CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: Market Issues/ADR Committee

From: Anjali Sheffrin, Director of Market Analysis

CC: ISO Governing Board; ISO Officers

Date: October 17, 2000

Re: Market Analysis Report

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

This report summarizes key market conditions, developments, and trends for September 2000. It compares September's prices and total costs of procurement to last month as well as a year ago.

SEPTEMBER HIGHLIGHTS

- Normal temperature conditions for September meant lower energy and A/S prices compared to the previous three months. Average daily peaks reached nearly 35,000 MW, down from 39,000 MW in August. A hot week in the middle of the month meant the September monthly peak reached 43,069 MW, up 7.4% from September 1999, while total energy increased by 2.5%.

- The estimated total energy and A/S cost for September was about $2.597 billion, or about $126/MWh of load served, compared to about $4.168 billion ($180 per MWh of load served) in August and $.764 million ($38 per MWh of load served) in September 1999.

- The average constrained PX price for the month was $104/MWh, significantly less than the August 2000 average price of $142/MWh, but a 200% increase from the $34/MWh average in September 1999. Real time prices (SP15 & NP15) averaged $149/MWh, less than the August price of $175/MWh, but up 300% from September 1999.

- Average daily peak loads reached nearly 35,000 MW in September 2000, a 3% increase from the 34,000 MW level in September 1999. Loads exceeded the 40,000 MW level a total of 21hours during the month, compared to only 1 hour exceeding 40,000 MW in September 1999.

- September prices (weighted) in the ancillary service markets were generally lower compared to August, with regulation up prices declining by 15%, and spin/non-spin prices 65% lower.

- Ancillary service costs were $7.39 per MWh of load compared to the August cost of $12.18/MWh and the September 1999 cost of $1.52/MWh. Total A/S costs were about $152 million for September 2000, about 6.2% of the total wholesale energy costs, and down from the August rate of 7.3% .

- Daily natural gas spot prices continue be more than double the level of prices one year ago. Average daily spot prices for September for PG&E Citygate were $6.02/MMBtu versus $4.97/MMBtu in August. Daily spot prices for the Southern California Border averaged $6.04/MMBtu for September 2000 versus $5.35/MMBtu in

August.. Comparable spot prices a year ago, last September 1999, were $2.79/MMBtu for PG&E City gate and an average of $2.70/MMBtu for Southern California Border.

- Export congestion in the day ahead market decreased substantially in September while import congestion on the Southwest branch groups increased. Path 15 S-N congestion increased to a 59% rate and Path 26 N-S congestion decreased to a 5% rate, substantially less than last month's rate of 32%. Total congestion costs were $24 million, a decrease from the August value of $73 million.

KEY MARKET CONDITIONS FOR SEPTEMBER 2000

I. <u>California Wholesale Energy Markets</u>

- **Loads –** September loads continued the trend of significant increases over the previous twelve months. Monthly system energy loads totaled 20,620 GWh, a 2.5% increase over September 1999. September's peak load reached 43, 069 MW, a 7.4% increase over September 1999 levels, occurring at HE 16 on September 19. Daily peak loads averaged 34,907 MW, a 3% increase over September 1999. There were 21 hours in which loads exceeded 40,000 MW compared to only one hour in September 1999. For the entire summer of 2000, there were 166 hours with loads above 40,000 MW compared to the 1999 total of 57 hours.

- **Wholesale Energy Prices** – . System real time prices averaged $149/Mwh while constrained PX prices averaged about $104/MWh, roughly 300% and 200% increases, respectively, from September 1999 levels. Both market continue to experience high off-peak prices , averaging $71/MWh for the constrained PX energy market and $121/MWh for the ISO real time market.

  Substantial under-scheduling of both loads and generation in the day ahead market continued to place large incremental requirements on the real time market in September. The difference between actual loads and hour ahead schedules averaged nearly 2,000 MW for all peak period hours in September, increasing to about 7,000 MW for hours with loads above 40,000 MW. On average, the ISO required nearly 2,500 MW of incremental generation during peak hours and nearly 1,500 MW during off-peak hours.

  Significant real time congestion persisted on Path 15 in the S-N direction, occurring during 47% of all hours. This led to NP15 real time prices being substantially higher than SP15 prices, averaging $173/MWh versus $122/MWh in the south.

  Natural gas prices are significantly higher in September 1999. Average daily natural gas spot prices are up about 125% from a year ago, averaging above $6/MMBtu compared to $2.70/MMBtu last September.

- Peak period prices in the PX energy markets were slightly higher in SP15 than NP15, while off-peak prices were substantially higher in NP15. The ISO real time market experienced much higher prices in zone NP15 due to the significant real time congestion on Path 15 in the S-N direction. Table 1 lists energy prices by zone and period.

