CALIFORNIA ISO

Memorandum

To: ISO Board of Governors

From: Anjali Sheffrin, Director of Market Analysis

cc: ISO Officers, ISO Board Assistant

Date: February 14, 2003

Re: **Market Analysis Report for January 2003**

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

Executive Summary

Despite the continued increase in the price of natural gas to approximately $5 per million British Thermal Units (MMBtu), the average incremental price of real-time electricity fell in January to $60.97 per megawatt-hour (MWh) from $62.38 in December. This is due in large part to moderate loads resulting from unseasonably mild weather. In addition, significant rain has fallen recently in areas of the Pacific Northwest leading to increased hydroelectric production in the region. Meanwhile, competition in the decremental energy market continues to improve. The average decremental price increased to $16.88/MWh, as thermal generators are increasingly looking to avoid high fuel costs.

Since January 1, the state's investor-owned utilities have resumed procurement of forward-contracted wholesale electricity to cover their net-short load requirements. To date, the utilities' scheduling performance has been encouraging, as forward energy schedules have better matched load during evening ramps.

2002 Year-end Highlights. The Department of Market Analysis (DMA) has observed the following key trends in California's wholesale electricity market in 2002:

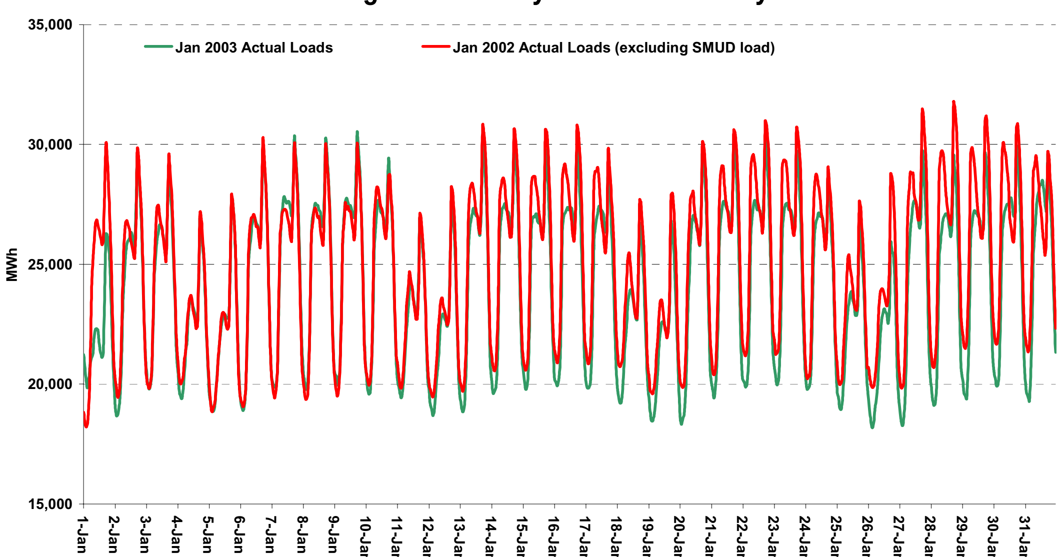
- **Dramatically lower costs in all wholesale market segments.** Overall wholesale market costs fell to $10.1 billion in 2002, or 62.2 percent less than the 2001 level of $26.7 billion. Improved forward scheduling has resulted in less reliance on the real-time market to meet load. Consequently, real-time costs fell to $99 million in 2002, compared to $4.16 billion in 2001, and $180 million in 1999, previously the year with the lowest real-time costs. The low real-time costs are due in part to the high frequency in 2002 of scheduling in excess of load, in which case suppliers repurchase decremental (DEC) energy; that is, they pay the ISO for the privilege of reducing output. Ancillary services costs fell to $165 million in 2002 from $1.35 billion in 2001. The costs of bilaterally-contracted forward-scheduled wholesale electricity also decreased significantly to $9.8 billion in 2002, from $21.2 billion in 2001.[1]

- **Significant improvements in forward scheduling.** During the Energy Crisis in 2000 and 2001, there were wide disparities between forward-scheduled energy and forecasted load. The situation has improved steadily since December 2000, when underscheduling reached its most extreme level of 14 percent below actual load. In 2002, underscheduling was 1 percent of actual load on average.
- **Improved hydro conditions.** Flows in the Pacific Northwest were near normal in 2002, leading to plentiful supplies of inexpensive hydroelectric power during most periods of peaking demand. This helped to maintain adequate margins of generation available to meet load throughout the year.
- **Rising gas prices.** The price of natural gas was remarkably low in the first quarter of 2002, averaging below $2.25/MMBtu at California delivery points in January and February 2002. Prices rose steadily over the course of the year, and particularly in the fourth quarter, closing the year in the neighborhood of $5/MMBtu, a 120 percent increase since the first quarter.

