California Independent
System Operator

CALIFORNIA ISO

Memorandum

To: ISO Board of Governors

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

cc: ISO Officers, ISO Board Assistant

Date: March 21, 2003

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

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

Executive Summary

Persistent extreme cold weather in the Eastern United States brought national gas storage levels to multi-year lows, causing the price of gas to increase by approximately 70 percent in the last week of February, closing the month in the range of $9 per million British Thermal Units (MMBtu). Western regional electric prices responded by peaking at approximately $140 per megawatt-hour (MWh) in the last week of February. Similarly, the ISO's real-time incremental imbalance energy prices exceeded $100/MWh during peak afternoon hours for most of that week, compared to prices in the $60/MWh range generally seen in recent months. Fortunately, the combination of mild weather in California and sufficient electricity supply from the addition of new units over the past two years has helped to mitigate suppliers' ability to hold prices significantly above competitive baseline levels.

The average market-clearing price (MCP) for real-time incremental (INC) electricity in the ISO's Balancing Energy Ex-Post Price auction market (the BEEP Stack) increased 21 percent to $73.66/MWh for all hours in February. As suppliers looked to avoid high gas costs, the average BEEP price for decremental (DEC) electricity increased 68 percent to $28.28/MWh for all hours in February.[1]

Higher-than-normal natural gas prices may continue into the spring, due to low storage levels. This likely will lead to continued strong demand for gas in the coming months, to replenish storage as the weather moderates. In addition, as of February 1, Western snowpack conditions and water supply forecasts were below normal, which could impact hydroelectric production this summer. Fortunately, basins in Central and Northern California are forecast to receive near-average spring stream flows.

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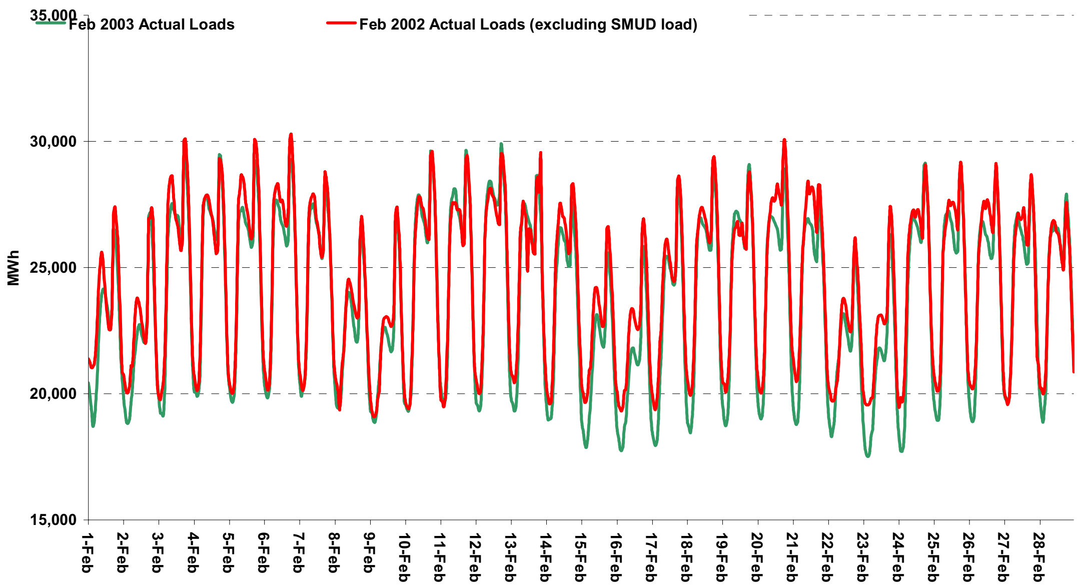
[1] In the ISO BEEP market, suppliers sell electricity at the INC price, and pay the DEC price for the privilege of decreasing output. All else equal, lower INC prices and higher DEC prices result in lower overall costs to load.

I. Market Trends

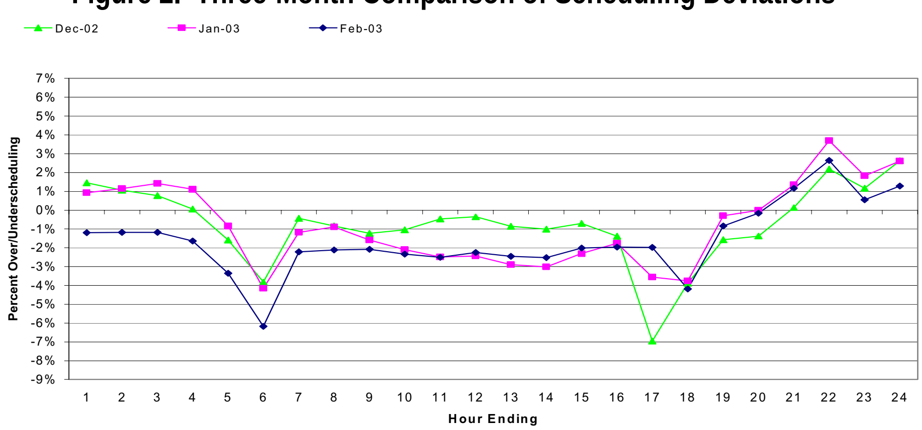
Loads and Scheduling. Loads in the ISO Control Area have been slightly lower than similar months in the previous year. Average load declined 0.9 percent to 23,820 MW in February, and the monthly peak load declined 0.3 percent to 29,672 MW. This is due in large part to unseasonably mild weather in California. The following chart shows hourly loads in February 2003 compared to those in February 2002.

