CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: ISO Board of Governors

From: Anjali Sheffrin, Ph.D.
Director of Market Analysis

cc: ISO Officers; ISO Board Assistants

Date: March 8, 2002

Re: Market Analysis Report for January and February 2002

This is a status report only. No Board action is required.

EXECUTIVE SUMMARY

Several indicators suggest that California's energy markets are improving in a variety of areas. Costs to load for wholesale energy and ancillary services ended the downward trend in January 2002 that had commenced in March 2001, falling to $39 per megawatt-hour (MWh), its lowest point since April 2000. Cost to load increased slightly in February 2002 to $40/MWh. A significant portion of real-time out of control area energy that had been procured by the Department of Water Resources' California Energy Resources Scheduler (CERS) in 2001 in out-of-market (OOM) transactions is now being bid into the ISO's Balancing Energy Ex-Post (BEEP) auction. Intertie bids into the BEEP market have increased since mid-December 2001, when CERS ceased its OOM activities. A large portion of this energy is produced by hydroelectric resources from the Northwest and has resulted in increased imports of electricity into California. This positive shift in supply put downward pressure on the average price of real-time incremental (INC) energy in the BEEP market, which has fallen to its lowest level since mid-2000. The average INC prices in January and February 2002 were $45.31 and $43.74, respectively, well in the range of the weighted average INC prices seen in 2001 for total BEEP and OOM energy.

However, issues that result in prices above competitive levels persist. Suppliers continue to exercise market power in both forward and real-time markets. For example, declined real-time dispatch instructions result in higher cost to load than necessary, and compromise the integrity of the BEEP auction market. This has been particularly problematic when the ISO finds it necessary to decrement (DEC) the energy supplied into the grid to balance generation with load. The DEC price, which suppliers pay to the ISO when they are permitted to reduce generation (and thus reduce variable costs), has descended to levels well below cost in the last several months. Furthermore, the ISO operators have recently found it necessary to make OOM calls to meet load in some hours, as suppliers submitted DEC bids into the BEEP market but failed to respond to dispatch instructions.

As the price of Ancillary Services (A/S) increased in January, utilities continued to employ their hydroelectric resources for A/S to provide reserve capacity, rather than to purchase A/S in the ISO's markets. The Department of Market Analysis (DMA) expects this to change in the spring, as utilities run hydro resources to exploit overflowing reservoirs due to runoff from melting snow.

KEY MARKET CONDITIONS FOR JANUARY AND FEBRUARY 2002

I. California Wholesale Energy Markets

Loads. Loads in January increased sharply above those in December, due to demand increases driven primarily by cool weather and waning conservation efforts. Monthly loads totaled 19,356 gigawatt-hours (GWh) in January and 17,153 GWh in February, compared with18, 770 GWh and 16,502 GWh for the same months in 2001. Peak loads for January and February were 33,182 GWh and 31,662 GWh, respectively, up 2.3 and 4.1 percent from the same months in 2001. The increase between 2001 and 2002 is due largely to the extraordinary measures taken to limit load during emergency periods in January 2001.

Conservation. The California Energy Commission (CEC) provides estimates of conservation after normalizing for growth and weather conditions. The CEC calculated that monthly peak demand for electricity in January increased 0.7 percent above 2001 levels. Monthly energy consumed increased 3.6 percent above 2001 levels. However, January 2001 was a month in which conservation efforts and curtailments substantially limited load. CEC estimates for February were not yet available at the time of this writing.

Price Cap Hits. An Order by the Federal Energy Regulatory Commission (FERC), on December 19, 2001, establishes market power mitigation with a soft price cap at $108/MWh for the winter months. Market-clearing prices (MCPs) for incremental energy exceeded the $107/MWh level in 12 of 1639 ten-minute intervals during which INC energy was dispatched in the NP15 region in January, and in three of 1922 intervals in which INC energy was dispatched in the SP15 region. MCPs exceeded $107/MWh in two of 1605 intervals with INC dispatches in NP15 in February, and in two of 1845 intervals with INC dispatches in SP15.

Wholesale Energy Prices. Average real-time INC prices decreased approximately 21 percent between December 2001 and January 2002, while average DEC prices decreased approximately 35 percent in the same period. Between January and February 2002, average INC and DEC prices both declined, approximately 3 and 25 percent, respectively.

Because CERS is no longer making out-of-market (OOM) calls to procure balancing energy and the BEEP stack was sufficient to meet the ISO's balancing requirements in January, there was no OOM activity in that month. However, the ISO was forced to make several OOM calls in February. During several hours on February 23 and 24, Path 15 was derated. In their efforts to manage the resulting congestion between Northern and Southern California, ISO operators exhausted the INC and DEC portions of the BEEP Stack in NP15 and SP15, respectively. This was partly due to generators declining instructions to dispatch or withhold energy. A general lack of energy bid into the BEEP Stack also contributed to the problem, particularly on the DEC side. As a result, the operators found it necessary to call upon OOM energy to meet load.

The ISO Department of Market Analysis (DMA) monitors several key price and volume statistics pertaining to the real-time balancing energy market. The real-time market now consists of components as displayed in numbered columns in Tables 1a and 1b (presented on the following page): (1) The market-clearing prices (MCPs) and quantities for incremental and decremental energy procured under the price cap from the BEEP Stack; and, in February, (2) average prices and quantities for out-of-market (OOM) calls. The combination of these components yields (3) the total overall average real-time prices. Average hourly system loads and percent underscheduling are shown in (4).

