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Energy
Market
Segment
Evaluation
Tool

Final Report

GEMSET Regional Segmentation Analysis:

Characterization of the CalPX Region

DRAFT

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The United States Department of Energy
National Energy Technology Laboratory

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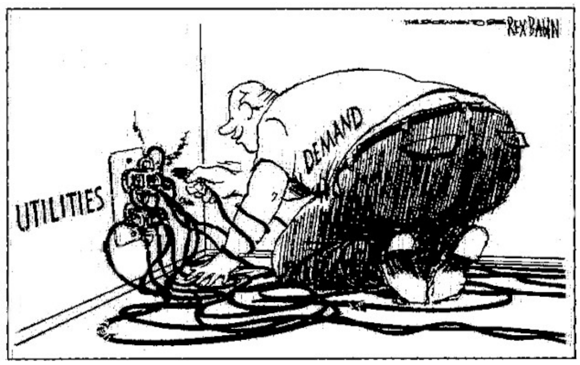
NOTICE

Summary

California recently suffered significant shortages of winter power. National news showed first the lighting of the governor's Christmas tree, then it being turned off to conserve electricity. Requests to limit use of electricity were instituted because of a generation shortage emergency. This was in part due to colder than expected weather that occurred coincident with planned maintenance outages, forced outages of other units, and the mandatory curtailment of generation units that had reached their annual environmental emission caps.



Increased demand has put California in the hot seat as it struggles to avert rolling blackouts. This followed earlier interruptions in the California electric supply, as their underconstructed system struggled to meet peak demand periods with limited availability of generation. Fears mount that the shortage will spill over into other western states like Washington that import a portion of their power from California in the winter. Energy Secretary Richardson posted temporary emergency orders requiring neighboring utility companies to export excess energy to California, causing howls of concern from the exporting states about their own supply and price of electricity.

The average price in CalPX over the past 12 months was already high, about $65/MWh, yet in recent months that has grown – dramatically. Public concern over the recent enormous price spikes in their competitive electric market led to establishing artificial price ceilings, distorting normal free-market responses, an action with significant consequence to supply, and how electricity will continue to be sold in that region. This exacerbated the problem, because reducing price also reduced supply of generation. Gas prices soared so high that some generators purchasing gas on the spot market had production costs higher than the cap. Because of the shortages, CalPX and FERC passed emergency "soft cap" tariffs allowing the wholesale electric price to float above the imposed $250/MWh cap. When that happened, price immediately soared, peaking above $1500/MWh. Two of the California's major electric utilities face bankruptcy.

The California power market is in big trouble.

Part of the problem lies in how their new competitive markets operate, and part in how new generation projects find the prospects of siting generation that would supply that region with electricity.

Right now, the structure of the competitive electric market in California is under review. The operation of this region is an important indicator of how competitive electric markets in the U.S. might operate in the future, should they become short on generation. Their approach to supplying demand, their structuring of their return to power generating companies will serve as an example, good or bad, to other regions with competitive electric sales structures, in how (or how not) to establish the market signals for new generation construction.

This report describes the competitive electric market in this one region of the United States, which has experienced considerable growing pains during the transition period between a former regulated market and now, a competitive market. It discusses the responsibilities of that State's independent system operator (CAISO), which is responsible for the electric integrity and unit dispatch in the State of California.

This is a report about electric power. This report describes electric generation supply and demand, and the price implications as the competitive market for electricity in California adjusts itself to these factors, and others as it goes through the transition from regulation to competition. It describes what is currently going on in the state. It is a market assessment for CalPX, the other entity responsible for the delivery of electric power to the state's consumers.

This report is one of the important keystones of the DOE GEMSET market model. It provides one of the regional segmentation elements necessary to project the market prospects of fossil power technologies in one of the nation's largest competitive electric markets. As delineated in this report, CalPX operates in a specific manner for the purchase and sale of electricity in a wholesale market. It is different in many respects from the other three ISO's currently in operation in the United States (PJM, NYISO, New England).

Based on an hour-by-hour evaluation of the fiscal year August 1999 – July 2000, the average price of electricity in the region was $51/MWh, a high average price. This past year there were a total of 413 hours with a market price above $100/MWh, and when that was subtracted from the total average price, it had a $14/MWh influence on that average price, reducing the average price to $37/MWh. There is a high value for generators supplying both baseline and peaking power in the region.

This report gives a detailed description of the CalPX organization and operation from a competitive market viewpoint. This historical background sets the stage for a separate GEMSET report in this series, one that provides a detailed forecast of potential operations in the region over the next 15 to 20 years.

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ACKNOWLEDGMENTS

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Abbreviations and Acronyms

Term	Meaning
Block Forwards Market	a continuously traded standardized product for month-ahead on-peak energy in blocks of 1 or 25 MW
CAISO	California Independent System Operator
CalPX	California Power Exchange
COE (meaning 1)	in economic sections: the cost of electricity, the levelized busbar cost of electric production including amortized capital, operating, and maintenance costs
combustion turbine, CT	a synonym for gas turbine, used interchangeably
Day-Ahead Market	functions as a physical forwards market and establishes the supply and demand for electric power in California one day in advance of delivery
Day-Of Market	provides for three auction periods daily, 6 a.m., noon, and 4 p.m.
DOE	United States Department of Energy
EIA	the Energy Information Administration of the DOE
EPRI	the Electric Power Research Institute
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FGD	flue gas desulfurization, a sulfur emission control device
gas turbine, GT	a synonym for combustion turbine, used interchangeably
GEMSET	government energy market segment evaluation tool
GNP	gross national product
GT	gas turbine (a synonym for combustion turbine)
GTCC	natural gas fueled gas turbine combined cycle
HHV	higher heating value of a fuel including the heat released if all of the water vapor in the combustion products were condensed
IPP	an independent power producer, an unregulated electric generating company
IRP	integrated resource plan
ISO	independent system operator; a regulated body that dispatches all competitive electric generation on the high voltage transmission grid within its service region; they operate the grind, administer the power pools power transfers, select the lower cost generation

bid into the pool according to the pool's operating rules, and maintains the integrity of the electric transmission grid

LCC ....local control center

LHV ....lower heating value of a fuel, the heat released if all of the water vapor in the combustion products remained as steam

MAAC ....Mid-Atlantic Area Council, a reliability council

MCR ....maximum continuous rating

MMC ....market monitoring committee

MVA ....megavolt amperes

MWe ....electrical megawatts

MWth ....thermal megawatts

NETL....................................the U.S. Department of Energy's National Energy Technology Laboratory

NOPR ....notice of proposed rulemaking

NOx.......................................nitrogen oxides, types of air pollutant, mainly NO and NO_2

NUG......................................non-utility generator, a competitive, unregulated independent electric power producer

OTAG...................................Ozone Transport Assessment Group

OTR ....Northeast Ozone Transport Region

Parsons I&T, PI&T ....Parsons Infrastructure & Technology Group Inc., a global business unit of Parsons Corporation, an engineering/construction company; part of the DOE team that prepared this report

PCD ....particulate emission control device

P.E. ....licensed professional engineer

PJM ....Pennsylvania, New Jersey, Maryland, or PJM Interconnection LLC, an ISO

PSC ....local state Public Service Commission

RACT ....reasonably available control technology (pollution control)

RMCP...................................regulation market clearing price

RTO ....regional transmission owner

SOx ....sulfur oxides, types of air pollutant, mainly SO_2

1 CalPX Region

This section discusses the California regional segmentation used in the DOE GEMSET market analysis model. This power exchange and its ISO (CAISO) is representative of a competitive market situation, and is significantly different from a regulated utility scenario where new generation options are approved by a commission or regulatory body. Under a competitive market, new generation is at more of a risk than a regulated market.

1.1 The Independent System Operator: CAISO Interconnection

A competitive electric power system, including the California Independent System Operator (CAISO) and the California Power Exchange (CalPX), has been fully operating in California since March 31, 1998. During the first year, 231,400 GWh of electric power were traded in the CalPX Day-Ahead Market and the CAISO Ancillary Services and Real-Time markets involving $12 billion of transactions on the buy and sell sides, establishing a market totaling $6 billion in dollar volume. The number of participants in the Day-Ahead Market increased from 39 at the start to 68 by July of 1999. The system is working. It is, however, still in a state of transition from fully regulated markets to unregulated competition. It has faced, and will continue to face, many challenges.

1.2 Territory

The CalPX covers the entire State of California, and through the CAISO, interconnection is responsible for the day-to-day operation of one of the largest centrally dispatched electric systems in North America.

The state regulatory commission and the Federal Energy Regulatory Commission (FERC) have jurisdiction within the CalPX control area. The Federal Energy Regulatory Commission (FERC), as part of its approval of California's electric industry restructuring, ordered both the California Independent System Operator (CAISO) and the California Power Exchange (CalPX) to maintain ongoing surveillance of their respective markets. The FERC also ordered the monitoring functions of each institution to cooperate, recognizing the integrated character of the CAISO and the CalPX markets.

1.3 CAISO Responsibilities

All ISOs have the principal responsibility for the safe and reliable operation of the transmission system. As regulated entities, they are charged with ensuring the reliable supply of energy from generating resources to wholesale customers.

Since the CalPX region is a competitive electric market, it is also charged with administering the competitive wholesale energy market for the region, and, under the provisions of FERC Order 888, with facilitating open and fair access to transmission.

The California Power Exchange included as part of its tariff and protocol filings with the FERC the establishment of an independent committee, the Market Monitoring Committee (MMC), charged with monitoring the CalPX market operations. If the CalPX were a traditional membership exchange, the function of the MMC would be an internal part of the operation of the exchange, and members of the CalPX would likely serve on this committee.

The MMC currently has four independent members. The CalPX Governing Board elects each member for a three-year position. The terms are staggered so that at least one member is subject to renewal or replacement annually. Committee members cannot consult to nor have affiliations with any participants in CalPX markets. They are restricted in the use of any private information they obtain as members of the committee.

The monitoring and analysis of market behavior in the CalPX markets is carried out by the Compliance Unit. The Unit currently has a Director and three staff analysts supporting the Director.

In addition to daily monitoring of markets, the Compliance staff is responsible for developing fundamental analyses of markets, models, and methods of effective monitoring, and for carrying out investigations of market abuse. When complaints are filed with the Compliance staff or the MMC, the Compliance staff undertakes the appropriate inquiries. Also, the staff itself may initiate investigations if evidence of market abuse is detected or developed through analysis.

2 Historical Data

California restructured its utility industry through a complex stakeholder process that brought diverse interests together to build a consensus vision of the future electricity industry. The design reflects the inherent compromise that is the essence of an effective consensus process. The market structure that has evolved will be analyzed in this section.

Once any system is launched, continual design changes must be possible so that the system can adapt to the changing dynamics of the market it was designed to serve. Over the past year, the CalPX has designed many changes to help California's electricity markets work more efficiently. These include:

- Modification of the CalPX Hour-Ahead Market to a Day-Of Market
- Initiation of a CalPX Block-Forwards Market
- Initiation of a Post-Close Quantity Match
- Initiation of a Green Exchange Service
- Initiation of Book-Out Services

The California ISO has also been actively changing key aspects of its operations. The changes made thus far and those changes contemplated for the future will be discussed in this and following sections.

2.1 The Structure of California's Electric System

2.1.1 The Institutional Framework

The California wholesale electricity marketplace has two principal components – a market of contracts executed directly between buyers and sellers (referred to as the *bilateral market*) and buy-sell transactions executed through organized commodity-exchange type markets (referred to as *exchange-based markets*).

During the mandated transition period in California, investor-owned utilities (IOUs) are required by law to buy and sell their electricity through the CalPX. The CalPX is a commodity exchange for electricity; it runs a Day-Ahead Market, a Day-Of Market, and a Block-Forwards Market. The Day-Ahead Market is an auction system of essentially 24 hourly markets, bid for simultaneously and cleared at the same time. The Day-Of Market is composed of 24 auctions conducted in three batches over the course of a day. These allow buyers and sellers to adapt to unexpected circumstances occurring the day in which power is being delivered based on the preceding Day-Ahead auction. The Block-Forwards Market began operating June 10, 1999, and consists of a forward contract of 16 on-peak hours, traded in multiples of 1 or 25 MW. It allows participants to realize the benefits of forward contracts while also participating in the efficient and transparent CalPX Day-Ahead and Day-Of markets where delivery and settlement are arranged.

The CalPX is also a Scheduling Coordinator (SC). SCs were established as part of the California system to manage the transmission assets of California's IOUs. SCs are qualified by the CAISO to submit balanced schedules of electricity supply and demand for use of the transmission network the CAISO administers. Access to the CAISO transmission network is restricted to SCs.

The CAISO manages the transmission network in real time. Its mission is to ensure at least as high reliability as the transmission owners provided prior to its formation. Market mechanisms are used to ensure continuously high reliability. To this end, the CAISO runs a Real-Time Market, an auction that runs every 10 minutes around the clock, but is settled hourly. This auction's purpose is to enable the CAISO to acquire the power needed to ensure that the system stays in balance and operates reliably.

System reliability is derived from various forms of reserves as well. These are obtained through acquisition of capacity in four markets that are referred to generically as the Ancillary Services (AS) Markets, and through contractual sourcing of system regulation and system reliability power supply. The four generic Ancillary Services Markets are: (1) Spinning Reserves, (2) Non-Spinning Reserves, (3) Regulation, and (4) Replacement. In addition, the CAISO obtains local reliability-related resources through "Reliability Must-Run" contracts.

Both the CalPX and the CAISO were created by the California Legislature and operate as not-for-profit public benefit corporations under California law. The Governing Board of each institution is made up of stakeholders. Board members are asked to function as true corporate board members, not as representatives of their constituents.

Assembly Bill 1890 established the Electricity Oversight Board so that the State of California could retain an ongoing involvement in the new electric market system. The Governor appointed the initial Electricity Oversight Board, which then elected the original slates of Governing Board members for both the CAISO and the CalPX.

2.1.2 Description of Auction Process

Prior to 7 a.m., buyers and sellers submit to the Day-Ahead Market their final portfolio of energy supply and demand bids for each of the next 24 hours. These bids are used to determine the intersection between supply and demand, which sets the overall market-clearing price and quantity. The auction for each of the 24 hours is conducted individually.

2.1.3 Characteristics of California's Market System

The California energy auction process has two characteristics. First, the CalPX, the CAISO and other Scheduling Coordinators interact closely in matching participants' generation and loads and transmission needs. Second, the adjustment process follows the bidding process. The CalPX participants allocate their generation capacity according to their perceived opportunity costs. The CalPX Market Monitoring Committee has described the consequence of this sequencing:

> *"Most participants will be eligible to bid in several of the markets. The exact sequence of bids and market responses affects how they will bid. Bids in the day-ahead energy market are accepted before bids in the AS markets need to be placed. If generators want to offer a larger quantity in any AS market, they must offer a smaller amount of their given capacity in the day-ahead market. They can implement this directly, or they can offer the smaller quantity at " reasonable" prices, and then offer the rest at very high prices. Once the day-ahead market results are revealed at 7:15 a.m., the generators know how much capacity they actually can offer to the AS markets."*

By bidding for some of its capacity at a price sufficiently higher than the predicted market-clearing price, a generation participant can be assured that this capacity will not be awarded in the Day-Ahead Market. The capacity will then be available for bidding in the later markets as the participant follows the auction sequence. Holding capacity for this later bid has the effect of reducing supply and therefore increasing price in the Day-Ahead Market. This creates an inherent linkage among the markets: capacity sold in an earlier-closing market is not available for a later-closing market, and capacity held back to be bid later is not available in an earlier market.

As noted in the first Compliance report, California restructured its utility industry through a complex stakeholder process that brought diverse interests together to build a consensus vision of the future electricity industry. The core structure and operation of the CalPX is largely unchanged in the second year of market operations. However, in the second year of operations, several key developments, all discussed in section 2.3, occurred in the CalPX markets, including:

- Steady growth in valid hours of operation of the Day-Of Market.
- Remarkable growth in participation and in volumes in the CalPX Block-Forwards Market.
- Introduction of the Post-Close Quantity Match.

The CAISO has actively continued to change key aspects of its operations. Since submission of the first Compliance report to FERC, the CalPX introduced the Block-Forwards Market (BFM) and the Post-Close Quantity Match (PCQM). The BFM, which began operating June 10, 1999, consists of a forward contract of 16 on-peak hours, trades in multiples of 1 or 25 MW. It allows participants to realize the benefits of forward contracts while also participating in the efficient and transparent CalPX Day-Ahead and Day-Of markets. The PCQM started experimentally on July 27, 1999 in the smaller Day-Of Market and was extended to the full Day-Ahead Market on September 2, 1999. PCQM allows participants to round the quantity of their positions scheduled in the CalPX markets after the initial market auction.

The CalPX role in the Competition Transition Charge (CTC) is changing. The first investor-owned utility, San Diego Gas & Electric (SDG&E), recovered its CTC earlier than expected and terminated its rate freeze as of July 1999. The other IOUs may also recover CTC early because IOU generation plants have been selling at higher than expected multiples of book value. This means the size of total CTC may be smaller.

In the two years since the opening of the CalPX markets, power trading in the western states has evolved to adapt to the establishment and effective operation of a deep and liquid commodity exchange for electric power.

Prior to the restructuring in California, the Western Systems Coordinating Council (WSCC) power markets were exclusively bilateral – i.e., transactions took place between buyers and sellers without the involvement of intermediaries, or multi-party transactions were organized through a power-marketing intermediary, but not executed on a formal commodity exchange.

In the past two years, exchange-based markets have been integrated into the broader western states system in several ways:

- Northwest and Southwest buyers make use of CalPX markets not only as demand centers offering opportunities for the sale of power, but as a ready supply center during periods of high demand in their own regions. Also these regions, in particular the Northwest, rely on CalPX markets for unexpected supply needs.

- Power marketers are using CalPX prices as reference or index prices for their bilateral contracts throughout the West. CalPX markets also influence, through contracts that use CalPX prices as reference points, electricity prices throughout the western United States, a power market of approximately 742,000 GWh.

- Bilateral traders are using all CalPX markets, and associated liquidity, coupled with systematic exploitation of congestion patterns in California (fully risk hedged through various financial instruments) in the development and management of their portfolios.

While CalPX prices are having an impact throughout the western United States, the Must-Buy/Must-Sell provisions of AB 1890 focused most of the trading activity in California. Creating the CAISO placed an additional institution between out-of-state users of California transmission and California generators and buyers. Nevertheless, California is firmly linked financially, as evidenced by the aforementioned indexing to CalPX prices and the presence of marketers who trade in CalPX markets as well as actively throughout the West.