Figure 1. Hourly Loads in February 2003 vs. February 2002



Forward schedules have come closer to actual load in recent months since the investor-owned utilities resumed scheduling their net short load requirements, particularly during the evening ramp hours. In addition, an overscheduling pattern in off-peak morning hours has been replaced with underscheduling. The following chart shows monthly average scheduling deviations by hour of day since December 2002.

Figure 2. Three-Month Comparison of Scheduling Deviations



II. Real-Time Market Performance

Average BEEP Prices and Volumes. Due primarily to the large increase in natural gas prices, both average incremental and decremental prices increased significantly in February over January averages. The average BEEP price for incremental (INC) electricity was $73.66/MWh in February, compared to $60.97/MWh in January. The average BEEP price for decremental (DEC) electricity in February was $28.28/MWh, compared to $16.88/MWh in January.

Prior to the dramatic increase in the price of natural gas during the final week of February, the peak-hour INC price averaged $69.56/MWh, still above the January average peak-hour INC price of $61.30/MWh. In comparison, the average peak-hour INC price in the final five days of February was $97.08/MWh.

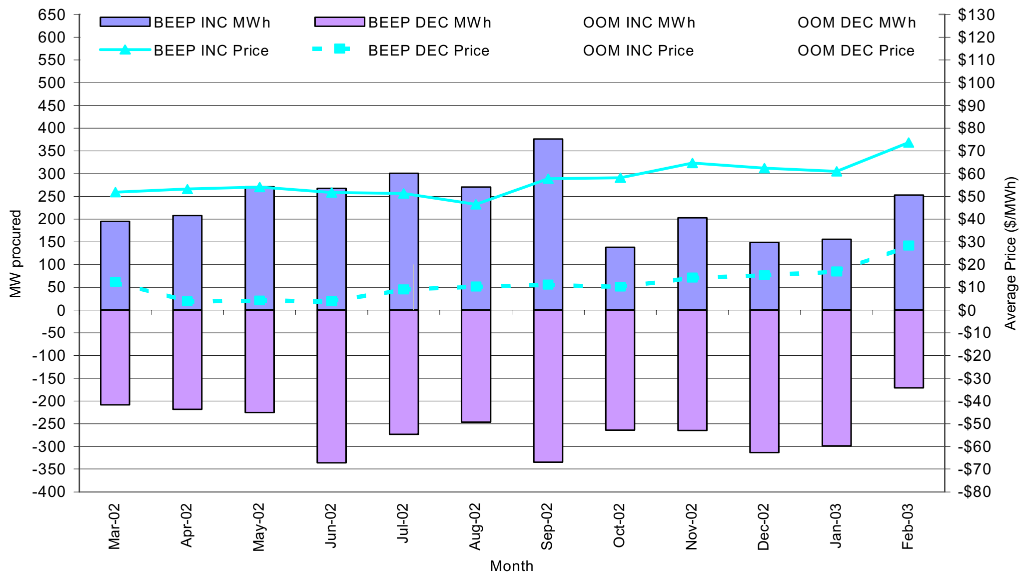
Between January and February, there was a shift in the BEEP Stack in the relative proportions of incremental and decremental volumes. In the several months prior to February, volume on the decremental side of the market was substantially heavier than on the incremental side as forward schedules had exceeded actual load. However, forecasts have improved and forward schedules are now slightly below actual load. The following table shows BEEP prices, volumes, loads, and scheduling deviations through February.

Table 1. Average BEEP Prices and Volumes, Loads, and Underscheduling in February

	Avg. BEEP Price and Total Volume		Avg. Out-of-Market Price and Total Volume		Overall Avg. Real-Time Price and Total Volume		Avg. System Loads (MW) and Pct. Underscheduling
	Inc	**Dec**	**Inc**	**Dec**	**Inc**	**Dec**	
Peak	$ 77.38	$ 28.13	$ 151.23	No Procurement	$ 77.58	$ 28.13	25,682 MW
	121 GWh	89 GWh	*	*	121 GWh	89 GWh	1.6%
Off-Peak	$ 64.78	$ 28.79	No Procurement	No Procurement	$ 64.78	$ 28.79	20,096 MW
	49 GWh	26 GWh	*	*	49 GWh	26 GWh	1.6%
All Hours	$ 73.73	$ 28.28	$ 151.23	No Procurement	$ 73.88	$ 28.28	23,820 MW
	170 GWh	115 GWh	*	*	170 GWh	115 GWh	1.6%

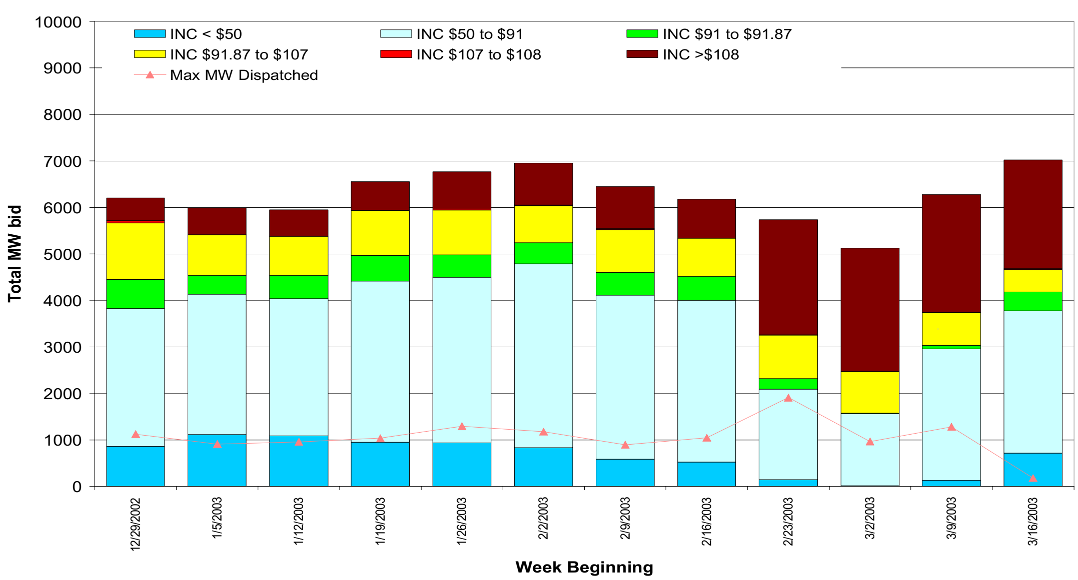
The following chart shows monthly average BEEP volumes and prices through February.