Table 1a: Real-Time Energy Price Summary for January 2002

	Avg. Market-Clearing Price and Total Volume (1)		Avg. Out-of-Market Price and Total Volume (2)		Overall Avg. Real-Time Price and Total Volume (3)		Avg. System Loads (MW) and Pct. Under-scheduling (4)
	Inc	Dec	Inc	Dec	Inc	Dec	
Peak	$ 46.50	$ 5.96	No Procurement	No Procurement	$ 46.50	$ 5.96	27,951 MW
	129 GWh	142 GWh	*	*	129 GWh	142 GWh	2.0%
Off-Peak	$ 41.66	$ 2.90	No Procurement	No Procurement	$ 41.66	$ 2.90	22,148 MW
	42 GWh	74 GWh	*	*	42 GWh	74 GWh	1.0%
All Hours	$ 45.31	$ 4.91	No Procurement	No Procurement	$ 45.31	$ 4.91	26,017 MW
	171 GWh	216 GWh	*	*	171 GWh	216 GWh	2.0%

* Indicates procurement under 1 GWh.

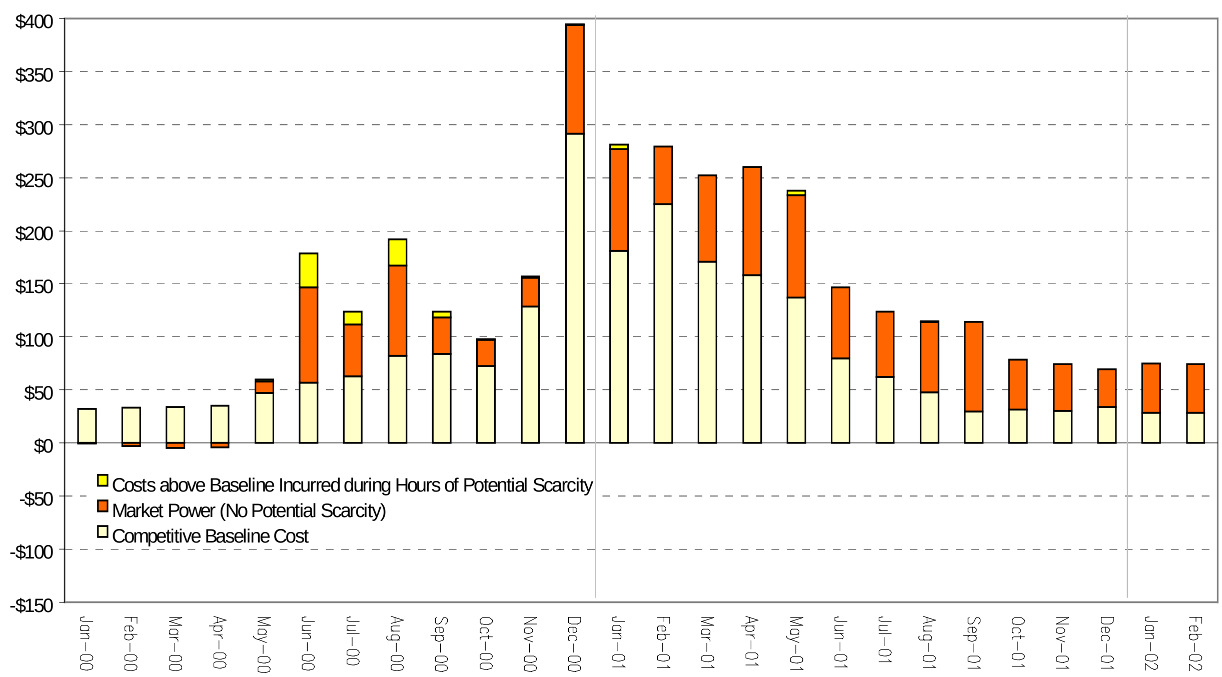
Table 1b: Real-Time Energy Price Summary for February 2002

	Avg. Market-Clearing Price and Total Volume (1)		Avg. Out-of-Market Price and Total Volume (2)		Overall Avg. Real-Time Price and Total Volume (3)		Avg. System Loads (MW) and Pct. Underscheduling (4)
	Inc	Dec	Inc	Dec	Inc	Dec	
Peak	$ 43.72	$ 4.92	$60.51	$ 8.61	$ 44.30	$ 5.12	27,363 MW
	126 GWh	91 GWh	5 GWh	5 GWh	131 GWh	97 GWh	3.0%
Off-Peak	$ 43.63	$ 2.21	$72.70	$ 6.15	$ 47.58	$ 2.46	21,849 MW
	27 GWh	72 GWh	4 GWh	5 GWh	32 GWh	77 GWh	1.0%
All Hours	$ 43.70	$ 3.72	$66.43	$ 7.41	$ 44.94	$ 3.94	25,525 MW
	154 GWh	164 GWh	9 GWh	10 GWh	163 GWh	174 GWh	2.0%

Market Power. DMA has observed that certain units that are dispatched frequently continue to bid into the BEEP stack with bidding strategies that are indicative of the exercise of market power. This has particularly been a problem with DEC bids and INC bids dispatched mid-hour, for which out-of-state generators cannot provide a reliable substitute. Furthermore, in order to hedge against the risk of future shortages, CERS entered into several high priced bilateral contracts during the crisis period in early 2001, when prices were near their peak, that remain in effect today.

The following chart shows estimates of price-to-cost markup, a key index of market power, included in average prices for forward and real-time energy in the ISO Control Area, for the period between January 2000 and February 2002. The markup is the difference between the average price and an estimate of a baseline price that would exist under competitive conditions. The amount of markup has decreased on an absolute basis since the first quarter of 2001; however, a significant amount of markup per dollar spent persists.

Figure 1: Markup above Estimated Competitive Price Net-Short and Real-Time Energy in ISO Control Area*
January 2000-February 2002



*The prices reported here do not include generation by IOUs and are therefore different than average costs reported in Table 3.

