Executive Summary

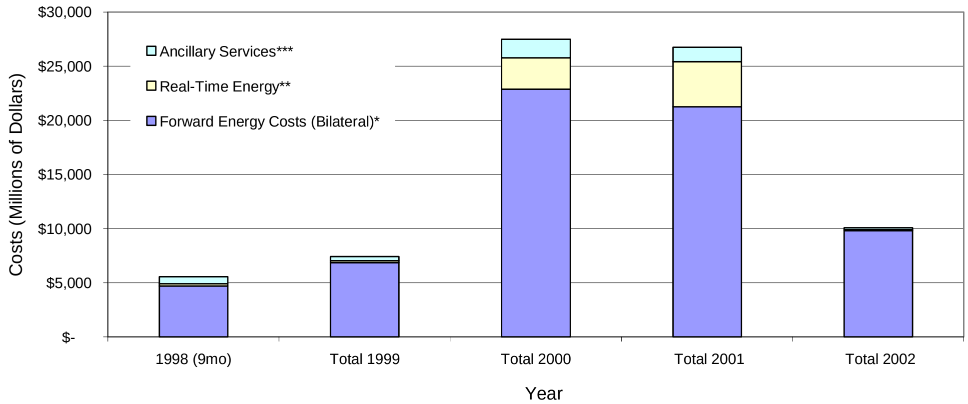
The California ISO operates the high voltage transmission grid and provides control area services through the operation of an imbalance energy market and reserve service for generation and transmission contingencies. The health of the California ISO's imbalance energy market and ancillary service reserve markets was considerably better in 2002 compared to the preceding two years of massive market dysfunction. This improvement was primarily due to the large amount of long-term contracts secured in early 2001 to meet the utilities' load not covered by their retained generation resources. Another key reason was the improved market supply and demand resulting from near normal hydroelectric production and the net addition of 1,355 MW of new generation resources combined with moderate loads. For the year, the average cost for short-term energy showed a mark-up of 17 percent above estimated competitive baseline costs.[1]

Total wholesale energy comes from utility owned generation, long-term contract purchases, bilateral transactions, and the ISO's imbalance energy market. Total wholesale energy and ancillary service costs for 2002 were just over $10 billion. This was significantly less than the nearly $27 billion in 2000 and 2001 yet still significantly greater than the 1999 total of $7.4 billion. Costs were higher in 2002 than in 1999 primarily because of the high cost of energy procured through long-term contracts entered into by the State of California in early 2001 and higher natural gas costs.

Figure E.1 below shows each market's contribution to total wholesale energy costs for each year the ISO has been in operation. Next, Figure E.2 illustrates monthly average wholesale energy costs and system loads from 1999 through 2002.

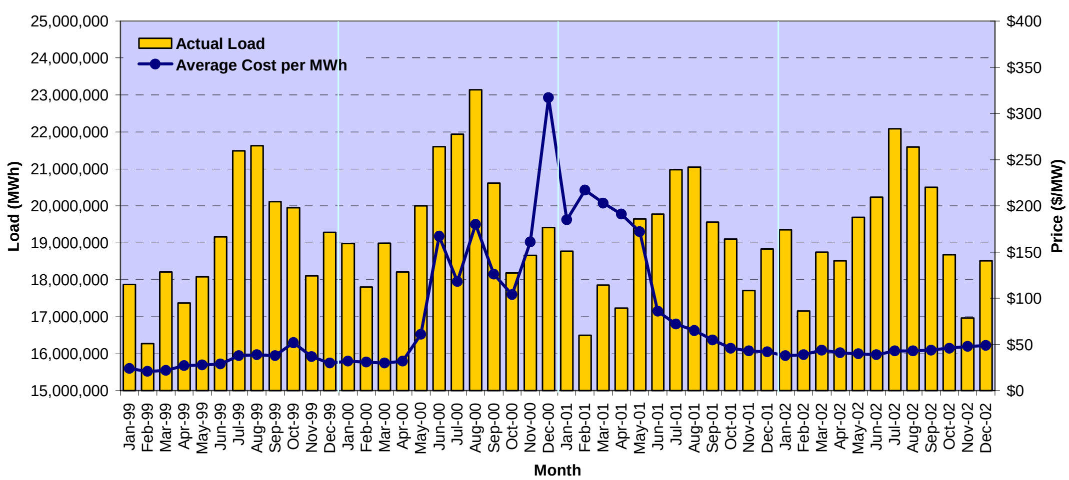
[1] Spot market energy includes bilateral day-ahead, hour-ahead and ISO real-time prices. Competitive baseline costs are estimated as the hourly system marginal costs.

Figure E.1. Total Wholesale Annual Energy Costs[2]



Total Wholesale Energy Costs in 2002 were more than 62 percent less than 2000 and 2001 levels

Figure E.2. Average Costs and Total Energy Delivered



Average total wholesale energy costs have remained stable since late 2001 as the majority of load was met by utility generation and long-term contracts. The average cost of energy and ancillary services was $43/MWh in 2002.

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2 * Includes utility distribution company (UDC) energy costs (based on cost of production), estimated CERS energy costs, and other bilateral energy purchases priced at hub prices.
** Includes OOM, dispatched real-time paid at the market clearing price, and energy dispatched in real-time paid as-bid.
***Includes ISO purchased and self-provided ancillary service priced at the corresponding ancillary service market price for each hour, less replacement reserve refund.

Market Rule Changes

The ISO market structure continues to evolve. Significant market changes during 2002 included:

- **Importers Bid Zero into Real-time Imbalance Energy Market:** Implementation of the Federal Energy Regulatory Commission's (FERC) December 19, 2001 Order that required suppliers outside of the ISO control area to submit bids of $0/MWh to the imbalance energy market. This caused a significant decrease in the amount of bids received for imbalance energy from importers to the ISO control area. However, this effect decreased in April when the ISO filed Amendment 43, which provided that imbalance energy supplied over interties would receive the instructed imbalance energy market clearing price for energy delivered during the course of an operating hour. After implementation of Amendment 43 to the ISO tariff, the ISO received significantly increased bid volumes over the interties. However, in October, interties bids again diminished as the Commission reaffirmed the requirement for a zero bid until such time as the ISO could implement software to run a day-ahead energy market.

- **Automated Dispatch Instructions:** In May 2002, the ISO operators began using new automated dispatch systems (ADS) to enhance dispatch capabilities and include reliability must-run (RMR), out-of-sequence (OOS), and out-of-market (OOM) calls in the ADS dispatch.

- **Market Power Mitigation Measures:** In the fall of 2002, the ISO made a series of changes to the market power mitigation rules that had been in place since June 2001. In particular, it increased the damage control soft cap on market bid prices of $91.87 to $250/MWh and put an automatic mitigation procedure (AMP) in place.

Supply and Demand Conditions

While still moderate, loads were 2.2 percent greater in 2002 than in 2001 as the levels of conservation seen during the energy crisis diminished. At the same time, California's supply picture continued to improve as significant amounts of new supply came on line in California in 2002. 2,764 MW out of a projection from the California Energy Commission of 6,083 MW of new generation capacity within the California ISO control area began commercial operation in 2002. The vast majority of the new capacity was combined-cycle natural gas units located within northern California (NP15). However, there were also 1,409 MW of retirements in 2002 resulting in a net capacity addition of 1,355 MW.

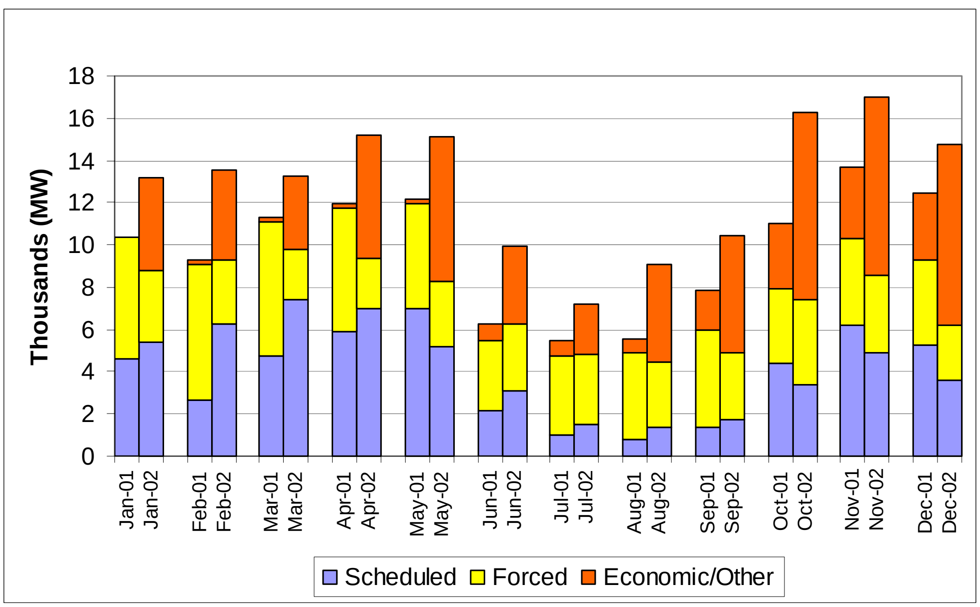
Table E.1 below shows the amount of new capacity added to each zone within the California ISO control area.

