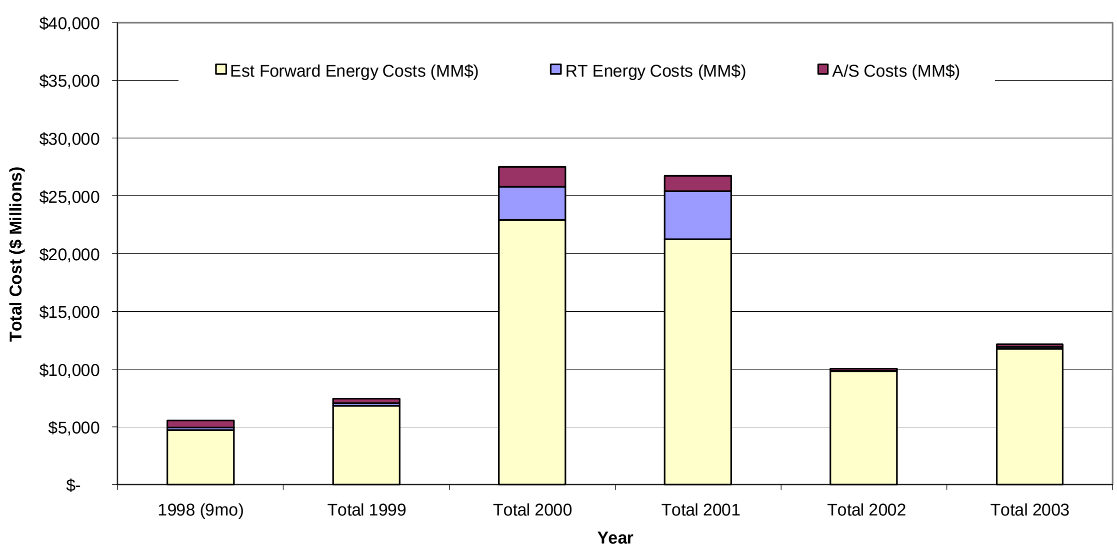
Executive Summary

The CAISO operates the majority of the high voltage transmission grid in California, manages reliability, and provides control area services through the operation of an imbalance energy market and reserve service markets for generation and transmission contingencies. Calendar year 2003 represents the second full year of stable market outcomes since the energy crisis that began in mid 2000. A review of market performance shows that 2003 resulted in the most competitive short-term energy market since the start of the restructured California electric market in 1998. Continued stability in the market is due to increased sources of supply from new generation, increased availability of existing generation, higher level of imports, and forward contracting of supply to meet a significant portion of the load serving entities' (LSE) load requirements. Supply was sufficient to meet growing electric demand as the California economic recovery picked up in the last half of 2003.

Despite the favorable market conditions, higher prices for natural gas resulted in total wholesale energy costs that were significantly greater than the preceding year. We estimate 2003 total wholesale energy and ancillary service costs to be $12.1 billion. This is nearly 20 percent higher than 2002 costs ($10.1 billion). The total wholesale energy cost to serve load represents the sum of: utility owned generation production costs; bilateral contract purchase costs estimated at day-ahead prices; ancillary services costs; and imbalance energy costs. Figure E.1 compares the wholesale energy and ancillary service costs from 1998 through 2003.

Figure E.1 1998 through 2003 Wholesale Energy Cost Components[1]

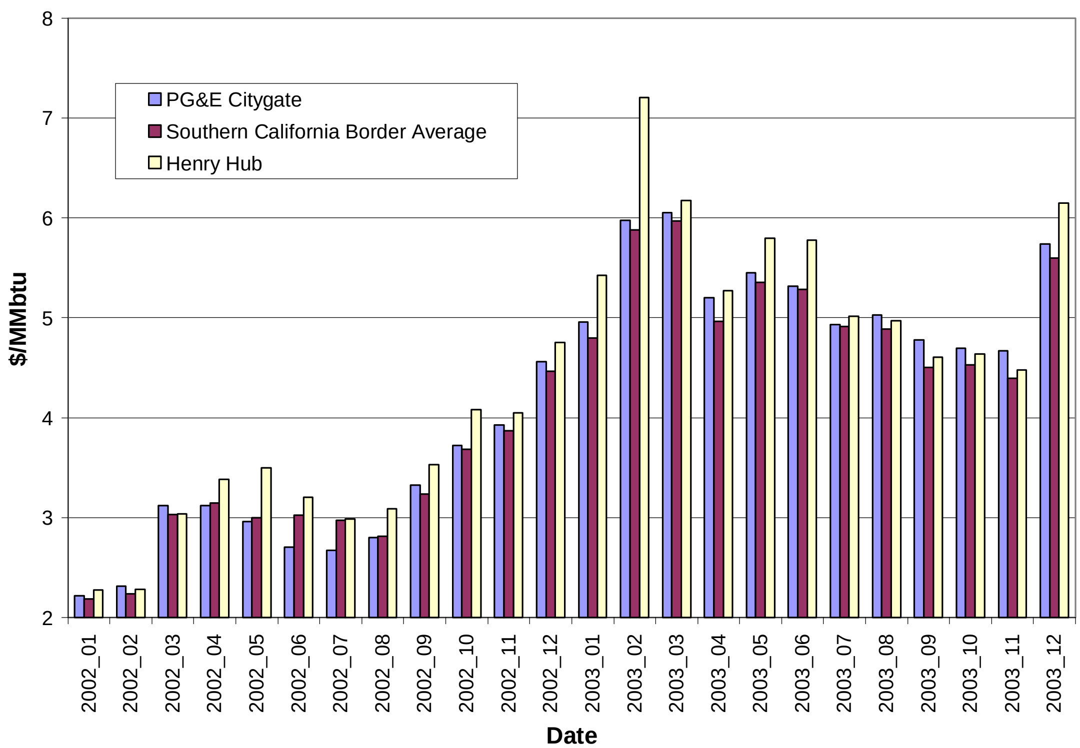


Markets have stabilized, however, total wholesale energy costs increased 20 percent in 2003 compared to 2002 due to higher natural gas prices.

[1] See Chapter 2, Section 2.2.1 for more detail on how these costs were calculated.

The increase in costs is primarily due to the increased cost of natural gas. The average annual cost of natural gas at California delivery points increased 64 percent in 2003 compared to 2002. Natural gas prices spiked in late February and early March as persistent cold weather in the northeast portion of the country depleted storage levels. This increased demand, resulting from both having to replenish depleted inventories and a recovering economy, maintained prices higher than 2002 levels for the remainder of the year. California natural gas prices remained below national prices throughout the year. Regional western trading hub forward electric prices closely tracked natural gas prices. Figure E.2 shows monthly average natural gas prices in 2002 and 2003.

Figure E.2 2002 and 2003 Monthly Average Natural Gas Prices[2]



Average annual natural gas costs increased 64 percent over 2002 levels due to depleted storage levels and increased demand in the Northeast. California border prices remained below the national average.

[2] Natural gas prices provided by Natural Gas Intelligence, http://intelligencepress.com.

Although abundant supplies of energy to serve demand resulted in a competitive and well-performing wholesale electric energy market, the CAISO experienced significant localized congestion problems in 2003. Intrazonal (within–zone) congestion was a significant market and operational problem for the CAISO in 2003. The insufficiency of ancillary service bids was another problem. Although there was ample physical capacity to meet load and reserve requirements throughout the year, at times there was not enough reserve capacity bid into the ancillary services markets to satisfy the CAISO's reserve requirements. This was caused by the significant amount of generation capacity under RMR Condition 1 contracts that switched to RMR Condition 2 contracts which prohibits them from participating in the ancillary service markets and units denied waivers pursuant to the must-offer obligation which would lose their start-up and minimum load cost guarantee if they sold or self provided ancillary services, an outcome that creates disincentives for bidding into the ancillary services markets. These problems are being addressed through market rule changes.

Market Rule Changes in 2003

The CAISO continues to move forward with its MD02 market redesign effort. Phase 1A, which included payments for must offer waiver denials and new market power mitigation measures was implemented on October 30, 2002. Phase 1B, which includes security constrained economic dispatch in real-time, accommodation for multiple ramp rates and uninstructed deviation penalties is scheduled to be implemented in late 2004. A day ahead market (for energy, ancillary services, and congestion management) and locational marginal pricing will follow. Significant market rule changes that impacted the markets in 2003 markets included:

- **Market Power Mitigation Measures.** The CAISO began operating under the market power mitigation provisions of the FERC's July 17, 2002 Order on October 30, 2002. The new rules increased the damage control soft cap on market bid prices from $91.87 to $250/MWh and put an automatic bid mitigation procedure (AMP) in place, and extended an obligation for supply resources to offer all available capacity to the CAISO real-time energy market (Must Offer Obligation); and

- **Local Market Power Mitigation Measures.** FERC ordered that, where RMR resources are not available and bids must be taken out of merit order for the specific purpose of alleviating intrazonal congestion, the CAISO should apply an automated procedure with a $50/MWh threshold (incremental energy bid above the MCP) to mitigate the local market power. In July 2003, the CAISO filed a methodology for determining reference prices that would apply to decremental energy bids taken out of merit order. This mitigation procedure took effect on July 28, 2003. It has been used quite frequently in addressing intrazonal congestion problems in San Diego's service territory.