Figure 3. Monthly Average BEEP Volumes and Prices



Due primarily to the increase in natural gas prices in the final week of February, bid prices for incremental energy into the BEEP Stack increased dramatically, as shown in figure 4 below. In that week, most BEEP INC volume was bid in the range of $108 to $200/MWh, whereas it was primarily bid below $91.87/MWh only weeks earlier. High gas prices also caused an increase in DEC prices, which suppliers pay to the ISO to decrease output when the ISO is in an over-generation situation. The following chart shows weekly average bid volume in the BEEP Stack by price bin through March 16, 2003.

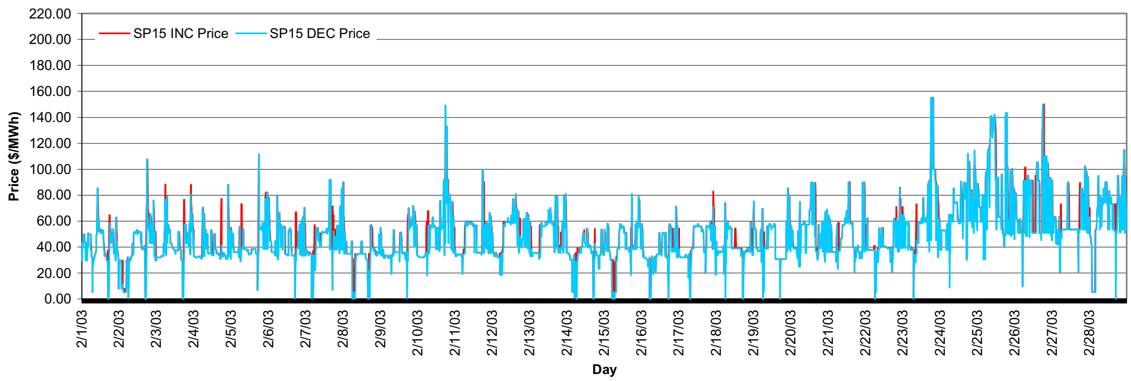
Figure 4. Weekly Average BEEP INC Bid Volume by Price Bin, January 1 through March 16



Price Spikes. There were many events in February that caused prices to rise in excess of \$100/MWh. Thus, prices that normally would be considered anomalous were in fact common between February 24 and 28. However, some anomalous events prior to February 24 did cause the price to spike during that period as well.

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

Figure 5. Ten-Minute BEEP Prices in SP15 for February 2002



On February 2, the BEEP INC price spiked to \$107.47 between 6:00 p.m. and 6:20 p.m. (hour ending (HE) 19:00, intervals 1 and 2). This spike was driven by undergeneration caused by units dispatched for supplemental energy that did not sufficiently follow their incremental dispatch instructions combined with the need to preserve operating reserves. This forced operators to dispatch additional supplemental energy bids from the BEEP stack.

On February 5, between 5:40 and 6:00 p.m. (HE 18:00, intervals 5 and 6), the INC price spiked to \$111.60/MWh in SP15 only. This spike occurred during a period when the ISO needed to conserve operating reserves and some units dispatched for supplemental energy declined ISO dispatch instructions. Similar to the February 2 spike, this forced operators to dispatch additional supplemental energy bids from the BEEP stack.

On February 10, between 5:40 and 7:00 p.m. (HE 18:00 interval 5 through HE 19:00 interval 6), the electricity price peaked for two intervals at \$149.35/MWh, and then stayed at \$133.01/MWh for another six intervals. This spike occurred during a period in which the ISO needed to preserve operating reserves. As in the spikes on February 2 and 5, ISO Operators had to dispatch additional supplemental energy bids from the BEEP Stack in order to balance system loads resulting in higher prices for the period.

On February 23 at 6:00 p.m., a small aircraft collided into a 500kV static wire on the Adelanto-Rinaldi transmission line in Palmdale owned by the Los Angeles Department of Water and Power (DWP). The incident caused the Adelanto-Rinaldi line to trip, and also tripped a number of other lines emanating from the Adelanto substation, as well as the Mohave Unit 1 generating station. ISO operators dispatched within-Control-Area resources as needed, causing the price to spike continuously for approximately three hours, peaking at \$155.08/MWh.

As-Bid Procurement. During the February 23 price spike discussed earlier, the ISO procured approximately 3 MWh "as bid" from the BEEP Stack at a price of $749/MWh. In accordance with the current market power mitigation rules in place since October 30, 2002, bids greater than $250/MWh cannot set the market clearing price; however, they are paid their respective bid prices, and are subject to cost justification. In this case, the supplying unit was a resource operating under severe environmental constraints in Southern California that does not receive must-offer waivers due to its quick-start capability. This was its only BEEP dispatch to date in 2003. The MCP, at which all other units were priced in those intervals, was set by the next highest-priced bid, which at the time was $155.08/MWh.

