Memorandum

To: ISO Board of Governors

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

cc: ISO Officers, ISO Board Assistants

Date: September 13, 2002

Re: Market Analysis Report for July and August, 2002

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

Executive Summary

July 2002 was characterized by high loads due to extreme high temperatures and multiple changes in the price cap in the ISO markets, followed by a relatively mild August. During the heat wave of July 8-11, supply conditions reached near-critical levels. The monthly peak system load reached 42,352 megawatts (MW) in July, the highest since the crisis period of August 2000, but retreated to 40,771 MW in August 2002. In spite of this unusually high load, the average total cost of energy and ancillary services (AS) increased only modestly to $44 per megawatt-hour (MWh) in July, and retreated to $43/MWh in August, as utilities continue to serve load under long-term contracts procured by the California Department of Water Resources (CDWR) on their behalf. Market-clearing prices for incremental (INC) and decremental (DEC) energy in the ISO's real-time Balancing Energy Ex-Post Price Auction (the BEEP Stack) averaged $51.40 and $8.90/MWh in July, and $46.72 and $9.94/MWh in August. Congestion costs remained high in July, as transmission path deratings, primarily due to technical constraints, continued to constrict flows from the Pacific Northwest into California and the Southwest. By August, these congestion costs abated substantially.

I. Energy Market Statistics

Loads. ISO loads totaled 22,079 gigawatt-hours (GWh) and 21,616 GWh in July and August, respectively. Monthly average loads were 29,676 MW and 29,054 MW, respectively. In comparison, loads averaged 26,959 MW and 27,879 MW in July and August 2001, respectively, and 27,358 MW in June 2002. The peak load in July reached 42,352 MW, 5.25 percent higher than the peak load of July 2001. The peak load dropped significantly in August to 40,771 MW, which was 0.9 percent lower than the August 2001 peak.[1]

Conservation. The California Energy Commission (CEC) estimates conservation as the change in monthly peak load, adjusted for growth and weather conditions. The CEC reports that adjusted monthly peak loads in July were 8.8 percent above the peak for the same months in 2001, but were 2.8 percent lower than the July 2000 peak. In comparison, the peak for June 2002 was 3.3 percent above the June 2001 peak, and 11.2 percent below June 2000. The substantial difference between the June and July 2002 indices suggests that conservation has begun to wane, particularly on days with peak temperatures. Moreover, PG&E recently reported that in 2001, residential usage among its customers declined by 11 percent compared to 2000. This year, power usage was down just 4.4 percent compared with the same period two years ago. The CEC had not published the August conservation numbers at the time of this writing.

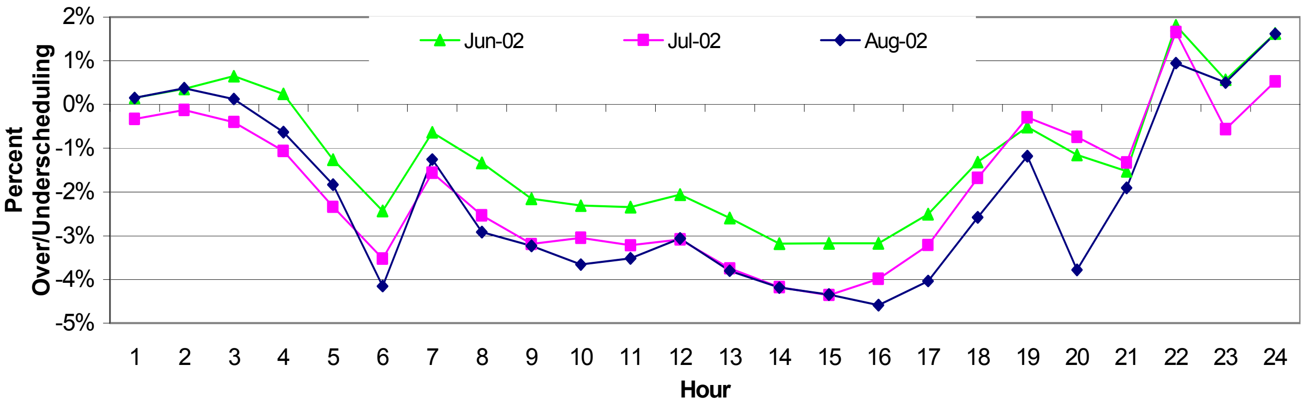
Real-Time BEEP Prices and Volumes. In July, prices for incremental (INC) balancing energy, which the ISO procures when the volume of generation scheduled is not sufficient to meet actual load, were similar to those seen in June. In August, the average INC price declined somewhat. The average price for decremental (DEC) balancing energy, which generators pay to the ISO for the privilege of decreasing output during periods in which scheduled generation exceeds actual load, reached its highest level in several months in July, and remained high in August leading to lower real-time energy costs. All other factors equal, lower INC prices and higher DEC prices both result in lower total costs to load.

The overall average real-time prices for INC and DEC balancing energy in July were $51.40 and $8.90/MWh, respectively. INC and DEC prices in August were $46.72 and $9.94/MWh, respectively. In comparison, INC and DEC prices in June were $51.90 and $3.41/MWh, respectively.

INC and DEC volumes were 227 and 205 GWh in July, and 196 and 174 GWh in August, respectively. Real-time INC volume increased 16 percent in July over the level seen in June, as under-scheduling during peak afternoon hours was between 4 and 5 percent. Meanwhile, real-time DEC volume was 19 percent below the level seen in June, due to improved accuracy in scheduling during off-peak hours. Both real-time INC and DEC volume in August were slightly reduced compared to July. The chart below compares hour-of-day average deviations of schedules from actual load in June, July and August.

[1] SMUD loads are excluded from current and historical figures.

