines. In the winter months the supply capacity dips due to upstream demands in the Pacific Northwest that reduce the ability to deliver natural gas to California.

Residential and small commercial and industrial customers are included in the core sector. Noncore comprises the large commercial and industrial customers. PG&E also makes off-system deliveries to SoCal Gas at Wheeler Ridge. All the electric generation is included in the electric generation demand forecast.

The area under the supply capacity indicates the opportunities to place natural gas in underground storage facilities. The plot indicates the probability will be high that pipeline capacity will be available for storing natural gas.

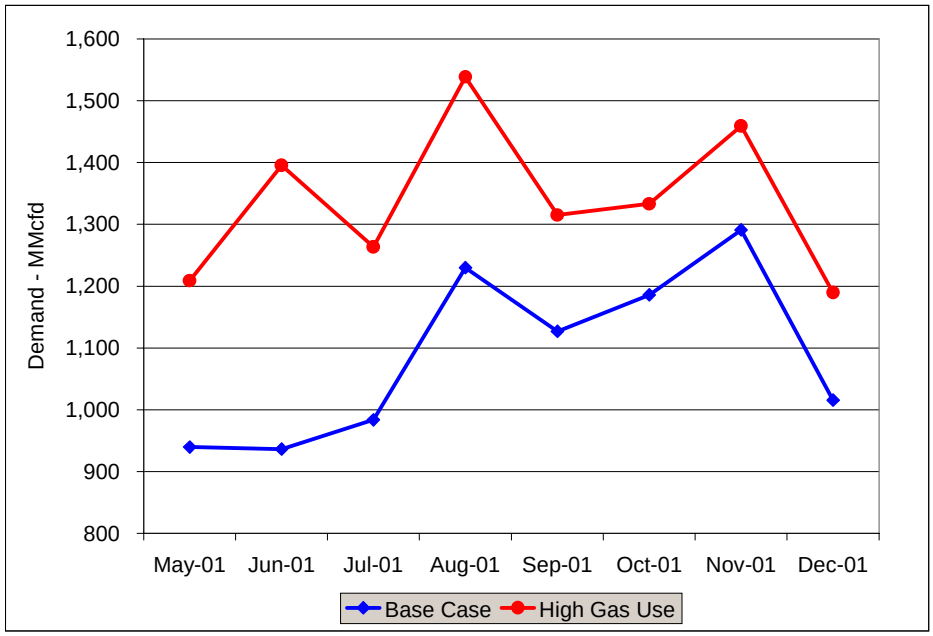
Figure 6-2
PG&E Demand and Pipeline Supply Capacity – February 2001 Though January 2002



To test the sensitivity of these results, a high gas use case scenario was calculated. **Figure 6-3** shows the comparison of the estimated natural gas

demands by electric generators served by PG&E under the base case and high gas use scenarios. As the figure shows, during the summer months, gas usage by electric generators could be 25 percent higher than the base case.

Figure 6-3.
2001 Electric Generation Scenarios – PG&E



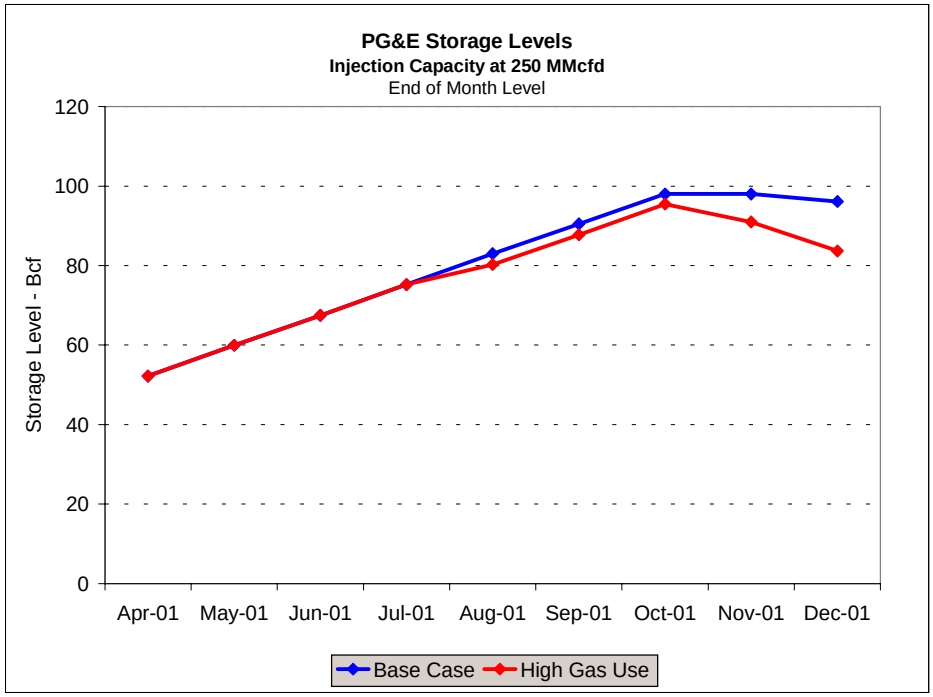
PG&E needs to place 33 billion cubic feet (Bcf) in storage for its core customers by October 31, 2001. **Figure 6-4** indicates that, assuming a 250 MMcfd injection rate, PG&E will be able to physically reach its core storage level by as early as July. The figure also indicates that, even in the high gas use scenario, PG&E will still be able to meet 2001 core and electric generation needs for storage. This scenario assumes that noncore customers actually inject gas into storage.

Figure 6-4 indicates that over 500 MMcfd of pipeline capacity is projected to be available in the base case to provide supplies of gas for injection into storage. Thus, even in the high gas use case, it should be physically possible for PG&E to store over 90 Bcf of gas for this coming winter of 2001-02.

Although PG&E appears to have the physical ability to meet noncore customer storage needs, financial questions cloud the picture. On April 6, 2001, PG&E filed for Chapter 11 reorganization in federal bankruptcy court. It is too early to tell whether the bankruptcy proceedings will affect the ability of PG&E to purchase gas for storage or the willingness of noncore customers to use PG&E storage facilities.

PG&E is required to store gas during the summer to meet the needs of core customers in the winter. Because of deregulation, noncore customers have the freedom to elect to pay for the storage of gas. They may use either a PG&E or a private storage facility. In the summer of 2000, electric generators elected not to fully utilize the PG&E storage capacity available to them.

Figure 6-4.
PG&E End of Month Storage Levels – April 2001 through December 2001



This decision by the electric generators not to fully use available storage in the summer of 2000 put pressure on the natural gas infrastructure in the winter of 2000-01 and contributed to higher prices of natural gas for all consumers in California. If the winter of 2000-01 had been slightly more severe, the failure of the noncore customers such as the electric generators to store gas could have lead to curtailments during the latter months of this past winter.

The operator of the Wild Goose facility reports that space in its storage facility is completely subscribed for this summer. Continuing to monitor noncore customer usage of the Wild Goose and PG&E storage facilities is warranted, especially for electric generators.

Southern California Gas Assessment

Two operational issues face natural gas storage in the SoCal Gas service area. They are physical and deregulation.

For SoCal Gas, the problem in getting sufficient natural gas into storage will be finding the physical space on the pipelines. The preliminary staff analysis indicates that SoCal Gas should have enough pipeline capacity between April 1 and October 31 to just barely inject gas to meet the storage needs of the core and noncore sectors.

Monthly Analysis

Figure 6-5 shows the monthly natural gas demand by sector in the SoCal Gas service area, which includes service to SDG&E and to the Mexican power plant at Rosarito Beach. SoCal Gas has the firm capacity to receive 3,500 MMcfd, consisting of California production and pipeline capacity from several interstate pipelines and PG&E. If the interstate pipelines are able to maintain high delivery pressures, So Cal Gas can receive in excess of 3,700 MMcfd. That has been the case during March. It has been assumed that supply will drop to 3,600 MMcfd through May and then return to 3,700 MMcfd through November when expansion projects increase capacity to 3,875 MMcfd.

Residential and small commercial and industrial customers are included in the core sector. Noncore comprises the large commercial and industrial customers. All the electric generation is included in the electric generation demand forecast.

