Chapter 1. Executive Summary

1.1 Overview

Over the last decade, electric markets have been significantly restructured throughout the world. Consumers and producers now benefit from a more competitive marketplace and have greater choice in buying and selling electricity. In perhaps no other jurisdiction has this transformation been more profound than in California. Two new institutions were created to operate California's new market structure, the California Power Exchange (PX) and the California Independent System Operator (ISO). The PX and the ISO began operation on March 31, 1998.

This ***Annual Report on Market Issues and Performance*** provides a comprehensive discussion and analysis of how the various markets comprising the California system have performed, what issues arose in the first year of operation and how they were addressed, and what issues remain to be resolved. The report focuses primarily on those markets the California ISO manages: the ancillary services, real-time energy, and congestion management markets.

This Executive Summary provides an overview and summary of the market performance issues and analyses discussed in greater detail in subsequent chapters. Section 1.1 highlights the major market issues encountered during the first year of operation. Section 1.2 describes the California market structure, the role of the ISO, and the ISO's approach to monitoring and analysis of market performance. Sections 1.3, 1.4, and 1.5 provide discussions of the ISO's ancillary services, real-time energy, and congestion management markets, respectively. Section 1.6 reviews the key challenges that arose during the first year of operation and describes how they were resolved. Finally, Section 1.7 describes the major issues the ISO will address during the coming year.

The California market structure is unique both in its design and in its actual operation. It relies on decentralized, market-based decision making to an unprecedented degree, and incorporates many features that have never been tested in any other restructured electric market. Some of the unique features of the California structure are:

- A day-ahead power pool (PX) that is completely separate from the transmission system operator (ISO);
- The provision for market participants to buy and sell forward energy through the PX and/or through bilateral contracts; and,
- Competitive markets for provision of ancillary services and congestion management.

Even with the uniqueness and complexity of the California market, its first year of operation has provided clear evidence of the viability of many of the innovative ideas and concepts upon which its design was based.

The ISO faced many challenges in the first year due to market design imperfections, implementation problems, and regulatory disparities. One of its key challenges was to begin operating all the new markets simultaneously, even though some of the more important facilities had to be developed in phases when all hardware and software was not fully functional on the target startup date in 1998.

Overall, the ISO responded well to the challenges. During the course of the year, the ISO has adopted emergency measures to deal with critical issues as they arose. It has undertaken a comprehensive market redesign program to enhance the efficiency of the markets it conducts. It has worked to eliminate the regulatory disparities impeding market competition. The measures implemented to date have been valuable in lowering market prices and ISO costs, and increasing bid sufficiency in markets that were chronically "thin" in the first months of operation. The following results attest to these improvements. They are more fully addressed in the subsequent sections of the Executive Summary and in the main report:

- The ISO was able to operate the system under its control reliably, utilizing bid markets to obtain the generation services essential for system operation. After initial market corrections were made, ancillary services were bid in sufficient supply in most hours.

- Ancillary service costs dropped from a high of almost 30 percent of energy costs in May, 1998, to one-third that level (10 percent of energy costs) by September. Over the first 12 months of operation, total ancillary service costs averaged about 11 percent of total energy costs. Due to elimination of all cost-based caps, which applied to the majority of A/S capacity provided prior to November 1998, total A/S costs can be expected to increase in the second year of operation, even if A/S prices decrease significantly. The ISO has adopted a goal of limiting total A/S costs to 10 to 15 percent of total energy costs over the next two years.

- The ISO successfully demonstrated the feasibility of balancing system loads and generation using a real-time energy market, without compromising reliability, under severe conditions during the first year of operation. Over 99 percent of the time, the ISO's real-time market has functioned to balance loads and supply through price signals, without needing to rely on price caps. When the cap was hit, significant amounts of additional generating capacity were offered at the $250 price cap, so that short-term supply shortages did not threaten system reliability.

- Overall, the congestion management market worked well in allocating available transmission capacity, with congestion costs totaling less than one percent of total energy costs.

The markets experienced significant exercise of market power during certain periods. This was due to market design flaws, software deficiencies, and regulatory disparities that have since been recognized. Further improvement in market performance should be realized as major elements of the ISO's market redesign are implemented later this year. These elements include:

- Reform of the Reliability Must Run (RMR) contract structure; and

- Re-design of certain features of the ancillary services markets to promote competition and efficiency.

California's first year of the new market structure has also produced some surprising outcomes compared to earlier assumptions and expectations. For example, cost-based caps on ancillary services capacity prices had the effect of raising overall ancillary services prices, rather than lowering them as intended. Similarly, market experience now indicates that inter-zonal congestion may lower, rather than raise, overall energy costs to consumers. As a result it will likely be the producers, rather than California consumers, who have the greatest incentive to upgrade constrained transmission capacity.

Finally, a number of challenges remain for the ISO to address in the coming year. These include:

- Continuing RMR reform;
- Reducing demand for Regulating Reserves;
- Continuing to enhance the hour-ahead A/S markets;
- Increasing A/S imports;
- Implementing, and monitoring market power in, the new Firm Transmission Rights (FTR) market;
- Developing an integrated grid planning process;
- Promoting demand responsiveness to prices; and
- Further mitigating market power in the A/S markets.

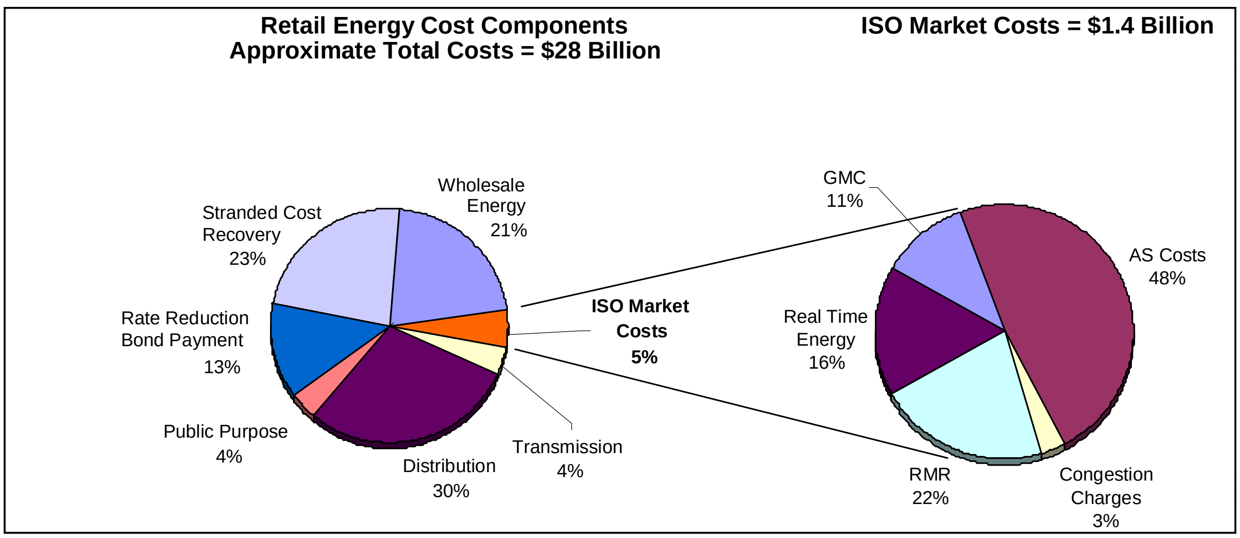
The ISO's Market Surveillance Unit discusses these topics in the following sections of this Executive Summary, and in greater detail in the body of this ***Annual Report on Market Issues and Performance*** covering the first year of ISO operation.

1.2 The New California Electric Market

1.2.1 Annual Retail Energy and ISO Costs

California's electric market is among the largest in the world, representing a total annual retail volume of over $28 billion. Of this amount, $6 billion was for wholesale energy, and $1.47 billion was for ISO services. Figure 1-1 illustrates major categories of total retail costs and the major components of the California ISO share. The left-hand chart shows that total ISO costs account for 5 percent of total energy costs, or $1.4 billion. The right-hand chart shows that 89 percent of this amount, $1.3 billion, was the cost of procuring the various generation services required for market and system operations, while 11 percent, or $160 million, reflects the ISO's operating expenses that are paid by market participants through the Grid Management Charge (GMC). During the first year of operation, the GMC amounted to just over one-half of one percent (0.58 percent) of total retail energy costs.

Figure 1-1. Annual Retail Energy and ISO Market Costs



The annual retail cost of electricity in California totaled approximately $28 billion during the first year of deregulation. The ISO's markets accounted for about 5 percent of total retail cost, or about $1.4 billion. Of this amount nearly 90 percent, or $1.3 billion, was the direct cost of procuring the generation services required for system operation and reliability. The largest share of this procurement cost, amounting to 48 percent of the total ISO cost, was for ancillary services – Regulation, Spin, Non-Spin, and Replacement Reserves. Another 40 percent was made up of Reliability Must-Run (RMR) payments and real-time energy costs. The remaining 11 percent, or $0.163 billion, was the administrative cost of operating the ISO markets and the transmission system. These administrative costs are collected through the Grid Management Charge (GMC), which is about 0. 58 percent of total retail energy cost.

1.2.2 Market Structure

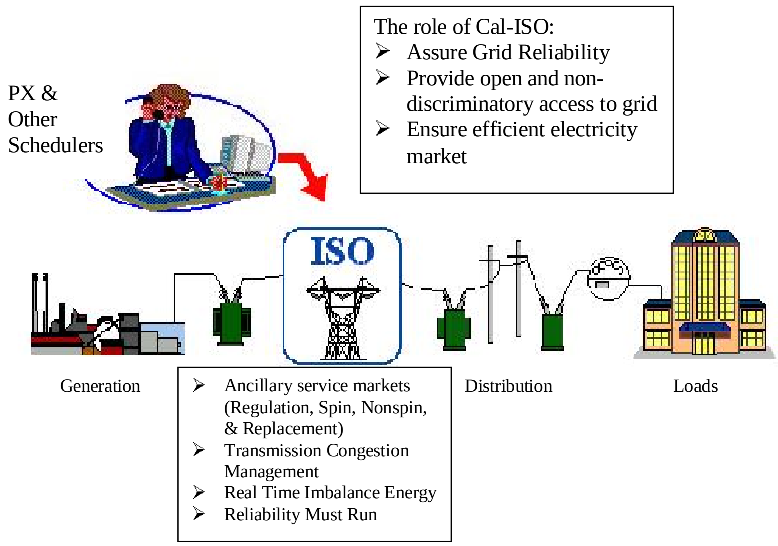
Assembly Bill (AB) 1890, passed unanimously by both houses of the California legislature and signed into law on September 26, 1996, radically restructured the electric industry in California. Prior to restructuring, electricity had been supplied as a “bundled” service by vertically integrated utilities, operating as regulated monopolies in their respective service territories. The utilities performed all the functions involved in the supply of electricity. They owned and operated the power generating plants, the high-voltage transmission systems, and the distribution systems that delivered electricity to consumers. They also performed all aspects of the business of electricity supply, such as retailing and marketing, customer service, metering and billing.