II. Ancillary Services Markets

Ancillary Services Prices and Volumes. The ISO procures ancillary services (A/S) in its day-ahead and hour-ahead markets to meet reserve requirements. Reserve requirements that are not met at prices at or below the soft cap are purchased at the bid price, and are subject to just and reasonable cost review by FERC. Since December 31, 2000, the ISO has been rescinding capacity payments for Replacement Reserve services whenever energy is dispatched from the corresponding resource in real time, pursuant to FERC's Order of December 15, 2000. This has resulted in significant savings.

Weighted average day-ahead and hour-ahead prices for A/S generally rose sharply between December 2001 and January 2002, and then declined to previous levels in February. Upward and downward regulation prices both traded for an average of $19/MWh of capacity in January, compared with $14/MWh and $11/MWh, respectively, in December. Both types of regulation capacity retreated to $14/MWh in February. Average prices for spinning reserves increased from $2/MWh to $3/MWh between December and January, and returned to $2/MWh through February. The average price for non-spinning reserves has remained in the neighborhood of $1/MWh since December. The average price of replacement reserves fell from $3 to $1 between December and January, and remained near $1/MWh in February.

The volume of A/S traded in the ISO's markets has not varied widely since December, as utilities have continued to self-provide to meet most of their A/S requirements. Utilities rely primarily on idle hydroelectric resources for self-provided A/S. DMA expects the level of self-provision to decrease in the spring, as hydroelectric generators increase production due to spring runoff.

Between 69 percent and 88 percent of A/S were purchased in the day-ahead markets.

Tables 2a and 2b show weighted day-ahead A/S prices by market for January and February, respectively.

Table 2a: Weighted Average Prices by Market for Ancillary Services - January

	Day-Ahead Market	Hour-Ahead Market	Quantity Weighted Price	Average Hourly MW Day Ahead	Average Hourly MW Hour Ahead	Percent Purchased in Day Ahead
Regulation Up	$ 14	$ 14	$ 14	480	57	89%
Regulation Down	$ 14	$ 9	$ 14	466	62	88%
Spin	$ 2	$ 2	$ 2	744	37	95%
Non-Spin	*	*	*	714	47	93%
Replacement	*	$ 3	$ 1	65	43	60%

Table 2b: Weighted Average Prices by Market for Ancillary Services - February

	Day-Ahead Market	Hour-Ahead Market	Quantity Weighted Price	Average Hourly MW Day Ahead	Average Hourly MW Hour Ahead	Percent Purchased in Day Ahead
Regulation Up	$ 14	$ 13	$ 14	481	57	89%
Regulation Down	$ 14	$ 9	$ 13	463	65	87%
Spin	$ 2	$ 2	$ 2	746	34	95%
Non-Spin	*	*	*	720	43	94%
Replacement	*	$ 3	$ 1	64	42	60%

All prices are per MWh. * Indicates prices under $1/MWh.

III. Summary of Market Costs

Costs to load for wholesale energy and A/S totaled approximately $763 million in January, compared with $838 million in December. These totals are approximately 79 percent lower than those in the crisis month of January 2001, during which costs to load totaled $3,713 million. The average total cost to load of energy and A/S was $39/MWh in January 2002, down from approximately $45/MWh throughout the fourth quarter of 2001, and substantially below the level of $198/MWh seen in January 2001. However, costs remain higher than those seen in the first two years of ISO operation, during which total costs of energy and A/S averaged $33/MWh. The higher costs are due primarily to long-term energy contracts procured by CERS early last year during periods of high market prices.

Costs to load increased in February to $682 million, or $40/MWh. This was the first increase in the per-MWh monthly cost index since February 2001, when it increased to $229/MWh from $198/MWh.

Tables 3a, 3b, and 3c summarize energy costs for 2002, 2001, and earlier, respectively.

March 8, 2002

Summaries of Wholesale Energy Costs

Table 3a: 2002 Wholesale 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-02	19,356	18,940	$737	$7	$19	$744	$763	$38	$0.97	2.5%	$39
FEB-02	17,153	16,654	$663	$7	$12	$670	$682	$39	$0.68	1.7%	$40
Total 2001	36,509	35,594	1,399	15	30	1,414	1,444				
Avg 2001	18,255	17,797	700	7	15	707	722	39	1	2.2%	$40

Table 3b: 2001 Wholesale 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	$ 1,048	$ 20	$ 19	$ 1,067	$ 1,087	$ 55	$ 0.97	1.8%	$ 56
OCT-01	19,105	19,395	$ 863	$ 10	$ 15	$ 873	$ 888	$ 46	$ 0.77	1.7%	$ 46
NOV-01	17,707	18,028	$ 754	$ 10	$ 12	$ 764	$ 776	$ 43	$ 0.66	1.5%	$ 44
DEC-01	18,830	18,673	$ 785	$ 14	$ 12	$ 800	$ 812	$ 42	$ 0.65	1.5%	$ 43
Total 2001	227,024	220,484	21,248	4,162	1,346	25,410	26,756				
Avg 2001	18,919	18,374	1,771	347	112	2,117	2,230	115	6	5.3%	$ 118

Table 3c: Wholesale Energy Costs for 2000 and Earlier

	ISO Load (GWh)	Est PX Energy Costs (MM$)*	Est Bilateral Energy Costs (MM$)*	RT Energy Costs (MM$)**	AS Costs (MM$)***	Total Energy Costs (MM$)	Total Costs of AS+ Energy (MM$)	Avg Energy Cost ($/MWh)	A/S Cost ($/MWh Load)	A/S Costs as % of Energy Costs	Total Costs ($/MWh load)
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.