I. January 2003 Loads and Schedules

Loads in January 2003 were 3.0 percent lower on average than those in January 2002, with the bulk of the difference coming after January 10, due to mild weather throughout the West. January was the first month since May 2002 in which loads were lower than those in the same month the previous year. The following chart compares hourly loads in January 2002 and 2003.

Figure 1. Hourly Loads in January[2]

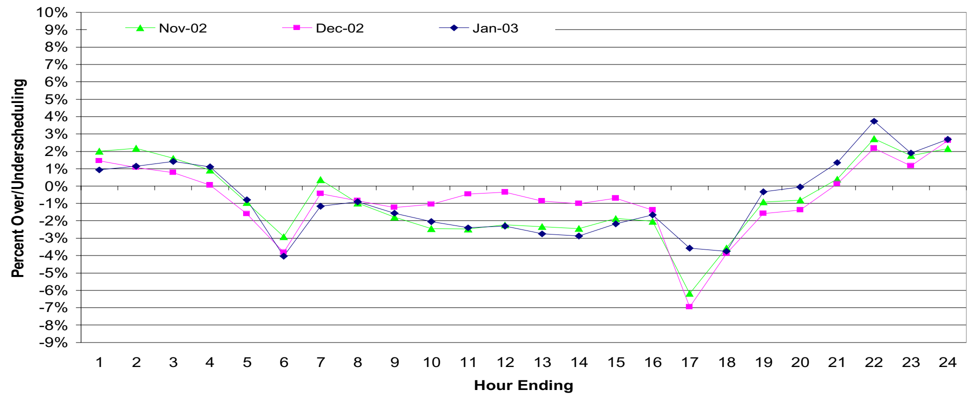


On average, forward-scheduled energy was within 1 percent of actual load in January, the first such month since January 2002. There has been significant improvement in scheduling during the

[1] Year-to-year comparisons do not adjust for inflation or gas costs.
[2] In order to keep weekdays consistent, this chart compares January 1-31, 2003, with January 2 through February 1, 2002.

steep early-evening ramp in particular, as utilities are once again procuring their own net-short load. Previously, from January 2001 through December 2002, the California Department of Water Resources' California Energy Resources Scheduling Division (CERS) had procured the net short on the utilities' behalf. The following chart compares monthly average scheduling deviations by hour of day since November 2002.

Figure 2. Monthly Average Scheduling Deviations by Hour of Day



II. Real-Time Market Performance

Average BEEP Prices and Volumes. The average price for real-time incremental energy was \$60.97/MWh in January, compared to \$62.38/MWh in December. The average decremental (DEC) price was \$16.88/MWh in January, compared to \$15.23/MWh in December. Average load was 24,182 MW in January, with 0.9 percent underscheduling, compared to 24,879 MW in December, with 0.8 percent underscheduling.

The following table shows weighted-average BEEP prices, total volumes, and average system loads and underscheduling in January.

Table 1. BEEP Prices and Total Volumes in January

	Avg. BEEP Price and Total Volume		Avg. System Loads (MW) and Pct. Underscheduling
	Inc	Dec	
Peak	\$ 61.30	\$ 20.54	26,067 MW
	97 GWh	132 GWh	1.0%
Off-Peak	\$ 59.22	\$ 11.48	20,413 MW
	18 GWh	90 GWh	-0.5%
All Hours	\$ 60.97	\$ 16.88	24,182 MW
	116 GWh	222 GWh	0.9%

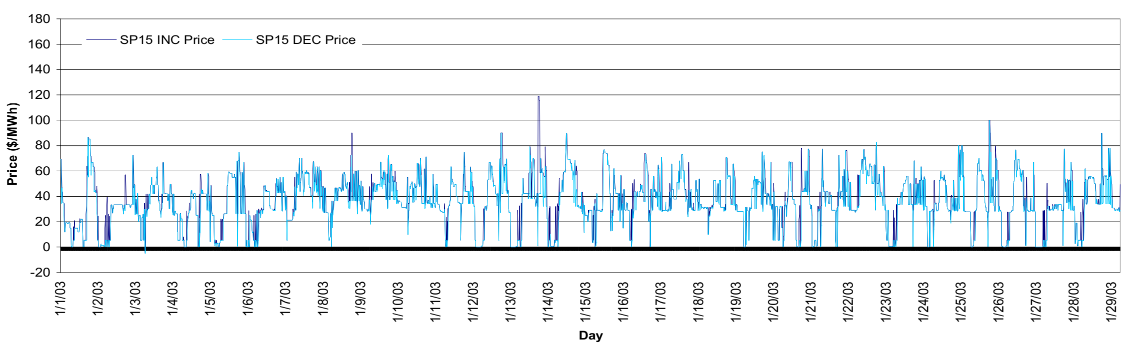
Review of Price Spikes. Although average incremental energy prices decreased in January, the BEEP market sustained several price spikes.