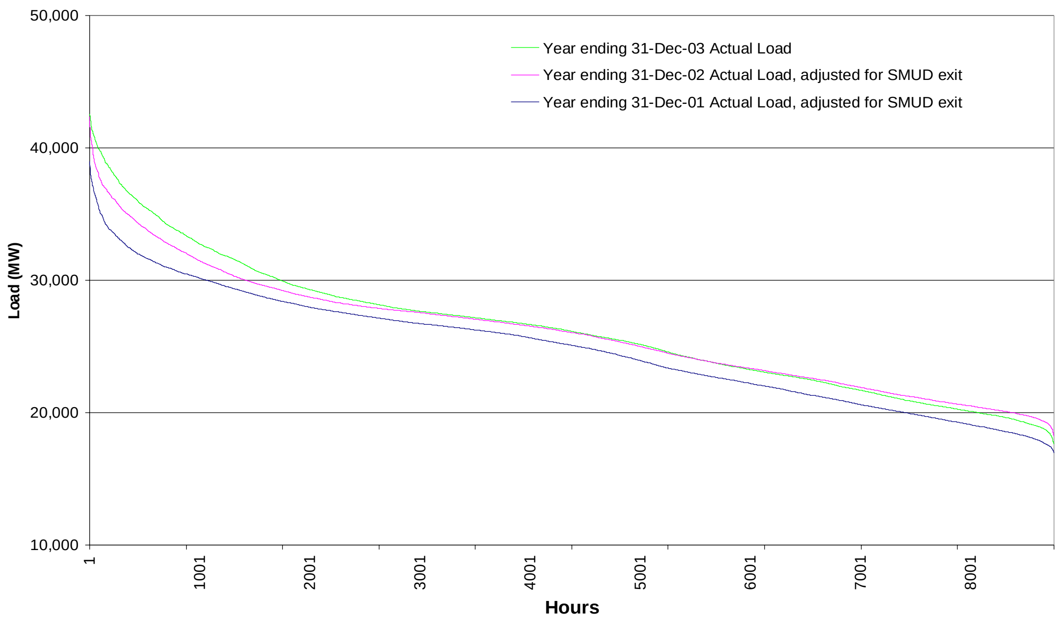
Supply and Demand Conditions

Loads in 2003 were similar to 2002 levels averaging only 1 percent higher for the year. However, as the economy recovered in the second half of the year, consistently higher loads occurred than in the same period in 2002. For the last six months of 2003, loads averaged 3.7 percent higher than the same period in 2002. Table E.1 shows load statistics for 2001 to 2003 and Figure E.3 provides an hourly load duration curves for 2001 through 2003.

Table E.1 2001-2003 Load Statistics[3]

Year	Avg. Load (MW)	% Chg.	Annual Total Energy (GWh)	% Chg.	Annual Peak Load (MW)	% Chg.
2001	24,878		217,905		38,975	
2002	26,065	4.8%	228.339	4.8%	42,352	8.7%
2003	26,329	1.0%	230,649	1.0%	42,581	0.5%

Figure E.3 Hourly Load Duration Curves, 2001-2003



A recovering California Economy lead to higher loads in 2003 compared to previous years.

[3]Historical loads have been adjusted to reflect SMUD exiting the ISO Control Area. Loads are measured on integrated hourly averages rather than instantaneous basis as reflected in other documents reported by the ISO, such as Summer and Winter Assessments, or reported by other entities.

Available supply was more than sufficient to meet the higher loads. California's energy supply continued to improve as 4,829 MW of new generation came on line in 2003. This was the third year in a row of net annual generation additions greater than 2,500 MW. Although there were significant generation additions, 2003 also experienced a sharp increase in the number of generation retirements. Generation retirements increased to just over 2,151 MW, an increase from 1,400 MW in 2002. Soft wholesale market prices and the lack of strong resource adequacy requirements may accelerate this trend during 2004. The net addition of capacity was 2,678 MW. Table E.2 shows the generation additions and retirements by congestion zone during 2003.

Table E.2 2003 Generation Additions and Retirements[4]

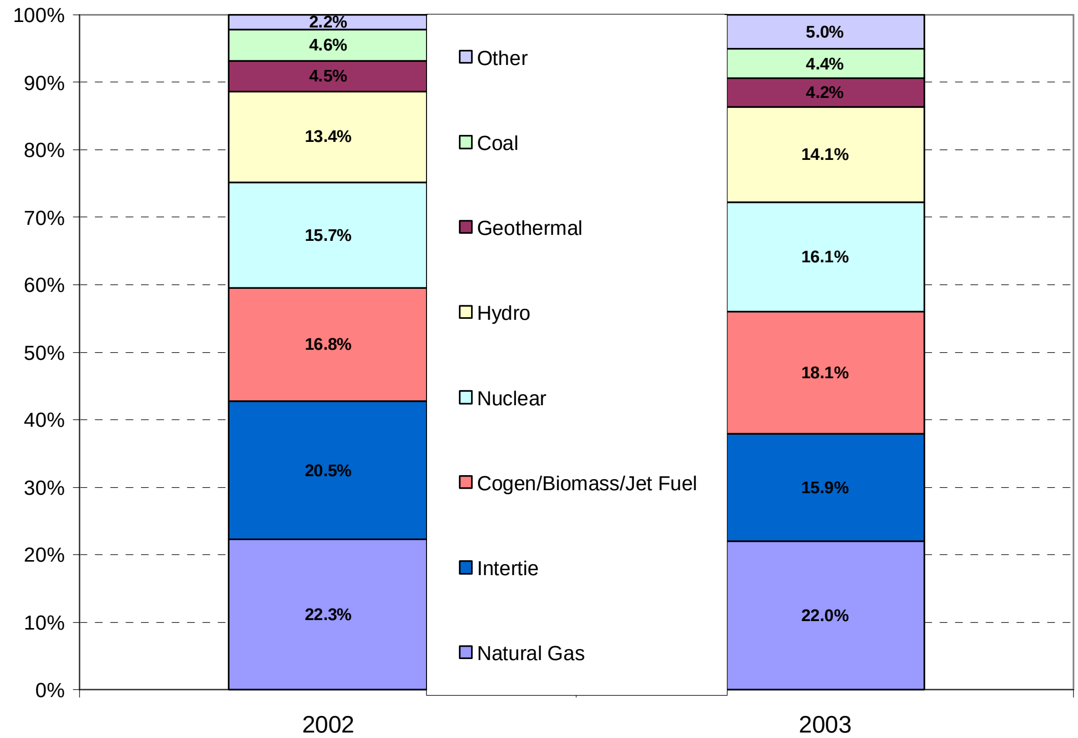
Congestion Zone	Generation Additions (MW)	Generation Reductions (MW)	Net Change
NP-15	853	-638	215
SP-15	2,247	-1,171	1,075
ZP-26	1,729	-342	1,387
ISO Control Area	4,829	-2,151	2,678

Sources of Energy

A diverse mix of energy supply was available to serve load in 2003, similar to 2002. Natural gas-fueled units provided 22% of the energy mix. Net energy imports represented 15.9%, similar to 2002 levels.[5] Near normal hydro conditions in the Pacific Northwest and new generation in the southwest combined to provide healthy levels of energy available for import into California. The higher percentage of net import's contribution to the total in 2002 was also due to imports to serve SMUD load, SMUD was part of the CAISO control area through June 19, 2002. Figure E.4 shows the comparative contribution of energy by fuel source for 2002 and 2003. Figure E.5 shows the level of average annual imports, exports, and net imports for 2001 through 2003.

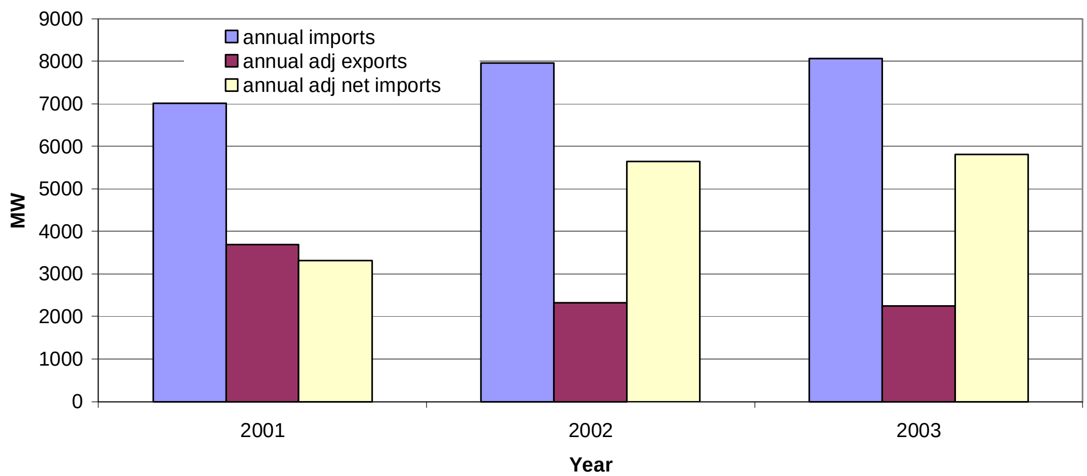
[4] California ISO 2003 Summer Assessment, 2003-2004 California ISO Winter Assessment.
[5] When normalized for SMUD load.

Figure E.4 2002 and 2003 Sources of Energy



Natural gas fired generation resources and imports (interties) provided 38 percent of the energy to meet load requirements in 2003.

Figure E.5 2001 through 2003 Average Annual Net Imports

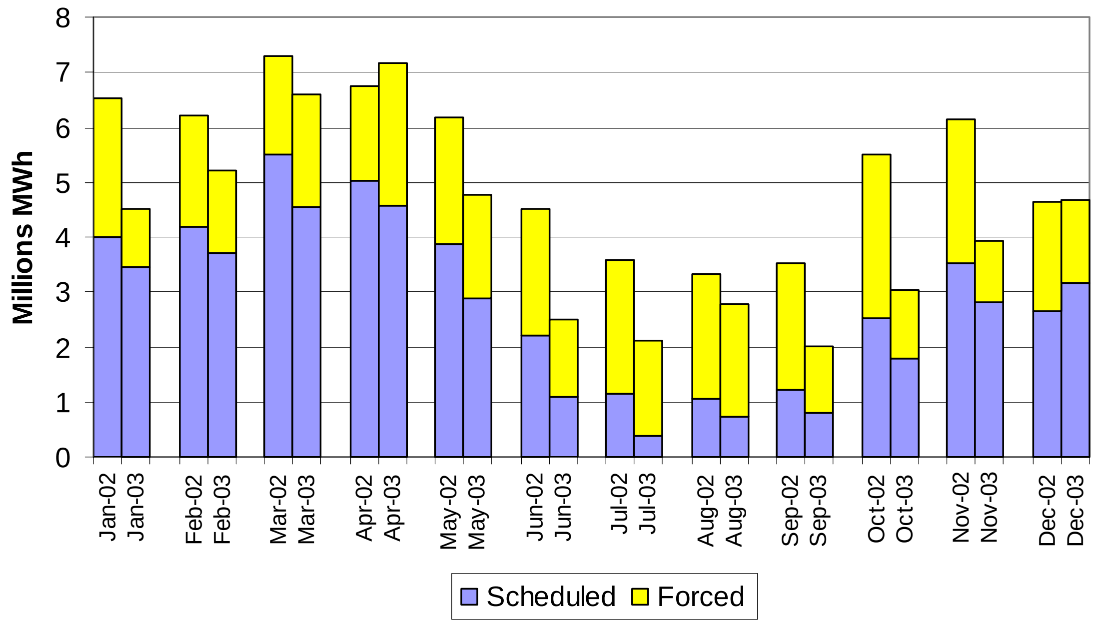


Average Net imports of 5900 MW in 2003 were second year in a row of healthy net import levels.