Table E.1. 2001-2002 New Generation Additions and Retirements[3]

Congestion Zone	2001 Generation Additions (MW)	2002 Generation Additions (MW)	2002 Generation Reductions (MW)	Net Generation Change (MW)
NP-15	1,550	2,263	-8	3,805
ZP-26	338	71	0	409
SP-15	685	430	-1,401	-286
ISO Control Area	**2,573**	**2,764**	**-1,409**	**3,928**

Generation outage levels within the California ISO control area returned to their previous historically lower levels. Significant new generation resources and moderate demand enabled the ISO to grant a significant amount of must-offer waivers to uneconomic generators. Figure E.3 below illustrates the average monthly forced, scheduled, and economic outages (must-offer waivers) for 2002.

Figure E.3. 2001 and 2002 Average Outages By Month



Forced and scheduled outage levels were manageable throughout 2002. New generation and higher hydro production allowed the ISO operators to grant significant must-offer waivers for non-economic resources (economic outages) in 2002.

[3] See California ISO 2003 Summer Assessment for more details.

An essential part of an efficient competitive market is demand response to price. In the summer of 2002, 1,409 MW in load reduction programs were available. Of that, 1,349 MW was in interruptible load resources and 60 MW was in controllable load. Although the ISO has taken an active role to develop and encourage demand response programs, there is still insufficient demand response in place to significantly impact market competitiveness. There was only one new demand program introduced in California in 2001, the discretionary load curtailment program, and there were not any new demand response programs put in place in California during 2002.

Reserve Margin[4]

The improved supply picture brought about by the new generation in California combined with moderate loads resulted in stronger reserve margins throughout the year. The peak hour reserve margin improved from 1.8 percent in 2001 to 6.9 percent in 2002. Given the high dependence on imported energy, the reserve margin is highly dependent on the level of imported energy available to meet system demand. Figure E.4 below compares the 2001 and 2002 peak hour reserve margins. Next, Figure E.5 shows the monthly peak hour reserve margins for 2002. The reserve margin is highly dependent on the level of imported energy available to meet system demand.

[4] The hourly Reserve Margin percentage shown here is the integrated metered generation quantity across the ISO control area over an hour divided by the integrated metered load quantity less the net scheduled interchange at real-time into the ISO control area over an hour. Note that this reserve margin percentage will differ from reserve margin percentages based on the instantaneous generation and load levels at points within an hour. The reserve margin discussed here is not an operating reserve margin. For capacity to be considered as operating reserve, it must be either synchronized with the system or available for immediate start-up. The capacity must be capable of being loaded within ten minutes. Available generation is defined as total generation + net imports less forced and scheduled outages.

Figure E.4. Reserve Margin During Peak Load Hours of 2001 and 2002

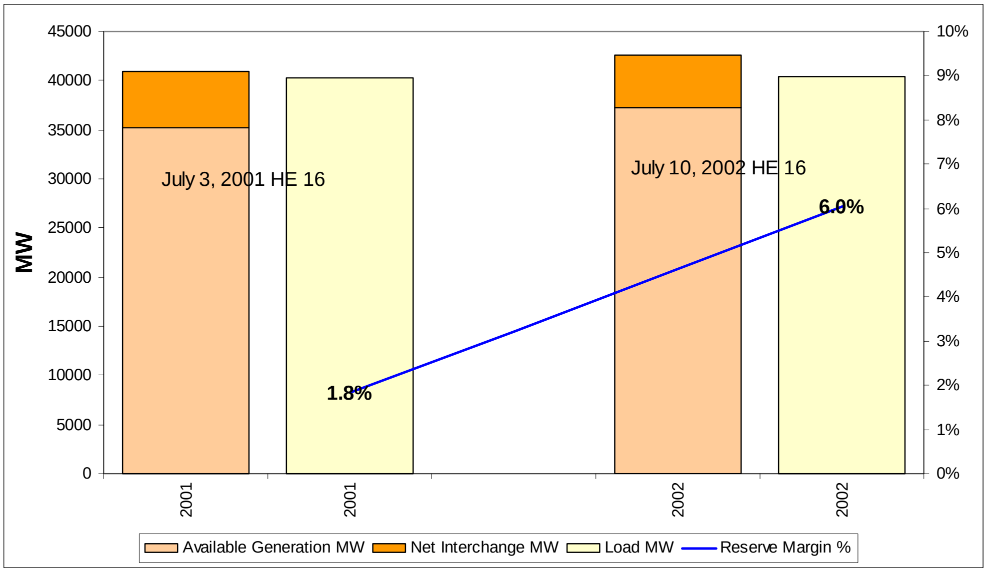
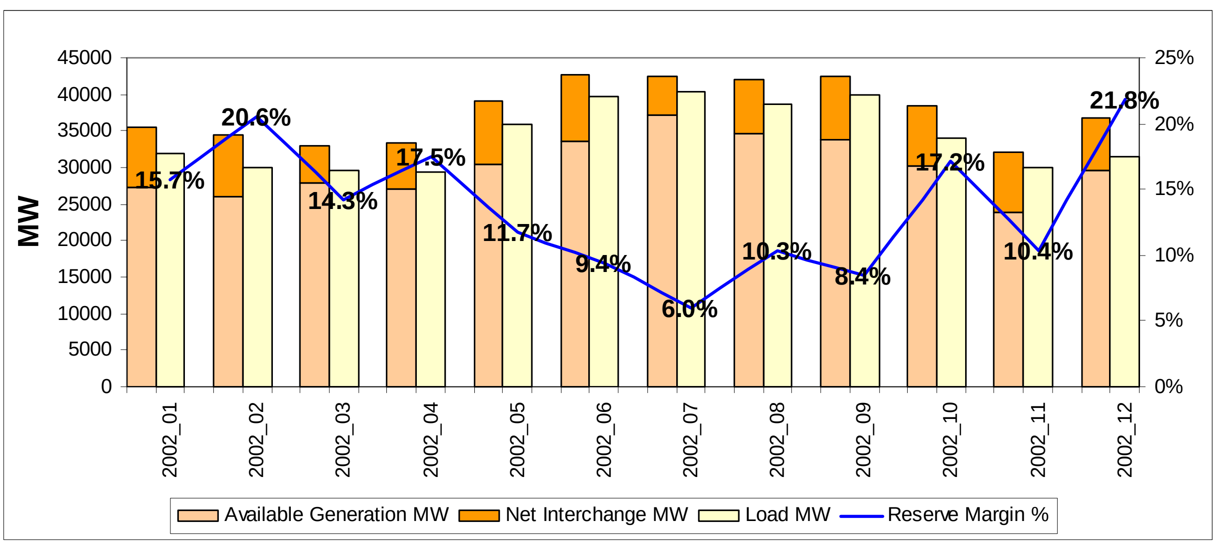


Figure E.5. 2002 Reserve Margin During Monthly Peak Hours



One adverse consequence of the addition of new supply is that it has caused increased strain on the existing transmission lines within the ISO's system. Additionally, the ISO expects retirement of generation in SP15 to exacerbate path overloads in that region. The consequence is increased severity of load pockets within the system that, at times, allow suppliers located within the constrained region to exercise significant market power. This also increases difficulties for ISO operators who, under the current market design, must deal with this congestion entirely in real-time and at potentially great cost.

Long-term Contracts

In early 2001, the State of California entered into long-term contracts for a significant amount of power to hedge the three investor-owned utilities' net-short load requirements. When the markets finally stabilized in mid-2001, the state began negotiations with many of its contractors to change some of the terms of the contracts. The new contract terms secured by the State during 2002 did not significantly change the quantity of long-term contractual energy procured to cover the utility distribution companies' (UDCs) net short load requirements. During peak periods, these contracts provide approximately 70 percent of the UDC net short load requirements leaving the balance to be supplied by short-term bilateral contracts and spot purchases. However, the new contract terms did shift much of the previously non-firm or unit-contingent energy to a firm but dispatchable nature that provides greater dependability and somewhat greater dispatch flexibility under varying operating conditions. However, accommodating the terms of these contracts continue to cause ISO operators tremendous difficulties in maintaining system reliability. The majority of the capacity from the contracts is provided on a 6 by 16 basis, that is they are scheduled to supply energy six days a week for 16 hours per day, usually from 6:00 a.m. to 10:00 p.m. When the energy associated with these contracts rushes in around 6:00 a.m., it causes significant strain on real-time operators who must make extraordinary arrangements to accommodate the sudden inrush of energy. The reverse situation occurs around 10:00 p.m. when the associated energy is retracted, causing the same level of strain on ISO operators in their attempt to continuously match resources with load posing a significant threat to western interconnection reliability.

