Memorandum

To: ISO Board of Governors

From: Anjali Sheffrin, Director of Market Analysis

CC: ISO Officers, ISO Board Assistants

Date: July 20, 2001

Re: Market Analysis Report for June 2001

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

This report summarizes key market conditions, developments, and trends for June 2001.

EXECUTIVE SUMMARY

Real time electricity and ancillary service prices decreased in June compared to May due to high hydro flows in the Northwest and lower natural gas prices. On average, the price of real time electricity in June decreased 62% to $104/MWh from the May average of $275/MWh. Although loads increased slightly in June compared to May as warmer temperatures increased cooling demand, loads declined significantly from June 2000 levels showing visible conservation efforts. Total load in June was down 8.45% from June of last year. Exact conservation estimates must be made on a weather-normalized basis.

In June, two separate FERC-ordered market power mitigation measures were in place. For the period June 1 through June 20, the FERC April 26, 2001 order was in place capping prices during emergency hours at a formula determined proxy price. The proxy price is determined by calculating the marginal cost of the highest priced unit dispatched. Bids accepted above the price cap during emergency hours were paid as bid subject to cost justification or refund. On June 19, 2001, FERC issued an order expanding the price mitigation to all hours and to all suppliers throughout the WSCC. In non-emergency hours, the cap will equal 85 percent of the highest (mitigated) hourly ex-post price during the last ISO Stage 1 emergency. On June 20, the FERC's June 19 mitigation order became effective throughout the West initially capping prices at $91.87/MWh, 85 percent of the highest hourly ex-post price calculated during the ISO's last Stage 1 emergency (which was $108.08/MWh and occurred in hour ending 10:00 on May 31, 2001). FERC ordered an adder of 10% to the market-clearing price for generators selling into the ISO markets to account for increased credit risk. The cap will be reset upon the next full hour of a Stage 1 emergency. Bids accepted above the cap are paid as bid subject to cost justification.

From June 1-20, 50% of the accepted INC bids (MWh) were above the June 19 Order price cap of $91.87/MWh. From June 21-30th, the period when the FERC June 19 Order was in place, only 18% of the accepted INC bids were above the $91.87 price cap. The weighted average accepted INC bid price from June 1-20 was $117.04/MWh, which fell to $62.54/MWh for the period of June 21-30. A preliminary review shows that the FERC's June 19 Order has been somewhat effective in mitigating real time prices. Figure 1 shows the amount of bids accepted as-bid and under the proxy market clearing price had the FERC's June 19 Order been in place for the entire month. Figure 2 shows the reduction in the real-time price was due in part to the reduction in costs in real-time as well as the reduction in the mark-up suppliers charged over costs.

Figure 1. June Accepted Real Time Market Bids

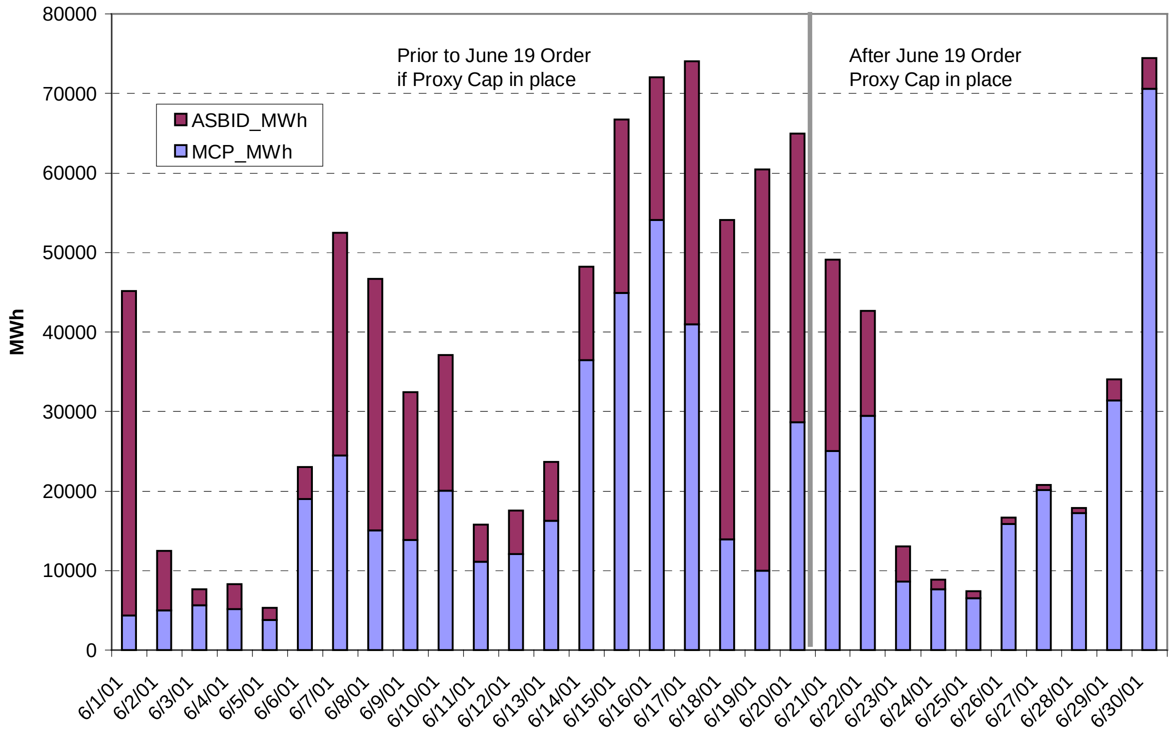
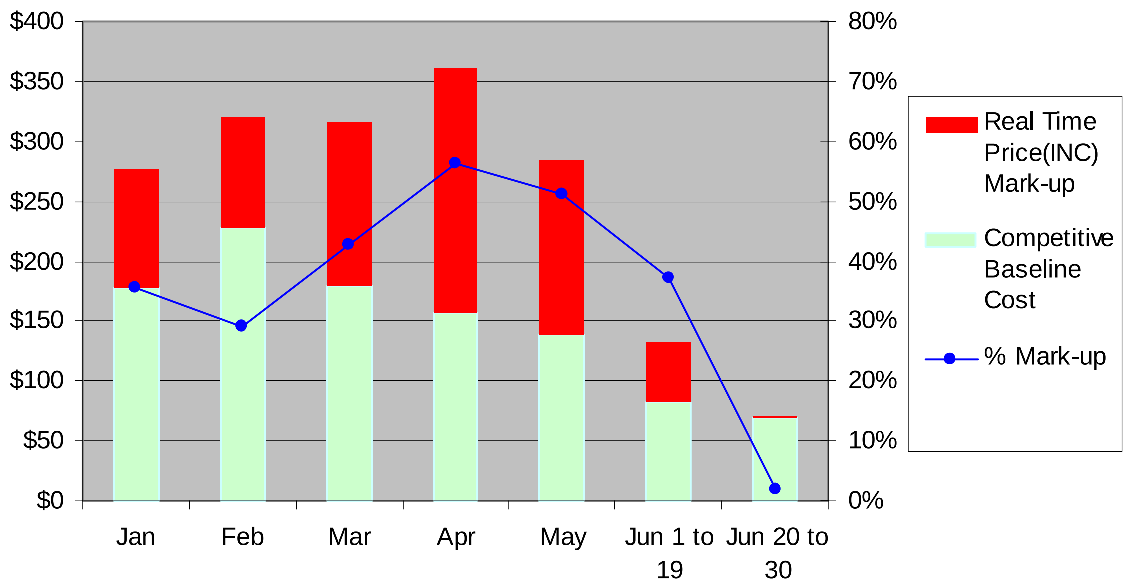