- The ISO real time market experienced 78 hours where the $250/MWh price cap was reached in either SP15 or NP15, and 140 hours with prices at or above the $248/MWh level. The significant majority of these price cap hits occurred during peak hours. When loads exceeded 40,000 MW, real-time prices were above the $248/MWh level. Constrained PX prices were at or near the price cap level for 19 hours during the month.

Table 1: Energy Price Summary for September 2000

	System Average	NP15	SP15	ZP26	Pct. Hours of Zonal Pricing
Real Time Price					
Peak	$162.89	$187.39	$138.38	$138.38	44%
Off-Peak	$121.08	$150.44	$ 91.72	$ 91.97	54%
Total	$148.95	$175.08	$122.83	$122.91	47%
PX Constrained					
Peak	$121.56	$119.90	$123.22	$119.19	47%
Off-Peak	$ 74.57	$ 86.25	$ 62.89	$ 62.89	97%
Total	$105.90	$108.69	$103.11	$100.43	64%

II. Ancillary Service Markets

Ancillary Service Prices

- The price cap was hit 27 times in the day ahead ancillary service markets during September, with the regulation down market having the highest count with twelve. The hour ahead market hit the cap 82 times, with 34 hits occurring in the replacement reserve market.
- The ISO procured most of its A/S requirements in the day-ahead market, with between 41% to 87% of A/S MW quantities procured in the day-ahead market. Table 2 below summarizes weighted average prices and quantity procurements for September 2000 in both the day-ahead and hour-ahead markets.
- Procurement of replacement reserve capacity was lower for the month due to the lower loads experienced during September. However, for hours with loads above 40,000 MW, the amount of replacement reserves procured ranged from 2,300 MW to 5,100 MW.
- Table 3 compares 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).

Table 2. Summary of Weighted Day-Ahead A/S Prices by Market – September 2000

	Day-Ahead Market (all hours)	Hour-Ahead Market	Quantity Weighted Price	Average Hourly MW Day Ahead	Average Hourly MW Hour Ahead	Percent Purchased in Day Ahead
Regulation Up	$118.30	$124.43	$119.11	560	86	87%
Regulation Down	$ 93.94	$ 81.06	$ 92.24	524	80	87%
Spin	$ 32.26	$ 27.61	$ 31.45	763	159	83%
Non-Spin	$ 13.05	$ 41.68	$ 17.49	857	157	84%
Replacement	$ 36.82	$ 62.87	$ 52.20	252	364	41%

Table 3. Summary of Weighted Day-Ahead A/S Prices by Zone and Period – September 2000

	NP15		SP15		Percent of Hours with
	Peak	**Off Peak**	**Peak**	**Off Peak**	**Zonal Procurement**
Regulation Up	$122.25	$115.63	$131.85	$ 98.50	15%
Regulation Down	$ 67.69	$114.06	$111.93	$138.43	12%
Spin	$ 30.83	$ 5.16	$60.00	$ 15.42	10%
Non-Spin	$ 15.68	$ 2.38	$ 21.28	$ 1.94	10%
Replacement	$ 33.96		$ 42.64		8%

Ancillary Service Costs

- A/S costs in September were $152 million compared to the August total of $282 million, a result of lower requirements and load conditions. September A/S costs were about 6% of total energy costs. Day ahead A/S prices in September were lower than August, with regulation up prices declining by 15%, spin/non-spin 65% lower, while regulation down prices increased 13% from August levels.

Month	Avg. Daily A/S Cost* (Millions)	Avg A/S Cost per MWh of System Load ($/MWh)	A/S % of Energy Costs
June	$14.533	$20.19	13.8%
July	$ 4.014	$ 5.71	5.1%
August	$ 9.097	$12.18	7.3%
September	**$ 5.077**	**$ 7.38**	**6.2%**

* Includes day-ahead and hour-ahead procurement costs including self-provided MW (valued at MCP)

Cost savings from A/S Redesign Changes continue to be significant. Rational buyer protocols and separate pricing of Reg Up/Reg Down have resulted in estimated savings of about $241 million since their implementation on August 17, 1999, which represents a saving of about 20% of total A/S costs for this time period.

III. <u>Cost of Out of Market Calls</u>

Figure 1 below presents an estimate of total monthly OOM (Out-Of-Market) calls made in response to general system shortages when all available market bids were exhausted. For September, 56,047 MWh were called out-of-market to meet system conditions at a cost of $13.9 million.