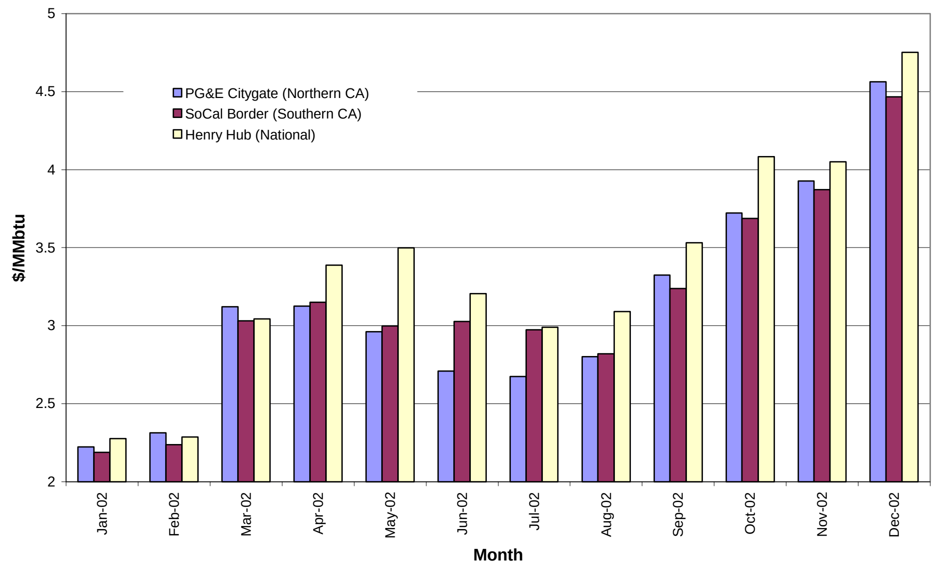
Imported Energy

California relied on imported energy to meet 23.35 percent of its energy needs in 2002. Energy imports significantly increased in 2002 from 2001 levels. This contributed significantly to the favorable supply picture in California. Annual average net imports scheduled into the California ISO control area increased approximately 40 percent in 2002 due primarily to increased imports from the Pacific Northwest where improved hydrological conditions enabled suppliers to export significant energy to California.

Fuel Costs

Marginal generating units in California under most conditions are natural gas-fired thermal units. Therefore, natural gas prices have a direct effect on California wholesale electric prices. The price of natural gas was remarkably low during the first quarter of 2002, averaging below $2.25/mmbtu at California delivery points in January and February 2002. However, prices rose steadily over the course of the year, particularly during the fourth quarter, as shown in Figure E.6 below. They ended the year near $5/mmbtu, a 120 percent increase since the beginning of the year. The increase in natural gas prices was caused primarily by increased heating demand in the mid-west and northeast, those regions experiencing unseasonably cold weather during the latter part of the year. Higher natural gas storage levels in California resulted in California hub prices that were lower than the national benchmark prices at Henry Hub for the last nine months of the year.

Figure E.6. 2002 Average Monthly Natural Gas Prices



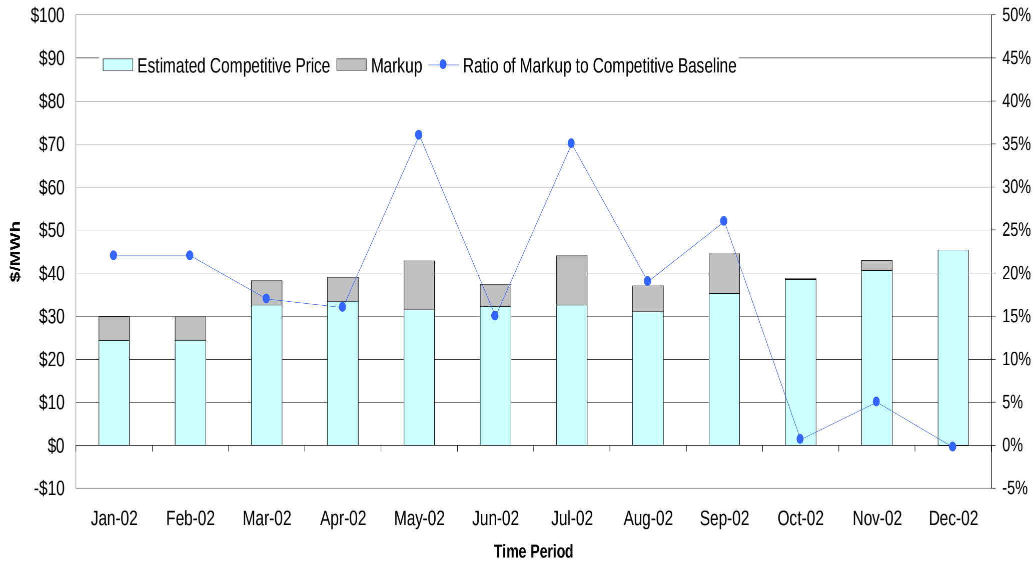
Gas prices increased steadily during 2002 leading to higher wholesale electric prices

Market Competitiveness

The short-term energy[5] market in California produced near competitive results throughout 2002 with the greatest mark-ups above competitive baseline levels occurring during peak summer periods. The ISO measures market competitiveness using the price-to-cost markup index, which is defined as the percentage difference between the actual price and an estimated competitive baseline price for each hour. For the year, the average price-to-cost mark-up above a competitive baseline level was 17 percent, significantly lower than markups observed during 2000 and 2001. Markups in the summer months approached 35 percent above the competitive baseline level, however, this was offset by minimal markups in the fall. Figure E.7 below shows the average monthly markup for short-term energy during the year.

[5] Short-term energy includes day-ahead, hour-ahead, and real-time energy.

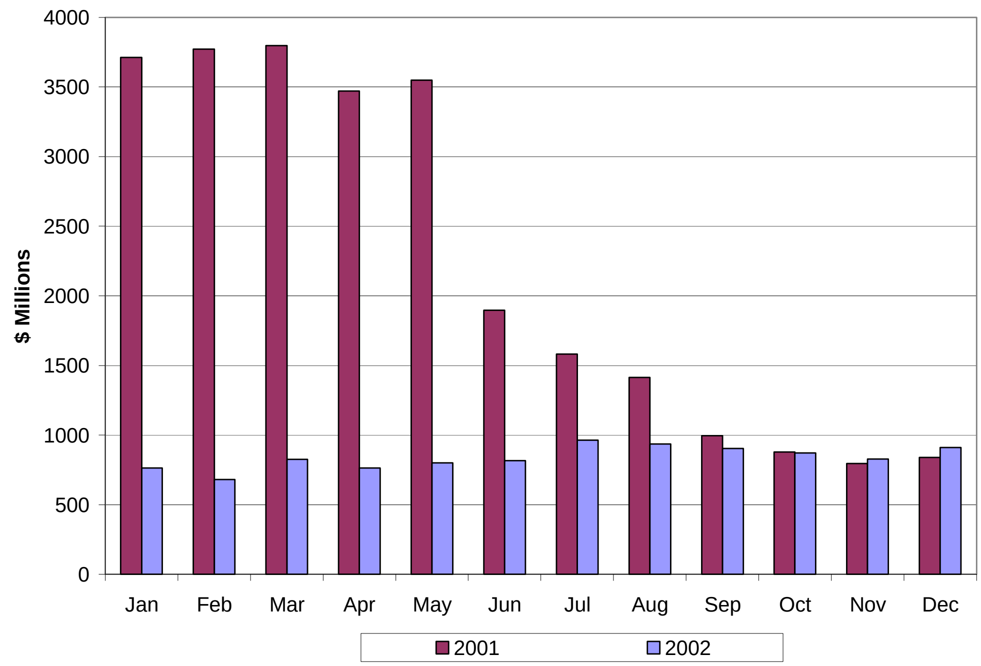
Figure E.7. Price-to-Cost Markup in Short-Term Energy in 2002



Favorable market conditions mitigated suppliers' ability to exercise levels of market power seen in 2000 and 2001, even during peak summer months

More competitive conditions contributed significantly to lower total wholesale energy market costs in 2002 compared to 2001 cost levels. Figure E.8 below compares 2002 total monthly costs of energy and ancillary services to 2001 levels.

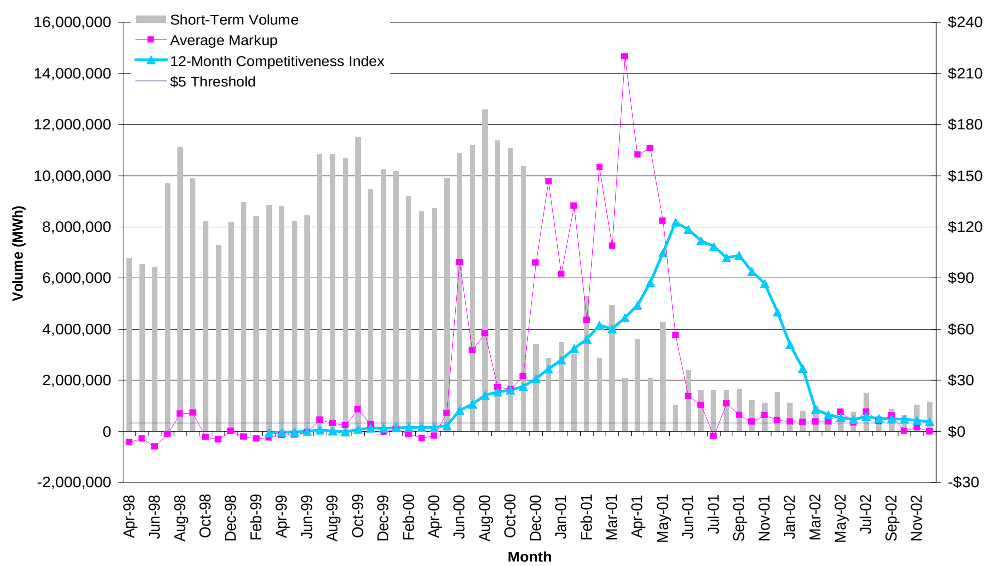
Figure E.8. Total Costs of Energy and Ancillary Services



Total wholesale costs of energy and ancillary services decreased significantly in 2002 from 2001 levels due to improved market fundamentals

Another index the ISO uses to evaluate market competitiveness is the 12-month competitiveness index. The ISO developed the index to measure market outcomes over a long period of time and to compare them to expected competitive market outcomes. The index is a volume-weighted twelve-month rolling average of the short-term energy markup above estimated competitive baseline cost. The index provides a benchmark to measure the degree of market power exercised in the California short-term energy market during a 12-month period. The ISO's Department of Market Analysis assumes that the market is workably competitive when the index is approximately $5/MWh or below. The index, which crossed the $5 threshold in May 2000 and remained very high during the California energy crisis, served as a barometer for uncompetitive market conditions. The index moved back into the competitive range in May 2002 and remained in that range for the remainder of the year. This indicates that the short-term energy market in California has stabilized and produced fairly competitive results during the past year. Figure E.9 below shows the index from April 1998 through December 2002.