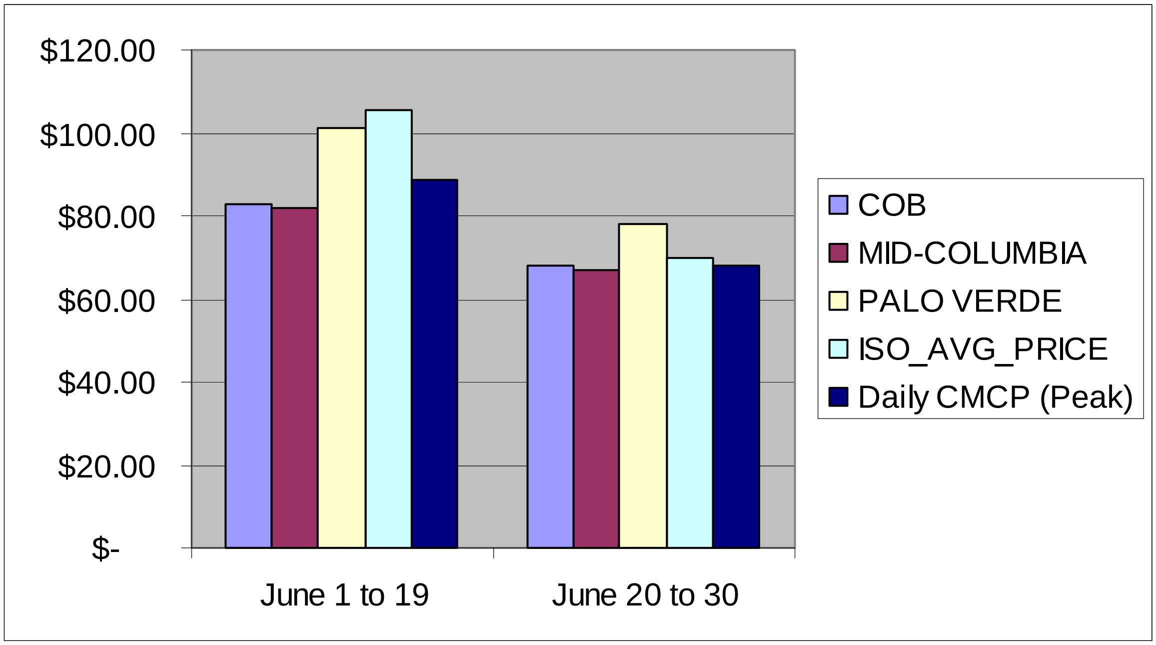
Figure 2. Price-Cost Mark-Up in ISO Real-Time Market



Comparing the competitive baseline cost to other Western regional spot market prices, we see a similar reduction in the mark-up of suppliers in those markets as well. Figure 3 shows peak period spot prices for

California Oregon Border, Mid-Columbia, Palo Verde, and the ISO real-time price compared to the competitive baseline cost.

Figure 3. Regional Spot Prices Compared to Daily Competitive Baseline



Other key market activities include the following:

- **Regional spot electricity prices decreased significantly in June from May**. Higher than expected hydro flows in June from spring runoff, low natural gas prices, and increased generation put downward pressure on prices. Overall, regional prices reported in the Northwest were 26% lower than "effective real time energy prices" in NP15, while regional prices reported in the Southwest were 11% lower than "effective real time energy prices" in SP15. Since the trading volume at the reported regional spot prices is unknown, it is difficult to make direct comparison to California volume and spot prices.

- **Spot natural gas prices decreased from $9.23/MMBtu in May to $5.28/MMBtu in June**. The California average natural gas spot price is the average of the PG&E Citygate and Southern California Border prices. The decrease in prices was due to warmer weather conditions leading to less heating demand combined with increased hydro generation reducing demand for gas fueled generation.