AB 1890 changed California’s electricity industry by “unbundling” the traditional service of the utilities into functional components, and creating a new structure and new institutions to allow competition in the generation and retail areas. To enable competition in these areas, AB 1890 retained the regulated monopoly structure for the transmission and distribution components. It transferred transmission service to a new corporation, the California Independent System Operator (ISO). It left distribution service to the incumbent utilities. As a result, a major role of the ISO is to provide electric transmission services, on an open and nondiscriminatory basis, to all suppliers of commodity electricity. Figure 1-2 illustrates this role.

In the new market structure for generation services, the generators compete to sell electric energy and generating capacity in several separate but inter-related markets. They may sell into the forward energy markets operated by the California Power Exchange (PX), the second new corporation created by direction of AB 1890, or into the real-time energy and ancillary services markets operated by the ISO, or into a combination of these markets. Generators may also enter into bilateral contracts for forward energy and ancillary services, with specific consumers directly or with new intermediaries called Scheduling Coordinators (SCs) who interact with the ISO to schedule transmission service.

The bilateral forward energy market includes the *Direct Access* market and is the foundation of retail competition in the California marketplace. As a consequence of direct access and the opening of retail competition, AB 1890 has in fact stimulated numerous varieties of new businesses, including retail marketing and customer service, load and supply aggregation, metering, data management, and retail revenue cycle services. Providers of these business services, plus the providers of generation, transmission and distribution services, collectively comprise the new California electric marketplace.

Figure 1-2. The ISO's Role in the California Market



The California Independent System Operator (ISO) operates the high-voltage transmission grid in California for its users, the Power Exchange and other Scheduling Coordinators, in an open, nondiscriminatory manner. The ISO also acquires reliability services and manages congestion on the transmission grid through markets.

1.2.3 Unique Features of the Californian Electric Services Marketplace

The California marketplace is unique in several respects:

- **Decentralized Decision Making**. Instead of having a central authority determine which generation units will be scheduled to meet the load, the California markets are designed to let the generation providers themselves determine their own schedules. They do this by deciding which markets to serve, and then marketing their services to obtain direct access contracts and/or bidding into the PX and ISO markets. This "self-scheduling" results in greater transparency in the process of selecting which units will generate. It also allows individual generators to have the greatest flexibility to choose the markets that offer the most attractive profit opportunities. Thus the market, not a central authority, permits participants to bid and commit their resources where they are most valued and market competition among suppliers sets the prices.

- **Accommodates a Power Exchange and Bilateral Contracts**. Many other jurisdictions that have restructured their electric industries have mandated that all participants must sell all power to and buy all power from the central power pool or exchange. The California market is structured to accommodate both bilateral contracts and a central power pool called the California Power Exchange (PX). This structure allows the new marketplace to develop with the benefits of forward price transparency through a power exchange, and individual choice through a bilateral market.

- **Divestiture of Utility Generating Assets.** California is the first restructured market to require its investor-owned utilities (IOUs) to divest 50 percent of their fossil-fuel generating assets in order to reduce concentration of ownership, better separate the generation and transportation components, and thereby develop a more competitive market structure. The 50 percent requirement ultimately led California's three major IOUs to divest all of their fossil fuel generation units. Because the promise of a large competitive energy market in California attracted eager investors, the prices paid for the divested generation units were much greater than their book value. These unexpected receipts have helped to accelerate the recovery of stranded asset costs by the IOUs, to bring earlier development of retail competition.

- **Separate Forward Power Pool Market and Transmission System Operator.** The California structure made the forward power pool market (the PX) a separate entity from the transmission system operator (the ISO). This separation ensures that none of the generating firms who rely on the ISO for transmission service receive any preferential treatment. For the purpose of scheduling energy flows over the ISO system, the PX has the same status as all other Scheduling Coordinators (SCs). The separation of the PX and the ISO has also demonstrated that the two functions can be independent without loss of system reliability.

- **Ancillary Services Procurement through Competitive Bidding.** California is the first restructured market to obtain its ancillary services through a competitive bidding process. After one year of operation, this feature has demonstrated that system reliability can be maintained while relying on open markets for these essential services. Another benefit is that California's ancillary services markets have allowed the sellers to determine where their generation would be most valuable, thus enhancing market efficiency. Four primary ancillary services – Regulation, Spinning, Non-Spinning, and Replacement Reserves – are now priced at separate market prices rather than combined in a single uplift charge, or procured together with commodity energy.

- **Zonal Market Design**. The California market uses by a zonal structure for congestion management. The ISO system is divided into geographic zones. The zones are defined so that congestion within them is infrequent and has little operational impact, while congestion across zonal interfaces tends to be predictably frequent and to have significant impact. The ISO has different procedures for managing inter-zonal and intra-zonal congestion. The zonal structure has certain benefits. First, the relatively simple topology helps to make the bidding, market operation, and pricing rules simpler and more transparent, and thereby promotes competition. Second, zones tend to reduce market power since many suppliers will generally be located within a single zone. Third, the system of adjustment bids used to manage inter-zonal congestion results in an efficient allocation of scarce transmission capacity.

- **Reliability Must-Run (RMR) Contracts for Local Reliability.** Two ancillary services, voltage support and black start, are highly location dependent and cannot be procured competitively. Moreover, the zonal design for congestion management requires an additional mechanism to ensure reliability in pockets of local congestion, where there is not adequate competition to ensure that reliability needs can be met through markets. The mechanism to address such locational reliability and market power concerns is the RMR contract. The RMR contracts provide partial or full fixed-cost payments to RMR units in return for these units being available when called by the ISO for local reliability purposes. An RMR unit has locational market power since the ISO needs a portion of its generation for reliable operation of the ISO grid in that unit's area and there are no alternative generators in the same area.

1.2.4 Market Surveillance

Because the new California market structure is innovative and complex, the ISO recognizes the continuing need to review and evaluate the performance of the various markets, and to identify ways to improve market efficiency. To sustain healthy competition, we think it is essential that no market participant be able to take unfair advantage of the market rules or procedures or to concentrate market power and impede competitive market forces.

The **Market Surveillance Unit** (MSU) is an ISO staff unit within the General Counsel Group whose mission is to monitor and analyze the performance and efficiency of the markets operated by the ISO. The MSU's duties include monitoring market activity and the behavior of market participants. We identify market rules that may impede fair and open competition, and we formulate changes to market rules to improve market efficiency. We investigate gaming or market power concerns and support the activities of the Market Surveillance Committee. One of the MSU's duties is to produce and file, on behalf of the ISO, the present ***Annual Report on Market Issues and Performance***.

The **Market Surveillance Committee** (MSC) is an independent advisory group. Its members (three at present) possess expertise in essential areas of economics (competition, market power, commodity markets), law (anti-trust, utility regulation), and the electric industry (transmission system operations, congestion, power plant economics). They are not affiliated with, nor do they have any financial interest in, any of the market participants. The role of the MSC is to review market performance and market power problems, develop a record of structural problems and propose corrective actions. Since market start-up, the MSC has been actively engaged with the MSU in monitoring market performance, analyzing problems, and advising on possible solutions.

1.3 Ancillary Services Market Performance

1.3.1 Summary of Market Performance

In order to understand the performance of the ancillary service (A/S) market, we have divided the past year's experience into four periods. These periods provide a guide to the month-by-month behavior of the performance indicators discussed in the remainder of this section. Figure 1-3 presents a time line that illustrates these periods.

Period 1: April through June 1998. Cost-of-service based caps, bid insufficiency, introduction of REPA. The markets began operation with all suppliers subject to FERC-approved cost-based caps for A/S capacity. Because suppliers could earn market-based rates in the energy market, the A/S markets often received total bid quantities below the ISO's requirements. This resulted in bid insufficiency[1] in many hours and forced the ISO to rely heavily on Reliability Must-Run (RMR) units to meet its A/S needs. The ISO implemented some short-term solutions in the Regulation market, where supplies were thinnest and demand was highest. One solution was the Regulation Energy Payment Adjustment (REPA). Introduced in May, it was an additional payment to Regulation providers designed to provide incentives above the cost-based caps and make Regulation as attractive as the energy market. Even with REPA, however, the continuing practice of paying a single Market Clearing Price (MCP) for both Regulation Up and Regulation Down kept Regulation costs excessively high.

Period 2: July through September 1998. Market rates, price spikes, price caps, opening to imports. Market-based rates for a few suppliers, combined with bid insufficiency, required the ISO to mitigate market power. Price spikes of $5,000 on July 9 and $9,999 on July 13 in the Replacement Reserve market appeared to be unrelated to any shortages in the energy or other A/S markets, and thus signaled a need for price caps in the A/S markets. The ISO established price caps of $500/MW (lowered by the ISO Governing Board later in July to $250), and began an investigation into market design flaws that were causing the A/S markets to be non-competitive. Among the issues identified were:

(1) Some market participants were not offering supply while they waited for FERC to approve market-based rates;

(2) The structure of RMR contracts created incentives for generators to withhold capacity from the A/S market and wait to be called under their cost-based RMR contracts; and

(3) Software delays had not allowed the ISO to accept out-of-control area bids for A/S. In August, the ISO software was in place to allow imports of A/S. This resulted in increased supply and improved bid sufficiency. Due to reliability concerns, however, the ISO has limited imports of Operating Reserves to 25 percent of requirements. To date it has also precluded import bids for Regulation, pending further software upgrades to accommodate dynamic scheduling.

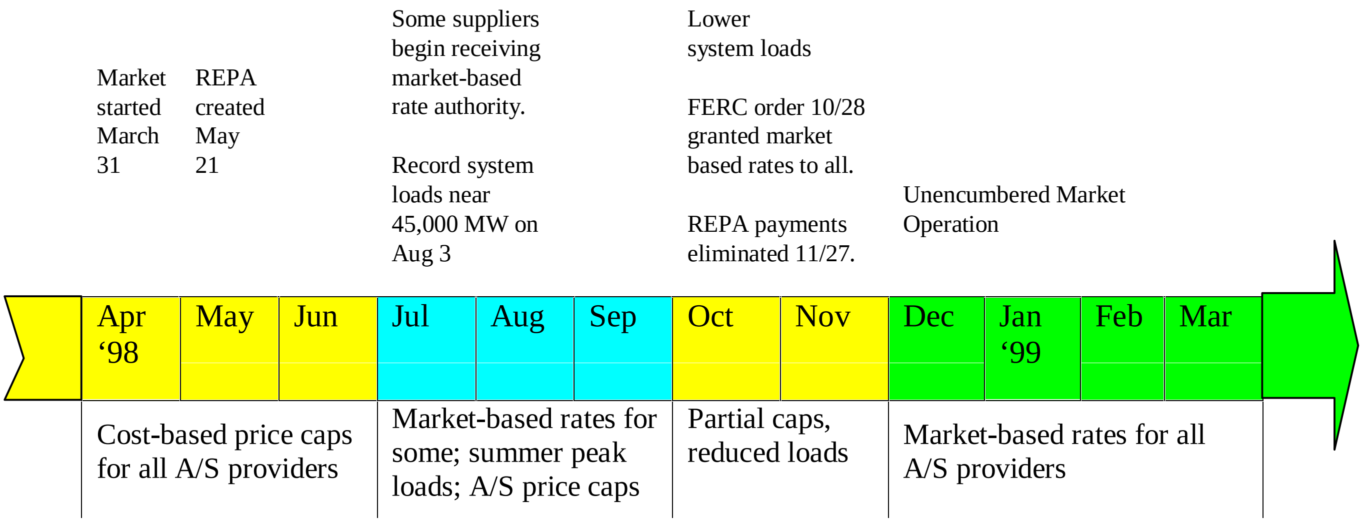
Period 3: October and November 1998. Reduced demand, fewer problems. The existence of cost-based caps for some, but not all, A/S suppliers continued into early November. At the same time, lower levels of demand reduced some of the upward pressure on A/S prices. Although the investor-owned utilities (IOUs) were still subject to cost-based caps for providing A/S, they were also net buyers of A/S. They chose to forego potentially higher prices for capacity in unregulated markets. Instead they increased the supplies they offered as a defensive measure, to avert the potential cost impacts of price spikes. Other market participants, however, consistently offered supply at the $250 price cap regardless of supply conditions. Thus when the capacity bid by the IOUs was insufficient supply, price spikes occurred.