Figure E.9. Twelve-Month Competitiveness Index Through December 2002

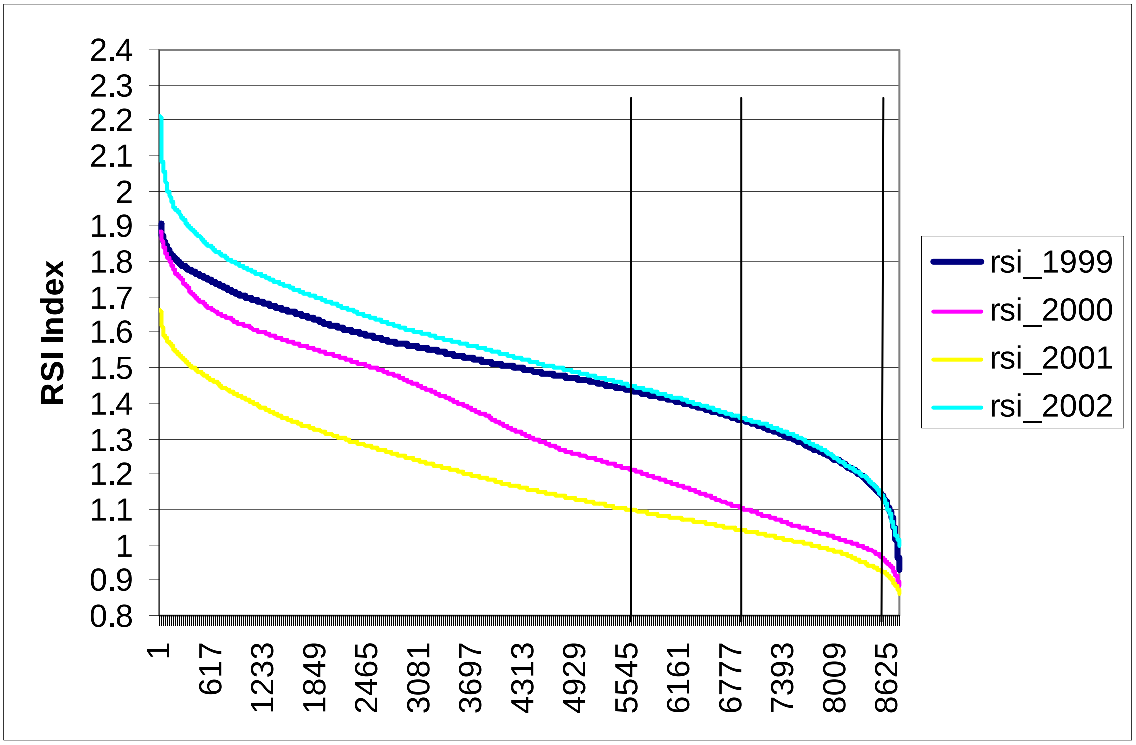


Long-term market outcomes returned to workably competitive levels in 2002

The ISO also has defined a measure of the degree to which suppliers are pivotal in setting market prices, called the residual supplier index (RSI). Specifically, the RSI measures the degree that the largest supplier is "pivotal" in meeting demand. The largest supplier is pivotal if the total demand cannot be met absent the supplier's capacity and such a case would translate to an RSI value less than 1. When the largest suppliers are pivotal (an RSI value less than 1), they are capable of exercising market power. An RSI value of 1.1 provides for some degree of tacit collusion, which may exist in the market.

Figure E.10 below compares the RSI duration curves from 1999 to 2002. The RSI indices were significantly higher in 2002 than those in 2001 and 2000, but were comparable to those in 1999. In 2002, the RSI indexes were less than 1.1 in less than 1.5 percent of the hours (only 135 hours out of 8760). In contrast, there were 3,215 hours or 37 percent of the hours in 2001 where the RSI was less than 1.1. These results indicate that the California markets in 2002 were significantly more competitive than in 2001 and 2000. The RSI indices are consistent with the observed market outcomes and price-cost markups we observed in 2002. As mentioned above, the improvements in market competitiveness in 2002 can be associated with many factors, including a significant volume of forward contracts, additional capacity added into the system, moderate demand, as well as mitigation procedures implemented by the FERC.

Figure E.10. Residual Supplier Index 1999-2002[6]



RSI provides additional verification of the return to more healthy market conditions. Large suppliers were pivotal in less than 1.5 percent of the hours in 2002 compared to 37 percent of the hours in 2001.

Revenue Adequacy of New Generation

Another benchmark the ISO proposed for assessing the health of markets is the degree to which prices support the cost of investment in new supply needed to meet growing demand and replace existing capacity that is no longer economical to operate. In calculating this benchmark, the ISO examines the economics of investment in new supply capacity given observed prices in California's wholesale energy markets.

The ISO's analysis is based on a typical 500 MW combined cycle unit, since the majority of projects proposed in California and the Western Electricity

6 In this RSI computation, the demand is computed as the sum of metered-generation, regulation-up, and operating reserve requirement; metered-imports are not included.

Coordinating Council (WECC) area during the last three years have been gas-fired combined cycle plants of approximately this size. In practice, new investment would typically be supported, at least in part, by a long-term contract rather than entirely by real-time energy and ancillary service capacity sales in the ISO's markets. However, conservatively, the ISO calculated revenues from a hypothetical unit operating solely in the real-time market to provide a benchmark for prices in the ISO's markets.

Results of this analysis (Table E.2 below) show that during 2002, real time energy and ancillary service revenues in California were $72 to $77/kW/yr (or $72,000 to $77,000/MW/yr) which is within the lower range that would be needed to support new investment in baseload supply ($70 to $100/kW/yr).[7] These results serve to highlight the key role that forward contracts must play in stimulating investment in new supply with the current structure of California's wholesale market.

Table E.2. Financial Analysis of New Combined Cycle Unit

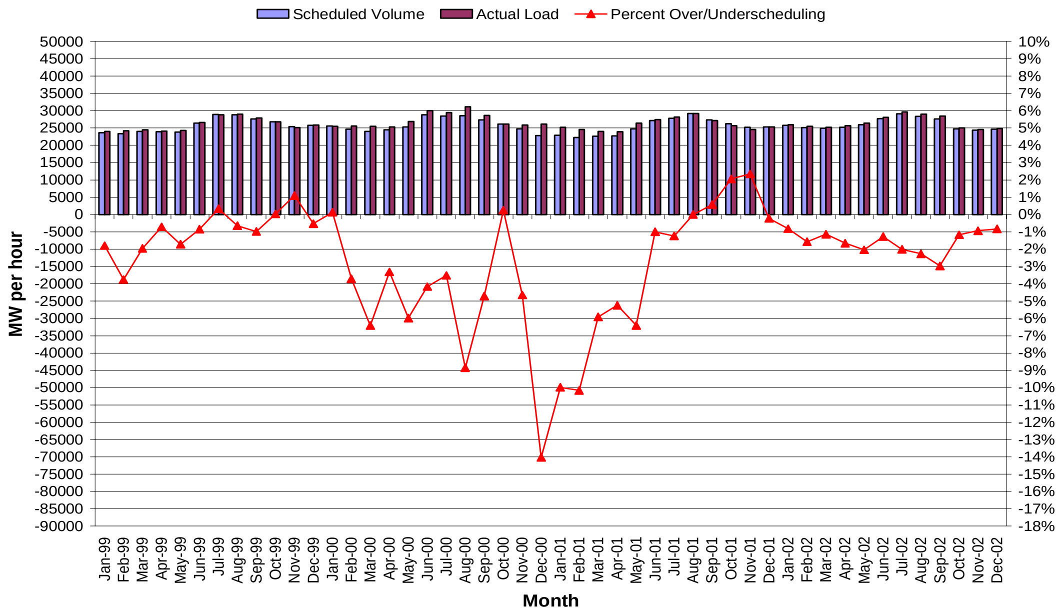
	NP15	SP15
Load Factor	61%	62%
Average Energy Revenue ($/MWh)	$ 40	$ 41
Average Operating Cost ($/MWh)	$ 26	$ 26
Net Energy Revenue ($ /kW/yr)	$ 66	$ 71
A/S Capacity Revenue ($/kW/yr)	$ 6	$ 6
Total Net Revenue ($/kW/yr)	$ 72	$ 77

Imbalance Energy Market Performance

By mid-2001, the ISO's real-time market returned to its intended role as a market for small quantities (within 5 percent of scheduled load) of energy needed to balance forward schedules with actual load. The market size remained stable through 2002 where balancing energy was only a small fraction of the ISO system energy requirements. This resulted in real-time market costs decreasing 98 percent from 2001 levels to $99 million. Underscheduling, which had been a problem in 2000 and 2001, improved significantly averaging only 2 percent of load in 2002. Figure E.11 below illustrates the average monthly scheduling deviations from 1999 through 2002.