Figure 1. Scheduling Deviations for June, July, and August 2002



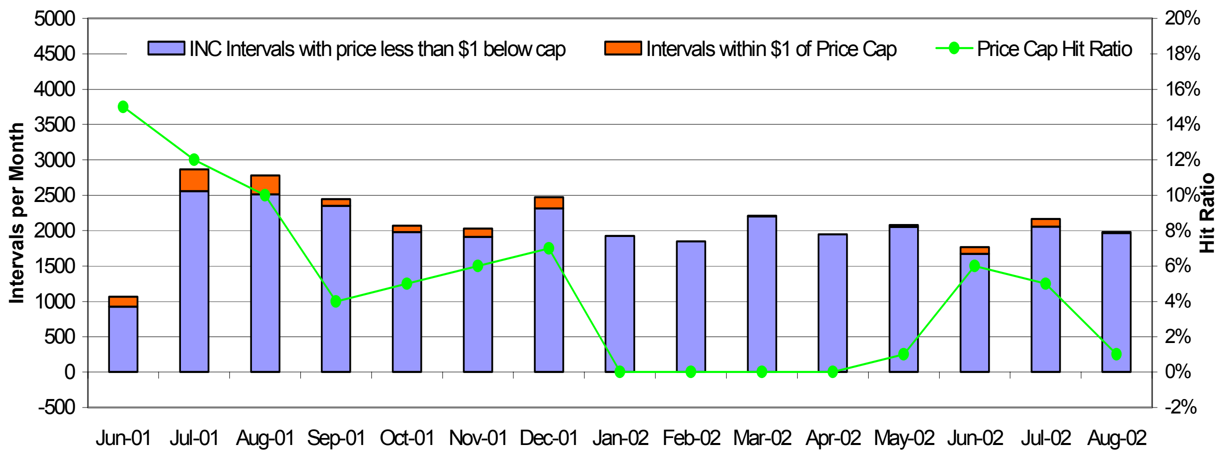
Price Cap Changes. Pursuant to Orders by the Federal Energy Regulatory Commission of June 19, 2001, and May 15, 2002, the mitigated market clearing price (the "soft price cap") on energy transacted through the BEEP Stack changed three times in July due to operating reserve deficiency conditions. The following table shows the four pricing regimes.

Table 1. Price Cap Regimes in July and August 2002

From	Until	Price Cap ($/MWh)	Notes
4/30/2002	7/9/2002 HE 20:00	$91.87	Original cap per FERC Orders of 6/19/2001 and 12/19/2001. Change per FERC Order of 5/15/2002.
7/9/2002 HE 20:00	7/10/2002 HE 20:00	$57.14	Change per FERC Order of 5/15/2002. Following 7% deficiency for full operating hour.
7/10/2002 HE 20:00	7/12/2002 HE 1:00	$55.26	Change per FERC Order of 5/15/2002. Following 7% deficiency for full operating hour.
7/11/2002 HE 1:00	9/30/2002	$91.87	Change per FERC Order of 7/11/2002. $91.87 Cap to be used regardless of deficiencies through 9/30/2002.

Price Cap Hits. The ISO monitors the frequency with which the BEEP MCP comes within $1 of the current soft price cap (in this analysis, anytime the MCP comes within $1 of the price cap, it is categorized as a price cap "hit"). Most hits in July occurred during the hot afternoons of July 9 through 12, although some occurred during late evening hours on July 9 and 10, during which the soft price cap had been lowered. The MCP came within $1 of the price cap or exceeded it in 109 of 2066 ten-minute intervals (5 percent) in which the ISO procured incremental energy in NP15, and also in 109 of 2058 such intervals (5 percent) in SP15. All hits in July occurred during the extreme peak load days of July 9-13. In August, the MCP came within $1 of the price cap or exceeded it in 15 of 2168 intervals (less than 1 Percent) in NP15, and in 15 of 1963 intervals (less than 1 Percent) in SP15. The following chart shows monthly price cap hits in SP15 since June 20, 2001.

Figure 2. Price Cap Hits in SP15 by Month



As-Bid Procurement. The ISO procured as-bid energy on July 10 and 11, during the two brief reductions in the soft price cap. On July 9, HE 21:00, and on July 10, HE 10:00 through 14:00 and HE 19:00, the ISO procured approximately 1417 MW above the new price cap. After the second price cap change, the ISO procured a total of approximately 177 MWh on July 10, HE 24:00, and on July 11, HE 16:00 through 18:00. All of these as-bid procurements were at prices below $91.87, the price cap that existed prior to July 10 and after July 11. The total cost of all as-bid procurement in July was approximately $108,600, at an average price of approximately $68/MWh. The ISO did not procure any as-bid energy in August.

Real-Time OOM Procurement. Because the volume of bids into the BEEP Stack was not always sufficient to balance generation with load, ISO operators resorted to OOM calls in certain hours in July. The ISO procured 1,173 MWh and 2,113 MWh of incremental energy, respectively, during eight (8) deficiency hours on the afternoons of July 9 and 10. In addition, the ISO procured 120 MWh of incremental energy on July 1, HE 16:00. In two hours on the afternoon of August 10, the ISO procured 700 MWh of incremental energy.

As has been the case in recent months, ISO operators made decremental OOM calls during seven (7) morning ramp and overnight hours totaling 1,575 MWh, on July 5, 6, 8, 15, and 21. As noted previously, decremental OOM volume has decreased significantly since June. The ISO did not procure decremental OOM energy at all in August.

