Memorandum

To: ISO Board of Governors

From: Anjali Sheffrin, Director of Market Analysis

cc: ISO Officers, ISO Board Assistants

Date: May 16, 2002

Re: Market Analysis Report for April 2002

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

Executive Summary

The ISO's real-time energy market has enjoyed relative stability since the fall of 2001. Increased hydroelectric output due to spring runoff in the Northwest has resulted in lower total cost to load, averaging $41 per megawatt-hour (MWh) in April, compared with $44/MWh in March. The average prices for real-time incremental (INC) and decremental (DEC) energy in the ISO's real-time energy market were $53.14 and $3.79/MWh in April, compared with $51.85 and $12.29/MWh in March, respectively.

The ISO's Department of Market Analysis (DMA) is in the process of conducting a review of the trading practices outlined in recently released internal Enron memoranda. A preliminary review shows that many of the trading practices outlined in the memoranda have been previously identified by the ISO. In some cases, the ISO issued market notices prohibiting such practices. In other cases, new rules and market design changes have been or are being implemented to prevent market participants from engaging in those trading strategies. In some cases, these incidents are difficult to verify because the some of the relevant transactions are outside the ISO Control Area. This underscores the need for regional market monitoring and mitigation measures for the entire Western United States. Please see the "Issues under Investigation" section at the end of this Report for a detailed description of DMA's activities in regard to the Enron trading practices.

I. Energy Market Statistics

Loads. ISO load totaled 18,511 gigawatt-hours (GWh) in April 2002, compared with 17,237 GWh in April 2001 and 18,212 GWh in April 2000. Average hourly load was 25,710 GWh in April 2002.

Conservation. The California Energy Commission (CEC) estimates conservation levels as changes in total energy and peak load, adjusted for growth and weather conditions. The CEC reports that adjusted monthly peak load increased 5.8 percent above the April 2001 level, but was 3.7 percent below the April 2000 level.

Real-Time Prices and Volumes. Real-time INC prices in April were similar to those seen in March; however, DEC prices were substantially lower. The average real-time prices for INC and DEC energy respectively were $53.14/MWh and $3.79/MWh in April, compared with $51.85/MWh and $12.29/MWh in March. Total INC and DEC volumes were 149 GWh and 158 GWh in April, respectively. These volumes average to 207 MW and 219 MW, respectively, on an hourly basis, compared with 216 MW and 232 MW for March.

The ISO made out-of-market (OOM) calls in twelve of 719 hours in April. Most consisted of DECs during the morning ramp. INC and DEC OOM prices averaged $37.57 and $5.88/MWh, respectively. In April, the ISO procured 128 MWh and 929 MWh of INC and DEC energy out of market, respectively, compared with 30 MWh of INC energy and no DEC energy in March.

The ISO monitors key price and volume statistics for real-time energy that it procures on behalf of load. The following chart shows (1) average prices and total volumes for real-time energy procured through the BEEP Stack; (2) average prices and total volumes for real-time energy procured in out-of-market transactions, when BEEP energy was not sufficient to meet load; (3) average prices and total volumes for all real-time energy, equal to a weighted average of (1) and (2); and (4) average hourly system load and the percent of underscheduled energy (the proportion of volume that is not scheduled ahead and must be procured in real time).

