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: March 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 February, 2000.

FEBRUARY HIGHLIGHTS

February's average PX energy prices were 58% higher than those a year ago. ISO real-time energy market prices were about 53% above February 1999 levels. The higher energy prices may be attributable to a combination of higher loads, less hydro generation, and higher natural gas prices. Energy prices eased while congestion lessened significantly in the second half of February as increased hydro generation entered the market.

Ancillary service prices were very moderate throughout the month with a maximum price of $200/MW in the hour-ahead replacement reserve market. Ancillary service costs as a percentage of total energy costs were 1.9% in February, slightly lower than January and down substantially from a year ago.

The congestion rate on Path 15 was 13%, down from 40% in January. Path 26 experienced only 6% congestion, mostly in the N-S direction. The lack of congestion on these paths resulted in small differences between zonal prices for both the PX and ISO real-time energy markets. Roughly 80% of February's congestion costs occurred during the first half of the month.

Zone ZP26 and the ISO's FTR market started operation on February 1, 2000. There were very few transactions in the secondary FTR market for February.

KEY MARKET CONDITIONS FOR FEBRURARY 2000

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

- **Loads -** February 2000 system energy loads totaled 17,807 GWh, a 6% decrease from January 2000 and a 9.4% increase over February 1999 loads. Average daily energy in February 2000 was 0.2% higher than January 2000 and 5.6% above February 1999. Daily peak loads averaged 30,361 MW, 4.5% higher than average daily February 1999 peak loads. The peak load for the month was 32,071 MW at HE 19 on February 22.

- **Wholesale Energy Prices -** Prices in February, particularly in the ISO real time market, fluctuated in a narrow range between peak and off-peak averages. Table 1 below shows very little difference between peak and off-peak period prices in the real-time market. PX prices showed substantially less peak/off-peak variation than in previous months. NP15 average real-time energy prices were about 2% higher than SP15.Constrained PX energy prices were only slightly higher in NP15 than SP15. The PX day-ahead market was split zonally due to congestion on Path 15/Path 26 during 19% of the hours in the month. The ISO's real-time market was split zonally for only 3% of the hours in February. This is due to differences in usage of day-ahead capacity and real-time capacity on existing transmission contracts and success in clearing congestion prior to real-time.

Table 1: Energy Price Summary for February 2000

	System Average	NP15	SP15	Pct. Hours of Zonal Pricing
Real Time Price				
Peak	$29.18	$29.40	$28.95	2.4%
Off-Peak	$28.61	$28.98	$28.25	3.0%
Total	$28.99	$29.26	$28.72	2.6%
PX Constrained				
Peak	$31.85	$31.76	$32.09	19.4%
Off-Peak	$25.85	$26.38	$25.61	18.5%
Total	$29.85	$29.97	$29.93	19.1%

- PX unconstrained energy prices for February 2000 were about 56% higher than in February 1999. The average ISO real-time price was about 53% higher than the same month last year. Most of this difference is due to the change in generation sources as well as increases in natural gas prices. Table 2 shows the average total load (measured as Final Hour-Ahead Schedules) in February 2000 exceeded those in February 1999 by about 5%. At the same time, total generation scheduled from hydro decreased by a total of about 1,850 MW, or about 7% of total average Hour-Ahead Schedules. This required increases in generation scheduled from thermal units of about 40% compared to February 1999.

Table 2: Generation Sources – February 1999 and 2000

	Average Hourly MW*		Difference	
Generation Source	**Feb-1999**	**Feb-2000**	**MW**	**Percent**
Hydro	3,906	2,059	-1,846	-47%
Nuclear/Coal	3,711	5,591	+1,880	+51%
Other Reg. Must-Take/Must Run	4,970	4,142	- 828	-17%
Other Thermal	4,407	6,171	+1,765	+40%
Imports	8,084	8,299	+ 215	+ 3%
Exports	-1,403	-1,404	- 1	+ 0%
Totals	23,675	24,858	+1,183	+ 5%

- Improved snow pack and stream-flow conditions in late February led to a doubling of hydro generation over the course of the month. However, late February hydro generation levels were still 25% below February 1999 levels.

- **Price Volatility -** Energy price volatility in both the ISO real-time and PX energy markets was moderate. The real-time market had only nine hours where prices exceeded $50/MWh, with a maximum price of $74.32/MWh occurring at HE 18 on February 2. Constrained PX energy prices exceeded $50/MWh for only one hour during the month. The maximum unconstrained PX energy price of $59.99/MWh occurred for zone SP15 at HE 7 on February 3.