2.2 The Value of California Electricity Commodity Markets

The market structure in California is composed of seven distinct active markets interacting in varying degrees under different circumstances. Table 1 below summarizes the size of the markets.

Table 1: California's Wholesale Electricity Markets: April 1998 – March 1999

Market	Annual Volume (GWh)	Annual Average Price	Annual $ Value ($ million)
CalPX Day-Ahead	189,000	$24.44 /MWh	$5,033
CalPX Day-of/Hour Ahead	400	$29.34 /MWh	$21
CAISO Real-Time	10,000	$25.62 /MWh (NP-15) $23.54 /MWh (SP-15)	$296
CAISO AS – Spin	6,700	$13.43 /MW	$90
CAISO AS – Non-Spin	5,500	$7.27 /MW	$40
CAISO AS – Regulation	14,800	$34.00 /MW	$500
CAISO AS – Replacement	5,000	$13.80 /MW	$69
TOTAL	231,400	----	$6,049

In addition to these markets, CalPX has added four new markets and services in 1999:

(1) Block-Forwards Market

(2) Green Exchange Service

(3) Post-Close Quantity Match

(4) Book-Out Services

The total administrative fees received by the CalPX for the period April 1, 1998 through March 31, 1999 were $59.7 million.

2.3 CalPX Markets in Relation to the Competition Transition Charge

The prices of the Day-Ahead Market are also critical to the calculation of the Competition Transition Charge (CTC) in California. CTC is defined in detail in Section 367 of AB 1890:

> The commission [California Public Utilities Commission (CPUC)] shall identify and determine those costs and categories of costs for generation-related assets and

> obligations, consisting of generation facilities, generation-related regulatory assets, nuclear settlements, and power purchase contracts, including, but not limited to, restructuring, renegotiations or terminations thereof approved by the commission, that were being collected in commission-approved rates on December 20, 1995, and that may become uneconomic as a result of a competitive generation market, in that these costs may not be recoverable in market prices in a competitive market, and appropriate costs incurred after December 20, 1995, for capital additions to generating facilities existing as of December 20, 1995, that the commission determines are reasonable and should be recovered, provided that these additions are necessary to maintain the facilities through December 31, 2001.

Section 367 addresses the stranded costs associated with restructuring. Stranded costs are defined as generation plants approved by the CPUC and built to serve the monopoly franchises held by IOUs prior to restructuring that no longer hold a value at least equal to their costs. AB 1890 accepted the prevailing argument concerning stranded costs that without compensation IOU shareholders would have unfairly shouldered the burden of associated losses when regulatory approvals had been granted and plants built and placed in service for the benefit of customers. The CTC allows for IOU recovery of such stranded costs. AB 1890 allows for CTC to be collected from customers to offset these costs, but only until December 31, 2001, with certain exceptions, also detailed in the law.

The CalPX is central to the collection of CTC. As part of restructuring, electricity rates were reduced by 10 percent and frozen at that level until all CTC is collected or December 31, 2001, whichever comes first. A CTC charge is shown on customer bills. The CTC charge, however, is not fixed. It fluctuates because it is determined to be the difference between the rate cap and the utility's cost of buying power at the CalPX (plus other charges such as transmission and distribution costs). If the CalPX price goes up, the CTC is recovered more slowly because electricity rates to the customer cannot change. If the CalPX price goes down, the CTC is recovered more rapidly. The IOUs are obligated by the CPUC and the FERC to sell and buy all of their power through the CalPX for a fixed transition period. Stakeholders have various views on the duration of the transition period; some argue it ends on December 31, 2001, others that it ends when the CTC is fully collected.

At least one IOU (SDG&E) will recover its CTC earlier than expected and others may as well. One reason for this is that IOU generation plants have been recently sold at higher than expected multiples of book value. Consequently, the size of total CTC will be smaller, i.e., the IOUs will be facing smaller losses, or, in some cases, earning profits, on the sale of generating assets. Also, plant divestiture is proceeding at a good pace. San Diego Gas & Electric, for example, on December 14, 1998 announced that it had completed the sale of all of its fossil fuel plants and proposed to terminate its rate freeze as of July 1, 1999.

The significance of the collection of the CTC for the Day-Ahead Market is important. At least during the transition period, the true impact of the Day-Ahead Market on value actually exceeds its aggregate annual value measured in dollar volume. CTC recovery alone makes this so. The initial CPUC rate filings of California's IOUs estimated total CTC to be approximately $27 billion.

Further, the CalPX market also influences, through contracts that use CalPX prices as reference points, electricity prices throughout the western United States, a power market of approximately 735 TWh per year.

2.4 CalPX Markets in Relation to the WSCC Power Markets

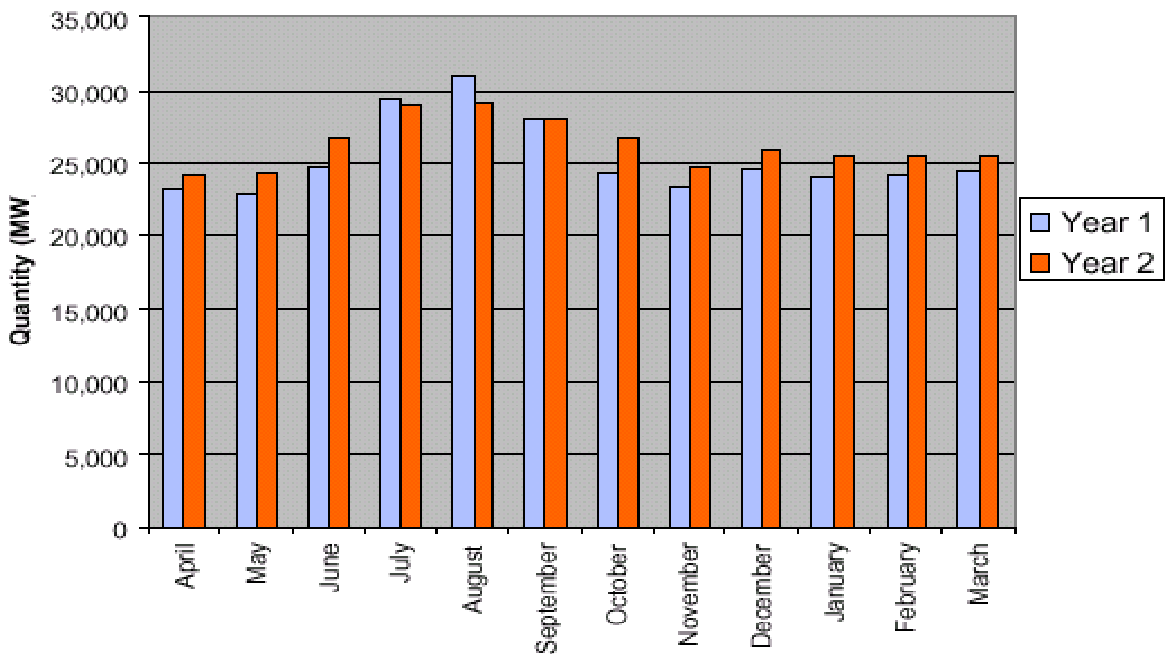
Prior to the restructuring in California, the Western Systems Coordinating Council (WSCC) power markets were exclusively bilateral – i.e., transactions took place between buyers and sellers without the involvement of intermediaries, or multi-party transactions were organized through a power-marketing intermediary, but not executed on a formal commodity exchange. Because these bilateral transactions were organized without the use of an exchange-based market, the current levels of price transparency did not exist in the WSCC. The CalPX brings this valuable feature to the western states and bilateral traders are now indexing some of their trades to CalPX's transparent prices.

While CalPX prices are having an impact throughout the western United States, the Must-Buy/Must-Sell provisions of AB 1890 focused most of the trading activity in California. Creating the CAISO placed an additional institution between out-of-state users of California transmission and California generators and buyers. Nevertheless, California is firmly linked financially, as evidenced by the aforementioned indexing to CalPX prices and the presence of marketers who trade in CalPX markets as well as actively throughout the West.

2.5 Demand

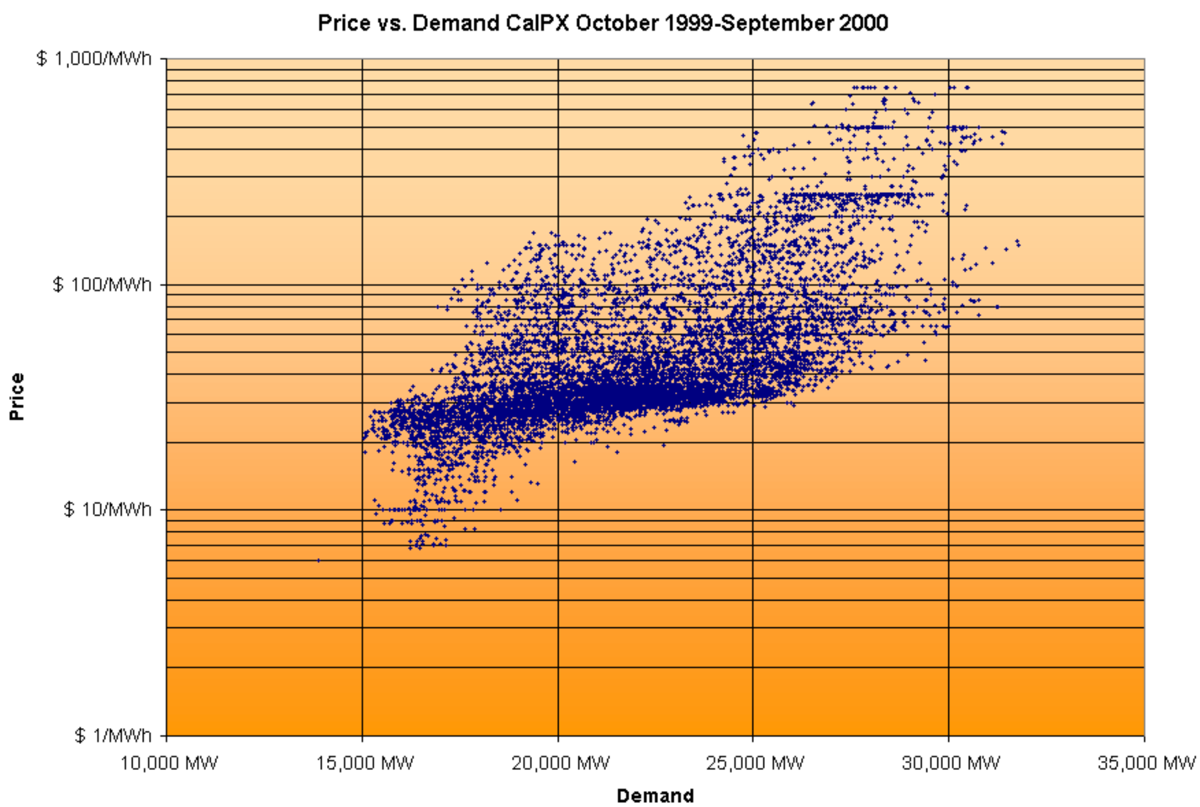
The CAISO load forecast is an indication of the demand for electricity in the CAISO controlled grid, which is served by demand in the CalPX market and bilateral agreements of other Scheduling Coordinators. The forecast load, as opposed to the actual load, is monitored because the forecast load is used by the CalPX market participants to develop Day-Ahead supply and demand bids. Exhibit 2-1 shows that the CAISO load forecast for Year 1 was consistently lower than the load forecast for Year 2. The exception to this observation is for the months of July and August 1998 when California experienced exceptionally hot weather. Year 2 forecast load was an average of 3.7 percent higher than Year 1 forecast load, reflecting the general economic growth in California. The average hourly increase in actual demand was 400 MW from Year 1 to Year 2 with an increase in the system peak demand of 2 percent.

Exhibit 2-1
CAISO Forecast Load - Hourly Average by Month



The price demand relationship for CalPX is shown in Exhibit 2-2.

Exhibit 2-2
Price-Demand Profile for CalPX

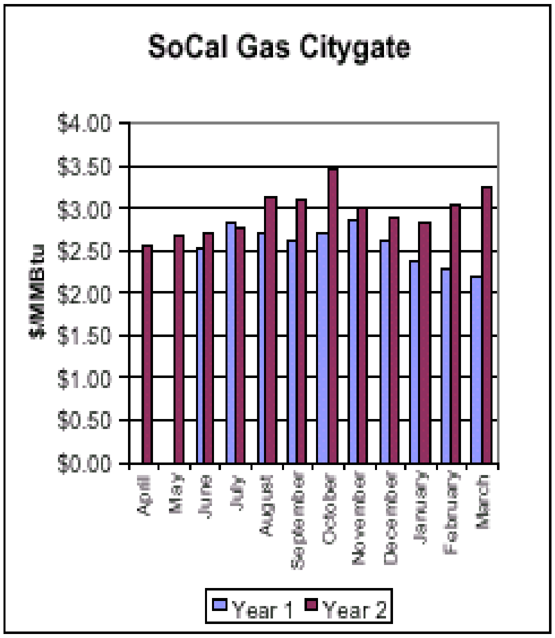


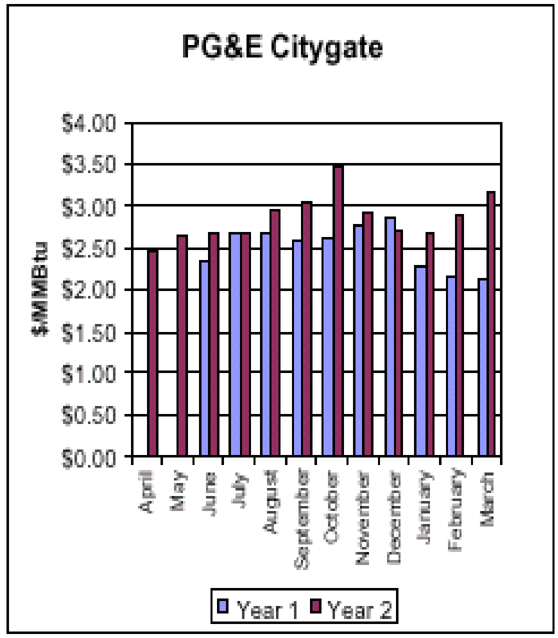
2.6 Natural Gas Price

Gas prices increased by 50 percent from March 1999 to March 2000. The increase in gas prices is reportedly due to a decrease in natural gas production as a result of lower prices in Year 1 and an inability to ramp up quickly to meet high demand levels in Year 2. High gas prices in the year 2000 do not appear to be the result of a decline in natural gas storage inventory levels because the western region is in a relatively healthy storage position.

It is not possible to determine exactly the marginal resource in the CalPX Day-Ahead market due to the nature of the supply portfolio bids. However, participants owning a significant amount of conventional natural gas-fired generating units are most often the incremental supplier, and thus are most likely the marginal resource influencing the market clearing price. Conventional natural gas-fired generating units total over 18,000 MW in the state of California. Pacific Gas and Electric Citygate prices are used to represent the price of gas for approximately 6,200 MW located in NP15 and ZP26. Southern California Gas Company Citygate index prices are used to represent the 11,800 MW located in SP15. Exhibit 2-3shows the monthly average gas prices at the Citygate of the SoCal Gas and PG&E as reported by the industry publication, Gas Daily.

Exhibit 2-3
Natural Gas Prices ($/10^{6}Btu)



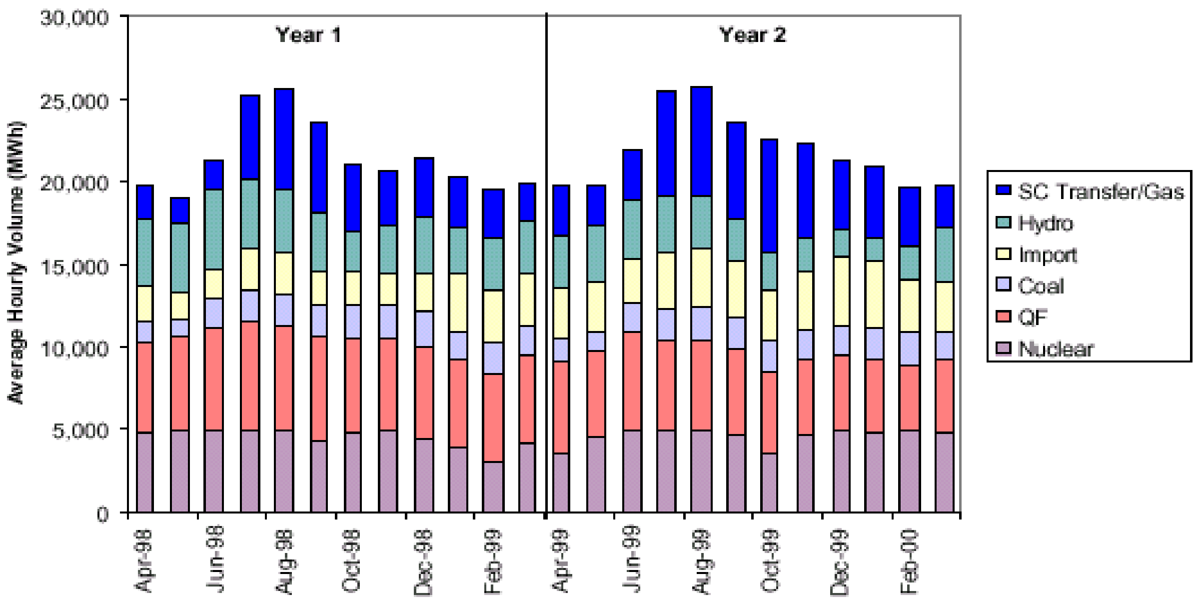


2.7 Resource Availability

About 6,000 MW of baseload resources such as nuclear and coal units are scheduled through the CalPX, more than half of total supply to the CalPX Day-Ahead energy market. In addition, Qualifying Resources (QF), which are FERC-designated alternate, or renewable resources, also supply a considerable amount of energy. Most of the energy from these units are must-run and therefore bid as a price taker. An outage of these units requires that the energy be replaced with higher cost gas or imports and has a significant effect on market clearing prices. Exhibit 2-4 shows the average mix of resources by category and by month based on Final Schedules (after congestion management).