Figure 3a. ISO Real-Time Prices and Volumes July 2002

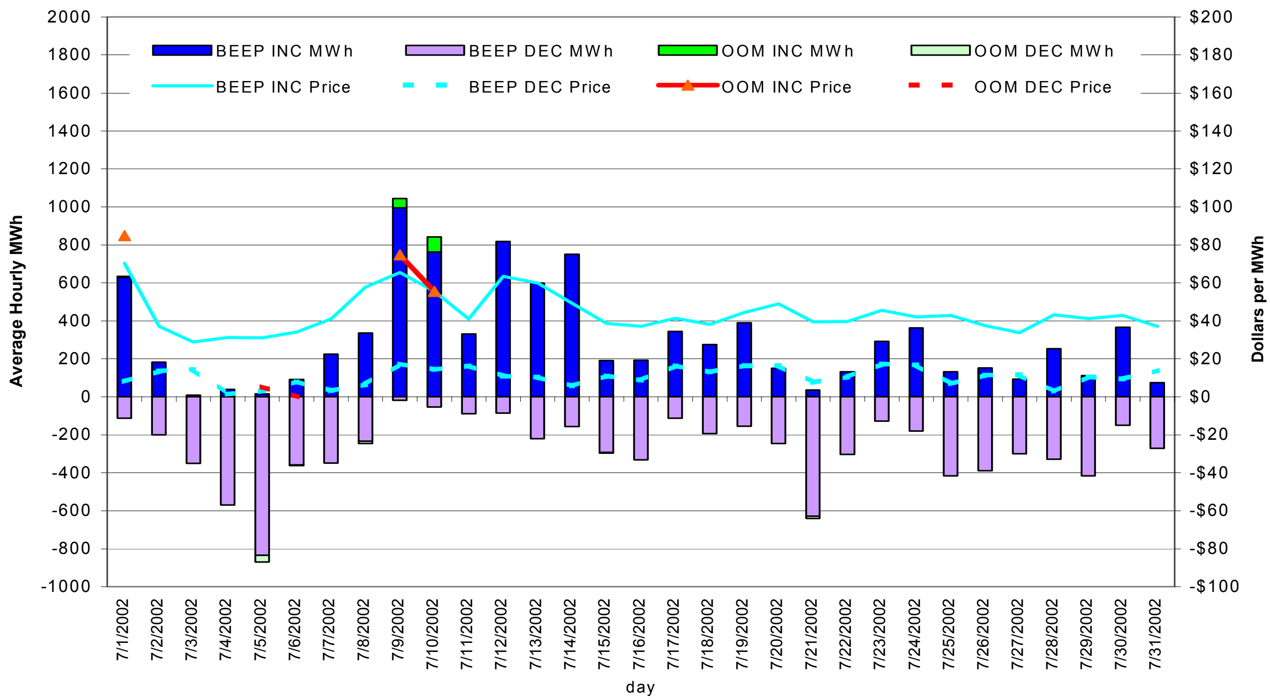
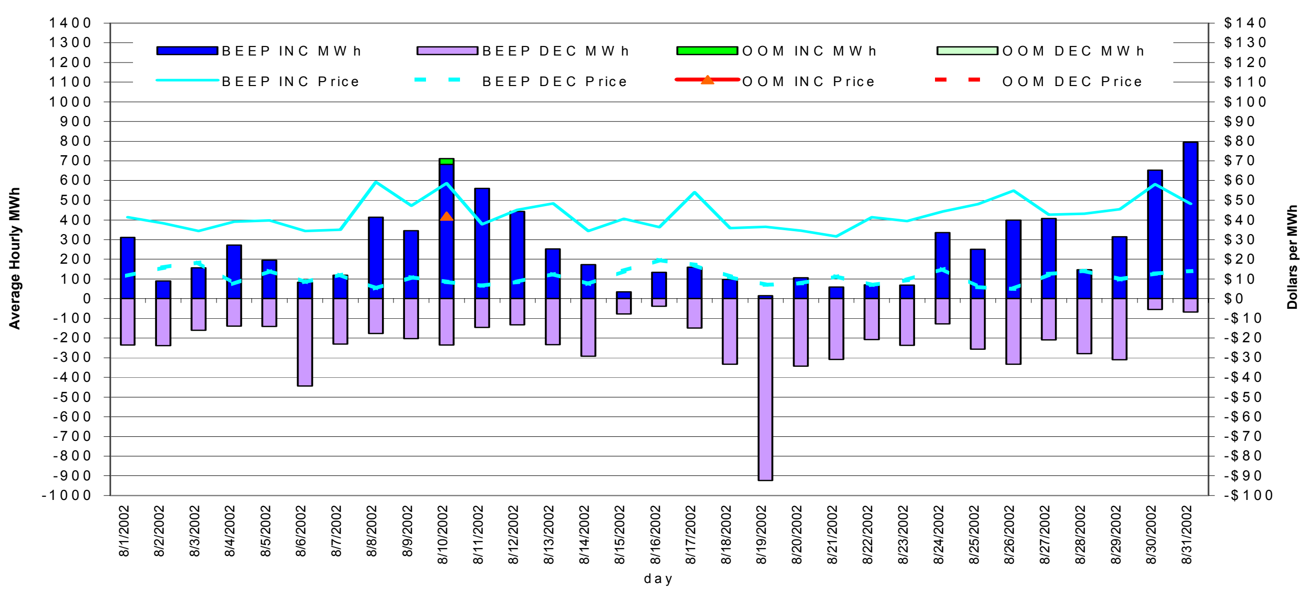


Figure 3b. ISO Real-Time Prices and Volumes August 2002



The ISO monitors key price and volume statistics for real-time energy transactions. The following tables show (1) average prices and total volumes for real-time energy procured through the BEEP

Stack. Also shown are (2) average OOM prices and volumes. The combination of (1) and (2) comprise (3) average real-time prices and total volumes of all real-time balancing energy. The final column (4) shows average system loads and percent underscheduling.

Table 2a. Real-Time Energy Statistics for July 2002

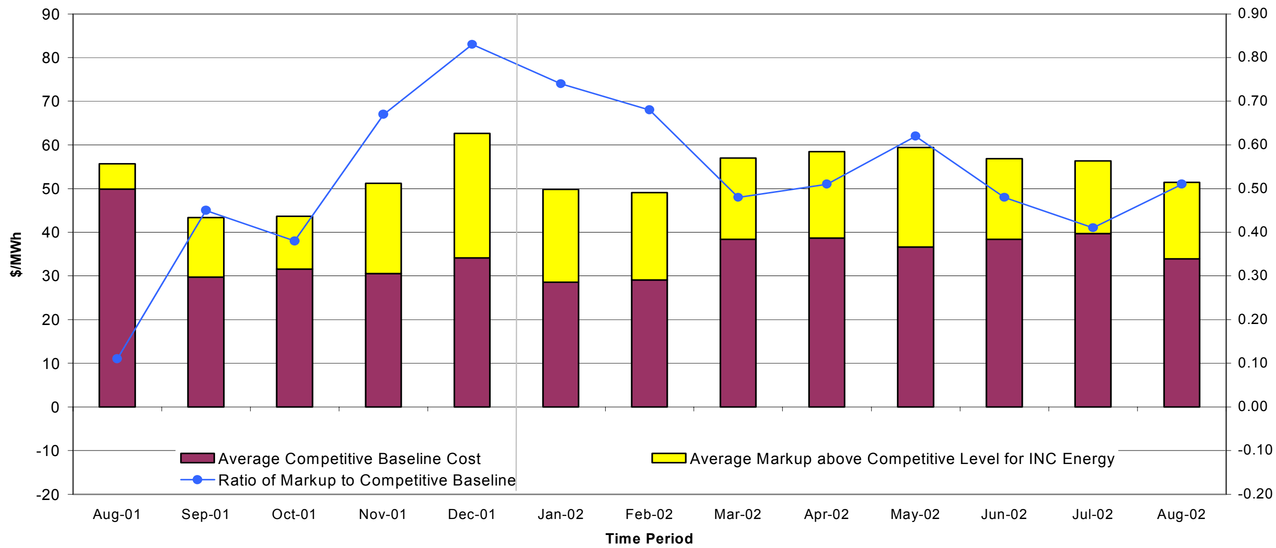
	Avg. BEEP Price and Total Volume (1)		Avg. Out-of-Market Price and Total Volume (2)		Overall Avg. Real-Time Price and Total Volume (3)		Avg. System Loads (MW) and Pct. Underscheduling (4)
	Inc	Dec	Inc	Dec	Inc	Dec	
Peak	$ 53.79	$ 12.18	$ 63.42	$ 4.80	$ 53.96	$ 12.13	32,360 MW
	189 GWh	135 GWh	3 GWh	*	192 GWh	136 GWh	3%
Off-Peak	$ 37.47	$ 2.58	No Procurement	$ 1.35	$ 37.47	$ 2.57	24,307 MW
	35 GWh	69 GWh	*	*	35 GWh	69 GWh	2%
All Hours	$ 51.22	$ 8.94	$ 63.42	$ 3.39	$ 51.40	$ 8.90	29,676 MW
	224 GWh	203 GWh	3 GWh	2 GWh	227 GWh	205 GWh	3%