[7] Previous analyses by the ISO indicates that the revenue requirements for most new combined cycle projects in 2000 was between $70-$90/kW/yr. The CEC's 2002-2012 Electricity Outlook Report (February 2002) estimates that the revenue requirement for most new combined cycle projects is between $85-$100/kW/yr. (p.32)

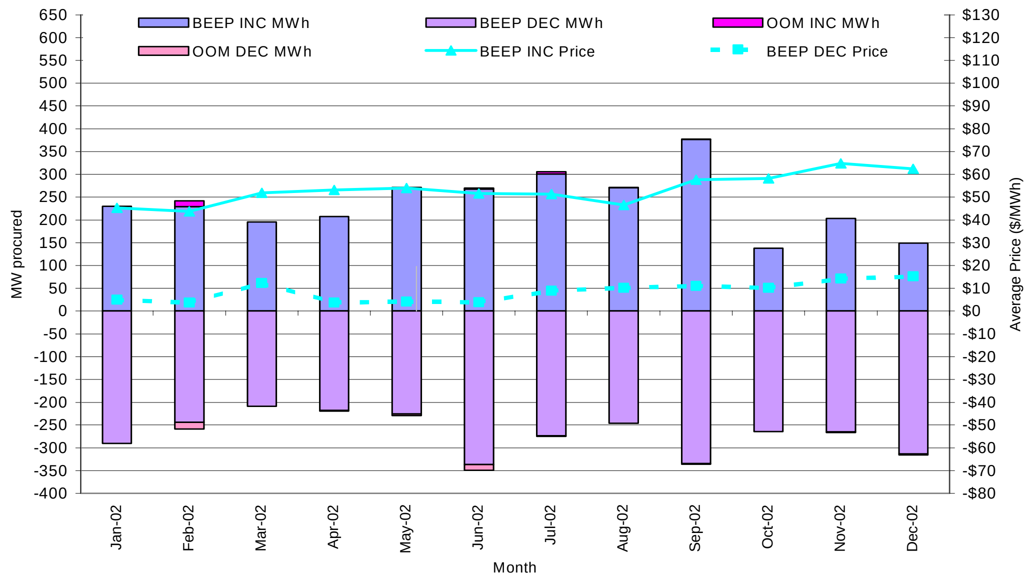
Figure E.11. Monthly Scheduling Deviations



Average monthly load was within 3 percent of scheduled load throughout 2002

Vastly improved scheduling resulted in very low real-time imbalance energy requirements. In fact, ISO operators called more on decremental energy than on incremental energy as more energy than actual load was scheduled during the year. Low real-time volumes contributed significantly to the stable imbalance energy prices throughout 2002. Average incremental and decremental prices increased at the end of the year due to the increase in natural gas prices. Figure E.12 below illustrates the monthly average real-time prices and volumes during 2002.

Figure E.12. 2002 Monthly Average Real-Time Prices and Volumes



Stable prices and low real-time volumes persisted throughout 2002. ISO volume to decrement generation was higher than volumes of increment generation to balance system needs.

Market Power Mitigation Measures

The ISO is currently analyzing the new market power mitigation measures that it implemented on October 30, 2002 to determine their effectiveness in mitigating the exercise of market power. Each of these measures are discussed briefly below.

- **Automatic Mitigation Procedure (AMP)**[8]

At the present time, it is difficult to determine with certainty the effectiveness of AMP mitigation. Fundamental market demand and supply conditions have been favorable since its implementation. As a result of generous AMP conduct threshold levels, the AMP conduct test has rarely been violated and the AMP impact test has yet to be violated, resulting in no mitigation being applied. The effectiveness of AMP mitigation will become apparent only if market conditions become less favorable and suppliers' ability to exercise market power increases.

8 See Chapter 1 for a detailed outline of the AMP procedure

Mild temperatures in the western region have kept loads at moderate levels. Moderate loads, combined with adequate supply and positive trends in scheduling deviations, have resulted in fundamental market conditions that limited suppliers' ability to exercise market power. A small number of units have consistently failed the conduct test but they were seldom or never dispatched by ISO due to ramp rate limitations. Price spikes above $100/MWh have occurred in part because AMP conduct test thresholds are sufficiently generous that price setters have ample latitude to bid successfully at prices well above their reference levels and marginal costs.

The future may provide a clearer picture of the mitigating efficacy of AMP. Natural gas and electricity hub prices recently spiked causing a series of price spikes in the ISO real-time market. A low snow pack in the Northwest may reduce hydro-based imports into California in the spring and summer of 2003 from 2002 levels. If hydro conditions do not improve, supply conditions this summer could be tight, making the market generally less competitive and creating conditions that may provide a more appropriate test of the effectiveness of AMP as a market power mitigation tool.

Must-Offer

All non-hydroelectric generating units in the state of California, including units that have executed a Participating Generator Agreement (PGA) and all non-public utility sellers that own or control generators in California and participate in ISO markets or use the ISO controlled grid, are required to bid all available capacity into the ISO's real-time market in all hours (the "Must-Offer Obligation"). This means if capacity is available and has not been already scheduled in a bilateral contract, it has an obligation to offer it into the ISO real-time market. The capacity is paid to start-up and any minimum load costs incurred. For long-start-time units, the obligation is extended into the day-ahead time frame to enable the ISO to issue start-up instructions (or deny shut-down requests) for units the ISO expects to need to dispatch the next day. The ISO has implemented the must-offer requirement by granting must-offer waivers for uneconomic generation units, i.e., units that cannot cover their costs given the current market conditions. Figure E.3 on page 4 shows the monthly average must-offer waivers for 2002.

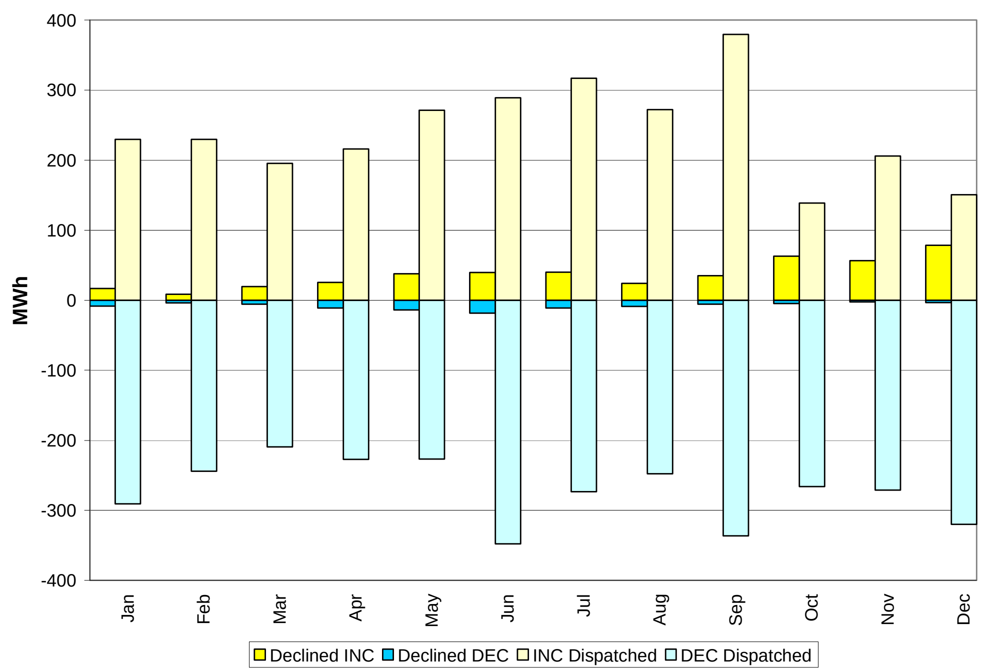
Although the must-offer requirement mandates that all available generation in the California ISO system must be offered to the imbalance energy market, in 2002 the ISO experienced significant non-compliance with dispatch instructions directed at such available generation.[9] During the course of the year, suppliers declined nearly 15 percent of the incremental energy dispatched through ISO dispatch instructions. The average monthly rate of declined energy ranged from a low of just over 4 percent in February to a high of nearly 52 percent in December. Declined dispatch instructions create considerable real-time operational difficulties for ISO operators who must dispatch significantly more imbalance energy, including those dispatches that are declined, than what is actually needed based on the bids available to the ISO. As a result, declined dispatch instructions can significantly increase real-time

[9] Instances of non-compliance with the must-offer obligation are reported to FERC.

energy prices, as operators have to reach deeper into the merit order stack and dispatch higher cost resources to meet imbalance energy needs that could have been met by a more efficient supplier that declined a dispatch instruction.