IV. Congestion Management Markets

Interzonal Congestion. A number of paths experienced moderate levels of interzonal congestion in January in the day ahead, and significant levels in the hour ahead. Path 15 experienced day-ahead congestion in the South-to-North direction during 41 percent of the operating hours in January, with unusually high congestion prices for this path. There was day-ahead import congestion in nearly 9 percent of hours on Palo Verde, and in 2 percent of hours on COI, NOB, and Path 26. Prices on NOB averaged over $86/MWh as Palo Verde remained derated due to work on the Hassayampa Substation, constraining flows into Southern California. In the hour ahead, there was congestion on Palo Verde and Eldorado, in 19 and 5 percent of the operating hours, respectively; and low rates of congestion on COI, Mead, NOB, Path 15, and Sylmar. Path 26 experienced occasional congestion in the export direction in the day ahead and in the hour ahead.

In February, Palo Verde and COI sustained day-ahead import congestion in 11 and 1 percent of hours, respectively. There was scant congestion on Eldorado. Path 15 sustained day-ahead congestion in the South-to-North direction in 41 percent of the operating hours. Palo Verde was managed without a congestion price. The average prices on COI, Eldorado, IID-SDGE, and Mead were $0.01/MWh, $20/MWh, $18.93/MWh, and $0, respectively. There was hour-ahead import congestion on Palo Verde, Eldorado, COI, Mead, IID-SDGE, North Gila, and Sylmar; and hour-ahead congestion in the South-to-North direction on Path 15. IID-SDGE and North Gila had scant export congestion in the hour ahead. Hour ahead prices exceeded $30 on nine key branch groups.

The following tables show day-ahead interzonal congestion rates and average congestion charges by branch group.

Table 4a: Day-Ahead Interzonal Congestion Summary – January

Branch	Peak Cong. Pctg.	Off-Peak Cong. Pctg.	All-hour Cong. Pctg.	Peak Cong. Price	Off-Peak Cong. Price	All-hours Cong. Price
COI (Import)	3.0	0	2.0	$4.21		$4.21
Eldorado (Import)	0	0.8	0.3		$43.00	$43.00
NOB (Import)	2.6	0	1.8	$101.80	$71.51	$86.18
Palo Verde (Import)	6.3	13.3	8.6	$0	$0	$0
Path 15 (South-to-North)	19.2	85. 9	41.4	$22.15	$31.82	$24.30
Path 26 (South-to-North)	2.0	1.6	1.9	$30.00	$0	$30.00
Sylmar AC (Import)	0.6	0	0.4	$0	$0	$0

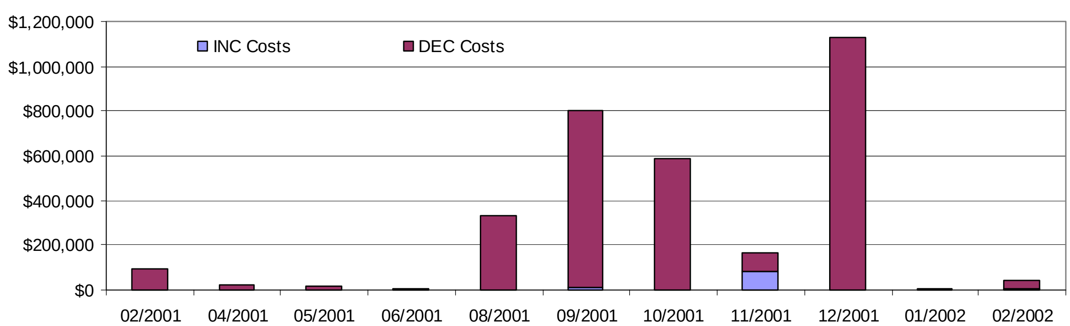
Table 4b: Day-Ahead Interzonal Congestion Summary – February

Branch	Peak Cong. Pctg.	Off-Peak Cong. Pctg.	All-hour Cong. Pctg.	Peak Cong. Price	Off-Peak Cong. Price	All-hours Cong. Price
COI (Import)	1.8	0	1.2	$0.01		$0.01
Eldorado (Import)	0	0.9	0.3		$20.00	$20.00
Palo Verde (Import)	5.6	22.3	11.2			
Path 15 (South-to-North)	24.1	74.1	40.8			

Intrazonal Congestion. Transmission constraints within a zone of the ISO Control Area occasionally make it impossible to move the lowest-cost real-time energy available in a zone to other areas of a zone where it is needed. This is known as Intrazonal congestion. When Intrazonal congestion is present, the ISO must deviate from the economic merit-order sequence of the BEEP Stack for the zone when it procures energy. Rather, it must procure higher-cost energy in the small local area where it is needed to meet load. For this energy, a generator would receive the higher price at which it bid the energy into the BEEP Stack. However, the BEEP MCP, at which all other generation is paid, remains at the lower in-sequence clearing price.

DMA estimates the cost of the Intrazonal congestion as the difference in cost between the energy procured as-bid and that energy if it were procured at the zonal MCP. DMA has observed that this cost has fallen substantially since December, as Intra-zonal congestion costs decreased significantly from December levels as shown below in Figure 2. The bulk of the cost in December was due to congestion within NP15 that forced the ISO to call on low decremental energy bids from certain plants east of the Bay Area.

Figure 2: Intrazonal Congestion Costs



V. Western Regional Spot Electric Market Prices

Price volatility in the electricity spot market declined significantly from December levels, with prices in the first half of January markedly more volatile than prices in the latter half. Prices ranged between $17.25 and $30.74/MWh across the 5 trading hubs, with a median price of approximately $24/MWh. Outages, including scheduled maintenance at Ormond Beach #1 (750 MW) and an unplanned outage at Alamitos #6 (480 MW) on January 3, reduced supply, causing prices throughout the West to increase slightly during the first week of January. Low temperatures increased heating demand, which somewhat offset the effect of low natural gas prices. The price of natural gas was effective in keeping energy prices to a low of around $18/MWh on January 6. January 7 to 10 saw low temperatures, but forecasts indicated that warmer weather would arrive later in the week.

