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: February 10, 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 January, 2000.

JANUARY HIGHLIGHTS

January was characterized by low ancillary service costs and low price volatility in the energy and ancillary services markets. Average PX energy prices were 49% higher than those in January 1999. The ISO real-time energy market prices were about 65% above January 1999 levels. The high energy prices were due to higher natural gas prices combined with less hydro generation and more thermal generation compared to January 1999. The highest energy prices experienced were $123.12/MWh in the ISO real-time market and $80/MWh in the PX energy market. Ancillary service costs as a percentage of total energy costs were 2% in January, up slightly from December. The highest price in the ancillary service markets was $168.20/MW in the day-ahead Spin market. Average ancillary service prices in the day-ahead market ranged from $13.07/MW for Regulation Down to $0.25/MW for Non-Spin Reserves. Congestion on Path 15 was at 40%, similar to December 1999 but down substantially from congestion levels experienced last fall. This resulted in small differences in zonal prices for the PX and ISO real-time energy markets.

KEY MARKET CONDITIONS FOR JANUARY 2000

<u>In the California Wholesale Energy Markets</u>

- January 2000 system energy loads totaled 18,983 GWh, a 2% decrease from December 1999 and a 6% increase over January 1999 loads. Daily peak loads averaged 30,829 MW, roughly 5% higher than January 1999 peak loads. The peak load for the month was 32,675 MW at HE 18 on January 4.

- Prices in the PX day-ahead market were about 6% higher than those in December 1999 while average real-time prices were virtually unchanged. The relatively low level of congestion on Path 15, compared to previous months, resulted in small differences between constrained prices in zones NP15 and SP15. The table below shows that average real-time energy prices were about 7% higher in NP15 than SP15, while constrained PX energy prices were only 4% higher in NP15 than SP15. The PX day-ahead market was split zonally due to congestion on Path 15 during 40% of the hours in the month, while the ISO's real-time market was split zonally for only 6% of the hours in January. This reflects differences in usage of day-ahead capacity and real-time capacity on existing transmission contracts and success in clearing congestion prior to real-time.

Energy Price Summary for January 2000

	System Average	NP15	SP15	Pct. Hours of Zonal Pricing
Real Time Price				
Peak	$ 34.63	$ 35.66	$ 33.61	5%
Off-Peak	$ 27.75	$ 28.81	$ 26.69	8%
Total	$ 32.34	$ 33.37	$ 31.30	6%
PX Constrained				
Peak	$ 33.41	$ 33.93	$ 32.88	40%
Off-Peak	$ 25.34	$ 26.29	$ 24.39	42%
Total	$ 30.72	$ 31.38	$ 30.05	40%

- Prices in the ISO's real-time energy markets were about 4% higher than the PX day-ahead energy market prices. The preceding table shows that ISO real-time prices in SP15 averaged $31.30/MWh compared to an average constrained PX price of $30.05/MWh. In NP15, ISO real-time prices averaged $33.37/MWh compared to an average constrained PX price of $31.38/MWh. The higher prices in the ISO Real-time market may be due, in part, to the ISO's continual need for incremental generation. In January the ISO needed to increment generation during 80% of hours with an average hourly increment of 670 MW.

- PX unconstrained energy prices for January 2000 were about 49% higher than in January 1999 while the average ISO real-time price was about 65% higher than the same month last year.

- Energy price volatility in both the ISO real-time and PX energy markets was very moderate. The real-time market had only six hours where prices exceeded $75/MWh, with a maximum price of $123.12/MWh for zone NP15 occurring at HE 12 on January 15, an hour where the real-time market was split zonally. Constrained PX energy prices exceeded $50/MWh for only six hours during the month. The maximum unconstrained PX energy price of $80/MWh occurred at HE 10 on January 13.

- The monthly price of natural gas (PG&E's Citygate hub) for January 2000 was $2.47/MMBtu compared to December's value of $2.52/MMBtu and the January 1999 value of $2.40/MMBtu. However, daily spot prices in January averaged 20% higher in January 2000 ($2.48/MMBtu) over January 1999 ($2.08/MMBtu). Higher spot market gas prices contributed to the higher energy prices in the PX and ISO markets compared to last year.