- **Natural Gas Prices** - Monthly natural gas prices (PG&E's Citygate hub) for February 2000 were $2.61/MMBtu compared to the January 2000 price of $2.47/MMBtu and the February 1999 value of $2.04/MMBtu. However, daily spot prices were, on average, about 40% higher in February 2000 ($2.71/MMBtu) compared to February 1999 ($1.94/MMBtu). Higher spot market gas prices contributed to the higher energy prices in the PX and ISO markets compared to last February.

In the Ancillary Service Markets

Ancillary Service Prices

- The ISO continued to procure the bulk of A/S in the day-ahead market, with between 69% to 89% of A/S MW quantities being procured in the day-ahead market. The following table summarizes weighted average prices and procurements for February 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	$ 8.89	$ 9.34	$ 8.97	495	100	83%
Regulation	$10.60	$11.70	$10.77	490	86	85%
Spin	$ 2.00	$ 8.07	$ 2.81	625	96	87%
Non-Spin	$ .78	$ 1.99	$ .91	645	81	89%
Replacement	$ 1.28	$ 4.84	$ 2.39	211	96	69%

- The ISO's Ancillary Service markets had fewer hours of zonal procurement (due to less congestion on Path 15/Path 26) in February compared to preceding months. As a result, differences in the average prices between zone NP15 and SP15 were small. 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 (day ahead & hour ahead combined).

Summary of A/S Markets by Zone – February 2000

	NP15		SP15		Percent of Hours with
	Peak	**Off Peak**	**Peak**	**Off Peak**	**Zonal Procurement**
Regulation Up	$ 8.46	$ 10.24	$ 7.66	$11.86	5.4%
Regulation Down	$10.89	$ 13.57	$ 8.67	$14.01	5.3%
Spin	$ 1.44	$ 1.07	$ 7.12	$ 1.13	7.8%
Non-Spin	$ .53	$ .10	$ 1.88	$ .25	7.6%
Replacement	$ 1.03		$ 1.82		1.9%

- The $750 price cap was not reached in any of the A/S markets during the month. The maximum price in any of the A/S markets was $200/MW in the hour-ahead replacement reserve market for zone SP15. In the day-ahead market, the maximum price was $122/MW in the replacement reserve market. Other than this single occurrence, A/S prices did not exceed $70/MW in the day-ahead market.

Ancillary Service Costs

- A/S costs in February continued to be low compared to a year ago. Overall A/S costs were $10,410,734 or 1.9% 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**
December	$ .341	$ .55	1.8%
January	$ .382	$ .62	2.0%
February	**$ .359**	**$ .58**	**1.9%**

* 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 the separate pricing for Upward and Downward Regulation. These two measures have resulted in estimated savings of about $43.2 million since their implementation on August 17, 1999. This is a 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.

A/S Redesign Savings

	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%
February	$ 295,000	3%	$ 1,239,000	12%
Total	$12,212,000	8%	$30,952,000	20%

* Savings after implementation on August 17, 1999.

Inter-zonal Congestion Management Markets

- February congestion markets had significantly lower congestion in the latter half of the month as energy prices declined. Roughly 80% of February's congestion costs occurred during the first half of the month.

Day-Ahead Market – Congestion Summary for February 2000

	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	**Off peak**	**All Hours**	**Peak**	**Off peak**	**All Hours**
COI (Import)	34%	6%	24%	$ 2.99	$ .23	$ 2.77
Palo Verde (Import)	13%	27%	18%	$ 2.02	$ 6.28	$ 4.22
Eldorado (Import)	14%	16%	15%	$12.49	$ 5.80	$10.07
Path 15 (S-N)	11%	16%	13%	$ .64	$ 5.29	$ 2.54
Path 26 (N-S)	8%	2%	6%	$ 4.90	$ 2.82	$ 4.66
Path 26 (S-N)	0%	1%	1%		$ .80	$ .80

- Path 15 had significantly lower congestion (S-N) in February than in January, 2000. Congestion (S-N) occurred for 11% of peak hours and 16% of off-peak hours compared to January's congestion rates of 40% and 42%, respectively. Day-ahead congestion charges on Path 15 ranged from $.01/MW to $22.99/MW and averaged $2.54/MW, down from the January value of $3.29/MW.

- Part of the reduction in Path 15 congestion could be due to congestion mitigation on Path 26. Path 26 experienced a congestion rate of 6% for the month with most of the congestion in the N-S direction.

