CALIFORNIA ISO

Third Annual Report on Market Issues and Performance

Market Monitoring, Investigative, and Compliance Activities

January – December 2001

California Independent System Operator

January 2002

Executive Summary

This report summarizes the overall market performance and the major activities of the ISO during 2001 involving market monitoring, investigations, and compliance. The report summarizes the group efforts to:

- Monitor Performance of California's Wholesale Energy Markets
- Assess Market Power and Identify Market Power Mitigation Options
- Investigate Market Design Options to Address Market Inefficiencies and Anomalies
- Ensure Compliance with ISO Tariff Provisions
- Provide Assistance to External State and Federal Regulatory Agencies and Policy-makers

Monitor Market Performance

- After the market turmoil which started in May 2000, California's energy prices finally moderated in the summer of 2001.

  The ISO identified market power problems soon after the price spikes began.[1] The Department of Market Analysis (DMA) formulated sophisticated methods to analyze the components of the high prices. Their analysis showed that although a portion of the increase in prices could be attributed to higher gas prices, low hydro production, and lower imports, the most significant cause of the increase was due to uncompetitive market conditions. This resulted in prices significantly in excess of levels that would be expected under actual supply conditions. Monthly wholesale prices exceeded competitive levels by 50% to 100% for the first six months of the year, before moderating in July and August 2001.
- Energy prices decreased significantly in late June as mild weather and conservation lowered the demand for electricity. This, combined with significant lower natural gas prices, forward contracting by the California Department of Water Resources for the utilities' net short load requirements and the imposition by the Federal Energy Regulatory Commission (FERC) of west-wide market power mitigation measures, significantly reduced energy prices in the summer and fall of 2001. Prices in the real-time market continued to moderately exceed competitive levels throughout the fall and continue to be investigated by DMA.

Assess Market Power

- DMA identified the root causes of market power early in the crisis including the following fundamental flaws with the structure of deregulation:

  1. **Inadequate federal regulatory oversight of prices sellers could charge**. DMA noted that sellers had market power that was inconsistent with obligation to maintain just and reasonable rates. Inadequate tests were used by FERC in determining whether sellers possessed market power.

[1] Appendix A contains a listing of reports by the DMA and Market Surveillance Committee that address the exercise of market power in the California energy markets. These reports documented the impacts of market power and established the record for action used by state legislators, consumer groups, state regulators, and eventually FERC.

2. **Over-reliance on spot markets that caused large volumes of wholesale power to be transacted in volatile real-time spot markets.** DMA noted that this created opportunities for sellers to "name their price" and charge prices significantly above competitive levels and found that if investor owned utilities had been able to contract with sellers through long-term contracts, there would have been fundamental changes in the incentives of sellers to profit from spiking prices in real-time.
3. **Market Monitors in California did not have the authority to mitigate unreasonable market participant behavior.** Even after market power problems had been identified, the ISO lacked any authority to mitigate market power or sanction suppliers for market abuses.
4. **No clear obligation to identify sufficient capacity in advance to serve load.** This resulted in insufficient capacity margins under dry hydro conditions. With little forward contracting of supply in place, suppliers were pivotal in the market. Tight supply/demand conditions created opportunities for suppliers to raise prices.
5. **Lack of price responsive demand to contain high prices.** Consumers were insulated from the real-time cost of supplying power. Current retail rate structure provides no incentives to install technology that would enable consumers to respond to market price signals.

- During 2001, the ISO continued to perform a number of investigations and studies to document the evidence for the exercise of market power in California's wholesale market and its impacts on wholesale power prices. The major objective of these investigations and studies was twofold: (1) to support filings by the ISO at FERC calling for more effective mitigation of market power on a going forward basis, and (2) to support refunds for purchases of wholesale energy and ancillary services made at unjust and unreasonable prices since May 2000 due to the exercise of market power and other market conditions.
- In order to demonstrate the magnitude of market power being exercised in the California markets, the ISO's Department of Market Analysis prepared two detailed studies of market power. The analyses were filed with FERC in support of ISO's March 22, 2001 filing in response to FERC Staff's *Recommendations on Prospective Market Monitoring and Mitigation for the California Wholesale Market*. The purpose of these studies was to provide empirical evidence on an individual seller's ability to exercise market power in California's wholesale energy market since May of 2000, and to emphasize the need for effective, comprehensive action to prevent the exercise of market power in the future. The studies quantified the potential overall impact of the exercise of market power on wholesale prices. They also provided evidence that overall market outcomes resulted to a large degree from the exercise of market power by individual entities, rather than from the effect of scarcity in the market.
- The first study[2] was an analysis of the impact of market power on overall system prices from May 2000 through March 2001 based on the system price-cost markup for the combined Power Exchange (PX), ISO markets, and other bilateral transactions scheduled through the ISO. Results showed that after incorporating potential NOx costs and hours of resource scarcity into the analysis, over 30% of wholesale energy costs over the last year could be attributed to market power – a level that clearly exceeded the range that would be consistent with a workably

[2] *Further Analyses of the Exercise and Cost Impacts of Market Power In California's Wholesale Energy Market,* prepared by Eric Hildebrandt, Manager of Market Monitoring.

competitive market. The results provided compelling evidence that market power rather than increases in the cost of production explain the significant portion of the price levels seen in the summer of 2000.

- The second study[3] examined bidding behavior of individual market participants in the ISO real-time market from May to November 2000. It addressed the issue of whether high prices were actually due to the exercise of market power by individual participants, or were simply due to fundamentals of low supply needed to meet demand. The study developed an innovative methodology for assessing bidding strategies used by individual suppliers to systematically maintain high prices. The study's fundamental finding was that a wide range of suppliers systematically bid capacity into the ISO real-time market at prices many times above their actual cost of production. Sellers were able to command high prices for themselves as well as set high prices for other sellers. The evidence described in this study provided a direct link between the observed pattern of high prices and the bidding behavior of individual suppliers to produce those prices.

- During the first half of the year, the DMA performed extensive analysis of costs over the "soft cap" thresholds and filed results with FERC to support just and reasonable rates through the exercise of the Commission's refund authority for all sales over this "soft cap." Analysis by DMA quantified potential refunds from individual sellers for sales above just and reasonable levels based on both supplier costs as well as a benchmark of prices consistent with competitive market conditions. In an Order issued on March 9, 2001, the Commission identified about $125 million in sales above monthly "proxy prices" established by the Commission to be refunded unless sellers could justify these costs before the Commission. Potential refunds based on these monthly "proxy prices" were ultimately superseded by a July 25 Order that provided an alternative "rate formula" that is expected to result in much higher levels of refunds.

- Following the June 19, 2001 Order, the ISO performed extensive analysis and testimony as part of a Settlement Conference on the issue of refunds, and supported the case for refunds pursuant to the FERC's July 25 Order, which outlined a "rate formula" to be used in determining refunds for transactions in the ISO's energy and AS markets and the PX energy markets from October 2, 2000 to June 20, 2001. DMA staff have provided extensive analysis and testimony as part of the evidentiary hearing being conducted to implement the July 25 Order. Refunds that would be issued under FERC's July 25 Refund Order (and subsequently modified in a December 19 Order) for transactions through ISO and PX are estimated to be in excess of $1 billion. Additional refunds are being sought through regulatory requests of rehearing and judicial appeals of limitations on refunds under the July 25 Order.

- The ISO submitted numerous filings recommending the necessary elements for effective market power mitigation during 2001. This effort started with the ISO's Offer of Settlement on October 20, 2000; Comments to FERC Order Proposing Remedies for California Electric Markets, November 22, 2000; Comments of Order Proposing Remedies for California Wholesale Electric Markets, December 4, 2000; Proposed Market Power Monitoring and Mitigation Measures, February 6, 2001; and finally the Market Stabilization Plan filed on April 6, 2001. As a result of efforts by the ISO and other parties, the strength of market power mitigation features incorporated in FERC's

[3] *Empirical Evidence of Strategic Bidding in California ISO Real-time Market*, prepared by Anjali Sheffrin, Director, Dept. of Market Analysis. CAISO filing before FERC in Docket No. EL00-95-012 on March 22, 2001.

March plan, and the subsequent April 26 and June 19 Orders, have increased significantly during each subsequent Order. Analysis by the DMA indicates that the June 19 Order has contributed to lower market prices starting in summer 2001, especially in regard to setting ***expectations of prices***. There are market power mitigation features of the June 19 Order, such as the must offer with penalties for noncompliance, which may need to be extended beyond the September 2002 expiration date if similar mitigation measures are not in place by that time.

- DMA has developed a variety of special market monitoring indices and reports filed with FERC on a weekly and monthly basis. Weekly reports to the Commission include analyses of the exercise of market power by individual sellers through direct comparison of bids to the operation of gas-fired generators. DMA has provided analysis of the market impacts of the June 19 Order that has been incorporated in quarterly reports submitted to FERC.

- In October, DMA provided the FERC with its views on the role of, and responsibility for, monitoring market power in an RTO market. DMA focused on five key areas necessary to achieve effective market monitoring and ensure competitive market outcomes. The five areas included: 1) Setting an explicit standard for just and reasonable rates and formulating an effective enforcement mechanism for this standard; 2) Enhancing the authority of monitoring units of the ISOs and RTOs to mitigate undue exercise of market power; 3) Overhauling the criterion for granting market-based rate authority to sellers; 4) Improving federal and state co-ordination on issues that may impede competitive outcomes; and 5) Promoting supply adequacy requirement which will promote competitive market results, and moderate the boom/bust cycle of prices.

Investigate Market Inefficiencies

DMA and Compliance staffs have actively taken part in the investigation of market inefficiencies and anomalies, and the development of options for alleviating market design problems. For example:

- In order to remove incentives that some energy-limited resources may have to bid extremely high prices in the real-time market, the BEEP software was modified to include a "flag" for skipping of spin/non-spin real-time energy bids from energy-limited resources in March.
- The new Target Price methodology was implemented on October 29, 2001, which mitigates gaming opportunities while providing more efficient price signals in the real-time market.

- DMA and Compliance staff continues to work with other parts of the ISO to monitor outage levels, and develop enhanced outage reporting, scheduling and performance standards to reduce potential gaming, inefficiencies and reliability issues associated with unit outages. Enhanced outage reporting requirements and tracking were established pursuant to the "must bid" provisions of the April 26 Order. The ISO has also developed performance standards for filing at FERC.

Ensure Compliance

- Compliance staff has assessed approximately $122 million in penalties covering the period from December 8, 2000 through July 3, 2001 for suppliers' failure to follow dispatch instructions during system emergencies under Amendment 33. Penalties – which are based on real-time prices –

could be reduced to approximately $42 million under lower mitigated prices calculated by the ISO as part of refund proceedings pursuant to the July 25 Order.

- Compliance has rescinded $23.5 million in Regulation capacity payments from suppliers that failed to provide the service between January 1 and October 14, 2001. As part of an investigation of performance prior to the implementation of "No Pay" on September 10, 2000, Compliance staff also identified additional payments for Ancillary Service capacity that was not actually available for dispatch prior to September 10, 2000.
- Compliance has monitored compliance with the "must-offer" obligation for all hours established for generators through FERC's June 19 Order. Several reports were submitted to FERC's Office of Market Oversight & Enforcement detailing instances of declined Dispatch Instructions.
- Other Compliance Department activities include on-going monitoring of unaccounted-for-energy, compliance with bidding certified ramp rates, and tariff requirements for timely submission of meter data for settlement.

Provide Assistance to Other Regulatory Agencies and Policy-Makers

The ISO provides assistance to state and federal regulatory agencies and policy-makers in a variety of ways, ranging from responses to subpoenas on detailed market information on a confidential basis to provision of special studies and analysis to address key issues. For example:

- The California State Auditor General conducted a comprehensive review of the ISO's Market Monitoring activities with a final report issued in March 2001.[4] Their final report was favorable on the professional level of studies and analysis done in market monitoring. Specifically, the State Auditor found that misjudgments on the part of regulators in implementing corrective actions contributed to the energy crisis. In reporting these findings, they noted that starting in 1998, market monitoring groups within the ISO and PX warned the Federal Energy Regulatory Commission (FERC) and the California Public Utilities Commission (CPUC) of potential problems with the market structure. They reported that although hindsight has shown the accuracy of the DMA's predictions, neither FERC nor the CPUC fully or successfully addressed these concerns at the time.
- In response to a request from the California Legislature, the DMA performed a study to address the issue of sufficient capacity reserve margin for the control area to ensure that the average price of energy is reasonably close to the prices that would result in a competitive market.
- DMA conducted a study of the impacts of Path 15 expansion on market power to supplement a larger study completed by the ISO that evaluates the costs and benefits of building additional transmission capacity on Path 15 in year 2005. A report and testimony are being provided for upcoming CPUC hearings on Path 15 expansion.

[4] The California State Auditor Report, "Energy Deregulation: *The Benefits of Competition Were Undermined by Structural Flaws in the Market, Unsuccessful Oversight, and Uncontrollable Competitive Forces,"* can be found at http://www.bsa.ca.gov/bsa/summaries/20001341.html.

- The California ISO has provided responses to over 100 subpoenas and data requests by state and federal regulatory agencies and policy-makers during 2001 (see table on next page). ISO legal staff has produced formal responses to data requests on over 200 days of the year, or about 3 out of every 4 workdays during the year. In conjunction with these responses, the ISO has produced over 800 CDs & floppy disks of data and over 200,000 pages have been produced.