Period 4: December 1998 through March 1999. Market-based rates for all suppliers. Market behavior in this period reflected FERC's October 28 order (effective November 3) to eliminate all remaining cost-based price caps, allowing market-based rates for all A/S providers. This policy change dramatically increased the supply of A/S and allowed the ISO to suspend the REPA payments. Elimination of the cost-based caps may have increased A/S payments in some

[1] Bid insufficiency is the situation where the total quantity offered by all bidders for a particular A/S is less than the ISO's requirement for that service.

hours, but overall it appeared to have increased competition, decreased prices during many hours, and prevented dramatic price spikes. The $250/MW price caps remain in place to curb market power and control the damage from extremely high prices that might result due to remaining imperfections in the market. These imperfections are being addressed in the A/S redesign effort currently underway.

Figure 1-3. Key Periods of Market Performance



In reviewing A/S market performance, we identified four distinct periods in the first year, demarcated by changes in market structure and demand. In the first period, A/S prices were limited by FERC-approved caps set at $5 to $12 /MW/hour. In the second or summer period, some suppliers were allowed to charge market-based rates, up to a FERC-approved maximum that was ultimately set at $250 /MW/hour. In the third or fall period, the market structure was similar to the second period, but demand for A/S was significantly lower due to the reduction in system loads. Period four was characterized by the removal of cost-based caps, allowing market rates for all A/S and all providers.

1.3.2 Analysis of Ancillary Services Market Performance

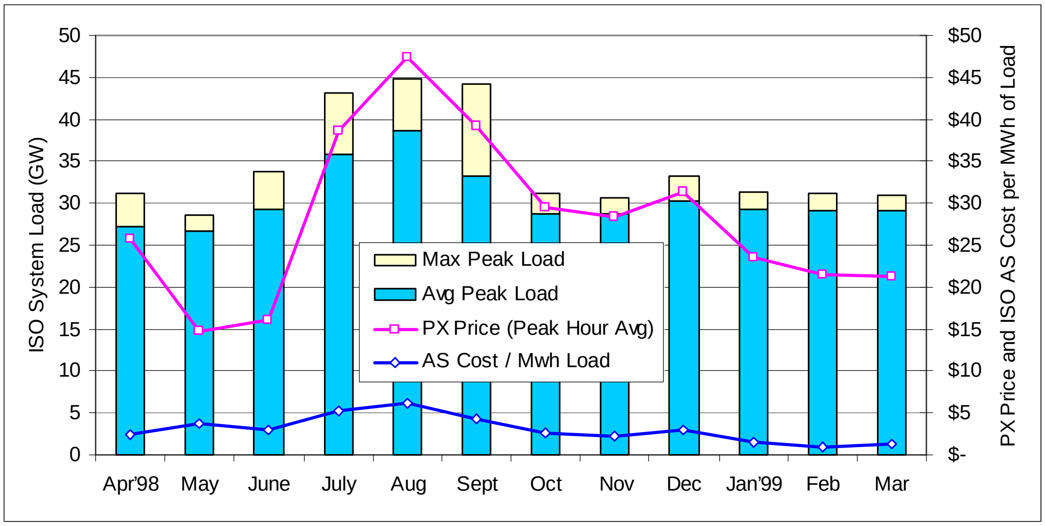
The key market performance indicators include the cost of ancillary services, the frequency of high prices, market shares and bid sufficiency. We discuss each of these indicators below.

1.3.2.1 Cost of Ancillary Services

The ISO obtains four ancillary services through competitive bid markets: Regulation, Spinning, Non-Spinning, and Replacement Reserves. Regulation consists of two products, Regulation Up and Regulation Down, which have been procured as a single product, an arrangement that has proven to be problematic and has already been partially revised. With the redesign scheduled for implementation in summer 1999, Regulation Up and Regulation Down will be procured and priced separately.

As a general rule, the cost of ancillary services closely follows the pattern of prices in the energy market, with prices in all these markets being affected by overall system load and supply conditions (see Figure 1-4). When system loads hit peaks above 40,000 MW during July, August, and the first half of September, PX prices during peak hours averaged $40 to $50 per MWh, and ancillary service costs averaged $4 to $6 per MWh.

Figure 1-4. ISO System Daily Peak Load, PX Price and A/S Cost by Month



The most important driver of energy and A/S prices is system load. The vertical bars in the graph show the average daily peak load for each month and the single highest hourly load in the month. The top line shows the average monthly PX day-ahead price, and the lower line shows the average monthly A/S cost per MWh of load.

Figure 1-5 compares the total costs of each of the four A/S – Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve. Regulation comprises the largest share of A/S. Figure 1-6 breaks the cost of Regulation into three portions by how the cost was incurred: the Regulation auction market, REPA (Regulation Energy Payment Adjustment), and RMR (Reliability Must-Run Units called to provide Regulation service). These figures illustrate how total and component A/S costs changed significantly over the course of the year, reflecting the changes noted in the time periods of Figure 1-3.

At the start of the market (April to June), the investor-owned-utilities (IOUs) were operating all the generation units that ran in the A/S markets. During that period, A/S prices were regulated by FERC at cost-based rates in the range of $5 to $12 /MWh. These prices were not adequately high to motivate the IOUs to provide the required quantities of A/S. The problem is best illustrated in the Regulation market (Figure 1-6). Although the direct market cost of Regulation was small during the first three months (the top portion of the bars in Figure 1-6), the market was plagued by insufficient supply. Bid sufficiency[2] was below 100 percent – meaning that the total

---

[2] Bid sufficiency is defined as the ratio, expressed as a percent, of the total quantity of capacity offered in the market to the total quantity required by the ISO, for any given hour. A healthy competitive market should have bid sufficiencies in the *(footnote continued)*

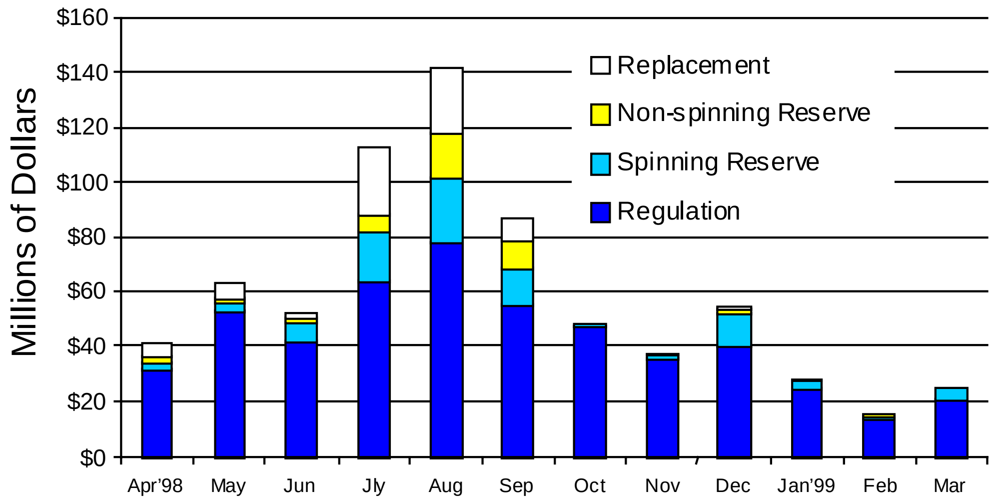
quantities offered in the market were less than the requirement for Regulation – in more than 80 percent of the hours during April and May. As a result, the RMR units and other "out-of-market" resources had to be called for Regulation. In general, this period can be described as a "market mechanism without a market," and administrative intervention was necessary to keep the system running.

To improve market incentives in Regulation, which suffered the most from insufficient bids, the ISO introduced the Regulation Energy Payment Adjustment (REPA) on May 21, 1998. It was subsequently accepted by FERC and allowed to go into effect as of the May 21 filing date. REPA was a payment adder, pegged to the energy market price and guaranteed to be at least $20/MWh, to enhance the incentives for generation capacity to bid into Regulation. Soon after the introduction of REPA, bid sufficiency improved significantly. Bid insufficiency occurred in fewer than 30 percent of hours in June, and fewer than 10 percent of hours in August. With greater sufficiency of market bids, the amount of RMR required for Regulation service dropped (see Figure 1-6).

Although the high cost of REPA payments kept the total cost of Regulation high, Regulation cost as a percentage of the market energy cost actually decreased (see Figure 1-7), indicating that REPA was effective in moving Regulation service toward a more efficient and functional market. On October 28, 1998, FERC approved market-based rates for all providers of A/S, and the REPA payment was eliminated one month later. Market-based rates allowed suppliers to include all costs in their Regulation capacity bids.

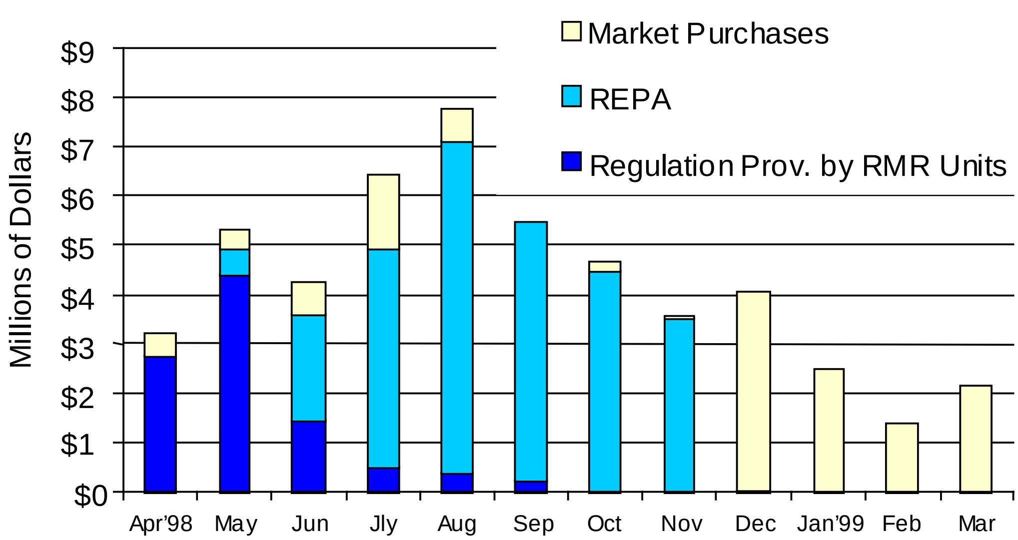
range of 150 to 200 percent in all hours. Bid sufficiencies below 150 percent, while not strictly insufficient, indicate situations where a key player in the market may have the ability to exercise market power and raise the price above the competitive level. During the first year of operation, bid sufficiencies in Regulation were typically below 150 percent for 30 to 50 percent of the hours in most months, except for April and May when bid sufficiencies were below 150 percent nearly 100 percent of the time. In the other A/S markets the situation was less severe. During April through July, values below 150 percent were occurring in 45 to 75 percent of the hours per month. Starting in August, however, such low values became much less frequent and have consistently occurred in fewer than 10 percent of the hours per month.