Table 2b. Real-Time Energy Statistics for August 2002

	Avg. BEEP Price and Total Volume (1)		Avg. Out-of-Market Price and Total Volume (2)		Overall Avg. Real-Time Price and Total Volume (3)		Avg. System Loads (MW) and Pct. Underscheduling (4)
	Inc	Dec	Inc	Dec	Inc	Dec	
Peak	$47.87	$13.98	$42.00	No Procurement	$47.85	$13.98	31,658 MW
	171 GWh	94 GWh	*	*	171 GWh	94 GWh	4%
Off-Peak	$38.98	$5.25	No Procurement	No Procurement	$38.98	$5.25	23,731 MW
	25 GWh	81 GWh	*	*	25 GWh	81 GWh	1%
All Hours	$46.74	$9.94	$42.00	No Procurement	$46.72	$9.94	29,054 MW
	196 GWh	174 GWh	*	*	196 GWh	174 GWh	3%

Market Power. Market power is often measured by comparing the price paid for energy to an estimate of the price that would exist under competitive conditions. The Department of Market Analysis (DMA) tracks several such indices, one such index is the price-to-cost markup for real-time energy. The index is calculated as the ratio of the markup of prices in California's real-time 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 chart shows the price-to-cost markup in real-time energy since August 2001. Price-to-cost markup has been stable in recent months due to adequate supply conditions. Short-term indices which include DA, HA, and real-time energy cost were not included due to unavailability of data on CERS purchases.

Figure 4. Price-to-Cost Markup in Real-time Energy



II. Ancillary Services

The ISO monitors AS prices and volumes by type and market. Costs for AS rose to $23 million in July, or an average of $1.04 per MWh of load, up from $20 million in June, as load has increased significantly over the past several months. In August, costs declined significantly to $12 million, or an average of $0.55/MWh of load due to significantly lower load levels in August. Average day-ahead prices for Upward and Downward Regulation services moderated somewhat, averaging $14.95 and $16.58/MWh in July, and $10.32 and $11.69/MWh in August, respectively, compared with $16.22 and $18.27/MWh in June. Average day-ahead prices for Spinning and Non-Spinning Reserves had increased substantially in the last few months but were back down in August. Spin and Non-Spin averaged $10.82 and $6.50/MWh in July and $5.06 and $2.77/MWh in August, respectively, compared with $6.61 and $3.88/MWh in June. The average day-ahead price for Replacement services continued to rise well above normal levels at $3.21 in July, but retreated to $1.01/MWh in August, compared with $2.93/MWh in June.

Table 3a. AS Prices and Volumes by Market for July 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	$14.95	$14.47	$14.93	413	19	95%
Regulation Down	$16.58	$14.79	$16.45	435	35	92%
Spin	$10.82	$8.34	$10.70	886	43	95%
Non-Spin	$6.50	$7.50	$6.52	854	22	97%
Replacement	$3.21	$1.94	$3.15	44	2	94%

Table 3b. AS Prices and Volumes by Market for August 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	$10.32	$9.81	$10.30	384	23	94%
Regulation Down	$11.69	$9.47	$11.52	413	34	92%
Spin	$5.06	$3.84	$5.03	826	26	96%
Non-Spin	$3.01	$2.51	$2.76	837	22	97%
Replacement	$1.01	$0.81	$1.00	36	3	91%

Figure 5 shows A/S cost as percentage of total energy. By this measure, the A/S market continues to outperform previous years.

Figure 5: 2002 A/S Cost as Percentage of Total Energy

III. Interzonal Congestion

Fires continued to sweep across California and neighboring areas in the Western interconnection in July, often physically near transmission lines, resulting in deratings and curtailments of transmission from the Northwest into California. In addition, flows in Oregon caused other technical constraints on transmission. North-to-South congestion on Path 26, which totaled over $4 million in July occurred predominantly on two days, July 16th and 31st, when high loads combined with significant exports from SP15 to the Southwest. Due to the large volume of flows over paths such as COI and Path 26, significant congestion costs often occur whenever these paths are congested. Consequently, congestion costs continued their sharp upward trend of the last few months, totaling approximately $11.8 million in July, compared with $10.3 million in June. However, these costs largely dissipated in August, totaling only $1.1 million. As in June, import schedules from the Pacific Northwest and into Los Angeles borne a significant portion of these costs. The chart below shows total congestion costs through July and August. The following tables show day-ahead congestion frequencies and prices, and total day-ahead and hour-ahead congestion costs.

Table 3a. Day-Ahead Interzonal Congestion Frequencies and Prices And Total Congestion Costs for July 2002

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)
CASCADE	Import	3%	0%	2%	$ 14.65		$ 14.65	$ 68,399
COI	Import	60%	19%	47%	$ 12.50	$ 8.69	$ 12.06	$5,000,826
ELDORADO	Import	0%	0%	0%				$ 7,695
NOB	Import	87%	20%	65%	$ 0.94	$ 0.01	$ 0.84	$ 728,385
PALO VERDE	Import	0%	0%	0%				$ 334
PARKER	Import	0%	0%	0%				$ 1,951
PATH 15	South-to-North	0%	4%	1%		$ 0	$ 0	$ 14,551
SYLMAR-AC	Import	0%	0%	0%				$ 29,196
MCCULLOUGH	Export	9%	0%	6%	$122.47		$122.47	$1,397,391
MEAD	Export	1%	0%	1%	$ 28.27		$ 28.27	$ 156,942
PARKER	Export	0%	0%	0%				$ 361
PATH 26	North-to-South	14%	0%	9%	$ 23.78		$ 23.78	$4,104,102
SUMMIT	Export	2%	0%	1%	$245.00		$245.00	$ 318,601
Total Costs								**$11.8 million**

