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ELECTRICITY AND NATURAL GAS ASSESSMENT REPORT

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- Electricity Oversight Board
- California Consumer Power and Conservation Financing Authority
- Department of Water Resources
- Department of Motor Vehicles
- California Air Resources Board
- California Independent System Operator

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Executive Summary

Introduction

Over the last two years, the Executive and Legislative branches of California government have stressed the need to revive the stability of the state's electricity industry, re-design the market rules to create a workable and competitive system, and restore an incentive system for building needed infrastructure. Progress is occurring in several key areas, such as ideas for re-designing the market structure, ensuring the adequate availability of energy resources, managing costs, re-building regulatory certainty, and developing preferred resource choices. However, further actions are needed to reduce the system's vulnerability to risks of adverse shocks from supply-demand imbalances and price volatility.

In 2002, the Legislature passed Senate Bill 1389, which directed the Energy Commission, in collaboration with other state agencies, to:

- Identify historic and current energy trends,
- Forecast and analyze potential future energy developments, and
- Recommend new policies for current and pressing energy issues facing the state.

California needs a strong and flexible energy infrastructure to meet the unique energy needs of the state. This infrastructure, when coupled with efficient industry performance rules, will ensure that consumers receive reliable, reasonably-priced electricity and natural gas that will promote economic growth, protect public health and safety, and protect the environment. Achieving these goals is complicated by the interrelationship between electricity and natural gas markets.

Electricity and Natural Gas Infrastructures are Closely Linked

California's electricity and natural gas markets have become closely inter-related since natural gas has become the predominant fuel for electricity generation. The growing demand for electricity is, in turn, driving the increasing need for natural gas supplies throughout California. The role of natural gas in electricity generation affects how the natural gas system must be designed and operated.

Natural gas-fired generation has become the technology of preference among developers. Technology advancements over the past decade have enabled power plants to operate more efficiently at lower overall cost, and to better follow load, that is, increase or decrease output as consumer demand waxes and wanes. Gas-fired generation units can be constructed in many sizes and located either near load centers, or in remote locations close to gas pipelines and transmission wires. In addition to these advantages, natural gas comes from regions throughout North America, which is supplied by a gas market that until recently has been considered to be workably competitive.

The inter-related nature of the electricity and natural gas systems also means that price fluctuations in the fuels market directly affect electricity costs. Price shocks or shortages in one market quickly cross over into the other system. When natural gas-fired generation is used extensively to serve summer air conditioning needs, then natural gas providers defer storage injections or even draw down inventories, which are needed to meet next winter's gas heating demands.

As a result, natural gas demand now has two peak periods, summer and winter. These two seasonal peaks challenge the industry's ability to ensure a reliable supply throughout the year, especially for the winter peak heating demand. As a result, the natural gas market has become more volatile with price increases in both the fuel and electricity markets. The price of natural gas and electricity during the winter is also affected by the storage patterns of merchant power plant operators.

Not only are the electricity and natural gas markets inter-connected, but they reach far beyond California's border. Both the electricity and natural gas infrastructure have become increasingly regional in nature. In the case of natural gas, broad national and international developments are being driven by changes in the market and the infrastructure. Consequently, future decisions to build additional natural gas storage, gas pipeline capacity, or a liquefied natural gas (LNG) terminal somewhere on the West Coast will affect what consumers pay for electricity. Other resources that can be developed such as renewable generation and electricity demand reductions can also influence the price of natural gas.

Growing Population Increases Energy Demand

In the next decade, California will add five million people to its current population of about 35 million. These five million people will need power and fuel; three-quarters of our electricity growth and all of our natural gas growth will be driven by the need to serve these new citizens.

Commercial growth, spurred by the state's economic expansion, will be the largest contributor to the incremental increase in electricity demand. However, California's commercial rates and bills are expected to continue to be far higher than those of businesses in other western states, which may ultimately effect commercial growth. Demand-side management programs can reshape current patterns of energy use, and encourage commercial growth.

Peak electricity demand increases dramatically in the summer due to air conditioning loads. The difference in demand between an average summer day and a very hot peak day is 6 percent. This difference is equivalent to three years average growth in electricity demand. Electricity use also varies widely over the time-of-day and time-of-year. On a typical day, electricity use may increase 60 percent from the early morning to the afternoon. On a hot summer day, the demand increase can be 85 or 90 percent higher in the afternoon. To meet these changes in demand, the generation system must be extremely flexible. It must be capable of adding or dropping generation from some facilities to accommodate the wide daily swings in demand, the high summer peaks, weather variability, and economic growth cycles.

Along with adapting to these shifts in demand and changes in consumer habits, the system must accommodate the varying availability of generation, pipelines, transmission lines, storage facilities, and fuel sources. These contingencies can be addressed by using risk management tools to create a system that delivers safe, reliable, affordable energy services.

Electricity and Natural Gas Demand and Supply: 2003 - 2006

Currently, the physical infrastructure is providing reliable electricity, but at higher consumer prices than in the 1990s. The current capacity levels, together with the planned transmission upgrades in California and the rest of the west, make the reliable delivery of electricity at stable prices likely during 2004 – 2006.

The expected amount of extra reserve capacity to generate electricity helps to ensure that spot market prices remain reasonable. The reserve margin also minimizes the potential adverse effects from variations in actual generation additions and retirements that differ widely from our forecasts. With demand increasing over time, however, this surplus will shrink, leaving ratepayers exposed to potentially higher prices and an increased risk of supply shortfalls. Actions are underway now to firm up new resources by the end of 2006.

Through 2006, natural gas supply and pipelines are sufficient to meet California's annual average needs, but fuel supply will likely be delivered at higher prices than in the 1990s. Despite this positive outlook, the system remains vulnerable to seasonal price volatility and difficulties in delivering gas to consumers on the coldest days of the year.

Post 2006 Supply-Demand Balance: Future Choices

Currently, the power and fuel industry spends over a billion dollars every year on modernizing and expanding the infrastructure, including demand-side investments. These investments come in the form of power plants and pipelines, energy efficiency and renewable technologies, transmission lines, and storage facilities. Any future infrastructure projects will be expensive and will need to operate for the next forty to fifty years. In using an integrated portfolio assessment, the options can be balanced against the risks, allowing us to make the best choices.

California now has the time to fashion the basic energy infrastructure in ways that meet multiple public interests. But without an energy policy that provides sufficient resources, ratepayers will be exposed to the renewed risk of high prices and outages by 2007. Acquiring additional resources must begin in 2004, given the time needed to bring new generation and transmission resources on-line, or to build up demand reductions by changing consumer investments and behavior.

These declining reserve margins could improve, pushing out the need for additional peak load resources to 2008 or 2009 if price responsive programs, renewable generation additions, and peak demand reduction program goals are met. Committing to the successful completion of these programs is important to stabilize California's long-term electricity needs. We must carefully monitor this balance and accurately evaluate the progress of these programs to ensure California's electricity needs are met without compromising our economic and environmental goals.

Environmental Performance

The environmental performance of California's power plants is mixed, with some good news on air emissions, while some on-going problems remain in areas like water supplies, water quality, and aquatic habitats.

California is turning the corner on power plant emissions. Because of concerted actions by air regulators, contributions to air inventories from power plants are low on a statewide average basis, though there are specific communities where the relative contribution is greater. The retrofit of older units has reduced their total nitrogen oxide (NO_x) emissions 50 percent between 1996 and 2001. Yet the power and fuel systems do contribute a larger share of greenhouse gases. In both cases, further reductions will be needed to meet long-term environmental goals. These reductions will come from adding demand side management programs and renewable energy to the system, as well as replacing older, less efficient facilities with modern units.

Reducing greenhouse gases will, in the long-term, help slow the impacts of global climate change. In the near-term, California's power system will need to adjust to current global climate impacts, including greater weather variability, hotter days, warmer winters, smaller Sierra snow packs, additional smog, sea level rise, reduced surface water, and earlier spring run-offs. In one instance, earlier runoffs mean that less hydropower is available during a year to help stabilize of the electricity system or to serve summer peak demand.

In terms of water supplies, despite the limited availability of freshwater supplies, many power plants still rely on fresh water for power plant cooling even though alternatives are available. As California moves further into the twenty-first century, water supplies will become increasingly constrained, presenting an issue for California's future energy needs.

Power plants continue to affect sensitive aquatic ecosystems on the ocean and in sensitive estuaries. The 21 coastal thermal and nuclear power plants continue to draw water from these ecosystems, using hundreds of millions of gallons of sea water each day.

Hydropower is often considered a “clean” energy resource, yet it too can adversely affect California’s water quality. River and stream habitats have been degraded and no longer support their former populations of native salmon, trout, or amphibians. Environmental restoration, however, can provide benefits through part of a balanced relicensing review that looks at the multi-purpose functions of dams.

With diverse ecology, California’s many endangered wildlife and plant populations are vulnerable to the impacts from future infrastructure projects. Although the effects of one project on terrestrial habitats may be insignificant, the cumulative impacts from many infrastructure projects could be significant and will require further investigation.

Policy Areas to Watch

From among the many issues discussed in this report, we highlight the following issues as the most current and pressing areas to develop policy. Supporting technical documents and the record of the public proceedings are also available to provide stakeholders with a fact based understanding of the challenges and actions necessary to build a sustainable infrastructure.

1. California is in the process of restoring its electricity infrastructure and market. Several activities are underway that should be completed and then linked to maintain an integrated portfolio approach. For electricity, the key processes include the following:
   - Forecasting and planning,
   - Investor-owned utilities and municipal utility procurement,
   - Demand side management and dynamic pricing proceedings,
   - Implementing the renewable portfolio standard,
   - Proceedings on market design, and
   - State and local air district rule-makings and determinations.

2. Meeting resource needs requires dependable construction and operation of thermal power plants, renewable generation and demand side management programs. Uncertainty in power plant long-term contracts, financing, permitting, and construction, and demand side management program development, implementation, and impact must be analyzed and accounted for ahead of time.

   The policy preferences of meeting resource needs, first through demand side management and secondly through renewables, increases the importance of these programs being implemented to deliver the resources. As these programs translate potential into delivered resources, performance feedback will establish if there are resource gaps that need to be filled by other resources, which also require dependable construction and operation. If new preferred resources are brought on-line more quickly or slower than anticipated, then short-term thermal options must be adjusted to balance with expected demand. This report examined uncertainties associated with thermal generation. In the companion ***Public Interest Energy Strategies Report***, the Energy Commission proposes actions to ensure performance of the preferred resources.

3. Many older power plants have been retrofit with air emission controls, and we expect their continued performance through most of this decade. But California has several marginally performing older units. When these become too costly to compete with new generation, then these plants will likely retire or be refurbished because either the power plants use too much gas or emission levels cannot be reduced. However, some of these plants are necessary for local reliability. As a consequence, they must be replaced with local resources or upgraded transmission before shut down.

   While market forces will lead to these plants' retirement, state agencies must monitor whether sufficient new generation or transmission are added where it can function as a substitute.

4. Future transmission planning and permitting must ensure that the transmission system is upgraded while protecting local quality of life.

   Although few new bulk transmission lines have been built in the last two decades, billions of dollars has gone into reinforcing and making maximum use of the current major connections. Among the obstacles to timely transmission development, the most common are related to debates over the need for and benefits of the project, financing difficulties, and local opposition related to environmental and property value impacts. Efforts are underway on the part of the Energy Commission, California Independent System Operator, and California Public Utilities Commission to develop a common approach to use in the planning and permitting of transmission projects. This approach would serve to determine the value of proposed projects that may be needed to provide economic benefits to the state and see that projects are brought on-line in a timely manner.

5. For the natural gas system, two principal areas of concern are expanding overall supply and using storage to meet seasonal needs.

   - Declining output from several gas-producing basins in the "lower-48" states has been a long-term concern. The state has several supply options to address this concern. New supply options are available in North America, and some additional gas can be gathered within California's borders.

     Internationally, liquefied natural gas is becoming an option as it becomes cost-effective to cool, move, and re-gasify abundant but remote natural gas to load centers. Liquefied natural gas technology, despite the numerous economic and technological uncertainties and risks, may shift natural gas from a continent-wide market to a world-wide commodity market. Developing shipping access to natural gas producing basins throughout the Pacific and Indian Oceans has the potential for significantly enhancing system reliability, price stability, and environmental performance.

   - Natural gas storage is key to dealing with the seasonal variability needs of end users and electricity generation. Although physical storage appears to be adequate, state agencies and stakeholders have concerns over whether the market for storage is shifting risks among various natural gas customers in the residential sector, large industrial and commercial, and merchant generators.

6. The state's electrical generation and transmission system affects the natural environment and human communities. While there is good news on air emissions from natural gas-fired power plants, there continue to be serious ongoing impacts to water supplies, water quality, and aquatic habitats from the state's current natural gas, nuclear, and hydro power plants. Impacts to terrestrial ecosystems are well controlled for new power plant cases under Energy Commission jurisdiction, but the impacts from extant and new transmission lines, natural gas pipelines, and non-jurisdictional projects are not as well understood and long-term impacts remain a concern, which require further investigation.

Chapter 1: Introduction and Findings

Background

California needs a strong and flexible energy infrastructure that will promote reliable and reasonably-priced energy supplies. Coupled with an efficient market design, this infrastructure will promote economic growth, protect public health and safety, and protect the environment. As the electricity and natural gas systems become increasingly integrated, the system must be able to absorb supply risks, price shocks, volatility and an evolving role for consumers in taking greater control of their energy futures.

Senate Bill 1389 (Chapter 568, Statutes of 2002; Bowen) requires the Energy Commission to adopt an ***Integrated Energy Policy Report*** every two years. The first report is due to the Governor and the Legislature on November 1, 2003. It must provide an overview of major energy trends and issues facing California, including supply, demand, price, reliability, and efficiency. It must assess the impacts of these trends and issues on public health and safety, the economy, resources, and the environment. Finally, it must make policy recommendations to the Governor and the Legislature that are based on an in-depth and integrated analysis of the most current and pressing energy issues facing the State.

Specifically, the legislation directs that the electricity and natural gas assessment shall:

- Assess trends in electricity and natural gas supply, demand, and wholesale and retail prices for electricity and natural gas.
- Forecast statewide and regional electricity and natural gas demand including annual, seasonal, and peak demand, and the factors leading to projected demand growth.
- Assess the potential impacts of electricity and natural gas load management efforts, including end user response to market price signals, to support reliable operations.
- Assess the adequacy of electricity and natural gas supplies to meet forecasted demand growth, natural gas production capability both in and out of state, natural gas interstate and intrastate pipeline capacity, storage and use, and western regional and California electricity and transmission system capacity and use.
- Assess the potential impacts of electricity and natural gas supply, demand, infrastructure and resource additions on the electricity and natural gas systems, public health and safety, the economy, resources, and the environment.
- Assess the environmental performance of the electric generation facilities of the state.
- Assess short-term and long term performance of electricity and natural gas markets to determine if they are adequately meeting public interest objectives including: economic benefits; competitive, low-cost reliable services; customer information and protection; and environmentally sensitive electricity and natural gas supplies.
- Identify impending or potential problems or uncertainties in the electricity and natural gas markets, potential options and solutions, and recommendations.

The Energy Commission is preparing three reports that will provide the analytical foundation for potential energy policy recommendations found in the ***Integrated Energy Policy Report***: the ***Electricity and Natural Gas Assessment Report***; the ***Transportation Fuels, Technologies and Infrastructure Assessment***; and the ***Public Interest Energy Strategies Report*.**

The ***Electricity and Natural Gas Assessment Report*** provides the findings of expected energy infrastructure developments and an analysis of the implications that a number of important uncertainties may present. The primary goal of the report is to identify key factors that may stress the energy infrastructure and to determine if there may be a need for additional development to mitigate potential supply shortfalls in the next decade. Considering that electricity generation is the largest user of future natural gas demand, the energy infrastructure study is also focused on the potential stresses to the natural gas fuel system.

Integrated Markets

The electricity and natural gas markets are closely inter-related. Both exist to serve our population and economy, so are affected by the same economics, weather, new technologies, and economic growth. But, the advent of natural gas-fired power plants as the dominant new source of power has linked electricity and natural gas markets even more closely. For example, a decision on whether to add natural gas storage can affect what consumers pay for electricity. Conversely, development of renewables generation or electricity demand reductions can influence the demand for and price of natural gas.

These common markets mean that risks and uncertainties are also linked. We have become familiar with the short-term price run-ups which happen when hot temperatures drive up air conditioning use and the demand for natural gas. But there are long-term risks that need to be evaluated in developing a secure and affordable energy infrastructure. These risks include the natural risks of physical supply, demand growth, temperature and weather variations. They also include the human aspects of market design, regulatory uncertainty, and social preferences for how much to mitigate risks.

In this report, we examine the current status and pressing issues that arise from linked elements in the electricity and natural gas markets. This includes the conventional grid-connected electricity market, and new additions include conventional generation, renewables and energy efficiency.

This ***Draft Electricity and Natural Gas Assessment Report*** is the Energy Commission's initial report of its response to the Legislature's directives. The report is organized to follow a logical flow of interrelated topics ranging from a description of the trends assessment, risks and policy preferences, to findings, conclusions and policy recommendations. These electricity and natural gas assessments address interfuel and intermarket effects to provide a more informed evaluation of potential tradeoffs when developing energy policy across different markets and systems

Report Development Process

On September 11, 2002, the Energy Commission opened an informational proceeding (Docket No. 02-IEP-01) and designated Commissioner James Boyd, Presiding Member, and Chairman William Keese, Associate Member to oversee the process. The Committee was aided by an inter-agency advisory group consisting of members of nine agencies with energy expertise: the California Public Utilities Commission, California Air Resources Board, Consumer Power and Conservation Financing Authority, Department of Motor Vehicles, Department of Transportation (Cal Trans), Department of Water Resources, California Public Utilities Commission, Office of Ratepayer Advocates; Electricity Oversight Board, and California Independent System Operator.

The Committee held 13 full day workshops on technical subjects. In addition to Energy Commission staff analysis, the Committee heard from 73 electricity and natural gas related stakeholder groups. The inter-agency parties participated in monthly updates and provided additional comment through pre-publication review of staff documents.

This assessment is linked to the ***Public Interest Energy Strategies Report*** (publication number 100-03-012C), which examines in more detail the potential for and challenges associated with public interest policy preferences. It is also supported by a panoply of supporting material providing greater technical detail. The attachments to this report include:

1. ***California Energy Demand 2003-2013 Forecast*** - 100-03-002,
2. ***Natural Gas Market Assessment*** - 100-03-006,
3. ***Comparative Cost of California Central Station Electricity Generation Technologies*** - 100-03-001,
4. ***Aging Natural Gas Power Plants in California*** - 700-03-006,
5. ***Upgrading California's Electric Transmission System: Issues and Solutions*** - 100-03-011,
6. ***2003 Environmental Performance Report*** - 100-03-010,
7. ***California Municipal Utilities Electricity Price Outlook 2003-2007*** - 100-03-005,
8. ***California IOU Retail Electricity Price Outlook 2003-2013*** - 100-03-003,
9. ***Joint Working Paper on Municipal Utility Resource Adequacy*** - 100-03-015.

Summary of Findings

A summary of the findings of each chapter follows.

Chapter 2 Summary: Electricity and Natural Gas Demand Trends Assessment

Reliable assessments of the amount, location and timing of demand growth are essential to evaluate the options that can best target California's energy needs.

Electricity Trends, Overall, by Sector, and Per Capita

Between 2003 and 2013, California will add over 5 million people (a 15 percent increase) and the state economy will grow at double that rate (a 30 percent increase). Given current trends, approximately 10,000 MW (including reserves) of generation or demand-reducing resources will be needed to serve the growth in the state economy.

Electricity demand growth is dominated by adding new households and new commercial businesses. Eighty percent of residential energy growth is from adding new homes; only twenty percent is caused by new end-uses. In the residential sector, average electricity use per household has increased one-half percent per year, reflecting higher incomes, larger homes, more homes with air conditioning, and home electronics. This increase in use per household explains only twenty percent of the 1.9 percent per year growth in the residential sector over the last two decades; growth in the number of households explains the rest.

In the commercial sector, businesses have increased electricity use per square foot. Three-fourths of commercial demand growth is due to business expansion – more floor space used by businesses – and one-fourth of growth reflects greater per unit energy use. In the industrial sector, improved productivity has led to greater electricity use per employee; the contribution of the manufacturing to gross state product grew twice as fast as the commercial sector.

While a growing population and economy are the fundamental drivers of energy demand, demand growth is also affected by the types of businesses that are growing, building and energy efficiency standards and programs, energy prices, and customer behavior. California uses electricity more efficiently than do other Western states or the U.S. as a whole. This legacy of efficiency standards and programs has kept per capita use constant for many years.

Daily and Seasonal Patterns of Use

Electricity use varies widely over the time-of-day and time-of-year. In a typical day, use increases 60 percent from the early morning low to the afternoon high. On a hot summer day, this swing is 85- 90 percent. This variable load requires a generation system that is extremely flexible.

Peak electricity demand needles up in the summer due to air conditioning loads. The demand difference between an average summer day and the probability of a 1-in-10 hotter peak day is 6.1 percent, over three times the amount of new demand added each year. Temperature-related variation in demand introduces the need for risk management. We know that hot or cold days are going to happen and have some idea of the frequency of these events, but it is difficult to predict specific long-term weather patterns.

Natural Gas Demand Trends

California natural gas demand is composed of about two-thirds from end-users – consumers in homes and businesses - and one-third from electric generation facilities. While end-user demand has increased relatively slowly over the last decade (less than one percent per year), gas used to fuel gas-fired power plants has increased by an average of 4.5 percent per year since 1990.

The Energy Commission's forecast for total natural gas demand increases at an average of 1.0 percent per year in California from 2003 to 2013. This represents less than half of the annual rate by which total U.S. natural gas demand is projected to grow during the same period. Gas demand for electricity generation remains the fastest growing segment of California's natural gas demand. From 2003 to 2013, natural gas demand in California will increase as follows:

- **Core demand** (including residential, commercial, and smaller industrial customers) will increase from 0.66 to 0.73 trillion cubic feet (Tcf), a rate of 0.9 percent per year,
- **Non-core demand** (large industrial customers) will increase from 0.74 to 0.77 Tcf, an annual growth rate of only 0.4 percent.
- **Electric generation demand** will increase from 0.8 to 0.93 Tcf, or 1.5 percent per year.

The biggest variable in demand forecasts is economic growth. We estimate that peak electricity demand has a 20 to 40 percent chance of being plus or minus 1,700 MW (3 percent) by 2008, depending on whether the state has high or low economic growth. The swing on potential natural gas use is also 3 percent by 2008. Energy resources must be able to accommodate these variations in the business cycle, again calling for a very flexible system. The analysis of high and low DSM scenarios shows an impact of half the growth impact, not reaching 1,700 MW until 2012.

Chapter 3 Summary: Electricity Infrastructure Assessment

California's electricity and natural gas system must supply as much power and fuel as people demand, at both the immediate moment and location of that demand. The system must accommodate the wide daily swings, the summer peaks, the variability, and the cyclical economic growth described in Chapter 2. This complex interaction among consumer habits, generation, pipelines, transmission lines, storage facilities and fuel sources must be designed to achieve safe, reliable, affordable energy services.

Gas-fired Generation

Gas-fired generation has increased from 25 percent of California's electricity resources twenty years ago to 34 percent of the actual generation used to meet current demand. Under baseline conditions, the gas-fired generation share will increase to about 44 percent by 2013. Since natural gas is now the primary swing fuel, the amount of natural gas that is used in any given year depends on the availability of hydropower. Electricity generation from hydropower resources, including imports, has ranged from a high of 45 percent during the very wet year (1983) to an all time low of 12 percent during the drought in 2001.

Much attention has recently been focused on the age and reliability of the state's gas-fired power plants. These combustion turbines, combined cycles, cogeneration units and steam boilers provide a wide range of services. These generation services include baseload energy, following load through its daily swings, and serving as the source of peak capacity that occur only a few times per year. Overall the system has become more efficient as new units are added. Of the 54,675 MW of capacity available to California utilities, there were 9,369 MW that have been added since 2000 and 2,356 MW of older units have been retired.

A number of the older plants still in service can be expected to retire during the remainder of the decade, largely for economic reasons. Careful maintenance and upgrades over their lifetimes have extended their service lives, but they will likely become increasingly unable to compete with newer plants in the marketplace; 13 percent of the state's gas-fired capacity (3,873 MW) and 9 percent of its gas-fired energy in 2002 came from plants built before 1960.

2004 -2006 Resource Adequacy

Currently, the physical infrastructure is up to the task of meeting California's energy needs, but at higher consumer prices than those of the 1990s. The current capacity surplus makes the reliable delivery of electricity at stable prices likely during 2004 – 2006. This surplus, combined with reduced reliance on the spot market, facilitates generator participation in the spot market at reasonable prices, and minimizes the risks associated with uncertain amounts of capacity additions and retirements. This surplus will shrink as demand increases, leaving ratepayers exposed to potentially higher prices and an increased risk of delivery interruptions.

Choices for the Future

California has the time now to fashion its basic infrastructure in ways that meet multiple public interests but, in the absence of an energy policy which guarantees resource adequacy, ratepayers faced the renewed risk of high prices and outages by 2007. Given the lags in bringing new generation and transmission resources on line or building up demand reductions by changing consumer investments and behavior, this acquisition of additional resources must commence in 2004.

Peak reduction program goals, accelerated renewable generation additions and price responsive programs can push the need for additional conventional resources out to 2008 or 2009. Committing to the programs and their successful completion is important to stabilizing California's electricity needs.

Upgrading and Expanding the Transmission System

As expressed in the ***Energy Action Plan***, California has committed itself to upgrading its bulk transmission system and to reducing constraints in local reliability areas. Upgrades to the intra-state connector between Northern and Southern California are underway, and studies have commenced on three inter-state connectors plus the San Diego and San Francisco local reliability areas. The state is also committed to streamlining its transmission planning and siting processes. Part of this includes increasing community participation, since transmission impacts local areas while the benefits extend to regional stakeholders.

Few new bulk transmission has been built in the last two decades, though billions of dollars have gone into reinforcing and making maximum use of the current major connections. Transmission system planners estimate it takes five to seven years to complete a major upgrade to the bulk transmission system. Demonstrating need, securing environmental permits and rights-of-way, securing financing (for private projects), and time requirements for construction, require that planners anticipate the need for transmission expansion projects ten years and more before these projects are in service.

In California obstacles to timely transmission development are most commonly related to debates over project benefits and the need for the project, project financing difficulties and local opposition related to environmental and property value impacts. Efforts are underway on the part of the Energy Commission, CA ISO and CPUC to develop a common methodology that would be used in the planning and permitting of transmission projects. This planning and permitting process would serve to determine the value of proposed projects that may be needed to provide economic benefits to the state.

Retail Rates

Prices paid by consumers are projected to drop between 2003 and 2007, with the biggest decreases coming in the commercial and industrial sectors. California's electricity consumers currently face considerably higher rates than consumers in other Western states. Residential, commercial, and industrial consumers currently pay as much as 53, 110 and 117 percent more in electricity rates in California than similar consumers in other Western states. Although this trend will likely decline in 2004, rates could still be 37, 58 and 47 percent higher for California's residential, commercial, and industrial users.

Residential consumers in California use much less electricity than their counterparts in other western states. Consequently, electricity bills for California's residential consumers are comparable to bills for similar consumers in other states even though their rates are 53 percent higher. Next year, a residential consumer in California will pay lower electricity bills than his counterpart in other states.

California's commercial consumers, on the other hand, pay more than double in rates and bills than similar consumers in other states. Although the trend declines next year, the burden for commercial customers remains high. California industrial consumers fare relatively better than commercial customers. Current electricity bills for California' industrial customers are approximately 67 percent higher than customers of other Western states. These bills could decline to be only 13 percent higher next year.

Chapter 4 Summary: Natural Gas Infrastructure and Markets

About 85 percent of the natural gas supply that California uses comes from out-of-state resource areas. Large pipelines extending hundreds of miles and across several states supply natural gas from areas in the southwest, Rocky Mountains and Canada. These pipelines need to be large enough not only to meet California's needs, but also the needs of the states along the delivery paths.

Over the past three years, pipeline expansions and additions have made pipeline capacity sufficient to serve California's need through 2006. Beyond this date, annual average capacity is adequate, but peak day conditions could warrant further expansion. The natural gas pipeline market is working and the market design is highly likely to deliver additional cost-effective pipelines, once electricity generation contracts for natural gas are established.

Increasing gas demand in Arizona and New Mexico may absorb a significant amount of the natural gas flowing west from the San Juan and Permian basins. These markets can consume a significant amount of the supply that would otherwise serve Southern California. Expanding the interstate infrastructure serving the East-of-California markets can alleviate this potential.

Despite the favorable supply outlook, the natural gas system is vulnerable over the course of a year. This vulnerability exists because summer-peaking power plants are increasingly using gas during the time the firms store gas for the winter heating peak season. Recent years have shown that natural gas demand peaks not only in winter, but also in summer due to increasing gas-fired power generation. These two seasonal peaks challenge the industry in its ability to ensure a reliable supply picture throughout the year. Regulators and the industry need to determine how storage capacity can be utilized to achieve the desired supply reliability.

The problem of how much natural gas to store is compounded by the market design issue of who should store. Natural gas is bought by three sets of users – utilities on behalf of end-use customers, electricity merchant generators, and unregulated large end-users that buy their own gas. Utility planning allows for meeting all core consumption during the coldest temperature-day on record assuming that the non-core customers would be curtailed. If merchant generators mismanage their gas supplies, curtailment would harm core customers who need electricity to operate gas heaters.

Chapter 5 Summary: Meeting Public Interest Objectives

There are many public interest concerns associated with the California energy system and program goals that are intended to improve the use of available resources. Public interest objectives include energy conservation and efficiency goals, opportunities for retail consumers to be able to choose their own suppliers, and balancing the environmental concerns associated with the California energy systems.

Efficiency

We can minimize the resources needed to provide usable energy for consumers through three principal techniques: energy-efficient end uses and behaviors that reduce the need for power in the first place, using renewable resources instead of depletable resources, and making the remaining system more efficient. California already has an enviable track record compared to the rest of the U.S. on both how little power we use while supporting economic and population growth, and the lower environmental impacts of the built system. These trends can be extended through the policies supported in this report.

The future trend for per capita annual electric energy consumption and peak demand can be held flat with savings achieved from DSM programs funded by the current level of the Public Goods Charge surcharge. An approximate doubling of DSM funding can cause a downward turn in the future trends for per capita electric energy and peak demand, up to 3 percent lower per person in 2013. Natural gas DSM programs funded by the current level of the PGC surcharge are expected to steadily reduce per capita natural gas consumption over the next decade. Additional funding for natural gas DSM programs could reduce per capita natural gas consumption even further.

Between 1990 and 2001, there was little change in the electricity system's overall efficiency. The addition of about 9,300 MW of very efficient gas-fired generation in the last few years, the is improving the overall system efficiency including the amount of natural gas needed to generate the electricity needs of a typical household. Adding the renewables called for in the Renewable Portfolio Standard will improve the system's efficiency further.

Customer Choice Opportunities

An evolving concept in the electricity market structure involves the ability of a customer to choose their supplier of electrical services. This concept reflects the belief that when customers can choose between competing suppliers, the market becomes more efficient. In many other markets, choice can lead to lower prices and technology innovations.

As a result of various initiatives, there is renewed interest in choice. Programs to have local communities act as load aggregators are being considered, along with the recent models of individual customer direct access programs. Distributed generation and self-generation through cogeneration facilities are also expressions of choice. To be effective, a new customer choice paradigm will need to address the concerns of cost-shifting between participants and non-participants. Further, it must address the instability caused by customers who abruptly leave the utility only to abruptly return. Since the IOUs will once again be responsible to procure sufficient electricity for their customers, such “in and out” vacillation will have significant impacts upon their ability to forecast their loads.

Despite the complexities, the creation of the core/non-core customer classes could be a way of empowering customer choice for those customers who truly want that choice. Such a customer structure could also mitigate many of the issues that were encountered in direct access.

Environmental Performance

All parts of the state’s electrical generation and transmission system affect the natural environment and human communities. While there is good news on air emissions from natural gas-fired power plants due to declining emission rates, there continue to be serious ongoing impacts to water supplies, water quality and aquatic habitats from the current fleet of natural gas, nuclear and hydro power plants. Impacts to terrestrial ecosystems are well controlled for new power plant cases under Energy Commission jurisdiction, but impacts caused by extant and new transmission lines, natural gas pipelines and non-jurisdictional projects are not as well understood and long-term impacts remain a concern and require further investigation.

Air Quality and Global Climate Change

For many years, air quality has been the focus of environmental attention for the power supply system. Due to air quality regulations and new technologies, the system is quite clean and on a positive trajectory towards further reductions in most areas of the state. California’s reliance on in-state generation from natural gas, the cleanest of the available fossil fuels, benefits the state’s air quality. Statewide, combustion-fired electric generation comprises 3 percent of the state’s average daily inventories of NO_x, 0.47 percent of PM10 and

16 percent of the CO_2 inventory. Between 1996 and 2002, the generation emissions and emission percentages stayed relatively flat.

The older combined cycles have been cleaned up. Implementation of the NO_x emissions control retrofit rules for utility boilers over the last decade has resulted in 80 to 90 percent reductions in NO_x emission rates per MWh from these facilities. Over 85 percent of California combustion-fired generation uses some form of NO_x emission controls. Nearly 21,000 MW, or 60 percent, use selective catalytic reduction for NO_x emission control.

While emissions from power plants in California have improved with cleaner new technologies and tougher air quality rules, air quality levels continue to be poor. Further reductions will be needed from all sectors, including the power system, throughout the state. Improvements are most likely to come from technological advances in emissions control, efficiency improvements and by decreasing reliance on combustion-fired generation through reduced demand or increased use of non-fired electricity sources. The Air Resources Board is investigating whether additional controls on combustion turbines are warranted. These rules will result in retrofit for some units and retirement for others. Agency coordination and research will be critical components to timely and cost-effective advances.

Reductions in residual air emissions (those emissions permitted to occur by environmental regulators) or conservation of natural resources used in energy production and consumption may come from a wide variety of measures. They include:

- Deploying cost-effective energy efficiency measures, which can avoid an environmental effect);
- Conducting energy research that may result in developing beneficial technological advances in energy use, conversion, production or transmission through continuing energy research;
- Decreasing reliance on combustion-fired generation through reduced consumer demands (especially peak); and
- Increasing use of renewable or more efficient electricity sources.

These actions will also reduce greenhouse gas emissions. California's global climate change strategy must deal with the near-term consequences of existing levels of greenhouse gases while we embark on a path to reduce future impacts. Taking appropriate measures to minimize current and future adverse impacts of global climate change is a priority for California, as highlighted by several recent legislative actions. Among states, California ranks second in total emissions, behind only Texas, due primarily to the size of the state's economy and population. Greenhouse gas emissions, on a per person basis in California, are relatively low compared to the rest of the United States.

Water, Biology, and Other Environmental Issues

The impacts on water supply, water quality, and biological resources from new and existing generating facilities are also important elements of the power system's impact on the human and natural environment. Since most of these impacts are localized, for new facilities they can be mitigated in siting cases. Mitigation is an integral part of the cost of new supply, just as much as the cost of a new pipeline or transmission connector.

Power plants use a very small portion of the overall water supply, but like air quality, the impact can be significant in strained resource basins. In new or repowered thermal generation, alternatives to fresh water cooling need to be investigated for local impacts and cost-effectiveness. These impacts include both water use and water quality impacts on surface water bodies, groundwater and land from waste water discharge. For hydroelectric facilities, the primary impacts are on stream flow, water temperature, dissolved oxygen, water management and fish passage. Improvements need to be investigated as part of a balanced relicensing process at FERC.

The biological impacts of new power plants are mitigated as part of the licensing process and can be minimized by building facilities on previously disturbed lands. Serious impacts to aquatic ecosystems on the ocean and in sensitive estuaries are continuing at 21 power plant sites where once-through cooling systems use hundreds of millions of gallons of sea water each day. Opportunities to reduce or mitigate these impacts need to be evaluated in individual repowering cases. Pending federal regulations under the Clean Water Act for these cooling systems may provide further opportunities to mitigate impacts from existing facilities. The two primary areas of emerging concern are habitat disruption from transmission lines and facilities with large land areas such as transmission lines, gas pipelines and wind farms.

Land use, socioeconomic impacts and environmental justice are more closely tied to urbanized areas. In rapidly growing urban areas, energy infrastructure development and repowering often occurs very close to sensitive community resources such as new residential areas, schools, and recreation areas. These local quality of life issues must be addressed.

Chapter 6 Summary: Problems and Risks

California’s electricity and natural gas markets are closely inter-related. Electricity generation demand for natural gas is driving the growth in natural gas demand throughout the United States and in California. Consequently, decisions about building additional natural gas storage, gas pipeline capacity, or an LNG terminal somewhere on the West Coast will affect what consumers pay for electricity. Conversely, development of renewable generation and electricity demand reductions can influence the demand for and price of natural gas. These common markets mean that uncertainties and risks are also linked.

California’s fundamental energy problem stems from the short-term inflexibility of both energy supplies and demand. This constrains the energy market’s ability to respond quickly to adverse shocks to the system. These shocks are not precisely predictable or knowable. They can only be forecasted in a probabilistic sense. These risk factors, however, can be subjected to better identification, assessment and analysis. More rigorous and robust analytical work requires reliable data inputs that can only be provided by greater transparency of market transactions, better monitoring, and improved reporting requirements.

Natural Gas Supply and Availability Concerns

In both the near-term and the long-term, supplies of natural gas will be more costly than the ten-year historic average in the 1990s. The dynamic, competitive natural gas markets will continue to exhibit variation in price over time, primarily in response to supply, demand, and regulatory factors. There is always a risk of unpredictable price volatility, though a repeat of the past three years is not expected.

For natural gas, one challenge is to determine how the infrastructure should be designed to avoid involuntary curtailment of any customer. The problem of how much to store natural gas is compounded by the market design issue of who should store, and who should have the obligation.

Declining output from several producing basins in the "lower 48" states is a long-term concern. There are new supply options within North America, and some additional gas can be gathered within California's borders. Internationally, liquefied natural gas is becoming an option as it becomes cost-effective to cool, move and re-gasify abundant but remote natural gas to load centers. LNG technology, with numerous economic and technological uncertainties and risks, has the promise to shift natural gas from a continent-wide market to a world-wide commodity market. Developing shipping access to natural gas producing basins throughout the Pacific and Indian oceans has the potential for significantly enhancing system reliability, price stability, and environmental performance.

Resource Adequacy Concerns

The state is re-establishing requirements on utilities and energy service providers to ensure that they have procured enough resources to meet their loads. This, coupled with a revitalized market design administered by CA ISO and municipal utility control areas, will stabilize the entry and exit of cost-effective resources. For the three major IOUs, the CPUC is formulating a resource adequacy requirement that may also include a planning reserve margin for direct access load in their service territories. Resource adequacy for individual municipal utilities is being addressed by their elected governing boards. While a clear path has been developed for investor-owned utilities and municipal utilities, it is not yet clear whether the CPUC can enforce requirements for direct access providers.

Chapter 2: Electricity and Natural Gas Demand Trends Assessment

Reliable assessments of the amount, location and timing of demand growth are essential to system operators and policy makers to assess future infrastructure needs and evaluate resource options. This chapter presents the electricity and natural gas demand forecasts and a sensitivity case study prepared by the Energy Commission staff, including a discussion of major uncertainties of those forecasts. More detail on the demand forecast methods and results are presented in the staff technical report titled ***California Energy Demand 2003 – 2013 Forecast***, publication number 100-03-002.

California Electricity Demand: Recent Trends and Drivers

While California has more than half (55 percent) of the population in the western U.S., the state uses only about forty percent of the electricity. In California, improvements in how efficiently we use electricity have largely offset growth, so that per capita use has increased only very slowly. As **Figure 2-1** shows, since the initiation of energy efficiency standards and programs in the mid-1970s, per capita use has been essentially constant, while U.S. and western use has increased. The shaded bars show the effect of economic conditions on usage. Since 1976, per capita use declined on average by two percent during recessions (the shaded bars in **Figure 2-1**), while in non-recession years use typically increased by one half of one percent. Only a small fraction of this variation is explained by weather. In the baseline demand forecast, discussed later in this chapter, this trend of relatively constant use per capita is projected to continue.

Figure 2-2 shows key drivers for the three largest energy-using sectors, residential, commercial and industrial. While population growth, which drives residential energy growth, has been relatively stable, employment growth is more cyclical. In the late 1990s, commercial employment grew almost twice as fast as population (2.8 percent versus 1.4 percent). The growth in the commercial sector, much if it in business, computer, and financial services, increased demand for and use of office space. This rapid growth in the commercial sector is forecast to continue, with three million new jobs created by 2013.

By contrast, manufacturing employment has still never returned to the two million jobs in place before the 1990 recession, although the technology boom turned the job losses of the early 1990s to moderate growth. As with the U.S. in general, manufacturing has been shifting abroad. Industrial employment is forecast to grow at 0.7 percent over the next decade. The value of products shipped increases at less than 3 percent annually over the next ten years, compared to over 5 percent in the 1990s. Within the state, employment and population are expected to increase fastest in the Sacramento and San Diego areas.

Figure 2-1
Total Electricity Use
KWh per Capita, 1960-2001

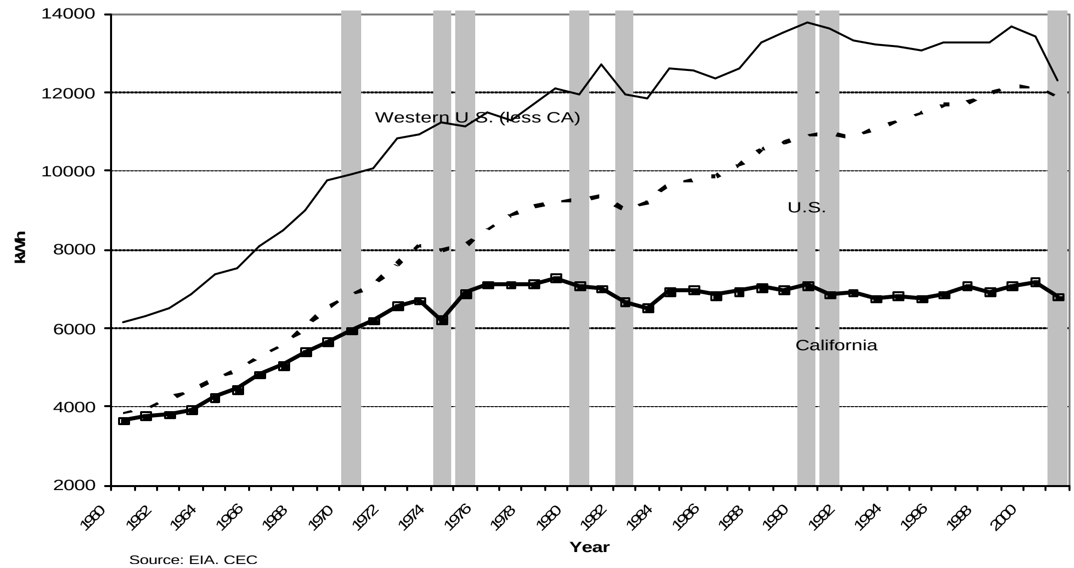
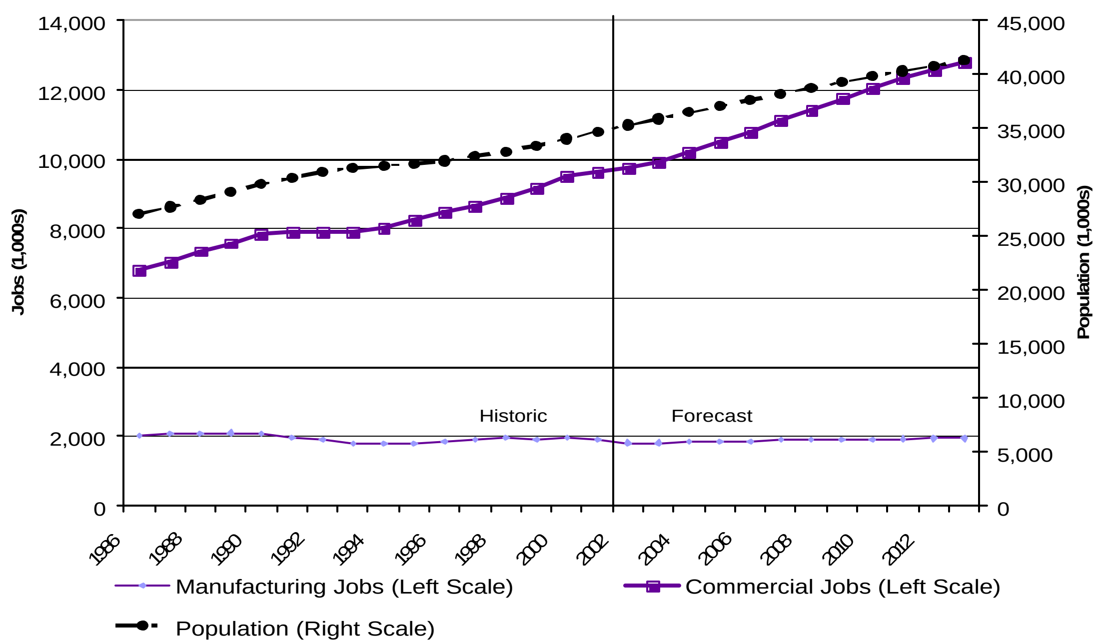


Figure 2-2
California Population and Employment Growth



While a growing population and economy are the fundamental drivers of energy demand, demand growth is also affected by the types of businesses that are developing in California, building and energy efficiency standards and programs, energy prices, and customer behavior. **Figure 2-3** illustrates usage trends for each of the major customer sectors, indexed to 1990. In the residential sector, average electricity use per household has increased one-half percent per year, reflecting higher incomes, larger homes, more homes with air conditioning, and home electronics. This increase in use per household explains only twenty percent of the 1.9 percent per year growth in the residential sector over the last two decades; growth in the number of households explains the rest.

In the commercial sector, businesses have increased electricity use per square foot. Three-fourths of commercial demand growth is due to business expansion – more floor space used by businesses – and one-fourth of growth reflects greater per unit energy use. In the industrial sector, improved productivity has led to greater electricity use per employee; even while employment was stagnant, the contribution of the manufacturing sector to gross state product grew twice as fast as the commercial sector.

Figure 2-3
Electricity Utilization Rates by Sector
1990=100

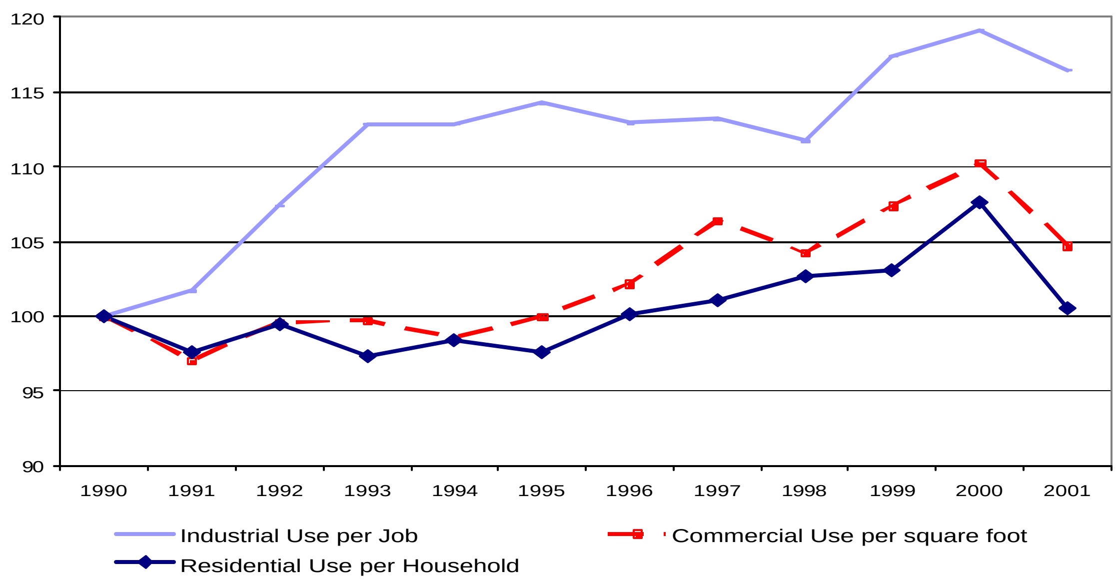
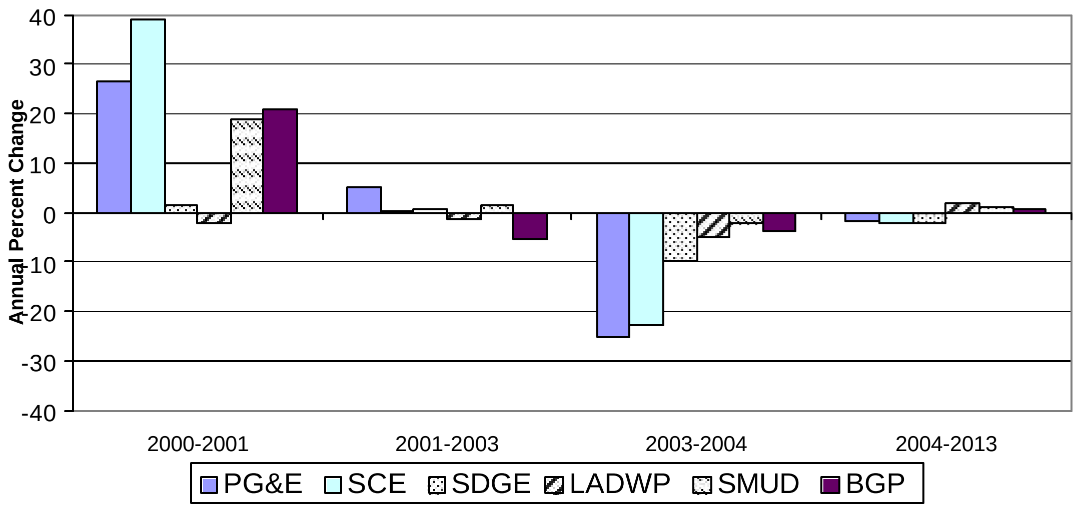


Figure 2-3 also shows the effect of the 2001 energy crisis by sector: usage per household declined by 6.5 percent, commercial by 5 percent, and industrial by 2.2 percent. While these measures are imprecise indicators of utilization, they are roughly consistent with the Energy Commission's analysis of CA ISO data which estimated that weather- and economic-adjusted demand dropped by 6.5 percent in 2001. Most, if not all, of the decline in the industrial sector can be explained as a response to weak economic conditions and higher electricity rates. The residential and commercial decline reflects both investment in energy efficiency and behavioral changes. In the forecast, these usage rates return to an increasing trend.

Electricity rates influence how much electricity businesses and homes use. In the forecast of rates used for this demand forecast, rates stay relatively stable through 2003. As bonds are repaid in 2004, rates drop by 20 to 25 percent for the three largest utilities, shown in **Figure 2-4**. However, under a proposed bankruptcy settlement currently under consideration at the CPUC, PG&E customer rates would drop by 2.5 to 3.5 percent yearly through 2008.

Figure 2-4
Percentage Change in System Average Electricity Rates
(2001 $)



Electricity Demand Futures

The Baseline Electricity Demand Forecast

Tables 2-1 and **2-2** show the annual electricity consumption and peak demand forecasts for selected years by utility (BGP is a composite average for the cities of Burbank, Glendale and Pasadena). These data, both historical and forecast, include the impacts of energy efficiency programs, including building and appliance standards and utility energy efficiency programs. While the robust growth in income and employment of the late 1990s through 2000 is not expected to return, moderate economic growth is forecast to resume in 2004. This, combined with retail electricity rate cuts as bonds are paid off, contributes to demand growth averaging 2.2 percent for 2004 and 2005. For the rest of the forecast period, consumption growth slows to an average of 1.4 percent, as retail rates and economic trends stabilize and the benefits of energy efficiency programs and building standards increase. Peak demand grows by more than 1,000 MW per year for the next five years. For the rest of the forecast, peak growth slows to about 700 MW per year.

Table 2-1
Non-Coincident System Peak Demand by Utility (MW)

Year	PG&E	SMUD	SCE	LADWP	SDG&E	BGP	OTHER	DWR	Total
1990	17,250	2,195	17,647	5,312	2,973	812	801	241	47,231
2000	20,628	2,688	19,757	5,344	3,476	825	1,023	250	53,991
2001	19,413	2,485	17,890	4,805	3,147	729	1,024	131	49,625
2003	20,145	2,657	19,118	5,372	3,806	864	1,049	341	53,351
2006	21,477	2,785	20,629	5,533	4,065	887	1,132	341	56,849
2008	22,206	2,861	21,211	5,588	4,223	888	1,172	341	58,491
2013	23,585	3,055	22,558	5,731	4,530	894	1,354	341	62,048
Annual Growth Rates (%)									
1990-2000	1.8	2.0	1.1	0.1	1.6	0.2	2.5	0.4	1.3
2000-2003	-0.8	-0.4	-1.1	0.2	3.1	1.6	0.8	10.9	-0.4
2003-2008	2.0	1.5	2.1	0.8	2.1	0.6	2.2	0.0	1.9
2008-2013	1.2	1.3	1.2	0.5	1.4	0.1	2.9	0.0	1.2
2003-2013	1.6	1.4	1.7	0.6	1.8	0.3	2.6	0.0	1.5

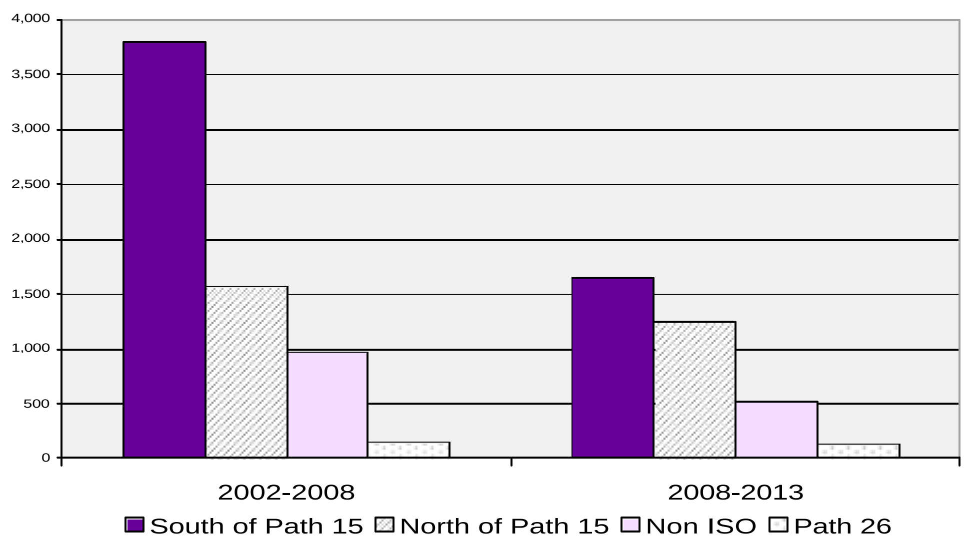
Table 2-2
Electricity Consumption by Utility Planning Area (GWh)

Year	PG&E	SMUD	SCE	LADWP	SDG&E	BGP	OTH	DWR	TOTAL
1990	86,806	8,358	81,673	21,971	14,798	2,951	3,310	8,171	228,038
2000	101,980	9,491	96,496	23,803	18,791	3,320	4,227	5,490	263,599
2001	98,748	9,334	90,506	23,265	17,822	3,275	4,230	6,349	253,528
2003	98,597	9,563	90,419	23,703	18,663	3,380	4,262	7,889	256,476
2006	105,101	10,060	97,637	24,570	19,988	3,504	4,580	7,889	273,329
2008	108,699	10,388	100,745	24,935	20,847	3,530	4,740	7,889	281,773
2013	115,507	11,172	107,654	25,839	22,518	3,592	5,415	7,889	299,586
Annual Growth Rates (%)									
1990-2000	1.6	1.3	1.7	0.8	2.4	1.2	2.5	-3.9	1.5
2000-2003	-1.1	0.3	-2.1	-0.1	-0.2	0.6	0.3	12.8	-0.9
2003-2008	2.0	1.7	2.2	1.0	2.2	0.9	2.2	0.0	1.9
2008-2013	1.2	1.5	1.3	0.7	1.6	0.4	2.7	0.0	1.2
2003-2013	1.6	1.6	1.8	0.9	1.9	0.6	2.4	0.0	1.6

Peak Demand by Transmission Zone

To anticipate infrastructure needs and manage congestion, system operators need to know where growth is likely to occur. Congestion occurs on the grid when there is not enough transmission capacity to accommodate load, generation, or interchange requirements. The CA ISO service area, which comprises about 88 percent of California demand, uses three zones to manage congestion: South of Path 15, North of Path 15, and zone Path 26. North of Path 15 is largely Northern California. SCE, SDG&E, and other areas in Southern California constitute the South of Path 15 zone. Zone Path 26 is made up of the southern portion of the PG&E system. **Figure 2-5** shows growth in peak demand by zone. Demand is expected to grow fastest in the South of Path 15 area, increasing 3,800 MW (seventeen percent) by 2008.

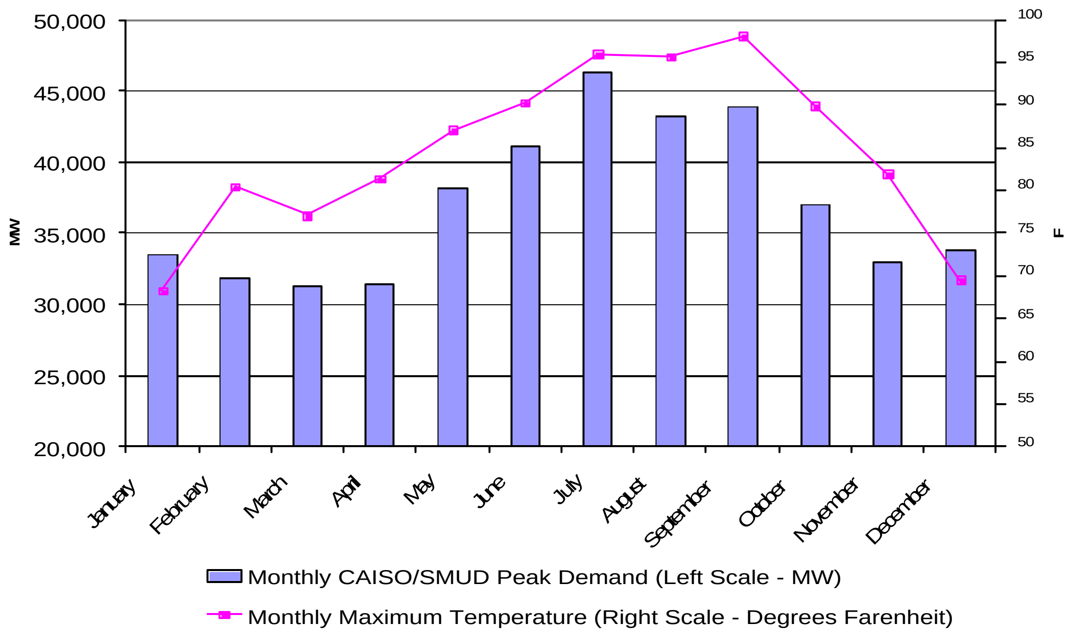
Figure 2-5
Increase in Non-Coincident Peak Demand by Transmission Zone (MW)



Peak Demand and Weather

Peak demand in a given year or month varies greatly with temperature. **Figure 2-6** shows 2002 monthly peak demand for the CA ISO and SMUD areas combined, and the maximum statewide average temperature for each month. The Energy Commission uses temperature data from ten weather stations throughout the state to account for the effect of weather on peak demand in each utility planning area. The peak for 2002 was on Wednesday, July 10 when the average temperature (weighted by distribution of air conditioning load) exceeded 96 F^{o}. In this case, the peak demand day did not fall on the hottest day of the year, September 2, because that was a Monday holiday.

Figure 2-6
CA ISO/SMUD 2002 Monthly Peak Demand and Maximum Temperatures



To account for the effect of temperature on demand, the Energy Commission develops demand forecasts for varying degrees of hotter than average temperatures. The baseline peak demand forecast assumes average temperatures—temperatures that are expected to occur, on average, in one out of every two years (one-in-two). To account for warmer than average conditions, temperature sensitivities for 1-in-five, -ten, and -forty weather conditions are applied to the baseline peak demand forecast. The resulting coincident peak demand weather scenarios are shown in **Figure 2-7**. The one-in-five scenario, which has a twenty percent chance of occurring in any year, increases peak demand by 3.6 percent. In the one-in-ten scenario demand is increased by 6.1 percent, while in the one-in-forty scenario demand is increased by 8.5 percent.

The distribution of load over the course of the year is an important characteristic of demand. LSEs and system operators must plan for sufficient capacity to meet peak demand, but in off-peak hours only some fraction of that capacity will be used. The load factor, defined as average demand relative to peak demand, measures the extent to which capacity is being used. A load factor of 100 percent would mean demand is constant in all hours, so there need be no unused capacity in any hour. Conversely, a low load factor means much of the resources needed to meet demand in the peak hour sit idle in other hours. While the increasing proportion of homes and businesses with air conditioning has caused load factors to trend down, load factors vary year to year depending on weather, as shown in **Figure 2-8**. For example, 1998 was overall a very cool year except for a brief hot spell, so average hourly demand was much less than the peak hour, resulting in a load factor of only 52.7 percent. In

2001, the load factor was up to 60 percent as businesses and consumers chose to use less air conditioning in response to the energy crisis.

Figure 2-7
Coincident Peak Demand (MW)
Normal and Hot Weather Scenarios

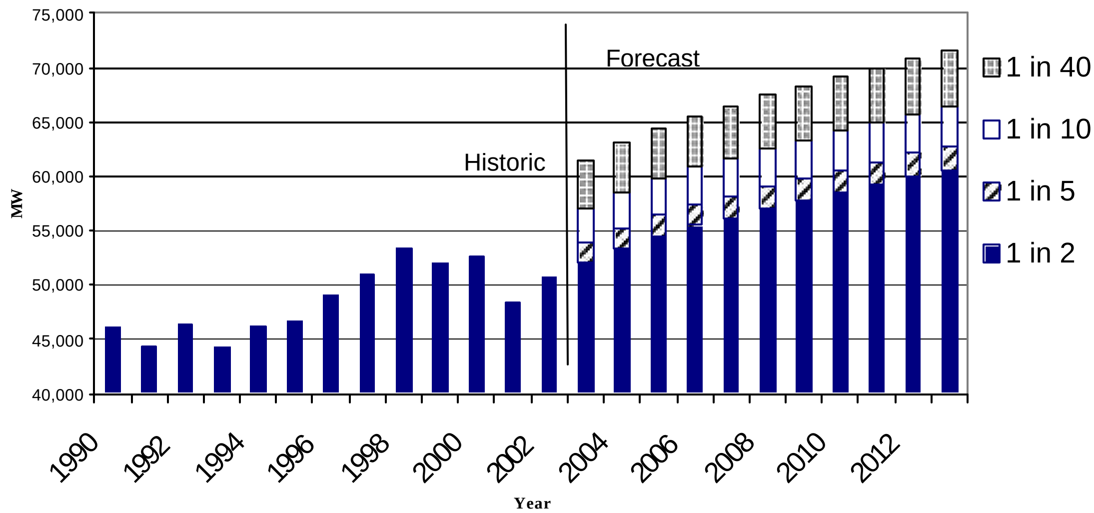
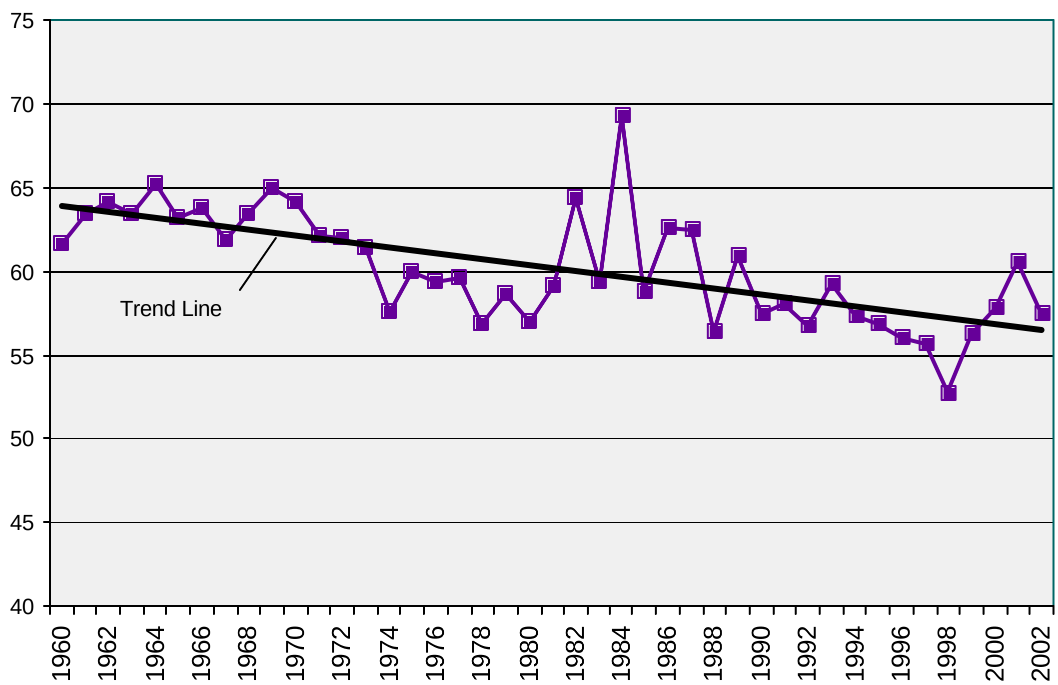


Figure 2-8
California Annual Load Factors (%)



Electricity use varies widely over the time of day and time of year. In a typical day, use increases 60 percent from the midnight low to the afternoon high. On a hot summer day, this swing is 85- 90 percent. To supply this variable load requires a generation system that can respond to these swings.

Demand response or load management programs can increase the load factor by shifting demand away from peak hours. On the other hand, while energy efficiency programs or building standards may contribute to a lower absolute peak, they may also increase the load factor - they reduce off-peak demand more than they reduce on-peak demand. In the Energy Commission's peak demand forecast, load factors are projected to remain at about 57 percent.

A Range of Demand Futures

While Energy Commission demand forecasts have historically been reasonably accurate, they have tended to err on the high side. That tendency may be less likely in this forecast. Major sources of forecast error are uncertainty in the economic forecast, price forecast, and usually conservative assumptions about uncertain trends. For example, the ***California Energy Demand 2002-2012*** (***CED 2002***) forecast was 8 percent higher than the current forecast in 2008, reflecting the more optimistic outlook on the economy at that time. Because current economic forecasts reflect greatly reduced expectations, this forecast may be less likely to overestimate future demand.

This forecast assumes utility energy efficiency programs will be funded at current levels through 2011, as approved by the Legislature. This is a less conservative assumption than past Energy Commission practice, when typically not more than three years of future funding were assumed, as approved in the CPUC ratemaking cycle. However, since the completion of this forecast, the three major utilities have proposed significant increases in spending on energy efficiency programs for 2004 – 2008 in the ongoing CPUC procurement proceeding. So while it is more uncertain whether the assumed savings in the latter part of the forecast will be achieved, in the near term savings will likely be higher.

The utilities estimate that this incremental spending would achieve 800 MW (4,277 GWh) by 2008. The Commission has not yet developed its own forecast of the impacts of these proposals. However, historically, rapid increases in energy efficiency program spending have typically delivered less than proportionate increases in energy savings.

To quantify the potential impact on demand of unanticipated economic or energy efficiency trends, the Energy Commission developed several sensitivities to assess the effect of uncertainty on infrastructure and supply adequacy.

Economic Cases

The baseline forecast assumes that stronger economic growth will resume in 2004, followed by steady growth, but at a lower rate than previous recoveries. The high economic growth scenario reflects the effects of a more robust economy on energy demand. Over the last twenty years, the average annual post-recession employment growth rate has averaged about one percent higher than the growth rate assumed in the baseline employment forecast. To estimate the effects of stronger economic growth on energy demand, the employment forecast was accelerated to achieve a new forecast with an annual growth of slightly more than 1 percent higher for the years 2004-2007. Other economic drivers for the sector forecasts were also accelerated by one or two years for similar results. After 2007, the baseline forecast trend resumes. The resulting forecast is very similar to the ***California Energy Demand 2002*** forecast.