Outages

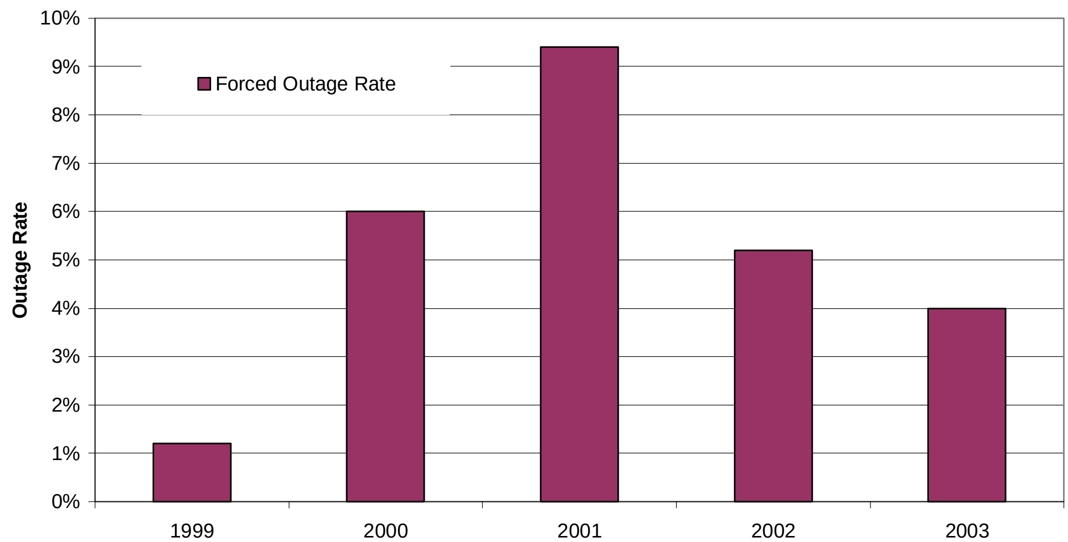
Generation availability was greater in 2003 than 2002. Monthly combined forced and planned outages were lower in each month other than April. The forced outage rate, the annual average percentage of generation out due to unplanned reasons, also fell in 2003 to approximately 4 percent down from just over 5 percent in 2002. Maintenance (planned outages) and economic outages (higher cost units shutting down due to inadequate price levels) increased in the spring and autumn during low load and low price periods. Outages decreased during the high load summer periods. During the summer, there was a small increase in forced outages as power plants ran for longer durations and thus had more exposure to forced outages. Figure E.6 shows the monthly outage levels for 2002 and 2003 while Figure E.7 compares the forced outage rates over the past five years.

Figure E.6 2002 and 2003 Monthly Outages



Increased generation availability in 2003 with forced outage rate second lowest in five years (Figure E.7). Outages followed historical seasonal patterns.

Figure E.7 1999 through 2003 Forced Outage Rates

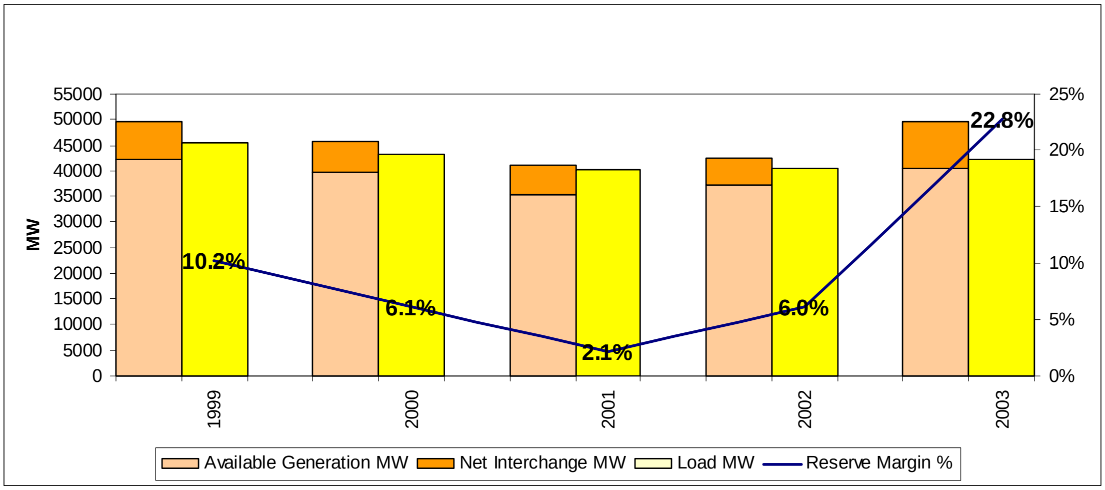


Reserve Margin[6]

Reserve margins, the ratio of available generation over and above actual load to actual load, increased significantly in 2003 compared to 2002. Net supply additions combined with increased net imports into California to exceed the rate of load growth in the CAISO's control area. Ample reserve margins have been a factor in the overall competitive market outcomes experienced throughout the year. The annual peak-hour reserve margin grew from 6 percent on July 10, 2002 to nearly 23 percent on August 25, 2003. However, the significant generation additions have strained many parts of the transmission system resulting in localized load and generation pockets. This stress is not reflected in the healthy overall system reserve margins reported on the following page. Figure E.8 shows the reserve margin during the peak hour in each month.

[6] The reserve margins represented here illustrates the ratio of excess available generation (i.e., available generation minus load) to load. Available generation is defined as total generation less planned and forced outages. We consider capacity out on Must-Offer Waivers available for this analysis. This is not the same as an operating reserve margin where units must be synchronized with the grid.

Figure E.8 1999-2003 Reserve Margins During Annual Peak Load Hour

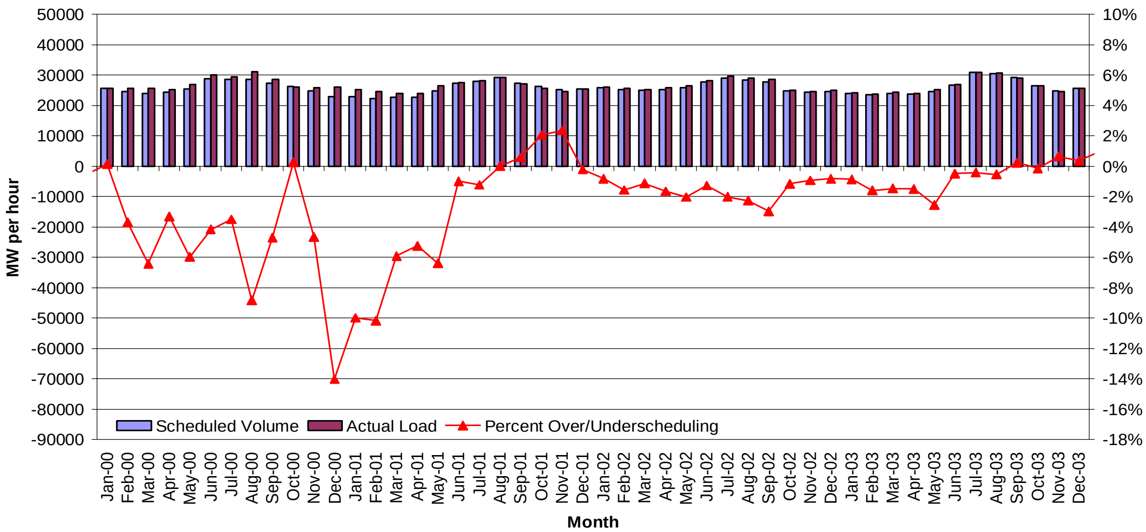


Peak Hour Reserve margin rose to nearly 23% in 2003 due to ample supply resulting from generation additions, imports, and near normal hydro conditions.