January – December 2001 Subpoenas and Data Requests

CPUC:	10 Formal Subpoenas/Requests* 12 Data Requests
EOB:	15 Formal Subpoenas/Requests* 2 Informal Requests
California Attorney General:	1 Subpoena 15 Informal Requests
FERC:	10 Formal Subpoenas/Requests** 9 Informal Requests
State Legislative Committees:	19 Formal Subpoenas/Requests 1 Informal Request
PG&E Bankruptcy Proceedings:	2 Formal Subpoenas/Requests
District Attorney, San Diego County:	1 Subpoena
Senator Wyman:	1 Data Request
TOTAL:	58 Formal Subpoenas/Requests 40 Informal Requests ~ 100 Total Requests

* In addition, EOB & CPUC are provided monthly productions (operator logs & market data).

** DMA also provides FERC with bid and scheduling data and Market Monitoring Reports on a weekly basis.

I. Summary of 2001 Market Performance

This section reviews the overall performance of California's energy and ancillary service markets during 2001. California's energy markets were in a continuing state of crisis in late 2000 through the spring of 2001. Credit problems and high level of unit outages produced energy prices that were multiples above the levels observed during similar periods in prior years. Natural gas fired generator production costs increased to unprecedented levels as natural gas prices escalated in California, and spiked on December 8-11, 2000 to an all-time high of $58.76/mmbtu in Southern California, compared with a national high of $10.52. It wasn't until late June that energy prices decreased significantly as mild weather and conservation produced more favorable demand conditions. This, combined with a precipitous drop in natural gas prices, significant forward contracting by CERS for the utilities' net short load requirements, and the imposition by the Federal Energy Regulatory Commission (FERC) of west-wide market power mitigation measures, moderated energy prices in the summer and fall of 2001. The significant forward contracting by CERS has made suppliers less pivotal in the markets and reduced their incentives to spike prices. The FERC's market power mitigation measures that went into effect on June 20, 2001 had a moderating effect on price expectations for suppliers, and worked to reduce withholding during periods when the ISO needs to procure imbalance energy.

The following chart depicts total system load and average cost to load per megawatt-hour (MWh) of energy consumed from 1999 through 2001:

Figure 1. System Load and Average Cost, 1999-2001

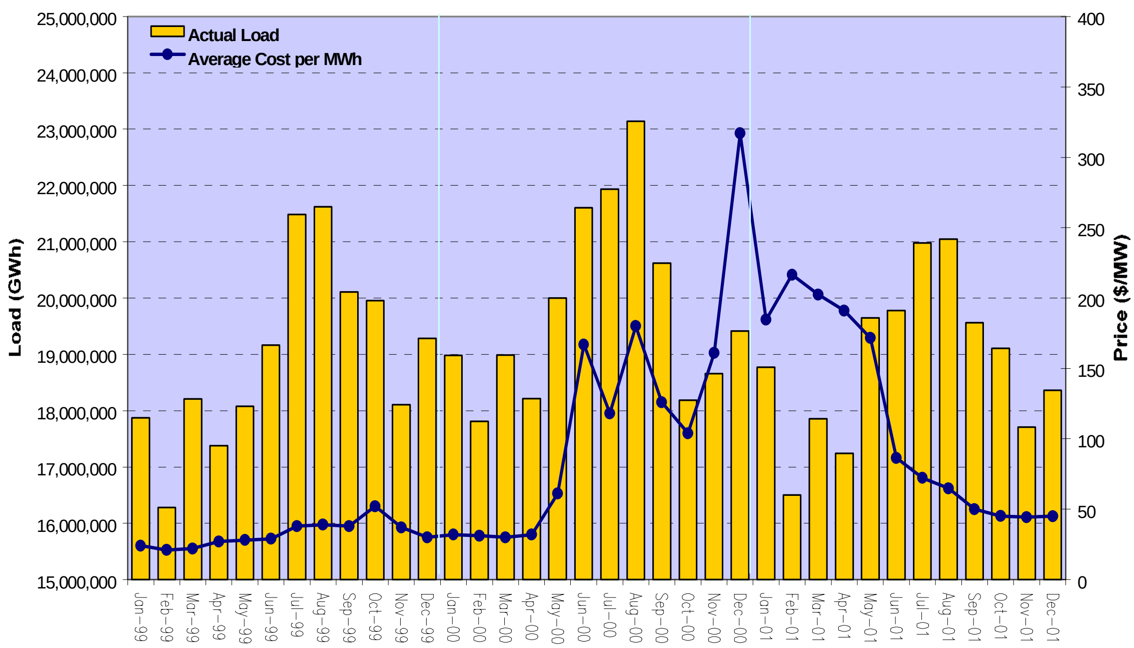


Figure 1 shows that total energy cost to those entities serving load (customers), while high and volatile in the first several months of 2001, stabilized by the end of the year to levels under $50/MWh. Load (demand) was reduced due to the softening economy, mild weather, and aggressive conservation efforts by California consumers. Meanwhile, FERC's regional mitigation measures in late June limited suppliers' ability to charge prices substantially above competitive levels and helped moderate the expectation on futures prices.

Figure 2. Monthly System Cost Table: 2000 and 2001

Summary of 2000 Estimated Energy Costs

	ISO Load (GWh)	Est PX Energy Costs (MM$)*	Bilateral Energy Costs (MM$)*	RT Energy Costs (MM$)**	AS Costs (MM$)***	Total Energy Costs (MM$)	Costs of AS+ Energy (MM$)	Avg Energy Cost ($/MWh)	A/S Cost ($/MWh Load)	A/S Costs as % of Energy Costs	Total Costs ($/MWh load)
Jan-00	18,984	$ 495	$ 103	$ 3	$ 12	$ 601	$ 612	$ 32	$ 0.62	2.0%	$ 32
Feb-00	17,807	$ 419	$ 103	$ 20	$ 10	$ 542	$ 552	$ 30	$ 0.58	1.9%	$ 31
Mar-00	18,989	$ 432	$ 90	$ 39	$ 11	$ 561	$ 572	$ 30	$ 0.60	2.0%	$ 30
Apr-00	18,212	$ 429	$ 101	$ 31	$ 17	$ 561	$ 578	$ 31	$ 0.95	3.1%	$ 32
May-00	19,997	$ 828	$ 225	$ 108	$ 63	$ 1,161	$ 1,224	$ 58	$ 3.16	5.4%	$ 61
Jun-00	21,605	$ 2,303	$ 529	$ 339	$ 436	$ 3,171	$ 3,607	$ 147	$20.19	13.8%	$ 167
Jul-00	21,935	$ 1,896	$ 346	$ 216	$ 125	$ 2,458	$ 2,583	$ 112	$ 5.71	5.1%	$ 118
Aug-00	23,141	$ 2,786	$ 585	$ 515	$ 282	$ 3,886	$ 4,168	$ 168	$12.18	7.3%	$ 180
Sep-00	20,620	$ 1,819	$ 389	$ 236	$ 152	$ 2,445	$ 2,597	$ 119	$ 7.39	6.2%	$ 126
Oct-00	18,184	$ 1,400	$ 356	$ 27	$ 56	$ 1,388	$ 1,434	$ 100	$ 3.33	3.3%	$ 104
Nov-00	18,656	$ 2,292	$ 402	$ 195	$ 114	$ 2,889	$ 3,004	$ 155	$ 6.13	4.0%	$ 161
Dec-00	19,412	$ 3,742	$ 820	$ 1,149	$ 440	$ 5,711	$ 6,151	$ 294	$22.65	7.7%	$ 317
Total 2000	237,543	$ 18,842	$ 4,048	$ 2,877	$ 1,720	$25,373	$27,083				
Avg 2000	19,795	$ 1,570	$ 337	$ 240	$ 143	$ 2,114	$ 2,257	$ 107	$ 7.24	6.8%	$ 114
Total 1999	227,533	$ 5,866	$ 982	$ 180	$ 404	$ 7,028	$ 7,432				
Avg 1999	18,961	$ 489	$ 82	$ 15	$ 34	$ 586	$ 619	$ 31	$ 1.78	5.7%	$ 33
1998 (9mo)	169,239	$ 4,148	$ 556	$ 209	$ 638	$ 4,913	$ 5,551				
Avg 1998	18,804	$ 461	$ 62	$ 23	$ 71	$ 546	$ 617	$ 29	$ 3.77	13.0%	$ 33

* Estimated PX Energy Costs include UDC owned supply sold in the PX, valued at PX prices.
Estimated Bilateral Energy Cost based on the difference between hour ahead schedules and PX quantities, valued at PX prices.
** Beginning November 2000, ISO Real Time Energy Costs include OOM Costs.
*** AS costs include self-provided quantities.

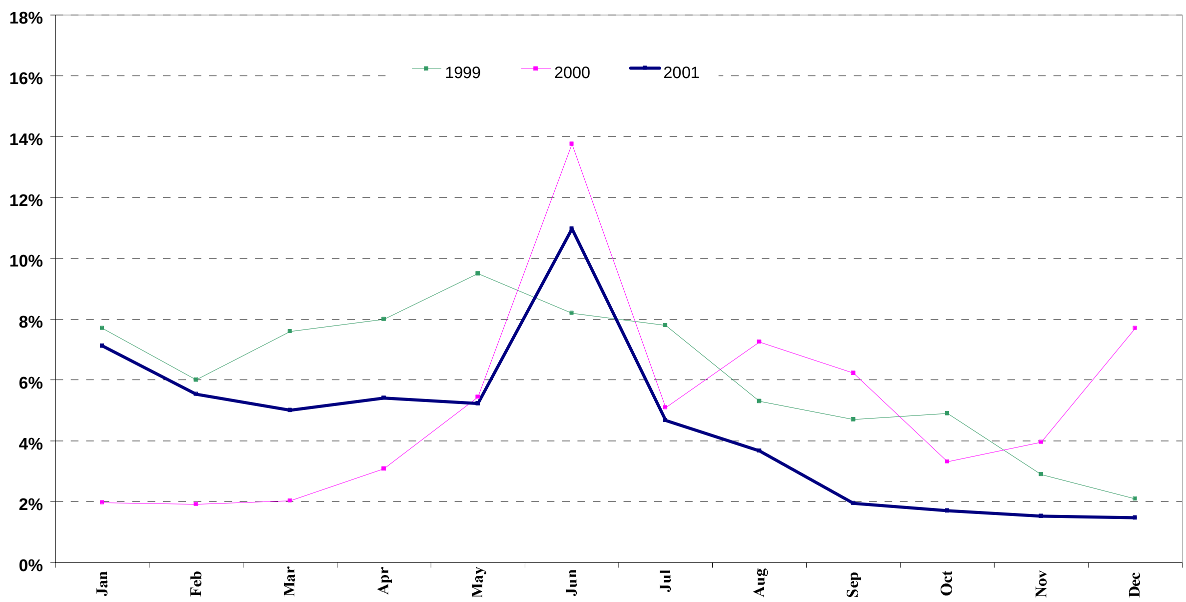
Summary of 2001 Estimated Energy Costs

	ISO Load (GWh)	Forward Energy (GWh)*	Est Forward Energy Costs (MM$)**	RT Energy Costs (MM$)***	A/S Costs (MM$)****	Total Energy Costs (MM$)	Total Costs of Energy and A/S (MM$)	Avg Cost of Energy ($/MWh)	A/S Cost ($/MWh Load)	A/S % of Energy Cost	Avg. Cost of Energy & A/S ($/MWh Load)
Jan-01	18,770	16,950	$ 2,710	$ 756	$ 247	$ 3,466	$ 3,713	$ 185	$13.15	7.1%	$ 198
Feb-01	16,503	14,876	$ 2,657	$ 917	$ 198	$ 3,574	$ 3,772	$ 217	$12.00	5.5%	$ 229
Mar-01	17,857	16,744	$ 2,736	$ 881	$ 181	$ 3,616	$ 3,797	$ 203	$10.14	5.0%	$ 213
Apr-01	17,237	16,267	$ 2,537	$ 755	$ 178	$ 3,292	$ 3,471	$ 191	$10.34	5.4%	$ 201
May-01	19,651	18,351	$ 2,771	$ 601	$ 176	$ 3,372	$ 3,548	$ 172	$ 8.97	5.2%	$ 181
Jun-01	19,777	19,468	$ 1,598	$ 111	$ 187	$ 1,709	$ 1,896	$ 86	$ 9.48	11.0%	$ 96
Jul-01	20,976	20,599	$ 1,458	$ 54	$ 71	$ 1,513	$ 1,583	$ 72	$ 3.37	4.7%	$ 75
Aug-01	21,048	21,571	$ 1,329	$ 34	$ 50	$ 1,363	$ 1,414	$ 65	$ 2.38	3.7%	$ 67
Sep-01	19,562	19,562	$ 958	$ 19	$ 19	$ 977	$ 996	$ 50	$ 0.97	1.9%	$ 51
Oct-01	19,105	19,395	$ 854	$ 10	$ 15	$ 864	$ 878	$ 45	$ 0.77	1.7%	$ 46
Nov-01	17,707	18,028	$ 774	$ 10	$ 12	$ 784	$ 796	$ 44	$ 0.68	1.5%	$ 45
Dec-01	18,830	18,673	$ 811	$ 14	$ 12	$ 826	$ 838	$ 44	$ 0.65	1.5%	$ 44
Total 2001	227,024	220,484	$21,194	$ 4,162	$ 1,346	$25,356	$26,702				
Avg 2001	18,919	18,374	$ 1,766	$ 347	$ 112	$ 2,113	$ 2,225	$ 114	$ 5.93	5.3%	$ 118

***** Sum of hour-ahead scheduled quantities
****** Includes UDC (estimated cost of production), CDWR costs after 8/2001projections only; bilaterals estimated at hub prices
******* includes OOM, dispatched real-time paid MCP, and dispatched real-time paid as-bid
******** Including ISO purchase and self-provided A/S priced at corresponding A/S market price for each hour, less Replacement Reserve refund

Energy and Ancillary Services (AS) costs continue to be higher than those seen in the first two years of operation. Total energy and AS costs for the first ten months of ISO operation in 1998 were approximately $5.55 billion resulting in an average cost of $33/MWh. Total costs in 1999 were comparable to 1998 with a total cost of approximately $7.03 billion (for twelve months) and an average cost of energy and AS remaining steady at $33/MWh. Costs increased substantially in 2000. Total costs for energy and AS in 2000 were over $27 billion, resulting in an average cost of $114/MWh. In 2001, total energy and AS costs were comparable to 2000 at more than $26.7 billion with an average cost of $118/MWh of load served, with the majority of these costs being incurred in the first half of the year.