Figure 1-5. Cost Components of Ancillary Services



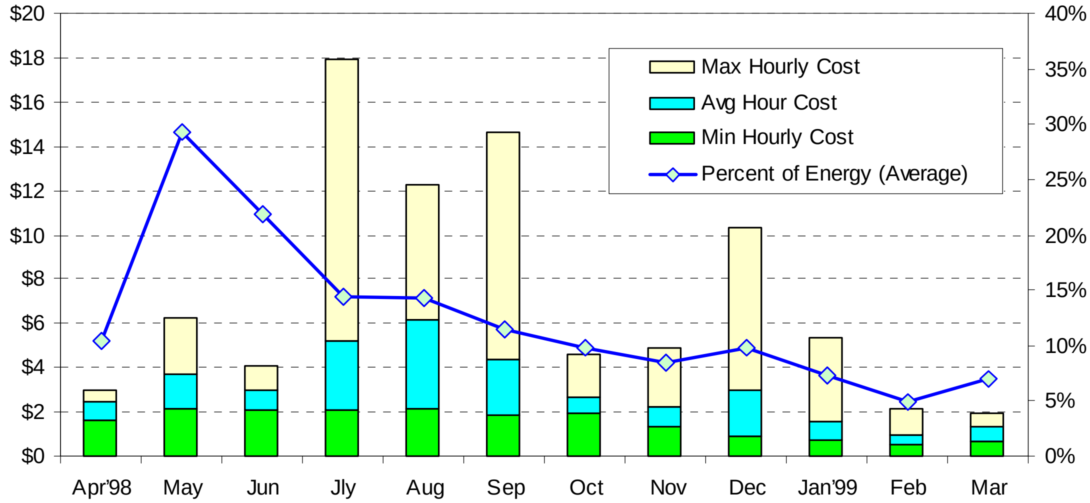
The largest cost component of ancillary services is Regulation, which for the first operating year was about 70 percent of total A/S costs. Spinning Reserve is the next largest cost component at 13 percent, then Replacement Reserve at 11 percent, and Non-Spinning Reserve at 6 percent. Since October, when specific market rules regarding Replacement Reserve were modified, Replacement Reserve has been the least costly component of A/S.

Figure 1-6. Cost Components of Regulation Service



The cost of Regulation has three components: (1) Regulation capacity purchased directly from the market; (2) the Regulation Energy Payment Adjustment (REPA) payments, which provide the generator the difference between the energy and A/S market prices; and (3) the energy payment for Regulation provided by Reliability Must-Run (RMR) units. When REPA was introduced in May, RMR procurement of Regulation decreased. When market-based rates were approved for all providers in November, REPA payments were eliminated.

Figure 1-7. Ancillary Service Costs Per MWh of Load and as Percent of Energy Cost



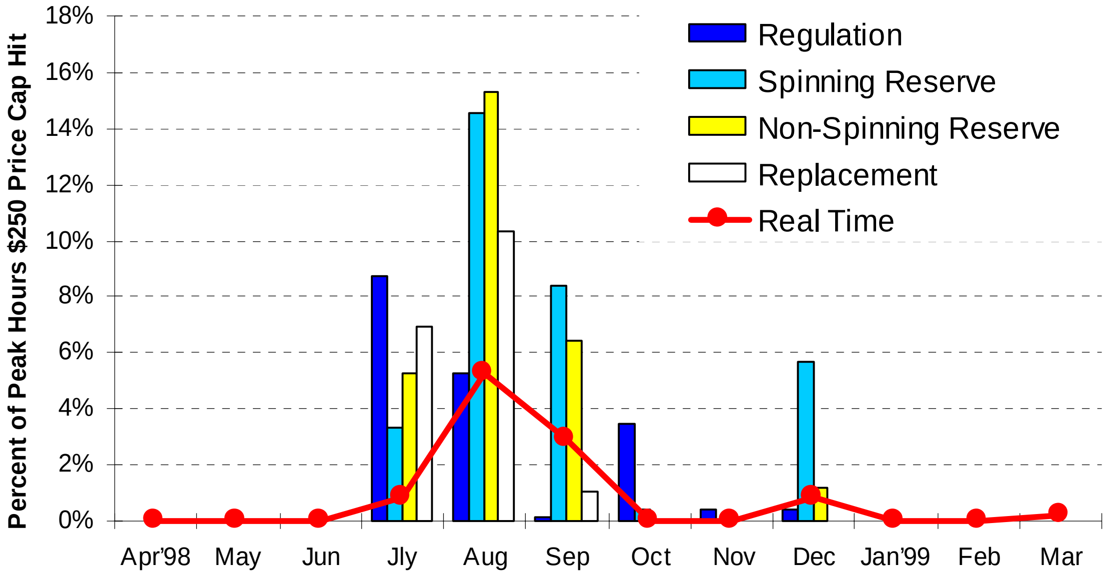
The bar for each month shows the maximum, average, and minimum cost of A/S expressed as a cost per unit of energy consumed ($/MWh). The line expresses the same data as a percent of energy cost. A/S costs spiked in July at $18/MWh, and generally decreased since then due in part to the decline in demand and in part to the increase in A/S supply in response to market-based rates.

1.3.2.2 Frequency of High Prices

The frequency of high prices and an evaluation of whether they are related to market shortages is an important indicator or market performance. After the initial period, the A/S market experienced frequent high prices. For operating day July 9 the Replacement price reached $5,000, and on July 13 it reached $9,999, when there were no apparent shortages in either the energy market or the other A/S markets. The market apparently believed ISO software limited bids to four digits, but in reality the software could clear bids up to 17 digits. In response to these prices and the completely inelastic demand for each ancillary service, the ISO imposed emergency A/S price caps of $500/MW. These caps were later lowered to $250/MW while the ISO examined design flaws in the A/S markets. Throughout this period market prices for one ancillary service frequently hit the price cap while there remained excess supplies of other ancillary services.

Figure 1-8 shows the percentage of hours the market price hit the cap of $250/MW. Price caps were hit most frequently in August, when peak system loads occurred. The frequency of price spikes in Regulation dropped in August and September, reflecting the additional incentive for market suppliers to bid into Regulation created by REPA payments. REPA payments were based on real-time energy prices and were designed to offset the opportunity cost due to lost real-time energy earnings when units were dispatched for Regulation.

Figure 1-8. Percent of Peak Hours the A/S Price Hit the Cap



> ***One indicator of market performance is the number of hours the price cap is triggered, instead of achieving a balance of supply and demand at a clearing price below the cap. This occurred often during the summer months, when loads were greatest and demand for A/S was high. During August, prices for Spinning and Non-Spinning Reserves were at the $250 cap for about 15 percent of the peak hours, or approximately 40 hours.***

1.3.2.3 Market Shares and Bid Sufficiency

A constant concern in the ISO markets is market power. A/S markets are highly concentrated, with the single largest supplier bidding more than 50 percent of the market capacity and the bids of the three largest suppliers comprising more than 90 percent. This high concentration was less of a problem than might be expected, however, due to the current retail rate freeze enacted by AB 1890. For many hours the three largest A/S suppliers were the IOUs. Yet in most hours they were also *net buyers* of A/S to serve the load of their retail customers. The IOUs tended to bid their capacity into the A/S markets to defend against price spikes that could not be passed on to their retail customers due to the rate freeze. As a result, the AB 1890 rate freeze has created incentives that tend to offset the potential exercise of market power by the IOUs.

The new generation owners (NGOs), in contrast, are *net sellers* in the energy and A/S markets. Higher prices would mean higher profits for them. The market share of the NGOs was only a few percent in April and May, but increased in June and ranged from 25 to near 50 percent for some A/S from July to September. In the future, given the growing market shares of the NGOs and eventual loss of the rate freeze as a mechanism for mitigating market power, other measures may need to be put in place to sustain competition.

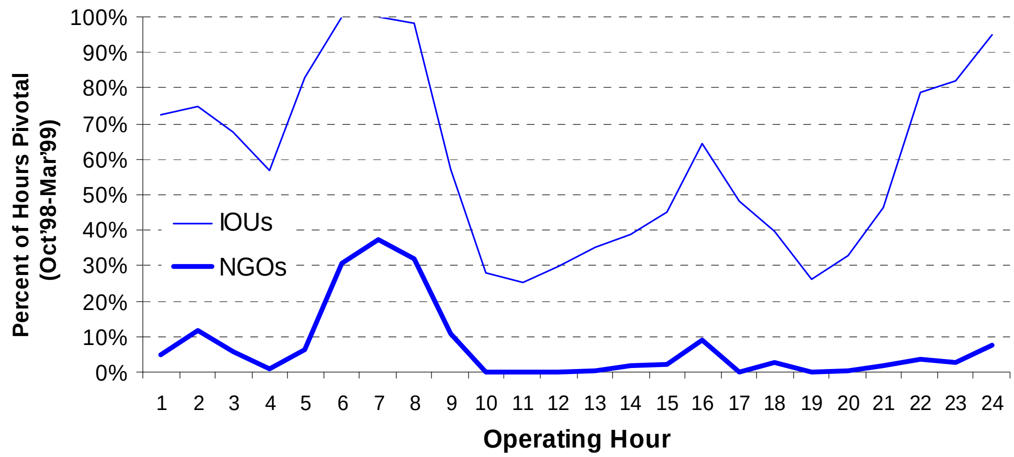
During the first year the IOUs dominated the market most of the time. The IOUs' share ranged from 76 to 97 percent in the Regulation market, and from 55 to 98 percent in Spinning Reserve. Although NGOs' market share was smaller, it grew to be significant over time. In individual hours, the share of bids submitted by NGOs accounted for as much as 50 percent of capacity bid into different A/S markets. The average share of Regulation capacity bid by NGOs peaked in August and September, when NGOs accounted for an average of about 20 to 25 percent of capacity bids. NGOs have accounted for a smaller portion of total Regulation bids since October, but continue to play a pivotal role in setting prices during many of the shoulder ramping hours, when bid sufficiency for Regulation Up and Down is typically very low.

The MSU has performed a closer analysis of market power conditions using a form of *pivotal player* analysis based on the *Residual Supply Index* (RSI). The RSI is based on the concept of bid sufficiency, defined as the total of market capacity bids expressed as a percent of market demand. Bid sufficiency of 100 percent means there is just enough capacity bid, at all prices, to meet the system requirement. The first year's experience indicates that, given the current concentration of capacity in the California market, bid sufficiencies of 200 percent will provide the extra supply needed to promote competition and curb market power.