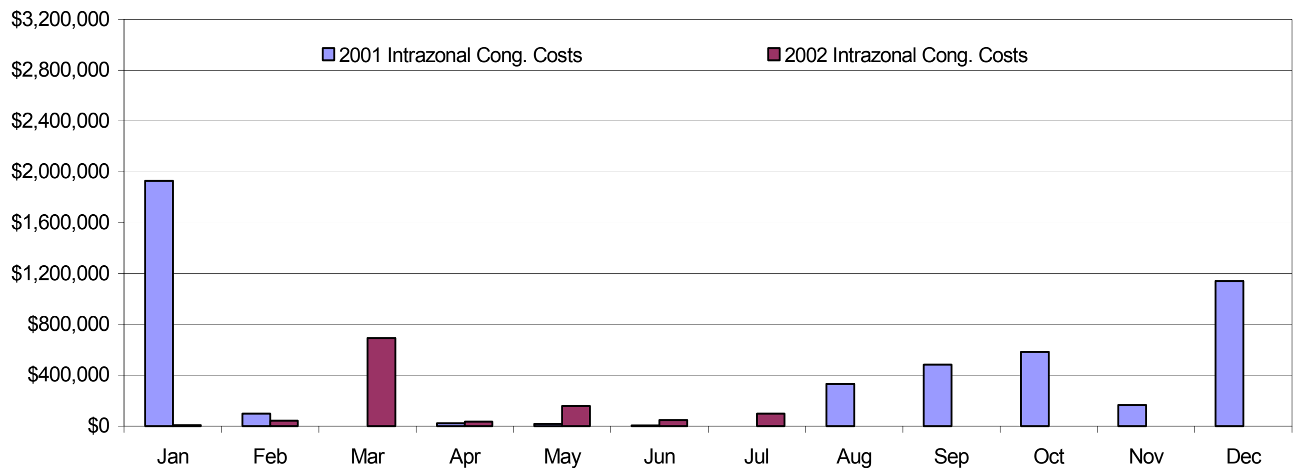
Table 3b. Day-Ahead Interzonal Congestion Frequencies and Prices And Total Congestion Costs for August 2002

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)
CASCADE	Import	0%	0%	0%				$ 5,153
COI	Import	59%	2%	40%	$ 1.51	$ 3.50	$ 1.54	$ 689,320
PATH15	South-to-North	1%	18%	7%	$ 0.00	$ 0.00	$ 0.00	$ 30,824
PATH26	South-to-North	0%	0%	0%	$ 0.02		$ 0.02	$ 25
SYLMAR-AC	Import	0%	0%	0%				$ 34,927
Total Costs								**$ 1.1 million**

IV. Intrazonal Congestion

Intrazonal congestion, exclusive of reliability must-run (RMR) costs, has remained moderate since April 2002. In July, intrazonal costs totaled approximately $97,000, compared with $47,000 in June. Intrazonal costs were only $4,833 in August.

Figure 6. Intrazonal Congestion Costs (Excluding RMR Costs) in 2001 and 2002



V. Summary of Market Costs

DMA estimates that total wholesale cost to load for energy and ancillary services totaled $933 million in July, or an average of approximately $44/MWh, compared with $40/MWh in June. Total cost in August was $922 million, or an average of $43/MWh. With the exception of a small number of peak days in June and July, loads have been relatively manageable. In addition, continued strong hydroelectric conditions in the Northwest have helped to keep market costs stable. The following tables show costs for wholesale energy and AS for 2002 to date, including actuals from the California Department of Water Resources' California Energy Resources Scheduling Division (CERS) through June, and estimates of bilateral purchases at day-ahead hub prices. CERS costs for July and August are estimates; actuals for these months are expected to be available in the October report, to be released in November.

Table 4a. Energy Cost Summary for 2002

	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
May-02	19,690	19,031	$ 774	$ 11	$ 15	$ 786	$ 801	$ 40	$ 0.78	2.0%	$ 41
Jun-02	20,232	19,691	$ 786	$ 10	$ 20	$ 796	$ 816	$ 39	$ 0.97	2.5%	$ 40
Jul-02	22,079	21,319	$ 931	$ 11	$ 23	$ 942	$ 965	$ 43	$ 1.04	2.4%	$ 44
Aug-02	21,588	20,798	$ 914	$ 8	$ 12	$ 922	$ 935	$ 43	$ 0.58	1.3%	$ 43
Total 2002	157,358	152,652	$ 6,358	$ 69	$ 123	$6,427	$ 6,550				
Avg 2002	19,670	19,082	$ 795	$ 9	$ 15	$ 803	$ 819	$ 41	$ 0.78	1.9%	$ 42

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

Table 4b. Energy Cost Summary for 2001 and Earlier

	ISO Load (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)
Total 2001	227,024	$ 21,248	$ 4,162	$ 1,346.09	$ 25,409.97	$ 26,756				
Avg 2001	18,919	$ 1,771	$ 347	$ 112	$ 2,117	$ 2,230	$ 115	$ 6.07	5.3%	$ 118
Total 2000	237,543	$ 22,890	$ 2,877	$ 1,720	$ 25,373	$ 27,083				
Avg 2000	19,795	$ 1,907	$ 240	$ 143	$ 2,114	$ 2,257	$ 107	$ 7.24	6.8%	$ 114
Total 1999	227,533	$ 6,848	$ 180	$ 404	$ 7,028	$ 7,432				
Avg 1999	18,961	$ 571	$ 15	$ 34	$ 586	$ 619	$ 31	$ 1.78	5.7%	$ 33
1998 (9mo)	169,239	$ 4,704	$ 209	$ 638	$ 4,913	$ 5,551				
Avg 1998	18,804	$ 523	$ 23	$ 71	$ 546	$ 617	$ 29	$ 3.77	13.0%	$ 33

1998-2000:
* Forward costs include estimated PX and bilateral energy costs.
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.
2001 only:
* Sum of hour-ahead scheduled costs. 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

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

VI. Firm Transmission Rights

FTR scheduling. FTRs were used on some paths for their scheduling priority feature in the day-ahead markets. As shown in the following table, a large proportion of FTRs was scheduled on certain paths (e.g. 84% on Eldorado, 72% on IID-SCE, 51% on Palo Verde, and 97% on Silver Peak in July, all in the import direction; and 71% on Eldorado, 70% on IID-SCE, 54% on Palo Verde, and 97% on Silver Peak in August, also all in the import direction). Most FTRs used for scheduling priority on Eldorado, IID-SCE, Palo Verde, and Silver Peak are held by Southern California Edison Company (SCE1).