On January 13, ISO operators dispatched incremental energy to meet the sharp rise in load between 6:00 and 7:00 p.m. (hours ending 18:00 and 19:00). The Southern California Import Transmission Nomogram (SCIT) constrained import supply into Southern California on this day. During the early-evening ramp, the real-time market clearing price in SP15 was at least \$115.55/MWh for seven intervals, and peaked at \$119/MWh. Most dispatched units were those with high ramp rates, needed to meet the steep load ramp. The market-clearing price was set by a peaker unit that had also set the price during several spikes in December.

On January 25, at 5:34 p.m. (in HE 18:00), a major unit malfunctioned in NP15. ISO operators responded by incrementing several resources, causing the MCP to spike to \$100/MWh for the next four intervals. The resource that set the MCP in HE 19:00, intervals 1 and 2 (between 6:00 and 6:20 p.m.), has a reference price below \$5/MWh, which places it in a position to fail the Conduct Test whenever AMP is applied. However, due to an unusual time sequence of events, AMP was not applied in these hours; thus, the MCP-setting resource was not subject to the Conduct Test.

The following chart shows ten-minute interval prices in SP15 in January.

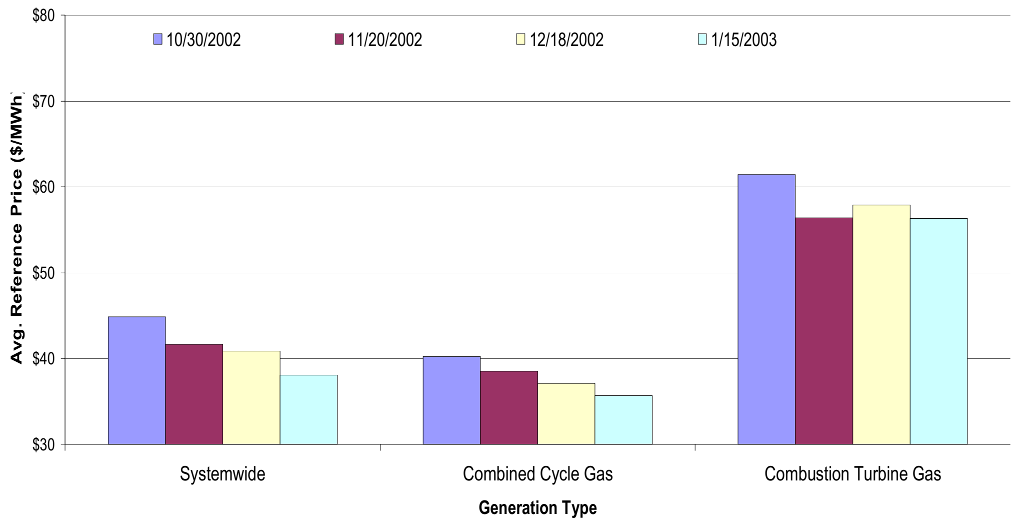
Figure 5. SP15 Interval Prices in January 2002



Automated Mitigation Procedures (AMP). The Conduct Test was triggered in only six hours in January. Since the introduction of AMP on October 30, 2002, the Impact Test has yet to be failed. The same units that had triggered the Conduct Test in November and December largely accounted for the January incidences. Most units that have triggered the Conduct Test are municipals, hydroelectrics, pumped storage, and qualifying facilities, either with very low reference prices, or with reference prices at the FERC-directed price ceiling of \$250/MWh and bids exceeding \$1000/MWh. In addition, at least one merchant thermal peaking unit with an extraordinarily low reference price failed the Conduct Test in two hours in January. DMA does not infer that a conduct test failure necessarily indicates an attempt to exercise market power; however, these incidents are continually monitored.