Figure 3. Ancillary Services as a Percent of Energy Cost

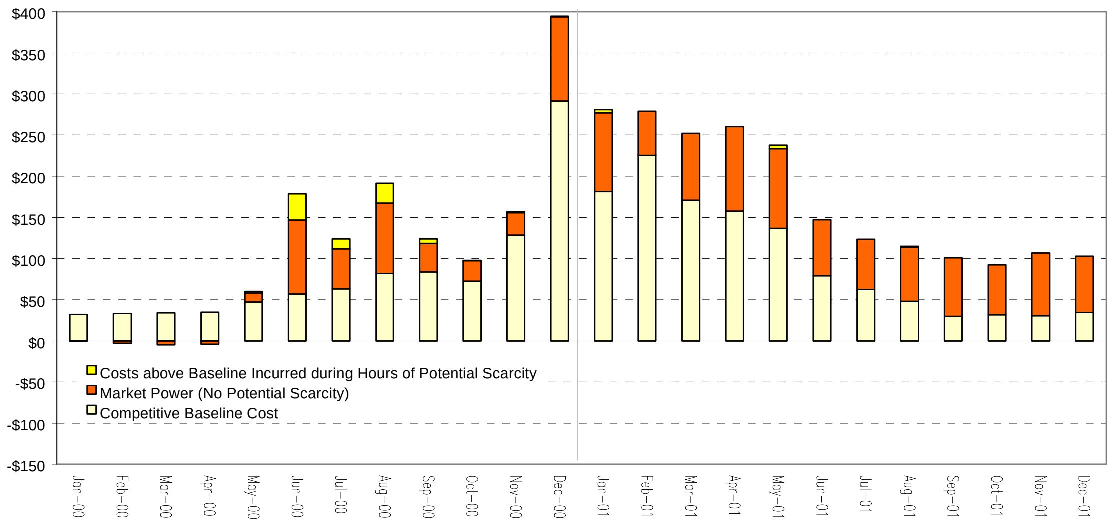


Ancillary service costs as a percentage of total energy costs decreased from June 2001 as utilities chose to self-provide AS and abundant capacity was available to serve the ancillary services markets. During the latter half of the year 2001, ancillary service costs as a percentage of total energy costs have been significantly less than those seen in 1999 and 2000. Ancillary service prices peaked in June as energy prices dropped precipitously but there was a lag in AS prices dropping.

Market Power

Suppliers to California's electricity market possessed and exercised significant market power during the first half of the year. Suppliers were able to raise prices significantly above competitive levels. The following chart shows the markup of prices above those in a competitive market (price-cost markup) for forward-energy purchases and real-time energy:

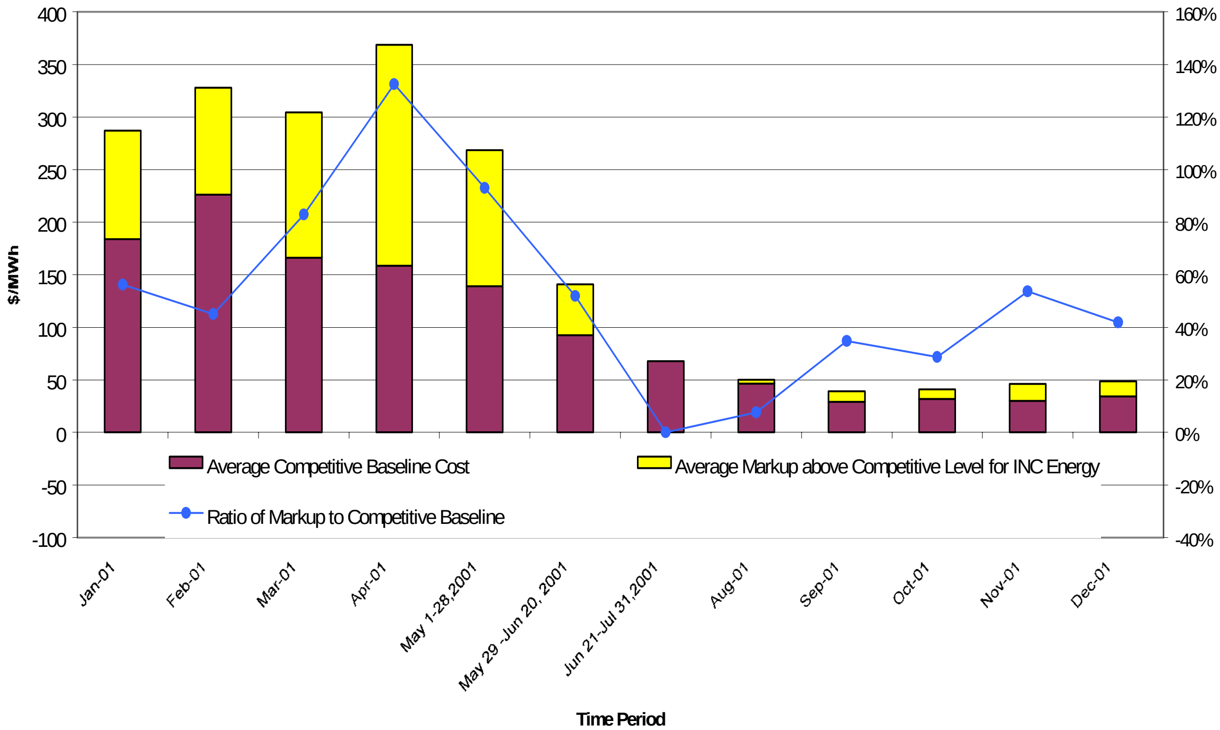
Figure 4. Price-cost Markup of Forward and Real-Time Energy



The area depicted in red shows that generators enjoy substantial ability to raise prices significantly above the competitive baseline cost, even when hours of scarcity are excluded (in yellow). Scarcity is defined as hours when reserves were 10% or below.

The bulk of the markup observed after June is embedded in the long-term forward contracts entered into by CERS during the period of January through April 2001. Thus market power is embedded in long-term average costs for electricity. Generators' exercise of market power in the real-time market was substantially reduced in July due to more favorable supply/demand conditions, the imposition of Western-wide market power mitigation, and significant forward purchases, as shown in the following chart:

Figure 5. Price-cost Markup in the Real-Time Energy Market

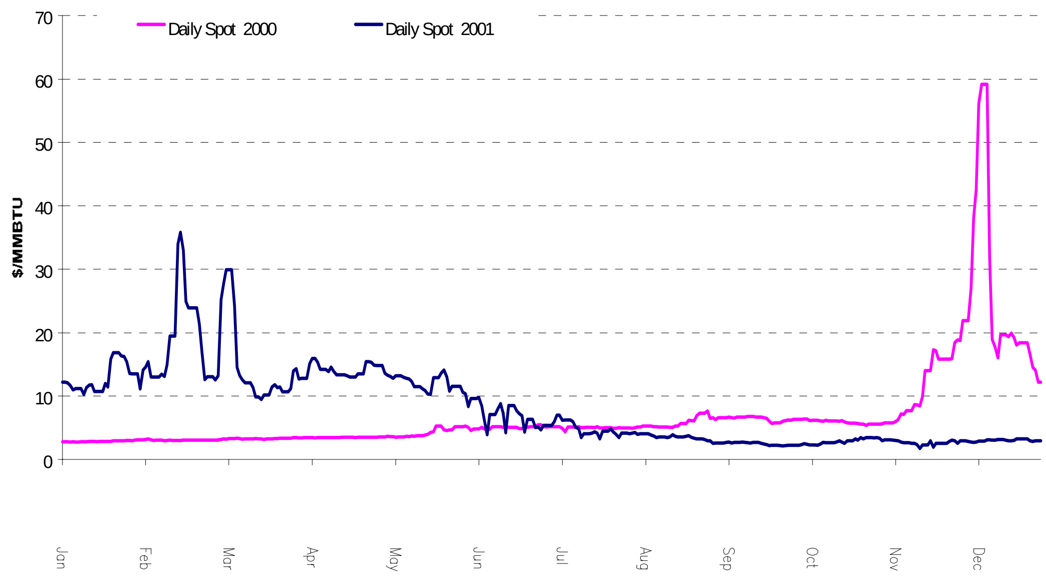


The markup, while high in the winter and spring months of 2001, fell substantially in July and August. Then the level of markup slowly increased throughout the fall. DMA is currently monitoring the increase in markup in the fall of 2001 and investigating its causes.

Natural Gas Market

A key input of electric prices is the price of natural gas. Gas prices reached an all-time high of $58.76 per million British Thermal Units (mmbtu) on December 11, 2000 at the Southern California Border, and prices in general continued to be high and volatile through the winter and spring of 2001. Low demand in the summer brought prices under control. The price reached a low of $1.74/mmbtu on November 16, 2001, and stabilized in the $2 to $3/mmbtu range by late fall (its lowest levels in two years) as shown in the following chart for the Southern California burner-tip price:

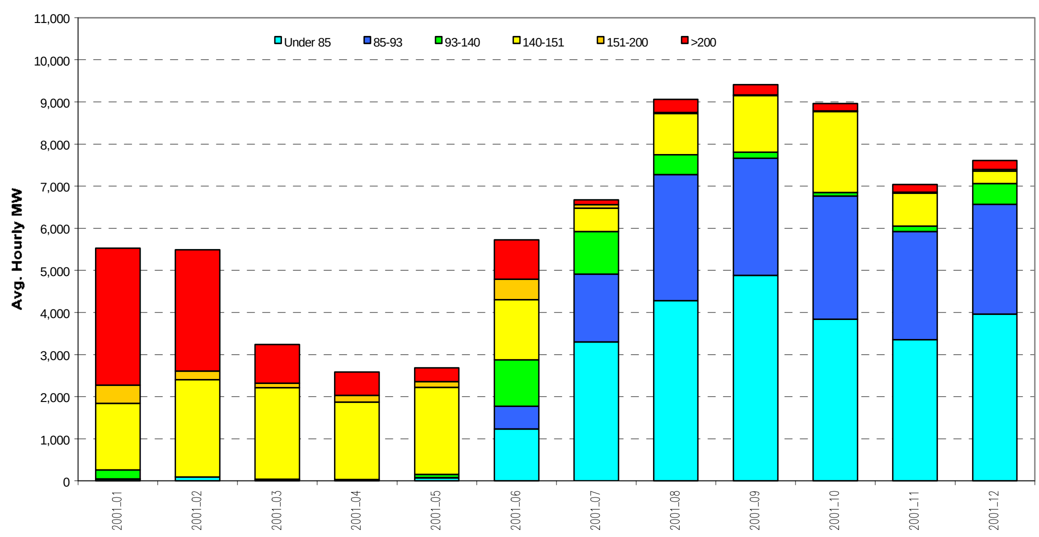
Figure 6. Southern California Border Natural Gas Spot Price – 2000 vs. 2001



Bids into Balancing Energy Ex-Post Price (BEEP) Stack

In January and February 2001, most BEEP bids were in the range above $200/MWh. As FERC's mitigation orders changed expectation as to prices which would be allowable, suppliers began to bid below the price caps, as shown in the following chart.