Out-of-Market (OOM) Calls. During the aforementioned system disturbances on February 23, ISO operators ran out of energy bids to dispatch from the BEEP stack and were forced to incrementally dispatched a number of units out of market to meet imbalance energy requirements. During the spike around 6:00 p.m., 332 MWh of OOM energy was purchased at prices that ranged between $83 and $155, resulting in a total cost of approximately $50,000. Stability was restored to the market shortly thereafter, at which point BEEP INC calls were quickly substituted for the OOM calls.

Out-of-Sequence (OOS) Calls. ISO operators called 163 MWh out-of-sequence on February 20, to manage congestion around repair work at the Vincent substation.

On the decremental dispatch side, there has been a series of dispatches due to ongoing work at the Pittsburg substation, scheduled between February 11 and 22. Total decremental dispatches amounted to approximately 14,000 MWh. An additional 389 MWh of decremental energy was dispatched on February 14 due to work on the Jamacha-Miguel transmission line.

Total net intrazonal congestion costs[2] for both incremental and decremental dispatches were approximately $253,000 for the month of February. The 163 MWh of INC comprised only a small portion of the total.

Automated Mitigation Procedures (AMP). Certain bidders failed the AMP Conduct Test in 48 hours in February. In nearly all of those hours, the same units that had failed repeatedly in recent months again failed, due largely to persistently high bids or to very low reference prices. These units are seldom competitive in the BEEP Stack, because of either high bids, low ramp rates, or both.

In the final week of February, approximately four units that typically sell significant volumes of electricity through the BEEP Stack failed the conduct test for the first time, and did so in several hours. This is due in part to the lag between the sudden increase in the price of natural gas in that week, which increased suppliers' operating and/or opportunity costs, and the natural gas price adjustment of reference levels for thermal units, which typically occurs on or about the seventh day

[2] Intrazonal congestion costs are costs for out-of-sequence energy used to manage intrazonal congestion. Incremental OOS costs are the costs of dispatching a unit out of economic merit order. That is, for each OOS dispatch, the OOS portion of the cost is the difference between the bid price and the MCP in the corresponding interval, multiplied by the volume of that dispatch. Reliability Must-Run costs are not included in totals.

of the following month. Reference levels for thermal generators in March will be adjusted to reflect a monthly gas price $7.27/MMBtu, in comparison to the February price of $4.99/MMBtu. The March adjustment to thermal reference levels will raise suppliers' reference levels accordingly, and enable thermal suppliers to bid significantly higher prices without failing the Conduct Test.

No unit has yet failed the AMP Impact Test, a considerably stricter standard than the Conduct Test. The table below shows the number of hours in each day that units failed the Conduct Test in February.

Table 2. AMP Conduct Test Failures in February

Date	No. of Hours
2/10/2003	1
2/21/2003	1
2/23/2003	4
2/24/2003	5
2/25/2003	14
2/26/2003	12
2/27/2003	4
2/28/2003	7

The Department of Market Analysis (DMA) monitors trends in reference levels. Overall, reference levels have increased over the past several months. The bulk of the increase in gas-fired thermal generators' reference levels can be attributed to rising gas costs; when normalized against gas prices, gas-fired units' reference levels have trended downward. Non-gas-fired generators' reference levels have risen; however, those units comprise only a small share of electricity procured through the BEEP Stack. The following charts show (a) average unadjusted reference levels by generation type; and (b) reference levels for thermal generators, normalized to the October gas price index.

Table 3a. Average Reference Levels through February 2003
By Generation Type, Not Adjusted for Gas Price Changes

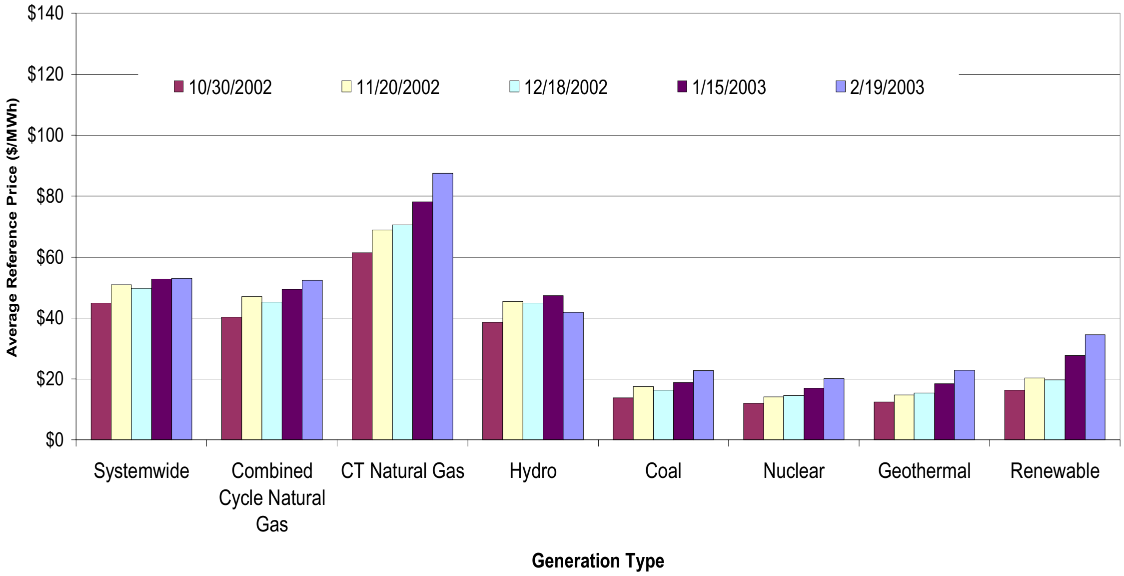
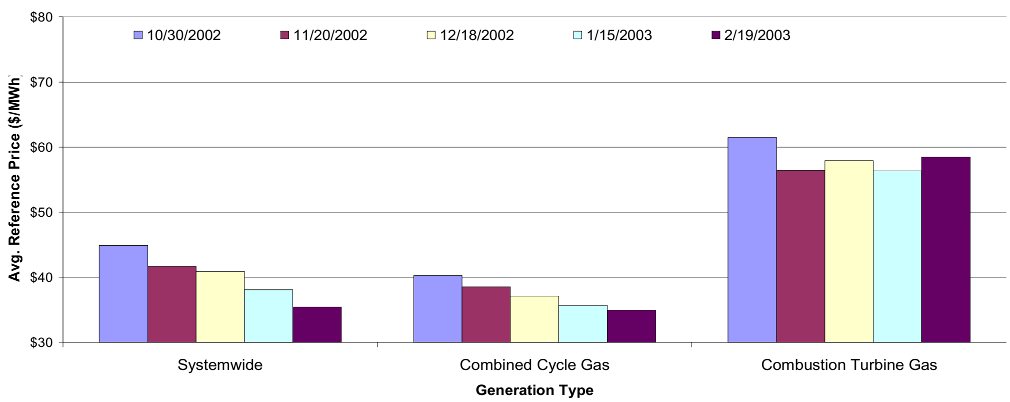