The RSI for a firm, in any given market and hour, is total market bid sufficiency *minus* the share of total bid capacity that was offered by that firm. For example, if market bid sufficiency is 140 percent and one large firm provided 60 percent of the bid capacity, the RSI for that firm would be 80 percent. The RSI is interpreted much like the bid sufficiency – the higher the RSI the more competitive the market is, and 100 percent is a crucial threshold. When bid sufficiency is below 100 percent, or when bid sufficiency is more than 100 percent but the RSI for a large firm is below 100 percent, there could be a serious market power concern. In these situations the residual supply from all other suppliers is less than enough to meet the requirement. The large supplier is then pivotal for the market and is in a position to set the market price. As a result the price is likely to go as high as the price cap.

Figure 1-9 illustrates the RSI measure in the Regulation Down market from October 1998 to March 1999. The curves in the figure were constructed using the largest bid shares of individual firms among the IOUs and the NGOs, respectively, in each hour. For a large percent of hours, the RSI was less than 100 percent. IOUs were more frequently pivotal than NGOs. Detailed analysis indicates that low RSI does correspond to high frequency of extreme prices, and it is a better indicator of market power than some traditional indicators such as the Herfindahl-Hirshman Index (HHI). Summary results of the MSU's analysis of market power using the RSI are provided in Chapter 7.

Figure 1-9. Percent of Hours with RSI < 100% in Downward Regulation by Operating Hour



Market power is a concern when the Residual Supply Index is less than 100%. The graph shows the percent of hours with RSI < 100% in the Regulation Down market for each hour of the day, for the period of October 1998 to March 1999. IOUs were pivotal more often than NGOs, and the worst hours were the morning hours when load was ramping up rapidly and the demand for Regulation Down was highest. In these hours IOUs were pivotal almost all the time, and NGOs were pivotal more than 30 percent of the time. During the first year of operation, IOUs generally did not have incentives to inflate market price. They actually used their market share to bid defensively to contain market prices. This situation may change in the second year as divestiture continues, stranded cost recovery is completed, and the AB 1890 rate freeze nears an end.

1.3.3 Summary

Despite all the challenges in the first year, A/S market performance improved over time. After the ISO made initial market corrections, A/S were bid in sufficient supply to operate the system reliably through the markets for most hours. By the second half of the first operating year there was, on average, 200 percent of the required amount of capacity bid into the A/S markets. Bid insufficiency in some hours continued to be a source of concern.

A/S costs dropped from a high of almost 30 percent of energy costs in May to one-third that level (10 percent of energy costs) by September. This occurred even though September 1998 was a "summer shoulder" month having unusually hot weather. Although the drop in the ratio was due in part to relatively higher energy costs in September, analyzing a similar, recent period (April and May 1999) leads us to expect the A/S costs for the second operating year will be less than 15 percent of energy costs, with all participants being paid market prices rather than cost-based rates. Still, market concentration and market power remain serious concerns. The ISO is implementing some short-term and long-term market redesign measures to mitigate market power and improve market efficiency.

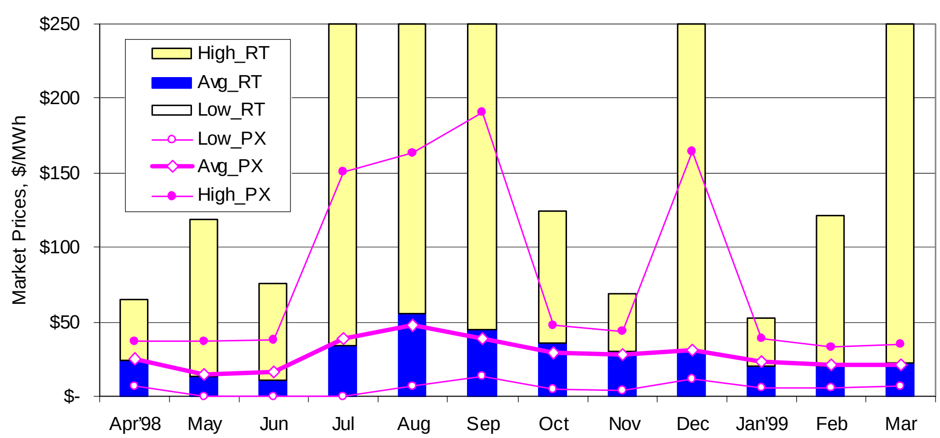
1.4 Real-time Energy Market Performance

1.4.1 Comparison of PX and Real-time Prices

The performance of the ISO real-time energy market is linked to the PX day-ahead market and the A/S markets. The real-time market is where A/S resources and supplemental energy resources are dispatched to follow load and provide imbalance energy. Since both the real-time energy market and the PX day-ahead energy market use similar resources, and generators want to sell their generation to the market with higher price, arbitrage activity will tend to equalize the prices between the PX and real-time markets. Figure 1-10 shows monthly average prices in the PX and real-time markets, and the high and low ranges of prices during peak hours.

The ISO real-time price followed the PX price closely but was more volatile than the PX price. In every month, the minimum real-time price was zero, and in each of five months the maximum real-time price reached the $250 price cap. We expected this kind of volatility because in real time a much smaller pool of supply must meet a much more volatile demand, which has ranged from 3000 MWh decremental to 5000 MWh incremental during peak hours. This is caused by unplanned factors such as weather changes and generation and transmission outages that cause load and generation to deviate in real time from their scheduled levels.

Figure 1-10. Comparison of PX Day-ahead and ISO Real-time Energy Prices (Average, Minimum and Maximum - Peak Hours)



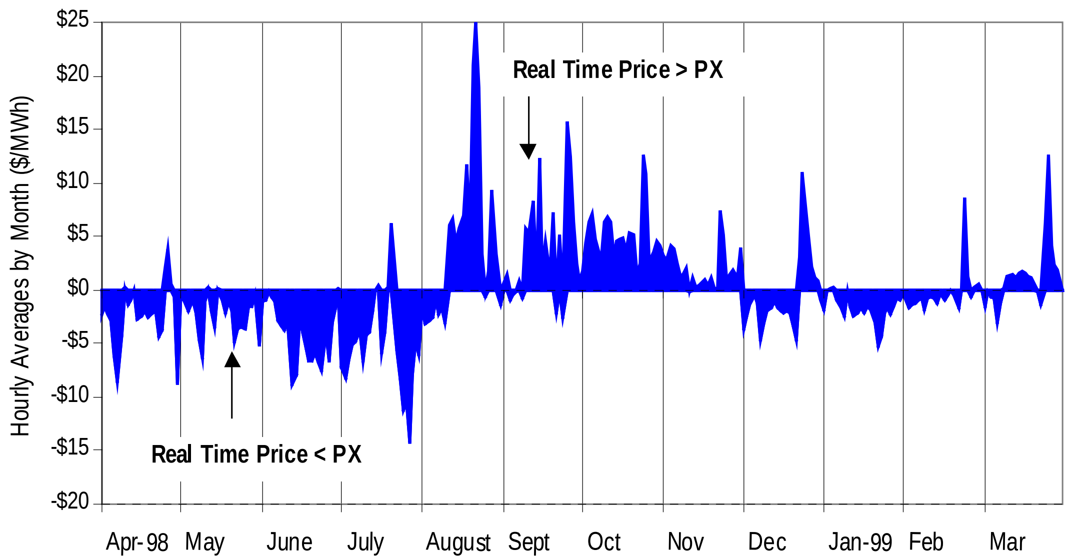
This figure shows the monthly averages and ranges of PX day-ahead market prices and ISO real-time market prices. Although the average PX and real-time prices tracked closely most months, there is a greater volatility associated with real-time prices due to changes in weather and unexpected supply and demand variations.

There were two periods when equilibrium between the PX price and real-time price broke down (see Figure 1-11). During the first four months of ISO operation, except in some “super-peak” hours (hours ending 18 to 20), real-time prices were lower than PX prices by $5 to $10 dollars per MWh. In August and September, and in super-peak hours in the following months, real-time prices were higher than PX prices. In August, the difference was as high as $25 for hour 19, on average over the month.

These consistent price differences between real-time and day-ahead are mainly due to systematic over-generation or under-scheduling. Over-generation in spring of 1998 was caused by abundant supplies of hydro generation and regulatory must-take resources such as nuclear generation and contracts with Qualifying Facilities (QFs). During the same period, the ISO had to dispatch unusually large amounts of RMR due to bid insufficiency in the A/S markets, adding to the excess generation problem. Negative price bids for real-time energy would have helped counteract the problem of excess generation.

During summer peak months, and on super-peak hours in the later months, the real-time price was consistently higher than the PX price. This was due to significant under-scheduling of load that results from two identified economic incentives: (1) the ability of parties to avoid some A/S charges, which are presently calculated based on scheduled rather than actual load, and (2) reduction in forward energy prices that result from market participants shifting load to the real-time market.

Figure 1-11. Average Hourly Difference between Real-Time and PX Prices



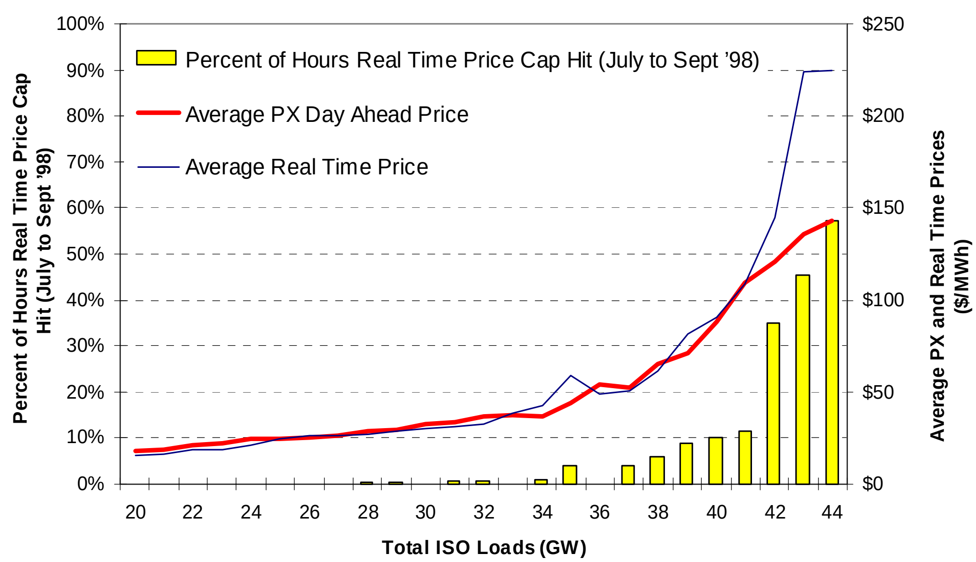
This figure shows the average differences between prices in the PX day-ahead and ISO real-time markets for each of the 24 daily operating hours for each month. Average prices for most hours were systematically lower in the real-time market for the first four months of operation, but were systematically higher for most hours during the next four summer and early fall months. Since the late fall, average prices in the two markets have tracked much more closely, with real-time market prices tending to be higher than PX day-ahead prices in a few super-peak (early evening) hours, but lower in off-peak hours.