Exhibit 2-4
Resource Mix by Type - Hourly Average by Month (MW)

Hourly Avg (MW)	Year 1	Year 2	Difference
SC Transfer/Gas	3,429	4,540	32%
Hydro	3,488	2,681	-23%
Import	2,427	3,315	37%
Coal	1,786	1,779	0%
QF	5,749	4,940	-14%
Nuclear	4,537	4,621	2%
Toal	21,416	21,875	2%



Several periods of either planned or forced outages of nuclear resources had a significant impact on market clearing prices. These periods include one week in December 1998 when California and the Pacific Northwest experienced a cold front and prices soared to $164.63/MWh. Also, an outage of Diablo 2 (1090 MW) in October 1999, combined with unseasonably warm weather, and an increase in the CAISO price cap, caused several spikes above $100/MWh and a monthly average of $47/MWh.

Exhibit 2-4 shows the largest change in the resource mix came from imports with a 37 percent increase from Year 1 to Year 2. The increase represents the opportunities that Pacific Northwest and Desert Southwest see in the CalPX Day-Ahead auction. Northwest imports contributed the largest share of the 37 percent change. The next largest change in Year 2 is the increased reliance on energy transferred from other Scheduling Coordinators in the CalPX Day-Ahead Market (SC Transfer/Gas). This category includes energy supplied by natural gas-based generating units divested from the IOUs. SC Transfer/Gas category represents 32 percent of the increase from Year 1 to Year 2 and 20 percent of the total supply volumes.

The availability of hydroelectric resources also has a significant impact on market clearing prices. From Year 1 to Year 2, energy scheduled from hydro resources decreased 23 percent. The effect of El Niño contributed to the abundance of hydro energy in the May through June 1998 period, resulting in nearly 150 hours of a $0/MWh market-clearing price. The impact of El Niño continued through mid-summer, somewhat mitigating the effect of the hot summer of 1998. Hydro resources again had a significant impact on prices in the beginning of 2000. The drought experienced in January and February of Year 2 contributed to average prices for these months nearly 50 percent higher than in Year 1. The reduction of hydro resources results in greater reliance on higher cost gas and import resources. Together, these two resources increased by 34 percent from Year 1 to Year 2.

In summary, the price trends from Year 1 to Year 2 in the CalPX Unconstrained Day-Ahead Market appear to be highly influenced by external factors such as temperature spikes, increased demand, higher gas prices, and resource availability. Often, the price spikes are magnified when combinations of these factors occur simultaneously with market conditions such as transmission constraints and market design or structural changes and increases in the price cap. As will be described later, the Compliance statistical model has determined that these fundamental external factors explain approximately 88 percent of the price trends in this market.

2.8 Transmission Basics

After electricity is generated, it is transmitted over high-voltage power lines, usually at voltages from 50,000 to 500,000 volts. Prior to electric industry restructuring, electric utilities transferred power to one another using their transmission system. They also provided service to transmission-service customers, usually large industrial plants. For most other customers, transmission-level electric service is "stepped down" to lower voltages (such as 120 volts for residential customers).

Presently, anyone who owns transmission facilities, or who has firm contractual rights to use transmission facilities to be operated by the ISO, is referred to as a transmission owner. These transmission owners calculate and monitor transmission-line capacities in order to avoid line overloading and possible damage to equipment.

California has an extensive system of high-voltage transmission, which provides access to supplies from the western region of the United States. (See maps following this section.) The western interconnected system represents the western half of the United States and includes every state from the Rocky Mountains to the Pacific Ocean, plus parts of Canada and Mexico.

Electricity can be shipped for long distances over transmission lines from one transmission system to another. For example, electricity generated by the Bonneville Power Administration in Portland, Oregon can be shipped to the Department of Water and Power in Los Angeles, California.

Transmission losses naturally occur between the point of receipt and the point of delivery. The point of delivery occurs at the utility distribution company boundary or at the ISO's control area boundary. Transmission lines have physical limits beyond which they cannot transmit additional quantities of electrical power without serious damage to transmission equipment.

2.8.1 Main Grid and Distribution Networks

The main transmission grid (backbone), Exhibit 2-5, consists of 500 kilovolts (kV), some 230 kV, and the 500 kV direct current (dc) high-voltage transmission lines. Distribution networks deliver electricity to and from the ISO-controlled grid. Distribution power lines generally include some 50 kV and all voltages below 50 kV.

California utilities are electrically linked through an extensive network of transmission lines. They also are members of the Western Systems Coordinating Council (WSCC, Exhibit 2-6), a regional council with a charter of promoting reliable electric service by adopting operating criteria and facilitating electric system support among utilities throughout the WSCC region.

Exhibit 2-5
The Major Sources of California Power Generation

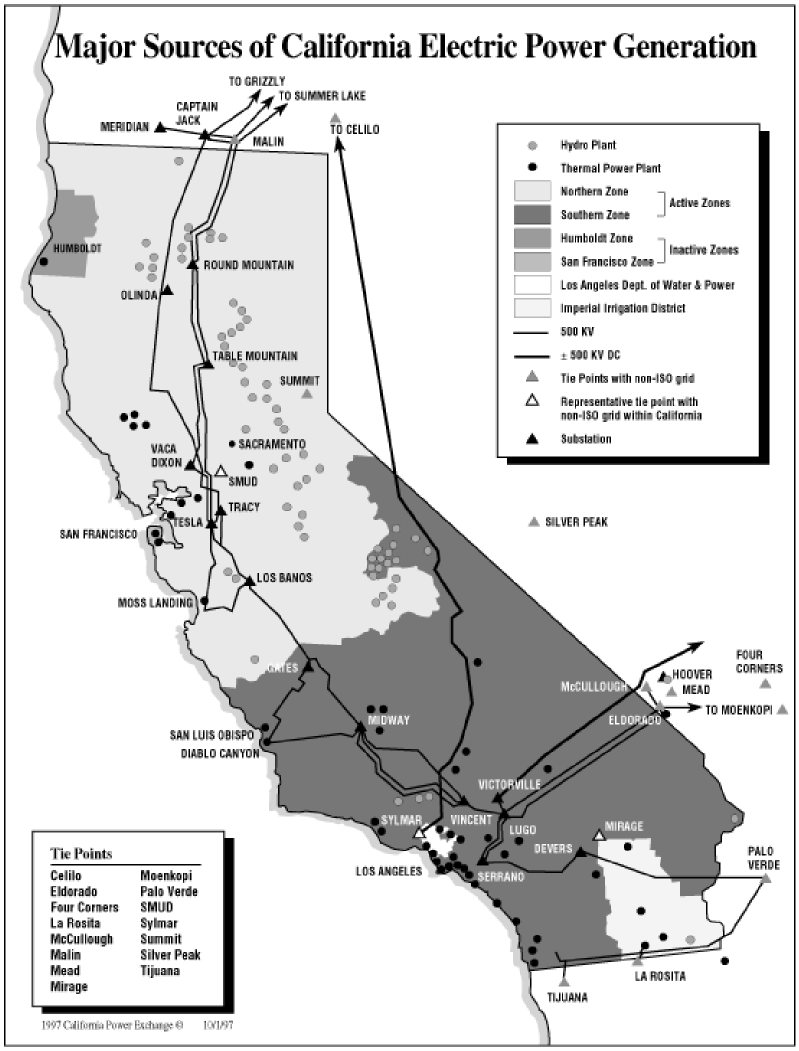
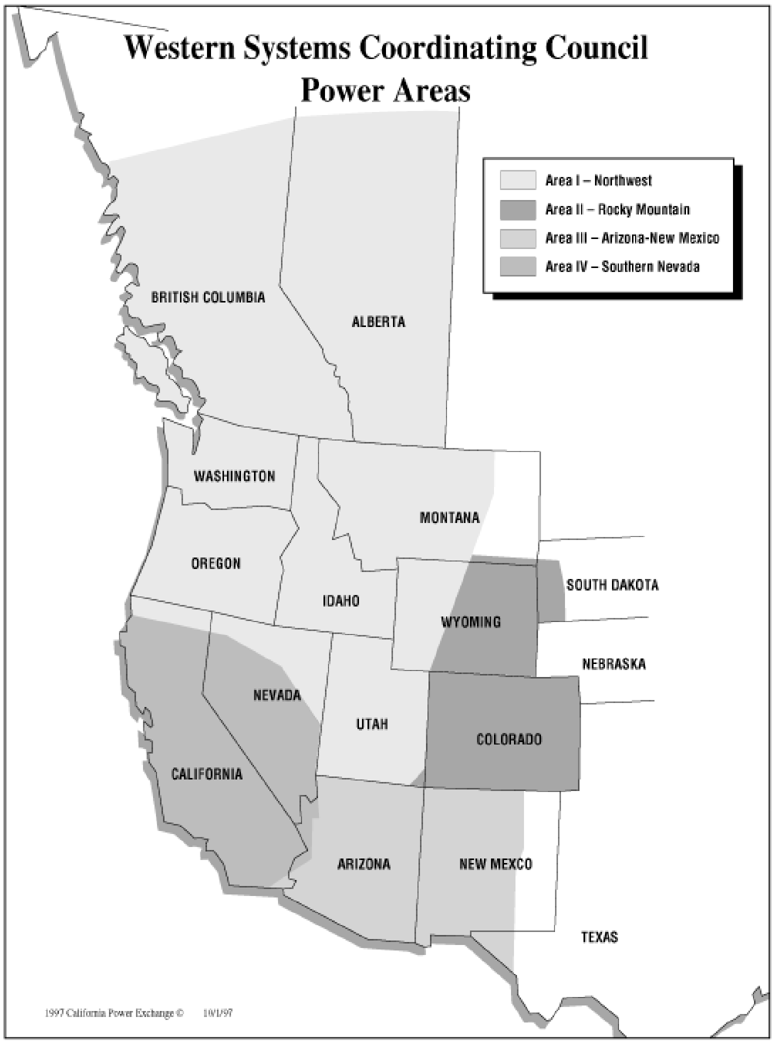


Exhibit 2-6
WSCC Power Areas



2.8.2 Voltage Support

Voltage support refers to those services provided by generating units, or other equipment, that are required to maintain established grid-voltage criteria. These services are required under both normal and system emergency conditions.

2.8.3 Congestion

Congestion occurs when there is insufficient transfer capacity to simultaneously implement all of the preferred schedules that Scheduling Coordinators submit to the ISO.

The ISO uses a zone-based approach to manage congestion. A zone is a portion of the ISO-controlled grid within which congestion is expected to occur infrequently or have relatively low congestion-management costs. "Inter-zonal" congestion occurs as a result of transmission system constraints between two zones. "Intra-zonal" congestion occurs as a result of transmission system constraints within a zone.

The zones are set forth in Appendix I to the ISO tariff. CalPX publishes current and historical prices for each zone through its Web site (www.calpx.com). When congestion occurs, zonal prices supersede CalPX's unconstrained market clearing price (UMCP), which is based on the aggregated energy supply and demand curve intersection point for each hour.

2.8.4 Electric Distribution System

The electric distribution system links the transmission system with customers who require service voltage as low as 120 volts. To serve these customers, several levels of voltage reduction are required. The first voltage reduction usually occurs at a substation, where power from high-voltage transmission lines is transformed to a lower voltage and is then carried via primary distribution lines. Voltage can be further reduced by secondary distribution transformers near the customer's home or business.

2.9 Demand Basics

Demand is the amount of electricity used by a customer or the measure of power that a customer receives or requires. It is the rate at which energy is delivered to customers and scheduling points by generation, transmission, or distribution facilities.

A demand bid is a bid into CalPX indicating a quantity of energy that a participant wishes to buy at a particular price. This bid is accepted into the CalPX auction process only if the market clearing price is at or below the price of the demand bid. A buyer may state, for each hour, a different price or preference for each generation quantity required.

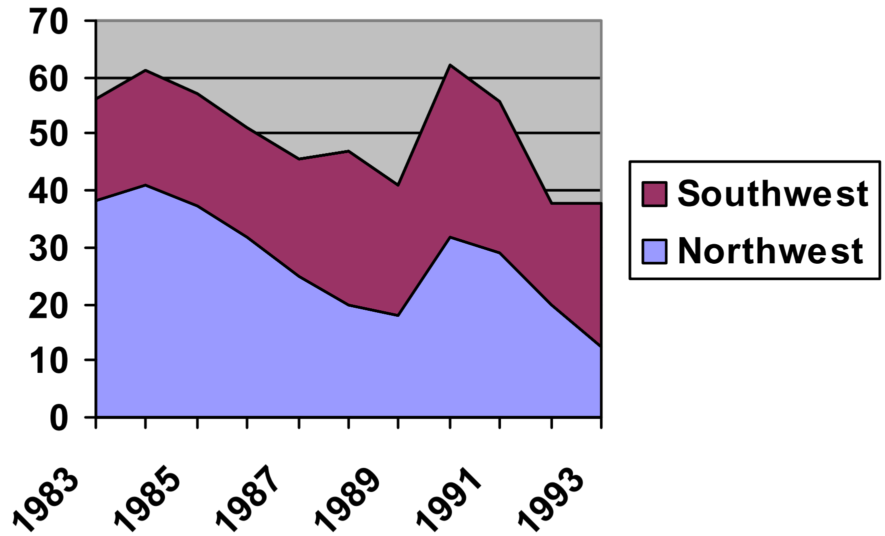
3 Electric Power Import and Export Basics

Exhibit 3-1 shows a 10-year record of power imports to California (1983-1993). The import of electricity to California over natural gas and electricity imports are used more during periods of drought, when hydroelectric generation is lower.

The Pacific Northwest, which is winter peaking, has a large hydroelectric generating capacity that can be exported to California during late spring and summer. California, in turn, provides power to the Northwest to meet winter heating loads.

Coal-fired plants in the Southwest also produce excess capacity that can be exported to the West.

Exhibit 3-1
California Imports of Electricity
(billions kWh)



Source: California Energy Commission

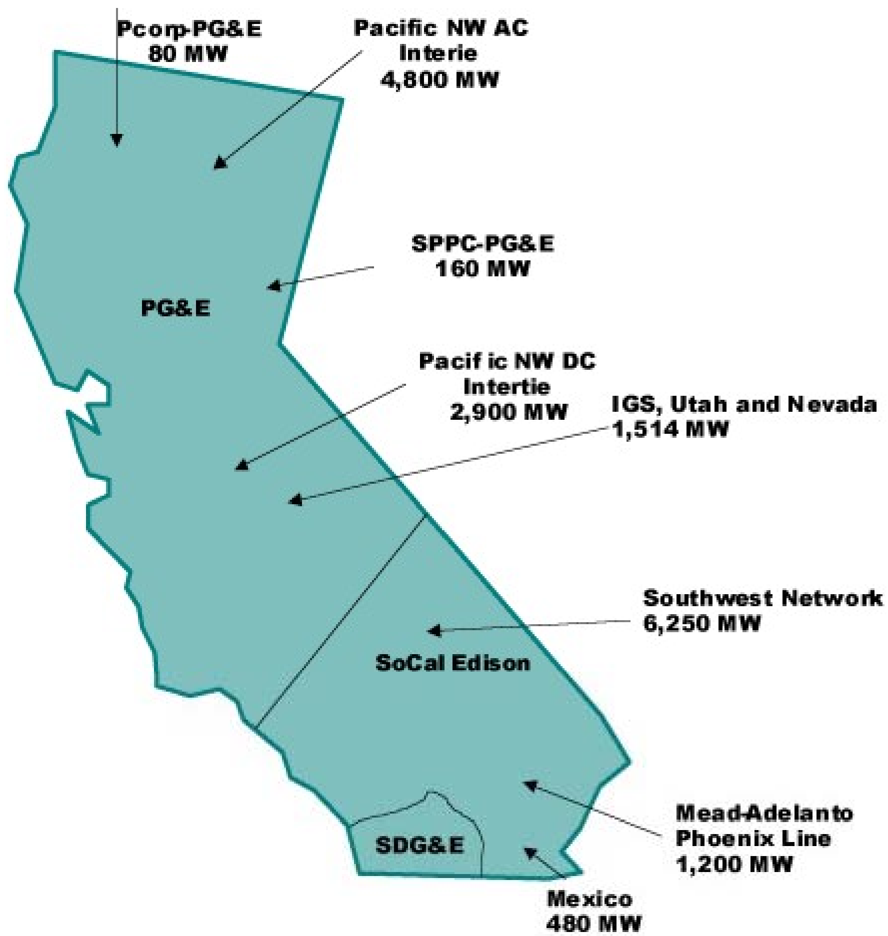
3.1.1 Import and Export Capabilities

California has an extensive high-voltage transmission system that enables access to diverse supplies from the western region of North America. The western interconnected system includes all states, from the Rocky Mountains to the Pacific Ocean, including parts of Canada and Mexico (see map on next page).

3.1.2 California Transmission Import and Export Capabilities

Exhibit 3-2 shows the major electric power import and export transmission lines to the region.

Exhibit 3-2
The Capability of California Transmission to Import and Export Electric Power



3.2 Price Patterns and Characteristics

This section describes the price patterns and associated characteristics of CalPX markets in the second year of market operations compared to the first year and, in some cases, cumulative two-year patterns.

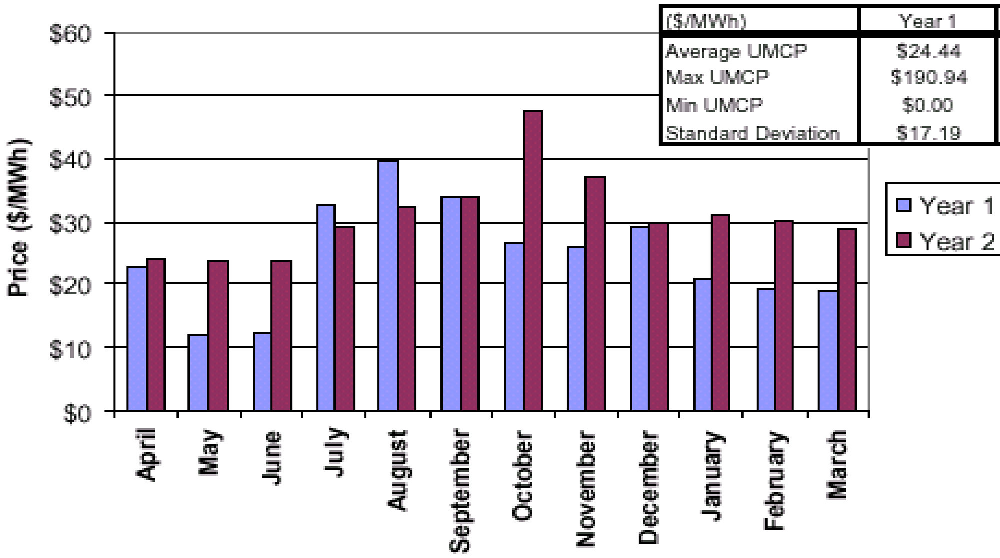
3.2.1 Day-Ahead Market – Operations

Overview of Price Trends in the Day-Ahead Unconstrained Market from Year 1 to Year 2 of CalPX Operations. Prices changed significantly between the first and second year on a nominal basis, reflecting a fairly dramatic upward movement. But almost all of the increase in price is explained by fundamentals. After consideration of these fundamentals, the unexplained variance in prices is small and appears to have contributed nothing to the trends. A comparison of the monthly average UMCP for the first year and second year of operation is shown in Exhibit 3-3. The average price for Year 2 is higher in all months except July and August of 1999.