Conversely, to develop a low economic growth sensitivity, the forecast growth beginning in 2004 is delayed by one to two years so that growth on average is slightly more than 1 percent lower than the baseline economic forecast. **Table 2-3** summarizes key economic drivers under each case.

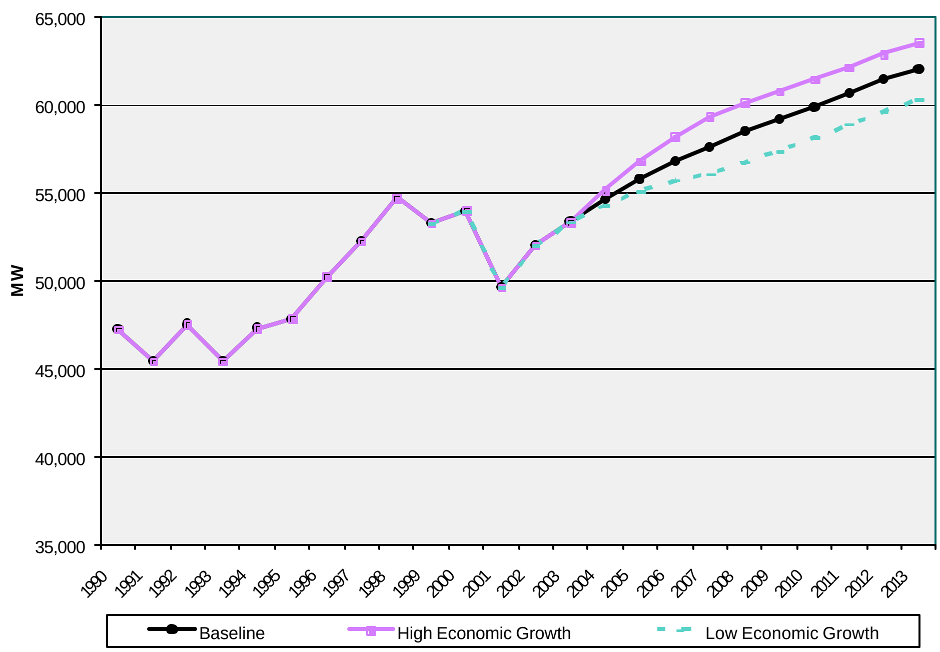
Table 2-3 summarizes these sensitivity cases and their effects on forecast electricity demand. In the highest case, an increase in economic growth increases energy consumption by more than 8,300 GWh in 2008. In the low economic growth case, demand is about 8,400 GWh lower in 2008. **Figures 2-9 and 2-10** show the forecasts of peak and net energy for load, which is the amount of energy including losses that must be served by the grid.

Table 2-3
Summary of Demand Sensitivity Cases

Sensitivity Name	Description	Average Annual Load Growth 2004-2008	GWh Difference in 2008
Baseline		1.9%	0
High Economic Growth	Economic growth 2004-2008 one percent higher than baseline	2.3%	8,330
Low Economic Growth	Economic growth 2004-2008 one percent lower than baseline	1.3%	-8,397
High DSM	Doubling of energy efficiency spending 2004-2013	1.3%	-6,258
Low DSM	Elimination of energy efficiency spending 2004-2013	2.3%	5,991

How likely are these sensitivity cases? Because economic outcomes are a result of interactions of many variables, we cannot easily calculate probabilities of future events based on the past. For example, while previous recessions were driven by declines in consumer spending, the recession that began in 2001 has been driven by a decline in business investment. Therefore previous post-recession periods do not provide a valid comparison for predicting future outcomes. While it is virtually certain that sometime in the next ten years we will experience a business cycle higher or lower than anticipated, under current economic conditions, these specific sensitivities probably each have between 10 and 20 percent likelihood. These are not worst case scenarios, but are intended to provide a plausible range of outcomes for infrastructure assessment.

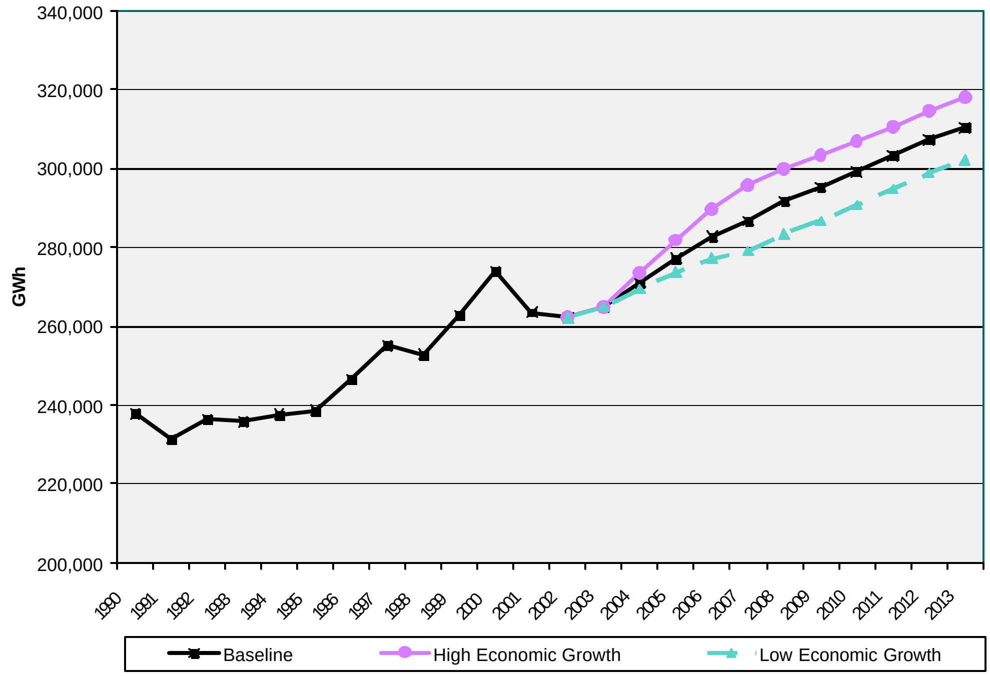
Figure 2-9
Statewide Demand Forecast
Net Peak (MW)



Energy Efficiency Cases

The baseline electricity forecast reflects the assumption that current levels of funding for utility energy efficiency programs will continue through 2011, as authorized by the Legislature. To estimate the effect on demand of increased investment in energy efficiency, sensitivity cases were developed as part of a recent series of studies of energy efficiency savings potential in California.[1] These studies estimated the amount of cost-effective, achievable potential available statewide, and then estimated how much of that potential would be attained at alternative funding levels. These studies use Energy Commission data as the foundation of their analysis, so the results are largely consistent with the assumptions embedded in the baseline forecast.

Figure 2-10
Statewide Demand Forecast
Net Energy for Load (GWh)



The high demand-side management (DSM) case estimates the effect on demand of roughly doubling the amount of energy efficiency spending statewide beginning in 2004 and continuing through 2013. Increasing public goods charge (PGC) spending on electricity efficiency to $572 million per year from $240 million per year (based on average spending 1996-2000), reduces peak demand by about 1,800 MW in 2013. Eliminating all spending on energy efficiency after 2003 would increase peak demand in 2013 by about 1,900 MW. These scenarios and their policy implications are discussed in more detail in the ***Public Interest Energy Strategies Report***, publication number 100-03-012.

In **Figures 2-11 and 2-12,** the DSM case results are shown per capita. In the high DSM case, per capita consumption declines by about 240 kWh per person (more than three percent) by 2013, compared to almost constant use per capita in the baseline. Without any future spending on energy efficiency programs, per capita consumption would increase by more than three percent by 2013.

Figure 2-11
Statewide DSM Electricity Consumption per Capita (kWh)

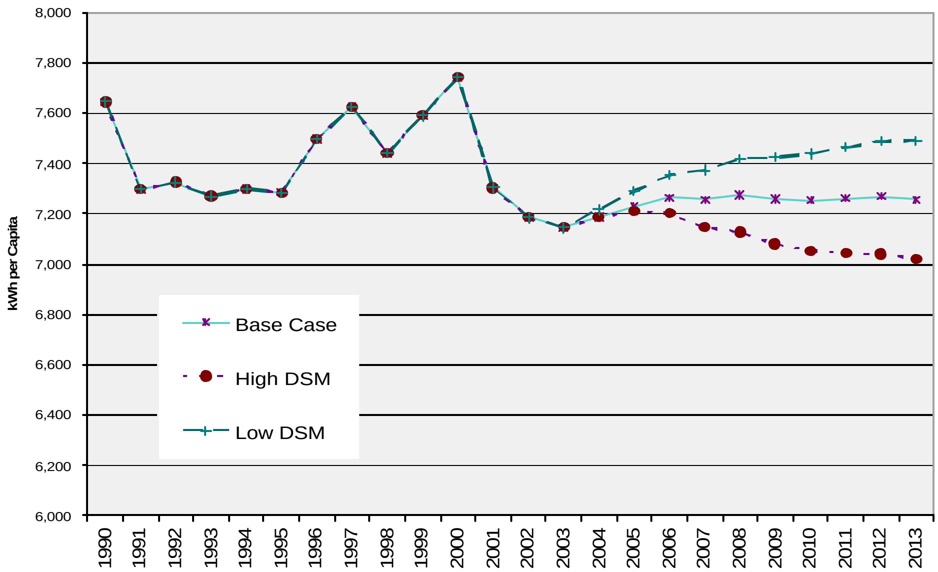
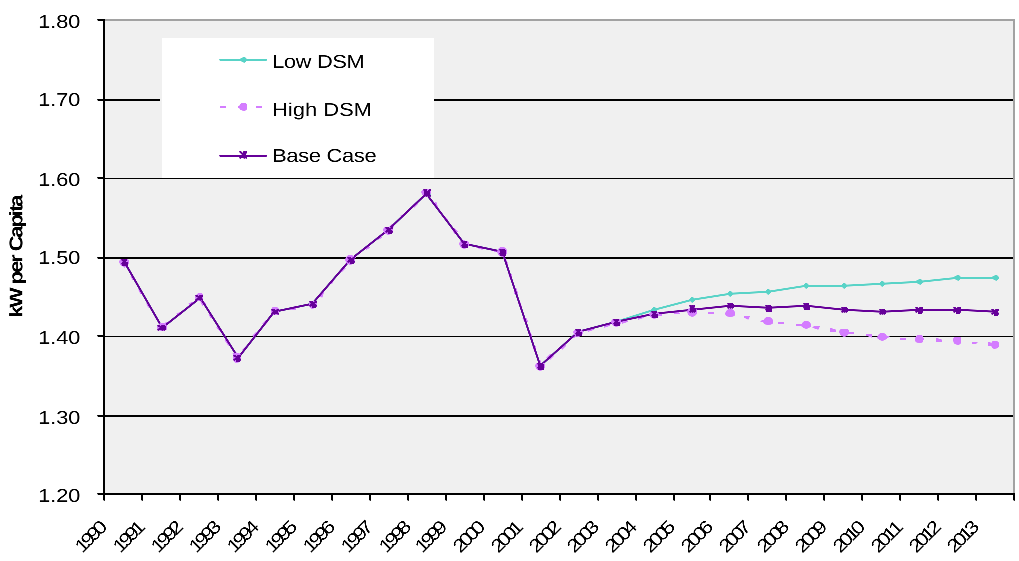


Figure 2-12
Statewide Electricity DSM End Use Peak Demand per Capita (kW)



Other Uncertainties that May Affect the Forecast

Rate Structures and Levels

These forecasts assume that current rate structures continue, in which case most electricity customers are not exposed to prices that vary in response to market conditions or time of use. If increasing numbers of customers are subject to dynamic pricing or other more variable rate structures, increased investment in energy efficiency and behavior changes such as load shifting could affect both peak and annual energy demand.

Privately Supplied Energy

Electricity consumption needs that are met by self-generation or distributed generation reduce the demands on the grid. About 4 percent of the total electricity consumption reported in **Table 2-2** is served by this privately supplied energy, such as cogeneration. Private supply is different from sales to direct access customers, which are served by the grid. About 10 percent of current and forecast annual consumption represent sales by direct access providers.

After several years of no growth, private supply has increased by about ten percent over the last three years. This is a result of the energy crisis, changes in the regulatory environment, and higher rates, but it is not yet clear whether this more favorable environment for increased off-grid private supply will continue. After 2003, privately supplied load is assumed to grow at one percent per year. This conservative estimate is used because of the uncertainty of the effects of regulatory policy on the economic attractiveness of self-generation. If private supply grows faster than anticipated, the demand for energy from the grid is reduced. For example, if private supply were to grow at five percent per year, peak demand would be reduced by about 430 MW in 2008 compared to the baseline forecast.

Effects of the Energy Crisis

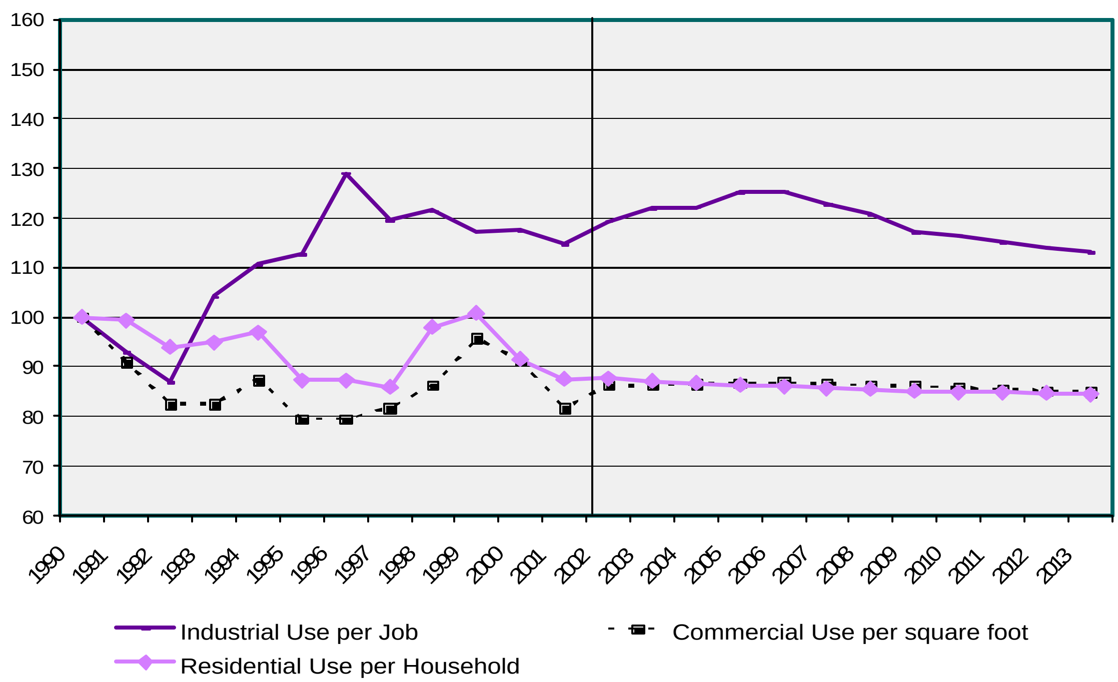
The energy crisis of 2001 motivated a dramatic response from customers. While some of this was the effect of investments in energy efficiency that will persist for many years, a large portion of the response was voluntary behavior change, e.g., not running air conditioners. For 2002, the Energy Commission estimates that about one-third to one-half of this reduction in annual energy consumption remained. After dropping by more than 3,000 MW in 2001, statewide non-coincident peak demand increased by 2,375 MW in 2002, as the need for public response to the crisis ended. This reduction in crisis-driven conservation behavior in 2002 is accounted for in the forecast, and the forecast assumes the remaining behavioral conservation will gradually diminish. By 2005, commercial use per square foot is expected to return to the levels of the late 1990s. However, residential consumption per household does not return to those levels until 2007. If this conservation behavior diminishes more rapidly, residential peak demand could grow more quickly than forecast.

California Natural Gas Demand: Recent Trends and Drivers

California natural gas demand is composed of about two-thirds from end-users – consumers in homes and businesses - and one-third from electric generation facilities. While end-user demand has increased relatively slowly over the last decade (less than one percent per year), gas used to fuel gas-fired power plants has increased by an average of 4.5 percent per year since 1990.

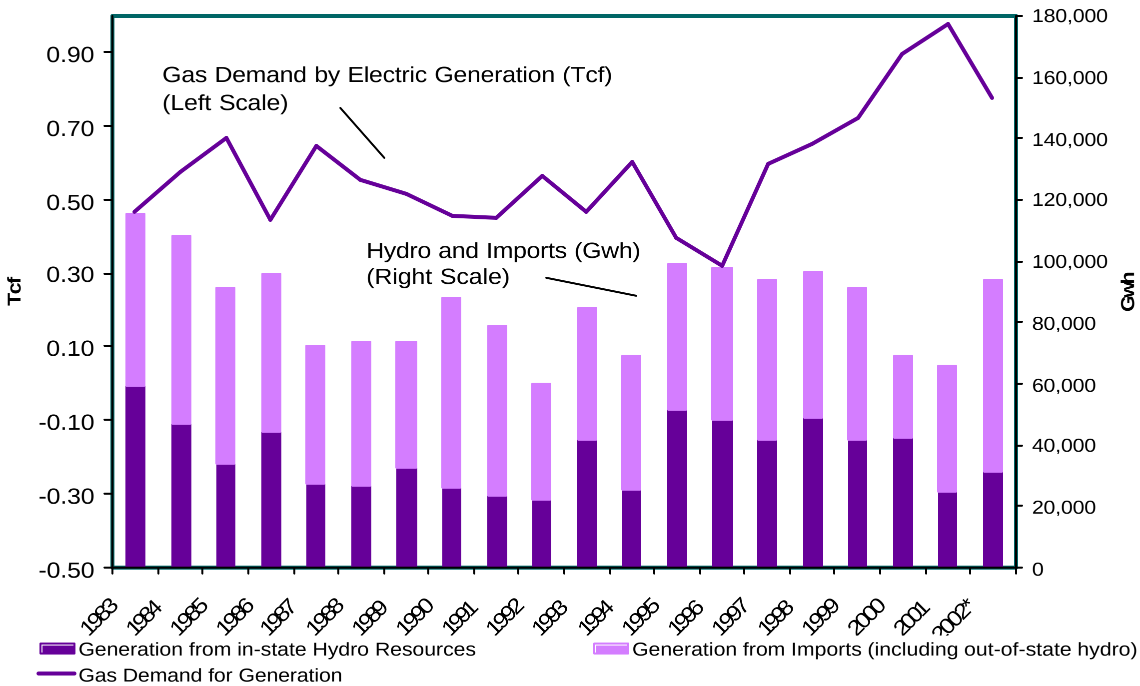
End-user natural gas demand is affected by weather, economic and demographic trends, and building and heating efficiency. Residential use per household, shown in **Figure 2-13**, has generally declined reflecting savings from building and appliance standards. The exceptions to this trend, such as 1998 and 1999, were years with much cooler temperatures causing increases in demand for heating. The commercial sector shows a similar trend, although with utilization declining more during periods of economic weakness. In manufacturing, increasing energy use in the 1990s reflects in part a shift away from petroleum-based fuels to cleaner-burning natural gas. With that transition complete, manufacturing usage is relatively flat.

Figure 2-13
End-User Natural Gas Utilization Rates by Economic Sector
1990=100



Gas demand for utility electricity generation (UEG) is driven by the amount and efficiency of in-state gas-fired generation facilities, weather conditions that affect the availability of hydroelectric resources, and the demand for electricity. **Figure 2-14** shows how gas demand for generation typically declines in years with high hydro and other imports. UEG demand low points correspond to high hydro years of 1983, 1995, and 1996. By the late 1990s, declining hydro and imports, little new in-state generation, and a healthy economy meant demand growth had to be met by running older, less efficient plants more heavily. Natural gas use for electricity generation reached a historic high in 2001 of 0.98 TCF (trillion cubic feet) with the combination of low availability of hydroelectric power and other imports.

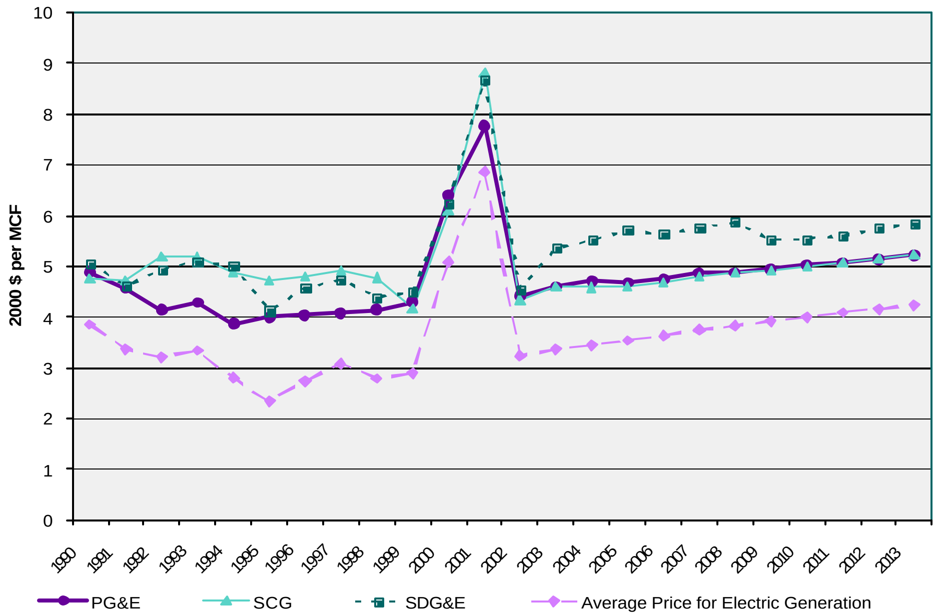
Figure 2-14
Natural Gas Demand for Electric Generation
(Trillion Cubic Feet)



Natural Gas Prices

The retail price forecast used for the demand analysis is shown in **Figure 2-15.** After forty percent increases during the energy crisis in 2000 and 2001, natural gas prices in 2002 fell back to 1999 levels. Prices are expected to increase at less than two percent annually, on average.

Figure 2-15
System Average Natural Gas Prices
$2000 per MCF



Natural Gas Demand Futures

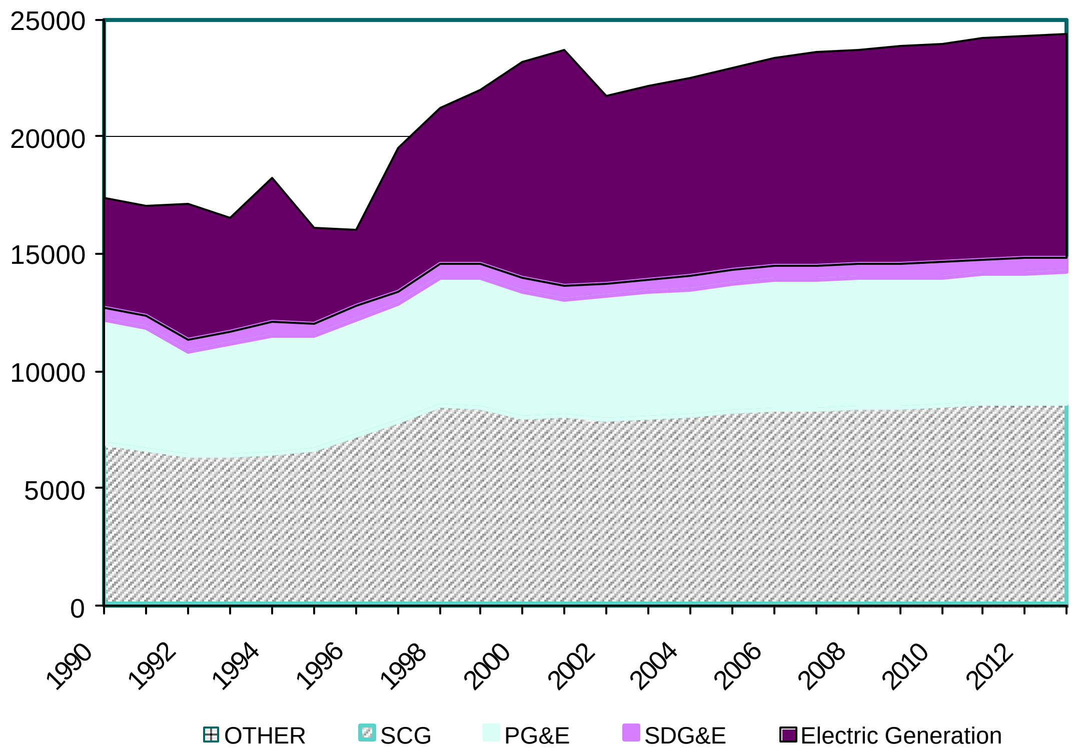
Baseline Natural Gas Demand Forecast

The Energy Commission's forecast for total natural gas demand increases at an average of 1.0 percent per year in California from 2003 to 2013. This represents less than half of the annual rate by which total U.S. natural gas demand is projected to grow during the same period. Gas demand for electricity generation remains the fastest growing segment of California's natural gas demand. From 2003 to 2013, natural gas demand in California will increase as follows:

- **Core demand** (including residential, commercial, and smaller industrial customers) will increase from 0.66 to 0.73 trillion cubic feet (Tcf), a rate of 0.9 percent per year.
- **Non-core demand** (large industrial customers) will increase from 0.74 to 0.77 Tcf, an annual growth rate of only 0.4 percent.
- **Electric generation demand** will increase from 0.8 to 0.93 Tcf, or 1.5 percent per year.

Figure 2-16 shows historic and forecast natural gas consumption for each California natural gas utility planning area—PG&E, SDG&E, Southern California Gas (SCG), and Other, and for electric generation. The natural gas demand data, both historical and forecast, include the impacts of natural gas energy efficiency programs, including building and appliance standards and utility energy efficiency programs. This forecast assumes that current levels of funding for utility energy efficiency programs will continue through 2011, as authorized by the state Legislature.

Figure 2-16
Natural Gas Consumption by Utility Planning Area
(Millions of Therms)



After dropping more than 6.5 percent in response to the gas price spikes of 2000-2001, end-user natural gas demand is expected to increase at a rate of 0.6 percent per year over the next ten years. Demand in PG&E territory increases at less than a half percent per year, as a result of weak economic growth and declining demand in the industrial sector. In SDG&E, higher than average population and economic growth produce the strongest demand growth (1.3 percent). **Figure 2-17** shows statewide demand by economic sector. Growth is strongest in the commercial and residential sectors (averaging 1 percent and 0.9 percent per year respectively), and weakest in the industrial sector (-0.1 percent per year).

Figure 2-17
Statewide Natural Gas Consumption by Economic Sector
(Millions of Therms)

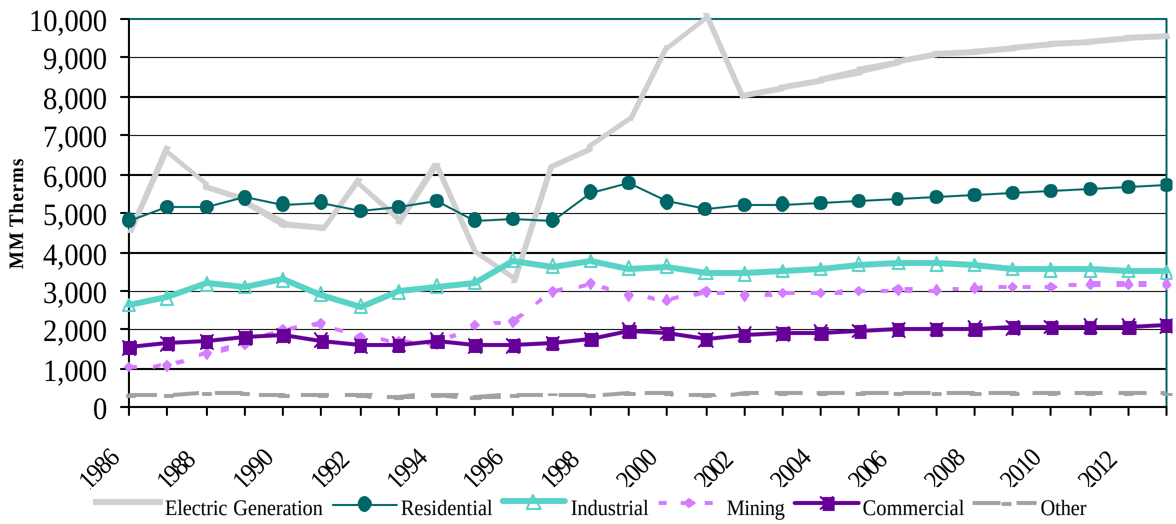


Figure 2-18 illustrates natural gas demand in California, by natural gas market sector. Total California natural gas demand grows 8 percent from 2003 to 2010. Three-fifths of this increase comes from power generation. If electricity generation gas use were held constant at the 2003 level, total demand for the state would only grow four percent.

Alternative Natural Gas Demand Futures

To quantify the potential impact on natural gas demand of unanticipated economic or energy efficiency trends, the Energy Commission developed several sensitivity cases to support our evaluation of the implications to the natural gas infrastructure. **Table 2-4** and **Figure 2-19** summarize these cases and their effects on forecast demand. See the electricity demand section for discussion of the case definitions. In the highest demand case, an increase in economic growth increases the natural gas use by 2.6 percent in 2008. In the low economic growth case, demand is about 2 percent lower in 2008. The demand-side management (DSM) scenarios have a much smaller effect on gas demand.

Figure 2-17
Forecast Natural Gas Demand in California by Market Sector

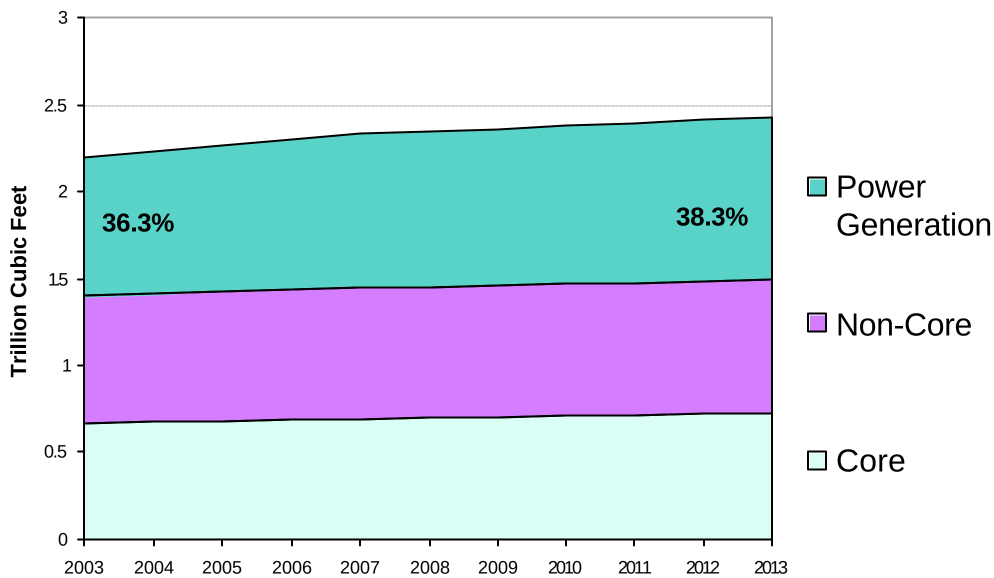
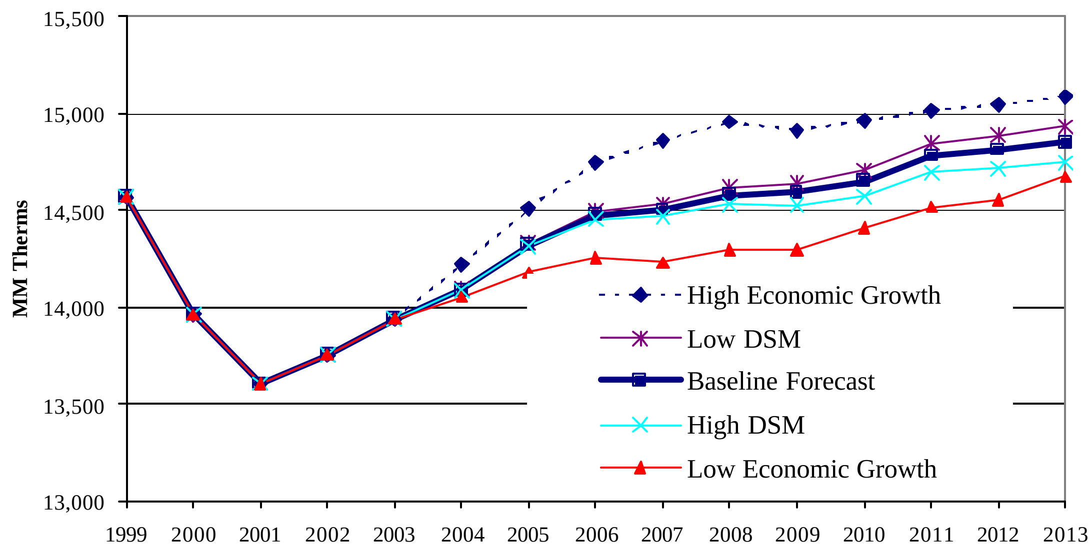


Table 2-4
Summary of Natural Gas Demand Forecast Sensitivity Cases

Scenario Name	Description	Average Annual Demand Growth 2004-2008	MM Therms Difference in 2008
Baseline		0.9%	0
High Economic Growth	Economic growth 2004-2008 1 percent higher than baseline	1.4%	377
Low Economic Growth	Economic growth 2004-2008 1 percent lower than baseline	0.5%	-280
High DSM	Doubling of energy efficiency spending 2004-2013	0.8%	-50
Low DSM	Elimination of energy efficiency spending 2004-2013	1.0%	40

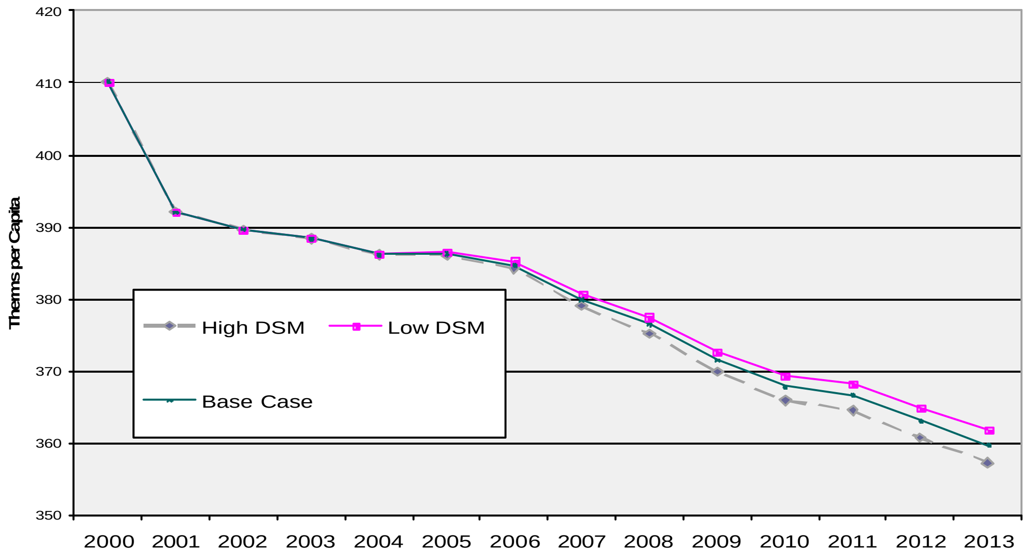
Figure 2-19
Statewide Natural Gas Demand Cases
(Excluding Fuel Demand for Electric Generation)



The natural gas high DSM case estimates the effects of roughly doubling spending on energy efficiency programs for the residential and commercial sectors. Increasing spending on natural gas efficiency to $71 million per year from $37 million per year (based on average spending 1999-2000) reduces demand by about 103 million therms in 2013. No data were available on industrial energy efficiency potential, so industrial demand is unchanged in the DSM scenarios. The low DSM scenario assumes that no utility energy efficiency spending continues after 2003.

Figure 2-20 shows the effect of the DSM cases on per capita natural gas demand. In the high DSM scenario, per capita consumption declines by 8 percent by 2013, compared to only a 7.4 percent decrease in the baseline. Without any future spending on energy efficiency programs, per capita consumption would decline more slowly, decreasing by less than 7 percent by 2013.

Figure 2-20
Statewide Natural Gas Savings by Sensitivity Cases
Therms per Capita



Chapter 3: Electricity Infrastructure Assessment

This chapter begins with a brief description of how the expansion and operation of the electricity generation, electricity transmission, natural gas supply and natural gas pipeline infrastructure are integrated. Then a brief description of the state's existing electricity generation and transmission system is provided, followed by an assessment of current (2003) electricity market conditions. With that foundation laid, the chapter next assesses the near-term (2004-2006) market conditions, providing a near-term electricity supply and demand balance and a discussion of a variety of uncertainties that need to be managed during this period.

The latter part of the chapter discusses the results of longer term (2007-2013) sensitivity analyses. These sensitivity cases are focused on identifying the potential effects on the natural gas supply and transmission infrastructure of variations in key uncertainties affecting the electricity market. Collectively, these sensitivity studies, together with the preceding short-term market assessments, provide the background for the discussion of long-term electricity market problems and potential policy options found in Chapters 5 and 6.

Integration of Electricity and Natural Gas Markets and Infrastructure

California's electricity and natural gas system must supply as much power and fuel as people demand, at both the immediate moment and location of that demand. This complex interaction among consumer habits, generation, pipelines, transmission lines, fuel sources and fuel storage facilities must be designed to achieve safe, reliable, affordable energy services. The electricity and natural gas that are delivered on demand to end-users comes to them via a physical infrastructure that stretches across Western North America. In each case, the customers are connected to local distribution systems, which are in turn connected to higher volume regional transmission systems. The transmission systems are supplied by a widespread network of conversion (power plant) or collection (wellhead) facilities, which depend on a variety of fuel or primary energy sources from different locations and with different characteristics.

Primary energy supplies for electric generation can be coal, uranium, geothermal heat, wind, the heat or light of the sun, biomass, landfill or agricultural digester gas, oil, or natural gas. Each of these primary energy sources of electricity has its own geographic distribution, determining which resources are economic to develop and by whom. Likewise, the primary energy sources of the natural gas delivered to end users are geographically widespread. Even if the physical nature of these different gas supplies (e.g., heat content of the gas) is somewhat similar, the techniques and costs of mining them can be very different.

Electricity cannot be stored in large quantities and is generated virtually at the instant it is demanded, with the primary energy source being consumed at that moment. Delivering power on demand to the end user at the precise voltage and frequency required by electrical appliances requires the coordinated planning, development and operation of the network of distribution wires, high voltage transmission lines, and generating plants. Reliable service is a function of this system as a whole, not any individual part. As the demand for power on the system changes from second to second, corresponding adjustments are made to the operating level of generating units across the system to precisely balance supply and demand. At times of highest power demand, usually on hot summer days, “peaking capacity” resources reserved for this situation are dispatched to maintain the system’s supply and demand balance. Since natural gas is the prime fuel of these peaking power plants as well as many of the power plants dispatched before and more often than the peaking plants, electricity and natural gas supply and transmission infrastructures are linked—as are the prices of the wholesale electricity and natural gas markets.

Natural gas is consumed directly by end-users as a fuel in the residential, commercial, industrial sectors, and to a lesser extent in the transportation sector. Cold winter weather is a major driver of this end-use demand for gas. Another major end-use of natural gas is as a feedstock in the industrial sector. Increasingly, natural gas is an important fuel for the generation of electricity. The consumption of natural gas for electric generation is the largest driver of the long-term trend of increasing demand for natural gas. To complicate matters, there can be large annual variations in natural gas demand for electric generation because gas-fired generation is the system’s marginal source of electricity. Generally higher temperatures and low availability of hydroelectric (or other) generation resources are made up by increased gas-fired generation. Conversely, gas-fired generation will be cut back if temperatures are milder and other generation supplies are abundant.

Delivering natural gas on demand to the end-user requires the coordinated planning, development and operation of the network of distribution pipeline, high volume transmission pipeline system, gas storage facilities, and supply sources. As mentioned above, the electricity and gas infrastructures are linked by the key role of gas-fired electricity generators, whose generally upward trending but annually variable gas demand is a key factor in natural gas infrastructure issues. So, maintaining an adequate natural gas infrastructure also requires coordinating its planning, development and operations with that of gas-fired electricity generators. Unlike electricity, natural gas can be stored (in peaking storage facilities). This gives the natural gas system more flexibility than the electricity system in supplying peak gas demand. However, having an adequate infrastructure to meet peak gas demand is as important for the gas system as it is for the electric system to meet its peak demand.

Existing Electricity Supply and Transmission Infrastructure

Generation Resources

California's demand for electricity is served by a mixture of resources. Energy is provided from plants that are owned by California utilities, independent generators, and federal and state agencies. The more than 54,000 MW of capacity producing energy[2] include plants using gas and oil (54 percent of capacity), hydropower (16 percent), nuclear (11 percent), coal (9 percent), and renewable energy sources (9 percent). Energy is provided from plants that are owned by California utilities (48 percent of capacity), merchant generators (35 percent), qualifying facilities (11 percent) and federal and state agencies (7 percent). California utilities own more than 6,200 MW of capacity in Arizona, Nevada, Utah and New Mexico. In addition, out-of-state utilities provide energy to California under long-term contract and through spot market sales. A detailed description of California's generation facilities is contained in the companion document: the ***2003 Environmental Performance Report***, publication number 100-03-010**.**

Natural gas-fired power plants have become the capacity of choice among developers in California, as they are more efficient, more flexible to site and operate, and cheaper and cleaner than many other central station options. This has resulted in an increased reliance on natural gas as a generation fuel. **Figure 3-1** shows the growth of gas-fired generation from its 25 percent share twenty years ago. Today, 35 - 40 percent of the electricity consumed in California is generated using natural gas. The figure also illustrates the variability of hydro generation in both California and in the Northwest, the latter reflected in the amount of energy imported. Combining in-state and out-of-state sources, hydropower's contribution ranges from a low of 12 percent in 2001 to a high of 45 percent in the very wet year 1983.

Much attention has been focused recently on the state's older gas-fired power plants. These plants have varying characteristics and provide a range of services including baseload energy, load, following, and reserve support. However, there is continued concern over the cost, reliability, function and emissions of these power plants. **Table 3-1** shows the age distribution of power plant capacity and each age cohort's share of total 2002 energy generation.

While almost half of the natural gas-fired generation capacity were built between the 1950s and 1960s, the data reported in the staff report on ***Aging Natural Gas Power Plants in California*** (publication number 700-03-006) do not suggest that these older plants are all dirty or inefficient. Though the overall age of these facilities raises a degree of concern, consideration of the efficiency and emissions profiles of these units suggest that the vast majority of this capacity is from units that have installed current emission control equipment are reasonably efficient. In addition, more than 25 percent of the state's gas fired-generation capacity was either built or has been repowered since 2000.

While the retirement of older plants can be anticipated during the remainder of the decade, the modernization of California's generation fleet is under way. More than 2,100 MW of capacity that was more than 40 years old have been retired or are scheduled be retired by the end of 2003, another 825 MW that are more than 30 years old are also being taken off-line by 2004.

Figure 3-1
Sources of California Electrical Energy Consumption
1983 - 2002

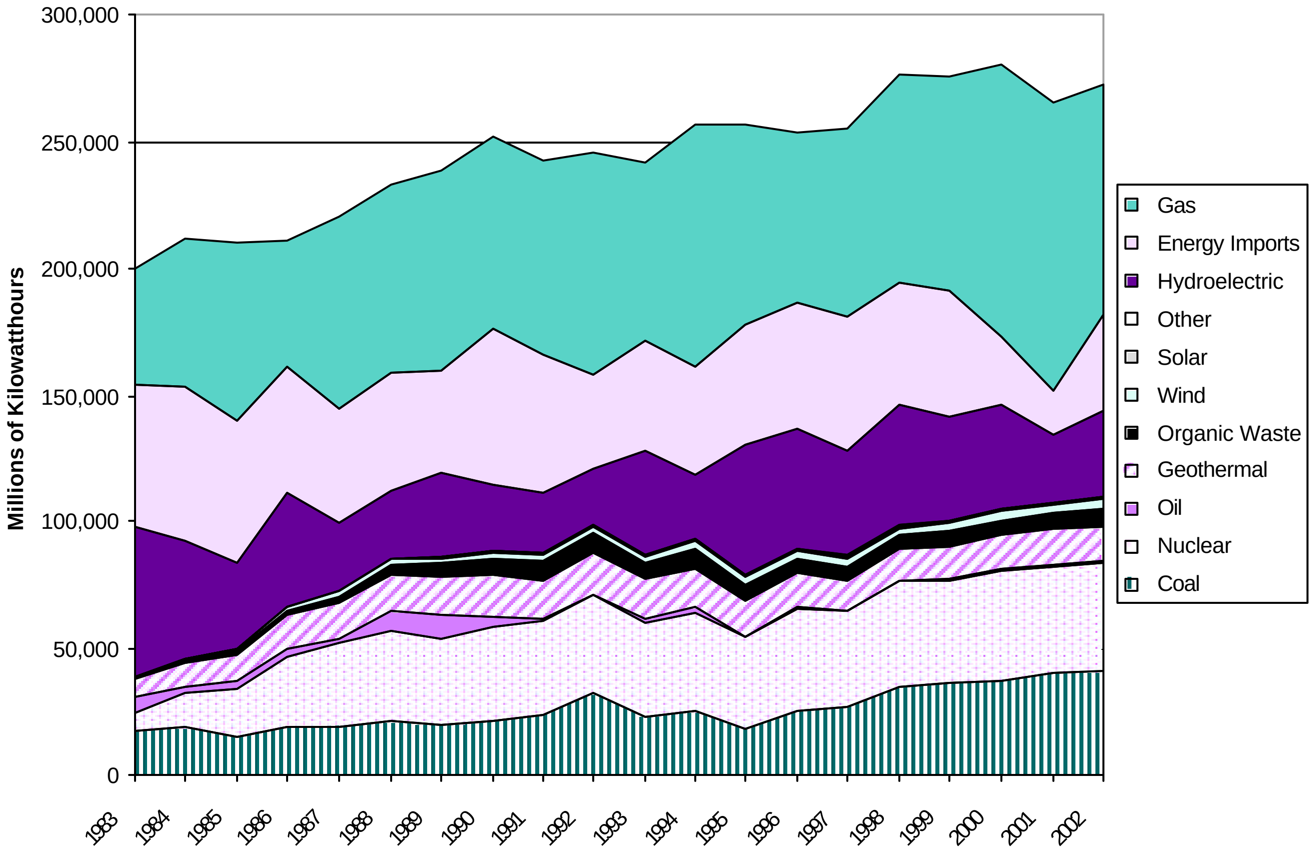


Table 3-1
Role of Gas-Fired Generation in Serving 2002 Load by Age of Unit

On-line Date	Capacity (MW)		2002 Gas-Fired Generation (GWh)	
1940s	285	1%	460	1%
1950s	3,568	12%	7,074	8%
1960s	9,607	31%	19,542	22%
1970s	5,511	18%	8,929	10%
1980s	3,965	13%	23,232	27%
1990s	2,742	9%	14,296	16%
2000-	5,210	17%	14,077	16%
Total Gas-Fired	30,888		87,610	

*Gas-fired plants 10 MW or larger, as of 12/31/02
Source: Energy Commission staff

Table 3-2
Capacity Additions and Retirements California, 2000 – 2003 (MW, Calendar Year)

Calendar Year	Additions	Retirements
2000	59	285
2001	2,329	396
2002	2,970	423
2003*	4,011	1,252
Total	9,369	2,356
Net Additions	7,013	

Includes all plants expected to be on-line or retired by August 1, 2003
Source: Energy Commission Staff

Natural Gas Market Conditions Affect the Electricity Market

Several factors have led to an increasingly important role for natural gas as a generation fuel. Natural gas prices increasingly impact wholesale energy costs; shocks are transmitted from one market to the other.

Well over 90 percent of the generation capacity added in California and the rest of the Western Electricity Coordinating Council (WECC) during the past twenty years is fueled by natural gas. Environmental, safety, or economic concerns have precluded the addition of nuclear, hydro, coal- and oil-fired generation. We expect that in 2006, for the first time, natural gas will surpass hydropower as the West's largest single generation energy source. As a result, the cost of meeting growth in electricity demand is driven by natural gas prices.

A combination of economic and environmental reasons has limited the use of fuel oil as a substitute for natural gas in power generation. A large share of California's generation capacity was once able to generate using either fuel oil or natural gas; only a handful of facilities remain able to do so. As an alternative to natural gas, fuel oil placed a competitive cap on the price of fuel for a particular generator. Having an alternate fuel also protected generators from natural gas curtailments, since using natural gas for electric generation was a lower priority than for end-use consumption. Using fuel oil is no longer permitted, meaning that fuel costs for electric generation have increasingly been linked to natural gas prices.

The link between the price of natural gas and electricity means that cycles in and shocks to natural gas prices are transmitted to electricity markets:

- Short-term supply shocks (e.g., pipeline disruptions in the western US, hurricanes in the Gulf of Mexico) and spikes in demand (a cold storm in the Pacific Northwest) mean higher spot prices for electricity in California markets. Events in the eastern US affect California as regional gas markets are integrated by the nation-wide pipeline system; gas marketers in western Canada and the Rockies have the option of shipping gas east or west and do so in response to spot market prices. The events need not actually occur for electricity prices to be affected; the gas market will often react in expectation of them. Because of their brief duration and unanticipated nature, these shocks have short-term effects (day-ahead to balance-of-month) but do not impact longer-term markets.

- Annual cycles in and shocks to the gas market include higher winter prices due to the use of natural gas to meet heating loads, and price swings resulting from changes in the amount of gas that is put into storage. The increased use of natural gas to meet peak summer electricity needs can occur at the cost of putting gas into storage. If storage levels are low during the spring and summer, prices in gas markets increase as a greater storage need competes with immediate consumption, and winter prices are higher as there is less gas in storage to be withdrawn. Increased integration has led the gas market to react to expected conditions in the electricity market: predictions of poor hydro conditions lead to higher spot and forward prices for gas. These swings affect forward gas markets through the end of the next heating season or water year and, through them, all shorter-term trades.

- Longer-term swings in gas exploration, development and production result in similar cycles in electricity prices. As gas prices fall, producers cut back, driving prices higher. Production and development resume, sending prices down again. This "boom and bust" phenomenon is similar to the one observed in electricity markets, where investment in new generation capacity leads and lags growth in demand. The cycle is arguably shorter in the gas industry as gas can be stored in the ground and "construction" is less capital intensive and has a shorter lead time. This cycle has a substantial impact on prices negotiated for electricity under long-term contracts; even though this may be a two- to three-year cycle it can influence expectations regarding long-run prices. The price volatility associated with this cycle is the primary driver of the price premium needed to assume price risk under long-term, fixed-price contracts or, equivalently, the cost of hedging it.

- A long-term decline in North American gas reserves could lead to increasingly higher prices over the next thirty years. If exploration, drilling and extraction costs increase due to the depletion of the most easily accessible reserves, long-term prices will increase. The opening up of additional basins (e.g., the MacKenzie Delta in western Canada, Alaska) might slow the increase, but will entail higher costs nevertheless.

Transmission Links Generation to Load

California is criss-crossed by 31,270 miles of bulk electric transmission lines, along with its supporting towers and substations. The transmission system links generation to load in a complex electrical network that must balance supply and demand on a moment by moment basis. An efficient transmission system not only helps deliver the lowest-cost generation to consumers, but also facilitates markets to stimulate competitive behavior, pools resources for ancillary services, and provides emergency support in the event of unit outages or natural disasters.

Most of California's electric transmission system was originally built to connect generating facilities to major load centers in the Los Angeles, San Francisco, and Sacramento areas. Thermal generating facilities, such as large gas-fired and nuclear plants, have been built near the coast or in nearby valleys close to the load centers, thereby requiring relatively short transmission lines. Hydroelectric facilities in the Sierra Nevada have typically been some of the most remote sources of generation in the state. Each of the state's investor-owned utilities (PG&E, SCE, and SDG&E) designed, built, and operated its own system to meet the needs of its customers.

Until the mid-1960s, the three IOUs operated their transmission systems as islands, with only a few small ties between utilities. As California's dependence on oil and gas generation increased, and licensing of large generating stations was increasingly difficult, the IOUs began planning and building higher-voltage, long lines to neighboring states. The 500 kV transmission lines were built primarily for importing hydroelectric power from the Pacific Northwest and thermal generation from the Southwest. While these transmission lines provided access to less costly out-of-state power, they also provided the additional benefit of emergency interconnection support among the state's utilities to avoid potential wide scale power disruptions. The 1965 East Coast blackout that affected almost 30 million people and prompted the creation of the North American Electric Reliability Council (NERC) highlighted the need to strengthen ties between utilities as a means of promoting a more reliable interconnected system. Between 1968 and 1974, California utilities built or participated in the construction of about 3,700 miles of 500 kV lines to access remote generation. Since the 1980s only two additional 500 kV projects have been built to access out-of-state resources, and both of these projects were initiated by California municipal utilities.

While IOUs have not built inter-state connections, they have made intra-state transmission upgrades to serve new load, reduce local congestion pockets and improve overall efficiency.

Since 2001, California's utilities have been authorized by the Public Utilities Commission to invest $2.34 billion in such upgrades.

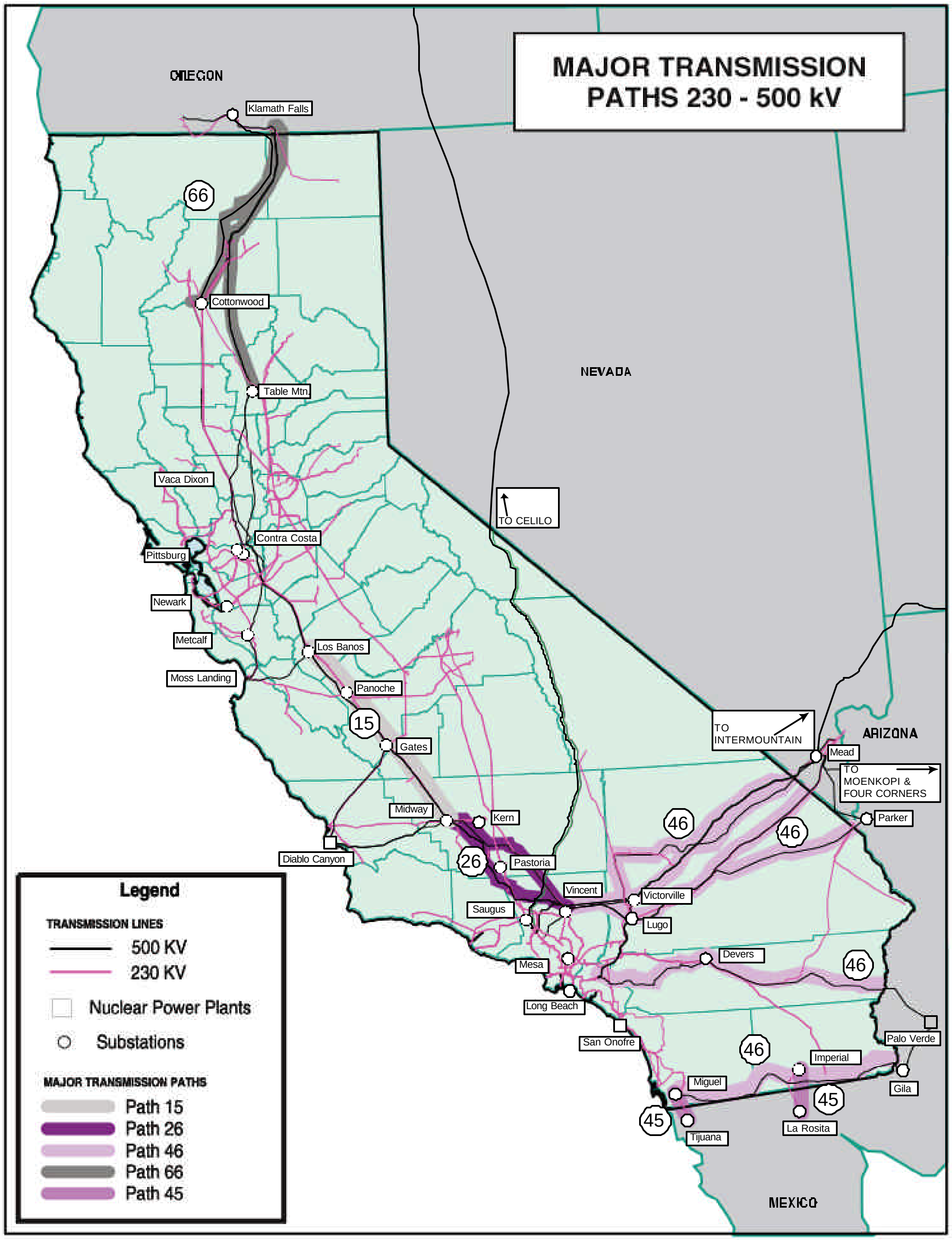
California's current bulk inter- and intra-state transmission system is shown in **Figure 3-2**. The map highlights the paths that are most heavily utilized and whose expansion may thus provide significant benefits. The map also shows major substations and the three nuclear power plants owned by California's IOUs.

With the passage of AB 1890, which restructured California's electricity industry, the California Independent System Operator (CA ISO) was formed to operate the state's wholesale power grid covering 25,526 miles (approximately 75 percent of the state) provide open and nondiscriminatory transmission service; ensure safe and reliable operation of the grid; and operate energy and reliability markets. The individual IOUs and participating municipal utilities continue to own their lines and continue to be involved in transmission planning by filing annual transmission expansion plans with the CA ISO. The CA ISO's coordinated planning process integrates the individual plans to ensure reliability, as well as to ensure that proposed expansion projects do not negatively impact the western regional grid.

The state has three other control areas which provide similar functions. The Los Angeles Department of Water and Power (LADWP), the Sacramento Municipal Utility District (SMUD), and the Imperial Irrigation District (IID) have chosen to serve their own customers, but they must coordinate with the CA ISO and other Western control areas.

Concerns regarding transmission system obstacles and incentives for its development and the possible costs and benefits of specific upgrades are discussed at the end of this chapter, in Chapter 6 and are amplified in the Energy Commission staff report entitled ***Upgrading California's Electric Transmission System: Issues and Actions***, publication number 100-03-011.

Figure 3-2
Major Transmission Paths
230 – 500 kV



Current Conditions in the California Electricity Market

The combined effect of the capacity additions and reduced demand was an increase in the state's expected peak operating reserve margin under normal conditions in the summer 2003 to 20 percent. This compares to the roughly 7 percent needed to meet reliability criteria and avoid a Stage 1 emergency. Sufficient capacity currently exists through 2005 to meet 1-in-10 year peak loads with a 7 percent operating reserve margin. For updated reports and details regarding the assumptions underlying this estimate, see the Energy Commission website (www.energy.ca.gov).[3]

While concerns remain regarding the performance of the California electricity system in the long-term, the measures taken to stabilize the market during the past two years have been successful. Since July 2001, the California electricity market has returned to its pre-crisis performance levels of reliable delivery and moderate spot market prices for the small increments of power needed but not bought under long-term contracts.

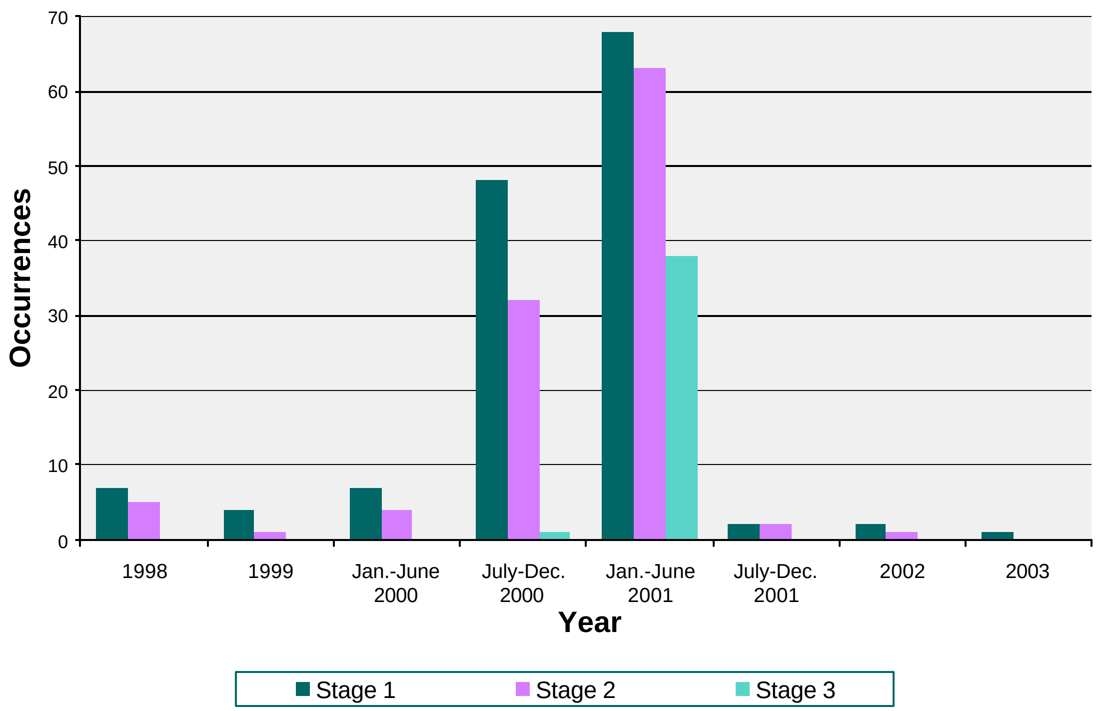
Reliability

Figure 3-3 illustrates that system reliability, as measured by the number of CA ISO-declared emergencies, has dramatically improved since mid-2001. The events in 2002 and 2003 are notable for the circumstances under which they occurred. Neither reflected an inadequate amount of capacity to meet energy demand:

- In 2002, peak temperatures, combined with reduced transmission capability from the Northwest, caused a Stage 1 alert on July 9, reducing the price cap for spot market energy to $57.14/MWh. A large number of forced plant outages the next day, combined with continued high temperatures and reduced transmission capacity from the Pacific Northwest, resulted in a Stage 2 alert. Declaration of this emergency allowed 1,400 MW of load to be voluntarily curtailed and reserves to be restored to required levels.

- On May 28, 2003, demand in the CA ISO exceeded the day-ahead forecast by 4,400 MW due to an unexpected temperature spike. As a result, more than 11,000 MW of capacity excused from participating in the market ("economic outages") and another 3,200 MW out for scheduled maintenance was unavailable. Had even a fraction of this capacity not been off line, the emergency would not have occurred.

Figure 3-3
Emergencies, California ISO Control Area, 2001 – 2003



Spot Market Prices

The trend in spot market prices is a key indicator of both supply adequacy and market conditions.[4] Wholesale spot market prices in California have been moderate since July, 2001, as evidenced by **Figure 3-4** and noted in the CA ISO's numerous market assessments.[5] Prices increased in Spring 2003 due to run-ups in the natural gas price in California and nationwide. These gas prices have been caused by low storage levels and fears that insufficient amounts of natural gas will be available to meet heating needs this winter; this is discussed in detail in the Energy Commission staff's ***2003 Preliminary Natural Gas Market Assessment***, publication 100-03-006SR. Unlike the price run-ups of 2000 - 2001, these increases do not appear to be due to shortages of generation capacity or dysfunction in either the electricity or natural gas markets. Increases in gas storage levels in June and July 2003 have caused both gas and electricity prices to ease somewhat and recent increases in exploration, drilling and production are expected to bring prices down in mid-2004. Concerns remain, however, that national natural gas prices may not return fully to previous levels. These higher prices will ripple through the electricity sector.

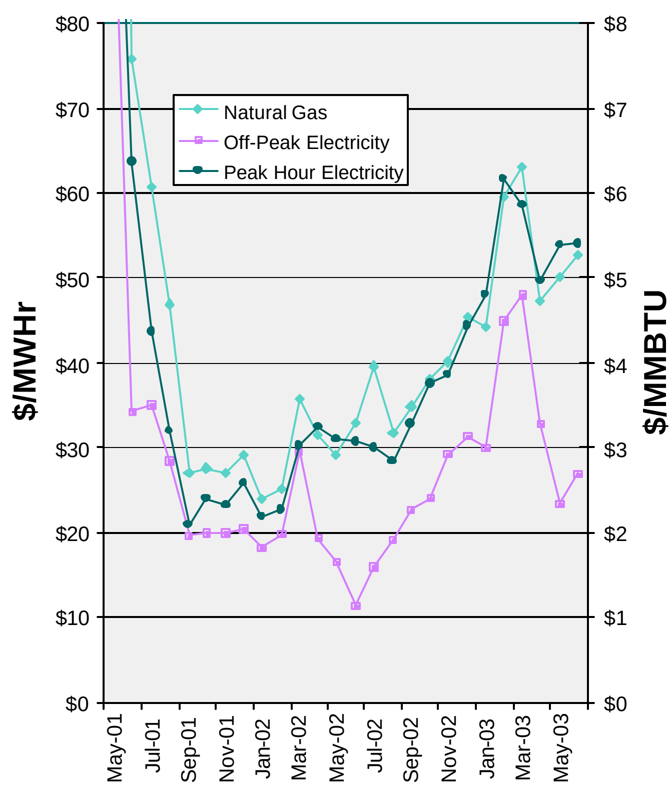
The stabilization of the spot market for electricity in California has been largely the result of three factors:

- Conservation by California consumers, their adoption of energy efficiency measures and a slowdown in the economy. Despite the growth in population, 2003 peak loads are about the same as the 1999 peak.

- The addition of more than 9,369 MW of new capacity in the state between 2000 and 2003, as illustrated in **Table 3-1**.

- There has been a dramatic reduction in the amount of energy purchased in the spot market by load-serving entities in California. As documented in CA ISO monthly reports, the spot market purchases have declined dramatically. Most of the energy needs of the investor-owned utilities in the state are being met by utility-owned resources, contracts with QFs and other utilities, and long-term contracts signed by the State's Department of Water Resources in 2001. Additional energy needs are being met by contracts being entered into as part of the interim procurement proceedings being conducted by the California Public Utilities Commission.

Figure 3-4
Monthly Average Prices, SP15 Delivery[6]
May 2001 – May 2003



Source: Economic Insight, Inc. market surveys, published in *Energy Market Report* and Natural Gas Institute survey data

Projected Supply/Demand Balance through 2006

The Energy Commission expects that loads will be reliably served (largely through LSE owned-generation and long-term contracts) and that spot market prices should remain at workably competitive levels[7] through 2004 - 2006. This conclusion is based on an assessment of the current supply-demand balance, expectations regarding load growth, capacity additions and retirements, and a decreasing reliance on the spot market for energy.

Dependable reserve capacity in California and the remainder of the WECC is at a high level not seen since the late 1980s. **Table 3-3** presents the state's projected operating reserve margins for 2004 – 2006 using conservative assumptions, such as adverse hydro conditions and only new generation additions with a high probability of being constructed.
The supporting assumptions for the outlook can be found in **Appendix D, Tables D-1 through D-3**. For the most current outlook, see the Energy Commission's website at www.energy.ca.gov/electricity.

Table 3-3
2004 – 2006 Statewide Supply/Demand Balance
(MW)

	Aug-04	Aug-05	Aug-06
Existing Generation	57,434	56,956	58,902
Forced and Planned Outages	-3,750	-3,750	-3,750
Retirements	-1,191	-1,054	-2,385
Net Firm Imports	5,895	5,748	5,848
Additions	713	3,000	1,096
Spot Market Imports	2,700	2,700	2,700
Total Supply (MW)	**61,801**	**63,600**	**62,411**
1-in-2 Summer Demand	**53,331**	**54,500**	**55,487**
Projected Operating Reserve (1-in-2)	**16%**	**17%**	**12.5%**
1-in-10 Summer Demand	**56,571**	**57,811**	**58,858**
Projected Operating Reserve (1-in-10)	**9%**	**10%**	**6%**
Emergency Response Programs/ Interruptible	**1,102**	**1,102**	**1,102**

Note: Does not include an estimate for new DSM or dynamic pricing demand reductions. August 2003. The projected planning reserves do not include Spot Market Imports. Existing Generation includes dependable hydro generation capacity estimates under adverse water conditions.