- Overall day-ahead congestion on the northwest paths decreased in February compared to January. On COI, day-ahead congestion occurred for the import direction during 34% of peak hours and 6% of off-peak hours, compared to the January congestion rates of 56% and 17%, respectively. However, congestion rates on NOB averaged 9% for peak and 0% for off-peak hours, respectively, compared to January 2000 rates of 1%

and 0%, respectively. Average congestion charges on COI increased slightly from $2.61/MW in January to $2.77/MW in February.

- February congestion on the southwest paths was lower compared to January. Palo Verde was congested in the import direction for 18% of all hours in February, down from the January rate of 30%. Eldorado's congestion rate (import) decreased to 15% compared to January's 23%. Average congestion prices increased for Eldorado and decreased for Palo Verde. February's average congestion prices for the two paths were $10.07/MW and $4.22/MW, respectively, compared to January's average prices of $3.13/MW and $5.81/MW, respectively.

Performance of the FTR Market in February 2000

The primary FTR auction was conducted on November 17 and 18, 1999. The FTRs were auctioned for the period February 1, 2000 through March 31, 2001 on nineteen paths. In total, 9,553 MWs of FTRs (at 99.5% annual availability) were sold for total amount of $40.8 million, i.e., 8% higher than the target price (normalized for 14 months). Payments were $33 million for FTRs to import into the control area, $6 million across Path26 and the remaining $1.8 million for exports.

The DMA has set up a system to monitor the FTR market and Adjustment Bid markets and report periodically regarding the performance of the FTR market and its impact on the other ISO markets. The areas of primary interest in tracking the performance and impact of FTR markets are: 1.) Secondary FTR market activity 2.) FTR Concentration, and 3.) Scheduling of FTR's.

We will conduct comparative analysis of the ISO markets before and after the release of FTRs, in terms of:

- Congestion patterns (congestion frequency, magnitude, price, and cost)
- Market efficiency (depth of the Adjustment Bid market, phantom congestion, market power and gaming)
- Reliability (shifting congestion to the real-time market)

Secondary Market Activity

The secondary FTR market has had little activity since its start on December 13, 1999. Only 4 transactions have taken place. They are summarized in the following table.

Seller	Buyer	Branch Group	From	To	Start Date	End Date	Hours	MW	Price ($)	Price/MCP Ratio
IPC1	AZUA	PV	AZ3	SP15	2/1/00	2/29/00	Peak	10	$5,800	2.19
PETP	PGES	COI	NW1	NP15	2/1/00	3/31/01	All	19	$598,500	1.00
PETP	PGES	COI	NW1	NP15	7/1/00	3/31/01	All	31	$795,038	1.26
PGES	PETP	COI	NW1	NP15	2/1/00	6/30/00	All	12	$93,499	0.70

Legend: IPC1 = Idaho Power Company
AZUA = City of Azusa
PETP = PG&E Energy Trading Power
PGES = PG&E Energy Services
MCP = Primary Auction Market Clearing Price

We expect to see increased activity in the secondary FTR market as we approach the peak summer season.

FTR Concentration

The following Table summarizes FTR ownership and control concentration as of the end of February 2000.

Branch Group	CFE IMP	COI IMP	ELD IMP	IID-SCE IMP	MEAD IMP	NOB IMP	PV IMP	P26 S-N	Silvpk IMP	VictVl IMP
FTR MW Auctioned	408	422	694	600	366	347	1,650	127	10	386
Max Single Ownership Concentration	47%	27%	59%	77%	64%	68%	37%	61%	90%	68%
FTR MW with SC Assignment	217	287	194	25	35	110	661	127	0	125
% FTR with SC Assignment	53%	68%	28%	4%	10%	32%	40%	100%	0%	32%
Max Single SC Concentration	25%	27%	13%	4%	7%	11%	13%	61%	0%	26%

Branch Group	CFE EXP	COI EXP	ELD EXP	IID-SCE EXP	MEAD EXP	NOB EXP	PV EXP	P26 N-S	Silvpk EXP	VictVl EXP	Total
FTR MW Auctioned	408	33	615	-	380	442	852	1,621	10	182	9,553
Max Single Ownership Concentration	43%	76%	49%	-	67%	43%	51%	62%	100%	50%	29%
FTR MW with SC Assignment	150	8	50	-	25	100	100	328	10	116	2,668
% FTR with SC Assignment	37%	24%	8%	-	7%	23%	12%	20%	100%	64%	28%
Max Single SC Concentration	25%	24%	8%	-	7%	11%	6%	19%	100%	50%	-

The table contains FTR data for both import (S-N for Path 26) and export data (N-S for Path 26) by branch group. The table lists the MW amount auctioned for each path for each direction followed by the maximum ownership share by any of the FTR holder and its affiliates. The next line is the amount of FTRs assigned to a scheduling coordinator and the following line is the value in percentage terms. The last line is the maximum percentage of FTRs controlled by any schedule coordinator for a given branch group.