Imbalance Energy Market

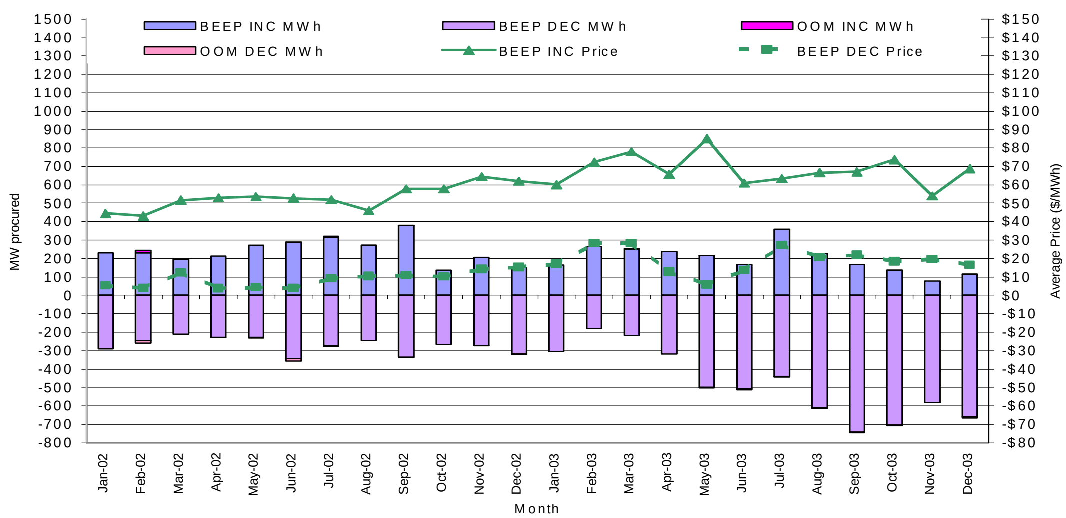
Significant forward scheduling by load serving entities resulted in low imbalance energy volumes throughout 2003. Monthly average forward energy schedules were within 3 percent of actual loads as shown in Figure E.9. Decremental energy dispatch volumes exceeded incremental energy dispatch volumes by nearly a 2.5 to 1 margin. Incremental energy dispatches were primarily limited to evening load ramping periods. This resulted in stable average monthly incremental energy prices in the $55 to $90/MWh range. Decremental energy prices were also stable in the $25 to $5/MWh range as shown in Figure E.10, which shows monthly average imbalance energy prices and volumes for 2002 and 2003.

Figure E.9 Monthly Average Loads and Deviations between Schedules and Loads 2000 through 2003



Forward energy schedules were within 3% of actual load in 2002 and 2003 in most hours, a significant improvement from two previous years.

Figure E.10 2002 and 2003 Monthly Average Imbalance Volumes and Prices



Decremental energy dispatch volumes continued to increase in 2003, outweighing incremental dispatch volumes by 2.5 to 1 as a result of abundant forward scheduled energy throughout the year.

Competitiveness of Electricity Markets

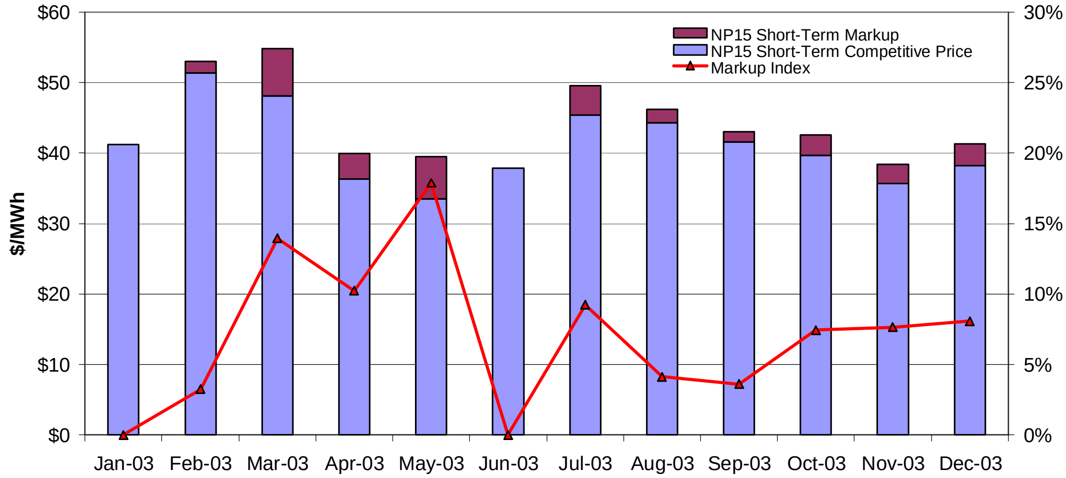
The long-term contracts entered into by the State of California in 2001 and significant amounts of new generation have provided effective market power mitigation in 2002 and 2003. When load serving entities are adequately supplied though longer-term arrangements, administrative market power mitigation rules are less crucial because the residual exposure of consumers to spot price volatility does not have a large cost impact. Contracts also reduce incentives for supply resources to try to elevate spot prices. Market power mitigation measures are needed to prevent opportunistic exploitation of contingencies and extreme circumstances. However, mitigation measures must not excessively dampen spot market volatility to discourage development of demand-side response programs or discourage fixed cost recovery for new generation entrants. Market conditions during 2003 limited the need for administrative market power mitigation measures outside of locally constrained areas. As discussed below, analysis of the 2003 short-term energy market shows competitive market conditions persisted throughout the year. Therefore, the current market power mitigation rules were largely unconstraining on prices and behavior and had minimal impact on 2003 market outcomes.

Estimated Markup of Hour-Ahead Bilateral Transactions

Having no formal forward energy market makes a comprehensive review of competitiveness difficult. DMA has had to develop separate temporary measures of real-time and hour ahead mark-up of prices above costs until information is available to compute our traditional weighted average of real-time and day ahead mark-up index. The first set of these indices compares real-time market prices to estimates of real-time system marginal costs considering operating constraints of supply in real-time. It is provided in Chapter 2. A second view of mark-up is associated with the higher volume hour ahead bilateral transactions. Analysis of the hour-ahead bilateral energy market is difficult due to lack of reporting. DMA has estimated the hour ahead mark-ups based on data collected from Powerdex, Inc.,[7] an independent energy information company featuring the first hourly wholesale power indexes in the WECC. Analysis of this data produced significantly lower markups compared to the real-time market. Figure E.12 shows the monthly average short-term markup for NP15. The SP15 results were similar and can be found in Chapter 2, which also includes a detailed description of the methodology and assumptions used in the analysis. NP15 short-term markups ranged between zero and 17 percent, indicating competitive market conditions in the short-term wholesale energy markets in California. The highest monthly average markups occurred in March, May and July. The higher March markup is likely a result of the natural gas price spike that occurred in late February that led electric energy suppliers to raise prices in anticipation of prolonged gas shortages. Unexpectedly high loads at the end of May and summer peaking loads in July likely led to the slightly higher markups calculated for those months. Overall, the index indicates that short-term wholesale energy markets produced competitive outcomes in 2003 with mark-up averaging below 10%.

[7] www.hourlyindexes.com.

Figure E.11 Estimated Mark-up for Day Ahead Bilateral Energy Markets in NP15 for 2003



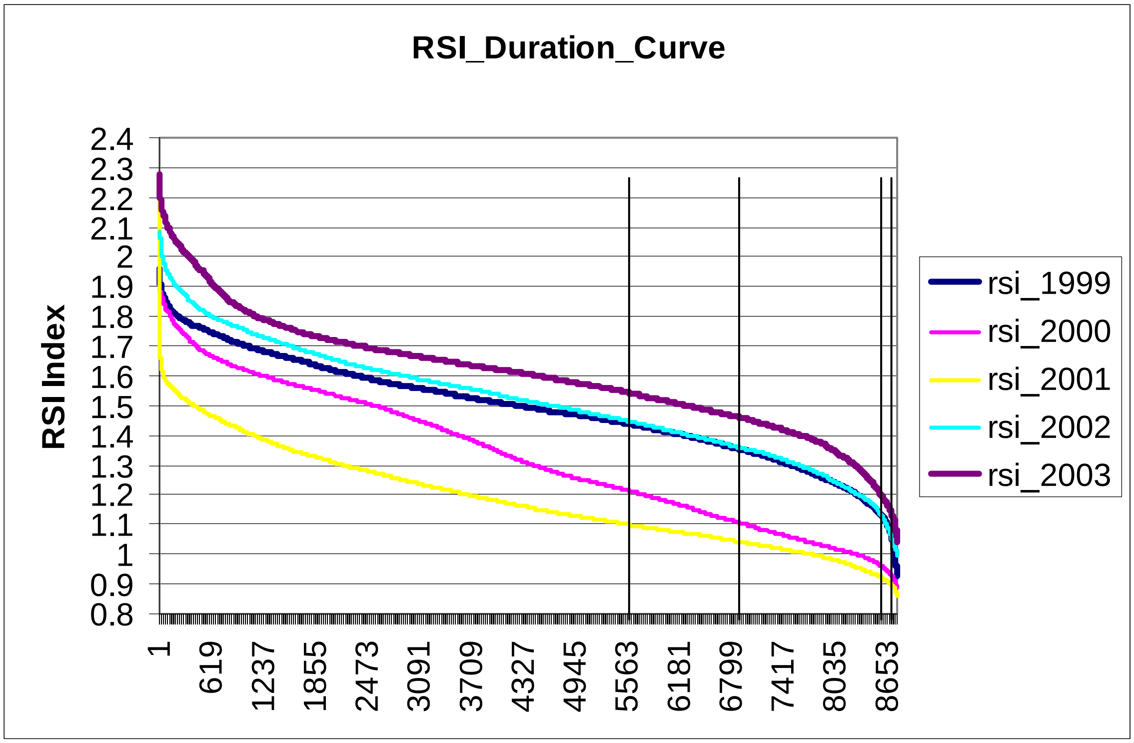
Competitive market conditions limited price-to-cost markups in the short-term energy markets throughout the year.

Structural Measure of Whether Suppliers are Pivotal in Setting Prices: Residual Supplier Index

An index used to measure the market structure rather than market outcomes is the residual supplier index (RSI). This index measures the degree to which suppliers are pivotal in setting market prices. 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. 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 of 1.1 provides for some degree of tacit collusion where two or more suppliers can raise prices through independently raising their bids or withholding generation. In general, higher RSI values correspond to greater market competitiveness.

The RSI indices in 2003 were the highest of the past five years. In 2003, the RSI indexes were less than 1.1 in less than 0.2 percent of the hours (only 21 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 2003 were significantly more competitive than in 2001 and 2000. The RSI indices are consistent with the market outcomes and short-term energy market price-cost markups we observed in 2003. As mentioned above, the improvements in market competitiveness in 2003 can be associated with many factors, including a significant volume of forward contracts, additional capacity added into the system and healthy levels of imports. Figure E.12 compares RSI duration curves for the past five years.