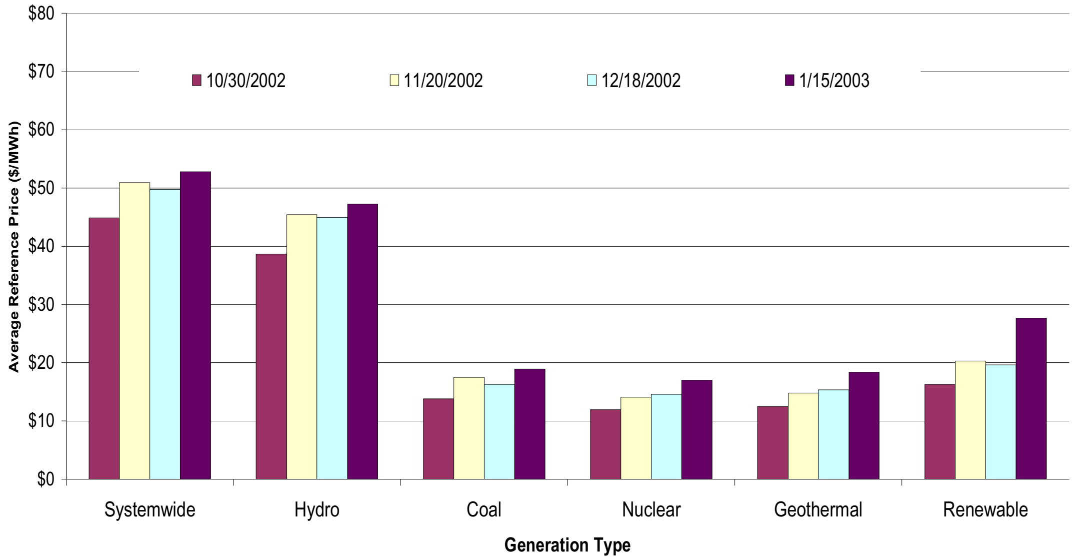
DMA monitors reference levels to detect whether suppliers are attempting to increase their reference levels through their bidding behavior. Although reference prices in general have been increasing, they remain within reasonable levels. While the reference curves for generators of all types continue to move upward, thermal generators' curves are actually decreasing when adjusted for the price of natural gas. DMA will continue to monitor trends in reference prices. The following charts show average reference prices for thermal generation types normalized to the price of natural gas in October 2002, and absolute average reference prices for non-thermal generation types.

Figure 3. Average Reference Levels for Gas-Fired Thermal Generation, Adjusted for the Price of Natural Gas4



[4] Reference prices are based on 90-day rolling average prices of accepted bids and/or the BEEP Market Clearing Price. DMA calculates average reference prices on the third Wednesday of each month.

Figure 4. Average Reference Levels for Non-Gas Fired Generation (Not Adjusted for the Price of Natural Gas)



III. Ancillary Services (AS) Markets

Day-ahead upward regulation service prices averaged $15.91/MWh in January, compared to $10.30/MWh in December. Day-ahead downward regulation (RD) service prices averaged $18.22/MWh in January, compared to $10.60/MWh in December. Spinning reserves day-ahead prices averaged $4.56/MWh in January, compared to $5.12/MWh in December. Non-spinning reserves day-ahead prices averaged $3.26/MWh in January, compared with $2.44 in December. Replacement reserves day-ahead prices averaged $1.68/MWh in January, compared to $1.31/MWh in December. The following table shows average ancillary service prices and volumes by market in January.

Table 2. Average AS Prices and Volumes by Market in 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	$ 15.91	$ 16.88	$ 15.99	344	31	91%
Regulation Down	$ 18.22	$ 17.36	$ 18.12	377	47	88%
Spin	$ 4.56	$ 4.09	$ 4.54	666	32	95%
Non-Spin	$ 3.26	$ 2.85	$ 3.24	667	24	96%
Replacement	$ 1.68	$ 1.74	$ 1.68	22	*	101%

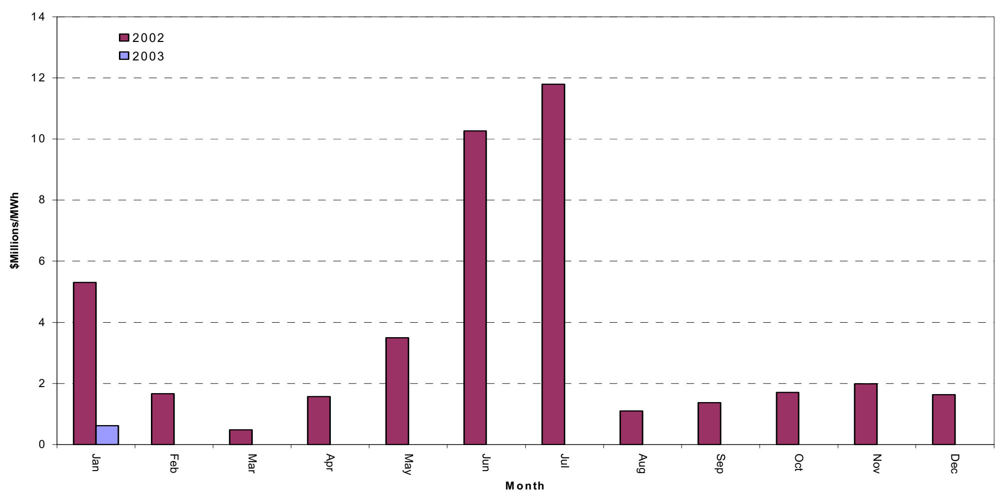
[5] This is an hypothetical situation; a different rules regime necessarily would result in different behavior.

Hourly AS prices were stable in January. One significant price spike occurred in the hour-ahead market on January 1, HE 24:00, when the RD price peaked at $250/MWh. DMA has investigated this incident and found that the bid stack was thin in this hour, and that all lower bids were either exhausted, or could not have been accepted due to physical constraints. This enabled several other flexible units which bid at $250/MWh to set the price.