<u>In the Ancillary Service Markets</u>

Ancillary Service Prices

- The ISO continued to procure the bulk of A/S in the day-ahead market, with an average of about 81% to 92% of A/S being procured in the day-ahead market. The following table summarizes weighted average prices and procurements for January 2000 in both the day-ahead and hour-ahead markets.

	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	$ 9.21	$ 6.88	$ 8.93	533	73	88%
Regulation	$ 13.07	$ 11.21	$ 12.85	517	70	88%
Spin	$ 3.94	$ 1.16	$ 3.59	650	95	87%
Non-Spin	$ .25	$ .24	$ .25	742	65	92%
Replacement	$ .47	$ .24	$ .43	183	43	81%

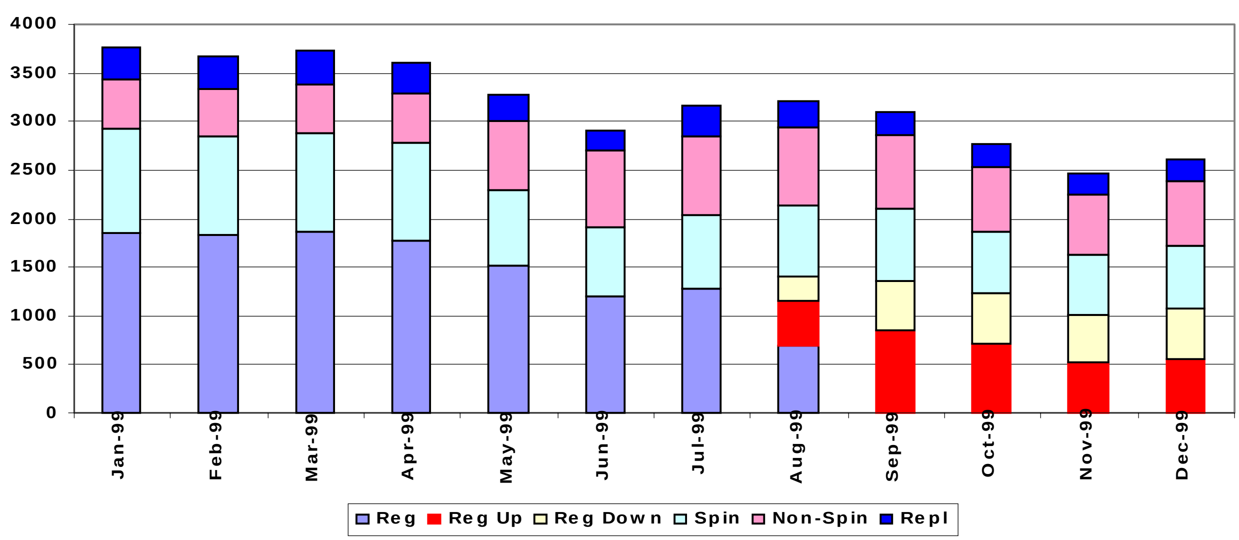
- The ISO's Ancillary Service markets had fewer hours of zonal procurement (due to less congestion on Path 15) in January compared to preceding months. As a result, differences in the average prices between zone NP15 and SP15 were small compared to the last few months. The following table compares weighted 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.