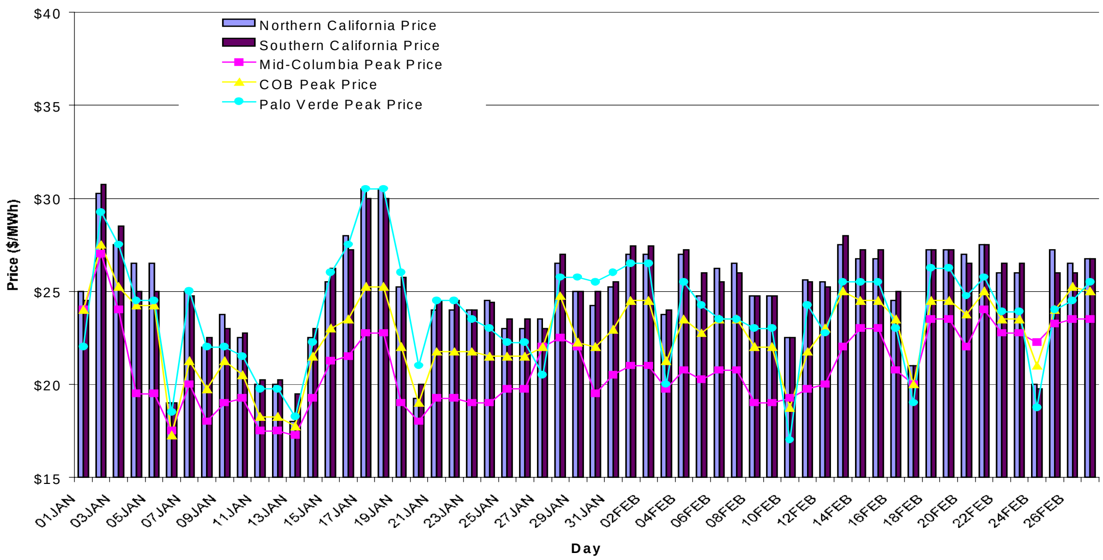
With forecasts of below-average temperatures across the United States, electricity prices rose around January 15, along with slightly higher natural gas prices. Diablo Canyon #2 (1,141 MW) ran at 50% capacity for maintenance on the 15th, constraining supply and resulting in price increases. January 16 saw further unit outages, as Pittsburg #7 (682 MW) and El Segundo #3 (335 MW) went offline. Prices for January 20 fell due to weaker than expected weekend loads. Prices for the remainder of the month hovered between $24 and $26/MWh, with a single spike on January 28 owing to cold weather forecasts. Prices increased as the month drew to an end owing to the continuing cold weather and increasing natural gas prices.

Excluding usual weekend-related price fluctuations, prices during the first 11 days of February remained flat or decreased slightly owing to flat natural gas prices and stable temperature. Peak power prices on February 12 increased to the $19- $25/MWh range, due to strengthening gas prices and another partial derate of Ormond Beach #1 (725 MW) to 25 MW. Prices remained at monthly highs until February 16 and 17, when prices fell to the $18-$22/MWh range on anticipated decreased loads over the weekend. Prices for February 18 returned to $25/MWh levels following announcements of numerous outages of key units throughout the West. Diablo Canyon #1 and #2 (1126 MW and 1141 MW, respectively) were derated to 50% output; and Four Corners #4 (750 MW) and Columbia Generating Station (1115 MW) in the Northwest were out entirely. Gas prices kept peak power prices high until February 22, after which they fell to the $22/MWh level and remained relatively level, again excluding price fluctuations owing to reduced weekend load.

The following chart shows peak-hour firm product spot prices for short-term forward electricity at trading hubs around California, compared with ISO prices for short-term forward electricity.

[2] Prices are peak hour, firm product prices as reported by Energy Market Report, published by Economic Insight, Inc.

Figure 3: Western Regional Electric Spot Prices – January and February 2002[3]



VI. California Natural Gas Prices

California natural gas spot prices ranged from $1.90 per million British thermal units (MMBtu) to $2.60/MMBtu range during the month of January. The first half of January saw Henry Hub prices higher than the California hub prices, mostly owing to winter storms striking the Northeast, Midwest and Southeast United States. The highest prices of the month occurred during the first days of January, where, despite cold temperatures through much of the U. S., high storage levels, warming weather and flat natural gas futures prices caused prices to continue to drop from their levels at the end of December. Demand in the West was further reduced by a high-linepack operational flow order issued by PG&E. Temperatures fell to below-average levels after January 14, causing western hub prices to increase to $2.28/MMBtu to $2.35/MMBtu by January 17. After January 17, prices decreased despite cold temperatures throughout much of the country. With weak prices throughout much of the month, however, traders expected suppliers to reduce supplies from wells, and the reduced supply and continued cold weather caused prices to increase in the last days of January to the range of $2.11-$2.25/MMBtu. Average bid-week prices for February were $2.02/MMBtu, $1.99/MMBtu, and $2.07/MMBtu for SoCal Gas, Malin, and PG&E Citygate, respectively.