Generation Additions

- Net additions assumed in **Table 3-3** for 2004 – 2006 are not expected to keep pace with load growth. Many plants currently before the Energy Commission are proposed by municipal utilities. These entities have both the need and the financial capability to acquire new resources. Several of these projects replace existing facilities that have been or will be retired; others will cover short positions during peak hours year –round or during the summer. These 6 projects and two smaller plants proposed by municipal utilities total 1528 MW (see **Appendix D, Table D-4**). In addition, two major projects being undertaken by the Los Angeles Department of Water and Power (LADWP) and the Salton Sea 6 geothermal project, which has contracted with the Imperial Irrigation District to provide up to 177 MW for 20 years are expected to be constructed. Projects proposed by the cities of Pasadena and San Francisco and the Kings River Conservation District are expected to be completed.

- The **Table 3-3** 2004-2006 projections assume the mid-2005 completion of one of the two major projects being considered for the San Diego area. These are Otay Mesa (Calpine, 510 MW) and Palomar (Sempra Energy, 546 MW). The state has step-in rights on Otay Mesa, allowing it to take over construction in the event that the developer does not meet certain milestones. In addition, the CPUC is considering a request by the California Power Authority (CPA) to require San Diego Gas & Electric to sign a long-term contract with Calpine for the output of Otay Mesa, which would allow the CPA to provide the capital necessary to complete the project. The Palomar was permitted by the Energy Commission in August 2003. The completion of 500 MW of merchant generation in Southern California in each of 2005 and 2006 is also assumed in **Table 3-3**.

- The **Table 3-3** 2004-2006 projections include the development of new renewable facilities, partly in response to the Renewable Portfolio Standard established under SB 1078 (Sher, Statutes of 2002). While existing facilities may meet a share of the RPS requirements in the short-run, the past year has witnessed both new merchant development and announcements by municipal utilities of new projects. The load-resource projections for 2004 – 2006 assume the addition of 244 MW of dependable renewable capacity to meet RPS targets by summer 2006 (see **Appendix D**, **Table D-1** for details). This is a conservative estimate, pending the CPUC procurement outcomes.

Trends in Retirements of Older Generating Units

New power plants, demand-side management programs, and energy efficiency measures not only help to meet California's energy needs, but reduce the amount of hours aging power plants are dispatched. The economic displacement of generation from, or complete physical replacement of, older, less efficient power plants results in lower wholesale electricity prices, potential reductions of air pollutant emissions, and reductions of global climate change emissions in California or throughout the West.

Energy Commission staff has provided an overview of the age, emissions and efficiency characteristics, and recent operations of the natural gas power plants in California in the ***Aging Natural Gas Power Plants in California*** report, publication number 700-03-006. Staff has not conducted a detailed analysis of the contractual arrangements, such as Reliability Must-Run (RMR) contracts with the CA ISO or the reliance of specific units as part of Department of Water Resources (DWR) contracts. Such contractual arrangements dictate to a large extent the current and future use of many of the older units in the state.

The owners of a majority of the natural gas-fired capacity in California have either built the facilities in recent years or invested in retrofitting steam boiler units with current emission control technology, suggesting that owners are acting to keep the units available. Implementation of the NO_x emissions control retrofit rules for utility boilers over the last decade has resulted in 80 to 90 percent reductions in NO_x emission rates per MWh from these facilities. Over 85 percent of California combustion-fired generation uses some form of NO_x emission controls. Nearly 21,000 MW, or 60 percent, use selective catalytic reduction for NO_x emission control.

Since 2000, there has been 2,356 MW of generation capacity in California that retired (see **Table 3-2**). Some of this capacity has been retired as owners decided the going-forward costs, including the cost of installing mandatory emission controls, were too high given projections of future income. Much of this capacity and that expected to be retired during the next 18 months is being replaced with new plants that are both more efficient and meet the strict emission control standards for new facilities.

The retirements assumed in **Table 3-3** during 2004 – 2006 are listed in **Appendix D**, **Table D-2**. The continued operation of most of these plants would require that emission controls be installed; and expected income from continued operation is assumed to be insufficient to warrant doing so.

At present, the Energy Commission expects that the potential retirements of additional facilities during 2004 – 2006 is minimal, despite the age of the existing generation fleet. **Table 3-3** indicates that, even if retirements exceed anticipated levels by 1,200 MW during 2004 – 2006, the expected operating reserve during the summer peak will be above 10 percent (for 1-in-2 demand level).

The continued operation of older power plants during the next three years will be affected by the following factors:

- ?An increasing number of plants are apt to be provided capacity contracts during the next two years. This could result from resource adequacy requirements imposed upon load serving entities in California by regulators, or CPUC approval of capacity contracts as a component of risk- mitigation strategies pursued by the IOUs. The payments from these contracts, to the extent that they cover going forward costs, will encourage older facilities to remain on-line.

- Several older plants have DWR or reliability-must-run (RMR) contracts, including major facilities in the San Diego and San Francisco areas. Those facilities paid under RMR contracts are highly unlikely to shut down unless and until their reliability function is provided by a new plant or no longer needed due to upgrades to the transmission system.

- The cancellation of numerous development projects and delays in bringing additional capacity on line mitigates against the retirement of existing plants. While short-term revenue projections may lead to temporary shut-downs of existing plants, even these facilities will remain available with sufficient notice. Increased congestion on transmission lines which move power into the greater Los Angeles area, combined with delays in completing several new plants in Southern California, raises the possibility of a wholesale electricity price premium during peak hours in the summer in the near-term for generation located in the SP15 zone.

The Energy Commission should conduct an in-depth study and develop a strategy for targeted retirement and replacement of old, inefficient power plants to reduce natural gas dependence. This should be done as part of the IEPR update proceeding with a more definitive recommendation to the Governor and Legislature in November 2004 Integrated Energy Policy Update Report.

Reduced Dependence on the Spot Market

During the next three years, the use of the spot market for energy needs will continue to decline. Reduced spot market needs, accompanied by increases in reserve margins, both in California and the remainder of the WECC, mean that more megawatts of capacity will be chasing fewer megawatt-hours of demand. This served to discipline the spot market in mid-2001[8] and the Energy Commission expects it to continue to do so, given the following:

- The CPUC will authorize IOUs to enter into forward contracts for energy and capacity. It is anticipated that the spot market needs of the IOUs during the summers of 2004 – 2005 will be more than 1,000 MW to 2,000 MW in only a handful of hours.

- Municipal utilities continue to rely upon their own plants and long-term contracts to meet a majority of their needs. They plan to add sufficient capacity and contract forward so as to offset retirements and expiring contracts.

- Direct access consumers appear to be served by a mix of mid-term contracts and the spot market. Assuming that the direct access market remains roughly the same size, the spot market requirements of these entities during peak hours will not put additional pressure on prices in the near-term, given existing reserve margins.

Near–Term Uncertainties

This section assesses the uncertainties that affect electricity supply and price during 2004 – 2006, and the measures that can be taken to reduce them. These risks can be mitigated by continuing to contract forward for energy and capacity needs, using financial hedges to reduce exposure to possible high electricity and natural gas prices, and reducing demand with DSM and load-reduction programs. Collectively, these measures will increase the amount of generation capacity available to meet peak summer demand and minimize the likelihood and consequences of spikes in spot market prices for electricity and natural gas.

The following are the significant uncertainties facing the electricity market during 2004 – 2006:

- The failure of generators to participate in the California market,
- Fewer generation additions than anticipated,
- More retirements than expected,
- A failure to resolve local reliability concerns in the San Diego and San Francisco areas, and
- Spikes in the spot market price for natural gas.

These uncertainties are also affected by market concerns such as: utility credit worthiness, merchant generation financing, the CA ISO's market redesign, and regulatory outcomes.

Failure of Generators to Participate in California Market

Threats to reliability or increased spot market prices due to capacity withholding or the commitment of energy and capacity to neighboring states are unlikely because:

- Performance requirements have been put in place by the FERC (through the CA ISO) and the Legislature (through the CPUC) to increase the incentives for market participation.

- Adequate reserve margins limit the ability of generators to sustain non-competitive prices. There is no incentive to withhold capacity or offer power at prices well in excess of production costs since there is abundant surplus power available throughout the WECC system that can be sold in the spot market.

- Reduced reliance on the spot market puts further downward pressure on prices, as a relatively large amount of capacity is competing to meet demand in the spot market.

- The addition of 9,000 MW of new capacity in the Southwest during 2001 - 2003, coupled with a dramatic improvement in the supply-demand balance in the Northwest, reduces the likelihood that California generators will be used to meet energy needs in neighboring states during the summer at the expense of reliability in California.

The state can facilitate participation by generators in California energy markets in the near-term by continuing to allow and encourage LSEs to forward contract for energy and capacity. Using firm contracts to encumber capacity reduces the amount of capacity that is at risk for non-participation, as well as limits exposure to high spot market prices should a sufficient share of the remaining capacity fail to offer itself into the market.

Fewer Generation Additions

The number of capacity additions included in the assessment in 2004 – 2006 is conservative. First, we assume that six permitted projects larger than 300 MW (totaling almost 3,500 MW), and two projects for which approval has been recommended (1,633 MW) will not come on line by 2006, despite the possibility that one or more will do so. Moreover agency, utility and stakeholder commitment to an effective Renewable Portfolio Standard provides a reasonable basis for assuming that new renewables will be constructed.

As mentioned above, generation additions in the near-term can be facilitated by encouraging load-serving entities to sign contracts of long enough terms to warrant the development of new facilities. Given the time necessary to complete the procurement process and the two-year lead time to develop peaking capacity, this would suggest that utilities issue RFPs before the summer of 2004 to ensure its availability by summer 2006. The CPUC procurement process is on schedule to meet this target. The resolution of outstanding issues related to the procurement process before the end of 2004, including allowing the IOUs to enter into long-term contracts, will enable new capacity to come on-line by the time it is needed.

More Retirements

Several large power plants are required to install emission controls during 2004 – 2005. Spot market price forecasts indicate that it may not be economic for the owners of several of these plants to do so. The plants are Potrero 3 (207 MW), Pittsburg 7 (700 MW) and Contra Costa 6 (336 MW), all located in the greater San Francisco Bay Area. For more details on the aging power plant fleet, see the Staff Paper, ***Aging Natural Gas Power Plants in California*** (publication number 700-03-006).

Preliminary studies by the CA ISO indicates that RMR requirements in the greater San Francisco Bay Area may be reduced substantially in 2005. This would occur if planned upgrades to the Tesla-Newark 230 kV line are completed by PG&E. Under these circumstances, Contra Costa 6 and Pittsburg 7 may be unlikely to recover emission control installation costs in a competitive bid to provide reliability services. In 2005, planners should examine whether there are any reasons that these plants need to be maintained. Even if these units are retired, the expected reserve margin during peak summer hours in 2005 remains large enough to avoid CA ISO-declared emergencies.

Local Reliability in the San Diego and San Francisco Areas

The most significant reliability-related uncertainty in California in the near term is the potential that capacity in San Diego will be inadequate to meet the area's local reliability needs, but there is a process underway to address the concern. On May 16, 2003, San Diego Gas & Electric (SDG&E) issued a Request for Proposals (RFP) for 69 MW, 189 MW, and 291 MW of local capacity in 2005, 2006 and 2007, respectively to meet reliability needs. At least 100 MW of new capacity is needed in San Diego by summer 2006 and an additional 100 MW by 2007, to meet local reliability requirements.[9] Proposals were submitted to SDG&E on June 27. Proposed contracts were submitted to the CPUC and are now under consideration for approval.

There are two major projects under development that, if completed, could provide the necessary capacity. Otay Mesa has been permitted; construction has started, but progress is delayed due to financing problems. Palomar has also been permitted and both of these projects responded to the RFP, along with developers proposing smaller facilities.

The state must ensure that the capacity necessary in San Diego is built in a timely fashion. This entails an agreement between SDG&E and one or more developers that allows SDG&E or another entity to step in and complete construction should specific milestones not be met. There are also local reliability concerns in the San Francisco area. Unless generation is added or transmission upgrades are performed, local reliability criteria for the San Francisco peninsula will be violated as soon as 2006. In addition, environmental concerns have led to a strong local desire to have Hunters Point 4 (163 MW), a forty-five year old unit located in San Francisco proper, shut down at the earliest possible date.

The Jefferson-Martin transmission upgrade would allow for a 400-MW increase in the import of power into the San Francisco peninsula. Assuming the continued operation of the other facilities in San Francisco and other planned transmission upgrades, this would allow Hunters Point 4 to be shut down and meet reliability criteria for the peninsula for the next ten years. In the absence of the Jefferson-Martin upgrade, the proposed addition of 180 MW of combustion turbines in San Francisco would not alleviate reliability concerns for the peninsula (reliability criteria would be violated as early as 2007), and thus require the continued operation of Hunters Point 4.

The state must ensure that either the Jefferson-Martin upgrade is completed by 2006 or that new capacity is added on the San Francisco peninsula by the same date.

High Natural Gas Prices

Wholesale electricity costs are affected by natural gas prices. The cost of spot market purchases, short-term energy contracts, utility-owned gas-fired generation with short-term fuel contracts, QF contracts indexed to the gas price, dispatchable DWR contracts, and tolling agreements are all driven by the price of natural gas.

The risk of high natural gas prices in the near-term can be mitigated to an extent by allowing natural gas users to hedge exposure using forward contracts and financial instruments. The CPUC currently allows the IOUs to buy gas forward for tolling agreements and dispatchable contracts, protecting ratepayers against sudden price spikes.

While short-term contracts (six months or less) and financial instruments can protect ratepayers against price spikes and high prices, they are of limited defense against high prices due to:

- Seasonal supply-demand imbalances due to adverse weather conditions (*e.g.*, poor hydro conditions, which result in more gas-fired generation during the summer),
- Price increases due to the cyclical nature of expenditures on exploration, drilling and extraction, and
- A concern about inadequate long-term natural gas supplies.

If poor hydro conditions or supply lags are expected, their impact is priced into short-term contracts and near-term forward markets. While longer-term fixed-price contracts provide some protection against these sources of volatility, the market for such contracts is not liquid. Substantial uncertainties regarding gas prices more than one year into the future result in longer-term contracts tending to be high-priced. Demand-side and supply resources not linked to natural gas prices are ways to limit exposure to high and volatile natural gas prices.

Long-Term Assessment

Electric generation system simulation modeling was employed to assess potential long-term electricity system and market trends. This assessment examined changes in generation patterns, electricity spot market price, and natural gas use by electric generators across a number of sensitivity cases. The cases are described below, followed by the assessment results.

Market Simulations: Changes in DSM and Renewable Generation

State policy favors additional DSM and renewable resources to meet incremental demand. To test the system impacts of accelerating or stopping public investments in DSM and renewables, a sensitivity analysis was conducted to evaluate the longer-term impact on natural gas use and electricity market conditions from changes in DSM savings and renewable generation. The changes in demand and renewable generation are assumed to be a result of changes in Public Goods Charge (PGC) funding. In each case, the WECC electricity market was simulated for the years 2004 through 2013.

Description of Sensitivity Cases

To provide a benchmark for evaluating the impacts of changes in DSM and renewable generation, a base case was developed and characterized by the following[10]:

- Energy Commission staff's baseline demand forecast for California for 2004 – 2013.

- The addition of sufficient renewable capacity to meet RPS targets. This averages slightly less than 400 MW annually and yields an average annual increase in renewable energy of 2,000 GWh. By 2013, the renewable capacity increased by 3,751 MW, producing 19,450 GWh of electricity.

- Thermal additions during 2004 – 2013 across the WECC are those necessary to sustain reserve margins for each quadrant of the region at 1998 – 1999 levels. At these levels of reserves, the system is reliable on a region-wide basis; at higher levels, prices would be too low to support new capacity.

A second case was developed in which it is assumed that: (a) increased PGC funding yields additional demand reductions, and (b) 50 percent more new renewable capacity and energy is added each year under RPS-related contracts.[11]

- Annually, the Higher DSM/Renewable Impacts Case adds about 200 MW more DSM peak reductions and about 1,200 GWh more DSM energy savings than in the baseline (averaged over the 2004-2013 period).

- By the year 2013, the Higher DSM/ Renewable Impacts Case has 19,700 GWh more energy from DSM savings (10,000 GWh) and renewable generation energy (9,700 GWh) than what is included in the baseline.

- In the Higher DSM/ Renewable Impacts Case, future gas-fired resources were reduced by about 2,500 MW by 2013—700 MW fewer new additions and 1,800 MW more retirements. These changes are based on the assumption that the market will respond to a decrease in "residual" demand by cutting back on new additions or increasing retirements of marginally utilized existing units.

Results of DSM/Renewable Sensitivity Cases

As expected, having more DSM savings and renewable energy generation decreases the amount of gas-fired energy generation, gas use, and the average annual electricity spot market price. The differences in electricity market impacts between the Baseline and Higher DSM/Renewable Impacts cases are discussed below. The differences in gas market impacts between these cases are discussed in **Chapter 4**. The analysis identifies system impacts; the likelihood of achieving these DSM and renewable goals were addressed in separate quantitative studies. Cost savings and other benefits (e.g., emissions, fuel savings) have not been expressed in monetary terms. Thus, results do not provide a quantitative basis for comparison.

Change in Generation Patterns

The changes in DSM savings and renewable generation levels in the Higher DSM/Renewable Impacts case affect mostly gas-fired generation, only a very small amount of fuel oil, but little or no coal-fired generation. Most of the changes to gas-fired generation occur in the output of new gas-fired additions, rather than the output of existing gas-fired power plants. This is because committed and assumed new resource additions as well as plant retirements, already displaces as much of the generation from older plants as economic or allowable by local or system reliability constraints. The generation changes are spread throughout the hundreds of power plants within the interconnected WECC area and are not confined to California.

The additional DSM savings and renewable generation in the Higher DSM/Renewable Impacts case displaces about 7,600 GWh of gas-fired generation in the WECC by 2007, 14,600 GWh by 2010 and 19,100 GWh by 2013. This gas-fired generation reduction amounts to about 3 percent, 5 percent, and 6 percent of annual WECC gas-fired production, respectively. Of the total WECC gas-fired generation reduction by 2013, 53 percent occurs in California, 32 percent in the Desert Southwest, 11 percent in the Pacific Northwest, and 4 percent in the Rocky Mountain region.

Change in Electric Generation Gas Use

The additional DSM savings and renewable generation in the Higher DSM/Renewable Impacts case decrease the amount of natural gas consumed for electric generation across the WECC by 3 percent in 2007 and by 6 percent in 2010 and 2013. The percentage decrease in gas consumption for electric generation in California is 4, 7 and 9 percent in 2007, 2010 and 2013, respectively.

Change in Annual Average Electricity Spot Market Clearing Price

In the High DSM/Renewable Impact case, reduced demand and increased generation from new renewables led to a 5 percent reduction in the wholesale market price by 2013. Reducing dependence on gas-fired generation is likely to result in lower natural gas prices, although this effect was not quantified. Electric generation gas demand will soon be 30 percent of the total demand for natural gas in the Western United States. A 6 percent decrease in the natural gas use by generators in the western U.S. would reduce natural gas demand in the west by 1.8 percent. The effect of such a reduction on the spot market price for California natural gas would be about 1 percent.

Low Hydro Case Study

The WECC market was simulated under a 1-in-20 year adverse hydro conditions to evaluate the potential affect on natural gas demand for electricity generation in 2007. Based on historic information for adverse conditions, California hydro-generation was reduced to 54 percent of normal from January – September, with October – December values escalating to normal levels by the end of the year. A similar pattern was assumed for the Pacific Northwest (including British Columbia), with January – September values being 82 percent of normal. There is a small correlation between California and Pacific Northwest hydro conditions, with a low probability for coincident regional droughts. The case study is considered to evaluate an extreme condition, similar to what occurred during 1992.

Hydropower comes from run-of-river systems and the large dams with storage. Storage dams can manage their release of water. The actual amount of generation from hydro in the WECC for the Low Hydro and Baseline Cases are shown in **Table 3-4**.

Table 3-4
Comparison of the Low Hydro and Baseline Cases
Hydro Generation 2007

Year	Baseline Case GWh	Low Hydro Case GWh	Percent Change in Hydro Generation
Northwest /Canada	184,343	155,289	-16%
Rocky Mountains	7,780	6,952	-11%
Southwest/Mexico	11,806	10,785	-9%
California	35,603	21,622	-39%
WECC Total Hydro Generation	**239,532**	**194,649**	-19%

This case has the most significant effect, in the form of an increase in the amount of generation and fuel used from natural gas resources than any of the other sensitivity simulations. The effects on generation and natural gas used by electric generators in the WECC are shown in **Table 3-5**.

Table 3-5
Comparison of the Low Hydro and Baseline Cases
Natural Gas Use and Generation 2007

	Baseline Scenario	Low Hydro Scenario	
Region	**Natural Gas Used in Electric Generation (Gbtu)**	**Natural Gas Used in Electric Generation (Gbtu)**	**Percent Difference in Gbtu**
Northwest/Canada	554,096	654,210	18%
Rocky Mountain	122,169	140,505	15%
Southwest/Mexico	345,620	431,314	25%
California	926,287	1,089,068	18%
WECC Total	**1,948,171**	**2,315,097**	**19%**
	Electric Generation From Natural Gas (GWh)	**Electric Generation From Natural Gas (GWh)**	**Percent Difference in GWh**
Northwest/Canada	75,441	89,358	18%
Rocky Mountain	15,046	17,316	15%
Southwest/Mexico	43,785	53,096	21%
California	120,529	137,680	14%
WECC Total	**254,801**	**297,451**	**17%**

Electricity Retail Rates and Bills Outlook

This summary is supplemented by the staff reports titled ***California Municipal Utilities Electricity Price Outlook*** (publication number 100-03-005) and ***California Investor-Owned Utilities Retail Electricity Price Outlook*** (publication number 100-03-003).

Electricity Rates

Over the last two and a half years, IOUs have been collecting from customers more than enough revenues to cover their cost of electricity. This excess revenue will likely be used by the IOUs to pay off the debt they incurred during the crisis of 2000/2001. Once this debt is repaid, rates are expected to decrease; although, policy makers could allow utilities to use the funds for alternative purposes. Under current Energy Commission projections, retail rates for all investor-owned utility (IOU) customers in California will most likely decline in the 2004 – 2006 period (year 2000 dollars) and level thereafter (**Table 3-6**).

Table 3-6
IOU Retail Electricity Rates
($2000) ¢/kWh

	Residential	Commercial	Industrial	GDP Deflator
2003	12.3	16.0	11.7	105.0
2004	10.7	11.7	7.7	108.9
2005	10.3	11.2	7.2	112.8
2006	10.0	10.9	7.0	116.7
2007	9.9	10.8	7.0	119.4

Source: Energy Commission Staff

If current trends in projected energy prices, utility plans and programs, regulatory decisions and assumptions prevail, retail electricity rates are likely to have the following attributes:

- A substantial rate decrease was approved by the CPUC in 2003 for Edison. The rate decrease will continue through August 2004. For SDG&E customers, a rate decrease in 2004 would likely be smaller. Rates for Edison and SDG&E after 2004 would slowly increase to capture the cost of energy but not to offset the effect of inflation. Rates for PG&E electricity customers depend on the bankruptcy settlement.

- Major IOU electricity rate component costs, except for the energy surcharges, have been established for the next four years. Therefore, major cost-based rate fluctuations are unlikely.

- Future retail electricity rates for the IOUs depend, to a certain extent, on the regulatory decisions of the Federal Energy Regulatory Commission, the California Public Utilities Commission, the State Legislature, and the Governor, rather than the spot market prices.

Rates for California's municipal utility customers are likely to decrease slightly in 2004 due to the accumulation of excess net income funds, and the desire of municipal utilities to maintain competitive rates with investor-owned utilities. The municipal utilities in this assessment include Los Angeles Department of Water and Power (LADWP), Sacramento Municipal Utility District (SMUD), the City of Burbank Public Department, the City of Glendale, and Pasadena Water and Power. The 2004 rates, and the rates thereafter, will most likely reflect the utilities' cost of generation. Cost of generation is projected to increase slightly every year through 2007 (**Table 3-7**). The rate analysis suggests:

- Rates could decline by as much as five percent in 2004 as a consequence of accumulation of excess funds for LADWP, Glendale, Burbank, and Pasadena; however, the rate decrease would be smaller once the estimated increase in energy costs and inflation are taken into account.

- Future retail electricity rates for municipal utilities will depend on the price of natural gas and, to some extent, on the need to replenish their rate stabilization funds.

Table 3-7
Municipal Utility Retail Electricity Rates
($2000) ¢/kWh

Year	Residential	Commercial	Industrial	GDP Deflator
2003	10.0	10.0	7.2	105.0
2004	9.6	9.4	6.8	108.9
2005	9.6	9.4	6.6	112.8
2006	9.8	9.6	6.8	116.7
2007	10.0	9.8	7.1	119.4

Source: CEC staff

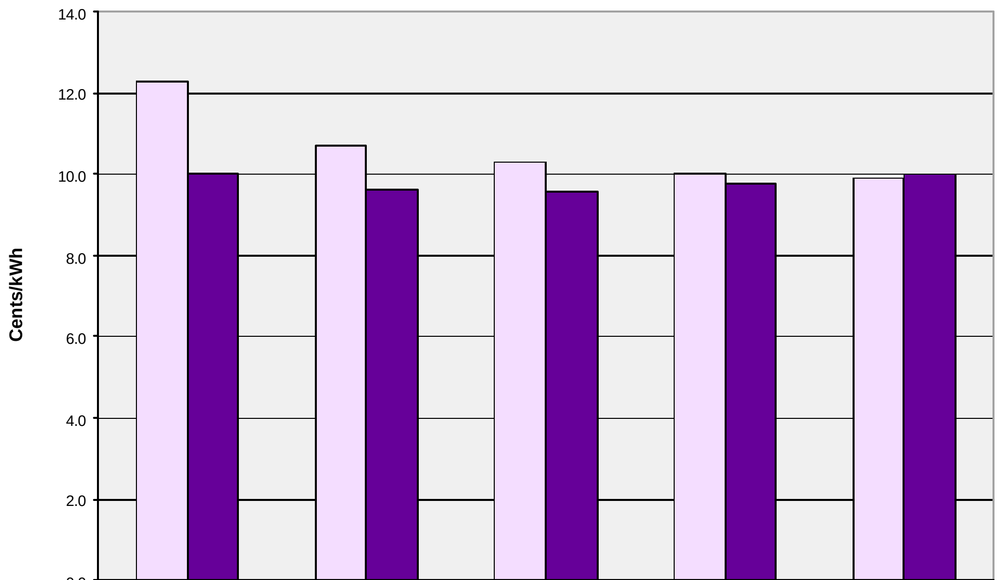
California IOU vs. Municipal Utility Electricity Rates

Current customers of IOUs face higher electricity rates than customers of municipal utilities. IOU residential customers pay up to 22 percent higher rates than their municipal counterparts. Rates for IOU residential customers are projected to decrease next year. Thereafter, they will slightly increase through 2007 (**Figure 3-5**).

Electricity rates for commercial customers are currently 60 percent higher for IOUs than municipal customers. If the same rate structures persist for both IOU and municipal utilities, rates for IOU commercial customers could decline in 2004 and be level thereafter. The difference in rates between an IOU and a municipal commercial customer could be small by 2007 (**Figure 3-6**).

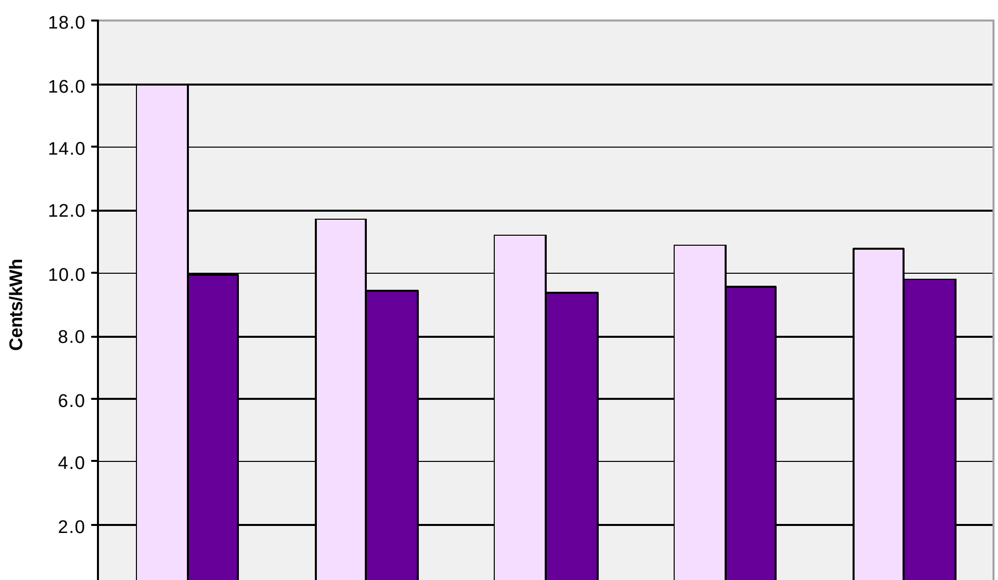
IOU industrial customers currently pay 63 percent more than municipal utilities industrial customers. Once energy surcharges decline, or disappear in 2004, the difference will be quite small. If current rate structures prevail, IOU industrial customers could be paying electricity rates similar to their municipal counterparts by 2006 (**Figure 3-7**).

Figure 3-5
Residential IOU/Municipal Electricity Rate Outlook
2003 – 2007
($2000) ¢/kWh



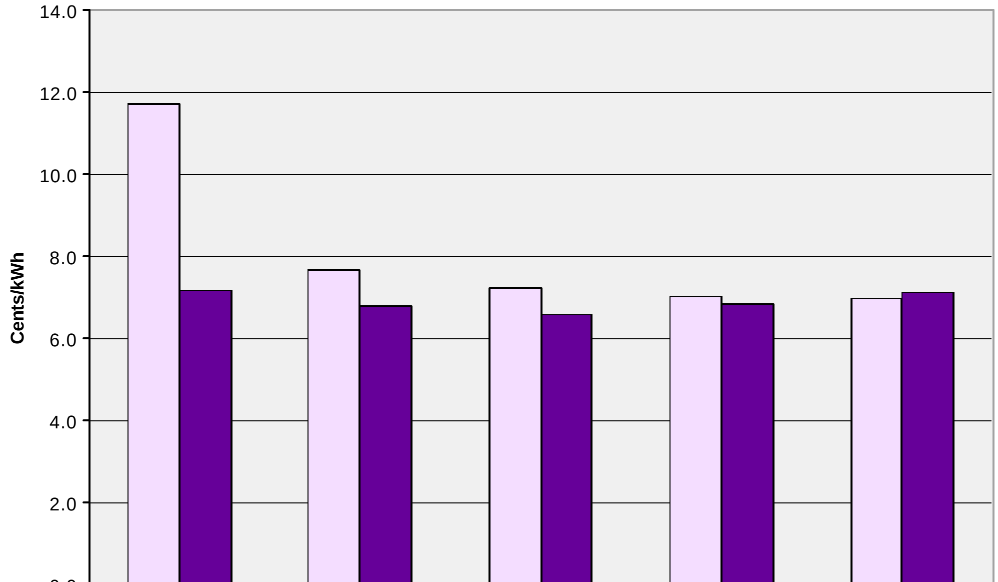
	2003	2004	2005	2006	2007
IOU	12.3	10.7	10.3	10.0	9.9
Muni	10.0	9.6	9.6	9.8	10.0

Figure 3-6
Commercial IOU/Municipal Electricity Rate Outlook
2003 – 2007
($2000) ¢/kWh



	2003	2004	2005	2006	2007
IOU	16.0	11.7	11.2	10.9	10.8
Muni	10.0	9.4	9.4	9.6	9.8

Figure 3-7
Industrial IOU/Municipal Electricity Rate Outlook
2003 – 2007
($2000) ¢/kWh



	2003	2004	2005	2006	2007
IOU	11.7	7.7	7.2	7.0	7.0
Muni	7.2	6.8	6.6	6.8	7.1

The difference between IOU and municipal utility rates in California is significant; however, this difference will decline once the IOUs pay off their debt, which for some IOUs might happen in 2004.

Some large commercial and industrial firms are served through "direct access." These customers negotiate their own terms with suppliers, and the prices they pay are confidential.

Electricity Bills - California vs. Western States

Although residential rates in California are much higher than those prevailing in other Western states, monthly residential bills are comparable to those facing customers in other states because average residential usage is lower in California. However, commercial and industrial customers are affected significantly by higher electricity rates in the state. Although commercial customers will most likely not leave the state due to electricity rates, industrial customers may look for alternative places to locate their operations. This can reduce the job pool and affect the economic well being of the state.

California's electricity consumers currently face considerably higher rates than consumers in other Western states. Residential, commercial, and industrial consumers currently pay as much as 53, 110 and 117 percent more in electricity rates in California, respectively, than similar consumers in other Western states. This difference is due to a number of factors, including the use of lower cost resources (hydro in the BPA federal system and coal in the Southwest) to generate electricity in other states that are not available in California. Although this trend will likely decline in 2004, rates could still be 37, 58 and 47 percent higher for California's residential, commercial, and industrial users, respectively (**Table 3-8** and **Figures 3-8, 3-9** and **3-10)**

Table 3-8
Comparison of Retail Electricity Rates in California and other Western States in ($2000) ¢/kWh

Residential			
	2002	**2003**	**2004**
CA	12.5	11.7	10.4
Western US	7.5	7.6	7.6
% difference	67%	53%	37%
Commercial			
CA	12.4	14.3	11.1
Western US	6.7	6.8	7.0
% difference	85%	110%	58%
Industrial			
CA	8.0	10.4	7.3
Western US	4.7	4.8	5.0
% difference	68%	117%	47%
GDP Deflator	103.6	105.0	108.9

Source: EIA and CEC staff. Western States include Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming, Oregon, and Washington

Figure 3-8
Residential Electricity Prices and Monthly Bills for California and Western State Consumers ($2000)

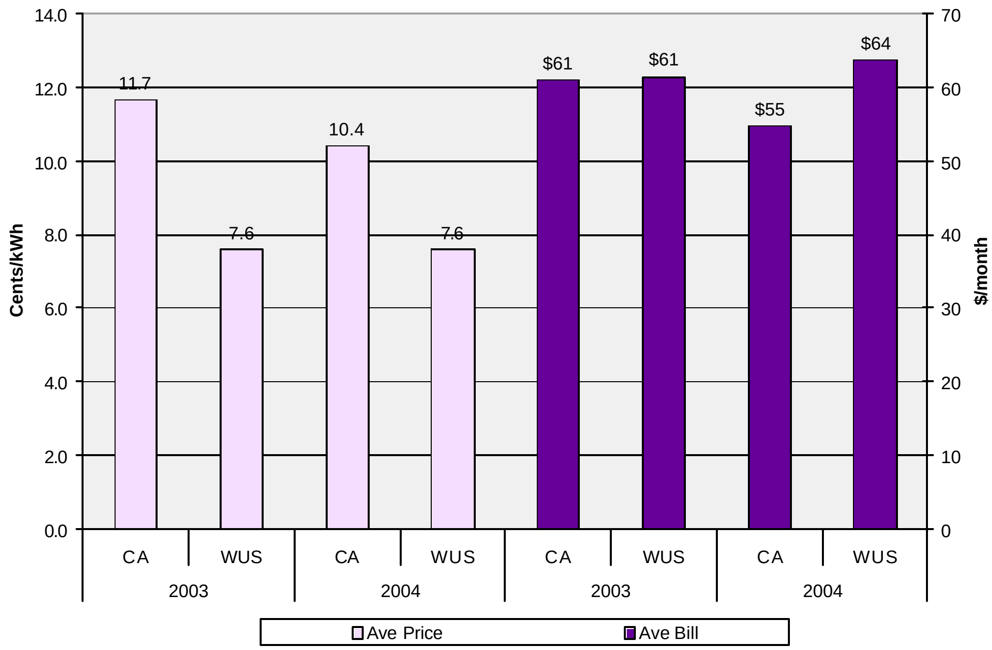


Figure 3-9
Commercial Electricity Prices and Monthly Bills for California and Western State Consumers ($2000)

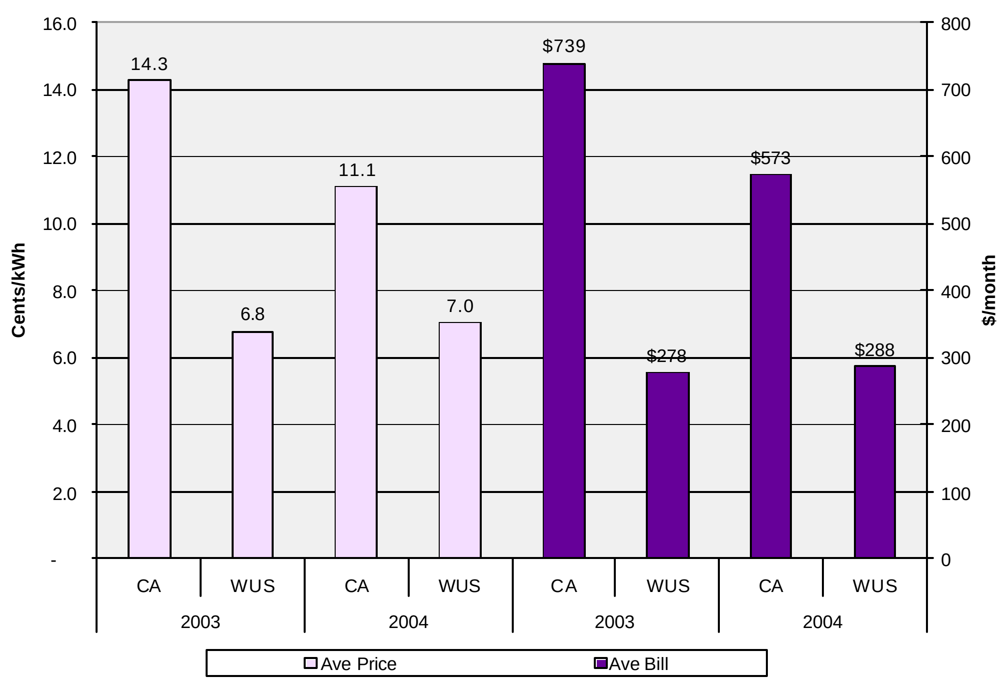
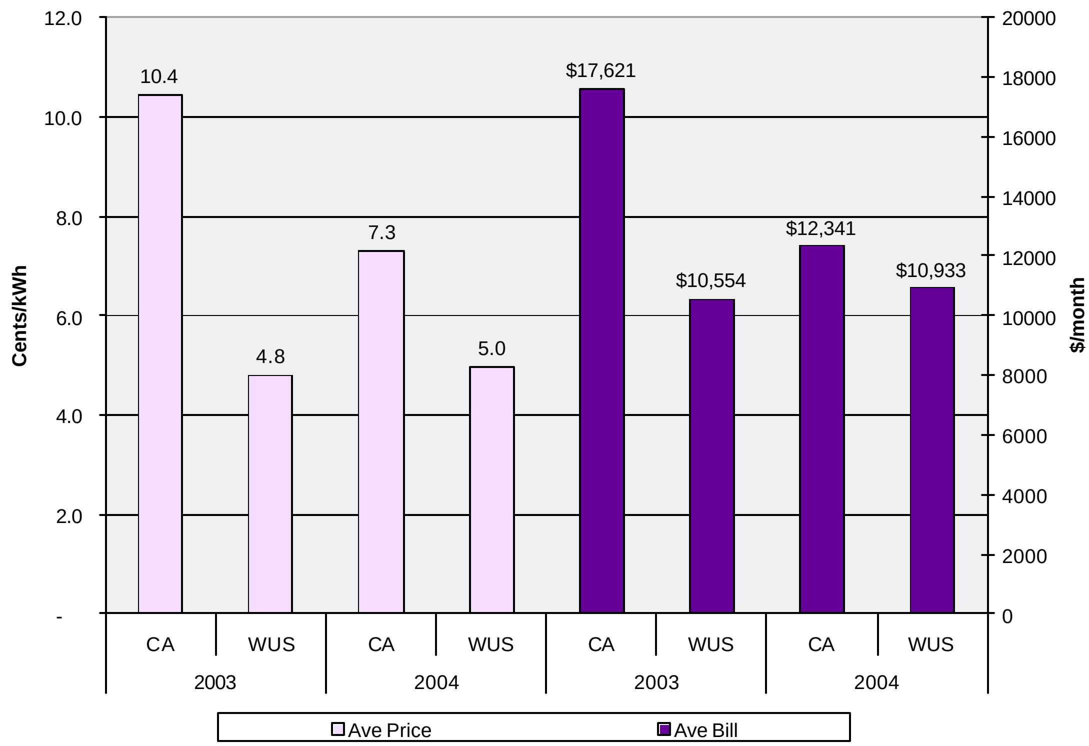


Figure 3-10
Industrial Electricity Prices and Monthly Bills for California and Western State Consumers ($2000)



Electricity bills for California's residential consumers are slightly lower than bills for similar consumers in other states. At the same time, residential consumers in California currently pay 53 percent higher rates. If a rate decrease projection for California's consumers materializes next year, a residential consumer in California would pay even lower electricity bills than residential consumers in other states (**Table 3-9 and Figure 3-8**).

California's commercial consumers, on the other hand, pay more than double in rates and bills than similar consumers in other states. Although the trend declines next year, the burden for commercial customers remains high. California industrial consumers fare relatively better than commercial customers. Current electricity bills for California's industrial customers are approximately 67 percent higher than for customers of other Western states. These bills could decline to be only 13 percent higher next year **(Tables 3-8** and **3-9** and **Figures 3-9** and **3-10)**.

Table 3-9
Comparison of Monthly Retail Electricity Bills in California and other Western States in ($2000) $/kWh

Residential			
	2002	**2003**	**2004**
CA	$65	$61	$55
Western US	$61	$61	$64
% difference	8%	-1%	-14%
Commercial			
CA	$640	$739	$573
Western US	$274	$278	$288
% difference	134%	166%	99%
Industrial			
CA	$13,429	$17,621	$12,341
Western US	$10,405	$10,554	$10,933
% difference	29%	67%	13%
GDP Deflator	103.6	105.0	108.9

Source: EIA and CEC staff. Western States include Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming, Oregon, and Washington

Electric Transmission System Assessment

A robust transmission system provides many benefits to California, including reliability enhancement and access to cheaper generation, as well as strategic benefits. Recognizing this, the state has adopted an Energy Action Plan whose goal is to "Ensure that adequate, reliable, and reasonably-priced electrical power and natural gas supplies, including prudent reserves, are achieved and provided through policies, strategies, and actions that are cost-effective and environmentally sound for California's consumers and taxpayers."

Specifically, the Energy Action Plan seeks to achieve this goal in part by upgrading and expanding the electricity transmission infrastructure and reducing the time before needed facilities are brought on line. For example, the Plan recognizes that the current CPUC Certificate of Public Convenience and Necessity process has not been updated in response to the many industry, marketplace, and legislative changes that have occurred since the passage of AB1890 in 1996. It also asks that agencies collaborate in the Energy Commission's integrated energy planning process to determine the statewide need for bulk transmission projects.

These actions are intended to resolve some of the major transmission issues currently facing California, including constrained transmission paths (both now and predicted in the future), local reliability problems in the San Francisco and San Diego areas, local stakeholder participation, accommodating new renewable generation which will be needed in order to meet the Renewable Portfolio Standard, and the implications of the August 14, 2003 Eastern Interconnection Outage.

Constrained Transmission Paths and Local Reliability Areas

This section briefly describes a number of areas where transmission-related problems, combined with changes caused by deregulation, have contributed significantly to higher prices and reliability problems on the CA ISO-controlled grid.[12] These include four major transmission paths within California—Paths 15, 26, 45 and 46, and two local reliability areas - San Diego and the San Francisco Peninsula. For a map of the major transmission paths and constraints in and into California, see **Figure 3-2**.

- Path 15 provides an example of how an insufficient transmission infrastructure coupled with poorly designed electricity markets can affect electricity costs. Path 15 enables economic transfers between southern California and the Southwest and northern California markets during much of the year. The path is often constrained during heavy summer peak load periods, limiting the level of transfers between the two areas. When Path 15 is constrained in the south-to-north direction, the CA ISO is required to dispatch less efficient, higher cost generation north of Path 15 to meet northern California loads; the resulting "congestion costs" can produce significantly higher electricity prices in northern California relative to south of Path 15. The congestion problem was exacerbated in 2000 - 2001 as strategically located generators north of path 15 were able to increase prices significantly. The CA ISO has estimated that building a third 500 kV transmission line between the Los Banos and Gates substations to relieve congestion in this areas would pay for itself within 5 to 10 years.

  Formal CPUC proceedings on Path 15 closed in Fall 2002. In March 2003, the presiding Administrative Law Judge for the Path 15 case submitted a proposed decision recommending that the CPUC reject PG&E's request for a CPCN. The draft decision argued that, among other things, the proposed Path 15 expansion would not provide sufficient congestion relief, market power mitigation or reliability benefits to justify its anticipated $300 million costs. The presiding CPUC Commissioner on the case, Loretta Lynch, also submitted a proposed decision recommending that the CPUC grant a CPCN for the upgrade. Commissioner Peevey, the new CPUC President, proposed a third alternative decision for the CPUC to consider. President Peevey proposed that the CPUC accept PG&E's request to withdraw its application for a CPCN, a request PG&E had made earlier, but which had been rejected by the presiding Commissioner. He also recommended that the CPUC find that PG&E could perform the expansion upgrades it proposed as part of the joint PG&E, WAPA, Trans-Elect agreement, without a CPCN.

Finally, Peevey's proposed decision recommended that environmental assessments for Path 15 previously performed by WAPA should be accepted by the CPUC.

On May 22, 2003 the CPUC found that the Path 15 upgrade should go forward based on the recommendations contained in Commissioner Peevey's proposed decision. The decision limited further involvement by the CPUC in the Path 15 expansion case, except in the event that PG&E increases the costs of its upgrade obligations.

- Path 26, an extension of Path 15 within Southern California, was built to allow transfers of lower cost power from Northern to Southern California during periods of high hydro availability in the north. This path is often constrained. Congestion on Path 26 has increased to such a level that the CA ISO has designated it as a separate pricing zone within California.

- Path 45 connects Northern Mexico with San Diego and the Imperial Valley. New generation in the amount of 1,665 MW has been completed in Northern Mexico near Mexicali—the 600 MW Sempra Termoelectrica de Mexicali and the 1,065 MW Intergen La Rosita Power Project are both fully commercial. Of this capacity, 1,070 MW are intended for export to the U.S. The remaining 590 MW will be available to Mexico (CFE). The former portion will connect to the Imperial Valley substation, but not all of it will be available to the San Diego area until upgrades at the substation are completed. The CPUC has found needed for economic purposes this Imperial Valley Substation modification, as well as a Miguel-Mission transmission line upgrade. The Miguel-Mission project is currently undergoing an expedited CPCN review. However, increasing transfers into the San Diego area will also require reinforcement of the Imperial Valley-Miguel transmission line and an additional Miguel 500/230 kV transformer.

  On May 2, 2003, a U.S. District Court found that the environmental assessment associated with the presidential permit issued by the US DOE and the right-of-way grant issued by the Bureau of Land Management allowing for the cross-border transmission lines had not adequately addressed air and water quality impacts. On July 8, 2003 the judge provided for the continued operation of both new plants while giving the US DOE until May 15, 2004 to demonstrate why the court should not set aside the presidential permit.

- Path 46 connects Southern California to Nevada and Arizona. Another wave of generation development is currently occurring in the southwest, particularly in central Arizona and the area around the Palo Verde hub. Arizona expects to see more than 6,000 MW of new gas-fired generation on line in this area by 2007. Additional generation is being developed in southern Nevada. Most of this new generation capacity is intended for sale in California electricity markets. The existing transmission capacity on Path 46 - linking western Arizona and Southern California markets - is not sufficient to transport this amount of power without significant upgrades. The CA ISO has initiated a regional stakeholder process to evaluate transmission expansion options for Path 46.

The process, known as the Southwest Transmission Expansion Plan (STEP), is a regional collaborative planning process, designed to identify transmission constraints that limit economic power transfers between areas within the southwest and propose transmission expansions to remove those constraints. The process involves grid planners from Arizona, southern Nevada, Northern Mexico, and Southern California (SCE and SDG&E). The STEP process can also be viewed as an extension of the CA ISO's Coordinated Grid Planning Study process in which the CA ISO is involved, along with stakeholder groups, in resolving constraints on the CA ISO-controlled bulk power system within California.

A study plan has been developed and two screening (power flow) studies have been performed thus far, using a 2007 base year with assumed generation additions in the Palo Verde area, southern Nevada, and Mexico. Generation additions and retirements are also assumed in the SDG&E and the SCE areas. Without any transmission upgrades, the initial screening study identified significant constraints between Palo Verde and southern California on both the Southwest Power Link (SWPL) and PaloVerde-Devers. Some 20 alternative cases were then developed to evaluate their relative effects in mitigating those constraints. Three AC and two DC cases were selected from this group for further evaluation. These cases will be refined through additional assessment. STEP is also performing an economic assessment of these five cases to identify their potential economic benefits.

Local Reliability Areas

San Diego and the San Francisco Peninsula were both impacted by serious reliability problems during parts of 2000 and 2001. Both areas are characterized by limited generation within their electrical boundaries and limited transmission capacity to access resources outside of those boundaries. This combination of conditions has resulted in limited competition, providing local generators the potential to influence both reliability and electricity prices during heavy summer peak load conditions. To provide local voltage support for reliability purposes, as well as mitigate market power problems, much of the generation in both areas has been designated by the CA ISO as RMR. This means the CA ISO has contracted with certain generators in San Diego and on the San Francisco Peninsula to enter "must run" contracts that obligate them to operate at specified prices during periods designated by the CA ISO.

San Diego

The San Diego area has about 2,250 MW of local generation. With a summer 2003 peak load of about 3,800 MW, it must rely on imports from outside the area to meet a major portion of its peak load requirements. These requirements are supplied by two major transmission paths, Path 44 and the 500kV Southwest Power Link (SWPL), part of Paths 46 and 49. Path 44 connects San Diego with the San Onofre Nuclear Generating Station, has a transfer capability of 2200 MW, and is San Diego's only major link with the CA ISO grid. SWPL connects San

Diego to generation resources at the Palo Verde hub in western Arizona. With all lines in service, the simultaneous transfer capability into San Diego is about 2,800 MW. As a part of their area reliability studies, the CA ISO and SDG&E found that a sequential outage of the area's largest local power plant and its largest transmission line, SWPL, could result in local-area reliability criteria violations beginning in the 2005 time frame. Based on those findings, they proposed the construction of a 500 kV power line to provide a second major connection to the CA ISO-controlled grid in the SCE service area—the Valley-Rainbow project.

SDG&E submitted an application to the CPUC for a CPCN for Valley-Rainbow in 2001. In December 2002, after over a year and one-half of hearings and debate, the CPUC denied SDG&E's request for a CPCN without prejudice (see D.02-12-066.) The CPUC denial was based on its view that Valley-Rainbow was not needed in the five-year planning horizon it allotted for the project from the time of project submittal to construction. Following the CPUC decision rejecting Valley-Rainbow, SDG&E filed a petition for a rehearing and a petition to modify the decision with the CPUC. On June 5, 2003 the CPUC rejected SDG&E's rehearing request and its petition to modify and denied the proposed Valley-Rainbow upgrade.

On April 15, 2003, SDG&E filed its 20-year long-term resource plan with the CPUC in proceeding R.01-10-024. SDG&E proposes a two-phase transmission expansion plan that would strengthen the 500-kV "backbone" system, allowing additional imports into the southern CA ISO-controlled grid from Arizona, Mexico, and southern Nevada. For this expansion to provide local reliability benefits in addition to likely statewide reliability and economic benefits, it needs to tie into SDG&E's service area. The proposed expansion includes the Valley-Rainbow upgrade (renamed the Near-Term Interconnection Project) assumed for 2008 and an additional 160-mile, 500 kV line from the (new) Rainbow Substation to the existing Imperial Valley Substation assumed for 2012. The project would significantly increase SDG&E's ability to import power from northern Mexico and Palo Verde and provide an additional connection between San Diego and the CA ISO-controlled transmission system. In order to increase import capacity and serve the San Diego area more reliably, it is expected that SDG&E will need to upgrade the internal transmission and distribution system.

New generation development or demand reduction programs in San Diego could contribute to a near-term resolution of SDG&E's reliability problems. Two large power plants have been proposed for the immediate San Diego area that could provide substantial reliability support, if completed. An application for the Otay Mesa power plant (Calpine, 510 MW) has already been approved by the Energy Commission, but the facility is still in the very early stages of construction and there is uncertainty about its near term completion. The proposed Palomar facility (Sempra, 546 MW) was permitted by the Energy Commission in August 2003.

San Francisco Peninsula

San Francisco, like San Diego, has limited transmission and generation resources. PG&E currently projects peak loads of approximately 1,230 MW for the San Francisco/Peninsula area for 2005. Electricity to serve these loads is provided by six transmission lines in a single corridor and three aging and unreliable area power plants. These resource characteristics cause significant reliability risks for future outages on the SF Peninsula.

Local generation is expected to provide 618 MW of power to the SF Peninsula in 2005 (363 MW from the Potrero Power Plant, 215 MW from the Hunters Point Power Plant and 20 MW from the United Golden Gate Cogeneration Plant). All of this generation (except United Golden Gate) is under RMR contract with the CA ISO. This existing generation (except the United Golden Gate Plant built in 1986) is also highly susceptible to problems because of age and environmental issues. The Hunters Point Power Plant will be shut down as soon as it can be displaced by new generation and/or increased imports from outside the area according to an agreement between the City and County of San Francisco and PG&E. The lack of generators and their vulnerability has also impacted the ability of PG&E to perform maintenance on the transmission facilities.

The remaining 600+ MW of power needed to meet SF Peninsula load requirements (including reserves) is imported over transmission lines from the East Bay. Approximately a third of the generation needed for the San Francisco Peninsula is served by power delivered at San Mateo Substation from 230kV transmission lines connecting the Tesla, Newark, and Ravenswood Substations. The remaining San Francisco Peninsula load is met through power delivered to San Mateo Substation via two 230kV lines crossing San Francisco Bay.

The San Francisco electric reliability problem is being evaluated in several forums. Two major facilities (one transmission line and one power plant) are currently in permitting proceedings at the CPUC and Energy Commission, respectively. A second transmission project is also in the planning stages. The City and County of San Francisco has also looked at the problem and developed an energy plan that includes transmission, generation and conservation options. Finally, the CA ISO, through a PG&E stakeholder process, is analyzing the long-term (10-years) reliability of the San Francisco and Peninsula region. The fragmented planning process is discussed in the following section and **Appendix E**: Local Reliability Issues.

Two transmission projects intended to increase electricity imports into the Peninsula have been proposed to increase import capability into the SF Peninsula area. The San Mateo-Martin Conversion Project, an upgrade of an existing 60 kV line to 115 kV, could increase area imports by 200 MW by 2004. PG&E has not yet filed an application at the CPUC for this project, however. PG&E has filed an application with the CPUC for a CPCN for the 230 kV Jefferson-Martin transmission line. This project, along with other system improvements, would increase the import capability into San Francisco by approximately 400 MW.

Mirant has proposed a 540 MW expansion of its Potrero Power Plant that would displace existing generation on the Peninsula. "However, Mirant filed for Chapter 11 protection in U.S. Bankruptcy Court on July 14, 2003. Thus, even if the expansion project is certified by the Energy Commission, it is uncertain whether the project would be built, either by Mirant or another entity." This project is currently in licensing review at the Energy Commission.

Local Stakeholder Participation

Both San Diego and San Francisco face substantial constraints for generation-based grid service. In response, local stakeholder groups have developed integrated energy plans that balance generation, transmission, and demand options to serve local customers. San Diego and San Francisco's experiences may demonstrate some "best practices" that could be used to deal with other local energy concerns, and the Legislature may wish to consider encouraging such local efforts if these are desirable components of solving the state's energy problems.

In order to meet demand in the San Diego and San Francisco Peninsula regions, investment in energy infrastructure is needed in the next five years. Because local stakeholders perceive that there are preferable alternatives to the central station and grid expansion options which can be developed by utilities and merchant power, they have organized to explore a broader range of options.

A variety of stakeholders and agencies have organized to develop solutions to the energy challenges faced in San Diego and the San Francisco Peninsula. The processes in which these stakeholders can participate to affect a change are:

- The CA ISO transmission planning process,
- The CPUC's transmission permitting proceeding,
- The San Diego Regional Energy Office's processes,
- The Governor's Office of Planning and Research Environmental Justice Committee,
- City and county led processes, and
- Other CPUC and Energy Commission proceedings.

A variety of stakeholders who often hold disparate views participate in these processes and much good work has been done by the stakeholders in these contexts. Unfortunately, the resource planning and resource deployment roles of agencies are not always clearly defined. As a result, the agreements that stakeholder groups work out are sometimes duplicated and/or in conflict with agreements and decisions that arise from an alternative process.

The following is a summary of the "best practices" that the stakeholder groups suggest for future development of balanced portfolios in local areas:

- Some transmission and generation projects are difficult to sell to certain local interest groups. Smaller scale generation, renewables, demand response and efficiency are more desired by local residents and their deployment will probably have broader support and thus faster implementation. Both the San Diego Regional Energy Infrastructure Group's and the San Francisco City Departments' resource plans feature diversity of resources.

- Successful resource plans are those which reflect the local communities' concerns. This requires outreach, education and interaction with stakeholder groups in order to build consensus. If the final resource plan is one that everyone can live with (even if not all stakeholders agree on every aspect) then deployment of the plan will face less opposition.
- The existing market structure is still dominated by utilities and regulators. So far, no local group from either region has been able to set up an institution which is viewed as the definitive regional resource planner and which has the ability to implement regional plans.
- The existing regulatory, planning and permitting processes are fragmented and quite complicated.
- The Energy Action Plan, adopted by the California Energy Commission, the CPUC and the California Power Authority, provides a framework for reducing the conflicts between the CPUC and the CA ISO when determining the need for transmission projects. The CPUC will start a rulemaking which, among other things, proposes to use the results of the Energy Commission's collaborative transmission assessment process to guide and fund IOU-sponsored transmission expansion or upgrade projects without having the CPUC revisit questions of need for individual projects in certifying transmission improvements.
- Successful local groups are very skilled at working within the existing and established regulatory process to divert a larger share of statewide funding to meet local objectives. This requires a lot of time, persistence, and skill. Successful local groups have to be active at separate regulatory processes for transmission, generation, energy efficiency, demand side management, renewables and DG. They need to know the ins and outs of working with the CA ISO, the local utility, the CPUC, the Energy Commission and the Legislature.
- A new intermediate local organization that could coordinate planning and lobbying in the region would be helpful in developing balanced energy portfolios that serve local needs. At the minimum, it would have to be able to work with customers and all the other public and private organizations that have responsibility for energy-related decisions and resources. If the local regions have the will and capability, the new organization could possibly be a joint power authority that could group energy efficiency projects to take advantage of economies of scale and the resultant cost savings and also could issue revenue bonds to support construction of generation resources. Further work would need to be done to determine the costs of starting a new organization, what new powers are needed, what structure best fits the organization's goals, and what steps are necessary to create these new capabilities.

Appendix E provides a more detailed description of the attempts of local stakeholder groups within San Diego and the San Francisco Peninsula areas to craft regional solutions and describes lessons learned along the way.

Facilitating Existing and New Renewables to Meet the Renewable Portfolio Standard

Senate Bill (SB) 1078 (Chap. 516, Stat. of 2002) was enacted to increase California's use of renewable energy resources. SB 1078 created the Renewables Portfolio Standard (RPS) Program under which the state will increase its electrical generation from renewable sources by at least one percent annually until renewables comprise 20 percent of total investor-owned utility (IOU) procurement by the end of 2017 within certain cost constraints. If a transmission facility is an integral part of a renewables project approved pursuant to the RPS process, it creates a prima facie finding that the network upgrade will facilitate achievement of the renewable power goals established in SB 1078. The Energy Commission was charged with providing a resource assessment study to the CPUC that the CPUC would use in producing a transmission plan for renewable electricity generation facilities. The Energy Commission has provided this assessment to the CPUC, the CA ISO and stakeholders.

The CA ISO held a stakeholders' workshop on July 7, 2003 to facilitate the process of formulating a transmission expansion plan for renewable generation, based upon the resource estimates provided by the Energy Commission. The IOUs, developers and the CA ISO worked together to develop conceptual plans that the CPUC will include in their transmission plan for renewable electricity generation.

The CPUC initiated investigation I.00-11-001 in November 2000 to identify and take actions necessary to reduce or remove constraints on the state's existing electrical transmission and distribution system, per AB 970 (Chap. 329, Stat. of 2000). Phase 6 of this proceeding, the Tehachapi Transmission Project, is currently underway, and evidentiary hearings were held on June 9 through 11, 2003.

As part of this process, Southern California Edison (SCE) has completed conceptual studies funded by interested wind developers on the Tehachapi region. These studies have identified the substations and lines that would be required to meet the potential growth of wind resources in the region. SCE plans to conduct detailed environmental studies in 2003, and file the application for a Certificate of Public Convenience and Necessity (CPCN) around February 1, 2004.

Implications of August 14, 2003 Eastern Interconnection Outage

The largest blackout in U.S. history occurred on August 14, 2003, affecting approximately 50 million customers in the upper Midwest and Northeast United States and Eastern Canada. An investigation led by the U.S.-Canada Joint Task Force is underway; however, at this time it is too soon to draw conclusions on the cause or causes of the outage. The investigation is focusing on both the technical and human aspects of the events. From a technical perspective, reconstructing the timing of events has been slowed by the fact that the time stamps associated with major events such as faults and circuit breaker operation are not accurate.

According to NERC President and CEO Michehl Gent's September 3, 2003 testimony before the House Committee on Energy and Commerce, this occurred either because the computers that recorded the information became backlogged, or the clocks from which the time stamps were derived had not been calibrated to the national time standard. Thus, the exact sequence of events surrounding the minutes just after 4:00 P.M. EST is still being sorted out.

In the hours before the acceleration of events, there were three notable events. First, the 680 MW East Lake Unit No. 5 experienced a forced outage just after 2:00 P.M. This loss, combined with last year's shut down of the 882 MW Davis-Besse nuclear unit, left Northern Ohio much more vulnerable to disruptions in service.[13] Second, just after 3:00 P.M., one of FirstEnergy's major transmission lines suddenly shut down. Third, At 3:32 P.M. another transmission line to which power had shifted after the first line failed apparently overloaded and automatically tripped, possibly because it began to sag from the increased load and made contact with a tree.

The human aspects of the investigation are focusing on answering such questions as the following:

- What were system operators and reliability coordinators doing leading up to the blackout?
- What indications of problems did they see or not see?
- What were their qualifications and training to recognize and respond to system emergencies?
- Did they follow established NERC and regional reliability standards and procedures?
- Were those standards and procedures effective?
- Were responsibilities clearly assigned and did operating personnel have the necessary authority to act in a timely manner to avoid the blackout?
- How effective were the control center computers and displays in providing information to the operators?
- What communications took place among system operators and reliability coordinators in different parts of the grid prior to and during the outage?

On August 10, 1996 the Western States experienced a cascading black-out that affected 7.5 million customers for up to nine hours. That outage was triggered by a combination of random transmission line outages and resulting system oscillations, causing the Western Interconnection to separate into four electrical islands, with significant loss of load and generation. According to NERC[14], the Western transmission system was fairly heavily loaded (for a Saturday) prior to the disturbance. This was due to hot weather and there were high electricity transfers from Canada into the Northwest, and from the Northwest into California due to high hydroelectric availability. Failure to trim trees and remove others, identified as dangers to the system, caused short circuits when the lines sagged into trees due to the high ambient temperature (even though the first failures were on lightly loaded lines).

Control room personnel had been unknowingly operating the system in a condition in which one line outage could trigger subsequent cascading outages because adequate operating studies had not been conducted. Because California had been relying on extensive imports and did not have knowledge from neighboring control areas of developing problems, it did not have sufficient in-state generation to maintain the supply/demand balance when the Western Interconnection separated into islands as a safety mechanism.

As a result of lessons learned from the 1996 outage, there have been many actions taken to improve reliability in California and the West. Some of the major actions include the following:[15]

- Critical transmission line ratings were immediately reduced until extensive studies were performed to assure that their ratings could be justified as appropriate under contingency situations.
- WSCC (now WECC) Reliability Coordinators have been in place since 1997 to enhance monitoring, communication, coordination, and reliability of the Western grid.
- The WECC Coordinated Off-Nominal Load Shedding and Restoration Program was implemented in 1998-1999. The goal of the program is to reduce the impact of an over- or under-frequency event by coordinating the operation of protection equipment throughout the WECC.
- In 1999 the WECC Reliability Management System (RMS) was implemented to ensure compliance with WECC and NERC operating standards. The RMS program imposes fines for non-compliance with RMS standards, which include criteria for proper and adequate operation of the electric grid. The utilities have voluntarily agreed to pay fines.
- The CA ISO, which began operating in March 1998, controls approximately 40 percent of the WECC grid. It has implemented the following actions to ensure reliable operation of its portion of the interconnected grid:
  - The CA ISO is a WECC- and NERC-certified Control Area and all CA ISO system operators are WECC- and NERC-certified.
  - Voltage collapse studies have been conducted, and as a result, VAR upgrades have been made throughout the state. The CA ISO has ensured adequacy of under-frequency protection for load, generation, and interties through testing of under-frequency relays.
  - The CA ISO has studied both planned and forced outages on the system. It pre-plans for contingencies. In the event of a contingency, it re-adjusts transmission system operations to stay within reliability margins. Following contingencies, it reviews system performance.
  - The CA ISO had the authority and responsibility to ensure adequate transmission maintenance. It reviews all Participating Transmission Owner (PTO) engineering studies and transmission maintenance standards. It investigates incidents on the system to ensure that CA ISO standards are being met and procedures are being followed. Proper transmission maintenance is ensured through random annual audits.
  - All generators wishing to interconnect to the CA ISO-controlled grid must complete the New Resource Interconnection process and meet data communication standards. All in-state and interconnected generators are tested to ensure their response is in line with CA ISO standards. The CA ISO tests and certifies all generators that provide ancillary services to validate their ability to properly respond to contingencies.

While the Eastern and Western Interconnections share many similarities, they also differ due to geography and population patterns. The Northeast portion of the Eastern Interconnection resembles one large load center, with relatively short transmission lines connecting power plants that are close together and close to the loads they serve. The Western Interconnection is characterized by load centers separated from one another by mountains, plains, and deserts, and hence the Western Interconnection has long-distance, high-voltage lines that connect distant load centers and generators.

Despite these differences, it appears that the contributing factors to the August 14, 2003, Eastern Interconnection Outage could share many similarities with the contributing factors to the August 10, 1996 Western States Outage, including lack of communication among control areas, failure to re-adjust operating parameters in response to contingencies, and insufficient right-of-way maintenance. In fact, Bonneville Power Authority (BPA) engineer Bill Mittelstadt has become the first of likely several BPA representatives who have been assigned to the Task Force to help discern the causes of the August 14, 2003, outage and share lessons learned and improvements made to the Western system as a result of the August 10, 1996 outage. The NERC Steering Group which is investigating the 2003 outage includes Terry Winter, President and CEO of the CA ISO. NERC and the US DOE have been jointly conducting the fact-finding investigation of events, with technical support provided by the Consortium for Electrical Reliability Technology Solutions (CERTS).

CERTS is also currently providing technical support to the Energy Commission to develop grid management tools for the CA ISO to help avert system disruptions. These tools are being developed in recognition of the fact that despite the best efforts to prevent and mitigate the technical and human factors which contribute to large-scale outages, the possibility remains that such an event could happen again.

More information on the status of the investigation can be found at the US DOE website at http://www.electricity.doe.gov/2003_blackout.htm, as well as the NERC website at http://www.nerc.com/~filez/pressreleases.html .

Chapter 4: Natural Gas Market Assessment

Introduction

Chapter 3 introduced and generally described the integrated elements of the electricity and natural gas markets and infrastructure. This chapter discusses the topic further with greater attention to natural gas issues.

About 85 percent of the natural gas supply that California uses comes from out-of-state resource areas. Large pipelines extending hundreds of miles and across several states supply natural gas from areas in the southwest, Rocky Mountains and Canada. These pipelines need to be large enough not only to meet California's needs, but also the needs of the states along the delivery paths.