Figure E.12 Hourly Residual Supplier Index 1999-2003



High RSI levels in 2003 indicate a healthy market with suppliers pivotal in less than 0.2% of the hours of the year. The hours where RSI is less than 1.1 indicates suppliers able to set the market price. The high RSI levels indicate 2003 encompassed the most competitive market conditions since California restructuring was implemented

Revenue Adequacy of New Generation

Another benchmark for assessing the health of the 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 CAISO examined the economics of investment in new supply capacity given observed prices in the CAISO's imbalance energy and ancillary service markets. A detailed explanation of the costs and assumptions used in the analysis can be found in Chapter 2, Section 2.2.2.

For this analysis, generation unit costs and operation information were obtained from a 2003 California Energy Commission Study (CEC).[8] The CEC estimates that over a 20 year period, a new combined cycle unit would need to recover on average $90/kW-year or $90,000/MW-year in fixed costs to be profitable. Similarly, the CEC estimates the fixed cost recovery requirement for a new combustion turbine unit to be $78/kW-year or $78,000/MW-year. The net revenue analysis was run for both the 2002 and 2003 calendar years. The results show that in 2002, a combined cycle unit selling solely into the CAISO imbalance energy and ancillary service spinning reserve markets would have received a net revenue in the range of approximately $74 to $78/kW-year for NP15 and SP15 respectively. In 2003, the largely decremental imbalance energy market resulted in significantly lower net revenues of $47 to $58/kW-year for NP15 and SP15, significantly less than the $90/kW-year net revenue requirement that would be required to signal new investment.

Similarly, a new combustion turbine unit selling solely into the CAISO imbalance energy and non-spinning reserve markets in 2002 would have received a net revenue in the range of approximately $32 to $34/kW-year for NP15 and SP15 respectively. In 2003, the net revenue for the combustion turbine unit was similar to 2002 levels in a range of $32 to $36/kW-year for NP15 and SP15, well below the CEC estimated fixed cost recovery requirement of $78/kW-year, again as a result of the low volume of energy transacted in real-time imbalance energy market.

The net revenue results for both a new combined cycle unit and a new combustion turbine are below the estimated range of revenue that would be needed to stimulate investment in new supply relying only on spot market revenues. These results serve to highlight the key role that forward contracts must play in stimulating investment in new supply in California's wholesale market and the importance of effective resource adequacy rules to facilitate new generation infrastructure. These results also point to the historical boom/bust investment in generation infrastructure as 2003 was characterized by three consecutive years of significant new generation additions that have led to wide reserve margins in the year 2003. Therefore, short-term price signals for new investment would not be expected during this period. Tables E.3 and E.4 provide the results of the financial analysis of a new combined cycle combustion turbine unit and a new combustion turbine unit. The net revenues account for the higher operating cost due to natural gas price increases in 2003.

[8] "Comparative Cost of California Central Station Electricity Generation Technologies", California Energy Commission, Report # 100-03-001F, June 5, 2003, Appendices C and D.

Table E.3 Financial Analysis of New Combined Cycle Unit

	2002		2003	
	NP15	**SP15**	**NP15**	**SP15**
Capacity Factor	69.7%	70.2%	57.6%	60.1%
Energy Revenue ($/kW-yr)	$ 238.0	$ 245.0	$ 263.9	$ 280.3
Ancillary Service Capacity Revenue ($/kW-yr)	$ 1.2	$ 1.1	$ 3.2	$ 2.8
Operating Cost ($/kW-yr)	$ 165.4	$ 168.3	$ 220.6	$ 225.6
Net Revenue ($/kW-yr)	$ 73.8	$ 77.8	$ 46.5	$ 57.5

Profits for a new typical combined cycle generation unit fell approximately 30 percent in 2003 from 2002 levels to well below the estimated annual fixed cost recovery needed to sustain profitability, highlighting the need for strong resource adequacy requirements to ensure efficient investment in new generation resources.

Table E.4 Financial Analysis of New Combustion Turbine Unit

	2002		2003	
	NP15	**SP15**	**NP15**	**SP15**
Capacity Factor	36.2%	36.8%	16.0%	20.2%
Energy Revenue ($/kW-yr)	$ 158.7	$ 164.7	$ 103.7	$ 130.8
Ancillary Service Capacity Revenue ($/kW-yr)	$ 6.1	$ 5.9	$20.6	$19.2
Operating Cost ($/kW-yr)	$ 132.5	$ 136.2	$ 91.9	$ 113.6
Net Revenue ($/kW-yr)	$ 32.3	$ 34.4	$ 32.4	$ 36.4

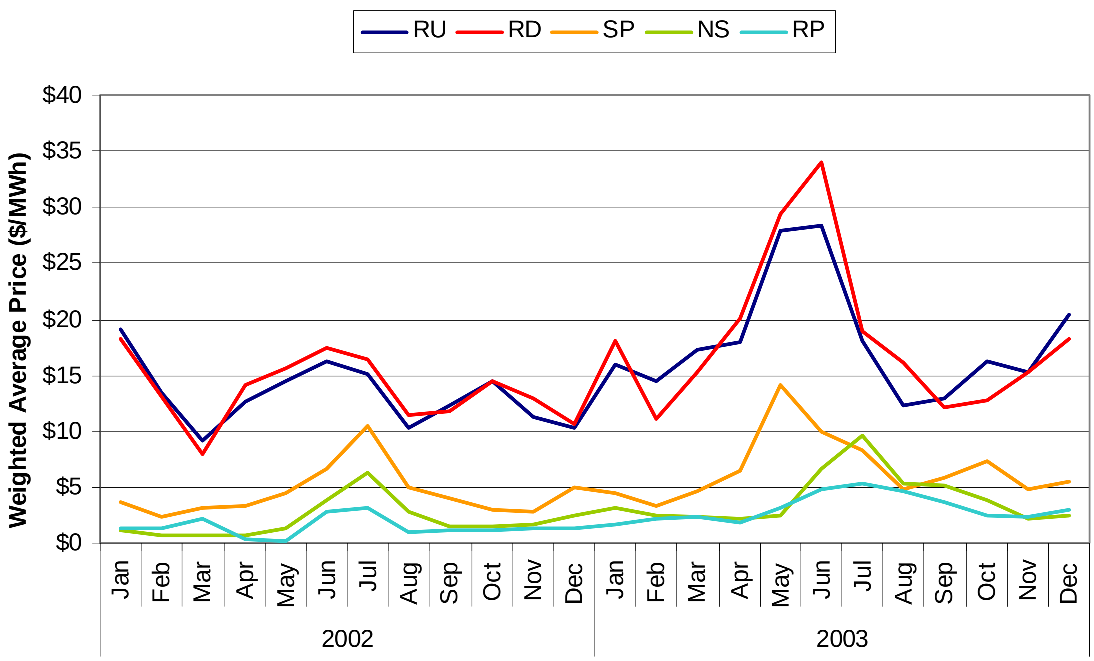
Combustion turbine profitability remained constant in 2003, significantly below the annual fixed cost recovery levels needed to sustain profitability based solely on spot market revenues.

Ancillary Service Market Performance

The CAISO procures reserve services for contingencies through Day Ahead and Hour-Ahead markets for regulation up and regulation down (RU and RD), spinning reserve (SP), non-spinning reserve (NS) and replacement reserves (RP). The total procurement plus the quantity self-provided by load-serving entities must meet or exceed the WECC Minimum Operating Reliability Criteria (MORC) for operating reserves (SP and NS) and NERC Control Performance Standards (CPS2) for regulation (RU and RD). Definitions of each of these services and a more detailed analysis of the 2003 ancillary services markets can be found in Chapter 4.

Average ancillary services prices increased 38.5 percent in 2003 compared to 2002. However, 2003 ancillary services prices were lower on average than in 1999, 2000, and 2001. The cost of ancillary services to load increased by 25.3 percent from 2002 to 2003 or an increase in the cost of ancillary services to load from $0.691/MWh in 2002 to $0.865/MWh. The increase in cost was primarily due to a reduction in the amount of A/S capacity supplied to the market. Figure E.13 shows the monthly weighted average ancillary service prices in 2002 and 2003.

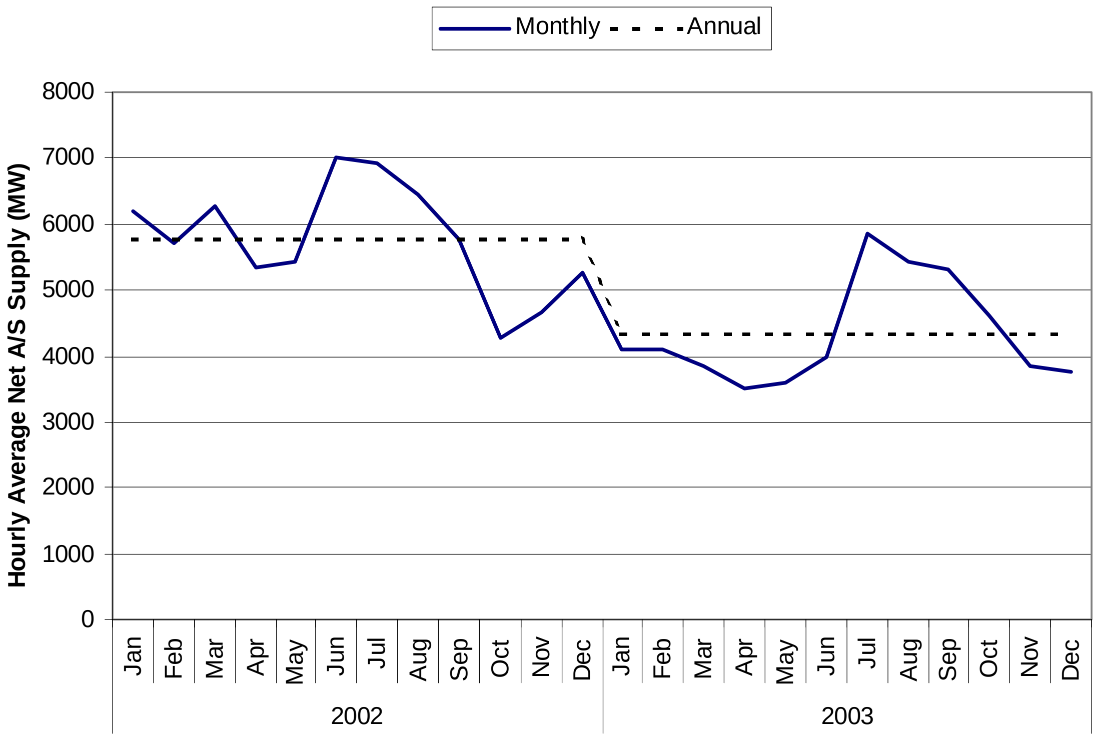
Figure E.13 Monthly Weighted Average Ancillary Service Prices, 2002-2003



Reduced ancillary service capacity resulted in higher prices and increased bid insufficiency in 2003 compared to 2002.