- **Underscheduling of loads and generation was reduced significantly**. The California Energy Resources Scheduling division of the California Department of Water Resources (CERS) purchases limited the underscheduling of loads to an average of 1.6 percent in June.

- **Lower Ancillary Service Costs.** In June, ancillary service prices decreased, although not as much as energy costs, compared to May as total costs ancillary service costs decreased by 1%. Total ancillary service costs were $184 million in June, up from the May total of $171 million, representing an increase from $8.71 to $9.31 per MWh of load served.

- **Lower Congestion Costs.** Congestion in June was primarily limited to Path 26 in the south to north direction (all during off-peak hours), exports to the Northwest on NOB, and imports from Eldorado. Total congestion costs for June were approximately $0.5 million, down from $7 million in May.

KEY MARKET CONDITIONS FOR MAY 2001

I. California Wholesale Energy Markets

- **Loads.** Monthly system energy loads for June totaled 19,777 GWh, an 8.45% decrease from June 2000, reflecting significant conservation efforts by California consumers. The California Energy Commission provides refined estimates of conservation after normalizing for weather conditions. The peak load for the month reached 39,613 MW, an 8.82% decrease from the June 2000 peak of 43,447 MW. Daily peak loads averaged 27,468 MW, an 8.45% decrease from June 2000.

- **Wholesale Energy Prices.** On May 28, 2001, the FERC's April 26, 2001 price mitigation order went into effect through June 20, 2001 (when FERC's June 19, 2001 Order went into effect). During this period, a soft price cap was imposed during emergency conditions based on a formula for the calculation of the system marginal cost. Bids accepted above the price cap continued to be paid as-bid subject to cost justification. The April 26, 2001 price mitigation measures did not have an effect on prices from June 1 through June 19 because the ISO did not declare any system emergencies during the period. On June 20, the FERC's West-wide system mitigation went into effect capping real-time prices at $91.87/MWh. Bids accepted above the cap are paid as bid subject to cost justification.[1]

  The as-bid structure of the market and out-of-market purchases have created several prices and volumes related to the real time market. The BEEP market now consists of several components displayed in numbered columns: the market clearing price (MCP) and quantity for bids under the price cap (1), the as-bid price and volume for bids accepted over the price cap (2), and the Out-of-market purchases in real-time (4). The combination of these components yields the total "effective real time price" in column 5. The OOM costs in column 4 include CERS purchases on behalf of the IOU's in real-time. The averages for each of these different segments of total real time purchases for peak, off-peak, and all hours are reported below in the numbered columns:

Table 1: Real Time Energy Price Summary for June 2001*

	Market Clearing Avg. Price and Total Volume (1)	As-bid Avg. Price and Total Volume (2)	Total BEEP* Avg. Price and Total Volume (3)	Out-of-market Avg. Price and Total Volume (4)	"Effective Real Time Avg. Price" and Total Volume (5)	Average System Loads and Percent Under-scheduling
Peak	$72.34 (37 GWh)	$137.24 (-0.05 GWh)	$76.02 (37 GWh)	$127.47 (504 GWh)	$116.97 (541 GWh)	29,966 MW 2.6%
Off-peak	$49.41 (27 GWh)	$123.93 (0.8 GWh)	$52.74 (28 GWh)	$85.02 (116 GWh)	$77.96 (144 GWh)	22,472 MW -1.0%
All Hours	$64.02 (64 GWh)	$135.70 (0.76 GWh)	$67.77 (65 GWh)	$113.27 (620 GWh)	$103.77 (685 GWh)	27,468 MW 1.6%

* The values in this table represent the average prices of all transactions and should not be used to value total transactions which occur at separate INC and DEC prices.

Note: Dollar figures are $/MWh and % represents percent underscheduling. The above dollar values are the average prices per MWh transacted in real-time and do not represent the average cost of

[1] Accepted bids in the California ISO market below the price cap are paid an additional 10 percent on top of the (mitigated) market-clearing price in the relevant ISO market as a credit risk premium.

electricity. For reference, the average cost of electricity and ancillary services for the entire system (including UDC generation at cost, bilateral transactions at hub prices, and real time costs) for the month of June is estimated at $96/MWh.

- Average real time prices decreased 62% in June compared to May. Total loads in June increased from May while average hourly underscheduling which decreased as a percent of load from 7.1% to 1.6%. Contributing to the monthly price differences in real time prices was a decrease in the average spot price for natural gas from $9.23/MMBtu in May to $5.28/MMBtu in June.[2]

II. Ancillary Service Markets

Ancillary Service Prices

- The five ancillary services are procured through a day-ahead and an hour-ahead market to meet reserve requirements. Effective May 28, 2001 (for operating day May 29) though June 19, 2001 (for operating day June 20), the FERC April 26, 2001 price mitigation order was in effect. This order capped ancillary service prices at the real time price cap during emergency conditions. Effective June 20, 2001 (for operating day June 21), the FERC's June 19, 2001 Order when into effect, which the ISO is interpreting to cap ancillary service prices at the effective real time cap during all hours. Reserve requirements that are not met at prices at or below the soft cap are purchased at the bid price and are subject to just and reasonable cost review. Beginning December 31, 2000, capacity payments for Replacement Reserve are rescinded to the extent that Replacement Reserve energy is dispatched from the corresponding resource in real- time. The resulting savings have ranged from $10 million to $20 million per month.

- The California investor-owned utilities continued to self provide a portion of their A/S requirements. The volume reported in Table 2 includes the IOU's self-provision of A/S.