The area under the supply capacity indicates the opportunities to place natural gas in underground storage facilities. The plot indicates the probability will be high that there will be just barely enough pipeline capacity available for storing natural gas.

Figure 6-5
SoCal Gas Demand and Supply Capacity – February 2001 though January 2002

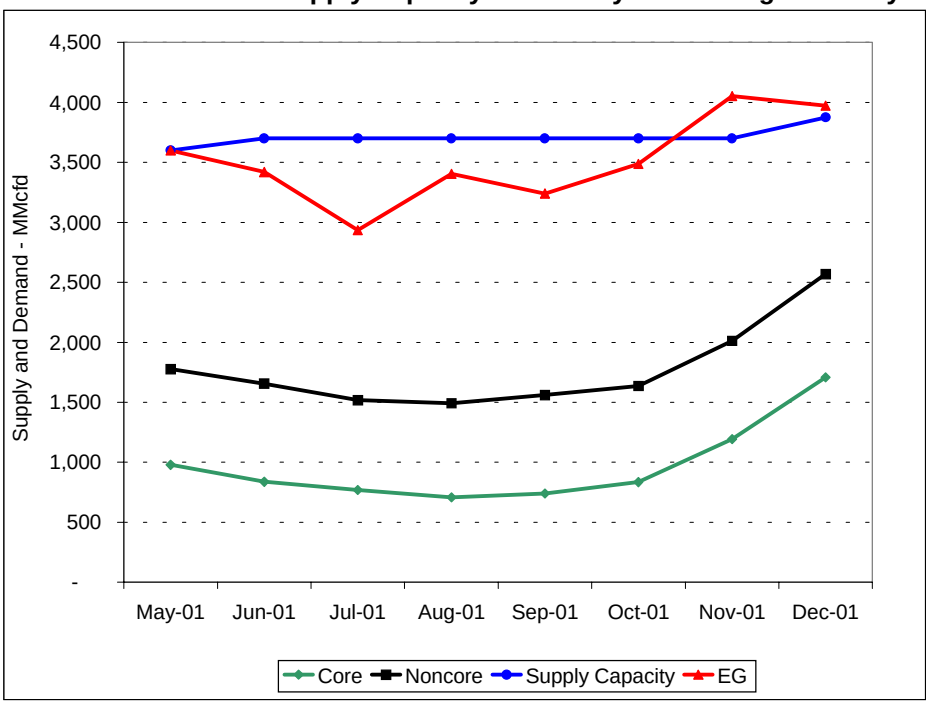
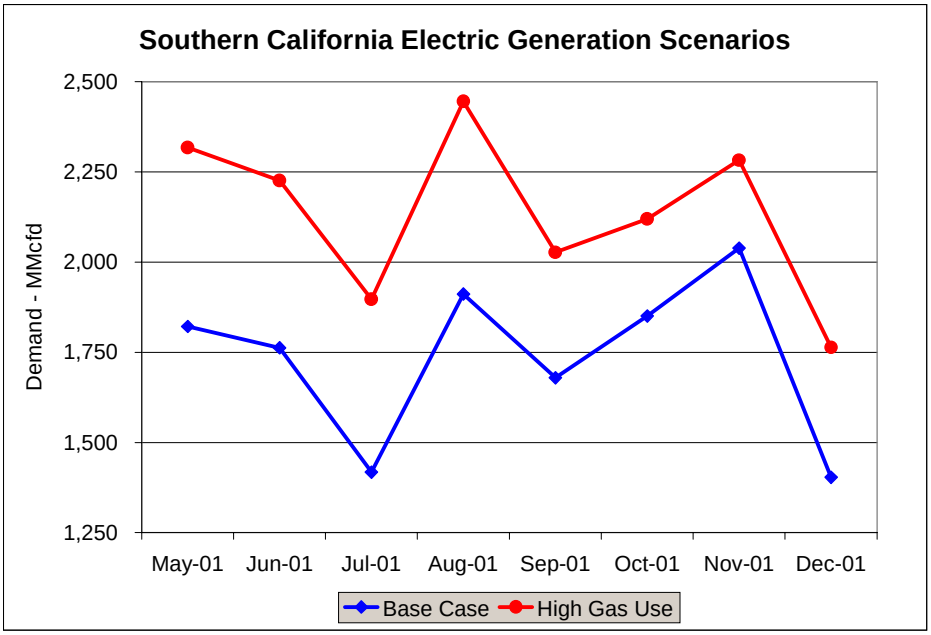


Figure 6-5 forecasts high natural gas demand for the Southern California region throughout the year. SoCal Gas should be able, during the summer months, to store the natural gas need by the core and noncore customers for the winter. During the winter months, gas from storage will be needed to meet the core heating needs and to prevent curtailment of electric generators on the coldest days of the winter.

To test the sensitivity of these results a high gas use scenario was calculated. **Figure 6-6** shows the comparison of the estimated natural gas demands by electric generators served by SoCal Gas (includes SDG&E and Rosarito Beach) under the base case and high gas use scenarios. As the figure shows, during the summer months, gas usage by electric generators could be over 25 percent higher than the base case.

Figure 6-6
2001 Electric Generation Scenarios – SoCal Gas



SoCal Gas has more flexibility than PG&E to meet its core storage requirements. At 800 MMcfd, its injection capacity is considerably higher than PG&E's. At the core injection allocation of 327 MMcfd, it would take 214 days to place core's 70 Bcf into SoCal Gas's storage facilities. This is the length of time between April 1 and October 31. However, to accelerate the process of reaching the core target, SoCal Gas can inject more than 327 MMcfd whenever the noncore customers are not using their full allocation.

SoCal Gas and PG&E have nearly the same capacity to receive gas into their service areas. But SoCal Gas has nearly twice as much in place gas-fired generation as PG&E. This higher demand caused SoCal Gas's natural gas

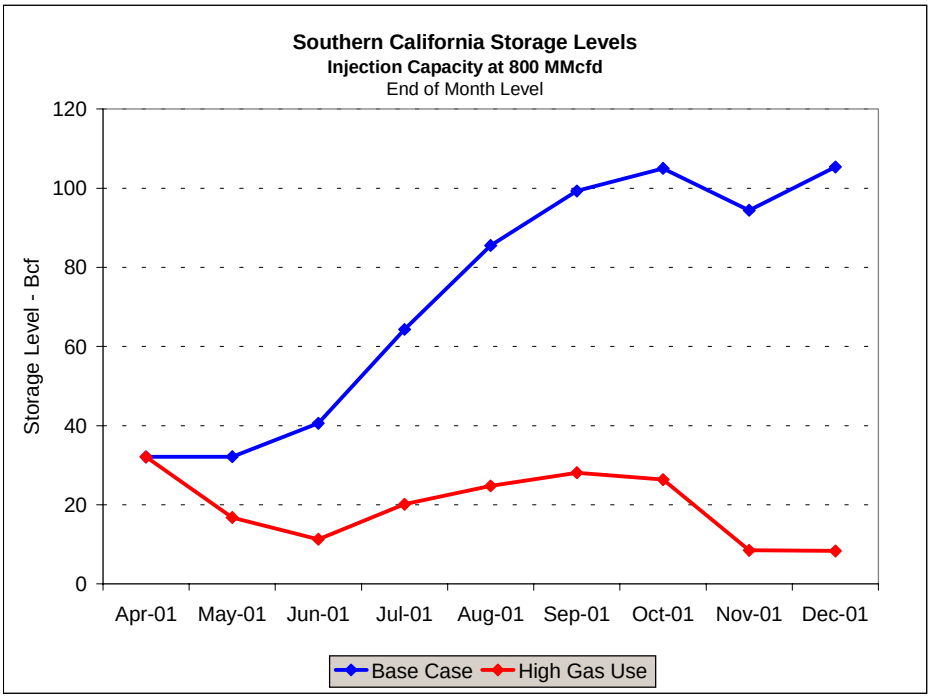
supply receiving capability to operate at or near capacity since the early part of the 2000 summer. It appears that the SoCal Gas system will continue to be stressed into the summer of 2001.
The current Energy Commission base case analysis indicates that SoCal Gas will be able to meet its core and noncore storage requirements. This analysis assumes that SoCal Gas and the noncore customers fully utilize spare pipeline capacity to maximize storage injections. Because of partial deregulation that SoCal Gas system operates under, noncore customers who have elected to purchase their own gas must decide whether they will use the available storage.