Despite the fact that the ISO tariff currently requires that dispatch instructions must be followed short of causing risk of equipment damage or health and human safety, currently there are no penalties or disincentives in place for declining ISO dispatch instructions. The ISO regularly shares information regarding declined dispatch instructions with the FERC Office of Market Oversight and Investigation for further review and potential enforcement of the must offer obligation. To provide market participants with direct incentives to comply with ISO dispatch instructions, the ISO will implement some uninstructed deviation penalties for scheduling coordinators who decline or fail to follow dispatch instructions as part of the MD02 Phase 1B market design elements. If a resource is physically unable to follow a dispatch instruction, this information must be supplied to the ISO, otherwise the ISO must assume all resources under the must-offer obligation are available and subject to uninstructed deviation penalties. Figure E.13 below shows the average monthly decline rates for incremental and decremental energy dispatches in 2002.

Figure E.13. 2002 Average Dispatch Instruction Decline Rates



Although the must-offer requirement was in place, suppliers declined a significant portion of ISO dispatch instructions, particularly in the latter part of the year

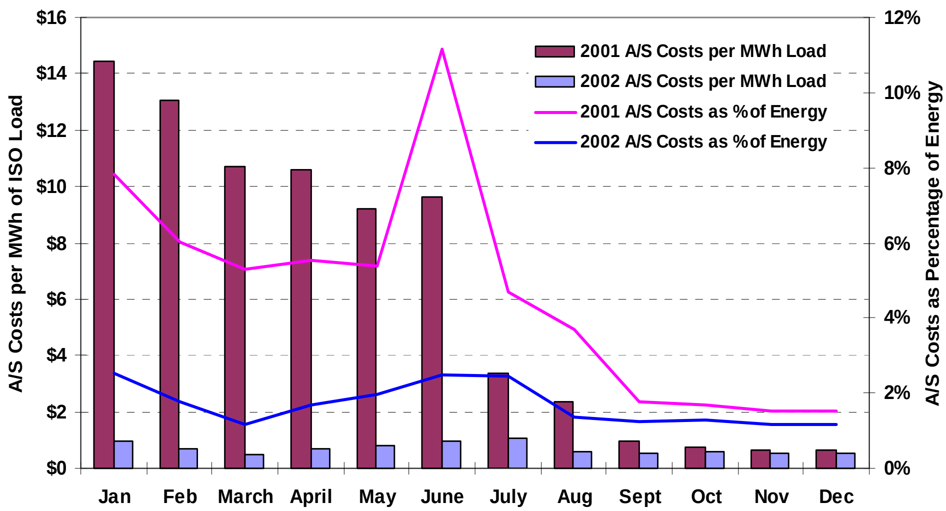
- **Zero Bid Requirement for Suppliers Outside of the ISO Control Area**

The ISO has a significant concern that the current real-time market structure ordered by FERC places a significant price risk on suppliers located outside of the ISO system that choose to participate in the real-time market. Since California relies extensively on imported energy to serve its load, especially during the summer, it is extremely important that the ISO have market rules in place that encourage the participation of out-of-state suppliers in the ISO's markets. If marketers seeking to import energy into the ISO Control Area are required to bid $0/MWh, they have no assurance that the price they will receive will cover their marginal costs. Therefore, they risk losing money on transactions in the ISO's markets. The current zero-bid requirement creates significant uncertainty about what price an importer will receive for its energy. This discourages out-of-state suppliers from offering supplies to the ISO imbalance energy market.

Ancillary Services Market Performance

The performance of the ISO ancillary service markets also improved dramatically in 2002 compared to 2001, as shown in Figure E.14 below. The ancillary service markets functioned in an efficient, competitive manner for the majority of hours during the year. The cost of ancillary services in 2002 averaged about $0.7/MWh of total system load served, much less than the $6.4/MWh in 2001. Similarly, in 2002, ancillary services were only 1.7 percent of total market energy costs, a drop of nearly 70 percent from 2001, when ancillary service costs averaged approximately 5.3 percent of total market costs. We attribute the reduction in ancillary service costs to a variety of factors including fewer hours of super peak loads and, more importantly, a variety of modifications the ISO made in ancillary service requirements and procurement practices.

Figure E.14. Ancillary Service Costs in 2001 and 2002



2002 ancillary services costs were 88 percent less than 2001 levels.

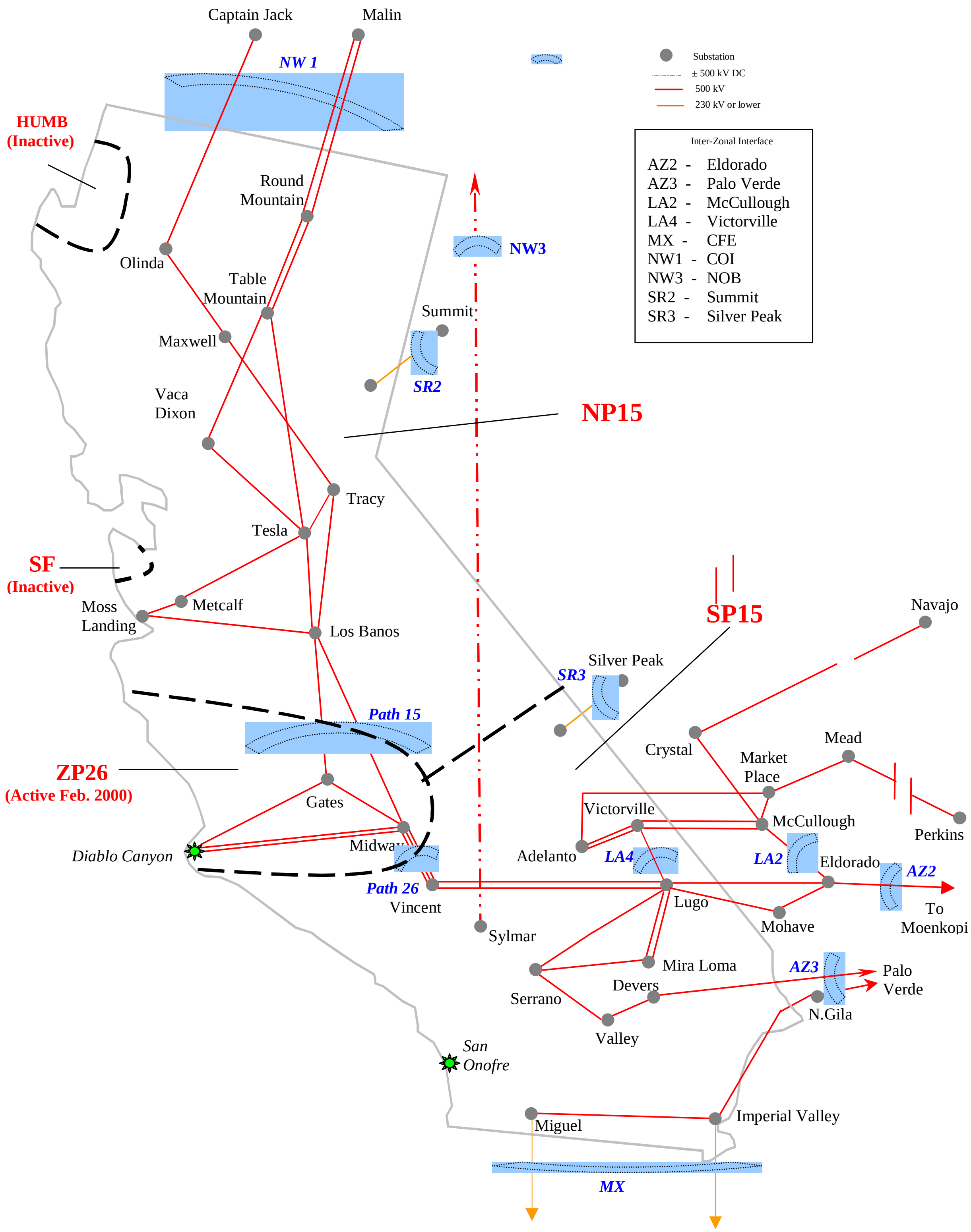
The largest single factor causing the decrease in ancillary service costs was the significant decrease in the amount of ancillary service capacity required and purchased by the ISO. That amount was reduced from 13 percent of total system load in 2001 to 10 percent in 2002. In particular, the amount of regulation service required was reduced on July 2, 2002 due to the ISO's adoption of a new regulation requirement methodology. The new methodology identifies actual regulation used over a historical period and uses it as the benchmark for procurements. This new methodology contributed to a reduction in regulation cost in the second half of 2002 to $48 million, almost 30 percent less than the $68 million cost for the first half of the year. Significant 2002 regulation cost reduction was also due to an increase in self-provision that increased 41 and 50 percent for upward and downward regulation, respectively, from 2001 levels. Finally, ancillary service costs were less due to the continued decrease in the quantity of replacement reserves as a result of FERC's April 26, 2001 Order containing the must-offer provisions. This Order ensures, to some extent, that capacities not bid into the day-ahead market and hour-ahead markets, will be available in real-time. Therefore, in August 2002, the ISO removed its minimum procurement criteria for replacement reserves and substituted payment of start-up and minimum load costs to resources with the must offer obligation. The ISO also implemented other ancillary service market improvements in 2002 that can be expected to improve the future performance of the ancillary services markets, particularly under high load conditions.