IV. Interzonal Congestion

Interzonal congestion costs were relatively low in January, totaling approximately $200,000, compared to $1.6 million in December. Roughly $170,000 of the January total was incurred in the day ahead on two key paths into Southern California in the import direction. The following chart compares Interzonal congestion costs in January 2003 to those in each month in 2002.

Figure 5. Monthly Congestion Costs, January 2003 vs 2002



Approximately $85,000 in congestion costs was incurred on Eldorado, due almost entirely to a single spike. On January 11, hour ending 6:00, the congestion price spiked to $144.84/MW, resulting from a scheduled de-rate of Eldorado from nearly 1,600 MW to less than 600 MW. During this first hour of the derate, certain SCs with import schedules neither decreased their schedules sufficiently, nor submitted adjustment bids, causing the high congestion costs for the hour.

Palo Verde incurred approximately $87,000 in congestion costs as schedules were at or near the path limit for most of the month, and exceeded the limit on several days. Most congestion costs were incurred on January 13, when the usage charge was $2/MWh.

The following table shows day-ahead congestion statistics and total day-ahead and hour-ahead Interzonal congestion costs by path and direction for January.

Table 3. Day-Ahead Interzonal Congestion Statistics and Total Interzonal Congestion Costs

Branch Group	Direction of Congestion	Peak Cong. Pctg.	Off-Peak Cong. Pctg.	All-Hours Cong. Pctg.	Avg. Peak Cong. Price	Avg. Off-Peak Cong. Price	Avg. All-Hours Cong. Price	Total Cong. Cost (DA+HA)
CFE	Import	0%	0%	0%				$ 6,002
COI	Import	0%	0%	0%				14,014
ELDORADO	Import	0%	0%	0%		$ 144.84	$ 144.84	85,416
LUGO-TO-MONA	Import	6%	6%	6%	$ 1.00	1.00	1.00	8,049
NOB	Import	0%	0%	0%				9,360
PALO VERDE	Import	4%	1%	3%	1.95	0.69	1.74	87,246
PATH 15	South-to-North	9%	44%	21%	0.	0.	0.	4,844
PATH 26	North-to-South	3%	0%	2%	10.44		10.44	399,626

V. Firm Transmission Rights Market

FTR scheduling. On some paths, FTRs were used to establish scheduling priority in the day-ahead markets. As shown in the following table, high percentages of FTRs were scheduled on certain paths (84% on Eldorado, 74% on IID-SCE, 75% on Palo Verde, and 100% on Silver Peak in the import direction). FTRs on these paths are owned primarily by Southern California Edison Company (SCE1). The following table shows FTR scheduling statistics for January.

Table 4. FTR Scheduling Statistics for January 2003[6]

	Direction	MW FTR Auctioned	Avg. MW FTR Sch.	Max MW FTR Sch.	Max Single SC FTR Schedule	% FTR Schedule
COI	Import	678	28	125	100	4%
ELDORADO	Import	793	670	700	700	84%
IID-SCE	Import	600	442	456	456	74%
MEAD	Import	522	33	174	150	6%
PALO VERDE	Import	1192	890	954	579	75%
SILVER PEAK	Import	10	10	10	10	100%
NOB	Export	181	12	23	23	7%
PATH 26	North-to-South	1586	341	803	500	22%

[6] only those paths on which 1% or more of FTRs were attached are listed

FTR Revenue per Megawatt. FTR revenue on COI has decreased significantly since October. Due to relatively light congestion in January, there was no significant FTR revenue on any intertie. The following table summarizes FTR revenue per MW through January 2002.

Table 5. FTR Revenue Per MW ($/MW)

Branch Group	Direction	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Cumm Net REV	Pro Rated Annual NET Rev
CFE	IMPORT	0	0	0	0	0	0	0	0	0	15	15	18
COI	IMPORT	1,088	888	4,129	4,278	581	562	153	15	0	10	11,706	14,047
ELDORADO	IMPORT	268	26	2	10	0	37	1,255	1,178	38	103	2,916	3,500
IID-SCE	IMPORT	0	0	0	0	0	0	0	2	0	0	2	2
LUGO-TO-MONA	IMPORT	0	0	0	0	0	0	0	0	0	17	22	26
MEAD	IMPORT	19	22	0	0	0	0	97	166	23	0	327	393
NOB	IMPORT	13	0	48	472	14	5	32	1	31	6	624	749
PALO VERDE	IMPORT	23	839	0	0	4	86	226	376	887	42	2,484	2,980
PATH 26	IMPORT	0	133	370	0	0	25	28	44	31	0	631	757
MEAD	EXPORT	0	0	0	262	31	0	0	0	0	0	293	351
PATH 26	EXPORT	61	134	125	1,703	116	114	23	35	178	191	2,681	3,217
VICTORVILLE	EXPORT	0	249	724	0	0	0	0	0	0	0	973	1,168

* Pro-rate Annual FTR revenue is estimated based on the actual FTR revenue collected in this FTR cycle and assumes that FTRs would collect same rate of revenue in the remaining months of this FTR cycle

FTR Auction for 2002-2003. The ISO conducted an auction in January 2003 for FTRs valid from April 1, 2003, to March 31, 2004. Results of the auction are summarized as follows.