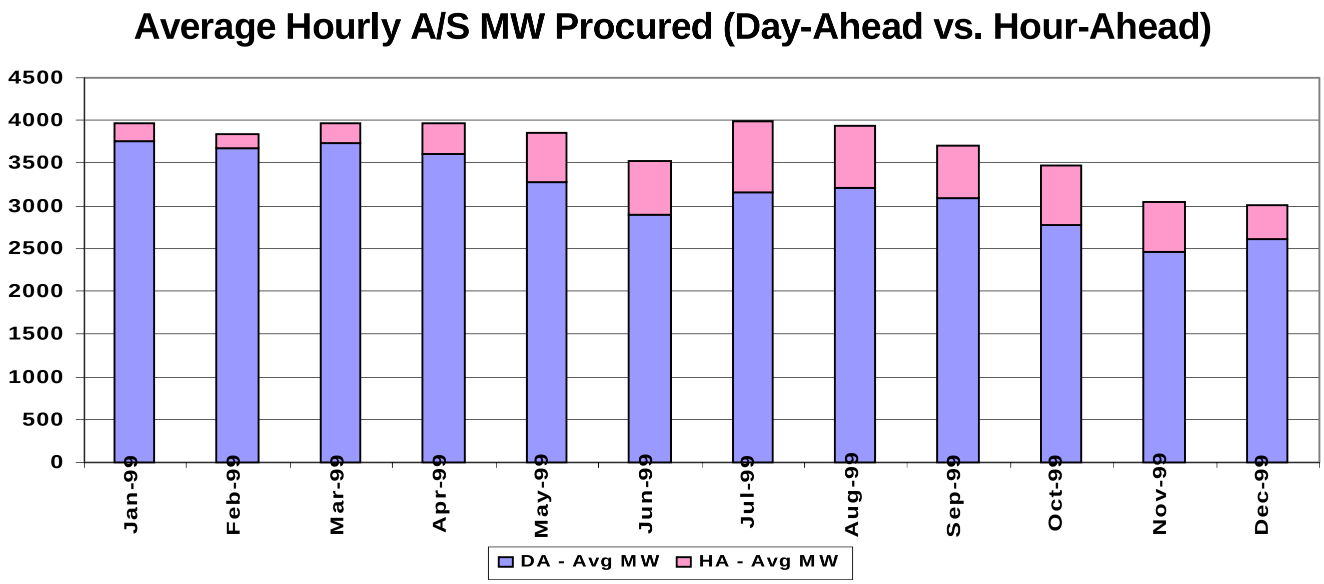
	NP15 Peak	Off Peak	SP15 Peak	Off Peak	Percent of Hours with Zonal Procurement
Regulation Up	$ 7.10	$ 9.43	$ 9.52	$ 12.44	23%
Regulation Down	$ 11.17	$ 19.66	$ 10.00	$ 18.82	3%
Spin	$ 1.37	$ 1.14	$ 19.83	$ 4.65	15%
Non-Spin	$ .27	$ .06	$ .38	$ .09	13%
Replacement	$ .37		$ .76	--	8%

- There were no hours where the $750 price cap was reached in any of the A/S markets during the month. The maximum price in any of the A/S markets was $168/MW in the day-ahead spinning reserve market for zone SP15. Other than this price, A/S prices did not exceed $80/MW in either the day-ahead or hour-ahead markets.

- In response to ISO Board Chairman Jan Smutny-Jones' request last month, DMA has provided the following charts to illustrate the relative quantities of Ancillary Services MW procured in 1999.

Average Hourly MW Procured - Day Ahead Market





Ancillary Service Costs

- A/S costs in January continued the trend of very low values compared to a year ago. Overall A/S costs were $11,840,000, or 2% of total energy costs.

Month	Avg. Daily A/S Cost* (Millions)	Avg A/S Cost per MWh of System Load ($/MWh)	A/S % of Energy Costs**
November	$ .720	$1.19	3.1%
December	$ .341	$ .55	1.8%
January	**$ .382**	**$ .62**	**2.0%**

* Includes day-ahead and hour-ahead procurement costs including self-provided MW (valued at MCP)
** Energy cost = actual hourly loads multiplied by the PX Day-ahead Unconstrained MCP.

Cost Savings From A/S Redesign Changes

The following table summarizes estimated savings from two key Ancillary Services Redesign measures: the Rational Buyer protocols and separate pricing for Upward and Downward Regulation. These two measures have resulted in estimated savings of about $41.5 million since their implementation on August 17. This represents savings of about 28% of total A/S costs during this time period. Significant direct savings continue to be realized from the application of the Rational Buyer protocols to bids submitted to the ISO by market participants. The savings from separate pricing of regulation should continue since the ISO was paying a single price for upward and downward regulation due to initial software constraints. However, these savings will decrease as the ISO procures less regulation service.