Figure 7. Original (non-Proxy) Bids into BEEP Stack



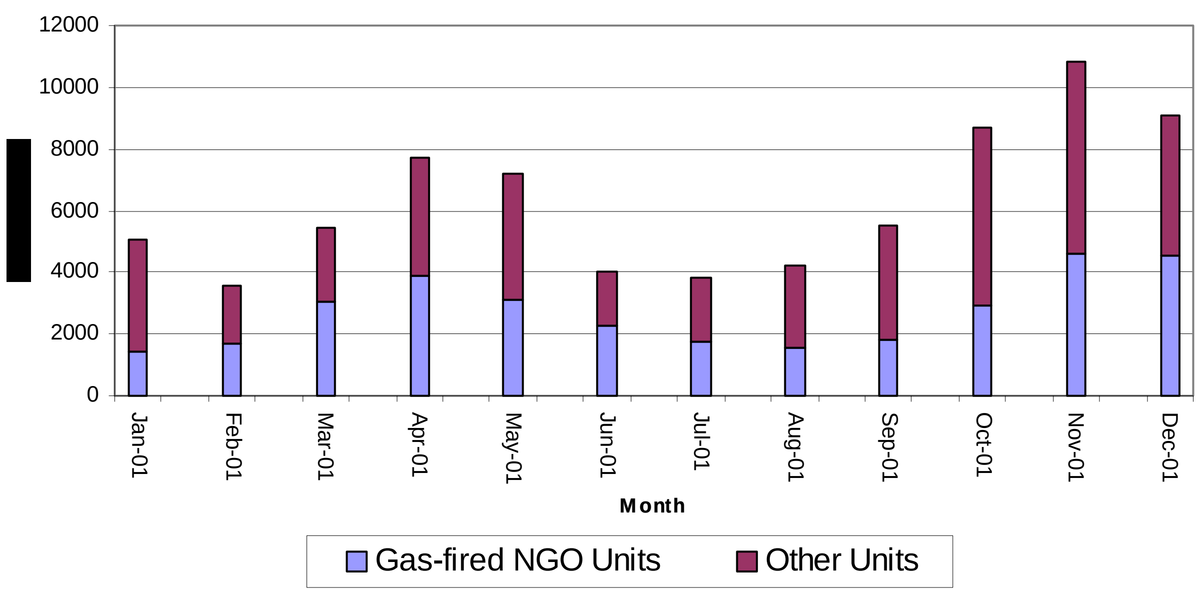
During the period January 1, 2001 through June 20, 2001, a soft price cap of $150/MWh was in effect. The proportion of bids in the range of $140 to $151/MWh, those at or just below the price cap, are depicted in red. The chart shows that most bids were either in this range or above $200/MWh.

FERC's Order of June 19, 2001 lowered the soft price cap to a formula-determined $91.87, and it remained at that level through December 19, 2001. In that Order, FERC also directed generators to offer all available generation into the BEEP market. The combination of these actions resulted in a substantial increase in bids well below the price cap, as shown by the areas in pale yellow. On December 19, the FERC issued an Order instituting a winter mitigation methodology that set a new mitigated price cap floor at $108/MWh.[5] The winter methodology prescribes that the cap be adjusted whenever the average monthly natural gas price rises 10 percent above $6.641/mmbtu, the price used in setting the original mitigated price.

Monthly Outages 2000 and 2001

Average monthly outages decreased significantly in 2001 from 2000, particularly during the peak summer months. The decrease was due in large part to improvements in outage coordination procedures and improved performance spurred by the FERC's west-wide market power mitigation plan that went into effect in June.

Figure 8. Preliminary Monthly Outage Data for 2001*



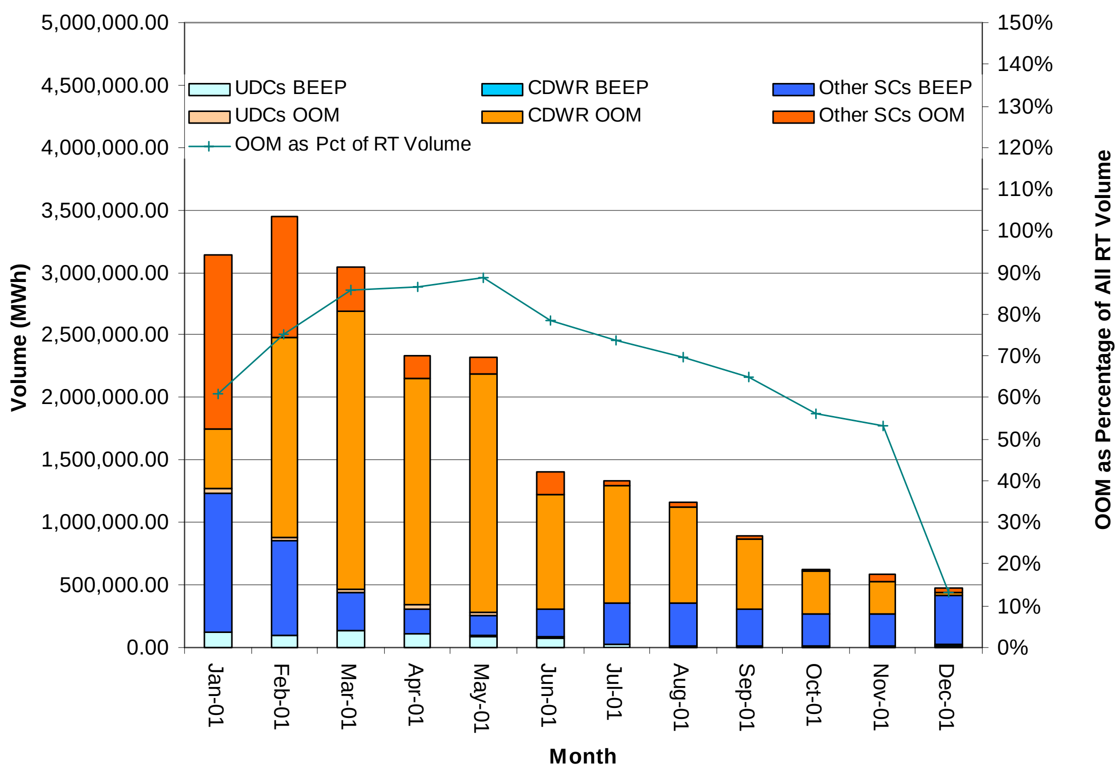
[5] $108/MWh is the actual mitigated price set using the methodology adopted by the FERC on June 19, 2001 during the last reserve deficiency on May 31, 2001. The new interim mitigated price supercedes the existing mitigated price of $91.87/MWh which was set at 85 percent of the originally calculated $108/MWh.

*Includes only reported outages, but not economic outages.

California Department of Water Resources (CDWR) Out-of-Market (OOM) Activity

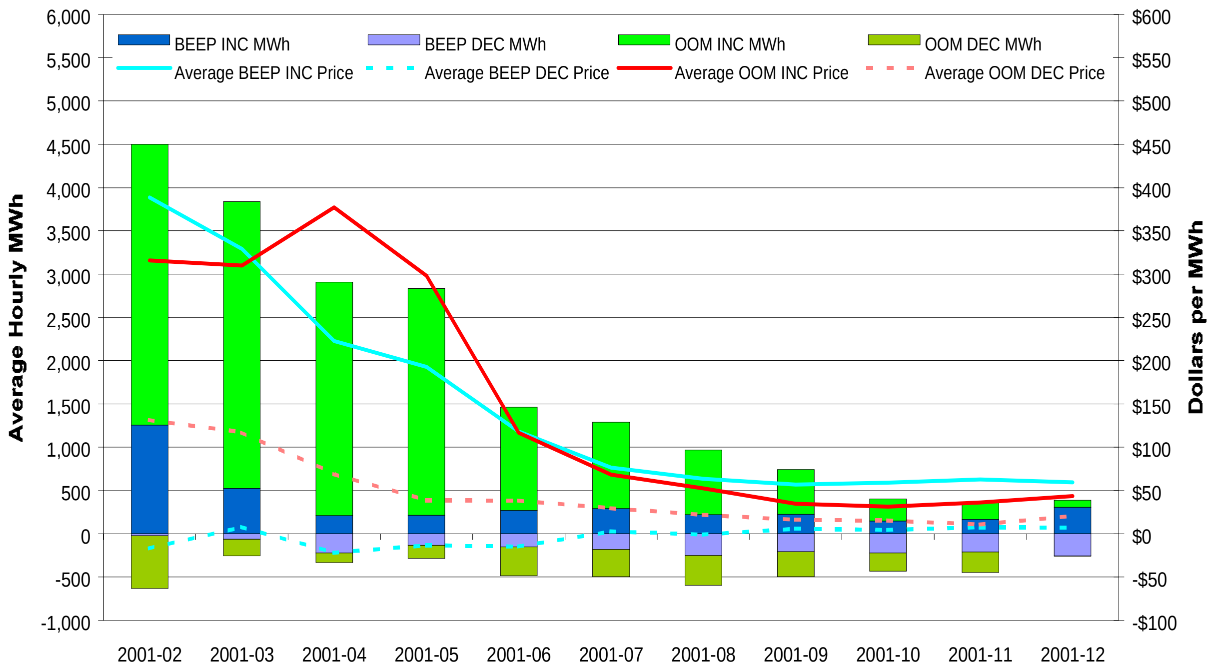
Another significant trend has been California Energy Resource Schedulers' (CERS) OOM procurement activity. CERS, under the auspices of AB1X of the California Assembly, procured real-time energy out of market through November. As a condition of providing its service as guarantor for the ISO's real-time market, CERS procured real-time OOM energy prior to the close of the BEEP market, significantly reducing BEEP volumes. The following chart shows total incremental (INC) and decremental (DEC) procurement by schedule source in California's real-time wholesale energy markets in 2001.

Figure 9. Sources of Real-Time Energy (INC + DEC) by Source and Market



On November 7, 2001, FERC ordered the ISO to invoice CDWR for payables due and to treat it as a conventional scheduling coordinator (SC) for a certain portion of the IOUs' load. This has returned most real-time procurement activity to the BEEP stack. Figure 10 shows the OOM and BEEP volumes and average INC and DEC prices for 2001.

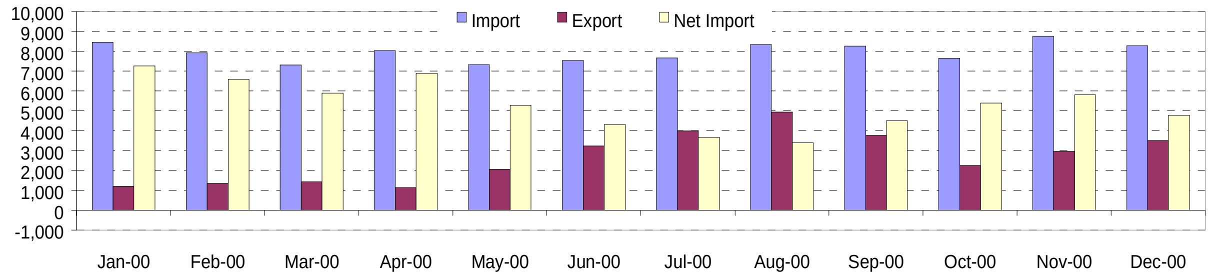
Figure 10: Price and Volume of INC INC and DEC Transactions in Real-Time Market

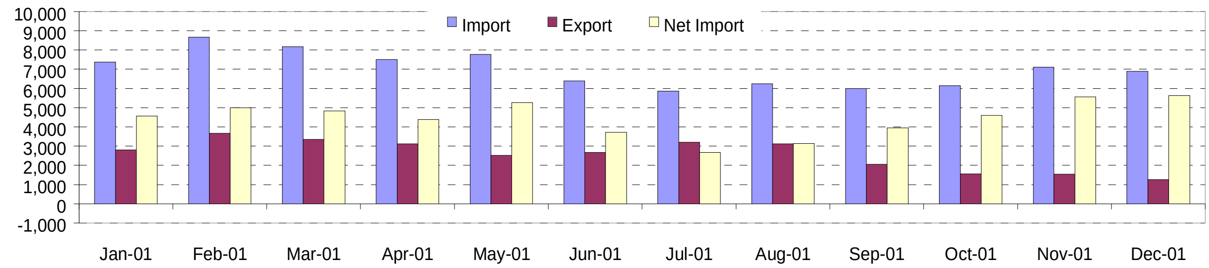


Large real-time volumes occurred during the first five months of the year prior to CERS entering into forward contracts to meet the UDCs' net short load requirements. The majority of this energy was purchased out-of-market by CERS. As CERS continued to increase its forward position in the market, real-time volumes and prices decreased until stabilizing in November and December. In response to the November FERC order directing CERS to cease OOM purchases, real-time volumes moved back into the BEEP market in December.

The following charts on the next page compare net imports in 2000 and 2001.

Figures 11a and 11b. Imports, Exports, and Net Imports; 2000 and 2001





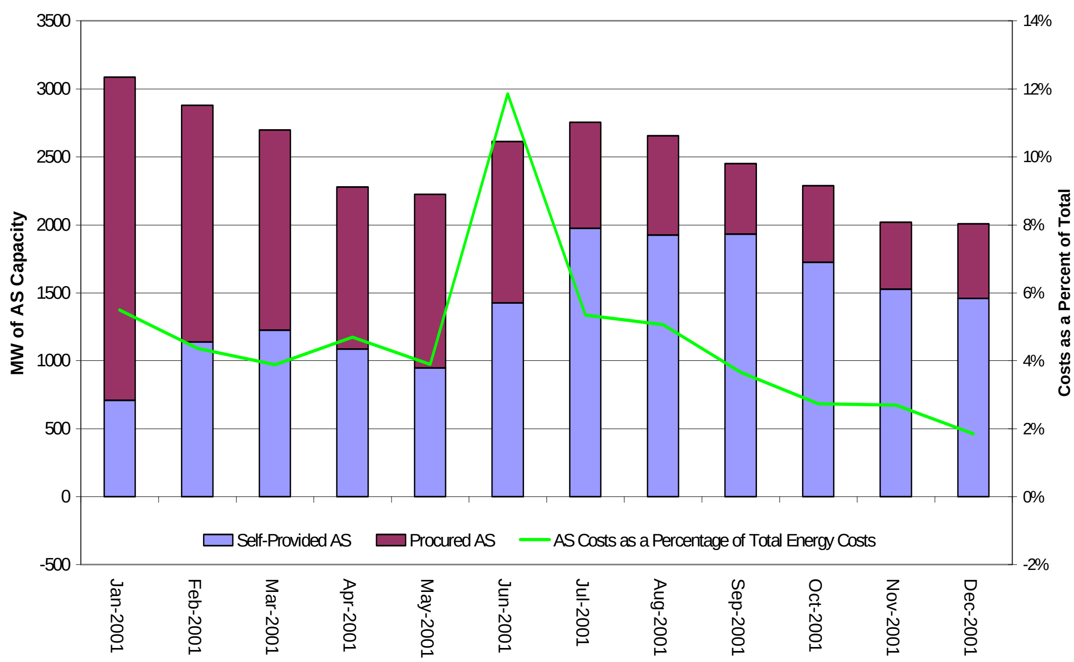
The charts show the relative increase in imports as a proportion of total transactions, due primarily to more favorable supply conditions in the Pacific Northwest.