Since December day-to-day differences in prices have adjusted much more quickly, and revert toward equality in these two markets. This may indicate the improved ability of market participants to respond to and arbitrage between these two markets. As these markets continue to operate, additional data will become available to allow further analysis of relationships between prices and such factors as seasonal trends and learning on the part of market participants.

1.4.2 Frequency of High Real-time Prices

The higher volatility in the real-time energy price has caused the price to reach the $250 cap at times when system load has been high. Figure 1-12 illustrates the relationship between total system loads and prices, in both the PX day-ahead and the ISO real-time markets. During the peak load months of July to September, average prices in both markets tracked system loads closely up to levels of about 40 GW. At higher load levels, the frequency of real-time prices reaching the $250 cap increases significantly and average real-time prices exceed day-ahead prices. During the 48 hours when the $250 real-time price cap was hit, total demand in the real-time market averaged 2,450 MW, or about 6 percent of total ISO loads. As Figure 1-8 indicates, the frequency of high real-time prices is lower than in most A/S markets. When the real-time bid cap was hit, significant amounts of additional generating capacity were offered at the $250 cap, so that short-term supply shortages did not appear to threaten system reliability.

Figure 1-12. Energy Prices and Frequency of Hitting the Cap, in Relation to System Loads (July–Sept. 1998)



This figure shows the relationship between total system loads and average prices in the PX day-ahead and ISO real-time energy markets. During the peak load months of July to September, average prices in both markets rose at a linear rate up to 35 GW, then rose exponentially at higher system load levels. Average prices in both markets tracked closely up to system loads of about 40 GW. At higher load levels, the frequency of real-time prices reaching the $250 cap increased significantly, causing average real-time prices to exceed day-ahead market prices.

1.4.3 Summary

The ability to balance system loads though a real-time energy market without compromising reliability was tested under severe conditions during the ISO's first year of operation. Record loads during the peak summer months coincided with market design features that created incentives for significant under-scheduling of loads in the day-ahead energy market, increasing demand in the real-time market. Despite these conditions, average prices in the real-time market closely tracked prices in the day-ahead market for most of the year, and rose significantly above day-ahead prices only during the very highest system peak load hours.

Over 99 percent of the time, the ISO's real-time market has functioned to balance loads and supply through price signals, without the need to rely on caps. The real-time price cap was hit during just 48 hours, or only about one-half of one percent of all hours over the first year of operation. In most cases, the price cap was hit only when high system loads were combined with high demand in the real time market.

1.5 Congestion Management Market Performance

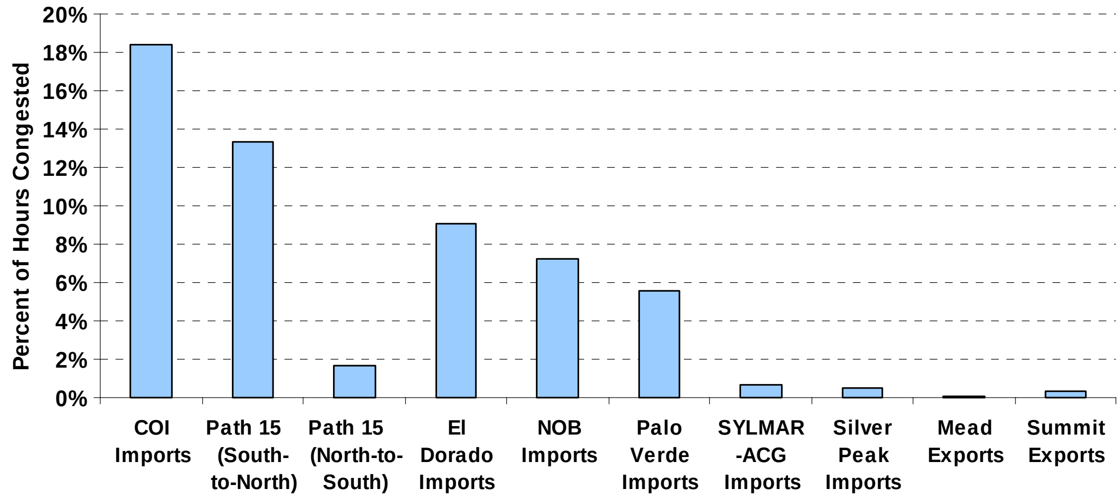
The design of the California congestion management market is based on the premise that market participants do not need to acquire physical transmission rights prior to scheduling energy. All schedules are accommodated except when the transmission capacity on a given inter-zonal path is not sufficient to accommodate all the power flows. In this event, the available transmission capacity (i.e., the transmission capacity remaining after removing the capacity reserved under the Existing Transmission Contracts or ETCs) is allocated through a competitive market. Upward and downward adjustment bids, submitted by each SC with its preferred schedules, indicate the SC's valuation of incremental changes to its resource schedule. The ISO's congestion market management system minimizes the cost of such schedule adjustments while keeping each SC's schedules and adjustment bids internally balanced and separate from those of other SCs. The ISO conducts both day-ahead and hour-ahead inter-zonal congestion management, as well as real-time intra-zonal congestion management. We describe the performance of these markets below, and provide greater detail in Chapter 5 of the report.

1.5.1 Congestion Frequency and Cost

The congestion management market worked well in allocating available transmission capacity during the first year of operation. Congestion costs were less than one percent of total energy costs. Most of the congestion in the day-ahead market occurred on five branch groups: California-Oregon Intertie (COI), Nevada-Oregon Border (NOB), El Dorado, Palo Verde, and Path 15. Figure 1-13 shows congestion frequency, and Figure 1-14 shows congestion costs and prices. The overall average usage charge was $12.3 per MWh during hours of congestion.

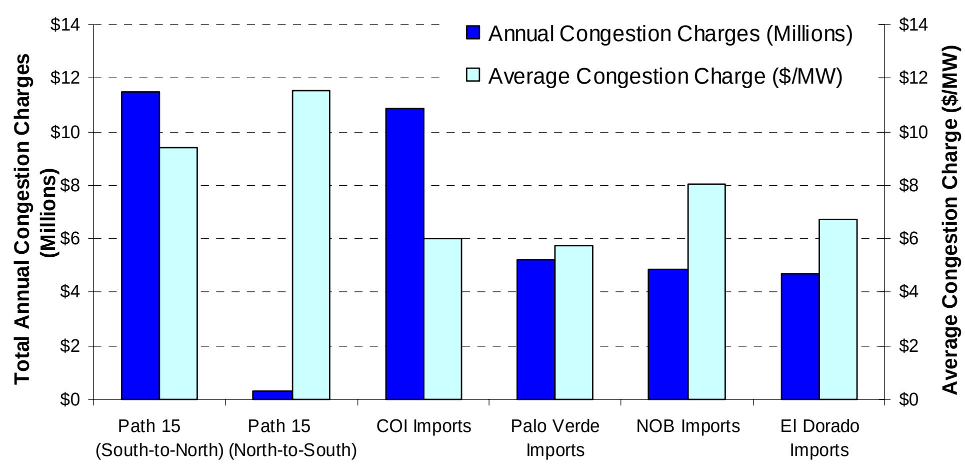
Inter-zonal congestion followed expected seasonal patterns. Congestion directions, frequencies and magnitudes were generally as anticipated based on line operating limits. The direction of congestion on Path 15, between the two zones within the ISO control area, was predominantly south-to-north during the fall, and north-to-south during the summer, with the former having a far greater financial impact. Figure 1-15 shows the congestion pattern on Path 15 by month.

Figure 1-13. Inter-zonal Congestion Frequency by Major Path in Day-ahead Market



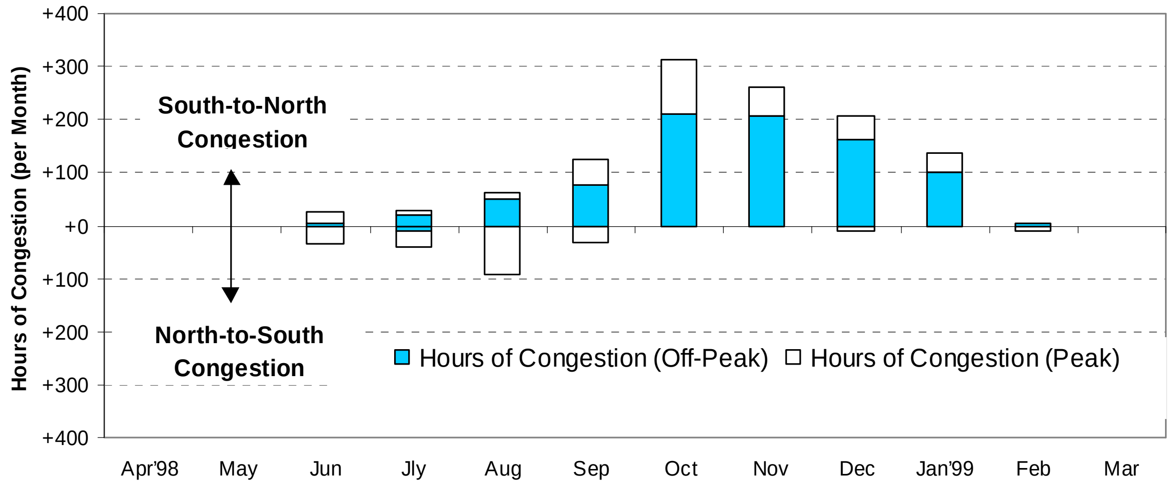
Virtually all congestion on branch groups connecting California with other control regions required curtailment of imports of energy into California, or wheeling of energy through the state. On Path 15, the major branch group connecting zones within the state, most congestion occurred in the south-to-north direction.

Figure 1-14. Congestion Cost and Price by Major Paths in Day-ahead Market



Over half of all congestion charges were incurred due to south-to-north congestion on Path15 and congestion on imports from the Pacific Northwest on COI. Congestion charges on each of these paths totaled about $12 million for the year, while congestion charges on Palo Verde, NOB and El Dorado totaled about $5 million each for the year.

Figure 1-15. Congestion Frequency and Direction on Path 15 by Month



During the summer months, congestion on Path 15 was predominantly north-to-south during peak hours, and south-to-north during off-peak hours. During the fall and winter months, virtually all congestion was in the south-to-north direction, with congestion occurring during a very high proportion of off-peak hours during these months.

Hour-ahead inter-zonal congestion occurred during 315 hours on all interties, primarily as a result of line capacity being derated after close of the day-ahead market. Hour-ahead congestion prices were generally higher than day-ahead prices, but were applied to much smaller quantities and thus had minor impacts on energy prices. The main reason for this outcome was the very low volume of energy trades and A/S procurement in the hour-ahead market.

Real-time inter-zonal congestion occurred in 1,077 hours on Path 15. We would expect some correlation between forward congestion prices and real-time congestion prices, similar to the relationship between PX day-ahead and ISO real-time prices. One factor that causes day-ahead congestion to be more costly than real-time congestion is the inefficient use of transmission capacity under Existing Transmission Contracts (ETCs). The ISO cannot require ETC owners to release unused ETC capacity into the forward congestion management market. This unused capacity does become available in real time, however. Consequently, forward congestion prices may not reflect the actual availability of transmission in real time. In developing its Firm Transmission Rights (FTR) market proposal, the ISO is working actively with ETC owners to set up incentives to encourage their participation in the forward congestion management markets.