Table 3b. Average Reference Levels through February 2003
For Gas-Fired Units, Normalized to October 2002 Gas Price Index



III. Ancillary Services Market Performance

Average ancillary services prices were down significantly from January due to an increase in the volume of lower priced bids. Day-ahead upward regulation (RU) service prices averaged $14.34/MWh in February, compared to $15.91/MWh in January. Day-ahead downward regulation (RD) service prices averaged $10.80/MWh in February, compared to $18.22/MWh in January. The chart below shows the daily average RU bids by price bin for January and February.

Figure 7. Upward Regulation - Average Hourly Bid Quantities and Purchases (Day-Ahead plus Hour-Ahead Market)

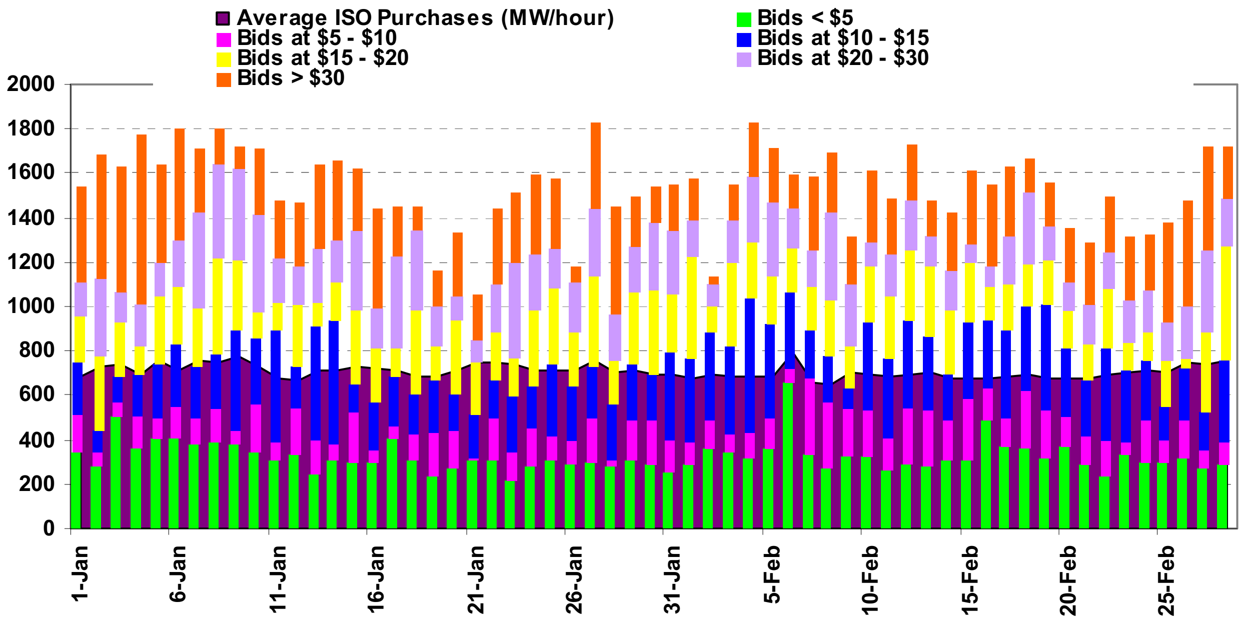


Table 4 below shows that the volume of lower priced RU bids in February increased from January. Bids lower than $15/MWh accounted for 53.8 percent of total RU bids in February, up from 45.7 percent in January. Also slightly more RU bids were available in February than in January, as the RU final MW as a percentage of total RU bids shows below. In February, 45.5 percent of all RU bids were purchased, down from January's level of 46.4 percent. Similar results were also observed in the RD market as well as the operating reserve markets.

Table 4. Monthly Average Upward Regulation Bids in Bid Bins

	RU final MW as % of total RU bids	RU bids <$5 as % of total RU bids	RU bids between $5 and $10 as % of total RU bids	RU bids between $10 and $15 as % of total RU bids	RU bids between $15 and $20 as % of total RU bids	RU bids between $20 and $30 as % of total RU bids	RU bids > $30 as % of total RU bids
January	46.4%	20.6%	8.4%	16.7%	16.7%	16.7%	20.9%
February	45.5%	21.6%	10.9%	21.3%	15.7%	13.1%	17.3%

Average operating reserve prices were also lower. Spinning reserves day-ahead prices averaged $3.26/MWh in February, compared to $4.56/MWh in January. Non-spinning reserves day-ahead prices averaged $2.41/MWh in February, compared with $3.26 in January. Replacement reserves day-ahead prices averaged $2.16/MWh in February, compared to $1.68/MWh in January.