Natural gas prices have been extremely volatile since the summer of 2000. There are a number of theories to explain this volatility. One school of thought is that natural gas prices have at times increased due to a strong demand in the power generation sector and the ability to pass the high fuel prices on to electricity customers. A second theory is based on the assumption that high gas prices are the result of inadequate pipeline capacity due to increased demand for heating needs, as happened during the last winter season. A third approach attributes high prices to the low levels of storage and the fear that this would mean a tight supply situation in the coming summer and winter peaks.

Finally, some industry experts believe that there are direct links between current high prices and the anticipation that the high prices will continue into the intermediate future. This is because there are not as many large pools of natural gas that can be developed to sustain a level of production to match the growing demand. In this school of thought, it is believed that the new wells drilled and the new pools developed will provide supplies only for short durations of time and do not promise the lasting life as older wells and supply basins. While the number of drilling rigs has increased, the futures prices have not yet reacted sufficiently to give the market a confidence that significant supplies will be available in the future.

A combination of volatile gas and electricity markets and anticipation of a supply shortage in spite of an increasing number of drilling rigs, have raised the fear of increased uncertainty in the energy market. These uncertainties are discussed in the following sections. Detailed analysis supporting this chapter may be found in the staff report, ***Natural Gas Market Assessment*** (publication number 100-03-006).

Background

Over the past three years, pipeline expansions and additions have enhanced the state's ability to import gas from supply basins throughout western North America. California is currently in a position where pipeline capacity to the state will meet its needs until about 2006. Beyond that, although annual average capacity will be adequate, peak day requirements may not be met. More efficient use of storage capacity would also address peak requirements for not only the residential and commercial consumers, but also for the industrial and power generation markets.

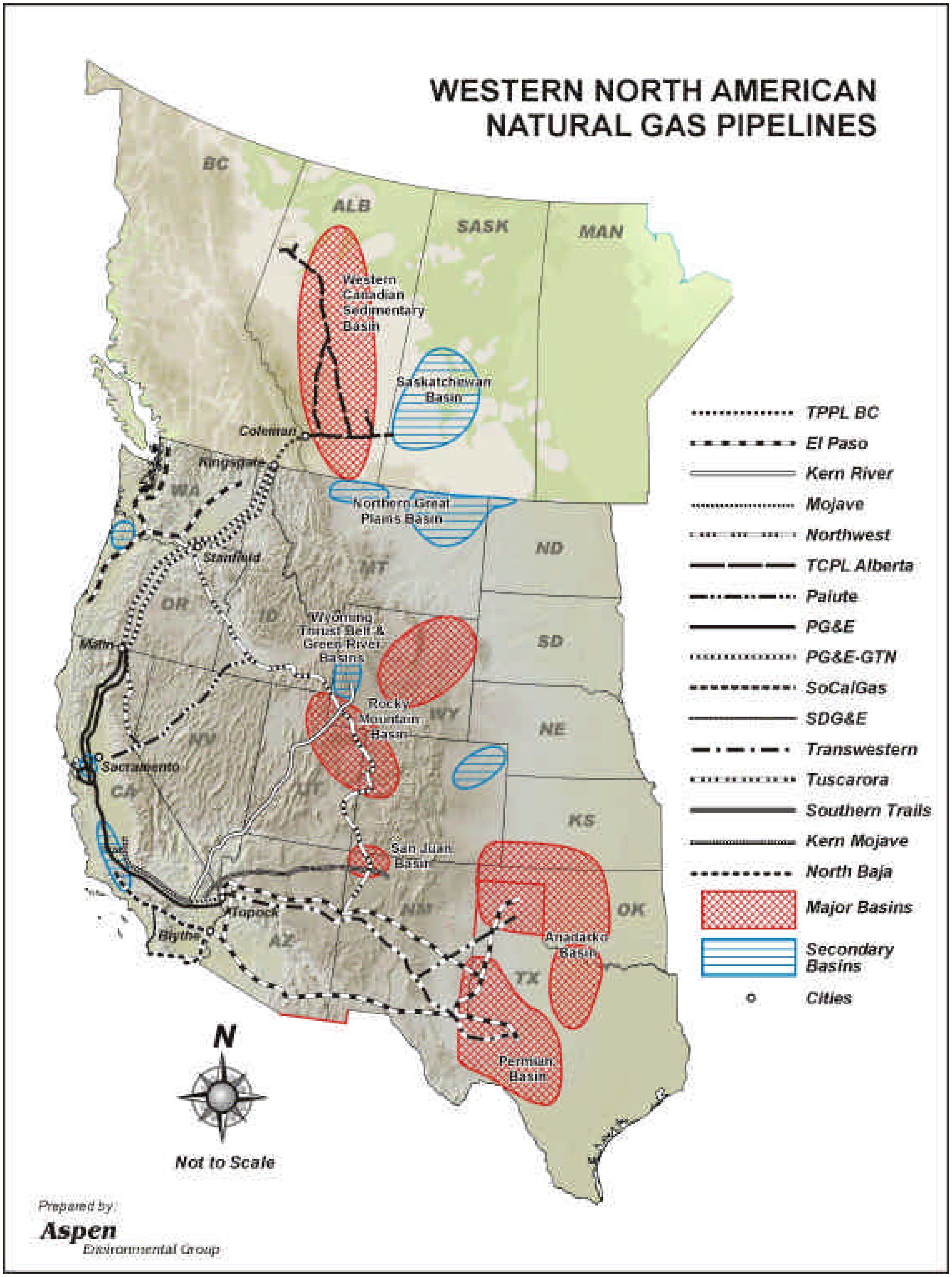
Figure 4-1 shows the natural gas pipeline system supporting California and its neighboring states. The winter of 2000-2001 turned out to be an exceptional year when demand was high and pipeline capacity was inadequate to meet peak conditions. The resulting crisis prompted action from the industry who proposed several projects to expand or add new pipelines.

Three recently-completed interstate pipeline projects (the Kern River Expansion, the Southern Trails project and the North Baja Project) coming into the state will provide significant benefits to California by improving the ability to move gas supplies to regional demand centers. In addition, Kern River's recently completed High Desert Lateral and El Paso's Line 1903 conversion to be completed by July 2004, will interconnect a number of main pipelines and should provide additional flexibility to both SoCalGas and PG&E. PG&E also benefits from the 180 MMcfd expansion of the PG&E-NEG's interstate pipeline from Canada to the California border at Malin, Oregon, completed in 2002

Natural gas demand in the U.S. and Canada has increased and continues to grow, with power generation being the prime driver in all regions. Key parameters raising uncertainty in satisfying the regional natural gas demand are the number of proposed power plants that will be built and the extent to which each of these plants consume natural gas. If the proposed plants are abandoned or delayed, natural gas demand will actually increase in the near term because the older, less efficient generation plants will need to run more often. This will be true not only for power plants in California, but also for those in the neighboring states. Furthermore, the need for new California power plants and the gas supply to serve them would decrease if power plants were constructed outside of California, and the electricity was imported at competitive prices. This could increase the reliability of gas supply within the state, as demand will be less, but might divert gas to generation "upstream" from California's end users. It also raises uncertainty in depending on larger amounts of electricity supplies from out-of-state sources.

Natural gas prices in various regions of the North American continent are strongly interrelated, and changing conditions in one region influence other regions significantly. An example was the observed regional gas prices over the past winter. Colder weather and higher prices in the Eastern U.S. lifted prices on the West Coast even though demand was less than normal and pipelines were not completely utilized.

Figure 4-1
Western U.S. Natural Gas Pipeline System



Uncertainty in the Natural Gas Market

General trends in natural gas are driven by market demand, natural gas resources and their associated exploration and development costs, transportation rates, pipeline capacities, and alternative fuel prices. There is a band of uncertainty around each of these factors. The level of uncertainty helps to define how volatile prices are in the market place. Even if long-term price and supply were stable, price spikes and volatility would occur in daily or monthly average prices. Hence, the long-term picture masks the volatility or spikes observed in the day-to-day market transactions.

Differing supply and demand sensitivity cases were assessed to determine the range of uncertainty introduced by changes in individual parameters. The cases examined how changing market conditions, over time, influence the price and supply of natural gas. Market conditions can and do cause significant seasonal disruptions, increased price volatility in the spot market, or create supply tightness on peak days. Short-term imbalances will occur at times, especially during peak days when system capacity will be stressed beyond its capacity.

Volatility is an indication of the uncertainty in market prices and supply availability. Volatility is characteristic in the daily and monthly average prices. The annual average prices, on the other hand, show changing trends in prices but mask the volatility or spikes observed in the day-to-day market transactions.

Natural Gas Market Trends

The Energy Commission uses the North American Regional Natural Gas (NARG) Model as the principal tool to assess natural gas market conditions and to generate the California border price forecast. Basic inputs to the NARG model include estimates of resource availability, proved reserves and expected appreciation, production costs, pipeline capacity and transportation costs, regional demand projections, and other parameters defining the market fundamentals. The basecase analysis resulting from the above inputs assumes average hydroelectricity and weather conditions and well-functioning competitive markets. Cases with alternative assumptions test the impacts of different market conditions on demand, price and supply availability and investigate the inherent uncertainty in the natural gas market.

The long-term assessments include annual gas consumption by end-use sectors under a range of sensitivity cases. The market assessments include a base or reference case, with high and low price cases designed to capture the uncertainty in the natural gas market, providing a range of possible price trends over the next decade. The basecase describes the most likely outcome of the natural gas market over the forecast horizon. These two bounding cases provide an indication of how high or low gas prices can reach when assumptions in the basecase deviate from their expected trend due to either expected or unexpected event changes over the forecast horizon. While these bounding trends are reachable, they are not sustainable as market forces are expected to change dynamically and impact the trends. The assumptions in high and low price cases are described later in this chapter.

Demand Projections

Natural gas production, transportation and distribution systems are an integrated grid throughout the North American continent. Natural gas market trends in one region impact other regions across the country. Studying energy trends in California necessitates analyzing natural gas markets in the United States, Canada, and Mexico.

As mentioned in Chapter 3, electricity generation provides for the largest demand growth for natural gas of all sectors. While California's demand for natural gas in the electricity generation sector grows between one to two percent per year, national electricity generation gas demand will grow at nearly five percent per year. Growth in the residential, commercial, and industrial sectors in the US and in California is relatively flat over the assessment period.

Demand Sector Classifications

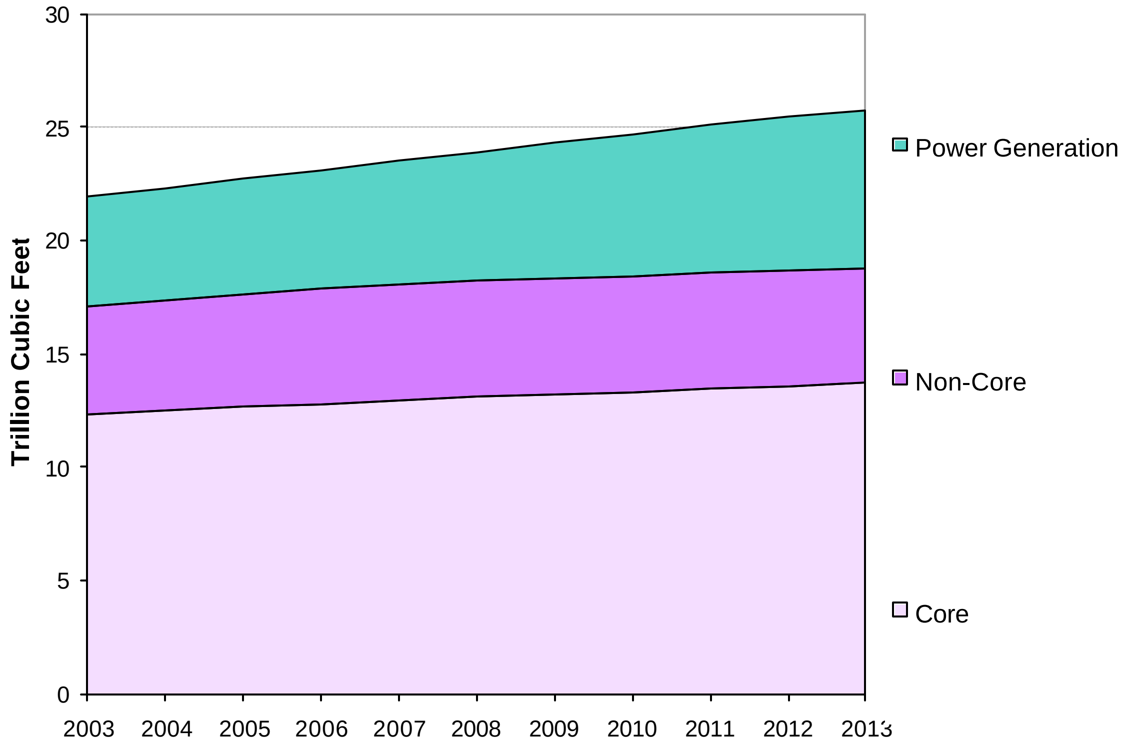
- **Core demand** consists of residential, commercial, transportation, and one-half of the industrial natural gas demand. Core customers are totally dependent on natural gas and cannot use alternative fuels, such as petroleum, in place of natural gas;
- **Non-core demand** consists of the remaining half of the industrial natural gas demand, 25 percent of commercial oil demand, and increasing amounts of industrial oil demand (20 percent in 2002, 30 percent in 2007, 40 percent in 2012, and 50 percent thereafter); and
- **Power generation demand** consists of all the natural gas demanded by electricity generation. For regions where petroleum fuel is used for power generation, oil demand is included in this category.

Natural gas demand can be classified into three major sectors: core, non-core, and power generation. A description of the three major sectors that consume natural gas is provided in the side bar, to the right. Historically fuel switching has played a major role in the way the thirst for energy has been met at different times of the year. Natural gas, distillates, diesel, coal, residual fuel oils and propane fuels have competed for market shares, varying in type and quantity over the different regions and seasons. Recent environmental regulations have restricted the ability to switch between fuels in many regions of the U.S. reducing the number of regions where switching can occur. The details of regional demand and fuel switching abilities are discussed in the staff report on natural gas markets.[16]

Figure 4- 2 shows the core and non-core natural gas demand for the U.S. (excluding California). According to EIA's ***Annual Energy Outlook 2002***, natural gas demand in the U.S. (excluding California) will increase as follows:

- **Core demand** will increase from 11.67 trillion cubic feet (Tcf) in 2003 to 12.98 Tcf in 2013, an annual growth rate of 1.1 percent.
- **Non-core demand** will increase at an annual rate of 1.7 percent between 2003 and 2013, from 4.35 Tcf to 5.12 Tcf.

Figure 4-2
U.S. Core and Non-core Natural Gas Demand (excluding California)



Source: Department of Energy, EIA

Natural gas demand for electricity generation is the fastest growing sector, according to both EIA's projection for outside the WECC, and the Energy Commission's projection within the Western Electricity Coordinating Council (WECC). The EIA estimates that from 2003 to 2013 gas demand for power generation will grow at an annual rate of 4.6 percent compared to 1.2 percent for all other sectors. In fact, EIA projects that by 2020, electricity generators will account for 55 percent of total natural gas consumption in the United States.
The natural gas demand for electricity generation in the WECC states surrounding California is anticipated to increase at an annual rate of 6.6 percent over the next decade. Specifically, gas demand for power generation will increase by:

- 7.4 percent per year in the Desert Southwest,
- 8.5 percent per year in the Rocky Mountain region, and
- 4.0 percent per year in the Pacific Northwest.

Table 4-1 shows the growth in natural gas demand for power generation in the WECC states surrounding California, compared to the rest of the United States (excluding California).

Table 4-1
Natural Gas Demand for Power Generation

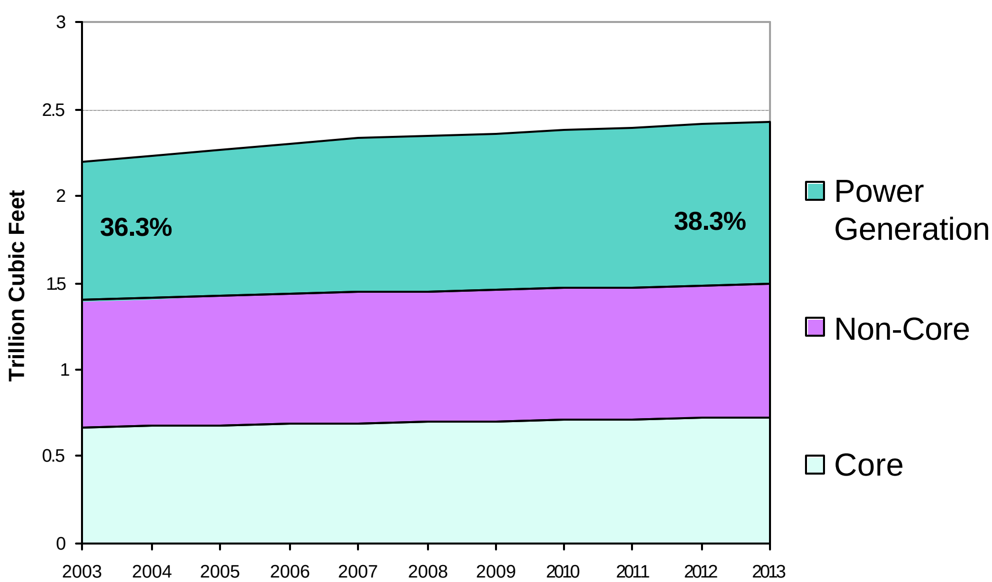
	Trillion Cubic Feet 2003	Trillion Cubic Feet 2013	Annual Growth Rate (2003-2013)
Pacific Northwest	0.18	0.27	3.96%
Southwest Desert	0.26	0.53	7.43%
Rocky Mountains	0.10	0.23	8.46%
Western States (excluding California)	0.54	1.03	6.60%
United States (non WECC)	4.18	6.53	4.57%

Source: California Energy Commission and Department of Energy, Energy Information Administration

As presented in Chapter 2, the Energy Commission's forecast for the combined core and non-core natural gas demand grows at a rate of 0.6 percent per year in California from 2003 to 2013. This represents less than half of the annual rate by which total U.S. core and non-core natural gas demand is projected to grow during the same period. The forecast includes the impacts of natural gas energy efficiency programs, and assumes that the current levels of funding for utility energy efficiency programs will continue through 2011, as authorized by the California Legislature.

Gas demand for electricity generation remains the fastest growing segment of California's natural gas demand. Over the next ten years, natural gas demand for power generation will grow from 0.80 to 0.93 Tcf per year, yielding an annual growth rate of 1.5 percent per year. Total California natural gas demand increases 10.4 percent from 2003 to 2013. **Figure 4-3** shows the natural gas demand in California by sector.

Figure 4-3
Forecasted Natural Gas Demand in California by Market Sector



Natural Gas Resources and Supply Adequacy

Natural gas resources and their associated costs to explore, develop and produce are the primary drivers of the price paid in the market. The total amount of resources considered to be in the ground is more than sufficient to satisfy the growing demand for many years. The uncertainty is how much it will cost to get the gas supplies into the pipeline and delivered to their destination. One significant driver underlying the price of natural gas is the *reserve appreciation*, or the amount by which the resource grows over time. Historically, the assessment of the total amount of gas has continually grown, and the annual increase in the amount has been significant, as high as five percent in some years. In this analysis the total potential resource assumed to be available in the U.S. is about 640 Trillion cubic feet (Tcf). About 160 Tcf, in addition, is proved and currently available for production. Similarly, the amount of potential and proved resources available in Canada is assumed to be 260 and 70 Tcf, respectively.

Historically, the producers identified and developed large amounts of resources to meet the contracted or demanded quantity in the market; a resource to production ratio (R/P ratio) of about 10 was considered normal. In recent years, however, deregulation of the industry and reliance on short-term contracts and/or spot market purchases has not provided the incentive for producers to *prove* large chunks of resources. As a consequence, the developing and drilling of natural gas has become a more short-term cycle. The challenge then is to determine how quickly supplies can come to the market and whether the quantity is sufficient to meet the market needs. Despite technology advances, uncertainty abounds in the supply side of the natural gas industry.

A recent development regarding FERC's ruling on the El Paso pipeline case, which takes away the *full requirements* clause from its customers located in Arizona and New Mexico markets, will impact the infrastructure plans for the future. Since the customers can now contract with pipelines other than El Paso, the interest from the pipeline industry could grow significantly. We will see one or more new projects that could be completed in the future to satisfy not only the Arizona/New Mexico markets but also those in California. Increased interest in pipeline projects serving the Arizona/New Mexico markets such as the Coronado pipeline or the Pacific-Texas Pipeline could change the dynamics of gas supply to California. Further, projects such as El Paso's Ruby pipeline or Kinder Morgan's Silver Canyon pipeline could provide additional capacity to California.

Natural Gas Transportation and Distribution System

The third component of the gas market analysis is the transportation and distribution system. Natural gas once produced from the wells has to be transported over long distances and distributed in the demand region to all consumers. As shown in **Figure 4-1**, each supply region is connected to one or more demand regions through one or more pipelines. The natural gas pipelines are well connected throughout the continent to form a flexible grid with multiple market hubs where gas is bought and sold by the producers, marketers, brokers and customers. The analysis includes the costs and capacities of pipelines represented as individual pipes or as a corridor of many pipes as appropriate. The detail on the transportation system assumed in the basecase is described in detail in the staff ***Natural Gas Market Assessment Report*** .

California Natural Gas Storage

Natural gas, unlike electricity, can be stored; it can be injected into storage facilities when demand is low or withdrawn when need arises. This provides flexibility in balancing supply and demand. Also, the flexibility to store or withdraw gas helps to buffer volatile price movements in the market place.

Table 4-2 below shows the capacity of storage facilities in California. In Northern California, three companies own storage facilities. PG&E has three separate fields it uses to meet its customer's needs. Two storage facilities located in Northern California, Wild Goose Storage and Lodi Gas Storage, are independently owned. SoCalGas has four fields located in Southern California. Locations of each storage field are found in **Figure 4-4**. A fifth field, the Montebello Storage facility, owned by SoCalGas, was abandoned in 2002 and no longer provides any storage services, and is not indicated on the map. SDG&E has no storage in its territory. However, SDG&E can use storage in the SoCalGas system to meet San Diego's needs.

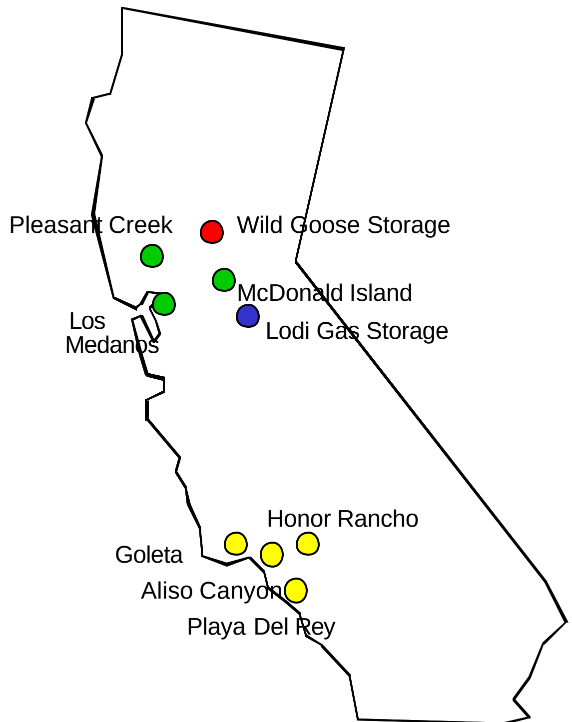
Table 4-2
California Natural Gas Storage Facilities

Storage Facility Name	Working Gas Capacity (Bcf)	Maximum Withdrawal Capacity (MMcf/d)	Maximum Injection Capacity (MMcf/d)
PG&E	98*	1,534	375
SoCalGas	120	3,200	800
Wild Goose Storage [17]	14	80	200
Lodi Gas Storage	12	500	400

*For the PG&E storage system, the 98 Bcf includes both cycling and non-cycling working gas capacity.

Natural gas is typically produced at a relatively steady pace over time while consumption of gas peaks in the winter when space-heating needs are high. In the past few years California has seen a second, smaller peak in consumption when demand for gas-fired in power generation peaked during summer months. This peak changes character as weather variation and the balance between steady production and varying demand is met mostly by storage systems. During times of low demand, usually in spring and fall seasons, natural gas from the pipelines is used to fill the storage facilities. During summer and winter seasons, both the pipelines and storage facilities are used to meet the demand peaks, with storage complementing any quantity demand in excess of what is supplied by the pipelines.

Figure 4-4
Natural Gas Storage Facilities Map



Map not to scale

Hedging of natural gas prices is a second major advantage of storage for natural gas users who buy gas when prices are low and using it during peak periods when the prices are high. Likewise, gas suppliers can hedge their production by putting gas into storage when prices are lower and then sell the gas in the future when prices are better.

In general, natural gas storage complements short- and long-term needs. Core customers purchase a certain level of these storage services to meet peak winter space heating needs. A small portion of these services is allocated to the natural gas utility for pipeline balancing activities. The remainder is available for non-core customers, such as industrial users and electric generators, to meet their variable consumption patterns and possibly to hedge prices.

Winter 2002-2003 Natural Gas Storage Use

On November 1, 2002 California entered the heating season with nearly 100 percent of its 243 Bcf of natural gas storage capacity filled. By the third week of March 2003, storage inventories reached a nadir, around 90 Bcf, because many storage customers withdrew gas from storage throughout the winter to avoid paying higher prices. The large draw down of California's natural gas storage this past winter surprised many observers, given that the Western U.S. experienced moderate-to-warm temperatures throughout the heating season.

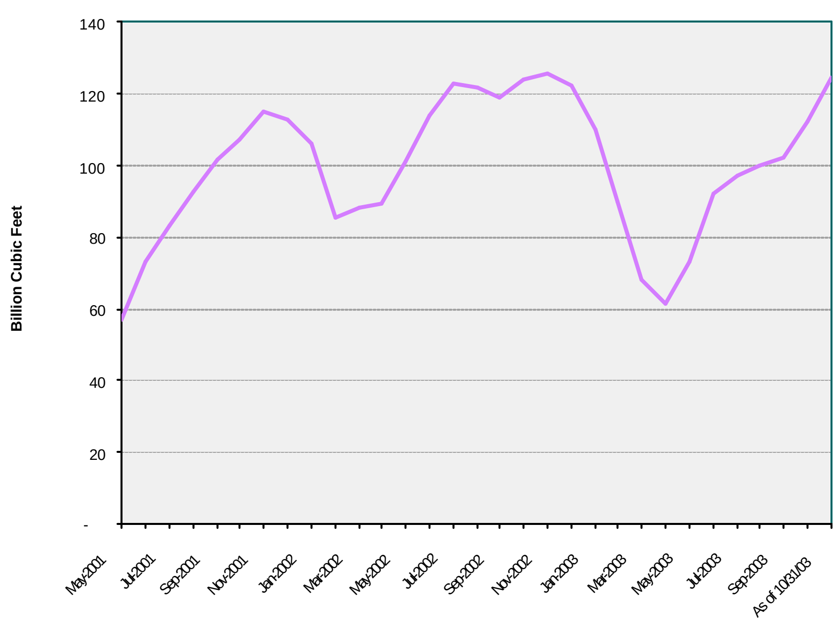
Since April 1, 2003, the beginning of the traditional storage injection season, California storage customers have made significant headway towards replenishing inventories bringing inventories to levels higher than what is normally required to meet the winter season needs

Storage levels as of October 2003 are shown in **Figures 4-5** and **4-6** for Northern California and Southern California respectively. Northern California level includes PG&E, Wild Goose Storage, and Lodi Gas Storage inventories. The Southern California level represents gas in SoCalGas' storage fields. **Figure 4-7** shows the monthly trend in California's total storage inventory levels.

The rest of the nation experienced a more severe winter than did the West. Even into early spring, extreme cold temperatures in the eastern half of the continent forced the rapid depletion of natural gas storage inventories. **Figure 4-8** provides U.S. storage inventories through October 2003. Earlier this year, there was major concern is whether national gas storage levels, having reached record lows last April, can reach the desired level of around 3 trillion cubic feet by November 1, 2003.

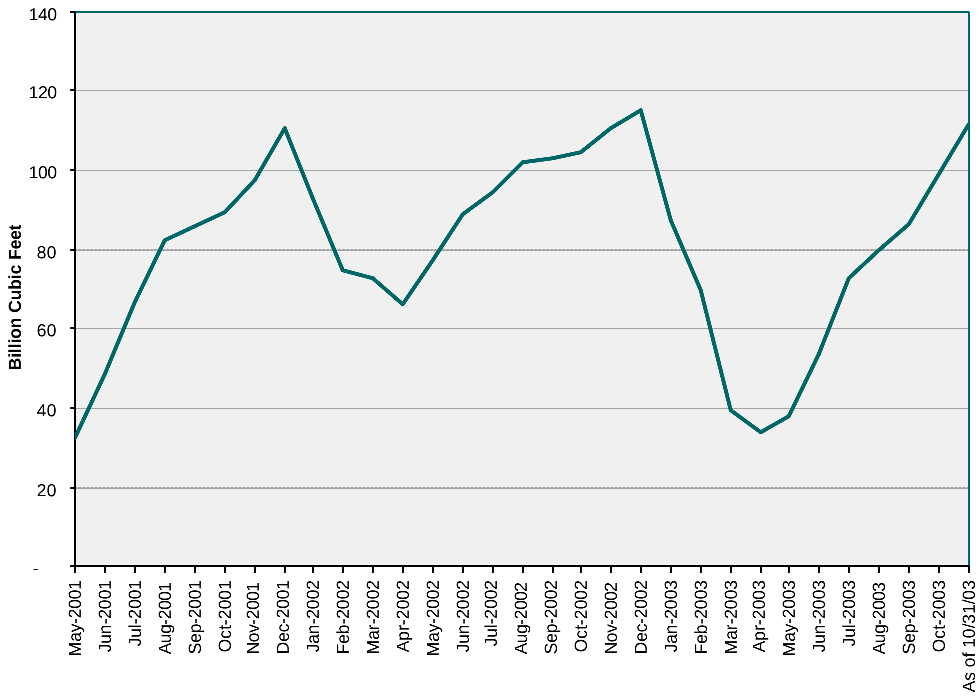
There was a major concern with regard to making large storage injections prior to the winter season. Unregulated storage customers, such as power plant operators and large industrials make storage decisions based on their assessment of future market conditions. If customers expect that natural gas prices next winter will be cheaper than the current spot market prices, these customers might choose to defer gas purchases until next winter when they believe gas will be less costly, rather than store gas in the summer. While this approach might be a sound business strategy for a private company to manage fuel costs, it provides little protection against tight natural gas supplies next winter. Despite these concerns, overall U.S. storage has reached a level of 3.1 Tcf as of October 24, 2003 meeting the 3.0 Tcf target for November 1, 2003.

Figure 4-5
Northern California Storage Inventory



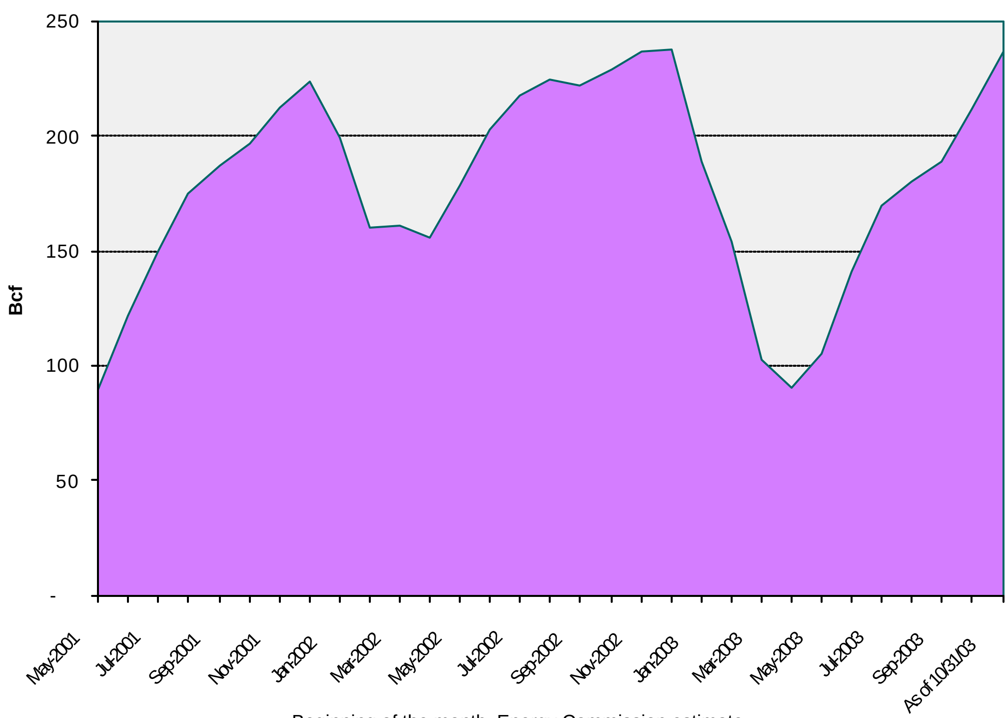
Energy Commission estimate; Beginning of the month inventory

Figure 4-6
Southern California Storage Inventory



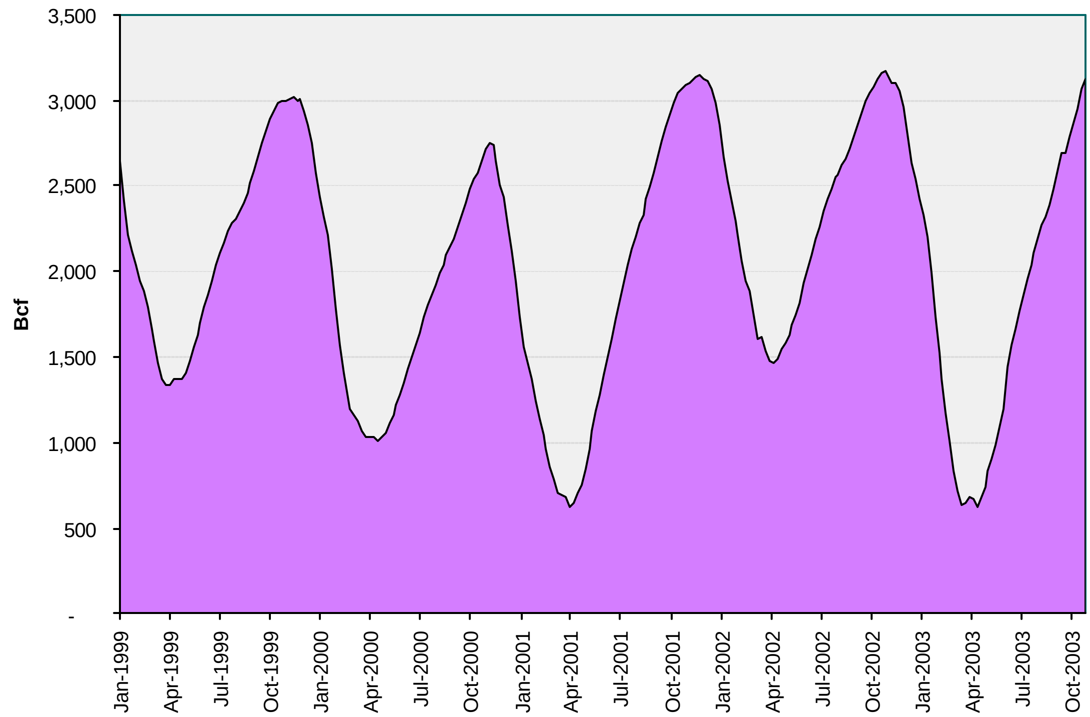
Energy Commission estimate; Beginning of the month inventory.

Figure 4-7
California Storage Inventory



Beginning of the month, Energy Commission estimate

Figure 4-8
U.S. Storage Inventory



Source: EIA/AGA; U.S Total Capacity 3,262 Bcf

Natural Gas Price and Supply in the Basecase

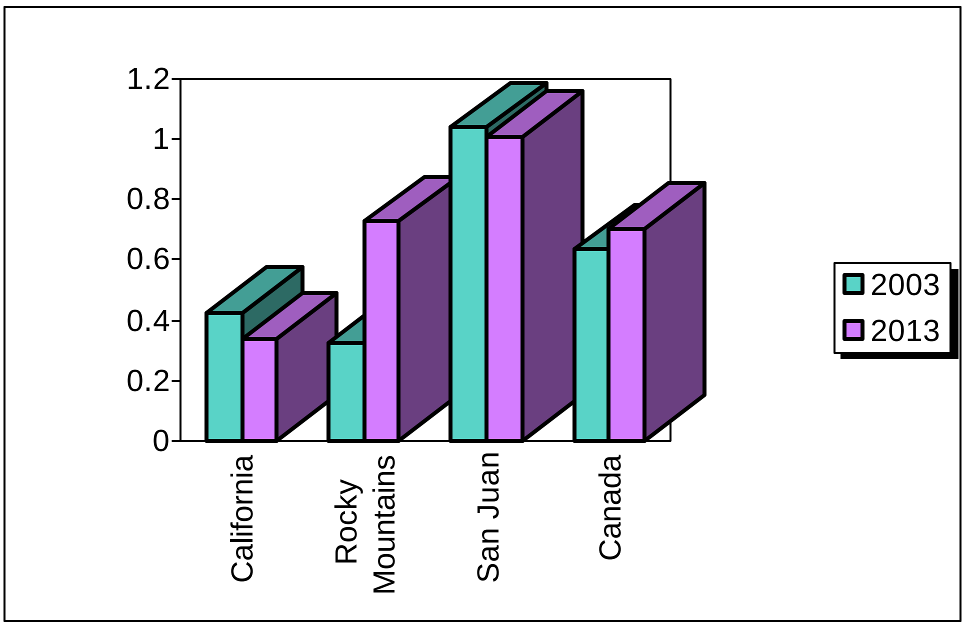
The volatility of the natural gas market has influenced not only the major industrial and power generation customers, but also the residential and commercial customers. Natural gas bills have risen sharply, especially in the winter season when residential demand for natural gas is the greatest. This section discusses the long-term impacts and trends in natural gas markets including wellhead and border or city-gate prices in North America. The retail price projections for various market sectors or customer classes are discussed in Chapter 5. A primary finding is that increasing costs to find and produce natural gas to meet growing demand are driving natural gas prices to rise between 2003 and 2013.

California receives nearly 85 percent of its natural gas needs from outside the state. The three primary supply regions are the San Juan Basin, the Rocky Mountain Basin and the Western Canadian Sedimentary basin. **Figure 4-9** shows the sources for natural gas in California during this year and the projected sources in 2013. The Rocky Mountain region is a relatively new supply basin compared to other supply basins in the U.S. The prices in this region have been low when natural gas prices in the rest of the nation had been very high due to a lack of transportation pipeline capacity out of the Rocky Mountain Basin. Recent expansion of the Kern River pipeline (in May 2003) demonstrates the importance of this supply source for

California, and supplies coming from the Rocky Mountain region will double over this time period.

As shown in **Figure 4-9**, supplies from in-State production and from the southwest basins (i.e., San Juan and Permian Basins) are expected to remain relatively flat. Forecasted Canadian production will occupy a larger share of California's consumption, reaching 0.7 Tcf/yr by 2013. Supplies from the Rocky Mountain and Canadian basins provide the incremental growth in gas demand. The Rocky Mountain Basin shows the highest growth rate in production.

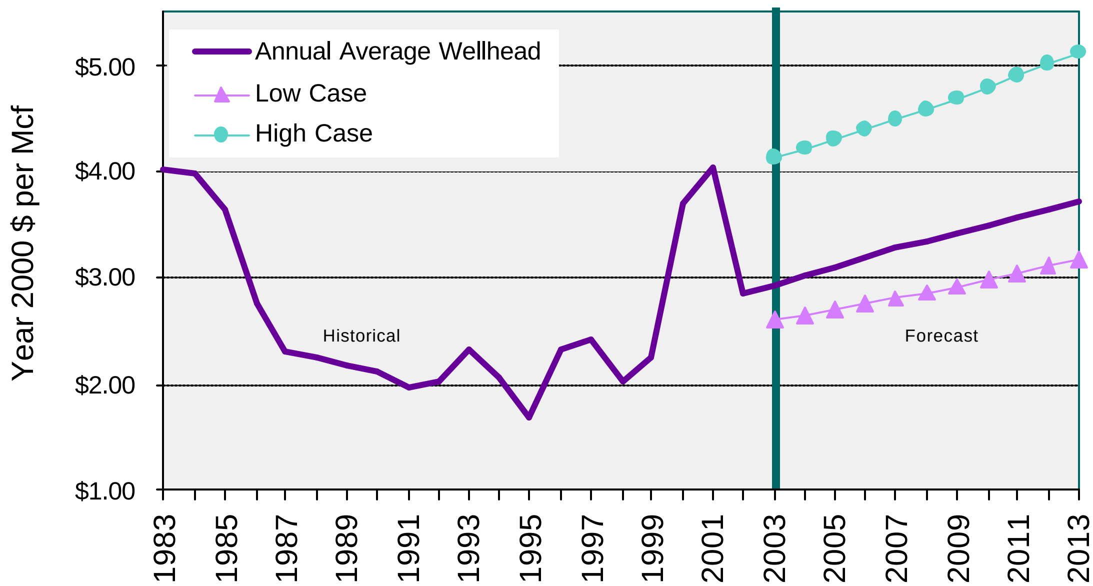
Figure 4-9
Projected Natural Gas Supplies for California (in Tcf/yr)



Wellhead Prices in North America

Wellhead prices reflect the capital and production costs of natural gas and the willingness of buyers to pay for it. These prices motivate gas producers to explore, drill, develop, and produce the gas needed to satisfy consumer demand. Reduced price control at the wellhead in the United States and Canada caused natural gas supplies to increase, surpassing total natural gas demand from the mid-1980s to the late-1990s, which resulted in a reduction in natural gas prices. **Figure 4-10** illustrates the historical path of annual average wellhead prices in the lower-48 states along with the projections under the basecase for the years 2003 to 2013. Also shown in **Figure 4-10** are results of two scenarios describing the upper and lower bounds for natural gas prices. These bounding sensitivity cases represent plausible trends indicating the range over which gas prices can move up or down, depending on market conditions, over the future years between 2003 and 2013.

Figure 4-10
Historical and Projected Wellhead Prices in the Lower 48 States with High and Low Boundaries – Annual Averages



Source: EIA (Historical Data) and the California Energy Commission (Forecast)

Table 4-3 provides the projected prices, in year 2000 dollars per Mcf, for major gas-producing regions throughout North America. The differenc es in wellhead prices between regions stem from dissimilar regional demand growth, varying resource costs, differences in access to production basins, and available pipeline capacity.

Wellhead prices in the San Juan Basin, Rocky Mountain Basin, and Alberta are of special interest to California because they are expected to provide nearly 85 percent of natural gas consumed in the state. Wellhead prices for Canadian gas supplies will likely be less than those in the lower-48 states, but prices from both sources are expected to increase by more than two percent annually. The 2013 weighted-average price for Canadian wellhead gas is projected to be $3.12 per Mcf, compared to $2.49 in 2003. By 2013, the lowest-cost production regions in the lower-48 states will most likely be the Rocky Mountains, the San Juan Basin in the Four Corners region, and the Northern Great Plains Basin in Montana. In 2013, all three production regions will have wellhead prices below the weighted-average price for the lower-48 states of $3.71 per Mcf.

Table 4-3
Projected Wellhead Prices – Annual Averages (2000$ per Mcf)

Producing Region	2003	Projected 2008	Projected 2013
Lower 48 States			
Anadarko	3.14	3.57	4.04
Appalachia	3.55	3.91	4.19
California	3.16	3.56	3.89
Gulf Coast	3.04	3.42	3.82
North Central	3.22	3.54	3.83
Northern Great Plains	2.57	2.78	2.95
Permian	3.04	3.44	3.85
Rocky Mountains	2.73	2.96	3.20
San Juan	2.76	3.12	3.46
Weighted Average: Lower 48	**3.02**	**3.34**	**3.71**
Canada			
British Columbia	2.65	3.05	3.41
Alberta	2.41	2.73	3.02
Saskatchewan	3.22	3.76	4.14
Eastern Canada	3.72	3.64	3.88
Weighted Average: Canada	**2.49**	**2.82**	**3.12**

Source: California Energy Commission

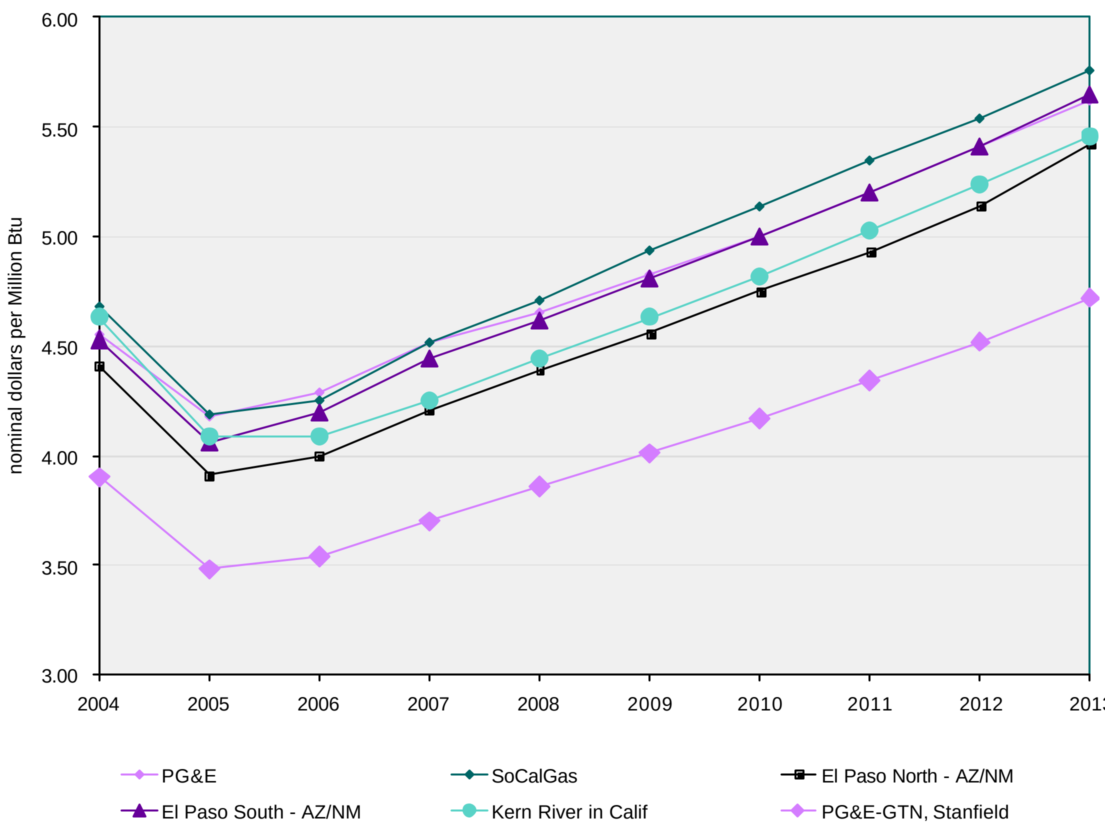
Prices for gas produced in the lower-48 states are expected to increase 2.1 percent per year, climbing from $3.02 in 2003 to $3.71 per Mcf in 2013. Canadian wellhead prices will likely increase 2.2 percent per year, from $2.49 in 2003 to $3.12 per Mcf in 2013.

Low wellhead prices and easy access to affordably priced natural gas along interstate pipelines are attractive to gas-fired electricity power generators. **Figure 4-11** shows the price projections for electricity generators located within the WECC region. Buying gas directly from interstate pipelines allows customers to avoid gas-utility distribution costs, associated taxes, and surcharges. Other costs or constraints, however, may be incurred by locating a power plant near an interstate pipeline. Saving on gas costs is particularly important to merchant generators who compete for market share based on their electricity prices. Other factors that power plant developers consider include proximity to electricity transmission systems and costs to connect to it, including congestion costs.

The long-term analysis is based on annual average natural gas supply price and demand conditions and does not include the influences of seasonal or spot-market behavior. In order to capture the current market conditions experienced by the power generation sectors, electricity generation simulations and price assessment incorporate short-term NYMEX price information for the earlier years of the analysis. **Figure 4-11** displays the NYMEX based prices for 2003 to 2005. Projected prices for 2006 and beyond correspond to the model based analysis conducted at the Commission.

Electricity generators that receive large gas shipments from in-state utility-owned gas lines are classified as non-core customers in the PG&E, SoCalGas, and SDG&E gas utility systems. They purchase gas supplies from third parties. We expect the electricity generators located in California to pay higher natural gas prices, approximately two percent above inflation annually. As non-core customers in the utility systems, these electricity generators will be paying higher prices for gas compared to electricity generators taking gas directly from interstate pipelines. Electricity generators located near California demand centers, however, may be offsetting these higher gas prices by reducing other expenses, such as transmission line losses and costs.

Figure 4-11
Projected Natural Gas Prices for Electricity Generators within the WECC Region



Source: California Energy Commission

Electricity generators receiving gas from PG&E will pay about the same price as electricity generators in Southern California. Commodity prices will be lower in PG&E's service area, but these are partially offset by higher transportation costs that eventually become cheaper over time. PG&E is likely to attain a slight price advantage over Southern California after 2006.

The lowest-cost for natural gas is, and will continue to be, Canadian gas via the PG&E Gas Transmission Northwest (GTN) interstate pipeline at the Washington-Oregon border in Stanfield, Oregon.

The Rocky Mountain region is another supply basin that has experienced extremely low prices over the past few years due to pipeline constraints. With the expansion of the Kern River pipeline, California will get a significant share of its needs from this region, thus moderating the price volatility in the state. Kern River will be able to provide increased supplies to both Northern and Southern California.

In Arizona, electricity generators will probably see a slight price advantage through 2013 for gas delivered using the northern El Paso pipeline corridor – a corridor that includes El Paso, Transwestern, and Southern Trails pipeline systems – rather than the southern El Paso corridor. The major advantage comes from easier access to low-priced San Juan Basin gas compared to gas from the Permian and Anadarko Basins. Since much of the new, electricity generation capacity appears to prefer locations along the northern El Paso pipeline corridor, the necessary pipeline infrastructure improvements would add costs to these prices.

Infrastructure Assessment

Average annual requirements for natural gas in California are expected to be met with existing capacity over the 10-year forecast horizon. However, there is a critical need for expanding pipeline capacity to transport San Juan Basin and Rocky Mountain natural gas through the southwest corridors to meet Arizona, southern Nevada and California needs. New electricity generation plants recently completed, under construction or proposed in the Phoenix, Arizona area are the driving force for this new pipeline capacity. Several pipelines (Silver Canyon and the Coronado proposals, the Pacific-Texas pipeline and Transwestern expansion) have been proposed to meet the growing electric generation requirements, but response by prospective shippers has been limited. Considering that the El Paso shipper transport contract disputes have been resolved by the FERC (full requirements versus contractual demand issues), it is anticipated that shipper interest for additional capacity on these corridors will increase and the proposed projects will progress further to add the required capacity.

Additional capacity on the Kern River system that carries Rocky Mountain natural gas to markets in Utah, Nevada and California will be needed to meet seasonal peaking demand. As demand in the Utah and Nevada regions increase over time, additional capacity on this corridor would be beneficial to ensure that California continues to receive the needed supplies. Kern River has announced that it is in the process of evaluating the additional expansion by 2007.

Additionally, the conversion of El Paso's Line 1903 to transport natural gas will be very valuable in meeting the East-of-California customers' demand in Arizona, southern Nevada and Baja California. While the conversion would allow two way flows between Daggett, California and Erhenburg, Arizona, it also provides direct access to Rocky Mountain natural gas from the Kern River system at Daggett, California. Energy Commission analysis indicates that if shippers would take advantage of the capacity on Line 1903, the need for additional new southwest pipeline capacity would be reduced by 300 to 400 MMcfd.

LNG will be a new source of supply and will also provide the '*storage value*'. As indicated elsewhere in this report there are numerous proposals for facilities located in Baja California and along California's coast. LNG on the U.S. West Coast will provide the needed new supply source that can compete with traditional supply regions and reduce the necessity for some of the new pipeline required in the western states during the next ten years.

The natural gas utilities in California have enhanced their abilities to receive natural gas supplies from interstate pipelines in response to the energy crisis. SoCalGas has added 385 MMcfd in new pipeline capacity. SoCalGas now has enough receiving capacity to meet its needs for the next ten years.[18] Any problems in meeting the demand growth would be either due to interstate capacity not responding to the development in power generation in the southwest, or a major shift in power generation plans in the SoCalGas service area increasing the demand for natural gas beyond the projected quantities.

PG&E increased its infrastructure to receive an additional 179 MMcfd from Canadian supply sources. It has recently added a new 300 MMcfd intertie with Kern River off the High Desert Lateral. While adding flexibility to provide supply options for its customers, the backbone pipeline adds no real receiving capacity for the utility. The backbone system is shared with a number of other supply receiving points with a transport capacity less than the combined receiving capacity. To ensure maintenance of adequate slack capacity, the PG&E system will need to consider additional ability to transport natural gas within the state after 2007. There are several options that may be considered, including:

- Increasing capacity transport on PG&E's two mainline pipelines. An example would be to increase the capacity of its Baja Path. This PG&E pipeline system is connected to a number of other pipelines with a combined capacity that exceeds the Path's transport capacity.
- A potential new pipeline, such as that proposed by El Paso's Ruby Pipeline, to deliver Rocky Mountain natural gas directly to northern California.
- LNG development. It not be sited within the PG&E service area to have an impact on supply, provided that necessary backbone capacity is built to receive and carry the supply to northern California.
- Expanding storage to take advantage of the unused backbone capacity during periods of low demand. This would provide for a greater utilization of the existing pipeline system and with the potential to provide more supply in storage to meet swings in demand.

Relative Costs of Pipelines and Transmission Lines

The relative costs of gas and electric transmission infrastructures affects where market participants propose to build power plants. Rough cost estimates suggest that new gas pipelines are cheaper than new electric transmission lines – in other words, moving fuel is cheaper than moving power. For construction in favorable terrain, a capital investment of $300 million will produce:

- About 100 miles of 500 kV AC electric transmission line that can transmit about 1,500 MW. The line can bring about 36,000 MWh per day to the electricity demand center.
- About 100-125 miles of 36 inch natural gas pipeline that can carry 1 billion cubic feet per day. That much gas, burned in modern combined-cycle power plants at 7,200 Btu/kWh, can generate about 140,000 MWh per day at the electricity demand center.

If the prices for shipping gas and electricity reflect the underlying capital and operating costs, many of the gas-fired power plants needed to serve California's electricity demand growth would be built in California. To date, FERC has imposed the costs of transmission projects directly on consumers, not generators. If this policy remains in effect, developers will tend to site power plants near gas supply basins, rather than within California. FERC is also considering elimination of export fees, which will further encourage remote siting of power plants.

Additional Natural Gas Market Cases

The basecase assessment described in the previous section represents the best estimate of the behavior of the natural gas market over the next ten years. This assessment uses a specific set of assumptions about demand, natural gas resources, transportation rates, and pipeline capacities. Many of the input parameters included in the assessment have uncertainty tied to them. The observed volatility indicates this uncertainty in market prices and supply availability. One way to include the assessment of uncertainties in the market place is to conduct sensitivities to test the impact of one or more variables on the assessed price and supply availability. A detailed description of the sensitivity case inputs, assumptions and results is included in the staff ***Natural Gas Market Assessment Report*.** The sensitivity case studied can be generally classified under supply or demand based market changes.

The assumptions in each of the cases are briefly noted below:

1. Low Economic Growth Case: The recovery forecasted in the Baseline in 2004 is delayed by one to two years so that growth on average is about 1 percent lower than the baseline economic forecast. This case assumes lower growth in all sectors of gas demand.

2. High Economic Growth Case: This case assumes a more robust economy with a stronger recovery than forecasted in the Baseline. Based on employment data for the last twenty

years, the economic drivers for the sector forecasts are accelerated by 1-2 years to achieve an annual growth of about 1 percent higher than in the Baseline, for the years 2004-2007. Demand changes occur in all sectors under this case.

3. Dry Hydro Case: Natural gas demand assuming dry instead of average hydro conditions. This case reflects increases in gas demand in the electricity generation sector with the same capacity expansion plan as in the Baseline. The core and non-core demand projections remain unchanged as compared to the basecase.

4. Lower PGC Impacts Case: Natural gas demand assuming no utility DSM spending after 2003 and only 100 MW per year new renewable generation. It reflects UEG gas demand of a capacity expansion plan with more gas-fired resources than in the baseline.

5. Higher PGC Impacts Case: Natural gas demand assuming a doubling of PGC funding for DSM and an increase to 600 MW per year of new renewable generation. It reflects UEG gas demand of a capacity expansion plan with less gas-fired resources than in the baseline.

6. Low Gas Supply Case: Given the many views about the difficulty in finding new resources combined with many projections suggesting tight or insufficient gas production to meet growing demand, this case attempts to limit the availability of supplies in the market. This is accomplished by lowering the 'reserve appreciation' factor, which leads to a rise in the cost of natural gas at the wellhead. This case investigates the impact of low resource availability on gas supply and the ability and extent to which the market will switch to other alternative fuels in response to higher natural gas price.

7. Increased Vehicle Transportation use Case: Natural gas demand can increase significantly with the expectation that fuel cells will play a major role in auto industry. Further, clean air initiatives could increase demand for LNG and CNG vehicles. This case assumes that vehicles equipped with fuel cells using hydrogen, generated from natural gas will increase significantly by the year 2015, reaching nearly 5 to 10 percent of the total gas consumed in the state.

Integrated Price and Supply Outlook

Natural gas markets do not experience variations in their fundamental drivers one at a time. Two integrated cases including simultaneous changes of several parameters in the model, were studied. Critical input variables--natural gas resource potential, LNG availability, natural gas demand projections and the availability of alternative fuels competing with natural gas for market share formed the basis of the parameter changes.

What would happen if events associated with model input assumptions simultaneously occurred? The selection of the range of input parameters is intended to provide the boundaries for natural gas price in the market under the Integrated Price and Supply Outlook cases. Thus, the high and low price cases illustrate the possible extremes of annual average natural gas prices over the forecast horizon. These extreme price levels are achievable on a short-term basis, but, they are not sustainable over a longer duration. The interaction of market forces and response to high or low prices would tend to push supply and demand away from the extremes and toward the more plausible basecase.

8. Large Quantity of LNG to California Case: Liquefied natural gas or LNG is a premium fuel, globally traded, available in large quantities at reasonable prices in many countries around the world. High natural gas prices in California have raised the interest in importing LNG supplies along the western coast of the U.S. This case considers the potential impacts of building one or more terminals in California and Baja Mexico. LNG terminals are assumed to be built at Humboldt Bay in Northern California, Los Angeles or Long Beach in Southern California and along the coast in the northern part of Baja California, Mexico. The terminal specifications are based on currently proposed LNG projects.

9. Integrated High and Low Gas Price Case: As mentioned earlier, the high and low gas price cases provide a boundary to higher or lower prices that could be achieved by the gas market. These integrated scenarios make assumptions on various factors or outcomes that tend to either raise or lower prices. **Table 4-4** summarizes the input assumptions in the integrated cases.

Results for Natural Gas Market Cases

Integrated High and Low Gas Price Cases

Figure 4-12 shows the wellhead price trends in the Integrated High and Low Gas Price cases and compares them to the basecase projections. In the High Price case, prices climb from $4.12 per MCF in 2003 to $5.12 per MCF in 2013. Prices in this case experience an annual growth rate of 2.2 percent. On the other hand, the Low Price case demonstrates a slightly lower growth rate, climbing at 1.98 percent. Prices in the Low Price case grow from $2.56 per MCF in 2003 to $3.11 in 2013.

In the Low Price case, lower-48 production reaches 22.6 TCF in 2012, whereas, in the High Price case, production grows to 26.8 TCF. The higher production results from the severe environmental constraints that lead to natural gas being the primary fuel of choice throughout the US. As shown in **Figure 4-13,** the production of natural gas in the lower-48 states increases in both cases when compared to the basecase. The increase in production of natural gas in the Low Price case is due to the fact that as natural gas prices drop, fuel switching in specific regions of the US tends to use more natural gas than that used in the basecase. **Table 4-5** tabulates the price growth rates and compares them with the rate of the basecase.

Table 4-4
Integrated Price and Supply Assessment Assumptions

Parameters	High Price Outlook	Basecase Projection	Low Price Outlook
Natural Gas Resources			
Reserve Appreciation	Lowered by 25%.	Appreciation range: 0.03% to 2.2 %.	Raised by 33%.
Gas Resources	Land Access: 11% land restrictions in Rocky Mountains	Lower 48: 975 Tcf Canada: 417 Tcf	Same as basecase.
Liquefied Natural Gas			
Liquefied Natural Gas	Same as basecase	Four facilities operating	Three facilities added: NorCal, SoCal, Baja
Natural Gas Demand			
Gas Demand	Low efficiency improvements. Step increase in gas demand, up 10% by 2017. 5% comes from demand in transportation sector.	Total US consumption by 2007: 23.99 Tcf.	High efficiency improvements. More total usage offset efficiency gains.
Competing Fuel Sources			
Oil Price	World oil prices rise to $35 per barrel by 2007, thereafter	World oil prices rise to $26 per barrel by 2007, then remain constant through forecast horizon.	Same as basecase.
Oil Burn	All states are constrained from switching to oil, by 2007	Switching allowed in four North American regions.	Same as basecase.

Figure 4-12
Annual Average Lower 48 States' Wellhead Price ($/MCF)

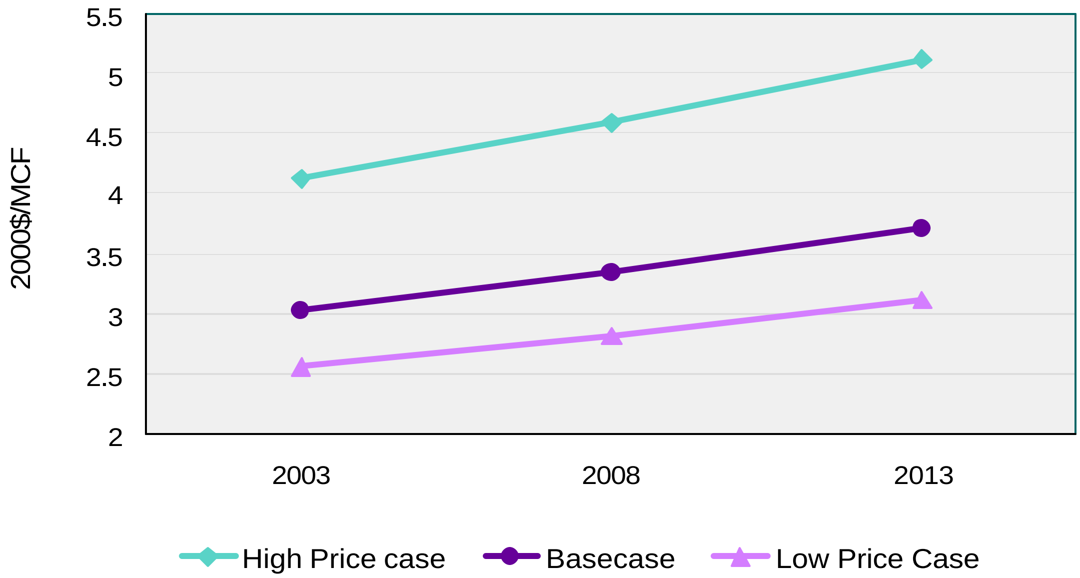


Figure 4-13
Natural Gas Production in US (TCF per year)

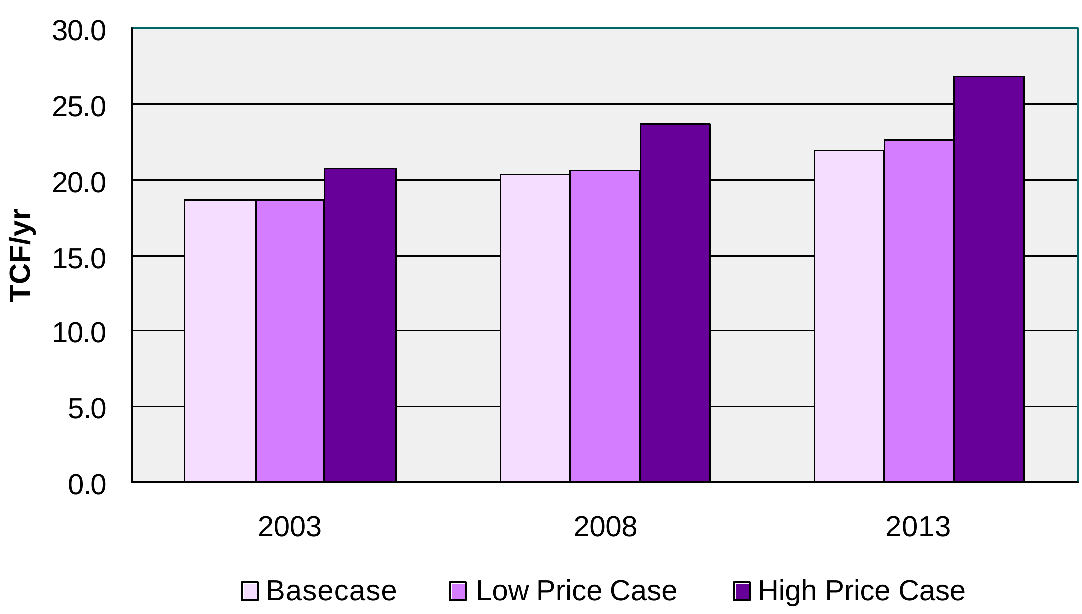


Table 4-5
Annual Price Growth Rate, %

Low Price Scenario	1.98
Basecase Scenario	2.08
High Price scenario	2.19

Demand Cases

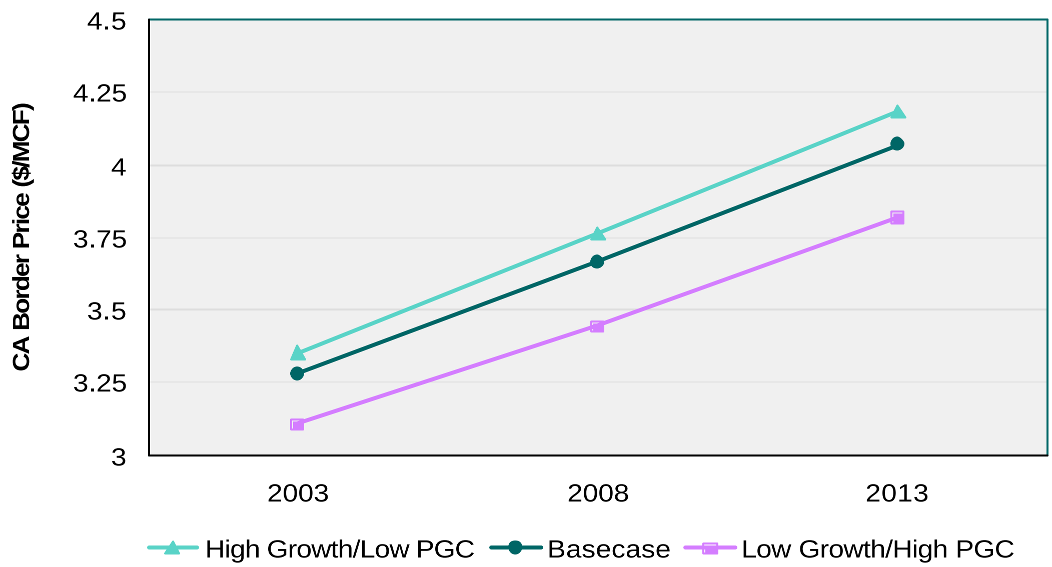
Overall, the demand case indicates that changes in natural gas demand, due to factors such as low hydro-generation due to drought conditions or moderate slowing or speeding up of the state's economy, do not appear to affect the long-term trends in the natural gas market. Also, the Economic Growth and Public Goods Charge Impacts cases indicate that the impacts on price and supply of natural gas are not very significant from a long-term perspective. However, the growth and efficiency factors, when addressed from a short-term or seasonal perspective can and will impact markets.