The Day-Ahead unconstrained prices had their first year of operation in 1999. The second year of operation, from April 1, 1999 to March 31, 2000, saw an increase in the simple average price to $30.90/MWh, a 26 percent increase. The maximum in the first year of operation occurred on September 3, 1998 at $190.94/MWh. The maximum price was higher in the second year of operation by $34/MWh, reaching $225/MWh on August 27, 1999. However, the standard deviation of the price was lower in the second year by 15 percent, indicating less volatility in the market.

Exhibit 3-3
Day-Ahead Unconstrained Market Clearing Price

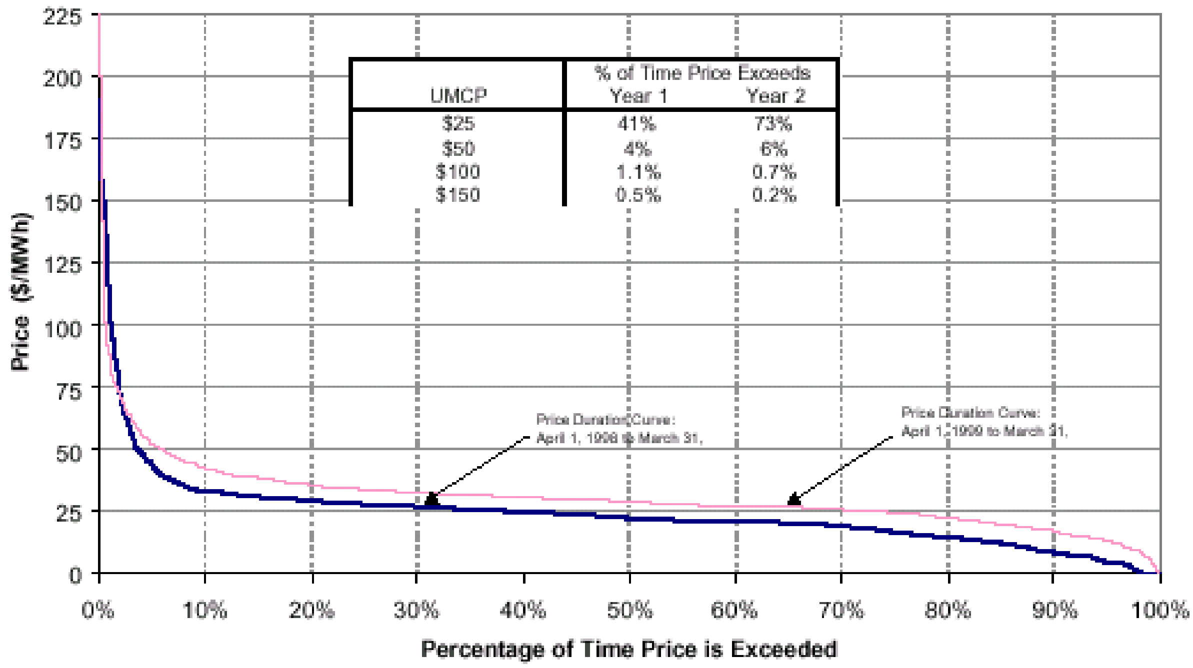
($/MWh)	Year 1	Year 2
Average UMCP	$24.44	$30.90
Max UMCP	$190.94	$225.00
Min UMCP	$0.00	$0.00
Standard Deviation	$17.19	$14.90



3.2.2 Price Duration Curve

The price duration curve shown in Exhibit 3-4 indicates the percent of time during the year that prices were greater than a certain price level. For example, prices were greater than $25/MWh for 41 percent of the time, or 3,600 hours in Year 1 and 73 percent of the time, or 6,400 hours in Year 2. The exhibit shows that for approximately 97 percent of the time, Year 2 prices were higher than the Year 1 prices by about $6/MWh. However, Year 1 appears to be more volatile as seen by the greater number of high-priced hours. Prices were greater than $100/MWh in Year 1 for approximately 97 hours compared to only 60 hours in Year 2. At the highest price range, prices were above $150/MWh for only 42 hours in Year 1, but only 20 hours in Year 2. This corresponds to the higher standard deviation for Year 1 as seen in Exhibit 3-4.

Exhibit 3-4
Price Duration Curve



The UMCP is influenced primarily by several external factors including temperature, load forecast, natural gas price, and resource availability. Temperature and resource availability are more likely to influence short-term price spikes lasting hours or days, while load growth and natural gas prices have greater influence on trends over months or years.

Significant events can be identified during the first two years that generally explain the rise in the average price. For example, in May and June of 1998, the "El Niño" phenomenon produced an abundance of low-cost hydroelectric generation in California and about 150 hours with a UMCP of $0/MWh. July and August of 1998 were extremely hot, with average temperatures seven degrees above normal. The UMCP for October 1999 averaged 78 percent greater than October 1998, also because of unseasonably warm temperatures. Compounding the unusually high load in October 1999 were three additional factors: (1) an outage of Diablo 2 nuclear unit for the entire month, (2) an increase on October 1, 1999 of the CAISO price cap to $750 from $250, and (3) frequent and severe congestion on Path 15. From January through March of 2000, the average UMCP prices were about 50 percent higher than the same months the year before. This higher UMCP for the first three months of 2000 corresponds to proportionally higher prices of natural gas. In addition, significantly less hydroelectric power was available in January and February 2000.

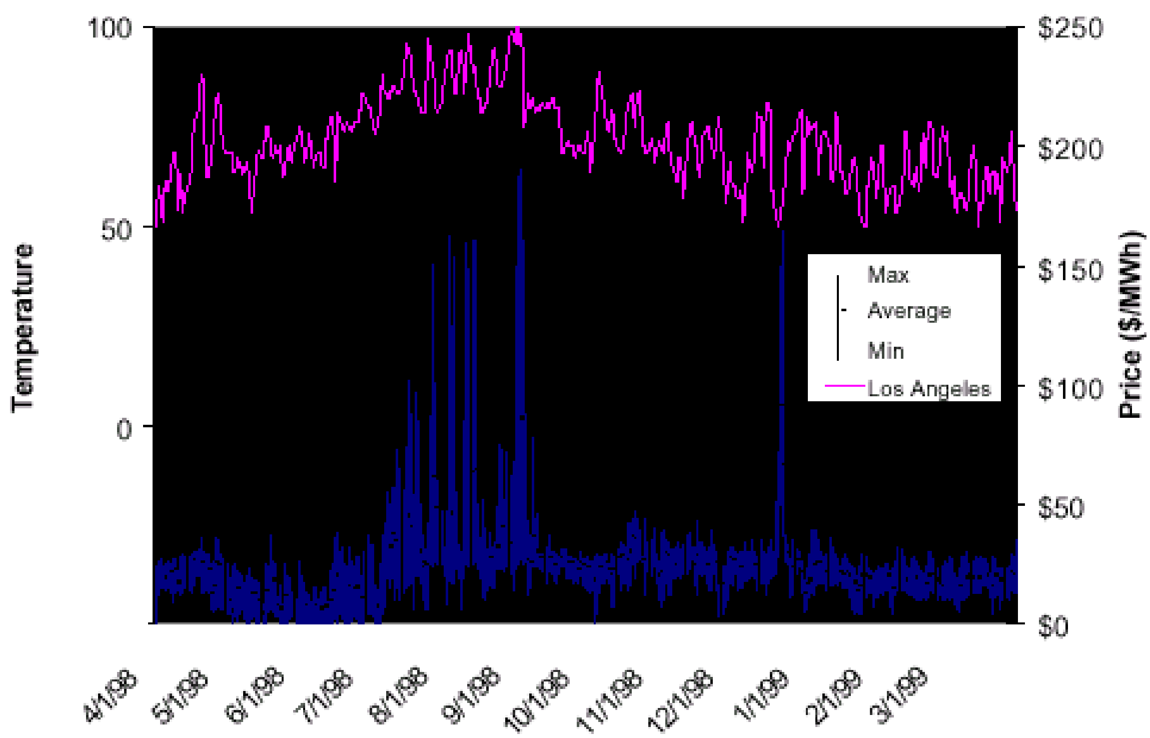
These external factors influencing prices in the Day-Ahead unconstrained market are described in more detail below.

3.2.3 Temperature and Effect on Demand

Temperature spikes account for the timing of most of the price spikes in the Day-Ahead unconstrained market. The number of other external events experienced at the same time has a compounding effect and greatly influences the magnitude of the price spike. As temperatures approach the 100-degree mark, the Day-Ahead Market inevitably reaches high price levels. The longer the heat wave, the higher the price spike. In general, however, temperature spikes and price spikes do not last more than a few days.

Exhibit 3-5 shows Year 1 of operations. The summer of 1998 experienced four heat waves where daily maximum prices exceeded $150/MWh.

Exhibit 3-5
Year 1 Daily UMCP Range vs. Temperature

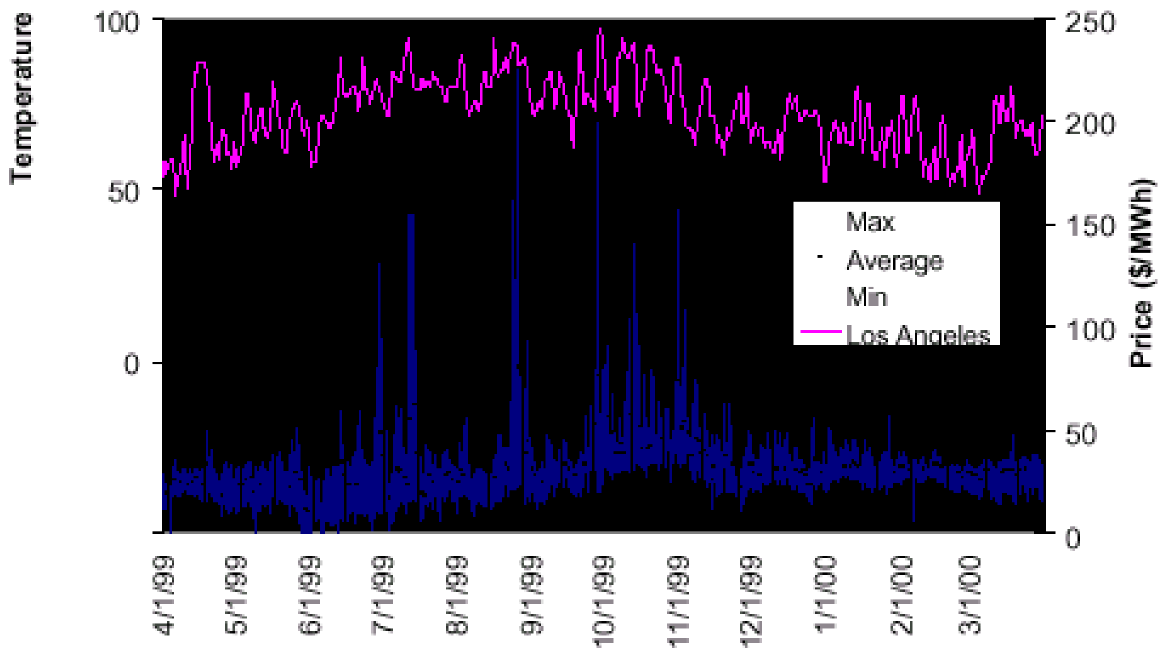


Severe cold weather can also create a price spike in the Day-Ahead unconstrained market. The West Coast was overwhelmed by a cold front for the five days before Christmas of 1998. Heating load was high in California. Compounding the impact of the cold weather was an outage of a Diablo nuclear unit. The high price of natural gas also contributed to the high

UMCP prices. Prices peaked at about $7/MMBtu, due to high demand in Northern California and the Pacific Northwest.

Exhibit 3-6 shows the relationship between UMCP and temperatures for Year 2, in which six episodes of price spikes above $100/MWh occurred. The three summer spikes occurred at the beginning and end of the summer. The three other spikes occurred in October 1999. Although more frequent episodes occurred in Year 2, the spikes were of shorter duration and generally less severe.

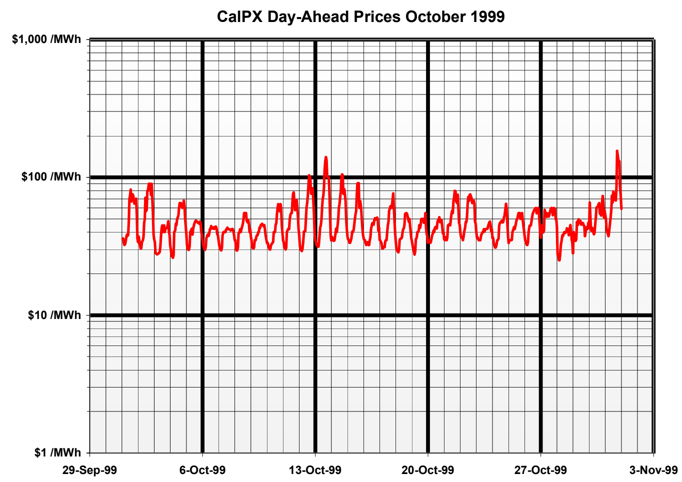
Exhibit 3-6
Year 2 Daily UMCP Range vs. Temperature

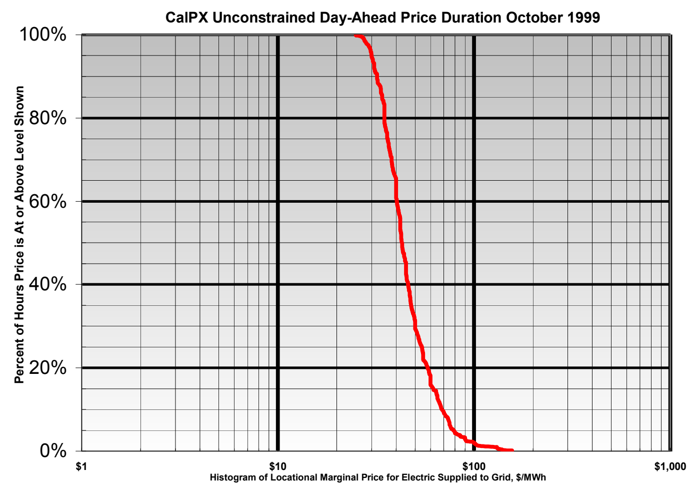


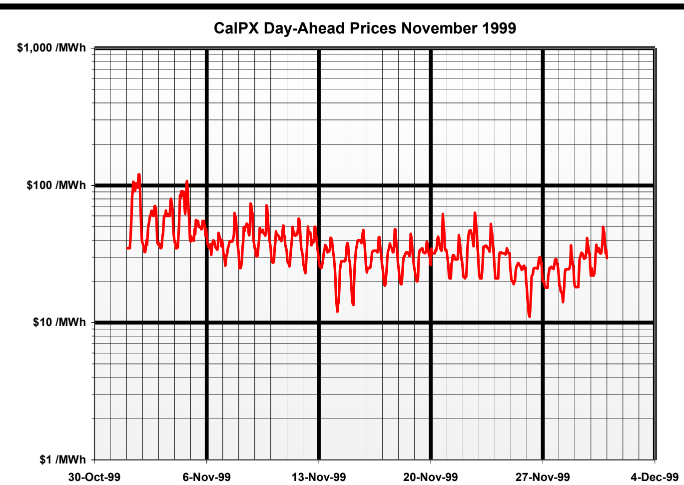
3.2.4 By Month

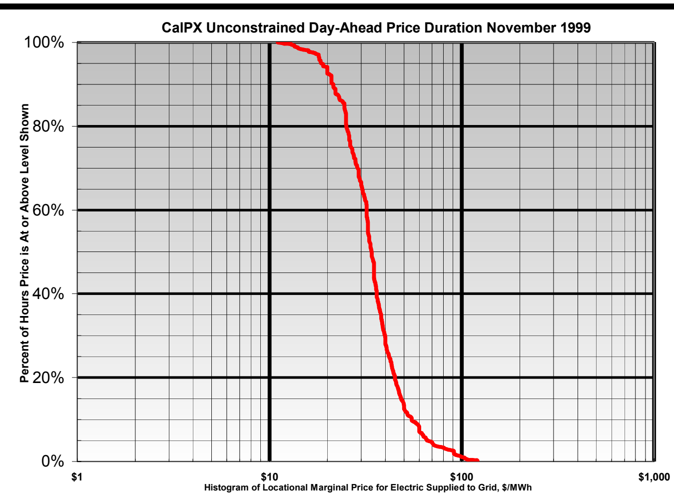
The GEMSET team took CalPX Day-Ahead, unconstrained price data from their Internet web site, and developed price duration curves for CalPX. These were for the entire state, which averages the prices at all of the hubs. Exhibit 3-7 shows the month-by-month data for a one-year period beginning with October 1999, and ending with September 2000.