Figure 2 compares actual OOM costs incurred due to general system shortages when all available market bids were exhausted to what would have been the value of these OOM energy purchases at the ex-post price. Total OOM costs averaged $250/MWh, compared to a value of this energy of $248/MWh at real time price. These data show ISO's reliance on OOM purchase to meet real time demand remains high, compared with that of August. So far, ISO has been able to control the cost of OOM purchase by limiting the price of purchases to the real time market price cap.

Figure 1. Summary of Out-of-Market Purchases for General System Shortages

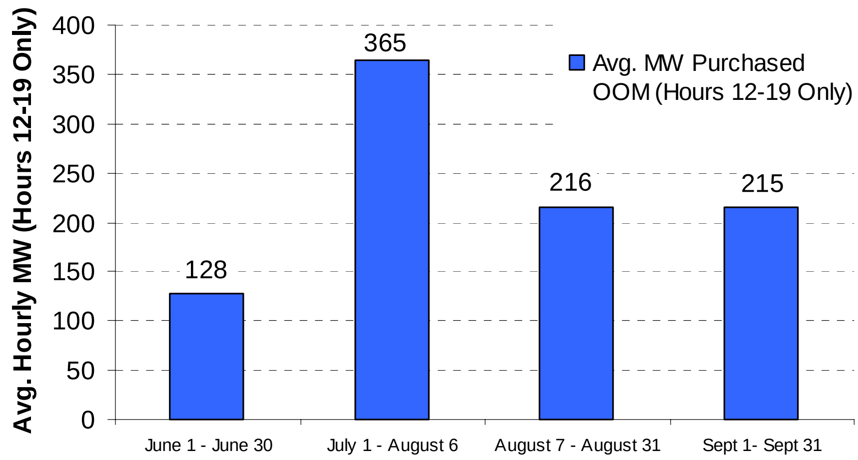
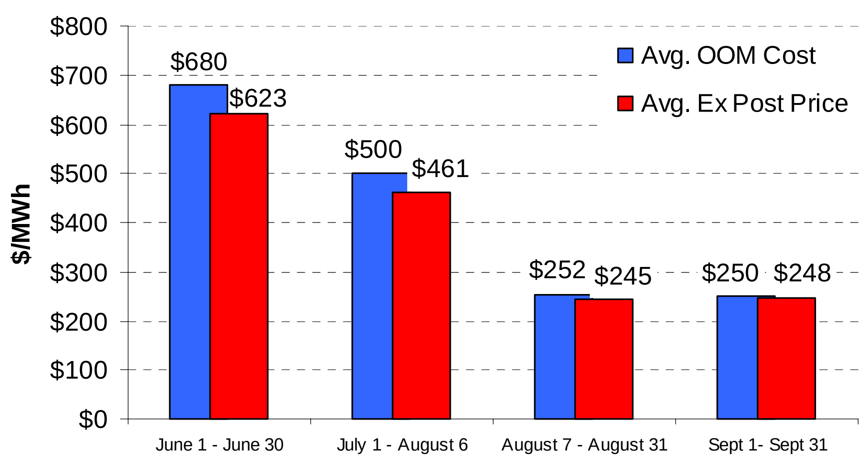


Figure 2. Comparison of Out-of-Market Purchase Costs to Real Time Prices



IV. Inter-zonal Congestion Management Markets

September had far less export congestion than August while import congestion increased on the Southwest branch groups. Path 26 N-S congestion decreased significantly while Path 15 S-N congestion increased substantially. The following table summarizes congestion rates and average congestion charges by branch group for the day-ahead market.

Day-Ahead Market – Congestion Summary for September 2000

	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	**Off peak**	**All Hours**	**Peak**	**Off peak**	**All Hours**
Path 15 (S-N)	30%	97%	52%	$21.76	$24.17	$23.25
Eldorado (Import)	3%	50%	19%	$24.78	$25.46	$25.39
NOB (Export)	7%	20%	12%	$21.48	$18.60	$19.78
Palo Verde (Import)	1%	32%	11%	$32.94	$18.11	$18.30
Path 15 (N-S)	10%		7%	$58.17		$58.17
Path 26 (N-S)	7%		5%	$56.94		$56.94
Sylmar (Import)	1%	3%	2%	$24.81	$47.60	$41.38
COI (Export)	1%		1%	$32.03		$32.03

- The Path 26 N-S congestion rate decreased to 5% in September compared to the 32% rate in August.. Day-ahead congestion charges ranged from $.62/MW to $102.51/MW and averaged $56.94/MW, lower than the August average of $73/MW. Total congestion costs on Path 26 totaled $4.64 million in September, a reduction from $40.2 million in August..

- Total Path 15 congestion increased from the 42% rate in August to a rate of 59% in September. Roughly 90% of the congested hours were in the S-N direction. Day-ahead congestion charges on Path 15 ranged from $.01/MW to $123/MW and averaged $27.20/MW, a decrease from the August average of $39.13/MW.