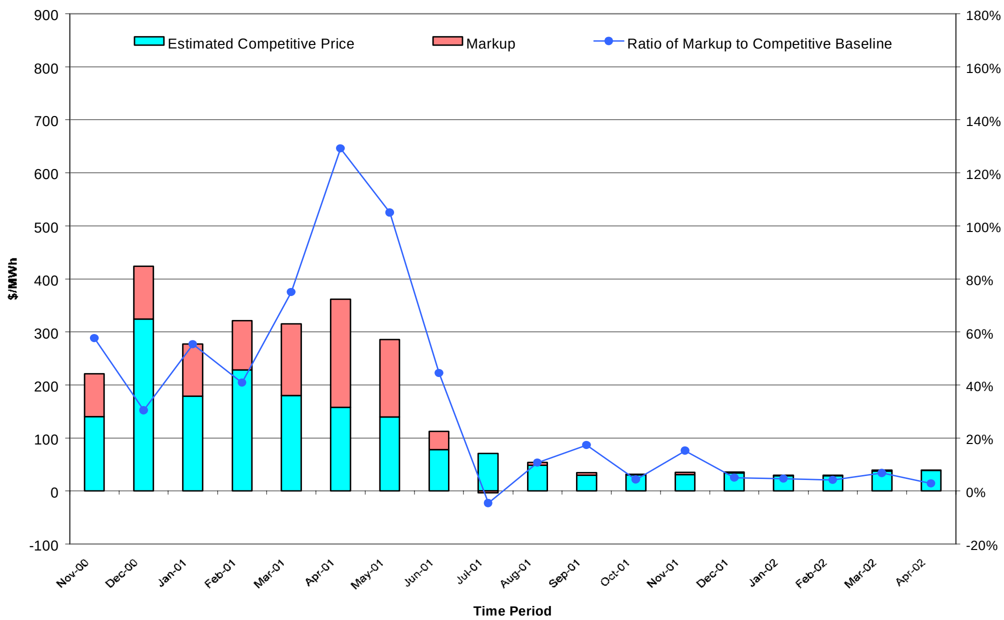
Table 1. Real-Time Energy Statistics for April 2002

	Avg. Market-Clearing 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	$ 54.19	$ 5.80	$ 37.57	$ 5.88	$ 54.17	$ 5.80	27,424 MW
	123 GWh	91 GWh	*	*	123 GWh	92 GWh	3%
Off-Peak	$ 48.41	$ 0.95	No Procurement	No Procurement	$ 48.41	$ 0.95	22,196 MW
	27 GWh	66 GWh	*	*	27 GWh	66 GWh	1%
All Hours	$ 53.16	$ 3.78	$ 37.57	$ 5.88	$ 53.14	$ 3.79	25,681 MW
	149 GWh	157 GWh	*	*	149 GWh	158 GWh	2%

Price Cap Hits. The ISO monitors the frequency with which the BEEP MCP comes within $1 of the current soft price cap. Pursuant to an order by the Federal Energy Regulatory Commission (FERC) on December 19, 2001, this cap was fixed at $108/MWh through April 30, and reverted to its summer-season level of $91.87/MWh on May 1. The MCP did not come within $1 of the cap in any pricing interval in April. However, DMA has continued to observe significant quantities of energy bid into the BEEP Stack at prices just below the cap. These bids will have an impact if system demand requires that they be called.

Market Power. Economists commonly measure market power by comparing the price paid for energy to an estimate of the price that would exist under competitive conditions. DMA tracks one such index, the price-to-cost markup for short-term energy, by calculating the ratio of the markup of prices in California's *short-term* energy markets to the estimated competitive price. A perfectly competitive market would be indicated by the index equal to zero (no percentage markup). The following table shows the price-to-cost markup in short-term energy (which does not include long-term forward energy contracts) since late 2000. The markups for March and April 2002 are estimates only until actual purchase prices are available from the Department of Water Resources' California Energy Resources Scheduling Division (CERS).

Figure 1. Price-to-Cost Markup in Short-Term Energy[1]