Ancillary Services Markets

SCs have increasingly self-provided AS in 2001. Self-provision has been especially strong by the UDCs. Soft demand, particularly in the summer and fall, has enabled generators to operate at less than maximum capacity, freeing some capacity for AS. AS costs as a percentage of total energy costs have decreased significantly since June 2001. The ratio of AS costs as a percentage of total energy costs increased briefly in June due to significantly lower energy costs while a reduction in AS costs lagged. The ratio dropped in July as AS costs fell as well.

The following chart shows total MW of AS capacity, including capacity both self-provided by SCs and procured in the ISO's markets. The chart also shows AS costs as a percentage of total energy costs.

Figure 12. Self-Provision of Ancillary Services

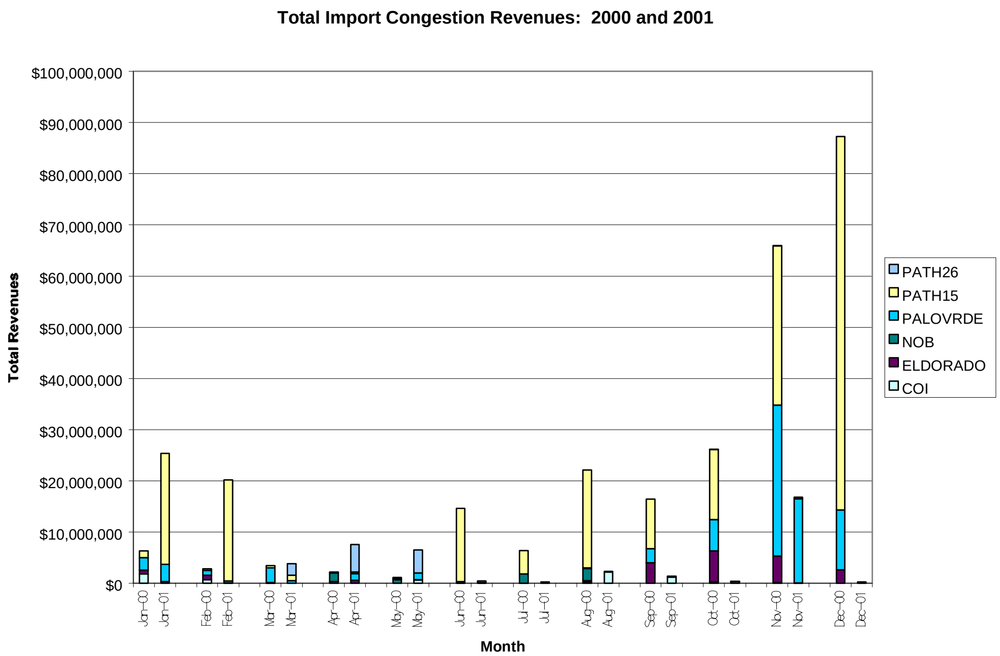


Congestion Market

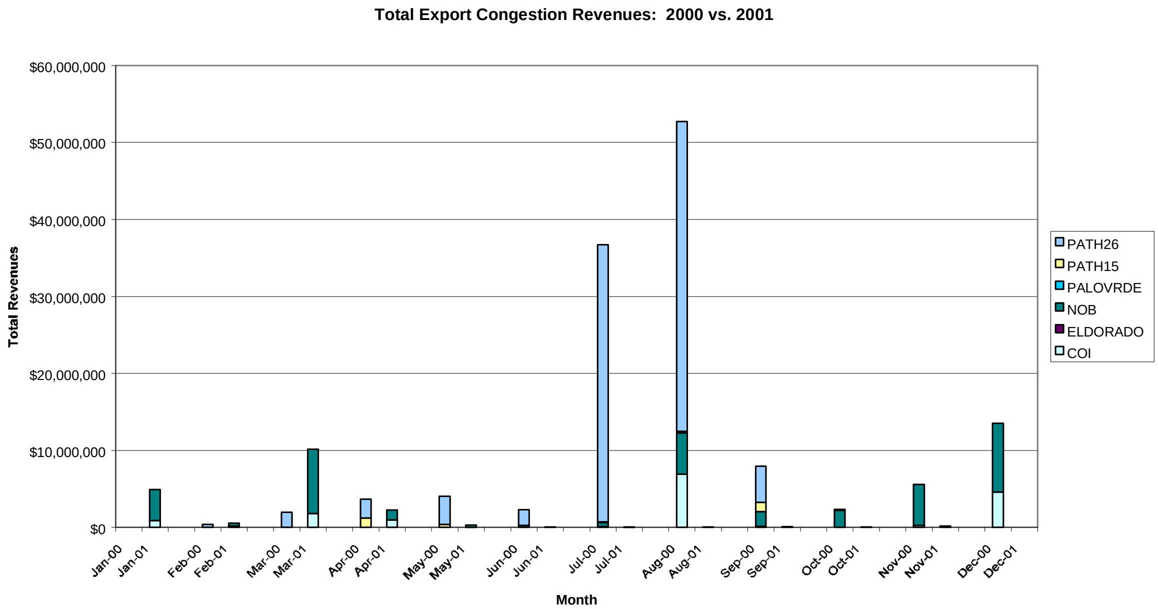
The congestion frequency and cost increased during the first few months of the year 2001 compared to the year 2000, but decreased thereafter. The following figures show the congestion cost by month for the two years[6] for the import and export directions respectively. For the internal ISO control area paths (Path 15 and Path 26) the import direction is conventionally south to north, and the export direction is north to south.

Congestion costs were particularly high in the export direction on Path 26, NOB and COI during summer 2000, and in the import direction on Path 15, Eldorado and Palo Verde during the latter part of 2000 and early 2001. Path 15 congestion deserves particular attention because total congestion costs on Path 15 have dropped significantly since mid-2001. Although the frequency of congestion continues to be moderate on this path, usage costs were set to zero due to a variety of actions described below.

Figures 13a and 13b:



[6]The congestion market during the period December 8-20, 2000 was problematic due to a disconnect between the congestion and energy (PX) markets immediately after the implementation of the $250 soft cap on December 8, 2000 until a fix was implemented on December 20, 2000.



The following charts compare average day-ahead congestion charges and congestion frequency (percent of hours congested) between 2000 and 2001:

Figure 14: Average Annual Congestion Charges

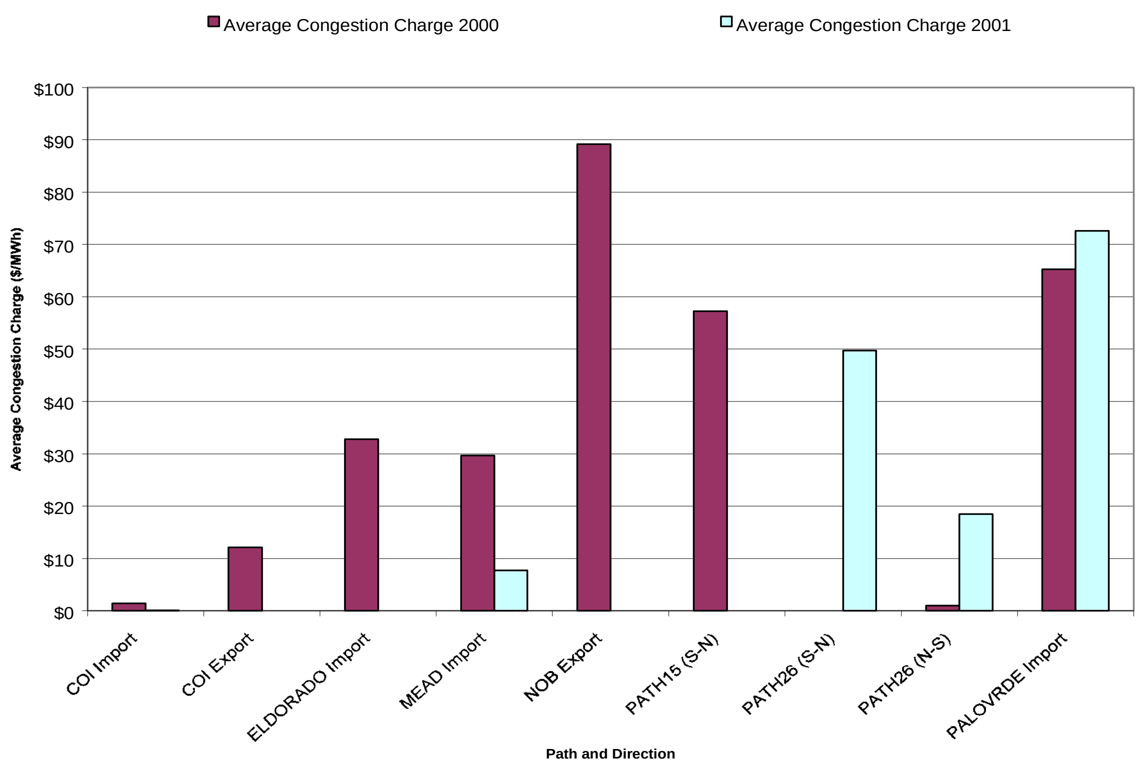
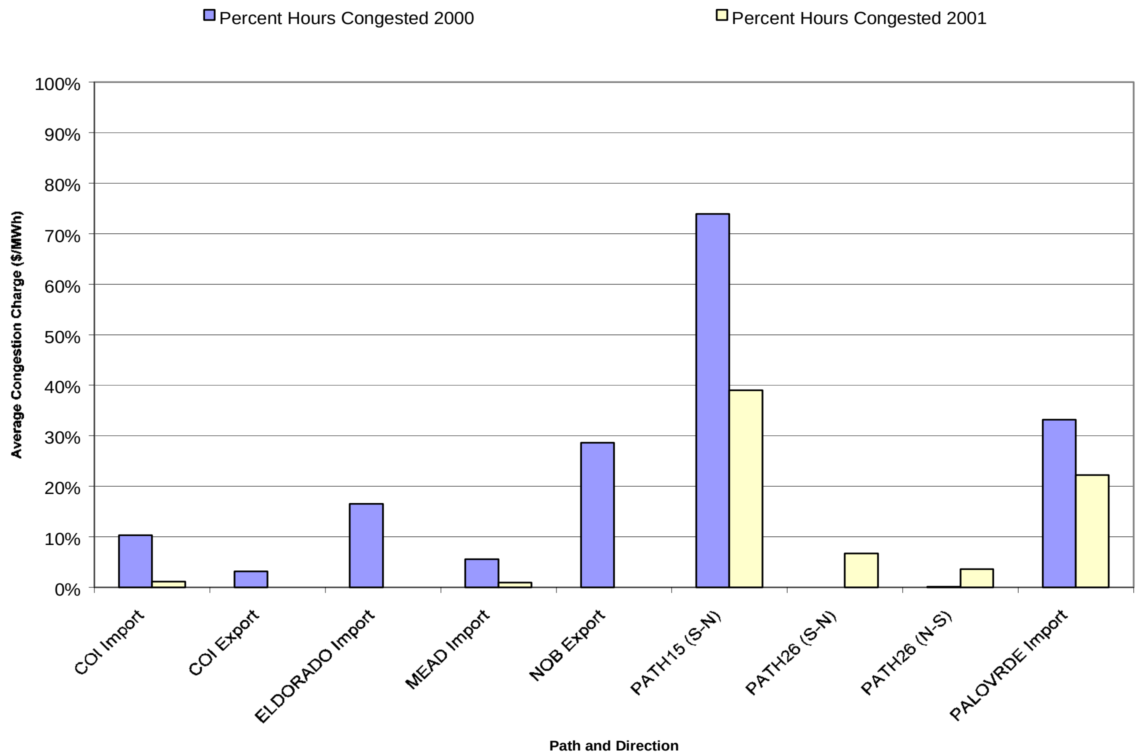