The following table shows average ancillary service prices and volumes by market in February.

Table 5. Average AS Prices and Volumes by Market in 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	$ 14.34	$ 17.47	$ 14.65	330	36	90%
Regulation Down	$ 10.80	$ 14.31	$ 11.17	371	44	89%
Spin	$ 3.26	$ 5.76	$ 3.32	685	16	97%
Non-Spin	$ 2.41	$ 3.41	$ 2.44	651	21	96%
Replacement	$ 2.16	$ 2.65	$ 2.16	22	*	100%

Hourly AS prices were stable in February. No significant price spikes occurred in either the day-ahead or hour-ahead markets.

IV. Congestion Markets

Interzonal congestion costs in February were higher than in January due to capacity derates of some of the major interties into California. Of the approximately $800,000 in interzonal congestion costs, approximately $446,000 was incurred in the day-ahead market on Eldorado, in the import direction, due entirely to congestion between HE 9:00 and HE 18:00 on February 4, with congestion prices ranging between $58.79 and $61/MWh. The congestion was caused by a derate from nearly 1,600 MW capacity to less than 800 MW capacity. Path 26 incurred approximately $112,000 in North-to-South day-ahead congestion costs, primarily on February 7, HE 18:00 and 20:00, with congestion prices of $30/MWh. Path 26 had been derated from approximately 2000 MW to approximately 1500 MW.

Table 6. Interzonal Congestion Costs and Day-Ahead Statistics in February

Branch Group	Direction of Congestion	Peak Congestion Pctg.	Off-Peak Congestion Pctg.	All-Hours Congestion Pctg.	Avg. Peak Cong. Price	Avg. Off-Peak Cong. Price	Avg. All-Hours Cong. Price	Total Cong. Cost (DA+HA)
COI	Import	0%	0%	0%				$ 485
Eldorado	Import	2%	0%	1%	$ 60.11		$ 60.11	$ 479,050
Lugo IPPDC	Import	0%	0%	0%				
Lugo-Mona	Import	17%	10%	15%	$ 0.55	$ 0.41	$ 0.51	$ 8,895
Mead	Import	1%	0%	1%	$ 2.00		$ 2.00	$ 51,430
NOB	Import	1%	0%	0%	$ 1.50		$ 1.50	$ 3,263
Palo Verde	Import	2%	1%	1%	$ 2.05	$ 1.00	$ 1.86	$ 65,441
Path 15	South-to-North	1%	5%	2%				$ 47,739
Path 26	North-to-South	2%	0%	1%	$ 6.42		$ 6.42	$ 113,574
Sylmar-AC	Export	0%	0%	0%				$ 37,561

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, a high percentage of FTRs was scheduled on certain paths (77% on Eldorado, 70% on IID-SCE, 72% on Palo Verde, and 100% on Silver Peak, all in the import direction). FTRs on those paths are held primarily by Southern California Edison Company (SCE1).

Table 7. FTR Scheduling Statistics for January, 2003

Path	Direction	MW FTR Auctioned	Avg. MW FTR Sch.	Max MW FTR Sch.	Max Single SC FTR Schedule	% FTR Schedule
COI	Import	678	54	150	100	8%
Eldorado	Import	793	613	700	700	77%
IID-SCE	Import	600	421	447	447	70%
Mead	Import	522	61	185	175	12%
NOB	Import	734	28	150	150	4%
Palo Verde	Import	1,192	856	954	579	72%
Silver Peak	Import	10	10	10	10	100%
NOB	Export	181	14.10863	23	23	8%
Path 26	Export	1586	259.8646	1013	525	16%

* only those paths on which 1% or more of FTRs were attached are listed

FTR Revenue per Megawatt. The following table summarizes FTR revenue per MW up to February 2002 in the current FTR cycle. Eldorado reports the highest FTR revenue per MW in this month, due to the congestion that occurred on February 4. Because congestion was relatively light on other paths, they did not incur substantial FTR revenues. The following table shows FTR revenues by path since April 1, 2002, the beginning of the current FTR cycle.

Table 8. FTR Revenue Per MW ($/MW)