FTRs on other paths were used chiefly to collect transmission usage charges. FTR concentration levels do not appear to raise concerns of market manipulation at the present time.

Table 5a. Transmission Usage Statistics for July

Branch Group	Direction	MW FTR Auctioned	Avg. MW FTR Sch.	Max MW FTR Sch.	Max Single SC FTR Schedule	% of FTR Scheduled
COI	Import	658	145	225	175	22%
ELDORADO	Import	793	666	700	700	84%
IID-SCE	Import	600	434	442	442	72%
MEAD	Import	478	8	95	75	2%
NOB	Import	698	80	162	100	11%
PALO VERDE	Import	1167	592	707	579	51%
SILVER PEAK	Import	10	10	10	10	97%
VICTORVILLE	Import	926	10	11	11	1%
ELDORADO	Export	702	28	125	125	4%
MEAD	Export	456	138	363	173	30%
PALO VERDE	Export	601	121	475	250	20%
PATH 26	North-to-South	1566	191	623	519	12%

Table 5b. Transmission Usage Statistics for August

Branch Group	Direction	MW FTR Auctioned	Avg. MW FTR Sch.	Max MW FTR Sch.	Max Single SC FTR Schedule	% of FTR Scheduled
COI	Import	658	114	200	150	17%
ELDORADO	Import	793	564	700	700	71%
IID-SCE	Import	600	421	441	441	70%
MEAD	Import	478	13	112	100	3%
NOB	Import	698	45	81	75	6%
PALO VERDE	Import	1167	629	804	579	54%
SILVER PEAK	Import	10	10	10	10	97%
VICTORVILLE	Import	926	10	12	12	1%
ELDORADO	Export	702	8	75	75	1%
MEAD	Export	456	123	348	173	27%
PALO VERDE	Export	601	46	345	250	8%
PATH 26	North-to-South	1566	402	965	519	26%

FTR Revenue per Megawatt. The following table summarizes FTR revenue per MW through August in the current FTR cycle. FTR revenue remained relatively high on COI in the import direction, totaling $4,278/MW in July but was significantly reduced to $581/MW in August. Revenue was significantly higher in July than previous months on Path 26 in the export direction, due primarily to the increase in congestion frequency on the path in the North-to-South direction. However, revenue on Path 26 in August was back to the normal range.

Table 6. Revenue Per MW in the 2002-2003 FTR Cycle

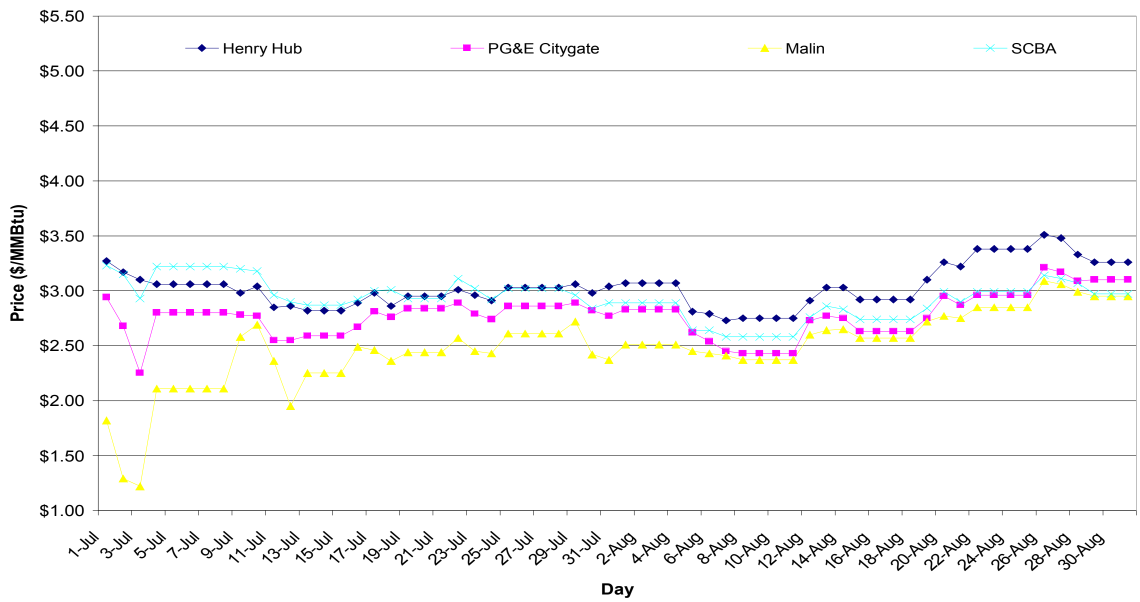
Branch Group	Direction	April	May	June	July	August
COI	Import	$1088	$888	$4129	$4278	$581
ELDORADO	Import	$268	$26	$2	$10	$0
MEAD	Import	$19	$22	$0	$0	$0
NOB	Import	$13	$0	$48	$472	$14
PALO VERDE	Import	$23	$839	$0	$0	$4
PATH 26	South-to-North	$0	$133	$370	$0	$0
MEAD	Export	$0	$0	$0	$262	$31
PATH 26	North-to-South	$61	$134	$125	$1703	$116
VICTORVILLE	Export	$0	$249	$724	$0	$0

VII. Natural Gas Markets

With the exception of the Pacific Northwest where natural gas prices were low due to plentiful hydroelectric energy, natural gas prices in California remained moderate around $3.00/MMbtu throughout most of July, owing to significant cooling demand brought on by high temperatures throughout much of the West. Between July 1 and July 11 Southern California Border Average prices ranged between $3.00 and $3.35/MMBtu, while PG&E Citygate prices ranged from $2.50 to $3.00, excluding the price drop on July 3. California natural gas prices continue to track closely to Henry Hub prices which are often used as a national benchmark. Malin prices, however, due to plentiful hydroelectric energy and subsequent reduced gas-fired generation demand, were quite low, ranging between $1.00 and $2.10, with the exception of July 9 through 11, where high electricity load conditions resulted in high demand for natural gas. Improved natural gas supply conditions and abating heat in the West caused Southern California Border and PG&E Citygate prices to return to the $2.50 to $3.00/MMBtu level between July 11 to July 17. Malin prices returned to the $2.00 to $2.50/MMBtu range. Prices in the latter half of July remained essentially flat to slightly increasing; however, as the hydroelectric energy supply abated and demand for gas-fired generation increased, Malin prices increased to the $2.50/MMBtu level. Average bid week prices for August were $2.92, $2.48, and $2.74 for SoCal Gas, Malin, and PG&E Citygate, respectively, down 11%, 5%, and 5% from July bid week prices.