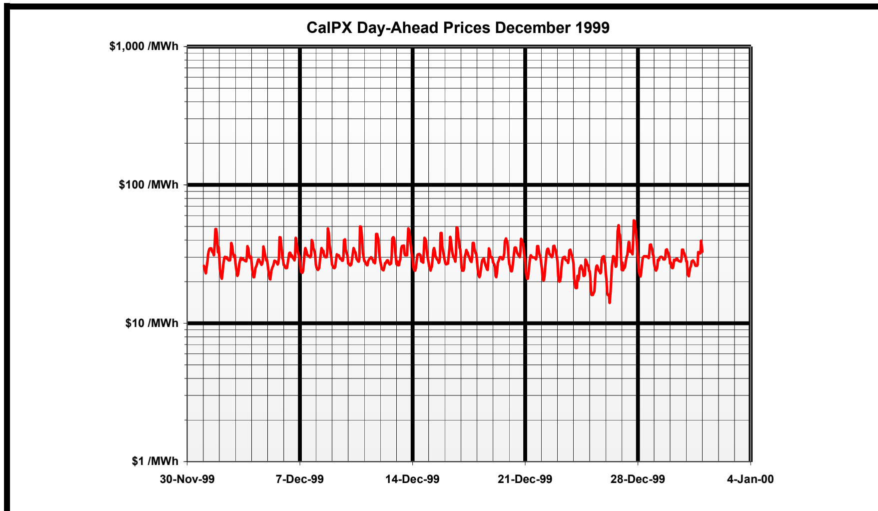
Exhibit 3-7
Monthly Hour-by-Hour CalPX Day-Ahead Market Prices, and Price Duration Histograms – October 1999-September 2000

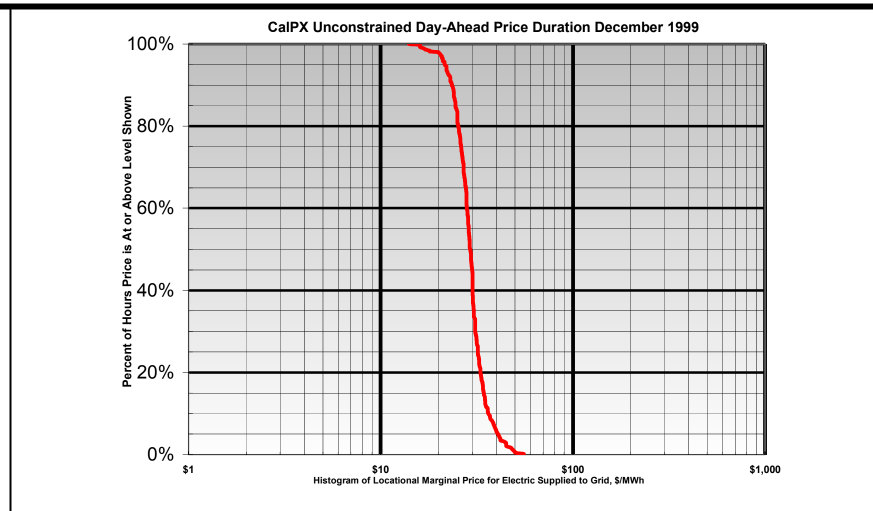


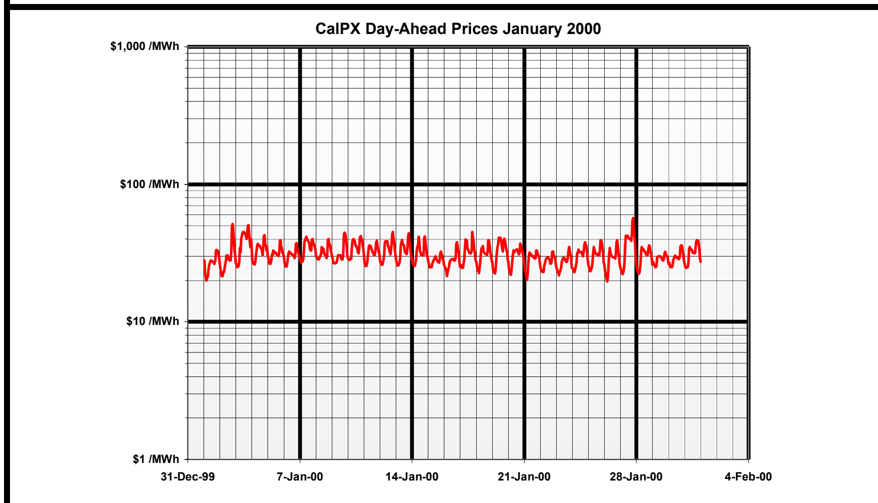


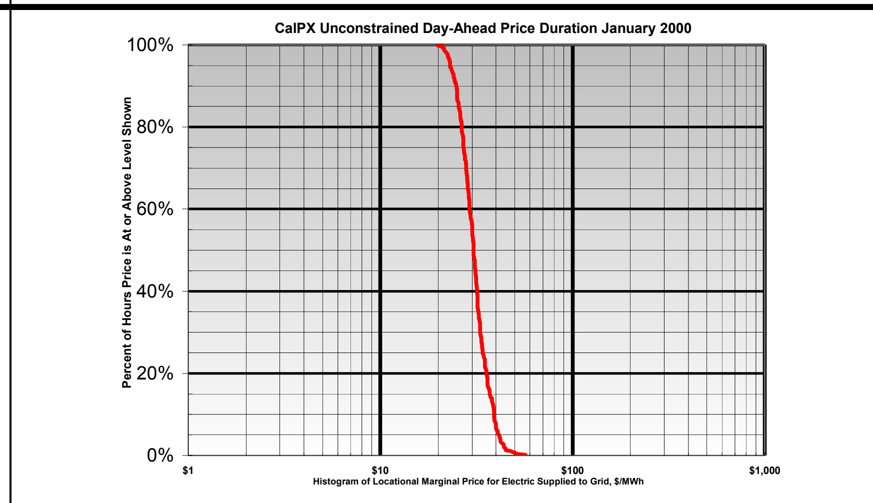


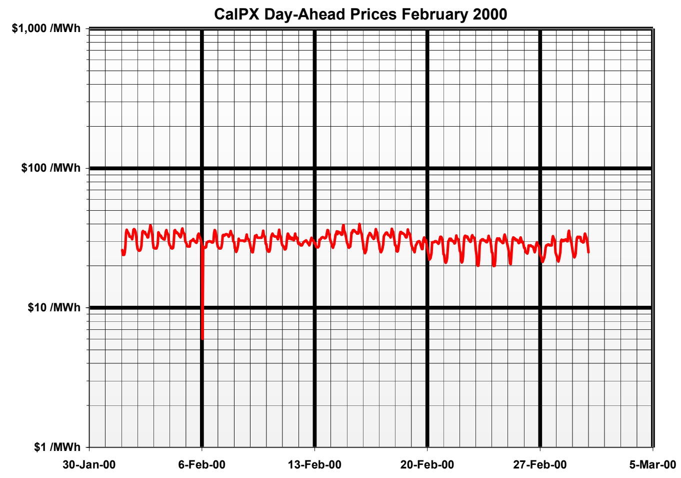


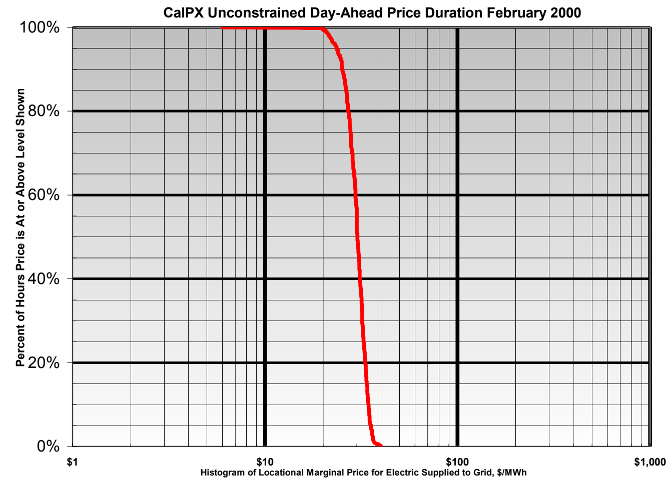

CalPX Day-Ahead Prices December 1999
$1,000 /MWh
$100 /MWh
$10 /MWh
$1 /MWh
30-Nov-99
7-Dec-99
14-Dec-99
21-Dec-99
28-Dec-99
4-Jan-00

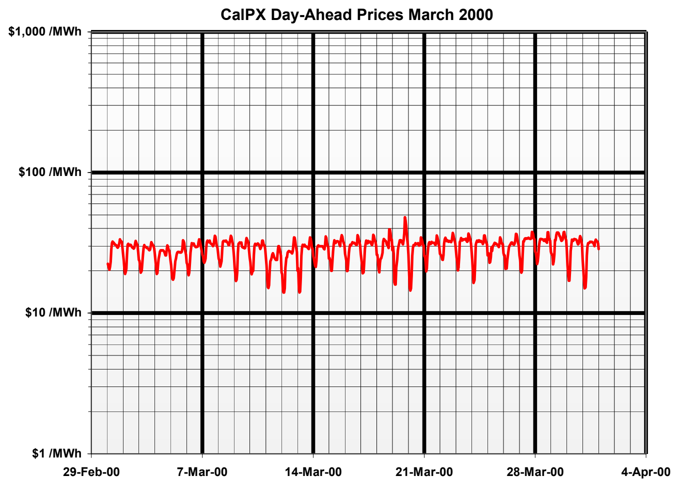

CalPX Unconstrained Day-Ahead Price Duration December 1999
Percent of Hours Price is At or Above Level Shown
100%
80%
60%
40%
20%
0%
$1
$10
$100
$1,000
Histogram of Locational Marginal Price for Electric Supplied to Grid, $/MWh

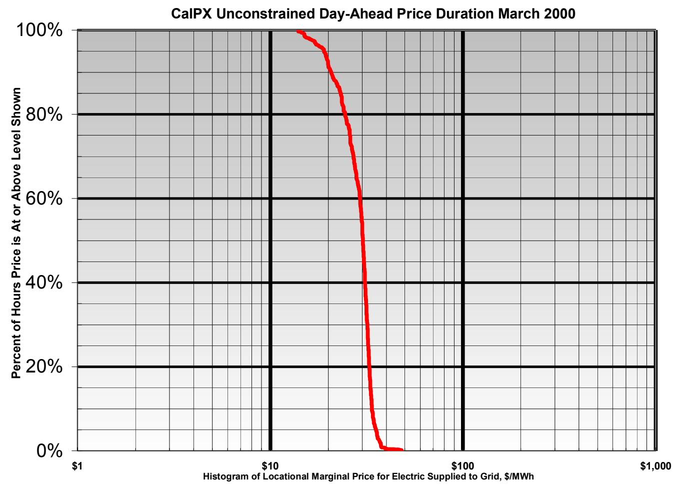

CalPX Day-Ahead Prices January 2000
$1,000 /MWh
$100 /MWh
$10 /MWh
$1 /MWh
31-Dec-99
7-Jan-00
14-Jan-00
21-Jan-00
28-Jan-00
4-Feb-00


CalPX Unconstrained Day-Ahead Price Duration January 2000
Percent of Hours Price is At or Above Level Shown
100%
80%
60%
40%
20%
0%
$1
$10
$100
$1,000
Histogram of Locational Marginal Price for Electric Supplied to Grid, $/MWh

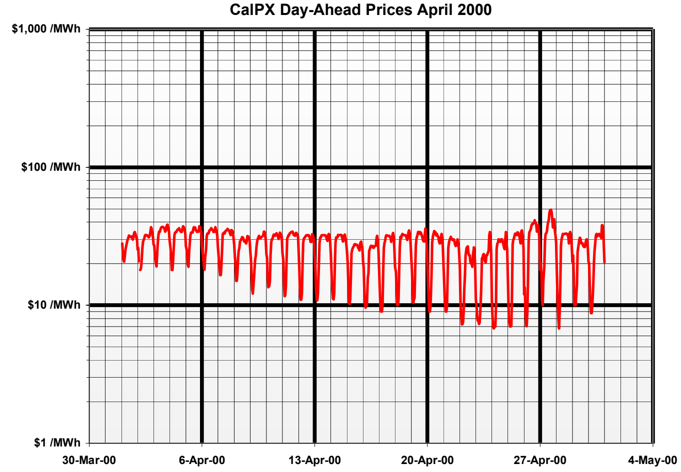

CalPX Day-Ahead Prices February 2000
$1,000 /MWh
$100 /MWh
$10 /MWh
$1 /MWh
30-Jan-00
6-Feb-00
13-Feb-00
20-Feb-00
27-Feb-00
5-Mar-00


CalPX Unconstrained Day-Ahead Price Duration February 2000
Percent of Hours Price is At or Above Level Shown
100%
80%
60%
40%
20%
0%
$1
$10
$100
$1,000
Histogram of Locational Marginal Price for Electric Supplied to Grid, $/MWh

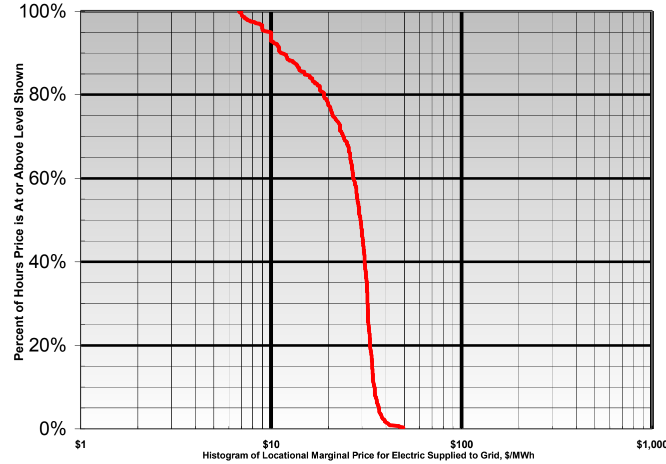

CalPX Day-Ahead Prices March 2000
$1,000 /MWh
$100 /MWh
$10 /MWh
$1 /MWh
29-Feb-00
7-Mar-00
14-Mar-00
21-Mar-00
28-Mar-00
4-Apr-00


CalPX Unconstrained Day-Ahead Price Duration March 2000
Percent of Hours Price is At or Above Level Shown
100%
80%
60%
40%
20%
0%
$1
$10
$100
$1,000
Histogram of Locational Marginal Price for Electric Supplied to Grid, $/MWh

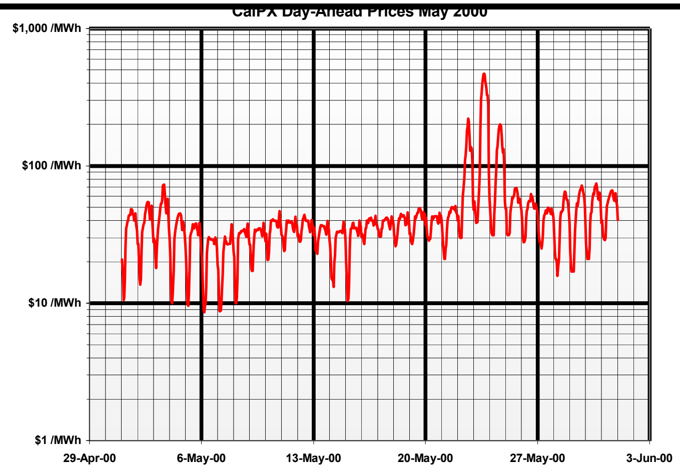
CalPX Day-Ahead Prices April 2000



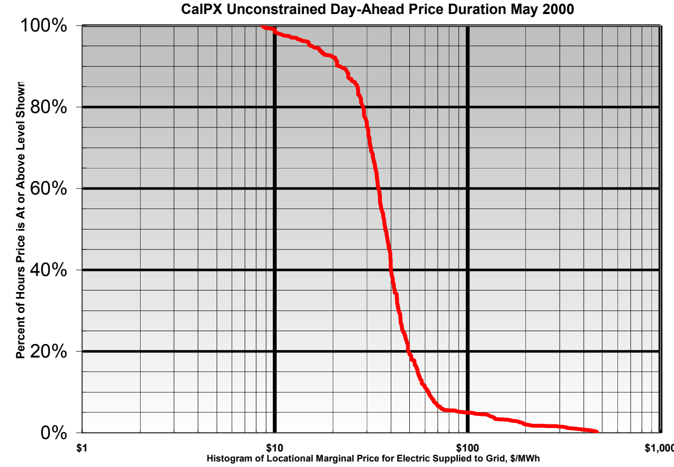
CalPX Unconstrained Day-Ahead Price Duration April 2000

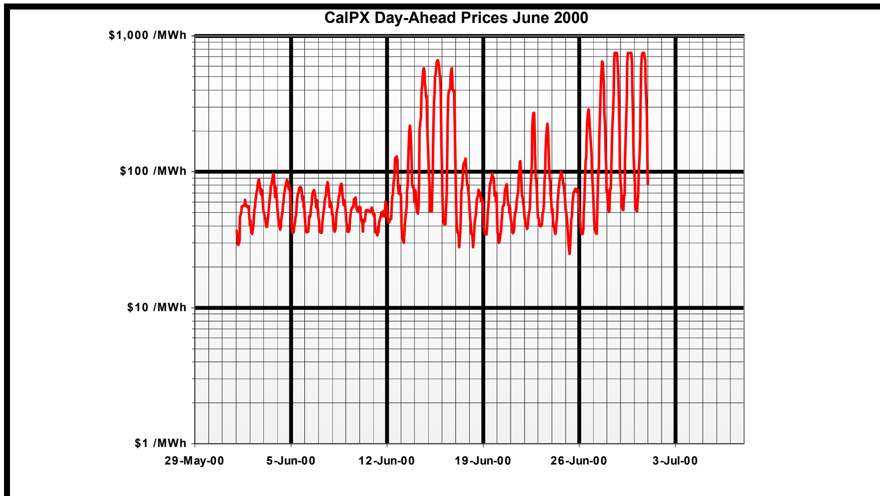


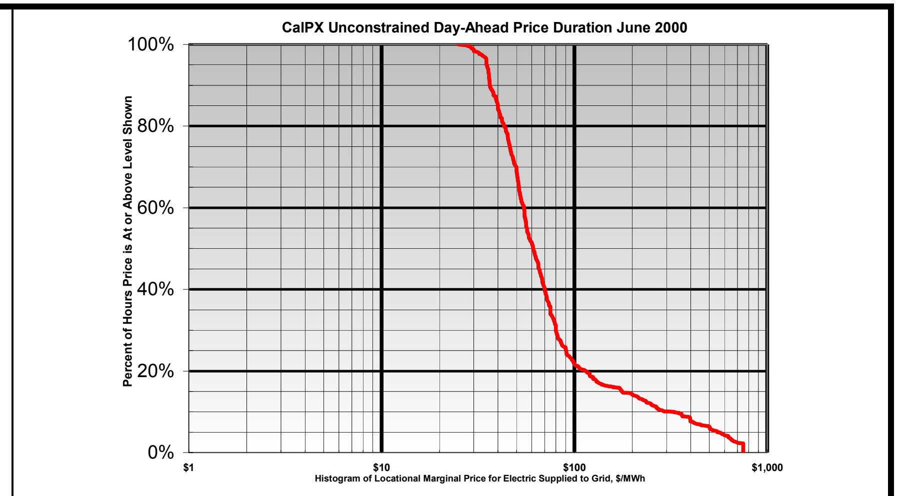
CalPX Day-Ahead Prices May 2000

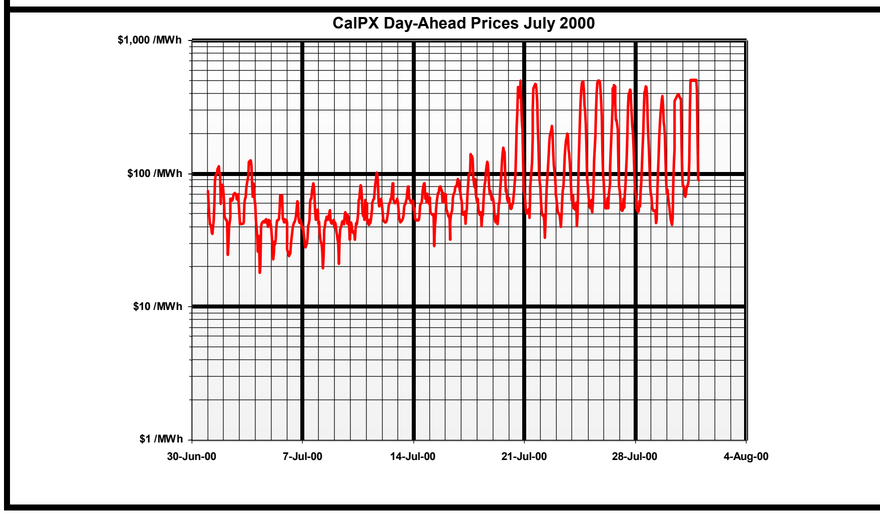


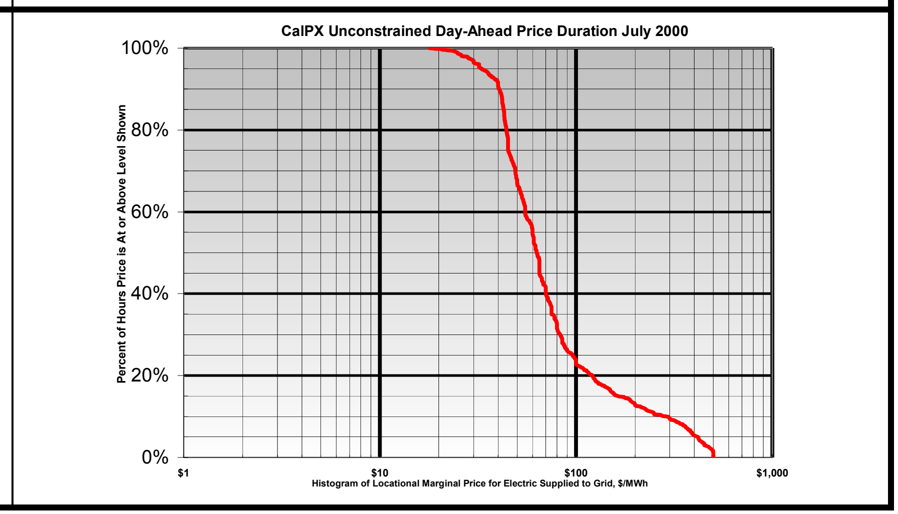
CalPX Unconstrained Day-Ahead Price Duration May 2000