A/S capacity offered to the market in 2003 declined by 25% from 2002 levels. The decline in supply was due to four major factors: the removal of available capacity in the ancillary service markets as several resources opted for RMR Condition 2 contracts, several retirements of units that frequently provided ancillary services, an increase in load that reduced available unloaded capacity, and incentives not to participate in the ancillary service markets by those units that would lose their eligibility for start-up and minimum load cost compensation if they won in the A/S markets or self provided ancillary services. Figure E.14 shows average hourly net A/S supply by month in 2002 and 2003.

Figure E.14 Average Hourly Net A/S Supply by Month, 2002-2003[9]



Ancillary service supply dropped 25 percent in 2003 from 2002 levels as a result of several factors including suppliers switching to RMR Condition 2 contracts and generation retirements.

[9] Net A/S supply measures the physical capacity offered to the market. The market accepts offers of the same physical capacity into several markets in the case of upward reserves. The market clearing mechanism only allocates the capacity to one market. For this reason, summing the capacity offers from a resource overstates the physical capacity offered to the markets. This does not apply to self-provision, because the SC allocates the physical capacity to each market.

The reduced supply led to frequent bid insufficiency where market bids were not sufficient to meet the CAISO's reserve requirements. This occurred most frequently during the shoulder months of mid-April through mid-June and mid-October through mid-December due the significant amount of resources unavailable due to planned maintenance and hydro production constraints. In addition, current market rules that require rescission of minimum load payments when bidding into ancillary service markets provided a disincentive to bid in these markets. When market bids are insufficient to meet the CAISO's reserve requirements, the CAISO calls on RMR units to fill the gap.

Despite the reduction in A/S capacity offered to the market, the CAISO was still able to procure the required capacity more than 96 percent of the time during 2003. Bid insufficiently was not evenly spread across the A/S markets. Bid insufficiency in Regulation Down (RD) declined substantially in 2003 compared to 2002, while increasing in Spinning Reserve (SP). The increase in SP bid insufficiency was the most significant change. Table E.5 lists the frequency of bid insufficiency for each A/S market in 2002 and 2003. In order to attract more supply into the ancillary service markets, rules changes are being contemplated that would allow supply resources to earn both administrative compensation for must offer start-up and minimum load costs and market revenues from ancillary services.

Table E.5 Frequency of Bid Insufficiency, 2002-2003

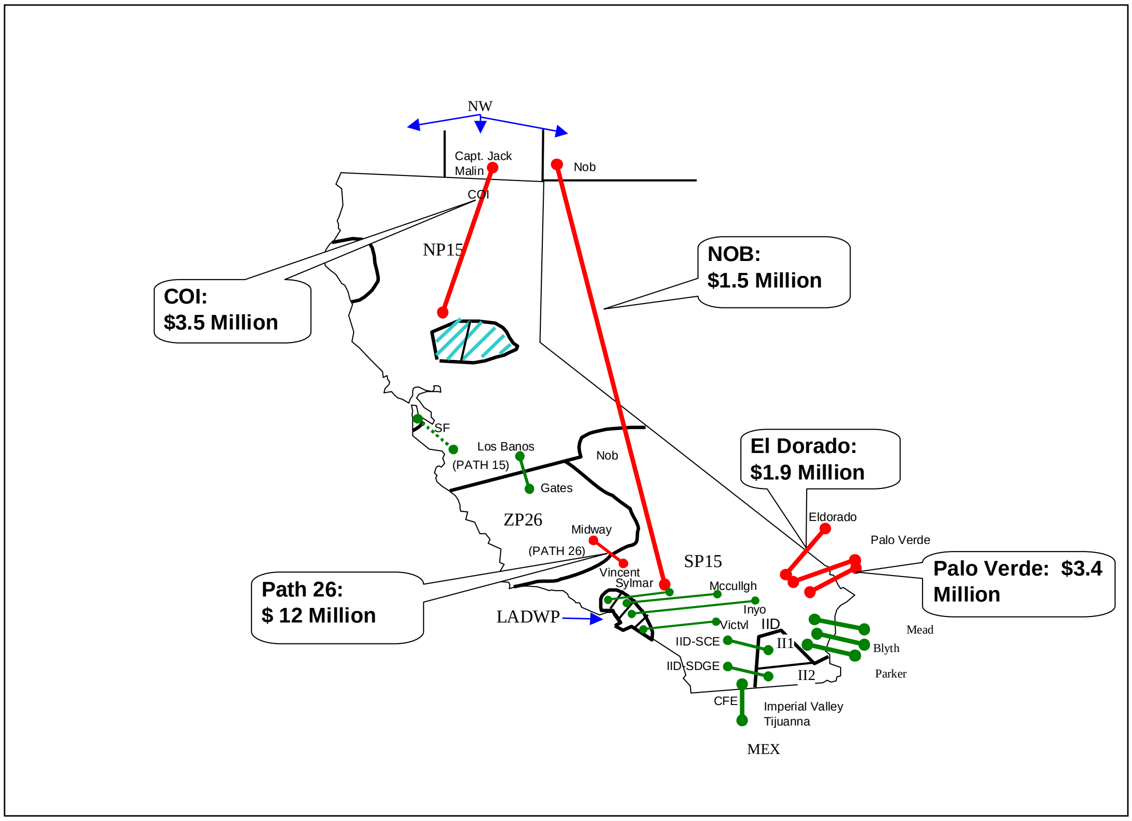
	RU	RD	SP	NS
2002	0.9%	4.9%	0.8%	0.3%
2003	1.1%	3.3%	3.3%	0.8%

Interzonal Congestion (Between Zones)

Managing congestion between zones through *interzonal* congestion markets worked well in 2003 with low congestion costs. The total congestion costs for 2003 were approximately $28 million, less than the $42 million in 2002. They were significantly lower than the $108 million in 2001 and $400 million in 2000. Although the overall congestion market performed well, there was frequent congestion on some of the major paths, especially Path 26 (north to south), COI (import), NOB (import), Palo Verde (import), and Path 15 (south to north). Unexpected events occurring on the existing transmission system also had large and prolonged affects on both congestion and energy markets. For example, due to a fire at the Vincent substation on March 18, 2003, Path 26 was derated from 3,000 MW to 2,500 MW in the north to south direction for most of the remaining period of 2003. The derate resulted in congestion costs on Path 26 of $12 million, almost double the congestion cost reported for 2002. Figure E.15 shows the major congested interties in 2003 and associated congestion costs for the year.

One phenomenon identified in the congestion market in previous years has been the absence of adequate adjustment bids to manage congestion. Adjustment bid sufficiency improved significantly in 2003 over 2002 levels indicating increasingly competitive congestion markets. The increased competitiveness lead to lower prices and ultimately the historically low total congestion costs in 2003, despite increased congestion frequency on many of the major paths. Chapter 5 provides a detailed discussion on the performance of the interzonal congestion market in 2003.

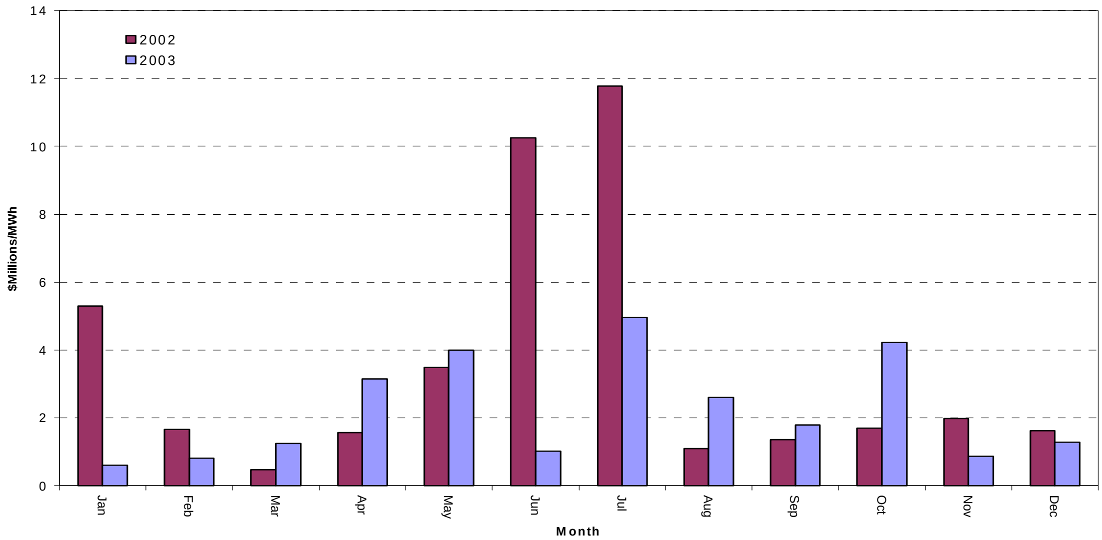
Figure E.15 2003 California ISO Major Congested Interties and Congestion Costs



A significant continuing problem in the interzonal congestion market is the prior allocation of substantial portions of interzonal transmission capacity to the holders of existing transmission contracts (ETC) rights. Substantial portions of ETC capacity went unscheduled and created the phenomenon of phantom congestion.[10] CAISO analysis, which is described in Chapter 5, Section 5.1.4, indicates that releasing unscheduled ETC could have significantly reduced the congestion frequencies (and costs) on several major paths. For instance, the release of unscheduled ETC could have significantly reduced most of the congestion on Path 15 in the south to north direction. In actuality, CAISO had to curtail about 50,000 MWh in January 2003. These curtailments could have been significantly reduced if unscheduled ETC would have been released to the market. Phantom congestion compromises market efficiency and can potentially increase the total costs to the final consumers. Figure E.16 compares the monthly interzonal congestion costs for 2002 and 2003. Figure E.17 shows congestion revenues on selected paths in 2002 and 2003.