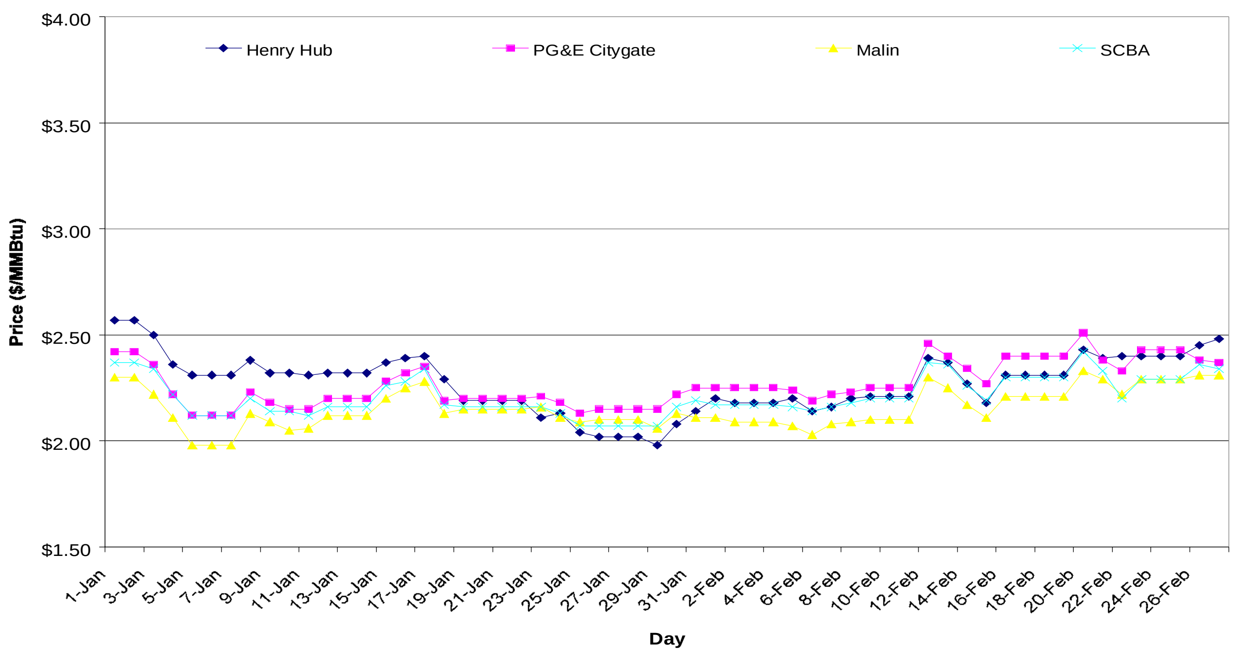
February prices through February 11 stayed within the $2.00- $2.25/MMBtu range in the absence of fundamental factors to drive prices in either direction. During that period supplies remained high and widespread winter storms moderated. Prices at all hubs increased to the range of $2.30-$2.46/MMBtu on February 12, despite the absence of explanatory fundamental data; supplies were still high and weather forecasts remained substantially unchanged. A market correction occurred on February 15, as prices retreated to near-February 11 levels. While possibly colder weather and

[3] Prices, including California prices, are peak hour, firm product prices as reported by Energy Market Report, published by Economic Insight, Inc.

storms caused prices to increase on the 16th and 20th, temperatures in the West were relatively mild, causing prices at Western hubs to fall after the 20th.

The following chart shows gas spot prices at California trading delivery points.

Figure 4: Average Natural Gas Spot Prices - January and February 2002



VII. Firm Transmission Rights Market

Concentrations of Firm Transmission Rights. There were no trades in the secondary market for firm transmission rights (FTRs) or reassignments of FTRs to scheduling coordinators (SCs) in January or February 2002. Thus, FTR ownership concentrations remain the same as those reported in the December 2001 Market Analysis Report.

Scheduling. On most paths, holders of FTRs have used the rights in scheduling, primarily to hedge against the risk of exposure to high congestion charges. A key metric of FTR use is the volume of schedules on transmission lines with FTR priority attached, relative to all scheduling volume on those lines. This ratio was 16 percent for both January and February, compared to 18 percent in December 2001. The index was well above the mean on some lines; for example, 59 percent on Eldorado, 100 percent on Silver Peak, and 71 percent on IID-SCE, all in the import direction in January; and 45 percent on Eldorado, 100 percent on Silver Peak, 61 percent on IID-SCE, and 39 percent on Palo Verde, all in the import direction in February. Most congestion charges incurred in these two months were a consequence of the derate of Palo Verde. Now that Palo Verde has returned to full capacity, DMA does not believe that FTR concentrations remain a cause for concern. However, DMA will continue to monitor activity in the FTR markets. The following tables show FTR scheduling statistics for January and February.

Table 5a: FTR Scheduling Statistics – January

Path	MW FTR Auctioned	Avg. MW FTR Scheduled	Max. MW FTR Scheduled	Max. Single SC FTR Scheduled	Percent of FTR Scheduled
COI –Import	600	196	376	175	32.60%
Eldorado-Import	707	417	707	582	59.00%
IID-SCE-Import	600	428	447	447	71.30%
Palo Verde-Import	1819	682	1160	600	37.50%
Silver Peak-Import	10	10	10	10	100.00%

Table 5b: FTR Scheduling Statistics – February

Path	MW FTR Auctioned	Avg. MW FTR Scheduled	Max. MW FTR Scheduled	Max. Single SC FTR Scheduled	Percent of FTR Scheduled
COI – Import	658	205	445	219	31%
Eldorado – Import	793	356	480	355	45%
IID-SCE – Import	600	366	373	373	61%
Mead – Import	487	30	86	50	6%
Palo Verde – Import	1819	712	1181	600	39%
Silver Peak – Import	10	10	10	10	100%
Victorville – Import	1013	30	96	70	3%
Path 26 - Import	1727	21	307	307	1%

FTR Auction for 2002-2003. The ISO creates a primary market for FTRs by auctioning them each year. The FTRs released in the primary auction conducted in January 2001 are valid through March 31, 2002. The third FTR auction, for FTRs valid from April 1, 2002, to March 31, 2003, was conducted on January 15-17, 2002.