- Export congestion on COI fell from a rate of 17% in August to less than 1% in September. There was no import congestion on COI during the month. Export congestion NOB was also less than August levels, falling from a rate 17% to 12%. Import congestion on NOB was minimal (less than 1%) by comparison and September 1999 import congestion rates on COI and NOB were 46% and 6%, respectively, with no export congestion on either branch group.

- September import congestion on the southwest paths picked up significantly with Palo Verde and Eldorado experiencing congestion rates of 11% and 19%, respectively, up from the 1% and 3% rates experienced last month. There were no other SW branch groups with any significant day ahead congestion. Average congestion prices for Palo Verde and Eldorado were $18.30/MW and $25.39/MW, respectively.

- Total congestion costs for September were about $24 million, substantially less than the August 2000 total of $73 million, but 50% greater than September 1999's $16.73 million. Path 15 incurred the largest congestion costs with a total of $10.6 million while Path 26 dropped drastically to$4.6 million from the $38 million value for August 2000.

V. Performance of the FTR Market in September 2000

The observation of the FTR and Adjustment Bid markets in August 2000 indicate the following:

1. 70% of the FTRs released in the primary auction have now been assigned Scheduling Coordinators.
2. The use of FTRs for their scheduling priority has been relatively small. Thus far FTRs have been used mostly to hedge against transmission price uncertainties.
3. FTR ownership and control concentration on some paths is quite high. We are monitoring these paths closely for any unusual scheduling behavior during the high load periods.

VI. Issues Under Investigation

1. **Impact of 10-minute Settlement.** DMA is investigating the market impact of the 10-minute Dispatch and Settlement (10-MDS) implementation that has been in operation since September 1, 2000. The objectives of the 10-minute dispatch of the imports was to correct the "stuck price" phenomenon, the reduction of uninstructed deviations, and a consequent reduction of the Regulation requirements. The main concern with 10-MDS implementation was that it could result in a reduction of import participation in the real-time market. Except for the elimination of the stuck price problem, we believe it premature to draw conclusions on whether or not these objectives have been met or the concerns have proved valid. Preliminary summary results of this investigation will be presented at the October Board meeting.

2. **Investigations by External Agencies**. DMA continues to devote significant time to support seven on-going investigations from external agencies including the Federal Energy Regulatory Commission, California Public Utilities Commission, Electric Oversight Board, California State Attorneys, and General, California State Auditor General.

3. **System-wide Market Power**. DMA is designing and analyzing a variety of options for mitigation of system-wide market power. The current market structure has relied on price caps as the only available measure to mitigate market power. This has not been adequate to protect customers from the high cost of energy and the exercise of market power during tight supply conditions. Another measure of protection missing has been the contracting of loads at a fixed price so only small amounts of energy purchases would be subject to daily price fluctuations. Any mitigation measure must provide adequate protection to consumers while insuring proper price signal are available to stimulate the development of price responsive load programs, new generation and continued imports, all of which are critical for meet California's growing loads. Options being analyzed include:
   A) FERC/CPUC sanctioned forward contracts
   B) Resource -specific bid caps and availability requirements
   C) Payment cap with market power trigger
   D) ISO capacity payments
   E) PG&E's option combining A and B
   F) Load differentiated price caps
   G) Real-time price capped at PX price
   H) Other Options Suggested: Lower price caps to $100, Pay as bid

4. **Underscheduling.** DMA is formulating changes in market rules and financial incentives needed to improve the level of underscheduling seen in the forward markets by both generation and load. This has resulted in trading volume in the ISO real-time energy market of 15% to 25% of daily system loads when the imbalance market was designed to handle approximately 5% of system loads. These changes will be brought forward as part of the Comprehensive Market Redesign Package

5. **Adjustment Bid Caps.** The PX has requested the ISO review its price cap on adjustment bids of $250/MWh. The PX has identified the $250/MWh cap as a "major" contributing factor to underscheduling in its market. This is because the current cost allocation method for Deviation Replacement Reserve, offers a perceived de facto payment which is the sum of the ISO's price caps on the Replacement Reserve of $100/MWh and $250/MWh in the Real-time Energy markets, i.e., $350/MWh. The PX believes that if the cap on the ISO's Adjustment Bid market is raised to $350/MWh, the amount of under-scheduling in the PX market would decrease substantially since load could then bid at higher than $250/MWh without the risking the payment of a default usage charge. However, simply raising the adjustment bid cap would allow increased exercise of market power. The ISO and the PX are investigating the issue jointly. Both agree that the best solution is to correct the misalignment of the forward and real-time effective de facto caps by changing the Deviation Replacement Reserve cost allocation.