Milder temperatures in the West caused prices to range between $2.45 and $2.80/MMBtu between August 3 and August 11. As temperatures increased after August 11, prices increased to the $2.50 to $3.00/MMBtu range between August 12 and August 18. Concerns on storage levels and increased cooling demand attributable to temperatures in excess of 100° F between August 23 and 27 throughout the West caused prices to increase to between $2.80 and $3.20/MMBtu, with Henry Hub prices reaching $3.50/MMBtu on 25 August. Average bid week prices for September were $3.12, $2.93, and $3.14 for SoCal Gas, Malin, and PG&E Citygate, respectively, up 6%, 18%, 15% from August bid week prices.

Figure 7. Daily Gas Prices for July and August 2002

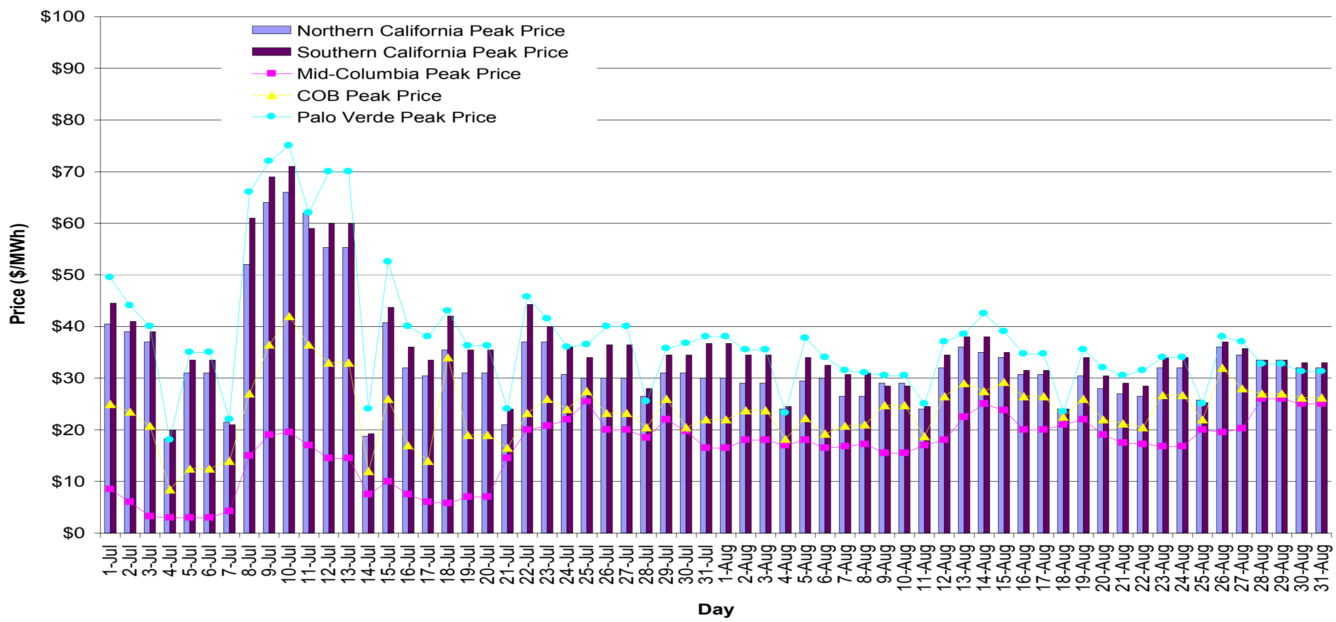


VIII. Regional Electricity Markets

With the exception of the sharp price increases from July 8 to July 13, regional day-ahead electricity prices were substantially flat, although somewhat higher in the southwestern U.S. Prices at the Mid-Columbia and the California-Oregon Border (COB) hubs were substantially lower than California and Palo Verde hub prices between July 1 and July 20, owing to a large supply of hydroelectric power from the Northwest and constrained transmission between the Northwest and California. Through much of July and August, transmission constraints were present on the California-Oregon Intertie (COI) and the Pacific DC Intertie (PDCI) due to resource limitations and fires in the Pacific Northwest. California and Palo Verde prices began July at between $40 and $50/MWh and decreased to between $30 and $35/MWh as temperatures cooled from the end of June. After July 8, however, a combination of increased cooling demand due to extremely hot weather in Arizona and California exceeding 110° F, unusually high levels of scheduled and forced unit outages in the West (Boardman (350 MW), Columbia Generating Station at 45% (1,115 MW)), and transmission deratings on the COI due to fires and unit outages in the Northwest caused California and Palo Verde prices to increase to the $60 to $75/MWh range, COB prices to increase to the $30 to $40/MWh range, and Mid-Columbia prices to increase to nearly $20/MWh. After July 13, Palo Verde prices decreased from $55/MWh to $35/MWh by July 20. COB prices spiked sharply to over $30/MWh on July 17, however, due to fires burning near COI, forcing a derating to 1000 MW from north to south. Forecasted increases in temperatures during the week of July 22 caused Palo Verde prices to increase from $35 to $46/MWh. The abundant supply of hydroelectric power from the Northwest also began to abate at this time, causing Mid-Columbia and COB prices to converge to the $20 to $35/MWh level from the $5 to $15/MWh level.

Mild temperatures in August resulted in substantially flat electricity prices. Palo Verde and California prices remained within the $30 to $40/MWh range, although Palo Verde prices increased past $40/MWh and California prices increased past $35/MWh on transitory hot weather in the Southwest during the second week of August. Mid-Columbia and COB prices remained within the $15 to $30/MWh range during August.

Figure 8. Daily Regional Day-Ahead Forward Electricity Prices for July and August 2002



IX. Long-Term Contracts

CERS has actively sought to renegotiate its long-term contracts for delivery of wholesale power that it had entered into in early 2001. Recently, CERS succeeded in renegotiating two more power purchase agreements.