- Average prices for ancillary services were mixed in June, on average, compared with May 2001. Regulation Up prices decreased by 12% while Regulation Down prices increased by 30%. Prices for Spinning Reserve decreased by 26% while prices for Non-Spinning Reserve fell by 19%. Replacement Reserve prices decreased by 25%. Between 83% and 125% of requirements were purchased in the day-ahead market. The higher percentage (125%) occurred in the Replacement Reserve market and is partially attributed to the lack of precise information regarding out-of-market procurements by CDWR. Table 2 below summarizes the weighted average prices and quantity procured for June 2001 in both the day-ahead and hour-ahead markets.

- Table 3 compares the weighted average A/S prices in the day-ahead market during peak and off-peak periods along with the percentage of hours during which ancillary services were procured zonally (day-ahead and hour-ahead combined) for June 2001.

[2] Average spot price for natural gas is equal to the average of PG&E Citygate and Southern California Border prices.

Table 2. Summary of Weighted Day-Ahead A/S Prices by Market – June 2001

	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	$ 111	$108	$ 110	385	80	83%
Regulation Down	$ 72	$ 82	$ 74	515	103	83%
Spin	$ 59	$ 36	$ 59	1182	22	98%
Non-Spin	$ 44	$ 24	$ 42	773	86	90%
Replacement	$ 97	$ 20	$ 85	632	-126	125%

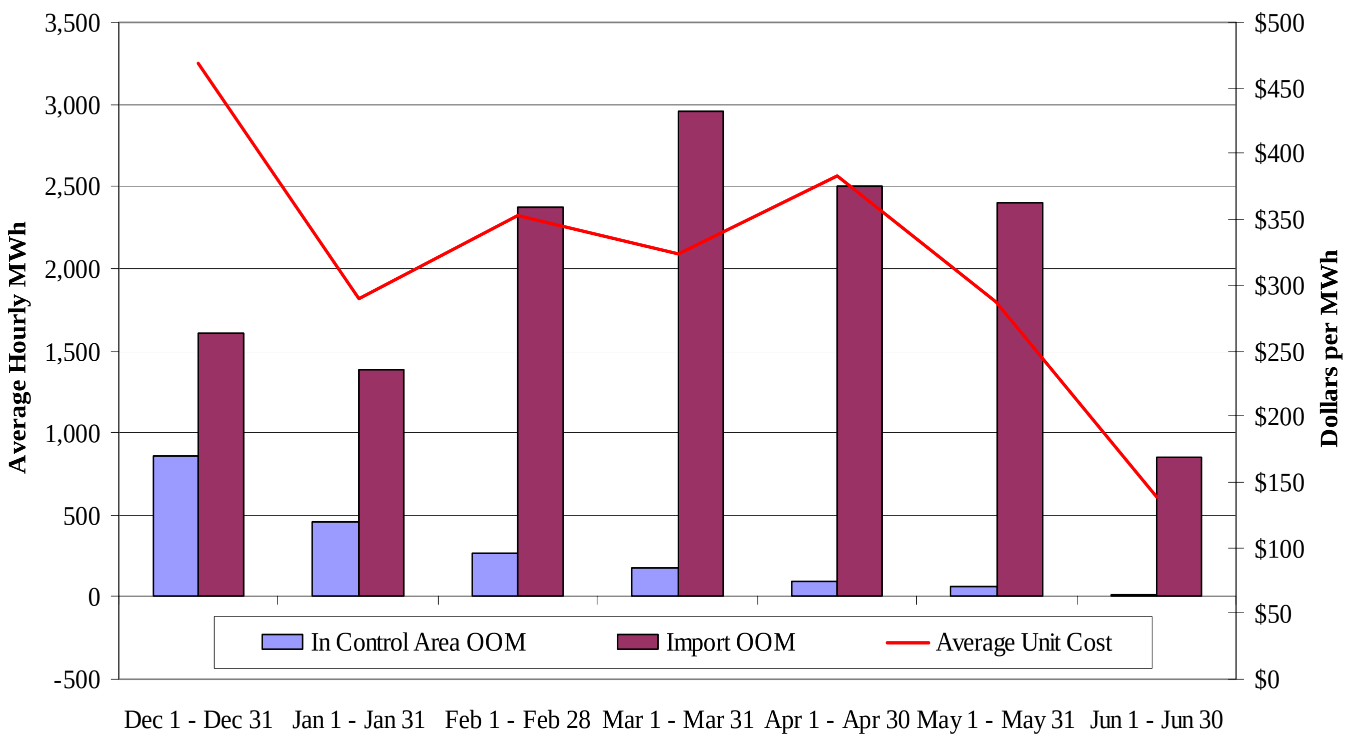
Table 3. Summary of Weighted Day-Ahead A/S Prices by Zone and Period – June 2001

	NP15		SP15		Percent of Hours with Zonal Procurement
	Peak	Off Peak	Peak	Off Peak	
Regulation Up	$ 89	$ 101	$ 121	$ 122	0%
Regulation Down	$ 42	$ 87	$ 105	$ 117	0%
Spin	$ 84	$ 10	$ 81	$ 11	0%
Non-Spin	$ 45	$ 2	$ 93	$ 6	0%
Replacement	$ 90	$ 7	$ 82	$ 31	0%

III. Out of Market Calls (OOM)

June out-of-market calls remained high largely due to purchases by CERS in real-time being recorded as OOM. The average out-of-market costs for June were $138/MWh, down $149/MWh compared with the May average of $287/MWh. On an hourly average basis, 861 MW were purchased out of market in May, with 99% of the OOM electricity coming from imports in each month. The total cost of out -of-market purchases in May were $85.6 million.