High electric generation natural gas demand during the spring months precludes SoCal Gas from making normal injections for gas storage. There are two apparent causes for this. First, one of the SONGS generation units is down for unscheduled repairs and will not be available until at least early June. Second, because of the expected reduction in the Columbia River generation, BPA will not have the normal amount of short-term electricity for LADWP.

The strain on the Southern California gas-fired generators is reduced in June, leading to the ability to place gas into storage. The strain is reduced because of the return of the SONGS unit currently off line for repairs and due to the startup of new efficient gas fired generators in California that displace output from some of the older, less efficient gas fired units.

Figure 6-7 indicates, in the high gas use scenario, SoCal Gas will not be able to inject sufficient gas into its storage facilities to meet the winter core storage requirements. SoCal Gas needs 70 Bcf in storage by October 31 of each year to meet its system design criteria for winter service to core customers.

Figure 6-7
SoCal Gas End of Month Storage Levels – April 2001 through December 2001



As the **Figure 6-7** shows, in the high gas use case, SoCal Gas would have slightly over 20 Bcf in storage by October 31 of this year. Under these circumstances, SoCal Gas will have to determine whether it would need to curtail noncore customers in the fall months so that it could place the additional gas into storage for core use later in the winter.

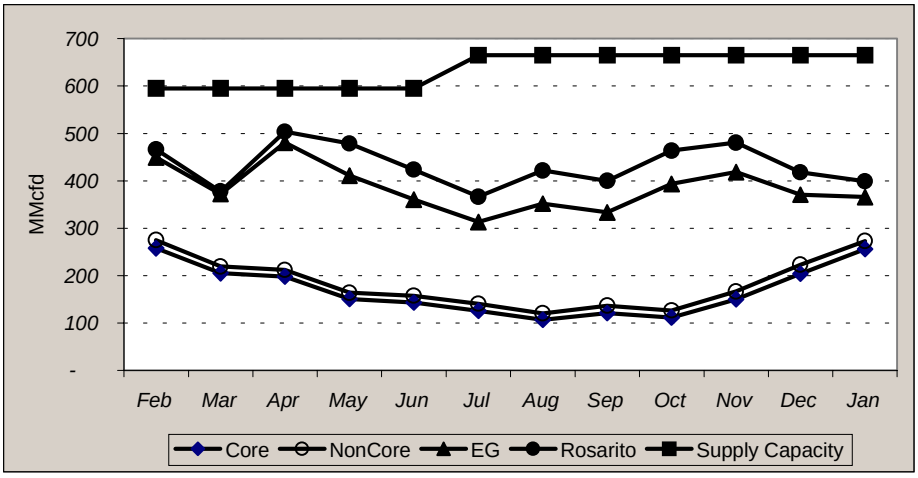
If a scenario similar to the high gas use case were to occur and southern California were to experience just an average winter, SoCal Gas would most likely have to curtail all noncore customers on the coldest days in January and February 2002. With only about 6.0 Bcf left in storage at the end of December, there would be less gas in storage than would be used during a cold week in January.

SDG&E Service Area Assessment

Monthly Analysis

Figure 6-8 shows the monthly natural gas demand by sector in the SDG&E service area. SoCal Gas delivers all the supply to SDG&E. This includes service to the Mexican power plant at Rosarito Beach. SDG&E currently has firm capacity to receive 595 MMcfd. By the end of June this should have increased by 70 MMcfd to 665 MMcfd.

Figure 6-8
SDG&E Demand Supply and Demand Capacity



On a monthly average basis there would be sufficient supply to meet the natural gas demand. There is no underground natural gas storage available in the service area.

Natural Gas Curtailments

Under the high gas use scenario for electric generator demand, curtailments and diversions of natural gas will be necessary this summer and into the winter of 2001-02. The existing curtailment scheme is based on the original design criteria of the natural gas system as a whole: that core industrial and electric generation customers have fuel-switching capabilities. This old assumption no longer holds true. These noncore customers have increasingly relied on natural gas over the last 20 years and use of fuel oil or other petroleum products have been virtually eliminated.[15]

The CPUC has an open proceeding to examine current natural gas curtailment policies and practices. In general, existing natural gas curtailment rules for PG&E and SoCal Gas were developed for cold winter conditions. In addition, the current rules call for pro-rata curtailment and diversion of gas from noncore customers when supplies are insufficient to meet winter core peak demand. This means that a set percentage of each customers needs would be not be met, with the percentage of needs that go unmet continuing to ratchet down, until core needs are met.

There is growing recognition that existing curtailment rules do not factor in the current realities of the market. Diversion or curtailment of natural gas supplies for electric generators could contribute to summer electric system reliability problems exacerbating rolling blackouts. In addition, curtailment of natural gas

[15] There are four gas-fired generators in California that still have the ability to switch to petroleum fuels including the Humboldt plants on the Northern California coast, the Potrero plants in the Bay Area, and South Bay and Encina plants in the San Diego Area.

supplies for industrial customers could exacerbate the economic impacts of anticipated rolling blackout on their production.

Some electric generators have filed testimony in the CPUC proceeding calling for modification of curtailment rules that would allow electric generators to be served. Under this scheme other noncore customers, including industrial customers, would be curtailed before the electric generators were looked to for curtailments or diversions. While this would help reduce the possibility of rolling blackouts this summer, it also appears to impose unfair economic consequences on industrial customers and the economy as a whole.

One option that might lessen the consequences of natural gas curtailments on both electric generators and industrial customers is a curtailment rule that is tied to the efficiency of the electric generators. Under such a rule, generators with the highest heat rates, the least efficient generators in the system, would be curtailed first. The generators with the lowest heat rates, the most efficient generators on the system, would be the last to be curtailed. This curtailment scheme would result in more efficient use of natural gas in the two gas utility systems, thereby conserving more of the available natural gas supplies for use by industrial customers. This would also provide air quality benefits as the least efficient plants also tend to be the most polluting plants.

The Energy Commission and the CPUC should work together to see that such an efficiency scheme for natural gas curtailments in developed for use this summer and for the winter of 2001-02.

Rebundling Utility Storage Functions

Under the “unbundled” environment in California, noncore customers, such as electric generators, can use a portion of utilities' storage facilities for their own use. In return for that flexibility, noncore customers are required to more closely balance the amount of natural gas nominated and the amount that is actually consumed. As storage levels decline, balancing requirements also tighten, increasing the penalties for non-compliance. During peak generating days, generators are willing to pay these penalties since the added costs can be recouped through prices charged for electricity.

The Energy Commission and CPUC should investigate rebundling each gas utility’s noncore storage function. This would allow utilities to optimally use its entire storage inventory to meet peak needs. In addition, it would allow utilities to allocate rebundled storage costs to all customer classes, which would be offset by less volatile spot market prices.

Encouraging Independent Gas Storage Facilities

Noncore customers can currently store gas in independent storage facilities in Northern California with now open Wild Goose storage facility and the Lodi storage facility expected to be operational later this year. However, there are

currently no independent storage facilities in Southern California. Noncore customers can currently store gas in independent storage facilities in Northern California with now open Wild Goose storage facility and the Lodi storage facility expected to be operational later this year. However, there are currently no independent storage facilities in Southern California.

The Energy Commission and the CPUC should jointly investigate the prospects for developing additional independent storage facilities throughout the State, but especially in Southern California where none currently exist. Noncore customers who choose to inject and withdraw natural gas from storage for economic reasons would be free to use these facilities for these purposes. This would allow the gas utilities to optimize their storage, including noncore portions, to meet peak demands.

Chapter 7 – Natural Gas Prices

Overview

This chapter addresses natural gas pricing issues. In 2000, natural gas prices rose dramatically throughout the United States as a result of increased wellhead prices. In addition, gas prices at the California border rose at a much higher rate than experienced in other parts of the country. The dramatic increase in California was caused by premiums that marketers were able to charge for transporting gas to California.

Inadequate infrastructure contributed to the higher natural gas prices paid in California. Market participants may have manipulated prices even higher than justified by existing bottlenecks, but the inability to use gas-on-gas competition contributed to the high gas prices.