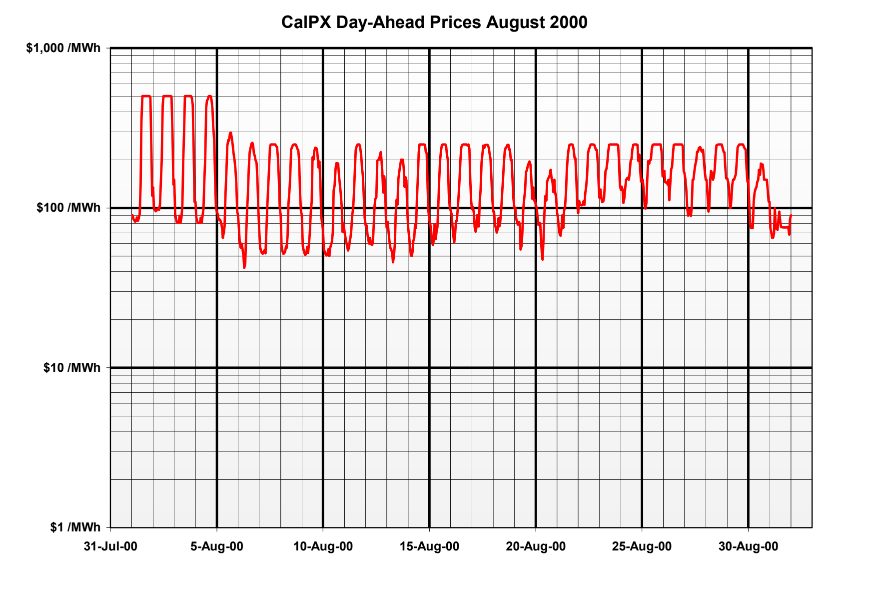


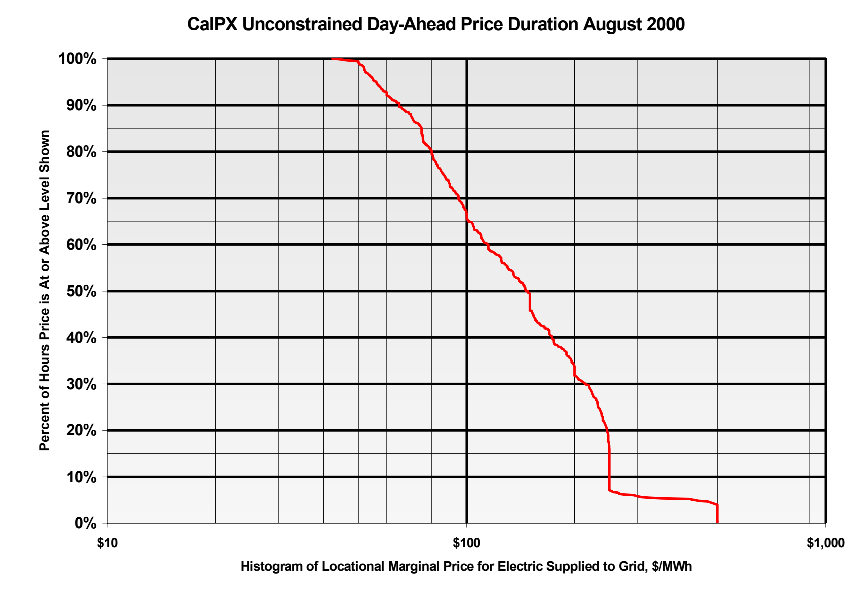

CalPX Day-Ahead Prices June 2000
$1,000 /MWh
$100 /MWh
$10 /MWh
$1 /MWh
29-May-00
5-Jun-00
12-Jun-00
19-Jun-00
26-Jun-00
3-Jul-00

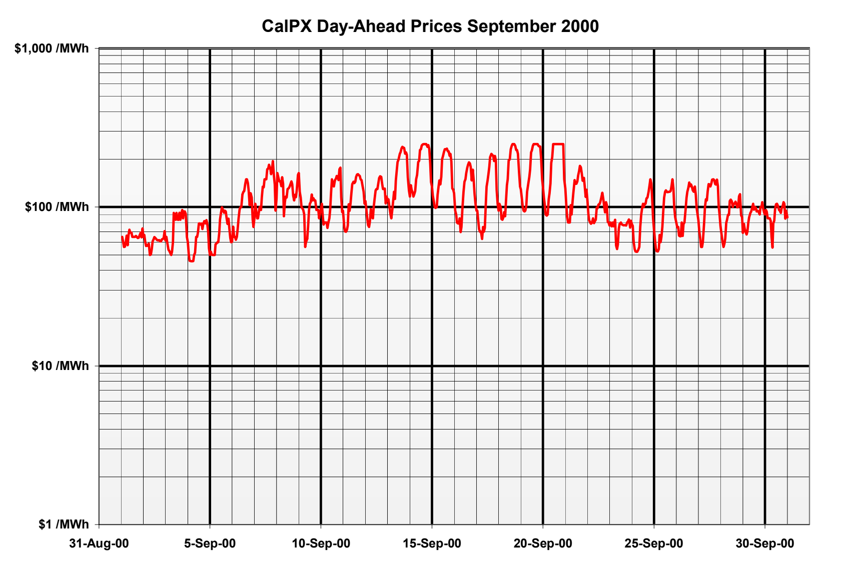

CalPX Unconstrained Day-Ahead Price Duration June 2000
Percent of Hours Price is At or Above Level Shown
100%
80%
60%
40%
20%
0%
$1
$10
$100
$1,000
Histogram of Locational Marginal Price for Electric Supplied to Grid, $/MWh

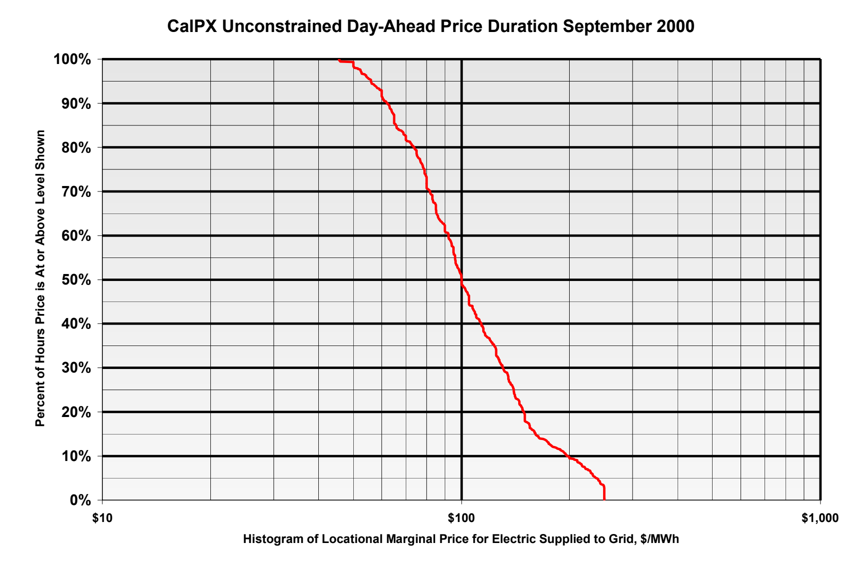

CalPX Day-Ahead Prices July 2000
$1,000 /MWh
$100 /MWh
$10 /MWh
$1 /MWh
30-Jun-00
7-Jul-00
14-Jul-00
21-Jul-00
28-Jul-00
4-Aug-00


CalPX Unconstrained Day-Ahead Price Duration July 2000
Percent of Hours Price is At or Above Level Shown
100%
80%
60%
40%
20%
0%
$1
$10
$100
$1,000
Histogram of Locational Marginal Price for Electric Supplied to Grid, $/MWh


CalPX Day-Ahead Prices August 2000
$1,000 /MWh
$100 /MWh
$10 /MWh
$1 /MWh
31-Jul-00
5-Aug-00
10-Aug-00
15-Aug-00
20-Aug-00
25-Aug-00
30-Aug-00


CalPX Unconstrained Day-Ahead Price Duration August 2000
Percent of Hours Price is At or Above Level Shown
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
$10
$100
$1,000
Histogram of Locational Marginal Price for Electric Supplied to Grid, $/MWh


CalPX Day-Ahead Prices September 2000
$1,000 /MWh
$100 /MWh
$10 /MWh
$1 /MWh
31-Aug-00
5-Sep-00
10-Sep-00
15-Sep-00
20-Sep-00
25-Sep-00
30-Sep-00


CalPX Unconstrained Day-Ahead Price Duration September 2000
Percent of Hours Price is At or Above Level Shown
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
$10
$100
$1,000
Histogram of Locational Marginal Price for Electric Supplied to Grid, $/MWh

3.2.5 Characterization of One Year's Data

A composite of the month-by-month hourly price data was assembled that gives one year's worth of data. This is shown in Exhibit 3-8. This year's worth of data was developed into an annual price duration curve as shown in Exhibit 3-9.

The correlation of demand versus price is shown in Exhibit 3-10. The correlation is weak. The three "bands" evident in this curve and also in Exhibit 3-8 occurred when artificial ceilings on the free-market price were constrained; these occurred in the summer of 2000 when, alarmed by the high market prices, the ISO artificially imposed successively lower price ceilings at $750/MWh, $500/MWh, and $250/MWh. It is still not yet clear what the long-term impact of ceilings will be; while they temporarily constrain price, they might also have the effect of suppliers diverting electricity out of the CalPX region to more lucrative markets, exacerbating power shortages during periods of high demand.

Exhibit 3-8
CalPX Day Ahead Prices: October 1999 – September 2000

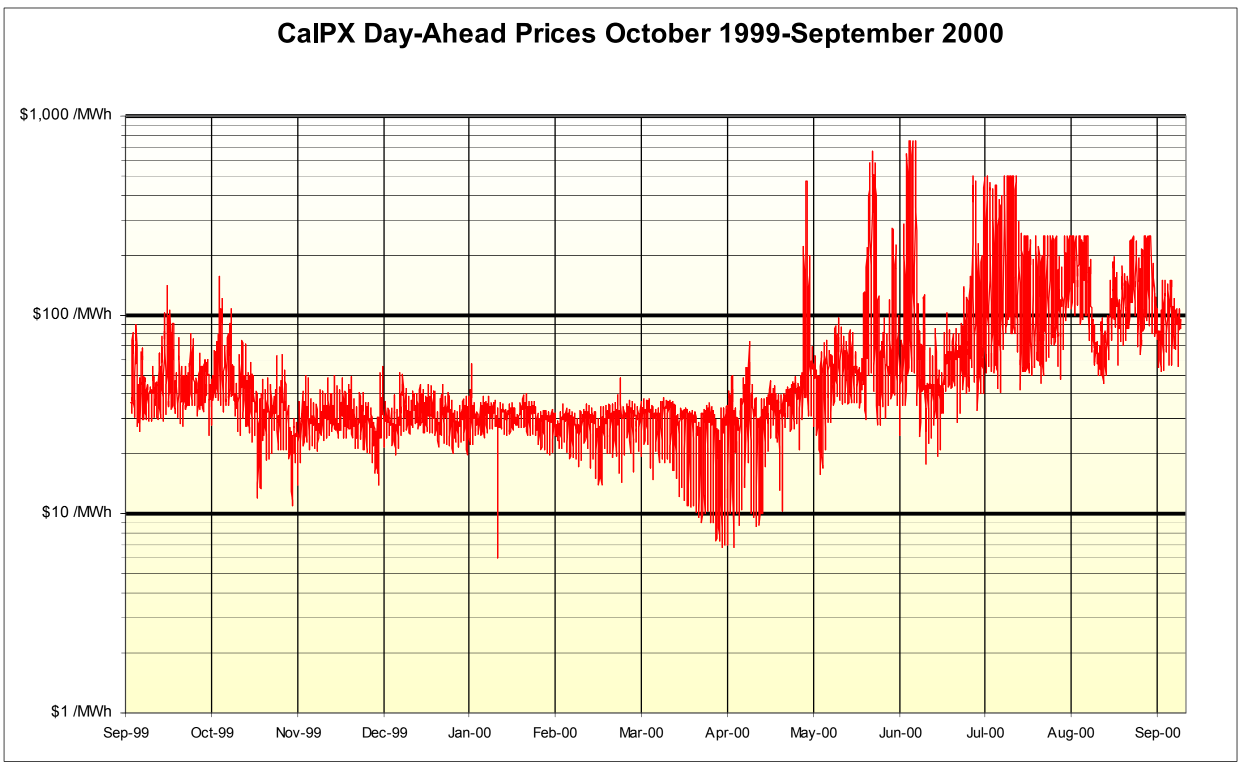


Exhibit 3-9
CalPX Unconstrained Day-Ahead Price Duration: October 1999-September 2000

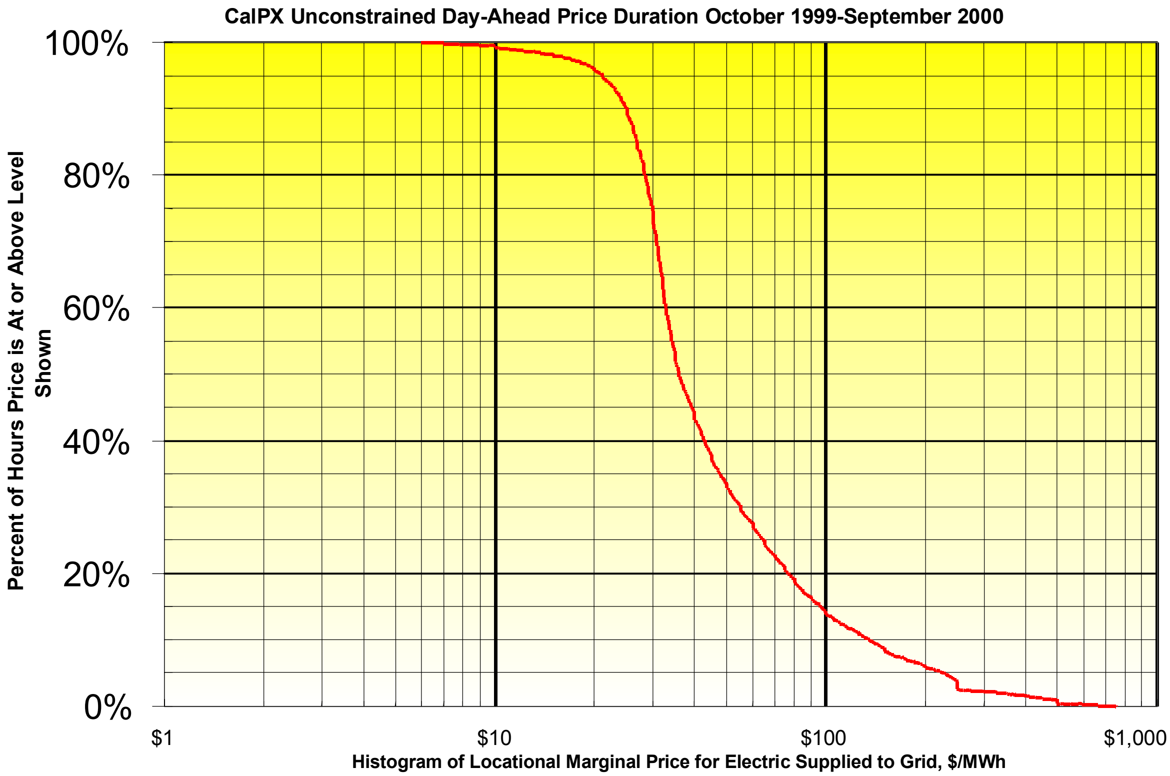
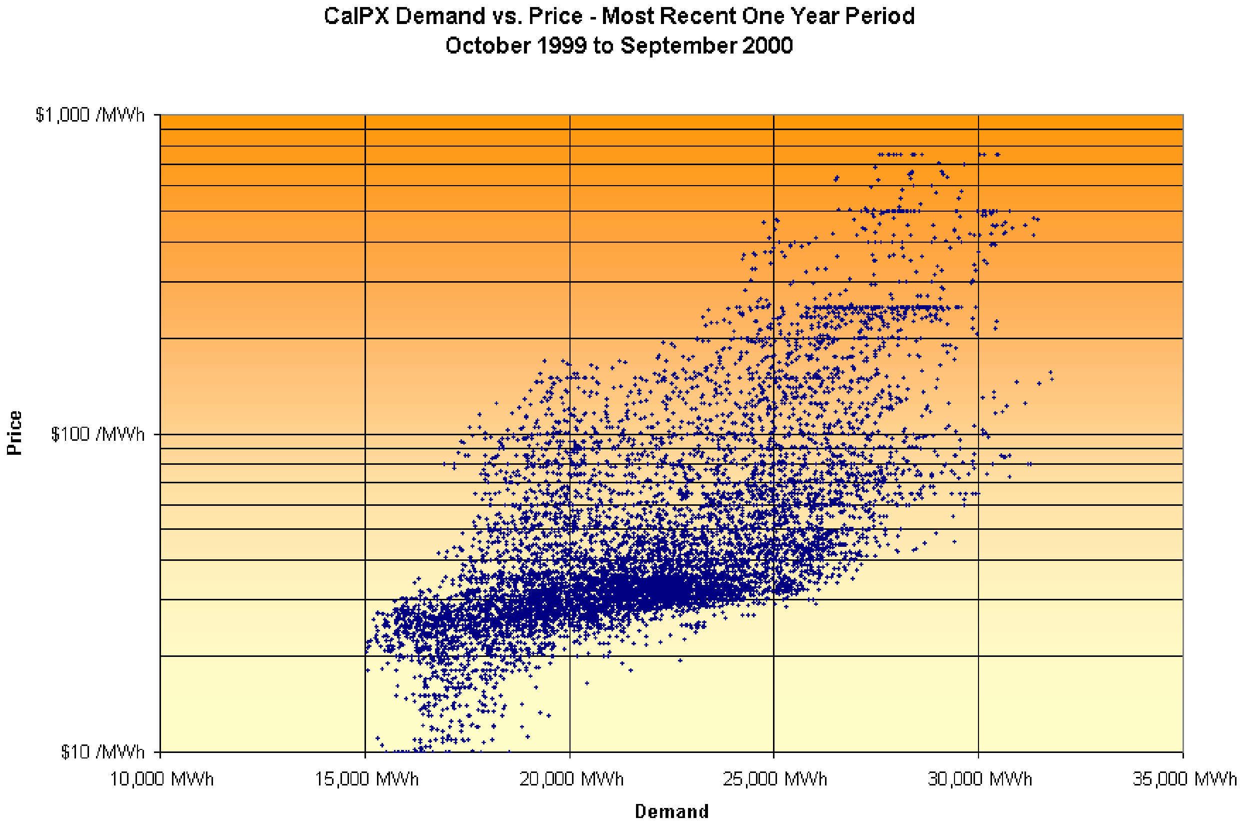