Figure 1. Quantities of Out-of-market Purchases (Average Hourly)
December 2000 - June 2001



IV. Summary of Market Costs

The total cost of energy and ancillary services in June was approximately $1.9 billion, decreasing from $3.54 billion in May. The average cost of energy and A/S decreased from $180/MWh in May to $96/MWh in June. Energy and A/S costs continue to be significantly higher than those seen in the first two years of operation. Total energy and A/S costs for the first nine months of ISO operation in 1998 were approximately $5.55 billion resulting in an average cost of $33/MWh. Total costs in 1999 were comparable to 1998 with a total cost of approximately $7.03 billion (for twelve months) and an average cost of energy and A/S remaining steady at $33/MWh. Costs increased substantially in 2000. Total costs for energy and A/S in 2000 were over $27 billion resulting in an average cost of $114/MWh. In 2001, through June, total energy and A/S costs are more than $20 billion with an average cost of $184/MWh of load served. The costs for the first 6 months in 2001 have increased significantly over the first six month costs of 2000 increasing to over $20 billion from approximately $7.1 billion in 2000. The table on the next page provides a summary of Energy and A/S costs. The costs estimated in is this table include estimates for utility generation, CERS purchases, and bilateral transactions in the ISO control area.

Table 4
Summary of Energy and Ancillary Services Costs

A. Cost Summary through December 2000:

	ISO Load (GWh)	Est PX Energy Costs (MM$)*	Bilateral Energy Costs (MM$)*	RT Energy Costs (MM$)**	AS Costs (MM$)***	Total Energy Costs (MM$)	Costs of AS+ Energy (MM$)	Avg Energy Cost ($/MWh)	A/S Cost ($/MWh Load)	A/S Costs as % of Energy Costs	Total Costs ($/MWh load)
1998 (9mo)	169,239	$ 4,148	$ 556	$ 209	$ 638	$ 4,913	$ 5,551				
Avg 1998	18,804	$ 461	$ 62	$ 23	$ 71	$ 546	$ 617	$ 29	$ 3.77	13.0%	$ 33
Total 1999	227,533	$ 5,866	$ 982	$ 180	$ 404	$ 7,028	$ 7,432				
Avg 1999	18,961	$ 489	$ 82	$ 15	$ 34	$ 586	$ 619	$ 31	$ 1.78	5.7%	$ 33
Jan-00	18,984	$ 495	$ 103	$ 3	$ 12	$ 601	$ 612	$ 32	$ 0.62	2.0%	$ 32
Feb-00	17,807	$ 419	$ 103	$ 20	$ 10	$ 542	$ 552	$ 30	$ 0.58	1.9%	$ 31
Mar-00	18,989	$ 432	$ 90	$ 39	$ 11	$ 561	$ 572	$ 30	$ 0.60	2.0%	$ 30
Apr-00	18,212	$ 429	$ 101	$ 31	$ 17	$ 561	$ 578	$ 31	$ 0.95	3.1%	$ 32
May-00	19,997	$ 828	$ 225	$ 108	$ 63	$ 1,161	$ 1,224	$ 58	$ 3.16	5.4%	$ 61
Jun-00	21,605	$ 2,303	$ 529	$ 339	$ 436	$ 3,171	$ 3,607	$ 147	$20.19	13.8%	$ 167
Jul-00	21,935	$ 1,896	$ 346	$ 216	$ 125	$ 2,458	$ 2,583	$ 112	$ 5.71	5.1%	$ 118
Aug-00	23,141	$ 2,786	$ 585	$ 515	$ 282	$ 3,886	$ 4,168	$ 168	$12.18	7.3%	$ 180
Sep-00	20,620	$ 1,819	$ 389	$ 236	$ 152	$ 2,445	$ 2,597	$ 119	$ 7.39	6.2%	$ 126
Oct-00	18,184	$ 1,400	$ 356	$ 27	$ 56	$ 1,388	$ 1,434	$ 100	$ 3.33	3.3%	$ 104
Nov-00	18,656	$ 2,292	$ 402	$ 195	$ 114	$ 2,889	$ 3,004	$ 155	$ 6.13	4.0%	$ 161
Dec-00	19,412	$ 3,742	$ 820	$ 1,149	$ 440	$ 5,711	$ 6,151	$ 294	$22.65	7.7%	$ 317
Total 2000	237,543	$ 18,842	$ 4,048	$ 2,877	$ 1,720	$25,373	$27,083				
Avg 2000	19,795	$ 1,570	$ 337	$ 240	$ 143	$ 2,114	$ 2,257	$ 107	$ 7.24	6.8%	$ 114

* Estimated PX Energy Costs include UDC owned supply sold in the PX, valued at PX prices.
Estimated Bilateral Energy Cost based on the difference between hour ahead schedules and PX quantities, valued at PX prices.
** Beginning November 2000, ISO Real Time Energy Costs include OOM Costs.
*** AS costs include self-provided quantities.