During 2000, gas prices increased in part because of a drop in drilling rigs in use in the United States during 1999, interstate pipelines serving Southern California were fully utilized, intrastate pipelines in Southern California were bottlenecked, and storage facilities were stressed in Southern California and underutilized in Northern California. The number of drilling rigs is increasing, interstate pipelines are expanding capacity, the bottleneck in southern California is being partially removed, and storage facilities throughout California are being expanded and more fully utilized.

These efforts will take time. Over the next several years, California should begin to see natural gas prices decrease at the wellhead and premiums for transportation either reduced or eliminated. Efforts to accelerate this process could save billions of dollars for California consumers.

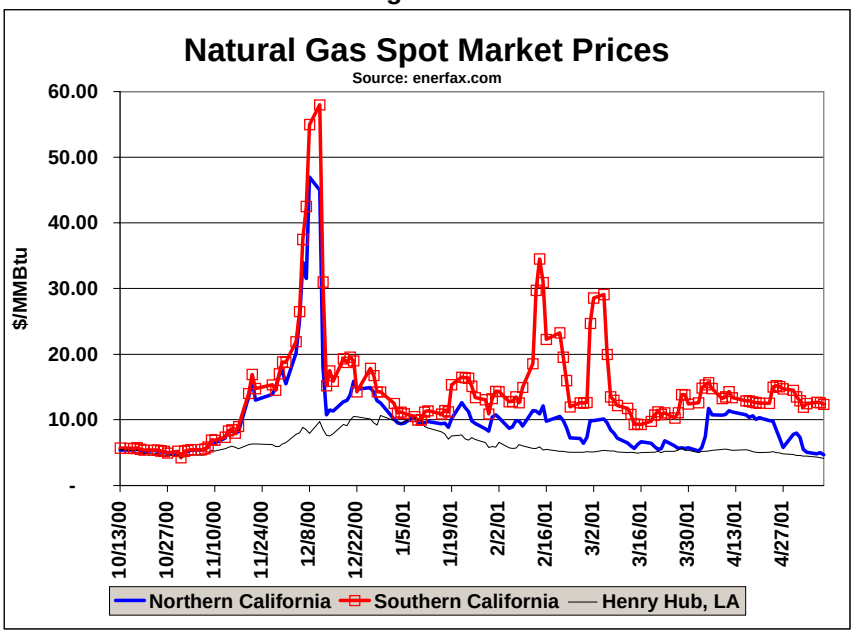
Natural Gas Prices

Figure 7-1 compares natural gas volume-weighted average spot prices at Henry Hub in Louisiana with prices posted at Topock and Malin. Henry Hub is a major gas hub and commodity futures contracts for gas at Henry Hub trade on the New York Mercantile Exchange. As shown in the figure, prices at the California border have spiked significantly during peak demand days. This phenomenon is expected to continue throughout 2001 and may continue through next winter and beyond.

Topock and Malin are the trading hubs at the California-Arizona and California-Oregon borders respectively. The higher prices at Topock reflect in part the bottleneck caused by the inadequate receipt capacity in Southern California. The higher prices at Topock also reflect the greater concentration of gas-fired power plants in Southern California and the high utilization of the interstate pipelines serving Southern California. Another factor was the 1999 El Paso interstate pipeline explosion that limited the amount of gas flowing to California from the

Southwest. High Topock prices may also reflect price manipulation by marketers that control the rights to ship on those pipelines.

Figure 7-1



Natural Gas Price Components

Given the integrated nature of the natural gas infrastructure, natural gas prices in California are impacted by prices in other parts of the United States and Canada. Wellhead production in West Texas affects California gas prices, as does production in the Gulf Coast, Canada, and the Rocky Mountains.

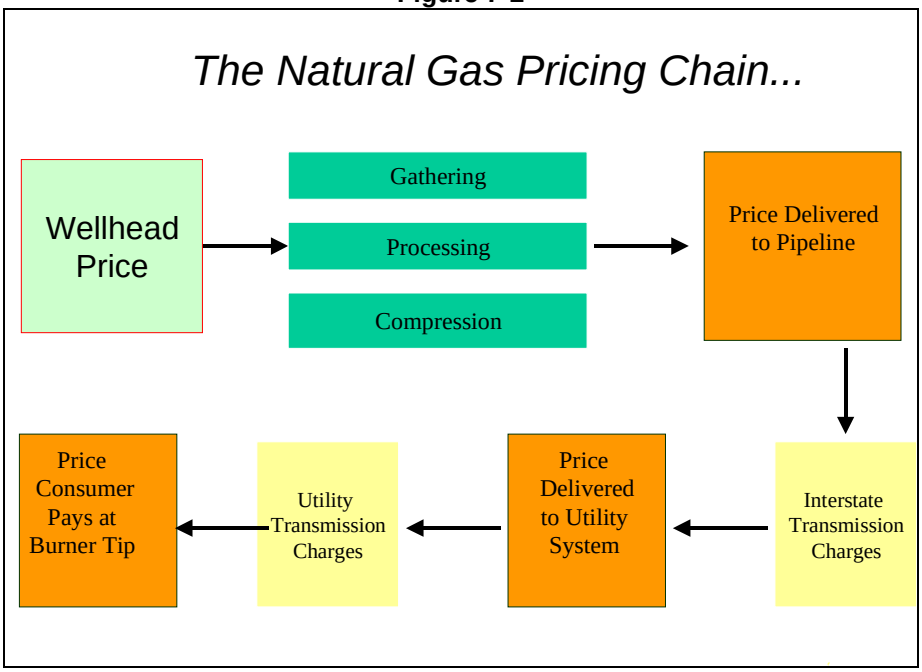
California gas prices are also affected by transmission charges levied by the many interstate pipelines delivering natural gas from the wellhead to California, as well as the transmission and distribution charges assessed by utility and non-utility distributors inside the state.

Figure 7-2 illustrates the natural gas pricing chain described above. Gas that is produced in the production basin is referred to as wellhead production. The gas is then processed to ensure pipeline quality gas enters the gas system, compressed and then delivered to the gathering system attached to the gas pipeline network.

The resulting *Price Delivered to the Pipeline* is the price of natural gas delivered to an interstate or intrastate pipeline once the gas has been produced, treated, and gathered. For gas moving to California, it represents a price in the Rocky Mountains, the San Juan Basin, the Permian Basin, or Western Canada.

Normally, interstate pipeline transmission charges are added to the wellhead price to obtain the California border price. Subsequent additions accounting for utility transmission and distribution costs will eventually produce a price that each consumer will pay for using gas, with variations based on the customer classification.

Figure 7-2



Before 2000, natural gas wellhead prices were generally around $2.00 per MMBtu and included the cost of production plus some rate of return on investment. Gathering, processing, and compression usually added around $0.12 per MMBtu, with transportation to the California border ranging from $0.40 per MMBtu to $1.00 per MMBtu. Utility transmission and distribution charges run another $0.25-0.50 per MMBtu for larger customers and $2.00 per MMBtu to $4.00 per MMBtu for smaller customers. In total, the price at the burner tip in California typically ranged from about $2.75 to $5.10 per MMBtu depending on customer size and location.

2001 California Natural Gas Prices

The average price for natural gas paid by California consumers increased roughly 70 percent from December 1999 to December 2000. The average price paid by PG&E residential customers increased about another 60 percent from December 2000 to January 2001.

The average prices paid by commercial, industrial and electric generator gas consumers is not currently, publicly available. At this time, these customers can buy their own gas supplies and are not required to report the prices they pay for

natural gas. Beginning in May 2001, the Energy Commission begins collecting price data from gas marketers serving California.

In the interim it is evident that natural gas became considerably more expensive in California beginning in early 2000, jumped in the summer of 2000, and drastically increased in late 2000 and early 2001. Evidence to support this price pattern can be found in the average city-gate[16] price in California in 2000. The average California city-gate price in 1999 was $2.61 per cubic foot (cf) of gas. By March 2000, that price had increased to $2.90 per cf, increasing to $4.70 per cf by July. By December 2000, the city-gas price had reached $7.30 per cf.[17]

The city-gate price represents the price paid by gas utilities for supplies acquired on behalf of their core customers. To determine the prices paid by core customers, utility charges must be added to the city-gate price. For a residential customers in California this adds roughly another $3.00 per cf to the cost of gas.