Only one intra-zonal interface (Path 26) has incurred noticeable intra-zonal congestion. During the first six months of ISO operation, Path 26 was congested in 343 hours, or eight percent of the time. The total cost of intra-zonal congestion on Path 26 for these months was approximately $3.9 million.

1.5.2 Congestion and Market Efficiency

The impact of congestion on Path 15 on the market is greater than the actual the cost of congestion management. When Path 15 is congested, the ISO divides the California market into two zones, NP15 and SP15. The PX energy market and the ISO A/S market auctions are then conducted separately for the two zones. With smaller zones comes higher concentration of generation owners. In almost all hours when the markets were split, the largest suppliers were pivotal in the A/S markets in their zones. The zonal PX energy markets are less concentrated than the A/S markets, and no generation owner is normally pivotal. However, the reduced market size of the split zones will still enhance market power and allow some generation owners to bid a higher mark-up over their cost. For this reason, we believe it is beneficial to eliminate Path 15 congestion as much as possible.

Another impact of congestion is its effect on PX energy prices.[3] The net impact of inter-zonal congestion on energy costs (compared to unconstrained costs) during the first year of ISO operation was a cost reduction of about $28 million. This fact, however, may not outweigh the added costs due to other factors, such as market power and possible adverse impacts of congestion on A/S costs. Even if we look only at the impact on energy costs, a reduction in total purchase costs certainly does not increase market efficiency as measured by the combined producer and consumer surpluses. Grid enhancement and expansion are important elements which will help to mitigate market power and improve market efficiency in the future.

1.5.3 Bid Sufficiency and High Usage Charges

As in the A/S market, one of the main performance indicators for the congestion management market is bid sufficiency of the adjustment bids. Adjustment bid insufficiency occurs if the adjustment bid pairs from all SCs are exhausted on either or both sides of the congested interface before the congestion is fully mitigated. In this case, the ISO applies a default usage charge of $250/MWh. If the adjustment bids are exhausted on only one side, a lower usage charge (with a floor of $30/MWh) may apply.

During the first year of operation, adjustment bid insufficiency occurred during 92 hours in the day-ahead market, and 150 hours in the hour-ahead market. The default usage charge of $250 was imposed 31 times in the day-ahead market and 90 times in the hour-ahead market. The latter was mostly due to line de-rating after the day-ahead market. Bid insufficiency was much less frequent here than in the A/S markets.

The incidents of high usage charges may be the outcome of market inefficiency or market power. The SCs may fail to submit adjustment bid quantities that truly reflect their cost. Some current market design features also limit SCs' capability to submit adjustment bids. The risk of market power exists on both intra-state interfaces and interstate interfaces. The large size of the congestion zones promotes competition among generators and SCs and constrains market power. On the other hand, intra-zonal congestion can occur when there are very few generation owners on one side or another of the congested interface. Those few generators may submit very high incremental adjustment bids or very low decremental adjustment bids when intra-zonal congestion is expected and unduly influence market prices. We observed this frequently in recent months, as the participants have learned where and when they are able to set prices. The ISO Governing Board has approved changes to intra-zonal congestion dispatch practices to ensure

[3] The constrained, zonal PX energy prices are determined so that the zonal price differential is equal to the congestion price ($/MWh) on the corresponding inter-zonal interface, as determined by the ISO congestion management software based on the adjustment bids.

that this type of market power is mitigated. The changes are expected to become effective in mid-August 1999.

Overall, the congestion management market worked well in allocating available transmission capacity during the first year of operation, with congestion costs totaling less than one percent of total energy costs. Congestion directions, frequencies and magnitudes were generally as anticipated based on line operating limits, and inter-zonal congestion patterns followed expected seasonal variations. Only one intra-zonal interface (Path 26) experienced noticeable intra-zonal congestion.

1.6 Key Challenges Affecting First-year Performance

The first year of operation of the California ISO was full of challenges. The ISO acted quickly in the face of each challenge to maintain system reliability and improve market efficiency. The ISO Market Surveillance Unit (MSU) and the Market Surveillance Committee (MSC) have monitored the ISO markets since market simulation began a few months before actual market startup. They have been actively involved in detecting and addressing a number of major issues. The major issues can be classified into the following five areas: (1) system implementation, (2) gaming behavior, (3) regulatory disparities, (4) market design, and (5) market power. Some issues involved two or more of these areas. In addition to dealing with the immediate issues, the ISO was also proactive in developing new market design features and other initiatives to enhance competitiveness and market efficiency.

1.6.1 System Implementation Issues

The California market operating system was developed and implemented in a period of one year. Such record speed in creating a new and innovative market naturally resulted in some imperfections in implementation. For example, we discovered prior to market opening that the software was dispatching imbalance energy resources assuming that the generator operators had already implemented the instructions of the previous dispatch periods. As a result, the software calculated excessively high prices for the imbalance market, based on bids from units that may not have been dispatched. This problem threatened to delay the start up of ISO operation. In response, the ISO immediately placed a cap on real-time energy bidding to allow the market to open on time. It then initiated a redesign of the dispatch module to eliminate the problem. We identified other imperfections that arose as the result of necessary staging of software implementation, and over time have sought to adopt changes to address those imperfections.

1.6.2 Gaming Behavior

The California market design was complex and unproven. It inevitably allowed a variety of gaming opportunities for both generators and loads. The first gaming opportunity involved the ability of generators to submit high real-time decremental bids, then to engage in high levels of uninstructed over-generation using other units in the same generator's portfolio. This would force the ISO to utilize the high decremental bids and establish very high real-time prices. In response the ISO implemented a software procedure to reduce excessively high decremental bids and, if necessary, increase excessively low incremental bids, to eliminate the opportunity to profit between incremental and decremental energy markets. Another gaming behavior we observed was generation units deviating from the ISO's real-time dispatch instructions. Such deviations were actually rewarded by the existing settlement methodology. In response the ISO developed an "effective price" settlement methodology based on each unit's actual output in each 10-minute period. When this is implemented in summer 1999, it will remove the ability of generating units to gain by not following the ISO's dispatch instructions, and, combined with charging deviation Replacement Reserve based on schedule deviations, will reduce the incentives to engage in uninstructed deviations.

1.6.3 Regulatory Disparities Leading to Bid Insufficiency

Bid insufficiency in the ancillary services markets was a major difficulty during the first few weeks of operation. We concluded that the problem could be linked to the existence of cost-of-service based rate caps for A/S while energy prices were not similarly regulated. This encouraged suppliers to avoid the A/S markets and earn more money by selling energy at uncapped day-ahead PX prices. The ISO worked with the FERC to quickly implement REPA, which improved bid sufficiency in the Regulation market where the problem was most severe. Soon after, the FERC moved quickly to eliminate the cost-based caps and grant market-based rates for all A/S suppliers.

1.6.4 Market Design and Market Power Issues

In addition to addressing market difficulties as they arose, the ISO was also proactive in launching a substantial market redesign initiative. Intended to go beyond quick fixes to address fundamental design flaws, the elements of this initiative were designed to improve market efficiency and curb market power. The market redesign program includes elements to be implemented during summer 1999, and longer-term elements. Two major elements of the near-term program are the Rational Buyer Procedure, and Negative Pricing of Supplemental Energy. Two other important ISO market initiatives are the reform of Reliability Must Run (RMR) Contracts, and creation of a market for Firm Transmission Rights (FTRs). Each of these is described briefly below:

The Rational Buyer Procedure

The ISO realized that the inflexibility of its A/S procurement requirements, combined with the sequential clearing of the A/S markets, created opportunities for exercise of market power. The principle of the Rational Buyer Procedure is to permit the ISO to shift its purchases among the A/S markets, substituting more of a higher quality service for some portion of a lower quality service requirement, when this action can reduce total A/S procurement costs. By introducing demand elasticity into the A/S markets, Rational Buyer will allow the ISO to reduce its total A/S purchase cost while fully meeting all A/S requirements. The settlement for Rational Buyer will charge the same prices to the users as it pays to the suppliers. The market efficiency impact of this algorithm and the settlement issues are discussed in Section 3.8.

Negative Pricing of Supplemental Energy

During the spring of 1998 the ISO had excessive over-generation that could not be mitigated through available market mechanisms. On several occasions the ISO had to pay neighboring control areas to take excess hydro and must-take generation. To avoid this situation in the next peak hydro season, the ISO has introduced negative pricing of supplemental energy. Negatively priced bids for supplemental energy, and for energy dispatched out of A/S capacity, started on March 17, 1999.

Reform of RMR Contracts

As part of its investigation into the A/S market price spikes, the ISO Market Surveillance Committee (MSC) identified incentives inherent in RMR contracts to withhold capacity, exercise market power, and create market inefficiency. RMR units enjoy locational market power, since the ISO needs a portion of their generation for reliable operation of the grid. Accordingly, RMR contracts are regulated based on the units' costs. These regulated contract terms produced unexpected incentives in two ways: (1) by providing "insurance" that encouraged owners not to bid in the PX market and to withhold capacity to drive up prices for their other non-RMR capacity, and (2) by artificially increasing the PX market clearing price because RMR currently may not clear the PX market as bid even though it is known that RMR energy will serve some load. The MSC suggested two basic changes to these contracts to eliminate the perverse incentives. The first modification has to do with the structure of payments to RMR units, and will be implemented in summer 1999. The second modification, still under discussion, would alter the procedure for dispatching RMR energy and make a coordinated adjustment to the level of demand in the PX day ahead market. The second modification is intended to reduce the impact on the PX day-ahead and other inter-related market prices due to RMR dispatch order.

Creation of a Market for FTRs

Under the original design of the congestion management market, access to congested inter-zonal transmission pathways has been awarded to users through a competitive market, based on the adjustment bids they submitted with their preferred schedules for each hour. Under this design there was no provision for users to reserve physical transmission rights prior to the scheduling process. In its October 1997 Order approving the operation of the ISO, the FERC determined that a market for Firm Transmission Rights (FTRs) was needed in order to conform with FERC's Order No. 888, but it allowed the ISO to start operation with the original design in the interim.

In designing FTR's for the California market, three issues were most prominent: (1) Should FTRs be financial rights only, or should they also carry scheduling priority? (2) Should all, or only a portion, of the available capacity be traded in the FTR market? and (3) Should available capacity be based on non-simultaneous WSCC ratings or on simultaneous path ratings. After a lengthy stakeholder process and several ISO Governing Board meetings, the Board adopted a design that specified that FTRs will carry financial rights in both the day-ahead and the hour-ahead markets, but will have scheduling priority in the day-ahead market only. The ISO proposed an initial release of 25 percent of available capacity based on non-simultaneous WSCC path ratings.