Figure 15: Percent Hours Congested - Day-Ahead



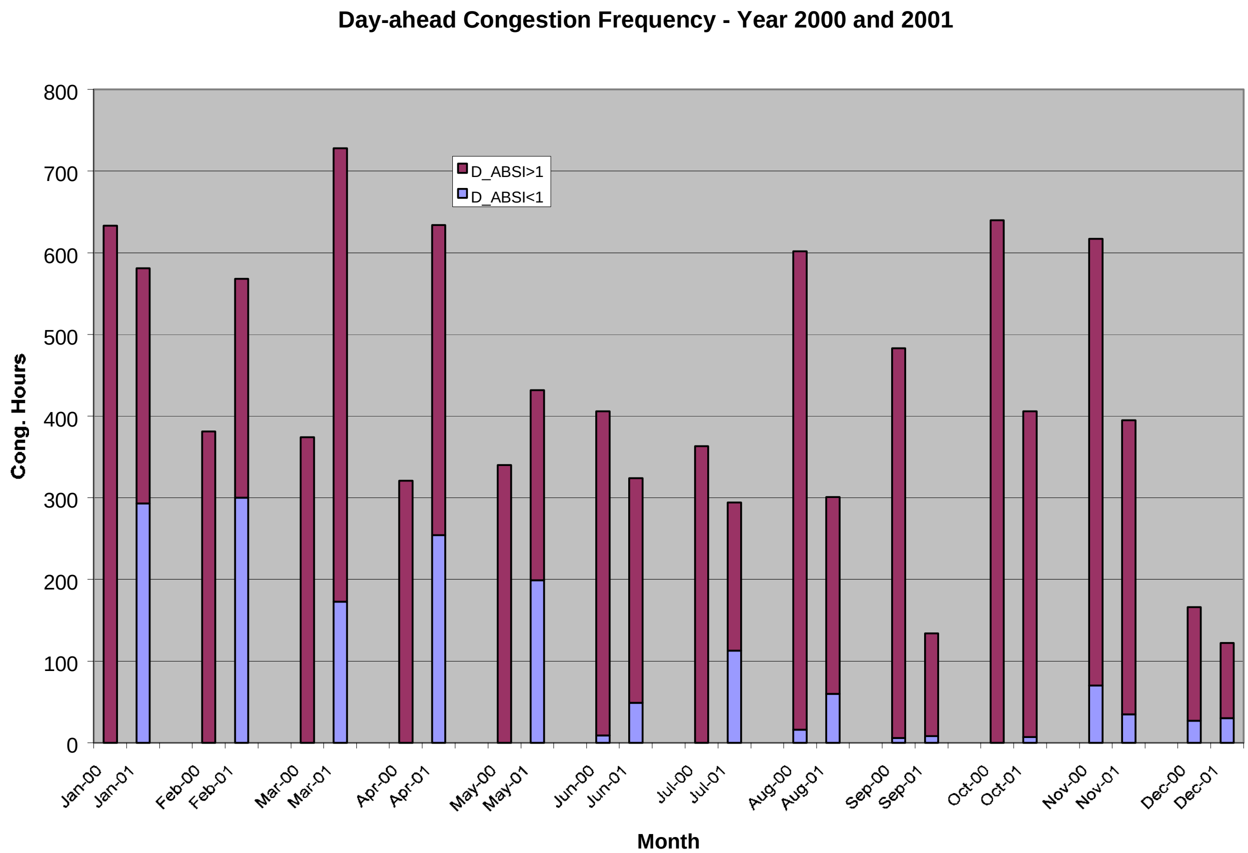
The number of hours congested decreased on most paths in 2001 compared to 2000, with the exception of Path 26. Percent of hours congested decreased from 74% to 39% on Path 15 in the South-to-North (import) direction, and from 33% to 22% on the Palo Verde intertie in the import direction.

Average congestion charges decreased on most paths as well. The exception is on Palo Verde, in which average congestion charges increased slightly. The congestion charges on Path 15 since mid-2001 have been very low ($0/MWh in many hours) despite rather frequent occurrence of congestion on this path. This is to a large extent due to a very narrow (or zero) spread of INC and DEC adjustment bid prices submitted to resolve congestion on Path 15, primarily by one of the UDCs. Since some of the adjustment bids are submitted on non-dispatchable load, some of the congestion presumably managed in the forward (day-ahead and hour-ahead) markets re-appears in real time. This could present potential reliability problems, depending on whether Path 15 congestion mitigated in the day-ahead market by phantom adjustment bids reappears in the real-time market. If this were to occur, the UDC would be effectively paying a positive real-time usage charge and the more the real-time congestion, the larger the real-time zonal market-clearing price spread between NP15 and ZP26/SP15 and the higher the effective real-time usage charge to the UDC. Moreover, whereas the day-ahead congestion revenues are paid to the Transmission Owners with rights on Path 15, the real-time net payment by PG&E would go to the suppliers in the ISO's real-time market. Our analysis shows that on average, congestion appeared in real time 10 percent of the time that Path 15 congestion was mitigated in the day ahead. During these instances, the real-time zonal price difference between NP15 and ZP26 (the effective real-time usage charge) averaged about $70/MWh, substantially higher than the day-ahead usage charge. DMA will continue to monitor and scrutinize this type of behavior going forward to determine if it leads to other unintended consequences or if it rises to a level that would warrant imposing preventative or remedial penalties or sanctions.

Another phenomenon in the congestion market in the year 2001, particularly earlier in the year, has been lack of adequate adjustment bids to manage congestion. This has often resulted in pro rata schedule curtailments. To track and measure the extent of this problem, DMA has defined an indicator, the Adjustment Bid Sufficiency Index (ABSI), which is the ratio of quantity of the available Adjustment Bids to the adjustment quantity needed to resolve congestion (taking the market separation rule into account).

The following figure shows the number of hours of day-ahead congestion by month in the years 2000 and 2001, along with a breakdown between the congested hours when there were inadequate adjustment bids (ABSI < 1) and when sufficient bids were available (ABSI ≥ 1). The figure clearly shows a large percentage of hours in the first few months of the year 2001 where the ISO's congestion market suffered from Adjustment Bid Insufficiency.[7] The situation seems to be re-appearing in November and December.

Figure 16.



[7] The congestion data for December cover only the period December 1 – 7 in each year for comparability of the two.

II. Identify and Assess the Impacts of Market Power

During 2001, the ISO continued to perform a number of investigations and studies to document evidence of the exercise of market power in California's wholesale market and the impacts of this market power on wholesale energy prices. The major objective of these investigations and studies was twofold: (1) to support filings by the ISO at FERC calling for more effective mitigation of market power on a going forward basis, and (2) to support refunds for purchases of wholesale energy and ancillary services made at unjust and unreasonable prices since May 2000 due to the exercise of market power and other market conditions. Provided below is a summary of major investigations by the ISO and related actions taking place during 2001 related to mitigation of market power in California's wholesale market.

- **Reports and Filings on Prices Above the "Soft Cap"**

  Pursuant to FERC's December 15, 2000 Order, a $150 "soft cap" was in effect in the ISO markets from January 1 through June 20, 2001, with all sales of energy or ancillary services at prices over this threshold being subject to cost reporting and justification before FERC. In addition, pursuant to Amendment 33, a $250 "soft cap" and FERC refund authority was in effect from December 8-31, 2000. During 2001, DMA performed extensive analysis of costs over the "soft cap" thresholds and submitted results of this analysis to FERC to support just and reasonable rates through the exercise of this refund authority by FERC.[8] Analysis by DMA quantified potential refunds from individual sellers for sales above just and reasonable levels based on both supplier costs as well as a benchmark of prices consistent with competitive market conditions.

  <u>Result</u>: Pursuant to a monthly "proxy price" formula established in a March 9, 2001 Order, the Commission identified about $125 million in sales above monthly "proxy prices" established by the Commission to be refunded unless sellers could justify these costs before the Commission.[9] Potential refunds based on the monthly "proxy price" formula established under the March 9 Order were ultimately superseded by a July 25 Order (summarized later in this report), which provided an alternative "rate formula" that is expected to result in much higher levels of refunds.

- **Analysis of Market Power Impacts and Strategic Bidding by Individual Sellers**

  In support of the ISO's March filing with FERC calling for stronger market power mitigation, DMA submitted two reports providing evidence of the exercise and impacts of market power in California's wholesale market since May 2000. The first study quantified the degree to which overall prices and costs in California's wholesale market exceeded levels consistent with competitive market conditions.[10] A second study provided analysis and evidence of the exercise of market power in the ISO's real-time energy market by individual suppliers during May to November 2000 through both economic withholding (bidding significantly in excess of costs) and physical withholding (not bidding all available capacity).[11]

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[8] *Report on Real Time Supply Costs Above Single Price Auction Threshold: December 8, 2000 - January 31, 2001*, March 2001

[9] The $125 million in potential refunds pursuant to the March 9 Order includes potential refunds from two notices issued in subsequent months applying the monthly "proxy price" established in the March 9 Order to transactions occurring in subsequent months.

[10] *Further Analyses of the Exercise and Cost Impacts of Market Power In California's Wholesale Energy Market,* March 2001.

[11] *Empirical Evidence of Strategic Bidding in California ISO Real-time Market*, March 2001.

<u>Result</u>: By providing strong evidence of the exercise and impacts of market power, DMA studies supported ISO filings that ultimately led to significantly stronger market power mitigation under FERC's April 26 and June 19 Orders. These Orders contributed significantly in terms of changing expectations in the market and contributing to stabilizing market prices starting in the summer 2001.

- **Analysis of Market Power Mitigation Options**

  The DMA collaborated with other areas of the ISO to provide extensive recommendations and analysis of options for prospective market power mitigation during 2001. FERC's December 15, 2000 Order directed the DMA to develop and present a comprehensive proposal for prospective market power mitigation on January 23, 2001 at a technical conference aimed at exploring options for a prospective mitigation and monitoring plan to be in place in May 2001. Following the issuance of FERC staff's recommended plan in March, DMA collaborated with other areas of the ISO to provide extensive comments and proposed alternatives on FERC staff's proposal. Additional comments, analysis and proposed alternatives were submitted in response to the Commissions' April 26 and June 19 Orders. DMA has provided analysis of the market impacts of the June 19 Order that has been incorporated in quarterly reports submitted to FERC.

  <u>Result</u>: The market power mitigation features incorporated in FERC's March plan and the subsequent April 26 and June 19 Orders have increased significantly in effectiveness in each subsequent Order. Analysis by the DMA indicates that the June 19 Order contributed to lower market prices starting in summer 2001, but that the market power mitigation features incorporated in the June 19 Order may need to be strengthened and extended beyond the September 2002 date these provisions are scheduled to expire.

- **Refund Proceedings Pursuant to FERC's June 19 and July 25 Orders**

  In addition to establishing much stronger market power mitigation on a going-forward basis, the FERC's June 19 Order established a process for refunds and an *ex post* basis for sales in California's wholesale energy market prior to June 19, 2001. DMA staff performed extensive analysis and testimony relating to the issue of refunds as part of the June 25-July 9 Settlement Conference held in Washington, DC pursuant to the June 19 Order. DMA also continues to play a major role in pursuing refunds pursuant to the FERC's July 25 Order, which outlined a "rate formula" to be used in determining refunds for transactions in the ISO's energy and AS markets and the PX energy markets from October 2, 2000 to June 20, 2001. DMA staff have provided extensive analysis and testimony as part of the evidentiary hearing being conducted to implement the July 25 Order. On December 19, 2001, FERC issued another Order providing clarification and modifying, in part, the July 25 Order refund methodology. The evidentiary hearing on refunds pursuant to these Orders has resumed and is scheduled for completion by the summer of 2002.

  <u>Result</u>: Also led to series of FERC orders on refunds to address unjust and unreasonable market outcomes prior to implementation of June 19 Order. Refunds that would be issued under FERC's July 25 Refund Order (and modified on December 19) for transactions through ISO and PX from October 2, 2000 to June 20, 2001 are estimated to be in excess of $1 billion. Additional refunds are being sought through regulatory requests of rehearing and judicial appeals of limitations on refunds under the July 25 Order.

- **Monitoring and Reporting of Anti-Competitive Bidding Practices**

  Pursuant to the April 26 Order, DMA developed a variety of special market monitoring indices and reports which have been filed with FERC on an ongoing basis. The Order requires the ISO to submit weekly reports to the Commission of schedule, outage and bid data to keep the Commission informed on the current market performance, and directs the ISO to identify any concerns about possible inappropriate bidding behavior in the weekly reports.

  Result: Reports and data on bidding behavior are filed with FERC staff on a weekly basis.

- **Cost Review of Bids Over Mitigated Price Limits Under April 26 and June 19 Orders**

  DMA staff reviews cost justifications submitted by suppliers with bids and sales of real-time energy and ancillary services over mitigated price levels which are subject to cost reporting and refund under the April 26 and June 19 Orders. DMA also performs independent cost analysis of sales of real-time energy and ancillary services over mitigated price levels. Results of this analysis, which shows that most sales over mitigated price levels cannot be justified based on costs, have been incorporated in filings to FERC in support of refunds for all sales in excess of cost-based levels.

  In the fall of 2001, FERC issued several rulings disallowing payment for costs above mitigated prices during the months of June and July, on the grounds that cost justifications submitted by these suppliers for bid prices above the proxy market clearing price (mitigated price) in June were not filed in a timely manner and/or were inadequately supported. Consistent with filings by the ISO, FERC also noted that sellers who did not file cost justifications within the time period provided for doing so are not entitled to receive more than the mitigated price.

  DMA's analysis shows the total amount of refunds resulting from these FERC orders on the months of June and July is about $1.8 million. DMA continues to monitor sales above mitigated prices, but a very limited amount of sales were made above mitigated prices since July.

