CALIFORNIA ISO

Memorandum

To: ISO Board of Governors

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

cc: ISO Officers, ISO Board Assistant

Date: April 18, 2003

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

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

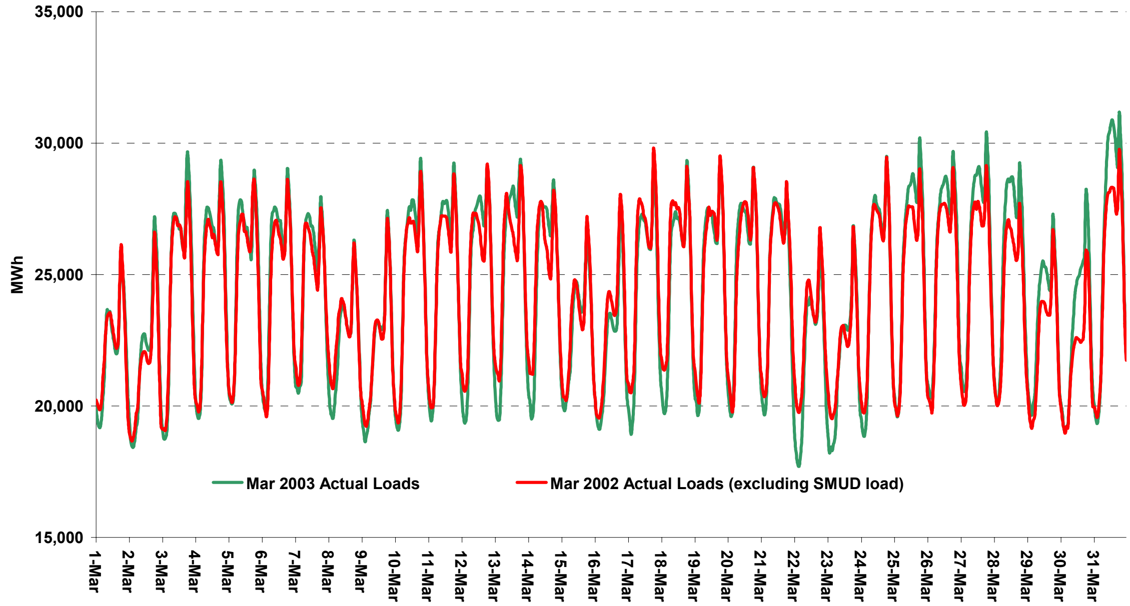
Executive Summary

During March, natural gas prices receded to the January levels of $4 to $5/MMBtu from the high prices that occurred in late February and early March. Day-ahead bilateral electricity prices fell in step with the lower fuel costs. Several price spikes occurred in March due to the need to dispatch higher cost peaking units to meet evening load ramps and during late evening hours when standard bilateral contract products for peak-hour energy deliveries end. In addition, on March 21, an explosion of a transformer bank at the Vincent substation in Southern California resulted in the ISO having to completely derate Path 26, a key transmission artery between Northern and Southern California. ISO operators and utility workers worked to partially restore flows on Path 26 to 600-925 MW by March 23, and were able to restore the path to its full capacity of 2500-3000 MW by early April. The capacity derates on Path 26 caused significant interzonal and intrazonal congestion around the State through the end of the month.

I. Electricity Market Trends through Q1 2003

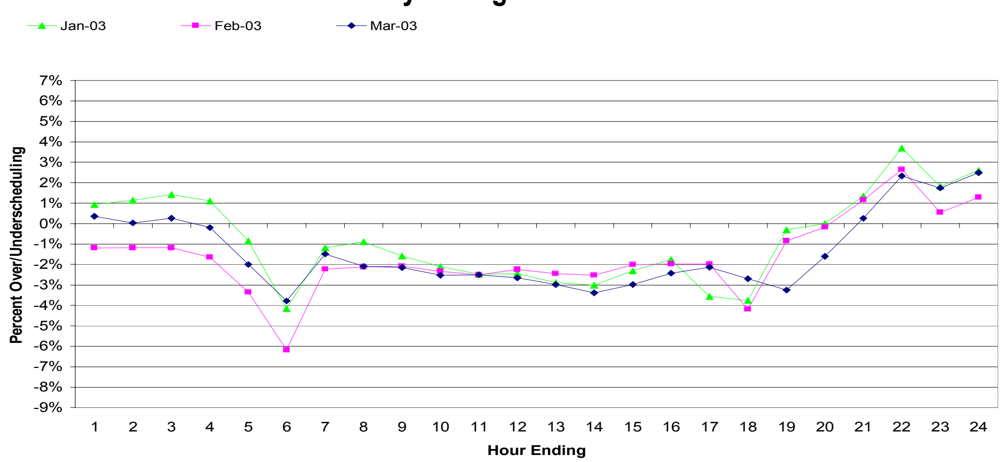
Loads and Schedules. Loads during March 2003 were slightly higher than those seen in March 2002, due primarily to warm temperatures during the final week of the month, and on March 31 in particular. Daily load averaged 24,334 MW or 0.7 percent above the average for March 2002. The actual peak load of 31,151 MW occurred on March 31, 2003. The March 2003 peak load was 4.7 percent higher than the March 2002 peak. Energy consumption was 2.0 percent higher than that of March 2002. The following chart compares actual hourly loads in March 2002 and 2003.