The economic growth and PGC impact cases result in either lowering or increasing the demand for natural gas. The Low Economic Growth or High PGC Impact case assumes that the core and non-core demand is reduced by 2.5 percent while the gas demand for all power generation in the US drops by 9 percent. The High-Economic Growth and Low PGC Impact cases both assume an increase in gas demand of 2.6 percent in the core and non-core sectors and a 7.4 percent increase in the power generation in the US.

The total change in annual gas demand for the power generation sector in California in these cases is not very significant compared to the total gas demand in California. The low PGC Impact or the high growth case does not increase the gas demand significantly enough to raise gas prices. By 2013, the price increases by about 2.7 percent above the basecase prices.

On the other hand, the High PGC Impact or Low Economic Growth cases result in lowering the gas demand across all sectors and the price drop in this case is about 7 percent lower than basecase prices. **Figure 4-14** compares the California border prices in the high and low growth cases with basecase price projections.

Figure 4-14
California Border Gas Price
for the High/Low Economic Growth and PGC Impact Cases



Dry Hydro Case

The sensitivity analysis indicates that increased gas demand for power generation in California and in neighboring states, resulting from persisting dry hydro conditions, does not exert much influence over the gas price on an annual basis. The incremental gas demand under the assumed conditions is not very large compared to the quantity of gas consumed in the state. However, this analysis is based on annual average representations. A low-hydro generation case will affect the peak cooling days during the summer when the stress on power generation needs is the greatest. Hence a short-term (seasonal) analysis addressing short-term price movements due to high utilization of gas pipeline capacities and storage operations on the increased need for gas in the power generation sector should be conducted to analyze this case further.

In this sensitivity case, it was assumed that 'low hydro' conditions persist throughout the assessment horizon, which is not an expected outcome under even severe conditions. In the electricity infrastructure assessment, the low-hydro-generation conditions are assumed to occur for only a one-year period, unlike this case description.[19] Under those conditions, the impact of the increased generation on long-run prices will be even smaller than noted here.

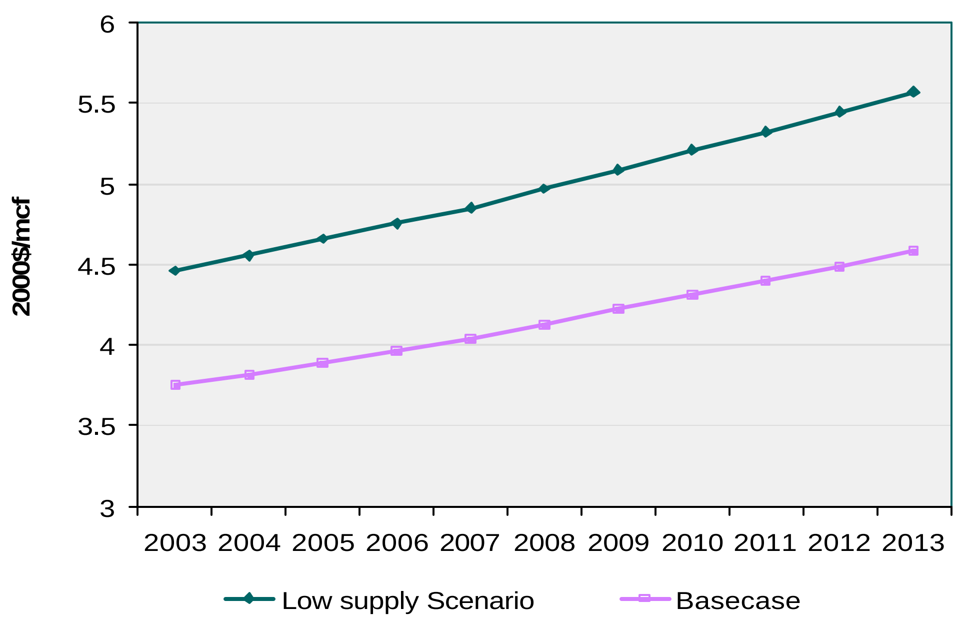
Low Gas Supply Cases

The uncertainty in availability of resources has been a prominent issue in North America. Discussions indicate that the production life of the majority of natural gas fields in the U.S. and Canada have matured and that natural gas production in the US will begin to decline within the time frame analyzed in this assessment. In fact, the industry view regarding potential supply sources, is that supplies will be tight over a longer term and that it will cost more to find and produce the natural gas to meet the growing demand. The contrary view is that the new and unconventional resources which exist in abundance can economically be developed and explored. These unconventional resources refer to the coal bed methane deposits, shale and tar sands in the US and Alberta.

If the resource base is restricted, the market needs will be met by more expensive gas resources and the cost to access these resources will increase over time at a faster rate than assumed in the basecase. Annual average wellhead prices in the US increase by about 25 percent above basecase values over the next 10 years. The wellhead prices rise by about $0.60 to $3.60 per MCF in 2003. By the end of the forecast horizon, wellhead prices rise to $4.40 per MCF by 2013. With regard to supplies to California, market shares of Canada and domestic production do not change significantly while the loss in market share for the Southwest region is offset by increasing supplies from the Rocky Mountain region. The San Juan Basin, being a more mature basin, loses its market share to the relative new Rocky Mountain Region. California's statewide average price rises by nearly $1.00 per Mcf by the year 2013.

As a result of increasing wellhead prices there is an increase in fuel switching from natural gas to alternative fuels in the four regions where fuel switching is assumed to occur (Mid Atlantic, South Atlantic, West North Central and the West South Central census regions. **Figure 4-15** shows the US wide annual average natural gas price paid by the power generation sector under basecase assumptions and compared with the Low Gas Supply scenario. As shown, if natural gas supplies do not materialize as anticipated in the basecase assumptions, power generation prices will increase by about 20 percent above the basecase, over the assessment period.

Figure 4-15
Impact of Low Gas Resources on US Wide Gas Price



Liquefied Natural Gas facilities on the U.S. West Coast

The potential for large quantities of LNG to supply California, Baja California and the Southwest Desert markets is gaining prominence. Several companies have put forward proposals to build LNG facilities along the US and Mexico's West Coast. LNG brought in to serve California markets would be on way to meet the growing demand for natural gas.

This sensitivity case examines the impact of building three LNG facilities on the West Coast: one in Northern California, one in Southern California, and the third in Baja California, Mexico. While there are no final decisions to locate the LNG facilities at these locations, this case attempts to capture the infrastructure impacts on California and neighboring states if the LNG facilities are indeed permitted and constructed, and bring significant quantities of LNG into the Western States. This case also assumes that the North Baja Pipeline reverses its flow direction and takes the LNG supplies from Baja, Mexico to Ehrenberg AZ, where it interconnects with the El Paso's southern system serving the Southwest Desert region, SoCalGas' backbone pipeline to serve Southern California markets, and El Paso's bi-directional Lateral pipeline inside California. (North Baja pipeline currently serves markets in Baja California with gas supplies from the CA/AZ border point at Ehrenberg, AZ).

LNG - A Global Resource

One of the most controversial topics being currently discussed is the potential to increase the amount of liquefied natural gas (LNG) that can be imported into the U.S. Global resources are plentiful and are available from multiple countries. The Gulf and Eastern U.S. seaboard has been importing LNG for more than 20 years. The four terminals, are currently operating. A number of new projects are being pursued to increase the quantity of LNG imports. There are several projects being proposed along the U.S. West Coast. California is a growing state demanding more natural gas to satisfy all classes of customers. Being at the end of the pipelines, California has little control on the amount of natural gas that can be brought in by pipelines. There would be benefits to finding a fourth supply source in addition to the San Juan, Rocky Mountain and Canadian sources that have historically supplied gas to the state. Thus significant efforts are now underway to build and supply California with LNG from a variety of sources including the Indonesia, Bolivia, Peru, Australia, Russia and Alaska.

The basis for choosing these three locations for LNG facilities is that there are one or more proposals active in each of the three locations. Several scenarios were conducted with varying assumptions on the LNG facility location. One of the scenarios attempts to evaluate the impact of costs for landed LNG on the West Coast to ensure that the assumed three facilities operate at relatively high load factors.

Figures 4-16 and 4-17 compare potential LNG imports into the US under various cases. The projections for LNG imports on the West Coast assume that facilities will be built and operational by 2007 or 2008. Further, since the assumption in the analysis of the LNG scenario was to study impacts of LNG flowing into the Western States on natural gas pipeline infrastructure, the price at which LNG can come into the West Coast market was adjusted lower to accommodate the higher flows.

Figure 4-16
LNG Imports Along US West Coast

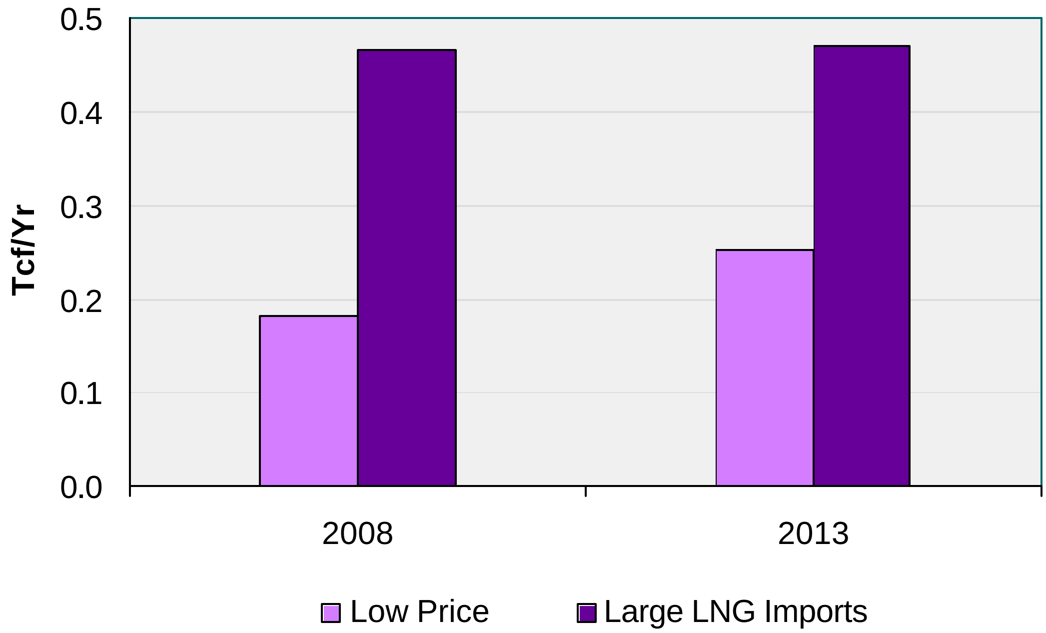
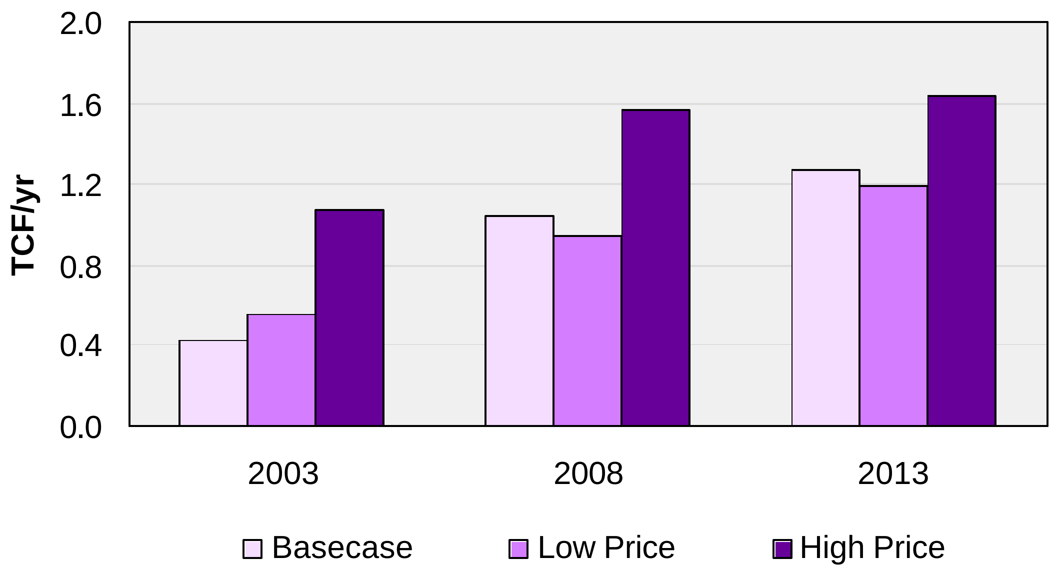


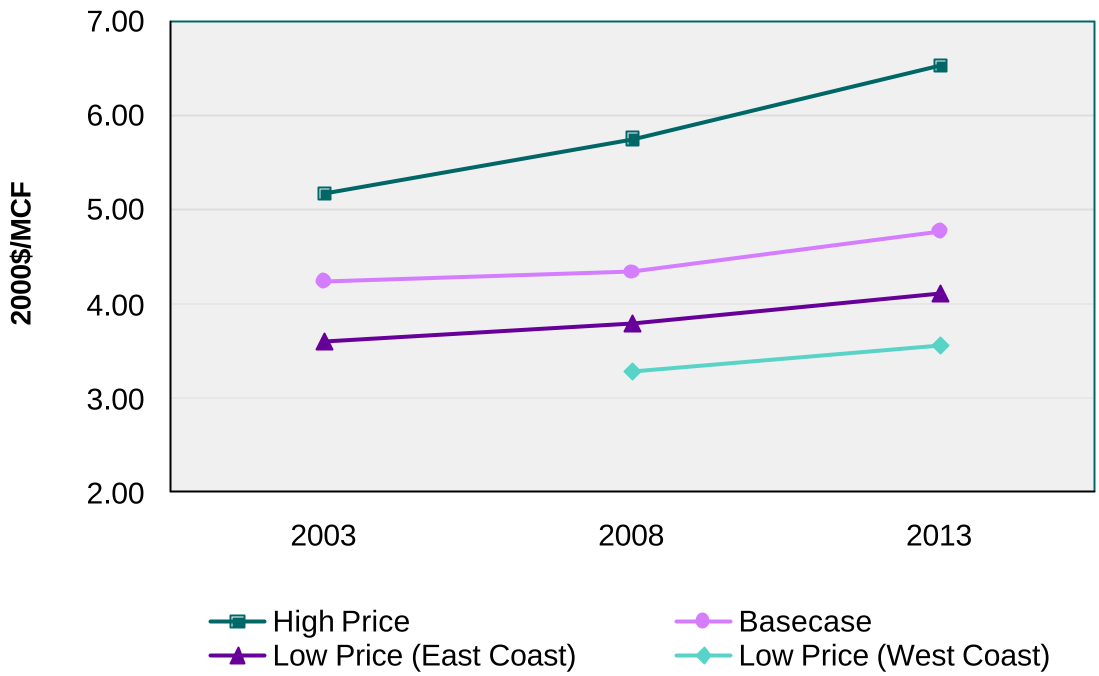
Figure 4-17
LNG Imports along US Gulf and East Coast



The East Coast continues to import LNG under all cases. LNG continues to be an economic option under the High Integrated Gas Price case, with imports rising throughout the assessment period to satisfy the increasing demand. The Low Integrated Gas Price case also sees a growing demand over time for LNG, although imports are slightly less than those in the basecase. In the Low Gas Price case, natural gas prices in the US drop significantly to be competitive with the LNG import prices. On the West Coast, one LNG case was designed to provide large quantities of LNG at the three potential terminals.

Figure 4-18 shows prices of LNG on the East Coast for the Basecase and the two Integrated Gas Price cases. The Figure also shows the price of LNG on the West Coast in the Low Integrated Gas Price case.

Figure 4-18
Annual Average Price for LNG Imports



Differences Between the Sensitivity Studies and Short-Term Markets

This section discussed multiple cases that could result from various actions taken by governments, industry, utility and end-use groups over the next 10 years and more. The actions and behavior of the market players will significantly impact the natural gas market. For the most part, this analysis has focused on long-term implications and trends over the next ten-year period. The cases highlight implications of market fundamentals and provide critical information to decision-makers from the perspective of need and planning on capital intensive projects such as new pipelines, LNG terminals and storage facilities.

Uncertainties exist in both the short-term markets and in the long-term trend assessment. Such uncertainties in the market place will place stress on the supply/demand equilibrium that can result in price shifts over long-term trends or spikes in short-term analysis. While supply and demand will come into equilibrium at all times, short-term imbalances will occur, especially during peak days when the system capacity will be stressed beyond its capacity.

Major short-term concerns in the gas industry include natural gas production levels, related drilling activities, pipeline slack capacity and utilization, and use of storage to buffer swings in supply and demand imbalances during seasonal and peaking market conditions. Analysis of these issues requires the Energy Commission to focus on short-term market fundamentals requiring monthly or even daily time periods as opposed to the current annualized analysis.

Additional Analytical Needs on Gas Storage

The Energy Commission recognizes the need to conduct a comprehensive analysis of short-term energy trends to complement its long-term energy forecasting work. A joint effort between the Energy Commission and University of California, Davis (UC, Davis) has been established to develop a monthly short term analysis and model simulation to study California's natural gas network. The objective of this effort is to understand the role of storage. This work will entail viewing regional storage issues integrated with the electricity market needs for natural gas.

Preliminary development of the analytical tools have provided the following insights:

- A major factor in storage activity is the cost of transporting and storing gas or of utilizing pipeline supplies during peak demand periods.
- There is an optimal combination of pipeline and storage capacity. Generally, storing gas becomes more valuable as pipelines become more congested.
- Flexibility in the pipeline and storage systems is important. For instance, storage becomes less critical if the amount of gas flowing through pipelines can be altered in a short time.
- Short-term price spikes are a result of combined inflexibility of demand and supply.
- The ability to store gas may reduce price variability and annual average gas price. Also, storage smoothes the pattern of pipeline flows and of the corresponding transportation costs.

These insights bring up several policy questions that the Energy Commission and UC Davis will continue to investigate:

- Is there a need for additional storage capacity, including working gas, withdrawal, or injection capacities?
- Would transmission and storage pricing mechanisms that more closely track operating costs contribute to a more efficient operation of the existing infrastructure?
- Has the injection and withdrawal pattern changed as gas-fired electricity generation demand has increased, especially during the summer months?

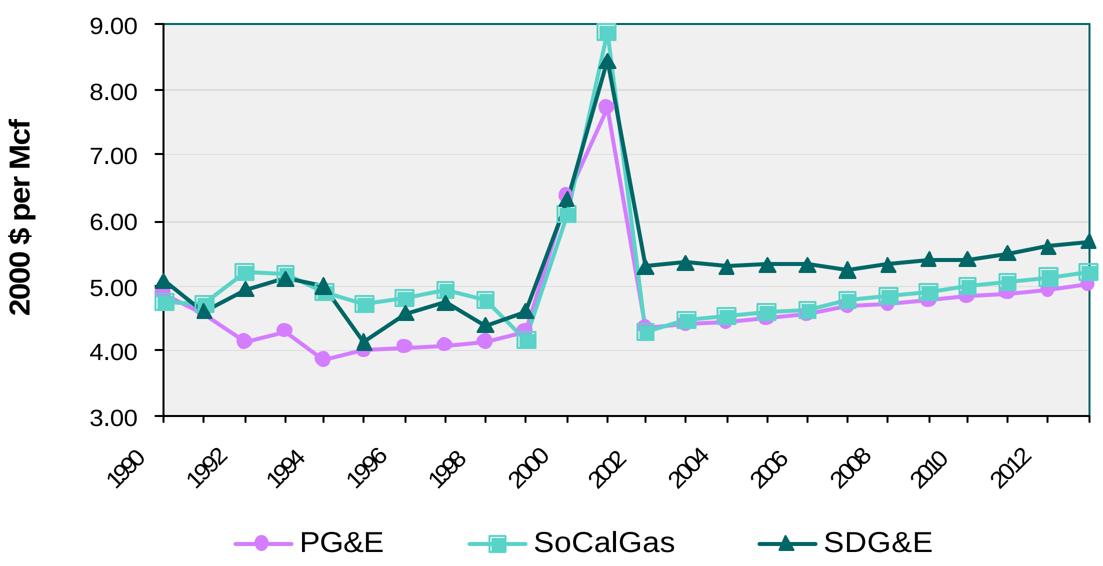
Natural Gas Retail Price Outlook

Average annual natural gas costs comprise a smaller portion of the typical energy bill than electricity. In 2002, the average California residence paid $356 for natural gas and $816 for electricity. The average annual commercial bill was $2,408 for natural gas and $7,968 for electricity. [20] Monthly residential natural gas bills are noticeable because they are consolidated into the heating season instead of being spread evenly throughout the year. And, of course, these average annual and monthly bills mask wide variations among individual users. For some industrial customers, natural gas can be a significant cost, both as feedstock and as a power source.

High natural gas prices over the past few years have gained significant attention, impacting all market sectors. Natural gas bills have increased sharply, especially in the winter season when residential demand for natural gas is the greatest. Increasing costs to find and produce natural gas will cause natural gas retail prices to rise between 2003 and 2013.

Natural gas prices for the end-user are made up of the wellhead prices, the cost of gathering and conditioning the natural gas, the price of interstate pipeline transportation, and utility costs of distribution. [21] The wellhead price comprises about 80 percent of the price for industrial and electricity-generation customers and about 50 percent for core customers. **Figure 4-19** shows volume-weighted annual-average prices for all customers in the PG&E, SoCalGas, and SDG&E service areas, expressed in year 2000 dollars per Mcf. These system-average prices are expected to settle between $4 and $6 per thousand cubic feet (Mcf).

Figure 4-19
Historical and Projected Utility End-Use Prices in California
Annual Averages



Source: California Energy Commission

During the next ten years, gas prices are likely to fluctuate above or below this basecase assessment due to short-term shifts in supply availability, seasonal and demand fluctuations, regulatory changes, and other factors affecting short-term market trends. **Figure 4-19** also shows the price spike of 2000-2001, when prices reached about $9 per Mcf, on an annual average basis, in some areas. The spike occurred because demand was strong, supply deliverability was tight, and price manipulation occurred.

In response to these price increases, producers increased drilling, and other market participants expanded pipeline capacity and storage facilities. At the same time, gas consumers conserved energy to decrease their demand, and lower utility bills. A slowdown of the national and California economies also contributed to lower demand. As a consequence, prices returned to the $4 to $6 per Mcf range after 2001. The long-term assessment calls for gas prices to remain between $4 and $6 per Mcf.

Conclusions

Market Conditions: Between 2003 and 2013, annual average supplies of natural gas will be sufficient but more costly. With the increase in demand for natural gas throughout North America, supplies at cheap prices are not as plentiful as expected earlier. The number of supply basins that are able to produce sufficient quantities of gas will decline over time, increasing the need for infrastructure to transport natural gas from a limited number of supply basins to various demand regions. As a consequence, the U.S. will likely become increasingly reliant on natural gas from Canadian and liquefied natural gas imports, while continuing to develop the domestic “unconventional” sources of natural gas to meet growing demand. Under tight supply conditions, some customers might get priced out of the natural gas market, leading to “demand destruction.”

In some regions of the U.S., industrial and power generation customers with dual-fuel capability will likely switch to another fuel, such as distillates or residual oil during high natural gas price conditions. However, no appreciable level of switching to any coal or oil derived fuels can occur in California.

Natural gas infrastructure has a strong impact on price and supply availability in each demand region. New gas-fired power plants in the Western U.S. are increasing gas demand and, in turn, triggering the need for new investments in interstate pipeline projects. The gas flow patterns in the basecase indicate that additional pipeline capacity will be needed to meet growing electricity generator demand in southern Nevada, Arizona, and New Mexico. The San Juan and Rocky Mountain basins will be the primary supply basins of choice. Also, the anticipated increase in production in the Rocky Mountain basin depends on additional pipeline capacity to move the gas to various markets.

Projects Completed: Within California, analysis shows that in addition to the 180 mmcfd capacity added in 2002 at Malin, Oregon, PG&E will need additional receiving capacity or storage after 2006. SoCalGas completed major infrastructure projects with a total pipeline capacity addition of 375 million cubic feet per day. As a result, under average conditions, SoCalGas has adequate intrastate slack capacity for its service territory through 2013.

New Pipelines: Projects anticipated to supply the state's growing thirst for natural gas include El Paso's Ruby Pipeline and Kinder Morgan's Silver Canyon pipeline. Ruby pipeline increases access to the Rocky Mountain region while the Silver Canyon provides access to both the Rocky Mountain and the San Juan basins.

LNG: California needs access to new supply sources that can compete with the existing sources. Having access to LNG in California would have a major impact on infrastructure needs and reliability for gas supplies in the state. A facility that can provide 1 Bcfd of LNG supplies represents nearly 16 percent of the average daily need for natural gas in the state. This would significantly increase the need for "*slack capacity'* on interstate pipelines serving the state. LNG imports on the West Coast would enhance supply reliability. They would also temper the number and extent of price spikes like those of the past three years. Competitive market forces will dictate the increase and timing for capacity from the above options.

Chapter 5: Meeting Public Interest Objectives

This chapter first discusses how well we are meeting the goal of conserving resources and increasing the efficiency of the electricity system. This chapter also summarizes the environmental assessments that are the subject of the comprehensive ***2003 Environmental Performance Report***, a subsidiary report of this ***Electricity and Natural Gas Assessment Report*** and, ultimately, of the ***Integrated Energy Policy Report.***

As required by SB 1389 (Section 25303 (b)), a full evaluation of public benefits would address economic benefits; competitive, low-cost reliable services; customer information and protection; and environmentally sensitive electricity and natural gas supplies. This first integrated planning report was not able to address the full range of the legislation in the time allowed. This report has not attempted to conduct a comprehensive assessment of either the economic benefits of electricity and natural gas markets, or customer information and protection *per se*. However, key pieces of such assessments can be found within this report and within the other subsidiary energy policy reports of the Energy Commission's ***Integrated Energy Policy Report.*** A more comprehensive discussion of public interest objectives and the progress of programs designed to achieve them is included in the ***Public Interest Energy Strategies Report***.

Efficiency of Energy Consumption and Supply

We can minimize the resources needed to provide usable energy for consumers through three principal techniques: energy-efficient end uses and behaviors that reduce the need for power in the first place, using renewable resources instead of depletable resources, and making the remaining system more efficient. California already has an enviable track record compared to the rest of the U.S. on both how little power we use while supporting economic and population growth, and the lower environmental impacts of the built system. These trends can be extended through the policies supported in this report.

The future trend for per capita annual electric energy consumption and peak demand can be held flat with savings achieved from DSM programs, funded by the current level of the Public Goods Charge surcharge (**Chapter 2**, **Figures 2-8** and **2-9)**. An approximate doubling of DSM funding can cause a downward turn in the future trends for per capita electric energy and peak demand. By 2013 per capita demand would be 240 kWh per person, or 3 percent lower, than in the baseline trend. Natural gas DSM programs funded by the current level of the PGC surcharge are expected to steadily reduce per capita natural gas consumption over the next decade (**Figure 2-14**). Additional funding for natural gas DSM programs could reduce per capita natural gas consumption even more.

In addition to reducing the end use demand, fossil fuels can also be conserved by increasing the overall efficiency of the electricity system's use of fuel to provide power for end-users, and by increasing the proportion of power that comes from renewable non-fossil energy sources such as geothermal, wind, solar, biomass, and hydroelectric resources. Most new fossil-fired power plants are very efficient gas-fired combined cycle plants or even more efficient gas-fired cogeneration plants. Besides helping to meet load growth, they are displacing generation from old, less efficient power plants. Between 1990 and 2001, there was little change in the system's overall efficiency. But, with the addition of about 9,300 MW of efficient gas-fired generation, the average system efficiency has begun to drop from 8,800 Btu/kWh in 2001 towards a forecasted 8,200 Btu/kWh in 2004.[22]

Customer Choice Opportunities

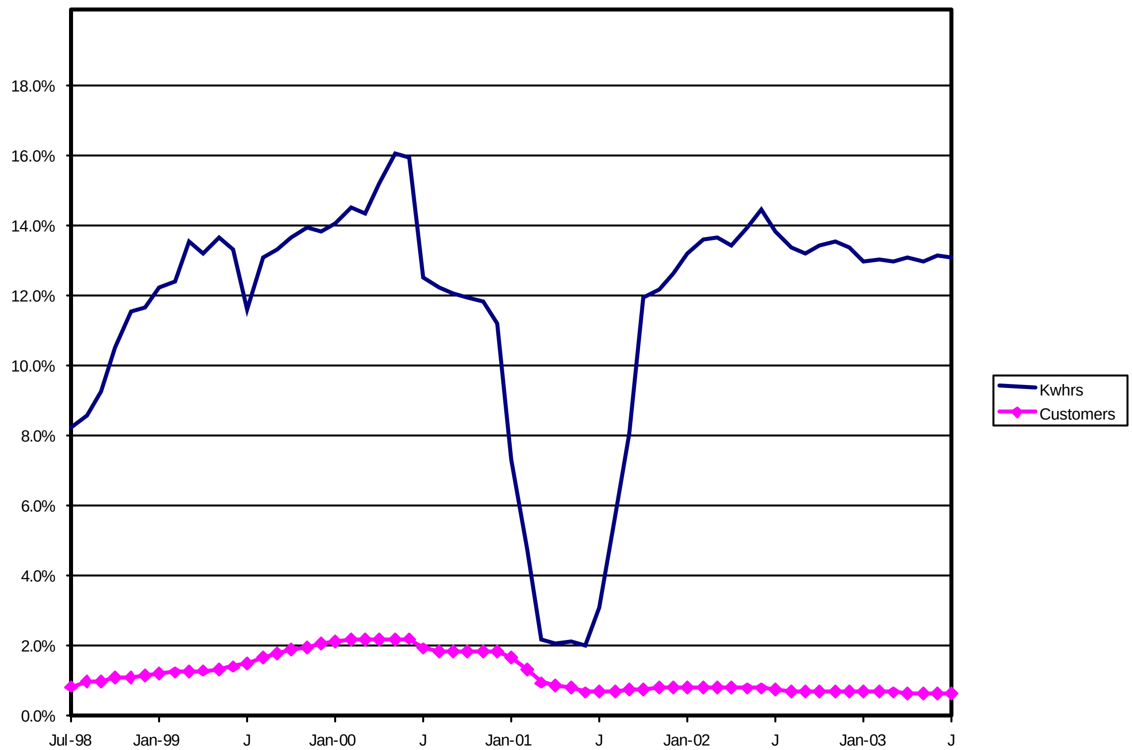
An evolving concept in the electricity market structure involves the ability of a customer to choose their supplier of electrical services. This concept reflects the belief that when customers can choose between competing suppliers, the market becomes more efficient. In many other markets, choice can lead to lower prices and technology innovations. While historically, California's customers had no choice other than to purchase their electricity from their local utility, a trend towards competition, and therefore opportunities to choose, was slowly taking shape.

AB1890 (1996) offered the retail customers of the three investor-owned utilities the opportunity to choose alternative suppliers for electricity. These alternative suppliers were known as "energy service providers" or ESPs. The opportunity for retail choice is generally termed Direct Access. **Figure 5-1** provides an indication of the overall participation in the direct access markets between 1998 and 2001. Participation, as measured by the percent of energy served by direct access compared to total energy consumed, reached its highest point in late spring of 2000 with approximately 16 percent. While that overall consumption was significant, it did not mean that direct access appealed to all customers. Participation in Direct Access barely exceeded 2 percent of all customers at its peak. Currently, the Direct Access customer base is down to under 1 percent and represents about 13 percent of total utility electricity demand.

Large retail customers, primarily customers in the commercial and industrial rate classes, showed the most interest in direct access. Other customers had less enthusiasm for direct access. Participating large customers were only 0.2 percent of all customers, yet the energy served to those large customers through Direct Access reflected 14 percent of all energy served to IOU customers. All other customer groups that participated in Direct Access reflected only 2.1 percent of total IOU customers and only 1.6 percent of total energy served to IOU customers.

By the summer of 2000, participation in Direct Access began to wane. Because of very high spot market prices, the ESPs found it increasingly harder to beat the frozen IOU rates. This was especially the case for those ESPs who bought their supplies from the short-term power markets. By 2000, market prices were rising as evidenced by the increase in the PX and ISO markets. ESPs who had eagerly signed-up retail customers in 1998-99 now began to refuse the renewal of those contracts. Retail customers were returned to their local utilities. Then, by late-2000, many ESPs started to default on their remaining contracts with customers. Customers were now abruptly returned to their utilities.

Figure 5-1
Total Direct Access Participation as a Percentage of All IOU Customers and Load



Supplying these retail customers now became the obligation of the local utility. The utilities also developed financial hardships since they were buying supplies in a rapidly increasing spot market, but selling under fixed frozen rates. By the winter of 2000-01, the investor-owned utilities' financial conditions had become critical. The State found itself in the role of the electricity procurement agency on behalf of the investor-owned utilities. The Governor signed emergency legislation AB1x1 (Keeley) on February 1, 2001 which, among other things, directed the CPUC to suspend direct access until the State no longer purchased electricity on behalf of those utilities. The CPUC, on September 20, 2001, issued Decision 01-09-060 suspending the right to enter into direct access contracts or agreements after September 20, 2001. Those customers with existing Direct Access contracts remain in effect.

As a result of various initiatives, there is renewed interest in consumer choice. Programs to have local communities act as load aggregators are being considered, along with the recent models of individual customer direct access programs. Distributed Generation and Self-generation, through cogeneration facilities, are also expressions of choice. To be effective, a new Customer Choice paradigm will need to address the concerns of cost-shifting between participants and non-participants. Further, it must address the instability caused by customers who leave the utility only to abruptly return. Since the IOUs will once again be responsible to procure sufficient electricity for their customers, such "in and out" vacillation will have significant impacts upon their ability to forecast their loads.

One model for customer choice is the "core" and "non-core" market structure from the natural gas industry. Core customers are customers who receive full service from their local gas utility, i.e., commodity, transportation, and billing/metering administration. Non-core customers do not purchase the commodity (i.e., the gas itself) from the local gas utility. Those customers must purchase the commodity from other suppliers. However, the local gas utility still provides the services of transportation and administration to such non-core customers.

In electricity, a core customer would receive all the traditional services that the local utility has provided in the past, i.e., generation, transmission, distribution, and billing/metering administration. A non-core customer would be required to self-generate or purchase its energy from alternative suppliers. However, it could still rely upon the local utility for transmission, distribution, and administration.

There are several ways to divide the total customers into the two categories. In the natural gas industry, gas volume consumed by the customer is the defining criteria. The CPUC sets consumption threshold for non-core statues at amounts above 20,800 therms per month. A similar criterion for electricity could easily be determined. As an example, customers with more than 50 kW of peak demand could be considered non-core electric customers. Another possibility to establish an electricity non-core group is to have customers select their retail purchase status. For example, a customer could declare itself to be non-core and be served accordingly. This is a form of "opt-in" participation. A customer would be considered a core customer unless otherwise declared. The determination process has added complexities if a community aggregation program are initiated. In that case, if a community declares itself "non-core", there may be problems with individual small customers within the community that would have otherwise not exercised an "opt-in" decision.

Despite the complexities, in general, the creation of the core/non-core customer classes could be a way of empowering customer choice for those customers who truly want that choice. Such a customer structure could also mitigate many of the issues that were encountered in Direct Access.

First, a "bright-line" which separates core and non-core customer groups can help the CPUC in determining which IOU services are performed for which group. Therefore, cost-shifting could be minimized. This would be true not only for administrative costs, but also for costs related to system reliability. Non-core customers could be required to obtain equivalent reserves as what the local utility has provided to its core customers. Second, if non-core customers were required to remain "non-core" for several years, the ability for IOUs to forecast their resource needs could be increased. Finally, the requirement that a non-core customer must procure its power needs from an alternative supplier, or self-generate, would create a stable and committed group of buyers which would encourage the growth of the non-utility power marketplace.

Environmental Performance

The general environmental trends for the electricity generation sector are positive though significant impacts from fuel delivery and electricity generation and transmission remain on a regional basis, generation sector basis, and environmental media basis. Decreases in air emissions from the power plants are impressive and can be attributed to successful application of “Clean Air Act” regulations by State of California regulators (at the Air Resources Board) and local air quality management districts. Air quality levels continue to be poor throughout the state, and the relative contributions of power plant emissions to local air basin inventories and air quality varies regionally.

The tradeoffs between impacts to air, water and land are more complex. Impacts to aquatic ecosystems continue to be the most difficult to understand scientifically, and the most difficult to alleviate. For example, hydropower does not contribute to air quality impacts, but aquatic ecosystems at a watershed scale have been fundamentally changed by hydropower development and operation. Repowering a large natural gas-fired power plant at one of California’s 21 coastal power plants means that new generation units with high thermal efficiency and very low emissions can be installed. Existing infrastructure can also be re-used, which minimizes new impacts to terrestrial habitats from new foundations, roads and transmission lines. But, the tradeoff can be continuing impacts to sensitive estuaries, bays and marine areas.

Electric transmission lines enable the effective transfer of electricity from areas of generation to areas of demand, which means that a wide array of energy resources can be brought to large urban areas from distant parts of the state, and western North America. But, the full environmental effect of transmission lines on birds, desert ecosystems, and forested regions has yet to be documented, and is an issue of concern.

Differences among regulatory systems contribute to these varying impacts to differing parts of the natural environment. Poor air quality impacts human health, so air emissions are closely monitored, well understood, and tightly regulated by an interlocking system of federal, state and local authorities. The impacts to water quality and aquatic ecology from power plants of all types do not typically tend to directly affect human health. This may be why impacts to river fisheries and coastal bays are more difficult to regulate and mitigate. The regulatory system for water quality and aquatic species is fragmented across multiple laws (i.e. Clean Water Act, Porter-Cologne, Federal Power Act, California Fish and Game Code, Warren Alquist and California Coastal Act) and multiple state and federal jurisdictions. Differing agencies have differing priorities and statutory mandates.

Energy imported from outside of California’s borders means less impact to California’s natural resources, and has positive effects for the economies of other states and countries. California utilities own more than 6,200 MW throughout the west, primarily coal-fired generation. Coal is a low cost and reliable energy resource, but emits higher levels of NO_x, particulate matter, CO_2 and SO_x than in-state generation. Air quality in neighboring states tends to be better, so the net impact to air quality is less than if the plants were located in California. This scenario does not hold for Mexico. Poor air quality in the border region of

Mexico raises issues of varying international regulatory standards, especially for power plants built to serve California energy markets.

Such examples of tradeoffs between regions - between impacts to air versus land versus water, or between impacts to a Southern California air basin compared to a Northern California watershed - are extremely difficult to assess given current structures of governance and regulation. The Energy Commission cannot yet report on cumulative energy effects, nor assess the relative contributions of electricity generation and transmission, to different air basins, watersheds and bioregions. Two root causes are a lack of systematic environmental monitoring data and compilation across all statutes related to the energy sector, and the lack of a scientific method to assess the variation in environmental effects across technology sectors and environmental media. As reported in the ***2003 Environmental Performance Report*** (publication number 100-03-010), lack of current, sufficient scientific environmental data hampers the Energy Commission's ability to fulfill its statutory responsibility to report to the Legislature, Governor and public on the environmental performance of all aspects of California's electricity generation and transmission system. Life-cycle impact analytic methods may offer a promise to better understand the full systems-level effects of the state's energy generation and transmission system. Such methods require large amounts of environmental data however, and are complex when an energy system as vast as California's is analyzed.

Global climate change will create a series of effects on California's climate and hydrology that will in turn impact the state's wide array of bioregions and ecosystems. Many of the state's habitats and ecosystems are already stressed. The scale of climate change effects, while uncertain in timing and magnitude, will be pervasive and may alter ecological balances in specific ecosystems and bioregions. Specific electricity generation and transmission effects on local environmental systems may, in turn, become more acute. Electricity generation from fossil fuels contributes to climate change, and in turn, climate change will affect hydro-power generation. Climate change and climate variability may be the most significant environmental issues before the state.

As summarized below for the various environmental media, the general environmental performance trend is positive. The environmental footprint of the energy system required to supply the state's people and economy is relatively small compared to that for other parts of the nation, and the world. Discrepancies in impacts to various parts of the natural environment, though remain large. The Energy Commission has direct jurisdiction over a relatively small portion of the state's electrical generation system. As cooperative relationships are formed with other state and federal agencies, and a more robust collective understanding of the state's energy system emerges, the Energy Commission will be able to more capably report on the complete extent of the environmental performance of California's electrical generation and transmission systems.

Air Emissions

California's reliance on in-state generation from natural gas, the cleanest of the available fossil fuels, and the state's overall mix of energy resources - including hydropower and renewables - benefits the state's air quality. Statewide, combustion-fired electric generation comprises a relatively small portion of the state's average daily inventories of NO_x (3 percent) and PM10 (0.47 percent), and a higher portion of the fossil-fuel CO_2 (16 percent) inventory. California's electricity consumption, however, is responsible for much higher emissions, because the state imports a substantial amount of electricity from other states – some of which is generated by coal-burning power plants. Burning coal generates about twice the amount of CO_2 per unit of energy released during combustion than natural gas. Between 1996 and 2002, the generation emissions and emission percentages in California stayed relatively flat. The overall efficiency of California's electric generation system has continued to improve with the addition of new efficient combined-cycle power plants. Further additions of new efficient combined-cycle power plants, new renewable power plants, and energy efficiency and load management programs in the coming years will continue this trend. Some existing facilities have been displaced as a result of decisions to reduce the use of, retire, or replace these units with new natural gas combined-cycle units. This trend is driven in large part by the costs of upgrades that would be needed to comply with current air emission regulations.

Emissions control retrofit rules continue to be effective in reducing power plant NO_X emissions. Implementation of the NO_x emissions control retrofit rules for utility boilers over the last decade has resulted in 80 to 90 percent reductions in NO_x emission rates per MWh from these facilities. Over 85 percent of California combustion-fired generation uses some form of NO_x emission controls. Nearly 21,000 MW, or 60 percent, use selective catalytic reduction (SCR) for NO_x emission control. Deployment of additional retrofit emission control equipment will continue based on consideration of ongoing cost for control equipment, dispatch of existing units, the attainment status and air quality management plan of the district, and possible regulatory changes.

California is making air quality progress in most regions, although in some regions progress has been slower than anticipated. For this reason new measures targeting existing generation, as well as other combustion sources, are being developed. Under existing rules, new generation will be more efficient and cleaner than the system averages, resulting in continued reduction in the emission factors. **Figure 5-2** shows how system averages are compared to potential new additions for NO_x emission rates.

The recent merchant-owned capacity additions and former utility-owned fuel-fired boiler and combustion turbine facilities, with a capacity of about 23,100 MW, now operate as the swing or load-following units on a daily, seasonal, and emergency basis. These units tend to be dispatched to accommodate the swings in demand and availability of in-state hydro and imported sources. Generation from these facilities increased 145 percent between 1996 and 2001, with the main increases in 2000 and 2001 in response to limited hydro resources throughout the west (**Figure 5-3**). While generation from these units increased 145 percent, the increase in NO_x emissions during this period was only 41 percent because of improvements in the NO_x emission rate per MWh that resulted primarily from retrofit of the steam boiler facilities. In 2002, when generation from these units dropped almost 40 percent compared to 2001, total NO_x emissions from these units was 25 percent below 1996 levels. By 2002, the NO_x emission rate per MWh was 50 percent below that of 1996. [23]

Figure 5-2
NOx Emission Rates:
System Averages and Potential Resource Additions

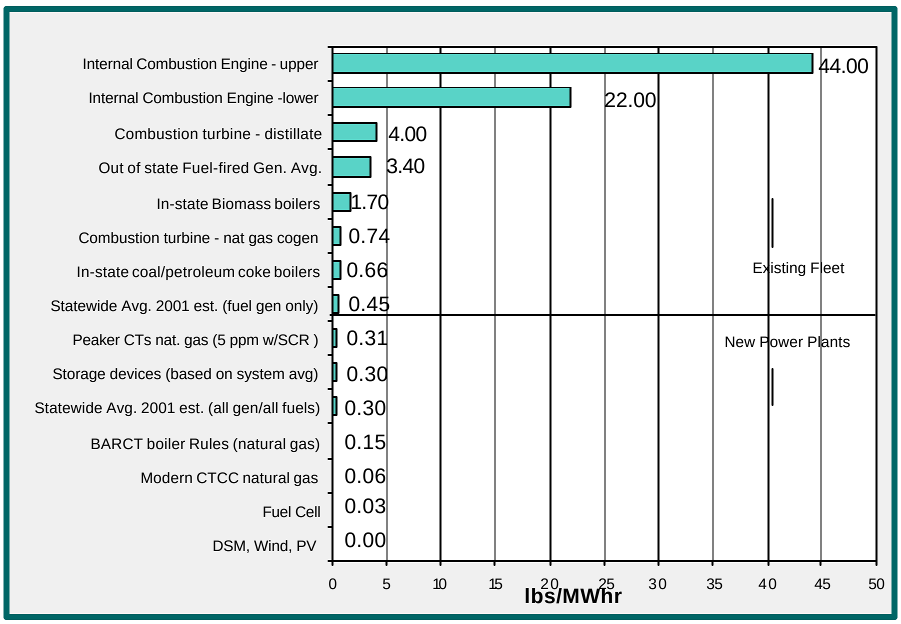
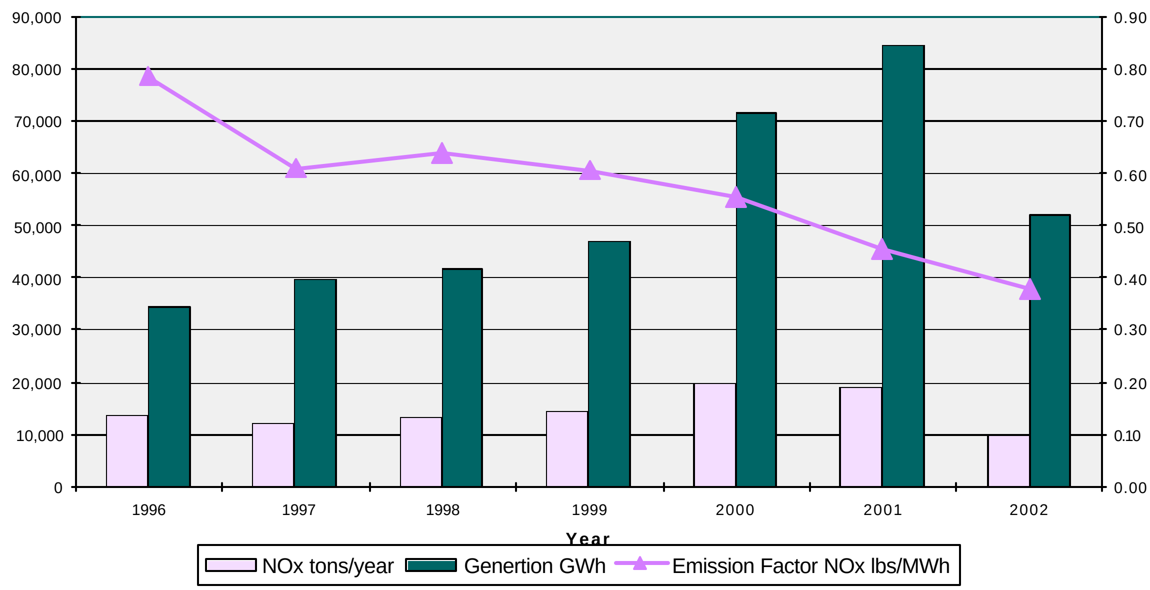
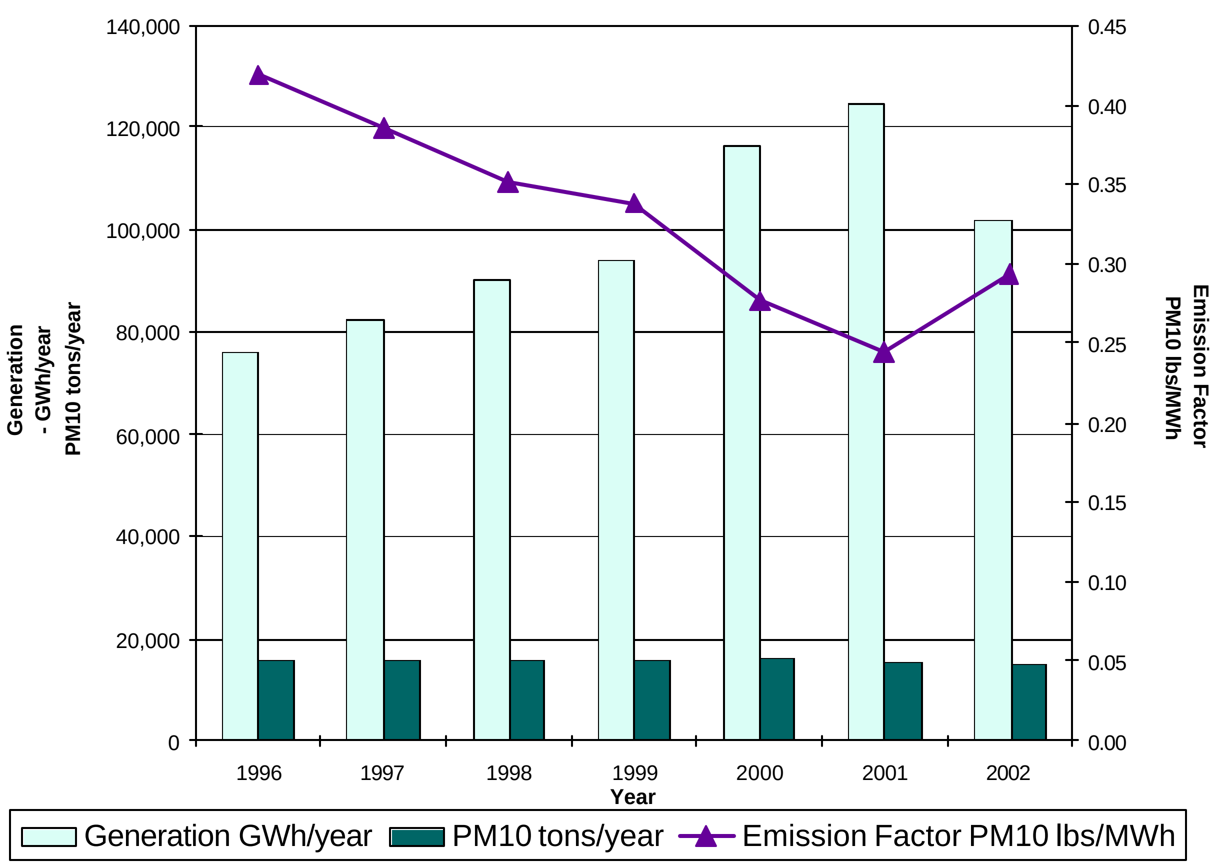


Figure 5-3
Generation and NOx Emissions from In-state
Load Following Units



Increases in gas-fired generation in 2001 and 2002 also resulted in increased emissions of particulate matter smaller than 10 microns (PM10). The level of PM10 emissions from fired electric generation in California depends almost entirely on the type of fuel combusted. Generation using natural gas results in very low PM10 emissions, while the use of coal and biomass can result in much higher emissions. **Figure 5-4** shows the trends in PM10 emissions and emission rates for the fired portion of the state fleet using data from the US EPA's E-GRID data base. While the data show a significant decrease from 1996 to 2001 in lbs/MWh emitted, this decrease is not representative of a change in emission rates of individual facilities. As is discussed above, this period saw a sharp increase in the natural gas portion of in-state generation, and the sharp dip in the PM10 emission rate is probably a function of this resource mix change and generation PM10 numbers being so small and less than the potential error band.

Figure 5-4
E-GRID PM 10 Emissions and Emission Factor
For Fired Generation



Because emissions vary by region and season, further criteria pollutant air emission reductions from the generation sector may be needed in California. The state's air quality regulators will likely continue to provide practical and innovative rules to address both existing and new generation sources, resulting in appropriate emission reduction contributions from the generation sector.

Significant improvement in emissions have been achieved from retrofitting existing steam boiler power plants with emission controls, and permitting very clean new generation which can displace generation and emissions from older, less efficient plants. Further improvements in the air emissions performance of the generation sector will most likely come from technological advances in emissions control, efficiency improvements, or by decreasing reliance on combustion-fired generation through reduced demand or increased use of non-fired electricity sources. Agency coordination and research will be critical components to obtain timely and cost-effective advances.

As part of the evaluation of next steps in working to improve the state's air quality, the California Air Resources Board has initiated a proceeding to develop a guidance document for criteria emissions reductions from existing combustion turbines. The development of the guidance concepts and their potential adoption and implementation by local air pollution control districts, may affect the availability and cost-effectiveness of existing combustion turbines. This would be an additional factor that could affect when some turbines are retired.

Out-of-state generation appears to exhibit an improving NO_x emission factor, possibly due to the increased use of natural gas. Despite NO_x emission rates being higher for out-of-state generation, significant differences in ambient air quality make it difficult to predict how NO_x emissions from these plants might contribute to out-of-state air quality. It is encouraging that several new power plants close to the California-Mexico border are employing effective NO_x control technologies.

Global Climate Change Impacts

California has long recognized the potential dangers that climate change and variability can impose upon the state's populace, economy, and natural resources. The risks associated with increased climate change and variability represent a serious threat to the state's future, with possibly significant costs related to the state's water supply, agricultural productivity, forest health, energy production and demand, and coastal infrastructure. Projected impacts include hotter days, additional smog, sea level rise, and a 15 to 30 percent reduction in surface water supply to California's cities and farms over this century.[24]

Taking appropriate measures to minimize current and future adverse impacts of global climate change is a priority for California, as highlighted by several recent legislative actions. Among states, California ranks second in total emissions, behind only Texas, due primarily to the size of the state's economy and population. Greenhouse gas emissions, on a per person basis in California, are relatively low compared to the rest of the United States.

California's greenhouse emissions come from several sources with the primary cause being fossil fuel consumption in the transportation, industrial, and electricity sectors. The generation of electricity in California accounted for approximately 16 percent of all greenhouse gas emissions from combustion or fossil fuels in 1999. This share is significantly lower than the national average, where closer to 33 percent of greenhouse gas emissions result from production of electricity. However, California imports a substantial amount of electricity from other states, and is indirectly responsible for associated emissions of CO_2. **Figure 5-5** shows the trend in total annual carbon emissions from, and the carbon emission rate of, fossil-fired in-state generation. **Figure 5-6** allows comparison of California's in-state electricity generation mix with the average throughout the United States. Our in-state generation mix is significantly less carbon-intensive due to lack of appreciable in-state coal-fired generation, high production from hydro-electric facilities in the state, and the import of electricity from neighboring states.

Figure 5-5
CO2 E-GRID Emissions for the In-state Fired Capacity

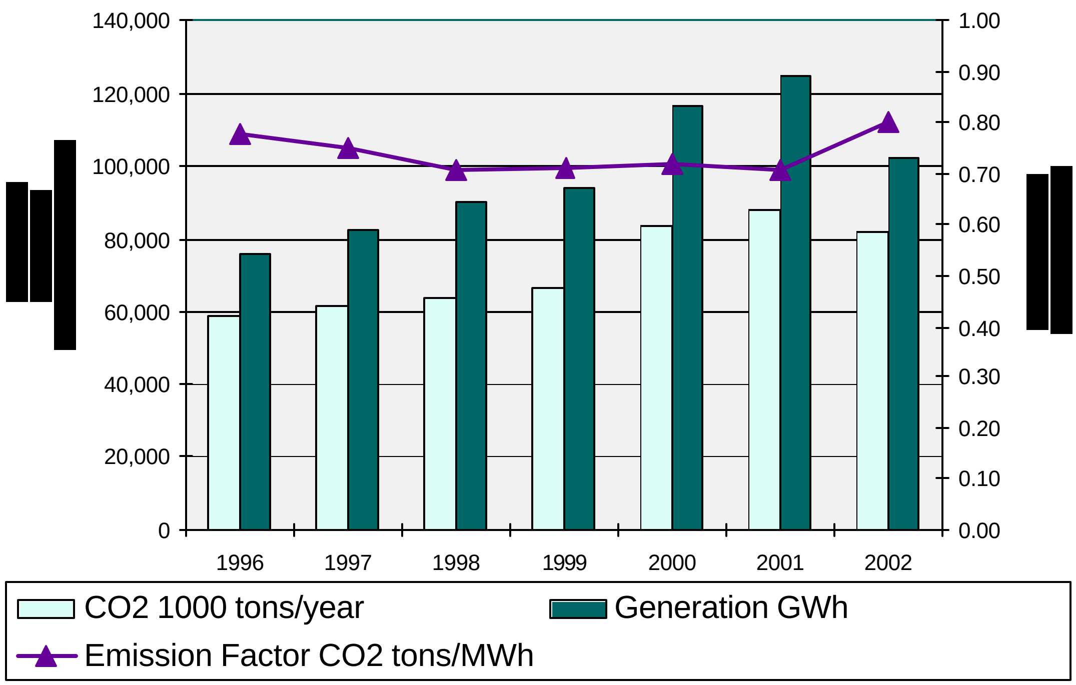
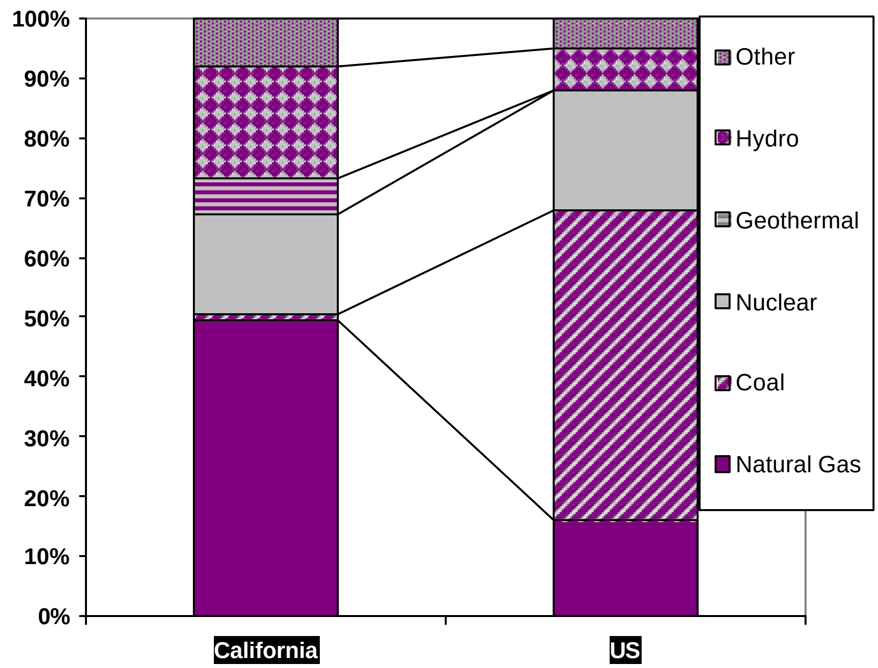


Figure 5-6
Electricity generation mix in California and the United States



Source: eGrid2002pc, Version 2.01, U.S. EPA

One impact of climate change linked directly to electricity production is a shift toward warmer winters that are reducing the volume of the Sierra snowpack. This snowpack is the state's principal water storage and allows hydropower to serve as a dispatchable resource that can be used throughout the year. More than a century of river flow data show that warmer winters have lead to reduced snowpack, and earlier snow melt has reduced Sierra watershed late spring/early summer runoffs by as much as 10 percent. Earlier runoff means that less hydropower is available to help regulate the stability of the electricity system, or to serve summer peak demand, and the possibility of less overall hydroelectric energy being available during the year.

While electricity production and industrial emissions are universally important sources, transportation is California's largest source of carbon dioxide from burning of fossil fuel. The ***Transportation Fuels, Technologies, and Infrastructure Assessment Report*** (publication number 100-03-013D), and ***Climate Change and California Report*** (publication number 100-03-017D) discusses strategies to reduce transportation greenhouse gas emission impacts.

Efficiency and Renewable Energy Cut GHG Emissions

Great progress has been made over several decades to improve energy efficiency and provide cleaner sources of electricity, both efforts that help reduce the state's GHG emissions. More remains to be done. Greenhouse gas emissions associated with the production of electricity consumed in California is the state's second largest source behind transportation sector emissions. Californians have managed to keep their per capita consumption of electricity at a relatively stable level, increasing one tenth of one percent on average in the 1990s. While electricity consumption on a per person basis may be relatively low and stable, power generation continues to be a large source of GHG emissions within the state.

It is possible for electricity generators to capture and store CO_2, but the ability to do so remains costly for most power producers. The Energy Commission has recently partnered with the Department of Forestry and Fire Protection, the Department of Food and Agriculture, agencies from neighboring states, and private sector organizations to form the West Coast Regional Carbon Sequestration Partnership. The focus of this partnership will be regional opportunities to capture CO_2 from processes such as electricity generation, transport it, store it in geological or terrestrial reservoirs, monitor and verify the long-term storage, and conduct public outreach on the potential value of carbon sequestration alternatives to mitigate GHG emissions.

As detailed in Chapter 3 of the ***Public Interest Energy Strategies Report*** (publication number 100-03-012D) demand-side-management (DSM) continues to hold great potential for reducing energy use and the associated reductions in GHG emissions. DSM activities include increasing energy efficiency, conservation, and electricity demand or load management. Energy efficiency improvements can be discovered and acted upon in many ways. In all cases, efficiency improvements that reduce energy demand help cut GHG emissions to the extent that less fossil fuel is consumed in the overall supply of energy within California. Changes in behavior that lead to energy conservation both improves some type of efficiency (e.g., annual amount of energy to heat or cool a house), saves the end-user of energy some money, and reduces GHG emissions.

Initiatives that increase energy efficiency help reduce energy expenditures in our economy, making businesses more competitive and allowing consumers to save money and live comfortably. Although efficiency programs and policies to reduce growth in demand for electricity and natural gas have resulted in significant consumer savings, research shows that additional cost-effective savings remain to be achieved. California's ***Energy Action Plan*** calls for the appropriate use of price signals, improved building and appliance energy efficiencies, increased conservation programs and other incentives to reduce the demand for electricity. These types of efforts can guide California along a path towards greater competitiveness, an improved environment, and reduced emissions of GHGs.

Renewable energy has the potential to be a cornerstone of policies that aim to reduce GHG emissions. Renewable sources of energy can replace traditional fossil fuels used for electricity generation, as well as reduce the state's reliance upon petroleum in the transportation sector. By reducing the state's dependence on imported energy from other states or countries, increased reliance upon the state's renewable sources of energy helps reduce GHG emissions and helps protect the economy and citizenry from fossil energy price spikes. A comprehensive discussion of renewable energy in California can be found in Chapter 5 of the ***Public Interest Energy Strategies Report***.

While California has aggressive policies and programs to promote use of renewable energy resources, there are additional measures the state can take to support increased utilization of renewable energy resources for electricity generation. California can partner with its neighboring states and countries to encourage the development and transmission of renewable sources of electricity generation. A regional partnership could make significant progress in developing an efficient renewable power tracking and certification program. In collaboration with others or independently, California can increase its effort to research, develop, and deploy renewable projects, and promote demand for renewable energy as an alternative to electricity generated from fossil fuels.

Regulatory frameworks at the federal, state, and local levels that encourage long-term financial commitments to the development of renewable resources and long-term contracts for electricity generated from renewable energy resources will be key factors. An example is the need to develop transmission infrastructure to support large-scale development of renewable projects. The state can increase demand for renewable energy by providing informational materials to raise consumer awareness of renewable energy and by supporting green pricing programs that are over and above the mandatory requirements of retail sellers to provide renewable energy.

Western states should work to improve the operating efficiency of the Pacific Coast transmission system. Finally, agencies from western states should investigate the potential benefits of biomass-to-energy facilities to address the growing safety concerns associated with wild fires. These and other strategies to develop additional renewable energy resources will be evaluated further in the next Integrated Energy Policy Report.

Mechanisms to Reduce Electricity Sector GHG Emissions

A variety of mechanisms are currently employed outside of California that lead to reduced GHG emissions associated with the production of electricity. A number of additional measures are being designed or tested and scheduled to begin in the near future. Mandatory reporting of GHG emissions is common for large emitters within the electricity sectors of many developed countries. The Energy Commission should consider required reporting of GHG emissions as part of its facility permitting process.

The European Union will launch its GHG emissions trading program in 2005. Individual countries within Europe also utilize energy or fuel carbon taxes to provide financial incentives to reduce GHG emissions within their electricity sectors. A voluntary project that includes power generators, the Chicago Climate Exchange, recently completed its rulebook for the launch of its pilot GHG emissions trading program.

Several states including Massachusetts, Oregon and New Hampshire established generation efficiency benchmarks for CO_2 emissions from power plants. These benchmarks are typically based upon the best available technologies to reduce GHG emissions and can be updated as new technologies are developed and marketed. Oregon combines two mechanisms to reduce GHGs from electricity generation, efficiency benchmarks and a requirement to offset a portion of GHG emissions from new sources of power generation. Offsets can be achieved by funding or implementing projects that reduce atmospheric concentrations of GHGs.

In addition to efficiency benchmarks and required offset projects, a reduction mechanism receiving considerable attention is the "cap-and-trade" system. One connection between these mechanisms is the use of benchmarks as a key factor in determining feasible GHG emission caps. In a cap-and-trade system, a set quantity of emissions permits is allocated to emitters of GHGs and then entities are allowed to buy and sell their permits to cover their actual emissions. Those entities with lower costs of cutting emissions can reduce more than required and sell excess permits to those facing higher costs to reduce. The states of New York, Connecticut, Vermont, New Hampshire, Delaware, Maine, New Jersey, Pennsylvania, Massachusetts, and Rhode Island have agreed to develop a regional cap-and-trade system for CO_2 emissions within their electricity generation sectors.

The 1990 Clean Air Act Amendments authorized various forms of emission trading systems. The federal Environmental Protection Agency concluded in 2001 that successful trading systems had been in operation for several years and that such systems can be applied to a wide variety of pollution sources. One example of a successful cap-and-trade system is the Acid Rain Program's marketable pollution allowance scheme with sulfur dioxide emissions from electric utilities in the northeast. This was initiated in 1995 and helped reduce annual emissions by 4 million tons and contributed to reductions of the acid content of rainfall by 25 percent.[25]

Biological Resources

Habitat loss impacts to terrestrial biological resources have been mitigated for Energy Commission-reviewed projects. The eighteen operational natural gas-fired power plants licensed by the Energy Commission after 1996 caused minimal terrestrial biological resource impacts, and included the loss of only 225 acres of habitat. Power generation development from 1996 through 2002 used approximately 3,900 total acres of land, but the footprint of fuel development is still being researched. Because California's most sensitive species tend to occupy small habitat ranges, energy development projects have the potential to cause impacts when built nearby. Use of previously disturbed lands for energy projects can minimize such effects.

California's 31,720 miles of electric transmission lines and 11,600 miles of natural gas pipeline rights-of-way can contribute to habitat loss, fragmentation and degradation. Electric transmission and distribution lines can cause bird mortality from bird strikes and electrocution. Electric transmission lines can cause wildfires; but between 1996 and 2002, the number of wildfires caused by power lines decreased from 284 to 181, annually. New transmission lines to improve system reliability and link new renewable generation resources to the grid may need to be mitigated to reduce the risks of increasing impacts to wildlife and habitats.

Mitigation of aquatic impacts from hydro operations and once-through cooling continues to be a controversial environmental issue. Twenty-one natural gas and nuclear power plants, totaling 23,883 MW, are located on the coast or on estuaries and use hundreds of millions of gallons of water per day for once-through cooling. Impacts to marine and estuarine ecosystems from the destruction of aquatic organisms can be adverse and an issue of concern. Case-specific information is needed to evaluate impacts and to determine appropriate mitigation. Recent proposals for repowering at five coastal power plants did not include changes to once-through cooling water systems that would substantially reduce impacts to aquatic organisms, though mitigation has been required or proposed as part of the projects. Recent and anticipated change in US EPA rules may require these systems to be substantially modified or replaced to reduce their effects on marine organisms.

Salmon or steelhead habitat is found at hydropower facilities in the Sacramento River basin, the San Joaquin River basin and on the North Coast. Very few California hydropower projects have adequate (as currently defined) fish passage structures for migrating salmon and steelhead. Hydropower impacts to salmon, steelhead, native trout and other species continue to be significant. Thirty seven percent (5,000 MW) of California's hydropower system will be relicensed by the Federal Energy Regulatory Commission between 2000 and 2015, presenting opportunities to address and mitigate impacts to salmon, trout and other aquatic species. The Energy Commission will continue to provide support to other agencies seeking to restore salmon fisheries, and other river species and habitats, during relicensing of hydropower projects.