These tables show high ownership concentration on several important interfaces. The table also shows that a relatively small percentage of the FTRs have been assigned Scheduling Coordinators. This is partly because the PX participants owning FTRs have not officially assigned the PX as the SC for their FTRs since the PX has not yet started its FTR scheduling system.

The FTR ownership concentration coupled with scheduling ability will be monitored to address potential concerns regarding gaming and possible exercise of market power. This experience will be key input in recommending higher rates of release of FTRs. The DMA will also monitor the scheduling activities of entities with FTRs in the directions inconsistent with the location of their resources within the ISO control area, or in amounts exceeding their historical scheduling needs.

FTR Scheduling

The use of FTRs for their scheduling priority is of particular interest. Thus far, the FTRs have been primarily used for their financial entitlement to hedge against transmission usage charges. Scheduling priority has been invoked only on four paths.

Branch Group	COI Import	ELD Import	MEAD Import	PV Import	Total
MW FTR Auctioned	408	694	366	1,650	9,553
Avg. MW FTR Scheduled	92	44	7.5	165	309
Percent FTR Scheduled	22%	6.3%	2.1%	10%	3.2%
Max MW FTR Scheduled	172	50	10	310	-
Max Single SC FTR	100	50	10	207	-

As the peak summer season approaches, the use of FTRs for their scheduling priority may increase.

Congestion Patterns

The DMA monitors and reports congestion frequency, magnitude, and price. We also monitor cumulative congestion revenues, as well as cumulative average congestion revenues per MW of New Firm Use capacity (NFU, i.e., Total Transfer Capability less ETC reservation) and compare them with corresponding figures in 1999. The following table is a summary comparison.

	Congestion Revenue ($)		Cumulative Revenue ($/MW ATC)	
	February 1999	February 2000	February 1999	February 2000
COI (IMP)	$1,070,474	$728,890	$859	$475
Eldorado (IMP)	$304,536	$839,737	$202	$585
Palo Verde (IMP)	$979,565	$919,976	$526	$472
NOB (IMP)	$114,735	$40,367	$69	$27
Path 26 (N-S)		$375,642		$178

The fact that the FTR market and the new ZP26 both started on February 1, 2000 makes it rather difficult to separate their relative impact on the congestion patterns on various interfaces, particularly, Path 15, COI, Palo Verde, and Eldorado. However, the analysis of the Adjustment Bid market (described next) may help identify the impact of FTRs on the congestion management market.

Adjustment Bid Markets

DMA will monitor the depth of the Adjustment Bid market, and several other related indicators to ensure that a healthy equilibrium develops between the FTR market and the Adjustment Bid market .

The indices used to track the impact on the Adjustment Bid market are based on the demand for transmission capacity (Transmission Demand Curve (TDC)). These indices will be compared for the periods before and after the start of FTR the markets. With the low level of FTR scheduling thus far, the impact of FTRs on the Adjustment Bid market is not yet noticeable.

The following table summarizes the performance of the Adjustment Bid market based on simulation runs for the period February 1-17, 2000, using the congestion management software (CONG) in the study mode. Simulation runs for the rest of February are underway. Simulation runs are conducted only for the paths and the hours with day-ahead congestion.

The simulation runs for each path and hour produce a Transmission Demand Curve (TDC) which is used in the DMA Market Monitoring System to generate certain indices to measure the depth and related attributes of the Adjustment Bid market. The TDC for a path in a given hour shows the variation in the transmission usage charge as a function of the available MW capacity.

Adjustment Bid Market Performance Indicators (February 1-17, 2000)

Path /Direction		MCR (MW)		Adjustment Bid Sufficiency (%)		Price Sensitivity ($/MWh change per 100 MW)	
		Avg.	Min	Avg.	Min.	Avg.	Max
COI	Import	1,432	939	1493%	207%	2.02	3.32
ELDORADO	Import	1,293	798	2551%	194%	2.53	4.16
MEAD	Import	363	299	6143%	521%	7.99	8.56
NOB	Import	1,232	344	1313%	131%	1.83	9.71
PALOVRDE	Import	977	529	1104%	203%	3.76	16.10
PATH15	S-N	1,624	521	1282%	257%	0.86	1.51
PATH26	S-N	432	420	671%	567%	0.10	1.08
PATH26	N-S	1,193	426	9652%	135%	5.87	15.11

Explanation:

MCR = Manageable Congestion Range is the depth of the Adjustment Bid market in MW with economic bids on both sides of the path taking into account market separation constraint.