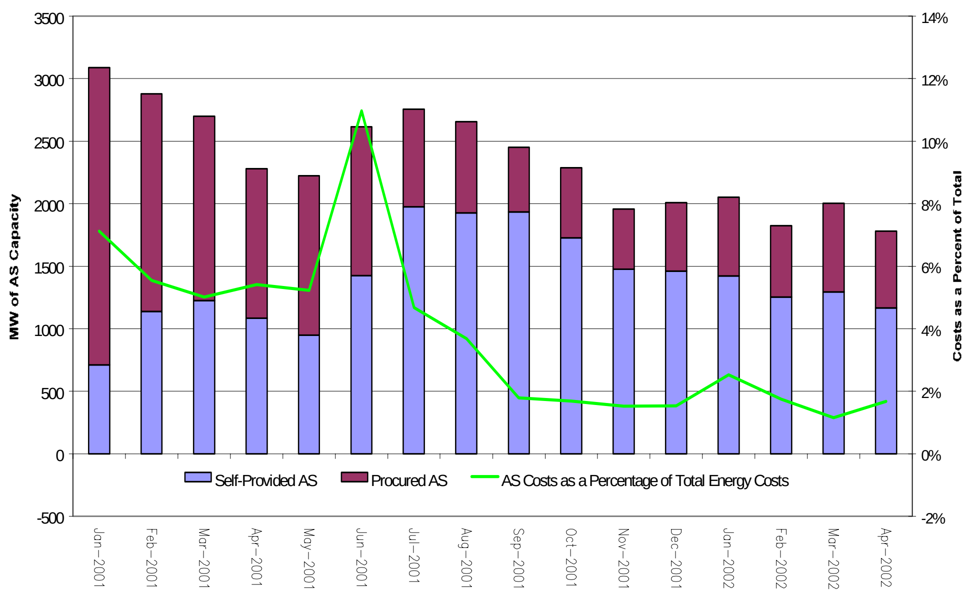
II. Ancillary Services

In order to ensure system reliability, the ISO tariff requires that scheduling coordinators supply energy with specific quantities of ancillary services (AS), or reserve capacity that the ISO can call upon during system emergencies. This is typically either self-provided or procured in the ISO's day-ahead and hour-ahead AS markets. Hydroelectric resources typically operate at maximum output in the spring, to exploit fully the benefit of runoff from melting snow. Thus, the ISO tends to see decreases in self-provided AS and increases in procured AS in the spring. However, a late freeze in California's Sierra Nevada has delayed runoff, resulting in AS volume in April similar to that seen in the winter months. This is the case even though the Northwest's more seasonable weather has enabled resources in that region to provide hydroelectric energy into California at low

[1] "Short-Term Energy" includes day-ahead and hour-ahead bilateral and real-time incremental energy. Bilateral transaction information is provided by CERS, on a lagged basis. Figures for March and April are estimated and will be replaced with actuals in the Market Analysis Report for June 2002, to be released in July. Real-time incremental transaction information is procured in ISO markets and reflects actual hourly figures.

cost. The following chart shows that self-provision in April has been consistent with that in the past few months. The cost of ancillary services in April was less than 2% of total cost to load.

Figure 2. Self-Provision of Ancillary Services and AS Costs



The ISO monitors AS prices and volumes by service type and market. The average prices of upward and downward regulation services (RU and RD) in the ISO's day-ahead market were $12.73/MWh and $14.92/MWh in April, up 41 percent and 79 percent from March levels, respectively, but consistent with levels seen in January and February. Please see further discussion of the drop in prices during March in the Issues under Investigation section at the end of this Report. Day-ahead spinning, non-spinning, and replacement reserve services (SP, NS, and RP) averaged $3.40/MWh, $0.73/MWh, and $0.22/MWh, respectively, all up nominally from March levels. The following table shows average monthly prices for AS by service type and market.

Table 2. Ancillary Services Statistics for April 2002

	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	$12.73	$ 10.27	$ 12.45	471	61	88%
Regulation Down	$14.92	$ 9.73	$ 14.24	449	68	86%
Spin	$ 3.40	$ 4.09	$ 3.43	668	27	96%
Non-Spin	$ 0.73	$ 0.89	$ 0.73	645	24	96%
Replacement	$ 0.22	$ 0.46	$ 0.28	59	21	73%

III. Interzonal Congestion

Day-ahead interzonal congestion was relatively light in April. The only branch group that suffered day-ahead congestion in significant number of hours was the California-Oregon Intertie (COI), which was congested in 13.3 percent of hours in the import direction, with an average congestion price of $10.91/MWh. Sylmar AC was congested in 1.7 percent of hours in the import direction, with a typically high average congestion price of $155.81/MWh. Path 15, meanwhile, had unusually low day-ahead congestion, at 3.2 percent of hours in the South-to-North direction, with a typically low average congestion price of $0/MWh. In the hour ahead, COI, Eldorado, Mead, NOB, and Palo Verde all experienced congestion in fewer than five percent of hours in the import direction, with average congestion prices in the range of $20 to $100/MWh. Day-ahead congestion costs totaled $1.3 million in April, compared with $388,366 in March and $7.6 million in April 2001.