On most paths, market-clearing prices were significantly higher than the projected FTR revenue, estimated to be equal to five times the seed prices.[7] This was the case for paths in the import directions into California. The result is due primarily to the current settlement system of FTR auction revenue. Because utility distribution companies (UDCs) are the primary transmission owners (PTOs) of these paths, and PTOs would eventually receive all of the auction proceeds, UDCs bid aggressively to secure their FTR rights on these lines. As a result, auction market clearing prices exaggerated the predicted value of the auctioned FTRs. Of the $100 million in FTR auction revenue, UDCs paid approximately $70 million, and other market participants paid approximately $31 million. In comparison, other market participants paid about $47 million and $34 million in the FTR auctions in 2001 and 2002, respectively.

[7] Seed prices are set by taking 1/5 of the 2002 congestion revenues.

Table 6. Summary of Results of 2003-2004 FTR Auction

Branch Group	From	To	Direction	Total FTR Auctioned (MW)	Total FTR Sold (MW)	Unsold FTR (MW)	Seed Price ($/MW)	Auction Clearing Price ($/MW)	Auction Revenue
BLYTHE	LC2	SP15	import	167	167	0	$100	$5,460	$911,820
CFE	MX	SP15	import	100	100	0	$100	$745	$74,500
COI	NW1	NP15	import	739	725	14	$1,863	$19,828	$14,375,300
ELDORADO	AZ2	SP15	import	519	510	9	$396	$16,944	$8,641,440
IID-SCE	II1	SP15	import	600	600	0	$100	$195	$117,000
IID-SDGE	II2	SP15	import	62	62	0	$100	$2,290	$141,980
MEAD	LC1	SP15	import	446	446	0	$100	$7,820	$3,487,720
NOB	NW3	SP15	import	526	526	0	$119	$12,245	$6,440,870
PALO VERDE	AZ3	SP15	import	625	602	23	$889	$88,167	$53,076,534
PATH 26	SP15	ZP26	South-north	285	285	0	$100	$245	$69,825
SILVER PEAK	SR3	SP15	import	10	10	0	$100	$650	$6,500
SUMMIT	SR2	NP15	import	98	98	0	$100	$650	$63,700
VICTORVILLE	LA4	SP15	import	991	991	0	$100	$115	$113,965
BLYTHE	SP15	LC2	export	72	72	0	$100	$180	$12,960
CFE	SP15	MX	export	100	100	0	$100	$135	$13,500
COI	NP15	NW1	export	422	422	0	$100	$480	$202,560
ELDORADO	SP15	AZ2	export	536	536	0	$100	$120	$64,320
IID-SDGE	SP15	II2	export	62	62	0	$166	$182	$11,284
MEAD	SP15	LC1	export	430	430	0	$100	$1,085	$466,550
NOB	SP15	NW3	export	509	509	0	$100	$565	$287,585
PALO VERDE	SP15	AZ3	export	845	845	0	$100	$165	$139,425
PATH 26	ZP26	SP15	North-south	1405	1405	0	$504	$8,602	$12,085,810
SILVER PEAK	SP15	SR3	export	10	10	0	$100	$100	$1,000
Total									$100,806,148

Table Column Definition:
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=total transmission capacity-ETCs) 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.

Total FTR Sold: This is the final MW clearing the auction. The difference between Total FTR Auctioned and Final MW sold can be either due to some FTRs not sold or the residual FTR allocation option exercised in the auction.

Auction Seed Price: The seed price for each branch group 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. But it is not lower than $100/MW per year

Auction Clearing Price: This is the market-clearing price in $/MW per year. For the paths with seed price > $100/MW per year, the comparison of the Auction Clearing Price and Seed Price* 5 indicates to what extent the bidders value the FTRs on the particular path and direction compared to the congestion revenues generated last year.

Auction Revenue: this is equal to the product of Auction Clearing Price and Final MW Sold.