  The Commission has not issued a ruling on any sales during hours of reserve deficiency on May 30-31, when the proxy price mitigation of the April 26 Order was in effect. Analysis by DMA submitted to the Commission shows that potential refunds on sales during hours of reserve deficiency on May 30-31 under the April 26 Order reach about $1.6 million.[12]

  Result: Refunds for sales above mitigated price levels ordered by FERC under the June 19 Order totaled approximately $1.8 million.

- **Investigation of RMR Unit Outages**

  In April 2001, an investigation of RMR unit outages at the Huntington Beach and Alamitos plants initiated by DMA in May 2000 culminated in a FERC Order accepting a settlement agreement between the FERC and Williams/AES. The agreement calls for a refund of $8 million of payments made for out-of-sequence calls to other non-RMR units controlled by Williams/AES to meet local

[12] Pursuant to the Commission's April 26 Order, no price mitigation was in effect from June 1-20, since price mitigation under the April 26 Order was in effect only during reserve deficiency hours (Stage 1, 2 or 3 Alerts), and no reserve deficiency hours occurred during June.

reliability requirements during the RMR unit outages in April-May 2000. The case was referred to FERC after DMA's initial investigation indicated that the out-of-sequence payments resulted from potential gaming and abuse of RMR status. After referral of the issue to FERC, DMA staff continued to provide information and filed an affidavit with the Commission regarding the ISO's findings and recommendations in the case. On March 14, 2001, FERC issued a Show Cause Order directing Williams and AES to "show cause why they should not be found to have engaged in violations and directed to make refunds and have certain conditions placed on Williams' market-based sales authority."

Result: Following a Show Cause Order issued by FERC in March 2001, a stipulated order between AES and the Commission was reached that resulted in a refund of approximately $8 million and one year suspension of AES' market based rate authority for any out-of-sequence/out-of-market sales due to RMR outages.

III. Market Inefficiencies/Anomalies

DMA staff has actively taken part in the investigation of market inefficiencies and anomalies, and the development of options for alleviating market design problems. For example:

- **Intrazonal Congestion Management**

  DMA staff continues to be concerned about the lack of locational market power mitigation available to the ISO. The ISO has requested that FERC provide the ISO the authority to mitigate locational market power on numerous occasions, however, FERC has yet to grant the ISO's request.[13] DMA has documented the frequency of intrazonal congestion and the impact of potential gaming or inefficiencies due to locational transmission constraints. DMA is working with other departments within the ISO to pursue a proposal for Tariff modifications. These modifications would permit the ISO to mitigate intrazonal congestion in the forward market, and to mitigate bids in cases where local market power is being exercised.

  Result: Options being identified and assessed by ISO for potential filing at FERC.

- **Target Price**

  The original Target Price was set at the level where the overlapping INC and DEC bids would have cleared the market. In early 2000, some market participants started to abuse this mechanism and increase the Target Price by submitting a large volume of phantom DEC bids at their desired price. To prevent this new gaming strategy, the ISO modified its Target Price methodology starting April 4, 2000 so that the target price was set at the lower of the lowest INC bid or $0/MWh. Although this eliminated some of the observed gaming behavior, it had some undesirable consequences, including the elimination of a portion of the real-time DEC market, increased real-time price volatility, and a potential increase in the cost of Upward Regulation capacity as bidders internalized real-time price risk associated with low real-time energy price for any energy they provided while providing Upward Regulation.

  The DMA has actively taken part in the design of a new Target Price to alleviate the problems with the earlier designs. The new design is based on the original Target Price methodology, but with important modifications as follows:

  1. Compute the original Target Price, using only the feasible bids (pre-dispatched import bids, generation bids within 10-minute ramp rate, and dispatchable load bids) in the BEEP stack.

[13] The ISO has long recognized the shortcomings of its intra-zonal congestion procedures and on Nov 10, 1999, the ISO filed Amendment 23 with FERC requesting expanded authority to employ an alternative payment option in non-competitive intra-zonal congestion situations. On January 7, 2000, the Commission issued an order rejecting the requested authority to manage intra-zonal congestion where generators have submitted bids for managing intra-zonal congestion but the ISO has determined that the market for such bids are not competitive. On February 7, 2000, the ISO filed a request for rehearing with the Commission's decision on Amendment 23.

2. Using gas fired unit proxy bids (for all market bids already in the BEEP stack as well as those included by the ISO as proxy bids), determine the lowest available incremental bid from the gas-fired units.
3. The new Target Price is the lower of the two. Limiting the original Target Price by the lowest available incremental gas-fired unit proxy price will eliminate any residual gaming opportunities with the original Target Price that may still persist despite using only feasible bids.

Result: The new Target Price was implemented on October 29.

- **Software "flag" for skipping of spin/non-spin real-time energy bids from energy-limited resources under non-emergency conditions**

With the implementation of the FERC $150 "soft cap" starting in January 2001, there was a noticeable reduction in the participation of the energy-limited resources in ISO's Operating Reserve (OR) markets (Spin and Non-spin). Prior to the implementation of the soft cap, these resources could submit high-priced energy bids to ensure they were not dispatched except under emergency conditions. DMA worked with other parts of the ISO to remedy the problem by providing energy-limited resources providing spinning and non-spinning reserve a way to "conserve" their energy other than to bid extremely high prices. This design change allows suppliers to "flag" bids for energy-limited units providing spinning and non-spinning reserve that should be "skipped" in the BEEP stack under non-emergency conditions and dispatched only under emergency conditions.

Result: Software with "flag" for skipping of spin/non-spin real-time energy bids from energy-limited resources initially implemented in March as a one-time selection and then implemented as an hourly selection in May.

- **Overscheduling**

During the second half of 2001, the ISO experienced significant overscheduling of generation resources in the forward markets, particularly during off-peak hours. DMA investigated the extent to which out-of-market (OOM) purchases by CERS were contributing to overscheduling problems. Results of this analysis indicate that, in general, the volume of OOM purchases by CERS was inversely related to overscheduling, which is what would be expected. However, certain hours showed positive OOM purchases during overscheduling periods. Further analysis is necessary to determine whether this relationship is due to the monthly averaging or whether it is due to block OOM purchases.

Result: On November 7 FERC issued an Order requiring the ISO to treat CERS the same as other SCs. As a result, CERS no longer procures OOM energy. DMA continues to monitor the accuracy of CERS' forward scheduling activities.

- **Underscheduling to Offset Unpaid Balances Due**

In response to concern that several generation owners may undergenerate in real-time in order to reduce the amount owed them by the bankrupt UDCs (utility distribution companies), DMA was asked to perform an analysis to determine whether any specific generators were in fact undergenerating, and, if so, whether they would pursue such a strategy out of concern for credit risk, or if other market incentives could explain such behavior. DMA reviewed uninstructed deviation behavior of five new generation owners (Duke, Dynegy, Reliant, Mirant/Southern, and Williams) as well as the three California IOUs (PG&E, SCE, and SDG&E) from May to September 2001. The results showed that in general, the NGOs undergenerated more frequently than the IOUs in June, July, and August, but that there was no consistent evidence that this was a practice designed to offset unpaid amounts owed to these generators for previous sales.

Result: Analysis indicated no action was warranted at this time. However, DMA continues to monitor this behavior.

- **Path 15 Expansion**

DMA conducted a study on Path 15 to supplement a larger study completed by the ISO that evaluates the costs and benefits of building additional transmission capacity on Path 15 in year 2005. The ISO's main study looks at two potential benefits from upgrading Path 15: 1) net-cost savings to load and 2) reduction in re-dispatch costs. While the ISO's main study provides some important information on the potential economic benefits from upgrading Path 15, its findings are based on the premise of a perfectly competitive electricity market where prices reflect marginal cost and no single supplier has the ability to manipulate prices.

DMA went beyond the fundamental assumption of a perfectly competitive market and examined the extent to which suppliers may be able to exercise market power in northern California (NP15) in year 2005 under various scenarios of new generation investments and hydro conditions. We utilized the same supply scenarios used in the ISO's main study and provided additional scenarios relating to the availability of Existing Transmission Contracts (ETC) and the State's long-term power contracts. We then examined the extent to which market power is mitigated through upgrading Path 15. By providing additional import capability into northern California, the expansion of Path 15 mitigates the ability of suppliers to exercise market power.

The results of this analysis indicate there is a potentially significant additional economic benefit to upgrading Path 15 in terms of mitigating costs associated with market power in northern California. Specifically, this study finds that under a number of reasonable supply scenarios in year 2005, the potential annual cost benefits to load in northern California (NP15) range from $208 million to $1.3 billion, assuming a dry hydro season and other reasonable assumptions relating to the amount of new generation investment and whether the State's long-term power contracts remain in effect through 2005. The projected cost of expanding Path 15's transmission capacity is estimated to be approximately $300 million. The results of this analysis suggest that the potential cost benefits to load in NP15 from expanding Path 15 will likely equal or exceed the project cost in one to three years.

Result: Study submitted to state officials, and DMA staff scheduled to provide testimony in CPUC hearings on Path 15 expansion.

- **Outage Reporting/Scheduling/Performance Standards**

  DMA and Compliance staffs work with other departments of the ISO to monitor outage levels, and develop enhanced outage reporting, scheduling and performance standards to reduce potential gaming, inefficiencies and reliability issues associated with unit outages.

  <u>Result</u>: Enhanced outage reporting requirements and tracking were established pursuant to the "must bid" provisions of the April 26 Order. The ISO has also developed performance standards for filing at FERC.

IV. Compliance

- **Failure to Follow Dispatch Instructions During Emergencies**

In Amendment 33, the ISO requested that resources be penalized for non-performance in response to Dispatch Instructions during an actual or threatened system emergency.

The penalty price is equal to the highest energy price paid by the ISO in the hour in which the non-performance occurs. An additional $1,000/MWh penalty applies for non-performance in any hour during which firm load is involuntarily curtailed. A Participating Generator that has notified the ISO in advance that the instructed resource is unavailable or de-rated shall not be subject to such penalties. If such notice is not provided, then the resource is presumed available. If a real-time outage occurs, then the Participating Generator must notify the ISO within the hour.

Result: Assessed $122 million in penalties from December 8, 2000 through July 3, 2001. Compliance has coordinated with the refund proceedings to identify the potential changes to the penalty amounts. Compliance has recalculated penalties based on the mitigated prices determined by DMA and Market Operations. If the refund proceedings were to be concluded at the prices identified, the penalties would be reduced to approximately $42 million.[14]

- **Revocation of Payment for Regulation Service Not Provided**

Regulation is considered the highest quality Ancillary Service in the ISO markets. The service provides the ISO with the ability to accommodate moment-by-moment changes in load and/or generation. Generators providing this service turn over direct control of their units to the ISO's Energy Management System computers.

Compliance monitors a variety of indicators on Generating Units providing Regulation to ensure that the unit is on or off control, whether its Regulating limits are constrained, and whether the unit is operating within its operating and/or Regulating ranges. In June of 2000, Compliance automated the monitoring process allowing the monitoring of all of the Generating Units providing Regulation to ensure that they are delivering their scheduled Regulation service in every minute of every hour of every day.

[14] In its December 19, 2001 order, FERC concluded that effective June 21, 2001 such penalties were unnecessary for the duration of the market mitigation period FERC established by its April 26 and June 19, 2001 orders. The ISO will seek to restore its authority to impose penalties for failure to follow dispatch instructions. However, until such time that FERC's directive is modified, the ISO will comply by suspending such penalties for the duration of the price mitigation period, and refunding approximately $220,000 in penalties that were assessed during emergencies that occurred on July 2 and 3, 2001.

Result: Between January 1 and October 14, 2001, Compliance has rescinded $23.5 million in Regulation capacity payments from suppliers that failed to provide the service, thus preventing buyers of Regulation Service from being charged for services not provided.

- **Unaccounted-for-Energy Monitoring Program**

  Unaccounted-for-Energy (UFE) is the result of meter measurement errors, power flow modeling errors, energy theft, statistical load profile errors, and distribution loss deviations. UFE can result in significant cost shifting among SCs. Compliance periodically reviews the UFE resulting from the daily preliminary settlement calculation. This review looks for trends (both increasing and decreasing UFE) for each UDC territory. Abnormal situations are further reviewed to determine the cause. We have identified this year cases where SCs have under-reported their load, over-reported their load, did not account for new customers, and had internal processing problems that caused incorrect meter data to be submitted. In addition, we have identified internal problems that could have resulted in significant UFE. These problems were identified and corrected either prior to the final settlement statement being published or during a scheduled re-run of the market.

  The identification and correction of issues that cause UFE allows the ISO settlement system to properly account for energy being generated and consumed. The ISO can then calculate settlement balances for all transactions carried out by SCs on the ISO Control Grid using the data that appropriately reflects those transactions. Additionally, identifying and correcting problems prior to the final settlement calculation reduces the amount of disputes initiated. Approximately 500,000 MWhs of UFE was properly accounted for through this effort.

  Result: Identified anomalies in meter data submitted by SCs as well as errors in ISO internal settlements processing. During 2001, over 500,000 MWhs have been correctly accounted for prior to final settlement of the market this year.