Table 3. Day-Ahead Interzonal Congestion Frequencies and Prices for April 2002

Branch Group and Direction	Peak Congestion Pctg.	Off-Peak Congestion Pctg.	All-Hour Congestion Pctg.	Avg. Peak Congestion Price	Avg. Off-Peak Congestion Price	Avg. All-Hours Congestion Price	Total Congestion Cost
COI (Import)	20 %		13.3 %	$ 10.91		$ 10.91	$994,601
Eldorado (Import)	2.1 %		1.4 %	$ 26		$ 26	$211,388
NOB (Import)	5.8 %		3.9 %	$ 0.01		$ 0.01	$500
Palo Verde (Import)	2.7 %	2.5 %	2.6 %	$ 0	$ 5.49	$ 1.73	$27,045
Path 15 (South-to-North)		9.6 %	3.2 %		$ 0	$ 0	$0
Sylmar-AC (Import)	2.5 %		1.7 %	$ 155.81		$ 155.81	$112,238

IV. Summary of Market Costs

Due to the delay in availability of CERS' day-ahead forward energy transactions, DMA can only provide actual net-short[2] wholesale energy costs on a two- to three-month delay basis. This report contains estimated (rather than actual) net-short energy costs for March and April 2002. Actual net short costs for March and April may not be available until the July Report is released.

DMA estimates that wholesale cost to load for energy and AS totaled $763 million in April, or an average of $41/MWh. These costs reflect substantial savings over March, during which the average cost was $44/MWh. This lower cost is due to substantially lower forward energy costs,

[2] Net short energy costs are the costs incurred to meet the IOU's load not served by their retained generation resources.

which DMA attributes to the increased availability of inexpensive hydroelectric power from Northwestern runoff. Costs are still well below the average of $191/MWh experienced during the crisis month of April 2001, but above the average of $33/MWh enjoyed in 2000 and 1999, due in part to the higher level of natural gas prices this year. The following tables show costs for wholesale energy and AS for 2002 to date and 2001.

Table 3a. 2002 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
MAR-02†	18,749	18,282	$ 811	$ 6	$ 9	$ 817	$ 826	$ 44	$ 0.50	1.2%	$ 44
APR-02†	18,511	17,937	$ 742	$ 8	$ 13	$ 750	$ 763	$ 41	$ 0.68	1.7%	$ 41
Total to Date 2002	73,770	71,813	2,952	29	52	2,981	3,033				
Avg 2002	18,442	17,953	738	7	13	745	758	40	1	1.8%	$ 41

***** Sum of hour-ahead scheduled quantities

****** Includes UDC (cost of production), estimated CDWR costs, and other bilaterals priced at hub prices

******* includes OOM, dispatched real-time paid MCP, and dispatched real-time paid as-bid

******** Including ISO purchase and self-provided A/S priced at corresponding A/S market price for each hour, less Replacement Reserve refund

†March and April forward costs (and resulting totals) are estimated. Values in July report will include true-up and may differ from values shown here.