Figure 1. Actual Hourly Loads in March



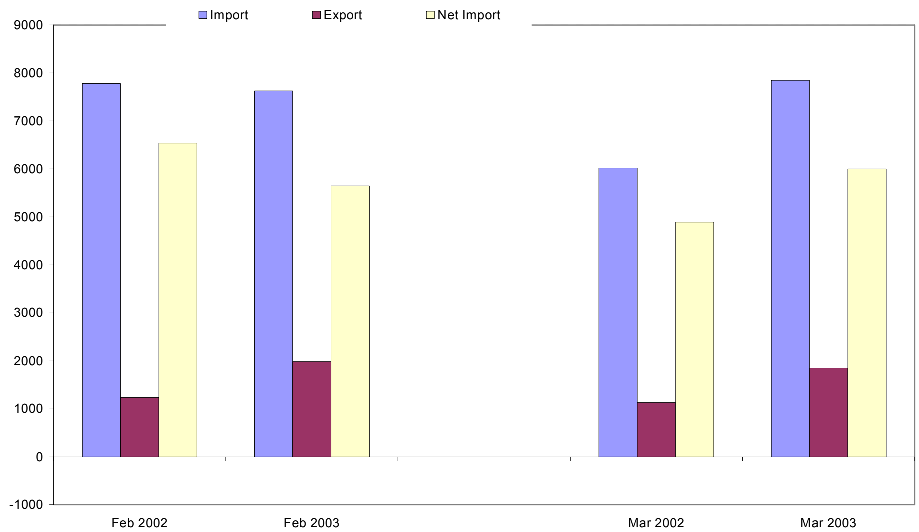
Forward schedules have increasingly diverged from actual load during the winter and spring evening load ramps as actual load rises sharply between 6:00 and 8:00 p.m. (hours ending (HE) 19:00 and 20:00) and again as daily bilateral contract products for peak-hour blocks end just after 10:00 p.m. (during HE 22:00). This has caused ramp planning challenges at those times when ISO operators must dispatch imbalance energy resources to meet the rapidly changing load, often necessitating that ISO operators dispatch peaking units. Deviations in HE 19:00, HE 20:00, HE 23:00, and HE 24:00 have increased since February. The following chart shows monthly average scheduling deviations by hour of day since January.

Figure 2. Average Scheduling Deviations by Hour of Day, January through March 2003



Imports and Exports. Imports averaged approximately 7,900 MW in March 2003, similar to the level seen in February but substantially more than approximately 6,000 MW in March 2002. This increase in imported energy is primarily due to the recent increase in hydroelectric energy production in the Pacific Northwest.   The following chart compares imports, exports, and net imports in February and March for this year and last year.

Figure 3. Imports and Exports, 2002 vs. 2003[1]



II. Real-Time Market Performance

Average Real-Time Imbalance Prices and Volumes. Incremental and decremental prices in the ISO's real-time Balancing Energy Ex-Post Price auction market (the BEEP Stack) averaged $78.49 and $28.72/MWh respectively in March, compared to $73.88 and $28.28/MWh in February. Total real-time volume remained almost constant on the INC side, at 188 GWh in March, or an average of 252 MW in all hours, compared to 170 GWh (average volume of 253 MW) in February. Total real-time DEC volume increased to 158 GWh (average volume of 212 MW) in March, compared to 115 GWh (average volume of 171 MW) in February. The following chart shows real-time prices and volumes and average loads and underscheduling in March.

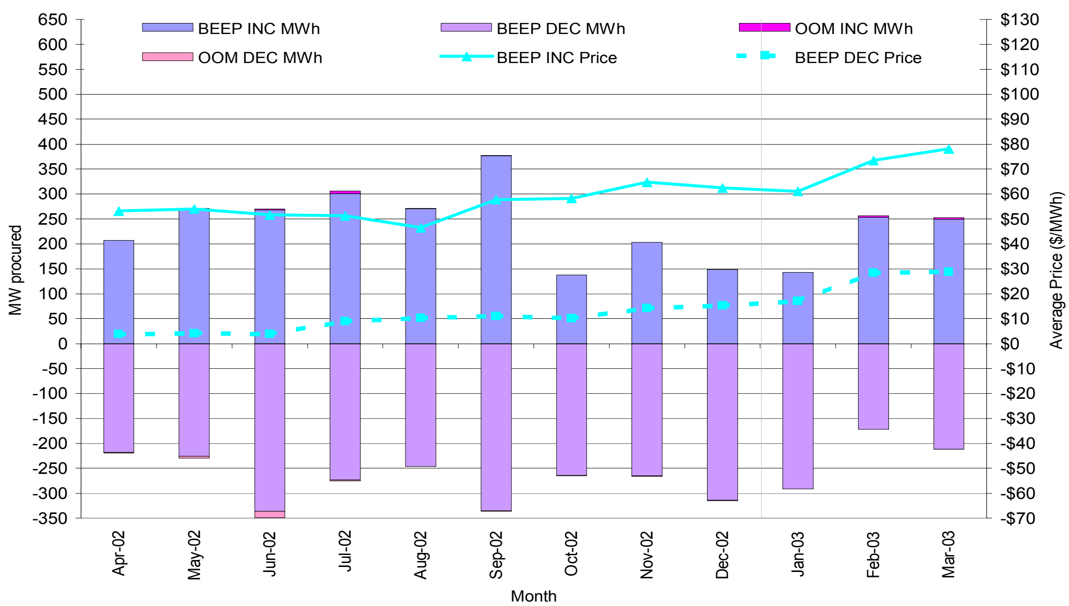
[1] The substantial increase in exports is due to flows into SMUD in 2003, which was part of the ISO control area in 2002.