X. Demand Response Program Development

The ISO is working to develop greater participation in its Participating Load Program (PLP), which enables loads to bid to be paid to curtail load, and offer to pay to increase load. Previously, only large pump loads managed by CDWR had participated in the program. However, as of July 1, The California Consumer Power and Conservation Financing Authority (also referred to as the California Power Authority, or CPA) has created the Demand Reserves Partnership Program (DRP), which allows several organizations to serve as “aggregators” of retail electric consumers. In periods of forecasted deficiency, these aggregators may then either contract with CERS to curtail load in exchange for an agreed payment in the day-ahead market, or participate in the ISO's PLP in real time. The CPA reports that participation in the DRP currently stands at 10 MW, and will increase to 240 MW (0.6 percent of peak load) by October 2002. For more information regarding the DRP, please see the CPA and DRP web sites at www.capowerauthority.ca.gov and www.caldrp.com.

XI. CPUC Order on Utilities' Net Short Obligations

On August 22, 2002, the California Public Utilities Commission (CPUC) voted to permit the three investor-owned utility companies (IOUs) to engage in multi-year contracting to cover substantial amounts of their residual net short obligations. The IOUs' net-short obligations consist of their loads that they are not able to meet through their retained generation. The IOUs net short resource requirements have been procured by CERS since early 2001. The order grants the IOUs the authority to enter immediately into multi-year contracts for terms of up to five years. Southern California Edison (SCE) and Pacific Gas and Electric (PG&E) may enter into the contracts directly, while continuing to use the credit of CDWR, until they regain investment-grade credit ratings. San Diego Gas and Electric (SDG&E) currently has an investment-grade credit rating, and thus already enters into contracts without CDWR backing. The decision grants the IOUs the authority to enter into the following types of contracts:

1) Capacity contracts;
2) Forward energy products;
3) Contracts arranging for the provision and delivery of gas or other physical commodities pursuant to or in support of capacity or energy product contracts;
4) Energy exchange contracts;
5) Financially settled hedging instruments.

The IOUs are to submit these contracts to the CPUC for approval through the advice letter process, subject to a 30-day procedural review and approval process. The IOUs will also be required to enter into long-term power purchase contracts with some qualifying facilities (small plants owned primarily by businesses for self-generation, which sell excess generation to the grid) already in their portfolios.

XII. Issues under Review

FERC Standard Market Design Notice of Proposed Rulemaking. DMA is contributing to the ISO's comment filing in response to FERC's Notice of Proposed Rulemaking (NOPR) on Standard Market Design and Structure (SMD), issued on July 31. In this NOPR, FERC is seeking comments in advance of a final rulemaking on standardization of unbundled electric markets. If the NOPR is ultimately adopted as a final rule by the Commission, all vertically integrated utilities in the United States subject to FERC jurisdiction will be required to move toward unbundled markets in the next two years and turn over the operation of transmission system to an independent transmission provider.

One issue on which DMA is providing input concerns FERC's proposed market monitoring reporting structure. Other topics include DMA's day-to-day reporting functions, as well as other policy positions, such as market power mitigation, and rules governing trading behavior.
DMA has also reviewed the SMD Supply Adequacy Requirement and compared it to the 2002 Market Design (MD02) Available Capacity Requirement (ACAP). The SMD imposes the requirement on load-serving entities, such as retail utilities, to procure generating resources in advance, using instruments such as long-term contracts, to ensure that resources are sufficient to meet load in real time. The obligation proposals are similar in principle to ACAP, but differ with respect to details, such as the time horizons of the requirements, and rules during the period of transition to the new adequacy requirement. The ISO will file comments with FERC in mid-October.

MD02 Implementation. DMA staff continue to support MD02 implementation. DMA participated in the MD02 stakeholder meetings of August 13, 14, and 15, 2002, sponsored by FERC, and is also participating in the four major stakeholder working groups formed to coordinate ISO and stakeholder issues in the final design and implementation of MD02. The four working groups and their primary sponsors are:

- Long-term Resource Adequacy (primary sponsor: State Inter-agency Working Group). This includes all the issues encompassed by the various resource adequacy proposals, addressing both system-wide and local reliability needs.
- Integrated Forward Markets (primary sponsor: investor-owned utilities). This includes day-ahead and hour-ahead markets, residual unit commitment (RUC), market monitoring, and market power mitigation.
- Locational Marginal Pricing/FTRs (primary sponsor: Municipal Utilities). This includes the full network model, nodal pricing, load aggregation, FTRs (referred to as Congestion Revenue Rights in SMD), , and market power mitigation in these markets.
- Interim Provisions (primary sponsors: Suppliers). This includes real-time economic dispatch, moving up the hour-ahead market time frame, near-term resource adequacy (must-offer obligation and interim RUC).

Development for Methodology of Evaluation of Transmission Expansion. Since September 2001, the ISO has retained the services of London Economics International LLC (LE) to develop a comprehensive methodology for evaluating the economic benefits of transmission investments. In January 2001, LE presented a draft final methodology paper to the ISO. It was determined that the methodology should be tested by applying it to the evaluation of proposed upgrades to Path 26. Over the past months, LE has made modifications to its methodology and has provided the CA ISO with various work papers and presentations of proposed methodology and its application to Path 26. DMA has reviewed these work products and worked closely with LE in their efforts to develop and test the methodology. DMA is working with LE to determine the changes needed to resolve concerns with the current methodology.

FERC Preliminary Report on Western Energy Markets. In August, the FERC Staff released an initial report on its Investigation of the Western Energy Market in response to the Commission's direction in February to gather information on whether any entity had manipulated short-term prices for electric energy or natural gas in the West, or otherwise exercised undue influence over wholesale electric prices since January 1, 2000, resulting in potentially unjust an unreasonable prices in long-term power sales contracts. The main findings of the Staff Report include:

- Staff recommended that the Commission initiate company-specific separate proceedings to investigate instances of misconduct for several companies: three Enron companies (Portland, Enron Power Marketing, Enron Capital and Trade Resources Corp.), El Paso Electric, and Avista;

- The trade press reported spot prices for natural gas at California delivery points were subject to manipulation and are not appropriate for use in computing the mitigated market-clearing price and subsequent refunds in the California refund proceeding. Instead, Staff recommended using basin prices plus the cost of transmission; and

- Many of the Enron trading strategies may have been attempts to manipulate prices and adversely affected the confidence of the markets far beyond their dollar impact on spot prices. Staff recommends that the Commission require all market-based rate tariffs include a specific prohibition against the deliberate submission of false information, or the omission of material information to the Commission or an independent system operator.