A small amount of FTR capacity was not sold out in the course of the auction. Most strikingly, the rights to five MW on NOB in the import direction remained unsold, even though the price had been bid up from $100/MW to $5,990/MW. This is due to the fact that one of the winners' bids had been broken into a smaller parcel in order to clear the market. The winner of this reduced parcel exercised the option not to purchase the reduced parcel, so these 5 MW went unsold. For certain other path-directions, some demand existed at the seed price; however, the demand was not sufficient to raise the price. Thus, in accordance with FTR auction rules, rights on these path-directions were partially sold at the seed price. The following table summarizes the results of this auction.

Table 6: Summary of Results of 2002-03 FTR Auction

Branch Group (Tie Areas)	Direction	Total FTR Auctioned (MW)	Quantity of FTR unsold	Final MW Sold	Auction Seed price ($/MW)	Auction Clearing Price ($/MW)	Path Revenue
CFE (MX-SP15)	import	408		408	100	165	67,320
CFE (SP15-MX)	export	408		408	100	165	67,320
COI (NW1-NP15)	import	658		658	757	17,610	11,587,380
COI (NP15-NW1)	export	165	114	51	10,002	10,002	510,102
Eldorado (AZ2-SP15)	import	793		793	621	8,432	6,686,576
Eldorado (SP15-AZ2)	export	702		702	100	420	294,840
IID-SCE (II1-SP15)	import	600		600	100	275	165,000
Mead (LC1-SP15)	import	452		452	113	4,488	2,028,576
Mead (SP15-LC1)	export	430		430	522	7,465	3,209,950
NOB (NW3-SP15)	import	610	5	605	100	5,990	3,623,950
NOB (SP15-NW3)	export	108	57	51	11,195	11,195	570,945
Palo Verde (AZ3-SP15)	import	1,167		1,167	3,863	14,868	17,350,956
Palo Verde (SP15-AZ3)	export	601		601	100	2,780	1,670,780
Path 26 (SP15-ZP26)	import	712	267	445	3,222	3,222	1,433,790
Path 26 (ZP26-SP15)	export	1,566		1,566	249	5,907	9,250,362
Silver Peak (SR3-SP15)	import	10		10	100	10,200	102,000
Silver Peak (SP15-SR3)	export	10		10	100	450	4,500
Victorville (LA4-SP15)	import	851		851	100	485	412,735
Victorville (SP15-LA4)	export	168		168	589	1,118	187,824
Totals		**10,419**		**9,976**			**$59,224,906**

Table Column Definitions:

Total FTR Auctioned (MW): The amount of FTRs in MW released on each branch group and direction is based on the New Firm Use capacity (NFU; equal to total transmission capacity (TTC) less existing transmission capacity (ETC)) available at least 99.5% of the time during the year, based on the historical operating capacity of the line during the most recent 12 months prior to announcement of the FTR quantities.

Final MW Sold: This is the final MW unit that clears the auction. The difference between total FTR auctioned and final MW sold can be due either to some FTRs that go unsold, or to the residual FTR allocation option exercised in the auction.

Auction Seed Price: This is the starting price of the simultaneous multi-round auction. It is set to the higher of $100/MW per year or 20% of the auction target price, which is the congestion revenue generated per MW of NFU during the most recent 12 months prior to announcement of FTR quantities.

Auction Clearing Price: This is the market-clearing price in $/MW per year. For the paths with seed prices that exceed $100/MW per year, the comparison of the auction clearing price and five times the seed price indicates to what extent the bidders value the FTRs on the particular path and direction compared to the congestion revenues generated last year.

Path Revenue: this is the auction clearing price, multiplied by the final MW sold.

FTR Revenue per MW collected through January 2002. As of January 2002, on only a few path-directions (Victorville export, COI Import, Palo Verde import, and Path 26 import) did cumulative FTR revenues in the 2001-2002 FTR period exceed the auction price for the following FTR period. However, this does not confirm that FTR holders on other paths have made poor investments in FTRs. An FTR holder can realize significant amounts of revenue in a short period of time in the event of a derated line. For example, when Palo Verde was partially derated in November 2001 and January 2002, FTR holders commanded $9,003 and $2,555 per MW in November and January, respectively. This is in addition to the benefit of FTRs as insurance against high congestion charges, as discussed previously. The following table summarizes FTR revenues collected through January for the 2001-2002 FTR cycle.

Table 7: FTR Revenues Collected through January in 2001-2002 FTR Cycle

Export Direction (for Path26 : north to south direction)													
Branch Group	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	cumulative $/MW as of Jan. 31, 2002	Pro Rated $/MW for the Whole Term	Auction Price ($/MW for12 months)
CFE	0	0	0	0	0	33	0	0	0	0	33	40	$255
COI	9,501	365	0	60	0	0	0	0	0	0	9,926	11,911	$47,537
ELDORADC	0	0	0	0	0	0	0	0	0	0	0	0	$2,130
MEAD	0	0	0	135	428	0	0	0	0	0	563	676	$7,327
NOB	10,412	1,649	312	249	461	0	0	0	0	0	13,083	15,700	$64,069
PALOVRDE	0	0	0	30	0	0	0	0	0	0	30	36	$14,100
PATH26	0	0	0	0	0	43	20	101	0	60	224	269	$17,724
SILVERPK	0	0	0	0	0	0	0	0	0	0	0	0	$28,374
VICTVL	0	0	46	1,371	653	0	0	0	0	0	2,070	2,484	$760
Import Direction (for Path26 : south to north direction)													
CFE	0	0	0	0	0	0	0	0	0	0	0	0	$300
COI	0	492	11	0	1,494	1,520	237	28	86	172	4,041	4,850	$3,234
ELDORADC	501	51	125	0	0	26	2	22	60	133	919	1,103	$19,028
IID-SCE	0	0	0	0	0	0	2	0	0	0	2	3	$625
MEAD	0	0	0	0	0	0	102	244	0	77	423	508	$2,386
NOB	0	0	0	0	0	0	0	0	0	0	0	0	$3,843
PALOVRDE	752	622	5	0	0	0	2	9,003	2	2,555	12,940	15,528	$6,960
PATH26	6,159	5,828	407	0	0	0	70	997	332	89	13,882	16,658	$2,564
SILVERPK	0	0	0	0	0	0	30	0	0	0	30	36	$2,100
VICTVL	0	0	0	0	0	0	0	0	0	0	0	0	$168