Table 1. Real-Time Prices and Volumes, and Loads and Underscheduling in March[2]

	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	$ 77.28	$ 32.57	$114.42	$50.91	$ 77.34	$ 32.57	26,205 MW
	150 GWh	101 GWh	*	*	150 GWh	101 GWh	1.0%
Off-Peak	$ 81.63	$ 21.90	$102.82	$16.21	$ 81.99	$ 21.89	20,592 MW
	35 GWh	57 GWh	*	*	36 GWh	57 GWh	0.1%
All Hours	$ 78.11	$ 28.74	$106.00	$16.91	$ 78.24	$ 28.73	24,334 MW
	185 GWh	157 GWh	*	*	186 GWh	158 GWh	1.0%

The following chart shows monthly average BEEP volumes and prices from April 2002 through March 2003.

Figure 4. Monthly Average BEEP Prices and BEEP and OOM Volumes



Review of Price Spikes. Several price spikes in March were due to ramp planning difficulties. The difference between the actual demand and the amount scheduled to be generated must be acquired for the most part in the imbalance market. This can be difficult to manage during volatile hours, such as in the early evening, when energy usage increases rapidly, and just after 10:00

[2] * indicates less than 1 GWh

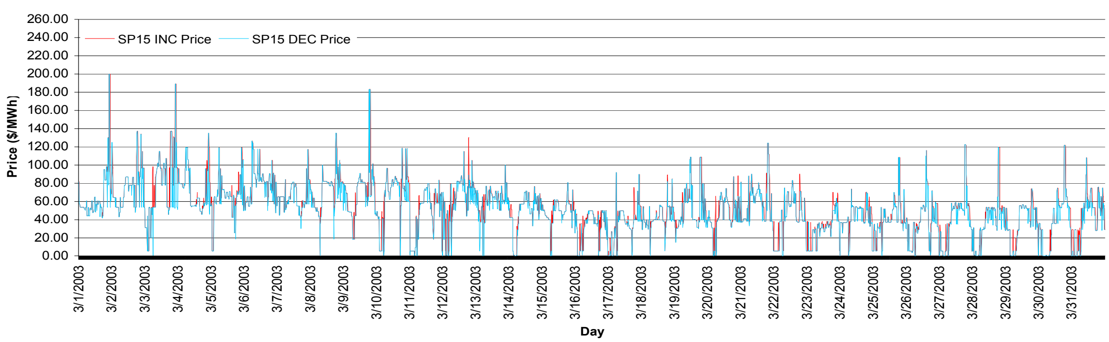
p.m., when 16-hour bulk peak contracts end, causing generation to decline rapidly. Meanwhile, units that are dispatched from the BEEP Stack sometimes decline the dispatch instruction or deviate from their instructions. At times, ISO operators have had to call on peaking resources to manage these volatile ramping periods.

To remedy this problem, uninstructed deviation penalties will be implemented as part of in MD02 Phase 1b. In the meantime, the only disincentive against failure to follow dispatch instructions is the spread of the INC and DEC prices (uninstructed deviations are paid the uninstructed price). This has not been a significant disincentive to suppliers, particularly during the hours in which price spikes occur. In the most spike-prone hours between 6:00 p.m. and 11:00 p.m. (HE 19:00 through 23:00), the pricing spread existed in only 32.4 percent of pricing intervals in March. That is, in the other 67.6 percent of intervals, there was effectively no penalty for uninstructed deviations.

In addition to the price spikes during daily ramping periods, a series of spikes also occurred beginning March 21 as a consequence of a transformer bank explosion at the Vincent substation, at the southern end of Path 26, a key electric transmission artery between Northern and Southern California. ISO operators were required to work around the resultant derate (to zero MW on some days) of Path 26, and other related outages, occasionally calling on higher-cost peaking generation units.

The following chart shows BEEP ten-minute interval prices in SP15 in March. Discussion of some individual spikes follows below.

Figure 5. Ten-Minute BEEP Prices in SP15 for March 2003



On March 1 between 10:00 and 10:50 p.m. (HE 23:00), the BEEP market-clearing price (MCP) was set at $200/MWh by a peaking unit in Southern California. This unit, which was called upon during a period of slow response from units dispatched through the BEEP Stack, had an estimated marginal cost of $105/MWh during the hour. With a reference price of $78.77/MWh, this was the first known instance of a price-setting unit that had failed the AMP Conduct Test. However, the unit's price setting bid was not sufficiently above the next-highest unit's bid to fail the AMP Impact Test. The estimated cost of this spike was approximately $90,000.[3] . The daily average net real-time energy cost (inclusive of spikes) was $323,010 in March.