Table 3b. 2001 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

***** Sum of hour-ahead scheduled quantities

****** Includes UDC (cost of production), estimated CDWR costs, and other bilaterals priced at hub prices

******* includes OOM, dispatched real-time paid MCP, and dispatched real-time paid as-bid

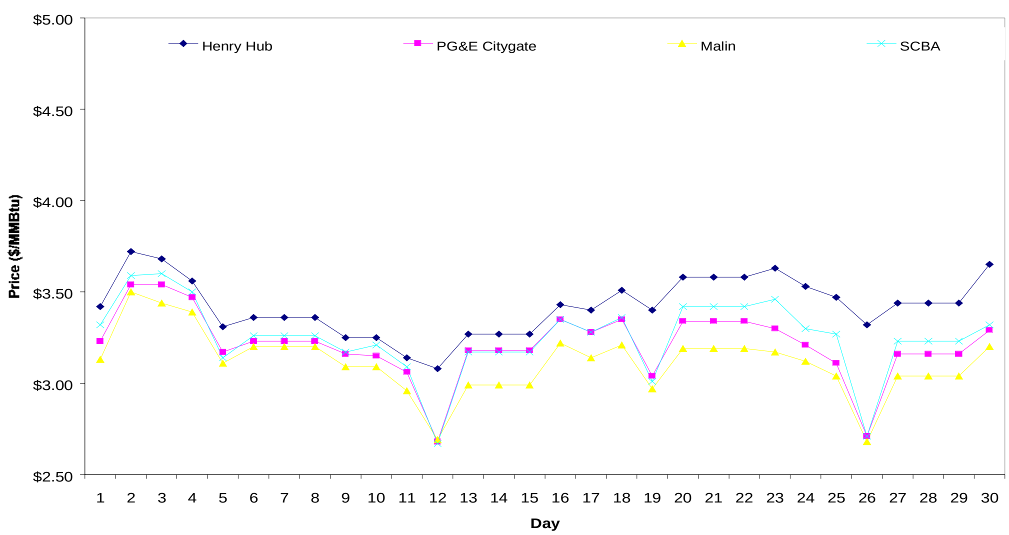
******** Including ISO purchase and self-provided A/S priced at corresponding A/S market price for each hour, less Replacement Reserve refund

V. Natural Gas Markets

Western spot natural gas prices were fairly stable in the first half of April, owing to generous supply conditions and fairly stable weather, while prices fluctuated more significantly in the latter half of the month. Prices on weekdays ranged from $3.10 to $3.75 per million British thermal units (MMBtu), and fell below $3.00/MMBtu on some Sundays at Western delivery points. The first five days of April saw locally high prices between $3.40 and $3.75/MMBtu, owing primarily to strong NYMEX Henry Hub (Louisiana) futures contract prices, which were in turn driven by political turbulence in the Middle East. Prices then fell to the range of $3.15 to $3.40/MMBtu, and remained at those levels until April 15, with the exception of a price drop across the West on April 12. Between April 16 and April 23, prices rose to a high at Henry Hub of $3.75/MMBtu. During this time, a heat wave on the East Coast kept the Henry Hub price consistently $0.25 higher per MMBtu than prices at Western delivery points. This hot weather was followed by a sudden cold snap in the Northeast and Midwest, which caused the price differential to persist through the end of April. After April 23, prices dropped back to the range of $3.05 to $3.60/MMBtu, and began to increase on April 30 in response to hot weather in the Southeast. Average bid week prices for May were $3.19, $2.96, and $3.09 for SoCal Gas, Malin, and PG&E Citygate, respectively, down 6%, 10%, and 10% from April bid week prices.

The following chart shows daily gas prices at California delivery points and Henry Hub for April.