Exhibit 3-10
Demand versus Price



4 Specifics on CalPX's Market Operations

CalPX manages two exchange-based "spot" markets. As of fall 1999, approximately 70 entities from the United States and Canada were certified to trade through CalPX.

- The first market is the Day-Ahead Market, in which participants can bid supply and demand for the next day's 24 hours. The Day-Ahead Market starts at 6 a.m. on the day ahead of the trading day, and closes at 1 p.m. on the day ahead of the trading day, when the ISO issues the final day-ahead schedule.
- For its first 12-month market year (ending March 31, 1999), Day-Ahead Market prices averaged just 2.4 cents per kilowatt-hour, based on an average price of $24.44 per megawatt-hour (MWh) for the 12 months. Prices ran below $30 per MWh about 80 percent of the time.
- Daily volume averaged 517,842 MWh, with 187 million MWh traded over the year at a value of more than $8 billion. This makes CalPX the largest electricity trading marketplace of its type in the world.
- Market clearing quantities exhibited the seasonal trends typical of the region. The hourly average for market clearing quantity volume ranged from a low of 19,532 MWh during February 1999 to a peak of 25,899 MWh in August 1998. Over the year, the CalPX share of market volume averaged 86 percent of the ISO's total day-ahead market schedules. About 90 percent of the energy purchased during this time went to customers of the state's three major investor-owned utilities (PG&E, SCE, and SDG&E).
- The second CalPX market is the Day-Of Market (originally introduced as the Hour-Ahead Market). This permits participants to conduct energy transactions nearer to the delivery hour, when generation and energy use conditions may require changes in trading positions. The Day-Of Market includes 24 auctions conducted in three batches during the course of the day – at 6 a.m., noon, and 4 p.m.

4.1 Day-Ahead Market

A participant may trade and schedule in the Day-Ahead Market for next-day delivery. Each trade incurs a mutual obligation for payment between CalPX and its market participants. Day-Ahead Market settlements are based on schedules, and are provided within three days after each trade day. Following are the trading procedures in the Day-Ahead Market:

- Participants provide supply and demand bids for electricity to CalPX. Once the bids are received, CalPX validates them. This involves verifying that the content of the bid complies with the requirements of the bid format, and checking for consistency with data contained in the master file.

- After validating the bids, CalPX constructs aggregate supply/demand curves and their intersection to determine the market clearing price (MCP) for each hour of the 24-hour scheduling day. Unless there is electrical transmission congestion (see below), the MCP becomes the single cost for electricity throughout California for that energy delivery hour.

- CalPX also determines if the bids submitted could create a potential over-generation condition. If a potential over-generation condition occurs, CalPX must inform the ISO.

- Bids initially submitted into the Day-Ahead Market auction need not be attributed to any particular unit or physical scheduling plant. Such bids are referred to as portfolio bids.

- Portfolio bids that are accepted into the Day-Ahead Market are then broken down into generation-unit schedules, which are submitted to the ISO along with adjustment bids (for congestion) and ancillary service bids.

- The ISO determines, based on all unit-specific supply bids and location-specific demand bids, whether there is congestion. If there is congestion, the ISO uses adjustment bids to submit an adjusted schedule to CalPX and other scheduling coordinators.

- These adjusted schedules and ISO-determined usage charges become the foundation for modified zonal MCPs and the final schedule submitted to the ISO.

4.2 Day-Of Market

In the Day-Of Market, participants submit unit-specific supply or demand bids to CalPX for auctions at 6 a.m., noon, and 4 p.m. This gives participants an opportunity to make adjustments based on their day-ahead schedules so they can minimize real-time imbalances. The MCP is determined the same way as in the Day-Ahead Market. CalPX communicates price and traded quantities to CalPX participants immediately after the Day-Of Market auctions close. The auction and delivery schedule in the Day-Of Market works as follows:

- The 6 a.m. auction period includes individual auctions for energy delivery hours ending 11 a.m. to 4 p.m. (same day).

- The noon auction period includes individual auctions for energy delivery hours ending 5 p.m. to midnight (same day).

- The 4 p.m. auction includes individual auctions for energy delivery hours ending 1 a.m. to 10 a.m. (following day).

4.3 Summary of Responsibilities of CalPX and its Participants

Responsibilities of CalPX	Responsibilities of Participants
• Receive demand and supply bids. • Determine market clearing price (MCP). • Determine zonal prices (MCP adjusted for congestion). • Serve as scheduling coordinator for participants. • Settle trades in CalPX markets (settlement). • Prepare and send invoices. • Operate funds transfers for settlement and billing.	• Submit demand or supply bids that are complete and on time. • Comply with operational instructions provided by CalPX or the ISO. • Provide end-user-metered data as required by the CalPX Tariff. • Promptly meet all obligations – operational and financial – arising from market participation.

Because it is a clearinghouse, CalPX may not participate in any market transactions itself, or on its own behalf.

4.3.1 Ancillary Services

All other services that are used to maintain a secure and reliable supply of power (ancillary services) are submitted to CalPX and selected by the ISO.

4.3.2 Real-Time Market

Real-time operations are managed by the ISO, which also determines the Real-Time Market price after the fact based on actual metered data (ex-post price).

4.3.3 New Products

To continue to meet its customers' evolving needs, CalPX has introduced several new products, in addition to enhancements for existing products. These include:

- **Bookout Service** – This voluntary energy delivery scheduling option is designed to lower the cost of purchasing energy at state border tie-points connected to California's electrical transmission grid. Whenever CalPX participants schedule energy sales and purchases at a particular tie-point, CalPX has the opportunity to net schedules and thus significantly reduce ISO and wheeling fees to Bookout participants. Bookout can eliminate export-based charges ranging from $3 to $7 per megawatt-hour when energy purchases are matched with sales at the same transmission system tie-point. Savings are shared by all participating CalPX energy purchasers involved in the Bookout process at individual tie-points.

- **Post Close Quality Match (PCQM)** – This seven-month experimental program permits CalPX market traders to even up market positions at the settlement price after the close of the market. This essentially provides suppliers a second-chance opportunity to contribute additional resources into the Day-Ahead Market, enabling them to better manage their market positions for the next trading day or delivery period. CalPX notifies participants of their eligibility to participate in PCQM when it publishes awarded schedules. The determination is based on supply and demand bids originally submitted in the Day-Ahead Market, and on a pre-determined bandwidth (fixed percentage) above and below the MCP. Eligible, interested traders then can submit supply and demand bids. CalPX calculates the matched quantities and publishes the results, which are priced at the established MCP for the hour.

4.4 Scheduling

CalPX and other scheduling coordinators actively participate in the forward market for electric power when the timeframe is one hour or more from the time of actual delivery.

The ISO manages the real-time electric power market. The ISO arranges for sources of energy for potential use in real time. These sources include ancillary service energy and supplemental energy bids received from CalPX and other scheduling coordinators.

4.5 Availability of Block-Forwards Market Trading

To provide market participants with a longer-term trading instrument to hedge hourly price risk, in June 1999 CalPX began offering monthly block-forward energy contracts. The first CalPX product to extend California's competitive marketplace beyond the Day-Ahead and Day-Of energy markets, the Block-Forwards Market enables both buyers and sellers to avoid exposure to the volatility of energy prices during peak usage periods, while continuing to reap the market liquidity and price discovery benefits offered by CalPX. Research shows that in western U.S. markets, about 20 percent of electricity is already traded in monthly blocks on a forward basis.

Initially, participants could enter into monthly on-peak energy contracts for delivery up to 6 months beyond the current trading month. In October 1999, CalPX extended this to 12 months, so that the Block-Forwards Market now accepts bids for energy sales and purchases up to a year in advance. The market matches bids to buy power with offers to sell power.

Energy delivery in the Block-Forwards Market can be scheduled through CalPX's Day-Ahead Market or the bilateral market for either the Northern California (NP 15) or Southern California (SP 15) zones. In addition, by Spring 2000, CalPX expanded block-forwards training outside of the state by offering contracts for delivery at the Mead substation in southern Nevada, the Palo Verde substation in western Arizona, and at the California-Oregon border scheduling point known as COB. These delivery points represent the most visible energy-trading hubs not currently served by CalPX in the West and marks CalPX's first trading products that are totally independent of the California energy marketplace.

The Block-Forwards Market is open to all energy traders, including those who do not participate in CalPX's Day-Ahead Market. CalPX accepts block-forward contract bids each weekday for energy delivery 1 to 12 months ahead of the current month, based on the following parameters:

- Every forward block contract consists of 16 on-peak hours, from 6 a.m. to 10 p.m. daily for every day of a month (excluding Sundays and certain holidays).
- Each contract also is based on a specific future month at a certain quantity (multiples of 1 or 25 MW), with trading ceasing two days before the start of the delivery month.
- When CalPX's Day-Ahead Market is used for delivery of energy bought and sold in the Block-Forwards Market, Day-Ahead Market energy is scheduled independently of the block-forward contracts, which enables participants to schedule delivery based on their current marginal costs rather than their block forward positions.
- Trading occurs through a telephone ordering process and a password-protected Internet Web site that allows each participant to check current market prices and download their specific trading and clearing information.
- Settlement of the Block-Forwards Market occurs on a monthly basis following the delivery month of the purchased contracts. Participants are invoiced or paid based on their net position in the Block-Forwards Market as compared to CalPX average Day-Ahead Market prices for the delivery month.

CalPX developed the Block-Forwards Market in response to participants' input, and traders have begun utilizing the tool to lock in energy prices for on-peak hours during periods (such as summertime) when higher electricity demand traditionally increases prices in the spot electricity markets.

The availability of a longer-term trading instrument will assist CalPX in improving California's overall market efficiency, plus provide price certainty and additional risk management for participants. In addition, with the planned expansion of block-forward trading into Nevada, CalPX continues its efforts to facilitate regionally efficient markets for the entire western region.

4.6 CalPX Offers Unparalleled Benefits to Market Participants

4.6.1 What You See Is What You Get

CalPX provides an open, visible market price. For consumers, this translates to a benchmarked price for other transactions or market-priced power obtained on their behalf through their utility distribution company or other service provider. For financial traders and other buyers and sellers, this translates to a reference price. For investor-owned utilities in California, this translates to prices that adequately capture, or determine, the Competitive Transition Charge (CTC) collection. (The CTC is a fee paid by California energy consumers to the state's three investor-owned utilities for certain past investments that are uneconomic under a competitive system.)

Overall, making as many consumers as possible aware of electricity prices and their daily changes ensures that the benefits of electricity industry restructuring and a competitive power market will be quickly and efficiently transferred to the California economy.

4.6.2 The Most Credible, Efficient Market Possible

CalPX also establishes a credible marketplace with no hidden margins or hidden price mark-ups. The rules under which CalPX operates, and the prices it generates, are open to public scrutiny and are regulated by the federal government (FERC). CalPX's Board of Governors represents the public interest and includes a broad range of stakeholders, which provides a balance of interest for those who participate in the market. In addition, CalPX monitors the market to ensure fair trading, and has no financial connection to the ISO or any of the entities that participate in its auctions.

CalPX implements all of the important features of an efficient market set forth by the CPUC, including:

- Market prices that are determined independently from all vested interests in the market.

- Easy entry and exit to the market for energy service providers and others.

- Bidding processes, auctions, and dissemination of resulting prices that are fully transparent to all potential and actual participants.

- Hourly prices to aid investors in long-term supply decisions and to promote load shifting and other demand-side responses to peak demand.

4.6.3 One-Stop Shopping

In just a single transaction, CalPX accomplishes schedule coordination; settlement and credit handling; physical delivery; and market priced power for every hour and any size bid.

4.6.4 Excellent Credit

CalPX's market price transparency and credit management practices all minimize counterparty risk. Participants maintain security deposits commensurate with their exposure to cover potential defaults. In 1998, CalPX had no defaults in payment or delivery.

Maintaining high credit ratings is one of CalPX's top priorities. In November 1998, CalPX received a short-term issuer rating of Prime-1 with a stable outlook from Moody's Investors Service. Nine days later, CalPX earned a first-time A-1 issuer credit rating from Standard & Poor's. These ratings resulted in reduced credit service costs, and thus lowered costs to participants.

4.6.5 Reduced Risk

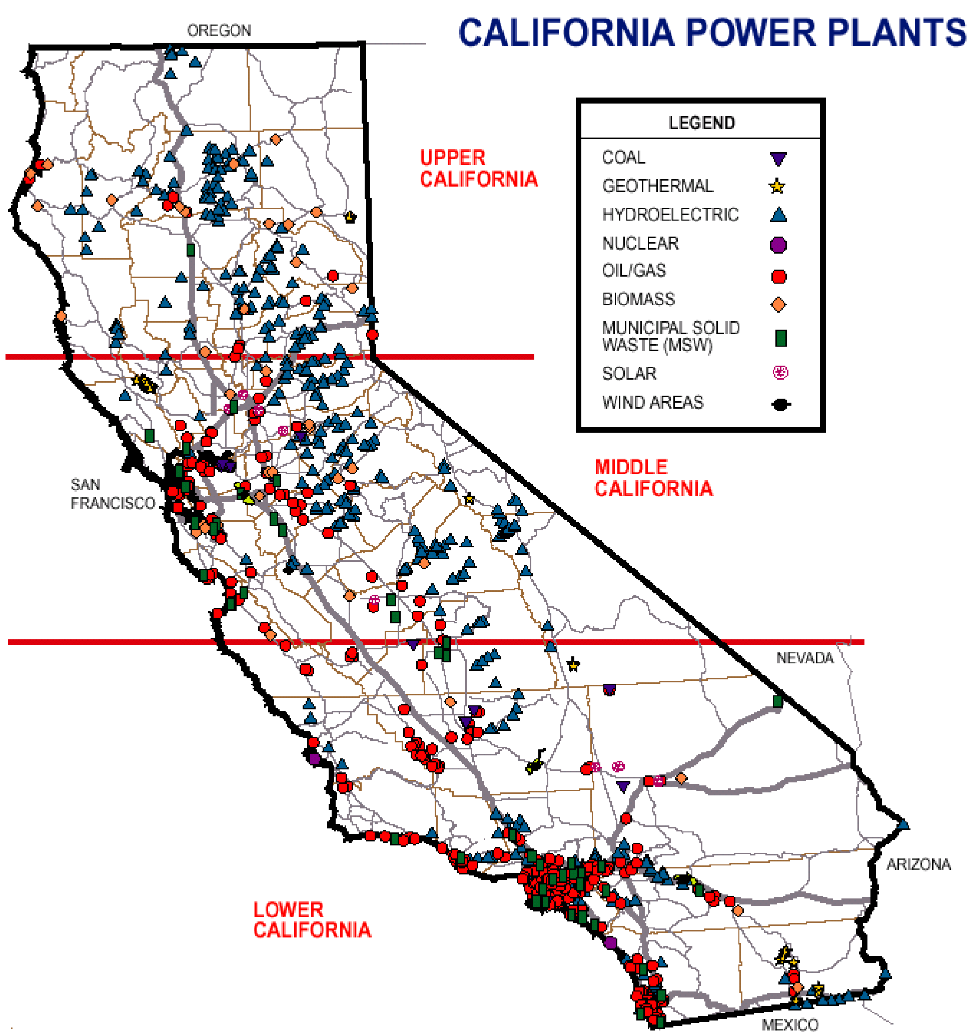
For buyers and sellers alike, CalPX minimizes risk, compared to the risk present in bilateral trading. This is because trading with CalPX involves a deep and liquid pool of buyers and sellers. For buyers, this means significantly reduced risk of delivery failure. For sellers, it means significantly reduced risk of non-payment. Overall, CalPX's operation helps keep the California marketplace robust and competitive.