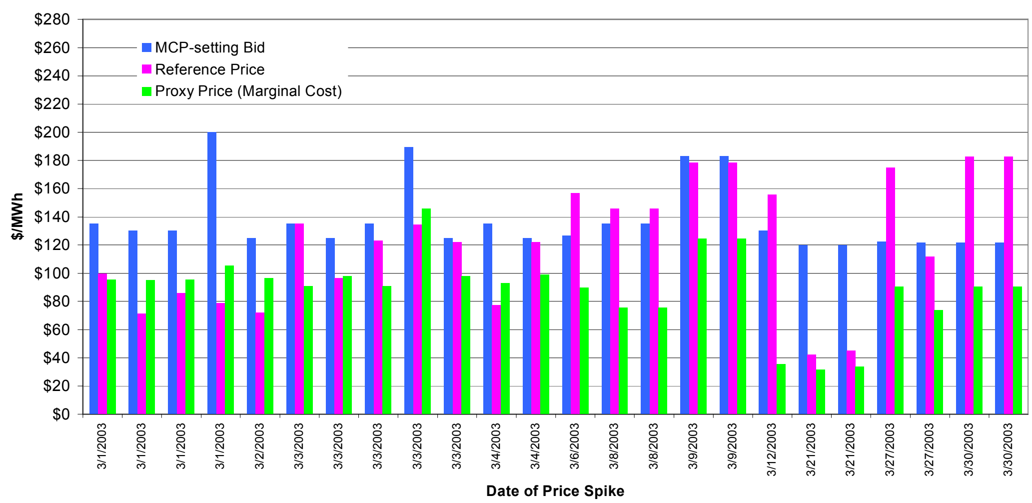
[3] The cost of a spike is estimated as the total of the procurement costs in SP15 and NP15 during the price spike, less the cost to procure the same volume at the monthly average price.

On March 3, between 9:50 and 10:50 p.m. (HE 22:00 and 23:00), the MCP varied between $180.70 and $189.24/MWh and was set by another high cost peaking unit. This unit was dispatched after a lower-priced unit claimed that it had not received a dispatch instruction. This spike cost approximately $92,000.

On March 9, between 6:30 and 7:30 p.m. (HE 19:00 and 20:00), the MCP was $182.97/MWh, set by yet another high cost peaking unit. The unit's reference price and marginal cost respectively were $178.68 and $124.50/MWh. This spike occurred due to ramping difficulties where operators dispatched high cost units to meet the rapidly changing load requirements. This spike cost approximately $100,000.

The following chart shows the ten-minute interval price spikes, compared to the price-setters' marginal AMP reference prices and estimated marginal costs.

Figure 6. BEEP Price Spikes, with Corresponding AMP Reference Prices and Marginal Costs, March 2003



Out-of-Market (OOM) Calls. There was a series of incremental OOM calls on March 4, 5, 8, 9, 22, and 23, to a reliability must-run (RMR) Condition 2 unit for a total of 3257 MWh. The calls were due, in part, to an absence of bids from the unit in the BEEP stack because of an error on the part of the unit's owner.

Out-of-Sequence (OOS) Calls. There were two significant decremental OOS dispatches in March due to work on the Pittsburg substation and the Magunden Pastoria No. 2 line. A total of 4,038 MWh of decremental dispatches were called out of sequence at a cost of approximately $163,000.

Several units were incrementally dispatched extensively to alleviate an overload at the Sylmar substation in northern Los Angeles. A total of 104,611 MWh of incremental dispatches were called OOS at a total cost of approximately $8.3 million.

Total net intrazonal congestion costs – the costs in excess of the market clearing price – for both incremental and decremental dispatches for the month of March amounted to $830,701. Most were incurred as a result of operational problems caused by the damage to the Vincent substation.

AMP Performance. Bidders failed the AMP Conduct Test in 135 distinct hours in March, mostly during ramping hours in the first ten days of the month, as the gas price spike persisted. By mid-March, natural gas prices were considerably lower. However, the monthly gas price inflator of $7.27/MMBtu in March, based upon California hub bid week prices, kept AMP reference prices high, allowing generators to offer higher prices without failing the Conduct Test. April's $4.83/MMBtu index will be considerably more restrictive for gas fired thermal generation units as it will lower the bid thresholds above which a bidder would fail the Conduct Test.

The following table shows the number of Conduct Test failures by day in March.

Table 2. AMP Conduct Test Failures in March

Date	No. of Hours
3/1/2003	5
3/2/2003	13
3/3/2003	15
3/4/2003	11
3/5/2003	6
3/6/2003	15
3/7/2003	15
3/8/2003	7
3/9/2003	8
3/10/2003	7
3/12/2003	1
3/15/2003	2
3/18/2003	1
3/19/2003	7
3/20/2003	5
3/21/2003	10
3/24/2003	1
3/29/2003	3
3/31/2003	3

The Department of Market Analysis continues to monitor trends in reference levels. The levels for both gas-fired and non-gas fired generation increased significantly in March, primarily due to the aforementioned spike in gas prices. However, DMA found the reference levels of gas-fired generators are stable when adjusting for gas prices. Non-gas-fired generators' reference levels have also increased although those units comprise a relatively small quantity of real-time generation. The following charts show (a) average unadjusted reference levels by generation type; and (b) reference levels for thermal generators, normalized to the October 2002 gas price index.