B. Preliminary Cost Summary Since January 2001:

	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	$ 761	$ 246	$ 3,472	$ 3,718	$ 177	$13.12	7.1%	$ 198
Feb-01	16,503	$ 14,876	$ 2,657	$ 955	$ 196	$ 3,612	$ 3,808	$ 206	$11.87	5.4%	$ 231
Mar-01	17,857	$ 16,744	$ 2,736	$ 856	$ 179	$ 3,591	$ 3,771	$ 186	$10.04	5.0%	$ 211
Apr-01	17,237	$ 16,267	$ 2,537	$ 749	$ 178	$ 3,286	$ 3,465	$ 181	$10.33	5.4%	$ 201
May-01	19,651	$ 18,351	$ 2,771	$ 600	$ 171	$ 3,371	$ 3,542	$ 167	$ 8.71	5.1%	$ 180
Jun-01	19,777	$ 19,468	$ 1,611	$ 110	$ 184	$ 1,721	$ 1,905	$ 85	$ 9.31	10.7%	$ 96
Total 2001	109,795	$ 102,656	$15,022	$ 4,032	$ 1,155	$19,053	$20,208				
Avg 2001	$ 18,299	$ 17,109	$ 2,504	$ 672	$ 192	$ 3,176	$ 3,368	$ 167	$10.57	6.5%	$ 184

***** Sum of hour-ahead scheduled quantities
****** Includes UDC generation (valued at estimated cost of production), CDWR purchases, and other bilaterals priced at spot 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

IV. Inter-zonal Congestion Management Markets

Very little inter-zonal congestion occurred in June. Congestion was limited primarily on Path 26 in the south to north direction with occasional congestion on imports from Eldorado and exports on NOB. Congestion on Path 26 decreased considerably compared to May in the south to north direction as did export congestion on NOB and COI. Total congestion costs for June decreased to approximately $0.6 million from $7 million in May. Path 26 congestion accounted for $0.35 million of the total congestion costs in June. Export congestion costs on NOB decreased from $0.27 million in May to approximately $0.1 million in June.

The following table summarizes the congestion rates and average congestion charges by branch group for the day-ahead market for June.

Table 5

Day-Ahead Market – Congestion Summary for June 2001

	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	**Off peak**	**All Hours**	**Peak**	**Off peak**	**All Hours**
Eldorado (Import)	1.5%	.5%	1%	$9	$1	$8
NOB (Export)	2%	36%	13%	$11	$29	$21
Path 26 (S-N)	0%	5%	2%	$0	$30	$30

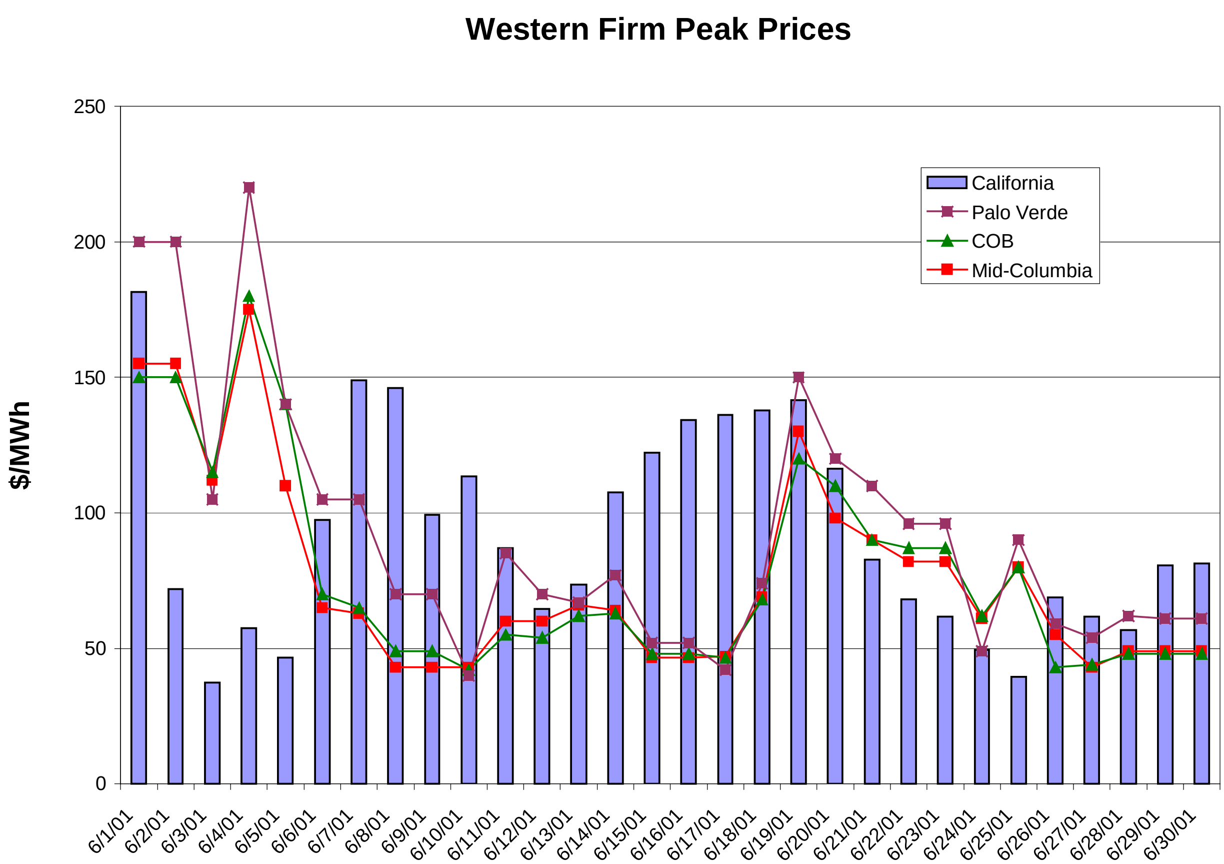
V. Western Regional Market Prices

Western Regional Spot Market Prices

Peak power prices in Western regional spot markets declined significantly in June. In early June, prices declined as normal temperatures returned to many regions and generation improved due in part to an increase in Northwest hydroelectric generation. The cooler weather and increased hydropower combined to reduce Northwest peak power prices by as much as $65/MWh on June 5th. Continued runoff into Northwest reservoirs caused dam operators to generate electricity to avoid spilling water over the dams. Mild temperatures and an increase in generation also brought peak energy costs down in California. Diablo Canyon #2 (1102 MW) returned to full capacity on June 4th and San Onofre #3 (1080 MW) increased to 99% capacity up from 18% the previous week due to an electrical fire on February 3rd. Southwest peak prices declined by the largest amount falling by $80/MWh on June 5th, however, Palo Verde remained the highest price power in the West with prices ranging from $140 to $110/MWh. Even though hot weather returned to the Southwest, Western prices continued to fall through June 10th where day-ahead prices dropped to their lowest levels in over a year as regional supply continued to exceed demand.