Figure 3. Natural Gas Trading Hub Prices for April 2002

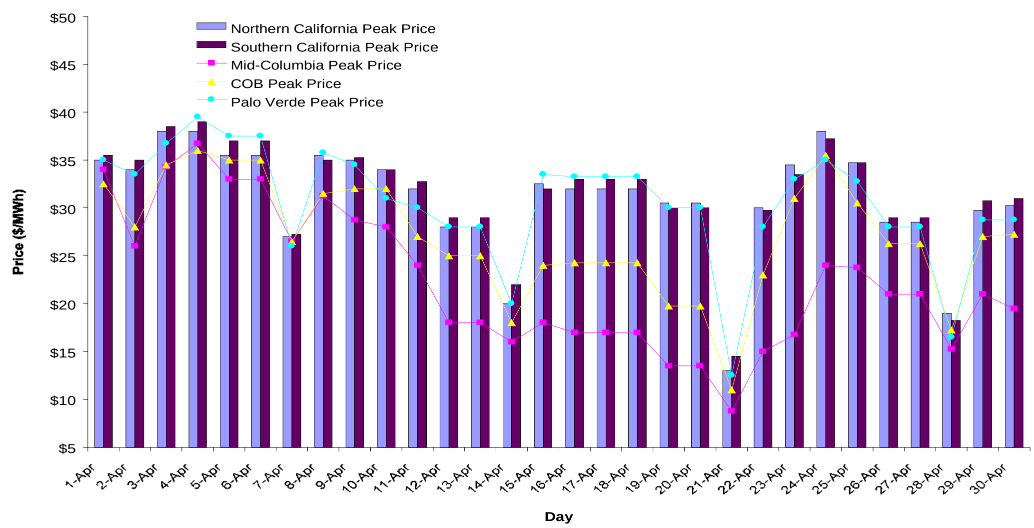


VI. Regional Day-Ahead Electric Markets

Day-ahead regional electricity prices varied widely across Western regions in April. Increased hydroelectric generation due to spring runoffs kept Mid-Columbia (Oregon) prices $10 to $20/MWh lower than those seen at Palo Verde and in California, and California-Oregon Border (COB) prices $5 to $10/MWh lower than Southwestern prices as well. High natural gas prices kept electricity prices during the first week of April within the $25 to $40/MWh range. After April 7, prices moved downward, with Northwestern prices falling more sharply than those at other locations, as hydroelectric generation increased. Weaker gas prices further contributed to the price decline, with prices reaching local lows of $15 to $27/MWh on April 14. April 15 saw prices decline sharply on expectations of lower weekend demand. Meanwhile, warm weather in the Southwest strengthened demand there, contributing to the differential in price across regions. Between April 16 and April 20, increasing natural gas prices drove prices back up to the $35/MWh level in California and at Palo Verde. Concerns over southbound congestion-related curtailments on COI contributed to price increases in the southwest from April 23 to April 26. Prices remained essentially flat for the remainder of the month, staying in the range of $20 to $30/MWh, with the exception a dip in prices on April 28 due to reduced weekend demand.

The following chart shows Western regional day-ahead prices for April.

Figure 4. Western Regional Day-Ahead Bilateral Market Prices for April 2002



VII. Issues under Investigation

Drop in Regulation Prices in March. Average prices in the upward and downward regulation capacity markets decreased from approximately $14/MWh in February to $9/MWh in March. This reduction is partly an unintended positive consequence of an otherwise contested element of FERC's Order of December 19, 2001 (and affirmed in FERC's Order of May 15, 2002; see below for details); namely, that importers bid energy into the BEEP Stack at prices of zero. The zero-bid requirement, as discussed in the Market Analysis Report for March 2002, had the effect of decreasing the supply of imports into the BEEP Stack. This caused the bid stack to become steeper. In other words, resources would be paid more when the ISO dispatches them to increase generation in real time, and would be charged less when the ISO dispatches them to decrease generation. Since providers of regulation services are paid based upon real-time prices, they could then net higher margins by providing regulation energy. Thus, generators had a stronger incentive to provide regulation services, so some participants bid lower prices into the regulation capacity market.

Investigations concerning activities cited in Enron Memos. On May 6, 2002, FERC released several internal memoranda written by attorneys of Enron Power Marketing, Inc. (EPMI) discussing EPMI trading strategies in the ISO's ancillary services and congestion markets. DMA has conducted a preliminary review of the strategies listed in the memos. The initial finding is that many of these strategies had been identified in some form, and had been investigated by DMA. Several have been discussed in previous monthly Market Analysis Reports.

Violations of the Market Monitoring and Information Protocol are referred to FERC, which has the authority to impose remedial action. The ISO had taken action in response to known activities, including issuance of market notices, proposal of market rule changes as necessary, and filing of timely reports to FERC. The following is a preliminary analysis of strategies discussed in the memos, including synopses of the ISO's responsive actions.