Factors Affecting California Natural Gas Prices

In today's environment, the level of these price components described in the previous section does not hold for the wellhead price or the interstate transmission charges. This section divides the discussion to first address factors affecting the wellhead portion of California's gas prices, factors that apply to all gas consumed in the United States. The latter part focuses on the *premium* added to interstate transmission charges to ship gas to California. The size of the premium currently charged for gas shipped to California is not charged in other markets in the United States.

Wellhead Prices

As discussed in ***Chapter 3***, the deployment of drilling rigs at the wellhead follows a cyclical pattern. In 1999, the number of active drilling rigs reached a historic low.

In 2000, several factors combined to increase demand for natural gas. First, storage levels nationwide were unusually low going into the winter of 1999-00. Then, the country experienced unseasonably cold weather that winter. This caused demand for gas to store during the summer of 2000 for the winter of 2000-01 to be higher than normal. A strong economy and increased demand for natural gas to power electric generators also added to the demand in 2000.

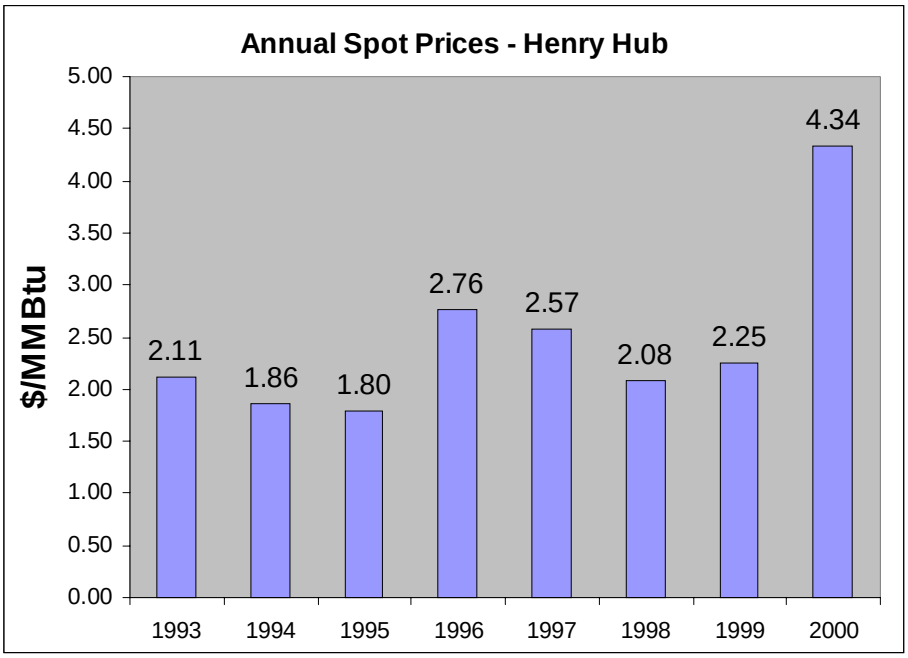
The result of a decade of low levels of drilling topped off with unusually high levels of demand was a jump in natural gas prices. As evidenced by the **Figure**

[16] The city-gate price is the price at the point where gas transfers from an interstate pipeline to the local gas distribution utility.

[17] Energy Information Administration, Monthly Gas Report, March 2001.

7-3, annual average spot prices at the Henry Hub have increased significantly in the year 2000. Prices have been at or above that amount for all of 2001 to date.

Figure 7-3



Source: Natural Gas Week, April 21, 2001

Electric Generation Demand for Natural Gas in California

As previously discussed in ***Chapter 3***, the demand for natural gas to power electric generation increased significantly in California due to decreases in imports of electricity from neighboring states. The decline in imports is due to adverse hydro conditions in the western United States and increased demand for electricity in the West. As a consequence, the surrounding states have less effective generating capacity and are using more of what capacity they have to meet their own needs. Without the increased demand for natural gas by electric generators in California, it is unlikely that the premiums currently charged to ship gas to California would be nearly so high as they are.

Interstate and Intrastate Pipeline Capacity Premiums

The increased demand for natural gas in California continues to place great stress on the current pipeline infrastructure serving California. The added stress allows the shippers of gas from the wellhead to the California border to charge premiums. The inadequate natural gas infrastructure will continue to produce higher gas prices until rectified.

The relationship between pipeline utilization and the cost of shipping natural gas is relatively straightforward: the cost remains low as long as adequate pipeline capacity is available and choices are available to consumers. High pipeline

utilization causes premium prices because without slack capacity in the pipeline system there is limited ability to use gas-on-gas competition to control prices.

As discussed in the previous Chapters on interstate and intrastate pipelines, efforts are underway to expand pipeline capacity. Once consumers have options and marketers compete, then the premium currently charged should be reduced or eliminated.

Storage

For purposes of understanding pricing impacts in California, storage can be considered an extension of the pipeline infrastructure. Thus, when storage availability declines, or when storage is depleted, prices rise. In 2000, storage inventories in the SoCal Gas and PG&E service territories were under-filled during the summer injection season. SoCal Gas storage was affected by an explosion on the El Paso pipeline that limited deliveries and by high demand for gas by generators. PG&E storage was affected by the decision of noncore customers, particularly electric generators, to not put gas into storage.

As a consequence, the 2000-2001 winter withdrawal period began at excessively low levels and ultimately declined to historically low levels. In fact, because of abnormally cold weather in November and December, energy officials were concerned about whether there would actually be enough gas available from storage during January, February, and March. This uncertainty produced a risk premium for gas in Southern California.

As discussed in the previous section on storage, efforts are underway to expand the storage capability in California. Once accomplished, this should give California consumers an option other than reducing consumption to force marketers to offer reasonable shipping charges, as California will have an alternative to paying premiums. California will be able to draw on storage gas on peak demand days.

Conclusion

The number of drilling rigs in use has increased, and the supply of natural gas should increase. Interstate pipeline companies are responding to demands for more capacity, and the pipeline capacity serving California should increase, and the premium charged to ship to California should decrease. Intrastate receipt facilities are being expanded and should ameliorate the premium charged to ship to California. Storage facilities are being optimized and expanded. If the storage facilities are used appropriately, this should allow consumers to use gas-on-gas competition to reduce the premiums

Appendix A – Existing Interstate Pipelines and Proposed Expansions

Interstate Pipelines Connected to Supply Basins

PG&E Gas Transmission-Northwest and Tuscarora Pipelines

PG&E Gas Transmission-Northwest (GTN) is a PG&E National Energy Group company. GTN extends from the Canadian border at Kingsgate, Idaho to the California Oregon border at Malin. The capacity at Kingsgate is about 2600 MMcfd and declines as it moves south due to compressor capability. The capacity at Malin is about 1900 MMcfd. The Tuscarora pipeline extends from Malin to Reno, Nevada, with a capacity of 125 MMcfd.

GTN connects to the PG&E pipeline system at Malin. The receipt capacity at Malin is rated at 1900 MMcfd. Thus, the physical capacity of the delivery and receipt at Malin match. However, upstream demands in the Pacific Northwest limit the amount of gas that is delivered to California at Malin.

The reductions in the delivery to California occur when upstream customers sign firm transportation contracts to serve increased demands. For example, when GTN built the Tuscarora pipeline it began drawing 125 MMcfd of capacity that used to be available to serve California. On February 12, 2001 Tuscarora Gas Transmission Company filed with FERC to expand the Tuscarora plant by 96 MMcfd. This expansion will draw capacity from PG&E-GTN to serve Dodge Flat and Tracey power plants and other customers in Nevada.

In addition, the gas utilities serving the Northwest have provided for the increased demand caused by population and economic growth in Oregon and Washington. Also, a number of gas-fired power plants recently constructed or about to come on line in the Pacific Northwest have arranged for firm transportation to serve their needs.

Cold weather also affects the capability of the GTN pipeline to serve California. If extreme cold weather strikes the Pacific Northwest, the local demand will draw off an additional 350 MMcfd from the GTN pipeline before it reaches California. In all likelihood this will occur on a day that California experiences its own peak cold weather demands. If extreme weather conditions freeze wellheads in Canada, the reduction in deliveries to California would be even more extensive.

In the long term, as gas resources are consumed and new pipelines to other regions of the United States are added, western Canada may become a less reliable source of natural gas for California. Recently, the Alliance pipeline started carrying 1300 MMcfd from Alberta to Chicago.