Dramatically improved supply and demand conditions in the ancillary service markets in 2002 also resulted in more competitive and stabilized markets and significant ancillary service cost reductions. Bid sufficiency increased to an average of 6,838 MW/hour in 2002, compared to only 6,343 MW/hour in 2001. More importantly, more low-priced ancillary service bids were offered to the markets in 2002 than in 2001. For instance, ancillary service bids below $10/MW accounted for 56.5 percent of the total bids in 2002 compared to only 38.5 percent in 2001. Improved bid sufficiency and bid prices resulted in market clearing prices and costs of ancillary services that were dramatically lower in 2002 than 2001. Overall average ancillary service prices were $7.1/MW in 2002, a fraction of the $45.5/MW in 2001.

Inter-zonal Congestion Management Market

During 2002, congestion occurred primarily on six branch groups shown in Figure E.15. Of the major paths between zones in the ISO system, Path 15, NOB (import), COI (import), Palo Verde (import), Path 26 (north to south), and McCullough (export) experienced the most congestion in 2002. With the exception of Path 15, each of the paths listed above were more congested in 2002 than in 2001. Another notable observation is that the congestion pattern on NOB and COI was reversed in 2002 compared to 2001. During 2002, these major paths connecting California to the Northwest were primarily congested in the import direction in 2002, while they were more frequently congested in the export direction in 2001. In total, export congestion was very infrequent during the year. Figure E.15 below shows the main branch groups in the ISO grid.

Figure E.15. Congestion Zones and Main Inter-zonal Pathways in the ISO Grid



Congestion revenues and average usage charges on the major branch groups decreased significantly in 2002 compared to 2001 levels. Specifically, congestion revenues decreased from $108 million in 2001 to $42 million in 2002. Out of the $42 million in 2002 congestion revenues, about $30 million occurred in the import direction. Congestion revenue on COI and Palo Verde in the import direction accounted for more than half of the total congestion revenue of all branch groups. For 2002, import congestion on COI occurred in approximately 18 percent of the hours in the day-ahead market with an average congestion charge of about $14/MW. On Palo Verde, import congestion in the day-ahead market occurred in approximately 5 percent of the hours at an average congestion charge of about $10/MW.

Figure E.16 below compares monthly congestion costs in 2001 and 2002.

Figure E.16. Monthly Congestion Costs 2001 and 2002

Monthly 2002 Congestion costs were either much lower or similar to 2001 levels, with the exception of June and July where deratings on key transmission paths between the Northwest and California resulted in higher congestion costs.

The efficiency and competitiveness of the current design of ISO's congestion management markets has been problematic due to the lack of adequate adjustment bids to manage congestion. To mitigate congestion, the current market rules require the ISO to adjust each scheduling coordinator's (SC's) schedule in a balanced manner. The ISO can do this only if SCs submit adjustment bids on both sides of a congested interface so that an incremental bid on one side of the interface can be matched with an equal-size decremental bid on the other side within the same SC's portfolio. When enough matched bids are submitted to fully mitigate congestion, there is bid sufficiency. Conversely, when the adjustment bid pairs are exhausted and there is not bid sufficiency, the ISO must then use pro rata schedule curtailments. The adequacy of adjustment bids improved significantly in 2002 from 2001. For instance, in 2002 the ISO managed 98 percent of congestion in the day-ahead market using economic adjustment bids compared to only 74 percent in 2001.

The ISO has concerns about the treatment of existing transmission contract (ETC) rights from a market efficiency perspective. Under the current market rules, ETC holders have the full amount of their ETC capacity reserved in the day-ahead and hour-ahead markets, regardless of whether they actually use it. The unused capacity on ISO controlled grid facilities is only released 20 minutes prior to real-time. Often, at that time, the ISO cannot efficiently utilize this capacity due to various factors, such as ramping limits of some generation facilities. This unused capacity can cause day-ahead phantom congestion. The ISO's inability to use the potentially available capacity can have several adverse market consequences. The presence of phantom congestion often undermines the price consistency between the forward and real-time markets and has a negative effect on market operation. Phantom congestion compromises market efficiency, results in underutilization of valuable transmission system capacity, and potentially increases the total costs to final consumers. Our analysis shows that an earlier release of the unscheduled ETC capacity would significantly reduce the congestion frequencies for all of the major paths.

The ISO is comprehensively redesigning its congestion management system to address some of these operational problems and market inefficiencies caused by the current system. The ISO hopes to have its redesigned congestion management system in place in 2004.

Firm Transmission Rights (FTR) Market Performance

FTRs provide benefits to the holders in that they can serve as insurance to hedge against high congestion prices. In addition, FTR holders are also entitled to scheduling priority in the day-ahead market. The ISO auctions FTRs for the period beginning on April 1 and terminating on March 31 the following year. For the past two FTR cycles, total FTR revenue exceeded the respective auction prices on only a few paths. For the 2002 cycle, total annual FTR revenue was lower than the FTR auction price for all paths. We conclude from this observation that most FTR holders did not directly profit from investing in the FTR market.

FTR scheduling percentage was low during the 2002 FTR cycle with only 18 percent of the total FTRs scheduled on average in the day-ahead market. However, on some paths, FTRs were used to establish the scheduling priority in the day-ahead market.

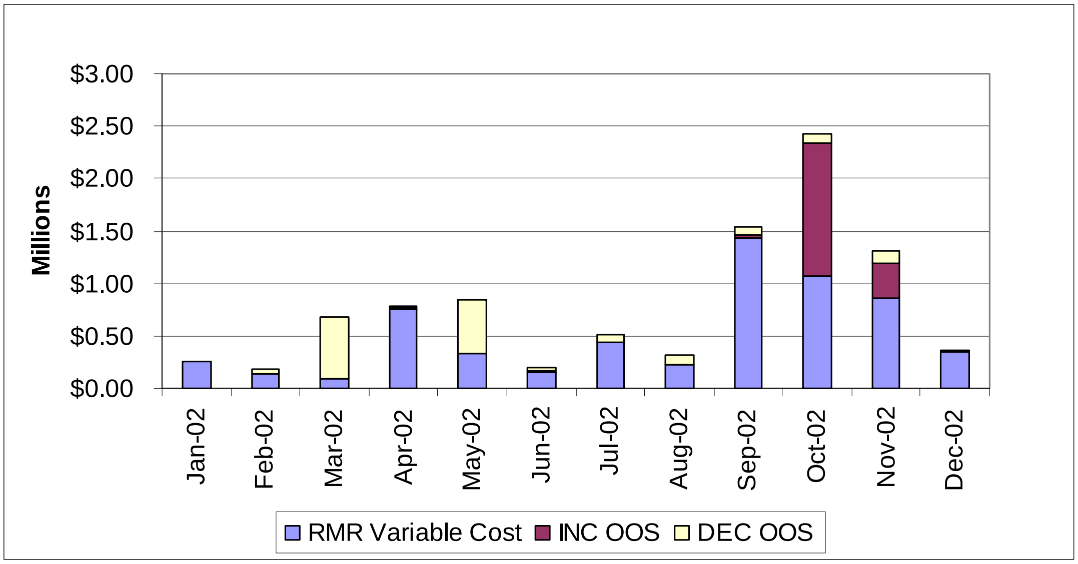
Successful bidders in the FTR primary auctions are allowed to conduct further FTR trades in the secondary market. FTR trades in the secondary market have been minimal in the past two FTR cycles. Possibly, secondary market activity has been minimal due to the fact that FTR revenues only exceeded their prices in a few paths in 2001 and most of the investments in FTRs did not generate positive financial profits. Therefore, there may have been little incentive for market participants to purchase additional FTRs in the secondary market.

Intra-zonal or Within Zone Congestion

Intra-zonal congestion refers to congestion on transmission paths within the ISO defined congestion zones (current active congestion zones include NP15, SP15, and ZP26). Though intra-zonal congestion may have many underlying causes, the resultant problem is that there is either insufficient or excess generation in a local area. In both cases, the absence of sufficient transmission access to or from that area means that the ISO has to solve the problem locally, either by incrementing generation within the area if there is not enough, or by decrementing it if there is too much. Historically, the ISO's preferred long-term method for dealing with intra-zonal congestion has been reliability-must-run (RMR) contracts. RMR units have been dispatched where available. However, this has often been insufficient to deal with all intra-zonal congestion and other units within the localized area have had to be dispatched out-of-sequence (OOS). OOS dispatches are so called because they require the ISO to bypass lower priced real-time market bids in order to find a unit whose grid location enables it to mitigate a particular intra-zonal congestion problem.

Levels of intra-zonal congestion within the ISO system have increased significantly during the past two years due to the large amount of new generation additions within the system. The current market design is prohibitive in allowing ISO operators to address intra-zonal congestion prior to real-time. To deal with this limitation and the increased reliability risk to real-time intra-zonal congestion, operators have resorted to requesting some voluntary scheduling limits for generators within locally congested areas. Fortunately, to date such voluntary measures have maintained reliability thus far; however, increased frequency of this problem could cause significant operational problems. Figure E.17 below shows monthly intra-zonal congestion costs associated with OOS and RMR dispatches. As shown, there was a substantial increase in intra-zonal congestion costs in October and November. This increase was due to a single incident involving a series of transmission line outages and contemporaneous generator outages. The events surrounding these occurrences are currently under investigation. Significantly, this chart does not include the costs associated with the voluntary limitation of generation from new efficient generators which, in turn, has to be provided by less efficient generators to mitigate localized transmission constraints. The chart also does not include the fixed cost of reliability must run contracts which was approximately $263 million in 2002.