Figure 7a. Average Reference Levels by Generation Type, Not Adjusted for Changes in Gas Prices

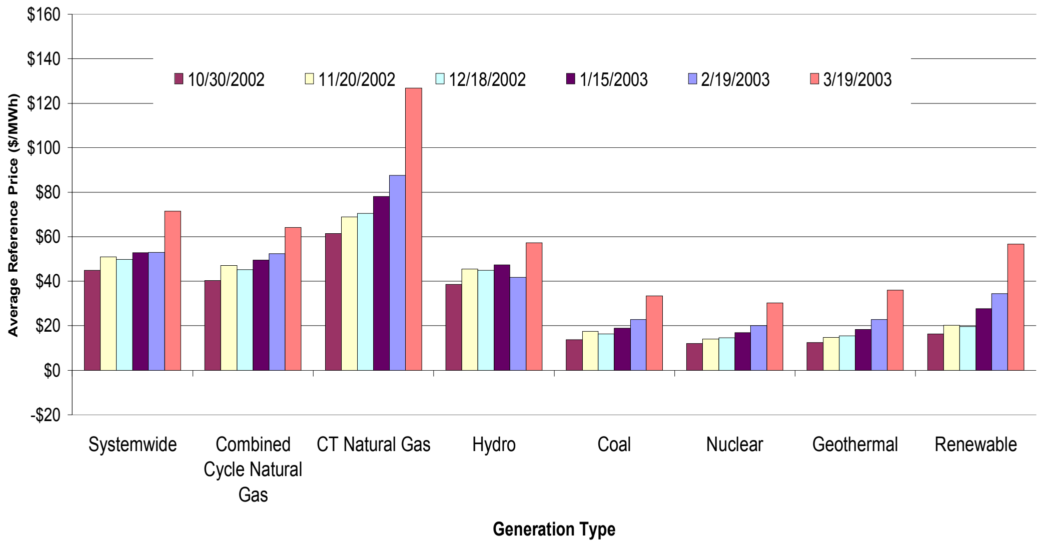
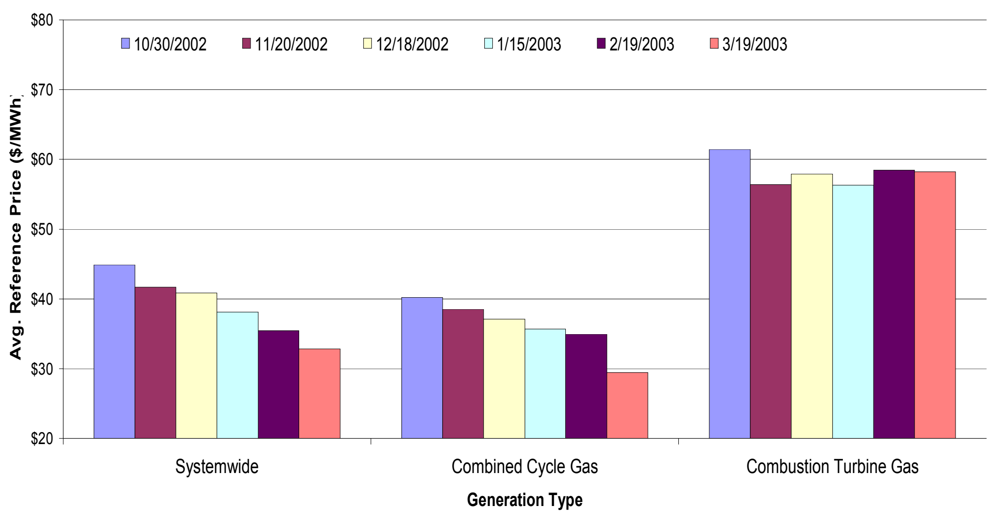


Figure 7b. Average Reference Levels by Generation Type for Gas-Fired Generation, Normalized to October 2002 Gas Price



III. Ancillary Services Market Performance

Average ancillary services prices were higher in March than in February for four out of the five ancillary services due to less bid volume and an increase in the share of higher priced bids. The day-ahead and hour-ahead quantity weighted average price of upward regulation (RU) was

$17.25/MWh in March, compared to $14.34/MWh in February. The average price of regulation (RD) was $14.91/MWh in March, an increase from $10.80/MWh in February. The average spinning (SP) service price was $4.59/MWh in March, slightly higher than price of $3.26/MWh in February. Finally, the non-spinning (NS) service price averaged $2.21/MWh, less than the $2.41/MWh in February. Self-provided AS accounted for 84.2 percent of total AS volume in March. Table 3 shows average ancillary service prices and volumes by market in March.