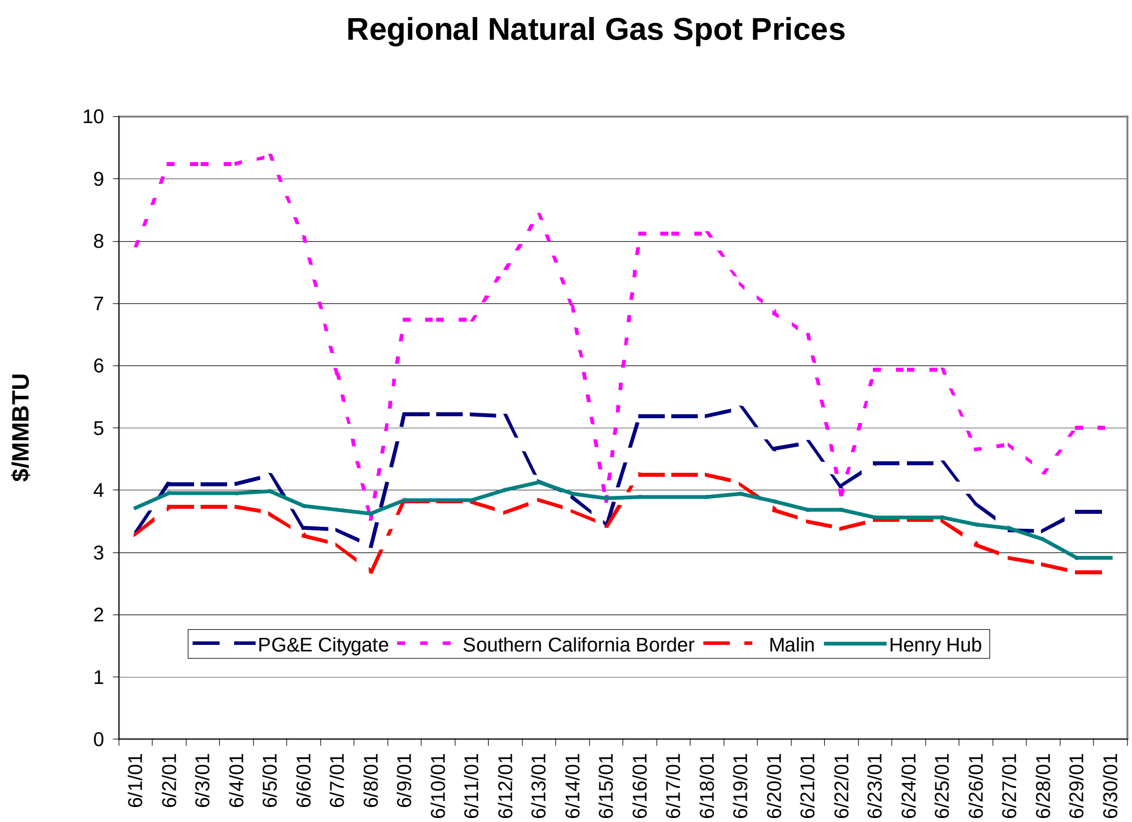
Generation supply increased due to stronger than expected Northwest hydro generation produced by early snowmelt. In mid-June, Grand Coulee reservoir was at 99% of full capacity. Although total precipitation in the Northwest remains at approximately 50% of normal, early runoff has increased recent supplies helping to avoid shortages. While the near term supply situation is improved, supply shortages could again become problematic when Northwest reservoir levels fall.

Prices increased significantly near the third week of June due to hotter temperatures in California and the Southwest and expectations of warming in the Northwest and Central Rockies. However, prices dropped on June 20th as the newly imposed FERC price controls went into effect. Peak load energy costs in the Northwest fell by $32/MWh while prices also fell sharply in the Southwest despite forecasted hot temperatures. Prices remained in the $50 to $60/MWh range through the end of June due in part to cooler temperatures for much of the West combined with lower natural gas prices.



California Natural Gas Prices

California natural gas prices continued to drop in June for all of the major trading hubs. Southern California Border prices continued to be volatile and increased and dropped in relation to electric load levels. PG&E was forced to issue a high-linepack operational flow order as supply outweighed demand causing prices to drop in the first week of June. SoCalGas also was forced to issue an Overnominations Day notice for June 23rd that caused prices to fall by more than $3/mmbtu. In the forward market, the bid week prices (for trades in the last week of June for July delivery) continued to decrease resulting in July bid week prices of $4.75, $3.24, and $3.82 for SoCalGas, PG&E, and Malin respectively.



VI. Performance of the Firm Transmission Rights Market in June 2001

FTR Concentration

There were no secondary FTR market trades in June 2001. Therefore, there was no change in the ownership concentration of FTR owners compared to those reported in the previous Director's Report.

FTR Scheduling

On most paths the FTRs have been primarily used for their financial entitlement to hedge against transmission usage charges. The relative volume of schedules with FTR priority attached for the period June 1-30, 2001 on all paths amounted to only 19% of the total available FTR volume, although on some paths the percentage was quite high (e.g., 100% on Silverpeak and 78% on Eldorado in the Import direction). The following table shows the paths on which FTRs were attached to schedules, along with related statistics for June 2001. Regarding specific paths with high FTR ownership concentration reported in previous Market Analysis Reports, namely, NOB (export direction) and Victorville (export direction), the FTR scheduling in June 2001 was insignificant to moderate.