5 Generation Resources

5.1 Existing Capacity

Exhibit 5-1 shows the location of California's existing base of electric power generation.

Exhibit 5-1
Location of Existing California Power Plants



5.2 Planned Additions

Exhibit 5-2, Exhibit 5-3, and Exhibit 5-4 list the planned generation additions in the region.

Exhibit 5-2
Power Plant Projects Before the Commission Since 1979

OPERATING PROJECTS	A.K.A.	PRIMARY FUEL	MW	CEC DOCKET#	DEEMED ADE-QUATE	DATE CERTI-FIED	START CONSTRUC-TION	ON-LINE DATE
GEYSERS #17		GEO	110	79-AFC-1	Mar-79	Sep-79	Jan-80	Mar-82
NCPA #2	NCPA Unit #1	GEO	110	79-AFC-2	Apr-79	Mar-80	Apr-80	Feb-82
GEYSERS #18		GEO	110	79-AFC-3	Apr-79	May-80	Sep-80	Nov-82
GEYSERS #16		GEO	110	79-AFC-5	Feb-80	Sep-81	Jan-82	Oct-85
SONOMA POWER	SMUDGEO #1	GEO	72	80-AFC-1	Mar-80	Mar-81	Jun-81	Dec-83
TEXACO WILMINGTON		NG	60	80-SPPE-1	n/a	Mar-81	Apr-80	Jun-83
GEYSERS POWER	Oxy, Calistoga, Santa Fe	GEO	80	81-AFC-1	Jan-81	Feb-82	Mar-82	Dec-83
NCPA #3	NCPA Unit #2	GEO	110	81-AFC-3	Dec-81	Dec-82	Jun-83	Oct-85
GEYSERS #20		GEO	110	82-AFC-1	Mar-82	Feb-83	Jun-83	Oct-85
KERN RIVER	Omar Hill	NG	300	82-AFC-2	Jul-82	Aug-83	Apr-84	Aug-85
TOSCO MARTINEZ	Tosco Cogen, Foster Wheeler Martinez, Inc	NG	100	83-SPPE-1	n/a	Nov-83	Jun-85	Aug-87
CALPINE GILROY	Gilroy Foods	NG	115	84-AFC-4	Sep-84	Nov-85	Jun-85	May-88
SYCAMORE		NG	300	84-AFC-6	Jan-85	Dec-86	Jun-87	Jan-88
AES PLACERITA		NG	120	84-SPPE-1	n/a	Dec-85	Feb-86	Jan-88
ARCO WATSON		NG	385	85-AFC-1	Jul-85	Sep-86	Oct-86	Apr-88
MIDWAY-SUNSET	Sun Cogen & S Sierra	NG	225	85-AFC-3	Feb-86	May-87	Jun-87	May-89
CALPINE KING CITY	American 1, Basic American Foods	NG	120	85-AFC-5	Feb-86	Jul-87	Aug-87	May-89
EL SEGUNDO		NG	77	85-SPPE-5	n/a	Apr-86	Dec-86	Dec-87
CHAMPLIN	Harbor	NG	79	85-SPPE-7	n/a	Jun-86	Jan-88	Apr-89
ACE (ARGUS)	Kerr McGee Argus Cogen	COAL	100	86-AFC-1	Jun-86	Jan-88	May-88	Sep-90
CHEVRON RICHMOND		NG	99	86-SPPE-1	n/a	Nov-87	Apr-91	Aug-92
SWEPI BELRIDGE		NG	60	86-SPPE-2	n/a	Oct-88	Dec-84	Dec-86
SEGS III-VII	Kramer Junction	SOLAR/NG	150	87-AFC-1	Mar-87	May-88	Mar-85	Feb-89
SEGS VIII	Harper Lake	SOLAR/NG	80	88-AFC-1	Aug-88	Mar-89	Apr-89	Dec-89
COSO NAVY 2		GEO	80	88-SPPE-1	n/a	Dec-88	Dec-88	Dec-89
MOJAVE		NG	55	88-SPPE-2	n/a	Apr-89	May-89	Dec-90
SEGS IX	Harper Lake	SOLAR/NG	160	89-AFC-1	Jan-89	Feb-90	Feb-90	Oct-90
IID EL CENTRO UNIT #2		NG	80	90-SPPE-2	n/a	May-91	Jan-92	Jul-93

CROCKETT		NG	240	92-AFC-1	Apr-92	Apr-93	Mar-94	May-96
SMUD GAS PIPELINE		NG	n/a	92-AFC-2P	n/a	May-94	Jul-95	Jul-96
CARSON ICE-GEN		NG	95	92-SPPE-1	n/a	Jun-93	May-94	Oct-95
REDDING PEAKING		NG	73	92-SPPE-2	n/a	May-93	Sep-93	Nov-95
PROCTER & GAMBLE		NG	171	93-AFC-2	Nov-93	Nov-94	Jun-95	Mar-97
CAMPBELL		NG	158	93-AFC-3	Dec-93	Nov-94	Jun-96	Oct-97
EQUILON	Shell	NG	99	93-SPPE-1	n/a	Mar-94	Oct-94	Dec-95
	TOTALS:	**35 Projects**	**4,393**					
CLOSED PROJECTS	**A.K.A.**	**PRIMARY FUEL**	**MW**	**CEC DOCKET#**	**DEEMED ADE-QUATE**	**DATE CERTI-FIED**	**START CONSTRUC-TION**	**ON-LINE**
COOL WATER		COAL	100	78-AFC-2	Nov-78	Dec-79	May-82	Jun-84
BOTTLE ROCK		GEO	55	79-AFC-4	Aug-79	Nov-80	Jun-81	Feb-85
DWR SOUTH GEYSERS		GEO	55	81-AFC-2	Apr-81	Nov-81	Jun-82	n/a
COLDWATER CREEK	CCPA #1	GEO	130	84-AFC-2	May-84	Jun-85	Oct-85	Jun-88
	TOTALS:	**4 Projects**	**340**					
APPROVED PROJECTS NOT BUILT	**A.K.A.**	**PRIMARY FUEL**	**MW**	**CEC DOCKET#**	**DEEMED ADE-QUATE**	**DATE CERTI-FIED**	**START CONSTRUC-TION**	**ON-LINE**
ALAMEDA STEAM		NG	60	76-SPPE-2	n/a	Dec-76	n/a	n/a
SILVER GATE		NG	93	76-SPPE-3	n/a	Feb-78	n/a	n/a
SOLAR 100		SOLAR	110	81-AFC-4	Jan-82	Dec-82	n/a	n/a
GEYSERS #21		GEO	140	84-AFC-1	Jun-84	Jun-85	n/a	n/a
IBM SAN JOSE		GAS	65	85-SPPE-2	n/a	Mar-86	n/a	n/a
SEGS X		SOLAR/NG	160	89-AFC-1	mae 89	Feb-90	n/a	n/a
SEPCO	Sacramento Ethanol	NG	149	92-AFC-2	Nov-92	May-94	n/a	n/a
SAN FRANCISCO ENERGY		NG	240	94-AFC-1	Sep-94	Mar-96	n/a	n/a
HIGH DESERT		NG	720	97-AFC-1	Dec-97	May-00	Expected Dec-00	Dec-02
	TOTALS:	**9 Projects**	**1,737**					
PROJECTS UNDER CONSTRUCTION	**A.K.A.**	**PRIMARY FUEL**	**MW**	**CEC DOCKET#**	**DEEMED ADE-QUATE**	**DATE CERTI-FIED**	**START CONSTRUC-TION**	**EXPECT TO BE ONLINE**
SUTTER POWER PROJECT		NG	500	97-AFC-2	Jan-98	Apr-99	Jul-99	Sep-01
LOS MEDANOS ENERGY CENTER	Pittsburg District Energy	NG	500	98-AFC-1	Jul-98	Aug-99	Sep-99	Jul-01
LA PALOMA		NG	1,043	98-AFC-2	Aug-98	Oct-99	Jan-00	Aug-01
DELTA ENERGY CENTER		NG	880	98-AFC-3	Feb-99	Feb-00	Apr-00	Jun-02
	TOTALS:	**4 Projects**	**2,923**					
PROJECTS UNDER REVIEW	**A.K.A.**	**PRIMARY FUEL**	**MW**	**CEC DOCKET#**	**DEEMED ADE-QUATE**	**DATE CERTI-FIED**	**START CONSTRUC-TION**	**ON-LINE**
SUNRISE COGEN		NG	320	98-AFC-4	Feb-99	n/a	n/a	n/a
ELK HILLS		NG	500	99-AFC-1	Jun-99	n/a	n/a	n/a
THREE MOUNTAIN		NG	500	99-AFC-2	Jun-99	n/a	n/a	n/a
METCALF		NG	600	99-AFC-3	Jun-99	n/a	n/a	n/a
MOSS LANDING		NG	1,060	99-AFC-4	Aug-99	n/a	n/a	n/a

OTAY MESA		NG	510	99-AFC-5	Oct-99	n/a	n/a	n/a
PASTORIA		NG	750	99-AFC-7	Jan-00	n/a	n/a	n/a
BLYTHE ENERGY		NG	520	99-AFC-8	Mar-00	n/a	n/a	n/a
WESTERN MIDWAY SUNSET		NG	500	99-AFC-9	Mar-00	n/a	n/a	n/a
CONTRA COSTA REPOWER		NG	530	00-AFC-1	May-00	n/a	n/a	n/a
MOUNTAINVIEW	San Bernardino	NG	1,056	00-AFC-2	May-00	n/a	n/a	n/a
NUEVA AZALEA		NG	550	00-AFC-3	n/a	n/a	n/a	n/a
POTRERO REPOWER		NG	520	00-AFC-4	n/a	n/a	n/a	n/a
HANFORD		NG	99	00-SPPE-1	Filed May-00	n/a	n/a	n/a
	TOTALS:	**14 Projects**	**8,015**					

Exhibit 5-3
Power Plant Licensing Cases Before the California Energy Commission Since 1998

(Listed Alphabetically as of September 13, 2000)
Grey row indicates license approved by Energy Commission.
Yellow row indicates Small Power Plant Exemption (SPPE) Case.
Turquoise blue row indicates public announcement made, but Application For Certification not filed.

Project Name (Commission Docket Number)	Applicant or Host	Size (megawatts)	Capital Cost (million)	Location	Filing Date [1]
Antelope [2] (98-SIT-8)	Enron	1000	$500 million	California City, Kern County	AFC Expected 2000
Blythe (99-AFC-8)	Summit Energy Group	520	$250 million	Blythe, Riverside County	AFC Filed December 9, 1999
Contra Costa (00-AFC-1)	Southern Energy	530	$200-300 million	Antioch, Contra Costa County	AFC Filed Jan. 31, 2000
Delta Energy Center (98-AFC-3)	Calpine and Bechtel	880	$350-400 million	Pittsburg, Contra Costa County	AFC Filed December 18, 1998 ----- **APPROVED by Commission 2/9/2000**
Elk Hills (99-AFC-1)	Sempra/OXY	500	$300 million	Elk Hills, Kern County	AFC Filed February 24, 1999
Hanford Energy Park (00-SPPE-1)	GWF Power Systems Company	99	$70 million	Hanford, Kinds County	Small Power Plant Exemption (SPPE) Filed May 19, 2000
High Desert (97-AFC-1)	Inland Group and Constellation Energy	720	$350+ million	Victorville, San Bernardino County	AFC Filed June 30, 1997 ----- **APPROVED by Commission 5/3/2000**
La Paloma (98-AFC-2)	PG&E National Energy Group	1,043	$500 million	McKittrick, Kern County	AFC Filed August 12, 1998 ----- **APPROVED by Commission 10/6/99**
Long Beach District Energy Facility [2]	Enron	500	$300 million	Long Beach Los Angeles County	AFC Expected 2000
Los Medanos Energy Center (Formerly known as Pittsburg District Energy Facility) (98-AFC-1)	Calpine	500	$300 million	Pittsburg, Contra Costa County	AFC Filed June 15, 1998 ----- **APPROVED by Commission 8/17/99**
Metcalf Energy Center (99-AFC-3)	Calpine and Bechtel	600	$300-400 million	San Jose, Santa Clara County	AFC Filed April 30, 1999

Project Name (Commission Docket Number)	Applicant or Host	Size (megawatts)	Capital Cost (million)	Location	Filing Date [1]
(Western) Midway-Sunset (99-AFC-9)	ARCO Western Energy Company	500	$250 million	McKittrick, Kern County	AFC Filed December 22, 1999
Morro Bay (99-AFC-6)	Duke Energy	530	n/a	Morro Bay, San Luis Obispo County	AFC Filed August 31, 1999 **WITHDRAWN** Expected to Refile September 200
Moss Landing (99-AFC-4)	Duke Energy	1,060	$475 million	Moss Landing, Monterey County	AFC Filed May 7, 1999
Mountainview (00-AFC-2)	Thermo Ecotek	1,056	$550 million	San Bernardino County	AFC Filed Feb. 1, 2000
Nueva Azalea (Formerly known as Sunlaw) (00-AFC-3)	Sunlaw Cogen. Partners	550	$450 million	Vernon, Los Angeles County	AFC Re-Filed March 8, 2000
Otay Mesa (99-AFC-5)	PG&E National Energy Group	510	$350 million	Otay Mesa area, San Diego County	AFC Filed August 2, 1999
Pastoria (99-AFC-7)	Enron	750	$350-450 million	Tejon Ranch, Kern County	AFC Filed November 30, 1999
Potrero[2]	Southern Energy	520	$200 - $300 million	Potrero, Contra Costa County	AFC Expected March 2000
Redondo Beach[2]	AES	700	n/a	Redondo Beach, Los Angeles County	AFC Expected 2000
San Francisco Bay Power Barge (Barge-Mounted Emergency Generator Project) (00-SPPE-02)	PG&E National Energy Group	---	n/a	San Francisco Bay Area	SPPE Filed July 2000 **WITHDRAWN 8/4/2000**
South City[2] (97-SIT-7)	(AES) South City LLC	550	n/a	South San Francisco, San Mateo County	AFC Expected 2000
Sunrise Cogeneration (98-AFC-4)	Texaco Global Gas & Power	320	$200 million	Fellows, Kern County	AFC Filed December 21, 1998
Sutter Power (97-AFC-2)	Calpine	500	$275 million	Yuba City area, Sutter County	AFC Filed December 15, 1997 ----- **APPROVED by Commission 4/14/1999**
Three Mountain (99-AFC-2)	Ogden Pacific Power	500	$300 million	Burney, Shasta County	AFC Filed March 3, 1999
Total Megawatts		14,938 MW			

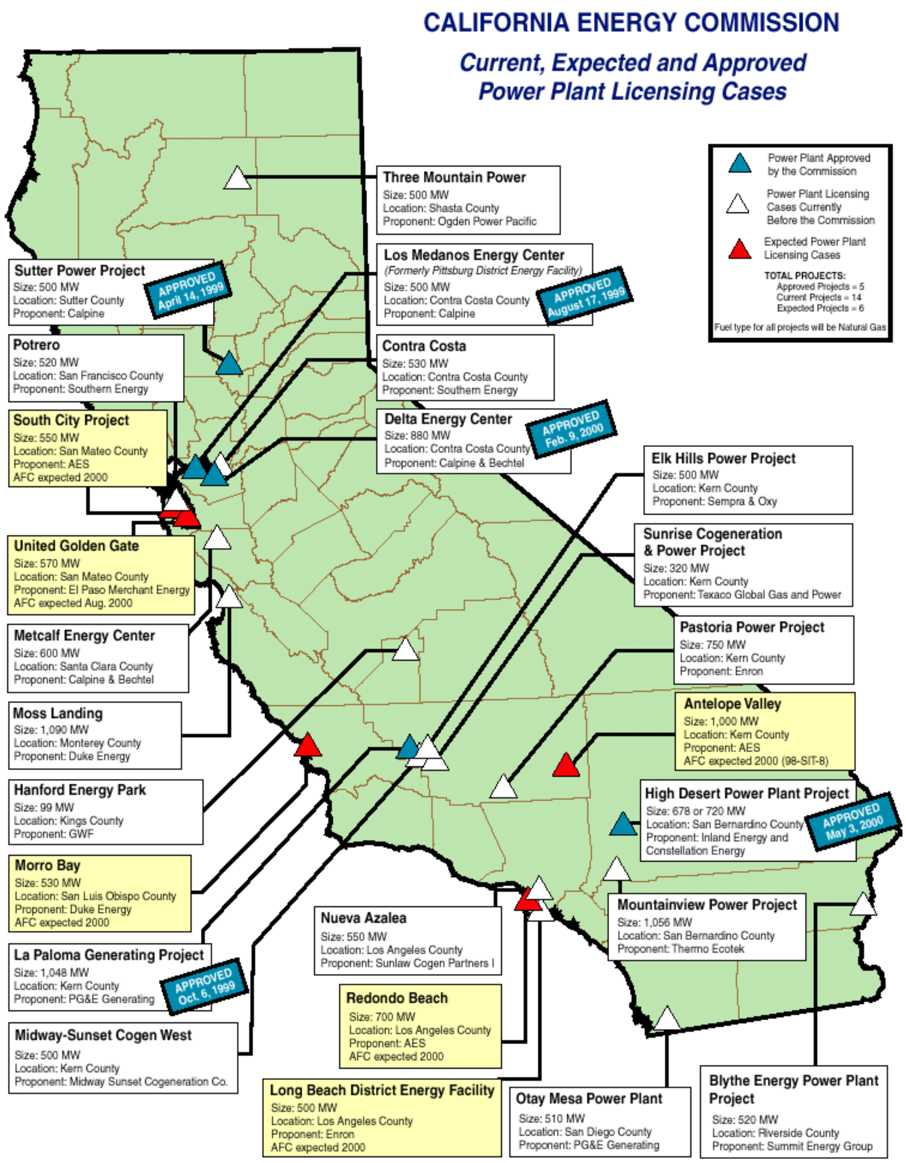
NOTES:

(1) Applicant s actual, expected or desired filing date. Note: this does not mean that the project has been deemed as data adequate and has entered the formal licensing process.

(2) Project has been publicly announced. Some cases have not been assigned a Commission docket number, as they have not formally filed anything with the Commission.

Status	**Northwest**	**Southwest**	**Rocky Mountain**	**California - Mexico**	**Total**
Total	**12,151**	**15,299**	**8,473**	**18,966**	**54,889**

Exhibit 5-4
Current, Expected, and Approved Plant Licensing Cases



August 1, 2000 - California Energy Commission