Nitrogen deposition from new power plants and repower projects has potential cumulative impacts if the power plant is within the vicinity of nitrogen sensitive habitats, such as serpentine soil and desert communities. Potential nitrogen deposition impacts from new power plant proposals is emerging as an issue of concern. Case-specific information is needed to evaluate nitrogen deposition impacts to determine appropriate mitigation.

About 35 renewable energy facilities representing about 400 MW of capacity have been built since 1996, but a substantial increase in renewable generation will result from California's new Renewable Portfolio Standard. Wind energy will play a large role in meeting the Renewable Portfolio Standard. Bird mortality from strikes with turbine blades continues to be the primary biological resources issue concerning wind energy. Building integrated solar photovoltaic and biogas-fired electric generators at landfills and sewage-treatment plants have the least risk of impacting biological resources. Other renewable energy types, such as biomass using in-forest fuels, could have wildlife-friendly benefits if biological resource protections were integrated into the planning.

Water Resources

Water Supply

Competition for the state's limited fresh water supply is increasing and in some years contractual obligations to supply water cannot be met. Water use for power plant cooling can cause significant impacts to local water supplies, but tends to be a relatively small use at the aggregate state level.

Since 1996, an increasing number of new power plants have been sited in areas with limited fresh water supplies. More than 5,700 MW of new power has been constructed or is being considered within Southern California. Use of fresh water for power plant cooling is increasing.

Fresh water use can be reduced or eliminated by use of recycled water or degraded groundwater, alternative cooling technologies, and zero liquid discharge (ZLD) systems. These alternatives to fresh, high quality water are technically feasible and practicable.[26] Of the 4,516 MW of new generation capacity brought on-line in California between 1996 and the end of 2002 for which Energy Commission staff has detailed water use information, more than 1,400 MW (31 percent) is cooled using recycled water.

Alternative cooling options, such as dry cooling, are available, commercially viable, and can reduce or eliminate the need for fresh water. Two projects using dry or air cooling became operational in 1996 and 2001. A third project using dry cooling in San Diego County is currently under construction.

Water Quality

Water quality impacts to surface water bodies, groundwater and land from waste water discharge are being increasingly controlled through use of technologies such as zero liquid discharge systems. ZLD systems eliminate wastewater discharges to land or water and produce purified water streams for re-use in plant processes. Of the 4,516 MW of new capacity brought online between 1996 and the end of 2002 for which the Energy Commission has detailed water use information, 12 percent use zero liquid discharge. More than 35 percent of the projects under licensing review or under construction will use this technology.

Continued use of once-through cooling at existing and repowered power plants perpetuates impacts to aquatic resources in the coastal zone, bays and estuaries. No power plants using once-through cooling have been proposed for new California coastal sites in the last two decades. Proposals to repower existing generation units at these sites have included proposals to continue the use of the once-through cooling system infrastructure.

Hydroelectric facilities can cause permanent alterations to stream flows, raise water temperatures, alter dissolved oxygen and nitrogen levels, and cause changes to the aquatic environment. These facilities can also provide benefits including water storage, flood control, and recreation. As of 2003, only a small portion of California's hydropower system meets current state water quality standards. Only six of 119 projects licensed by the Federal Energy Regulatory Commission have Section 401 Clean Water Act certification from the State Water Resources Control Board, and three more are nearly complete. These nine projects total 275 MW, which is about two percent of California's hydroelectric generating capacity.

Two potential policies relating to water supply and water quality should be considered for adoption by the Energy Commission:

- Any power plant applicant should be required to use water conservation cooling alternatives or reclaimed water, or prove these are not practicable. Such a policy could increase the influence of recycled water availability as a site selection factor for new power plants and reduce impacts on local water supplies.

- The discharge of liquid wastewater to land, groundwater or surface water bodies by power plants should be prohibited, and zero liquid discharge technology should be required unless proven not practicable. Such a policy could reduce water quality related impacts from power plant wastewater and increase the efficiency of water use in these facilities.

Hydroelectric Plants Combine Environmental and Societal Effects

Hydro facilities provide a variety of social benefits (e.g., water supply, electricity, flood control, recreation), but also can create significant impacts to aquatic ecosystems in rivers and streams. Important environmental restoration benefits can be achieved through hydropower relicensing before the Federal Energy Regulatory Commission, and through selective, targeted decommissioning projects.

The Energy Commission has been working with the Secretaries for Resources and Environmental Protection to determine whether greater environmental protection is needed for California rivers and streams affected by hydropower development and operation. Energy Commission staff have evaluated changes in energy production from hydro decommissioning projects to restore salmon and steelhead habitat. Energy Commission studies determined that the projects should have little appreciable aggregate effect on electricity supply or cost for California. The Commission will continue working with sister state agencies in assessing the environmental and energy effects of specific proposals to modify or decommission hydroelectric projects in California, subject to staff availability.

Societal Effects

The societal effects of power plants assessed in the ***2003 Environmental Performance Report*** include land use compatibility, socioeconomic resources, environmental justice, and cultural resources. The key findings and conclusions from this report are summarized below.

Land Use Compatibility

Local and regional land use and development planning efforts seldom designate sites or corridors for energy facilities such as electric power plants and transmission lines, and energy facility proponents are seldom involved in these long range efforts. 40 percent of Energy Commission siting cases from 1996 through 2002 required a general plan amendment or zoning change, or other local actions like parcel map changes or Williamson Act cancellations, although it is unclear if this is typical of other major industrial development.

In rapidly growing urban areas, energy infrastructure development and repowering often occur very close to sensitive community resources such as new residential areas, schools, and recreation areas, which can lead to intense controversy and delay the facility siting process. Existing coastal power plants are generally located in areas that have experienced significant development and residential growth, and the repowering of those projects has caused, and is likely to continue to cause, local debate and controversy.

Socioeconomic Resources

The 17 power plants permitted by the Energy Commission since 1996 that were on-line by December 31, 2002, added 4,418 MW in generation capacity, and have resulted in approximately 3,900 peak construction jobs, 125 operations jobs, capital costs of approximately $1.5 billion, and, for fiscal year 2002-2003, approximately $23 million in property taxes.

The ***2001 Environmental Performance Report*** estimated a 10-to-1 ratio of direct peak employment construction jobs to direct operation jobs for power plants. Data from the permitting of the non-emergency power plants approved by the Energy Commission since 1996 that were online by December 31, 2002, show this ratio was 25-to-1. This increase may be in part a result of faster construction cycles to meet the demands of the California energy crisis. Existing large steam boiler plants typically have 40 to 50 maintenance and operation employees. The gas-fired simple-cycle and combined-cycle power plants that are now being built have a range from only 2 to 24 maintenance and operational workers.

State law prevents public agencies such as the Energy Commission from imposing fees or other financial mitigation for impacts on school facilities. The school impact fee that can be levied by a school district usually ranges from $2,000 to $6,000 per power plant project. Municipal utility districts are exempt from these fees.

Starting in January 2003, the State Board of Equalization (BOE) assesses all privately owned electric generation facilities over 50 MW, including facilities divested by the public utilities that had been assessed by counties after deregulation. Some cogeneration and renewable facilities will continue to be assessed by counties. The BOE will assess at fair market value and revenues will be distributed to those jurisdictions located in the tax rate area where the power plant is located.

Environmental Justice

The Energy Commission and the California Department of Transportation were the first state agencies to include environmental justice concerns and demographic information in their environmental impact analyses. The Energy Commission's approach to environmental justice emphasizes local mitigation and seeks to reduce environmental impacts that could affect local populations to less than significant levels. Of the projects identified as having greater than fifty-percent minority populations within a six-mile radius, appropriate mitigation has been identified to reduce significant impacts to less than significant levels, thereby removing any potential for an environmental justice issue (high and adverse disproportionate impact associated with a proposed project).

Power plants proposed in densely populated urban areas are often sited where residential land uses encroach on older industrial areas. Community involvement related to environmental justice during siting cases has primarily occurred in proposed power plant cases in the large urban areas of Los Angeles and San Francisco.

Cultural Resources

Most facilities approved for construction and operation by the Energy Commission have involved archeological, historical or ethnographic cultural resource issues. Native American sacred sites and areas of traditional concern are particularly sensitive aspects of ethnographic concerns. One of the most significant cultural resource finds is the discovery of previously unknown Native American burials during construction.

Chapter 6: Problems and Risks

This chapter identifies a number of issues and risks for ensuring electricity and natural gas reliability for California. This chapter also provides an overview of the efforts to achieve electricity resource adequacy requirements, the options for reducing the long-term dependence on natural gas, and actions underway to address California's obstacles to realizing needed transmission system expansion. Considering that the electricity and natural gas markets are closely inter-related, the risks and uncertainties that affect one market will also affect the other. Decisions to expand the infrastructure of one system will also affect both markets.

Efforts to Achieve Electricity Resource Adequacy Requirements

The CPUC is developing resource adequacy[27] requirements for IOUs as part of its long-term procurement proceeding and is examining its authority to either impose similar requirements on energy service providers (ESPs) or to assign this responsibility to IOUs. In this IEPR proceeding, the Energy Commission has fostered a review of municipal resource adequacy issues. In principal, these two parallel efforts should result in a common or complementary set of resource adequacy requirements being established that covers all LSEs.

All stakeholders have realized the importance of ensuring resource adequacy, and many proposals for stabilizing this market design element have been offered over the last few years. There is widespread agreement on the need for load-serving entities to take responsibility for ensuring resource adequacy. Under the current industry structure, the nature of the "obligation to serve" varies across classes of LSEs. For utilities, the obligation is absolute. The CA ISO and other control area operators already enforce standards for guaranteeing operating reserves in the near-term market. Municipal utilities have partnered with the Energy Commission to demonstrate their willingness to guarantee resource adequacy for their customers.

In the initial market design, direct access providers could "return" their customers to utility service. This shifts risk from the latter to the former. If direct access providers (or their customers) can respond to adverse conditions by shifting the obligation to serve back to a utility without cost, they face less risk associated with high wholesale prices and thus have less of an incentive to facilitate the addition of new capacity when it is needed. The utility faces additional risk: that it must suddenly serve additional load, an event most likely to occur when spot market prices are high. The suspension of direct access pursuant to AB1x-1 makes such ESP behavior less likely, because once returned a direct access customer cannot easily escape from bundled service again. The California Public Utilities Commission, in R. 01-10-024, is developing resource adequacy requirements for investor-owned utilities and investigating how to address this issue for direct access and community aggregator providers.

Although it appears that there is widespread agreement that resource adequacy requirements are needed, there is little agreement about the nature of the specific requirements. A useful starting point for principles to guide development of these requirements was included in the Energy Commission Staff/California Municipal Utilities Association working paper.[28] They are:

1. A public demonstration by LSEs of a performance-based resource adequacy plan, approved by the LSE's applicable regulatory authority;

2. Appropriate application of a resource adequacy program by each LSE so that free riding on the resource adequacy provided by others is minimized;

3. Periodic reporting by LSEs to their control area operator or RTO (if established) to demonstrate that planned resource commitments are matched to load forecasts. Periodic reporting by generators of commitments to LSEs and remaining available capacity, reported by generators to their control area operator or other RTO;

4. A demonstration that each LSE has the necessary authority to implement its resource adequacy obligations;

5. LSE discretion within the framework of its regulatory authority in planning, procurement, and operation of its power portfolio is maintained;

6. Arrangements, perhaps formalized, through tariff provisions or protocols that describe the actions the LSE and its control area operator will take when LSE resources do not fully cover its loads and appropriate reserves.

As described in the previous chapters, California is expected to have a 15 percent increase in population by 2010 and the state economy is expected to grow at double that rate.[29] Population growth and economic activity are the principal drivers of electricity consumption in California, while hot weather drives peak electricity demand. **Table 6-1** provides the Energy Commission's outlook for 2004 through 2010. This outlook indicates that, given conservative assumptions, California should have an adequate supply of electricity through 2006. However, we have an increasing concern for adequate reserves starting in 2007. Under a hot 1-in-10 weather scenario, reserve margins could fall below 5 percent. It is difficult to project these outlying years with certainty, given that new generation, as well as additional retirements, is likely to occur.

It is important to note that these declining reserve margins could improve, pushing out the need for additional peak load resources to 2008 or 2009 <u>if</u> price responsive programs, renewable generation additions, and peak demand reduction program goals are met. Committing to the programs and their successful completion is important to stabilizing our electricity needs. An insufficient commitment can put the state at risk. It is critical that we carefully monitor this balance and accurately evaluate the progress of these programs to ensure California's electricity needs are met without compromising our economic and environmental goals. It is also important to note the long lead times often associated with bringing new generation and transmission facilities on-line. This can mean, for example, the need for an application for a power plant three to four years before the date it needs to operate.

Table 6-1
2004-2010 Statewide Supply/Demand Balance

	Aug 2004	Aug 2005	Aug 2006	Aug 2007	Aug 2008	Aug 2009	Aug 2010
Existing Generation	57,434	56,956	58,902	57,613	57,802	58,001	58,206
Forced and Planned Outages [1]	-3,750	-3,750	-3,750	-3,750	-3,750	-3,750	-3,750
Retirements [2]	-1,191	-1,054	-2,385	0	0	0	0
Net Firm Imports [1,3]	5,895	5,748	5,848	5,648	5,648	5,115	5,009
High Probability CA Additions	713	3,000	1,096	189	199	205	198
Spot Market Imports	2,700	2,700	2,700	2,700	2,700	2,700	2,700
Total Supply (MW)	61,801	63,600	62,411	62,400	62,599	62,272	62,364
Demand (revised June 2003):							
1-in-2 Summer Temperature Demand (Normal)	53,331	54,500	55,487	56,195	57,090	57,757	58,491
Projected Operating Reserve (1-in-2) [4]	15.9%	16.7%	12.5%	11.0%	9.7%	7.8%	6.6%
Demand (revised June 2003):							
1-in-10 Summer Temperature Demand (Hot)	56,571	57,811	58,858	59,609	60,559	61,266	62,044
Projected Operating Reserve (1-in-10) [4]	9.2%	10.0%	6.0%	4.7%	3.4%	1.6%	0.5%
Projected Planning Reserve [4]	17.9%	18.6%	14.4%	12.9%	11.5%	9.6%	8.4%
Projected Planning Reserve -Accelerated Programs [5]	19.4%	20.9%	17.5%	17.3%	16.3%	14.8%	13.9%
Emergency Response Programs/ Interruptables [6]	1,102	1,102	1,102	1,102	1,102	1,102	1,102

Notes: [1] Net firm imports and forced and planned outages estimates are based on 2003 estimate. [2] CEC recognizes that South Bay Units 1-4 will retire prior to summer 2009. We assume these plants will be replaced. [3] No new firm imports are assumed so contract expirations reduce net firm imports over time with exception of 2006 where 100MW export contract expires. This causes Net Firm Imports to increase 100MW in 2006. [4] These reserves do <u>not</u> consider potential capacity additions derived from price responsive demand programs adopted by the CPUC, incremental new renewables from Energy Action Plan or High DSM Peak Demand Reduction Scenario. [5] Includes potential capacity additions from programs excluded in the previous footnote.
[6] Emergency Response Programs / Interruptables not included in planning reserve or operating reserve calculations.

Pursuing resource adequacy throughout the Western Interconnection is also important to ensuring that the electricity system is reliable. California is not an island, independent from the rest of the Western Interconnection. The high prices in California's spot market in 2000 and 2001 reverberated across the West, although California's consumers and institutions suffered more harm than others, because we had a greater exposure to spot markets than most of the rest of the West. Existing institutions like Western Electricity Coordinating Council (WECC) and new ones like Seams Steering Group – Western Interconnection (SSG-WI) are attempting to bring improved focus on the assessment portions of resource adequacy. While these efforts are important, ultimately achieving resource adequacy will require the regulatory agencies in the Western states to embrace the need for explicit resource adequacy requirements, and then to design and implement them.

Reducing Dependence on Natural Gas

Chapter 4 discussed some ways to mitigate the risk of high natural gas prices in the near-term. Short-term contracts, financial hedges, and storage can reduce exposure to the spot market and the likelihood of price spikes. These do not address the additional risk that dwindling North American gas supplies pose. This risk will grow during the coming decade if only because the state will become increasingly reliant on natural gas as a generation fuel.

The risks associated with longer-run changes in the price of natural gas can only be mitigated by either developing new sources of natural gas, such as LNG imports, or by reducing the demand for natural gas as a generation fuel. The potential development of new sources of natural gas and its possible impacts are discussed elsewhere in this report.

Reducing the use of natural gas in electricity generation can be accomplished by the following:

- Replacing older, inefficient gas-fired power plants with newer plants that require less fuel,
- Reducing the demand for electricity in California, and
- Replacing gas-fired generation with generation from other fuel sources.

Natural gas is conserved by relying more on efficient new gas-fired generation than on the existing, older and less efficient power plants. The replacement of older gas-fired plants with newer ones has been taking place since 2001 and will continue through the remainder of the decade as new projects come on-line. Growth in the state's demand for electricity will still cause an increased reliance on natural gas as a generation fuel. Even with continued funding of energy efficiency and DSM programs at present levels, and even if the conditional mandates of the Renewable Portfolio Standard are met, natural gas-fired generation in California as a share of the state's electricity needs is still forecast to increase from 34 percent in 2004 percent to about 44 percent in 2013. In low-water years, reductions in available hydroelectricity will push this percentage even higher.

Dependence on natural gas can be lessened by reducing the demand for electricity. Programs which reduce the consumption of electricity have the greatest impact on natural gas demand if they are targeted at hours of peak electricity use, when the most inefficient power plants are called on to generate. During peak hours in the summer, the system's incremental heat rate is 12,000 Btu per kWh or greater. Reductions in demand during early morning hours or in the spring runoff season will have as much as 40 – 50 percent less impact. Reductions during peak summer hours also have the greatest impact on ratepayer cost and its volatility, as it is during these hours that the largest share of electricity is traded at both the spot market price and at other prices determined by the underlying gas price. How much the DSM programs cost and how the actual demand reductions they induce affect the generation system will determine how cost-effective these programs are at reducing dependence on natural gas.

Increased generation using other fuel sources will also reduce the demand for natural gas. Legal, political, environmental and cost issues make nuclear, large hydroelectric and coal generation unlikely candidates for offsetting natural gas generation. Energy Commission studies have indicated that the development potential of wind, geothermal, and biofuel generation is substantial and that the costs of these technologies are declining. The new Renewable Portfolio Standard Program should increase both the total amount and the percent share of electricity generated from renewable energy sources, offsetting generation that would otherwise have been gas-fired. This result depends on the renewable power having a market value that, together with a supplemental energy payment from funds provided through the Public Goods Charge, will result in a total payment to the plant developer that is sufficient to spur the plant's construction. It is too early to tell how much this program will cost, as the first RPS auctions will not be held until 2004.

As is the case for programs that reduce electricity consumption, renewable generation will displace the most natural gas if it is available during hours of peak electricity use. The extent to which increased generation from renewable sources can reduce and stabilize wholesale energy costs will depend on a number of factors. For example, renewable energy bought at fixed prices can have a stabilizing economic effect.

Natural Gas Infrastructure and Markets

One of the six action steps included in the ***Energy Action Plan*** is to ensure that natural gas supply is reliable, that prices are reasonable and stable, and that energy policies and strategies that are implemented protect the environment and consumers in the state.

From an overall market perspective, it is fair to assume that participants in the natural gas industry will act in a rational manner, and make their decisions on infrastructure investment and operation in a manner consistent with fundamental economic principles which may produce short-term economic dislocations. For these dislocations to be resolved, regulatory policies and decisions must guide this development in a balanced and efficient manner.

Resolving operational, pricing, stability, and reliability concerns in the gas market involves oversight in several areas: demand, supply, infrastructure, and price/market. The Specific steps described in the ***Energy Action Plan*** include:

- Identifying critically needed gas transmission and storage capacity,
- Monitoring market fundamentals to catch the early-warning signs of any market power or manipulation,
- Evaluating new supply options for the state including LNG, and
- Promoting customers' use of a portfolio approach to manage supply purchases that includes longer-term contracts as a hedge against price volatility and high spot market prices.

The key issues needing immediate action, from state and federal agencies:

- Data Quality - misrepresentation and inaccurate information,
- Adequate natural gas storage capacity,
- Regulatory need for natural gas storage utilization by all customers,
- Cost effective increase in interstate and intrastate pipeline capacity serving the state and neighboring regions,

- Access to new and competitive natural gas supplies, including LNG,
- Need for portfolio approach including longer-term natural gas contracts to complement the volatile nature of the market,
- Increased conservation and improved efficiency at the supply and demand side of natural gas markets,
- Evaluation of the need for a back-up fuel capability and available alternatives,
- Risk identification, assessment, and analysis, including market power issues, and utilization of financial instruments.

Data Quality - Misrepresentation and Distortion of Data in the Market Place

A major issue that surfaced following the energy crisis relates to the accuracy of data provided by market participants to the various data reporting entities. False data, previously reported in the market indices have led to a destruction of the credibility of the entire energy industry. Accusations and corrective actions have resulted in closing down many trading groups, while other companies have stopped reporting the information. Accuracy, timeliness and completeness problems have surfaced in the Energy Information and Administration's process of collecting and disseminating supply and demand information. As a result the national supply, demand and pricing information on natural gas is neither timely nor reliable enough to support fully informed market decisions.

The Federal Energy Regulatory Commission has issued voluntary guidelines that trading organizations must follow when they report information to pricing indexes. The objective is to restore confidence in such indices, which are critical in the market and used to help peg the price of natural gas. Energy companies are now voluntarily taking steps to implement corrective changes to enhance the accuracy of data supplied to reporting institutions. These new rules will provide guidance in gathering information about natural gas trades, establish a code of conduct for traders as well as a system that verifies the authenticity of the data they receive.

EIA is attempting to correct the imbalances in information on supply and demand through better verification and review processes to ensure that the quality of data is not compromised. Further, EIA is also working toward enhancing the credibility of its reports on storage activities throughout the U.S. This process will increase the confidence of the gas market and help decision-makers and market participants in reaching correct conclusions and implementing efficient decisions in the market. State agencies should continue to refine their data gathering and analytical procedures to ensure that accurate and timely information will be available to decision makers and industry participants to make balanced decisions and the right choices.

Adequate Natural Gas Storage Capacity

Given the benefits offered by stored natural gas in terms of price stability and supply reliability, the State should investigate impacts of having more storage capacity, especially in the Southern California region. Further, privately-owned storage facilities would provide the needed supply to balance the needs of the non-core customers including industrial and power generation customers. Analysis is needed on how much storage capacity is needed, and where the storage facilities should be located.

Gas Storage as a Tool for Managing Price Risk

Utilities (both gas utilities and electric utilities that own or buy gas-fired generation) and non-utility generators[30] currently use storage as a tool for mitigating price risk. Storage reduces the cost impacts of high spot market prices by lessening the need for the buyer to purchase on the spot market. This reduced dependency on the spot market also reduces the likelihood of the price spikes themselves.

As storage is costly, its mere availability does not always result in stable natural gas prices. In 2000, for example, high prices in the spring for fall and winter delivery discouraged storage during the summer by non-utility generators. As a result, increased demand for gas by these generators during the following winter led to even higher spot market prices than would otherwise have been the case.

Price volatility in the natural gas market can be influenced by imposing storage requirements, but this is not without cost. First, storage itself is costly, and is only undertaken when current prices are sufficiently below forward prices to justify the expense. Second, requiring storage may result in higher current prices. Mandating threshold storage levels during April – October can ensure that post-summer storage targets are met. This would reduce the likelihood of high prices during the winter heating season. If the demand for gas during the summer is high, however (*e.g.*, due to poor hydroelectric conditions requiring more gas-fired generation), this mandate may lead to substantially higher natural gas prices during the summer, which, in turn, will increase the spot market price for electricity.

Any storage requirement would have to be responsive to market conditions and, arguably, be applied to all buyers. Requiring only buyers for one class of customers to meet minimum storage requirements results in those customers subsidizing the cost of risk reduction for other consumers.

Regulatory Need for Natural Gas Storage Utilization by All Customers

Natural gas storage operations and costs have been partially unbundled in the California gas market. Core customers continue to receive a bundled rate with storage costs rolled in with other rate-based services provided by the utility companies. Non-core customers, on the other

hand, have the liberty to use and pay for storage facilities, if and when they use the facilities. Hence, the policy question that arises is whether the state should implement some regulatory program through which all consumers should be required to maintain some storage. The influence of storage on supply, demand and price needs to be addressed from a seasonal approach as well as from a daily balancing function in mitigating excessive volatility and price spikes.
There is inadequate evidence at this time to suggest mandating storage for non-core customers. Over the next year, the state should investigate if appropriate storage can be used by all customers to ensure reliable and reasonable prices of natural supplies under most market conditions. The investigation should answer these questions:

- Who should use storage capacity, and who is responsible for actions to ensure use of the capacity?
- Does the current market structure allow some customers to “lean on” the storage paid for by others?
- Are there any barriers that prevent proper operation of private and utility owned storage?
- What are the costs and related allocation issues of using utilities’ storage for their end-use customers, and non-utility merchant generators and customers?

Cost Effective Increase in Interstate and Intrastate Pipeline Capacity

Interstate and intrastate transportation pipelines form the critical grid needed to bring gas to end-use customers. The amount of gas used by customers varies between seasons, as well as during each day. Hence the pipeline system has to be adequate to meet this variation in the level of consumption. It is certainly not economical for pipelines alone to meet 100 percent of consumption, 100 percent of the time. There is a minimum need for storage facilities, and a need to use that storage when gas demand is low, so that combined supplies from pipelines and storage facilities are sufficient to meet the customers’ needs when gas demand is high. The Energy Commission continually evaluates the system serving the state and identify the bottlenecks and problem-areas so that supply adequacy will be maintained at all times. Adequate supply can be maintained in a variety of ways without going into the phase of forced curtailments. This includes sufficient pipeline capacity, ability to withdraw from storage, and customer's options to voluntarily not use natural gas under tight supply conditions.

Recent infrastructure expansions in California provide sufficient slack capacity to weather a tight market situation. This is very similar to the conditions that existed during the early 1990s when the Kern River, PG&E-GTN and the Mojave pipelines were constructed. Currently, Southern California has adequate capacity to meet the region’s needs under assumed demand projections over the forecast horizon. Northern California, on the other hand, will require additional capacity by about 2006 to 2007 when projected growth in demand begins to strain the system under seasonal and short-term durations.

The state should assess short-term and peaking conditions to determine the adequacy of the intrastate distribution system. The state should also evaluate the complementary aspects of utility owned distribution systems and private or interstate pipelines serving in-state customers. Further, the state should evaluate the status of the natural gas gathering pipelines to enhance the ability to transport supplies to meet all areas of need even on peak days.

Access to New and Competitive Natural Gas Supplies

Natural gas prices are determined by achieving a balance between supply availability and quantity demanded. In a growing market, with increased demand for natural gas as a premium fuel, it is essential to ensure that there is an adequate amount of supply that can be drawn in and distributed to consumers. To achieve the goal of reasonable and stable prices, the market needs to ensure that there is a portfolio of supplies available to mitigate spiking prices.

California has been depending on three sources for its natural gas supply in addition to local production, namely the San Juan, Rocky Mountain and Canadian basins. Natural gas markets have taken a different turn since 2000, after a decade or so of relatively stable and low prices. Market perspectives now indicate that natural gas production from these regions will be available, but it will cost more than what has been paid in the past. In order to reverse or reduce the price impact, it will be necessary to find new or alternative sources of supply. The state needs to ensure that markets have the choice, ability and assurance of bringing new gas supplies to the marketplace. New sources of supply include:

- Increased exploration, development and production of natural gas inside the state,
- Access to the resources along the U.S. West Coast offshore basins, and
- Import of LNG along the West Coast.

Accessing the global LNG market will provide a significant new source of supply to the state. However, acceptance of LNG as a reliable, safe and environmentally clean fuel source by all stakeholders is important. Building the terminal facility to import LNG requires evaluation of a variety of factors such as environmental issues, safety concerns, socio-economic feasibility and public acceptance. A coordinated approach by State and federal agencies is required to ensure that siting and permitting of LNG facilities is conducted efficiently, including meeting the necessary economics, safety and environmental requirements.

Portfolio Supplies Including Longer-term Natural Gas Contracts

Long-term contracts were conventional during the regulated era. Long-term contracts of as much as 20 years were normal. However, the competitive markets have led to significant changes. Now, long-term contracts refer to time slices of a few years. The majority of supply purchases is now done on a short-term contractual basis, or on the daily spot market. This arrangement was beneficial when a natural gas supply bubble existed and plenty of natural gas was immediately available to meet the needs in the spot markets. The current market is experiencing a new paradigm where supplies are unable to reach the market at a very fast pace. It is more expensive to produce the gas, and it takes longer to get that same quantity of gas to markets than it did in the past years. This has put a tremendous strain on the industry, resulting in either tight markets or spiking prices. The mentality of relying only on short-term supplies takes away the incentive from producers to develop resources that guarantee supplies over a longer period.

A portfolio approach should be taken to ensure reliable supply availability at all times. Utilities and private consumers must evaluate an appropriate level of short and longer-term contracts to ensure a level of supply that does not strain the financial existence of the entity. While the historical 20-year contracts may not be the answer today, a portfolio of supply options should provide a buffer against volatile and spiking price conditions. State agencies and industry participants should evaluate the options available to develop a sustainable portfolio approach that provides reliable supply options to the users while also maintaining the competitive market structure that we have found beneficial in the past.

Increased Conservation and Improved Efficiency

Efficiency improvements have played a significant role in energy production, transportation and consumption. With continuing development and technological advancements, efficiency improvements will continue into the foreseeable future. Conservation measures have been successful in the past, during times of crisis and also during periods of normalacy. It is essential that in order to effectively utilize limited resources, enjoy the benefits accrued through energy use, and ensure a clean environment, conservation and efficiency improvements be made continuously and on each energy front to achieve a balanced use. It is essential to not only promote increased efficiency in natural gas use, but also in electricity use. With increased efficiency in electricity generation and consumption, any reduction in natural gas use will enhance the reliability of gas supplies to other customers.

Back-up Fuel Capability

Back-up fuel capability is needed if the conventionally used fuel is not available at any given time. If natural gas supplies are short or too expensive, some consumers must be able to switch from gas to an alternative source to continue meeting the consumer's energy needs. In most cases, industrial and power generation customers need the ability to switch fuels the most. During peak winter days, for example, increased use of gas by the core customers for space heating could cause a tightness in supplies, leading power generation or industrial customers with a need to switch to an alternative fuel. Fuel switching is most important to ensure reliability during supply shortages, but it could also be used as an economic tool to minimize costs by taking advantage of a cheaper alternative fuel, as long as compliance with all environmental regulations is maintained.

The state should examine alternatives to facing gas supply shortages and spiking prices. Experience from the two crisis periods of winter of 2000 and 2003 demonstrates why an escape route should be provided to customers under harsh price and supply conditions. Use of oil is not an alternative for reasons of air quality. The state should evaluate other alternatives, such as using LNG, propane or other fuels as a back-up option at the end-user facility. Other alternatives include: adding additional storage facilities at regional locations to supplement pipeline supplies with storage supplies, using distributed generation as an option to spiking electricity prices or supply shortages, and increasing use of renewable sources of fuels to complement natural gas supplies.

Electric Transmission Infrastructure and Markets

Transmission system planners currently estimate that it takes five to seven years to complete a major upgrade to the bulk transmission system. Demonstrating need, securing environmental permits and rights-of-way, securing financing (for private projects), and time requirements for construction, require that planners anticipate the need for transmission expansion projects ten years and longer before these projects are in service. In California obstacles to timely transmission development are most commonly related to debates over project benefits and the need for the project, project financing difficulties and local opposition related to environmental and property value impacts. These obstacles arise because:

- Permit processes for the various types of transmission projects are fragmented and overlapping and environmental analyses are inconsistent.

- Total project benefits are not adequately addressed in the permitting process. Economic benefits and costs of projects requiring a Certificate of Public Convenience and Necessity must be viewed by the CPUC in the context of ratepayer benefits only. Therefore, statewide strategic benefits from a project may not be adequately addressed.

- The planning process may address issues important to individual transmission owners and CA ISO, but may overlook issues that are vital to broader interests, such as future right-of-way needs, more efficient use of the existing system, the environmental performance of the system, and the need for long term statewide strategic expansion of the system. As a result, projects with broad economic benefits may face opposition in permitting. They are not considered in the context of broader, long term transmission planning including project alternatives. Investor-owned utility and merchant transmission line developers may propose economic projects for consideration in the CA ISO process. Publicly owned utilities and federal agencies, for the most part, propose, plan, and build transmission projects to meet their own reliability and economic needs. Consequently, coordination among entities needing transmission may not occur and broader benefits of coordination are lost.

- Private investment in transmission, although encouraged by FERC, has been slowed by the financial distress of some developers, as well as regulatory and economic uncertainty.

- Potential adverse effects from system expansion are usually local and concentrated, whereas the benefits are normally diffuse and regional or statewide in nature. It is difficult to balance the larger public interest with legitimate concerns on the part of local citizens and local opposition to some projects.

The June 12, 2003 Joint Energy Commission and League of Women Voters workshop has helped to focus on public opposition as a significant input to the planning and expansion of the transmission system. Public opposition to the construction of new transmission is considered one of the most common and serious impediments to transmission system expansion in California and therefore an important consideration in the transmission system planning process. Because of the length and linear nature of transmission expansion projects, new transmission lines, even those proposed in existing corridors set aside for transmission development can experience serious local opposition. Public opposition is usually related to visual and aesthetic affects, land use conflicts, and potential economic impacts such as reduced property values. In addition, many transmission line projects have generated significant opposition from the public due to concerns about adverse impacts to public health from electromagnetic fields (EMF).

The consensus view emerging from the workshop was that public opposition to transmission expansion is tied to a lack of information and understanding of the transmission planning process, costs and benefits of expansion projects, and whether and to what degree alternatives such as generation, demand-side management (DSM) and alternative routes are considered. To address this problem, workshop participants suggested the need for better forums for public involvement in transmission planning and improved actions to mitigate community impacts from planned projects. Another view was also expressed that it is oftentimes difficult to get the public interested in transmission planning issues, perhaps even with the best educational and information programs.

Actions Underway to Resolve Issues

Over the past decade a number of recommendations have been made by various organizations to address California's obstacles to realizing needed transmission system expansion. Actions have been taken most recently by state government, the CA ISO and others to remove obstacles and ensure that the permitting and planning processes for transmission projects are coordinated and effective in addressing issues related to project benefits and costs. The most noteworthy of these recent actions are briefly discussed below. In addition, eminent domain issues need to be considered in the context of these actions.

Implementing the State *Energy Action Plan*

The 2003 State Energy Action Plan is a collaborative effort among the CPUC, Energy Commission and CPA. One goal of the plan is to ensure that the state will invigorate its planning, permitting and funding processes to ensure necessary expansions to the bulk transmission system are undertaken in a timely manner. In the plan, the state is committed to assure that necessary improvements and expansions to the distribution and bulk electricity grid are made on a timely basis. The above agencies will collaborate in partnership with other state, local and non-governmental agencies with energy responsibilities to ensure that state objectives are evaluated and balanced in determining transmission investments that best meet the needs of California's electricity users.

Developing Common Methods and Long-Term Planning

An effort is underway on the part of the CA ISO and CPUC to develop a common approach to be used in the planning and permitting of transmission projects to determine the value of proposed projects that may be needed to provide economic benefits to the state.

A separate effort is being initiated by the Energy Commission and CA ISO which is intended to ensure that long term planning and strategic project benefits are included in the CA ISO transmission planning process and state IEPR process, and appropriately considered in the state's permitting process for bulk transmission system expansion.

Coordination Among Actions

The above actions represent legislation and agency coordination agreements being implemented by governmental and nongovernmental agencies to ensure that the most crucial energy issues facing California can be addressed in the near term. The Energy Commission believes that the most crucial problem to solve from an electricity transmission perspective is the reinvigorating of the state's transmission planning and permitting processes to assure that necessary expansion to the bulk transmission system can be made on a timely basis. None of the above actions, standing alone, will assure necessary expansions on a timely basis. However, working together, the synergistic effects of these actions can resolve the problem. Whether or not the problem gets adequate resolution will depend in large part on the degree of cooperation realized among the key agencies. For example, it will be essential to the success of the State Energy Action Plan that the Energy Commission, CA ISO and the CPUC recognize each other's responsibilities and collaborate effectively towards solutions to questions of transmission project need and timely permitting of transmission projects.

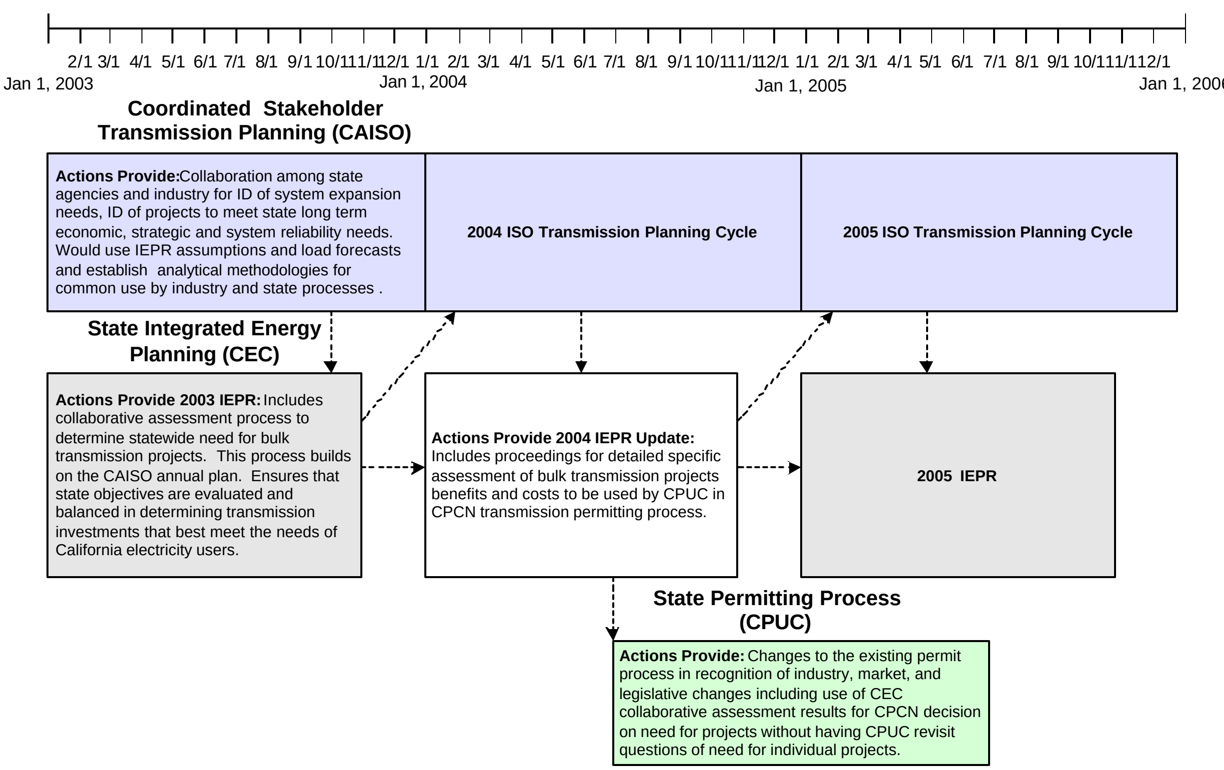
The synergies among the actions for which these agencies are responsible are shown on **Figure 6-1.** As shown, these actions, working together, make it very feasible to take a project originating in the CA ISO coordinated stakeholder transmission planning process, to the state permitting process with the basis for a need determination completed in the IEPR or IEPR Update, within about 18 months. With appropriate changes implemented for the CPUC

CPCN process, that process will not re-visit questions of need for certifying individual projects. The CPCN process will use the IEPR Update need assessment as a basis for its need determination and focus its efforts on the CEQA requirements for permitting. This will represent a major efficiency improvement in the planning and permitting of bulk transmission projects and bring the state much closer to effectively addressing the crucial issue of timely permitting for transmission projects.

Other synergies among the actions result from the CA ISO improving their transmission planning process to include longer-term transmission planning, valuing the strategic benefits of transmission projects, and developing analytical methodologies for common use by industry and state planning and permitting processes. The effects of these actions are to provide a more complete perspective of the value of individual planned transmission projects and reduce regulatory uncertainty.

With respect to public opposition to transmission projects, an additional action is identified by staff that could be pursued as a result of the League of Women Voters efforts. This action could be pursued during the 2004 IEPR Update and may help to give a better basis for considering public opposition to system expansion. First, staff could develop information on existing forums for public awareness and participation in transmission system planning, including right of way planning and local agency processes. Second, staff could identify the most effective and efficient methods to implement public participation in the context of the IEPR process and the Energy Action Plan, and ensure that community impacts associated with transmission expansion are appropriately considered in both the IEPR process and the CA ISO transmission planning process.

Figure 6-1
Synergies of Actions for Overcoming Transmission Issues



Endnotes

[1] *California Statewide Commercial Sector Natural Gas Energy Efficiency Potential Study*, Study ID #Sw039a, Prepared For Pacific Gas & Electric Company San Francisco, California, Prepared By Principal Investigators Fred Coito And Mike Rufo, XENERGY Inc., Oakland, California. *California Statewide Residential Sector Energy Efficiency Potential Study*, Study ID #SW063, Prepared for Pacific Gas & Electric Company. Prepared by Principal Investigator Fred Coito and Mike Rufo, KEMA-XENERGY Inc., Oakland, California, April 2003. *California's Secret Energy Surplus*, Prepared for The Energy Foundation and The Hewlett Foundation, Prepared by Principal Investigators Fred Coito and Mike Rufo, XENERGY Inc., September 23, 2002.

[2] In addition, roughly 6,000 MW of capacity meets "self-generation" needs on a regular, occasional or emergency basis.

[3] http://www.energy.ca.gov/electricity/2003_SUPPLY_DEMAND_PEAK.PDF

[4] In addition to reflecting the cost of real-time purchases, spot market prices serve the following functions:

- Spot market prices establish the real-time benchmark against which capacity is dispatched. If spot market prices are low relative to the cost of generation using a particular physical asset (*e.g.*, a utility-owned power plant) or option thereon (*e.g.*, a dispatchable contract), the owner will purchase spot market energy rather than dispatch the power plant/contract.
- Spot market prices provide a signal of the need for new capacity. High spot market prices relative to production costs indicate that new power plants will be profitable. In the absence of relatively high anticipated spot market prices ("forward prices"), new capacity will not be forthcoming without a long-term contract.
- Spot market prices indicate that generators are exercising market power. If the market is clearing at prices not warranted by production or opportunity costs, this may be a sign that generators are able to sustain prices at non-competitive levels.

[5] See, for example, the *2002 Annual Report on Market Issues and Performance* (CA ISO, April, 2003): "the short-term energy market in California has stabilized and produced fairly competitive results during [2002] (p. E-10)."

[6] Averaged prices are derived by taking the mid-points of the range of prices for each day, then using an (unweighted) average of these points. In those few instances where separate peak and off-peak prices were not available, the single average price derived was assumed to represent both the peak and off-peak price.

[7] Workably competitive is defined by the CA ISO as prices within 10 percent of a purely competitive benchmark.

8 See Frank Wolak, "Lessons from the California Electricity Crisis," CSEM working paper #110, April 2003

9 The amount of capacity necessary will be reduced on a MW-for-MW basis to the extent that new demand-side programs can be used to reduce capacity needs.

10 More detailed information regarding the assumptions underlying each of the cases can be found in **Appendix A** to this report.

11 Staff also developed a scenario in which PGC funding is reduced, resulting in less DSM savings and renewable capacity and energy. The assumptions underlying this scenario and detailed results for all three scenarios can be found in the Technical Appendixes.

12 This information is current as of July 10, 2003.

13 According Andrew Weissman's August 27, 2003 article entitled "Asking the Right Questions About the August 14th Black-Out," even when both units operating, there is less generation and transmission physically located in Northern Ohio relative to the size of the load in that area, as compared to other parts of the country.

14 ftp://www.nerc.com/pub/sys/all_updl/docs/misc/BlackoutTable.pdf

15 Sources: (1) Robert Sparks (CA ISO) electronic transmittal to Don Kondoleon (Energy Commission) on September 3, 2003. (2) "Could it Happen Here?" ***Journal: A Monthly Publication of the Bonneville Power Administration***, September 2003, www.bpa.gov/corporate/kc/home/journal.

16 ***Natural Gas Market Assessment***, California Energy Commission, August 2003, publication 100-03-006.

17 The Wild Goose Storage facility is expanding its facility, with Working Gas Capacity increasing to 29 Bcf, maximum injection capacity to 450 MMcf/d, and maximum withdrawal rate to 700 MMcf/d.

18 Infrastructure needs discussed here relate to a slack capacity of 20 percent. To meet seasonal changes in natural gas demand and to account for adverse weather conditions, the CPUC typically requires the utilities to maintain some excess receiving capacity, normally about 20 percent above the normal average daily demand.

19 Refer to ***Electricity Infrastructure Assessment***, Electricity Analysis Office, California Energy Commission, publication number 100-03-007, August 2003.

20 Source: EIA database "Current and Historic Monthly Sales, Revenues, and Average Revenues per kWh by State and Sector" and Energy Commission QFER database.

[21] Cost examples provided in **Figure 8** are based on the average of spot market transactions at the San Juan Basin to Topock, Arizona on October 4, 2002. The gathering and conditioning charge is based on various publications from the U.S. Department of Energy, Energy Information Administration (EIA). The transportation charge is the price of transporting natural gas from the San Juan Basin to the California border at Topock, Arizona.

[22] 2003 EPR, pages 7 and 8

[23] Analysis of NO_x emissions for this report has focused on the swing facilities, so information on the trends for the baseload facilities is not presented here. The baseload facilities were not undergoing significant retrofit during this period, so their emission rates are unlikely to have changed significantly. Because their electricity generation was also relatively constant, their total emissions are believed to have remained relatively steady during this period. Data collected for the cogeneration and base load units are inconsistent and are not presented here.

[24] For additional information on potential long-term changes in California's water supply, see:http//meteora.ucsd.edu/cap/

[25] *The United States Experience with Economic Incentives for Protecting the Environment*. National Center for Environmental Economics, U.S. Environmental Protection Agency. January 2001. Pages 67-88.

[26] Practicable is defined as available and capable of being done after taking into consideration, cost, existing technology and logistics in light of overall project purpose.

[27] The current resource adequacy can be expressed by a simple formula: Capacity Resources + Transfer Capabilities $\geq$ Peak Demand + Reserve Capacity.

[28] *Joint Working Paper on Resource Adequacy*, prepared by Energy Commission and California Municipal Utilities Association, July 1, 2003, IEPR Docket.

[29] Economic activity is measured as Gross State Product. ***Staff Draft Energy Demand Forecast Report***, California Energy Commission, August 8, 2003, Appendix F, p. F-1.

[30] Gas procurement is undertaken by gas utilities for "core" customers, primarily residential and smaller commercial consumers. Electric generators and other large consumers are "non-core," and are responsible for securing their own gas supplies and any necessary interstate transmission (pipeline) capacity, either directly or through marketers.

APPENDIX A
ELECTRICITY INFRASTRUCTURE ASSUMPTIONS

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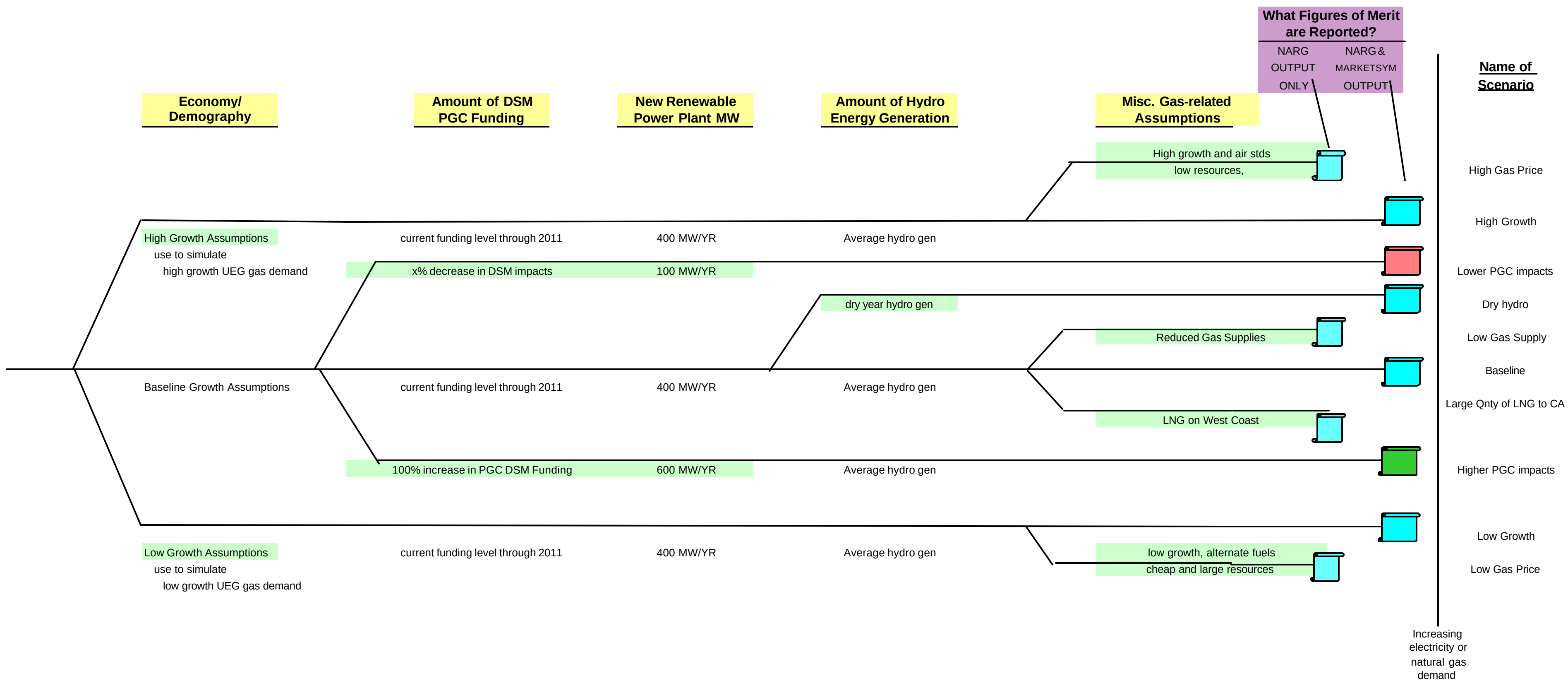
ELECTRICITY INFRASTRUCTURE ASSUMPTIONS

This Appendix summarizes the major assumptions used in the Marketsym simulations for the six scenarios assessed in the ***Electricity and Natural Gas Assessment Report*** and shown in **Figure A-1**. Results from these six simulations were included in the May 27, 2003 ***Staff Report on Electricity Infrastructure*** (100-03-07F) and discussed at the June 10, 2003 Integrated Energy Policy Report Committee Workshop. The assumptions remain unchanged from the staff report. However, parties requested additional information regarding the assumptions in the staff scenario analysis. The additional tables of the assumptions used in the analysis include the following:

- Derates of hydro energy assumed for the Dry Hydro Scenario – **Table A-13**
- High and Low PGC Scenario, including California capacity additions, retirement and modifications from the Baseline Scenario – **Tables A-5** and **A-6**
- The Baseline, High Growth and Low Growth Scenario forecast of peak demand for regions outside California – **Tables A-9, A-10** and **A-11** respectively
- Planning reserve margins for all WECC regions and scenarios for 2004-2013 –**Tables A-15, A-16** and **A-17** respectively. The Dry Hydro Scenario is excluded since this only impacts California energy assumptions

Figure A-1
Electricity and Natural Gas Scenario Infrastructure Study



*2003 retirements only, 2003 generation additions are included in **Table A**

Table A-1
2003 Generation Additions Statewide

Project	Nameplate	Summer Dependable	Online Date	Cumulative
Calpine - Creed Energy Center	45	40	1/1/2003	
Calpine - Lambie Energy Center	45	40	1/1/2003	
Calpine - Goose haven Energy Center	45	40	1/1/2003	
Calpine - Feather River	45	40	1/1/2003	
	January	**160**		**160**
La Paloma 1 & 3	562	539	01/10/03	
Paramount Refinery (Co-gen)	8	8	1/15/2003	
Calpine - Wolfskill Energy Center [formerly Milpitas Peaker]	45	40	1/23/2003	
	February	**587**		**747**
CalWind Resources, Inc., (WIND)	9	0	2/15/2003	
Blythe	520	499	3/1/2003	
	March	**499**		**1,245**
La Paloma 2 & 4	562	539	3/3/2003	
ISG Energy, LLC, Mesquite Lake Resource Recovery Facility (WASTE TIRE)	30	30	4/1/2003	
	April	**569**		**1,814**
Neo Corporation, Colton (LFG)	1	1	4/9/2003	
Neo Corporation, Mid-Valley (LFG)	3	3	4/11/2003	
Calpine- Riverview Peaker	45	40	4/21/2003	
High Desert	830	796	4/22/2003	
Calpine- Los Esteros Critical Energy Facility Units 1-4	180	160	4/30/2003	
Modesto Irrigation District - Woodland 2	80	77	5/1/2003	
	May	**1,076**		**2,891**
Neo Corporation, Milliken (LFG)	3	3	5/30/2003	
El Dorado Irrigation Dist. (SM HYDRO)	21	21	5/31/2003	
GWF - Tracy (Tesla Substation)	169	150	6/1/2003	
Energy Developments, Inc., Keller Canyon (LFG)	4	4	6/1/2003	
Elk Hills	500	480	6/1/2003	

Table A-1
2003 Generation Additions Statewide
(Continued)

Project	Nameplate	Summer Dependable	Online Date	Cumulative
	June	**657**		**3,548**
Anaheim Convention Center	2	2	6/15/2003	
FPL Energy, High Winds, LLC Phase 1 (WIND)	70	0	7/1/2003	
FPL Energy, High Winds, LLC Phase 2 (WIND)	80	0	7/1/2003	
Sunrise Phase 2 [Combined Cycle]	265	265	7/1/2003	
County of Santa Cruz, Dept. of Public Works, Buena Vista Landfill (LFG)	3	3	7/1/2003	
	July	**270**		**3,817**
Mark Tech. Corp./FORAS Energy, Inc., Alta Mesa VII (WIND)	15	0	8/1/2003	
AES- Huntington Beach Unit 4	225	225	8/1/2003	
	August	**225**		**4,042**
Oak Creek Energy Systems, Inc., Jawbone (WIND)	53	0	9/1/2003	
Oak Creek Energy Systems, Inc., Oak Creek 4	28	8	9/1/2003	
Oak Creek Energy Systems, Inc., Deetricity (WIND)	18	0	9/1/2003	
Oak Creek Energy Systems, Inc., Oak Creek 3	5	2	9/1/2003	
	September	**10**		**4,052**
Energy Unlimited, (WIND)	17	0	9/30/2003	
Wintec Energy #2 (WIND)	4	0	9/30/2003	
	October	**0**		**4,052**
Mark Tech. Corp./FORAS Energy, Inc., Alta Mesa IV (WIND)	25	0	10/31/2003	
Keating Associates, (SMALL HYDRO)	1	1	11/1/2003	
So Cal Water- Big Bear	8	8	11/12/2003	
	November	**9**		**4,061**
No projects in December ranked @ 75% Probability	**December**			**4,061**

Table A-2
Baseline Scenario - California Non RPS Generation
Additions and Retirements
2004* – 2013

Generation Additions					Generation Retirements		
Unit	**On Line Date**	**Installed Capacity**	**Dependable Capacity**	**Region**	**Unit**	**Retirement Date**	**Dependable Capacity**
Glenarm GT 3,4	9/1/2003	94	94	SP-15	Morro Bay 1	9/30/2003	171
Valley LADWP CC	10/1/2003	520	520	Los Angeles	Morro Bay 2	9/30/2003	171
LADWP Wind - SP15	7/1/2004	140	0	SP-15	Haynes 4	11/30/2003	222
Haynes Repower	12/1/2004	575	575	Los Angeles			
Walnut CC	12/1/2004	250	250	NP-15	Alamitos GT 7	12/31/2003	147
Pico	1/1/2005	147	147	NP-15	Etiwanda 5	12/31/2003	141
San Fran. Airport	1/1/2005	180	180	San Francisco	Magnolia GT 5	1/1/2004	22
Magnolia CC	3/1/2005	250	250	Los Angeles	Olive 3,4	1/1/2004	56
Cosumnes River	3/15/2005	547	547	Sacto.	Valley LADWP 1-4	4/15/2004	513
Vernon GTs	5/1/2005	135	135	SP-15	Haynes 3	9/30/2004	222
Metcalf	6/1/2005	602	608	NP-15	Magnolia 3,4	9/30/2004	53.5
Kings River Peaker	7/1/2005	45	45	NP-15	Mohave 1,2	12/31/2005	915
Salton Sea #6	7/1/2005	185	170	IID	Hunters Point 4	1/1/2006	163
MID Cogen	12/1/2005	80	80	NP-15	Hunters Point GT1	1/1/2006	56
Otay Mesa	12/31/2005	510	510	Miguel CA	South Bay 1-4	12/31/2008	623
Generic CC 1 & 2	1/1/2009	600	600	SDG&E	**Total Retirements**		**3,476**

Table A-2
Baseline Scenario - California Non RPS Generation
Additions and Retirements
2004* – 2013
(Continued)

Generation Additions					**Generation Retirements**		
Unit	**On Line Date**	**Installed Capacity**	**Dependable Capacity**	**Region**	**Unit**	**Retirement Date**	**Dependable Capacity**
Generic CC 1	4/1/2009	250	250	San Francisco			
Generic GT 1	4/1/2009	150	150	IID			
Generic GT 1	4/1/2009	150	150	SP15			
Generic GT 1	4/1/2010	150	150	NP15			
Generic GT 1	4/1/2011	150	150	NP15			
Generic GT 1	4/1/2012	150	150	NP15			
Generic GT 1	4/1/2012	150	150	SP15			
Generic CC 1	4/1/2013	250	250	SP15			
Generic GT 1	4/1/2013	150	150	SP15			
Total Additions		**6,410**	**6,261**				
Does not include RPS renewables							

*2003 retirements only, 2003 generation additions are included in table titled "2003 Generation Additions Statewide"

Table A-3
Renewable Portfolio Standard

New RPS Capacity Additions (Cumulative Installed MW) Baseline Scenario 2004 - 2013				
Year	**Biofuels**	**Geothermal**	**Wind**	**Total**
2004	50	0	342	392
2005	66	0	549	615
2006	129	115	762	1006
2007	180	252	973	1405
2008	266	366	1184	1816
2009	334	503	1394	2231
2010	419	616	1615	2650
2011	504	707	1825	3036
2012	572	775	2047	3394
2013	645	843	2263	3751
Geographic Composition	NP15 - 312 MW SP15 - 294 MW SD - 40 MW	IID - 743 MW NP15 - 100 MW	SP15 - 1454 MW NP15 - 808 MW	

Note: Dependable capacity equals installed capacity except for wind. Dependable wind capacity is assumed to be zero.

Table A-4
Southwest/Mexico Region
Baseline Scenario – WECC Region Outside California
2004 - 2013

Generation Additions					
Unit Name	**Number of Units**	**On Line Date**	**Fuel Type**	**Installed Capacity**	**Region**
Pyramid Power Plant	4	01-Oct-03	Natural Gas	152	Southwest/Mexico
Reliant Bighorn	2	01-Oct-03	Natural Gas	870	Southwest/Mexico
Harquahala Project	3	01-Nov-03	Natural Gas	1059	Southwest/Mexico
Mesquite CC	2	01-Jan-04	Natural Gas	625	Southwest/Mexico
Generic CC	1	01-Jun-05	Natural Gas	300	Southwest/Mexico
Santan CC New	3	01-Jun-05	Natural Gas	699	Southwest/Mexico
Generic GT	1	01-Apr-08	Natural Gas	150	Southwest/Mexico
Generic GT	1	01-Apr-09	Natural Gas	150	Southwest/Mexico
Generic GT	2	01-Apr-10	Natural Gas	300	Southwest/Mexico
Generic CC	1	01-Apr-11	Natural Gas	250	Southwest/Mexico
Generic GT	2	01-Apr-11	Natural Gas	300	Southwest/Mexico
Generic CC	2	01-Apr-12	Natural Gas	500	Southwest/Mexico
Generic GT	3	01-Apr-12	Natural Gas	450	Southwest/Mexico
Generic CC	1	01-Apr-13	Natural Gas	250	Southwest/Mexico
Generic GT	4	01-Apr-13	Natural Gas	600	Southwest/Mexico
Generic CC	2	01-Apr-13	Natural Gas	530	Southwest/Mexico
Generation Retirements					
Unit Name	**Unit Number**	**Retirement Date**	**Capacity**	**Fuel Type**	**Region**
Mohave (Southwest Portion)	1-2	31-Dec-05	492	Coal	Southwest/Mexico
Clark ST	3	31-Dec-11	70	Natural Gas	Southwest/Mexico

Table A-4a
Northwest Canada Region
Baseline Scenario

Generation Additions						
Unit Name	**Number of Units**	**On Line Date**	**Fuel Type**	**Installed Capacity**	**Dependable Capacity (Wind)**	**Region**
Goldendale	1	01-Jul-03	Natural Gas	253		NW/Canada
SP Newsprint	1	01-Jul-03	Natural Gas	35		NW/Canada
Edmonton Cogen	1	01-Sep-03	Natural Gas	30		NW/Canada
McBride	1	01-Sep-03	WT	75	18	NW/Canada
Labarge Shute Cogen	1	01-Oct-03	Natural Gas	12		NW/Canada
Pincher Creek	1	01-Oct-03	WT	108	28	NW/Canada
Bonanza Upgrade	1	01-Jan-04	Natural Gas	80		NW/Canada
MacKay River Cogen	1	01-Jan-04	Natural Gas	95		NW/Canada
Payson	1	01-Jun-04	Natural Gas	140		NW/Canada
Genesee	2	01-Dec-04	Natural Gas	450		NW/Canada
Generic GT	1	01-Apr-07	Natural Gas	150		NW/Canada
Generic CC	2	01-Apr-08	Natural Gas	500		NW/Canada
Generic GT	1	01-Apr-08	Natural Gas	150		NW/Canada
Generic GT	2	01-May-08	Natural Gas	300		NW/Canada
Generic GT	1	01-Jan-09	Natural Gas	175		NW/Canada
Generic CC	1	01-Jan-09	Natural Gas	295		NW/Canada
Generic CC	2	01-Apr-09	Natural Gas	500		NW/Canada
Generic GT	1	01-Apr-09	Natural Gas	150		NW/Canada
Generic CC	1	01-Jan-10	Natural Gas	295		NW/Canada
Generic CC	1	01-Apr-10	Natural Gas	300		NW/Canada
GenGT_NW	4	01-Apr-10	Natural Gas	150		NW/Canada
Generic New Coal	1	01-May-10	Coal	830		NW/Canada
Generic GT	3	01-May-10	Natural Gas	450		NW/Canada
Generic GT	1	01-Jan-11	Natural Gas	175		NW/Canada
Generic CC	1	01-Jan-11	Natural Gas	295		NW/Canada
Generic CC	2	01-Apr-11	Natural Gas	500		NW/Canada
Generic GT	4	01-Apr-11	Natural Gas	600		NW/Canada
Generic CC	2	01-Apr-12	Natural Gas	500		NW/Canada
Generic GT	3	01-Apr-12	Natural Gas	450		NW/Canada
Generic GT	1	01-May-12	Natural Gas	150		NW/Canada
Generic GT	1	01-Jan-13	Natural Gas	175		NW/Canada
Generic CC	1	01-Jan-13	Natural Gas	295		NW/Canada
Generic CC	4	01-Apr-13	Natural Gas	1000		NW/Canada
Generic GT	2	01-Apr-13	Natural Gas	150		NW/Canada

Table A-4a
Northwest Canada Region
Baseline Scenario
(continued)

Generation Retirements						
Unit Name	**Unit Number**	**Retirement Date**		**Capacity**	**Fuel Type**	**Region**
Wabamun	1	01-Jan-04		67	Coal	NW/Canada
Wabamun	2	01-Jan-04		67	Coal	NW/Canada
Chelan DGs	1	01-Apr-04		34	FO#2	NW/Canada
Tacoma Tideflats	1	01-Apr-04		58	FO#2	NW/Canada
Boston Bar Diesel	1	01-Apr-06		2	FO#2	NW/Canada
Wabamun	4	01-Jan-10		280	Coal	NW/Canada
Rossdale	8	01-Oct-10		71	Natural gas	NW/Canada
Rossdale	9	01-Oct-10		73	Natural gas	NW/Canada
Rossdale	10	01-Oct-10		72	Natural gas	NW/Canada

Table A-4b
Rocky Mountain Region
Baseline Scenario

Generation Additions					
Unit Name	**Number of Units**	**On Line Date**	**Fuel Type**	**Installed Capacity**	**Region**
Thompson River	1	01-Dec-03	Natural Gas	10	Rocky Mountain
Rocky Mountain EC	1a	01-May-04	Natural Gas	300.5	Rocky Mountain
Rocky Mountain EC	1b	01-May-04	Natural Gas	300.5	Rocky Mountain
Generic GT	1	01-Apr-11	Natural Gas	150	Rocky Mountain
Generic GT	1	01-Apr-12	Natural Gas	150	Rocky Mountain
Generic GT	1	01-Apr-13	Natural Gas	150	Rocky Mountain
Generation Retirements					
Unit Name	**Unit Number**	**Retirement Date**	**Capacity**	**Fuel Type**	**Region**
J E Correte	1	01-Jan-13	160	Coal	Rocky Mountain

Table A-5
California High PGC Scenario
Non RPS Generation Modifications from Baseline

Generation Retirements and Accelerated Retirements					
Unit Name	**Unit Number**	**Retirement Date**	**Capacity**	**Fuel Type**	**Region**
South Bay	4	31-Dec-03	150	Natural Gas	SDG&E was 12/31/2008
Glenarm GT	1	01-Jan-04	25	Natural Gas	SP15
Mobile GT	1	31-Dec-04	15	FO-#2	NP15
Glenarm GT	2	01-Jan-05	26	Natural Gas	SP15
Brawley GT	1	31-Dec-05	9	FO-#2	IID
Mobile GT	2	31-Dec-05	15	FO-#2	NP15
Brawley GT	2	31-Dec-06	9	FO-#2	IID
Mandalay	3	31-Dec-06	132	FO-#2	SP15
Mobile GT	3	31-Dec-06	15	FO-#2	NP15
Newhall	1	31-Dec-06	19.1	FO-#2	SP15
Newhall	2	31-Dec-06	19.8	FO-#2	SP15
Coachella GT	1	31-Dec-07	20	FO-#2	IID
Coachella GT	2	31-Dec-07	20	FO-#2	IID
Coolwater CC	3	31-Dec-07	241	Natural Gas	SP15
Oakland GT	1	31-Dec-07	58	FO-#2	NP15
Oakland GT	2	31-Dec-08	51	FO-#2	NP15
Coachella GT	3	31-Dec-09	20	FO-#2	IID
Coachella GT	4	31-Dec-09	20	FO-#2	IID
Coolwater CC	4	31-Dec-09	241	Natural Gas	SP15
Oakland GT	3	31-Dec-09	49	FO-#2	NP15
Morro Bay	3	30-Sep-10	343	Natural Gas	ZP26
Potrero GT	4	31-Dec-10	54	FO-#2	CSF
Rockwood GT	1	31-Dec-10	25	FO-#2	IID
Potrero GT	5	31-Dec-11	55	FO-#2	CSF
Rockwood GT	2	31-Dec-11	25	FO-#2	IID
Potrero GT	6	31-Dec-12	53	FO-#2	CSF
Yucca GT	4	31-Dec-12	47	FO-#2	IID
Generation Additions - Cancelled					
Unit Name	**Number of Units**	**On Line Date**	**Installed Capacity**	**Fuel Type**	**Region**
MID Cogen	1	01-Dec-05	80	Natural Gas	NP15
Generic CC	1	01-Apr-09	250	Natural Gas	City of San Francisco
Generic GT	1	01-Apr-09	150	Natural Gas	SP15
Generic GT	1	01-Apr-11	150	Natural Gas	NP15
Generic CC	1	01-Apr-13	250	Natural Gas	SP15
Generation Additions					
Unit Name	**Number of Units**	**On Line Date**	**Installed Capacity**	**Fuel Type**	**Region**
Generic GT	1	01-Apr-09	150	Natural Gas	City of San Francisco

Table A-6
Renewable Portfolio Standard

New RPS Capacity Additions (Cumulative Installed MW) High PGC Scenario				
Year	**Biofuels**	**Geothermal**	**Wind**	**Total**
2004	75	0	513	588
2005	99	0	823.5	922.5
2006	193.5	172.5	1143	1509
2007	270	378	1459.5	2107.5
2008	399	549	1776	2724
2009	501	754.5	2091	3346.5
2010	628.5	924	2422.5	3975
2011	756	1060.5	2737.5	4554
2012	858	1162.5	3070.5	5091
2013	967.5	1264.5	3394.5	5626.5
Geographic Composition	NP15 - 312 MW SP15 - 294 MW SD - 40 MW	IID - 743 MW NP15 - 100 MW	SP15 - 1454 MW NP15 - 808 MW	

Note: Dependable capacity equals installed capacity except for wind. Dependable wind capacity is assumed to be zero.