In both the near- and long-term, the supply of natural gas from Canada to California is at risk from actions that occur upstream. To evaluate this risk, the Energy Commission should determine whether the natural gas fired power plants in the Pacific Northwest would displace similar plants in California. The Energy Commission should also forecast total natural gas use along the interstate pipeline from Canada. In addition, the Energy Commission should quantify the effect of cold weather in Canada and the Pacific Northwest on deliveries to California.

Kern River Pipeline

Kern River Gas Transmission Company ("Kern River") is a Williams Company pipeline. Kern River originates in Wyoming, crosses Utah and Nevada, and then merges with the Mojave pipeline at Daggett, California to form the Kern/Mojave pipeline. Kern River began operations in 1992. The delivery capacity at Daggett is 700 MMcfd. Kern River connects directly with PG&E at Daggett.

In California, Kern River has four principal customers. Kern River can deliver 350 MMcfd to the PG&E system. Additionally, Kern serves the Cool Water electric generator. Through Kern/Mojave, gas is delivered to enhanced oil recovery operations and the associated co-generation facilities. At Wheeler Ridge, gas is delivered into the SoCal Gas system.

Kern River currently delivers only about half its original design capacity. The Kern River pipeline is still physically capable of delivering the original design capacity of 700 MMcfd. During the past winter, only about 450 MMcfd of natural gas supply reached California because customers including electric generation in the Las Vegas, Nevada area are now drawing from the pipeline before it reaches California.

Figure A-1 shows proposed power plants along the Kern River system including the Kern/Mojave extension. If all these power plants were built they would draw over 2000 MMcfd of natural gas.

The Energy Commission should continue to monitor the gas acquisition plans of applicants before the Energy Commission proposing to rely on the Kern River pipeline and continue to assure that the approved plants have adequate access to natural gas.

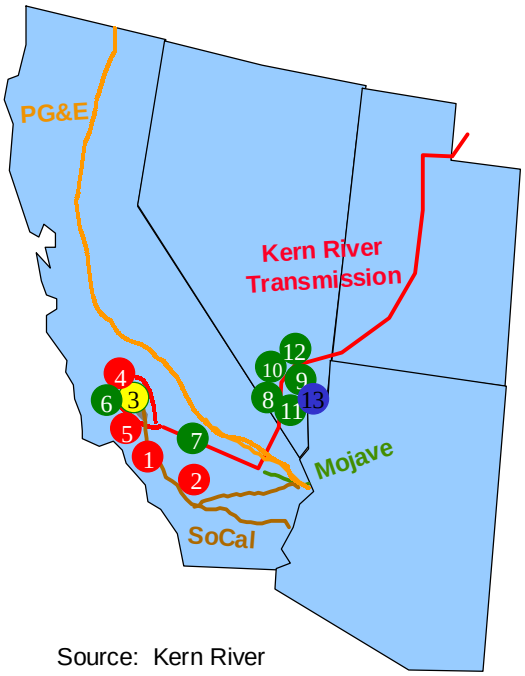
Transwestern Pipeline

Enron owns the Transwestern Pipeline ("Transwestern"), which stretches from West Texas to the California/Arizona border at Needles. Transwestern can deliver natural gas from the San Juan, Permian and Anadarko basins. In 1992 Transwestern put into service an expansion that increased firm capacity to 1050 MMcfd.

Through a lateral pipe Transwestern can deliver gas to PG&E and Mojave at Topock. Currently, SoCal Gas and marketers have firm contracts to receive 750 MMcfd of the Transwestern capacity at Needles, and PG&E and marketers have firm contracts to receive 300 MMcfd at Topock.

Figure A-1

Pastoria - Enron (750 MW)
High Desert - Constellation (720 MW)
La Paloma - PG&E (1050 MW)
Elk Hills - Oxy/Sempra (500 MW)
Sunrise - Mission Energy (320 MW)
Midway Sunset - Midway Cogen (500 MW)
Antelope Valley - Enron (1000 MW)
Apex - Mirant (1150 MW)
Moapa - Duke (1200 MW)
Meadow Valley - PG&E (1000 MW)
Arrow Canyon - Reliant (500 MW)
Crystal - Calpine (760 MW)
El Dorado - Reliant/Sempra (480 MW)



Source: Kern River

El Paso Pipelines

El Paso Corporation owns the El Paso Natural Gas System ("El Paso"). El Paso is divided into a Northern and a Southern System. The two systems are connected by the Havasu crossover and are both able to deliver natural gas from the San Juan, Permian and Anadarko basins to California. Besides serving customers in New Mexico, Arizona, and Nevada, the Northern System delivers 2080 MMcfd of firm capacity to Topock. Additionally, the Southern System delivers 1240 MMcfd of firm capacity to Ehrenberg, Arizona located across the Colorado River from Blythe, California.

The capacity to receive gas from El Paso's Northern System are divided as follows:

- PG&E 1140 MMcfd;
- SoCal Gas 540 MMcfd; and
- Mojave 400 MMcfd.

SoCal Gas holds the capacity to receive the entire 1240 MMcfd of firm capacity at Ehrenberg. If pressures are high enough (due to high demand in Southern California), SoCal Gas is able to receive an additional 200 MMcfd at Ehrenberg.

El Paso Merchant Energy ("EPNE"), an affiliate of El Paso, holds 1200 MMcfd of shipping rights on El Paso through the end of May 2001. EPNE decided not to exercise its right of first refusal and El Paso offered the 1200 MMcfd out to bid. The bids received by EPNE totaled approximately 1,200,000 MMcfd.

Interstate Pipelines not Connected to Supply Basins

Mojave and Kern/Mojave Pipelines

The El Paso Corporation owns the Mojave Pipeline Company ("Mojave"). Mojave originates at Topock, Arizona. Topock is on the California-Arizona border where Interstate 40 crosses the Colorado River. Mojave has a capacity of 400 MMcfd from a combination of receipts from El Paso and Transwestern at the California border. It joins with Kern River at Daggett to form the Kern/Mojave pipeline. Mojave and Kern/Mojave are bypass pipelines.

Mojave is entitled to receive 400 MMcfd of the capacity from the El Paso Northern system at Topock. Mojave may elect to take less than 400 MMcfd from El Paso and up to 150 MMcfd from Transwestern, as long as the total does not exceed 400 MMcfd.

Kern River and Mojave own about 64 and 36 percent respectively of Kern/Mojave. Kern/Mojave originates at Daggett and continues northwest into Kern County. Kern/Mojave then divides in two with laterals running up the east and west sides of the lower San Joaquin Valley to serve enhanced oil recovery customers. Kern/Mojave has a capacity of 1,100 MMcfd.

Kern/Mojave has a spur that connects with Wheeler Ridge, a receipt point for SoCal Gas. Kern/Mojave supplies about half of the 760 MMcfd capacity at Wheeler Ridge.