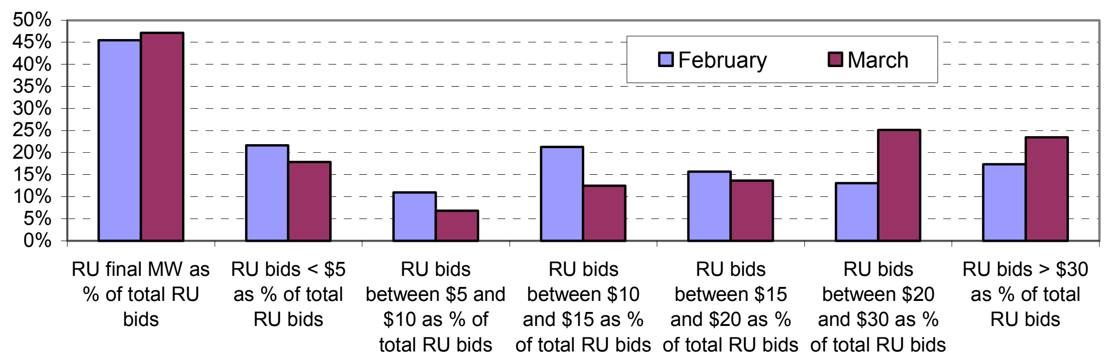
Table 3. Average AS Prices and Volumes by Market in March

	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	$ 17.25	$ 17.92	$ 17.31	354	35	90%
Regulation Down	$ 14.91	$ 19.09	$ 15.41	363	50	87%
Spin	$ 4.59	$ 5.93	$ 4.65	664	34	95%
Non-Spin	$ 2.21	$ 3.23	$ 2.24	664	24	96%
Replacement	$ 2.31	$ 1.96	$ 2.31	22	*	99%

The average hourly Regulation Up (RU) bid volume was 819 MW in March, down from 857 MW in February. Marginal RU bid prices were $10 - $15/MWh in February and $15 - $20/MWh in March. Average hourly volume of bids with prices below $15/MWh was 472 MW in February, compared to 304 MW in March. In contrast, the average hourly volume of bids priced above $15/MWh was 515 MW, compared to 241 MW in February.

The charts below compares ancillary service bid sufficiency in February and March. Bids lower than $15/MWh accounted for 37.1 percent of total RU bids in March, a decrease from 53.8 percent in February. Bids between $15 and $20/MWh accounted for 12.5 percent of total RU bids in March, compared to 21.3 percent in February.

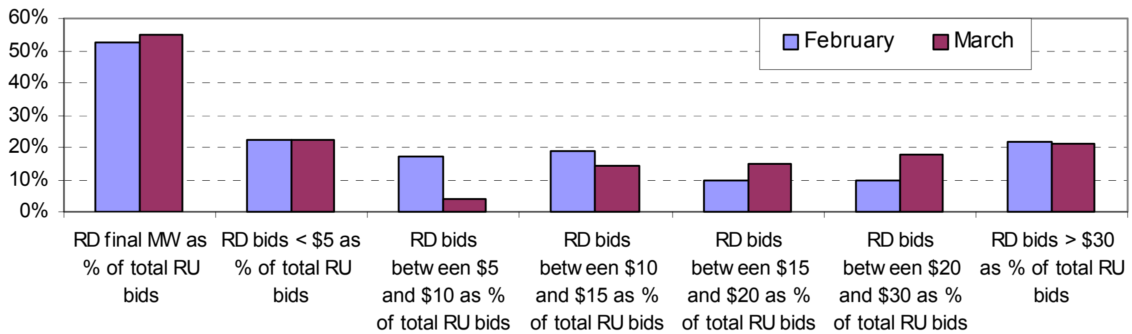
Figure 8a. Monthly Average Upward Regulation Bids by Price Bin



A similar situation occurred in the Regulation Down (RD) market. The chart below shows the daily average RD bids by price bin for February and March. Average hourly RD bid volume was 744

MW in March, a decrease from 803 MW in February. Marginal RD bids accepted were in the $10 - $15/MWh range in February while in March marginal RD bids were in the $15 - $20/MWh range.

Figure 8b. Downward Regulation - Average Hourly Bid Quantities and Purchases (Day-Ahead plus Hour-Ahead Market)



IV. Interzonal Congestion

Congestion costs in March were higher than in the previous two months. Of $1.4 million in interzonal congestion costs incurred, about $612,000 was due to congestion in the import direction, while about $800,000 was incurred in the export direction. In the import direction, congestion on COI, NOB, and Palo Verde resulted in costs of $200,000, $160,000, and $160,000 respectively. COI reported a significant amount of hour-ahead congestion, especially in the later half of the month. In most hours, schedules have been very close to the import capacity of the line. There was a significant increase in the flow on NOB in the import direction in the last week of March, causing congestion in the import direction. This is likely directly associated with the Vincent fire, which caused a significant derate on Path 26. NOB was the only other major path available to bring energy from the Pacific Northwest to the SP15 region. Flows on Palo Verde were near line capacity in most of the hours of the month, resulting in congestion in some hours.