Table A-7
Low PGC Scenario
California Non RPS Generation
Modifications from Baseline

Generation Additions					
Unit Name	**Number of Units**	**On Line Date**	**Fuel Type**	**Installed Capacity MW**	**Region**
Generic GT	1	01-Jan-08	Natural Gas	150	SMUD
Generic CC	2	01-Apr-09	Natural Gas	550	ZP26
Generic GT	1	01-Apr-09	Natural Gas	150	SDG&E
Generic GT	1	01-Jan-10	Natural Gas	150	City Of San Francisco
Generic GT	1	01-Apr-10	Natural Gas	150	SP15
Generic CC	1	01-Jan-11	Natural Gas	287	NP15
Generic GT	1	01-Apr-11	Natural Gas	150	IID
Generation Retirements					
Unit Name	**Unit Number**	**Retirement Date**	**Capacity**	**Fuel Type**	**Region**
None					

Table A-8
Renewable Portfolio Standard

New RPS Capacity Additions (Cumulative Installed MW) Low PGC Scenario				
Year	Biofuels	Geothermal	Wind	Total
2004	12.5	0	85.5	98
2005	16.5	0	137.25	153.75
2006	32.25	28.75	190.5	251.5
2007	45	63	243.25	351.25
2008	66.5	91.5	296	454
2009	83.5	125.75	348.5	557.75
2010	104.75	154	403.75	662.5
2011	126	176.75	456.25	759
2012	143	193.75	511.75	848.5
2013	161.25	210.75	565.75	937.75
Geographic Composition	NP15 - 312 MW SP15 - 294 MW SD - 40 MW	IID - 743 MW NP15 - 100 MW	SP15 - 1454 MW NP15 - 808 MW	

Note: Dependable capacity equals installed capacity except for wind. Dependable wind capacity is assumed to be zero.

Table A-9
Baseline Scenario Peak Demand
Regional Annual Peak Coincident with California Peak
(MW)

Year	California Coincident Peak	Southwest/ Mexico Coincident Peak	Rocky Mountain Coincident Peak	Northwest/ Canada Coincident Peak	WECC Peak Forecast Coincident With California
2004	53,331	24,986	10,391	46,840	135548
2005	54,500	25,926	10,698	48,233	139358
2006	55,487	26,832	10,963	49,009	142291
2007	56,195	27,801	11,202	49,906	145104
2008	57,090	28,714	11,429	50,752	147985
2009	57,757	29,648	11,677	51,562	150643
2010	58,491	30,585	11,913	52,497	153486
2011	59,217	31,559	12,150	53,411	156337
2012	59,975	32,554	12,395	54,289	159213
2013	60,562	33,587	12,631	55,337	162118

Table A-10
High Growth Scenario Peak Demand
Regional Annual Peak Coincident with California Peak
(MW)

Year	California Coincident Peak	Southwest/ Mexico Coincident Peak	Rocky Mountain Coincident Peak	Northwest/ Canada Coincident Peak	WECC Peak Forecast Coincident With California
2004	53,857	25,300	10,698	48,233	138,088
2005	55,420	26,188	10,963	49,009	141,580
2006	56,829	27,139	11,202	49,906	145,076
2007	57,943	28,113	11,429	50,752	148,237
2008	58,710	29,036	11,677	51,562	150,984
2009	59,316	29,949	11,913	52,497	153,675
2010	59,989	30,897	12,150	53,411	156,447
2011	60,654	31,898	12,395	54,289	159,236
2012	61,424	32,903	12,631	55,337	162,295
2013	62,043	33,946	12,853	56,271	165,114

Table A-11
Low Growth Scenario Peak Demand
Regional Annual Peak Coincident with California Peak
(MW)

Year	California Coincident Peak	Southwest /Mexico Coincident Peak	Rocky Mountain Coincident Peak	Northwest/ Canada Coincident Peak	WECC Peak Forecast Coincident With California
2004	53,021	24,666	10,270	46,693	134,650
2005	53,806	25,425	10,466	47,965	137,662
2006	54,390	26,188	10,645	48,921	140,144
2007	54,710	26,994	10,836	48,470	141,010
2008	55,396	27,913	11,086	49,259	143,653
2009	56,028	28,845	11,315	50,106	146,294
2010	56,755	29,777	11,563	50,936	149,031
2011	57,483	30,751	11,793	51,750	151,778
2012	58,231	31,714	12,027	52,720	154,691
2013	58,879	32,703	12,269	53,599	157,450

Table A-12
High and Low Public Goods Charge Scenarios
California DSM Impacts 2004 - 2013
(MW)

Year	High PGC Scenario DSM Reductions to Baseline Scenario	Low PGC Scenario DSM Additions to Baseline Scenario
2004	1	73
2005	149	156
2006	424	242
2007	729	325
2008	1,007	405
2009	1,235	482
2010	1,429	553
2011	1,586	622
2012	1,726	686
2013	1,843	747

Table A-13
Dry Hydro Scenario – Percent of Normal Hydro Generation Impacts by WECC Hydro Basin

Name	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Alberta Canada	82%	82%	82%	82%	82%	82%	82%	82%	82%	86%	90%	94%
Arizona State	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
British Columbia	82%	82%	82%	82%	82%	82%	82%	82%	82%	86%	90%	94%
Northern California	54%	54%	54%	54%	54%	54%	54%	54%	54%	60%	66%	71%
Colorado State	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Idaho State	82%	82%	82%	82%	82%	82%	82%	82%	82%	86%	90%	94%
Montana State	82%	82%	82%	82%	82%	82%	82%	82%	82%	86%	90%	94%
New Mexico State	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Nevada State	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Oregon State	82%	82%	82%	82%	82%	82%	82%	82%	82%	86%	90%	94%
Utah State	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Washington State	82%	82%	82%	82%	82%	82%	82%	82%	82%	86%	90%	94%
Wyoming State	82%	82%	82%	82%	82%	82%	82%	82%	82%	86%	90%	94%
Southern California	54%	54%	54%	54%	54%	54%	54%	54%	54%	60%	66%	71%
Kings River	54%	54%	54%	54%	54%	54%	54%	54%	54%	60%	66%	71%
Kern River	54%	54%	54%	54%	54%	54%	54%	54%	54%	60%	66%	71%
Owens R - Mono L	54%	54%	54%	54%	54%	54%	54%	54%	54%	60%	66%	71%

Table A-13
Dry Hydro Scenario – Percent of Normal Hydro Generation Impacts by WECC Hydro Basin
(continued)

Name	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Stanislaus River	54%	54%	54%	54%	54%	54%	54%	54%	54%	60%	66%	71%
Bear River	82%	82%	82%	82%	82%	82%	82%	82%	82%	86%	90%	94%
Lower Colorado R	82%	82%	82%	82%	82%	82%	82%	82%	82%	86%	90%	94%
Cow & Battle Cr	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Kaweah River	54%	54%	54%	54%	54%	54%	54%	54%	54%	60%	66%	71%
Tuolumne River	54%	54%	54%	54%	54%	54%	54%	54%	54%	60%	66%	71%
American River	82%	82%	82%	82%	82%	82%	82%	82%	82%	86%	90%	94%
Trinity River	54%	54%	54%	54%	54%	54%	54%	54%	54%	60%	66%	71%
Putah Creek	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Yuba River	54%	54%	54%	54%	54%	54%	54%	54%	54%	60%	66%	71%
Upper Sacramento	54%	54%	54%	54%	54%	54%	54%	54%	54%	60%	66%	71%
Mokelumne River	54%	54%	54%	54%	54%	54%	54%	54%	54%	60%	66%	71%
Truckee River	54%	54%	54%	54%	54%	54%	54%	54%	54%	60%	66%	71%
Merced River	54%	54%	54%	54%	54%	54%	54%	54%	54%	60%	66%	71%
Feather River	54%	54%	54%	54%	54%	54%	54%	54%	54%	60%	66%	71%
Butte Creek	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Upper San Joaqui	54%	54%	54%	54%	54%	54%	54%	54%	54%	60%	66%	71%
Eel R & Russian	54%	54%	54%	54%	54%	54%	54%	54%	54%	60%	66%	71%
Tule River	54%	54%	54%	54%	54%	54%	54%	54%	54%	60%	66%	71%
Klamath River	82%	82%	82%	82%	82%	82%	82%	82%	82%	86%	90%	94%

Table A-14
Baseline Scenario Planning Reserve Margins by WECC Region 2004-2013 MWs - August Dependable

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
California Control Area Baseline Planning Reserve Margins										
Total Statewide Coincident Demand	53,331	54,500	55,487	56,195	57,090	57,757	58,491	59,217	59,975	60,562
All Available Resources (excluding Interruptibles and no hydro derate)	65,003	67,484	67,222	67,070	67,170	67,223	68,350	68,918	69,374	69,993
Reserves	11,672	12,984	11,735	10,875	10,080	9,466	9,859	9,702	9,398	9,432
Reserve Margin	21.9%	23.8%	21.1%	19.4%	17.7%	16.4%	16.9%	16.4%	15.7%	15.6%
Southwest/Mexico Control Area Baseline Planning Reserve Margins										
Regional Coincident Demand	24,986	25,926	26,832	27,801	28,714	29,648	30,585	31,559	32,554	33,587
All Available Resources (excluding Interruptibles)	33,845	34,776	34,205	34,355	34,505	34,688	34,988	35,520	36,368	37,515
Reserves	8,859	8,849	7,373	6,554	5,791	5,040	4,403	3,961	3,814	3,927
Reserve Margin	35.5%	34.1%	27.5%	23.6%	20.2%	17.0%	14.4%	12.6%	11.7%	11.7%
Rocky Mountain Control Area Baseline Planning Reserve Margins										
Regional Coincident Demand	10,391	10,698	10,963	11,202	11,429	11,677	11,913	12,150	12,395	12,631
All Available Resources (excluding Interruptibles)	13,474	13,474	13,474	13,474	13,474	13,474	13,474	13,624	13,774	13,924
Reserves	3,082	2,776	2,510	2,272	2,045	1,797	1,561	1,474	1,379	1,292
Reserve Margin	29.7%	26.0%	22.9%	20.3%	17.9%	15.4%	13.1%	12.1%	11.1%	10.2%
NW-Canada Control Area Baseline Planning Reserve Margins										
Regional Coincident Demand	46,840	48,233	49,009	49,906	50,752	51,562	52,497	53,411	54,289	55,337
All Available Resources (excluding Interruptibles)	74,156	74,753	74,737	75,017	75,971	77,532	78,496	79,490	80,555	82,125
Reserves	27,315	26,519	25,728	25,112	25,218	25,970	25,999	26,079	26,267	26,788
Reserve Margin	58.3%	55.0%	52.5%	50.3%	49.7%	50.4%	49.5%	48.8%	48.4%	48.4%

Table A-15
High Growth Scenario Planning Reserve Margins by WECC Region 2004-2013 MWs - August Dependable

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
California Control Area High Growth Planning Reserve Margins										
Total Statewide Coincident Demand	53,857	55,420	56,829	57,943	58,710	59,316	59,989	60,654	61,424	62,043
All Available Resources (excluding Interruptibles)	65,003	67,484	67,222	67,070	67,170	67,223	68,350	68,918	69,374	69,993
Reserves	11,146	12,064	10,393	9,127	8,461	7,907	8,361	8,264	7,950	7,950
Reserve Margin	20.7%	21.8%	18.3%	15.8%	14.4%	13.3%	13.9%	13.6%	12.9%	12.8%
Southwest/Mexico Control Area High Growth Planning Reserve Margins										
Regional Coincident Demand	25,300	26,188	27,139	28,113	29,036	29,949	30,897	31,898	32,903	33,946
All Available Resources (excluding Interruptibles)	33,845	34,776	34,205	34,355	34,505	34,688	34,988	35,520	36,368	37,515
Reserves	8,545	8,588	7,066	6,242	5,469	4,739	4,091	3,622	3,465	3,568
Reserve Margin	33.8%	32.8%	26.0%	22.2%	18.8%	15.8%	13.2%	11.4%	10.5%	10.5%
Rocky Mountain Control Area High Growth Planning Reserve Margins										
Regional Coincident Demand	10,698	10,963	11,202	11,429	11,677	11,913	12,150	12,395	12,631	12,853
All Available Resources (excluding Interruptibles)	13,474	13,474	13,474	13,474	13,474	13,474	13,474	13,624	13,774	13,924
Reserves	2,776	2,510	2,272	2,045	1,797	1,561	1,324	1,229	1,142	1,071
Reserve Margin	26.0%	22.9%	20.3%	17.9%	15.4%	13.1%	10.9%	9.9%	9.0%	8.3%
NW-Canada Control Area High Growth Planning Reserve Margins										
Regional Coincident Demand	48,233	49,009	49,906	50,752	51,562	52,497	53,411	54,289	55,337	56,271
Resources With Transactions	74,156	74,753	74,737	75,017	75,971	77,532	78,496	79,490	80,555	82,125
Reserves	25,922	25,744	24,831	24,265	24,409	25,035	25,085	25,202	25,218	25,855
Reserve Margin	53.7%	52.5%	49.8%	47.8%	47.3%	47.7%	47.0%	46.4%	45.6%	45.9%

Table A-16
Low Growth Scenario Planning Reserve Margins by WECC Region 2004-2013 MWs - August Dependable

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
California Control Area Low Growth Planning Reserve Margins										
Total Statewide Coincident Demand	53,021	53,806	54,390	54,710	55,396	56,028	56,755	57,483	58,231	58,879
All Available Resources (excluding Interruptibles)	65,003	67,484	67,222	67,070	67,170	67,223	68,350	68,918	69,374	69,993
Reserves	11,982	13,679	12,832	12,360	11,775	11,195	11,595	11,435	11,143	11,114
Reserve Margin	22.6%	25.4%	23.6%	22.6%	21.3%	20.0%	20.4%	19.9%	19.1%	18.9%
Southwest/Mexico Control Area Low Growth Planning Reserve Margins										
Regional Coincident Demand	24,666	25,425	26,188	26,994	27,913	28,845	29,777	30,751	31,714	32,703
All Available Resources (excluding Interruptibles)	33,845	34,776	34,205	34,355	34,505	34,688	34,988	35,520	36,368	37,515
Reserves	9,179	9,350	8,017	7,361	6,592	5,842	5,211	4,769	4,654	4,812
Reserve Margin	37.2%	36.8%	30.6%	27.3%	23.6%	20.3%	17.5%	15.5%	14.7%	14.7%
Rocky Mountain Control Area Low Growth Planning Reserve Margins										
Regional Coincident Demand	10,270	10,466	10,645	10,836	11,086	11,315	11,563	11,793	12,027	12,269
All Available Resources (excluding Interruptibles)	13,474	13,474	13,474	13,474	13,474	13,474	13,474	13,624	13,774	13,924
Reserves	3,204	3,008	2,828	2,637	2,388	2,159	1,910	1,831	1,747	1,655
Reserve Margin	31.2%	28.7%	26.6%	24.3%	21.5%	19.1%	16.5%	15.5%	14.5%	13.5%
NW-Canada Control Area Low Growth Planning Reserve Margins										
Regional Coincident Demand	46,693	47,965	48,921	48,470	49,259	50,106	50,936	51,750	52,720	53,599
Resources With Transactions	74,156	74,753	74,737	75,017	75,971	77,532	78,496	79,490	80,555	82,125
Reserves	27,462	26,787	25,816	26,548	26,712	27,426	27,561	27,740	27,836	28,527
Reserve Margin	58.8%	55.8%	52.8%	54.8%	54.2%	54.7%	54.1%	53.6%	52.8%	53.2%

Table A-17
High PGC Scenario Planning Reserve Margins by WECC Region 2004 -2013 MWs - August Dependable

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
California Control Area High PGC Planning Reserve Margins										
Total Statewide Coincident Demand	53,331	54,500	55,487	56,195	57,090	57,757	58,491	59,217	59,975	60,562
High PGC Scenario - DSM Reductions to Baseline Scenario	1	149	424	729	1,007	1,235	1,429	1,586	1,726	1,843
DSM Adjusted Coincident Peak	53,330	54,351	55,064	55,466	56,083	56,522	57,062	57,631	58,249	58,718
All Available Resources (excluding Interruptibles and no hydro derate)	64544	67151	67158	67215	67362	67767	68892	69292	69885	70649
Reserves	11,214	12,800	12,095	11,749	11,279	11,245	11,830	11,661	11,636	11,931
Reserve Margin	21.0%	23.6%	22.0%	21.2%	20.1%	19.9%	20.7%	20.2%	20.0%	20.3%

Table A-18
Low PGC Scenario Planning Reserve Margins by WECC Region 2004 -2013 MWs - August Dependable

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
California Control Area Low PGC Planning Reserve Margins										
Total Statewide Coincident Demand	53,331	54,500	55,487	56,195	57,090	57,757	58,491	59,217	59,975	60,562
Low PGC Scenario - DSM Additions to Baseline Scenario	73	156	242	325	405	482	553	622	686	747
DSM Adjusted Coincident Peak	53,404	54,656	55,729	56,520	57,495	58,239	59,045	59,838	60,661	61,309
All Available Resources (excluding Interruptibles and no hydro derate)	64,600	67,054	66,651	66,351	66,445	67,038	68,255	69,115	69,453	69,953
Reserves	11,196	12,397	10,922	9,830	8,949	8,799	9,210	9,276	8,792	8,644
Reserve Margin	21.0%	22.7%	19.6%	17.4%	15.6%	15.1%	15.6%	15.5%	14.5%	14.1%

Table A-19a
Natural Gas Prices
Monthly Factors to Convert Annual Prices to Monthly Prices

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
PG&E	1.06	1.06	0.99	0.97	0.99	0.96	0.96	0.96	0.96	0.96	1.05	1.09
SoCal Gas	1.10	1.07	1.03	0.97	0.95	0.94	0.92	0.94	0.98	1.00	1.08	1.17
SDG&E	1.09	1.04	0.96	0.94	1.00	0.97	0.92	0.97	0.98	0.98	1.09	1.22
So. Calif Prod.	1.10	1.07	1.03	0.97	0.95	0.94	0.92	0.94	0.98	1.00	1.08	1.17
TEOR	1.10	1.07	1.03	0.97	0.95	0.94	0.92	0.94	0.98	1.00	1.08	1.17
Coolwater	1.08	1.05	1.02	0.97	0.96	0.94	0.93	0.94	0.97	0.99	1.08	1.19
Alberta	1.08	1.04	1.00	1.00	0.99	0.93	0.94	0.87	0.91	1.00	1.04	1.08
British Columbia	1.23	1.06	0.88	0.93	0.87	0.83	0.82	0.83	0.87	1.00	1.21	1.22
Colorado	1.08	0.90	0.84	0.86	0.94	1.03	1.02	0.99	0.93	1.04	1.08	1.13
El Paso North-Az	0.98	0.98	0.90	1.02	1.02	1.02	0.92	0.94	1.06	1.00	1.13	1.03
El Paso North-NM	1.12	0.98	0.93	0.94	0.96	0.94	0.97	1.00	0.99	1.03	1.09	1.12
El Paso South-Az	0.98	0.98	0.90	1.02	1.02	1.02	0.92	0.94	1.06	1.00	1.13	1.03
El Paso South-NM	1.12	0.98	0.93	0.94	0.96	0.94	0.97	1.00	0.99	1.03	1.09	1.12
Kern River	1.10	1.07	1.03	0.97	0.95	0.94	0.92	0.94	0.98	1.00	1.08	1.17
Mojave	1.10	1.07	1.03	0.97	0.95	0.94	0.92	0.94	0.98	1.00	1.08	1.17
Montana	1.08	0.90	0.84	0.86	0.94	1.03	1.02	0.99	0.93	1.04	1.08	1.13
Nevada-North	0.99	1.00	0.92	1.02	0.97	1.01	0.93	0.97	1.02	1.08	1.13	1.03
Nevada-South	0.99	1.00	0.92	1.02	0.97	1.01	0.93	0.97	1.02	1.08	1.13	1.03
PGT-Kingsgate	0.98	0.95	0.99	0.92	0.99	1.06	0.97	0.94	0.92	0.99	1.09	1.16
PGT-Malin	0.98	0.95	0.99	0.92	0.99	1.06	0.97	0.94	0.92	0.99	1.09	1.16
PGT-Stansfield	0.98	0.95	0.99	0.92	0.99	1.06	0.97	0.94	0.92	0.99	1.09	1.16
PNW	0.68	0.83	1.00	1.27	1.35	0.76	1.01	1.00	1.11	0.90	0.96	1.09
PNW-Coastal	0.68	0.83	1.00	1.27	1.35	0.76	1.01	1.00	1.11	0.90	0.96	1.09
Utah	1.08	1.09	1.08	1.05	1.00	0.98	0.95	0.82	0.88	0.98	1.08	1.25
Rosarito	1.09	1.04	0.96	0.94	1.00	0.97	0.92	0.97	0.98	0.98	1.09	1.22
Otay Mesa	1.09	1.04	0.96	0.94	1.00	0.97	0.92	0.97	0.98	0.98	1.09	1.22

Table A-19b
Natural Gas Prices for Electricity Generation
Nominal $/mmBtu

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
PG&E	4.55	4.18	4.29	4.52	4.65	4.83	5.00	5.20	5.41	5.62
SoCal Gas	4.68	4.19	4.25	4.52	4.71	4.94	5.14	5.35	5.54	5.76
SDG&E	4.68	4.19	4.25	4.52	4.71	4.94	5.14	5.35	5.54	5.76
So. Calif Prod.	4.46	4.12	4.20	4.43	4.62	4.81	5.01	5.22	5.44	5.69
TEOR	4.65	4.12	4.12	4.29	4.48	4.67	4.87	5.08	5.30	5.52
Coolwater	4.65	4.11	4.12	4.29	4.48	4.67	4.87	5.08	5.30	5.51
Alberta	3.93	3.50	3.59	3.74	3.88	4.03	4.18	4.34	4.51	4.70
British Columbia	4.17	3.78	3.94	4.12	4.29	4.46	4.64	4.82	5.02	5.22
Colorado	4.48	3.93	4.02	4.17	4.31	4.46	4.61	4.76	4.93	5.11
El Paso North-Az	4.41	3.91	4.00	4.21	4.39	4.56	4.75	4.93	5.14	5.42
El Paso North-NM	4.43	3.94	4.00	4.21	4.39	4.56	4.75	4.93	5.14	5.42
El Paso South-Az	4.53	4.06	4.20	4.44	4.62	4.81	5.00	5.20	5.41	5.65
El Paso South-NM	4.55	4.10	4.20	4.44	4.62	4.81	5.00	5.20	5.41	5.65
Kern River	4.63	4.09	4.09	4.25	4.44	4.63	4.82	5.03	5.24	5.46
Mojave	4.85	4.36	4.41	4.62	4.81	5.00	5.20	5.41	5.62	5.87
Montana	N/A	N/A	N/A	4.20	4.36	4.51	4.67	4.83	5.01	5.20
Nevada North	4.96	4.58	4.66	4.85	5.04	5.22	5.42	5.62	5.83	6.07
Nevada South	4.93	4.41	4.45	4.63	4.83	5.02	5.22	5.43	5.65	5.88
PGT-Kingsgate	3.73	3.29	3.35	3.50	3.64	3.79	3.94	4.09	4.26	4.45
PGT-Malin	4.13	3.72	3.80	3.96	4.13	4.29	4.46	4.64	4.82	5.03
PGT-Stansfield	3.90	3.48	3.54	3.70	3.86	4.01	4.17	4.34	4.52	4.72
PNW	4.87	4.49	4.62	4.81	5.00	5.19	5.38	5.58	5.80	6.02
PNW-Coastal	4.28	3.89	3.99	4.18	4.36	4.53	4.72	4.91	5.11	5.33
Utah	4.43	4.01	3.99	4.14	4.29	4.43	4.58	4.74	4.90	5.09
Rosarito	4.82	4.32	4.36	4.56	4.75	4.95	5.14	5.35	5.57	5.82
Otay Mesa	4.76	4.28	4.32	4.54	4.73	4.93	5.13	5.33	5.56	5.78

Table A-20
2004 – 2006 California Generation Additions and Retirements Assumed in Load – Resource Balance

Generation Additions				Generation Retirements		
Unit	**On Line Date***	**Dependable Capacity (MW)**	**Owner**	**Unit**	**Retirement Date**	**Dependable Capacity (MW)**
Glenarm 3-4	2004	94	City of Pasadena	Valley LADWP 3-4	2004	323
Valley LADWP CC	2004	520	Los Angeles DWP	Etiwanda 5	2004	130
Grayson 9	2004	49	City of Glendale	Magnolia GT 5	2004	22
New renewables	2004	50		Haynes 4	2004	222
Haynes Repower	2005	575	Los Angeles DWP	Pittsburg 3-4	2004	304
Kings River peaking units	2005	85	Kings River Conservation District	Alamitos GT 7	2004	134
Ripon	2005	90	Modesto Irrigation District	Olive 3-4	2004	56
Pico	2005	147	Silicon Valley Power	Haynes 3	2005	222
San Francisco peaking units	2005	180	City of San Francisco	Haynes 5-6 derates	2005	82
Magnolia CC	2005	315	SCPPA	Miscellaneous retirements	2005	750
Cosumnes I	2005	458	SMUD	Mohave 1-2	2006	916
Malburg	2005	135	City of Vernon	Hunters Point 1-4	2006	219
SP15 Combined Cycle	2005	500		Miscellaneous retirements	2006	1,250
San Diego Combined Cycle	2005	500		**Total Retirements**		**4,630**
New renewables	2005	15				
Salton Sea #6	2006	177	Cal Energy			
Walnut CC	2006	240	Turlock Irrigation District			
SP15 Combined Cycle	2006	500				
New renewables	2006	179				
Total Additions		**4,809**				

TRANSMISSION UPGRADES ASSUMED IN SIMULATIONS

As noted in its February 11, 2003 Staff Draft Report entitled ***Preliminary Electricity and Natural Gas Infrastructure Assumptions***, there are seven major transmission projects conservatively expected in the next ten years which staff modeled in its MarketSym™ simulations:

1. Path 15 upgrade: The addition of a third 500 kV line between Los Banos and Gates would reduce a major intrastate bottleneck that limits economic transfers between northern and southern California. This joint TransElect/WAPA/PG&E project is modeled by increasing the North-to-South capacity by 1,135 MW and the South-to-North capacity by 1,450 MW beginning in January 2005.

2. Path 26 (Midway to Vincent) upgrade: This project would allow an increase in the path rating from 3,000 MW to 3,400 MW by installing a new remedial action scheme (RAS) to drop new generation in PG&E's Midway area in the event of a contingency. Due to an explosion and fire at SCE's Vincent transformer bank 2AA on March 21, 2003, the current transfer capability of Path 26 is 2,500 MW. Because the installation of a fourth transformer at Vincent had already been planned for July 1, 2003, the fourth transformer will now serve as a functional equivalent for transformer bank 2AA, thereby allowing a return to a path rating of 3,000 MW once it becomes operational. The RAS upgrades are being made independent of the transformer installation, and according to PG&E should be operational by November 2003. Staff had previously assumed an effective date of October 2003; the slip of one month will not impact staff's simulations.

3. Path 45 upgrade: The physical upgrades (line reconductoring from the La Rosita Substation in Mexico to the Imperial Valley Substation in California) necessary to increase the entire path rating from about 400 MW to 800 MW have been completed; however, the WECC has not yet approved the increase in the South-to-North direction for the summer months. That approval is expected in mid-July 2003.

4. Miguel-Mission and Imperial Valley Substation upgrades: The combination of these upgrades will allow for an additional 560 MW of capacity to be delivered to the San Diego load center. The CPUC approved the construction of these projects based on their economic (rather than reliability) merits on February 27, 2003; however, SDG&E must still obtain a Certificate of Public Convenience and Necessity (CPCN) for the Miguel-Mission portion of the project. The CPUC will expedite the CPCN since the economic need for the project has been established and the work will be done within SDG&E's rights-of-way. Staff has assumed an on-line date of January 2005. The most recent SDG&E monthly filing to the CPUC shows an on-line date of June 2005.

5. Path 46 upgrade: Staff has assumed a 1,000 MW increase in the West of Colorado River path from the Imperial Irrigation District area to the SCE area in January 2009. Unlike the other projects discussed here, this is a generic project assumption that does not reflect an actual proposal by a project proponent, but is assumed to be needed to accommodate

the movement of RPS-driven renewable energy from new geothermal facilities in the Salton Sea area.

6. Jefferson-Martin project: This reliability-driven project would increase the transfer capability from PG&E north of Path 15 into the San Francisco area from 700 MW to 1,100 MW. Staff has assumed the CPUC will issue its CPCN and construction will be complete by January 2006. For more information on this project, see the section entitled "Constrained Transmission Paths and Local Reliability Areas."

7. Valley-Rainbow project: Staff has modeled this project as an increase in transfer capability between SCE and SDG&E beginning in January 2009. The CPUC denied SDG&E a CPCN for this project in December 2002. A decision on SDG&E's appeal is currently scheduled for the CPUC's June 5, 2003 business meeting. For more information on the status of this project, see the section entitled "Constrained Transmission Paths and Local Reliability Areas."

APPENDIX B
COST OF GENERATION SUMMARY

APPENDIX B
COST OF GENERATION SUMMARY

As part of the Integrated Energy Policy Report, the California Energy Commission staff developed cost estimates for central-station electricity generation technologies. The *Comparative Cost of California Central Station Electricity Generation Technologies Report* was published on June 5, 2003 and can be found on the Energy Commission's website at http://www.energy.ca.gov/reports/2003-06-06_100-03-001F.PDF. The report is intended to provide a basic understanding some of the fundamental attributes that are generally considered when evaluating the cost of building and operating different electricity generation technology resources.

TECHNOLOGY COSTS

The report does not attempt to capture such site-specific factors such as radial transmission additions, fuel delivery, system upgrades or environmental mitigation expenses. In addition, the levelized cost analysis does not capture all of the system or other relevant attributes that would typically be examined by a portfolio manager when conducting a comprehensive "comparative value analysis" of a variety of competing resource options. A portfolio analysis will vary depending on the particular criteria and measurement goals of each study. For example, some forms of firm capacity are typically needed in conjunction with wind generation to support system reliability requirements. Costs associated with electric power facilities fall into three main categories: investment cost, annual operations and maintenance cost, and variable operating costs.

Initial investment costs are those which are spent in planning, permitting, constructing, and starting up a plant. They are typically financed through a combination of loans ("debt financing") and investment ownership ("equity financing"). The costs are then repaid to lenders and investors over the life of the project. Debt financing usually has fairly rigid conditions related to the term of the loan, the required periodic payments and the security of repayment, much like a home mortgage. Equity financing is usually repaid from the residual revenues remaining after paying all other costs and, as a result, has a higher risk of not being fully repaid compared to debt financing. This analysis makes the assumption that these investments are recovered on a relatively constant annual basis without regard to the amount of generation output. This annual expenditure is then divided over the annual generation to derive the average cost per kWh for the investment or "capital" component

Annual operations and maintenance (O&M) costs are relatively invariant with the amount of output, but would cease if plant operations ended. Operational costs include labor and management, insurance and other services, and certain types of consumables. Maintenance costs include scheduled overhauls and periodic upkeep. Unscheduled or "forced" outages that are a function of usage fall into the final category of costs described below. As with capital costs, these costs are summed and divided over the annual generation output to arrive at the average cost per kWh. However, unlike capital costs that are relatively insensitive to operational mode, the mode of operation can greatly affect these types of costs. For example, intervals between overhauls may be extended if a plant shifts from intermediate to peaking operations. Less labor may be required for a plant that operates only during the seasonal peak period rather than in baseload. In addition, these costs typically escalate over time, compared to capital costs that are considered constant and fixed once the initial investment is made. Nevertheless, once the mode of operation is determined, the annual O&M costs will vary little and are highly predictable over time.

Variable costs are derived from fuel consumption, maintenance expenditures for forced outages, and other input costs driven directly by hourly plant operations. For a natural gas-fired plant, the largest component of these costs is the consumption of natural gas. Fuel costs can represent two-thirds or more of total average costs. Renewable technologies typically exhibit low or zero variable costs, with the notable exception of biomass plants.

Table 1 shows the results of the cost analyses for various technologies. Expected levelized costs, constant annual payments made over the life of the plants, are shown to provide a common basis of measurement. By construction, levelized costs are given as constant, or real, dollars. This report uses a base year of 2002.

As is evident from **Table 1**, different technologies operate in different generation modes. These modes range from baseload, to intermediate, to a peaking type of facility. A baseload facility generally delivers power at a constant rate whenever the plant is available. A facility may also be used to provide spinning reserve to deliver power during intermittent emergencies on extremely short notice. In between these modes of operation are intermediate/load-following facilities, where a plant can be rapidly ramped up or down to follow daily load cycles. A peaking facility is called upon only during the highest daily loads during the seasonal peaks. Some facilities may provide ancillary services, where a plant provides system support, such as voltage regulation. An intermittent/variable facility may deliver power whenever the driving resource, such as wind, is available.

Comparing technologies on levelized cost alone is not appropriate, considering that different technologies provide different services. For example, wind is very competitive on the basis of cost per kWh, but it can only provide variable output. Other renewable resources, such as geothermal and fuel cells have much more predictable output that may be more valuable, although improvements have been made in wind resource predictability as reflected in recent changes in ISO tariffs.

Risk-management strategies generally use some type of financial or contractual methods to reduce the variability of future costs. Without any risk management efforts, all parties are subjected to cost variations inherent in the marketplace. Risk management strategies used in energy markets include participating in forward markets, vertical and horizontal integration through market segments, long-term contracting, commodities hedging on the natural gas and electricity markets and, of course, diversification of fuel supplies, suppliers and technologies. In this sense, adoption of a renewable energy project may be viewed as part of a greater fuel diversification strategy, and the State may deem higher cost renewable projects to be an acceptable investment to pay for natural-gas price risk mitigation.

Table B-1
Technology Costs

Technology	Energy Source Fuel	Operating Mode	Economic Lifetime (years)	Gross Capacity (MW)	Direct Cost Levelized (cents/kWh)
Combined Cycle	Natural Gas	Baseload	20	500	5.18
Simple Cycle	Natural Gas	Peaking	20	100	15.71
Wind	Wind; Resource Limited	Intermittent	30	100	4.93
Hydropower	Water; Resource Limited	Load-Following, Peaking	30	100	6.04
Solar Thermal					
Parabolic Trough	Sun; Resource Limited	Load-Following	30	110	21.53
Parabolic Trough-TES	Sun; Resource Limited	Load-Following	30	110	17.36
Parabolic Trough-Gas	Sun/Natural Gas; Partially resource limited	Load-Following; Peaking	30	110	13.52
Geothermal					
Flash	Water	Baseload	30	50	4.52
Binary	Water	Baseload	30	35	7.37

EMERGING TECHNOLOGY COSTS

In addition to the technologies mentioned previously in this report, staff also obtained levelized cost estimates for emerging technologies. Such technologies require further breakthroughs in research and development before they will be considered commercially viable on a central-station scale. These technologies include various fuel cell units, solar photovoltaics (PV), and solar thermal – stirling dish. Of these technologies, Solar PV has shown its usefulness as a distributed generation technology. However, the levelized cost of 42.72¢ per kWh for a 50 MW is uncompetitive at a central-station scale.

The appendices of the staff report contain the cost details that were used to derive levelized cost estimates.

Table B-2
Levelized Costs for Emerging Technologies

Technology	Energy Source Fuel	Operating Mode	Economic Lifetime (years)	Gross Capacity (MW)	Direct Cost Levelized (cents/kWh)
Solar Thermal-Stirling Dish	Sun; Resource Limited	Load-Following	30	31.5	15.37
Photovoltaic	Sun; Resource Limited	Load-Following	30	50	42.72
Phosphoric Acid	Natural Gas	Baseload	20	25	21.27
Molten Carbonate	Natural Gas	Baseload	20	25	10.15
Solid Oxide	Natural Gas	Baseload	20	25	13.04
Hybrid	Natural Gas	Baseload	20	25	9.41

APPENDIX B
COST OF GENERATION SUMMARY

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As part of the Integrated Energy Policy Report, the California Energy Commission staff developed cost estimates for central-station electricity generation technologies. The *Comparative Cost of California Central Station Electricity Generation Technologies Report* was published on June 5, 2003 and can be found on the Energy Commission's website at http://www.energy.ca.gov/reports/2003-06-06_100-03-001F.PDF. The report is intended to provide a basic understanding some of the fundamental attributes that are generally considered when evaluating the cost of building and operating different electricity generation technology resources.

TECHNOLOGY COSTS

The report does not attempt to capture such site-specific factors such as radial transmission additions, fuel delivery, system upgrades or environmental mitigation expenses. In addition, the levelized cost analysis does not capture all of the system or other relevant attributes that would typically be examined by a portfolio manager when conducting a comprehensive "comparative value analysis" of a variety of competing resource options. A portfolio analysis will vary depending on the particular criteria and measurement goals of each study. For example, some forms of firm capacity are typically needed in conjunction with wind generation to support system reliability requirements. Costs associated with electric power facilities fall into three main categories: investment cost, annual operations and maintenance cost, and variable operating costs.

Initial investment costs are those which are spent in planning, permitting, constructing, and starting up a plant. They are typically financed through a combination of loans ("debt financing") and investment ownership ("equity financing"). The costs are then repaid to lenders and investors over the life of the project. Debt financing usually has fairly rigid conditions related to the term of the loan, the required periodic payments and the security of repayment, much like a home mortgage. Equity financing is usually repaid from the residual revenues remaining after paying all other costs and, as a result, has a higher risk of not being fully repaid compared to debt financing. This analysis makes the assumption that these investments are recovered on a relatively constant annual basis without regard to the amount of generation output. This annual expenditure is then divided over the annual generation to derive the average cost per kWh for the investment or "capital" component

Annual operations and maintenance (O&M) costs are relatively invariant with the amount of output, but would cease if plant operations ended. Operational costs include labor and management, insurance and other services, and certain types of consumables. Maintenance costs include scheduled overhauls and periodic upkeep. Unscheduled or "forced" outages that are a function of usage fall into the final category of costs described below. As with capital costs, these costs are summed and divided over the annual generation output to arrive at the average cost per kWh. However, unlike capital costs that are relatively insensitive to operational mode, the mode of operation can greatly affect these types of costs. For example, intervals between overhauls may be extended if a plant shifts from intermediate to peaking operations. Less labor may be required for a plant that operates only during the seasonal peak period rather than in baseload. In addition, these costs typically escalate over time, compared to capital costs that are considered constant and fixed once the initial investment is made. Nevertheless, once the mode of operation is determined, the annual O&M costs will vary little and are highly predictable over time.

Variable costs are derived from fuel consumption, maintenance expenditures for forced outages, and other input costs driven directly by hourly plant operations. For a natural gas-fired plant, the largest component of these costs is the consumption of natural gas. Fuel costs can represent two-thirds or more of total average costs. Renewable technologies typically exhibit low or zero variable costs, with the notable exception of biomass plants.

Table 1 shows the results of the cost analyses for various technologies. Expected levelized costs, constant annual payments made over the life of the plants, are shown to provide a common basis of measurement. By construction, levelized costs are given as constant, or real, dollars. This report uses a base year of 2002.

As is evident from **Table 1**, different technologies operate in different generation modes. These modes range from baseload, to intermediate, to a peaking type of facility. A baseload facility generally delivers power at a constant rate whenever the plant is available. A facility may also be used to provide spinning reserve to deliver power during intermittent emergencies on extremely short notice. In between these modes of operation are intermediate/load-following facilities, where a plant can be rapidly ramped up or down to follow daily load cycles. A peaking facility is called upon only during the highest daily loads during the seasonal peaks. Some facilities may provide ancillary services, where a plant provides system support, such as voltage regulation. An intermittent/variable facility may deliver power whenever the driving resource, such as wind, is available.

Comparing technologies on levelized cost alone is not appropriate, considering that different technologies provide different services. For example, wind is very competitive on the basis of cost per kWh, but it can only provide variable output. Other renewable resources, such as geothermal and fuel cells have much more predictable output that may be more valuable, although improvements have been made in wind resource predictability as reflected in recent changes in ISO tariffs.

Risk-management strategies generally use some type of financial or contractual methods to reduce the variability of future costs. Without any risk management efforts, all parties are subjected to cost variations inherent in the marketplace. Risk management strategies used in energy markets include participating in forward markets, vertical and horizontal integration through market segments, long-term contracting, commodities hedging on the natural gas and electricity markets and, of course, diversification of fuel supplies, suppliers and technologies. In this sense, adoption of a renewable energy project may be viewed as part of a greater fuel diversification strategy, and the State may deem higher cost renewable projects to be an acceptable investment to pay for natural-gas price risk mitigation.

Table B-1
Technology Costs

Technology	Energy Source Fuel	Operating Mode	Economic Lifetime (years)	Gross Capacity (MW)	Direct Cost Levelized (cents/kWh)
Combined Cycle	Natural Gas	Baseload	20	500	5.18
Simple Cycle	Natural Gas	Peaking	20	100	15.71
Wind	Wind; Resource Limited	Intermittent	30	100	4.93
Hydropower	Water; Resource Limited	Load-Following, Peaking	30	100	6.04
Solar Thermal					
Parabolic Trough	Sun; Resource Limited	Load-Following	30	110	21.53
Parabolic Trough-TES	Sun; Resource Limited	Load-Following	30	110	17.36
Parabolic Trough-Gas	Sun/Natural Gas; Partially resource limited	Load-Following; Peaking	30	110	13.52
Geothermal					
Flash	Water	Baseload	30	50	4.52
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EMERGING TECHNOLOGY COSTS

In addition to the technologies mentioned previously in this report, staff also obtained levelized cost estimates for emerging technologies. Such technologies require further breakthroughs in research and development before they will be considered commercially viable on a central-station scale. These technologies include various fuel cell units, solar photovoltaics (PV), and solar thermal – stirling dish. Of these technologies, Solar PV has shown its usefulness as a distributed generation technology. However, the levelized cost of 42.72¢ per kWh for a 50 MW is uncompetitive at a central-station scale.

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Table B-2
Levelized Costs for Emerging Technologies

Technology	Energy Source Fuel	Operating Mode	Economic Lifetime (years)	Gross Capacity (MW)	Direct Cost Levelized (cents/kWh)
Solar Thermal-Stirling Dish	Sun; Resource Limited	Load-Following	30	31.5	15.37
Photovoltaic	Sun; Resource Limited	Load-Following	30	50	42.72
Phosphoric Acid	Natural Gas	Baseload	20	25	21.27
Molten Carbonate	Natural Gas	Baseload	20	25	10.15
Solid Oxide	Natural Gas	Baseload	20	25	13.04
Hybrid	Natural Gas	Baseload	20	25	9.41

APPENDIX C
TRANSMISSION PROJECT STATUS AND ASSUMPTIONS

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TRANSMISSION PROJECT STATUS AND ASSUMPTIONS

STATUS OF PG&E, SDG&E, AND SCE TRANSMISSION PROJECTS

Appendix B of the February 11, 2003 Staff Draft Report entitled ***Preliminary Electricity and Natural Gas Infrastructure Assumptions*** includes a comprehensive description of each of PG&E's, SDG&E's, and SCE's transmission projects. The information presented was based on each utility's 2002 transmission expansion plan submitted to the CA ISO, as well as each utility's latest (as of February 3, 2003) monthly status report submitted to the CPUC in response to AB 970 requirements.

An update of these tables is presented here. These tables were created from each utility's latest (as of July 1, 2003) monthly status report, as well as the ***2003 California ISO Controlled Grid Final Study Plan, Version 2.2*** released on July 16, 2003. The ***Study Plan*** presents only the major transmission projects (230 kV and above) which were approved by the CA ISO, whereas the utility monthly filings contain all transmission projects. With respect to the major projects, staff has used its informed judgment to resolve the few discrepancies found among these documents.

Tables C-1 through C-7 show the status of the projects in each of the seven PG&E planning areas (Humboldt Area, North Coast and North Bay Areas, Central Coast and Los Padres Areas, North Valley Area, Central Valley Area, Greater Fresno and Kern Areas, and Greater Bay Areas, respectively.) Table C-8 shows the status of SDG&E projects, while Table C-9 shows the status of SCE projects. The information about each project includes its identification number assigned by the Participating Transmission Owner (PTO), project name, purpose, current projected or actual on-line date, status of CA ISO approval, status of PTO funding approval, whether or not a Certificate of Public Convenience and Necessity (CPCN) is required from the CPUC, project status, and description/comments.

TRANSMISSION UPGRADES ASSUMED IN SIMULATIONS

There are seven major transmission projects conservatively expected in the next ten years which are modeled in MarketSym™ simulations. Staff has previously reported on the status of these projects in two reports: (1) the February 11, 2003 Staff Draft Report entitled ***Preliminary Electricity and Natural Gas Infrastructure Assumptions***; and (2) the May 2003

Staff Report entitled ***Electricity Infrastructure Assessment***. The following information is current as of July 31, 2003.

1. Path 15 upgrade: The addition of a third 500 kV line between Los Banos and Gates would reduce a major intrastate bottleneck that limits economic transfers between northern and southern California. This joint TransElect/Western Area Power Administration (WAPA)/PG&E project is modeled by increasing the North-to-South capacity by 1,135 MW and the South-to-North capacity by 1,500 MW beginning in January 2005. Staff learned from WAPA at the June 10, 2003 IEPR Electricity Infrastructure Assessment Workshop that approximately two-thirds of the right-of-way has been acquired. A contractor has been selected to construct the upgrade. Construction will begin when all of the right-of-way has been acquired, which is expected by the end of summer 2003. The project is expected to be on line on or before December 2004.

2. Path 26 (Midway to Vincent) upgrade: This project would allow an increase in the path rating from 3,000 MW to 3,400 MW by installing a new remedial action scheme (RAS) to drop new generation in PG&E's Midway area in the event of a contingency. Due to an explosion and fire at SCE's Vincent transformer bank 2AA on March 21, 2003, the current transfer capability of Path 26 is 2,500 MW. Because the installation of a fourth transformer at Vincent had already been planned for July 1, 2003, the fourth transformer will now serve as a functional equivalent for transformer bank 2AA, thereby allowing a return to a path rating of 3,000 MW once it becomes operational. The RAS upgrades are being made independent of the transformer installation, and according to PG&E should be operational by November 2003. Staff had previously assumed an effective date of October 2003; the slip of one month will not impact staff's simulations. On July 17, 2003 the WECC confirmed that the Path 26 accepted rating is 3,400 MW in the north-to-south direction, while the existing accepted rating in the south-to-north direction remains unchanged at 3,000 MW. However, the 3,400 MW north-to-south maximum flow will not be achieved physically until the replacement transformer bank becomes operational, which is currently estimated to occur on August 7, 2003.

3. Path 45 upgrade: The physical upgrades (line reconductoring from the La Rosita Substation in Mexico to the Imperial Valley Substation in California) necessary to increase the entire path rating from about 408 MW to 800 MW were completed in November 2001. On July 17, 2003 the WECC confirmed that the Path 45 accepted rating is now 800 MW in the south-to-north direction, while the existing accepted rating in the north-to-south direction remains unchanged at 408 MW.

4. Miguel-Mission and Imperial Valley Substation upgrades: The combination of these upgrades will allow for an additional 560 MW of capacity to be delivered to the San Diego load center. The CPUC approved the construction of these projects based on their economic (rather than reliability) merits on February 27, 2003; however, SDG&E must still obtain a Certificate of Public Convenience and Necessity (CPCN) for the Miguel-Mission portion of the project. The CPUC will expedite the CPCN since the economic need for the project has been established and the work will be done within SDG&E's

rights-of-way. Staff has assumed an on-line date of January 2005. The most recent SDG&E monthly filing to the CPUC shows an on-line date of June 2005.

5. Path 46 upgrade: Staff has assumed a 1,000 MW increase in the West of Colorado River path from the Imperial Irrigation District area to the SCE area in January 2009. Unlike the other projects discussed here, this is a generic project assumption that does not reflect an actual proposal by a project proponent, but is assumed to be needed to accommodate the movement of RPS-driven renewable energy from new geothermal facilities in the Salton Sea area.

6. Jefferson-Martin project: This reliability-driven project would increase the transfer capability from PG&E north of Path 15 into the San Francisco area from 700 MW to 1,100 MW. Staff has assumed the CPUC will issue its CPCN and construction will be complete by January 2006. According to PG&E, assuming the CPCN is granted by April 2004, land acquisition and project construction would start immediately to achieve an in-service date of September 2005 or earlier.

7. Valley-Rainbow project: Staff has modeled this project as an increase in transfer capability between SCE and SDG&E beginning in January 2009. The CPUC denied SDG&E a CPCN for this project in December 2002 (D.02-12-066). On January 23 2003 SDG&E filed two petitions, an Application for Rehearing of San Diego Gas & Electric Company Decision of 02-12-066 and a Petition to Modify Decision of 02-12-066. On May 12, 2003 the CPUC issued a decision denying rehearing of the Valley Rainbow decision and on June 5 2003, the CPUC issued a decision denying the Petition to Modify the Decision.

Table C-1
PG&E Transmission Projects – Humboldt Area

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
T376	Humboldt 60 kV Protection Upgrade	Resolve transient instability in the Humboldt area	9/1/2003	Yes	Yes	No	Construction	Upgrade to High Speed Protection Schemes.
T658	Humboldt - Arcata Jct. Third 60 kV Line	Reliability: Increase 60kV supply at Arcata Substation	10/1/2004	Yes (Scope modification)	Pending Cost Estimate	No (NOC)	Planning	Construct 3rd 60kV transmission line between Humboldt and Arcata Substation.

Table C-2
PG&E Transmission Projects – North Coast and North Bay Areas

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
T572	Fulton – St. Helena Jct. 60 kV Line SCADA	Low voltages, emergency overload	3/31/2002	Yes	Yes	No	In service	Install Supervisory Control and Data Acquisition (SCADA) for remote load transfer operation.
T118	St. Helena - Pueblo 115 kV Line Reinforcement Project (Dunbar SCADA)	Emergency line overload and low voltage	4/1/2002	Yes	Yes	No	In service	
T643	Tulucay - Napa #1 & #2 60 kV Line Reinforcement	Resolve thermal overload	9/1/2002	Yes	Yes	No (NOC effective)	In service	Reconductor a 60 kV line.
T245	Lakeville 230/115 kV Transformer	Reliability: Resolve Emergency low voltage and thermal overloads	5/1/2004	Yes (Scope modification)	Yes	No	Planning	Replace Transformers Nos. 1 and 1A with one large (420 MVA) transformer.
T254	Sonoma/ Mendocino Coast Voltage Support	Reliability: Provide voltage support	5/1/2004	Yes	Yes	No	Planning	Install distribution capacitors at Big River Substation. 6/1/03: Install capacitor control devices at Fort Bragg, Elk, Point Arena and Philo to control existing station capacitors.
T199	Ignacio 115/60 kV Transformer	Reliability: Increase 60 kV supply	5/1/2006	Yes	Not yet	No	Planning	Add a new 115/60 kV transformer. 6/1/03: In-service date changed from "April or May 2006" to 5/06.
T571	Lakeville 230/60 kV Transformer	Reliability: Increase 60 kV supply at Lakeville	5/1/2006	Yes	Pending Cost Estimate	No	Planning	Add a new 230/60 kV transformer at Borden.

Table C-2 - Continued
PG&E Transmission Projects – North Coast and North Bay Areas

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
T253	Sonoma - Napa Electric Transmission Capacity Project	Reliability: Increase capacity of power interchange	5/1/2006	Not yet	Pending Cost Estimate	CPCN/PTC TBD	Planning	Construct one or two 115 kV transmission circuits from Lakeville Substation to Sonoma and Pueblo Substations. May involve 230 kV facilities.
T654	Eagle Rock-Mendocino System Upgrade	Reliability: increase transmission capacity	TBD	Not yet	Pending Cost Estimate	TBD	Planning	In early planning stage, may involve construction of 230kV transmission facilities.
T777	Fulton-Santa Rosa 115 kV Lines	Reliability: category B; increase capacity of power interchange between substations.	TBD	Yes	Yes	No (NOC effective)	Construction	Reconductor 115 kV lines between Fulton and Santa Rosa Substations. 4/1/03: the Fulton-Munroe section is scheduled for May 2003. The Monroe-Santa Rosa Section is scheduled for December 2003. 6/1/03: In-service date changed from 5/1/03 and 12/1/03 to TBD, pending consultation with Federal agencies.

Table C-3
PG&E Transmission Projects – Central Coast and Los Padres Areas

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
T698	Salinas 115/60 kV Transformer Capacity Increase	Reliability: Increase 60 kV supply	5/1/2004	Yes	Pending Cost Estimate	No	Planning	Install a third 115/60 kV transformer bank at Salinas Substation.
T049	Moss Landing-Green Valley 115 kV Line Reconductoring	Reliability: category B; increase capacity of power interchange between substations.	12/1/2004	Yes	Yes	No (NOC)	Planning	Reconductor both lines.
T833	Diablo Canyon Power Plant Special Protection System	Reliability: Increase grid reliability	4/1/2005	Yes	Pending Cost Estimate	No	Planning	SPS to trip generation. Change in schedule to coordinate with re-fueling. 5/1/03: On-line date moved to 4/1/05.
T737	Mesa 230/115 kV Special Protection System	Reliability	TBD	Not yet	Not yet	No	Planning	Install protection equipment to guard against thermal overloads. Further analysis concluded that this SPS is very complicated and extremely difficult to implement. PG&E will work with the ISO on an alternate.
T695	Salinas-Watsonville Plan	Reliability	TBD	Not yet	Not yet	No	Planning	In early planning stage, may involved construction of a new 60 kV transmission substation and line facilities.

Table C-4
PG&E Transmission Projects – North Valley Area

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
T228	Paradise Area Reinforcement Project	Reliability: Resolve normal & emergency overload, low voltage	3/1/2002	Yes	Yes	No (PTC effective)	In service	Reliability: increase capacity of Paradise Substation.
T230	Cottonwood 60 kV Line Reconfiguration	Reliability: category A	7/31/2002	Yes	Yes	No	In service	Modify 60 kV switches.
N/A	Round Mountain 500/230 kV Transformer Bank Upgrade	Reliability	12/21/2003	N/A	Yes	No	Construction	Replace existing 3-280 MVA single phase bank with 4-374 MVA single phase banks.
T759	Atlantic Substation Second 230/60 kV transformer	Reliability: Increase 60 kV supply at Atlantic Substation	5/1/2005	Not yet	Pending Cost Estimate	No	Planning	Install second 230/60 kV transformer at Atlantic Substation. 4/9/03: ISO has insufficient information to assess project. Wants PG&E to resubmit no later than the completion of the 2003 Transmission Grid Expansion Plan.
T901	Cottonwood 230/60 kV Transformer	Reliability: Increase 60 kV supply at Cottonwood	5/1/2006	Yes	Not yet	No	Planning	Add a new 230/60 kV transformer at Cottonwood. 5/03: On-line date now 5/06.

Table C-5
PG&E Transmission Projects – Central Valley Area

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
T673 / T675	Cortina-Colusa 60 kV Transmission	Reliability: Normal and emergency overloads, low voltages	2/1/2002	Yes	Yes	No (NOC effective)	In service	Reconductor portion of the Cortina-Colusa 60 kV Transmission Line #3.
T686	Palermo-Nicolaus Line Rerate	Reliability: resolve overloads	5/1/2002	Yes	Yes	No	In service	9/2/02: name changed from Palermo-Rio Oso to Palermo-Nicolaus because the utility updated its naming conventions. The original 2007 date was set to allow time to include potential project changes such as reconductoring. Instead, this became a rerate project and was completed in May 2002, per the CA ISO, 5/30/03.
N/A	Tracy Second 500/230 kV transformer bank	Resolve normal and emergency overloads	5/1/2002	N/A	Yes	No	In service	Install new transformer bank.
T691	Rio Oso - Atlantic and Rio Oso -Gold Hill 230 kV Lines Rerate	Resolve normal and emergency 115 kV line overloads	9/1/2002	Yes	No	No	In service	Rerate 230 kV lines. 9/02: on-line date moved up from 5/03 to 9/02.
T881	Path 26 Contingency RAS South-to-North	Reliability: Increase capacity of power interchange between PG&E and SCE	12/1/2002	Yes	Yes	No	In service	Install substation equipment at Midway Substation and modify computer software at the San Francisco RAS Controller.
T242	Goldhill 230/115 kV Transformer Bank	Reliability: Resolve thermal overload	5/1/2003	Yes	Yes	No	In service	Increase transformer capacity. 5/1/03: Replace transformer banks 2 & 3 with one large (420MVA) transformer.
T891	Vaca Dixon 230kV Circuit Breaker	Reliability: Increase transmission of 115 kV power and reduce RMR contract cost.	5/1/2003	Yes	Yes	No	In service	Install 230 kV breaker at Vaca Dixon Substation dedicated to the Vaca Dixon 230/115 kV Transformer No. 4.

Table C-5 - Continued
PG&E Transmission Projects – Central Valley Area

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
T101	Atlantic-Del Mar New 60kV line	Reliability: Resolve normal overload and low voltage	5/1/2004	Yes	Yes	No (PTC effective)	Permitting	Currently in the CPUC permitting process. On-line dated changed from 5/1/03 to 5/1/04.
T758	Brighton Second 230/115 kV Transformer Bank	Reliability: Increase 115 kV supply	5/1/2004	Yes	Yes	No	Planning	Install second transformer.
T687	Colgate-Rio Oso Line Rerate	Reliability: Increase capacity of power interchange between substations	5/1/2004	Pending Cost Estimate	Yes	Exempt	Planning	Rerate 230kV transmission lines for capacity at 3 feet per second wind speed rather than 2 feet per second
T243	Colgate-Smartville 60 kV Line Reconductoring	Reliability: category B	5/1/2004	Yes	Pending Cost Estimate	No (NOC)	Planning	Reconductor Colgate-Smartville Nos. 1 and 2 lines. 01/27/03 PG&E Draft Yuba and Sutter Counties Long-Term Transmission Plan lists expected on-line date as 11/03.
T346	Cortina Substation Transformer Capacity Increase	Reliability: Resolve thermal overload	5/1/2004	Yes	Pending Cost Estimate	No	Planning	Install a new 230/115 kV transformer.
T678	Lockeford 230 kV Voltage Support	Reliability: Provide voltage support to area around Lockeford Substation	5/1/2004	Yes	Pending Cost Estimate	TBD	Planning	Loop the Brighton-Bellota 230 kV transmission line into Lockeford Substation; other alternatives are being investigated
T786	Lockeford 230/60 kV Capacity Increase	Reliability: resolve overload	5/1/2004	Yes	Yes	No	Planning	Replace existing 134 MVA transformer with two 200 MVA transformers. 5/1/03: Install 2nd 230/60 kV transformer. Project scope amended to include the replacement of the existing transformer due to its inadequate capability.

Table C-5 - Continued
PG&E Transmission Projects – Central Valley Area

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
T845	Tesla 230/115 kV Transformer	Reliability: Increase 115 kV supply	5/1/2004	Yes	Yes	No	Planning	Replace 230/115 kV Transformer Bank No. 1
NA	Path 15 Upgrade; new 500 kV line (MOU project)	Increase transfer capability of Path 15 from 3,900 MW to 5,400 MW (south to north)	12/31/2004	Yes	N/A	N/A	Letter Agreement accepted by FERC on 6/12/02	May 2002 - MOU between Trans-Elect, PG&E, and Western has been initiated with the following ownership percentages: Trans-Elect at 72%, PG&E at 18%, and Western at 10%. PG&E would be responsible for substation modifications at Los Banos and Gates. Western would act as project manager. Letter Agreement filed with FERC on April 30, 2002, and accepted by FERC on 6/12/02. Approved by ISO Board on 6/25/02. Participants are working on more detailed agreements necessary to complete the project. No release date has been identified. 12/30/02 MOU (Construction and Coordination Agreement) signed between Western, TransElect, PG&E. 2/3/03: Western issued solicitation for construction work; expects completion by 12/31/04. 5/27/03: Contractor selected
T809	Salado 115 kV and 60 kV System	Reliability Category B	2004	No (scope changes)	No	No	Planning	4/9/03: CA ISO has insufficient information to assess project. Wants PG&E to resubmit no later than the completion of the 2003 Transmission Grid Expansion Plan.
T314	Colgate 230/60 kV Capacity Increase	Reliability: Increase power to 60 kV grid	5/1/2005	Yes	Pending Cost Estimate	No	Planning	Installation of second transformer is an infeasible alternative. Other options are being assessed to determine recommended alternative. 5/1/03: Install 2nd 230/60 kV transformer at Colgate Powerhouse
T815	Marysville-Smartville 60 kV Line	Reliability: Increase 60 kV capacity to Marysville Substation	5/1/2005	Not yet	No	No (PTC)	Planning	PG&E is not requesting ISO approval at this time. Additional analysis will be performed as part of the 2003 Expansion Plan to determine a preferred plan. 5/1/03: In-service date changed from 5/07 to 5/05.

Table C-5 - Continued
PG&E Transmission Projects – Central Valley Area

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
T783	Vaca Dixon 230/115 kV Transformer Replacement	Vaca Dixon 230/115 kV Transformer Replacement	5/1/2005	Yes	Pending Cost Estimate	No	Planning	Transformer replacement. The addition of a 230 kV circuit breaker has changed the timing of this project
T444	Gold Hill-Placer 115 kV Lines	Reliability: category B; increase 115 kV supply to the Placer area	5/1/2006	Yes	Pending Cost Estimate	No (NOC)	Planning	Reconductor the limiting sections of the No. 2 line. 5/15/03: on-line date changed to 5/06.
T177	West Sacramento - Davis	Reliability: Serve increased loads	5/1/2006	Yes	Pending Cost Estimate	No (NOC/ PTC TBD)	Planning	Convert 60 kV facilities to 115 kV. 3/5/03: on-line date moved from 5/04 to 5/06.
T903 (PG&E) and 04833 (SCE)	Path 26 Upgrade Project, Phase 1 (Short-term solution) - - RAS to Drop SCE Load	Economic: Increase transfer capability and relieve transmission congestion	11/3/03 (staff estimate)	Yes	Yes (PG&E)	No	Planning	Phase 1. Project added on 5/1/02. Modify the existing remedial action scheme to trip generation in the Midway area for a 500 kV double line outage. This would increase the north-to-south transfer capability of Path 26 from the existing 3000 MW to 3400 MW (short-term solution). See also the Path 26 Upgrade Project Long-term solution. 1/27/03: SCE lists project as under construction, expected on-line 6/1/03; PG&E expects project on-line 11/03.

Table C-6
PG&E Transmission Projects – Greater Fresno and Kern Area

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
T362	Oakhurst Area Reinforcement: Kerckhoff 1-Kerckhoff 2 Lines and Breakers	Reliability: Emergency overload, low voltages	3/1/2002	Yes	Yes	No	In service	Breaker work completed in 3/02. See T756 for Phase 2 reconductoring work.
T765	Midway Third 500/230 kV Transformer	Reliability: Resolve normal and emergency overloads	11/1/2002	Yes	Yes	No	In service	Install third transformer to accommodate new Kern County generation.
T646	Panoche - Panoche Jct. Line Reconductoring	Reliability: Resolve thermal overload	11/1/2002	Yes	Yes	No (NOC effective)	In service	Reconductor 115 kV lines between Panoche-Oro Loma and Panoche-Mendota. 3/4/03: PG&E indicates in-service date was 11/02.
T848	Madera Power-Newhall Reconductoring	Reliability: category B	11/13/2002	Yes	Yes	No	In service	Reconductor line.
T756	Oakhurst Area Reconductoring	Reliability: Increase capacity	1/18/2003	Yes	Yes	No (NOC effective)	In service	Reconductor Lines.
T717B	Reedley 115/70 kV Special Protection System	Reliability: Increase grid reliability	3/1/2003	Yes	Yes	No	In service	Install Special Protection Scheme at Reedley Substation to guard against thermal overloads. 6/2/03: In-service date changed from expected of 6/61/03 to actual of 5/1/03.
T706A	Wilson 115 kV Bus Reconfiguration	Reliability: Increase 115 kV power and reduce Reliability Must Run contract cost	4/1/2003	Yes	Yes	No	In service	Reconfigure the Wilson 115 kV bus to balance thermal loading between transformers Nos. 1 and 2.
T855	Wilson-Le Grand 115 kV Reconductoring	Reliability: category B	4/1/2003	Yes	Yes	No (NOC effective)	In service	Reconductor lines.
T857	Arco 230/70 kV Special Protection System	Reliability: Resolve low voltage	5/1/2003	Yes	Yes	No	In service	Expand the existing Special Protection System to guard against low voltage.

Table C-6 - Continued
PG&E Transmission Projects – Greater Fresno and Kern Area

T726	Midway-McCall 115 kV Line	Reliability: Increase capacity of power interchange between substations	5/1/2003	Yes	Yes	No	In service	Rerate lines and add SCADA.
T710	Los Banos Second 230/70 kV Bank	Reliability: Increase 70 kV supply	5/1/2004	Yes	Yes	No	Planning	Install second transformer bank. .
T496	Westpark-Magunden 115 kV Reconductoring	Reliability: Increase capacity of power interchange between substations	5/1/2004	Yes	Pending Cost Estimate	No (NOC)	Planning	Reconductor 115 kV lines.
T708	Wilson 230/115 kV Transformer Upgrade	Reliability: Increase 115 kV supply at substation	5/1/2004	Yes	Pending Cost Estimate	No	Planning	Transformer replacement. Replace 230/115 kV Bank No. 2 at Wilson Substation with a larger (420MVA) bank.
T762	Path 15 Upgrade, new 500 kV line	Reliability: Increase transfer capability of Path 15 from 3,900 MW to 5, 400 (south-to-north)	10/1/2004	Yes	No	Yes	Application withdrawn 5/03	CPUC A.01-04-012. 5/22/03: CPUC granted PG&E's motion to withdraw its Application in D03-05-082. PG&E will join Trans-Elect and Western in a project to upgrade Path 15 (listed separately in these tables).
T773	Kern 230/115 kV Transformer Bank Replacement	Reliability: Increase 115 kV supply	5/1/2005	Yes	Pending Cost Estimate	No	Planning	Replace Transformer Bank 4 with a larger (420 MVA) bank.
T725	Midway 230/115 kV Transformer Bank Replacement	Reliability: Increase 115 kV supply	5/1/2005	Yes	Pending Cost Estimate	No	Planning	Replace Transformer Bank 1 with a larger (420 MVA) transformer.
T717A	Reedley Second 115/70 kV Transformer	Reliability: Increase 70 kV supply at Reedley	5/1/2005	Yes	Not yet	No	Planning	Add a second 115/70 kV transformer at Reedley
T706A	Wilson 230 kV Loop		5/1/2005	Yes	?	?	Detailed Scoping	Loop Warnerville-Border 230 kV line into Wilson.

Table C-6 - Continued
PG&E Transmission Projects – Greater Fresno and Kern Area

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
T316	Borden Second 230/70 kV Transformer	Reliability: Increase 70 kV supply	5/1/2006	Yes	Pending Cost Estimate	No	Planning	Install second transformer.
T778	Henrietta 230/70 kV Capacity Increase	Reliability: Increase 70 kV supply at Henrietta Substation.	5/1/2008	Not yet	Pending Cost Estimate	No	Planning	Replace the 230/70 kV transformer at Henrietta Substation. Project postponed in 5/03 filing due to decrease in demand growth. 6/1/03: Status changed from "postponed" to "planning."