Adjustment Bid Sufficiency Index (expressed as %) is the ratio of MCR to the curtailed demand for transmission on the path

Price Sensitivity = The change in the usage charge for 100 MW change in transmission demand

A large MCR MW value or adjustment bid sufficiency alone does not necessarily indicate competitive bidding behavior. Very high Adjustment Bids ($750) could indicate strategic bidding. The transmission price sensitivity (100* slope of the transmission demand curve over the manageable congestion range) indicates the change in the usage charge for 100 MW increase in the preferred schedule (or reduction of the ATC) on the path. A comfort level for DMA at this time is an average price sensitivity below $5/MWh per 100 MW schedule change. This is based on the historical observation that the demand price sensitivity in the forward competitive unconstrained energy market (PX day-ahead market) at high load levels (above 30,000 MW) is in the range of $3/MWh to $5/MWh per 100 MW increase in demand.

We will develop a baseline for all above indices based on the historical levels for similar months for the period February 1, 1999 through January 31, 2000 (when no FTRs were scheduled).

ISSUES UNDER INVESTIGATION

1. **Assessment of workable competitiveness.** DMA provided an assessment of whether the structural features of the California electricity markets promote workable competition. Such an assessment is needed at this time to assist the ISO Governing Board in determining the appropriate level of price caps in the ISO markets for Summer 2000, in accordance with the Board's August 1999 resolution on price caps. The results of this analysis are reported to the Board under a separate tab. The report summarizes progress made on four components of the August 26, 1999 Board resolution requiring information regarding: 1) whether the ISO's markets are workably competitive; 2) whether practicable demand side management options are in place; 3) whether the IOUs sought options to self-provide A/S; and 4) whether hedging instruments are available in the PX. The report also identifies potential options to price caps a part of a long term policy on price caps given Board authority from FERC on price caps expires on November 15, 2000.

2. **Congestion Management Reform and Redesign.** DMA is actively participating in the stakeholder process on Congestion Redesign addressing the interim and long-term solutions to congestion management in response to FERC's order of February 7, 2000 on Amendment 23. DMA has developed the list key questions on market design which need to be addressed in each redesign proposal. These key questions will allow each redesign proposal to be better understood and provide a basis to compare and evaluate each proposal.

3. **FTR Market Monitoring.** DMA continues to enhance the FTR Market Monitoring System (MMS) to track significant market indicators as the FTR market evolves. The design of the FTR MMS allows tracking of a number of indices including the FTR market activity, FTR ownership and control concentration, FTR scheduling, impact of FTRs on the Adjustment Bid market, possible phantom scheduling, and congestion magnitude, cost and frequency. Our preliminary observations show that FTRs are being used primarily as financial instruments (at least initially), indicating a tendency for a high participation in, and reliance on, the adjustment bid market.

4. **PG&E Hydro Divestiture.** The DMA provided testimony to the California Public Utilities Commission on market power mitigation measures related to PG&E's proposed auction of its hydroelectric generating resources. The DMA identified market power mitigation measures that should be incorporated into the auction process to ensure a competitive outcome.

5. **RMR Designation Process for Year 2001**. The DMA is working with the ISO Transmission Planning staff to incorporate considerations about the amount of market energy that may be relied upon with a high level of certainty into the RMR designation process. This proposed methodology is being tested on a limited basis in those areas that placing some reliance on energy likely to be scheduled in the market with a high level of confidence may allow a reduction in RMR designation requirements. DMA is focusing on the extent to which reliance on market energy may allow reduction in capacity under RMR designation while still providing effective mitigation of local market power in the intra-zonal congestion management market. Results of this effort will be presented and discussed with stakeholders at the March 9 LARS meeting.

6. **Amendment 26 Filing (RMR Pre-dispatch and Scheduling in Day Ahead Market).** The DMA provided input to the ISO's response to comments from parties on the ISO filing of Amendment 26. This would modify the tariff to allow for pre-dispatch of RMR requirements prior to the Day Ahead market and ensure that RMR energy being provided under the RMR contract is scheduled in the Day Ahead PX market.