VIII. Issues under Investigation

BEEP Skips and Declined Dispatch Instructions. As previously noted, generators have increasingly declined to produce (or withhold) energy that they have bid into the BEEP Stack to provide imbalance energy. As a result, ISO operators are forced to call on more expensive bids, increasing cost to load. This is a form of physical withholding that is detrimental to reliable system operation and inflicts excessive costs upon consumers. It is also in violation of the ISO Tariff, which states that SCs "shall be obligated to respond or to secure response to the ISO's Dispatch instructions in accordance with their terms, and to be available and capable of doing so."[4] However, if an SC fails to comply with dispatch instructions, the ISO only has the authority effectively to penalize the SC with a fine equal to the deviation from instructions, multiplied by the difference between the INC and DEC MCPs. This penalty is often equal to zero.

In light of these deficiencies, the ISO has filed Amendment 42, which contains penalties for uninstructed deviations, including declined dispatch instructions. Specifically, the proposed penalty for a declined dispatch instruction is effectively 25 percent of the real-time MCP, plus a dollar-per-megawatt-hour charge computed based upon as-bid-above-MCP and OOM procurement costs. The ISO expects an Order by FERC on the Amendment 42 filing by the end of March.

Continuation of Market Power Mitigation. DMA is project lead in developing a market power mitigation plan to take effect after September 30, 2002 when the current mitigation established in FERC's Order of June 19, 2001 is scheduled to expire. On February 28, 2002, the ISO publicly released a draft market power mitigation proposal and is currently seeking stakeholder input. The proposal contains a four-step process for market power mitigation, including (1) market design changes; (2) a damage-control bid cap; (3) resource-specific bid screens and mitigation; and (4) an explicit standard for "Just and Reasonable" rates, which, if violated, would automatically trigger the implementation of a more stringent market mitigation plan (such as the reimposition of 6/19/2001 measures, or cost-based bid caps only on those suppliers found to have exercised market power). DMA will provide an update on this process to the Board of Governors at its March 14 meeting.

Path 15 Expansion. DMA has also provided testimony to the California Public Utilities Commission (CPUC) on the economic benefits of upgrading Path 15. This testimony was largely based on a study completed by DMA that examined the economic benefits, including market power mitigation, that would result from expanding the transmission capacity on Path 15. In its analysis, DMA examined the extent to which suppliers may be able to exercise market power in Northern California in 2005, under various scenarios of new generation investment and hydro conditions. The study shows that an upgrade of Path 15, by reducing congestion, will make it easier for potential sellers to market electricity in NP15. This positive shift in supply will reduce the market power currently enjoyed by some owners of generation in NP15, and ultimately should bring prices closer to competitive levels. The study concludes that the potential annual benefits to load in Northern California range from $208 million to $1.3 billion, depending on hydro conditions and the duration of CERS' long-term contracts. The administrative law judge overseeing the proceedings has scheduled additional hearings for March 27-28.

Refund Proceedings. Administrative hearings on the mitigated price to be used in determining refunds under the July 25 Order are scheduled for the week of March 11-17. In responsive testimony filed prior to the hearings, FERC staff approved several aspects of the methodology used by the ISO to calculate the mitigated price pursuant to the July 25 Order. These include the use of incremental (rather than average) heat rates in calculating marginal costs, and the determination that units eligible to set the mitigated price should be limited to those that were actually bid into the BEEP Stack, and were eligible to set the MCP. FERC staff also approved the ISO's methodology to identify the "last unit dispatched" in the real time market; i.e., the highest cost

[4] ISO Tariff § 2.5.22.11.

gas-fired unit dispatched through BEEP (during intervals when at least one gas-fired unit was dispatched for INC energy through BEEP), and the lowest cost gas-fired unit dispatched through BEEP (during intervals when gas-fired units were only dispatched for DEC energy through BEEP).

During proceedings pertaining to intervals in which no gas-fired units were dispatched through BEEP, FERC staff also noted that none of the alternative approaches proposed was superior to the ISO's methodology for determining the mitigated price during these conditions (i.e. the lowest cost unit with an incremental energy bid submitted in BEEP). As FERC staff noted, "No party … has shown that the ISO's method is wrong…Before recommending a change to the ISO's calculations, a witness should show why what the ISO did was wrong or at the very least, the witness should demonstrate that his method is clearly superior."

FERC staff also approved several modifications proposed by California parties representing buyers in the proceedings. Specifically, FERC staff recommended that adjustments be made in heat rates submitted by generators, that non-thermal units be excluded from setting the mitigated price, and that incremental heat rates need not be adjusted upwards to ensure they are monotonically non-decreasing, as is done on a prospective basis under the price mitigation provisions of the June 19 Order due to software issues. Each of these modifications would have the effect of lowering the final mitigated price used in determining refunds.

Finally, FERC staff expressed support for two potential modifications proposed by witnesses on behalf of sellers. Specifically, FERC staff recommended that any out-of-sequence calls be eligible to set the mitigated price, and that any combustion turbines dispatched through the BEEP stack be allowed to set the mitigated price for the entire duration of their minimum run times. Each of these modifications would have the effect of increasing the final mitigated price to be used in determining refunds.