	Rational Buyer		Separate Pricing of Reg Up/Down	
	Savings	Pct. of Total A/S Costs	Savings	Pct. of Total A/S Costs
August *	$6,000,000	20%	$ 3,893,000	14%
September	$1,285,000	4%	$ 5,936,000	19%
October	$2,048,000	4%	$ 7,643,000	17%
November	$ 678,000	3%	$ 6,612,000	31%
December	$ 589,000	5%	$ 3,056,000	29%
January	$1,317,000	11%	$ 2,571,000	22%
Total	$11,815,000	8%	$29,714,000	20%

* Savings after implementation on August 17, 1999.

Inter-zonal Congestion Management Markets

- Path 15 had slightly lower congestion (S-N) in January than in December 1999. January congestion (S-N) existed for 40% of peak hours and 42% of off-peak hours as compared to December's congestion of 28% and 69%, respectively. Day-ahead congestion charges on Path 15 ranged from $.01/MW to $56.50/MW and averaged $3.29/MW, down slightly from the December value of $3.60/MW.

- Day-ahead congestion on the northwest paths was less in January than December. On COI, day-ahead congestion occurred for the import direction during 56% of peak hours and 17% of off-peak hours, compared to the December congestion rates of 56% and 40%, respectively. Average congestion charges on COI increased slightly from $2.54/MW in December to $2.61/MW in January. On NOB, the day-ahead congestion rate for all hours was 1%, down from the 4% congestion rate experienced in December.

- January congestion patterns on the southwest paths were generally higher compared to December. Palo Verde was congested for 30% of all hours in January, largely unchanged from the December rate of 31%. Eldorado's congestion increased to 23% compared to December's 13%. Average congestion prices were mixed, increasing for Palo Verde and decreasing for Eldorado. Average congestion prices for the two paths were $5.81/MW and $3.13/MW, respectively. December's average prices were $5.66/MW and $6.89/MW.

- For the first seven days of February, the day-ahead market congestion rates for COI, Path 15, and Path 26 were 29%, 21%, and 8%, respectively. These congestion rates are comparable to the rates experienced during the last week of January. Average congestion prices for COI, Path 15, and Path 26 were $2.25/MW, $4.16/MW, and $5.47/MW, respectively. There were no hours where congestion occurred simultaneously on both Path 15 and Path 26.

- There have been a total of three FTR transactions registered on the Secondary Registration System through the first week of February.

Day-Ahead Market – Congestion Summary for January 2000

	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	**Off peak**	**Total**	**Peak**	**Off peak**	**Total**
Path 15 (S-N)	40%	42%	40%	$2.65	$4.50	$ 3.29
COI (Import)	56%	17%	43%	$2.76	$1.59	$ 2.61
Palo Verde (Import)	32%	25%	30%	$5.66	$6.22	$ 5.81
NOB (Import)	1%	0%	1%	$21.18	N/A	$22.01
Eldorado (Import)	24%	22%	23%	$2.89	$3.67	$ 3.13
Mead (Import)	5%	0%	3%	$14.01	N/A	$14.01
IID-SCE (Import)	0%	1%	1%	N/A	$30.00	$30.00

ISSUES UNDER INVESTIGATION

1. **Analysis and Design of 10-minute Dispatch and Settlement.** DMA has provided input on the design of the major elements of 10-minute Dispatch and Settlement implementation to help ensure market efficiency, avoid differential treatment of suppliers within and outside the ISO Control Area and discourage gaming.

   We believe that uninstructed deviations (UID) are the primary cause of high Regulation Reserve costs and numerous real-time Imbalance Energy dispatch problems. We support the move to10-minute dispatch and settlement (10-MDS) as an effective remedy to align the economic incentives of the participants in the real-time market with the reliability and performance objectives of the real-time dispatch operators. We expect that 10-MDS would mean increased reliance on flexible resources (that can respond to 10-minute dispatch instruction), and less reliance on inflexible resources in the real-time market. We do not believe that this would necessarily lead to real-time supply shortage and higher real-time prices. The inflexible resources could shift their participation to the forward markets. This would help reduce the amount of demand that appears unscheduled in the real-time market. Alternatively, such resources could internalize the risk of 10-minute dispatch (uninstructed rather than instructed energy price, or possibly "no-pay") in their bids. The fact that flexible resources will have incentives to follow their schedules will reduce real-time balancing of energy demand, and thus reduce real-time prices.