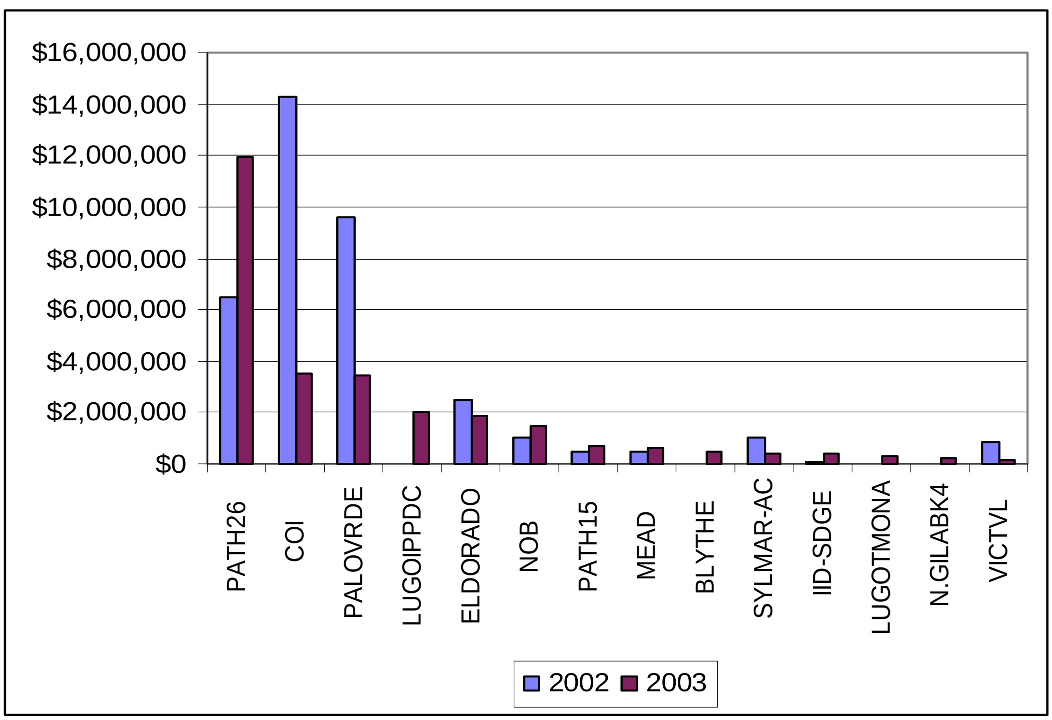
[10] Because the CAISO does not release the unscheduled portion of ETC until twenty minutes before the operating hour, a portion of ETC could go unscheduled. Therefore, it is conceivable that a path will appear congested in the forward market, but this congestion would not have occurred if all unscheduled ETC were available to the forward market. This kind of congestion in the forward market is called phantom congestion.

Figure E.16 2002 and 2003 Monthly Interzonal Congestion Costs



Interzonal congestion costs dropped 33 percent in 2003 from 2002 levels

Figure E.17 2002 and 2003 Congestion Revenues on Selected Paths

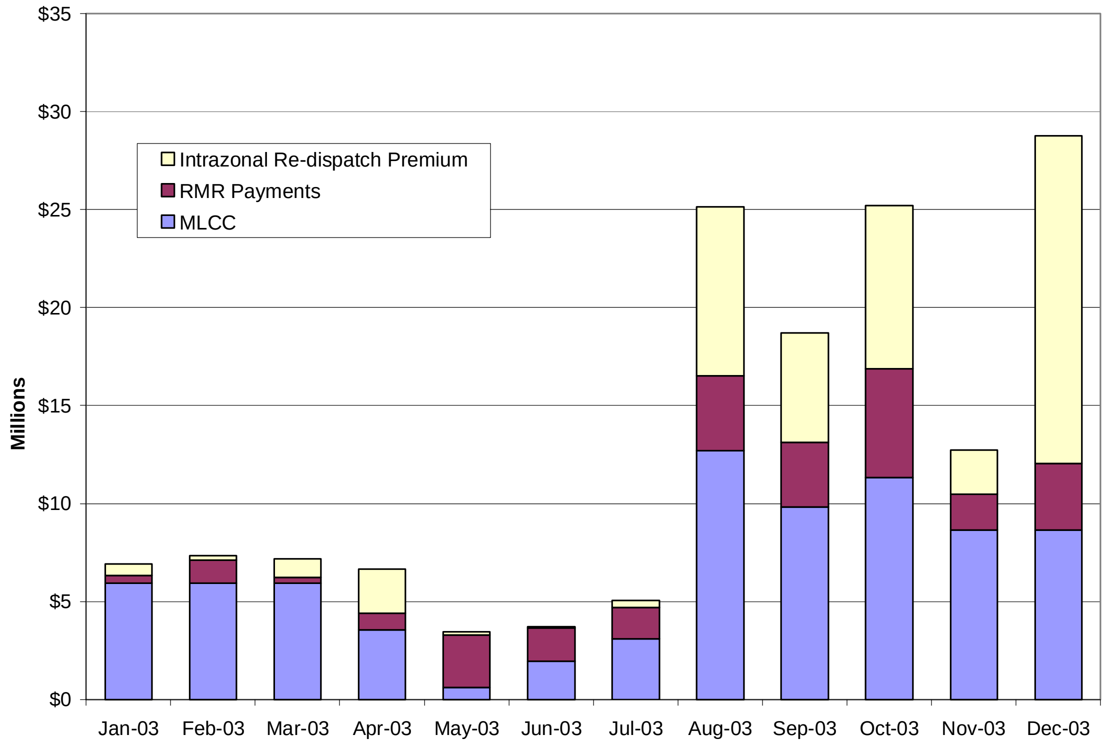


Intrazonal Congestion (Within Zone)

Intrazonal congestion at specific locations was the most significant operational problem in the CAISO markets during 2003 because congestion has to be managed in real-time. Intrazonal congestion is the result of there being either a generation pocket or a load pocket within a single zone. In both cases, the absence of sufficient transmission access to that pocket means that the CAISO has to solve the problem in real-time, either by incrementing generation within the pocket if not enough is scheduled, or by decrementing it if too much is scheduled. The CAISO's current method for dealing with incremental dispatch to mitigate intrazonal congestion is by first dispatching available RMR energy in real-time. Should that energy be insufficient, other units are then dispatched out-of-sequence (OOS) if they have submitted real-time imbalance energy market bids, or out-of-market (OOM) if they have not. The needed decremental dispatch to resolve intrazonal congestion is bid based, with a subset of the decremental bids (those from internal control area generation) subject to local market power mitigation (DEC reference price).

In 2003, there were approximately $151 million in intrazonal congestion costs up from approximately $6 million in 2002. A significant portion of the intrazonal congestion was incurred at the Miguel substation near San Diego where energy from new generation units in northern Mexico and energy imported from Arizona, which also increased due to the addition of new generation units in the Southwest, combined to overload the local transmission facilities. Significant congestion also occurred due to prolonged substation derates at Vincent and Sylmar. Components of intrazonal congestion costs include a redispatch premium above the zonal price, RMR payments, and minimum load compensation (MLCC) for units that are on to manage specific locational congestion. There was significant increase in all the intrazonal cost components in August of 2003 and thereafter, due largely to the congestion at the Miguel substation. This increase is obvious in Figure E.18.

Figure E.18 2003 Monthly Total Intrazonal Congestion Costs[11]



Intrazonal congestion costs surged in August as new generation came online in Northern Mexico and combined with imported energy from Arizona to overwhelm local transmission facilities at Miguel.

The CAISO's preference has always been that all congestion issues be resolved in the day or hour-ahead markets. This is the prevailing practice for congestion between zones (interzonal). To the extent that intrazonal congestion can be forecast, the CAISO also prefers to resolve it before real-time. Solving intrazonal congestion in real-time adds to the complexity of balancing the grid, and subtracts from the time and attention of the grid operators who could be better utilized solving problems not known in advance. Since the emergence of persistent congestion in southern California, Grid Operations has had to increase personnel in the control room to deal with the increased real-time actions.

[11] See Chapter 6 for a more detailed explanation of the intrazonal congestion cost categories.

The CAISO foresaw the Southern California congestion problem and, in response, filed Amendment 50 in late March 2003. Under the terms of the proposed Amendment 50, the CAISO would be provided a number of new tools with which to mitigate intrazonal decremental congestion prior to real-time. Amendment 50 was approved only in part by FERC. The approved change was the institution of bid reference levels for all control area resources. Under the new market rules, when the CAISO needs to decrement generation in a constrained region in real-time, it refers to the bid reference levels rather than the bid prices. Units are charged the lower of their reference level or the zonal decremental market clearing price.

On occasion the Miguel substation is so congested that the mitigation has to include the interties, in particular the Palo Verde-Devers intertie and the Palo Verde-North Gila intertie, both of which feed energy through the Imperial Valley substation and into the Miguel transformer banks. This is done by accepting supplemental energy exports (market-based DEC bids) OOS at the interties. By exporting out of the CAISO against the flow of power, the overloading of the path is mitigated. These bids are not subject to Amendment 50 since they are not control area resources. Consequently, they are paid as bid. Prior to the startup of the border generation units there were few supplemental energy exports accepted OOS. Since then, this has become a common method of mitigating the overloading of the Miguel banks. To address these problems, the CAISO considered creating a new zone in the region, which is discussed below in the next section covering Major Market Issues.