Table 6

FTR Scheduling Statistics in May 2001

Branch Group	COI IMP	ELD IMP	IID-SCE IMP	MEAD IMP	PV IMP	SilvPk IMP	ELD EXP	MEAD EXP	PV EXP	P26 EXP	VictVI EXP
MW FTR Auctioned	600	707	600	487	1,819	10	626	456	796	1,727	296
Avg. MW FTR Scheduled	38	552	238	6.5	657	10	11	82	220	120	14
% FTR Scheduled	6%	78%	40%	1.3%	36%	100%	2%	18%	28%	7%	4.7%
Max MW FTR Scheduled	151	607	442	75	1,055	10	75	230	631	575	121
Max Single SC FTR Schedule	101	582	442	75	600	10	50	209	381	575	121

VII. Issues Under Review and Analysis

Support for FERC Settlement Conference and Hearings

DMA staff performed extensive analysis and testimony relating to the issue of refunds as part of the FERC Settlement Conference June 25-July 9. Analysis included estimates of the potential refunds that would result from a "formula rate" for determining refunds based on the difference between actual transaction costs and prices that would result under competitive market conditions. Analysis has also been performed under an alternative "rate formula" ultimately recommended by the Chief Administrative Law Judge presiding over the Settlement Conference, based on a benchmark price derived from maximum heat rates of units dispatched in the real time market, spot market gas prices, and a variety of other "adders". DMA is continuing to refine its analysis.

Monitoring and Reporting of Anti-Competitive Bidding Practices

DMA is currently submitting reports to FERC on a confidential basis pursuant the FERC's April 26 Order. The reports provide indices, analysis and data on scheduling, outage and bidding practices, and identify any concerns about possible inappropriate bidding behavior.

Investigation of Market Power and Potential Price Manipulation

DMA continues to collaborate with a variety of state and federal agencies conducting confidential investigations of potential market power abuses and price manipulation.

Implementation of Must-Offer and Recovery of Start-up and No-load costs

The FERC Order of June 19, 2001 (the Order) clarified, but does not significantly change, the must-offer obligation established in the April 26 Order. The must-offer obligation is applicable to all Participating Generators and all other entities that own or control one or more non-hydroelectric generating units, System Units or System Resources located in California from which Energy or capacity is either: (i) sold through any market operated by the ISO, or (ii) transmitted over the ISO Controlled Grid.

Thus, the Commission clarified in the Order that the must-offer obligation applies to:

- generating units included in Participating Generator Agreements;
- non-public utility generators in California selling in ISO markets or using the ISO's grid; and
- municipal and state utilities, and Qualifying Facilities to the extent that any of their generating units are under a PGA, sell into ISO markets or use the ISO Controlled Grid.

In the June 19 Order, the Commission also clarified that generation committed to serve native load customers in real-time and set aside to satisfy reserve requirements is exempted from the must-offer obligation.

The must-offer requirement raises an issue relating to units with long startup times (LST). There may be periods when certain LST units may not be economic in the sense that the expected energy prices over some commitment period (i.e. 1 or more days) are too low for the unit owner to recover all of its costs (start-up, no-load, marginal). During such periods, some unit owners have maintained that absent a guarantee from the ISO/CERS of full recovery of start-up, no-load costs, and minimum-load costs, they will not bring their units on-line.

While there are periods when not all thermal units are needed for a) reliability and b) for ensuring a competitive market, simply giving unit owners the discretion to decide which LST units are needed on-line and when would undermine the whole intent of FERC's must-offer requirement. The Commission clearly ordered the ISO to implement the must-offer obligation to mitigate against physical withholding of generation to improperly influence prices. In its compliance filing to the June 19 Order, the ISO committed to work with Market Participants to develop a solution to this issue as soon as possible. However, the ISO also made very clear that until such a time as the ISO identifies alternative treatment of such generating units (and, if necessary, the Commission approves any such proposal), all present Tariff provisions apply to such units. Therefore, all such generating units subject to the must-offer obligation, including those with long start-up times, are obligated to submit bids in the ISO's real-time Energy market in every hour in which such units both have Available Generation and are, in fact, capable of operating, whether or not Energy associated with such units' minimum output has been scheduled.

DMA, together with others at the ISO, is currently working with Market Participants to determine a proposed accommodation for units with long start-up times.

Bid Insufficiency in the Regulation Market

The ISO has been facing a shortage of Regulation Reserve bids in recent months. There are two basic reasons for this shortage. First, the ISO's need for Regulation has increased due to forward scheduling practices involving out-of-market purchases of blocks of energy at a constant level over several hours. This increases the need for inter-hour "load following" (that ISO performs by relying primarily on AGC units) during the hours of inrush and exit of these schedules. Second, the IOUs who are the predominant suppliers of Regulation have reduced their participation in the Regulation market due to their insolvency. They prefer to use their available generation capacity to schedule against their own load rather than bid it in the Regulation Up market (and increase their own underscheduling penalty). They also prefer not to participate in the Regulation Down market in order to avoid uninstructed deviation charges associated with decremental energy dispatched from Regulation Down capacity. In fact, the current payment mechanism for Regulation energy (i.e., paying it as uninstructed deviation) creates some risk for all providers of Regulation.

DMA is collaborating in devising alternative payment options for Regulation Energy to reduce the risks associated with the current payment mechanism (including contractual arrangements with Regulation providers). In addition, the ISO is working with CDWR to refine scheduling practices to reduce the need for large amounts of Regulation.