   We are concerned, however, with the design of two elements of the proposed 10-MDS implementation: the Residual Imbalance Energy (RIE) and Netting of Deviations. Of these two elements, the Residual Imbalance Energy is the more significant concern. It represents a departure from ISO design of independent hours (RIE creates links across hours by carrying prices forward from one hour to the next). It also provides for differential treatment of out-of-state and in-state resources (RIE will only apply to in-state resources). We believe that the market impacts and complexity of RIE will outweigh its benefits and that it will generally weaken 10-MDS. A preferable approach would be to let the market internalize any perceived penalty in their bids and to treat deviations from schedules, whether due to instructions or uninstructed, as uninstructed deviation. To do otherwise introduces complexity beyond its value in terms of billing and settlements.

   We also believe that netting the UID across an SC's portfolio can exacerbate real-time congestion and, at best, provides little or no real benefit to market participants. SCs wishing to follow their load may do so by bidding their generation into the real-time market. If they are selected in BEEP, they earn the market price; if they are not selected, their load is served at a price below their own bids, so they are better off. This is a more efficient market outcome than would be achieved by netting the uninstructed deviations. We recommend settling UID at the resource-specific level rather than netting within each SC's zonal portfolio in order to reduce intra-zonal congestion.

2. **Assessment of workable competitiveness.** DMA is refining its methodology for market power analysis. We plan to use this methodology in the March 2000 report to the ISO Governing Board on price caps. This report will recount progress made on four components of a August 26, 1999 Board resolution requiring information regarding: 1) whether the ISO's markets workably competitive; 2) whether practicable demand side management options in place; 3) whether the IOUs sought options to self-provide A/S; and 4) whether hedging instruments are available in the PX. DMA is studying the relevant market conditions, and the development of demand responsiveness programs and hedging instruments in order to provide a status report to the Board in March as it decides price cap policy for the summer of 2000.

3. **Congestion Management Reform and Redesign.** DMA will participate in developing interim and long-term solutions to congestion management in response to FERC's order of January 7, 2000 on Amendment 23. DMA helped put together the request for Clarification/Rehearing filed on February 7, 2000. We will participate actively in the stakeholder process for the redesign of ISO's congestion management system and are supporting the MSC's input on possible redesign options.

4. **New Path ZP26 and FTR Market Monitoring.** DMA continues to develop the FTR Market Monitoring System (MMS) that tracks significant market indicators as the FTR market evolves. The design of the FTR MMS allows the tracking of a number of indices. Our preliminary observations show that FTRs are being used primarily as financial instruments. Only a small portion of the FTRs auctioned have been used for scheduling priority: on the average, about 25% on COI, 12% on Palo Verde, 6% on Eldorado, and 2% on Mead. This is encouraging as it shows a high participation in, and reliance on, the adjustment bid market. We will be tracking the pattern of FTR utilization for scheduling purposes.

   Congestion management of Path 26 seems to have relieved some of the congestion that would otherwise appear on Path 15. There have been no instances of simultaneous congestion on Path 15 and Path 26. This is consistent with our expectation that despite the creation of the new ZP26 zone, in any given hour there will be at most two price zones in the day-ahead market. Either Path 15 or Path 26 will be the boundary between the northern and southern part of the control area.

5. **Analysis of the Impact of Inter-zonal Congestion.** The Transmission Access Charge project has asked DMA to analyze the economic impact of inter-zonal congestion. Our objective is to determine the impact of unscheduled ETC capacity on the forward congestion management and energy markets. For the hours where forward market congestion has occurred, we will determine the amount of ETC capacity reserved in the forward markets, but unused in real-time for the corresponding inter-zonal interface(s). This will then be used to determine the reduction in congestion management and energy costs that would have occurred had the unused ETC capacity been released in the forward market.