The FERC conditionally approved the ISO's FTR proposal on April 28, 1999. Among the conditions were (1) to increase the release rate to 100 percent by the early part of the year 2000, and (2) to study whether it would be more appropriate to base the quantity of FTRs released on path operating limits rather than WSCC non-simultaneous ratings. FERC's Order requires the ISO to set the quantity of FTRs so that all FTRs can be simultaneously honored under normal operating conditions. Since path operating limits change by season and operating conditions, FERC's Order implicitly requires that a definite availability level (percentage of hours per year) be adopted in order to determine a precise number of MW of FTR capacity for each path. On

May 27, 1999, the ISO Governing Board directed the filing of an application for rehearing with FERC that would provide for release of 100 percent of available FTRs, calculated based on 99.5 percent availability under all projected operating conditions. The ISO will seek permission to release FTRs effective February 1, 2000 to avoid implementing a new software program at the start of Y2K.

1.7 Remaining Market Issues

The ISO addressed numerous challenges over the past year, through prompt action in response to immediate needs, and through elements of market redesign which have already been agreed upon and are scheduled for implementation. We discussed these challenges and the ISO's responses in the previous section. Even with these measures, the ISO will need to make further efforts in the coming year to advance the efficiency and sustainability of California's new, competitive electric markets. This section describes the areas the ISO has identified as high priorities for the next phase of market reform and redesign.

1.7.1 Further RMR Reform

The RMR market will be partially reformed with the implementation of new contract structures in summer 1999. As noted in the previous section, however, there is another change still under discussion that the ISO will be advocating for implementation later this year. The proposed change is referred to as "pre-dispatch and netting out" of RMR energy. This procedure entails the ISO determining how much energy will be required from the various RMR units for local reliability, and requiring that energy to be either included in some bilateral schedule prior to the PX day-ahead market, or bid as a price taker (at $0/MWh) into the PX market. This amount of energy would then be netted out of the required demand. The ISO currently intends to file this proposal with the FERC in October 1999.

1.7.2 Reduce the Demand for Regulation

In the restructured marketplace, by design, generation operators are free to make their own decisions about how much to generate in any given hour, subject only to the incentives embodied in market prices and in contractual relationships. The ISO simply does not have the same degree of control over generator operations as existed in the traditional, centrally-dispatched industry structure. Formerly the control area operator would order units to decrease generation when a rush of imports came into the State in the early morning hours, and would ramp up generation when imports ceased in the evening hours. Today, the ISO must use Regulation to make up for a deficiency in its ability to order units to follow these dramatic changes. As a result, the amount of Regulation capacity required to meet reliability criteria is much greater than the one percent of load that was typical under the old structure. The California ISO started operation with a 3 percent of load requirement, but failed to meet the WSCC CPS2 criteria, then increased the requirement to an average of 5 percent of load, with a maximum of 13 percent in high ramp hours.

The ISO has identified the following changes to improve the situation: (1) upgrade the real-time Balancing Energy and Ex-post Pricing (BEEP) software to perform within-hour load following, and improve communication of dispatch instructions to the field (this item is already an element of the redesign to be implemented in summer 1999); (2) modify software to check that units' bid ramp rates do not exceed their certified ramping capabilities. Other possibilities include modifying the settlement process to perform settlement for the real-time imbalance market on a 10-minute basis rather than on a net hourly basis, to provide stronger incentives for generators to comply with the ISO's real-time dispatch instructions. We will also investigate a change in the way Regulation is charged to factors causing high requirements in the morning and evening hours.

1.7.3 Enhance the Hour-ahead A/S Markets

Starting April 7, 1999, the ISO has been deferring up to 10 percent of its day-ahead A/S requirements to the hour-ahead market. This was a request made by market participants in the A/S redesign process to promote a more rational procurement of A/S, increased liquidity of the hour-ahead market, and reduction of A/S costs. Advisory requirements for A/S are set day ahead. Actual procurement is based on many factors: updated load projections, actual system conditions (e.g., generator availability and outages), weather conditions, estimated hour-ahead self provision, thickness of the hour-ahead market, and the purchase prices of A/S. Deferring a portion of the requirement to the hour-ahead market could substantially reduce the day-ahead A/S procurement cost, since even a small price reduction would apply to a large A/S quantity. The portion deferred to the hour-ahead market could raise the hour-ahead price, but that price would apply to a relatively small A/S quantity. Our preliminary analysis of bid data indicates that this practice has resulted in about 45 percent reduction in A/S procurement costs compared to the previous practice of procuring all A/S in the day-ahead market, since its inception in April 1999.

1.7.4 Reduce Barriers to Ancillary Service Imports

At present, there is a 25 percent-of-requirement limit on the import of Operating Reserves (Spinning and Non-Spinning Reserves), for two main reasons:

(1) Operating Reserves are mainly called under emergency conditions and must be available within 10 minutes. However, the WSCC has standard times for schedule changes (i.e., on-the-hour changes for normal operations, and on-the-quarter or half-hour for emergency operations). This limits the extent to which the ISO can rely upon timely availability of Operating Reserves from imports.

(2) Available import transmission capacity may be reduced due to loop flows and other contingencies during such emergency conditions. To increase the supply into the A/S markets, the ISO plans to increase its limit on the import of Operating Reserves to 50 percent in near future through a three-party arrangement with the SCs and the neighboring control areas. The control areas that are party to the agreement must reserve adequate transmission capacity, and will respond to ISO's intra-hour 10-minute interchange schedule change requests under normal or emergency conditions. The ISO plans to test this procedure in the first week of June 1999.

1.7.5 Monitor Market Power in New FTR Market

Our main market power concern in the new FTR market is the combination of FTR ownership concentration and ISO scheduling capability. A scheduling coordinator (SC) who holds a large share of FTRs could exercise market power by over-scheduling and withholding FTR capacity, to increase that SC's FTR revenues and/or protect its own generation from competing resources outside of a specific zone. With the release of a large percentage of FTR capacity, the ISO's adjustment bid market may become very thin, exacerbating the potential to exercise market power. We have formulated several indices for monitoring the FTR and adjustment bid markets. They are FTR ownership concentration, secondary FTR market activity, impact of FTRs on the adjustment bid market (depth of that market, congestion frequency, congestion price volatility, and congestion price sensitivity), and unused transmission capacity in real-time for hours exhibiting forward market congestion ("paper congestion"). The ISO is currently proposing to implement FTRs early in year 2000. If the MSU detects significant problems, we will propose remedies such as ownership concentration limits as needed.

1.7.6 Integrated Transmission Grid Expansion Process

In the restructured environment, grid expansion is important to mitigate market power and improve market efficiency. The present Transmission Access Charge structure is oriented toward meeting cost-based revenue requirements of the transmission owners (TOs). It provides no market signals for efficient transmission investment. We believe coordinated planning of transmission system expansion is critical to provide efficient price signals for new generation location decisions, to reduce barriers to entry for new generation capacity and mitigate market power. The ISO Tariff foresees a role for the ISO as a coordinator of transmission grid planning. The ISO has started a stakeholder process to design an *Integrated Grid Planning Process*. The grid planning process will incorporate a number of related efforts including the Local Area Reliability Service Project (LARS, which is a mechanism to replace RMR with investments in transmission upgrades, demand-side programs and new generation), and the New Generation Connection policy, which will incent grid expansion to mitigate intra-zonal congestion.

1.7.7 Promote Demand Responsiveness to Market Prices

Price responsiveness of demand varies among the ISO markets. In the congestion market, for example, demand price responsiveness is working full force. Our main concern is not to have it eroded away by large quantities of FTRs. In the ancillary services and real-time markets, however, demand responsiveness is minimal at present, due to the limited capability of loads to be dispatched by the ISO or to respond to real-time prices. The prospect of raising price caps from the present $250/MWh level to a much higher level has prompted serious activity by load serving entities to implement demand-side programs. Since the price cap in the ISO's real-time market acts as a de facto cap on the PX market, demand-side programs are being designed with a view to both the PX and the ISO markets. For example, a load serving entity could offer a contract to its large loads whereby they would agree to curtail on a block of hours on a near future operating date (e.g., two-days ahead) for a price. The entity would then either bid the quantity to the ISO as Replacement Reserve, or have it declared as self-provided reserve. Some such programs may become operational as early as June 1999.

1.7.8 Mitigation of Market Power after Stranded Cost Recovery Ends

During the first year of operation, the opportunity for new generation owners to exercise market power was limited to relatively narrow periods of time. These were periods when high loads, market design flaws and regulatory restrictions on other sources of market supply resulted in dramatic price spikes. During most hours, market power was overwhelmingly in the hands of the California IOUs, who remained the largest three suppliers of energy and A/S. They controlled from at least 50 up to nearly 100 percent of the A/S capacity in any given hour. Because the IOUs were net buyers of energy and A/S, and because their stranded asset costs were recovered through a net-of-energy residual charge, these IOU's exercised this market power defensively to keep prices low and accelerate recovery of stranded costs. As the IOUs divest additional generating capacity and complete their stranded cost recovery, this defensive exercise of market power can be expected to end. The retail rate freeze has been the key tool of mitigating market power in both the energy and ancillary service markets.

In the future, there will be increased need to monitor for market power, and to develop appropriate mitigation measures in the event that market power exists, is exercised and results in excessive market prices. Some of the key features will include interruptible loads, contracting forward or contracts for differences, and even bidding rules that say generators cannot bid into any subsequent market, unless they have a bid in the first market for their entire capacity, at any price curve they wish. All these measures may be necessary features of mitigating market power in the future. It is important to determine the amount of capacity that is available for energy, but is not being bid into A/S markets. This missing capacity has led to thin markets and price spikes even though capacity is up and operating. The Market Surveillance Unit is assessing possible barriers that may explain why this capacity is not being bid into the A/S markets.

As price caps are lifted there may be a need to implement alternative mechanisms to guard against extreme and sudden price spikes. All markets need to protect against the proverbial billion dollar bid being accepted. In anticipation of the raising of the present caps, the MSU is considering various types of "circuit breaker" mechanisms similar to those used in the stock and commodity markets to limit extremely large and rapid swings in prices. For example, a possible type of circuit breaker in the energy and A/S markets would automatically raise the existing cap level by a pre-specified amount after it has been hit two days in a row. Successive hits would continue to bump the cap up, but at a slower rate than if there were no controls. This mechanism would give buyers an opportunity to protect themselves against sudden swings by limiting the amount the price could move in a two-day period. The MSU believes mechanisms such as this will be an important factor in increasing the demand elasticity of the ISO's markets, without deterring new investment since prices will still be able to rise as a result of shortages. Such a mechanism could serve both as a way to transition out of the current price cap regime without suddenly eliminating the cap, and as an ongoing way to moderate price volatility in the markets. As the circuit-breaker levels are hit and price caps are lifted, the MSU will be able to assess the relative impacts of market manipulation and true supply shortages on market prices.

1.8 Conclusion

The first year of operation of the California ISO was full of challenges. The ISO acted quickly in the face of each challenge to maintain system reliability and improve market efficiency. Over the course of the year, the ISO improved market efficiency by introducing emergency measures and market reforms, and through on-going cooperation with FERC and other regulatory agencies to implement needed regulatory reforms. The ISO maintained system reliability through the record-high summer load period, and brought ancillary service costs down quickly after initial spikes. The ISO has implemented or has under development a number of short-term and long-term market redesign elements that will further mitigate market power and improve market efficiency. In the future the ISO will be aggressive in promoting a competitive market that benefits all participants including consumers and producers.