- **"Inc-ing load" into the real-time market (a.k.a. "Fat Boy").** This is the practice of deliberately scheduling excess delivery from generation to load over ISO-controlled transmission. During the hour of operation, load draws less energy than the scheduling coordinator (SC) had actually scheduled for delivery, so the generator is paid for providing excess "uninstructed" energy to the grid. DMA identified the potential for this behavior, which it originally called "overgeneration," when the market commenced operation in 1998. This practice is profitable when another market participant underschedules; that is, when an SC schedules less generation than it needs to meet its load. The ISO has implemented progressively higher penalties for load underscheduling, and has also petitioned FERC for additional penalties on generators for deviating from ISO instructions to increment or decrement generation. FERC did not approve the request for deviation penalties, on the grounds that it was waiting for a comprehensive solution to the problems in California's energy markets. Thus, the ISO has incorporated the penalties as a permanent feature of its 2002 Market Redesign (MD02) filing.
- **Export of California Power.** This practice involves the purchase of power generated in California, which is subject to a price cap, and selling it outside the State, where prices were not subject to any cap prior to June 19, 2001. The practice exacerbated energy shortages in California during the crisis in late 2000, and contributed significantly to the collapse of the California Power Exchange (PX). The ISO's filing with FERC in October 2000 noted the potential for such behavior and proposed solutions to address this problem. FERC did not accept the ISO's recommendations until it issued its Order of June 19, 2001, which addressed the export issue by instituting West-wide price mitigation. This has effectively prevented marketers from selling electricity outside California above the price cap. As part of its MD02 effort, the ISO has petitioned FERC to preserve West-wide mitigation beyond its current expiration date of September 30, 2002.
- **Non-Firm Export.** This is the practice of scheduling non-firm energy – energy that is not supported by ancillary services (AS), and whose transmission can be canceled -- for export along a transmission path when it is congested in the opposite (import) direction in the hour-ahead market. This appears to relieve the congestion, and allows the SC to collect the hour-ahead congestion charge. However, the SC cancels the export after the close of the hour-ahead market, thereby restoring the original congestion in the import direction just prior to real-time, so the imports must be curtailed to the capacity of the path. The SC also receives additional payments for the generation that is not exported, since it

effectively becomes uninstructed generation. Finally, because the energy is non-firm, the SC need not purchase or self-provide AS to support it. As noted in the Enron memo, the ISO became aware of this practice in the summer of 2000, and immediately issued a Market Notice on July 21, 2000 prohibiting it, with violators subject to investigation by DMA and possible corrective action. The practice ceased after the market notice was issued.

- **"Death Star.**" This is the practice of scheduling energy in a circular route that passes through two or more control areas in the forward (day-ahead or hour-ahead) market, in the direction opposite existing congestion – the "counterflow" direction -- within the ISO control area, without any actual generation or load. The SC may collect congestion revenues for scheduling counterflows in the ISO control area, even though it has not relieved congestion by scheduling resources to produce such counterflow. An SC may be able to engage in this practice if it owns or purchases scheduling rights for the part of the circular path that lies in another control area. This is profitable when other SCs neglect to move electricity over the least-cost route. This practice may compromise system reliability because there is no physical resource to control, if necessary, in any control area. DMA has been monitoring and investigating similar situations since late 2001. The ISO is in the process of designing rules for import and export schedules, to ensure that they are supported or identified by tagged generating resources outside the ISO Control Area. Market monitoring across different control areas is necessary to deal effectively with this practice.
- **"Load Shift."** This is an attempt to create congestion and increase congestion revenues on a path in which the SC owns transmission rights in the congested direction. The SC initially submits false schedules on the path in the congested direction, and then adjusts its loads on both ends of the path to decrease its schedule in the congested direction. Since the SC owns transmission rights, it is exempt from transmission charges in the congested direction, and can claim congestion payments for effectively reducing congestion. The ISO Board of Governors was made aware of this tactic in 1999 when considering limits on ownership concentrations of firm transmission rights (FTRs), and ultimately decided to limit the volume of FTRs auctioned to only a portion of total available transmission capacity. Enron's net revenue from FTR ownership on Path 26 in 2000 corresponds to the figure of $30 million noted in the memoranda. However, DMA has found in an analysis that Enron's income that can specifically be attributed to Path 26 in hours in which "Load Shift" occurred amounted to approximately $165,000.
- **"Get Shorty."** This is the practice of speculating that the price of an ancillary service will fall between the day-ahead and hour-ahead AS markets. An SC sells an ancillary service into the ISO's day-ahead AS market, and then repurchases its obligation from another SC in the hour-ahead market. This is an abuse of the AS buyback privilege, which allows an SC that is unable to provide a service due to a malfunction to purchase it in the hour-ahead market. The Enron memoranda suggested that the SC had intended to sell a service that it was unable to provide to the ISO, which may be an example of fraudulent behavior. In the event that the ISO must draw from the capacity that the SC sold in the day-ahead market – effectively exercising its option to purchase the energy from capacity it had reserved – the SC's failure to provide such energy compromises system reliability, and indeed undermines the very reason for purchasing AS. This illustrates an asymmetry between internal control area resources, -- which are not able to engage in this practice