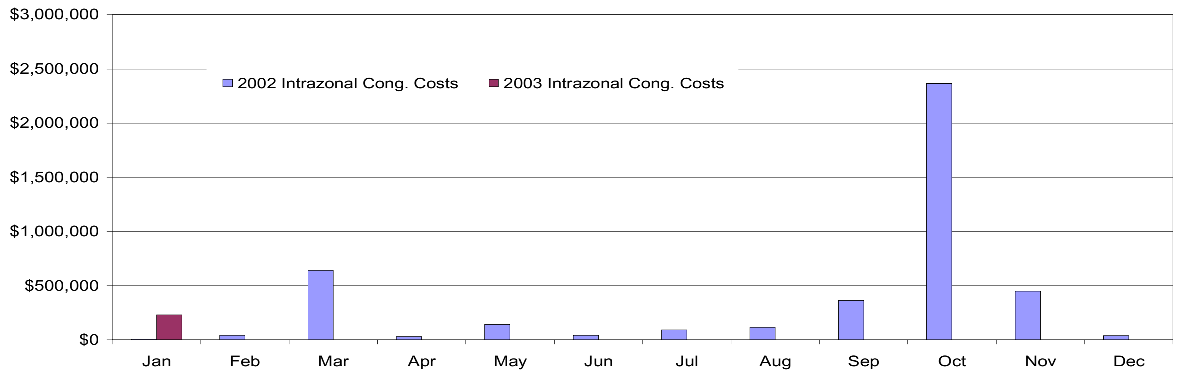
VI. Intrazonal (Within-Zone) Congestion

Intrazonal congestion costs totaled just over $230,000 in January, up from approximately $39,000 in December due in large part to outages of several transmission resources as listed below:

- Bailey Pastoria 230 kV transmission line on January 9 and 10
- Pittsburg Substation between January 21 and 23
- Tesla-Metcalf 500 kV line on January 23
- Serrano-Villa Park No. 1 on January 18 scheduled through February 13
- Vincent Substation scheduled repair work from January 20 through February 10

The following chart compares January 2003 intrazonal congestion costs with those in 2002.

Figure 6. Intrazonal Congestion Costs[9]



VII. Natural Gas Markets

Nationally, natural gas prices increased steadily through the month of January, due to extremely cold conditions in much of the continental United States, and particularly in the East in the third week of the month. This region-specific cold weather resulted in substantial spreads between Henry Hub and California natural gas prices.

The Henry Hub price was approximately $4.55/MMBtu at the beginning of the month, but quickly increased to the $5.00 to $5.25/MMBtu range, where it remained until mid-January. As noted, this was due to ongoing cold weather driving heating demand in the Northeast. Southern California Border Average and PG&E Citygate prices began the month at $4.50/MMBtu, and increased to the $4.70 to $4.90/MMBtu range through mid-January. Northwest (at Malin) prices steadily increased from $4.00/MMBtu to $4.50/MMBtu.

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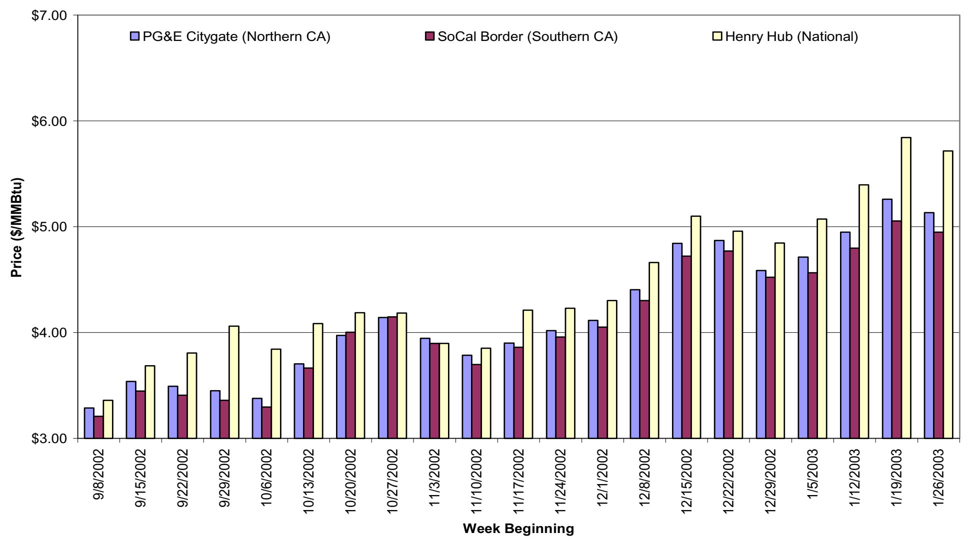
[9] Intrazonal congestion costs related to out-of-sequence dispatches only. Does not include RMR Intrazonal congestion costs.

Prices rose quickly to $5.73/MMBtu on January 17 at Henry Hub, due to sharp increases in futures prices, extremely cold weather through much of the Northeast, and a report from the Energy Information Administration that 136 Bcf of natural gas was withdrawn from storage, over a forecasted 100-120 Bcf. Prices ultimately peaked on January 23. Henry Hub prices reached a high of $6.77/MMBtu, while California prices peaked in the range of $5.40 to $5.55/MMBtu. At some Northeast locations, prices increased to highs of $22/MMBtu. After January 23, temperatures moderated throughout the country; moderate weather in California increased spreads between Henry Hub and California to over $0.50/MMBtu. Average bid week prices for February were $4.92, $4.91, and $5.17 for SoCal Gas, Malin, and PG&E Citygate, respectively, up 8%, 11%, and 6% from January bid week prices.