Major Market Issues

Creation of a New Zone

In an effort to find an acceptable solution to resolve the operational and financial impacts of intrazonal congestion at the Miguel substation, the CAISO analyzed the feasibility of creating a new Miguel-Imperial Valley (MIV) zone. The creation of the new zone would enable the ISO to manage the Miguel substation congestion in the forward market, thus eliminating to a large extent the ability of the suppliers to submit, and the inability of the ISO to reject or adjust, infeasible schedules that were causing the problem in real time. The CAISO determined that the creation of a new MIV zone was technically difficult to implement due to the looped structure of the local area facilities, and technical and contractual issues that would have to be resolved before the ISO embarks upon creation of a new zone or moves towards the more geographically granular locational pricing scheme targeted under MD02[12]. Some of the findings of the study were:

[12] Once MD02 is implemented, the enforcement of the Full Network Model in the forward congestion management process will prevent market participants from over-scheduling transmission facilities and thus will largely solve the intrazonal congestion problem.

- Clarification is required of some of the existing state contracts (about 6,000 MW) that include seller's choice provisions, which in the face of more granular forward market congestion management (creating new zones or adopting a locational marginal pricing paradigm) could be subject to different legal interpretations. Unless and until these provisions are interpreted satisfactorily by mutual agreement between the buyers and the sellers, they could potentially have large wealth transfer ramifications not contemplated in the contracts.
- Ultimately the best solution to any permanently transmission-constrained area is to upgrade the transmission infrastructure. The first round of transmission re-enforcements at Miguel is scheduled to be in service by December 1, 2004. Although this will not totally eliminate congestion at Miguel, the resulting increase in capacity should relieve the majority of the current congestion problem.
- There are possible competitive issues in the real time market with a new MIV zone solution based on a further examination of the real-time decremental bids provided at Palo Verde for relieving Miguel congestion.

Based on the above factors, the CAISO is instead implementing a combination of approaches to manage the problem in the interim. These approaches include:

- Additional staffing on the CAISO Control Room Floor to assist with mitigating the real-time intrazonal congestion,
- Voluntary agreements to reduce scheduling through the Miguel interface,
- Enhancement of the software tool that is used to manage real-time intrazonal congestion,
- Improve the reference price methodology for local market power mitigation, and
- Automating Market Quality Intrazonal post-processes.

The cumulative benefits of the above approaches are both operational and financial. With the reduction of infeasible schedules causing Miguel substation congestion, the operational impact of intrazonal congestion management in real time will be reduced. In addition, a financial benefit should be realized as a reduction in real time intrazonal congestion redispatch volume and costs through the combination of voluntary agreements to reduce scheduling through the Miguel interfaces and improved reference prices.

Must-Offer Waiver Process Redesign

In response to issues raised by stakeholders as well as concerns over recent bid insufficiency in the Ancillary Service markets, the CAISO has conducted a market issue and design forum with stakeholders to address Must-offer Waiver Denial procedures and compensation. The primary issues voiced by stakeholders were that they did not have information regarding the extent to which units were denied waivers, the reason these waivers were denied, the accuracy of components used in determining cost compensation, and the lack of compensation for the unloaded capacity of units denied waiver. In addition to the concerns raised by stakeholders, the CAISO observed low bid sufficiency in the Ancillary Service markets in the Fall of 2003 and Winter of 2004 and felt that a process revision including provisions for units denied a waiver to sell Ancillary Services without rescission of their start-up and minimum load cost compensation may help to alleviate this condition. The following is an abbreviated list of items the CAISO is scheduled to submit in a 205 filing to FERC in April 2004, to address the concerns raised:

- Allow units that are denied a waiver to sell Ancillary Services in the Day-Ahead and Hour-Ahead markets without rescission of minimum load compensation to increase participation of these units in the Ancillary Service markets;
- Adjust the timing of the waiver evaluation and notification to occur at such a time as to allow units that are denied a waiver to submit bids into the Day-Ahead Ancillary Service markets;
- Implement economic criteria in selecting units to be denied a waiver to replace the current first request process;
- Adopt a cost allocation mechanism more in line with cost-causation for waiver denials. The cost allocation will be to Participating Transmission Owners when waivers are denied for local reliability; to load and in-state exports when waivers are denied for zonal conditions; and to net negative deviation, load, and in-state exports when waivers are denied for control area conditions;
- Include Auxiliary Power costs in the start-up cost compensation, moving to daily spot natural gas prices and including applicable transportation costs in calculating the minimum load cost compensation; and
- Improve transparency by posting, with a 30-day lag, information regarding the amount of capacity denied waiver and the reason for waiver denial.

The issue of whether or not units constrained on from waiver denial should receive compensation for their unloaded capacity was not resolved in the first stage of the market issue and design forum with stakeholders and will be addressed through subsequent stakeholder process and filing with FERC.

Distribution of Ancillary Service Procurement

In addition to observed low bid sufficiency in the Ancillary Service markets, the CAISO has historically procured more of the required control area ancillary services procured from the northern than the southern region. During the winter the average percent of reserve requirements purchased in the southern region has been as low as 15% during peak periods, with the remaining 85% procured in the north. This disparity presents potential reliability concerns in cases where a contingency in one zone would require the delivery of energy from operating reserves that, in real-time, may be undeliverable due to their location outside that zone. The proposed changes to the Must-Offer Waiver process will bring some additional capacity to the Ancillary Service markets in the south, however the CAISO is currently exploring additional measures to restore parity to the distribution of Ancillary Service procurement between the northern and southern regions of the control area. Moreover, based on the recent NERC rules, the CAISO will target procurement of ancillary services with more even dispersion between the NP15 and SP15 zones.

Infrastructure Enhancement

Regardless of how well an energy market is designed, it cannot function effectively, i.e., efficiently and in line with reliable system operation in the absence of adequate infrastructure. Prominent infrastructure components are supply resource adequacy and transmission expansion, as described below.

Resource Adequacy Requirement

As the year 2000 crisis in California's energy market substantiated, lack of resource adequacy can contribute substantially to the melt down of an energy market.

Resource adequacy requirements on LSE's are critical to: 1) support reliable operation of the transmission system (short term reliability), 2) lead to competitive spot markets thus substantially mitigating the ability of the suppliers to exercise market power, and 3) promote supply investment (long-term reliability).

The CAISO offered an integrated available capacity obligation (ACAP) design as part of MD02. However, the CAISO did acknowledge that a resource or capacity obligation would have to go hand in hand with resource procurement rules that are under the purview of the state and local authorities, and would best be addressed in those forums. Accordingly, in November 2002 the CAISO Board directed the CAISO management to defer implementation of the ACAP element of MD02, and instead dedicate CAISO staff's efforts towards active participation in the CPUC Procurement Proceeding.

During 2003, the CAISO actively participated in the CPUC Procurement Proceeding. The CAISO filed written testimony, and later testified on the following six essential elements of a resource adequacy program:

1. Required planning reserve of 17%
2. Established and standardized load forecast (as a basis for defining the capacity obligation)
3. Specific deliverability criteria
4. Unambiguous and comprehensive rules for counting of resources towards meeting a LSE's obligation
5. Restricted reliance on spot markets to satisfy capacity requirements
6. Availability of LSE's procured resources for possible use by the CAISO, along with adequate provisions for the LSE's to manage their own use-limited resources under normal conditions.

On November 18, 2003, the ALJ at the CPUC assigned to the procurement proceeding issued a "Preliminary Decision" concurrently with an Alternative Ruling by President Peevey of the Commission, the assigned commissioner. At the time the ISO supported the Peevey Alternative, which included many of the desirable elements and characteristics that the CAISO had recommended.

Subsequently, on January 22, 2004, the CPUC issued its decision in the Procurement Proceedings. The decision deviated markedly from the Peevey Alternate and failed to adopt a number of the important recommendations supported by the CAISO and adopted in the Peevey Alternate. In particular, and of critical importance to the CAISO, the CPUC decision:

- deferred full implementation of the adopted procurement rules until 2008
- did not include, in any material respect, how compliance with the long-term rules would be monitored and enforced
- deferred resolution of a number of key issues including the following:
  a. deliverability,
  b. coordination with MD02,
  c. penalties for non-compliance,
  d. reporting,
  e. load forecasting methodology,
  f. counting of resources, and
  g. the phase-in period.

The issues are to be resolved in a series of workshops and another rulemaking process. The CAISO is engaged in discussions in different forums, participating in CPUC's Procurement Proceeding with a view to identifying the key linkages between resource adequacy and the MD02 project.

Economic Need For Transmission Expansion

Historically, transmission networks have been constructed primarily to guarantee reliability and not to strengthen transmission interconnections that fully facilitate competition and wholesale trade among regions. CAISO is engaged in a CPUC proceeding to define a common methodology for expanding the transmission grid that accounts for the economic benefits associated with an upgrade. With this methodology, market outcomes can be simulated with and without a proposed upgrade to determine the benefits of a proposed upgrade. The methodology proposed by the CAISO is based on five key principles that are summarized below:

- Benefit Framework – Application of a standard and comprehensive benefit framework capable of illustrating costs, benefits, and risks to both participants and non-participants of the proposed transmission upgrade.
- Network Representation – Physical transmission flows need to be accurately modeled by utilizing a full network model.
- Market Prices – Forecasting market prices in addition to marginal costs is critical to fully understand the range of potential benefits and the appropriate distribution of benefits. The methodology includes simulating bidding behavior and the corresponding impact on market prices.
- Uncertainty – The impact of a wide range of future system conditions (hydro, gas price, load growth, and other system contingencies) need to be evaluated.
- Resource Substitution – Alternative resource scenarios including central-station and distributed generation, demand-side resources, different transmission operating schemes, etc. need to be evaluated on a level-playing field with the proposed transmission upgrade.

The CAISO is preparing a report to the CPUC to be filed in June 2004 that will describe the methodology and its application coupled with an illustrative example focusing on a potential Path 26 upgrade.