since ISO software validates ramp rates and available capacity when accepting internal AS bids – and external resources, for which ISO operators do not have capacity information. Thus, the ISO relies on responsible commercial practice for the import of AS. Nonperformance is an explicit violation of rules of the Western Systems Coordinating Council (WSCC). The ISO withholds AS capacity payments whenever sellers fail to make the capacity available if it is needed.

- **"Wheel Out."** This is an opportunistic scheduling of a counterflow when another SC has erroneously scheduled a flow on a completely derated line, and primarily occurred in the PX market. The counterflow earns congestion charges since any flow on a downed (open) line will need to be zeroed out entirely. The ISO is aware of this practice and does not accept schedules on downed transmission lines, or schedules that significantly exceed the transfer capabilities of lines. The PX market monitoring unit investigated an occurrence of this type of behavior involving Enron on May 25, 1999 on the Silver Peak intertie, and reported it to FERC. The PX was in the process of developing a permanent procedure that would reject schedules on derated lines before it ceased operation in January 2001.
- **"Ricochet."** This falls into a class of transactions that DMA refers to as "Megawatt Laundering." An out-of-state marketer would buy energy generated in California through the PX day-ahead market, and then resell it back into California in real time, in order to speculate on the price spread between the two markets, and possibly to create a last-minute squeeze on supply. This practice likely evolved into the more recent varieties of megawatt laundering, in which marketers schedule energy for export, and then repurchase it for import back into California in real time, in order to evade California-specific price caps. The ISO recognized this practice and had petitioned FERC for West-wide price mitigation, which would prevent these types of transactions, since mid-2000. FERC granted West-wide mitigation in its Order of June 19, 2001. As noted above, the June 19 mitigation is set to expire on September 30, 2002, but the ISO has proposed that West-wide mitigation measures be retained.
- **Selling Non-Firm Energy as Firm Energy.** This is a type of transaction in which a seller falsely represents the terms of sale. This fraudulent behavior is a *per se* violation of WSCC rules. Firm energy export into California must be certified by the exporting control area for every hour through control area check-out procedures.
- **Scheduling Energy to Collect the Congestion Charge II.** This is the practice of scheduling energy in the counterflow direction even when the SC has no energy to transmit. The SC collects counterflow usage charges in the forward market. In real-time, since the SC fails to generate, it is charged the penalty for real-time for negative deviations from generating instructions (equal to the BEEP INC price per MWh) for every MWh it is short. If congestion on the line is significant, the usage charge offsets the real-time energy replacement cost. DMA investigated this behavior and found that it would rarely be profitable, but is on a watch list for continued monitoring. This would not be profitable with increased penalties for uninstructed deviations, and relaxation of the market separation constraint, as proposed under MD02.

FERC Orders of May 15, 2002. FERC issued several Orders accepting in part and rejecting in part the ISO's requests for rehearing and clarification of FERC's Orders of December 19, 2001.

DMA remains concerned that some of FERC's rulings do not give the California ISO the authority granted to other ISOs, and may result in incentives that will lead to uncompetitive market outcomes. For example, FERC denied the ISO's request to net market revenues against minimum load cost compensation for long start units (Order E-25). FERC rejected this feature based on the premise that "the revenues by generators for sales in the imbalance energy market are, under market-based authority intended to compensate the generators for recovery of fixed costs (page 9 of the Order). This argument is not valid, since the ground rule of the waiver procedure proposed by the ISO is that the unit would have shut down for economic reasons, during which it would be unable to recover revenues toward its fixed costs, unless the ISO needed it on.