Figure E.17. 2002 Intra-zonal Congestion Costs by Month



Intra-zonal congestion became more of a problem due to new generation—ISO operators resorted to voluntary scheduling limitations to help curb intra-zonal costs and real-time operation difficulties

Critical Market Issues and Potential Solutions

The ISO continued to face a number of critical market issues during 2002, which are being addressed in the ISO's market redesign effort (MD02). The following are some of the most critical:

- Lack of an effective local market power mitigation mechanism;
- Lack of forward market mechanism to resolve intra-zonal congestion;
- Lack of a day-ahead unit commitment mechanism; and
- Use of pro rata curtailment instead of effectiveness factors.

We discuss these issues and potential solutions briefly below:

Lack of an effective local market power mitigation mechanism

Although the ISO has repeatedly requested FERC for more authority to address local market power, the ISO continues to operate without an effective local market power mitigation mechanism. Because the ISO does not have the authority to mitigate the bids of market participants with local market power (outside of the current limited measures provided by the AMP conduct test) intra-zonal congestion costs have been much more frequent and costly than would be the case under an effective local market power mitigation mechanism.

Lack of forward market mechanism to resolve intra-zonal congestion

Since it began operation, the ISO has been managing intra-zonal congestion in real-time. Due to the non-competitive nature of the intra-zonal congestion market, its resolution in real-time has been a problem and prone to the exercise of local market power. Moreover, in the absence of forward market intra-zonal congestion management, since forward market schedules are accepted without checking for local transmission feasibility, the so-called "DEC game" continues in real-time. The DEC game refers to the situation where a generator submits an infeasible schedule that clears the day-ahead market, but must be decremented in real-time to accommodate locational transmission constraints (intra-zonal congestion). Suppliers can submit a very low (or even negatively-priced) DEC bid, have the ISO satisfy its day-ahead obligation, save on its fuel and other variable costs by not generating in real-time, and even pocket additional payment from the ISO for not generating.

Faced with this problem, the ISO, starting in 1999, began requesting FERC to grant it local market power mitigation measures to address intra-zonal congestion. FERC conditioned granting such measures on the redesign of ISO's congestion management market, including moving to a "nodal" framework.

In its MD02 design effort, the ISO has taken a two-pronged approach to resolve the problem. First, "intra-zonal" congestion will be addressed in the day-ahead market simultaneously with "inter-zonal" congestion (in fact, there is no longer a distinction between the two, except that the former is generally not amenable to a competitive market, whereas the latter is). Second, to resolve congestion on the paths that are not amenable to a competitive market, the ISO envisions using bid mitigation measures to curb the exercise of local market power.

In the interim, the intra-zonal congestion problem is being addressed marginally, and only in the incremental direction, through a combination of RMR contracts and conduct bid mitigation. The latter has not proven to be very effective. Moreover, FERC has not granted authority to the ISO to implement mitigation measures to address the DEC game (except for a bid floor of -$30/MWh that leaves significant room to exercise market power).

Lack of a day-ahead unit commitment mechanism

The initial design of the California market was based on decentralized unit commitment. This design is still in place and will continue until mid-2004 when Phase 2 of MD02 is expected to be operational. Lacking this centralized unit commitment service means that the forward generating unit schedules that emerge from the congestion management process may not be feasible with respect to inter-temporal physical constraints of generation units. Such constraints include start-up time, minimum run time and down time, inter-hour ramp rates, and the like. Moreover, the single-part bid system that fits in with decentralized unit commitment must internalize start-up and minimum load costs and constraints into an hourly energy bid price. A unit commitment service would provide the possibility to incorporate all these technical constraints and economic considerations explicitly.

Lack of a unit commitment service in the day-ahead market, combined with the demise of the California Power Exchange (in January 2001), has caused a serious reduction of adjustment bids for congestion management. This was because the present congestion management process does not take into account generating units' inter-temporal constraints, and may accept adjustment bids that, although they maintain the SC's schedule balanced in each hour (under protection of the Market Separation Rule), may cause the overall schedule to become infeasible over the course of the day.

The MD02 design includes both a day-ahead unit commitment service (in fact, a Security-Constrained Unit Commitment, SCUC, service) and a residual unit commitment (RUC) process that would run after the day-ahead market to ensure adequate supply is on-line for system security and reliability.

In the interim, decentralized unit commitment prevails in the day-ahead, and the "Must Offer Waiver" process is in place after the day-ahead market until RUC is implemented.

Use of Pro rata curtailment

Under the existing congestion management scheme, when economic adjustment bids are exhausted, schedules are curtailed pro rata to manage congestion. The pro rata curtailment is in effect since present inter-zonal congestion management model has no way of capturing the differences in the effectiveness of the resources on each side of the congested path in mitigating congestion. However, these differences in effectiveness do appear in real-time. ISO operators must use their knowledge of the relative effectiveness of resources in real-time to address real-time congestion.

This issue is addressed in MD02 in both the forward market and in real-time by using a full network model that captures the relative effectiveness of resource schedule adjustments (in the forward market) and dispatch (in real-time) in alleviating congestion.

Conclusions

Although overall market performance improved in 2002 due to favorable supply and demand conditions, risks remain that could disrupt the stability that has characterized the markets during the past 18 months. The current market stability is due, in large part, to the significant market structure improvements that have occurred since the California electricity crisis in 2000 and 2001. Long-term contracts, despite the difficulty in managing the energy associated with them in real-time, and new power plants have helped to stabilize California's wholesale energy market. However, one of the largest remaining threats is local market power that has been exacerbated by the addition of new generation in areas within and external to the ISO system that lack adequate transmission infrastructure to accommodate all of the new generation. Under the current market structure, ISO operators must alleviate all localized congestion in real-time. This causes significant operational difficulties. The ISO is studying and has requested additional market rules including locational marginal pricing (LMP) and continues to press FERC for the authority to implement effective local market power mitigation mechanisms to address these problems.

New market rules, such as the must-offer requirement and other market power mitigation measures, have also helped to stabilize the market. However, these measures may not be adequate under more severe market conditions. For instance, although the must-offer requirement requires all available thermal generators within the ISO system to offer all of their available capacity, during 2002 approximately 15 percent of the energy dispatched by ISO operators was declined. This has led to an increase in real-time prices as well as significant real-time operational difficulties. The new mitigation measures put into place in October also have shown signs of being ineffective in mitigating all but the most egregious attempts to exercise market power. The generous conduct and impact test thresholds of the AMP mitigation scheme have not resulted in any bid mitigation since its implementation. This is despite the fact that the ISO real-time market experienced several price spikes during that period. The ISO is continuing to review the effectiveness of the current market power mitigation measures.

Although market performance has improved, there is still risk that a lack of clearly defined obligations for resource adequacy, more stringent regulatory restrictions on generation and transmission siting or operational constraints on emission and water use, or changes in supply and demand fundamentals could deteriorate to a point that would enable large suppliers to exercise market power. Several of the largest suppliers of natural gas-fired generation within the ISO system are not under long-term contract to serve load and continue to bid at excessive levels. Energy prices in the ISO's real time market remained moderate through 2002 despite this systematic bidding pattern. This was due to the consistently low demand for incremental energy in the ISO's real-time market throughout most of the year. However, the bidding practices observed during 2002 indicate that, should California experience less favorable supply and/or demand conditions, there is a risk that unscheduled load could be exposed to considerably higher real time prices than those observed in 2002. This would not have a disastrous effect due to the significant amount of energy now provided under long-term supply agreements. This greatly reduces load serving entities' exposure to high short-term and spot market electric prices, unlike 2000 and early 2001 when significant amounts of energy were purchased in the spot market. Therefore, devastating market outcomes such as occurred in 2000 and 2001 are unlikely to recur.

The main risk is in supply and demand conditions changing quickly. This can occur if there is no new supply assured beyond the next two years, and demand grows unexpectedly due to extreme weather conditions or recovery of the economy. California continues to rely on hydroelectric power. Precipitation levels have a direct impact on imports and in-state hydro generation and the amount of hydro energy available can vary significantly on a year-to-year basis. Long-term contracts remain a way of limiting exposure to spot market volatility and provide a steady revenue source for financing new generation additions. However, non-dispatchability and non-firm deliverability of resources procured through contracts continue to cause real-time operational problems.

The ISO continues to work with state agencies and market participants to develop the much-needed infrastructure for a sustained, well functioning, and competitive wholesale electric market in California in the coming years. Together, we are working to develop resource adequacy standards and procedures to ensure adequate generation supply and transmission infrastructure is available in the long run. To facilitate this, the ISO is actively analyzing new transmission investment projects and has developed a comprehensive method to evaluate the cost and benefit of future transmission projects. The ISO is also continuing to make a significant effort to develop and encourage effective mechanisms for price responsive demand. The future success of the California market will depend largely on how well these developments can create healthy infrastructure and an efficient market design bringing the benefits of competitive supply to all customers.