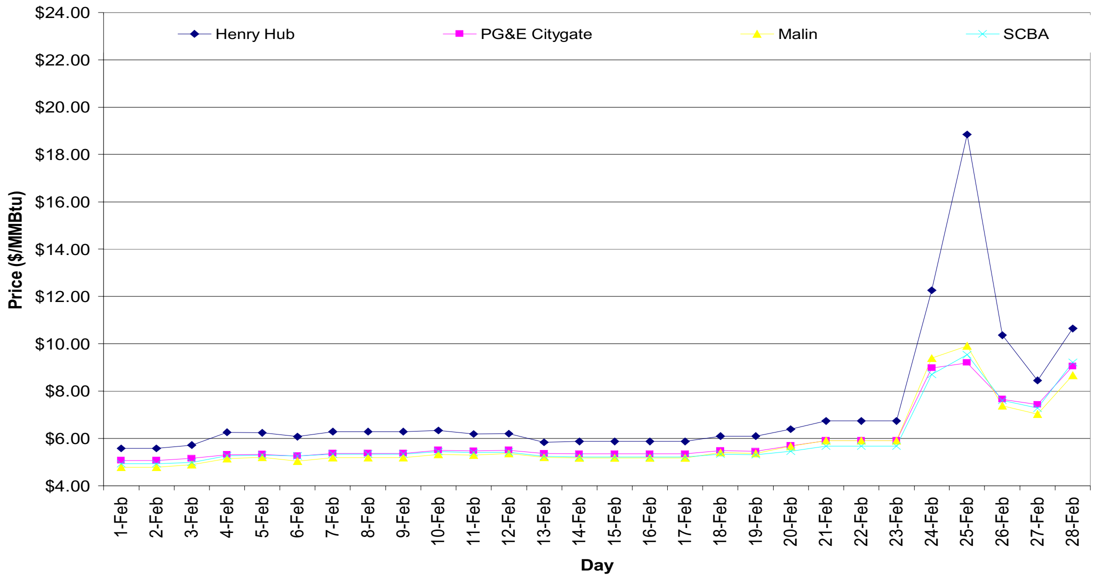
Branch Group	Direction	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Cum. Net REV	Pro Rated Annual NET Rev
CFE	Import	0	0	0	0	0	0	0	0	0	15	0	15	16
COI	Import	1,088	888	4,129	4,278	581	562	153	15	0	10	0	11,706	12,770
Eldorado	Import	268	26	2	10	0	37	1,255	1,178	38	103	584	3,500	3,819
IID-SCE	Import	0	0	0	0	0	0	0	2	0	0	0	2	2
Lugo-Mona	Import	0	0	0	0	0	0	0	0	0	17	19	37	40
Mead	Import	19	22	0	0	0	0	97	166	23	0	75	402	439
NOB	Import	13	0	48	472	14	5	32	1	31	6	4	628	686
Palo Verde	Import	23	839	0	0	4	86	226	376	887	42	32	2,515	2,744
Path 26	South-North	0	133	370	0	0	25	28	44	31	0	0	631	689
Mead	Export	0	0	0	262	31	0	0	0	0	0	0	293	320
Path 26	North-South	61	134	125	1703	116	114	23	35	178	191	71	2,751	3,002
Sylmar-AC	Export	0	0	0	0	0	0	0	0	0	0	120	120	131
Victorville	Export	0	249	724	0	0	0	0	0	0	0	0	973	1,062

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

VI. Regional Natural Gas Markets

The most significant event in the natural gas markets was the sharp increase in natural gas prices on and after February 23. While Henry Hub prices increased to above $6.00/MMBtu between February 4 and 12, and from February 18 onward, due to cold weather in the Northeast, Henry Hub spot gas prices exceeded $12/MMBtu on February 24 and approached $19/MMBtu on February 25. Much of this was due to the confluence of the following events: low natural gas storage throughout the Northeast and Midwest; continued cold weather throughout much of the Continental U.S.; and fossil fuel supply uncertainty attributed to political turmoil in oil-producing regions, such as Venezuela and the Middle East. All of these events also caused natural gas futures contract prices traded on the New York Mercantile Exchange (NYMEX) to remain at unusually high levels. The following chart shows daily gas prices at regional delivery points in February.

Figure 8. Regional Spot Gas Prices in February



As can be seen from the table below, nearly half of the natural gas in storage in the United States was consumed during the month of February, with just below 200 Bcf having been consumed between February 21 and 28. The following table shows natural gas storage levels across the continental United States in billions of Cubic Feet (Bcf).[3]

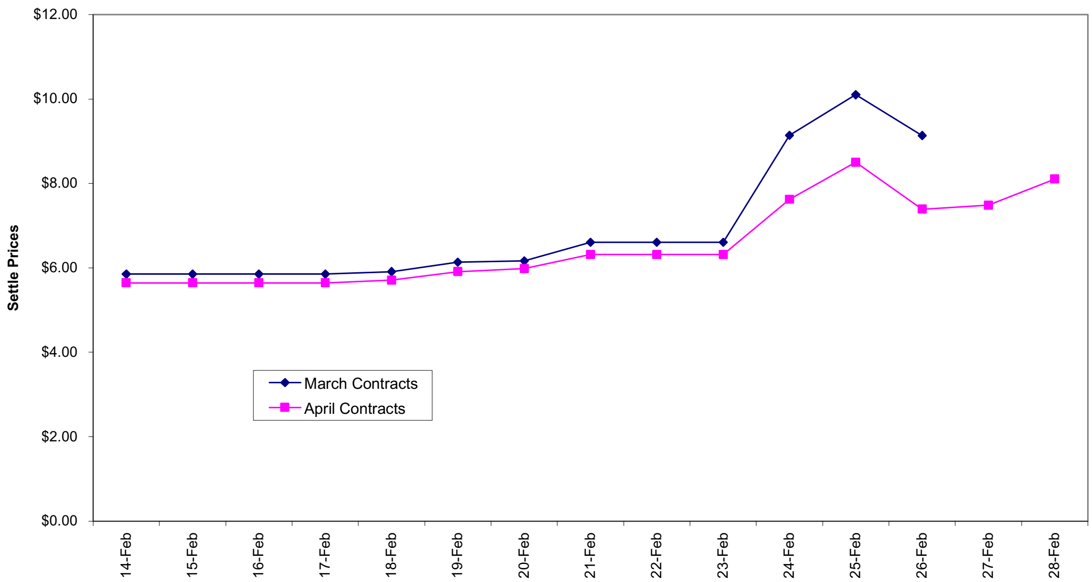
Table 9. National Natural Gas Storage Levels[4]

Week ending	Consuming Region East (Bcf)	Consuming Region West (Bcf)	Producing Region (Bcf)	Continental U.S. (excl. Alaska, Bcf)
31-Jan-03	805	285	431	1521
07-Feb-03	716	268	387	1371
14-Feb-03	594	241	333	1168
21-Feb-03	499	224	291	1014
28-Feb-03	403	198	237	838

In response to the sharp decrease in natural gas supply, NYMEX Henry Hub futures contracts climbed sharply, as indicated in the following chart. By February 25, Henry Hub futures contract prices for March delivery peaked above $10/MMBtu.