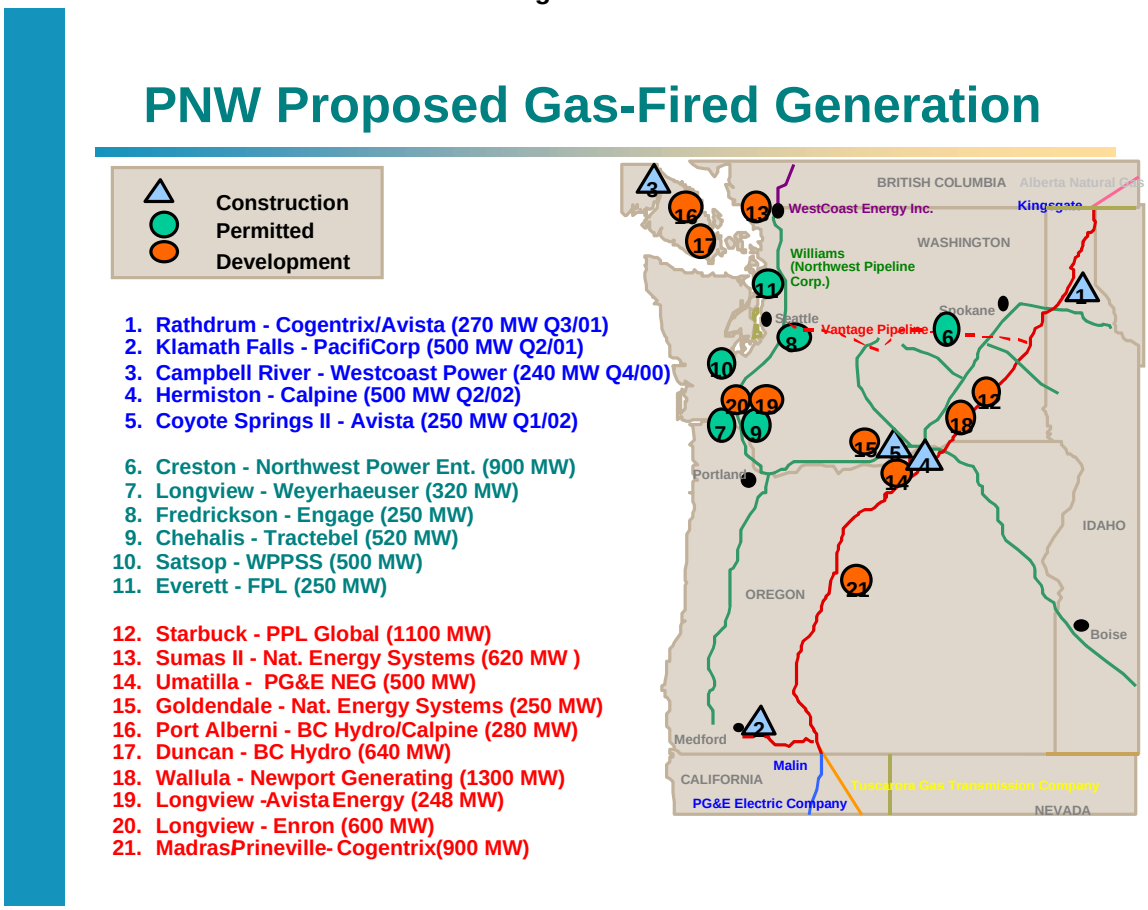
Mojave delivers to SoCal Gas at Hector Road and has direct deliveries to industrial customers such as U.S. Borax. Kern/Mojave delivers gas to SoCal Gas at Wheeler Ridge, PG&E at Daggett, the Coolwater power plant and enhanced oil recovery and associated co-generation in the lower San Joaquin Valley. Kern/Mojave is scheduled to deliver gas to electric generators under development such as La Paloma and Sunrise.

Interstate Pipeline Projects Proposed or Underway

GTN Pipeline Upgrade

Figure A-2 shows the location of the gas-fired power plants under construction and proposed in the Pacific Northwest. Even with the 200 MMcfd proposed expansion discussed below, the effective delivery capacity to California from Canada will decrease significantly if even a fraction of these plants is constructed and no additional pipeline capacity is added. The plants under construction will consume about 300 MMcfd when operating. If constructed, the plants pursuing permits and under development will consume about 465 MMcfd and 1100 MMcfd respectively. The rough total of all these plants of about 1,865 exceeds the entire receipt capacity into California at Malin.

Figure A-2



Shaded area represents numbers 6-21.

As the result of a recent open season solicitation, GTN has announced an expansion of about 200 MMcfd of additional firm transportation capacity from Canada to California. The additional capacity would originate at the interconnection with the TranCanada Pipeline at Kingsgate and extend to the

California-Oregon border at Malin. According to the PG&E National Energy Group, there was a ten-fold interest in the expansion. This expansion is expected to be available in April 2002. With expedited FERC approval a portion could be available for the 2001-02 winter.

In April 2001, GTN held an open season to determine additional support for new capacity to be available in 2003. GTN has not yet announced its plans for 2001. However, GTN has announced that over the next 10 years it anticipates adding 1,000 MMcfd in new pipeline capacity.

Tuscarora Pipeline Upgrade

The Tuscarora Pipeline Company files with FERC an application to expand the existing 125 MMcfd Tuscarora pipeline by an additional 96 MMcfd to be in service by early 2003.

Kern Pipeline Expansions

The new natural gas fired generation in Nevada and California caused Kern River to initiate expansion efforts. These proposed gas-fired generators are shown in **Figure A-1**. Kern River has already awarded allocations on a first expansion of 124.5 MMcfd that is expected to be online in May 2002.

To satisfy the immediate needs of electric generators in California for interstate gas shipping capacity for the summer of 2001, Kern River filed for an emergency expedited review at FERC for 135 MMcfd of new capacity to be available in July 2001. Ninety-five percent of this capacity was awarded to shippers for delivery to Wheeler Ridge. The expansion will be achieved by adding temporary compression facilities. Permanent facilities will be installed pursuant to the FERC filing for the 124.5 MMcfd expansion.

A second open season drew about 2000 MMcfd of interest in a second 300 MMcfd expansion. Based on this Kern River has announced that it will be expanding its system by 900 MMcfd for operation in 2003. This new capacity will require 400 miles of new pipeline and additional compression. The increased volume will principally serve new power generation.

Kern/Mojave Pipeline Expansion

The 135 MMcfd emergency expansion approved by FERC for Kern River includes compression at Daggett. This additional compression will increase the capacity on Kern/Mojave as well by an additional 135 MMcfd. The Kern River proposal to expand by 900 MMcfd would require additional compression on Kern/Mojave.

Transwestern Pipeline Expansion

Transwestern filed with FERC on March 29, 2001 an application to expand its system by 150 MMcfd that could be operational by the winter of 2001-2002. This expansion would serve both California and states to the East of California.

El Paso System Expansions

All American Pipeline

El Paso has announced plans to convert the All American Pipeline from an oil pipeline to a natural gas pipeline in mid 2001. El Paso has requested an expedited emergency review by FERC to bring the All American Pipeline into natural gas service. El Paso estimates that it could complete the cleaning of the existing oil pipeline and be transporting gas to California by August 2001. Capacity for this pipeline would be 230 MMcfd.

The conversion would provide backup for the El Paso Southern System as various segments are taken off line for scheduled testing and maintenance. The conversion would provide alternative capacity to keep the pipeline system operational during this testing and maintenance.

Open Season Solicitation

El Paso solicited interest in adding new capacity to their pipeline system. Based on the responses to the open season that concluded on March 23, 2001 El Paso has announced that 120 responses requested 9,700 MMcfd in new capacity. Of these, 76 solicitations requested 4,500 MMcfd for delivery to the California border or inside the State.

Based on the responses El Paso could decide to add new pipeline anywhere along their system. El Paso will also decide whether the All American Pipeline will be increased to 500 MMcfd.

Sacramento Valley Project

One potential expansion by El Paso is the Sacramento Valley Project. On May 11, 2001, El Paso announced that its subsidiary, Mojave Poplove is holding an open season to provide incremental transportation capacity along an expanded Mojave Pipeline system from Topock to the Antioch and Sacramento areas. The open season will be held from May 10 through May 31, 2001.

Bi-Directional Lateral Project

El Paso also announced on May 11, that its subsidiary the El Paso Natural Gas Company is holding an open season on a proposed bi-directional lateral between Daggett and Ehrenberg. El Paso proposes to connect its existing southern system with the new lateral that will utilize the portion of the former All American

Pipeline facilities that extends from Daggett to Ehrenberg. The open season will be held from May 1 through May 25, 2001.

North Baja Pipeline Project

The North Baja Project ("North Baja") is a joint effort of Sempra, PG&E National Energy Group and Mexico's Proxima originating at Ehrenberg, traveling south into Mexico east of Mexicali, and then west. Just south of the United States - Mexico border from Otay Mesa, it would link with the existing pipeline that currently receives natural gas from SDG&E for delivery to Rosarito. The proposed capacity of 500 MMcfd is expected to be in service by September 2002.

North Baja has submitted permit applications to FERC and its counterpart in Mexico. The North Baja pipeline is intended to serve power plants in Mexico and the Otay Mesa project in San Diego as well as other demands.

North Baja does not increase access to natural gas producing basins. North Baja potentially diverts natural gas from the El Paso South System at Ehrenberg and delivers it to Mexico and San Diego. Since SDG&E is currently providing gas to the Rosarito Beach power plant in Mexico, some of this gas will displace gas already serving SDG&E. However, to the extent that North Baja serves demands in Mexico not currently served by SDG&E, North Baja will reduce the amount of natural gas capacity reaching California.