- **Calculation of Refunds for Ancillary Services Not Provided**

  There was no automated review of Ancillary Service performance prior to the implementation of No Pay on September 10, 2000. Compliance has determined the extent to which a unit has been paid for Ancillary Service capacity that was not actually available for dispatch prior to September 10, 2000. The Ancillary Service Monitoring Program (the "ASM Program") has been developed by Compliance to determine the amount of Ancillary Service capacity that was unavailable from April 1998 to September 2000. Compliance will use hourly meter data and unit instructions to determine if a unit used Ancillary Service capacity for uninstructed deviations. Compliance conducted this analysis during the fall of this year and has determined the amount of Ancillary Service capacity that load paid for but was not delivered by the Generating Units that were obligated to provide the capacity and is considering how to appropriately reallocate the payments back to load.

  Result: Identified $47.6 million in Ancillary Service capacity payments for which the service was not provided by the resource obligated to do so.

- **Must-Offer Reporting**

  FERC established the must-offer obligation for all hours in its June 19 Order. The must-offer obligation applies to all sellers in California (including non-public utilities) that own or control one or more generating units, System Units or System Resources that are not hydroelectric generating units. In addition, the energy or capacity from these units must either be (i) sold through a market operated by the CAISO, or (ii) transmitted over the CAISO Controlled Grid. The must-offer obligation requires that generators offer the CAISO all available generating capacity except to the extent that generation or capacity is required to serve native load or if running the unit would violate a certificate, result in criminal violations or penalties or result in QF units violating their contracts or losing their QF status.

There are a variety of ways in which a generator may be found in violation of the must-offer obligation including: failing to submit energy bids for their available capacity, declining valid dispatch instructions or failing to fully deliver instructed energy.

Result: Delivered reports to FERC Office of Market Oversight & Enforcement (on July 26, August 15, September 7 and October 31) detailing instances of declined Dispatch Instructions. Revised process for committing long start-time units to ensure adequate payment for start-up and minimum load costs incurred when resources are required to maintain adequate planning reserves.

- **Validation and Verification of ISO Summer 2001 Demand Programs**

The Compliance Audit group reviewed all required implementation plans for the Summer 2001 Demand Relief Program (DRP). This review was intended to assure that all participating loads had interval meters and that they were not accounted for in other DRP bids. Throughout the summer a review of the submitted meter data was performed as well as spot audits of the participants' processes.

Result: Provided some assurance that the committed capacity as well as the curtailed demand met requirements set forth in the ISO DRP Agreement. Instructed Settlements to pay out $15.3 million to DRP participants.

- **Compliance with Bidding Certified Ramp Rates**

The ISO has a need to keep uncertified resources from bidding into ISO Ancillary Service markets to ensure reliability and quality of the services procured. Compliance uses the Ramp Rate Instances Exception Report to monitor instances in which uncertified units bid for Ancillary Services and in which certified units bid in excess of their certified ramp rates.

Compliance researches Energy Schedules, Ancillary Service schedules, plant data, Dispatch Instructions and revenue meter data to determine whether a scheduling coordinator has bid in excess of their certified ramp rate. When excessive ramp rates are scheduled and identified by the RRER program, Compliance coordinates with Client Services to inform the Scheduling Coordinator of the improper bids and to rescind Ancillary Service capacity payments for that capacity that could not have been delivered.

Result: Monitoring program has reduced non-compliance from as high as 35 incidents per week to almost none in September 2001.

- **Compliance with Tariff Requirement for Timely Settlement Meter Data**

Meter data is an essential element in the ISO's markets as it ultimately determines both payments to the ISO and payments from the ISO to market participants. Although the ISO directly reads some meters, the majority of the meter data representing loads is processed and submitted by Scheduling Coordinators. The timely delivery of meter data to the ISO is a critical milestone in the settlement process. If meter data is not received on time, it delays the entire settlement process.

In the first months after start-up, Scheduling Coordinators were regularly late in submitting meter data. Late meter data events totaled more than 80 per month, creating an unacceptable burden on ISO resources and potentially impacting settlements to market participants. To address this issue, the ISO developed a compliance program that uses a graduated system of written notices to Scheduling Coordinators that do not submit their meter data in a timely manner.

Result: During 2001, late meter data events leveled off at about five to ten events per month. The majority of these events were related to either new participants in the market or existing market participants that took on additional responsibilities.

- **Compliance Audits**

  MP section 4.2.1 is the ISO Tariff section that requires SCs to conduct annual Self-Audits of their Settlement Meter Data Processing. The audits assure Scheduling Coordinators that they meet their Tariff obligations for submitting accurate and correct Settlement Quality Meter Data. The results of the audits will be used to modify and/or correct the metering processes of the Scheduling Coordinators to minimize future Market cost shifting that may result from meter errors.

  Result: During 2001 the SCs completed their audits for settlement period July 1, 1999 through December 31, 2000. Many SCs have identified and, on a going forward basis, corrected problems that affect their processing of Settlement Quality Meter Data. A "lessons-learned" report containing good practices and generic areas of concern will be issued in the beginning of 2002.

V. Assistance to State and Federal Regulatory Agencies and Policy-Makers

The ISO provides assistance to state and federal regulatory agencies and policy-makers in a variety of ways, ranging from provision of detailed market information on a confidential basis to provision of special studies and analysis to address key issues. For example:

- **Bureau of State Audits**

  During the latter months of 2000 and early 2001, the ISO provided extensive information to a team from the Bureau of State Audits tasked to review operations of the ISO and the PX. The Auditor's report, released in March 2001, concluded that the price spikes in California's markets since May, 2000 were due to a combination of three major factors, including (1) structural market flaws creating over-reliance on spot markets by buyers and strategic bidding by sellers, (2) misjudgments on the part of state and federal regulators about the effectiveness of corrective actions taken, and (3) market conditions beyond the control of any regulatory agency, such as high gas prices, unusual weather patterns, air quality emissions requirements, and lack of investment in new supply to meet demand growth in recent years. The report specifically noted that "both the ISO and PX market monitoring groups identified anomalous behavior and structural design flaws that hindsight has shown contributed to the recent spikes in wholesale electricity prices," and provided a number of recommendations to improve market performance and monitoring. Since the time that the Auditor's report was concluded and released, California's wholesale electricity markets have undergone colossal changes that made many of the Auditor's recommendations no longer applicable to the market structure or the ISO's role. However, the ISO has taken the report's recommendations into consideration to the extent they remain applicable, in the context of some of the more comprehensive market design changes that are currently under consideration.

  Result: In August, the ISO provided a six month report to the State Auditor identifying actions taken by the ISO and other entities relating to recommendations provided in the auditor's report. Specific recommendations included in the auditor's report that the ISO has implemented include release of less detailed and timely data bid prices and bids accepted, and increased confidentiality of market monitoring tools and findings that are provided by the ISO to state and federal regulators. The ISO's response indicated that other recommendations of the State Auditor's report – such as increased emphasis on long-term contracts – had been incorporated in actions taken by other sate entities. In March 2002, the ISO will provide a 12 month report to the State Auditor identifying actions taken by the ISO and other entities relating to recommendations provided in the auditor's report.

- **Outage Reporting and Maintenance Standards**

  The ISO worked closely with state regulatory agencies and policy-makers on implementing state executive orders and developing state legislation aimed at establishing enhanced outage reporting, scheduling and performance standards to reduce potential gaming, inefficiencies and reliability issues associated with unit outages.

  Result: Tariff revisions providing for enhanced outage tracking and scheduling have been submitted to FERC, and additional provisions relating to maintenance standards have been developed for filing.

- **System Reserve Margin**

  In response to a request from the California Legislature, the DMA performed a preliminary study to address the issue of sufficient capacity reserve margin for the control area to ensure that the average price of energy is reasonably close to the average price that would result in a competitive market. DMA found the capacity reserve margin (based on dependable rather than nameplate capacity) should be 14% to 19% of the annual peak load to promote workably competitive market outcome.

  Result: Report submitted to the California Legislature.

- **Path 15 Expansion**

  As noted in Section III of this report, DMA conducted a study of the impacts of Path 15 expansion on market power to supplement a larger study completed by the ISO that evaluates the costs and benefits of building additional transmission capacity on Path 15 in year 2005.

  Result: Report and testimony are being provided for upcoming CPUC hearings on Path 15 expansion.

- **Subpoenas and Data Requests from State and Federal Legal and Regulatory Entities**
  - The California ISO has provided responses to over 100 subpoenas and data requests by state and federal regulatory agencies and policy-makers during 2001. The table in the Executive Summary includes a partial summary of the number of subpoenas and data requests from individual state and federal legal and regulatory entities to which ISO legal staff have issued a formal response in 2001. In addition, legal and other ISO staff have provided less formal responses and information to a large number of other requests.
  - The California ISO has produced a formal response to a data request during over 200 days of the year, or about 3 out of every 4 workdays during the year
  - In conjunction with these requests, the ISO has produced over 800 CDs & floppy disks of data and over 200,000 pages have been produced.

- **On-Going Data Reporting**
  - EOB & CPUC are provided monthly productions that include operator logs and confidential market data.
  - On a weekly basis, the ISO provides FERC with bid and scheduling data, as well as a Weekly Market Monitoring Report that includes a comparison of bid prices to costs and other indicators of anti-competitive bidding practices.

APPENDIX A

List of Reports/Filings by Department of Market Analysis and Market Surveillance Committee Regarding Market Power in the California Wholesale Electric Markets

Title	Proceeding/Date Submitted	Author
Presented Market Power Mitigation proposal to FERC at Market Power Mitigation Technical Conference	January 23, 2001	DMA
Draft Proposal – Market Power Mitigation Plan	Attached to Comments of the California Independent System Operator Corporation on Market Power Monitoring and Mitigation Measures *Docket No. EL00-95-012* February 6, 2001	DMA
Proposed Market Monitoring and Mitigation Plan for California Electricity Market	Attached to the Submission by the California ISO of a Proposed Market Monitoring and Mitigation Plan by its Market Surveillance Committee (MSC) *Docket Nos. EL00-95-000, et al.* February 6, 2001	MSC
Report on Real-time Supply Costs Above Single Price Auction Threshold: December 8, 2000 – January 31, 2001	Attachment to Motion for Issuance of Refund Notice to Sellers, Request for Data, Request for Hearing, and Request for Expedited Action of the California ISO and the California EOB *Docket Nos. EL00-95-000, et al.* March 1, 2001	DMA
Empirical Evidence of Strategic Bidding in California ISO Real-time Market	Attachment to Comments of the California ISO to Staff's Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market *Docket No. EL00-95-012* March 22, 2001	DMA

Title	Proceeding/Date Submitted	Author
Further Analyses of the Exercise and Cost Impacts of Market Power in California's Wholesale Energy Market	Attachment to Comments of the California ISO to Staff's Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market *Docket No. EL00-95-012* March 22, 2001	DMA
Comments on "Staff Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electricity Market"	*Docket Nos. EL00-95-000, et al.* March 22, 2001	MSC
Comments on discontinuance of Williams' market-based rate authority	*Docket No. ER99-1722-004* April 2, 2001	DMA
Market Stabilization Plan	*Docket No. EL00-95-012* April 6, 2001	DMA and Other ISO Staff
Impacts of Market Power in California Wholesale Energy Market: More Detailed Analysis Based on Individual Seller Schedules and Transactions in the ISO and PX Markets	Attachment to Supplemental Response of the California ISO to Letter Order of March 30, 2001 *Docket No. EL00-95-012* April 9, 2001	DMA
Protest and Motion for immediate suspension of AES' Market-based rate authority	*Docket No. ER98-2186-000* May 25, 2001	DMA
Emergency Motion for Termination of Duke's Market Based Rate Authority	*Docket Nos. ER98-2681-000, ER98-2682-000, ER99-1785-000, ER99-2774-000* June 8, 2001	DMA
Emergency Motion for Termination of Dynegy's Market-based rate authority	*Docket Nos. ER94-1612-000, ER99-4160-000* June 8, 2001	DMA
Emergency Motion for Termination of Mirant's Market-based rate authority	*Docket Nos. ER97-4166-000, ER99-1833-000, ER99-1841-000, ER99-1842-000* June 8, 2001	DMA

Title	Proceeding/Date Submitted	Author
Emergency Motion for Termination of Reliant's Market-based rate authority	*Docket Nos. ER98-2878-000, ER98-927-000, ER98-928-000, ER98-930-000, ER98-931-000, ER99-1801-000* June 8, 2001	DMA
Potential Overpayments Due to Market Power in California's Wholesale Energy Market: May 2000-2001	June 19, 2001	DMA
Potential Overpayments Due to Market Power in California's Wholesale Energy Market: May 2000-2001	Report Submitted to FERC as Part of the Settlement Conference *Docket Nos. EL00-95-031, et al.* July 9, 2001	DMA
First quarterly report on effectiveness of FERC's June 19 Market Power Mitigation Order	September 14, 2001	
Critical Actions Necessary for Effective Market Monitoring	Comments Presented at the FERC RTO Workshop *Docket No. RM01-12-000* October 19, 2001	DMA
Comments on West-Wide Market Power Mitigation for the Winter Season	November 9, 2001	DMA
Preliminary Study of Reserve Margin Requirements Necessary to Promote Workable Competition	Study Performed and Submitted to the California Legislature at the Request of the Joint Legislative Audit Committee and the Speaker's Office of Oversight November 19, 2001	DMA
Second quarterly report on the impact of FERC's June 19 Order	December 28, 2001	DMA