In the export direction, Path 26, Sylmar-AC, and Victorville incurred congestion costs of $273,000, $367,000, and $157,000, respectively. Path 26 was completely derated on March 22, due to the Vincent substation fire. The congestion on Sylmar was due primarily to significant increases in hour-ahead schedules on March 20, from midnight to 6:00 am, with congestion prices reaching $250/MWh for several hours. Similarly, the congestion costs on Victorville were due to the hour-ahead price spikes, again associated with the Vincent fire on March 22 from midnight to 5:00 a.m. (HE 1:00 through 5:00) with congestion prices as high as $249/MWh. In all, a total of $590,000 in congestion costs (incurred on Path 26, Victorville, and NOB) was due primarily to the Vincent fire.

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 (86% on Eldorado, 70% on IID-SCE, 72% on Palo Verde, and 100% on Silver Peak in the import direction). FTRs on these paths are held primarily by the Southern California Edison Company (SCE1).

Table 4. FTR Scheduling Statistics for January, 2003

	Direction	MW FTR Auctioned	Avg. MW FTR Sch.	Max MW FTR Sch.	Max Single SC FTR Schedule	% FTR Schedule
COI	Import	678	53	200	150	8%
Eldorado	Import	793	678	710	710	86%
IID-SCE	Import	600	417	453	453	70%
Mead	Import	522	40	114	75	8%
NOB	Import	734	30	160	150	4%
Palo Verde	Import	1192	853	954	579	72%
Silver Peak	Import	10	10	10	10	100%
NOB	Export	181	15	23	23	8%
Path 26	Export	1586	20	319	319	1%

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

FTR Revenue per Megawatt. The FTRs released in January 2002, expired on March 31, 2003. On April 1, 2003, a new FTR cycle begins, as FTRs released in the primary auction of January 2003 go into effect. Only one FTR had a direct, positive financial benefit in the previous FTR cycle. On Victorville, total revenue per MW was $1,609, greater than its auction clearing price of $1,118. FTR revenues on several other paths were also significant and approached their auction prices. For instance, the total FTR revenue on COI per MW was almost $12,000, while its auction price was $17,600 per MW. FTR holders enjoy, not only the direct benefit of FTR revenue from an instrument that can be used to hedge against spikes in congestion prices, but also the right to establish scheduling priority in the day-ahead market. The following table summarizes FTR revenue per MW for FTRs in the previous cycle.

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

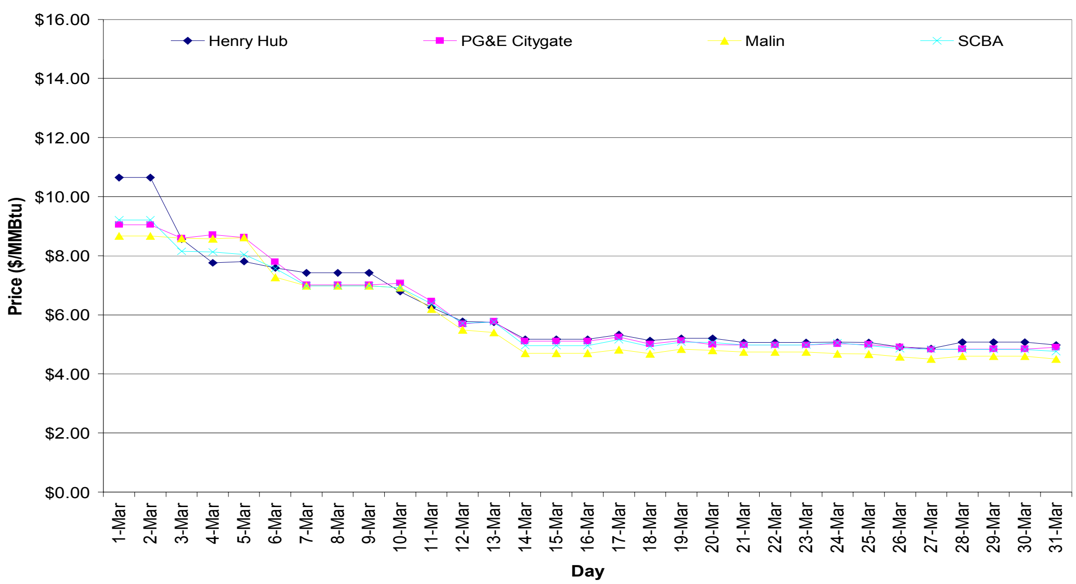
Branch Group	Direction	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Cumm. Net REV	FTR Auction Price
CFE	IMPORT	0	0	0	0	0	0	0	0	0	15	0	0	15	165
COI	IMPORT	1,088	888	4,129	4,278	581	562	153	15	0	10	0	173	11,879	17,610
Eldorado	IMPORT	268	26	2	10	0	37	1,255	1,178	38	103	584	11	3,511	8,432
IID-SCE	IMPORT	0	0	0	0	0	0	0	2	0	0	0	0	2	275
Lugo-Mona	IMPORT	0	0	0	0	0	0	0	0	0	0	0	30	30	0
Mead	IMPORT	0	0	0	0	0	0	0	0	0	17	19	2	38	4,488
NOB	IMPORT	19	22	0	0	0	0	97	166	23	0	75	0	402	5,990
Palo Verde	IMPORT	13	0	48	472	14	5	32	1	31	6	4	106	735	14,868
Path 26	IMPORT	23	839	0	0	4	86	226	376	887	42	32	86	2,601	3,222
Mead	EXPORT	0	0	0	262	31	0	0	0	0	0	0	0	293	7,465
Path 26	EXPORT	61	134	125	1703	116	114	23	35	178	191	71	159	2,910	5,907
Victorville	EXPORT	0	249	724	0	0	0	0	0	0	0	0	636	1,609	1,118