Table C-7
PG&E Transmission Projects – Greater Bay Area

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
T339	BART SFO Extension - Shaw Road Sub	Interconnect BART's Shaw Substation to the transmission grid	1/1/2002	Yes	Yes	No	In service	Customer funded. Reliability: serve new loads.
T764A	Metcalf-Moss Landing 230 kV Lines Rerate	Reliability: Increase capacity of power interchange between substations	4/1/2002	Yes	Yes	No	In service	Project added on 6/1/02. 1/27/03 - ISO changed on-line date from 4/3 0/02 to 4/1/02.
T768	Pittsburg 230 kV Line Reactors	Normal and emergency overloads	4/1/2002	Yes	Yes	No	In service	For accommodating Los Medanos generation.
T635	San Mateo-Martin 115 kV Line Capacity Increase	Increase import capability to San Francisco, Daly City and the Peninsula Corridor	4/30/2002	Yes	Yes	No (NOC effective)	In service	Increase rating by re-conductoring the underground 115 kV "dips" near the S.F. International Airport and rerating the overhead 115 kV lines. 1/31/03: CA ISO revised on-line date from 5/02 to 4/02.
T665	Pittsburg-Tassajara 230 kV Line Reconductoring - Phase 2	Normal and emergency line overloads	5/1/2002	Yes	Yes	No (NOC effective)	In service	Reconductor remainder (12 miles) of Pittsburg-Tassajara transmission line. 1/27/03: CA ISO lists in-service date as 4/1/02, not 5/02.
T558 Phase I	Tesla Third 500/230 kV Transformer Bank	Resolve normal and emergency overloads	6/15/2002	Yes	Yes	No	In service	Install new transformer bank - delayed from 6/1/01. In service as of June 2002. See also T558 Phase II.
T745	Bay Area Reactive: Potrero 115 kV Shunt Capacitor	Reliability: Provide voltage support	6/17/2002	Yes	Yes	No	In service	Install 150 MVar of 115 kV shunt capacitors at the Potrero Power Plant switchyard.
T181	North Receiving Station - Santa Clara	New customer substation	7/31/2002	Yes	Yes	No	In service	Connect Silicon Valley Power's (City of Santa Clara) Northern Receiving Substation to both existing Newark-Scott 115kV lines. 6/1/02 - Project delayed from June to July 2002.

Table C-7 - Continued
PG&E Transmission Projects – Greater Bay Area

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
T081	San Mateo South 115kV Transmission Reinforcements	Emergency 115 kV line overload	7/31/2002	Yes	Yes	No (NOC effective)	In service	Build 2nd Ravenswood-Bair line using existing structures. 6/1/02 - Project delayed from June to July 2002.
PM1133	South of San Mateo Special Protection Scheme	Reliability	11/1/2002	Yes	Yes	Unknown	In service	Install protection equipment to guard against an overlapping outage of two 230 kV lines, either the Ravenswood-San Mateo Nos. 1&2 or the Contra Costa-San Mateo Nos. 1&2. The SPS, if triggered, will trip up to 500 MW of customers in the mid-San Francisco Peninsula.
T088	BART SFO Extension - Santa Paula Sub	New customer substation	12/8/2002	Yes	Yes	No	In service	Customer funded. .
T787	Ravenswood-San Mateo 230 kV Line Reconductoring	Reliability: G-4, L-1	12/31/2002	Yes	Yes	No (NOC effective)	In service	Install bundled conductors on #2 circuit.
T771	Monta Vista 230/115 kV Transformer Replacement	Resolve emergency overload. Reliability: category B	3/1/2003	Yes	Yes	No	In service	Replace Transformer No. 3 with a 420 MVA bank. 4/1/03: on-line as of 3//03, ahead of 5/03 schedule.
T784	Pittsburg-Martinez 115 kV Line Reconductoring	Reliability: category B	3/1/2003	Yes	Yes	No (NOC effective)	In service	Reconductor two 115 kV lines. 4/1/03: on-line 3/03 ahead of 5/03 schedule
T655A	Jefferson Bank Capacity - Protection Work	Emergency overload, low voltages	5/1/2003	Yes	Yes	No	In service	Modify 60 kV line projection in 2002, and install second Jefferson transformer in 2005 (see T655b). 7/1/02.
T340	Metcalf 230/115 kV Fourth Transformer Bank	Reliability: Resolve emergency transformers' overload	5/1/2003	Yes	Yes	No	In service	Install a fourth transformer. 9/1/02 - PG&E approval obtained.

Table C-7 - Continued
PG&E Transmission Projects – Greater Bay Area

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
T590	Metcalf 500/230 kV Third Transformer	Reliability: Resolve emergency transformers' overload	5/1/2003	Yes	Yes	No	In service	Install third transformer.
T846	Newark/Dumbarton 115 kV Line	Reliability: category B	5/1/2003	Yes	Yes	No	In service	Install protection equipment to guard against an equipment overloading problem.
T769	San Jose B-FMC Junction 115 kV Line	Reliability: category B	5/1/2003	Yes	Yes	No	In service	Reconductor one span of the 115 kV line outside of San Jose B. 4/1/03: on-line date now 5/03.
T197	Ignacio 230/115 kV Capacity Increase	Resolve emergency overload	6/1/2003	Yes	Yes	No	In service	Install a new 230/115 kV transformer. 6/1/03: In-service date changed from 5/1/03 to 6/1/03.
T011	Northeast San Jose Reinforcement Project	Resolve normal and emerg. line and transformer overloads	6/1/2003	Yes	Yes	Yes; filed and completed in March 2002	In service	CPUC A.98-07-007. Construct new 230/115 kV Los Esteros Substation, two new 230 kV Los Esteros-Newark circuits, new 115 kV Los Esteros-Montague circuit, and reroute 115 kV line from Newark to Milpitas. The 230 kV circuits and 230/115 kV substation work is expected to be completed by late May/early June. The Los Esteros-Montague circuit is expected to be completed by early July 2003. 6/1/03: In-service date moved from 7/1/03 to 6/1/03.
T792	Pittsburg 230/115 kV Bank Capacity Increase	Congestion and RMR issues	6/1/2003	Yes	Yes	No	In service	Replace a smaller-size transformer (bank 12) with a 420 MVA transformer. 6/1/03: In-service date changed from 5/1/03 to 6/1/03.
T558 Phase II	Tesla 500/230 kV Third Transformer Bank	Resolve normal and emergency overloads	6/1/2003	Yes	Yes	No	In service	Install third transformer. Also see T558 phase I.

Table C-7 - Continued
PG&E Transmission Projects – Greater Bay Area

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
T157	Tri-Valley Long Term Transmission Project	Resolve insufficient 60 kV normal capacity	7/1/2003	Yes	Yes	Yes; filed and completed on 10/10/01	Construction	Construct two 230/21 kV distribution substations and sections of 230 kV overhead and underground transmission lines. 6/1/03: In-service date changed from 5/1/03 to 7/1/03.
T767	Metcalf 500 kV Special Protection Scheme	Reliability: Category C	4/1/2004	Yes	Pending Cost Estimate	No	Planning	Install a special protection scheme to drop load after an overlapping outage of two 500 kV lines. 5/1/03: On-line date moved from 12/03 to 4/04.
T747	City of Santa Clara (Silicon Valley Power) - PG&E 230kV Interconnection	Tariff Compliance	5/1/2004	No	Pending Cost Estimate	No	Planning	Interconnect Silicon Valley Power's proposed 230 kV line from its Northern Receiving Station to Los Esteros Substation.
T902	East Shore 230 kV Circuit Breaker	Reliability: Increase reliability of supply	5/1/2004	Yes	Pending Cost Estimate	No	Planning	Install a 230 kV circuit breaker at East Shore.
T521	FMC 115 kV Loop	Increase service reliability	5/1/2004	Yes	Yes	No (PTC effective)	Planning	Second 115 kV line to FMC Distribution Substation. Check on permitting requirement on-going. 5/1/02 - On-line date changed from May 2003 to May 2004.
T744	Hunters Point-Potrero 115 kV Circuit	Reliability: Increase reliability of supply in San Francisco	5/1/2004	Yes	Pending Cost Estimate	PTC/ NOC TBD	Planning	Install a 115 kV underground cable between Potrero and Hunters Point Power Plant Switchyards.
T694	Metcalf - El Patio 115 kV Reconductoring	Reliability: Increase 115 kV supply	5/1/2004	Yes	Pending Cost Estimate	No (NOC)	Planning	Reconductor 115 kV lines between Metcalf and El Patio Substations.
T847	Newark-Fremont 115 kV Line	Reliability: Increase capacity of power interchange between substations	5/1/2004	Yes	Pending Cost Estimate	NOC	Planning	Reconductor the Newark-Fremont 115kV transmission line.
T656	Ravenswood 230/115kV Capacity Increase	Reliability: Increase 115kV at Substation	5/1/2004	Yes	Yes	No	Planning	Install 2nd 230/115kV transformer at Ravenswood Substation. 5/1/03: Project scope was increased to include the expansion of the 230 kV bus at Ravenswood.

Table C-7 - Continued
PG&E Transmission Projects – Greater Bay Area

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
T790	Bay Area Reactive - Potrero SVC	Reliability: voltage support	9/1/2004	Yes	Not yet	No	Planning	Install a +240/-100 Static Var Compensator at either Potrero Switchyard or Hunters Point Switchyard.
T746	San Mateo-Martin 60kV Conversion to 115kV and Line Reconductoring	Reliability: Increase power supply to SF and northern San Mateo County	12/1/2004	Yes	Yes	Application withdrawn	Planning	The CPUC held evidentiary hearings on Feb. 25-27, 2002 to determine the plausible range of economic benefits from the Path 15 expansion project, on a stand-alone basis. Opening briefs were filed by ORA and PG&E on 6/14/02 regarding the potential application of General Order 131-D to the proposed MOU Path 15 upgrade project. Hearings were held on July 23, 2002, and additional testimony has been filed on the cost allocation of both the PG&E and the MOU projects (see ID# MOU). 1/31/03: CA ISO revised on-line date from TBD to 10/04. 3/7/03: CPUC issued proposed decision of ALJ Gottstein and alternate proposed decision of Cmsr. Lynch. Gottstein's proposed decision denies the project; Lynch's supports it. 5/22/03: CPUC gave permission to PG&E to withdraw its application.
T772	Contra Costa-Las Positas 230 kV Line	Reliability: category B; increase capacity of power interchange between substations.	5/1/2005	Yes	Pending Cost Estimate	No (NOC)	Planning	4/23/02 - Mirant has recently announced a two-year delay in its Contra Costa 8 power plant project. On line date changed from 5/1/03 to 5/1/05.
T655B	Jefferson Bank Capacity - Transformer Work	Emergency overload, low voltages	5/1/2005	Yes	Yes	No	Planning	Project added on 9/1/02. Install a second transformer bank. See also T655a (modify 60 kV line protection).
T854	Metcalf-Evergreen 115 kV Reconductoring	Reliability: Increase 115 kV supply	5/1/2005	Yes	Pending Cost Estimate	No (NOC)	Planning	Reconductor 115 kV lines between Metcalf and Evergreen Substations.

Table C-7 - Continued
PG&E Transmission Projects – Greater Bay Area

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
T082	Jefferson-Martin New 230 kV Line	Transmission deficiency under contingency condition	9/1/2005	Yes	Yes	Pending	Planning	ISO Board approved the beginning of permitting process. See S.F. Peninsula Long-Term Planning Study. 5/1/02 - Environmental evaluation on-going. 9/1/02 - PG&E still preparing Proponent's Environmental Assessment. PG&E filed CPCN application 9/30/02. 1/10/03 - Pre-Hearing Conf. at CPUC.
T692	Metcalf-Piercy, Swift-Metcalf, and Newark-Dixon Landing 115 kV Reconductoring	Reliability: Increase capacity of power interchange between substations	5/1/2006	Yes	Pending Cost Estimate	No	Planning	Reconductor the lines. 3/5/03: on-line date moved from 5/1/05 to 5/1/06. 6/1/03: Name change, adding "Swift-Metcalf."
T776	Monta Vista 60 kV Upgrade	Reliability: Increase 60 kV supply	5/1/2006	Yes	Pending Cost Estimate	No	Planning	Replace the existing Monta Vista 115/60 kV transformer with a larger unit.
T141	Lone Tree Substation (Transmission)	Greater Bay Area/East Bay (Diablo)	5/1/2007	Yes	Pending Cost Estimate	CPCN/ PTC TBD	Planning	7/16/03: CA ISO identified this as a major project in the Controlled Grid Study Plan. Connect a new 230/21 kV distribution substation with two 45 MVA transformers to the transmission grid.
T142	Robles 230 kV Substation (Transmission)	Reliability: Load growth	5/1/2009	Yes	Pending Cost Estimate	CPCN/ PTC TBD	Planning (Postponed)	Project deferred to 2004 due to reduced demand growth. 5/03: Project listed as "postponed due to decrease in demand growth."
T073	Bay Area 500 kV Transmission Long Term Plan	Increased electric demand in the Bay Area	TBD	Not yet	Pending Cost Estimate	TBD	Planning	In the conceptual planning stage: final alternative is not selected. Phase 2 economic studies underway with input from the CA ISO, San Francisco, and Palo Alto.
NA	Metcalf-Evergreen 115 kV Lines Special Protection System	Reliability	TBD	Not yet	Not yet	No	Planning	Install protection equipment to guard against thermal overloads. Further analysis concluded that this SPS is very complicated and extremely difficult to implement. PG&E will work with the CA ISO on an alternate.
NA	Newark-Scott 115 kV Lines Special Protection System	Reliability	TBD	Not yet	Not yet	No	Planning	Install protection equipment to guard against thermal overloads. PG&E is evaluating the feasibility and desirability of this SPS.

Table C-7 - Continued
PG&E Transmission Projects – Greater Bay Area

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
T010	Nortech (Kifer-Trimble) 115 kV Loop	Reliability: Increase reliability of supply to Nortech Substation	TBD	Yes	Yes	No (PTC Effective)	Construction	CPU A.98-06-001. A.K.A. North San Jose Capacity Project. New 115 kV substation and new 115 kV lines. Has encountered local permitting delays. 4/1/03: on-line date changed from 5/03 to TBD. Loops Kifer-Trimble 115kV transmission line through existing Nortech Substation. This project has recently encountered implementation issues.
NA	Ravenswood-Palo Alto Nos. 1 & 2 Special Protection System	Reliability	TBD	Not yet	Not yet	No	Planning	Install protection equipment to guard against thermal overloads. PG&E is evaluating the feasibility and desirability of this SPS.

Table C-8
SDG&E Transmission Projects

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
BP99117	Escondido Substation 230/69 kV Transformer	Emergency overload, increase SDG&E import capability by 200 MW, reduce future RMR cost	6/1/2001	Yes	Yes	No	In service	Install a new 224MVA 230/69 kV transformer at Escondido Substation.
BP98187	Rancho Santa Fe - Bernardo 69 kV Transmission Line	Normal overload	6/1/2001	Yes	Yes	Yes	In service	Reconductor 6.8 miles of the 69 kV line from the Rancho Santa Fe tap to the Bernardo tap
BP01140	Imperial Valley - La Rosita 230 kV Transmission Line Reconductor	Reliability	11/1/2001	Yes	Yes	No	In service	Reconductor 5.4 miles of the 230 kV transmission line from the Imperial Valley Substation to the US-Mexico border with two conductors per phase (6 conductors total)
BP98195	Sycamore Canyon Substation: New 230/69 kV Transformer	Reliability: Handle load growth	6/1/2002	Yes	Yes	No	In service	Install new transformer bank.
BP98191	Chollas-Spring Valley 69 kV Line: Reconductor TL 622	Reliability: Resolve Chollas-Spring Valley 2.5% overload	12/1/2002	Yes	Yes	No	In service	Supports load growth in the Lemon Grove and Spring Valley Areas.
BP99125A	Install reactive power support (Talega Substation capacitors and STATCOM)	Provide reactive power support and support increase to import capability	12/1/2002	Yes	Yes	No	In service	Install 207 MVAR, 230 kV capacitor bank and 100 MVAR, 230 kV STATCOM at Talega Substation.

Table C-8 - Continued
SDG&E Transmission Projects

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
BP99120	Expand 230 kV Capability at San Luis Rey Substation	Reliability: Support increase in import capability and load growth	2/1/2003	Yes	Yes	No	In service	Loop three 230 kV lines into San Luis Rey Substation and upgrade one 138 kV line to 230 kV.
BP01148A	Imperial Valley 500/230 kV Transformer Upgrades Phase A - replace existing bank	Economic: Mitigate congestion	6/1/2003	Yes	Yes	No	Design/ Construction	Phase A involves replacing the existing bank. Mitigates transmission system congestion due to new generation injection from the La Rosita Expansion Projects, SER's Thermoelectrica de Mexicali Project, and high exports from CFE. R
BP01143	Border Tap - Otay Lake: Reconductor TL649F Otay Lake Tap - Border Tap 69 kV Line	Economic: Remove Congestion	12/1/2003	Yes	Yes	No	Construction	Reconductor 5.7 miles of 69 kV line from Border Tap to Otay Lake Tap. 4/23/02 - SDG&E believes the CA ISO approval is premature since no party has submitted a system upgrade request for this economically-driven project pursuant to ISO tariff.
BP01148B	Imperial Valley 500/230 kV Transformer Upgrades Phase B	Economic: Mitigate congestion	12/1/2003	Yes	Yes	No	Design/ Construction	Phase B involves installing a new second 500/230 kV transformer bank. Mitigates transmission system congestion due to new generation injection from the La Rosita Expansion Projects, SER's Thermoelectrica de Mexicali Project, and high exports from CFE.
BP01146	Reconductor Portion of TL636 and TL638 at Santee Substation and Loop-in TL13821: Los Coches-Chicarita to Santee	Reliability: Load growth	12/1/2003	Yes	Yes	No	Construction	This project is associated with the Santee 138kV Conversion Project proposed by Distribution Planning. Reconductor 3.8 miles of two 69 kV lines near Santee Substation.

Table C-8 - Continued
SDG&E Transmission Projects

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
BP02164	Reconductor TL603 National City - Sweetwater-Naval Station Metering	Reliability	12/1/2003	Yes	Yes	No	Design/ Construction	This project is to increase the transmission capacity between Sweetwater Substation and the downtown area, which will increase operating flexibility and improve reliability to the downtown area load. Increase capacity of TL 603 to 1425 Amps.
BP01147	San Diego-Coronado 69 kV Line: Relocate Portion of the Line Under the San Diego Bay	Mandated: Reliability	2/1/2004	Yes	Yes	No	Design	Project conflicts with the proposed channel dredging by the US Army Corps of Engineers.
BP02162	TL 13813 and TL 13814 (South Bay-Main Street 138 kV lines) Capacity Increase	Reliability: Handle load growth	6/1/2004	Yes	Yes	No	Design	Increase capacity of TL 13813 and TL 13814, South Bay-Main street line reconductoring.
BP95144	Torrey Pines-UCM Substation 69 kV Line	Reliability: Handle load growth	6/1/2004	Yes	Yes	No	Design	Construct approximately 2.5 miles of new underground 69 kV line between UCM and Torrey Pines Substations.
BP00150	Reinforce TL23030 Transmission Between Escondido and Orange County	Reliability	12/1/2004	Yes	Yes	Part of Valley-Rainbow CPCN	On hold	Reinforce TL23030 Transmission Between Escondido and Orange County. On-hold due to pending appeal of the Valley-Rainbow decision.
BP98192	Escondido-Ash: Reconductor TL 696	Reliability: Escondido-Ash 1% overload & increases transmission capacity to Ash	6/1/2005	Yes	Yes	No	Design	Reconductor 3.5 miles of 69 kV line between Escondido and Ash Substations to serve additional load from new casino at Indian Reservation. Planned operating date may be advanced due to outage requirement. Three lines in this area are being upgraded by 6/03. 5/03:

Table C-8 - Continued
SDG&E Transmission Projects

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
BP00146	Escondido-Lilac: Reconductor TL688	Reliability: Mitigate thermal overload	6/1/2005	Yes	Yes	No	Design	Reconductor 9 miles of the Escondido-Lilac 69 kV transmission line to serve load growth in Lilac, Pala and Rincon areas.
BP01144	Miguel-Mission Second 230 kV line	Economic: remove congestion; accommodate new generation south of Miguel Substation	6/1/2005 (delay expected)	Yes	Yes	Yes (Filed)	Permitting/ Design	CPUC Proceeding I.00-11-001 (AB970). A. Construct a new 230 kV double-circuit line from Miguel Substation to Fanita Junction, using the existing 138 kV steel tower line. B. Extend the new 230 kV line from Fanita Junction to Mission Substation. 6/4/02 - Project slipped from 12/01/04 to 6/1/05. 6/25/02 - ISO approval obtained. 7/12/02 - Application for CPCN filed. 8/12/02 - SDG&E received deficiency letter for their CPCN application. 9/6/02 - Pre-hearing conference was held on CPCN application. 2/3/03: SDG&E indicated that the CPUC staff determined the CPCN application is adequate on 1/27/03. 2/28/03: CPUC approved project; CPCN still needed.
BP00152A	Static and Dynamic Reactive Power Support	Reliability	6/1/2005	Subject to re-evaluation	Yes	Part of Valley-Rainbow CPCN	On hold	A. At Sycamore Substation, install 138 MVAR, 230 kV capacitor bank; B. At Miguel Substation, install 69 MVAR, 230 kV capacitor bank; C. At Mission Substation, install 200 MVAR STATCOM.
BP02160	Transmission Capacitors	Reliability: Support load growth	6/1/2005	No	Yes	No	Planning	Install transmission capacitors at Telegraph Canyon, Sycamore Canyon, and San Luis Rey. 3/03: removed Sycamore Canyon STATCOM from project scope, pending further study. 6/03: In-service date moved from 6/2004 to 6/2005.
BP02161	Upgrade Scripps Sycamore Canyon and Miramar to Scripps	Reliability: Handle load growth	6/1/2005	Yes	Yes	No	Planning	Build new 69 kV line between Sycamore Canyon and Miramar Substations and Reconductor the Miramar-Scripps 69 kV line.

Table C-8 - Continued
SDG&E Transmission Projects

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
BP00154	Shadowridge-Calavera Tap 69 kV Line: Reconductor TL 13802B	Reliability: Load growth	6/1/2006	Yes	Yes	No	Design	Reconductor 3.5 miles of the 138 kV Shadow Ridge-Calavera Tap transmission line.
BP01142	Rincon-Lilac 69 kV: Reconductor TL683	Reliability: Load growth	6/1/2007	Yes	Yes	No	Design	Reconductor 12.2 miles of the 69 kV line Rincon-Lilac transmission line. New project due to casino load.
BP01141	Talega-Pico Transmission Line: Reconductor 138 kV TL	Reliability: Load growth	6/1/2007	Yes	Yes	No	Planning	Reconductor 0.68 miles of 138 kV line between Talega and Pico Substations.
BP03170	Silvergate-New 138/69 kV Substation	Reliability	12/1/2007	No	Yes	PTC to be filed	Planning	Move TL from Main Street Substation to Silvergate Substation; construct a new 138 kV/60 kV substation.
BP00153	Capistrano-Laguna Niguel Transmission Line: Reconductor 138 kV TL13837	Reliability: Handle load growth	6/1/2009	Yes	Yes	No	Planning	Reconductor 2.9 miles of 138 kV line from Capistrano Substation to Laguna Niguel and San Mateo Substations to meet projected load growth.
N/A	Imperial Valley-La Rosita Second 230 kV Line	Support increase to import capability and load growth	TBD	No	No	Yes (see comment)	Planning	CPUC proceeding Install a second 230 kV circuiton existing double-circuit towers between Imperial Valley and La Rosita Substations. Project added on 6/1/02. Project would add up to 800 MW of capacity to Path 45. SDG&E, CFE, IID, and several merchant generators are participating in a joint study process for further expansion of Path 45 in 2003-2005. Addition of a second circuit on the existing towers was authorized as part of the original CPCN decision D83-10-004, and was reaffirmed by CPUC decision D01-12-016.

Table C-8 - Continued
SDG&E Transmission Projects

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
BP99123	Valley-Rainbow Interconnection Project, 500 kV	Reliability: Support increase to import capability and load growth	Unknown (previously was 6/1/05)	Yes	Yes	Yes; filed 3/23/01. Docket closed & CPCN denied 12/19/02.	Denied 12/19/02; Appeal denied	CPUC A.01-03-036. Project denied 12/19/02. Appeal denied by CPUC 5/03.

Table C-9
SCE Transmission Projects

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
NA	Antelope-Bailey 66 kV System (Phase I)	Reliability: minimize voltage problems and improve system performance in the Tehachapi area.	1/1/2001	Yes	Yes	No	In service	Phase I: Upgrade existing 66 kV Tehachapi system (re-arrange line, add small segments of 66 kV lines and add a new CalCement line position. See below for additional project, #04825.
04376	Alamitos - Barre #2 230 kV Transmission Line	Reliability	6/1/2001	Yes	Yes	No	In service	Replace 2000A wave traps with 3000A wave traps on the Alamitos-Barre #2 line terminals at Alamitos and Barre Substations
04376	Midway-Vincent 33 Wave Trap (Path 26 500 kV Transmission Lines)	Reliability	6/1/2001	Yes	Yes	No	In service	Part of Path 26: Replace wave traps at Vincent and Midway. Due to increased load, the wave trap has to be replaced with a higher rating to avoid overload. 12/04/02 - Project added. 2/5/03: CAISO confirms in-service date as 6/01.
N/A	North of Lugo RAS Modifications - Alta RAS	System Stability	3/1/2002	Yes	Yes	No	In service	In service as of 3/1/02.
04701	Barre-Lewis, Barre Villa Park 230 kV Reconductoring and misc terminal equipment	Reliability plus elimination of higher-cost RMR contract	6/1/2002	Yes	Yes	No	In service	Reconductor Barre-Lewis/Villa Park 230 kV lines.
04917	Hinson-Lighthipe 230 kV Transmission Line	Reliability	6/1/2002	Yes	Yes	No	In service	Project added on 5/1/02. Replace existing wave traps with 3000A wave traps on the Hinson-Lighthipe 230 kV line terminal at Lighthipe Substation.
04701	Mesa/Pardee/ Sylmar 230 kV Transmission Lines	Reliability plus elimination of higher-cost RMR contract	6/1/2002	Yes	Yes	No	In service	Project added on 5/1/02. Replace wave traps on the Mesa/Pardee/Sylmar 230 kV line terminals at Eagle Rock Substation.

Table C-9 - Continued
SCE Transmission Projects

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
04701	Serrano-Villa Park #1 and #2 230 kV Transmission Lines	Reliability plus elimination of higher-cost RMR contract	6/1/2002	Yes	Yes	No	In service	Project added on 5/1/02. Re-rating of the line risers at Serrano Substation on the Serrano-Villa Park #1 and #2 230 kV lines.
N/A	North of Lugo RAS Modifications - Mc Gen RAS	Reliability: Eliminate risk of N-1 overload	12/31/2002	Yes	Yes	No	In service	
04701	2001 RMR Elimination Project Capacitor Banks	Reliability plus elimination of higher-cost RMR contract	5/1/2003	Yes	Yes	No	In service	Install 79 MVar, 230 kV capacitor banks at Mesa, La Freda, and Laguna Bell Substations. 6/1/03: In-service dated changed from 6/1/03 to 5/1/03.
03773	Valley Substation Phase 1: Third 500/115 kV Transformer	Reliability: relieve substation overload	6/1/2003	Yes	Yes	No	Construction	Install 500/115 kV Transformer #3 (560 MVA) at Valley Substation; Phase 1. Expected to be in service during 2003 (no month given in the monthly CPUC filing), with a 4th bank expected in service (Phase 2) in 2004. See separate entry for Phase 2. 3/03: filing lists Phase 1 expected on-line in 2003 (no month specified); Phase 2 for 6/2004.
04936	Vincent Fourth 500/230 kV Transformer bank	Reliability	8/1/2003	Yes	Yes	No	Construction	Install fourth transformer bank to avoid overload during outage of any of the three transformers at Vincent. 6/1/03: In-service date moved from 7/03 to 8/03.
T903 (PG&E) and 04833 (SCE)	Path 26 Upgrade Project, Phase 1 (Short-term solution) - - RAS to Drop SCE Load	Economic: Increase transfer capability and relieve transmission congestion	11/03 (Staff Estimate)	Yes	Yes (PG&E)	No	Planning	Phase 1. Project added on 5/1/02. Modify the existing remedial action scheme to trip generation in the Midway area for a 500 kV double line outage. This would increase the north-to-south transfer capability of Path 26 from the existing 3000 MW to 3400 MW (short-term solution). See also the Path 26 Upgrade Project Long-term solution. 1/27/03: SCE lists project as under construction, expected on-line 6/1/03; PG&E expects project on-line 11/03.

Table C-9 - Continued
SCE Transmission Projects

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
04825	Antelope-Bailey 66 kV System (Phase II)	Reliability: Minimize voltage problems & improve system performance in Tehachapi area.	5/1/2004	Yes	Yes	No	Construction	On-going studies aimed at resolving constraints placed upon wind developers. See also the Tehachapi Transmission Line project below (project ID#04928). Project added on 5/1/02. 3/17/03: SCE letter to CPUC indicates intention to proceed with Tehachapi project. 6/1/03: In-service date changed from 12/05 to 5/04.
04521	Mira Loma 500/230 kV Fourth Transformer Bank	Reliability: Resolve emergency overloads	6/1/2004	No	Yes	No	Planning	Install 500/230 kV Transformer #3 (1120 MVA) at Mira Loma Station.
04889	Upgrade the three 500 kV Transmission Lines South of Lugo: Lugo-Mira Loma #2 & #3; and Lugo-Serrano Substation.	Reliability: Avoid overload during outage of two of the three lines	6/1/2004	Yes	Yes	No	Construction	For each of the three lines, this upgrade will: (a) increase separation of line conductors from ground at several locations; (b) replace all 500 kV wave traps (18 total); and (c) upgrade the 500 kV GIS line riser at Serrano Substation on the Lugo-Serrano 500 kV line.
03773	Valley Substation, Phase 2: 560 MVA, Fourth 500/115 kV Transformer	Reliability: Relieve substation overload	6/1/2004	Yes	Yes	No	Construction	Install 500/115 kV Transformer #4 (560 MVA) at Valley Substation. See separate entry for Phase 1.
04902	Zack Tap 55 kV Reliability Project (AKA Silver Peak Circuit Breaker; AKA Control - Zack Switch)	Reliability: Reduction of circuit interruption (PBR Benefit)	6/1/2004	Yes	Yes	No	Construction	Install a switch at the tap for the Silver Peak leg on the Control-Zack-White Mountain -Deep Springs 55 kV transmission lines.

Table C-9 - Continued
SCE Transmission Projects

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
03603	Viejo 230/66 kV Substation	Reliability: Install various facilities to relieve A-Bank and transmission line loading and also to improve reliability by creating load-rolling options	5/1/2005	Yes	Yes	No (PTC expected)	Permitting	Connect to 230 kV system by looping San Onofre-Chino 230 kV line into it. 3/03: on-line date moved from 2004 to 5/1/05.
None	Devers-Palo Verde 2	Reliability: increase import capability from desert southwest into California and facilitate deliver of generation in Palo Verde area	6/2005	No	No	Yes	Planning	Preparing to file CPCN application in the 4th qtr of 2003 or early 2004 after preparation of the Proponent's Environmental Assessment (PEA). Will significantly increase the import capability from the desert southwest into CA and facilitate the delivery to California of additional generation supply from facilities in the Palo Verde area.
04928	Tehachapi Transmission Line	Reliability: minimize voltage problems, increase capacity, and connect wind generation	2006 or later	No	Yes	No (CPCN expected in first half of 2004)	Planning	CPUC I.00-11-001 (AB970). A new 230 kV line is a proposed alternative solution to the Antelope/Bailey 66 kV system upgrades (project ID#04825). Includes both 230 and 69 kV facilities. 1/15/03: SCE completed and issued the Phase 2 Tehachapi Transmission Conceptual Study. Project would include construction of 230 kV line between SCE's existing Pardee substation and a new substation in the Tehachapi area, plus construction of associated 66 kV collector lines from various windparks. Project would support development of potential new renewable resources in this area.

Table C-9 - Continued
SCE Transmission Projects

PTO ID # (ISO ID #)	Project Name	Purpose	Current Projected or Actual On-line Date	ISO Approved	PTO Approved for Funding	CPCN Required	Project Status	Description / Comments
None	Etiwanda 500/230 kV Substation	Reliability: Load growth	2008	No	No	No (PTC application expected 4th qtr of 2003)	Planning	Required to serve growing customer load in western San Bernardino County area.
None	Path 26 Upgrade Project (Long-term solution): Phase 2	Economic: Increase transfer capability and relieve transmission congestion	TBD	No	No	No	Planning	Phase 2; see Project 04833 for Phase 1. Upgrade the existing Path 26 transmission system by making facility upgrades at the Midway and Vincent Substations, and reconductoring PG&E's 500 kV line segment of the Midway-Vincent #3 500 kV line, in order to increase the bi-directional path rating from 3400 MW (following a short-term upgrade) to 4000 MW. Project added on 5/1/02. 6/1/02 - In service date changed from 2007 to TBD.

APPENDIX D
PROJECTED SUPPLY/DEMAND BALANCE THROUGH 2006

Table D-1
Three Year Outlook - Generation Additions

Unit	On Line Date	Status	Owner	Capacity	Region
Grayson 9	12/30/2003	UC	Glendale	49	Los Angeles
Glenarm GT 3,4	10/1/2003	UC	Pasadena	94	SP-15
Valley LADWP CC	10/1/2003	UC	LADWP	520	Los Angeles
New Renewables	7/1/2004	Planned	Unknown	50	Statewide
Total 2004 Additions				**713**	
Kings River Peaker	7/1/2005	UR	Kings River	85	NP-15
Vernon GTs	5/1/2005	Permitted	Vernon	135	SP-15
Magnolia CC	3/1/2005	Permitted	Anaheim&BGP	315	Los Angeles
Cosumnes River	3/15/2005	UR	SMUD	458	SMUD
MID Cogen	12/1/2005	UR	MID	90	NP-15
San Francisco Reliability Peaker	5/1/2005	UR	City of SF	180	San Francisco
Pico	1/1/2005	UR	SVP	147	NP-15
Haynes Repower	2/20/2005	UC	LADWP	575	Los Angeles
Generic CC	Prior to 8/1/2005	Planned	Unknown	1000	SP-15
New Renewables	Prior to 8/1/2005	Planned	Unknown	15	Statewide
Total 2005 Additions				**3,000**	
Walnut CC	12/1/2004	UR	TID	240	NP-15
Salton Sea #6	7/1/2005	UR	CalEnergy	177	IID
New Renewables	Prior to 8/1/2006	Planned	Unknown	179	Statewide
Generic San Diego	12/31/2005	Planned	Unknown	500	Miguel CA
Total 2006 Additions				**1,096**	

Status Key:
UC = Under construction
UR = Under review in permit process

Table D-2
Three Year Outlook for Generation Retirements

Unit	Retirement Date	Capacity	Region
Haynes 4	9/30/2003	222	Los Angeles
Pittsburgh 3&4	10/1/2003	304	NP-15
Alamitos 7	12/31/2003	134	SP-15
Etiwanda 5	12/31/2003	130	SP-15
Magnolia GT 5	1/1/2004	22	Los Angeles
Olive 3,4	1/1/2004	56	Los Angeles
Valley 1-4	4/15/2004	323	Los Angeles
Total 2004 Retirements		**1,191**	
Haynes 3	9/30/2004	222	Los Angeles
Haynes 5&6 derate	9/30/2004	82	Los Angeles
Generic Retirements	Prior to 8/1/2005	750	Statewide
Total 2005 Retirements		**1,054**	
Mohave 1,2	12/31/2005	916	SP-15&LADWP
Hunters Point 4	1/1/2006	163	NP-15
Hunters Point GT1	1/1/2006	56	NP-15
Generic Retirements	Prior to 8/1/2006	1250	Statewide
Total 2006 Retirements		**2,385**	

Table D-3
Three Year Outlook - Imports

Summary of Imports	August 2004	August 2005	August 2006
Dynamical Scheduled Imports	1,895	1,895	1,895
CA ISO Muni Share of Dynamics	903	903	903
Existing Firm Contracts	1,962	1,815	1,810
SCE QF Geothermal In IID	440	440	440
Firm Exports	(105)	(105)	-
Sempra CDWR Obligation	800	800	800
Total	**5,895**	**5,748**	**5,848**

Table D-4
Three Year Outlook - Municipal Utilities Generation Additions

Unit	On Line Date	Status	Owner	Capacity	Region
Grayson 9	12/30/2003	UC	Glendale	49	Los Angeles
Glenarm GT 3,4	10/1/2003	UC	Pasadena	94	SP-15
Vernon GTs	5/1/2005	Permitted	Vernon	135	SP-15
Magnolia CC	3/1/2005	Permitted	Anaheim&BGP	315	Los Angeles
Cosumnes River	3/15/2005	UR	SMUD	458	SMUD
MID Cogen	12/1/2005	UR	MID	90	NP-15
Pico	1/1/2005	UR	SVP	147	NP-15
Walnut CC	12/1/2004	UR	TID	240	NP-15
Total Municipal Utilities Proposed Additions 2004-2006				1528	

APPENDIX E
LOCAL RELIABILITY ISSUES

APPENDIX E
LOCAL RELIABILITY ISSUES

INTRODUCTION

In this chapter, we examine two energy-constrained California regions as examples of how local stakeholders can work towards solving their region's problems. Both San Diego and San Francisco – the case studies for this chapter – face substantial constraints for generation-based grid service. In response, local stakeholder groups have developed integrated energy plans that balance generation, transmission, and demand options to serve local customers. San Diego and San Francisco's experiences may demonstrate some "best practices" that could be used to deal with other local energy concerns, and the legislature may wish to consider encouraging such local efforts if these are desirable components of solving the state's energy problems.

In order to meet demand in the San Diego and San Francisco Peninsula regions, investment in energy infrastructure is needed in the next five years. Because local stakeholders perceive that there are preferable alternatives to the central station and grid expansion options which can be developed by utilities and merchant power, they have organized to explore a broader range of options. This chapter focuses on the attempts of local stakeholder groups within San Diego and the San Francisco Peninsula areas to craft regional solutions and describes lessons learned along the way.

A variety of stakeholders and agencies have organized to develop solutions to the energy challenges faced in San Diego and the San Francisco Peninsula. The processes in which these stakeholders can participate to affect a change are:

- The CA ISO transmission planning process,
- The CPUC's transmission permitting proceeding,
- The San Diego Regional Energy Office's processes,
- The Governor's Office of Planning and Research Environmental Justice Committee,
- City and county led processes, and
- Other CPUC and Energy Commission proceedings.

A variety of stakeholders who often hold disparate views participate in these processes and much good work has been done by the stakeholders in these contexts. Unfortunately, the resource planning and resource deployment roles of agencies are not always clearly defined. As a result, the agreements that stakeholder groups work out are sometimes duplicated and/or in conflict with agreements and decisions that arise from an alternative process.

After a general discussion of local reliability areas, this chapter covers the San Diego and San Francisco Peninsula regions in turn. These discussions are organized as follows:

- A description of the region's unique electrical constraints,
- Actions and positions of stakeholder groups, and
- Lessons learned.

The regional-specific sections are followed by a general discussion of best practices for future development of balanced energy portfolios in local areas. Finally, the chapter ends with a summary of actions suggested by stakeholder participants in the Energy Commission's July 16 - 23, 2003 virtual workshop on local reliability.

LOCAL RELIABILITY AREAS

The San Diego and the San Francisco Peninsula regions suffer from insufficient generation to support effective, competitive electricity markets within the area and from limited transmission capacity to import electricity from outside the area. Their generation and transmission infrastructure have not been expanded or modernized to keep pace with economic growth. In order for the system to meet consumer demand, the inefficient older units must be utilized, often at higher costs and with more pollution than newer units would produce. The higher level of pollution emitted from the inefficient power plants creates undesirable air quality impacts. This combination of conditions increases the susceptibility of the local area to reliability problems and to the exercise of market power.

San Diego

San Diego experiences many unique electricity supply challenges. New supplies in the region are not expected to keep pace with the demand growth expected over the 2004 - 2010 time period. Bounded by the Pacific Ocean on the west, the Laguna Mountains to the east, the Mexican border to the south and Camp Pendelton to the north, there are simply few transmission routes to import power generated outside the region to meet demand. Also, the configuration of San Diego's electrical grid limits the amount of power that can be imported into the region. To avoid near term imbalances, the region needs more generation plants, additional transmission capability, and more energy efficiency. Actions are needed to develop energy infrastructure so that the reliability problems will be alleviated and, presumably, there will be less chance of the regional price spikes.

Residents of the San Diego Region, especially Chula Vista, are very concerned about the pollutants from the older gas fired power plants, including south bay power plant.

Although San Diego's electricity situation is precarious even in the best of years, the community received a wake up call in the summer of 2000. San Diego was the first area of the state to experience sharply rising energy costs. As part of deregulation,[1] electricity rates were frozen until utility "stranded costs" were paid off. Since SDG&E had few stranded costs, it was the first utility to pay them off. It was thought that ratepayers in the San Diego Area would benefit from competitive market prices and see a decrease in their rates.

Unfortunately, the rate freeze ended just at the start of the wholesale energy crisis. As a result, when the wholesale prices in the restructured energy market rose dramatically, SDG&E passed on increases in wholesale energy costs to customers.

Rates paid by SDG&E customers doubled during the summer of 2000.[2] At the peak of that summer's startling cost run-up, typical residential customers were paying nearly $130 monthly for a quantity of power that cost $55 prior to the price spike.[3] After this crisis, the legislature re-instituted a rate freeze. However, San Diego will continue to be a high cost electric market through at least 2006.[4]

The following section describes some of the actions, positions, and recommendations of stakeholder groups.

The California Independent System Operator Transmission Planning Process

The CA ISO is responsible for grid operations for the state's IOUs. While it is each individual utility's responsibility to build transmission in their service territory, the CA ISO has taken a more regional approach to transmission planning. In 1999, the CA ISO initiated a transmission planning process to identify needed improvements. One outcome of this planning process was a determination that by 2004, SDG&E could be in violation of the CA ISO grid planning criteria in the event of a sequential outage of its largest generator and largest transmission line.

SDG&E, in conjunction with the CA ISO, SCE Company, and other CA ISO stakeholders, conducted several technical studies evaluating potential transmission upgrade alternatives on the basis of project reliability, cost effectiveness, and construction feasibility. Out of all the alternative projects, they concluded that the preferred project was the proposal for a 31 mile, 500 kV transmission line running from the Valley Substation in Riverside County to a new Rainbow Substation in Northern San Diego (the Valley-Rainbow project).

Despite opposition from parties located near the proposed construction site, the CA ISO board approved the project in May 2000. The CA ISO confirmed the need for the project three additional times.

Although the CA ISO is responsible for grid operations, it does not have authority to authorize construction of transmission projects. Approvals must be received from the FERC and the CPUC, serving in its capacity as the California Environmental Quality Act (CEQA) lead agency.

Construction of the Valley-Rainbow 500 kV line: California Public Utilities Commission Permitting Process

On March 23, 2001, SDG&E applied to the CPUC for a certificate of public convenience and necessity to construct the proposed 500 kV Valley-Rainbow transmission project and associated upgrades. As part of the CEQA process, the CPUC initiated its public process to see if the project would be needed for reliability or if it provides economic benefits. This provided an opportunity for the project opponents to present a case that the Valley-Rainbow project was not needed.

The CPUC found insufficient evidence to establish the need for this bulk transmission project in the next five years and did not issue the certificate of public convenience and necessity for the project.[5]

Subsequently, SDG&E filed a petition asking the CPUC to reverse its conclusion regarding the need for a project within the five year planning horizon based on "new evidence." The CPUC later denied this petition.

Demand Response: California Public Utilities Commission Process

An interagency working group led by the CPUC was formed to develop demand response as a resource to enhance electric system reliability, reduce power purchases and individual customers' costs, and protect the environment. The interagency group considered actions for all investor-owned electricity utilities.

A decision[6] issued by the CPUC on June 5, 2003 gives SDG&E's service territory special consideration. The decision granted SDG&E permission to convert an existing pilot program, the "Hourly Pricing Option", into a full-scale program. The program is targeted to all customers with monthly loads greater than 100 kW. Participating customers must have interval meters and are charged varying rates depending on the next day demand forecast. The day-ahead price signal would create an incentive for customers to avoid peak usage or to shift usage to off-peak periods. Customers are expected to adjust their usage accordingly.

San Diego Regional Energy Office Processes

Separate from the utility and CA ISO-led stakeholder planning processes, another stakeholder group was formed to address energy issues in the San Diego Region. A multi-agency team consisting of the City of San Diego, County of San Diego, Port of San Diego, San Diego County Water Authority, San Diego Association of Governments, San Diego Regional Energy Office (SDREO), and the Utility Consumers Action Network met to develop cost-effective strategies to achieve the goal of a reliable and affordable energy future for the San Diego Region. The team was called the San Diego Regional Energy Infrastructure Group.

The goal of the multi-agency San Diego Regional Energy Infrastructure Group was to develop a fact-based foundation for assessing the San Diego region's electricity and natural gas needs through 2030. The group also felt that it was important to get the San Diego region stakeholders more involved in planning the region's energy infrastructure so as not to count on state and federal regulators to make decisions that are in the best interest of the region.

The multi-agency San Diego Regional Energy Infrastructure Group is funded by all participating organizations, except the SDREO. In all, $400,000 was allocated to this effort. SDREO led the team and provided in-kind resources and staff.

On December 30, 2002, SDREO released the ***San Diego Regional Energy Infrastructure Study***. The infrastructure study provided an integrated, comprehensive analysis of the electricity and natural gas supply/demand inventory and critical energy issues for the region. This report was a step in helping the region to take a more cooperative, coordinated and proactive role in determining its energy future.

Key findings from the infrastructure study were as follows:

- Electricity demand in the region is expected to nearly double by the year 2030.
- It will become increasingly difficult to meet this growing electricity demand with traditional grid-based generation and transmission infrastructure.
- A significant portion of the new load growth can be met with energy efficiency, smaller scale generation and renewables.
- A minimum of two 500 MW baseload generating plants are still needed – more if the region does not pursue alternative energy sources.
- Additional transmission is also needed.
- Sufficient local gas natural gas distribution system capacity exists for core customers, but market issues continue and could worsen for natural gas capacity and supply.
- There is a long term concern about over-reliance on natural gas as a fuel source.

While it supported the need for more transmission, the team felt that it did not have enough information to specifically support the Valley-Rainbow project.

The report identified the need for a more formal approach to energy planning decision making and resource allocation. In 2002, SDREO followed up the infrastructure study by leading the development of a new process to promote smarter and more sustainable growth. The SDREO goal is to strive to get more stakeholder involvement and more consensus throughout the decision-making process. The San Diego Association of Governments contributed $50,000 and, along with the SDREO, worked to make the new strategy a success.

As a step in that process of getting more stakeholder involvement, they formed a Regional Energy Policy Advisory Council (REPAC). The San Diego Association of Governments' board of directors appointed the voting members of REPAC to represent diverse groups of stakeholders. Voting members are high level officials from business, elected officials from city and county and county government, consumer groups, the

SDREO, the water authority, the port district, and academia. In addition, several organizations and citizens serve in an advisory capacity.

REPAC meets monthly. In between the monthly meetings, SDREO supports the effort by holding educational workshops on a variety of energy related topics. The purpose of REPAC and the advisory group is to develop regional consensus on the energy issues. They decided to tackle the issues in two parts. First, they developed agreements on what needs to be done. Second, they decided on how to implement the recommendations. In between REPAC's monthly meetings, the SDREO supports the effort by holding educational workshops on a variety of energy related topics.

In May 2003, the team released the ***Regional Energy Strategy***, which describes the vision on what needs to be done in the San Diego region to develop a desirable energy future. Much of the supporting data and content for the ***Regional Energy Strategy*** were derived from the ***San Diego Regional Infrastructure Study***.

The stakeholder group is now talking about how to implement the energy vision. The group analyzed several options, finally choosing one that signaled their commitment to break with an energy planning paradigm dominated by a utility whose interests might sometimes conflict with those of local stakeholders.[7] In July, the REPAC voted overwhelmingly to recommend to the San Diego Association of Governments that it establish an energy committee. The nonprofit organization would attempt to acquire more secure funding and, through a Memorandum of Understanding (MOU), obtain the authority to implement the ***Regional Energy Strategy***. The new organization could have the power to float bonds, construct power projects, and could finance and promote renewables and DG.

The SDREO has learned that an open, inclusive and transparent planning process is effective in getting consensus on complex issues. The SDREO's advice is to accept that it takes a long time to get stakeholders to agree, but that it is important to listen to everyone. Stakeholders are more receptive to accept the final choice when they feel included and heard, even if their individual ideas were not implemented.

In terms of participating in other stakeholder processes, the SDREO has been very busy leading its own effort and has not had the resources to spend much time going to various proceeding held by the California Legislature, the Energy Commission, the CPUC, the SDG&E, and the CA ISO. The group has submitted comments to the CA ISO and attended CA ISO meetings. It has also used feedback and background material from the CA ISO, but staffing considerations limit their level of involvement. SDREO is very supportive of time-of-use pricing for residential customers but again staffing considerations limit their level of involvement in the working groups.

Lessons Learned

- Local stakeholders prefer to have a role in selecting solutions to energy problems so that their local objectives and needs are considered.
- It is important to educate stakeholders, to solicit their input early, and to try to get consensus on regional energy issues and solutions.
- While there is no single view about what resource mix or market structure would best serve the region, there is reason to believe that the majority of San Diego Stakeholders support smaller scale, environmentally friendly generation, and energy efficiency over expensive, larger scale and less environmentally friendly projects.
- People are rarely equally impacted by transmission projects. The people who live near the transmission site typically believe that they will lose property value, are concerned about visual impacts or may be concerned about health impacts. These are the issues that made the siting of certain transmission projects in San Diego contentious.
- The mechanism to carry out local wishes is not yet clearly established.
- The grid planning roles of the CA ISO and the CPUC are not clearly defined, and work done by the CA ISO may be superceded by the CPUC.
- SDREO is attempting to create a collaborative model with municipalities to determine San Diego Region's energy future

San Francisco

San Francisco's electricity system is supplied by two old, pollution intensive power plants, one at Hunters Point and one at the base of Potrero Hill, and through overhead and underground transmission lines along a single pathway through San Mateo County. San Francisco is transmission constrained. During periods of peak demand, the city can only import approximately 60 percent of the power needed using the existing transmission lines (if the largest single transmission line is out of service). Consequently, the CA ISO reliability requirements force operation of two high-polluting power plants to maintain grid reliability.

San Francisco Bay Area residents exhibit a high degree of interest in San Francisco's electricity system. The main concern centers on environmental justice. Power plants are located in communities consisting of a higher proportion of lower-income, predominately non-white residents.

For years, communities in the southeast, where there is a high level of respiratory disease, have been calling for the shut down of Hunters Point power plant. In 1998, PG&E and the mayor signed an agreement to close the plant as soon as replacement power was available to assure reliability. The Hunter's Point power plant, while owned and operated by PG&E, is required to remain in service until the CA ISO can certify that the plant is no longer essential for electric system reliability.

Also on December 8, 1998, PG&E's system experienced a severe disturbance that resulted in a blackout of most of the City of San Francisco and nearby communities on the

San Francisco Peninsula. This served as a wake-up call that something needed to be done about reliability and further galvanized the community to seek a new focus.

In 1999, as part of the deregulation process, PG&E sold its power plant at Potrero to a merchant energy company named Mirant. The new owner decided to add a new power plant more than twice the size of the existing plant. This proposal has met with strong community resistance that has raised concerns about environmental justice in the neighborhoods bordering the fossil fuel plants.

The following section describes some of the actions and positions of stakeholder groups as they develop recommendations and try to get them implemented within the context of a variety of processes.

SF Peninsula Planning Study Group

In response to severe blackouts faced by San Francisco, the CA ISO formed a stakeholder group whose purpose was to coordinate the development of a long term plan (five to ten years) to reliably serve the future electric needs of the San Francisco Area. The stakeholder group includes the City and County of San Francisco, PG&E, the CPUC, the Energy Commission, various generation developers, and others.

The stakeholder group completed various power flow studies for the summer and fall of 2004 and 2009 to evaluate the adequacy of the existing transmission system. The study results indicated that without new transmission or generation facilities, system performance would be unacceptable. To address these deficiencies, stakeholders evaluated potential generation, load reduction, and transmission solutions.

Due to the magnitude of load reduction that would be required, load reduction programs alone were not considered to be an effective long-term solution. Generation solutions were studied by assuming a generic 400 MW power plant connected to the Potrero 115 kV substation. Generation at this site was determined to be an effective long-term solution. Six potential transmission projects were considered. The preferred transmission project was the Jefferson-Martin 230 kV line in combination with system reinforcements within San Francisco. The conclusion of the CA ISO management and the stakeholder group was to recommend that PG&E initiate permitting activities for the Jefferson-Martin 230 kV line.

Construction of the Jefferson-Martin 230 kV line: California Public Utilities Commission Process

On September 30, 2002, PG&E filed an application with the CPUC requesting that the CPUC begin the CEQA review of proposed construction of the Jefferson-Martin 230 kV line. PG&E supports the project for four reasons: to reliably meet electricity demand; to satisfy the CA ISO planning criteria; to diversify the transmission system; and to implement the CA ISO board of governors' resolution approving the proposed Jefferson Martin project for addition to the CA ISO controlled grid. PG&E asserts that the CPUC must defer to the CA ISO's determination of need.

The positions of some key stakeholders are as follows. The City and County of San Francisco support the proposed project for reliability and economic reasons. Protests were filed by the Office of Ratepayer Advocates (ORA), the town of Hillsborough, the 280 Corridor Concerned Citizens Group, and several private citizens. In its protest, ORA contests PG&E's assertion that the CPUC has no authority to make findings regarding the need for the project in light of the CA ISO's determination. ORA raises questions regarding the need for the project, the respective roles of the CPUC and the CA ISO in determining need, and the CPUC's role in ratemaking for the project.

The remaining protests and the informal e-mails and letters variously question the need for and timing of the proposed project; raise concerns regarding electric and magnetic fields, visual impacts, construction impacts, property values, and community values, and ask for consideration of alternatives such as undergrounding the transmission lines or relocating the transmission towers farther west. The 280 Citizens Group asserts that a five-year planning horizon should be used consistent with CPUC decision D.02-12-066.

At the pre-hearing conference, the United States Department of the Interior (DOI) stated its position that the proposed project is subject to the requirements of the National Environmental Policy Act (NEPA) because a portion of the project would traverse National Park Service easements on San Francisco watershed land. As the lead federal agency for NEPA, DOI stated its preference that the CPUC prepare a joint environmental document, combining NEPA review with the CPUC's review under the CEQA.

On March 19, 2003 the CPUC issued a pre-hearing conference statement that provides the basic scope of the proceeding. The CPUC ruled that the proceeding will include the following issues (among others): the need for the project, community recreational aesthetic and environmental values, determination of the appropriate planning horizon, costs, and cost effectiveness. The CPUC decided not to prepare a joint environmental document with DOI.

Public Power Campaigns

San Francisco has an active group of stakeholders who are advocating replacing PG&E with a municipal power agency. They received enough signatures to place two initiatives on the 2001 ballot that would have mandated the revocation of PG&E electric distribution franchise and enough signatures to place another similar initiative on the ballot in 2002. Both public power initiatives were defeated; however, citizen interest in public power for San Francisco continues.

San Francisco City Departments

In May 2001, the City's Board of Supervisors unanimously passed (by a 10-0 vote) an ordinance introduced by Supervisor Sophie Maxwell, who represents both the Hunters Point and Potrero neighborhoods. The ordinance, called "Human Health and Environmental Protections for New Electric Generation," opposed an out-of-state merchant energy company, Mirant's, proposal to expand their power plant at Potrero. In addition, it directed the San Francisco Public Utilities Commission and San Francisco Department of Environment to prepare an energy resource plan that considers all practical transmission, conservation, efficiency and renewable alternatives to fossil fuel electricity generation in the city and county of San Francisco.

The San Francisco Public Utilities Commission and San Francisco Department of Environment published the electricity resource plan called ***Choosing San Francisco's Energy Future*** in December 2002. The plan emphasizes increased local control over energy resources so as to promote locally valued solutions. Ultimately, the goal is to allow closure of Hunters Point by 2005. The electricity resource plan recommends that San Francisco meet its future power needs from multiple small and medium-scale sources. Specific recommendations include the following:

- The city should rely on renewable resources, medium size generation, co-generation, and small scale DG.
- Demand should be reduced through energy efficiency and load management.
- Downtown commercial buildings and city-owned facilities should be targeted for peak reductions.

At the same time, the city recognizes the need for transmission improvements. The city supports both upgrades to an existing line and the proposed new transmission line on the peninsula.

The city is implementing the plan by using its existing financial resources as well as by applying at a variety of CPUC proceedings to get additional funding for energy efficiency and demand response.

Many steps have been taken to implement the plan. The city is installing a 600kW rooftop photovoltaic system at the Moscone Convention Center. Energy efficiency projects being implemented include: deploying LED traffic signals at 1100 city intersections, a lighting retrofit of San Francisco general hospital, and energy efficiency improvements at the Moscone Convention Center. The city is also seeking to build 4 new, small, publicly owned power plants that would use a combustion turbine technology. The city has also proposed a collaborative study with the Energy Commission and the CA ISO that would build upon the load serving capability assessment recently completed by the San Francisco Peninsula Planning Study Group. This collaborative study provides an opportunity for improving previous work through the employment of innovative analytic methods and the refinement of data assumptions including likely locations for the city's four combustion turbine generators.

CA ISO- led Stakeholder Groups Regarding Hunters Point

On April 25, 2002, the CA ISO Board of Governors instructed CA ISO staff to work with the City of San Francisco and interested stakeholder groups toward the goal of closing the Hunters Point Power Plant. The CA ISO created a Core Working Group consisting of representatives of various community and environmental groups including: Communities for a Better Environment, GreenAction, Literacy for Environmental Justice, Golden Gate Environmental Law and Justice Clinic, San Francisco Energy Co-op, Bayview/Hunters Point Advocates, and the San Francisco Labor Council. The group also includes representatives from: PG&E Company, the CPUC, the City and County of San Francisco, and the Governor's Office of Planning and Research. The Core Working Group developed a Community Energy Plan Mix, and evaluated the San Francisco Electricity Resource Plan developed by the San Francisco city departments.

The Core Working Group was then split into two separate working groups, the Demand Side Workgroup and the Power Flow/Forecasting Group. The purpose of the new working groups was to address technical issues, work towards solutions, and report back to the Core Working Group. The Demand Side Workgroup was tasked with identifying and coordinating demand side resources. This included distributed generation, load reduction, energy efficiency, and existing demand programs. The Power Flow/Forecasting Working Group was tasked with the technical analysis of the alternative resources presented first in the Community Energy Plan Mix and later in the San Francisco Electricity Resource Plan. The new working groups were structured so that most of the stakeholders representing the community and environmental interests need not be present at the Demand Side Workgroup and the Power Flow/Forecasting Group meetings. Instead, stakeholders decided to send one representative for all the stakeholders who represent the community and environmental interests. The plan was that the entire group of community stakeholders would get information from the one representative and would also attend the larger Core Working Group meeting where final reports would be given.

Approximately 30 meetings in the past 10 months have been held. CA ISO staff's perception is that the community stakeholder attendance at the Core Working Group meetings has been inconsistent. CA ISO staff is concerned that some of the stakeholders have not received all of the information from their representatives. This lack of information may have led to misunderstandings about the progress being made towards their goal of closing the Hunters Point Power Plant. CA ISO staff, with the Governor's Office of Planning and Research, has decided to approach the stakeholders more directly in order to better share information and foster credibility and trust.

Environmental Justice Steering Committee

In order to coordinate the State's environmental justice concerns, the Governor's Office of Planning and Research is running the Environmental Justice Steering Committee. The Environmental Justice Steering Committee is made up of all state agencies, boards, departments and constitutional offices and meets regularly to identify ways in which the state, through statutory, regulatory, or policy and practice reform, can address environmental justice concerns. On January 15, 2003, the youth of Bayview/Hunters Point, through Literacy for Environmental Justice, gave a presentation to the Environmental Justice Steering Committee about environmental justice from their experiences as residents and the youth of Bayview/Hunters Point. This forum allowed for the state agencies to focus on resources within their agencies that could be used to address the community concerns and goals in Bayview/Hunters Point.

Energy Efficiency Funding: California Public Utilities Commission Process

PG&E joined with the city and county of San Francisco to propose a "Demand Reduction through Energy Efficiency Pilot Program" to the CPUC.

On March 13, the CPUC issued an interim opinion that extends utility funding for energy efficiency programs beyond March 31, 2003 and which, among other decisions, approves $8 million for the San Francisco Pilot program. The opinion states that the program would step up existing aspects of PG&E's energy efficiency efforts in San Francisco and divert funds from its established 2003 program implementation plan for the effort. The program would be funded through the public goods surcharge 2003 funds. PG&E must file an advice letter comparing the costs of the proposed program elements to the costs of alternative means of improving system reliability in San Francisco.

Stakeholders intend for the pilot program to modify PG&E's existing programs to better fit San Francisco's unique needs and to include special programs for the Bayview/Hunters Point community and for small to mid size businesses. Stakeholders also are questioning the language in the CPUC's opinion that implies that San Francisco will get an increased share of the 2003 energy efficiency funding through this decision.

Demand Response: California Public Utilities Commission Process

An interagency working group led by the CPUC was formed to develop demand response as a resource to enhance electric system reliability, to reduce power purchases and individual customer's costs, and to protect the environment. The CPUC asked the City and County of San Francisco to work with PG&E to create a localized marketing and recruitment area and the triggering conditions for a critical peak pricing proposal.

On March 13, 2003, the CPUC unanimously approved a pilot program to test how a total of 2,575 residential and small business customers would respond to time of use and critical peak pricing signals.[8] One track of the pilot program targets customers in San Francisco's Hunters Point community. The pilot will start on August 1, 2003 and will run through 2004, with a cost of $9.6 million.

Lessons Learned

- Isolated attempts to solve San Francisco's problems through new generation or new bulk transmission are likely to face heavy opposition. An integrated approach that balances needs and cost is necessary.
- Public sentiment and perception about environmental impacts and justice are very important in San Francisco.
- The move to shut down the power plant at Hunters Point has wide community support.
- The city prefers a public-private partnership approach
- The city has been successful in working with PG&E and the CPUC to increase the share of energy efficiency funding allocated to the San Francisco area.

DEVELOPING BALANCED ENERGY PORTFOLIOS IN LOCAL AREAS: BEST PRACTICES FOR THE FUTURE

- Some transmission and generation projects are difficult to sell to certain local interest groups. Smaller scale generation, renewables, demand response and efficiency are more desired by local residents and their deployment will probably have broader support and thus faster implementation. Both the San Diego Regional Energy Infrastructure Group's and the San Francisco City Departments' resource plans feature diversity of resources.
- Successful resource plans are those which reflect the local communities' concerns. This requires outreach, education and interaction with stakeholder groups in order to build consensus. If the final resource plan is one that everyone can live with (even if not all stakeholders agree on every aspect) then deployment of the plan will face less opposition.
- The existing market structure is still dominated by utilities and regulators. So far, no local group from either region has been able to set up an institution which is viewed as the definitive regional resource planner and which has the ability to implement regional plans.
- The existing regulatory, planning and permitting processes are fragmented and quite complicated.
- The Energy Action Plan, adopted by the California Energy Commission, the CPUC and the California Power Authority, provides a framework for reducing the conflicts between the CPUC and the CA ISO when determining the need for transmission projects. The CPUC will start a rulemaking which, among other things, proposes to use the results of the Energy Commission's collaborative transmission assessment process to guide and fund IOU-sponsored transmission expansion or upgrade projects without having the CPUC revisit questions of need for individual projects in certifying transmission improvements.

- Successful local groups are very skilled at working within the existing and established regulatory process to divert a larger share of statewide funding to meet local objectives. This requires a lot of time, persistence, and skill. Successful local groups have to be active at separate regulatory processes for transmission, generation, energy efficiency, demand side management, renewables and DG. They need to know the ins and outs of working with the CA ISO, the local utility, the CPUC, the Energy Commission and the legislature.
- A new intermediate local organization that could coordinate planning and lobbying in the region would be helpful in developing balanced energy portfolios that serve local needs. At the minimum, it would have to be able to work with customers and all the other public and private organizations that have responsibility for energy-related decisions and resources. If the local regions have the will and capability, the new organization could possibly be a joint power authority that could group energy efficiency projects to take advantage of economies of scale and the resultant cost savings and also could issue revenue bonds to support construction of generation resources. Further work would need to be done to determine the costs of starting a new organization, what new powers are needed, what structure best fits the organization's goals, and what steps are necessary to create these new capabilities.

STAKEHOLDER COMMENTS

During the period between July 16, 2003 and July 23, 2003, Energy Commission staff held an electronic workshop. The workshop was conducted by posting a draft of this chapter on a bulletin board and requesting the public to post comments on the website. The public was especially encouraged to comment on the "Best Practices for the Future" section. Stakeholders representing a variety of organizations and views posted comments. The comments in their entirety can be found on the web at the following address: www.energy.ca.gov/energypolicy/board/index.html.

Some stakeholder comments were addressed by modifying the information presented in the previous sections of the chapter. Specific comments relating to best practices for the future are paraphrased below.

Specific Comments

I am generally pleased with the document and the recommendations. (Alan Ramo, Golden State University School of Law, Environmental Law and Justice Clinic)

Reliability requirements less stringent than those set by the CA ISO's would be feasible and could accelerate the closure of Hunter's Point power plant #4. (Alan Ramo, Golden State University School of Law, Environmental Law and Justice Clinic)

Any power authority should work with the public and not against it. (Alan Ramo, Golden State University School of Law, Environmental Law and Justice Clinic)

The CA ISO should continue to support locally based planning efforts by providing technical support and analysis. (Greg Carras, Communities for a Better Environment)

Communities have the capability for sophisticated energy planning. (Greg Carras, Communities for a Better Environment)

San Francisco has demonstrated the feasibility of reliable alternatives to power plants. (Greg Carras, Communities for a Better Environment)

PG&E strongly supports participation by local stakeholder groups in the existing electric facility planning and permitting processes. PG&E would welcome significant community involvement in many different emerging procurement efforts including: community aggregation; energy efficiency partnerships; and the development of local energy plans such as that of the city of San Francisco. (Les Guliasi, Director, State Agency Relations for PG&E)

It is not simple for stakeholder groups to effectively participate in planning, permitting and procurement processes. PG&E supports measures to make it easier for stakeholders to participate. (Les Guliasi, Director, State Agency Relations for PG&E)

Streamlining the processes and publishing of a “roadmap” to help stakeholders navigate the processes would make it easier for stakeholder groups to participate in the planning and permitting processes. (Les Guliasi, Director, State Agency Relations for PG&E)

The existing processes avoid duplication of efforts and consider the statewide perspective. (Les Guliasi, Director, State Agency Relations for PG&E)

Energy efficiency can make a positive contribution to the resolution of the Hunters Point situation. (Les Guliasi, Director, State Agency Relations for PG&E)

A partnership model rather than a new local institution will be the most effective and least costly long-term approach to increase energy efficiency in a defined area where local reliability issues exist. (Les Guliasi, Director, State Agency Relations for PG&E)

The CA ISO will continue to perform and support all technical analyses needed to address the technical concerns of all parties interested in the load serving capability of the San Francisco Peninsula area. (Lawrence Tobias, Senior Grid Planning Engineering, CA ISO)

Approximately 30 meetings on resource planning issues in the San Francisco were held in the past 10 months. Community stakeholder attendance at these meetings has been nonexistent or inconsistent. The lack of information flowing to community stakeholders may lead to misunderstanding of progress towards closing Hunters Point Power plant. (Lawrence Tobias, Senior Grid Planning Engineering, CA ISO)

ENDNOTES

[1] AB 1890
[2] San Diego Union Tribune September 30, 2000
[3] San Diego Union Tribune October 3, 2000
[4] San Diego Regional Infrastructure Plan page 4-1
[5] D.02-12-066
[6] Decision 03-06-032
[7] San Diego Union Tribune July 6, 2003
[8] Rulemaking D03-03-036