North Baja reports in its application to the FERC for permission to build the pipeline that North Baja has signed precedent contracts for about 300 MMcfd. These contracts include about 45 MMcfd of the roughly 80 MMcfd usage of the Otay Mesa project. The remaining 255 MMcfd in contracts are for 230 MMcfd for generators and 25 MMcfd for industrial users in Mexico.

The application details in Exhibit I the market for the remaining capacity. North Baja estimates that there is between 300 to 450 MMcfd of additional generator demand in Mexico as well as an additional 120 MMcfd of propane conversion and local distribution demand in Mexico.

Apparently, slightly less than 10 percent of the North Baja capacity will serve demands in San Diego. The current 90 MMcfd serving generator demands in Mexico would be displaced and available in San Diego. However, all of the flow on the El Paso system serving California was needed in the summer of 2000. Removing about 350 to 400 MMcfd of capacity from service to California to serve Mexico raises a serious question. One might ask: Where will California find the interstate pipeline capacity to replace such a significant amount? The simple answer is that if there are no firm capacity contracts on El Paso to serve the increased demand there will be no flow on the North Baja Pipeline.

The results of the recent El Paso open season will more fully answer this question. It is unlikely that marketers planning to use the North Baja Pipeline did not participate in the El Paso open season to obtain firm capacity to meet their needs. When negotiations have been finalized, the question will be answered.

In addition, Otay Mesa recently filed with FERC for construction of a new gas pipeline to connect its proposed natural gas-fired generating facility in San Diego with the North Baja Pipeline in Mexico.

The Energy Commission should investigate whether the North Baja project would force curtailments under conditions as experienced in the summer of 2000 and other plausible scenarios.

Questar Southern Trails Pipeline Project

Questar Southern Trails Pipeline Company applied to and received permission from the FERC to convert its existing crude oil pipeline to carry natural gas. Questar Southern Trails runs from the San Juan Basin to the Los Angeles area. The converted pipeline would be able to carry 90 MMcfd to the California border and 120 MMcfd into the Los Angeles area.

Questar announced that it has signed a long-term deal to deliver natural gas on the east zone of the Southern Trails Pipeline. Questar also says it is seeking customers for the west zone that serves California. The portion of the project that serves California is currently on hold until sufficient customer support is generated to make the conversion economically viable.

The major barrier raising questions about the conversion of the California portion of this project is a current peaking tariff contained in the existing rates of SoCal Gas. This tariff, referred to as the RLS tariff, makes it uneconomic for customers to seek an alternate supplier to SoCal Gas if the customer intends to have a portion of its needs satisfied via a direct link to an interstate pipeline. The CPUC will likely resolve this issue by early summer.

Even if the CPUC changes the RLS tariff the project may not be able to compete with the SoCal Gas transportation rates. The current SoCal Gas rate for electric generators is $0.26/MMbtu while the comparable Southern Trails rate would be $0.39/MMbtu. There may be customers who are willing to pay this extra cost to avoid CPUC regulation and the accompanying diversion rules.

Ruby Pipeline

The El Paso subsidiary, Colorado Interstate Gas, is holding an open season through May 31, 2001 to evaluate whether it should add pipeline capacity from Western Wyoming to Nevada and Northern California markets. This new pipeline would add up to 750 MMcfd of capacity that could be in service by late 2003.

Sonoran Proposal

On May 2, 2001, Kinder Morgan Energy Partners and Calpine Corporation announced plans to jointly develop the 1160 mile Sonoran Pipeline from the San Juan Basin in northern New Mexico to California markets in two phases. Phase I contemplates a 36-inch pipeline from New Mexico to Needles with a 24-inch lateral to Topock. The pipeline would initially transport 750 MMcfd. Phase II would consist of approximately 590 miles of 36-inch and 42-inch pipeline from Needles to Antioch. Phase II would transport from 1000 to 1500 MMcfd depending on shipper interest.

Appendix B – Natural Gas and Peak Electric Generation

Overview

This appendix presents the results of the Energy Commission analysis to determine if there will be sufficient natural gas infrastructure capacity to support what is expected to be unprecedented levels of natural gas demand by electric generators during peak week operations. California has embarked on an ambitious program to bring additional gas fired electric generating capacity on-line for the summer of 2001 that may further stress the natural gas system.

This analysis does not include gas demand by back-up generators that are expected to be used during rolling blackouts. The Energy Commission should monitor the gas demand by such units to determine their effect on the ability of the gas utilities to achieve their winter storage goals.

PG&E Peak Summer Week Analysis

In **Table B-1** the peak summer week natural gas demand for the PG&E service area is presented. To provide a high gas use scenario, one of the units at the Diablo Canyon Nuclear Power Plant is assumed to be on a forced outage during the week. This outage causes additional natural gas-fired generators to run, adding from 50 to 100 MMcfd to the total gas demand. The demand on a daily, average basis is about equal to PG&E's capacity to receive supply into its service area. Some natural gas from storage is likely to be needed to sustain the supply for meeting all the demand.

Table B-1 - PG&E Service Area
Peak Summer Week Natural Gas Demand
One Unit at Diablo Canyon is Forced Out
MMcfd

Day	Core	Noncore	Off System	Electric Generation	Total
Monday	449	701	350	1,606	3,105
Tuesday	449	701	350	1,618	3,117
Wednesday	449	701	350	1,668	3,167
Thursday	449	701	350	1,153	3,029
Friday	449	701	350	1,541	3,040
Saturday	449	701	350	1,427	2,926
Sunday	449	701	350	1,326	2,825

Notes:
- Supply Capacity is 3,200 MMcfd
- Peak week occurs in August

SoCal Gas Peak Summer Week Analysis

In **Table B-2,** the peak summer week natural gas demand for the SoCal Gas service area is presented. Substantial quantities of supply from storage would be needed to insure sufficient supply to meet power plant needs.

Table B-2 So Cal Gas Service Area Peak Summer Week Natural Gas Demand MMcfd				
Day	Core	Noncore	Electric Generation	Total
Monday	709	783	2,304	3,796
Tuesday	709	783	2,588	4,080
Wednesday	709	783	2,487	3,979
Thursday	709	783	2,487	3,979
Friday	709	783	2,445	3,937
Saturday	709	783	2,138	3,630
Sunday	709	783	1,767	3,259

Notes:
- Includes deliveries to SDG&E and Rosarito Beach Power Plant
- Supply Capacity is 3,500 MMcfd with an additional 200 MMcfd possible
- Peak week demand occurs in August

SDG&E Peak Summer Week Analysis

In **Table B-3,** the peak summer week natural gas demand for the SDG&E service area is presented. On a daily, average basis, the natural gas capacity would meet the peak week demand.

Table B-3 SDG&E Service Area Peak Summer Week Natural Gas Demand MMcfd					
Day	Core	Noncore	Electric Generation	Rosarito	Total
Monday	107	14	320	116	557
Tuesday	107	14	334	13	568
Wednesday	107	14	361	87	569
Thursday	107	14	329	100	550
Friday	107	14	317	97	535
Saturday	107	14	278	75	474
Sunday	107	14	201	57	379

Notes:
- Supply Capacity will be 665 MMcfd
- Peak week demand occurs in August

Peak Hour Demand Analysis for Utilities

The peak summer hour demand for each of the utility service areas is shown on **Table B-4**. Each of the utilities total demand exceeds flowing supply. For both the PG&E and SoCal Gas service areas, storage facilities are available to meet the demand if the electric generators have placed natural gas into storage. SDG&E does not have storage available to meet its demand and would have to resort to curtailing the electric generators on its system. They do have the capability for burning fuel oil.

Table B-4
Peak Summer Hour Natural Gas Demand Forecast
MMcf per Hour

Service Area	Electric Generation	NonElectric Generation	Total	Pipeline Capacity	Supply Shortage	Storage Withdrawal Capacity
PG&E	92	63	155	133	(21)	63
SoCal Gas	160	58	218	150	(69)	133
SDG&E	38	1	39	28	(12)	NA

Notes:
- SoCal Gas deliveries include SDG&E and Rosarito Power Plant
- SDG&E include Rosarito Power Plant