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

V. Regional Natural Gas Markets

Natural gas prices decreased steadily throughout March from a high of around $9.00/MMBtu at California hubs and $10.75/MMBtu at the national reference bus at Henry Hub to $5.00/MMBtu nationwide by March 14, where prices remained steady through the end of the month. Much of this was due to reduced heating demand resulting from more moderate temperatures throughout much of the continental U.S. Average bid week prices, which are the forward contracts for April, were $4.92, $4.60, and $4.98 for SoCal Gas, Malin, and PG&E Citygate, respectively, a decrease 29, 39, and 32 percent from March bid week prices. The following chart shows regional natural gas prices for March.

Figure 9. Regional Daily Natural Gas Prices in March

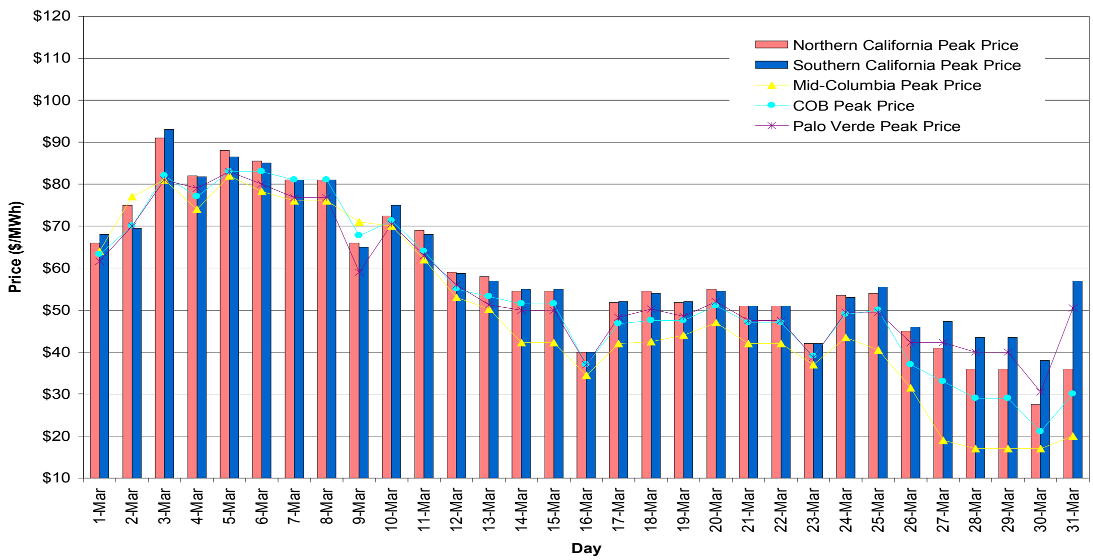


VI. Regional Bilateral Electricity Markets

Regional day-ahead electricity prices were reduced as natural gas prices declined during March but were also less favorably impacted by ongoing system constraints that occurred throughout the month. Prices increased for March 3 due to a forced outage at Columbia Generating Station (1,115 MW) in Washington, and other outages throughout the West. Prices declined after March 10 following the decline in natural gas prices throughout the continental U.S.

The Vincent substation fire on March 21 created some differentials between northwest and southwest prices but these differences were not immediately significant. Prices in the northwest also decreased as a result of increased hydroelectric generation. The ongoing transmission outages at Vincent substation, Path 26, and at Sylmar resulted in sharply increased pricing differentials between Northern and Southern California. By month's end, there was a $20/MWh spread between Northern California and Southern California prices. The following chart shows regional day-ahead bilateral contract prices for peak-hour blocks of electricity in March.

Figure 10. Regional Day-Ahead Bilateral Peak Electricity Prices in March



VII. Issues under Review

On March 26, FERC Staff issued the Final Report on Price Manipulation in Western Markets (Docket No. PA02-2-000). The report contained two key recommendations to the Commission pertaining to both the FERC Refund Proceeding and the Enron-style trading and scheduling strategies and other investigative work the ISO has performed regarding market manipulation and market power. Specifically, FERC Staff recommended that the Commission find the following:

- Enron-style trading and scheduling strategies were in violation of anti-gaming provisions in the ISO tariff and that proceedings should be initiated to disgorge profits from these strategies for the period January 1, 2000 through June 21, 2001. Disgorged profits will be in addition to amounts identified in the refund proceeding.
- The natural gas pricing methodology in the refund proceeding should be altered from published price indices that were found to be manipulated to producing-area prices plus transportation cost, with the caveat that actual gas costs can be recovered provided sufficient documentation that actual costs differed and will be allowed on a dollar-for-dollar basis not to impact the mitigated market price used in the refund methodology.