There has been some concern about the steady rise in natural gas prices since summer 2002. Below is a chart of natural gas prices from September 2002 to January 31, 2003.

Figure 7. Weekly Average Gas Prices through January 2003



The Federal Energy Regulatory Commission's Office of Market Oversight and Investigations released the 2003 Natural Gas Market Assessment Report on January 29, 2003. In this report, FERC Staff noted that potential for manipulation of the natural gas markets persists, primarily through five means:

(1) control of market places through weak liquidity;
(2) physical withholding of capacity;
(3) manipulation of illiquid physical marketplaces to affect prices in associated financial markets;
(4) inappropriate dealings with affiliates; and
(5) provision of false data to index publishers.

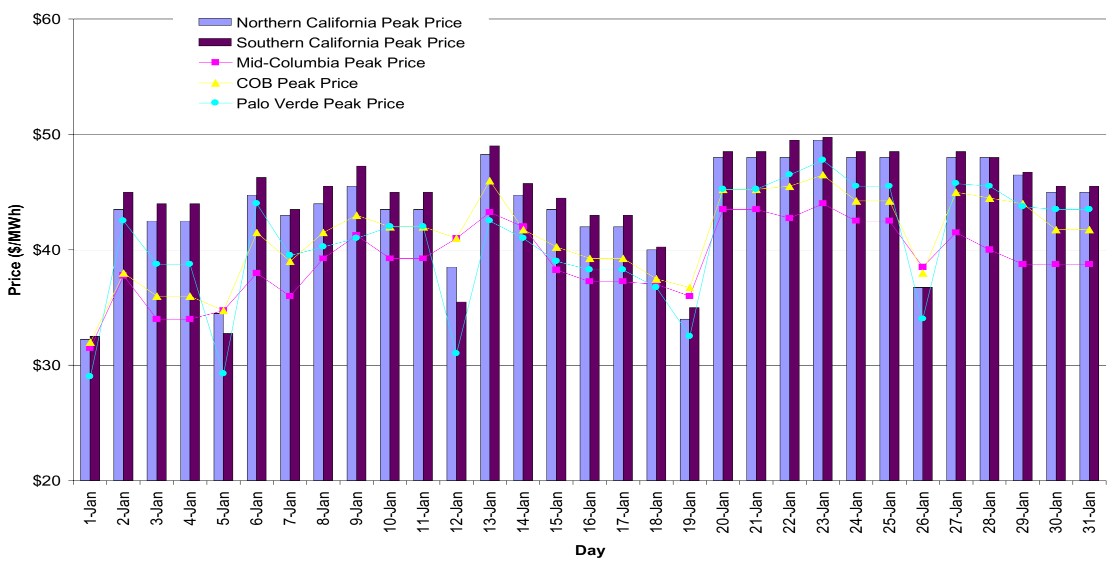
FERC reportedly has a number of active investigations pending.

VIII. Day-Ahead Bilateral Electricity Markets

Regional Day-ahead Electricity prices during peak periods were slightly lower at the beginning of January than at the end of December, due to lower demand during the holiday season and moderate West Coast weather. California prices remained between $43 and $45/MWh, while other prices remained between $35 and $43/MWh. Transitory gas increases a few days prior to January 6 resulted in slight increases in day-ahead electricity prices, but prices remained substantially flat until January 13. A string of relatively high gas prices, coupled with slightly colder weather caused electricity prices to increase to nearly $50/MWh on January 13 in California. Moderating demand before the Martin Luther King, Jr. holiday resulted in decreasing prices.

The sharp increase in California natural gas prices resulted in sustained electricity prices near $50/MWh between January 20 and 25. Subsequent electricity prices decreased as moderate weather and reduced gas prices resulted in price decreases. The following chart compares regional bilateral prices in January.

Figure 9. Regional Day-Ahead Bilateral Electricity Prices



IX. Issues under Review

100 Day Discovery. The ISO continues to provide extensive support to parties active in the 100-day discovery relating to the refund case before the FERC. The purpose of the 100-day discovery period is to provide parties with additional time to develop and present evidence that market power and/or market manipulation was present from January 1, 2000 through June 20, 2001. In addition to the refund case, the ISO is providing support to parties active in three additional FERC Proceedings (EL92-113, EL92-114, and PA02-2-00), concerning Enron and other entities under investigation for potential manipulation and misconduct in the Western wholesale electric and natural gas markets.

In addition, the ISO is reviewing several market events involving the scheduling of load and transmission, as well as the bidding of energy into the real-time market, and instances specific to the application of locational market power. Automated monitoring indices are currently being implemented to further enhance the ISO's ability to detect and investigate market behavior that was highlighted during the investigation of Enron trading strategies.