[3] 1 Bcf ≈ 1 trillion Btu = 1 million MMBtu.
[4] Source: U.S. Energy Information Administration: Form EIA-912, "Weekly Underground Natural Gas Storage Report," and the Historical Weekly Storage Estimates Database.

Figure 9. Daily NYMEX Henry Hub Futures Contract Prices



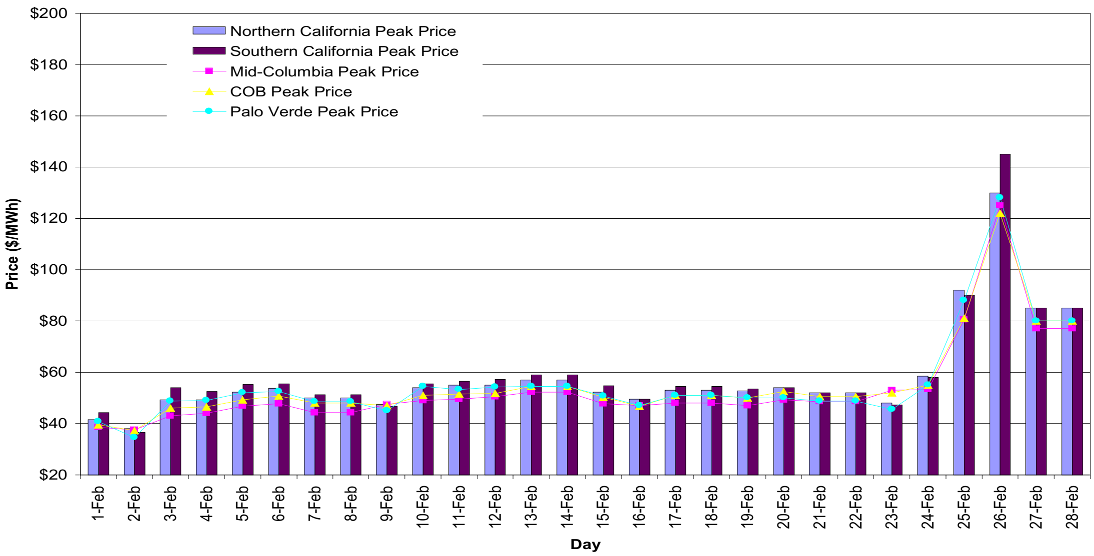
After the price spike on February 26, prices declined, although they remained above pre-spike levels. Spot gas prices and April futures contracts persisted at the $8.00/MMBtu level, and began to increase again as the month came to a close. Average bid week prices for March were $6.93, $7.55, and $7.36 for SoCal Gas, Malin, and PG&E Citygate, respectively, up 41%, 54%, and 42% from February bid week prices.

VII. Regional Bilateral Electricity Markets

As with natural gas prices, regional day-ahead electricity prices were substantially flat until February 24, although prices were slightly higher than in January due to low overnight temperatures in the Northwest. Prices for delivery on February 24 increased to nearly $60/MWh, and then increased to $80-90/MWh and $120-130/MWh for delivery on February 25 and 26, respectively. Southern California prices peaked at $145/MWh. Extraordinarily high natural gas prices have been the main driver in the sharp increase in electricity prices. Demand in Southern California was also higher due to the continuing outage at Mohave #1 (790 MW) associated with the aforementioned airplane contact with a 500kV static line near Adelanto substation.

Following the price spike for deliveries on February 26, prices decreased. As with gas prices, electricity prices remained above pre-spike levels. February prices ended at $80/MWh. The following chart shows regional day-ahead bilateral contract electricity prices at Western delivery points.

Figure 10. Western Regional Day-Ahead Bilateral Electricity Contract Prices



VIII. Outages

Outages remained at a manageable level in February, a fairly low load month. Most outages were economic outages; that is, units that had applied for and received waivers from the Must-Offer Obligation. Of the few forced outages, one of interest was the trip of San Onofre Nuclear Unit 2 in the early hours of February 1. The unit powered back to full load on the morning of February 3.

IX. Issues under Review

Low Import Volume on Interties. The ISO has undertaken an investigation to determine the reasons that bid volume in the BEEP Stack from import suppliers fell from approximately 1200 MW on average to approximately 150 MW, within only a few weeks in October 2002. After internal discussion and consultation with suppliers, ISO Staff concluded that the reason importers have fled the BEEP Stack is that there has not been an acceptable premium in BEEP prices above regional bilateral hub prices to bear the additional risks of selling into the BEEP Stack. Historically, BEEP prices have averaged approximately 20 percent higher than hub prices. Because FERC has clearly stated in multiple orders that they must enter bid prices of $0/MWh, the importers are not able to express minimum prices they are willing to accept to supply electricity. In addition, importers that sell in day-ahead markets at regional hubs transact known volumes in fixed sixteen-hour blocks, and avoid the uncertainties of congestion costs and of learning only one hour ahead of real time whether their electricity will be needed. ISO Staff is currently reviewing these concerns to determine whether further regulatory action on this issue is warranted.

Long-Term Transmission Planning Methodology. Over the past six months DMA has been working collaboratively with the ISO Grid Planning Department and a consultant, London Economics, to modify and enhance a methodology for evaluating the economic benefits of transmission expansions. This effort culminated in a report to the CPUC that was filed on February

28, 2003. The CPUC had requested that a workshop be held to review the methodology and discuss candidate transmission projects to test the methodology. This workshop was held at PG&E's San Francisco office on March 14, 2003.

100 Day Discovery. The ISO responded to requests for data, deposition, and testimony in the recent discovery period.